WEST VIRGINIA SECRETARY OF STATE

MAC WARNER

ADMINISTRATIVE LAW DIVISION

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Office of West Virginia
Secretary Of State

NOTICE OF PUBLIC COMMENT PERIOD

AGENCY: Air Quality

TITLE-SERIES: 45-44

RULE TYPE: Legislative Amendment to Existing Rule: No Repeal of existing rule: No

RULE NAME: Control of Greenhouse Gas Emissions from Existing Coal-Fired Electric Utility Generating Units

CITE STATUTORY AUTHORITY: W. Va. Code §§ 22-5-4 and 22-5-20

COMMENTS LIMITED TO:

Oral and Written

DATE OF PUBLIC HEARING: 07/28/2020 6:00 PM

LOCATION OF PUBLIC HEARING:

Virtual. Details in Public Notice

DATE WRITTEN COMMENT PERIOD ENDS: 07/28/2020 6:00 PM

COMMENTS MAY BE MAILED OR EMAILED TO:

NAME: SANDRA ADKINS

ADDRESS: WVDEP - DIVISION OF AIR QUALITY

601 57TH STREET SE CHARLESTON WV 25304

EMAIL: dep.comments@wv.gov

PLEASE INDICATE IF THIS FILING INCLUDES:

RELEVANT FEDERAL STATUTES OR REGULATIONS: Yes

(IF YES, PLEASE UPLOAD IN THE SUPPORTING DOCUMENTS FIELD)

INCORPORATED BY REFERENCE: No

(IF YES, PLEASE UPLOAD IN THE SUPPORTING DOCUMENTS FIELD)

PROVIDE A BRIEF SUMMARY OF THE CONTENT OF THE RULE:

This rule implements the federal emission guidelines established at 40 C.F.R. part 60, subpart UUUUa, commonly referred to as the Affordable Clean Energy (ACE) rule, in accordance with 40 C.F.R. part 60, subpart Ba. The federal emission guidelines establish the best systems of emission reduction (BSER) which, in the judgment of the U.S. EPA Administrator, have been adequately demonstrated and provide information on the degree of emission limitation achievable for the designated pollutant. The federal emission guidelines are heat rate improvements which target achieving lower carbon dioxide emission rates at designated facilities. The federal emission guidelines were developed pursuant to section 111(d) of the federal Clean Air Act, as amended.

This rule will regulate greenhouse gas emissions, in the form of carbon dioxide, from existing coal-fired electric generating units that commenced construction on or before January 8, 2014 that meet the definition of a designated facility. This rule establishes applicability criteria, permit application requirements, permit requirements, standards of performance requirements, and monitoring, recordkeeping and reporting requirements for designated facilities to control carbon dioxide emission rates based on the heat rate improvements analysis that can be applied to or at the affected steam generating unit.

SUMMARIZE IN A CLEAR AND CONCISE MANNER CONTENTS OF CHANGES IN THE RULE AND A STATEMENT OF CIRCUMSTANCES REQUIRING THE RULE:

Summary of changes in the rule:

This is a new rule.

Statement of circumstances requiring the rule:

West Virginia is required to submit a State Plan to the U.S. EPA that implements the emission guidelines contained in 40 C.F.R. 60, subpart UUUUa (Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units), commonly referred to as the Affordable Clean Energy (ACE) rule. This proposed rule will codify the implementation of these emission guidelines. Furthermore, Senate Bill 810 passed by the West Virginia Legislature in the 2020 Regular Session amended W. Va. Code § 22-5-20 and requires the DEP to propose a legislative rule to implement the ACE rule, consisting of the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (EGUs) in time for consideration during the 2021 legislative session.

This rule is exempt from the Regulatory Moratorium under Executive Order 2-18 under condition 3(f), implementing a federal mandate and no waiver is permitted.

Determination of Stringency:

The federal emission guidelines are adopted into this proposed rule. The proposed rule is no more stringent than the federal emission guidelines for existing sources.

Consultation with the Environmental Protection Advisory Council:

The Environmental Protection Advisory Council received a copy of this proposed rule in advance of the June 23 meeting to discuss this rule.

SUMMARIZE IN A CLEAR AND CONCISE MANNER THE OVERALL ECONOMIC IMPACT OF THE PROPOSED RULE:

A. ECONOMIC IMPACT ON REVENUES OF STATE GOVERNMENT:

Refer to Section B (Economic impact of the rule on special revenue accounts) below.

B. ECONOMIC IMPACT ON SPECIAL REVENUE ACCOUNTS:

The Division of Air Quality has special revenue accounts. This rule regulates carbon dioxide emissions from large coal-fired electric generating units (EGUs) that have a base load rating greater than two hundred fifty (250) MMBtu per hour heat input of coal (alone or in combination with any other fuel) and serves a generator connected to a utility power distribution system capable of selling greater than twenty-five (25) MW of electricity. The Division of Air Quality identified nine (9) sources that meet the applicability criteria.

The impact on state government revenues will be limited to a permit application for each coal fired power plant subject to this rule. Currently, there are nine (9) sources that will be required to submit a permit application at the base cost of $1,000 per permit for a total of $9,000 in revenues. The permit application fees should be received in the 2022 fiscal year. Carbon dioxide emissions are not included in the Title V operating fee calculation, so there will be no change from that revenue stream. Permit application fees are typically a one-time fee, unless there is a need to modify the permit. Given the small number of permit applications required by this rule, the number is within the yearly variability of permit applications and thus, is not identified as an increase in revenues in the fiscal note table below.

C. ECONOMIC IMPACT OF THE RULE ON THE STATE OR ITS RESIDENTS:

This rule will establish the process to determine case-by-case standards of performance for each of the affected steam generating units, consistent with the federal emission guidelines. This rule does not require specific technology to be installed for compliance. The case-by-case heat rate improvement analysis will evaluate the specified candidate technologies for technical and financial feasibility, with consideration given to any non-air quality health and environmental impacts.

The Division of Air Quality does not intend to add additional personnel to implement or to enforce this rule beyond current staffing levels.

The greatest potential economic impact on sources could be the design, installation, and operation of any efficiency-improving technology to comply with the established carbon dioxide emission rate standard. This rule requires each source submit a permit application with a recommendation for the standard of performance based on results from their heat rate improvement analysis. This rule does not require that any specific technology be installed. The WV coal-fired power plant fleet is one of the most efficient in the country and many of the technologies may have already been implemented by the EGUs. EGUs that operate with lower heat rates are more competitive; therefore, cost effective heat rate improvement projects should not create an economic burden on the sources because they could save money and potentially offset capital costs to implement the project.

The U.S. EPA provided a cost range table in the federal regulation to represent both the capital and operations & maintenance cost for each candidate technology that must be reviewed in the heat rate improvement analysis. The information below was pulled from Table 2 (Summary of Cost ($2016/kW) of HRI Measures) of 84 Fed. Reg. 32542 [July 8, 2019].

The minimum and maximum cost range in units of $2016/kW for each HRI technology is provided below.

Neural Network/ Intelligent Sootblowers -
For EGUs less than 200 MW in size, the minimum and maximum cost is $4.7;
For EGUs between 200 - 500 MW in size, the minimum and maximum cost is $2.5; and
For EGUs greater than 500 MW in size, the minimum and maximum cost is $1.4.

Boiler Feed Pumps -
For EGUs less than 200 MW in size, the minimum cost is $1.4, and the maximum cost is $2.0;
For EGUs between 200 - 500 MW in size, the minimum cost is $1.1, and the maximum cost is $1.3; and
For EGUs greater than 500 MW in size, the minimum cost is $0.9, and the maximum cost is $1.0.

Air Heater & Duct Leakage Control -
For EGUs less than 200 MW in size, the minimum cost is $3.6, and the maximum cost is $4.7;
For EGUs between 200 - 500 MW in size, the minimum cost is $2.5, and the maximum cost is $2.7; and
For EGUs greater than 500 MW in size, the minimum cost is $2.1, and the maximum cost is $2.4.

Variable Frequency Drives -
For EGUs less than 200 MW in size, the minimum cost is $9.1, and the maximum cost is $11.9;
For EGUs between 200 - 500 MW in size, the minimum cost is $7.2, and the maximum cost is $9.4; and
For EGUs greater than 500 MW in size, the minimum cost is $6.6, and the maximum cost is $7.9.

Blade Path Upgrade (Steam Turbine) -
For EGUs less than 200 MW in size, the minimum cost is $11.2, and the maximum cost is $66.9;
For EGUs between 200 - 500 MW in size, the minimum cost is $8.9, and the maximum cost is $44.6; and
For EGUs greater than 500 MW in size, the minimum cost is $6.2, and the maximum cost is $31.0.

Redesign/ Replace Economizer -
For EGUs less than 200 MW in size, the minimum cost is $13.1, and the maximum cost is $18.7;
For EGUs between 200 - 500 MW in size, the minimum cost is $10.5, and the maximum cost is $12.7; and
For EGUs greater than 500 MW in size, the minimum cost is $10.0, and the maximum cost is $11.2.

Improved O & M Practices -
There is minimal capital cost regardless of the size of the unit.

D. FISCAL NOTE DETAIL:

Effect of Proposal	Fiscal Year		
	2020 Increase/Decrease (use "-")	2021 Increase/Decrease (use "-")	Fiscal Year (Upon Full Implementation)
1. Estimated Total Cost		0	0
Personal Services	0	0	0
Current Expenses	0	0	0
Repairs and Alterations	0	0	0
Assets	0	0	0

Other	0	0	0
2. Estimated Total Revenues	0	0	0

E. EXPLANATION OF ABOVE ESTIMATES (INCLUDING LONG-RANGE EFFECT):

Explanation of above estimates is provided in Sections B (Economic impact of the rule on special revenue accounts) and C (Economic impact of the rule on the state or its residents) above.

In accordance with W. Va. Code §22-1A 3(c), the Secretary has determined that this rule will not result in a taking of private property within the meaning of the Constitutions of West Virginia and the United States of America.

BY CHOOSING 'YES', I ATTEST THAT THE PREVIOUS STATEMENT IS TRUE AND CORRECT.

Yes

Jason E Wandling -- By my signature, I certify that I am the person authorized to file legislative rules, in accordance with West Virginia Code §29A-3-11 and §39A-3-2.

TITLE 45
LEGISLATIVE RULE
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY

SERIES 44
CONTROL OF GREENHOUSE GAS EMISSIONS FROM EXISTING COAL-FIRED ELECTRIC UTILITY GENERATING UNITS

§45-44-1. General.

1.1. Scope. --

1.1.a. This rule regulates greenhouse gas emissions, in the form of carbon dioxide, from existing coal-fired electric generating units that commenced construction on or before January 8, 2014 meeting the definition of a designated facility.

1.1.b. This rule establishes applicability criteria, permit application requirements, permit requirements, standards of performance requirements, and monitoring, recordkeeping and reporting requirements for designated facilities to control carbon dioxide emission rates based on the heat rate improvements analysis that can be applied to or at the affected steam generating unit.

1.1.c. This rule implements the federal emission guidelines established at 40 C.F.R. part 60, subpart UUUUa, commonly referred to as the Affordable Clean Energy (ACE) rule, in accordance with 40 C.F.R. part 60, subpart Ba. The federal emission guidelines establish the best systems of emission reduction (BSER) which, in the judgment of the Administrator, have been adequately demonstrated and provide information on the degree of emission limitation achievable for the designated pollutant. The federal emission guidelines are heat rate improvements which target achieving lower carbon dioxide emission rates at designated facilities. The federal emission guidelines were developed pursuant to section 111(d) of the federal Clean Air Act, as amended.

1.2. Authority. -- W. Va. Code §§ 22-5-4 and 22-5-20.

1.3. Filing Date. -- .

1.4. Effective Date. -- .

1.5. Sunset Provision. -- Does not apply.

1.6. Federal Regulation. -- Unless otherwise indicated, where reference to a federal regulation or standard appears in this rule, such regulation or standard will, for the purpose of this rule, be construed as that version which was in effect as of June 1, 2020.

§45-44-2. Definitions.

2.1. "Administrator" means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

2.2. "Affected Steam Generating Unit" means a designated facility.

2.3. "Air Heater" means a device that recovers heat from the flue gas for use in pre-heating the incoming combustion air and potentially for other uses such as coal drying.

2.4. "Alternative method" means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for the Administrator's determination of compliance.

2.5. "Annual capacity factor" means the ratio between the actual heat input to an electric generating unit during a calendar year and the potential heat input to the electric generating unit had it been operated for 8,760 hours during a calendar year at the base load rating.

2.6. "Base load rating" means the maximum amount of heat input (fuel) that an electric generating unit can combust on a steady-state basis, as determined by the physical design and characteristics of the electric generating unit at ISO conditions.

2.7. "Blade Path Upgrade" (Steam Turbine) means an upgrade or overhaul of a steam turbine.

2.8. "Boiler feed pump" or "boiler feedwater pump" means a device used to pump feedwater into a steam boiler at an electric generating unit. The water may be either freshly supplied or returning condensate produced from condensing steam produced by the boiler. The boiler feed pumps required to be evaluated under this rule have an electric motor.

2.9. "Capacity factor" means either:

2.9.a. The ratio of a unit's actual annual electric output (expressed in MWe/hr) to the unit's nameplate capacity (or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity) times 8,760 hours; or

2.9.b. The ratio of a unit's annual heat input (in million British thermal units or equivalent units of measure) to the unit's maximum rated hourly heat input rate (in million British thermal units per hour or equivalent units of measure) times 8,760 hours.

2.10. "C.F.R." or "CFR" means the Code of Federal Regulations.

2.11. "Clean Air Act" ("CAA") means the federal Clean Air Act, as amended, 42 U.S.C. § 7401, et seq.

2.12. "CO_2" means carbon dioxide.

2.13. "Combined cycle unit" means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

2.14. "Combined heat and power unit" or "CHP unit" (also known as "cogeneration") means an electric generating unit that uses a steam generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

2.15. "Compliance period" means a discrete time period for a designated facility to comply with a standard of performance.

2.16. "Compliance schedule" means a legally enforceable schedule specifying a date or dates by which a source or category of sources shall comply with specific standards of performance contained in a permit or with any increments of progress to achieve such compliance.

2.17. "Designated facility" means a steam generating unit that meets the applicability criteria in section 3 of this rule.

2.18. "Designated pollutant" means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the CAA. For the purposes of this rule, CO_2 is the designated pollutant.

2.19. "Economizer" means a heat exchange device used to capture waste heat from boiler flue gas which is then used to heat the boiler feedwater.

2.20. "EGU" or "electric generating unit" means any steam generating unit that is subject to this rule (*i.e.* meets the applicability criteria).

2.21. "Equivalent method" means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method under specified conditions.

2.22. "Emission guideline" means a final guideline document published under 40 C.F.R. §60.22a(a), which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator has determined has been adequately demonstrated for designated facilities.

2.23. "Fossil fuel" means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material to create useful heat.

2.24. "Greenhouse gas" means only carbon dioxide gas (CO_2) for the purpose of this rule.

2.25. "Heat rate" is the amount of energy or fuel heat input (typically measured in British thermal units, Btu) required to generate a unit of electricity (typically measured in kilowatt-hours, kWh). The lower an EGU's heat rate, the more efficiently it converts heat input to electrical output. An EGU with a lower heat rate consumes less fuel per kWh of electricity generated and, as a result, emits lower amounts of CO_2 per kWh generated.

2.26. "Integrated gasification combined cycle facility" or "IGCC" means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

2.27. "Intelligent sootblower" means an automated system that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup at a steam generating unit.

2.28. "ISO conditions" means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

2.29. "Mechanical output" means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

2.30. "Nameplate capacity" means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

2.31. "Natural gas" means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot) that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

2.32. "Net electric output" means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s) and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads). Such auxiliary load uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

2.33. "Net energy output" means:

2.33.a. The net electric or mechanical output from the affected facility plus 100 percent of the useful thermal output measured relative to SATP conditions not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

2.33.b. For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the designated facility divided by 0.95 plus 100 percent of the useful thermal output (e.g., steam delivered to an industrial process for a heating application).

2.34. "Neural network" means a computer model that can be used to optimize combustion conditions, steam temperatures and air pollution at a steam generating unit.

2.35. "Secretary" means the Secretary of the Department of Environmental Protection or other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8.

2.36. "Simple cycle combustion turbine" means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself.

2.37. "Standard ambient temperature and pressure" or "SATP" conditions means 298.15 Kelvin (25 °C or 77 °F) and 100.0 kilopascals (14.504 psi or 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

2.38. "Standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated including, but not limited to, a legally enforceable regulation setting forth an allowable rate or limit of emissions into the atmosphere, or prescribing a design, equipment, work practice, or operational standard, or combination thereof.

2.39. "Stationary combustion turbine" means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment.

2.39.a. "Stationary" means the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may be mounted on a vehicle for portability.

2.39.b. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

2.40. "Steam generating unit" means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

2.41. "Useful thermal output" means the thermal energy made available for use in any heating application (e.g., steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the designated facility, to directly enhance the performance of the designated facility (e.g., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the designated facility. Useful thermal output for designated facility(s) with no condensate return (or other thermal energy input to the designated facility(s)) or where measuring the energy in the condensate (or other thermal energy input to the designated facility(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Designated facility(s) with meaningful energy in the condensate return (or other thermal energy input to the designated facility) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

2.42. "Variable frequency drive" means an adjustable-speed drive used on induced draft fans and boiler feed pumps with electric motors to control motor speed and torque by varying motor input frequency and voltage.

2.43. Other words and phrases used in this rule, unless otherwise indicated, shall have the meaning ascribed to them in 40 C.F.R. part 60 subparts UUUUa, TTTT, A and Ba. Words and phrases not defined therein shall have the meaning given to them in the federal Clean Air Act, as amended.

§45-44-3. Applicability.

3.1. This rule applies to the owner or operator of any EGU that is a designated facility that commenced construction on or before January 8, 2014.

3.2. A designated facility is a steam generating unit that meets the relevant applicability criteria specified in subdivisions 3.2.a through 3.2.c, except as provided in subsection 3.3:

3.2.a. Serves a generator connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net (i.e., capable of selling greater than 25 MW of electricity);

3.2.b. Has a base load rating (i.e., design heat input capacity) greater than 250 MMBtu/hr heat input of fossil fuel (either alone or in combination with any other fuel); and

3.2.c. Is an electric utility steam generating unit that burns coal for more than 10.0 percent of the average annual heat input during the previous three (3) calendar years.

3.3. An EGU is excluded from being a designated facility if it meets any condition specified below:

3.3.a. Any EGU subject to 40 C.F.R. 60, subpart TTTT and 45CSR16 as a result of commencing construction after January 8, 2014 or commencing a modification or reconstruction after June 18, 2014;

3.3.b. Any steam generating unit subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;

3.3.c. Any stationary combustion turbine that meets the definition of a simple cycle stationary combustion turbine, a combined cycle stationary combustion turbine or a combined heat and power combustion turbine;

3.3.d. Any IGCC unit;

3.3.e. Any non-fossil fuel unit (i.e., a unit that is capable of combusting 50 percent or more non-fossil fuel) that has always limited the use of fossil fuels to 10 percent or less of the annual capacity factor or is subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

3.3.f. Any EGU that serves a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;

3.3.g. Any EGU that is a municipal waste combustor unit subject to 40 C.F.R. part 60, subpart Eb and 45CSR18;

3.3.h. Any EGU that is a commercial or industrial solid waste incineration unit subject to 40 C.F.R. part 60, subpart CCCC and 45CSR18; or

3.3.i. Any steam generating unit that fires more than 50 percent non-fossil fuels.

§45-44-4. Permit application requirements.

4.1. The owner or operator of any affected steam generating unit that meets the applicability requirements set forth in section 3 shall limit CO_2 emissions pursuant to a permit issued by the Secretary under this rule and the procedural requirements set forth in 45CSR13.

4.2. The owner or operator of any affected steam generating unit in existence on the effective date of this rule shall submit a complete permit application in accordance with the procedural requirements for a construction or modification permit set forth in 45CSR13 to the Secretary within 120 days of the effective date of this rule. The application shall contain sufficient information that, in the judgment of the Secretary, will enable the Secretary to determine the appropriate standard of performance and applicable monitoring, reporting and recordkeeping requirements for each affected steam generating unit. The permit application shall at a minimum include the information required by sections 4 of this rule, as applicable.

4.3. The owner or operator of an affected steam generating unit shall provide a heat rate improvement analysis and the associated degree of emission limitation achievable for each affected steam generating unit as specified in subdivisions 4.3.a and 4.3.b.

4.3.a. The permit application must include an applicability evaluation for each of the following heat rate improvements technologies identified in paragraphs 4.3.a.1 through 4.3.a.7 to each affected steam generating unit:

4.3.a.1. Neural network and intelligent sootblowers;

4.3.a.2. Boiler feed pumps;

4.3.a.3. Air heater and duct leakage control;

4.3.a.4. Variable frequency drives;

4.3.a.5. Blade path upgrades for steam turbines;

4.3.a.6. Redesign or replacement of economizer; and

4.3.a.7. Improved operating and maintenance practices.

4.3.b. During the evaluation of each heat rate improvement to each affected steam generating unit, the owner or operator shall include an evaluation of the following degree of emission limitations achievable through the application of the heat rate improvements.

Table 45CSR44. Most impactful HRI measures and range of their HRI potential (%) by EGU size.

HRI Measure	< 200 MW		200 – 500 MW		> 500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network / Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign / Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved Operating and Maintenance (O & M Practices	Can range from 0 to > 2.0% depending on the affected steam generating unit's historical O & M practices.					

4.4. The owner or operator shall propose and justify a standard of performance for each affected steam generating unit in the permit application that satisfies the following requirements:

4.4.a. The standard of performance shall:

4.4.a.1. Be an emission performance rate relating mass of CO_2 emitted per unit of energy (*e.g.* pounds of CO_2 emitted per MWh).

4.4.a.2. Include an averaging period.

4.4.b. The justification shall:

4.4.b.1. Include a summary of how the owner or operator determined each standard of performance for each designated facility; and

4.4.b.2. Include a description for how each heat rate improvement and associated degree of emission limitation achievable were considered in calculating the proposed standard of performance.

4.5. In applying a standard of performance to an affected steam generating unit, the owner or operator may take into consideration source-specific factors, such as the remaining useful life of such affected steam generating unit, provided the owner or operator demonstrates with respect to each such affected steam generating unit (or class of such affected steam generating units):

4.5.a. Unreasonable cost of control resulting from plant age, location, or basic process design;

4.5.b. Physical impossibility of installing necessary control equipment; or

4.5.c. Other unique factors specific to the affected steam generating unit (or class of steam generating unit) that make application of a less stringent standard or final compliance time significantly more reasonable.

4.5.d. In accordance with the standard of performance definition provided in subsection 2.38, the owner or operator may take into consideration non-air quality health and environmental impact and energy requirements.

4.6. If the owner or operator considered remaining useful life and other factors for a designated facility, the application shall include a summary of how those factors were used in deriving a proposed standard of performance and must include a summary in the application of relevant factors from subsection 4.3 in deriving a proposed standard of performance.

4.7. The owner or operator of an affected steam generating unit shall submit a compliance schedule with the permit application to the Secretary if the owner or operator requests a compliance date past July 8, 2024.

4.8. Standards of performance for affected steam generating units proposed in the application shall be demonstrated to be quantifiable, verifiable, permanent, and enforceable with respect to each affected steam generating unit. The application shall include the methods by which each standard of performance meets each of the following requirements:

4.8.a. The standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.

4.8.b. The standard of performance is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the standard of performance.

4.8.c. The standard of performance is permanent if the standard of performance must be met for each compliance period, unless it is replaced by another standard of performance in an approved plan revision.

4.8.d. The standard of performance is enforceable if:

4.8.d.1. A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

4.8.d.2. Compliance requirements are clearly defined;

4.8.d.3. The designated facility responsible for compliance and liable for violations is identified; and

4.8.d.4. Each compliance activity or measure is enforceable as a practical matter.

4.9. The application shall include the information listed below, as applicable in establishing the standard of performance for each designated facility:

4.9.a. A summary of each designated facility's anticipated future operation characteristics, including:

4.9.a.1. Annual generation;

4.9.a.2. CO_2 emissions;

4.9.a.3. Fuel use, fuel prices, fuel carbon content;

4.9.a.4. Fixed and variable operations and maintenance costs;

4.9.a.5. Heat rates; and

4.9.a.6. Electric generation capacity and capacity factors.

4.9.b. A timeline for implementation.

4.9.c. All wholesale electricity prices.

4.9.d. A time period of analysis, which must extend through at least 2035.

4.10. The application shall include materials supporting calculations for the affected steam generating unit's standards of performance and any other materials necessary to support evaluation of the plan by the Secretary.

4.11. Each proposed standard of performance must include a proposed compliance period that ensures the standard of performance reflects the degree of emission limitation achievable though application of the heat rate improvements used to calculate the standard. Any compliance schedule extending past July 8, 2024 must include legally enforceable increments of progress to achieve compliance for each affected steam generating unit or category of affected steam generating units.

4.12. The permit application shall propose and justify monitoring, recordkeeping, and reporting requirements that satisfy either of the following options:

4.12.a. Report emission and electricity generation data according to 40 C.F.R. Part 75; or

4.12.b. Include an alternative monitoring, recordkeeping, and reporting program that includes specifications for the following program elements:

4.12.b.1. Monitoring plans that specify the monitoring methods, systems, and formulas that will be used to measure CO_2 emissions;

4.12.b.2. Monitoring methods to continuously and accurately measure all CO_2 emissions, CO_2 emission rates, and other data necessary to determine compliance or assure data quality;

4.12.b.3. Quality assurance test requirements to ensure monitoring systems provide reliable and accurate data for assessing and verifying compliance;

4.12.b.4. Recordkeeping requirements;

4.12.b.5. Electronic reporting procedures and systems; and

4.12.b.6. Data validation procedures for ensuring data are complete and calculated consistent with program rules, including procedures for determining substitute data in instances where required data would otherwise be incomplete.

4.13. The owner or operator of an affected steam generating unit shall keep records of all information relied upon in support of any aspect of the permit application for a minimum for five (5) years. Each record must be in a form suitable and readily available for expeditious review.

4.14. If an owner or operator requests a revision to an existing permit issued pursuant to 45CSR44, the owner or operator shall submit to the Secretary an application in accordance with the procedural requirements set forth in 45CSR13 that meets the application requirements of 45CSR44.

§45-44-5. Permit requirements, standards of performances and compliance periods.

5.1. No person may operate any affected steam generating unit meeting the applicability requirements set forth in section 3 without obtaining a permit in accordance with this rule and the procedural requirements of 45CSR13.

5.2. A separate permit shall be issued by the Secretary for the sole purpose of complying with this rule. The Secretary may issue a single permit for multiple affected steam generating units located within the same site.

5.3. The Secretary shall establish a standard of performance for each affected steam generating unit in a permit issued pursuant to this rule and the procedural requirements of 45CSR13. Each standards of performance shall:

5.3.a. Include a rate-based limit relating the mass of carbon dioxide emitted per unit of output energy (e.g. pounds of CO_2 emitted per MWh);

5.3.b. Specify whether the unit of energy in the rate-based limit is in terms of gross or net energy output; and

5.3.c. Reflect the degree of emission limitation achievable through application of heat rate improvements used to calculate the standard after the applicability of each of the heat rate improvements were considered by the Secretary.

5.3.d. The Secretary may establish multiple limitations or requirements for different time periods or operational condition provided each limitation or requirements is clearly defined and technically accurate.

5.4. The Secretary may consider remaining useful life or other source-specific factors when determining the standard of the performance for the affected steam generating unit based on the factors identified in subsection 4.5. If the Secretary considers remaining useful life, the shutdown date for the affected steam generating unit shall be a required permit condition.

5.5. The Secretary shall establish monitoring, recordkeeping, and reporting requirements and shall establish compliance requirements in a permit issued pursuant to this rule and the procedural requirements of 45CSR13.

5.6. The Secretary shall establish a compliance period for each standard of performance in a permit issued pursuant to this rule and the procedural requirements of 45CSR13.

5.6.a. The compliance period must reflect the degree of emission limitation achievable through application of the heat rate improvements used to calculate the standard of performance.

5.6.b. The compliance period must include the averaging period and a compliance date.

5.6.c. If the compliance date for any affected steam generating unit is later than July 8, 2024, the Secretary shall establish legally enforceable increments of progress to monitor progress toward final compliance.

5.7. The owner or operator of an affected steam generating unit shall notify the Secretary in writing if an affected steam generating unit ceases to meet the applicability requirements established in section 3 within 30 days of the change.

§45-44-6. Monitoring, Recordkeeping and Reporting.

6.1. The Secretary shall establish monitoring, recordkeeping and reporting requirements in accordance with either subdivision 6.1.a or 6.1.b for each affected steam generating unit in a permit issued pursuant to 45CSR13 and this rule.

6.1.a. The Secretary may require sources to report emission and electricity generation data according to 40 C.F.R. 75; or

6.1.b. The Secretary may include an alternative monitoring, recordkeeping, and reporting program that includes specifications for the following program elements:

6.1.b.1. Monitoring plans that specify the monitoring methods, systems, and formulas to measure CO_2 emissions;

6.1.b.2. Monitoring methods to continuously and accurately measure all CO_2 emissions, CO_2 emission rates, and other data necessary to determine compliance or assure data quality;

6.1.b.3. Quality assurance test requirements to ensure monitoring systems provide reliable and accurate data for assessing and verifying compliance;

6.1.b.4. Recordkeeping requirements;

6.1.b.5. Electronic reporting procedures and systems; and

6.1.b.6. Data validation procedures for ensuring data are complete and calculated consistent with program rules, including procedures for determining substitute data in instances where required data would otherwise be incomplete.

6.2. The Secretary shall establish test methods and compliance requirements in a permit issued pursuant to this rule and the procedural requirements of 45CSR13.

6.3. The owner or operator of an affected steam generating unit may decide how to comply with the standard of performance provided the compliance method does not include any of the following prohibited methods:

6.3.a. Averaging emission rates across multiple affected steam generating units;

6.3.b. Trading programs; and

6.3.c. Bio-mass cofiring.

§45-44-7. Inconsistency Between Rules.

7.1. In the event of any inconsistency between this rule and any other rule of the Division of Air Quality, the inconsistency shall be resolved by the determination of the Secretary and the determination shall be based upon the application of the more stringent provision, term, condition, method or rule.

§45-44-8. Disposition of Permits.

8.1. In the event the ACE Rule is withdrawn by the U.S. EPA or invalidated by a court of competent jurisdiction or legislative action, the Secretary may terminate any permit or section of an existing permit issued pursuant to this rule.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2017–0355: FRL–9995–70–OAR]

RIN 2060–AT67

Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is finalizing three separate and distinct rulemakings. First, the EPA is repealing the Clean Power Plan (CPP) because the Agency has determined that the CPP exceeded the EPA's statutory authority under the Clean Air Act (CAA). Second, the EPA is finalizing the Affordable Clean Energy rule (ACE), consisting of Emission Guidelines for Greenhouse Gas (GHG) Emissions from Existing Electric Utility Generating Units (EGUs) under CAA section 111(d), that will inform states on the development, submittal, and implementation of state plans to establish performance standards for GHG emissions from certain fossil fuel-fired EGUs. In ACE, the Agency is finalizing its determination that heat rate improvement (HRI) is the best system of emission reduction (BSER) for reducing GHG—specifically carbon dioxide (CO_2)—emissions from existing coal-fired EGUs. Third, the EPA is finalizing new regulations for the EPA and state implementation of ACE and any future emission guidelines issued under CAA section 111(d).

DATES: Effective September 6, 2019.

ADDRESSES: The EPA has established a docket for these actions under Docket ID No. EPA–HQ–OAR–2017–0355. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov/* or in hard copy at the EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC. The EPA's Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m. Eastern Standard Time (EST), Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about these final actions, contact Mr. Nicholas Swanson, Sector Policies and Programs Division (Mail Code D205–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–4080; fax number: (919) 541–4991; and email address: *swanson.nicholas@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. The EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms:

ACE Affordable Clean Energy Rule
AEO Annual Energy Outlook
ANPRM Advance Notice of Proposed Rulemaking
BACT Best Available Control Technology
BSER Best System of Emission Reduction
Btu British Thermal Unit
CAA Clean Air Act
CCS Carbon Capture and Storage (or Sequestration)
CFR Code of Federal Regulation
CO_2 Carbon Dioxide
CPP Clean Power Plan
EGU Electric Utility Generating Unit
EIA Energy Information Administration
EPA Environmental Protection Agency
FIP Federal Implementation Plan
GHG Greenhouse Gas
HRI Heat Rate Improvement
IGCC Integrated Gasification Combined Cycle
kW Kilowatt
kWh Kilowatt-hour
MW Megawatt
MWh Megawatt-hour
NAAQS National Ambient Air Quality Standards
NGCC Natural Gas Combined Cycle
NO_X Nitrogen Oxides
NSPS New Source Performance Standards
NSR New Source Review
OMB Office of Management and Budget
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
RIA Regulatory Impact Analysis
RTC Response to Comments
SIP State Implementation Plan
SO_2 Sulfur Dioxide
UMRA Unfunded Mandates Reform Act
U.S. United States
VFD Variable Frequency Drive

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

With this document, the EPA is, after review and consideration of public comments, finalizing three separate and distinct rulemakings. First, the EPA is finalizing the repeal of the CPP which was proposed at 82 FR 48035 (Oct. 16, 2017) (''Proposed Repeal''). Second, the EPA is promulgating ACE, which consists of emission guidelines for states to develop and submit to the EPA plans that establish standards of performance for CO_2 emissions from certain existing coal-fired EGUs within their jurisdictions. Third, the EPA is finalizing implementing regulations that provide direction to both the EPA and states on the implementation of ACE and any future emission guidelines issued under CAA section 111(d). This document does not include any final action concerning the New Source Review (NSR) reforms the EPA proposed in conjunction with the ACE proposal; the EPA intends to take final action on the proposed NSR reforms in a separate final action at a later date.

First, the EPA is repealing the CPP. In proposing to repeal the CPP, the Agency proposed a change in the legal interpretation of CAA section 111, on which the CPP was based, to an interpretation of the CAA that ''is consistent with the CAA's text, context, structure, purpose, and legislative history, as well as with the Agency's historical understanding and exercise of its statutory authority.'' [1] After further review of the EPA's statutory authority under CAA section 111 and in consideration of public comments, the Agency is finalizing the repeal of the CPP. The discussion of the repeal action, along with the EPA's explanation that it intends the repeal of the CPP to be independent from the other final actions in this document, can be found in section II below.

Second, the EPA is finalizing ACE, which consists of emission guidelines to inform states in the development, submittal, and implementation of state plans that establish standards of performance for CO_2 from certain existing coal-fired EGUs within their jurisdictions. In these emission guidelines, the EPA has determined that the BSER for existing EGUs is based on HRI measures that can be applied to a designated facility. ACE also clarifies the roles of the EPA and the states under CAA section 111(d). With the promulgation of this action, it is the states' responsibility to use the information and direction herein to develop standards of performance that reflect the application of the BSER. Per the CAA, states may also consider source-specific factors—including, among other factors, the remaining useful life of an existing source—in applying a standard of performance to that source. In this way, the state and federal roles complement each other as the EPA has the authority and responsibility to determine BSER at the national level, while the states have the authority and responsibility to establish and apply standards of performance for their existing sources, taking into consideration source-specific factors where appropriate. A full discussion of ACE can be found in section III of this preamble.

Third, the EPA is finalizing new implementing regulations that apply to ACE and any future emission guidelines promulgated under CAA section 111(d). The purpose of the new implementing regulations is to harmonize aspects of our existing regulations with the statute, in a new 40 CFR part 60, subpart Ba, by making it clear that states have broad discretion in establishing and applying emissions standards consistent with the BSER. The new implementing regulations also provide changes to the timing requirements for the EPA and states to take action to more closely align with the CAA section 110 state implementation plan (SIP) and federal implementation plan (FIP) deadlines. The discussion of the final revisions to the implementing regulations is found in section IV below.

The implementing regulations (and ACE which is promulgated consistent with those regulations) make clear that the EPA, states, and sources all have distinct roles, responsibilities, and flexibilities under CAA section 111(d). Specifically, the EPA identifies the BSER; states establish standards of performance for existing sources within their jurisdiction consistent with that BSER and also with the flexibility to consider source-specific factors, including remaining useful life; and sources then meet those standards using the technologies or techniques they believe is most appropriate. As this preamble explains, in the case of ACE, the EPA has identified the BSER as a set of heat rate improvement measures. States will establish standards of performance for existing sources based on application of those heat rate improvement measures (considering source-specific factors, including remaining useful life). Each regulated source then must meet those standards using the measures they believe is appropriate (*e.g.,* via the heat rate improvement measures identified by the EPA as the BSER, other heat rate improvement measures, or other approaches such as CCS or natural gas co-firing).

These three rules have been informed by more than 1.5 million public comments on the Proposed Repeal and 500,000 public comments on the proposals for ACE and the new implementing regulations. Per CAA section 307(d)(6)(B), the EPA is providing a response to the significant comments received for each of these actions in the docket. After careful consideration of the comments, the EPA is finalizing these three rules, with revisions to what it proposed where appropriate, to provide states guidance on how to address CO_2 emissions from coal-fired power plants in a way that is consistent with the EPA's authority under the CAA.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this document is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this document at *https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-emission-guidelines-greenhouse.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of these final rules and key technical documents at this same website.

C. Judicial Review and Administrative Reconsideration

Under CAA section 307(b)(1), judicial review of these final actions is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) by September 6, 2019. Under CAA section 307(b)(2), the requirements established by these final rules may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. This section also provides a mechanism for the EPA to reconsider a rule if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time

[1] Proposed Repeal, 82 FR 48036.

specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, WJC South Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

II. Repeal of the Clean Power Plan

A. Background for the Repeal of the Clean Power Plan

1. The Clean Power Plan

The EPA promulgated the CPP under section 111 of the CAA.[2] Section 111(b) authorizes the EPA to issue nationally applicable new source performance standards (NSPS) limiting air pollution from ''new sources'' in source categories that cause or significantly contribute to air pollution that may reasonably be anticipated to endanger public health or welfare.[3] In 2015, the EPA issued such a rule for GHG emissions—in particular, CO_2—from certain new fossil fuel-fired power plants[4] in light of the Agency's assessment ''that GHGs endanger public health, now and in the future.''[5] CAA section 111(d) provides that, under certain circumstances, when the EPA issues a CAA section 111(b) standard, the EPA must develop procedures requiring each state to submit a plan to the EPA that establishes performance standards for *existing* sources in the same category.[6] The EPA relied on CAA section 111(d) to issue the CPP, which, for the first time, required states to submit plans specifically designed to limit CO_2 emissions from certain existing fossil fuel-fired power plants.

The CPP established emission guidelines for states to follow in limiting CO_2 emissions from those existing fossil fuel-fired power plants. Those emission guidelines included both state-specific ''goals'' and alternative, nationally uniform CO_2 emission performance rates for two types of existing fossil fuel-fired power plants: Electric utility steam generating units and stationary combustion turbines.[7]

In the CPP, the EPA determined that the BSER for CO_2 emissions from existing fossil fuel-fired power plants was the combination of: (1) Heat rate (*e.g.,* efficiency) improvements to be conducted at individual power plants, in combination with (2, 3) two other sets of measures based on the shifting of generation at the fleet-wide level from one type of energy source to another. The EPA referred to these three sets of measures as ''building blocks'':[8]

1. Improving heat rate at affected coal-fired steam generating units;
2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for decreased generation from higher-emitting affected steam generating units; and
3. Substituting increased generation from new zero-emitting renewable energy generating capacity for decreased generation from affected fossil fuel-fired generating units.

While building block 1 relied on measures that could be applied directly to individual sources, building blocks 2 and 3 employed measures that were expressly designed to shift the balance of coal-, gas-, and renewable-generated power across the power grid.

2. Legal Challenges to the CPP, Executive Order 13783, and the EPA's Review of the CPP

On October 23, 2015, 27 states and a number of other parties sought judicial review of the CPP in the U.S. Court of Appeals for the D.C. Circuit.[9] After some preliminary briefing, the Supreme Court stayed implementation of the CPP, pending judicial review.[10] The case was then referred to an *en banc* panel of the D.C. Circuit, which held oral argument on September 27, 2016.

On March 28, 2017, President Trump issued Executive Order 13783, which affirms the ''national interest to promote clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation.''[11] The Executive Order directs all executive departments and agencies, including the EPA, to ''immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.''[12] The Executive Order further affirms that it is ''the policy of the United States that necessary and appropriate environmental regulations comply with the law.''[13] Moreover, the Executive Order specifically directs the EPA to review and initiate reconsideration proceedings to ''suspend, revise, or rescind'' the CPP ''as appropriate and consistent with law.''[14]

In a document signed the same day as Executive Order 13783 and published in the **Federal Register** at 82 FR 16329 (April 4, 2017), the EPA announced that, consistent with the Executive Order, it was initiating its review of the CPP and providing notice of forthcoming proposed rulemakings consistent with the Executive Order.

In light of Executive Order 13783, the EPA's initiation of a review of the CPP, and notice of the EPA's forthcoming rulemakings, the EPA asked the D.C. Circuit to hold the CPP litigation in abeyance, and, on April 28, 2017, the court (still sitting en banc) granted motions to hold the cases in abeyance for 60 days and directed the parties to file briefs addressing whether the cases should be remanded to the Agency rather than held in abeyance.[15] Since then, the D.C. Circuit has issued a series of orders holding the cases in abeyance. While the case has been in abeyance, the EPA has been reviewing the CPP and providing status reports to the court describing the progress of its rulemaking.

In the course of the EPA's review of the CPP, the Agency also reevaluated its interpretation of CAA section 111, and, on that basis, the Agency proposed to repeal the CPP.[16]

3. Public Comment and Hearings on the Proposed Repeal

Publication of the Proposed Repeal in the **Federal Register** opened comment on the proposal for an initial 60-day

[2] 42 U.S.C. 7411.

[3] *Id.* 7411(b)(1).

[4] The CPP identified ''[f]ossil fuel-fired EGUs'' as ''by far the largest emitters of GHGs among stationary sources in the U.S., primarily in the form of CO_2.'' 80 FR 64510, 64522 (October 23, 2015).

[5] Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, 80 FR 64510, 64518 (October 23, 2015); *see also* Endangerment and Cause or Contribute Findings for Greenhouse Gases Under section 202(a) of the CAA, 74 FR 66496 (December 15, 2009) (2009 Endangerment Finding). The substance of the 2009 Endangerment Finding, which addressed GHG emissions from mobile sources, is not at issue in this action.

[6] 42 U.S.C. 7411(d)(1) (emphasis added).

[7] *See* 80 FR 64707.

[8] *Id.*

[9] *See West Virginia* v. *EPA,* No. 15–1363 (and consolidated cases) (D.C. Cir. October 23, 2015).

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

[11] *See* Executive Order 13783, section 1(a).

[12] *Id.* section 1(c).

[13] *Id.* section 1(e).

[14] *Id.* section 4(a)–(c).

[15] Order, Document No. 1673071 (per curiam).

[16] *See* Proposed Repeal, 82 FR 48035 (October 16, 2017).

public comment period. The EPA held public hearings on November 28 and 29, 2017, in Charleston, West Virginia, and then extended the public comment period until January 16, 2018. In response to requests for additional opportunities for oral testimony, the EPA held three listening sessions in Kansas City, Missouri; San Francisco, California; and Gillette, Wyoming. The EPA also reopened the public comment period until April 26, 2018, giving stakeholders 192 days to review and comment on the proposal. The EPA received more than 1.5 million comments on the Proposed Repeal.

B. Basis for Repealing the Clean Power Plan

1. Authority To Revisit Existing Regulations

The EPA's ability to revisit existing regulations is well-grounded in the law. Specifically, the EPA has inherent authority to reconsider, repeal, or revise past decisions to the extent permitted by law so long as the Agency provides a reasoned explanation. The authority to reconsider prior decisions exists in part because the EPA's interpretations of statutes it administers ''[are not] instantly carved in stone,'' but must be evaluated ''on a continuing basis.'' [17] This is true when, as is the case here, review is undertaken ''in response to . . . a change in administrations.'' [18] Indeed, ''[a]gencies obviously have broad discretion to reconsider a regulation at any time.'' [19]

2. Legal Basis for Repeal of the Clean Power Plan

The CPP departed from the EPA's traditional understanding of its authority under section 111 of the CAA and promulgated a rule in excess of its statutory authority. Because the CPP significantly exceeded the Agency's authority, it must be repealed.[20] Fundamentally, the CPP read the statutory term ''best system of emission reduction'' so broadly as to encompass measures the EPA had never before envisioned in promulgating performance standards under CAA section 111. In contrast to its traditional regulations that set performance standards based on the application of equipment and practices at the level of an individual facility, the EPA in the CPP set standards that could only be achieved by a shift in the energy generation mix at the grid level, requiring a shift from one type of fossil-fuel-fired generation to another, and from fossil-fuel-fired generation as a whole towards renewable sources of energy. The text of the CAA is inconsistent with that interpretation, and the context, structure, and legislative history confirm that the statutory interpretation underlying the CPP was not a permissible construction of the Act.

a. CAA Requirements and Background

In 1970, Congress enacted section 111(b) of the CAA, authorizing the EPA to promulgate ''standards of performance'' for new stationary sources in certain source categories.[21] Congress also directed the EPA, under CAA section 111(d), to ''prescribe regulations which shall establish a procedure'' [22] for states to establish standards [23] for existing sources of certain air pollutants to which a standard of performance would apply if such existing source were a new source.[24]

Since 1990, new- and existing-source CAA section 111 rulemakings have been governed by the same statutory definitions.[25] The CAA defines the term ''standard of performance'' in two sections. CAA section 111(a)(1) defines it, for purposes of section 111 (which contains the new- and existing-source performance standard authority in, respectively, CAA section 111(b) and 111(d)), as:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[26]

And CAA section 302(*l*) defines ''standard of performance'' as ''a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous reduction.'' [27]

EPA's role under CAA section 111(d) is narrow. Indeed, CAA section 111(d) tasks states with ''establish[ing] standards of performance for any existing source'' and ''provid[ing] for the implementation and enforcement of such standards of performance.'' It requires further that the regulations the EPA is directed to adopt must permit the state ''to take into consideration, among other factors, the remaining useful life of the existing source to which such standard [of performance] applies.'' [28] After all, Congress found that ''air pollution prevention . . . and air pollution control at its source is the primary responsibility of States and local governments.'' [29]

In contrast to CAA section 111(b) (where the EPA may directly establish performance standards for emissions from new sources), the EPA implements CAA section 111(d) by issuing regulations that it calls ''emission guidelines'' [30] These guidelines provide states with information to assist them in developing state plans establishing standards of performance for existing designated facilities within their jurisdiction that are submitted to the EPA for review. Such information includes the EPA's determination of the ''best system of emission reduction,'' which is commonly referred to as the BSER.

b. The Plain Meaning of CAA Sections 111(a)(1) and (d)

CAA section 111(d) provides that ''each State shall submit to the Administrator a plan which (A) establishes *standards of performance* for any existing source for [certain air pollutants] . . . and (B) provides for the implementation and enforcement of such standards of performance.'' [31] Given how Congress has defined the phrase ''standard of performance'' for purposes of CAA section 111, the plain meaning of CAA section 111(d), therefore is that states shall submit a plan which ''establishes [a standard for

[17] *Chevron U.S.A. Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 863–64 (1984).

[18] *National Cable & Telecommunications Ass'n* v. *Brand X internet Services,* 545 U.S. 967, 981 (2005).

[19] *Clean Air Council* v. *Pruitt,* 862 F.3d 1, 8–9 (D.C. Cir. 2017).

[20] As noted above, the EPA received more than 1.5 million comments on the Proposed Repeal. The Agency's consideration of and responses to significant comments are reflected in section II.B.2 of this preamble.

[21] CAA Amendments of 1970, Public Law 91–604, 84 Stat. at 1683–84 (Dec. 31, 1970); *see also* 42 U.S.C. 7411(b).

[22] *See* section IV (addressing changes to the implementing regulations).

[23] As originally enacted, CAA section 111 required states to establish ''emission standards'' for existing sources, but Congress replaced that term with ''standard of performance'' as part of the CAA Amendments of 1977. *See* Public Law 95–95, 91 Stat. at 699 (Aug. 7, 1977) (''Section 111(d)(1) . . . is amended by striking out 'emissions standards' in each place it appears and inserting in lieu thereof 'standards of performance' '').

[24] CAA Amendments of 1970, 84 Stat. at 1684; see also 42 U.S.C. 7411(d).

[25] *See infra* n.51.

[26] 42 U.S.C. 7411(a)(1).

[27] 42 U.S.C. 7602(*l*).

[28] 42 U.S.C. 7411(d)(1).

[29] 42 U.S.C. 7401(a)(3).

[30] *See American Elec. Power Co.* v. *Connecticut,* 564 U.S. 410, 424 (2011). *See generally* Section IV, *infra* (discussing the promulgation of revised implementing regulations governing the EPA's issuance of emission guidelines); 40 CFR part 60, subpart B.

[31] 42 U.S.C. 7411(d)(1) (emphasis added).

emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER] . . .] for any existing source.''

While CAA section 111(a)(1) provides that the EPA determines the BSER upon which existing-source performance standards are based, Congress expressly limited the universe of systems of emission reduction from which the EPA may choose the BSER to those systems whose ''application'' to an ''existing source'' will yield an ''achievable'' ''degree of emission limitation.'' [32] ''[W]here . . . the statute's language is plain,'' courts explain, our '' 'sole function . . . is to enforce it according to its terms.' '' [33]

The EPA begins with the meaning of ''application,'' as it appears in CAA section 111(a)(1). In the absence of a statutory definition, the term must be construed in accordance with its ordinary or natural meaning.[34] Here the ordinary meaning of ''application'' refers to the ''act of applying'' or the ''act of putting to use.'' [35] Accordingly, a standard of performance must reflect the degree of emission limitation that can be achieved by putting the BSER into use. Furthermore, the ordinary and natural use of the term ''application,'' which is derived from the verb ''to apply,'' requires both a direct object and an indirect object. In other words, someone must apply *something* to *something else* (*e.g.,* the application of general rules to particular cases). In the case of CAA section 111, the direct object is the BSER. CAA section 111(d) also provides that the indirect object is the ''existing source''—''each State shall submit to the Administrator a plan which (A) establishes standards of performance *for any existing source*'' (emphasis added). The Act further defines an ''existing source'' as ''any stationary source other than a new source,'' [36] and in turn defines a ''stationary source'' as ''any building, structure, facility, or installation which emits or may emit any air pollutant.'' [37] Consequently, CAA section 111 unambiguously limits the BSER to those systems that can be put into operation *at* a building, structure, facility, or installation. Such systems include, for example, add-on controls (*e.g.,* scrubbers) and inherently lower-emitting processes/practices/designs.

Conversely, the plain language of CAA section 111 does not authorize the EPA to select as the BSER a system that is premised on application to the source category as a whole or to entities entirely outside the regulated source category. First, Congress specified that ''standards of performance'' are established ''for new sources *within such category*'' [38] and ''for any existing source.'' [39] CAA section 111, therefore, does not allow for the establishment of standards for the source category or for entities not within the source category. Instead, CAA section 111 standards must be established for individual sources. Second, because CAA section 111 standards reflect an ''achievable'' ''degree of emission limitation'' through application of the BSER, an owner or operator must be able to achieve an applicable standard by applying the BSER to the designated facility. Accordingly, the BSER—like standards of performance—cannot be premised on a system of emission reduction that is implementable only through the combined activities of sources or non-sources. Thus, the EPA is precluded from basing BSER on strategies like generation shifting and corresponding emissions offsets because these types of systems cannot be put into use at the regulated building, structure, facility, or installation.[40]

c. Statutory Structure and Purpose Confirm That a ''System of Emission Reduction'' Must Be Applied to an Individual Source and That CAA Section 111 Is Intended to Best Design, Build, Equip, Operate, and Maintain Sources so as To Reduce Emissions

While the plain meaning of CAA section 111 provides that the BSER must be applied to a building, structure, facility, or installation, Congress' intent is also manifest in the statutory structure and purpose. ''Statutory construction,'' the Supreme Court instructs, ''is a holistic endeavor.'' [41] The interpretation of a phrase ''is often clarified by the remainder of the statutory scheme—because the same terminology is used elsewhere in a context that makes its meaning clear, or because only one of the permissible meanings produces a substantive effect that is compatible with the rest of the law.'' [42]

(1) The Statutory Structure Limits a ''System of Emission Reduction'' to ''Systems'' That Have a Potential for Application to an Individual Source

The conclusion that CAA section 111 standards are limited as described above is confirmed by considering the section's place in the overall statutory scheme. Congress tied CAA section 111 to the Best Available Control Technology (''BACT'') provisions in CAA section 165.[43] Section 165 provides that ''[a]ny major stationary source or major modification subject to [preconstruction requirements] must conduct an analysis to ensure the application of [BACT].'' [44] A permitting authority must ''conduct a BACT analysis on a case-by-case basis . . . and must evaluate the amount of emission reductions that each available emissions-reducing *technology or technique* would achieve, as well as the energy, environmental, economic and other costs . . . .'' [45] The EPA has long recommended that permitting agencies conduct this analysis through a top-down assessment of the best available and feasible control technologies for the emissions subject to BACT.[46] ''Based on

[32] *Id.*

[33] *Air Line Pilots Ass'n* v. *Chao,* 167 F.3d 602, 791 (D.C. Cir. 2018) (quoting *United States* v. *Ron Pair Enterprises,* 489 U.S. 235, 241 (1989)).

[34] *See Leocal* v. *Ashcroft,* 543 U.S. 1, 10 (2004).

[35] Merriam-Webster's Collegiate Dictionary (11th ed. 2003) (''1: an act of applying: a (1) : an act of putting to use <~ of new techniques> (2) : a use to which something is put <new ~s for old remedies>''). Definitions are also provided from when CAA section 111(a)(1) was last amended, *see* The Oxford English Dictionary (2d ed. 1989) (''The action of applying; the thing applied. 1. a. The action of putting a thing to another, of bringing into material or effective contact''), and first enacted, *see* American Heritage Dictionary of the English Language (2d ed. 1969) (''1. The act of applying or putting something on. 2. Anything that is applied, such as a cosmetic or curative agent. 3. The act of putting something to a special use or purpose.'').

[36] 42 U.S.C. 7411(a)(6).

[37] 42 U.S.C. 7411(a)(3).

[38] 42 U.S.C. 7411(b)(1)(B) (requiring the Administrator to establish performance standards ''for new sources *within such category*'' rather than for the category itself as a whole) (emphasis added)

[39] 42 U.S.C. 7411(d)(1)(A).

[40] The CPP's BSER was in part designed to consist of generation-shifting. *See, e.g.,* 80 FR 64,776 (final rule) (describing 'building blocks' 2 and 3 as ''processes of shifting dispatch from steam generators to existing NGCC units and from both steam generators and NGCC units to renewable generators.'').

[41] *Czyzewski* v. *Jevic Holding Corp.,* 137 S. Ct. 973, 985 (2017) (citing *United Savings Ass'n* v. *Timbers of Inwood Forest Associates,* 484 U.S. 365, 371 (1988)).

[42] *Utility Air Regulatory Group* v. *EPA,* 573 U.S. 302, 321 (2014).

[43] 42 U.S.C. 7479(3) (''In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 or 7412 of this title.'').

[44] U.S. EPA, DRAFT New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, B. 1 (October 1990) (''NSR Manual''), *available at https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf.* Though the EPA never finalized this draft, it continues to follow the analytical approach to the BACT analysis contained within the NSR Manual. *See also* U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) (''GHG Permitting Guidance''), *available at https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf.*

[45] GHG Permitting Guidance at 17 (emphasis added).

[46] *See id.* at 17–44.

this [technology] assessment, the permitting authority must [then] establish a numeric emission limitation that reflects the maximum degree of reduction achievable. . . .'' [47]

In no event, Congress specified, can application of BACT result in greater emissions than allowed by ''any applicable standard established pursuant to section [1]11 or [1]12 . . . .'' [48] To ensure such an exceedance does not occur, NSPS serve as the base upon which BACT determinations are made and are commonly viewed as the BACT ''floor.'' [49] However, because Congress refers to ''any applicable standard established pursuant to section [1]11,'' without reference to either subsection (b) or (d), any applicable existing source standard would also function as a BACT ''floor.'' [50]

The EPA has consistently taken the position that BACT encompasses ''all 'available' control options . . . that have the potential for practical *application to the emissions unit* and the regulated pollutant under evaluation.'' [51] This is so because BACT reflects a level of control that the permitting agency ''determines is achievable *for such facility* through *application of* production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control.'' [52] Put simply, both the statutory text and the EPA's long-standing interpretation provide that BACT is limited to control options that can be applied to the source itself and does not include control options that go beyond the source.

Because CAA section 111 operates as a floor to BACT, section 111 cannot be interpreted to offer a broader set of tools than are available under section 165. Also, because BACT is limited to control options that are applied to an individual source, so too with section 111. The explicit statutory link of CAA section 111 standards to BACT, the statutory definition of the latter, the Agency's consistent position that BACT must apply to and be achievable for a particular facility, and the text of CAA section 111(b) and 111(d), confirm the conclusion that the text of 111(a)(1) can only be read to mean that standards of performance (and the BSER on which they are predicated) are likewise measures applied to individual facilities.

(2) The Purpose of CAA Section 111 is To Design, Build, Equip, Operate, and Maintain Individual Sources so as To Reduce Emissions

Congress intended that CAA section 111 would set minimum requirements [53] on individual sources to be designed, built, equipped, operated, and maintained to reduce emissions. This purpose is evidenced in the history of CAA section 111(a)(1)'s text and corroborated by legislative history. CAA section 111 was originally enacted as part of the 1970 CAA Amendments. In that enactment, state plans under CAA section 111(d) were to establish ''emission standards'' rather than ''standards of performance.'' The EPA's CAA section 111(d) implementing regulations, issued in 1975, provided that, in the case of existing sources, the EPA would issue ''emissions guidelines,'' that these guidelines would ''reflect the degree of emission reduction achievable through the application of the [BSER] which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities,'' and that state plans establishing standards of performance for existing sources would be developed in light of these guidelines.[54] Then in 1977, Congress replaced the term ''emission standard'' under CAA section 111(d) with the phrase ''standard of performance''—a phrase defined for all of CAA section 111 in section 111(a)(1). Thus, the history behind CAA section 111(a)(1) is relevant to understanding EPA's authority for both sections 111(b) and (d).

The 1970 enactment of CAA section 111 represents a choice between two alternative approaches to direct federal regulation of stationary sources. Under the House bill, the Administrator would have been authorized to establish ''emission standards'' for new sources of pollutants that may contribute substantially to endangerment of the public health or welfare. These standards would have ''require[d] that new sources of such emissions be *designed and equipped* to maximize emission control insofar as technologically and economically feasible.'' [55] The House bill did not contain any analogous provisions for existing sources. Nevertheless, the House bill contemplated that under CAA section 111, individual sources would be designed to emit less.

Under the Senate approach, the Administrator would have established

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[47] *Id.* at 17, 44–46.

[48] 42 U.S.C. 7479(3).

[49] GHG Permitting Guidance, 25 n.64 (''While this guidance is being issued at a time when no NSPS have been established for GHGs, permitting authorities must consider any applicable NSPS as a controlling floor in determining BACT once any such standards are final.'').

[50] Accordingly, certain commenters incorrectly argue that the scope of CAA section 169 is irrelevant to regulating existing sources under CAA section 111(d) because *only* CAA section 111(b) standards (*i.e.,* NSPS), not CAA section 111(d) existing-source standards, apply to sources subject to BACT. However, both CAA section 111(b) and (d) rely on the same definition of ''standard of performance'' in CAA section 111(a), and the term's statutory history (that is, its evolution through repeated acts of Congress from 1970 to 1990) supports the conclusion that Congress intended for the term to have the same meaning under both programs. Between the 1970 and 1977 CAA Amendments, ''standards of performance'' applied only to the regulation of new sources under CAA section 111(b); existing sources, on the other hand, were required to meet ''emission standards,'' which was an undefined term. *See* Public Law 91–604, 84 Stat. at 1683–84. Between the 1977 and 1990 CAA Amendments, CAA section 111(a)(1) provided three context-specific definitions: One definition applied to *all* new stationary sources regulated under CAA section 111(b) (basing standards on the best technological system of continuous emission reduction (''TSCER'')); the second applied only to new *fossil-fuel-fired* sources regulated under CAA section 111(b) (basing standards on the TSCER *and* requiring a percent reduction in emissions); and a third applied to *existing* sources regulated under CAA section 111(d) (basing standards on the best system of continuous emission reduction). *See* Public Law 95–95, 91 Stat. at 699–700. In 1990, however, Congress replaced the three separate definitions with a singular definition of ''standard of performance'' under CAA section 111(a)(1), to apply throughout CAA section 111, based on application of the BSER. *See* Public Law 101–549, 104 Stat. at 2631. The legislative history of CAA section 111 demonstrates that Congress knew full well how to require either that the regulations applying to new and existing sources would be different in definition and scope (as in both the 1970 and 1977 versions of the Act) or that they would be the same and demonstrates that in 1990 they plainly chose the latter course.

[51] GHG Permitting Guidance, 24 (emphasis added).

[52] 42 U.S.C. 7479(3) (emphasis added).

[53] In a 1978 BACT guidance document, the EPA explained that performance standards reflect emission limits ''which can reasonably be met by all new or modified sources in an industrial category, even though some individual sources are capable of lower emissions. Additionally, because of resource limitations in the EPA, revision of new source standards must lag somewhat behind the evolution of new or improved technology. Accordingly, new or modified facilities in some source categories may be capable of achieving lower emission levels that [sic] NSPS without substantial economic impacts. The case-by-case BACT approach provides a mechanism for determining and applying the best technology in each individual situation. Hence, NSPS and NESHAP are Federal guidelines for BACT determinations and establish minimum acceptable control requirements for a BACT determination.'' U.S. EPA, Guidelines for Determining Best Available Control Technology, 3 (December 1978).

Further, while some commenters suggest that the BSER must reflect the ''greatest degree of emission control,'' citing to section 113 of Senate bill 4358 (S. 4358, at 6, 1970 Legis. Hist. at 554–55), Congress imposed no such requirement. *See Sierra Club,* 657 F.2d at 330 (''we believe it is clear that this language is far different from the words Congress would have chosen to mandate that the EPA set standards at the maximum degree of pollution control technologically achievable.'').

[54] 40 FR 53346.

[55] H.R. Conf. Rep. No. 91–1783, 46 (December 17, 1970) (emphasis added).

''standards of performance'' for new sources based ''on the greatest emission control possible through application of [the] latest available control technology.'' [56] This would have ensured ''that new stationary sources are *designed, built, equipped, operated, and maintained* so as to reduce emission[s] to a minimum.'' [57] Accordingly, such standards would have reflected ''the degree of emission control which can be achieved through process changes, operation changes, direct emission control, or other methods.'' [58] A separate provision governing emissions of ''selected agents'' authorized the Administrator to develop ''emission standards'' for both new and existing sources.[59] However, the Senate ''recognize[d] that certain old facilities may use equipment and processes which are not suited to the application of control technology. The [Administrator] would be authorized therefore to waive the application of standards . . . .'' [60]

The conference substitute settled on the language largely reflected in the current wording of CAA section 111(a)(1); the differences between the 1970 enactment and the current version are not relevant to this discussion. As explained above, *both* the Senate and House bills contemplated only control measures that would lead to better design, construction, operation, and maintenance of an individual source [61] and, in the case of existing sources under the Senate bill, the waiver of standards if certain sources could not apply new control technologies. Accordingly, recognizing that a ''system of emission reduction'' is limited to control technologies or techniques that can be integrated into an individual source's design or operation (*i.e.,* add-on controls and lower-emitting processes/practices/designs) is the only interpretation compatible with the fundamental principle, reflected in the original competing drafts of the provision, that sources should be designed, built, equipped, operated, and maintained to reduce emissions.[62]

d. The CPP Unlawfully Exceeds the Scope of CAA Section 111(a)(1) and Must Be Repealed

Before the CPP, the EPA had issued only six CAA section 111(d) rulemakings, in the form of a ''guideline document'' with corresponding ''emission guidelines.'' [63] Conversely, the EPA has issued around seventy CAA section 111(b) rulemakings, including several for new fossil-fuel-fired steam-generating units.[64] Every one of those rulemakings applied technologies, techniques, processes, practices, or design modifications directly to individual sources.

In the CPP, the EPA determined that the BSER for reducing CO_2 emissions from existing fossil fuel-fired power plants was the combination of three ''building blocks'':

1. Improving heat rate at individual affected coal-fired steam generating units;

2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for decreased generation from higher-emitting affected steam generating units; and

3. Substituting increased generation from new zero-emitting renewable energy generating capacity for decreased generation from affected fossil fuel-fired generating units.

This was the first time the EPA interpreted the BSER to authorize measures wholly outside a particular source.[65] The EPA reached this determination by interpreting the statutory term ''application'' as if it instead read ''implementation'' (without pointing to any legal basis for equating those terms), and interpreting the phrase ''system of emission reduction'' broadly as ''a set of measures that work together to reduce emissions and that are implementable by the sources themselves.'' [66] ''As a practical matter,'' the Agency continued, ''the 'source' includes the 'owner or operator' of any building, structure, facility, or installation for which a standard of performance is applicable.'' [67] The EPA then concluded that the breadth of a dictionary definition of the word ''system'' established the bounds of its statutory authority, finding that the phrase '' 'system of emission reduction' . . . means a set of measures that source owners or operators can implement to

[56] *Id.* (describing the approach under the Senate amendment).

[57] S. Rep. No. 91–1196, 15–16 (September 17, 1970) (emphasis added).

[58] *Id.* at 17.

[59] *Id.* at 18–19.

[60] *Id.* at 19.

[61] References to ''other alternatives,'' ''other means,'' or ''other methods'' in the Senate bill and accompanying report are not evidence that Congress intended to confer boundless discretion. In fact, these terms must be interpreted in light of the other specifically listed control techniques. For example, the Senate bill's reference to ''control technology,'' ''processes,'' and ''operating methods'' are properly read to denote measures that can be applied to individual sources—and ''other alternatives'' must be interpreted *ejusdem generis:* in the same fashion.

[62] To be sure, the Agency does not contend that a ''system of emission reduction'' is limited to technological improvements. Indeed, the CAA Amendments of 1990 make clear that CAA section 111 is not to be limited to ''technological systems.'' *See supra* n. 51 (discussing amendments to CAA section 111(a)(1)). But that does not mean CAA section 111 therefore authorizes basing BSER on generation shifting ''measures,'' such as substitute generation from lower- or non-polluting power plants, which cannot be applied to individual sources like add-on controls or inherently lower-emitting processes/practices/designs.

[63] (*See* 1) Phosphate Fertilizer Plants, Final Guideline Document Availability, 42 FR 12022 (March. 1, 1977) [Final Guideline Document: Control of Fluoride Emissions from Existing Phosphate Fertilizer Plants, March 1977, Doc. No. EPA–450/2–77–005]; 2) Emission Guideline for Sulfuric Acid Mist, 42 FR 55796 (October 18, 1977); 3) Kraft Pulp Mills; Final Guideline Document; Availability, 44 FR 29828 (May 22, 1979) [Kraft Pulping, ''Control of Emissions from Existing Mills,'' March 1979, Doc. No. EPA–450/2–78–003b]; 4) Primary Aluminum Plants; Availability of Final Guideline Document, 45 FR 26294 (Apr. 17, 1980) [Primary Aluminum: Guidelines for Control of Fluoride Emissions from Existing Primary Aluminum Plants, December 1979, Doc. No. EPA–450/2–78–049b]; 5) Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, 61 FR 9905 (March 12, 1996); and 6) Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 70 FR 28606 (May 18, 2005) (hereafter, the Clean Air Mercury Rule or CAMR) (vacated in *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2007) (reviewing an action that sought to shift regulation of certain emissions from power plants from the CAA section 112 hazardous air pollutants regime to the section 111 standards regime and holding that the EPA failed to comply with the delisting requirements of section 112(c)(9) and thus vacating the corresponding section 111 standards for electric utility steam generating units). This list of six CAA section 111(d) rulemakings does not include any guideline documents mandated by and carried out in compliance with CAA section 129 (governing solid waste incinerator units).

[64] *See generally* 40 CFR part 60, subparts D–TTTT. In fact, steam-generating units were among the first sources regulated under section 111(b). *See* 36 FR 24876 (December 23, 1971) (promulgating standards for steam generators, portland cement plants, incinerators, nitric acid plants, and sulfuric acid plants).

[65] CAMR, which relied in part on a cap-and-trade mechanism, was still ultimately ''based on control technology available in the relevant timeframe,'' an approach fundamentally different than the CPP's second and third ''building blocks,'' which were not based on systems that could be applied to or at individual sources. Indeed, the rule explained that the BSER refers to ''the combination of the cap-and-trade mechanism *and the technology needed* to achieve the chosen cap level.'' 70 FR 28620 (emphasis added). Accordingly, the Agency concluded that it would be ''reasonable to establish a cap on [the basis of using a particular technology] and require compliance with that cap at a later point in time when the necessary technology becomes widely available.'' *Id.* To the extent that CAMR's BSER (*i.e.,* the combined control technology and cap-and-trade program) is premised on application to the source category (as opposed to an individual source), however, CAMR would be unlawful. Trading as a compliance mechanism under CAA section 111 is discussed in section III.F.2.a of this preamble.

[66] 80 FR 64762 (citing the Oxford Dictionary of English (3rd ed.) (2010), among others). The EPA reached this interpretation in part on the assumption that ''the terms 'implement' and 'apply' are used interchangeably.'' *See* Legal Memorandum Accompanying Clean Power Plan for Certain Issues at 84 n.175.

[67] 80 FR 64762.

achieve an emission limitation applicable to their existing source.'' [68]

In reviewing the CPP, the EPA concludes that the interpretation relied upon in the CPP ignored or misinterpreted critical statutory elements and rules of statutory construction. After reconsidering the relevant statutory text, structure, and purpose, the Agency now recognizes that Congress ''spoke to the precise question'' of the scope of CAA section 111(a)(1) and clearly precluded the unsupportable reading of that provision asserted in the CPP. Accordingly, this action repeals the CPP.[69]

(1) The CPP Is Impermissibly Based on ''Implementation'' Rather Than ''Application'' of the BSER

CAA section 111(a)(1) provides that standards of performance reflect an emission limitation achievable ''through the application of the [BSER] . . . .'' In the Legal Memorandum accompanying the CPP, the Agency stated in a footnote that ''the terms 'implement' and 'apply' are used interchangeably.'' [70] Thus, the Agency decided, ''the system must be limited to measures that can be implemented—''appl[ied]''—by the sources themselves . . . .'' [71] But Congress does not in fact use these terms interchangeably in the Act, and in CAA section 111(a)(1), as in other source-focused standard-setting provisions in the Act, used a term (''application'') meaningfully different than the one CPP read into that section (''implementation'')—and the term that Congress actually used is one that reflects the CAA's other source-focused standard-setting provisions.[72]

The Act is replete with provisions calling for the ''implementation'' of ''a system,'' [73] ''control measures,'' [74] ''emission reduction measures,'' [75] and even ''steps, *by owners or operators of stationary sources,*'' [76] but CAA section 111(a)(1) is not among them. Congress defines ''implementing'' under CAA section 105(a)(1)(A) as ''any activity related to the planning, developing, establishing, carrying-out, improving, or maintaining of such programs [for the prevention and control of air pollution or implementation of national primary and secondary ambient air quality standards].'' [77] But again, ''applying'' is not included in this list defining ''implementing.'' In the case of the Act's standard-setting provisions, on the other hand, BACT and maximum achievable control technology (MACT) requirements—like CAA section 111—are based on ''application of'' control measures to individual sources.

Functionally, the two terms send different signals. ''Implementation'' requires a subject and direct object (I implement the plan), whereas ''application'' requires a subject, direct object, and indirect object (I apply the protocol to the subject). That is, an owner or operator can implement a system (without anything more and without any particular object of the system being implied), but an owner/operator must apply a system *to* another object (*i.e.,* the source). CAA section 111 illustrates this distinction. Congress provided, in CAA section 111(d)(1), that state plans must provide ''for the implementation and enforcement of such standards of performance,'' but that EPA's regulations must also permit a state ''in applying a standard of performance to any particular source'' to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies. Thus, whereas state plans more broadly ''implement'' the CAA section 111(d) program, states ''appl[y]'' standards to individual sources. Congress could have defined a standard of performance as reflecting the ''implementation of the BSER by the owner or operator of a stationary source,'' but Congress did not. Simply put, equating the terms ''implement'' and ''apply'' conflicts with the plain language of CAA section 111(a)(1) and their use throughout the Act; this conflict is compounded by the conflation of the source with its owner, different concepts that are separately defined, *see* CAA section 111(a)(3), (5).

Now take generation shifting, the basis for the second and third ''building blocks'' of the CPP's BSER. The CPP recognized that an owner or operator of a regulated source can ''shift'' power-producing operations to a different facility, such as a nuclear power plant, through bilateral contracts for capacity or by reducing utilization. But just because generation shifting is ''implementable'' by an owner or operator (*i.e.,* just because an owner or operator of a given source can subsidize generation elsewhere that will reduce demand for generation from that) does not mean that generation shifting can be ''applied'' to the source.[78] And indeed, the CPP shifted generation from one regulated source category to another and from both those regulated source categories together to other forms of electricity generation outside any regulated source category. Because the CPP is premised on ''implementation of the BSER by a source's owner or operator'' and not ''application of the [BSER]'' to an individual source, the rule contravenes the plain language of CAA section 111(a)(1) and must be repealed.

[68] *Id.* The EPA acknowledged, nonetheless, that ''regulatory requirements'' in the CPP would be based ''on measures the affected EGUs can implement to assure that electricity is generated with lower emissions'' and that ''do not require reductions in the total amount of electricity produced.'' *Id.* at 64778. But the EPA did not exclude such ''measures'' (*i.e.,* reduced utilization and demand-side energy efficiency) as being outside the scope of the dictionary definition of ''system.'' Indeed, the EPA believed they would play an important compliance role under the CPP. *See id.* at 64753–657 (discussing reduced utilization and demand-side energy efficiency measures under rate-based and mass-based state plans). *See also* n. 83, *infra.*

[69] One commenter asserted that, rather than repeal the CPP, the EPA should retain building block 1. As explained in the Proposed Repeal, however, while heat rate improvement measures may be considered in a CAA section 111 standard, ''building block 1, as analyzed, cannot stand on its own. 80 FR 64758 n. 444; see also *id.* at 64658 (discussing severability of the building blocks).'' 82 FR 48039 n.5. Accordingly, today's action repeals the whole of the CPP and does not retain building block 1 as the BSER. In any case, as discussed in the ACE proposal, ''building block 1, as constructed in [the] CPP, does not represent an appropriate BSER, and ACE better reflects important changes in the formulation and application of the BSER in accordance with the CAA.'' 83 FR 44756 (discussing the EPA's change in approach to analyzing heat rate improvement measures). See section III for the EPA's evaluation of heat rate improvement measures under ACE.

[70] Legal Memorandum Accompanying Clean Power Plan for Certain Issues at 84 n.175.

[71] 80 FR 64720.

[72] *See, e.g.,* 42 U.S.C. 7412(d)(2) (describing MACT as ''through application of measures, processes, methods, systems or techniques including, but not limited to, measures which—(A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications, (B) enclose systems or processes to eliminate emissions, (C) collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point, (D) are design, equipment, work practice, or operational standards . . . , or (E) are a combination of the above;''); *id.* at 7479(3) (describing BACT as ''achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control'').

[73] 42 U.S.C. 7412(r)(7)(H)(vii) (''the Administrator . . . shall develop and implement a system for providing off-site consequence analysis information'').

[74] *Id.* 7511a(b)(2) (''Such plan provisions shall provide for the implementation of all reasonably available control measures'').

[75] *Id.* 7412(i)(5)(C) (''prior to implementation of emissions reduction measures'').

[76] *Id.* 7410(a)(2)(F) (emphasis added) (''require, as may be prescribed by the Administrator—(i) the installation, maintenance, and replacement of equipment, and the implementation of other necessary steps, by owners or operators of stationary sources'').

[77] 42 U.S.C. 7405(a)(1)(A).

[78] A contract, for example, is neither a ''system'' nor ''applied to'' a source.

(2) Dictionary Definitions Cannot Confer an ''Infinitude'' of Possibilities

Although the word ''system'' is not defined in the CAA, ''[t]he meaning—or ambiguity—of certain words or phrases may only become evident when placed in context.'' [79] Thus, the issue is not whether the dictionary provides a broad definition of the word ''system,'' but what are the permissible bounds of the *legal* meaning of the word ''system.'' The precise question in this case is whether the word ''system'' as used in CAA section 111 encompasses any ''set of measures'' [80] to reduce emissions, or whether it is limited to lower-emitting processes, practices, designs, and add-on controls that are applied at the level of the individual facility.

''System,'' as used in CAA section 111, cannot be read to encompass *any* ''set of measures'' that would—through some chain of causation—lead to a reduction in emissions. As an initial matter, Congress did not use the phrase ''set of measures'' in CAA section 111. On its own, this phrase could create unbounded discretion in the Agency. Moreover, even when the term ''measures'' is used elsewhere in the Act, it is intended to be limited. For example, CAA section 112 emission standards are derived ''through application of *measures,* processes, methods, systems or techniques.'' ''Measures,'' are further defined to include measures which:

- Reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications,
- enclose systems or processes to eliminate emissions,
- collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point,
- are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in subsection (h) of CAA section 111, or
- are a combination of the above.[81]

''Measures,'' as Congress provides, are limited to control measures that can be integrated into an individual source's design or operation. ''Measures'' do not include shifting production away from the regulated source. The CPP read ''system'' in CAA section 111(a)(1) to mean any ''set of measures,'' relying on the dictionary, and then determined that there was no limitation on those ''set of measures'' so long as they were measures that could be implemented through obligations placed on the owner or operator of a source.[82] At both steps, the CPP relied on an absence of an express textual commandment forbidding these open-ended interpretations. That methodology is untenable.

Construing ''system'' to offer such an ''infinitude'' [83] of possibilities would have significant implications. The fact is, fossil fuel-fired EGUs operate within an interconnected ''system.'' Thus, any action that would affect electricity rates will have generation-shifting and potentially emission-reduction consequences. By the very nature of the interconnected grid, EPA's authority to determine the BSER under CAA section 111 is, under the Agency's prior interpretation, stretched to every aspect of the entire power sector. This cannot have been the intent of the Congress that enacted CAA section 111.

The D.C. Circuit has previously disapproved of a federal agency's expansive reading of its authority in analogous circumstances. In *Cal ISO,* the D.C. Circuit vacated the Federal Energy Regulatory Commission's (''FERC'') attempt to reform a utility's governing structure on the theory that FERC's statutory authority over ''practice[s] . . . affecting [a] rate'' gave FERC ''authority to regulate anything done by or connected with a regulated utility, as any act or aspect of such an entity's corporate existence could affect, in some sense, the rates.'' [84]

Upholding FERC's interpretation of ''practice'' to include replacing the governing board of California's Independent System Operator Corporation, the Court warned, could authorize FERC to ''dictate the choice of CEO, COO, and the method of contracting for services, labor, office space, or whatever one might imagine . . . .'' [85] But where ''the text *and reasonable inferences from it* give a clear answer . . . that . . . is 'the end of the matter.' '' [86] There is no need, therefore, to consider ''such parade of horribles.'' [87]

The Court explained that, ''no matter how important the principle of ISO independence is to the Commission, '[the FERC Order] is merely a regulation,' and cannot be the basis to override the limitations of 'statutes enacted by both houses of Congress and signed into law by the president.'' [88] The court reasoned that both ''the history of the application of this and similar statutes and by the implications of FERC's amorphous defining of the term'' firmly barred FERC's attempt to stretch its authority.[89] On this point, Congress's intent is ''crystal clear''—FERC had no authority to ''reform and regulate the governing body of a public utility under the theory that corporate governance constitutes a 'practice' for ratemaking authority purposes.'' [90]

The EPA's prior interpretation underlying the CPP is untenable for the same reasons. The EPA began, like FERC, with an ordinary statutory term (''system'') and then read into it maximally broad authority to shift generation away from coal-fired and gas-fired power plants to other electricity producers on the basis that generation shifting would cause those regulated sources to be displaced and therefore not be a source of emissions. But for nearly 45 years prior to the CPP, this Agency had never understood CAA section 111 to confer upon it the implicit power to restructure the utility industry through generation-shifting measures. Indeed, the EPA has issued many 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)). In all those rules, the EPA determined that the BSER consisted of add-on controls or lower-emitting processes/practices/designs that can be applied to individual sources.[91]

The CPP deviated from this settled understanding of CAA section 111. By embracing an expansive dictionary definition of ''system,'' [92] the EPA ignored that the text and structure of the Act expressly limited the scope of the term ''system'' in a way that foreclosed the CPP's expansive definition. The Agency concluded that actions that would cause generation to shift from higher-emitting to lower- or non-

[79] *King* v. *Burwell,* 135 S. Ct. 2480, 2489 (2015) (quoting *FDA* v. *Brown & Williamson Corp.,* 529 U.S. 120, 132 (2000)).

[80] 80 FR 64762.

[81] 42 U.S.C. 7412(d)(2).

[82] The CPP identified purported limitations to the underlying legal interpretation (*e.g.,* ''system'' does not extend to measures that directly target consumer behavior), *see* 80 FR 64776–779, but those purported limitations still led to an interpretation that far exceeded the bounds of the authority actually conferred by Congress on the EPA.

[83] *See Cal. Indep. Sys. Operator Corp.* v. *FERC,* 372 F.3d 395, 401 (D.C. Cir. 2004) (''*Cal ISO*'').

[84] *Id.*

[85] *Id.* at 403.

[86] *Id.* at 401 (citing *Brown* v. *Gardiner,* 513 U.S. 115, 120 (1994)) (emphasis in original).

[87] *Id.* at 403.

[88] *Id.* at 404.

[89] *Id.* at 402.

[90] *Id.*

[91] See *supra* n. 66 (discussing CAMR).

[92] 80 FR at 64720 (defined by the Oxford Dictionary of English as ''a set of things or parts forming a complex whole; a set of principles or procedures according to which something is done; an organized scheme or method; and a group of interacting, interrelated, or independent elements'').

emitting power generators represent a means of reducing CO_2 emissions from existing fossil fuel-fired electric generating units—and thus constituted a "system" within the meaning of CAA section 111. Taken to its logical end, however, any action affecting a generator's operating costs could impact its order of dispatch and lead to generation shifting. This could include, for example, minimum wage requirements or production caps. It is axiomatic that "Congress . . . does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes." [93] Because Congress clearly did not authorize CAA section 111 standards to be based on *any* "set of measures," the EPA need not address the potential consequences of deviating from our historical practice under CAA section 111 when determining whether the CPP's interpretation was a permissible reading of the statute. Like the D.C. Circuit in *Cal ISO,* the EPA concludes that the text and reasonable inferences from it give a clear answer: "system" does not embody any conceivable "set of measures" that might lead to a reduction in emissions, but is limited to measures that can be applied to and at the level of the individual source

(3) Basing BSER on Generation Shifting Is Not Authorized by Congress

On the question of whether basing BSER on generation shifting is precluded by the statute, the major question doctrine instructs that an agency may issue a major rule only if Congress has *clearly* authorized the agency to do so. As the Supreme Court has stated, "We expect Congress to speak clearly if it wishes to assign to an agency decisions of vast 'economic and political significance.' " [94] Although the Court has not articulated a bright-line test, its cases indicate that a number of factors are relevant in distinguishing major rules from ordinary rules: "the amount of money involved for regulated and affected parties, the overall impact on the economy, the number of people affected, and the degree of congressional and public attention to the issue." [95]

While the EPA believes that today's action is based on the only permissible reading of the statute and would reach that conclusion even without consideration of the major question doctrine, the EPA believes that that doctrine should apply here and that its application confirms the unambiguously expressed intent of CAA section 111. The CPP is a major rule. At the time the CPP was promulgated, its generation-shifting scheme was projected to have billions of dollars of impact on regulated parties and the economy, would have affected every electricity customer (*i.e.,* all Americans), was subject to litigation involving almost every State in the Union, and, as discussed in the following section, would have disturbed the state-federal and intra-federal jurisdictional scheme. Building blocks 2 and 3 are far afield from the core activity of CAA section 111—indeed, no section 111 rule of the scores issued has ever been based on generation shifting since the enactment of CAA section 111 in 1970. Because the CPP is a major rule, the interpretative question raised in CAA section 111(a)(1) (*i.e.,* whether a "system of emission reduction" can consist of generation-shifting measures) must be supported by a clear-statement from Congress.[96] As explained above, however, it is not—indeed, Congress has directly spoken to this precise question and precluded the interpretation of CAA section 111 advanced by the EPA in the CPP.

Further evidence comes from the notable absence of a valid limiting principle to basing a CAA section 111 rule on generation shifting. In the CPP, the EPA explained that the Agency "has generally taken the approach of basing regulatory requirements on controls and measures designed to reduce air pollutants from the production process without limiting the aggregate amount of production." [97] But by shifting focus to the entire grid (which includes regulated sources and non-sources), the Agency could empower itself to order the wholesale restructuring of any industrial sector (whether or not it has authority to even regulate all the actors within that sector—so long, in keeping with the interpretation underlying the CPP, as it can place obligations on the owners and operators over whom it does have authority to carry out a "system" that goes beyond the EPA's actual direct reach). Appealing to such factors as "cost" and "feasibility" [98] as putative constraints on EPA's authority, furthermore, does not provide any assurance—indeed, the D.C. Circuit traditionally "grant[s] the [A]gency a great degree of discretion in balancing them." [99] Thus, it is not reasonable to find in this statutory scheme Congressional intent to endow the Agency with discretion of this breadth to regulate a fundamental sector of the economy.

As a final point, the CPP not only advanced a broad reading of CAA section 111(a)(1), the rule applied that interpretation to "the source category as a whole" [100] to cause a reduction in coal-fired generation.[101] To do so, the CPP relied on "emission reduction approaches that focus on the machine as a whole—that is, the overall source category—by shifting generation from dirtier to cleaner sources in addition to emission reduction approaches that focus on improving the emission rates of individual sources." [102] Consequently, it was designed as "an emission guideline for an entire category of existing sources . . . ." [103] However, by acting as a guideline for an entire category, the CPP ignored the statutory directive to establish standards *for* sources and overextended federal authority into matters traditionally reserved for states: "administration of integrated resource planning and . . . utility generation and resource portfolios." [104]

(4) Basing BSER on Generation Shifting Encroaches on FERC and State Authorities

The Federal Power Act (FPA) establishes the dichotomy between federal and state regulation in the electricity sector by drawing "a bright line easily ascertained, between state and federal jurisdiction." [105] The Supreme Court recently observed that, under the FPA, FERC has "exclusive jurisdiction over wholesale sales of electricity in the interstate market" and

[93] *Whitman* v. *American Trucking,* 531 US 457, 466 (2001). *See also* Letter from Neil Chatterjee, Chairman, Fed. Energy Reg. Comm'n, to Andrew Wheeler, Administrator, EPA at 5 (Oct. 31, 2018) (Docket ID# EPA–HQ–OAR–2017–0355–24053) ("The Supreme Court has explained several times that Congress 'does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes.' The challenges posed by global climate change present 'question[s] of deep 'economic and political significance' that [are] central to [the] statutory scheme[s]' administered by both the Agency and the Commission.") (internal citation omitted).

[94] *Utility Air Regulatory Group* v. *EPA,* 573 U.S. 302, 324 (2014) (quoting *Brown & Williamson,* 529 U.S. at 159).

[95] *U.S. Telecom Ass'n* v. *FCC, 855 F.3d 381,* 422–23 (D.C. Cir. 2017) (internal citations omitted).

[96] The EPA acknowledges that for the reasons noted above, its position on this major rule issue has evolved since the EPA addressed it in the CPP, 80 FR 64,783. *See FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009).

[97] 80 FR 64762.

[98] *See* Legal Memorandum Accompanying Clean Power Plan for Certain Issues at 117–20.

[99] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[100] 80 FR 64727.

[101] *Id.* at 64665.

[102] 80 FR 64725–726; see also *id.* at 64726 (noting "consideration of emission reduction measures at the source-category level").

[103] CPP RTC Chapter 1A, 170–72.

[104] *New York* v. *FERC,* 535 US 1, 24 (2002).

[105] *Fed. Power Comm'n* v. *S. Cal. Edison Co.,* 376 U.S. 205, 215 (1964).

establishing the associated just and reasonable rates and charges.[106] However, ''the law places beyond FERC and leaves to the States alone, the regulation of 'any other sale'—most notably, any retail sale—of electricity.'' [107] Therefore, under the FPA, Congress limited the jurisdiction of FERC ''to those matters which are not subject to regulation by the States,'' including ''over facilities used for the generation of electric energy.'' [108] Indeed, ''the States retain their traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost, and other related state concerns.'' [109] ''Such responsibilities include ''authority over the need for additional generating capacity [and] the type of generating facilities to be licensed.'' [110] Thus, the FPA ''not only establishes an affirmative grant of authority to the federal government to regulate wholesale sales and transmission of electricity in interstate commerce, but also draws a line where that exclusive authority ends and the state's exclusive authority to regulate other matters . . . begins.'' [111]

Courts have observed that regulation of other areas may incidentally affect areas within these exclusive domains, but there is no room for direct regulation by States in areas of FERC domain or vice-versa, and such regulation that would achieve indirectly what could not be done directly is also prohibited.[112] Just as ''FERC has no authority to direct or encourage generation'' [113] absent clear authority from Congress, neither does (indeed, *a fortiori* so much the less does) the EPA.[114] The EPA has no more ability to ''do indirectly what it could not do directly'' than FERC would with respect to matters that the FPA left to the states. Historically, any traditional environmental regulation of the power sector may have incidentally affected these domains without indirectly or directly regulating within them. For example, an on-site control, such as a scrubber, may affect rate determinations as it is factored into potentially recovered costs. The CPP, however, included a BSER that was based largely on measures and subjects exclusively left to FERC and the states, rather than inflicting only permissible, incidental effects on those domains.

The CPP identified as part of the BSER generation-shifting measures. Increased renewable generation capacity, building block 3, falls within a state's authority to determine its generation mix and to direct the planning and resource decisions of utilities under its jurisdiction.[115] Additionally, increased utilization of natural gas combined cycle (NGCC) plants, building block 2, falls within that state authority and within FERC's authority to determine just and reasonable rates by requiring a conclusion that the associated costs of increased utilization rates are reasonable, and, further ignores these areas of exclusive regulation by neglecting to consider changes to regional transmission organization (RTO) and ISO dispatch procedures necessary to achieve the increased utilization rates. By including generation-shifting measures within the states' and FERC's purview in the BSER, rather than relying on traditional controls within the EPA's purview, the EPA established a rule predicated largely upon actions in the power sector outside of the scope of the Agency's authority to compel. Some generation shifting may be an incidental effect of implementing a properly established BSER (*e.g.,* due to higher operation costs), but basing the BSER itself on generation shifting improperly encroaches on FERC and state authorities.

Further, the actual effect of the CPP as anticipated by the EPA was that the states would impose standards of performance based on the EPA's BSER, and sources would largely rely on generation-shifting measures to comply with those standards. In its analysis of potential energy impacts associated with the rule, the CPP modeling ''presume[d] policies that lead to generation shifts and growing use of demand-side [energy efficiency] and renewable electricity generation out to 2029.'' [116] In this manner, the CPP could directly shape the generation mix of a complying state. It is clear from the FPA that Congress intended the states to have that authority, not the relevant federal agency, FERC. Given that even FERC would not have such authority, the only reasonable inference is that Congress did not intend to give the EPA that authority via CAA section 111.[117] Federal law ''may not be interpreted to reach into areas of state sovereignty unless the language of the federal law compels the intrusion,'' [118] and, as discussed above, basing BSER on generation shifting is not authorized by Congress here. Such an interpretation is also consistent with the cooperative-federalism framework of the CAA.[119] While the EPA has previously asserted that the CPP only provides emissions guidelines, leaving the states with the flexibility to create their own compliance measures,[120] the guidelines are based on actions outside of the EPA's authority to directly or indirectly compel and the practical effect of

[106] *Hughes* v. *Talen Energy Marketing, LLC,* 136 S.Ct. 1288, 1291–92 (2016) (citing 16 U.S.C. 824(b)(1), 824d(a) and 824e(a)).

[107] *Id.* at 1292 (quoting *FERC* v. *Electric Power Supply Assn.,* 136 S.Ct. 760, 766 (2016) (EPSA) (quoting 824(b)). The States' reserved authority includes control over in-state ''facilities used for the generation of electric energy.'' 824(b)(1); see *Pacific Gas & Elec. Co.* v. *State Energy Resources Conservation and Development Comm'n,* 461 U.S. 190, 205 (1983) (''Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States.'').

[108] 16 U.S.C. 824(a), 824(b)(1); see also *id.* 824*o*(i)(2) (''This section does not authorize . . . [FERC] to order the construction of additional generation or transmission capacity''). There are other jurisdictional limitations under the FPA. For example, publicly-owned and many cooperatively owned utilities are subject to only some elements of the FPA. *Id.* 824(f), 824(b)(2). And entities not operating in interstate commerce, *i.e.,* entities in Alaska, Hawaii, and the Electric Reliability Council of Texas portion of Texas, are also subject to only limited FERC jurisdiction.

[109] *Pacific Gas & Elec. Co.* v. *State Energy Resources Conservation and Development Comm'n,* 461 U.S. 190, 205 (1983).

[110] *Id.* at 212.

[111] Dennis, Jeffrey S., et al., Federal/State Jurisdictional Split: Implications for Emerging Electricity Technologies, 3 (December 2016), *available at https://www.energy.gov/sites/prod/files/2017/01/f34/Federal%20State%20Jurisdictional%20Split-Implications%20for%20Emerging%20Electricity%20Technologies.pdf; see also* 16 U.S.C. 824*o*(i)(2) (''This section does not authorize . . . [FERC] to order the construction of additional generation or transmission capacity'').

[112] *Hughes,* 136 S. Ct. at 1297–98. *See also* EPSA, 753 F.3d at 221, 224 (''the Federal Power Act unambiguously restricts FERC from regulating the retail market'' and quoting *Altamont Gas Transmission Co.* v. *FERC,* 92 F.3d 1239, 1248 (D.C. Cir. 1996)) (noting that ''FERC cannot 'do indirectly what it could not do directly' '').

[113] CRS, The Federal Power Act (FPA) and Electricity Markets, 9 (March 10, 2017), *available at https://www.everycrsreport.com/files/20170310_R44783_dd3f5c7c0c852b78f3ea62166ac5ebdbd1586e12.pdf.*

[114] *See* 80 FR 64745 (explaining that ''the BSER also reflects other CO_2 reduction strategies that *encourage* increases in generation from lower- or zero-carbon EGUs'') (emphasis added); *cf.* 42 U.S.C. 7651(b) (providing that one purpose of Title IV (but not the CAA overall) is to encourage the ''use of renewable and clean alternative technologies'').

[115] *See* S.Cal. Edison Co., 71 FERC 61,269 (June 2, 1995); see also *Pacific Gas & Elec. Co.* v. *State Energy Resources Conservation and Development Comm'n,* 461 U.S. 190, 205, 212 (1983).

[116] 80 FR 64927.

[117] *See Solid Waste Agency of Northern Cook County* v. *U.S. Army Corps of Engineers,* 531 U.S. 159, 172 (2001) (citing *Edward J. DeBartolo Corp.* v. *Florida Gulf Coast Building & Constr. Trades Council,* 485 U.S. 568, 575 (1988)).

[118] *Am. Bar Ass'n* v. *FTC,* 430 F.3d 457 (D.C. Cir. 2005).

[119] *See, e.g.,* 42 U.S.C. 7401(b)(3) and (4), 7402(a) and (b), and 7416.

[120] 80 FR 64762 (''States will have the flexibility to choose from a range of plan approaches and measures, including numerous measures beyond those considered in setting the CO_2 emission performance rates'').

implementing the guidelines is that many of those actions likely must be taken.

(5) Commenters' Attempt To Recharacterize the BSER in the CPP as Applying to Sources By Pointing to ''Reduced Utilization'' Is Unavailing and Clearly Precluded by the CAA

(a) The CPP Rejected ''Reduced Utilization'' as a ''System'' for Purposes of CAA Section 111.

Some commenters claim reduced utilization can be ''applied to'' a source as an ''operational method'' for reducing emissions. In the CPP, however, the EPA was clear that reduced utilization on its own ''does not fit within our historical and current interpretation of the BSER.'' [121] The EPA explained: ''Specifically, reduced generation by itself is about changing the amount of product produced rather than producing the same product with a process that has fewer emissions,'' [122] and the EPA has historically based pollution control on ''methods that allow the same amount of production but with a lower-emitting process.'' [123] In proposing to repeal the CPP, the EPA noted that, ''[w]hereas some emission reduction measures (such as a scrubber) may have an incidental impact on a source's production levels, reduced utilization is directly correlated with a source's output.'' [124] Accordingly, ''predicating a section 111 standard on a source's non-performance would inappropriately inject the Agency into an owner/operator's production decisions.'' [125] The EPA is finalizing our proposal that reduced utilization cannot be considered a ''best system of emission reduction'' under CAA section 111(a)(1) because, as the EPA said in the CPP, the EPA has never identified reduced utilization as the BSER and the EPA interprets CAA section 111 to authorize emission limits based on controls that reduce emissions without restricting production. In addition, because the CPP was not premised on ''reduced utilization''—indeed, the EPA expressly renounced that as a basis for the CPP—commenters' attempt to justify the CPP on that basis is unavailing.

(b) Standards of Performance Cannot Be Based on Reduced Utilization

Even if the CPP could be reframed as employing reduced utilization, it would fail to satisfy statutory criteria.

CAA section 302(*l*) provides that a ''standard of performance'' means ''a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous reduction.'' Previously, the Agency has argued that the definitions in CAA section 111(a)(1) ''are more specific'' and therefore controlling,[126] but, to the extent that section 302(*l*) applies, that definition is met when a standard ''applies continuously in that the source is under a continuous obligation to meet its emission rate . . . .'' [127]

Here, the Agency concludes that CAA section 302(*l*) is relevant to interpreting CAA section 111.[128] Statutes should be construed ''so as to avoid rendering superfluous'' any statutory language: ''a statute should be construed so that effect is given to all its provisions, so that no part will be inoperative or superfluous, void or insignificant. . . .'' [129] Under the CAA, only section 111 requires the establishment of ''standards of performance.'' Thus, ignoring the generally applicable definition in CAA section 302(*l*) in interpreting CAA section 111 would read it out of the statute. Nor is this a situation where Congress provided that the provision-specific definition in CAA section 111 was to supplant the general definition in CAA section 302(*l*). First, the opening phrase of CAA section 302 indicates that the section 302 definitions apply ''[w]hen used in this chapter.'' By contrast, the definitions provisions in some statutes begins with text that expressly provides that the general statutory definitions are supplanted by provision-specific definitions. *See, e.g.,* Clean Water Act (CWA) section 502 (33 U.S.C. 1362) (which begins ''Except as otherwise specifically provided . . . .''). Second, one of the CAA section 302 definitions expressly states that it is supplanted by provision-specific definitions.[130]

However, the Agency was wrong to conclude that ''a requirement of continuous emission reduction'' means only that a standard of performance need apply ''on a continuous basis.'' In fact, Congress used such phrasing in the preceding definition under CAA section 302(k). The terms ''emission limitation'' and ''emission standard'' mean ''a requirement . . . 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 a source *to assure continuous emission reduction. . . .*'' [131] Whereas emission limitations and emission standards apply ''on a continuous basis, *including any* requirement . . . to assure continuous emission reduction,'' standards of performance *must* impose a ''requirement of continuous emission reduction.''

When Congress made explicit the requirement for ''continuous emission reduction,'' it was to ''affirm the decisions of four U.S. courts of appeals cases that the [A]ct requires continuous emission reductions to be applied.'' [132] Thus, as scholar David Currie observed,

[121] 80 FR 64780.

[122] *Id.*

[123] 80 FR 64782 n.602.

[124] 83 FR 44752.

[125] *Id.*

[126] *See* Brief of Respondent at 129–30, *New Jersey* v. *EPA,* No. 05–1097 (consolidated) (D.C. Cir. May 4, 2007).

[127] 80 FR 64841. *See also* 70 FR 28617 (''Even if the 302(*l*) definition applied to the term 'standard of performance' as used in section 111(d)(1), [the] EPA believes that a cap-and-trade program meets the definition. . . . That is, there is never a time when sources may emit without needing allowances to cover those emissions.'').

[128] Indeed, the provisions of CAA section 302 are supplanted by provision-specific definitions only to the extent that those specific provisions ''expressly'' do so. *See, e.g., Alabama Power* v. *Costle,* 636 F.2d 323, 370 (D.C. Cir. 1979) (holding that CAA section 169(1) is controlled by the general definition in CAA section 302(j) with respect to the ''rule requirement'' in CAA section 302(j) that is not expressly supplanted by CAA section 169(1)).

[129] *Hibbs* v. *Winn,* 542 U.S. 88, 101 (2004). *Cf.* Brief of Respondent at 129, *New Jersey* v. *EPA* (''[s]pecific terms prevail over the general in the same or another statute which might otherwise be controlling.'' (citation and quotation marks omitted)).

[130] *See* CAA section 302(j) (which defines ''major stationary source'' and ''major emitting facility'' and begins ''Except as otherwise expressly provided, ...'').

[131] 42 U.S.C. 7602(k) (emphasis added). *See* H.R. 6161, Rep. No. 95–294, 92 (May 12, 1977) (''Without an enforceable emission limitation *which will be complied with at all times,* there can be no assurance that ambient standards will be attained and maintained. Any emission limitation under the [CAA], therefore must be *met on a constant basis. . . .*'') (emphasis added).

[132] H.R. Conf. Rep. No. 95–564, 514 (Aug. 3, 1977); see also H.R. No. 95–294, 190 (May 12, 1977) (''To make clear the committee's intent that intermittent or supplemental control measures are not appropriate technological systems for new sources (and to prevent the litigation which has been conducted with respect to use of intermittent or supplemental systems at existing sources), the committee adopted language clearly stating that continuous emission reduction technology would be required to meet the requirements of this section.''); and *id.* at 92 (''By defining the terms 'emission limitation,' 'emmission [sic] standard,' and 'standard of performance,' the committee has made clear that constant or continuous means of reducing emissions must be used to meet these requirements.''). For example, ''The Sixth Circuit has agreed with the Fifth, upholding the EPA's rejection of a provision that would have allowed 'intermittent' controls when necessary to meet ambient standards, adding on the basis of a stray remark of the Supreme Court in *Train* that 'emission standards' were only those limiting the 'composition' of an emission, not restrictions on operation or on the content of fuels.'' David P. Currie, Federal Air-Quality Standards and Their Implementation, 365 American Bar Foundation Research Journal, 376 n.58 (1976).

Congress ''intended to forbid reliance on intermittent control strategies, such as temporary use of low-sulfur fuels *or reductions in plant output* . . . .'' [133] Because standards of performance cannot be based on intermittent control strategies, basing BSER on reduced utilization is statutorily precluded for purposes of CAA section 111.

Finally, basing the BSER on reduced utilization contravenes the plain meaning of a ''standard of performance.'' As the Supreme Court held most recently in *Weyerhaeuser* v. *FWS,* 139 S. Ct. 361 (2018),[134] and previously in *Solid Waste Agency of Northern Cook County,* courts must give statutory terms meaning, even where they are part of a larger statutorily defined phrase.[135] In the phrase ''standard of performance,'' the term ''performance'' is defined as ''[t]he accomplishment, execution, carrying out, . . . [or] doing of any action or work,'' [136] and thus refers to the source's manufacturing or production of product. Reduced utilization does not involve improvements to a source's emissions during ''performance;'' instead it calls for non-performance—the cessation or limitation of manufacturing or production —of a source. Accordingly, reduced utilization cannot form the basis of a ''standard of performance'' under CAA section 111.

The definition of ''standard of performance,'' and the scope of the ''best system of emission reduction'' contained within, confers considerable discretion on the EPA to interpret the statute and make reasonable policy choices pursuant to *Chevron* step two as to what is the best system to reduce emissions of a particular pollutant from a particular type of source. However, by making clear that the ''application'' of the BSER must be to the source, Congress spoke directly in *Chevron* step one terms to the question of whether the BSER may contain measures other than those that can be put into operation at a particular source: It may not. The approach to BSER in the CPP is thus unlawful and the CPP must be repealed.

C. Independence of the Repeal of the Clean Power Plan

Although this action appears in the same document as the ACE rule and the revisions to the emission guidelines implementing regulations, the repeal of the CPP is a distinct final agency action that is not contingent upon the promulgation of ACE or the new implementing regulations. As explained above, Congress spoke directly to the question of whether CAA section 111 authorizes the EPA to issue regulations pursuant to CAA section 111(d) that call for the establishment of standards of performance based on the types of measures that comprised the second and third building blocks of the CPP's BSER permits the Agency's to consider generation-shifting as a potential system of emission reduction in developing emission guidelines. The answer to that question is no.

The CPP described itself as a ''significant step forward in reducing [GHG] emissions in the U.S.'' and relied ''in large part on already clearly emerging growth in clean energy innovation, development and deployment . . . .'' 80 FR 64663. Market-based forces have already led to significant generation shifting in the power sector. However, the fact that those market forces have had that result does not confer authority on the EPA beyond what Congress conferred in the CAA.

The EPA does not deny that, if it were validly within the Agency's authority under the statute, regulations that can only be complied with through widespread implementation of generation shifting might be a workable policy for achieving sector-wide carbon-intensity reduction goals. But what is not legal cannot be workable. The CPP's reliance on generation shifting as the basis of the BSER is simply not within the grant of statutory authority to the Agency. The text of CAA section 111 is clear, leaving no interpretive room on which the EPA could seek deference for the CPP's grid-wide management approach. Accordingly, EPA is obliged to repeal the CPP to avoid acting unlawfully.

Because the EPA exceeded its statutory authority when it promulgated the CPP, the EPA's repeal of that rule will remain valid even if a future reviewing court were to find fault with the separate and distinct legal interpretations and record-based findings underpinning the ACE rule (see Section III) or the new implementing regulations (see Section IV). The EPA today repeals the CPP as a separate action, distinct from its promulgation of the ACE rule and of revisions to its regulations implementing section 111(d). The EPA would repeal the CPP today even if it were not yet prepared to promulgate these other regulations, or indeed if it knew that those other regulations would not survive judicial review.

III. The Affordable Clean Energy Rule

A. The Affordable Clean Energy Rule Background

1. Regulatory Background

In December 2017, the EPA published an Advanced Notice of Proposed Rule Making (ANPRM) to solicit comment on what the Agency should include in CAA section 111(d) emission guidelines, including soliciting comment on the respective roles of the states and the EPA; what systems of emission reduction might be available and appropriate for reducing GHG emissions from existing coal-fired EGUs; and potential flexibilities that could be afforded under the NSR program to improve the implementation of a future rule.[137] The EPA received more than 270,000 comments on the ANPRM.

Informed by the ANPRM, the EPA then published the ACE proposal, which consisted of three distinct actions: (1) Emission guidelines for GHG emissions from existing coal-fired EGUs, based on application of HRI measures as the BSER; (2) new emission guideline implementation regulations; and (3) revisions to the NSR program to facilitate the implementation of efficiency projects at EGUs.[138]

In this final action, the EPA has determined that the BSER for CO_2 emissions from existing coal-fired EGUs is HRI, in the form of a specific set of technologies and operating and maintenance practices that can be applied at and to certain existing coal-fired EGUs, which is consistent with the legal interpretation adopted in the repeal of the CPP (see above section II). Also, in this action, the EPA has provided information for state plan development. The state plan development discussion is consistent with the new implementing regulations for CAA section 111(d) emission guidelines discussed separately in section IV of this preamble.

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[133] David P. Currie, Direct Federal Regulation of Stationary Sources Under the Clean Air Act, 128 U. Pa. L. Rev. 1389, 1431 (1980) (emphasis added). Professor Curie also suggests that ''the requirement of continuous controls . . . may even have been implicit in the original section 111.'' *Id.*

[134] 139 S.Ct. at 368–69 (rejecting environmental group's contention that statutory definition of ''critical habitat'' is complete and does not require independent inquiry into meaning of the term ''habitat,'' which the statute left undefined).

[135] 531 U.S. at 172 (requiring that the word ''navigable'' in the Clean Water Act's statutorily defined term ''navigable waters'' be given ''effect'').

[136] The Oxford English Dictionary (2d ed. 1989) (1. The carrying out of a command, duty, purpose, promise, etc.; execution, discharge, fulfilment. 2. a. The accomplishment, execution, carrying out, working out of anything ordered or undertaken; the doing of any action or work; working, action (personal or mechanical'') and American Heritage Dictionary of the English Language (2d ed. 1969) (''1. The act of performing, or the state of being performed.'' [perform 1. To begin and carry through to completion]).

[137] *See* 82 FR 61507 (December 28, 2017).

[138] *See* 83 FR 44746 (August 31, 2018).

As noted above, the EPA also proposed revisions to the NSR program in parallel with the ACE rule and the new implementing regulations. The EPA is not finalizing NSR revisions at this time; instead, the EPA intends to take final action on the proposed revisions at a later date in a separate notification of final action.

2. Public Comment and Hearing on the ACE Proposal

The Administrator signed the ACE proposal on August 21, 2018, and, on the same day, the EPA made this version available to the public at *https://www.epa.gov/stationary-sources-air-pollution/proposal-affordable-clean-energy-ace-rule.* The 60-day public comment period on the proposal began on August 31, 2018, the day of publication in the **Federal Register**. The EPA held a public hearing on October 1, 2018, in Chicago, Illinois, and extended the public comment period until October 31, 2018, to allow for 30 days of public comment following the public hearing. The EPA received nearly 500,000 comments on the ACE proposal.

B. Legal Authority To Regulate EGUs

In the CPP, the EPA stated that the Agency's then-concurrent promulgation of standards of performance under CAA section 111(b) regulating CO_2 emissions from new, modified, and reconstructed EGUs triggered the need to regulate existing sources under CAA section 111(d).[139] In ACE, the EPA is not re-opening any issues related to this conclusion, but for the convenience of stakeholders and the public, the EPA summarizes the explanation provided in the CPP here.

CAA section 111(d)(1) requires the Agency to promulgate regulations under which the states must submit state plans regulating ''any existing source'' of certain pollutants ''to which a standard of performance would apply if such existing source were a new source.'' Under CAA section 111(a)(2) and 40 CFR 60.15(a), a ''new source'' is defined as any stationary source, the construction, modification, or reconstruction of which is commenced after the publication of proposed regulations prescribing a standard of performance under CAA section 111(b) applicable to such source. In the CPP, the EPA noted that, at that time, the Agency was concurrently finalizing a rulemaking under CAA section 111(b) for CO_2 emissions from new sources, which provided the requisite predicate for applicability of CAA section 111(d).[140]

The EPA explained in the CAA section 111(b) rule (80 FR 64529) that ''section 111(b)(1)(A) requires the Administrator to establish a list of source categories to be regulated under section 111. A category of sources is to be included on the list 'if in [the Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health and welfare.' '' Then, for the source categories listed under CAA section 111(b)(1)(A), the Administrator promulgates, under CAA section 111(b)(1)(B), ''standards of performance for new sources within such category.'' The EPA further took the position that, because EGUs had previously been listed, it was unnecessary to make an additional finding as a prerequisite for regulating CO_2. The Agency expressed the view that, under CAA section 111(b)(1)(A), findings are category-specific and not pollutant-specific, so a new finding is not needed with regard to a new pollutant. The Agency further asserted that, even if it were required to make a pollutant-specific finding, given the large amount of CO_2 emitted from this source category (the largest single stationary source category of emissions of CO_2 by far) that EGUs would easily meet the standard for making such a listing. The Agency further took the position that, given the large amount of emissions from the source category, it was not necessary in that rule ''for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution.'' [141]

That CAA section 111(b) rulemaking remains in effect, although the EPA has proposed to revise it.[142] That rule continues to provide the requisite predicate for applicability of CAA section 111(d).

C. Designated Facilities for the Affordable Clean Energy Rule

The EPA is finalizing that a designated facility [143] subject to this regulation is any coal-fired electric utility steam generating unit that: (1) Is not an integrated gasification combined cycle (IGCC) unit (*i.e.,* utility boilers, but not IGCC units); (2) was in operation or had commenced construction on or before January 8, 2014; [144] (3) serves a generator capable of selling greater than 25 megawatts (MW) to a utility power distribution system; and (4) has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) heat input of coal fuel (either alone or in combination with any other fuel). Consistent with the new implementing regulations, the term ''designated facility'' is used throughout this preamble to refer to the sources affected by these emission guidelines.[145] For this action, consistent with prior CAA section 111 rulemakings concerning EGUs, the term ''designated facility'' refers to a single EGU that is affected by these emission guidelines.

The EPA's applicability criteria for ACE differ from those in the CPP because the EPA's determination of the BSER is only for coal-fired electric utility steam generating units. In the ACE proposal, the EPA did not identify a BSER for IGCC units, oil- or natural gas-fired utility boilers, or fossil fuel-fired stationary combustion turbines and, thus, such units are not designated facilities for purposes of this action. In the ACE proposal (and previously in the ANPRM), the EPA solicited information on the cost and performance of technologies that may be considered as the BSER for fossil fuel-fired stationary combustion turbines and other fossil-fuel fired EGUs. The EPA currently does not have adequate information to determine a BSER for these EGUs and, if appropriate, the EPA will address GHG emissions from these EGUs in a future rulemaking.

A coal-fired EGU for purposes of this rulemaking (and consistent with the definition of such units in the Mercury and Air Toxics Standards (MATS) (77 FR 9304)) is an electric utility steam generating unit that burns coal for more than 10.0 percent of the average annual heat input during the three previous calendar years. Further, for purposes of this rulemaking, the following EGUs will be excluded from a state's plan: (1) Those units subject to 40 CFR part 60, subpart TTTT as a result of commencing

[139] *See* 80 FR 64715.

[140] *Id.*

[141] *See* 80 FR 64531.

[142] *See* 83 FR 65424.

[143] The term ''designated facility'' means ''any existing facility which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility.'' *See* 40 CFR 60.21a(b).

[144] Under CAA section 111, the determination of whether a source is a new source or an existing source (and thus potentially a designated facility) is based on the date that the EPA proposes to establish standards of performance for new sources. January 8, 2014, is the date the proposed GHG standards of performance for new fossil fuel-fired EGUs were published in the **Federal Register** (79 FR 1430).

[145] The EPA recognizes, however, that the word ''facility'' is often understood colloquially to refer to a single power plant, which may have one or more EGUs co-located within the plant's boundaries.

a qualifying modification or reconstruction; (2) steam generating units subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 megawatt-hour (MWh) or less on an annual basis; (3) a stationary combustion turbine that meets the definition of a simple cycle stationary combustion turbine, a combined cycle stationary combustion turbine, or a combined heat and power combustion turbine; (4) an IGCC unit; (5) non-fossil-fuel units (*i.e.,* units capable of combusting at least 50 percent non-fossil fuel) that have historically limited the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (6) units that serve a generator along with other steam generating unit(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit) is 25 MW or less; (7) a municipal waste combustor unit subject to 40 CFR part 60, subpart Eb; (8) commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or (9) a steam generating unit that fires more than 50-percent non-fossil fuels.

D. Regulated Pollutant

The air pollutant regulated in this final action is GHGs. However, the standards in this rule are expressed in the form of limits solely on emissions of CO_2, and not the other constituent gases of the air pollutant GHGs.[146] The EPA is not establishing a limit on aggregate GHGs or separate emission limits for other GHGs (such as methane (CH_4) or nitrous oxide (N_2O)) as other GHGs represent significantly less than one percent of total estimated GHG emissions (as CO_2 equivalent) from fossil fuel-fired electric power generating units.[147] Notwithstanding the form of the standard, consistent with other EPA regulations addressing GHGs, the air pollutant regulated in this rule is GHGs.[148]

E. Determination of the Best System of Emission Reduction

1. Guiding Principles in Determining the BSER

CAA section 111(d)(1) directs the EPA to promulgate regulations establishing a procedure similar to that under CAA section 110,[149] under which states submit state plans that establish ''standards of performance'' for emissions of certain air pollutants from existing sources which, if they were new sources, would be subject to new source standards under CAA section 111(b), and that provide for the implementation and enforcement of those standards of performance. Because CAA section 111(a)(1) defines ''standard of performance'' for purposes of all of section 111, and because federal standards for new sources established under section 111(b) and standards for existing sources established by a state plan under section 111(d) are both ''standards of performance,'' it is the EPA's responsibility to determine the BSER for designated facilities for standards developed under both CAA section 111(b) for new sources and section 111(d) for existing sources.[150] In making this determination, the EPA identifies all ''adequately demonstrated'' ''system[s] of emission reduction'' for a particular source category and then evaluates those systems to determine which is the ''best,''[151] while ''taking into account'' the factors of ''cost . . . non-air quality health and environmental impact and energy requirements.''[152] Because CAA section 111 does not set forth the weight that should be assigned to each of these factors, courts have granted the Agency a great degree of discretion in balancing them.[153]

The CAA limits ''standards of performance'' to systems that can be applied at and to a stationary source (*i.e.,* as opposed to off-site measures that are implemented by an owner or operator, such as subsidizing lower-emitting sources) and that lead to continuous emission reductions (*i.e.,* are not intermittent control techniques). Such systems include add-on controls and lower-emitting processes/practices/designs that can be applied to a designated facility, *i.e.,* a building, structure, facility, or installation regulated under CAA section 111.[154] As discussed in section II of this preamble, this is the only permissible interpretation of the scope of the EPA's authority under CAA section 111. But this clear outer bound on the EPA's authority leaves the Agency considerable room for interpretation and policy choice within that scope in determining the BSER that has been adequately demonstrated to address a particular source category's emission of a given pollutant. Case law under CAA section 111(b) explains that ''[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.''[155] While some of these cases suggest that ''[t]he Administrator may make a projection based on existing technology,''[156] the D.C. Circuit has also

[146] In the 2009 Endangerment Finding for mobile sources, the EPA defined the relevant ''air pollution'' as the atmospheric mix of six long-lived and directly emitted greenhouse gases: Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). *See* 74 FR 66497. Additionally, note that the new CAA section 111(d) implementing regulations at 40 CFR 60.22a(b)(1) do not change the requirement of the previous implementing regulations, 40 CFR 60.22(b)(1) that emission guidelines provide information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant. For this emission guideline, that information is contained in the 2009 Endangerment Finding.

[147] EPA Greenhouse Gas Reporting Program; *www.epa.gov/ghgreporting/.*

[148] *See, e.g.,* 79 FR 34960.

[149] CAA section 110 governs state implementation plans, or SIPs, which states develop and submit for EPA approval and which are used to ensure attainment and maintenance of the National Ambient Air Quality Standards (NAAQS) for criteria pollutants.

[150] *See also* 40 CFR 60.22a. However, while the BSER underlying both new- and existing-source performance standards is determined by the EPA, the performance standards for new sources are directly established by the EPA under section 111(b), whereas states establish performance standards (applying the BSER) for existing sources in their jurisdiction in their state plans under section 111(d), and Congress has expressly required that EPA permit states, in establishing performance standards for existing sources, to take into account the remaining useful life of the source and other source-specific factors. *See* 42 U.S.C. 7411(d)(1).

[151] The D.C. Circuit recognizes that the EPA's evaluation of the ''best'' system must also include ''the amount of air pollution as a relevant factor to be weighed . . . .'' *Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981). Additionally, a system cannot be ''best'' if it does more harm than good due to cross-media environmental impacts. *See Portland Cement,* 486 F. 2d at 384; *Sierra Club,* 657 F.2d at 331; *see also Essex Chemical Corp.,* 486 F.2d 427, 439 (D.C. Cir. 1973) (remanding standard to consider solid waste disposal implications of the BSER determination). Nevertheless, CAA section 111 does not require the ''greatest degree of emission control'' or ''mandate that the EPA set standards at the maximum degree of pollution control technologically achievable.'' *Sierra Club,* 657 F.2d at 330.

[152] The EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide or nationwide basis. Considered on a source-specific basis, ''energy requirements'' entail, for example, the impact, if any, of the system of emission reduction on the source's own energy needs. As discussed in this document, a consideration of ''energy requirements'' informs the EPA's judgment that repowering and refueling coal-fired facilities to be fueled by natural gas is not appropriate for consideration as BSER here.

[153] *Lignite Energy,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[154] *See* section 111(a)(3) for definition of ''stationary source.''

[155] *Essex Chemical Corp.,* 486 F.2d 375, 433–34 (D.C. Cir. 1973).

[156] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973).

noted that ''there is inherent tension'' between considering a particular control technique as both ''an emerging technology and an adequately demonstrated technology.'' [157] Nevertheless, the EPA appears to ''have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible.'' [158] The essential question, therefore, is whether the BSER is ''available.'' [159]

In considering the availability of different systems of emission reduction, the ''EPA must examine the effects of technology on the grand scale,'' because CAA section 111 standards are, after all, ''a national standard with long-term effects.'' [160] To that end, the Agency must ''consider the representativeness for the industry as a whole of the tested plants on which it relies. . . .'' [161] A CAA section 111 standard, therefore, ''cannot be based on a 'crystal ball' inquiry.'' [162]

Whereas the EPA establishes performance standards for new sources under CAA section 111(b), section 111(d) provides *that states* are primarily responsible for regulating existing sources. This bifurcated approach dovetails with testimony offered during development of the CAA Amendments of 1970 (which established the section 111 program)—specifically, Secretary Finch explained that ''existing stationary sources of air pollution are so numerous and diverse that the problems they pose can most efficiently be attacked by state and local agencies.'' [163] Indeed, Congress eventually made explicit the requirement that the EPA allow states to take into account the ''remaining useful life'' of an existing source, ''among other factors,'' when applying a standard of performance to any particular source.[164] Accordingly, the Agency's identification of the BSER is based on what is ''adequately demonstrated'' and broadly achievable for a source category across the country, while each state—which will be more familiar with the operational and design characteristics of actually existing sources within their borders—is responsible for developing source-specific standards reflecting application of the BSER.[165] Indeed, Congress has expressly provided that the EPA must permit states to take into consideration a source's remaining useful life, among other factors, when applying a standard of performance to a particular source.[166]

In the ACE proposal, the EPA provided a discussion of the identified systems of emission reduction and explained why certain systems were eliminated from consideration at a preliminary state or were otherwise determined not to be the ''best system.'' The EPA received public comments that challenged or refuted the Agency's evaluation of these systems of emission reduction. A discussion of those reduction measures and a summary of significant public comments are provided below.

The EPA proposed that ''heat rate improvement'' (HRI, which may also be referred to as ''efficiency improvement'') is the BSER for existing coal-fired EGUs. In this action, after consideration of public comments, the EPA is finalizing its proposed determination that HRI is the BSER. The basis for the final determination and a summary of significant public comments received on the proposed determination are discussed below.

2. Heat Rate Improvement Is the BSER for Existing Coal-Fired EGUs

a. Background and BSER Determination

Heat rate is a measure of efficiency that is commonly used in the power sector. The heat rate is the amount of energy or fuel heat input (typically measured in British thermal units, Btu) required to generate a unit of electricity (typically measured in kilowatt-hours, kWh). The lower an EGU's heat rate, the more efficiently it converts heat input to electrical output. As a result, an EGU with a lower heat rate consumes less fuel per kWh of electricity generated and, as a result, emits lower amounts of CO_2—and other air pollutants—per kWh generated (as compared to a less efficient unit with a higher heat rate). Heat rate data from existing coal-fired EGUs indicate that there is potential for improvement across the source category.

Heat rate improvement measures can be applied—and some measures have already been applied—to all existing EGUs (supporting the Agency's determination that HRI measures are the BSER). However, the U.S. fleet of existing coal-fired EGUs is a diverse group of units with unique individual characteristics that are spread across the country.[167] As a result, heat rates of existing coal-fired EGUs in the U.S. vary substantially. Thus, even though the variation in heat rates among EGUs with similar design characteristics, as well as year-to-year variation in heat rate at individual EGUs, indicate that there is potential for HRI that can improve CO_2 emission performance across the existing coal-fired EGU fleet, this potential may vary considerably at the unit level—including because particular units may not be able to employ certain HRI measures, or may have already done so. Accordingly, the EPA identified several available technologies and equipment upgrades, as well as best operating and maintenance practices, that EGU owners or operators may apply to improve an individual EGU's heat rate. The EPA referred to these HRI technologies and techniques as ''candidate technologies'' and solicited comment on their technical feasibility, applicability, performance, and cost.

The EPA received numerous public comments, both supporting and opposing, the proposed determination that HRI is the BSER. Many commenters supported the proposed concept of a unit-specific, state-led evaluation of HRI potential as a means of establishing a unit-specific standard of performance. The commenters argued that it is not possible to adopt uniform, nationally applicable standards of performance based on implementation of particular HRI technologies because each individual unit is subject to a unique combination of factors that can affect the unit's heat rate and HRI potential, many of which are geographically driven and outside the control of a

[157] *Sierra Club* v. *Costle,* 657 F.2d 298, 341 n.157 (D.C. Cir.1981); see also *NRDC* v. *Thomas,* 805 F.2d 410, n.30 (D.C. Cir. 1986) (suggesting that ''a standard cannot both require adequately demonstrated technology and also be technology-forcing'').

[158] *Sierra Club,* 657 F.2d at 364. It is not clear whether these cases would have applied the same technology-forcing philosophy to the regulation of existing sources, as at least one case noted that section 111 ''looks toward what may fairly be projected for the regulated future, rather than the state of the art at present, since it is addressed to standards for *new* plants—old stationary source pollution being controlled through other regulatory authority.'' *Portland Cement,* 486 F.2d at 391 (emphasis added).

[159] *See Portland Cement* v. *Ruckelshaus,* 486 F.2d at 391.

[160] *Id.* at 330.

[161] *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 432–33 (D.C. Cir. 1980).

[162] *Essex Chemical Corp.,* 486 F.2d at 391.

[163] Testimony of Robert Finch, Secretary of Health, Education, and Welfare (which regulated air pollution prior to the establishment of the EPA) in support of S. 3466/H.R. 15848, before the House Subcommittee on Public Health and Welfare, H. Hearing (May 16, 1970), 1970 CAA Legis. Hist. at 1369.

[164] 42 U.S.C. 7411(d)(1).

[165] This approach is analogous to the NAAQS program: Where ''[e]ven with air quality standards being set nationally . . . the steps needed to deal with existing stationary sources would necessarily vary from one State to another and, within States, from one area to another . . . .'' *Id.*

[166] 42 U.S.C. 7411(d)(1).

[167] For example, the current fleet of existing fossil fuel-fired EGUs is quite diverse in terms of size, age, fuel type, operation (*e.g.,* baseload, cycling), boiler type, *etc.* Moreover, geography and elevation, unit size, coal type, pollution controls, cooling system, firing method, and utilization rate are just a few of the parameters that can impact the overall efficiency and performance of individual units.

source. The EPA agrees with these commenters. As previously mentioned, the U.S. fleet of existing coal-fired EGUs is diverse in terms of size, vintage, fuel usage, design, geographic location, *etc.* The HRI potential for each unit will be influenced by source-specific factors such as the EGU's past and projected utilization rate, maintenance history, and remaining useful life (among other factors). Therefore, standards of performance must be established from a unit-level evaluation of the application of the BSER and consideration of other factors at the unit level. States are in the best position to make those evaluations and to consider of other unit-specific factors, and indeed CAA section 111(d)(1) directs EPA to permit states to take such factors into consideration as they develop plans to establish performance standards for existing sources within their jurisdiction.

Other commenters opposed the proposed use of unit-specific HRI plans because the commenters believe that this interpretation is inconsistent with the legislative history and that this approach does not enable significant emissions reductions. Some commenters said that defining BSER in terms of operational efficiency (heat rate) is not consistent with the understanding reflected in the EPA's historic practice in all previous CAA section 111(d) rules, where the BSER was determined based on a specific emission reduction technology. The EPA disagrees with the contention. The EPA proposed that HRI through the application of a specific set of emission reduction technologies (discussed in more detail below) and operational practices is the BSER. That approach is consistent with the direction given in the statute. It is also an approach that recognizes the challenges of applying a single specific emission reduction technology within such a diverse population of designated facilities.

After consideration of public comment, the EPA affirms its determination that, as proposed, HRI is the BSER for existing coal-fired EGUs.

b. The List of Candidate Technologies

While a large number of HRI measures have been identified in a variety of studies conducted by government agencies and outside groups,[168] some of those identified technologies have limited applicability and many provide only negligible HRI. The EPA stated in the proposal that it believed that requiring a state in developing its plan to evaluate the applicability to each of its sources of the entire list of potential HRI options—including those with limited applicability and with negligible benefits—would be overly burdensome to the states. Therefore, the EPA identified and proposed a list of the ''most impactful'' HRI technologies, equipment upgrades, and best operating and maintenance practices that form the list of ''candidate technologies'' constituting the BSER. The candidate technologies of the BSER are listed in Table 1 below. Those technologies, equipment upgrades, and best operating and maintenance practices were deemed to be ''most impactful'' because they can be applied broadly and are expected to provide significant HRI without limitations due to geography, fuel type, *etc.* The EPA solicited comment on each of the proposed candidate technologies and on whether any additional technologies should be added to the list, and on whether there is additional information that the EPA should be aware of and consider in determining the BSER and establishing the candidate technologies for HRI measures.

The EPA received numerous public comments on the list of candidate technologies. Some commenters stated that there are additional available HRI technologies that should be added to the list of candidate technologies, while many other commenters agreed that the proposed list of ''candidate technologies'' is reasonable and should be considered the core group for states to evaluate in establishing standards of performance. Commenters agreed that the proposed list of ''candidate technologies'' focuses the states' standard-setting process on those HRI measures with the greatest ability to impact CO_2 emissions. Commenters further stated that the EPA's proposed candidate technology list will limit the burden on states by eliminating the need to consider measures that would almost certainly be rejected due to negligible emission reduction benefits, disproportionate costs, or availability. However, commenters also noted that there may be additional HRI opportunities available to a significant number of designated facilities and that states should not be required to limit their evaluations to just the ''candidate technologies'' in establishing unit-specific standards of performance. Some commenters suggested that the EPA establish a process whereby HRI solutions can be added to the list of ''candidate technologies.''

Commenters also stated that some of the equipment upgrades and operating practices proposed as candidate technologies have the potential to improve an EGU's *net* heat rate by reducing auxiliary load but would have no impact on the unit's *gross* heat rate.[169] Comments regarding gross versus net heat rate, and gross- versus net-based standards of performance, are discussed in more detail below in section III.F.1.c of this preamble.

The EPA considered the public comments on the BSER technologies and believes that the proposed list still represents the most broadly applicable and impactful collection of HRI measures. Therefore, the EPA is, in this action, finalizing the proposed technologies, equipment upgrades, and best operating and maintenance practices provided in Table 1 of the proposal[170] as the final list of ''candidate technologies'' whose applicability to each designated facility within their boundaries states must evaluate in establishing a standard of performance for that source in their state plans under CAA section 111(d).

The technologies and operating and maintenance practices listed and described below are generally available and appropriate for all types of EGUs. However, some existing EGUs will have already implemented some of the listed HRI technologies, equipment upgrades, and operating and maintenances practices. There will also be unit-specific physical or cost considerations that will limit or prevent full implementation of the listed HRI technologies and equipment upgrades. States will consider these and other factors when establishing unit-level standards of performance. The final list of ''candidate technologies''—with the range of expected percent HRI—is provided below in Table 1.

[168] *See* Table 3 in ANPRM, 82 FR 61515.

[169] The *gross heat rate* is the fuel heat input required to generate a unit of electricity (typically presented in Btu/kWh-gross). The *net heat rate* is the fuel heat input required to generate a unit of electricity minus the electricity that is used to power facility auxiliary equipment (typically presented in Btu/kWh-net).

[170] *See* 83 FR 44757.

TABLE 1—SUMMARY OF MOST IMPACTFUL HRI MEASURES AND RANGE OF THEIR HRI POTENTIAL (%) BY EGU SIZE

HRI Measure	<200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved Operating and Maintenance (O&M) Practices	Can range from 0 to >2.0% depending on the unit's historical O&M practices.					

Two of the technologies shown in Table 1—''Blade Path Upgrade (Steam Turbine)'' and ''Redesign/Replace Economizer''—are candidate technologies that are expected to offer some of the largest improvements in unit-level heat rate. However, based on public comments from the ANPRM and the ACE proposal, those also are HRI technologies that have the most potential to trigger NSR requirements. Industrial stakeholders and commenters have indicated, if such HRI trigger NSR, the resulting requirements for analysis, permitting, and capital investments will greatly increase the cost of implementing those HRI technologies and, in the absence of NSR reforms, states will be more likely to determine that those technologies are not cost-effective when analyzing ''other factors'' in determining a standard of performance for an individual facility.

For the ACE proposal, the EPA reflected this in assumptions made in the power sector modeling, using the Integrated Planning Model (IPM), to assess potential costs and benefits of the proposed rule. In that modeling, the EPA assumed two different levels of potential HRI (in percentage terms)—a lower expected HRI without NSR reform and a higher expected HRI with NSR reform.[171]

As mentioned earlier in this preamble, the EPA is not taking final action on the proposed NSR reforms in this final rulemaking action; the EPA intends to take final action on that proposal in a separate final action at a later date. Without finalization of NSR reforms, the EPA anticipates that states in some instances may determine, when considering other factors, that the candidate technologies, ''Blade Path Upgrade (Steam Turbine)'' and ''Redesign/Replace Economizer,'' are less appropriate for application to a particular source or sources than the EPA anticipated would be when it proposed the ACE Rule. Nevertheless, the EPA is retaining these two candidate technologies as part of the final BSER, because it still expects these technologies to be generally applicable across the fleet of existing EGUs, and because the costs of the technologies themselves are generally economical and reasonable.

c. Level of Stringency Associated With the BSER

As discussed in section III.B above, the EPA has the authority and responsibility to determine the BSER. CAA section 111(d)(1), meanwhile, clearly assigns states the role of developing a plan that establishes standards of performance for designated facilities (with EPA's authority to promulgate a federal plan serving as a backstop in the event that a state fails to develop a satisfactory plan[172]). Based on these statutory divisions of roles and responsibilities, the EPA proposed to determine the BSER as HRI achievable through implementation of certain technologies, equipment upgrades, and improved O&M practices. The EPA also declined to propose a standard of performance that presumptively reflects application of the BSER because the establishment of standards of performance for existing sources is the states' role.[173] While declining to provide a presumptive standard, the EPA also proposed to provide *information* on the degree of emission limitation achievable through application of the BSER by providing a range of reductions and costs associated with each of the candidate technologies identified as part of the BSER.[174]

The EPA received numerous comments from states and industry requesting that the EPA provide a presumptive standard, or at minimum, additional guidance and clarity on how states could derive a standard of performance that meets the requirements of this regulation. Additionally, several commenters contended that under CAA section 111(a)(1), the EPA is legally obligated to identify ''the degree of emission limitation achievable through the application of the [BSER]'' (*i.e.,* a level of stringency) because such degree of emission limitation is inextricably linked with the determination of the BSER, which is the EPA's statutory role and responsibility. Upon consideration of these comments, especially the widespread request for more guidance from the EPA on developing appropriate standards of performance, the EPA agrees that it has a responsibility under the CAA to identify the degree of emission reduction that it determines to be achievable through the application of the BSER.

While the CAA provides that the responsibility to establish standards of performance is a state's responsibility, the EPA is identifying the degree of emission limitation achievable through the application of the BSER (*i.e.,* the level of stringency) associated with the candidate technologies. By providing the level of emissions reductions achievable using the candidate technologies the EPA is fulfilling its responsibility as part of the BSER determination. In this instance, the EPA has identified the degree of emission limitation achievable through application of the BSER by providing ranges of expected reductions associated with each of the technologies. These ranges are provided in Table 1, clearly presenting the percentage improvement ranges that can be expected when each candidate technology comprising the BSER is applied to a designated facility. Defining the ranges of HRI as the degree of emission limitation achievable through application of the BSER is consistent with the EPA's position at proposal, where EPA noted that ''while the HRI potential range is provided as guidance for the states, the actual HRI performance for each of the candidate technologies will be unit-specific and

[171] *See* 80 FR 44783.

[172] *See* section 111(d)(2).

[173] *See* 83 FR 44764.

[174] *See* 83 FR 44757, Table 1.

will depend upon a range of unit-specific factors. The states will use the information provided by the EPA as guidance but will be expected to conduct unit-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies.'' [175] For purposes of the final ACE rule, states will utilize the ranges of HRI the EPA has provided in developing standards of performance but may ultimately establish standards of performance for one or more existing sources within their jurisdiction that reflect a value of HRI that falls outside of these ranges. See section III.F.1.a of this preamble.

It is reasonable for the EPA to express the ''degree of emission limitation achievable through application of the BSER'' as a set of ranges of values, rather than a single number, that reflects application of the candidate technologies as a whole. This approach is reasonable in light of the nature of what the EPA has identified as the adequately demonstrated BSER (as well as of the structure of section 111 in general and the interplay between section 111(a)(1) and section 111(d) in particular): A suite of candidate technologies that the EPA anticipates will be generally applicable to EGUs at the fleet-wide level but not all of which may be applicable or warranted at the level of a particular facility due to source-specific factors such as the site-specific operational and maintenance history, the design and configuration, the expected operating plans, *etc.* Because of the importance for applicability of the BSER of these source-specific factors, and because the application and installation of the candidate technologies will result in varying degrees of reductions based on application of each of the BSER technologies into the existing infrastructure of the EGU, the EPA has provided ranges of HRI associated with each technology. This accounts for some of the variation that is expected among the designated facilities (*see* section III.F.1.a.(1) of this preamble for discussion of variable emission performance at and between designated facilities). While these ranges represent the degree of emission reduction achievable through application of the BSER, a particular designated facility may have the potential for more or less HRI as a result of the application of the candidate technology based on source-specific characteristics. As further discussed in section III.F. of this preamble, the level of stringency associated with each candidate technology is to be used by states in the process of establishing a standard of performance, and in this process, states may also consider source-specific factors such as variability that may result in a different level of stringency.[176]

d. Detail on the HRI Technologies & Techniques

(1) Neural Network/Intelligent Sootblower

Neural networks. Computer models, known as neural networks, can be used to simulate the performance of the power plant at various operating loads. Typically, the neural network system ties into the plant's distributed control system for data input (process monitoring) and process control. The system uses plant specific modeling and control modules to optimize the unit's operation and minimize the emissions. This model predictive control can be particularly effective at improving the plant's performance and minimizing emissions during periods of rapid load changes—conditions that commenters claimed to be more prevalent now than was the case 5 to 10 years ago. The neural network can be used to optimize combustion conditions, steam temperatures, and air pollution control equipment.

Intelligent Sootblowers. During operations at a coal-fired power plant, particulate matter (PM) (ash or soot) builds up on heat transfer surfaces. This build-up degrades the performance of the heat transfer equipment and negatively affects the efficiency of the plant. Power plant operators use steam injection ''sootblowers'' to clean the heat transfer surfaces by removing the ash build-up. This is often done on a routine basis or as needed based on monitored operating characteristics. Intelligent sootblowers (ISB) are automated systems that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup.

The cost to implement an ISB system is relatively inexpensive if the necessary hardware is already installed. The ISB software/control system is often incorporated into the neural network software package mentioned above. As such, the HRIs obtained via installation of neural network and ISB systems are not necessarily cumulative.

The efficiency improvements from installation of ISB are often greatest for EGUs firing subbituminous coal and lignite due to more significant and rapid fouling at those units as compared to EGUs firing bituminous coal.

Commenters recommended that the EPA disaggregate its analysis of neural networks and ISB because these technologies do not have to be deployed together and implementing one without the other may be appropriate in many cases. The EPA agrees that the technologies do not have to be implemented together and states must evaluate the applicability and effectiveness of both technologies. The technologies were listed together to emphasize that they are often implemented together and that the resulting HRIs from each are not necessarily additive.

(2) Boiler Feed Pumps

A boiler feed pump (or boiler feedwater pump) is a device used to pump feedwater into a boiler. The water may be either freshly supplied or returning condensate produced from condensing steam produced by the boiler. The boiler feed pumps consume a large fraction of the auxiliary power used internally within a power plant. For example, boiler feed pumps can require power in excess of 10 MW on a 500–MW power plant. Therefore, the maintenance on these pumps should be rigorous to ensure both reliability and high-efficiency operation. Boiler feed pumps wear over time and subsequently operate below the original design efficiency. The most pragmatic remedy is to rebuild a boiler feed pump in an overhaul or upgrade.

Commenters stated that because upgrading an electric boiler feed pump impacts only *net* heat rate (and not *gross* heat rate), it should be excluded from the candidate technologies list. The EPA disagrees that candidate technologies affecting only the *net* heat rate should be removed from the candidate technologies list. These technologies improve the efficiency and reduce emissions from the plant by reducing the auxiliary power load, allowing for more of the produced power to be placed on the grid. As is discussed below in section III.F.1.c., the state will determine whether to establish standards of performance as *gross* output-based standards or as *net* output-based standards. If states establish *gross* output-based standards, it will be up to the states to determine how to account for emission reductions that are attributable to technologies affecting only the *net* output.

[175] *See* 83 FR 44763.

[176] As described later in the preamble in section III.F., the EPA envisions states will develop standards of performance for designated facilities in a two -step process where states first apply the BSER and then consider source-specific factors such as remaining useful life.

(3) Air Heater and Duct Leakage Control

The air pre-heater is a device that recovers heat from the flue gas for use in pre-heating the incoming combustion air (and potentially for other uses such as coal drying). Properly operating air pre-heaters play a significant role in the overall efficiency of a coal-fired EGU. The air pre-heater may be regenerative (rotary) or recuperative (tubular or plate). A major difficulty associated with the use of regenerative air pre-heaters is air in-leakage from the combustion air side to the flue gas side. Air in-leakage affects boiler efficiency due to lost heat recovery and affects the axillary load since any in-leakage requires additional fan capacity. The amount of air leaking past the seals tends to increase as the unit ages. Improvements to seals on regenerative air pre-heaters have enabled the reduction of air in-leakage.

The EPA received comments that claimed the applicability of air pre-heater seals is limited, and that low-leakage seals are not feasible on certain units while other commenters agreed that the HRI estimates for leakage reduction are reasonable, and HRI improvement from 0.25 to 1.0 percent is achievable. The EPA agrees that the HRI estimates for air heater and duct in-leakage are reasonable. The EPA agrees that low-leakage seals are not feasible for certain units (*e.g.,* those using recuperative air heaters). However, the EPA is finalizing a determination that this candidate technology is an element of the BSER because limiting air in-leakage in the air heater and associated duct work can be evaluated on all units and limiting the amount of air in-leakage will improve the efficiency of the unit.

(4) Variable Frequency Drives (VFDs)

VFD on induced draft (ID) fans. The increased pressure required to maintain proper flue gas flow through downstream air pollutant control equipment may require additional fan power, which can be achieved by an ID fan upgrade/replacement or an added booster fan. Generally, older power plant facilities were designed and built with centrifugal fans.

The most precise and energy-efficient method of flue gas flow control is the use of VFD. The VFD controls fan speed electrically by using a static controllable rectifier (thyristor) to control frequency and voltage and, thereby, the fan speed. The VFD enables very precise and accurate speed control with an almost instantaneous response to control signals. The VFD controller enables highly efficient fan performance at almost all percentages of flow turndown.

Due to current electricity market conditions, many units no longer operate at base-load capacity and, therefore, VFDs, also known as variable-speed drives on fans can greatly enhance plant performance at off-peak loads. Additionally, units with oversized fans can benefit from VFD controls. Under these scenarios, VFDs can significantly improve the unit heat rate. VFDs as motor controllers offer many substantial improvements to electric motor power requirements. The drives provide benefits such as soft starts, which reduce initial electrical load, excessive torque, and subsequent equipment wear during startups; provide precise speed control; and enable high-efficiency operation of motors at less than the maximum efficiency point. During load turndown, plant auxiliary power could be reduced by 30–60 percent if all large motors in a plant were efficiently controlled by VFD. With unit loads varying throughout the year, the benefits of using VFDs on large-size equipment, such as FD or ID fans, boiler feedwater and condenser circulation water pumps, can have significant impacts. There are circumstances in which the HRI has been estimated to be much higher than that shown in Table 1, depending on the operation of the unit. Cycling units realize the greatest gains representative of the upper range of HRI, whereas units which were designed with excess fan capacity will exhibit the lower range.

VFD on boiler feed pumps. VFDs can also be used on boiler feed water pumps as mentioned previously. Generally, if a unit with an older steam turbine is rated below 350 MW, the use of motor-driven boiler feedwater pumps as the main drivers may be considered practical from an efficiency standpoint. If a unit cycles frequently then operation of the pumps with VFDs will offer the best results on heat rate reductions, followed by fluid couplings. The use of VFDs for boiler feed pumps is becoming more common in the industry for larger units. And with the advancements in low pressure steam turbines, a motor-driven feed pump can improve the thermal performance of a system up to the 600–MW range, as compared to the performance associated with the use of turbine drive pumps.

Some commenters stated that VFDs should be excluded from the candidate technologies list because the efficiency improvements are likely near zero when the EGU operates as a baseload unit. Commenters further stated that VFD installation may not be reasonable because of their high cost, large physical size, and significant cooling requirements. The EPA agrees that VFD HRIs will be less effective for units that operate consistently at high capacity factors at base load conditions. However, due to the changing nature of the power sector (increased use of natural gas-fired generating sources, more intermittent renewable generating sources, *etc.*), many coal-fired EGUs are cycling more often and the heat rate of such units will benefit from installation of VFD technology. In evaluating the applicability of the BSER technologies, states will consider ''other factors'' that will include expected utilization rate, remaining useful life, physical/space limitations, *etc.* That evaluation of ''other factors'' will identify whether implementation of a BSER candidate technology is reasonable. The EPA is finalizing a determination that this candidate technology is an element of the BSER because it contributes to emission reductions and it is broadly applicable at reasonable cost.

Commenters also stated that VFDs only impact *net* heat rate, so efficiency improvements may not be cost-effective. As stated earlier, if the states choose to establish *gross* output-based standards of performance, it will be up to the states to determine how to account for emission reductions attributable to improvement to *net* heat rate.

(5) Blade Path Upgrade (Steam Turbine)

Upgrades or overhauls of steam turbines offer the greatest opportunity for HRI on many units. Significant increases in performance can be gained from turbine upgrades when plants experience problems such as steam leakages or blade erosion. The typical turbine upgrade depends on the history of the turbine itself and its overall performance. The upgrade can entail myriad improvements, all of which affect the performance and associated costs. The availability of advanced design tools, such as computational fluid dynamics (CFD), coupled with improved materials of construction and machining and fabrication capabilities have significantly enhanced the efficiency of modern turbines. These improvements in new turbines can also be utilized to improve the efficiency of older steam turbines whose efficiency has degraded over time.

Commenters stated that steam turbine blade path upgrades may not be achievable for every turbine because of the potentially significant variability in an individual turbine's parameters when considering costs. Commenters further noted that these are large investments that can require lengthly outages and long lead times.

Other commenters noted that these steam turbine blade path upgrades have been commercially available for over 10 years and that the HRI estimates in Table 1 appear reasonable.

The EPA agrees that steam turbine blade path upgrades are commercially available and that the HRI estimates in Table 1 appear to be consistent with other estimates of HRI achievable from this type of upgrade. As mentioned earlier, based on public comments responding to the ANPRM and the ACE proposal, this HRI measure has the potential to trigger NSR requirements (in the absence of NSR program reforms), and the EPA anticipates that, among the candidate technologies identified as comprising the BSER, states may be relatively more likely to determine in light of the resulting requirements for analysis, permitting, and capital investments that this candidate technology is not economically feasible when evaluating it in the process of establishing standards of performance for particular existing sources within their jurisdiction. Nevertheless, the EPA is finalizing a determination that steam turbine blade bath upgrades are part of the BSER because the EPA anticipates they will still be generally available and feasible at a sufficient scale among the nationwide fleet.

(6) Redesign/Replace Economizer

In steam power plants, economizers are heat exchange devices used to capture waste heat from boiler flue gas which is then used to heat the boiler feedwater. This use of waste heat reduces the need to use extracted energy from the system and, therefore, improves the overall efficiency or heat rate of the unit. As with most other heat transfer devices, the performance of the economizer will degrade with time and use, and power plant representatives contend that economizer replacements are often delayed or avoided due to concerns about triggering NSR requirements. In some cases, economizer replacement projects have been undertaken concurrently with retrofit installation of selective catalytic reduction (SCR) systems because the entrance temperature for the SCR unit must be controlled to a specific range.

Commenters stated that redesigning or replacing an economizer may be limited for some units by the need to maintain appropriate temperatures at a downstream SCR system for nitrous oxides (NOx) control. Commenters also stated that applicability of this measure will be site-specific because boiler layout and construction varies widely between units. Commenters stated that the values in Table 1 appear to reflect a major economizer redesign which may not be possible for many units. The EPA agrees that there will likely be site-specific factors that must be considered to determine whether economizer redesign/replacement is a feasible HRI option (as is the case for all the BSER candidate technologies). Nevertheless, the EPA is finalizing a determination that economizer upgrades (or replacement) are part of the BSER because the EPA anticipates they will still be generally available and feasible at a sufficient scale among the nationwide fleet. As mentioned earlier, states may take into consideration site-specific characteristics (''other factors'') when establishing a standard of performance for each unit.

(7) HRI Techniques—Best Operating and Maintenance Practices

Many unit operators can achieve additional HRI by adopting best O&M practices. The amount of achievable HRI will vary significantly from unit to unit, ranging from no improvement to potentially more than 2.0 percent depending on the unit's historical O&M practices. In setting a standard of performance for a specific unit or subcategory of units, states will evaluate the opportunities for HRI from the following actions.

(a) Adopt HRI Training for O&M Staff

EGU operators can obtain HRI by adopting ''awareness training'' to ensure that all O&M staff are aware of best practices and how those practices affect the unit's heat rate.

Some commenters agreed that HRI training can improve staff awareness of plant efficiency measures, which should result in improved plant performance. Other commenters stated that the benefits of HRI training are highly variable and depend on existing equipment and staff. Some commenters stated that the operating staff already routinely undergo HRI training and that states should not be required to consider these measures in developing their plans. The EPA agrees that the benefits will be variable from unit to unit depending upon the unit's historical O&M practices. If operating staff at a source already undergo routine HRI training, then the state will note that in the standard-setting process. Just as an EGU that has recently installed new or reconstructed boiler feed pumps would not be expected to replace those pumps, a source that already has an effective HRI training program in place would not be expected to implement a new HRI training program. The EPA is finalizing a determination that this practice is an element of the BSER because it can result in emission reductions and can be broadly implemented at reasonable cost.

(b) Perform On-Site Appraisals To Identify Areas for Improved Heat Rate Performance

Some large utilities have internal groups that can perform on-site evaluations of heat rate performance improvement opportunities. Outside (*i.e.,* third-party) groups can also provide site-specific/unit-specific evaluations to identify opportunities for HRI.

Commenters stated that the benefits of on-site appraisals are variable, speculative, and site-specific. Commenters stated that no state should determine what opportunities a coal-fired EGU might find during an on-site appraisal, and, therefore, that states should not be required to evaluate the applicability of on-site appraisals when developing their plans and establishing standards of performance for existing sources within their jurisdiction. The EPA agrees that the benefits of on-site appraisals will be variable and site-specific. As with other BSER measures, it will be up to each state to determine the extent of this requirement. States may require that the owner/operator perform an on-site appraisal to identify areas for HRI or the state may choose to have a third party conduct an on-site HRI appraisal.

(c) Improved Steam Surface Condenser—Cleaning

Effective operation of the steam surface condenser in a power plant can significantly improve a unit's heat rate. In fact, in many cases ineffective operation can pose the most significant hindrance to a plant trying to maintain its original design heat rate. Since the primary function of the condenser is to condense steam flowing from the last stage of the steam turbine to liquid form, it is most desirable from a thermodynamic standpoint that this occurs at the lowest temperature reasonably feasible. By lowering the condensing temperature, the backpressure on the turbine is lowered, which improves turbine performance.

Condenser cleaning. A condenser degrades primarily due to fouling of the tubes and air in-leakage. Tube fouling leads to reduced heat transfer rates, while air in-leakage directly increases the backpressure of the condenser and degrades the quality of the water. Condenser tube cleaning can be performed using either on-line methods or more rigorous off-line methods.

Commenters stated that improved steam surface condenser cleaning is a viable O&M option. Commenters stated that the need for such cleaning can be determined by enhanced monitoring of condenser performance. The EPA agrees with this assessment and notes that many owner/operators may already have steam surface condenser cleaning as part of routine O&M for their units. The EPA is finalizing a determination that this O&M practice is an element of the BSER because it provides opportunity for heat rate improvement and is broadly applicable.

e. Cost of HRI

The EPA finds that the costs of the HRI technologies and practices that the EPA has identified as the BSER and provided in Table 1 are reasonable because they improve the efficiency of the units to which they are applied. This results in lower operating costs (especially lower fuel costs). In fact, these HRI technologies and practices are the types of efficiency improvement measures that some owners and operators have reasonably implemented at times over the course of the operating life of their EGUs. In specific circumstances the cost to implement one or more of the technologies may be determined to be unreasonable—after consideration of source-specific factors. This will be determined when states establish standards by applying the BSER and taking other factors, including remaining useful life, into consideration.

(1) Reasonableness of Cost

As mentioned earlier, under CAA section 111(a)(1), the EPA determines ''the best system of emission reduction which (taking into account the *cost* of achieving such reduction . . .) . . . has been adequately demonstrated.'' 42 U.S.C. 7411(a)(1) (emphasis added). In several cases, the D.C. Circuit has elaborated on this cost factor in various ways, stating that the EPA may not adopt a standard for which costs would be ''exorbitant,'' [177] ''greater than the industry could bear and survive,'' [178] ''excessive,'' [179] or ''unreasonable.'' [180] These formulations appear to be synonymous and suggest a cost-reasonableness standard. Therefore, in this action, the EPA has evaluated whether the costs of HRI are considered to be reasonable as a general matter across the fleet of existing sources.

Any efficiency improvement made by an EGU will also reduce the amount of fuel consumed per unit of electricity output; fuel costs can account for a large percentage of the overall costs of power production. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving HRIs after any savings from reduced fuel expenses. So, over some time period (depending upon, among other factors, the extent of HRIs, the cost to implement such improvements, and the unit utilization rate), the savings in fuel cost associated with HRIs may be sufficient to cover the costs of implementing the HRI measures. Thus, the net costs of HRIs associated with reducing CO_2 emissions from designated facilities can be relatively low depending upon each EGU's individual circumstances. It should be noted that this cost evaluation is not an attempt to determine the affordability of the HRI in a business or economic sense (*i.e.,* the reasonableness of the imposed cost is not determined by whether there is an economic payback within a predefined time period). However, the ability of EGUs to recoup some of the costs of HRIs through fuel savings supports a finding that costs are reasonable. While some EGUs may not realize the full potential of cost recuperation from fuel savings, the EPA finds that the net costs of implementing HRIs as an approach to reducing CO_2 emissions from fossil fuel-fired EGUs are reasonable because they are not exorbitant or excessive. In fact, these HRIs are the types of efficiency improvement measures that some owners and operators have reasonably implemented at times over the course of the operating life of their EGUs.

It will be up to the states to, either directly or indirectly, take cost into consideration in establishing unit-specific standards of performance. CAA section 111(d) explicitly allows the states to take into consideration, among other factors, the remaining useful life of the existing source in applying the standard of performance. For example, a state may find that an HRI technology is applicable for an affected coal-fired EGU but find that the costs are not reasonable when consideration is given to the timeframe for the planned retirement of the source (*i.e.,* the source's remaining useful life). A state may find that an HRI technology is applicable for an affected coal-fired EGU but find that the costs are not reasonable because the source is already implementing that HRI technology and it would not be reasonable to expect the source to replace that HRI technology with a newer version of the same technology.

There are several ways that cost can be considered. For example, when evaluating costs for criteria pollutants in a BACT analysis or for a ''beyond-the-floor'' analysis for HAP under CAA section 112, the emphasis is focused on the cost of control relative to the amount of pollutant removed—a metric typically referred to as the ''cost-effectiveness.'' There have been relatively few BACT analyses evaluating GHG reduction technologies for coal-fired EGUs. Therefore, there are not a large number of GHG cost-effectiveness determinations to compare against as a measure of the cost reasonableness. Nevertheless, in PSD and title V permitting guidance for GHG emissions, the EPA noted that ''it is important in BACT reviews for permitting authorities to consider options that improve the overall energy efficiency of the source or modification—through technologies, processes and practices at the emitting unit. In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per unit of output basis.'' [181] The EPA has also noted that a ''number of energy efficiency technologies are available for application to both existing and new coal-fired EGU projects that can provide incremental step improvements to the overall thermal efficiency.'' [182]

(2) Cost of the HRI Candidate Technologies Measures

The estimated costs for the BSER candidate technologies are presented below in Table 2. These are cost ranges from the 2009 Sargent & Lundy Study [183] updated to \$2016.[184] These costs correspond to ranges of HRI (percent) presented earlier in Table 1.

[177] *Lignite Energy,* 198 F.3d at 933.

[178] *Portland Cement,* 513 F.2d at 508.

[179] *Sierra Club,* 657 F.2d at 343.

[180] *Id.*

[181] See page 21, ''PSD and Title V Permitting Guidance for Greenhouse Gases,'' EPA–457/B–11–001, March 2011; *https://www.epa.gov/sites/production/files/2015-12/documents/ghgpermittingguidance.pdf.*

[182] *See* page 25, ''Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units,'' October 2010; *https://www.epa.gov/sites/production/files/2015-12/documents/electricgeneration.pdf.*

[183] ''Coal-Fired Power Plant Heat Rate Reductions'' Sargent & Lundy report SL–009597 (2009) Available in the rulemaking docket at EPA–HQ–OAR–2017–0355–21171.

[184] The conversion factor comes from Federal Reserve Economic Data (FRED). *See https://fred.stlouisfed.org.*

TABLE 2—SUMMARY OF COST ($2016/kW) OF HRI MEASURES

HRI Measure	<200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	4.7	4.7	2.5	2.5	1.4	1.4
Boiler Feed Pumps	1.4	2.0	1.1	1.3	0.9	1.0
Air Heater & Duct Leakage Control	3.6	4.7	2.5	2.7	2.1	2.4
Variable Frequency Drives	9.1	11.9	7.2	9.4	6.6	7.9
Blade Path Upgrade (Steam Turbine)	11.2	66.9	8.9	44.6	6.2	31.0
Redesign/Replace Economizer	13.1	18.7	10.5	12.7	10.0	11.2
Improved O&M Practices	Minimal capital cost					

These costs presented in Table 2 represent both capital and O&M costs. Investments in HRI measures at EGUs should also result in fuel savings which can offset some or all of the cost of the HRI. However, the EPA does not suggest that HRI measures should meet any particular economic criterion (*e.g.,* pay for themselves through reduced fuel costs) in order to be applied in state plans for the establishment of source-specific standards of performance.

The technical applicability and efficacy of HRI measures and the cost of implementing them are dependent upon site specific factors and can vary widely from site to site. Because there is inherent flexibility provided to the states in applying the standards of performance, there is a wide range of potential outcomes that are highly dependent upon how the standards are applied (and to what degree states take into consideration other factors, including remaining useful life).

Because the heat rate improvement technologies result in fuel savings and other potential cost savings and the listed candidate technologies are the types of improvements and equipment upgrades that have been previously undertaken, the EPA finds that the costs of the HRI technologies and practices that have been identified as the BSER and provided in Table 1 are reasonable.

f. Non-Air Quality Health and Environmental Impacts, Energy Requirements, and Other Considerations

As directed by CAA section 111(a)(1), the EPA has taken into account non-air quality health and environment requirements for each of the candidate BSER technologies listed in Tables 1 and 2. None of the candidate technologies, if implemented at a coal-fired EGU, would be expected to result in any deleterious effects on any of the liquid effluents (*e.g.,* scrubber liquor) or solid by-products (*e.g.,* ash, scrubber solids). The EPA has also taken into account energy requirements. All of these candidate technologies, when implemented, would have the effect of improving the efficiency of the coal-fired EGUs to which they are applied. As such, the EGU would be expected to use less fuel to produce the same amount of electricity as it did prior to the efficiency (heat rate) improvement. None of the candidate technologies is expected to impose any significant additional auxiliary energy demand.

Implementation of heat rate improvement measures also would achieve reasonable reductions in CO_2 emissions from designated facilities in light of the limited cost-effective and technically feasible emissions control opportunities. In the same vein, because existing sources face inherent constraints that new sources do not, existing sources present different, and in some ways more limited, opportunities for technological innovation or development. Nevertheless, the final emissions guidelines encourage technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency leading to reasonable reductions in CO_2 emissions.

3. Discussion of ''Rebound Effect''

At proposal, the EPA solicited comment on potential CO_2 emissions and generation changes that might occur as a result of efficiency improvements at designated facilities, including potential increased generation to the point of a net increase in emissions from a particular facility, also referred to as the ''rebound effect.'' In some instances, it is possible that certain sources increase in generation (relative to some baseline) as a result of lower operating costs from adoption of candidate technologies to improve their efficiency. The EPA conducted analysis and modeling for the ACE proposal, and found that while there were instances (in some scenarios) where a limited number of designated facilities that adopted HRI increased generation to the point of increasing mass emissions notwithstanding the lower emissions rate resulting from HRI adoption, due to their improved efficiency and marginally improved economic competitiveness relative to other electric generators, the designated facilities as a group reduce emissions because they can generate higher levels of electricity with a lower overall emission rate.

Some commenters on the proposed rule highlighted environmental and legal concerns with the rebound effect as undermining the BSER, while others commented that the concern was de minimis, not rooted in any legal basis, and not germane to establishing standards of performance. On one side, some commenters asserted that the determined BSER is not properly designed because it would not achieve emission reductions if it results in higher utilization and, therefore, emission increases. Some doubted the EPA claims of lower systemwide emissions and said the EPA had not adequately analyzed the concern. Some asserted that the assumptions used in the analysis do not reflect real world considerations that efficiency of all fossil fuel plants degrades over time, rather than being static. Also, some asserted that the EPA had understated the amount of coal capacity that will likely retire in its analysis, and, thus, the remaining coal fleet will consist of more efficient and competitive units that may end up emitting more than the EPA's analysis shows. In addition, some asserted that the EPA's proposed NSR reforms allow sources to extend lifetimes without requiring controls, exacerbating rebound issues.

Other commenters asserted that CAA section 111 does not require the Agency to obtain absolute reductions in emissions at a sector-wide level, and the EPA's obligation is to determine the BSER through evaluation of emissions performance per output at the unit-level. Some commenters stated that any rebound effect from more efficient units is most likely to come at expense of lower-efficiency coal units, negating the effect. Also, commenters contended that rebound is unlikely to change the dispatch order and/or utilization of units based upon the levels of HRI that are reasonable and part of ACE, and, thus, any rebound effect would be de minimis.

The EPA agrees with the commenters who do not see the rebound effect as undermining the BSER determination in this rule, because this rule is aimed at improving a source's emissions *rate* performance at the unit-level. Indeed, in repealing the ''percent reduction'' requirement from the 1977 CAA Amendments, Congress expressly acknowledged that standards of performance were to be expressed as an emissions rate.[185] In addition, as noted above, this rule results in overall reductions of emissions of CO_2. Because the BSER in this rule improves the emissions rate of designated facilities and results in overall reductions, the limited rebound effect that may occur does not undermine the BSER.

Nonetheless, to the extent commenters have asserted that ACE would cause an increase in aggregate CO_2 emissions due to some sources operating more, this concern is not supported by our analysis. The EPA conducted updated modeling and analysis for the final ACE rule (see Chapter 3 of the RIA for more details) and confirmed that aggregate CO_2 emissions from the group of designated facilities are anticipated to decrease (outweighing any potential CO_2 increases related to increased generation by certain units).

The final ACE rule establishes the BSER, and a framework for states to determine rate-based standards of performance for designated facilities. The BSER for ACE is expressed as a rate-based approach, which should necessarily result in rate-based emission reductions. The modeling and analysis show individual units and the entire coal fleet reducing emission rates, as well as an aggregate decrease in mass emissions. As such, any potential ''rebound effect'' is determined to be small and manageable (if necessary) and does not require any specific remedy in the final rule. However, if a state determines that the source-specific factors of a designated facility dictate that the rebound effect is an issue that should be considered in setting the standard of performance, that is within the state's discretion to consider in the process of establishing a standard of performance for that particular existing source. As noted above and as a result of modeling, the EPA does not expect these considerations to be necessary in the state plan development process.

4. Systems That Were Evaluated But Are Not Part of the Final BSER

The EPA identified several systems of GHG emission reduction that may be applied at or to designated facilities but did not propose that they should be part of the BSER. The Agency solicited comment on the rationale for eliminating or not identifying those alternative systems as part of the BSER. After consideration of public comments, the EPA is not revising its proposed determination and is not including any additional or different systems of emission reduction in the final BSER determination. A description of the considered systems of emission reduction that are not part of the final BSER along with a summary of significant public comments is provided below.

The EPA previously considered co-firing (including 100 percent conversion) with natural gas and implementation of carbon capture and storage (CCS) as potential BSER options. *See* 80 FR 64727. In that analysis, the EPA found some natural gas co-firing and CCS measures to be technically feasible but determined that switching from coal to gas is ''a relatively costly approach to CO_2 reductions at existing coal steam boilers when compared to other measures such as heat rate improvements. . . .'' [186] and that the cost to implement CCS for existing source standards is not reasonable and that ''CCS is not an appropriate component of the [BSER].'' [187] A more detailed description of the current consideration of these technologies is provided below.

a. Natural Gas Repowering

Coal-fired utility boilers can reduce their emissions by firing natural gas instead of—or in combination with—coal. This can be done in three different ways: (1) By repowering, (2) by co-firing, or (3) by refueling. *Repowering* is when an existing coal-fired boiler is replaced with one or more natural gas-fired stationary combustion turbines, while still utilizing the existing steam turbines. *Co-firing* and *refueling* involve the burning of natural gas at an existing boiler.[188]

In the ACE proposal, the EPA did not consider natural gas repowering as a potential system of emission reduction (*i.e.,* as a candidate for the BSER) based on the reasoning that this option would fundamentally redefine the existing sources subject to the rule.[189] Some commenters argued, however, that coal-fired utility boilers can reduce emissions through natural gas repowering and it should be the BSER. Other commenters argued that the 'redefining the source' concept from PSD was inappropriate for application to NSPS. After considering public comments on this issue, the EPA concludes that repowering should not be considered for purposes of CAA section 111(d). As described in more detail below, repowering is not a ''system'' of emission reduction for a source at all because it cannot be applied to the existing sources subject to this rule (steam generating units). Rather, repowering these existing units would replace them entirely with a different type of source (stationary combustion turbines) that would be subject to the NSPS in 40 CFR part 60, subpart TTTT.[190] Even if repowering were to be evaluated to determine if it was part of the BSER, the EPA has found non-air quality health and environmental impacts and energy requirements that demonstrate that repowering is not part of the BSER.[191]

As described above, a ''standard of performance'' under CAA section 111(d) must be ''establishe[d]'' for an ''existing source.'' However, repowering a coal-fired boiler—that is, the replacement of a boiler with a stationary combustion turbine—creates a ''new source,'' which is regulated directly by the EPA under 40 CFR part 60, subpart TTTT (establishing standards for the control of GHG emissions from new, modified, or reconstructed steam generating units, IGCCs, or *stationary combustion turbines*). The ''best system of emission reduction'' for an *existing* source,

[185] *See* 1990 CAA Amendments, section 403, 104 Stat. at 2631 (''the Administrator shall promulgate revised regulations for standards of performance . . . that, at a minimum, require any source subject to such revised standards to emit sulfur dioxide at a *rate* not greater than would have resulted from compliance by such source with the applicable standards of performance under this section prior to such revision'') (emphasis added).

[186] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units; Chapter 6, June 10, 2014, Available at Docket Item No. EPA–HQ–OAR–2013–0602–36852.

[187] *Id.* Chapter 7

[188] Co-firing and refueling are discussed in section III.E.4.b of this preamble.

[189] *See* 83 FR 44753.

[190] The EPA is not concluding whether or not the 'redefining the source' concept can or should be applied in the context of the NSPS program.

[191] These non-air quality health and environmental impacts and energy requirements are discussed in more detail below in the discussion of refueling and co-firing. Except to the extent that discussion involves the inefficient combustion of natural gas, the non-air quality health and environmental impacts and energy requirements found for these technologies are similar, if not identical, to those the EPA has found for repowering.

therefore, simply cannot be the creation of a *new* source that is regulated under separate authority. Otherwise, the EPA could subvert the provisions of CAA section 111(d) (which authorizes states to regulate existing sources in the first instance) and require all existing sources to transform into ''new sources,'' which the Agency can directly regulate under CAA section 111(b). Therefore, repowering a coal-fired boiler is not a ''system'' within the scope of the BSER.

b. Natural Gas Co-Firing and Refueling

Some coal-fired utility boilers use natural gas or other fuels (such as distillate fuel oil) for startup operations, for maintaining the unit in ''warm standby,'' or for NO_X control (either directly as a combustion fuel or in configuration referred to as natural gas reburn). During such periods of natural gas co-firing, an EGU's CO_2 emission rate is reduced as natural gas is a less carbon intensive fuel than coal. For example, at 10 percent natural gas co-firing, the net emissions rate (lb/MWh-net) of a typical unit could decrease by approximately 4 percent.

Commenters stated that the EPA should determine that natural gas co-firing is the BSER because it is technically feasible, readily available, achieves significant emission reductions, and may be the most cost-effective option for some facilities. Some commenters also provided data (from EIA) to assert that co-firing is widely used and adequately demonstrated at coal-fired EGUs. The commenters contended that a significant number of coal-fired EGUs have the capacity to burn both natural gas and coal. One commenter asserted that 35 percent of coal-fired utility boilers across 33 states co-fired with natural gas. Another commenter provided a table listing coal-fired EGUs that have recently converted to natural gas or are co-firing with natural gas. One commenter cited data from the EIA and claimed that 48 percent of steam generating EGUs are already co-firing some amount of natural gas.

While the EPA agrees with the assertion that there are existing coal plants that have some access to a supply of natural gas, the EPA disagrees that the data demonstrate that co-firing is a system of emission reduction that has been or that could be implemented on a nationwide scale at reasonable cost. The EPA believes that commenters have conflated operational co-firing (*i.e.,* co-firing coal and natural gas to generate electricity) with startup co-firing (*i.e.,* only using natural gas to heat up a utility boiler or to maintain temperature during standby periods). Coal-fired boilers always use a secondary fuel (most often natural gas or distillate fuel oil), utilizing burners specifically configured to bring the boiler from a cold, non-operating status to a temperature where coal, the primary fuel, can be safely introduced for normal operations.

The EPA conducted its own analysis using EIA fuel use data from 2017.[192] The EPA's analysis supports the assertion that nearly 35 percent of coal-fired units co-fired (in either sense of co-firing as described above) with natural gas in 2017. However, very few—less than four percent of coal-fired units—co-fired with natural gas in an amount greater than five percent of the total annual heat input. This strongly suggests that most of the natural gas that was utilized at these sites was used as a secondary fuel for unit startup or to maintain the unit in ''warm standby'' rather than as a primary fuel for generation of electricity. Further, the small number of units that co-fired with greater than five percent natural gas during 2017 operated at an average capacity factor of only 24 percent—indicating that they are not the most economical units and are not dispatched as frequently as those units that used less than five percent natural gas. For comparison, in 2017, 62 percent of coal-fired utility boilers co-fired with some amount of distillate fuel oil and, as with natural gas, the vast majority of those units used less than 5 percent distillate fuel oil (again, strongly suggesting that it is primarily used as a secondary fuel for startup and warm standby).

The EPA also disagrees that the data demonstrate that co-firing can be considered at the national level as an adequately demonstrated system of emission reduction and that there are easy paths to expand it at a reasonable cost. The EIA 923 fuel use data indicated that about 65 percent of coal-fired utility boilers use something other than natural gas as the secondary fuel for periods of startup and standby operations. Distillate fuel oil is by far the most commonly used secondary fuel. While the use of distillate fuel oil does not necessarily mean that the unit lacks access to natural gas, it suggests that for many of those units, there is an inadequate supply to serve even as a secondary fuel for startup and standby operations. The 2018 average price[193] of distillate fuel oil was more than four times higher than that of natural gas; so, if there was an adequate supply of natural gas, then it would be much more economically favorable to utilize that natural gas rather than the much more expensive distillate fuel oil. As explained earlier, for plants that require additional or new pipeline capacity, the capital cost of constructing new pipeline laterals is approximately $1 million per mile of pipeline built. Therefore, a 50-mile gas pipeline would add $50 million—$100/kW for a typical 500 MW unit—to the capital costs of adding co-firing capability.

As mentioned earlier, the EPA has previously evaluated the costs associated with using natural gas refueling or co-firing as a GHG mitigation option. *See* 79 FR 34875. For a typical base-load coal-fired EGU, the average cost of CO_2 reductions achieved through co-firing with 10 percent natural gas would be approximately $136 per ton of CO_2. While a utility boiler that is converted to 100 percent natural gas-fired can offset some of the capital costs by reducing its fixed operating and maintenance costs (though, as discussed below, the costs would still be considerably higher than the HRI technologies that the EPA identified as the BSER), a unit that is co-firing natural gas with coal would continue to bear the fixed costs associated with equipment needed for coal combustion, raising the cost per ton of CO_2 reduced.

In determining the BSER, CAA section 111(a)(1) also directs the EPA to take into account non-air quality health and environmental impacts and energy requirements. The EPA is unaware of any significant non-air quality health or environmental impacts associated with natural gas co-firing. However, in taking energy requirements into account, the EPA notes that co-firing natural gas in coal-fired utility boilers is not the best or most efficient use of natural gas and, as noted above, can lead to less efficient operation of utility boilers. NGCC stationary combustion turbine units are much more efficient at using natural gas as a fuel for generating electricity and it would not be an environmentally positive outcome for utilities and owner/operators to redirect natural gas from the more efficient NGCC EGUs to the less efficient utility boilers to satisfy an emission standard at the utility boiler. Some commenters disagreed with the EPA's claim that increased use of natural gas in a utility boiler would

[192] See the memorandum ''2017 Fuel Usage at Affected Coal-fired EGUs,'' available in the rulemaking docket (Docket ID No. EPA–HQ–OAR–2017–0355).

[193] The 2018 average U.S. power generation fuel costs for natural gas was $3.52 per million Btu while the cost for distillate fuel oil for power generation was $16.13 per million Btu. U.S. EIA Short Term Energy Outlook, *https://www.eia.gov/outlooks/steo/tables/pdf/2tab.pdf.*

come at the expense of its use in more efficient NGCC units. The EPA did not intend to imply that there is now (or that there will be) a restricted supply of natural gas. Instead, the EPA suggested that, if there were to be an increase in the use of natural gas, the more efficient use for that increased natural gas would be as fuel for under-utilized NGCC units rather than in less efficient utility boilers. The EPA does not believe that establishing a BSER that, for all practical purposes, would mandate increased use of natural gas in utility boilers is good policy.

Given that a natural gas co-firing-based BSER would result in standards that are more costly than standards based on application of the candidate technologies for heat rate improvements, that such a BSER would encourage inefficient use of natural gas, that implementation would be even more expensive and challenging for those units that currently have limited or no access to natural gas, the EPA concludes that co-firing natural gas in coal-fired boilers is not the BSER.

Some commenters requested that co-firing be added to the list of HRI candidate technologies (discussed in more detail below), the combination of which would represent the BSER. However, whereas all coal-fired utility boilers can apply (or have already applied) HRI measures, natural gas co-firing does not satisfy the same CAA section 111(a)(1) criteria (see above). Moreover, co-firing can negatively impact a unit's heat rate (efficiency) due to the high hydrogen content of natural gas and the resulting production of water as a combustion by-product.[194] And depending on the design of the boiler and extent of modifications, some boilers may be forced to de-rate (a reduction in generating capacity) to maintain steam temperatures at or within design limits, or for other technical reasons. Accordingly, natural gas co-firing cannot be applied in combination with the HRI measures identified as the BSER. However, natural gas co-firing might be appropriate for certain sources as a compliance option. For a discussion of compliance options, see below section III.F.2.

Some commenters also suggested that the EPA's concerns about using gas inefficiently were not persuasive because the United States has such an abundant supply of natural gas. The EPA disagrees for many of the same reasons that the Agency relied upon to reject the consideration of natural gas as the BSER. First, it is on the higher end of the cost of the measures the EPA considered even for units with ready natural gas availability; second, many designated facilities do not have natural gas availability, so it is not broadly applicable.

The same factors discussed above lead the Agency to conclude that refueling also cannot be BSER. *Refueling* is when an existing coal-fired boiler is converted to a natural gas-fired boiler (*i.e.,* firing 100% natural gas). In the ACE proposal, the EPA did not consider natural gas refueling as a potential system of emission reduction (*i.e.,* as a candidate for the BSER) based on the reasoning that this option would fundamentally redefine the existing sources subject to the rule.[195] Some commenters argued, however, that coal-fired utility boilers can reduce emissions through natural gas refueling and should be the BSER. Other commenters argued that the 'redefining the source' concept from PSD was inappropriate for application to NSPS.[196] After considering public comments on this issue, the EPA concludes that natural gas refueling, like natural gas co-firing, is not the BSER.

The EPA has previously evaluated the costs associated with using natural gas refueling or co-firing as a GHG mitigation option.[197] The capital costs of plant modifications required to switch a coal-fired EGU completely to natural gas are roughly $100–300/kW, not including any costs associated with constructing additional pipeline capacity. Many coal-fired plants do not have immediate and ready access to any supply of natural gas. Others that do have access to a supply of natural gas have only a limited supply (*i.e.,* enough for startup and warm standby firing, but not enough for full load firing). For plants that require additional pipeline capacity, the capital cost of constructing new pipeline laterals is approximately $1 million per mile of pipeline built. A 50-mile gas pipeline would add $50 million—$100/kW for a typical 500 MW unit—to the capital costs of the conversion.

While a coal-fired utility boiler that is converted to a 100 percent natural gas-fired boiler could offset some of the capital costs by reducing its fixed operating and maintenance costs, in most cases, the most significant cost change associated with switching from coal to gas is likely to be the difference in fuel cost. Using the EIA's projections of future coal and natural gas prices, switching a utility boiler from coal-fired to natural gas-fired could more than double the unit's fuel cost per MWh of generation. For a typical base-load coal-fired EGU, the average cost of CO_2 reductions achieved through gas conversion would be approximately $75 per ton of CO_2. This cost could also be much higher as there would very likely be an increase in natural gas prices corresponding to the increased demand from widespread coal-to-gas conversion.

The EPA also found that consideration of energy requirements (as required by CAA section 111(a)(1)) provides additional reasons why refueling natural gas in a utility boiler should not be considered BSER.[198] Burning natural gas in a utility boiler is not the best use of such fuel as it is much less efficient than burning it in a combustion turbine. New natural gas combined cycle (NGCC) units can convert the heat input from natural gas to electricity with an efficiency of more than 50 percent.[199] A coal-fired utility boiler that is repurposed to burn 100 percent natural gas will see a reduction in efficiency of up to five percent (to less than 40 percent efficiency) as the higher hydrogen content in the natural gas fuel will lead to higher moisture losses that will negatively impact the boiler efficiency.[200] Widespread refueling is not a practice that the EPA should be promoting as it is not the most efficient use of natural gas. Utilities choosing to increase use of natural gas in a combined cycle or simple cycle combustion turbine is a more efficient way to utilize natural gas for electricity generation. In reaching this determination, the EPA is mindful of Congress's direction to ''tak[e] into account . . . energy requirements'' in determining the best system of emission reduction in CAA section 111(a)(1). Consideration of ''energy requirements'' is one of the factors informing the EPA's judgment that it would be inappropriate to base performance standards on an

[194] Natural gas firing or co-firing degrades the boiler's efficiency (relative to the use of coal) primarily due to the increased production of water. Some of the heat that is produced in the combustion process will be used to heat that flue gas moisture (which will exit with the stack gases) rather than to converting water in the boiler tubes to steam. The efficiency declines because there is less heat available to produce useful steam.

[195] *See* 83 FR 44753.

[196] As with repowering, the EPA is not concluding whether or not the ''redefining the source'' concept can or should be applied in the context of the NSPS program.

[197] *See* 79 FR 34875.

[198] *See* 83 FR 44762.

[199] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity'' Rev. 3, DOE/NETL–2015/1723 (July 2015).

[200] ''Leveraging Natural Gas: Technical Considerations for the Conversion of Existing Coal-Fired Boilers'', Babcock Power Services, Presented at 2014 ASME Power Conference (July 2014), Baltimore, MD. Available in the rulemaking docket.

inherently energy-inefficient practice such as refueling.

NGCC units have become the preferred option for intermediate and baseload natural gas power generation. Other technologies (such as simple cycle aeroderivative turbines) offer significant advantages for peaking purposes in that they can start up quickly and require fewer staff to operate. Some combination of aeroderivative turbines and flexible combined cycle units offer advantages in both efficiency and the flexibility to change loads when compared to utility boilers. For these reasons, the power sector has moved away from the use of gas-fired boilers. There have been no new natural gas-fired utility boilers built since the 1980s.

There have been some cases where coal-fired utility boilers have chosen to refuel (*i.e.,* have chosen to convert to natural gas-firing). In those cases, the motivation was largely to preserve reserve capacity without investing in the air pollution controls needed to meet air emission standards—especially MATS.[201] The EPA examined fuel use data submitted by plant owner/operators to the U.S. Energy Information Administration (EIA) on Form 923.[202] According to that data, there were 131 natural gas-fired utility boilers[203] in 2012 and 170 such units in 2017. The average capacity factor for those units was only 11 percent in 2012 and 2017. Between 2012 (before the MATS compliance date) and 2017 (after MATS was fully in effect), 39 utility boilers converted from coal-fired units to become natural gas-fired utility boilers. Those natural gas-fired utility boilers operated at an average capacity factor of less than 10 percent, indicating that they were likely utilized only during periods of high demand.

These non-air quality health and environmental impacts and energy requirements demonstrate that refueling is not the BSER.

c. Biomass Co-Firing

The EPA previously proposed that co-firing of biomass in coal-fired utility boilers is not the BSER for existing fossil fuel-fired sources due to cost and achievability considerations.[204]

Although biomass co-firing methods are technically feasible and can be cost-effective for some designated facilities, these factors and others (namely, that any potential net reductions in emissions from biomass use occur outside of the regulated source and are outside of the control of the designated facility, which is incompatible with the interpretation of the EPA's authority and the permissible scope of BSER as set forth in section II above) are the considerations that prevent its adoption as the BSER for the source category.

In the ACE proposal, the EPA sought comment on the inclusion of forest-derived and non-forest biomass as non-BSER compliance options for affected units to meet state plan standards.[205] In response, the EPA received comments both supporting and opposing the use of biomass for compliance (as discussed in section III.F.2.b); however, commenters also spoke to the appropriateness of including biomass firing as part of the BSER. Some commenters noted that co-firing with biomass cannot be a ''system of emission reduction'' as it increases CO_2 emissions at the source. Commenters further asserted that the EPA has failed to demonstrate how firing biomass meets the CAA section 111 requirements and the criteria for qualifying as a system of emission reduction described in the Proposed Repeal and the ACE proposal.

Upon consideration of comments and in accordance with the plain language of CAA section 111 (discussed above in section II.B), the EPA is now clarifying that biomass does not qualify as a system of emission reduction that can be incorporated as part of, or in its entirety, as the BSER. As described in section III.F.2 of this preamble. the BSER determination must include systems of emission reduction that are achievable at the source. While the firing of biomass occurs at a designated facility, biomass firing in and of itself does not reduce emissions of CO_2 emitted from that source. Specifically, when measuring stack emissions, combustion of biomass emits more mass of emissions per Btu than that from combustion of fossil fuels, thereby increasing CO_2 emissions at the source. Recognition of any potential CO_2 emissions reductions associated with biomass utilization at a designated facility relies on accounting for activities not applied at and largely not under the control of that source, including consideration of offsite terrestrial carbon effects during biomass fuel growth, which are not a measure of emissions performance at the level of the individual designated facility. Use of biomass in affected units is therefore not consistent with the plain meaning of ''standard of performance'' and cannot be considered as part of the BSER.[206]

Additionally, many commenters agreed with the ACE proposal that biomass co-firing should not be part of the BSER because it is not sufficiently cost-effective, there is not a reliable supply of biomass fuel accessible nationally, co-firing with biomass has a negative impact on unit heat rate, and co-firing requirements would ''redefine the source.'' Many commenters supported inclusion of fuel co-firing as a component of the BSER but focused primarily on argument for natural gas co-firing (as discussed earlier). Some of these commenters specifically asserted that biomass use is a widely available and proven GHG reduction technology.

As discussed by the EPA previously in the ACE proposal and other instances,[207] biomass fuel use opportunities are dependent upon many regional considerations and limitations—namely fuel supply proximity, reliability and cost—that prevent its adoption as BSER on a national level (whereas nearly all sources can or have implemented some form of HRI measures). The infrastructure, proximity, and cost aspects of co-firing biomass at existing

[201] *See* 40 CFR part 63, subpart UUUUU.

[202] Monthly fuel use data is submitted to the EIA on Form 923. Available at *https://www.eia.gov/electricity/data/eia923/.* For details of the EPA data analysis, see the memorandum ''2017 Fuel Usage at Affected Coal-fired EGUs'' available in the rulemaking Docket ID No. EPA–HQ–OAR–2017–0355.

[203] Natural gas-fired utility boilers are those with capacity of more than 25 MW that use more than 90 percent natural gas on a heat input basis.

[204] *See* ACE proposal and 80 FR 64756.

[205] *See* 83 FR 44766.

[206] Notwithstanding this conclusion in the context of CAA section 111(d), the EPA believes that a PSD permitting authority may still reach the conclusion that use of some type(s) of biomass is BACT for greenhouse gases in the context of a PSD permit application where the applicant proposes to use biomass, as discussed in the EPA's Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production (March 2011). While biomass combustion may result in more greenhouse gas emissions (in particular CO_2) per unit of production than combustion of fossil fuels, a comparative analysis of biomass and other fuels may not be required in the BACT context. As EPA has observed, ''where a proposed bioenergy facility can demonstrate that utilizing a particular type of biogenic fuel is fundamental to the primary purpose of the project, then at the first step of the top-down process, permitting authorities can rely on that to determine that use of another fuel would redefine the proposed source.'' Bioenergy BACT Guidance at 15. Moreover, even if biomass is compared to fossil fuels and ranked lower at Step 3 of a top-down BACT analysis, broader offsite environmental, economic, and energy considerations related to biomass use (*e.g.,* any potential offsite net carbon sequestration associated with growth of the biomass feedstock) may be considered in Step 4 of a top-down BACT analysis. *See* Bioenergy BACT Guidance at 20–21. It is therefore consistent to determine that the firing of biomass does not qualify as a ''standard of performance'' for setting or complying with the BSER because it does not reduce the GHG emissions of a fossil fuel-fired source, while also allowing the consideration of any potential offsite environmental, economic, or energy attributes when considering an application that treats biomass as BACT for a proposed biomass facility in the PSD permitting context.

[207] *See* 80 FR 64756.

coal EGUs are similar in nature and concept to those of natural gas. While there are a few existing coal-fired EGUs that currently co-fire with biomass fuel, those are in relatively close proximity to cost-effective biomass supplies. Therefore, even if biomass firing could be considered a ''system of emission reduction,'' the EPA is not able to include the use of biomass fuels as part of the BSER in this action due to the current cost and achievability considerations and limitations discussed above. Additional discussion on biomass is provided in section III.F.2.b. below.

d. Carbon Capture and Storage (CCS) [208]

In the ACE proposal, the EPA noted that while CCS is an advanced emission reduction technology that is currently under development, the Agency must balance the promotion of innovative technologies against their economic, energy, and non-air quality health and environmental impacts. The EPA proposed that neither CCS nor partial CCS are technologies that can be considered the BSER for existing fossil fuel-fired EGUs and explicitly solicited comment on any new information regarding the availability, applicability, costs, or technical feasibility of CCS technologies.

Many commenters agreed with EPA's proposed finding that CCS (including partial CCS) should not be part of the BSER. The commenters stated that it is not adequately demonstrated, sufficiently cost-effective, or nationally available. Other commenters disagreed and claimed that CCS is technically feasible and adequately demonstrated and should be part of BSER, asserting that the EPA has previously provided evidence in the record during the 2016 denial of petitions for reconsideration of the CPP that CCS had been successfully implemented at power plants. Commenters also asserted that there are many vendors that offer carbon capture technologies for power plants, which demonstrates that the technology is commercially available and adequately demonstrated.

CCS is a difficult and complicated process, requiring numerous pieces of process equipment to capture CO_2 from the exhaust gas, compress it for transport, transport it in a CO_2 pipeline, inject it, and then monitor the injection space to ensure the CO_2 remains stored. Currently there are only two large-scale commercial applications of post-combustion CCS at a coal-fired power plant—the Boundary Dam project in Saskatchewan, Canada and the Petra Nova project at the W.A. Parish plant near Houston, Texas.[209] Commenters noted that both of the demonstration projects were heavily subsidized by government support and were able to generate additional income from the sale of captured CO_2 for enhanced oil recovery (EOR) and, without these subsidies, neither project would have been economically viable.

Commenters addressed the cost of installing CCS on an existing coal-fired EGU and noted that it can be much costlier and more technically challenging to retrofit the technology to an existing EGU as compared to installation on a newly constructed unit (where the system can be incorporated into the design and space allocation of the new plant). Other commenters claimed that CCS can achieve significant emission reductions (up to 90 percent), that there is opportunity for some sources to generate income from the sale of captured CO_2, and that there are additional financial incentives from the recently approved 2018 Internal Revenue Code (IRC) section 45Q tax credits for stored CO_2, so now CCS may be more cost-effective than HRI options for some facilities. One commenter performed modeling runs that included the section 45Q tax credit and found that, for some sources, CCS would provide much greater emission reductions than HRI options at a reasonable cost and concluded that the EPA should include CCS as part of the BSER. Other commenters minimized the impact of the section 45Q tax credit for a variety of reasons.

Several commenters claimed that access to appropriate CO_2 storage locations is critical to the feasibility and cost of CCS. They described the geographic limitations of both deep saline aquifers and depleted oil fields (EOR fields) noting that 15 states have little or no demonstrated storage capacity or have very limited storage capacity and that EOR sites are similarly geographically limited, with 19 states having little or no demonstrated EOR opportunity. However, other commenters claimed that a technology need not be feasible at every site to be a component of BSER especially since the EPA is relying on site-specific analyses. The commenters noted that not all HRI options are applicable to every source, so the EPA cannot disregard CCS from the BSER options based on ''national availability.''

Commenters noted that 60 GW (or about 20 percent) of the coal-fired power plant capacity might be amenable to CCS based on locality and that North America has widespread and abundant geologic storage options with the capacity to sequester over 500 years of the U.S.'s current energy-related CO_2 emissions. Commenters claimed that 90 percent of existing coal-fired power plants are within 100 miles from the center of a basin with adequate storage capacity and more than half of the existing plants are less than 10 miles from the center of a basin.

The EPA has considered all these public comments and has concluded that, as proposed, CCS is not the BSER for emissions of CO_2 from existing coal-fired EGUs—nor does it constitute a component of the BSER, as some commenters have suggested. As discussed in section III.E.1, above, concerning the ''guiding principles'' for identifying the BSER under CAA section 111(d), the BSER is based on what is adequately demonstrated and broadly achievable across the country. Under CAA section 111(b)(1), the EPA determines ''standards of performance'' for new sources and under section 111(d)(1), the states determine ''standards of performance'' for existing sources within their jurisdiction. Importantly, the term ''standard of performance'' is given a uniform definition under section 111(a)(1) for purposes of both new and existing sources, and, in accordance with that definition, the Administrator is required to determine the BSER as a predicate for the standards of performance for both new and existing sources. In this manner, the text and structure of section 111 indicate that the EPA must make the BSER determination at the national, source-category level. Thus, the EPA disagrees with the commenters who argue that because the EPA is emphasizing that standard setting will be done on a unit-by-unit (rather than fleetwide) basis, all viable emission reduction options should be evaluated at the unit level.

Whereas HRI measures are broadly applicable to the entire existing coal-

[208] CCS is sometimes referred to as Carbon Capture and Sequestration. It is also sometimes referred to as CCUS or Carbon Capture Utilization and Storage (or Sequestration), where the captured CO_2 is utilized in some useful way and/or permanently stored (for example, in conjunction with enhanced oil recovery). In this document, the EPA considers these terms to be interchangeable and for convenience will exclusively use the term CCS.

[209] Several commenters noted that the Petra Nova project received funding from the U.S. Department of Energy (DOE) through the Clean Coal Power Initiative and stated that the project is, pursuant to section 402(i) of the Energy Policy Act of 2005 (EPAct05), therefore, precluded from being used to demonstrate that the technology is ''adequately demonstrated'' under section 111 of the CAA. Some commenters noted that the DOE funding was only for the initial 60 MW slip-stream demonstration project, but the CCS project at Petro Nova was later expanded to a 240 MW slip-stream and no federal funding was received for this expansion.

fired power plant fleet, the EPA determines that CCS or partial CCS is not. The EPA agrees that there may be some existing coal-fired EGUs that find the application of CCS to be technically feasible and an economically viable control option, albeit only under very specific circumstances. However, the high cost of CCS, including the high capital costs of purchasing and installing CCS technology and the high costs of operating it, including high parasitic load requirements, prevent CCS or partial CCS from qualifying as BSER on a nationwide basis.

According to the DOE National Energy Technology Laboratory (NETL), the incremental cost from capital expenditures alone of installing partial or full capture CCS [210] on a new coal-fired EGU ranged from $626 (for 16% capture) to $2,098 (for full capture) per kW (2011 dollars).[211] These costs are for new CCS equipment installed on a new facility, but they fairly represent the costs of new CCS equipment installed on an existing facility; indeed, these costs are probably lower than the actual costs of installing new CCS equipment on an existing facility, because the costs of retrofitting pollution controls on an existing facility generally are greater than the costs of installing pollution controls on a new facility. In contrast, as noted elsewhere, the cost of the HRI that constitute the BSER for this rule range from $25–$47 per kW (2016 dollars). Thus, the costs of partial CCS, considering only the capital costs and not the operating costs, are far higher than—more than 13 times—the cost of what the EPA has identified as the BSER.

Viewing the costs of CCS through other prisms yields the same determination. According to NETL, the capital costs of a CCS system with 90 percent capture increases the cost of a new coal-fired power plant approximately 75 percent relative to the cost of constructing a new coal-fired power plant without post-combustion control technology. Furthermore, the additional auxiliary load required to support the CCS system consumes approximately 20 percent of the power plant's potential generation.[212] The NETL Pulverized Coal Carbon Capture Retrofit Database tool (April 2019) [213] estimates that the operating costs of existing coal-fired EGUs range from 22 to 44 $/MWh.[214] The incremental increase in generating costs, including the recovery of capital costs over a 30-year period, due to CCS range from 56 to 77 $/MWh.[215] For reference, according to the EIA, the average electricity price for all sectors in March of 2019 was 103.8 $/MWh.[216] About 60 percent of these latter costs (60 $/MWh) are associated with generation and 40 percent with transmission and distribution of the electricity.[217] Thus, the incremental increase in generating costs due to CCS by itself would equal or exceed the average generation cost of electricity for all sectors. The costs of partial CCS are less than full CCS, but due to economies of scale, costs do not reduce as quickly as reductions in the capture rate. For example, the capital costs of treating only 18 percent of the flue gas (a 16 percent reduction in emissions of CO_2) are about 30 percent of the capital costs of treating all of the flue gas (full capture or a 90 percent reduction in emissions of CO_2). Similarly, at full capture, treating only 18 percent of the flue gas (a 16 percent reduction in emissions of CO_2) still increases the cost of electricity by about 28 percent of the increase that results from treating all of the flue gas.[218] Again, these costs are probably lower than the actual costs of installing new CCS equipment on an existing facility. Not only are these costs far higher than what the EPA has identified as the BSER, they would almost certainly force the closure of the coal-fired power plants that would be required to install them. Many of those plants have a marginal profit margin, as demonstrated by the high rate of plant closure and the relatively low amounts of operation (*i.e.,* capacity factors) in recent years. Thus, these costs must be considered exorbitant. *See* section III.E.1. for a discussion of the guiding principles in determining the BSER.

As noted above, the Boundary Dam project in Saskatchewan, Canada and the Petra Nova project at the W.A. Parish plant near Houston, Texas are the only large-scale commercial applications of post-combustion CCS at a coal-fired power plant. They both have retrofit CCS or partial CCS, and they both received significant governmental subsidies—including, for the Petra Nova project, both direct federal grants from the DOE through the Clean Coal Power Initiative and the IRC section 45Q tax credits—and relied on nearby EOR opportunities. Due to the high costs of CCS, all of these subsidies and EOR opportunities were essential to the commercial viability of each project.[219]

Some commenters have asserted that the costs of CCS are reasonable and explain, as a central part of their assertion, that the availability of tax credits under section 45Q, as revised by the Bipartisan Budget Act of 2018, significantly lowers the costs of CCS. In fact, they have asserted, that the tax credits, which have an initial value of $35 per tonne (*i.e.,* metric ton) for CO_2 stored through EOR, offset about 70% of the cost of CCS, with EOR offsetting the rest.[220] However, the section 45Q tax credits are limited in time: The credit for equipment placed in service after the date of enactment of the Bipartisan Budget Act of 2018 is available, in general, only for facilities and equipment for which construction begins before January 1, 2024. IRC section 45Q(d)(1). Under the present rule, state plans are not required to be submitted until mid-2022 and the states have the authority to determine their sources' compliance schedule; compliance schedules are generally expected to last 24 months (*i.e.,* until mid-2024), but could in some instances be longer, as noted in preamble section

[210] Full capture is considered to occur when 100 percent of the flue gas is treated, resulting in a 90 percent reduction in emissions of CO2 relative to a power plant without carbon capture.

[211] "Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO2 Capture Rate in Coal-Fired Power Plants," une 22, 2015; DOE/NETL–2015/1720 *https://www.netl.doe.gov/projects/files/[FR Doc.SupplementSensitivitytoCO2CaptureRatein[FR Doc.CoalFiredPowerPlants_062215.pdf.*

[212] A CCS system requires both auxiliary steam and electricity to operate. According to NETL, a full capture system consumes 53 MW of direct electrical load and steam that could have otherwise been used to generate approximately 86 MW of electricity.

[213] *https://www.netl.doe.gov/energy-analysis/details?id=2949.*

[214] Existing coal-fired power plants have generally already paid off the initial construction (*i.e.,* capital) expenses.

[215] Variable operating costs represent approximately $15/MWh and the remaining costs are recovered capital over a 30-year period. The capital costs assume the power plant can recover the costs over 30 years. If the actual remaining useful life of the power plant itself is less, the costs would be higher because the capital would have to be recovered over a shorter time period. The average age of the remaining coal fleet is approximately 42 years, and the average age of retirement for coal-fired power plants is currently 54 years (*http://www.americaspower.org/wp-content/uploads/2018/03/Coal-Facts-August-31-2018.pdf*). Therefore, a significant portion of the existing coal-fired will likely retire in less than 30 years.

[216] *https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.*

[217] *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&cases=ref2019&sourcekey=0.*

[218] "Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants," June 22, 2015; DOE/NETL–2015/1720.

[219] The EPA discussed the government funding and the EOR revenue from the transport of captured CO_2 to the Hilcorp's West Ranch Oil Field in "Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units," 80 FR 64510, 64551 (October 23, 2015).

[220] EPA–HQ–OAR–2017–0355–24266 at 18.

III.F.1.a.(2).[221] In order for sources to implement CCS and be able to rely on the 45Q tax credit, they would have to complete all planning, including arranging all financing, preconstruction permitting, and commence construction within about 18 months (by December 31, 2023) of the state plan submittal. The EPA considers that timetable to be impracticably short for most sources, considering the complexity of implementation of CCS. In addition, the tax credit is, in general, available only for the 12-year period beginning on the date the equipment is originally placed in service. IRC section 45Q(a)(3)–(4). Thus, it would not be available to offset much of the capital costs of the CCS systems that are recovered over a 30-year period.[222] Further, like any federal income tax credit, the 45Q tax credits do not provide a benefit to a company that does not owe federal income tax, and thus it may not benefit some coal-fired power plant owners. Accordingly, the 45Q tax credits cannot be considered to offset the high costs of CCS for the industry as a whole. While nearby EOR opportunities are available for some EGUs, they alone cannot offset the high costs of CCS, as is evident from the comments discussed above.

In addition, nearby EOR opportunities are not available for many EGUs, which, as a result, would incur higher costs for constructing and operating pipelines to transport CO_2 long distances. Throughout the country, 29 states are identified as having oil reservoirs amenable to EOR, of which only 12 states have active EOR operations.[223] The vast majority of EOR is conducted in oil reservoirs in the Permian Basin, which extends through southwest Texas and southeast New Mexico. States where EOR is utilized include Alabama, Arkansas, Colorado, Louisiana, Michigan, Mississippi, Montana, New Mexico, Oklahoma, Texas, Utah, and Wyoming, whereas coal-fired generation capacity is located across the country.[224] For example, Georgia, Minnesota, Missouri, Nevada, North Carolina, South Carolina, and Wisconsin have coal-fired generation capacity but do not have oil reservoirs that have been identified as amenable for EOR. In addition, some of the states with the largest amounts of coal-fired generation capacity have no active EOR operations, including Illinois, Indiana, Kentucky, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. Even in states that are identified as having potential oil and gas storage capacity, the amount of storage resource varies by state. In some states, the total oil and gas storage resource is smaller than the annual energy-related CO_2 emissions from coal, including Indiana and Virginia.[225] The limited geographic availability of EOR, and the consequent high costs of CCS for much of the coal fleet, by itself means that CCS cannot be considered to be available across the existing coal fleet.

The high costs of CCS inform the Administrator's determination that this technology is not BSER. Some commenters have suggested that CCS be treated as BSER for some facilities on a unit-by-unit basis, but the EPA believes that this would be inconsistent with its role under section 111(a)(1) to determine as a general matter what is the BSER that has been adequately demonstrated, taking into account, among other factors, cost. To treat CCS as BSER for a handful of facilities would result in those facilities becoming subject to high costs from CCS—potentially much higher than those imposed on other facilities for whom CCS is not treated as BSER. This potential disparate impact of costs is inconsistent with the Administrator's role in determining BSER and is another reason why the Administrator is finalizing a determination that CCS is not BSER.

Nevertheless, while many commenters argued that CCS should not be considered part of the BSER, they supported its use as a potential compliance option for meeting an individual unit's standard of performance. The EPA agrees with this assessment. Evaluation of the technical feasibility (*e.g.,* space considerations, integration issues, *etc.*) and the economic viability (*e.g.,* the prospects and availability of long-term contractual arrangements for sale of captured CO_2, the cost of constructing a CO_2 pipeline, the availability of tax credits, *etc.*) of a CCS project is heavily dependent on source-specific characteristics. Accordingly, state plans may authorize such projects for compliance with this rule.

F. State Plan Development

1. Establishing Standards of Performance

CAA sections 111(d)(1) and 111(a)(1) collectively establish and define certain roles and responsibilities for the EPA and the states. As discussed in section III.B above, the EPA has the authority and responsibility to determine the BSER. CAA section 111(d)(1) clearly contemplates that states will submit plans that establish standards of performance for designated facilities (*i.e.,* existing sources).

States have broad flexibility in setting standards of performance for designated facilities. However, there is a fundamental obligation under CAA section 111(d) that standards of performance reflect the degree of emission limitation achievable through the application of the BSER, which derives from the definition for purposes of section 111 of ''standard of performance'' in those terms, with no distinction made between new-source and existing-source standards. In establishing such standards of performance, the statute expressly provides that states may consider a source's remaining useful life and other factors. Accordingly, based on both the mandatory and discretionary aspects of CAA section 111(d), a certain level of process is required of state plans: Namely, they must demonstrate the application of the BSER in establishing a standard of performance, and if the state chooses, the consideration of remaining useful life and other factors in applying a standard of performance to a designated facility. The EPA anticipates that states can correspondingly establish standards of performance by performing two sequential steps, or alternatively, as further described later in this section, by performing these two steps simultaneously. The two steps to establish standards of performance are: (1) Reflect the degree of emission limitation achievable through application of the BSER, and, if the state chooses, (2) consider the remaining useful life and other source-specific factors.

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[221] By comparison, the implementation period for the CPP began three years after the state plan submittal. *See* 80 FR at 64669.

[222] The NETL Pulverized Coal Carbon Capture Retrofit Database tool (April 2019) defaults to a capital recovery factor based on 30 years. Capital recovery factors based on 10 and 20 years are also selectable. If shorter periods are selected, the $/MWh for capital recovery would be higher. Table 10–12 of The Integrated Planning Model (version 6) uses a 15-year capital recovery factor for environmental retrofits, *https://www.epa.gov/sites/production/files/2019-03/documents/chapter_10.pdf.* Recovering costs over a 12-year period, as opposed to a 30-year period, increased the capital recovery factor by 40 percent.

[223] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL) and EPA Greenhouse Gas Reporting Program, *see https://www.epa.gov/ghgreporting.*

[224] U.S. Energy Information Administration, Electric Power Annual 2017, *see https://www.eia.gov/electricity/annual/pdf/epa.pdf.*

[225] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL) and U.S. Energy Information Administration, Energy-Related Carbon Dioxide Emissions by State, 2005–2016, *see https://www.eia.gov/environment/emissions/state/analysis/.*

If a state chooses to develop standards of performance through a sequential (*i.e.,* two step) process, the state would as the first step apply the BSER to a designated facility's emission performance (*e.g.,* the average emission rate from the previous three years or a projected emission rate under specific conditions such as load) and calculate the resulting emission rate. In this step, states fulfill the obligation that standards of performance reflect the degree of emission limitation achievable by evaluating the applicability of each of the candidate technologies that comprise the BSER to a specific designated facility and calculating a corresponding standard of performance based on the application of all candidate technologies that the state determines are applicable to the specific designated facility. A state may determine the most appropriate methodology to calculate a standard of performance (which for purposes of this regulation will be in the form of an emission rate, as further described in section III.F.1.c. of this preamble) by applying the BSER to a designated facility based on the characteristics of the specific source (*e.g.,* load assumptions and compliance timelines). For example, a state can start with the average emission rate of a particular designated facility and adjust it to reflect the application of each candidate technology and the associated emission rate reduction.

As the second step, under this two-step, sequential process approach, after the state calculates the emission rate that reflects application of the BSER, the state may adjust that rate by considering the remaining useful life of the designated facility and other source-specific factors. It should be noted that the state is not required to take this second step and consider remaining useful life and other factors. Rather, the state has the discretion to do so. A discussion on how a state can consider remaining useful life and other factors, if it so chooses, can be found in section III.F.1.b. below. States also have the discretion to apply a specific standard of performance to a group of existing sources within their jurisdiction, or to all existing sources within their jurisdiction.

As just described, the EPA believes it would be reasonable for states to follow a sequential two-step process to establish standards of performance. However, a state may develop its own process for calculating standards of performance outside of this two-step process, such as a hybridized approach which blends the two sequential steps into one combined step, so long as the state plan submission demonstrates application of the BSER in determining each standard of performance, (*i.e.,* evaluation of applicability of each and all candidate technologies to each designated facility). For example, if a state determines that the designated facility is able to implement only four of the six candidate technologies (due to the remaining useful life or other factors), the state is required to demonstrate in its plan submission that it in fact considered the two remaining candidate technologies in making this determination.

For the two-step approach, a state could do this by explaining in its plan submission that it considered the application of each of the candidate technologies in the first instance, but in the second step the state determined that the two candidate technologies should not be part of the methodology to calculate the EGU's standard of performance because of remaining useful life or other factors. The state should additionally provide a rationale for why and how it considered remaining useful life and other factors to discount a particular candidate technology from the calculation of a standard of performance (*e.g.,* by explaining that such technology has already been implemented by a particular source).

For a hybridized approach, when the state is applying the BSER and determining the emission reductions associated with the candidate technologies for a specific designated facility, it may be readily apparent that two of the candidate technologies are not reasonable to install because, for example, those technologies have recently been updated at the unit, independent of this final rule. This hybridized approach, which blends application of the BSER and associated stringency with consideration of remaining useful life and other factors in one step to calculate a standard of performance, may be appropriate provided that the state plan clearly demonstrates the standard of performance (expressed as a degree of emission limitation) that would result from application of the BSER and provides a rationale for why and how remaining useful life and other factors were considered to discount a particular candidate technology from the calculation of a standard of performance. This is one illustrative way in which states can demonstrate, in establishing a standard of performance, that they have both fulfilled their obligation to apply the degree of emission limitation achievable through the BSER to each designated facility and also properly invoked their discretion in considering remaining useful life and other factors.

In this section of the preamble, the EPA addresses discrete aspects of the standard-setting process. It is intended to provide states clarity and direction on each of these aspects to assist the states in developing standards of performance. The EPA is not requiring a specific method for states to develop standards of performance.

a. Application of the BSER

As described in other parts of this section, while the EPA's role is to determine the BSER, CAA section 111(d)(1) squarely places the responsibility of establishing a standard of performance for an existing designated facility on the state as part of developing a state plan. This final rule requires states to evaluate the applicability of each of the candidate technologies (HRI measures) that the EPA has determined constitute the BSER in establishing a standard of performance for each designated facility within their jurisdiction. The BSER is a list of candidate technologies that are HRI measures, which states will evaluate and apply to existing sources, establishing a standard of performance that is appropriately tailored to each existing source.[226] In establishing a standard of performance, a state may consider remaining useful life and other factors as appropriate based upon the specific characteristics of those units. In general, the EPA envisions that the states would set standards based on considerations most appropriate to individual sources or groups of sources (*e.g.,* subcategories). These may include consideration of historical emission rates, effect of potential HRIs (informed by the information in the EPA's candidate technologies described earlier in section III.E), or changes in operation of the units, among other factors the state believes are relevant. As such, states have considerable flexibility in determining standards of performance for units, as contemplated by the express statutory text.

States have discretion to apply the same standard of performance to groups of existing sources within their jurisdiction, as long as they provide a sufficient explanation for this choice and a demonstration that this approach will result in standards of performance achievable at the sources. But states also

[226] Because the candidate technologies that comprise the BSER can, at least in some cases, be applied in combination at an individual source, states should evaluate both individual candidate technologies and combinations of candidate technologies to appropriately establish standards of performance.

have discretion, expressly conferred on them by Congress in CAA section 111(d), to take into account a source's remaining useful life and other factors when establishing a standard of performance of that source, and much of the discussion in this final rule relates to the nature of that discretion and the factors that should influence states' exercise of it. As the EPA described in the proposal and as commenters have verified, the fleet of coal-fired EGUs is diverse and each EGU has been designed and engineered uniquely to fit the need at the time of construction. Because each coal-fired steam boiler subject to this rule has been designed, maintained, utilized, and upgraded uniquely, each designated facility has a unique set of circumstances with a set of source-specific factors governing its use. The outgrowth of the abundance of source-specific factors has led the EPA to determine that a tailored standard of performance (developed by states) that considers those factors can achieve emission reductions in the fleet without making broad assumptions about the fleet that may not be applicable to a particular unit. The source-specific circumstances at each EGU causes considerable variation in average emission rates across the fleet. If a single standard of performance (*i.e.,* a single degree of emission limitation resulting from a particular technology or fixed set of technologies) were to be applied to the entire fleet, the result could be either that a large portion of the fleet would not be required to achieve any meaningful emission reductions, or a large portion of the fleet would face overly stringent requirements. The goal of these emission guidelines is not to burden or shut down coal-fired EGUs—which could compromise the stability of the power sector and thus energy reliability to consumers, concerns which the EPA expresses, informed by, among other factors, Congress's direction to take into account energy requirements in determining BSER—as coal-fired EGUs still have considerable viability as part of the power sector.

When states apply the BSER's candidate technologies to a designated facility, the application of each technology and the associated degree of emission limitation achievable by such application will entail source-specific determinations. For this reason, in Table 1, the EPA provided the degree of emission limitation achievable through application of the BSER in the form of ranges, which capture the reductions and costs that the EPA expects to approximate the outcome of the application. The degree of emission limitation achievable through application of the BSER (*i.e.,* the ranges of improvements in Table 1) should be used by the states in establishing a standard of performance; however, the standard of performance calculated for a specific designated facility may ultimately reflect a degree of emission limitation achievable through application of the BSER outside of the EPA's ranges because of consideration of source-specific factors. If a state uses the sequential two-step process to establish a standard of performance, in the first step the EPA expects that the state will use the range of improvements for each candidate technology (and combinations thereof where technically feasible) to develop a standard of performance for a designated facility (the range of costs can be used in the second step which considers the remaining useful life and other factors as discussed in section III.F.1.b.). The ranges of HRI in section III.E are typical of an EGU operating under normal conditions. While a source with typical operating conditions (assuming no consideration of remaining useful life or other factors) will have a standard of performance with an expected improvement in performance within the ranges in Table 1, there may be source-specific conditions that cause the actual HRI of the applied candidate technology to fall outside the range. For example, if a designated facility had installed a new boiler feed pump just prior to a state's evaluation of the designated facility, the application of that candidate technology would yield negligible improvement in the heat rate and thus the value would fall outside the ranges provided by the EPA (*i.e.,* because the technology has already been applied and the baseline emission rate reflects that). As with the application of all the candidate technologies, the state plan submission must identify: (1) The value of HRI (*i.e.,* the degree of emission limitation achievable through application of the BSER) for the standard of performance established for each designated facility; (2) the calculation/methodology used to derive such value; and (3) any relevant explanation of the calculation that can help the EPA to assess the plan. In explaining the value of HRI that has been calculated, if the value of the HRI falls within the range identified by the EPA for a particular candidate technology, a state may note as such as part of its explanation. If a resulting value of HRI falls outside the range provided by the EPA, the state should in its state plan submission explain why this is the case based on application of the candidate technology to a particular source. In any instance, the state plan submission must identify the value of HRI that has been calculated and the calculation used to derive the value of HRI, and explain both. The states will thus use the information provided by the EPA, but will be expected to conduct source-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies. After a state applies the candidate technologies to a designated facility (*i.e.,* step one), it can consider the remaining useful life and other factors associated with the source and determine whether it is cost-reasonable to actually implement that technology at the source (*i.e.,* step two). This is described in detail below in section III.F.1.b.

The approach to require states to tailor standards of performance for designated facilities is both consistent with the framework of cooperative-federalism envisioned under CAA section 111(d), and the new implementing regulations for CAA section 111(d).[227] The new implementing regulations at40 CFR 60.21a(e) and 60.22a(b)(2) and (4) require emission guidelines to reflect, and contain information on, the degree of emission limitation achievable through the application of the BSER. By providing the BSER and the associated level of stringency in the form of HRIs and associated range of heat rate improvements, the EPA is thus meeting applicable statutory and regulatory requirements and is giving states the necessary information and direction to establish standards of performance for existing sources that reflect the degree of emission limitation achievable through application of the BSER.[228]

(1) Variable Emission Performance

The Agency received comments that there is considerable variation in emissions between designated facilities within the industry, as well as considerable variation of emissions for individual units based on the operating conditions. Commenters expressed concern that the degree of emission limitation achievable through the application of the BSER is similar to the

[227] *See* 83 FR 44746.

[228] By providing the BSER and level of stringency associated with the BSER, ACE meets the applicable requirements of the new implementing regulations at 40 CFR part 60, subpart Ba, regarding the contents of an emission guideline. An ''emission guideline'' is defined under 40 CFR 60.21a(e) as a ''final guideline document'' which must contain certain items enumerated under 40 CFR 60.22a. The preamble, regulatory text, and record for ACE comprise the ''final guideline document'' referenced as the emission guideline.

magnitude in the variation in the emission rate at a specific EGU due to different operating conditions (*e.g.,* the operating load of the EGU). Commenters contend that because of this similarity, a designated facility could fall out of compliance with its standard of performance if its operating conditions change despite the source's having installed/applied all of the candidate technologies.

Commenters further stated that oftentimes the operation of a designated facility is not in the control of the owner/operator when it goes to load and cycling, and because of that the emission rate varies based on circumstances that are outside of the designated facility's control. The commenters further state that they should not be held accountable to standards that are not reflective of this lack of control and variability. The EPA acknowledges commenters' concerns about variability among designated facilities and variability of emission performance at an individual designated facility, and believes the flexibilities provided for states in establishing standards of performance, as described in this section, are sufficient to accommodate these variables. In establishing standards of performance, states can consider the two distinct types of variable emission performance [229] (*i.e.,* variation between different facilities and variation of emissions at one facility at different times) and states can tailor standards of performance accordingly.

First, standards of performance should acknowledge and reflect variability across EGUs due to unit-specific characteristics and factors, including, but not limited to, boiler-type, size, *etc.* By allowing states to establish standards of performance for individual designated facilities (in accordance with the statute's text and structure which provides that states in their plans shall establish standards of performance for existing sources), the EPA expects that standards of performance will inherently account for unit-specific characteristics.[230] By applying the BSER to individual designated facilities within the state, standards of performance would account for unit-specific characteristics such as unit design, historical operation and maintenance. As further described in section III.F.1.b, states may also account for anticipated future design and/or operating plans—such as plans to operate as baseload or load following electricity generators.

Second, standards of performance should reflect variability in emission performance at an individual designated facility due to changes in operating conditions. Specifically, the agency believes it would be appropriate for states to identify key factors that influence unit-level emission performance (*e.g.,* load, maintenance schedules, and weather) and to establish emission standards that vary in accordance with those factors. In other words, states could establish standards of performance for an individual EGU that vary (*i.e.,* differ) as factors underlying emission performance vary. For example, states could identify load segments (ranges of EGU load operation) that reflect consistent emission performance within the segment and varying emission performance between segments. States could then establish standards of performance for an EGU that differ by load segment.

Another possible option to account for variable emissions is to set standards of performance based on a standard set of conditions. A state could establish a baseline of performance of a unit at specific load and operational conditions and then set a standard against those conditions via the application of the BSER. Compliance for the unit could be demonstrated annually (or by another increment of time if appropriate based on the level of stringency of the standard of performance set for the unit) at those same conditions. In the interim, between the demonstration of compliance under standardized conditions, a state could allow for the maintenance and demonstration of fully operational candidate technologies to be a method to demonstrate compliance as the standard of performance must apply at all times.

The Agency believes that these approaches to providing flexibility (and possible others not described here) in establishing standards of performance are reasonable and appropriate by accounting for innate variable emission performance across EGUs and at specific EGUs while also limiting this flexibility to instances in which underlying variable factors are evaluated and linked to variable emission performance.

(2) Compliance Timelines

Additionally, the new implementing regulations require that emission guidelines identify information such as a timeline for compliance with standards of performance that reflect the application of the BSER.[231] However, given the source-specific nature of these emission guidelines and the reasonably anticipated variation between standards established for sources within a state, the EPA believes it more appropriate that a state establish tailored compliance deadlines for its sources based on the standard ultimately determined for each source. Accordingly, the EPA is superseding this aspect of 40 CFR 60.22a for purposes of ACE, as allowed under the applicability provision in the new implementing regulations under 60.20a and allowing for states to include an appropriate compliance deadline for each designated facility based on its standard of performance determined as part of the state plan process. It is important that states consider compliance timelines that are consistent with the application of the BSER to ensure that the compliance timeline does not undermine the BSER determination made by the EPA. For most states, the EPA anticipates initial compliance to be achieved by sources within twenty-four months of the state plan submittal. If a state chooses to include a compliance schedule (because of source-specific factors) for a source that extends more than twenty-four months from the submittal of the state plan, the plan must also include legally enforceable increments of progress for that source [232]). The EPA does not envision that most states will be using increments of progress leading up to initial compliance. However, as with the consideration of other source-specific factors, where a state does choose to provide for a source to comply on a longer timeframe than twenty-four months and to employ legally enforceable increments of progress

[229] In this context, variable emission performance is a result of underlying variability in heat rate, as emissions of CO_2 from EGUs are proportional to the unit's heat rate performance.

[230] Note that for administrative efficiency in developing a state plan, a state may be able to calculate a uniform standard of performance that reflects application of the BSER for a group of designated facilities rather than performing the same calculation multiple times for multiple individual sources if the group of sources has similar characteristics such that application of BSER would be consistent between the EGUs. This final rule does not necessarily require a state to provide a discrete calculation and separate standard of performance for each designated facility within a group of similar designated facilities, but if a state chooses to calculate a uniform rate for such a group of sources the plan submission should explain how the uniform rate reflects application of the BSER for all of the units in the group (*e.g.,* because of similar operating characteristics). Additionally, even if the same emission rate is calculated for designated facilities at different facilities that are included in such a group, such standard is applicable to each individual designated facility, and each source would be required to meet that standard by implementing ACE requirements separately, consistent with the state plan requirements described in section III.F.2 of this rule.

[231] *See* 40 CFR 60.22a.

[232] *See* 40 CFR 60.24a(d).

along the way, the state should include in its state plan submission to the EPA an adequate justification for why that approach is warranted. The level of stringency can be compromised if a compliance schedule does not adequately reflect the BSER determination.

Several commenters requested clarity on when standards of performance must become effective (*i.e.,* when must designated facilities comply with their standards of performance) once a state plan has been submitted but not yet approved by the EPA. The contents of a state plan submission, such as standards of performance and related requirements, are not effective or enforceable under federal law until they are approved by the EPA. However, state plan requirements must be fully adopted as a matter of state law, or issued as a permit, order, or consent agreement, before the plan is submitted to the EPA (and therefore could be enforceable as a matter of state law, depending on when the state has chosen to make such requirements effective).[233] The EPA anticipates that in determining an appropriate compliance schedule (and more specifically the initial compliance) for designated facilities, a state will consider the anticipated timing of review of the state's plan by the EPA and what sources may need to do in the interim in order to assure ultimate compliance with their standards of performance while EPA is in the process of reviewing the plan.

States also have discretion in establishing a compliance schedule for designated facilities, but the Agency urges states to use caution as to not undermine the BSER by the determined schedules. Most programs under CAA section 111 do not have compliance timelines greater than a year and the Agency believes that is a good indicator for states to take into consideration determining compliances schedules. Much of how a compliance schedule is structured can be based on how the standard of performance is structured. In section III.F.1.a.(1) there is a discussion about how a state might account for variable emissions. One of the options is to set a standard of performance under standardized conditions to take into account many of the factors that can lead to variable emissions from a designated facility. The standardized conditions (*e.g.,* load, ambient temperature, humidity *etc.*) that apply to the standard of performance must also be met when there is a compliance demonstration. Because these standardized conditions are not maintained throughout a compliance period, the segmented nature of demonstrating compliance could mirror the compliance schedule. For example, a designated facility could have a monthly demonstration under standardized conditions that mirrors a monthly compliance schedule. This is one example to illustrate how a standard of performance can align with a compliance schedule.

Another consideration for states in establishing standards of performance is the emission averaging time (*e.g.,* the amount of time that a designated facility may average its emission rate). As described above in section III.F.1.a.(1), EGUs may have considerably variable emissions due to numerous operating factors. A method to account for seasonal variability is to average a designated facility's emission rate over the course of multiple seasons.

b. Consideration of Remaining Useful Life and Other Factors

CAA section 111(d) requires, in part, that the EPA ''shall permit the State in applying a standard of performance to any particular source under a plan submitted under [CAA section 111(d)] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' Consistent with the requirements of this provision, the EPA is permitting states to consider remaining useful life and other factors in establishing a standard of performance for a particular source in this final rule. States may do this in several ways. If a state is following the sequential two-step process, the state would first apply all of the candidate technologies to a designated facility to derive a standard of performance with consideration to the EGU's historical or projected performance, as previously described in section III.F.1.a. In the second step of this process, the state would consider the ''remaining useful life and other factors'' for the EGU and develop a standard of performance accordingly. It should be noted that the consideration of remaining useful life and other factors is a discretionary step for states. If a state were to establish a standard of performance for a designated facility based solely on the application of the BSER, it would be reasonable to do so and not precluded under the statute.

The CAA explicitly provided under CAA section 111(d)(1) that states could, under appropriate circumstances, establish standards of performance that are less stringent than the standard that would result from a direct application of the BSER identified by the EPA. CAA section 111(d)(1) achieves this goal by authorizing a state, in applying a standard of performance, to take into account a source's remaining useful life and other source-specific factors. As such, the EPA is promulgating, as part of the new implementing regulations at 40 CFR 60.20a-29a, a provision to permit states to take into account remaining useful life, among other factors, in establishing a standard of performance for a particular designated facility, consistent with CAA section 111(d)(1)(B). The new implementing regulations (also consistent with the previous implementing regulations) give meaning to CAA section 111(d)(1)(B)'s reference to ''other factors'' by identifying the following as a nonexclusive list of several factors states may consider in establishing a standard of performances:

- Unreasonable cost of control resulting from plant age, location, or basic process design;
- Physical impossibility of installing necessary control equipment; or
- Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

Given that there are unique attributes and aspects of each designated facility, there are important factors that influence decisions to invest in technologies to meet a potential standard of performance. These include factors not enumerated in the list provided above, including timing considerations like expected life of the source, payback period for investments, the timing of regulatory requirements, and other source-specific criteria. The state may find that there are space or other physical barriers to implementing certain HRIs at specific units. Alternatively, the state may find that some HRI options are either not applicable or have already been implemented at certain units. The EPA understands that many of these ''other factors'' that can affect the application of the BSER candidate technologies distill down to a consideration of cost. Applying a specific candidate technology at a designated facility can be a unit-by-unit determination that weighs the value of both the cost of installation and the CO_2 reductions.

The EPA received comment on the ACE proposal that the EPA should provide more information and guidance for what could be considered ''other factors'' in addition to the considerations of the remaining useful life. In addition, commenters also requested more information on the remaining useful life and other source-

[233] 40 CFR 60.23a, 60.27a(g)(2)(iii).

specific factors that could be considered in developing a standard of performance. The EPA acknowledges that there are a host of things that could be considered ''other factors'' by states that can be used to develop a standard of performance. While the EPA cannot identify every set of circumstances and factors that a state could consider, the EPA agrees with the commenters that it would be helpful for states if the EPA were to provide a non-exhaustive set of qualitative examples that states could consider in developing standards of performance as described below. The EPA will evaluate each standard of performance and the factors that were considered in the development of the standard of performance on a case by case basis. The state should include all of the factors and how the factors were applied for each standard of performance in the state plan. The EPA received many notable comments that states would like more direction and assistance in developing standards of performance. The examples are intended to help provide this assistance, but the EPA also understands that, because there are so many considerations for each source, states might have further questions while developing plans. States are encouraged to reach out to the Agency during the development of plans for further assistance.

As noted above, the consideration of the remaining useful life and other factors most often is a reflection of cost. When the EPA determines the BSER for a source category, the EPA typically considers factors such as cost relative to assumptions about a typical unit. Because the costs evaluated for the BSER determination are relative to a typical unit, the source-specific conditions of any particular existing designated facility that a state will evaluate in developing its plan under CAA section 111(d) are not inherently considered. A state's consideration of the remaining useful life and other factors will reflect the costs associated with the source-specific conditions. As part of the BSER determination, the EPA has provided a range of costs associated with each candidate technology (*see* Table 1). These costs are provided to serve as an indicator for states to determine whether it is cost-reasonable for the candidate technology to be installed. These cost ranges are certainly not intended to be presumptive (*i.e.,* the ranges are not an accurate representation for each designated facility and should not be used without a justified analysis by the state), but rather are provided as guide-posts to states. If a state considers the remaining useful life and/or other factors in determining a standard of performance, the state is required to describe, justify, and quantify how the considerations were made in its plan. Because these considerations are discretionary and source-specific, the burden is on the state in its plan to demonstrate and justify how they were taken into account.

A state might consider the remaining useful life of a designated facility with a retirement date in the near future by a number of ways in the standard setting process. One way that a state may take into account this circumstance is in applying the BSER (either through the sequential, two-step process or through some other method that reflects application of the BSER), establish a standard that ultimately only applies the less costly BSER technologies in the development of the standard of performance that the state establishes for the particular designated facility. The shorter life of the designated facility will generally increase the cost of control because the time to amortize capital costs is less. Another outcome of a state's evaluation of a designated facility's remaining useful life may lead to the state setting a ''business as usual'' standard. This could be an appropriate outcome where the remaining useful life of the designated facility is so short that imposing any costs on the EGU is unreasonable. Because a state plan must establish standards of performance for ''any'' designated facility under CAA section 111(d), the standard applied to this designated facility would reflect ''business as usual'' and require the unit to perform at its current level of efficiency during the remainder of its useful life. Under all of these examples and under any other circumstance in which a state considers remaining useful life or other factors in establishing a standard of performance, the state must describe in its state plan submission such consideration and ensure it has established a standard for every designated facility within the state, even one with an anticipated near-term retirement date.

Another consideration for a state in setting standards of performance with consideration to the remaining useful life and other factors is how the different candidate technologies interact with one another and how they interact with the current system at a designated facility. Commenters have expressed, and the EPA agrees, that the application of efficiency upgrades at EGUs are not necessarily additive. Installing HRI technologies in parallel with one another may mitigate the effects of one or more of the technologies. While states must apply the BSER and the degree of emission limitation achievable through such application in calculating a standard of performance, states may also consider the mitigating effects on the emission reductions that would result from the installation of a particular candidate technology, and may as a result of this consideration determine that installing that particular candidate technology at a particular source is not reasonable. This consideration is authorized as one of the ''other factors'' that states may consider in establishing a standard of performance under CAA section 111(d)(1) and the new implementing regulations under 40 CFR 60.24a(e).

A prime example of an ''other factor'' is ruling out the reapplication of a candidate technology. The EPA anticipates this to be a part of many state plans. In this scenario, a designated facility recently applied one of the candidate technologies prior to the time ACE becomes applicable. To require that designated facility to update that candidate technology again, as a result of ACE, would not be reasonable because the costs will be significant with marginal, if any, heat rate improvement.

As described in section III.F.1.c., states are obligated to set rate-based standards of performance. These will generally be in the form of the mass of carbon dioxide emitted per unit of energy (for example pounds of CO_2 per megawatt-hour or lb/MWh). The emission rate can be expressed as either a *net* output-based standard or as a *gross* output-based standard, and states have the discretion to set standards of performance in either form. The difference between net and gross generation is the electricity used at a plant to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices. The gross generation is the total energy produced, while the net generation is the total energy produced minus the energy needed to operate the auxiliary equipment.

Most of the candidate technologies, when applied, affect the gross generation efficiency. However, some candidate technologies, namely improved or new variable frequency drives and improved or new boiler feed pumps, improve the net generation by reducing the auxiliary power requirement. Because improvements in the efficiency of these devices represent opportunities to reduce carbon intensity at existing affected EGUs that would not be captured in measurements of emissions per gross MWh, states may want to consider standards expressed in terms of net generation. If a state chooses to set standards in the form of *gross* energy output, it will be up to the state to determine and demonstrate how to account for emission reductions that are achieved through measures that only affect the *net* energy output.

One of the more significant changes between the ACE proposal and this action is that the EPA is not finalizing the NSR reforms that it proposed in the same document that it proposed ACE. While the EPA intends to take final action on the NSR reform at a later time in a separate action, the consequences of that action are no longer considered in parallel with ACE. Two of the candidate technologies, blade path upgrades and a redesigned/replaced economizer, were proposed as part of the BSER considering that NSR would not be a barrier for installation. Under ACE as finalized without parallel NSR reforms, the EPA anticipates that states may take into account costs associated with NSR as a source-specific factor in considering whether these two technologies are reasonable. While the EPA believes that states are more likely to determine that blade path upgrades and redesigned/replaced economizers are not as reasonable as anticipated at proposal when these were proposed as elements of BSER alongside proposed NSR reforms, as discussed above, the EPA is still finalizing a determination that these candidate technologies are elements of the BSER because it still expects these technologies to be generally applicable across the fleet of existing EGUs, and because the costs of the technologies themselves are generally economical and reasonable. In any case, under ACE as finalized, states are required to evaluate the applicability of all candidate technologies (*i.e.,* the BSER) to a particular existing source when establishing a standard of performance for that source.

c. Forms of Standards of Performance

While the EPA is allowing broad flexibility for states in establishing standards of performance for designated facilities, the EPA is finalizing a requirement that all standards of performance be in the form of an allowable emission rate (*i.e.,* rate-based standard in, for example, lb CO_2/MWh-gross). As described in the proposal an allowable emission rate is the form that corresponds to the EPA's BSER determination for these emission guidelines. When HRIs are made at an EGU, by definition, the CO_2 emission rate will decrease as described above in section III.E. There is a natural correlation between the BSER and an allowable emission rate as the standard of performance in this action. Also, by the Agency prescribing that only a singular form of standard (*i.e.,* an allowable emission rate) is acceptable, it will promote continuity among states and power companies, prevent ambiguity, and promote simplicity and ease of administration and avoid undue burden on the states and regulated parties.

The EPA received considerable comment that it should allow mass-based standards of performance. While the EPA understands the appeal of a mass-based standard for some stakeholders, this form of standard is not compatible with the EPA's BSER determination. In fact, the EPA believes that a mass-based standard would undermine the EPA's BSER. If designated facilities were to have mass-based standards, it is likely that many would meet their compliance obligation by reduced utilization. A standard of performance that incentivizes reduced utilization and possibly retirements does not reflect application of the BSER. See section II.B above for a discussion of reduced utilization and CAA section 111.

Additionally, given that the EPA has the obligation under CAA section 111(d)(2) to determine whether state plans are ''satisfactory,'' certain programmatic bounds are appropriate to facilitate the state's submission of, and EPA's review of, the approvability of state plans. Having a uniform type of standard of performance will help streamline the states' development of their plans, as well as the EPA's review of those plans as there will be fewer variables to consider in the development of each standard of performance. While the Agency has experience implementing mass-based programs, the uncertainty associated with projecting a level of generation for designated facilities is unnecessary when there is a more compatible format, *i.e.,* a rate-based standard.

The EPA also notes that it is not establishing a preference or requirement for whether a rate-based standard of performance be based in gross or net heat rate. The EPA acknowledges that there are ramifications of applying the BSER to establish a standard of performance with the consideration of type of heat rate used. This may be particularly important when considering the effects of part load operations (*i.e.,* net heat rate would include inefficiencies of the air quality control system at a part load whereas gross heat rate would not). This will also be important in recognizing the improved efficiency obtained from upgrades to equipment that reduce the auxiliary power demand. The consideration of this factor is left to the discretion of the state.

2. Compliance Mechanisms

Just as states have broad flexibility and discretion in setting standards of performance for designated facilities, sources have flexibility in how they comply with those standards. To the extent that a state develops a standard of performance based on the application of the BSER for a designated facility within its jurisdiction, sources should be free to meet that standard of performance using either BSER technologies or certain non-BSER technologies or strategies. Thus, a designated facility may have broad discretion in meeting its standard of performance within the requirements of a state's plan. For example, there are technologies, methods, and/or fuels that can be adopted at the designated facility to allow the source to comply with its standard of performance that were not determined to be the BSER, but which may be applicable and prudent for specific units to use to meet their compliance obligations. Examples of non-BSER technologies and fuels include HRI technologies that were not included as candidate technologies, CCS, and natural gas co-firing. In keeping with past programs that regulated designated facilities using a standard of performance, the EPA takes no position regarding whether there may be other methods or approaches to meeting such a standard, since there are likely various approaches to meeting the standard of performance that the EPA is either unable to include as part of the BSER, or is unable to predict. The EPA is, however, excluding some measures from use as compliance measures: averaging and trading and bio-mass cofiring. These measures do not meet the criteria for compliance measures. Those criteria, which are designed to assure that compliance measures actually reduce the source's emission rate, are two-fold: (1) The compliance measures must be capable of being applied to and at the source, and (2) they must be measurable at the source using data, emissions monitoring equipment or other methods to demonstrate compliance, such that they can be easily monitored, reported, and verified at a unit.

With respect to the first criterion, the EPA believes that both legal and practical concerns weigh against the inclusion of measures that cannot qualify as a ''system of emission reduction.'' Allowing those measures would be inconsistent with the EPA's interpretation of the BSER as limited to measures that apply at and to an individual source and reduce emissions from that source. Because state plans must establish standards of performance—which by definition [234] ''reflect[ ] . . . the application of the [BSER]''—implementation and enforcement of such standards should correspond with the approach used to set the standard in the first place. Applying an implementation approach that differs from standard-setting would result in asymmetrical regulation. Specifically, a state's implementation measures would result in a more or less stringent standard implemented at an EGU than could otherwise be derived from application of the BSER.

There are certainly methods that affected EGUs could use to meet compliance obligations that are not the BSER, but these methods still fit the two criteria: They can be applied to and at the source and can be measured at the source using data, emissions monitoring equipment or other methods to demonstrate compliance, such that they can be monitored, reported, and verified at a unit. Such examples include CCS and natural gas cofiring.

Commenters also requested that reduced utilization be an available compliance mechanism. While a designated facility reducing its utilization would certainly reduce its mass of CO_2 emissions, it would likely not lead to an improved emission rate. As noted above in section III.F.1., a state can certainly take into account a designated facility's projected decreased utilization in setting a standard of performance, but it cannot make it the means of meeting compliance obligations because the degree of emission limitation achievable through the application of the BSER must still be reflected in setting the standard of performance. See section II.B above for a discussion of reduced utilization under CAA section 111.[235]

a. Averaging and Trading

This section discusses the question of whether averaging and trading are permissible means for sources to comply with ACE. For a discussion of averaging EGU-emissions over a compliance period, see section III.F.1.a.(2). In the proposal, the EPA solicited comment on whether CAA section 111(d) authorizes states to include averaging or trading between existing sources in the plans they submit to meet the requirements of final emission guidelines.[236] Specifically, the EPA: (1) Proposed to allow states to incorporate, as part of their plan, emissions averaging among EGUs across a single plant; and (2) solicited comment on whether CAA section 111(d) should be read not to authorize states to include trading and averaging between sources.[237]

The EPA received numerous comments on the topic of averaging and trading for compliance with ACE. With respect to averaging across designated facilities that are located at the same plant—including, but not limited to, EGUs that are served by a common stack—some commenters disapproved of this flexibility while others supported the ability to implement ACE via averaging in state plans. On the topic of averaging and trading between designated facilities located at different plants, the Agency received mixed support and opposition. Some commenters suggested that the EPA's proposed prohibition on averaging and trading between designated facilities at different plants was necessary given the Agency's construction of the BSER as limited to systems that could be applied to and at the ''source'' itself. Other commenters suggested that averaging and trading for compliance with ACE is not precluded under CAA section 111(d). Commenters also suggested that the statutory cross-reference under CAA section 111(d)(1) to CAA section 110 suggests that trading could be used for implementation under ACE. Several commenters provided examples of prior CAA section 111(d) regulations in which the agency allowed trading for implementation (*e.g.,* CAMR).

In this final action, the EPA determines that: Neither (1) averaging across designated facilities located at a single plant; nor (2) averaging or trading between designated facilities located at different plants are permissible measures for a state to employ in establishing standards of performance for existing sources or for sources to employ to meet those standards. CAA section 111(d) authorizes states to establish standards of performance for ''any existing source,'' which the CAA defines as ''any stationary source other than a new source.'' [238] ''Stationary source,'' in turn, means ''any building, structure, facility, or installation which emits or may emit any air pollutant.'' [239] In the ACE proposal, the EPA explained that an EGU ''subject to regulation upon finalization of ACE is any fossil fuel-fired electric utility steam generating unit (*i.e.,* utility boilers) that is not an integrated gasification combined cycle (IGCC) unit (*i.e.,* utility boilers, but not IGCC units) that was in operation or had commenced construction as of [January 8, 2014],'' and ''serves a generator capable of selling greater than 25 MW to a utility power distribution system and has a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel).'' [240] The proposal then identified HRI measures as the BSER for such units.[241] This action finalizes the Agency's determination that HRI measures are the BSER for designated facilities. *See* sections III.C & III.E.

Although the D.C. Circuit has recognized that the EPA may have statutory authority under CAA section 111 to allow plant-wide emissions averaging,[242] the Agency's determination that individual EGUs are subject to regulation under ACE precludes the Agency from attempting to change the basic unit from an EGU to a combination of EGUs for purposes of ACE implementation.[243]

In *ASARCO,* the EPA promulgated regulations re-defining ''stationary source'' as ''any . . . *combination of* . . . facilities.'' [244] By treating a ''combination of facilities'' as a single source, the EPA intended to adopt a ''bubble concept,'' which would allow a facility to ''avoid complying with the applicable NSPS so long as emission decreases from other facilities within the same source cancel out the increases from the affected facility.'' [245] The Court concluded, however, that the Agency ''has no authority to rewrite the statute in this fashion.'' [246] In a subsequent case, the D.C. Circuit recognized that the EPA has ''broad discretion to define the statutory terms for 'source,' [*i.e.,* building, structure, facility or installation], so long as guided by a reasonable application of the statute.'' [247]

Following these two decisions, the EPA adopted a new regulation defining ''building, structure, facility, or installation'' for nonattainment-area

[234] *See* CAA section 111(a)(1)

[235] For a discussion of reduced utilization in other CAA contexts, please see ACE RTC Chapter 1, response to comment 76.

[236] *See* 83 FR 44767–768.

[237] *Id.*

[238] 42 U.S.C. 7411(a)(6).

[239] *Id.* at section 7411(a)(3).

[240] 83 FR 44754.

[241] *Id.* at 44755.

[242] *See U.S. Sugar* v. *EPA,* 830 F.3d 579, 627 n.18 (D.C. Cir. 2016) (pointing to the definition of ''stationary source'').

[243] *See, e.g., ASARCO* v. *EPA,* 578 F.2d 319, 327 (D.C. Cir. 1978).

[244] *Id.* at 326 (emphasis added).

[245] *Id.*

[246] *Id.* at 327.

[247] *Alabama Power Co.* v. *Costle,* 636 F.2d 323, 396 (D.C. Cir. 1979).

permitting under the NSR program as ''all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel.'' [248] That rulemaking lead to the Supreme Court's decision in *Chevron* v. *NRDC,* 467 U.S. 837 (1984). In *Chevron,* the Court recognized that ''it is certainly no affront to common English usage to take a reference to a major facility or a major source to connote an entire plant as opposed to its constituent parts.'' [249]

Here, the EPA does not need to determine whether it would have been reasonable to interpret ''building, structure, facility, or installation'' as an entire plant for purposes of CAA section 111 (thus, encompassing all EGUs located at a single plant). Because ACE identifies individual EGUs as the designated facility,[250] state plans cannot accommodate any ''bubbling'' of EGUs for compliance with these emission guidelines.

In addition, as proposed, the EPA is precluding averaging or trading between designated facilities located at different plants for the following reasons.

The EPA believes that averaging or trading across designated facilities (or between designated facilities and other power plants, *e.g.,* wind turbines) is inconsistent with CAA section 111 because those options would not necessarily require any emission reductions from designated facilities and may not actually reflect application of the BSER.[251] Because state plans must establish standards of performance—which by definition ''reflects . . . the application of the best system of *emission reduction*''—implementation and enforcement of such standards should be based on improving the emissions performance of sources to which a standard of performance applies. Additionally, averaging or trading would effectively allow a state to establish standards of performance that do not reflect application of the BSER. For example, under a trading program, a single source could potentially shut down or reduce utilization to such an extent that its reduced or eliminated operation generates adequate compliance instruments for a state's remaining sources to meet their standards of performance without any emission reductions from any other source. This compliance strategy would undermine the EPA's determination of the BSER in this rule, which the EPA has determined as heat rate improvements.

In light of these concerns, as proposed, the EPA concludes that neither averaging nor trading between EGUs at different plants can be used in state plans for ACE implementation. Regarding commenters' assertions that the statutory text of CAA section 111(d) does not preclude averaging or trading, the Agency finds that the statutory text of CAA section 111(d) does not require the EPA to allow averaging or trading as a measure for states in establishing existing-source standards of performance or allow for sources to adopt as a compliance measure, and the interpretation of the limits on the scope of BSER under CAA section 111(a)(1) set forth in section II above as a basis for the repeal of the CPP suggests that those measures are not permissible, as they are not applied to a source.

Regarding commenters' assertions that the cross-reference in CAA section 111(d) to CAA section 110 authorizes averaging or trading for implementation, the Agency disagrees. The cross-reference to CAA section 110 indicates that ''[t]he Administrator shall prescribe regulations which shall establish a *procedure similar to that provided by CAA section 110* of this title under which each State shall submit to the Administrator a plan . . . .'' (emphasis added). The Agency's interpretation of this cross-reference is that it focuses on the *procedure* under which states shall submit plans to the EPA. It does not imply anything affirmative or negative about implementation mechanisms available under CAA section 111(d). In the absence of definitive instruction under this CAA provision, the Agency uses its best judgment to conclude that the meaning and scope of the BSER in this rule preclude the use of averaging or trading for covered EGUs at different plants in state plans. Commenters also asserted that the EPA has promulgated regulations under CAA section 111(d) that included trading in the past, such as CAMR. As an initial matter, CAMR was vacated by the D.C. Circuit and never implemented. Nonetheless, the Agency notes that the CAMR included trading both in the establishment of the BSER and as an available implementation mechanism. In the ACE rule, by contrast, trading was not factored into the determination of the BSER and so should not be authorized for implementation.

Moreover, it is not clear that trading would qualify as a ''system of emission reduction'' that can be applied to and at an individual source and would lead to emission reductions from that source. Indeed, the nature of trading as a compliance mechanism is such that some sources would not need to apply any pollution control techniques at all in order to comply with a cap-and-trade scheme. A compliance mechanism under which multiple sources can comply not by any measures applied to those sources individually, but instead by obtaining credits generated by measures adopted at another source, is not consistent with the interpretation of the limits on the scope of BSER adopted in section II above. Accordingly, trading is not permissible under CAA section 111.

b. Biomass Co-Firing

The ACE proposal solicited comment on the inclusion of forest-derived and non-forest biomass as non-BSER compliance options for affected units to meet state plan standards. The proposal also solicited comment on what value to

[248] 46 FR 50766.

[249] 467 U.S. at 860.

[250] Fossil fuel-fired steam generators (*i.e.,* EGUs) were among the first source categories listed under CAA section 111. *See* 36 FR 5931. Since then, the Agency has promulgated multiple rulemakings specifically regulating EGUs. *See e.g.,* 40 CFR part 60, subparts D, Da, TTTT, and UUUU. In any case, the decision to identify EGUs as the regulated source is made under CAA section 111(b); that is because regulations under CAA section 111(d) are authorized for sources ''to which a standard of performance . . . would apply if such existing source were a new source.'' In this case, new source performance standards have been established for certain ''new, modified, and reconstructed'' EGUs. 80 FR 64510. While the EPA proposed to revisit several portions of those standards, *see* 83 FR 65424, the Agency did not propose to revise the applicability requirements for them, *id.* at 65429. Accordingly, individual EGUs continue to be the appropriate regulatory target for purposes of ACE (and not, for example, multiple EGUs that may be co-located at a single power plant).

[251] The EPA's interpretation of CAA section 111 on this point has changed since the promulgation of the since-vacated CAMR and does not necessarily extend to other CAA programs and provisions, which can be distinguishable based on the applicable statutory and regulatory requirements and programmatic circumstances. For example, the EPA has implemented several trading programs under the so-called Good Neighbor provision at CAA section 110(a)(2)(D)(i)(I). *See* Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone (also known as the NO_X SIP Call), 63 FR 57356 (October 27, 1998); Clean Air Interstate Rule (CAIR) Final Rule, 70 FR 25162 (May 12, 2005); Cross State Air Pollution Rule (CSAPR) Final Rule, 76 FR 48208 (August 8, 2011); CSAPR Update Final Rule, 81 FR 74504 (October 26, 2016). Section 110(a)(2)(A), which is applicable to the requirements of the Good Neighbor provision, explicitly authorizes the use of marketable permits and auctions of emission rights. Additionally, the Good Neighbor provision prohibits emissions activity in certain ''amounts'' with respect to the NAAQS. The affirmative requirement under this provision to reduce certain emissions means it is appropriate to implement measures which will result in the required emission reductions. The EPA has done so previously by implementing trading programs to reduce ozone and particulate matter, the regional-scale nature of which can be effectively regulated under a trading program.

attribute to biogenic CO_2 associated with non-forest biomass, if included. The EPA received a range of comments both supporting and opposing the use of forest-derived and non-forest biomass feedstocks for compliance under this rule. Additionally, the EPA received a range of comments regarding the valuation of CO_2 emissions from biomass combustion.

Numerous commenters supported the inclusion of biomass as a compliance measure. Some reiterated the EPA's 2018 policy statement regarding biogenic CO_2 emissions, which laid out the Agency's intent to treat biogenic CO_2 emissions from forest biomass from managed forests as carbon neutral in forthcoming Agency actions. Specifically, these commenters stated that the nature of biomass and its role in the natural carbon cycle (*i.e.,* carbon is sequestered during biomass growth that occurs offsite) makes biomass a carbon-neutral fuel, and therefore that biomass should be eligible as a compliance option under this rule. Commenters opposing the inclusion of biomass for compliance asserted that biomass combustion does not reduce stack GHGs emissions, as it emits more emissions per Btu than fossil fuels, and therefore should not be eligible for compliance. Some comments noted that the scientific rationale underlying the use of biomass as a potential GHG reduction measure at stationary sources relies primarily on terrestrial CO_2 sequestration occurring due to activities offsite (*i.e.,* activities outside of and largely not under the control of a designated facility).

The construct of this final ACE rule necessitates that measures taken to meet compliance obligations for a source actually reduce its emission rate in that: (1) They can be applied to the source itself; and (2) they are measurable at the source of emissions using data, emissions monitoring equipment or other methods to demonstrate compliance, such that they can be easily monitored, reported, and verified at a unit (see section III.F.2). While the firing of biomass occurs at a designated facility, biomass firing in and of itself does not reduce emissions of CO_2 emitted from that source. Specifically, when measuring stack emissions, biomass emits more CO_2 per Btu than fossil fuels, thereby increasing the CO_2 emission rate at the source. Accordingly, recognition of any potential CO_2 emissions reductions associated with biomass firing at a designated facility relies on accounting for activities not applied at and largely not under the control of that source (*i.e.,* activities outside of and largely unassociated with a designated facility), including consideration of terrestrial carbon effects during the biomass fuel growth. Therefore, biomass fuels do not meet the compliance obligations and are not eligible for compliance under this rule.

3. Submission of State Plans

CAA section 111(d)(1) provides that states shall submit to the EPA plans that establish standards of performance for existing sources within their jurisdiction and provide for implementation and enforcement of such standards. Under CAA section 111(d)(2), the EPA has the obligation to determine whether such plans are ''satisfactory.'' In light of the statutory text, state plans implementing ACE should include detailed information related to two key aspects of implementation: Establishing standards of performance for covered EGUs and providing measures that implement and enforce such standards.

Generally, the plans submitted by states must adequately document and demonstrate the process and underlying data used to establish standards of performance under ACE. Providing such documentation is required so that the EPA can adequately and appropriately review the plan to determine whether it is satisfactory; the EPA's authority to promulgate a federal plan is triggered in ''cases where the State fails to submit a satisfactory plan . . . .''[252] For example, states must include data and documentation sufficient for the EPA to understand and replicate the state's calculations in applying BSER to establish standards of performance. Plans must also adequately document and demonstrate the methods employed to implement and enforce the standards of performance such that EPA can review and identify measures that assure transparent and verifiable implementation. Additionally, state plan submissions must, unless otherwise provided in a particular emissions guideline rule, adhere to the components of the new implementing regulations described in section IV. The following paragraphs discuss several components that states are required to include in their state plans as required under these final emission guidelines.

First, state plans must detail the approach or methods used by the state to apply the BSER and establish standards of performance. The state should include enough detail for the EPA to be able to reproduce the state's methods and calculations. The methodology submitted should clearly identify the approach by which states evaluate all of the HRIs finalized in this action, both alone and in combination with each other where technically feasible. To the extent that HRIs are not feasible to apply at a particular EGU, states must provide a rationale (and supporting data or metrics where relied upon) for why the calculation would be invalid or inappropriate.

Second, state plans must identify EGUs within their borders that meet the applicability requirements and are thereby considered a designated facility under ACE. Plans must also include emissions and operational data relied upon to apply BSER and determine standards of performance. These data must include, at a minimum, an inventory of CO_2 emissions data and EGU operational data (*e.g.,* heat input) for designated EGUs during the most recent calendar year for which data is available at the time of state plan development and/or submission. State plans must also include any future projections data relied upon to establish standards of performance, including future operational assumptions. To the extent that state plans consider an existing source's remaining useful life in establishing a standard of performance for that source, the state plan must specify the exact date by which the source's remaining useful life will be zero. In other words, the state must establish a standard of performance that specifies the designated facility will retire by a future date certain (*i.e.,* the date by which the EGU will no longer supply electricity to the grid). It is important to note that (as with all aspects of the state plan) the standard of performance and associated retirement date will be federally enforceable upon approval by the EPA. In the event a source's circumstances change so that this retirement date is no longer feasible, states generally have the authority and ability to revise their state plans. Such plan revisions must be adopted by the state and submitted to the EPA pursuant to the requirements of 40 CFR 60.28a.

Third, state plans should submit detailed documentation demonstrating in detail the application of the state's methodology to the state's data. In other words, states should include the calculations relied upon when applying the BSER to establish standards of performance. States should also include detailed documentation demonstrating the relied upon compliance mechanisms, consistent with section III.F.2.

Regarding establishing standards of performance and ensuring verifiable implementation for EGUs with complex

[252] CAA section 111(d)(2)(A).

stack configurations, states should include approaches (*e.g.,* formulas) that appropriately assign emissions and generation to individual EGUs. For example, if two EGUs share a common stack, the state should provide a methodology for disaggregating monitoring data to the individually covered EGUs. Another example for states to consider when appropriately assigning emissions and setting standards of performance is apportioning HRI that affect and improve the performance of multiple EGUs at a plant (*e.g.,* apportioning improvement credited to installed variable speed drives that affect multiple designated facilities at a plant).

As part of ensuring that regulatory obligations appropriately meet statutory requirements such as enforceability, the EPA has historically and consistently required that obligations placed on sources be quantifiable, permanent, verifiable, and enforceable. The EPA is similarly requiring that standards of performance placed on designated facilities as part of a state plan to implement ACE be quantifiable, permanent, verifiable, and enforceable. A state plan implementing ACE should include information adequate to support a determination by the EPA that the plan meets these goals.

Additionally, the EPA is finalizing a determination that states must include appropriate monitoring, reporting, and recordkeeping requirements to ensure that state plans adequately provide for the implementation and enforcement of standards of performance. Each state will have the flexibility to design a compliance monitoring program for assessing compliance with the standards of performance identified in the plan. To the extent that designated facilities or states already monitor and report relevant data to the EPA, states are encouraged to use these existing systems to efficiently monitor and report ACE compliance. For example, most potentially affected coal-fired EGUs already continuously monitor CO_2 emissions, heat input, and gross electric output and report hourly data to the EPA under 40 CFR part 75. Accordingly, if a state plan establishes a standard of performance for a unit's CO_2 emissions rate (*e.g.,* lb/MWh), states may use data collected by the EPA under 40 CFR part 75 to meet the required monitoring, reporting, and recordkeeping requirements under these emission guidelines.

The EPA is further generally applying the new implementing regulations for timing, process and required components for state plan submissions and implementation for state plans required for designated facilities. The new implementing regulations are described in detail in section IV. In section 40 CFR 60.5740a there is a complete description and list of what a state plan must include.

a. Electronic Submission of State Plans

The EPA will, in the near future, provide states with an electronic means of submitting plans. While the EPA proposed the use of the SPeCS software which has been used by the Agency for SIP submittals, the Agency is still developing the software to be used for ACE submittals. The EPA recommends that states submit state plans electronically as it will provide a more structured process and provide more timely feedback to the submitting state. The Agency also anticipates that many states will choose to submit plans electronically as states have a level of familiarity with EPA software, such as SPeCS. The EPA envisions the electronic submittal system as a user-friendly, web-based system that enables state air agencies to officially submit state plans and associated information electronically for review. Electronic submittal is the EPA's preferred method for receiving state plan submissions under ACE. However, if a state prefers to submit its state plan outside of this forthcoming system, the state must confer with its EPA Regional Office regarding additional guidance for submitting the plan to the EPA.

b. Approvability of State Plans That Are More Stringent Than Required Under ACE

One issue raised by several commenters is whether the EPA can approve, and thereby render federally enforceable, a state plan that contains requirements for an existing source within a state's jurisdiction that are more stringent than what is required under CAA section 111(d).[253] At proposal, the EPA acknowledged that CAA section 116 allows states to be more stringent than federal requirements as a matter of state law, but also noted that nothing in section 116 provides for such more-stringent requirements to become federally enforceable.[254] Some commenters assert that it is not within the EPA's authority under the CAA to approve such more-stringent requirements as part of the federally enforceable state plan, and the EPA should instead direct states to make such requirements exclusively a matter of state law and enforceability. Other commenters assert that the Supreme Court in *Union Electric Co.* v. *EPA,* 427 U.S. 246, (1976), precluded a reading of section 116 that would functionally require two separate sets of requirements, one at the stricter state level and one at the federally approved level.

In response to the commenters who contend the EPA does not have the authority to approve more stringent state plans, the EPA believes that these comments have merit. However, the EPA does not think it is appropriate at this point to predetermine the outcome of its action on a state plan submission in this regard without going through notice-and-comment rulemaking with regard to the approval or disapproval of that submission.[255]

[253] Requirements under state plans generally become federally enforceable once the EPA determines that they are ''satisfactory'' per section 111(d)(2). Section 113(a)(3) provides the EPA with the authority, in part, to enforce any requirement of any plan approved under the same subchapter as section 113; section 111(d) is within the same subchapter as section 113. Additionally, section 304(a)(1) grants citizens the authority to bring civil action against any person in violation of an ''emission standard'' under the CAA. Section 304(f)(1) and (3) respectively define ''emission standard'' as a standard of performance or any requirement under section 111 without regard to whether such requirement is expressed as an emission standard. Accordingly, citizens with standing could attempt to enforce the requirements of an EPA-approved section 111(d) state plan.

[254] 83 FR 44767 n.37.

[255] In the CPP, the EPA took the position that because ''the EPA's action on a 111(d)(1) state plan is structurally identical to the EPA's action on a SIP,'' the EPA is required to approve a state plan that is more stringent than the BSER because of CAA section 116 as interpreted by *Union Electric.* Legal Memorandum Accompanying Clean Power Plan for Certain Issues at 28–30; 80 FR 64840. For the reasons further described in this preamble, the EPA's position on this state plan stringency issue has evolved since the EPA addressed it in the CPP, and the Agency now identifies a potentially salient structural distinction between CAA sections 110 and 111(d). Notably, the BSER aspect of section 111(d) is absent from section 110, as SIP-measures required for attainment or maintenance of the NAAQS are not predicated on application of a specific technology. Under CAA section 109, the EPA establishes a health-protective standard, and CAA section 110 then gives states broad latitude on designing the contents of SIPs intended to meet that standard. By contrast, under CAA section 111, the EPA identifies a particular measure or set of measures, and CAA section 111(d) more narrowly prescribes that the contents of state plans include performance standards based on the application of such measures, and measures that provide for the implementation and enforcement of such standards. Given this key distinction between CAA sections 110 and 111(d), the EPA no longer takes the position it took in the CPP that these two statutory schemes are ''structurally identical'' and that therefore, under *Union Electric,* it must approve section 111(d) state plans that are more stringent on this basis. See *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009). However, for the reasons discussed in this preamble, the EPA is not at this stage prejudging the approvability of any future plan submission in this regard and will evaluate any plan submission, including one that is more stringent than what the BSER requires, on an individual basis through notice-and-comment rulemaking.

In response to the commenters who contend the EPA has the authority to approve more stringent state plans, as an initial matter, the EPA notes that the Court's decision in *Union Electric* on its face does not apply to state plans under CAA section 111(d). The decision specifically evaluated whether the EPA has the authority to approve a SIP under *section 110* that is more stringent than what is necessary to attain and maintain the NAAQS. The Court specifically looked to the requirements in CAA section 110(a)(2)(A) as part of its analysis, a provision that is wholly separate and distinct from CAA section 111(d). CAA section 110(a)(2)(A) requires SIPs to include any assortment of measures that may be necessary or appropriate to meet the ''applicable requirements'' of the CAA, which largely relate to the attainment and maintenance of the NAAQS. CAA section 111(d), by contrast, directs state plans to establish standards of performance for existing sources that reflect the degree of emission limitation achievable through the application of the BSER that EPA has determined is adequately demonstrated—and CAA section 111(d) expressly provides that it cannot be used to regulate NAAQS pollutants. Because the Court's holding was in the context of section 110 and not CAA section 111(d), the EPA believes that *Union Electric* does not control the question of whether CAA section 111(d) state plans may be more stringent than federal requirements.

Thus, *Union Electric* and the SIP issues that it addresses are distinguishable from the CAA section 111(d) context. States have broad discretion under section 110 to select the measures for inclusion in their SIPs to meet the NAAQS, which are health- or welfare-based standards not predicated on the application of any particular technology, whereas state plans under 111(d) must establish standards of performance, which are defined at CAA section 111(a)(1) as reflecting the degree of emission limitation achievable through application of the BSER at a source. However, the EPA is mindful that it does not prejudge the approvability of any state plan submission, but rather must determine whether it is ''satisfactory'' through undertaking notice-and-comment rulemaking.[256] Further, some issues of approvability are most appropriately handled through the submission, review, and approval or disapproval processes (with approvals and disapprovals then being subject to judicial review). The EPA anticipates that some states may wish to apply additional measures beyond those that the EPA has identified as BSER when setting the standard of performance, which states may believe are better suited to particular existing sources within their jurisdiction. The EPA notes, as stated above, that the comments suggesting that the EPA does not have the authority to approve a state plan that establishes standards of performance for existing sources more stringent than those that would result from an application of the BSER identified by the EPA have merit. However, the EPA believes that the question of whether it has the authority to approve, and thereby render federally enforceable, a state plan that establishes standards of performance that are more stringent than those that would result from the application of the BSER that the EPA has identified is addressed properly in the context of evaluating an individual state plan.

While the EPA does not prejudge the approvability of a state plan that establishes standards of performance for existing sources within the state's jurisdiction that are more stringent than those that would result from the application of the BSER that the EPA has identified, there are clear principles and limitations imposed by CAA section 111(d) that will apply to the EPA's review of *any* state plan. As a first principle, states must apply the BSER measures, as further described in section III.E. of the preamble, and derive a standard of performance that reflects the degree of emission limitation achievable through application of the candidate technologies, taking into account remaining useful life and other factors as appropriate.

As a second principle, whatever the scope of a state's authority under state law may be to design a scheme to meet the emissions guidelines, the EPA's authority to approve state plans that contain standards of performance for existing sources only extends to measures that are authorized statutorily. Specifically, the EPA's authority is constrained to approving measures that comport with the statutory interpretations, including interpretations of the limitations on ''standards of performance'' and the underlying BSER. For example, CAA section 111(d)(1) clearly contemplates that state plans may only contain requirements for existing sources, and not other entities. Therefore, in implementing the ACE rule, the EPA may not approve state plan requirements on entities other than existing EGUs, which are the designated facilities under this rule.[257] Another example that would exceed the EPA's authority is a state plan that includes standards of performance or implementation measures that do not result in emission reductions from an individual designated facility, such as the use of biomass or emissions trading, for the reasons discussed at section III.E.4.c. and III.F.2.a, respectively. Finally, the EPA does not have the authority to approve measures that purport to be standards of performance but that actually do not meet the statutory and regulatory terms for such standards. For example, under ACE, the EPA cannot approve a standard that is a requirement for a designated facility shut down. Such a standard is an operational standard rather than a standard of performance.[258] The EPA has not authorized the use of operational standards under CAA section 111(h) because the EPA has determined that it is feasible to prescribe a standard of performance for this source category and pollutant, expressed as an emission rate.[259]

As previously described, the EPA must review state plans, including plans that establish standards of performance for a particular existing source or sources that are more stringent than the standards that would result from application of the BSER, through notice-and-comment rulemaking to determine whether they are ''satisfactory''. This review includes ensuring that the state

[256] *See* CAA section 111(d)(2), 40 CFR 60.27a(b).

[257] Section 111(d) clearly identifies that the regulated entity under this provision is an existing source that would be of the same source category as a new source regulated under section 111(b), *i.e.,* a designated facility, as defined at 40 CFR 60.21(b). If the EPA were to approve a state plan that contained provisions regulating entities other than designated facilities, that approval would give the EPA (and citizen groups) federal enforcement authority over such entities. The EPA believes such a result would be contrary to statements by the U.S. Supreme Court that caution an agency against interpreting its statutory authority in a way that ''would bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization,'' *Utility Air Regulatory Group* v. *EPA,* 134 S. Ct. 2427, 2444 (2014).

[258] This example is distinguishable from the one described in section IV.H. where a state chooses to rely on a source's remaining useful life in establishing a less stringent standard of performance for that source than would otherwise result from an application of the BSER. In that instance, a state would include the shutdown date as a measure for implementation of a standard of performance, as required under section 111(d)(1)(B).

[259] The EPA also notes that for purposes of a federal plan, the EPA is limited to promulgating a standard of performance, which, as defined by section 111(a)(1) must reflect the degree of emission limitation achievable by the BSER; in promulgating a standard of performance under a federal plan, the statute directs the EPA to take into account, among other factors, remaining useful life of the source to which the standard applies. *See* section 111(d)(2).

plan submission does not contravene the statute by including measures that the EPA has no authority to approve or enforce as a matter of federal law, and that the state actually has evaluated the BSER in setting a standard. Though the EPA lacks the authority to approve certain measures, thereby rendering them federally enforceable, nothing precludes states from implementing or enforcing such requirements as a matter of state law.[260]

G. Impacts of the Affordable Clean Energy Rule

1. What are the air impacts?

In the RIA for this action, the Agency provides a full benefit-cost analysis of an illustrative policy scenario representing ACE, which models adoption of HRI measures at coal-fired EGUs. This illustrative policy scenario represents one set of potential outcomes of state determinations of standards of performance and compliance with those standards by affected coal-fired EGUs. Throughout the RIA, the illustrative policy scenario is compared against a single baseline that does not include the CPP. As described in Chapter 2 of the RIA, the EPA believes that a single baseline without the CPP represents a reasonable future against which to assess the potential impacts of the ACE rule. The EPA also provides analysis in Chapter 2 of the RIA that satisfies any need for regulatory impact analysis that may be required by statute or executive order for the repeal of the CPP.

The EPA has identified the BSER to be HRI. The EPA is providing states with a list of candidate HRI technologies that must be evaluated when establishing standards of performance. The cost, suitability, and potential improvement for any of these HRI technologies is dependent on a range of unit-specific factors such as the size, age, fuel use, and the operating and maintenance history of the unit. As such, the HRI potential can vary significantly from unit to unit. The EPA does not have sufficient information to assess HRI potential on a unit-by-unit basis. Therefore, any analysis of the final rule is illustrative. Nonetheless, the EPA believes that such illustrative analyses can provide important insights.

In the RIA, the EPA evaluated an illustrative policy scenario that assumes HRI potential and costs will differ based on unit size and efficiency. To establish categories and HRI potential for use in the RIA, the EPA developed a methodology that is explained in Chapter 1 of the RIA. Designated facilities were grouped into twelve groups based on three size categories and four efficiency categories. Cost and performance assumptions for the candidate technologies were applied to the groupings to establish representative and illustrative assumptions for use in the RIA. The EPA then assumed these varying levels of HRI potential and costs for the different groups in the power sector and emissions modeling as an illustration of the potential impacts.

The EPA evaluates the potential impacts of the illustrative policy scenario using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2023–2037 from the perspective of 2016, using both a three percent and seven percent end-of-period discount rate. In addition, the EPA presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. These specific snapshot years are 2025, 2030, and 2035.

Overall, the impacts of the illustrative policy scenario in terms of change in emissions, compliance costs, and other energy-sector effects are small compared to the recent market-driven changes that have occurred in the power sector. These larger industry trends are discussed in detail in Chapter 2 of the RIA. In evaluating the significance of the illustrative policy scenario, as presented in the RIA and summarized here, it is important for context to understand that these impacts are modest and do not diverge dramatically from baseline expectations.

Emissions are projected to be lower under the illustrative policy scenario than under the baseline. Table 3 shows projected aggregate emission decreases for the illustrative policy scenario, relative to the baseline, for CO_2, SO_2 and NO_X from the electricity sector.

TABLE 3—PROJECTED CO_2, SO_2, AND NO_X ELECTRICITY SECTOR EMISSION IMPACTS FOR THE ILLUSTRATIVE POLICY SCENARIO, RELATIVE TO THE BASELINE

[2025, 2030, and 2035]

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2025	(12)	(4.1)	(7.3)
2030	(11)	(5.7)	(7.1)
2035	(9.3)	(6.4)	(6.0)

Note: All estimates in this table are rounded to two significant figures.

The emissions changes in these tables do not account for changes in HAP that may occur as a result of this rule. For projected impacts on mercury emissions, please see Chapter 3 of the RIA. The EPA was unable to project impacts on other HAP emissions from the illustrative policy scenario due to methodology and resource limitations.

As noted earlier in this section, the illustrative policy scenario is compared against a baseline that does not include the CPP. This is because the ACE action only occurs after the repeal of the CPP. Chapter 2 of the RIA discusses the EPA's analysis of the CPP repeal. It explains how after reviewing the comments and fully considering a number of factors, the EPA ultimately concluded that the most likely result of implementation of the CPP would be no change in emissions and therefore no cost or changes in health benefits. This conclusion (*i.e.,* that repeal of the CPP has little or no effect against a baseline that includes the CPP) is appropriate for several reasons, consistent with OMB's guidance that the baseline for analysis ''should be the best assessment of the way the world would look absent the proposed action.'' [261] It is the EPA's consideration of the weight of the evidence, taking into account the totality of the available information, as presented in Chapter 2 of the RIA, that leads to the finding and conclusion that there is likely to be no difference between a world where the CPP is implemented and one where it is not. As further explained in Chapter 2 of the RIA, the EPA comes to this conclusion not through the use of a single analytical

[260] *See* CAA section 116; 40 CFR 60.24a(f).

[261] OMB circular A–4, at 15.

scenario or modeling alone, but rather through the weight of evidence that includes: Several IPM scenarios that explore a range of changes to assumptions about implementation of the CPP; consideration of the ongoing evolution and change of the electric sector; and recent commitments by many utilities that include long-term CO_2 reductions across the EGU fleet.

2. What are the energy impacts?

This final action has energy market implications. Overall, the analysis to support this action indicates that there are important power sector impacts that are worth noting, although they are small relative to recent market-driven changes in the sector or compared to some other EPA air regulatory actions for EGUs. The estimated impacts reflect the EPA's illustrative analysis of the final action. States are afforded considerable flexibility in the final action, and thus the impacts could be different to the extent states make different choices than those assumed in the illustrative analysis.

Table 4 presents a variety of energy market impacts for 2025, 2030, and 2035 for the illustrative policy scenario representing ACE, relative to the baseline.

TABLE 4—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS FOR THE ILLUSTRATIVE POLICY SCENARIO, RELATIVE TO THE BASELINE

[Percent change]

	2025 (%)	2030 (%)	2035 (%)
Retail electricity prices	0.1	0.1	0.0
Average price of coal delivered to the power sector	0.1	0.0	(0.1)
Coal production for power sector use	(1.1)	(1.0)	(1.0)
Price of natural gas delivered to power sector	0.0	(0.1)	(0.6)
Price of average Henry Hub (spot)	0.0	0.0	(0.6)
Natural gas use for electricity generation	(0.4)	(0.3)	0.0

Energy market impacts are discussed more extensively in the RIA found in the rulemaking docket.

3. What are the compliance costs?

The power industry's ''compliance costs'' are represented in this analysis as the change in electric power generation costs between the baseline and illustrative policy scenario, including the cost of monitoring, reporting, and recordkeeping. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the HRI required by the final action.

The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the plans that states may ultimately pursue. The illustrative policy scenario is designed to reflect, to the extent possible, the scope and nature of the final guidelines. However, there is considerable uncertainty with regards to the precise measures that states will adopt to meet the final requirements because there are considerable flexibilities afforded to the states in developing their state plans.

Table 5 presents the annualized compliance costs of the illustrative policy scenario.

TABLE 5—COMPLIANCE COSTS FOR THE ILLUSTRATIVE POLICY SCENARIO, RELATIVE TO THE BASELINE

[Millions of 2016$]

Year	Cost
2025	290
2030	280
2035	25

Note: Compliance costs equal the projected change in total power sector generating costs plus the costs of monitoring, reporting, and recordkeeping.

More detailed cost estimates are available in the RIA included in the rulemaking docket.

4. What are the economic and employment impacts?

Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Market and employment impacts of this final action are discussed more extensively in Chapter 5 of the RIA for this final action.

5. What are the benefits?

The EPA reports the estimated impact on climate benefits from changes in CO_2 and the estimated impact on health benefits attributable to changes in SO_2, NO_X, and $PM_{2.5}$ emissions, based on the illustrative policy scenario described previously. The EPA refers to the climate benefits as ''targeted pollutant benefits'' as they reflect the direct benefits of reducing CO_2, and to the ancillary health benefits derived from reductions in emissions other than CO_2 as ''co-benefits'' as they are not direct benefits from reducing the targeted pollutant. To estimate the climate benefits associated with changes in CO_2 emissions, the EPA applied a measure of the domestic social cost of carbon (SC–CO_2). The SC–CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. The SC–CO_2 estimates used in the RIA for these rulemakings focus on the direct impacts of climate change that are anticipated to occur within U.S. borders.

The estimated health co-benefits are the monetized value of the human health benefits among populations exposed to changes in $PM_{2.5}$ and ozone. This rule is expected to alter the emissions of SO_2 and NO_X emissions, which will in turn affect the level of $PM_{2.5}$ and ozone in the atmosphere. Using photochemical modeling, the EPA predicted the change in the annual average $PM_{2.5}$ and summer season ozone across the U.S. for the years 2025, 2030, and 2035 for the illustrative policy scenario. The EPA next quantified the human health impacts and economic value of these changes in air quality using the environmental Benefits Mapping and Analysis Program—Community Edition (BENMAP–CE). The EPA quantified effects using concentration-response parameters detailed in the RIA, which are consistent with those employed by the Agency in the PM NAAQS and Ozone NAAQS RIAs (U.S. EPA, 2012; 2015) (Table 6).

TABLE 6—ESTIMATED ECONOMIC VALUE OF AVOIDED $PM_{2.5}$ AND OZONE-ATTRIBUTABLE DEATHS AND ILLNESSES FOR THE ILLUSTRATIVE POLICY SCENARIO USING ALTERNATIVE APPROACHES TO REPRESENTING $PM_{2.5}$ EFFECTS

[95% Confidence interval in parentheses; millions of 2016$] [a]

	2025			2030			2035		
Ozone Benefits Summed With $PM_{2.5}$ Benefits									
3% Discount rate									
No-threshold model [b]	$390 ($37 to $1,100)	*to*	$970 ($86 to $2,800)	$490 ($47 to $1,300)	*to*	$1,200 ($110 to $3,500).	$550 ($52 to $1,500)	*to*	$1,400 ($120 to $3,900).
Limited to above LML [c]	$370 ($36 to $1,000)	*to*	$480 ($42 to $1,400)	$440 ($42 to $1,200)	*to*	$520 ($47 to $1,500)	$480 ($25 to $1,300)	*to*	$610 ($16 to $1,800).
Effects above NAAQS [d]	$76 ($8 to $210)	*to*	$250 ($23 to $760)	$75 ($8 to $210)	*to*	$260 ($23 to $770)	$90 ($10 to $250)	*to*	$320 ($28 to $930).
Ozone Benefits Summed With $PM_{2.5}$ Benefits									
7% Discount rate									
No-threshold model [b]	$360 ($34 to $990)	*to*	$900 ($80 to $2,600)	$460 ($44 to $1,200)	*to*	$1,100 ($100 to $3,200).	$510 ($48 to $1,400)	*to*	$1,300 ($110 to $3,600).
Limited to above LML [c]	$350 ($33 to $950)	*to*	$460 ($41 to $1,300)	$410 ($39 to $1,100)	*to*	$500 ($44 to $1,400)	$450 ($22 to $1,200)	*to*	$590 ($13 to $1,700).
Effects above NAAQS [d]	$76 ($8 to $210)	*to*	$250 ($23 to $760)	$75 ($8 to $210)	*to*	$260 ($23 to $770)	$90 ($10 to $250)	*to*	$320 ($28 to $930).

[a] Values rounded to two significant figures.
[b] PM effects quantified using a no-threshold model. Low end of range reflects dollar value of effects quantified using concentration-response parameter from Krewski et al. (2009) and Smith et al. (2008) studies; upper end quantified using parameters from Lepeule et al. (2012) and Jerrett et al. (2009). Full range of ozone effects is included, and ozone effects range from 19% to 22% of the estimated values.
[c] PM effects quantified at or above the Lowest Measured Level of each long-term epidemiological study. Low end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 μg/m^3); high end of range reflects dollar value of effects quantified down to LML of Lepeule et al. (2012) study (8 μg/m^3). Full range of ozone effects is still included, and ozone effects range from 20% to 49% of the estimated values.
[d] PM effects only quantified at or above the annual mean of 12 to provide insight regarding the fraction of benefits occurring above the NAAQS. Range reflects effects quantified using concentration-response parameters from Smith et al. (2008) study at the low end and Jerrett et al. (2009) at the high end. Full range of ozone effects is still included, and ozone effects range from 91% to 95% of the estimated values.

To give readers insight to the distribution of estimated benefits displayed in Table 6, the EPA also reports the PM benefits according to alternative concentration cut-points and concentration-response parameters. The percentage of estimated avoided $PM_{2.5}$-related deaths occurring in 2025 below the lowest measured levels (LML) of the two long-term epidemiological studies the EPA uses to estimate risk varies between 5 percent (Krewski et al. 2009) [262] and 69 percent (Lepeule et al. 2012).[263] The percentage of estimated avoided premature deaths occurring in 2025 above the LML and below the NAAQS ranges between 94 percent (Krewski et al. 2009) and 31 percent (Lepeule et al. 2012). Less than 1 percent of the estimated avoided premature deaths occur in 2025 above the annual mean $PM_{2.5}$ NAAQS of 12 μg/m^3.

Table 7 reports the combined domestic climate benefits and ancillary health co-benefits attributable to changes in SO_2 and NO_X emissions estimated for 3 percent and 7 percent discount rates in the years 2025, 2030, and 2035, in 2016 dollars. This table reports the air pollution effects calculated using $PM_{2.5}$ log-linear no threshold concentration-response functions that quantify risk associated with the full range of $PM_{2.5}$ exposures experienced by the population (U.S. EPA, 2009 [264]; U.S. EPA, 2011 [265]; NRC, 2002 [266]).

TABLE 7—MONETIZED BENEFITS FOR THE ILLUSTRATIVE POLICY SCENARIO, RELATIVE TO THE BASELINE

[Millions of 2016$]

	Values calculated using 3% discount rate			Values calculated using 7% discount rate		
	Domestic climate benefits	Ancillary health co-benefits	Total benefits	Domestic climate benefits	Ancillary health co-benefits	Total benefits
2025	81	390 to 970	470 to 1,000	13	360 to 900	370 to 920.
2030	81	490 to 1,200	570 to 1,300	14	460 to 1,100	470 to 1,100.
2035	72	550 to 1,400	620 to 1,400	13	510 to 1,300	520 to 1,300.

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (*e.g.,* from Krewski et al. (2009) with Smith et al. (2009) to Lepeule et al. (2012) with Jerrett et al. (2009)). The health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment.

[262] Krewski, D., Jerrett, M., Burnett, R.T., Ma, R., Hughes, E., Shi, Y., Turner, M.C., Pope, C.A., Thurston, G., Calle, E.E., Thun, M.J., Beckerman, B., DeLuca, P., Finkelstein, N., Ito, K., Moore, D.K., Newbold, K.B., Ramsay, T., Ross, Z., Shin, H., Tempalski, B., 2009. Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. Res. Rep. Health. Eff. Inst. 5–114–36.

[263] Lepeule, J., Laden, F., Dockery, D., Schwartz, J., 2012. Chronic exposure to fine particles and mortality: An extended follow-up of the Harvard Six Cities study from 1974 to 2009. Environ. Health Perspect. *https://doi.org/10.1289/ehp.1104660.*

[264] U.S. EPA, 2009. Integrated Science Assessment for Particulate Matter. U.S. Environmental Protection Agency, National Center for Environmental Assessment, Research Triangle Park, NC.

[265] U.S. EPA, 2011. Policy Assessment for the Review of the Particulate Matter National Ambient Air Quality Standards. Research Triangle Park, NC.

[266] NRC, 2002. Estimating the Public Health Benefits of Proposed Air Pollution Regulations. National Research Council. Washington, DC.

In general, the EPA is more confident in the size of the risks estimated from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, the EPA is less confident in the risk the EPA estimates from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.[267] Furthermore, when setting the 2012 PM NAAQS, the Administrator also acknowledged greater uncertainty in specifying the ''magnitude and significance'' of PM-related health risks at PM concentrations below the NAAQS. As noted in the preamble to the 2012 PM NAAQS final rule, ''EPA concludes that it is not appropriate to place as much confidence in the magnitude and significance of the associations over the lower percentiles of the distribution in each study as at and around the long-term mean concentration.''[268]

Monetized co-benefits estimates shown here do not include several important benefit categories, such as direct exposure to SO_2, NO_X, and HAP including mercury and hydrogen chloride. Although the EPA does not have sufficient information or modeling available to provide monetized estimates of changes in exposure to these pollutants for this rule, the EPA includes a qualitative assessment of these unquantified benefits in the RIA. For more information on the benefits analysis, please refer to the RIA for these rules, which is available in the rulemaking docket.

IV. Changes to the Implementing Regulations for CAA Section 111(d) Emission Guidelines

The EPA is finalizing new regulations to implement CAA section 111(d) (implementing regulations) which will be codified at 40 CFR part 60, subpart Ba. The current implementing regulations at 40 CFR part 60, subpart B, were originally promulgated in 1975.[269] Section 111(d)(1) of the CAA explicitly requires that the EPA prescribe regulations establishing a procedure similar to that under section 110 of the CAA for states to submit plans to the EPA establishing standards of performance for existing sources within their jurisdiction. The implementing regulations have not been significantly revised since their original promulgation in 1975. Notably, the implementing regulations do not reflect CAA section 111(d) in its current form as amended by Congress in 1977, and do not reflect CAA section 110 in its current form as amended by Congress in 1990. Accordingly, the EPA believes that certain portions of the implementing regulations do not appropriately align with CAA section 111(d), contrary to that provision's mandate that the EPA's regulations be ''similar'' in procedure to the provisions of section 110. Therefore, the EPA proposed to promulgate new implementing regulations that are in accordance with the statute in its current form (*See* 83 FR 44746–44813). Agencies have the ability to revisit prior decisions, and the EPA believes it is appropriate to do so here in light of the potential mismatch between certain provisions of the implementing regulations and the statute.[270] While the preamble for the final new implementing regulations are part of the same **Federal Register** document as certain other Agency rules (specifically, the repeal of the CPP and the promulgation of the ACE rule), these new implementing regulations are a separate and distinct rulemaking with its own regulatory text and response to comments. The implementing regulations are not dependent on the other final actions contained in this **Federal Register** document.

The EPA proposed to largely carry over the current implementing regulations in 40 CFR part 60, subpart B to a new subpart that will be applicable to emission guidelines that are finalized either concurrently with or subsequently to final promulgation of the new implementing regulations, as well as to state plans or federal plans associated with such emission guidelines. For purposes of regulatory certainty, the EPA believes it is appropriate to apply these new implementing regulations prospectively and retain the existing implementing regulations as applicable to CAA section 111(d) emission guidelines and associated state plans or federal plans that were promulgated previously. Additionally, because the original implementing regulations also applied to regulations promulgated under CAA section 129 (a provision enacted in the 1990 Amendments that builds on CAA section 111 but provides specific authority to address facilities that combust waste), which has its own statutory requirements distinct from those of CAA section 111(d), the original implementing regulations under 40 CFR part 60, subpart B continue to apply to EPA-regulations promulgated under CAA section 129, and any associated state plans and federal plans. The new implementing regulations are thus applicable only to CAA section 111(d) regulations and associated state plans issued solely under the authority of CAA section 111(d).

The EPA is aware that there are a number of cases where state plan submittal and review processes are still ongoing for existing CAA section 111(d) emission guidelines. Because the EPA is finalizing new state plan and federal plan timing requirements under the implementing regulations to more closely align CAA section 111(d) with both general CAA section 110 state implementation plan (SIP) and federal implementation plan (FIP) timing requirements, and because of the EPA's understanding from experience of the realities of how long these actions typically take, the EPA is applying the new timing requirements to both emission guidelines published after the new implementing regulations are finalized and to all ongoing emission guidelines already published under CAA section 111(d). The EPA is finalizing applicability of the timing changes to all ongoing 111(d) regulations for the same reasons that the EPA is changing the timing requirements prospectively. Based on years of experience working with states to develop SIPs under CAA section 110, the EPA believes that given the comparable amount of work, effort, coordination with sources, and the time required to develop state plans, more time is necessary for the process. Giving states three years to develop state plans is more appropriate than the nine months provided for under the existing implementing regulations, considering the workload required for state plan development. These practical considerations regarding the time needed for state plan development are also applicable and true for recent emission guidelines where the state

[267] The **Federal Register** notice for the 2012 PM NAAQS indicates that ''[i]n considering this additional population level information, the Administrator recognizes that, in general, the confidence in the magnitude and significance of an association identified in a study is strongest at and around the long-term mean concentration for the air quality distribution, as this represents the part of the distribution in which the data in any given study are generally most concentrated. She also recognizes that the degree of confidence decreases as one moves towards the lower part of the distribution.'' *See* 78 FR 3159 (January 15, 2013).

[268] *See* 78 FR 3154, January 15, 2013.

[269] *See* 40 FR 53346.

[270] The authority to reconsider prior decisions exists in part because the EPA's interpretations of statutes it administers ''[are not] instantly carved in stone,'' but must be evaluated ''on a continuing basis.'' *Chevron U.S.A. Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 863–64 (1984). Indeed, ''[a]gencies obviously have broad discretion to reconsider a regulation at any time.'' *Clean Air Council* v. *Pruitt,* 862 F.3d 1, 8–9 (D.C. Cir. 2017).

plan submittal and review process are still ongoing.

For those provisions that are being carried over from the existing implementing regulations into the new implementing regulations, the EPA is not intending to substantively change those provisions from their original promulgation and continues to rely on the record under which they were promulgated. Therefore, the following provisions remain substantively the same from their original promulgation: 40 CFR 60.21a(a)–(d), (g)–(j) (Definitions); 60.22a(a), 60.22a(b)(1)–(3), (b)(5), (c) (Publication of emission guidelines); 60.23a(a)–(c), (d)(3)–(5), (e)–(h) (Adoption and submittal of state plans; public hearings); 60.24a(a)–(d), (f) (Standards of performance and compliance schedules); 60.25a (Emission inventories, source surveillance, reports); 60.26a (Legal authority); 60.27a(a), (e)–(f) (Actions by the Administrator); 60.28a(b) (Plan revisions by the state); and 60.29a (Plan revisions by the Administrator).

As noted at proposal, the EPA is also sensitive to potential confusion over whether these new implementing regulations would apply to emission guidelines previously promulgated or to state plans associated with prior emission guidelines, so the EPA proposed that the new implementing regulations are applicable only to emission guidelines and associated plans developed after promulgation of this regulation, including the emission guidelines being proposed as part of this action for GHGs and existing designated facilities. The EPA is finalizing this proposed applicability of the new implementing regulations.

While the EPA is carrying over a number of requirements from the existing implementing regulations to the new implementing regulations, the EPA is finalizing specific changes to better align the implementing regulations with the statute. These changes are reflected in the regulatory text for the new implementing regulations, and include:

- An explicit provision allowing specific emission guidelines to supersede the requirements of the new implementing regulations;
- Changes to the definition of ''emission guidelines'';
- Updated timing requirements for the submission of state plans;
- Updated timing requirements for the EPA's action on state plans;
- Updated timing requirements for the EPA's promulgation of a federal plan;
- Updated timing requirement for when increments of progress must be included as part of a state plan;
- Completeness criteria and a process for determining completeness of state plan submissions similar to CAA section 110(k)(1) and (2);
- Updated definition replacing ''emission standard'' with ''standard of performance'';
- Usage of the internet to satisfy certain public hearing requirements;
- Elimination of the distinction between public health-based and welfare-based pollutants in emission guidelines; and
- Updated provision allowing for consideration of remaining useful life and other factors to be consistent with CAA section 111(d)(1)(B).

Because the EPA is updating the implementing regulations and many of the provisions from the existing implementing regulations are being carried over, the EPA wants to be clear and transparent with regard to the changes that are being made to the implementing regulations. As such, the EPA is providing Table 8 that summarizes the changes being made.

TABLE 8—SUMMARY OF CHANGES TO THE IMPLEMENTING REGULATIONS

New implementing regulations—Subpart Ba for all future and ongoing CAA section 111(d) emission guidelines	Existing implementing regulations—Subpart B for all previously promulgated CAA section 111(d) emission guidelines
Explicit authority for a new 111(d) emission guidelines requirement to supersede these implementing regulations.	No explicit authority.
Use of term ''standard of performance''	Use of term ''emission standard''.
''Standard of performance'' allows states to include design, equipment, work practice, or operational standards when the EPA determines it is not feasible to prescribe or enforce a standard of performance, consistent with the requirements of CAA section 111(h).	''Emission standard'' allows states to prescribe equipment specifications when the EPA determines it is clearly impracticable to establish an emission standard.
State submission timing: 3 years from promulgation of final emission guidelines.	State submission timing: 9 months from promulgation of final emission guidelines.
EPA action on state plan submission timing: 12 months after determination of completeness.	EPA action on state plan submission timing: 4 months after submittal deadline.
Timing for EPA promulgation of a federal plan, as appropriate: 2 years after finding of plan submission to be incomplete, finding of failure to submit a plan, or disapproval of state plan.	Timing for EPA promulgation of a federal plan, as appropriate: 6 months after submittal deadline.
Increments of progress are required if compliance schedule for a state plan is longer than 24 months after the plan is due.	Increments of progress are required if compliance schedule for a state plan is longer than 12 months after the plan is due.
Completeness criteria and process for state plan submittals	No analogous requirement.
Usage of the internet to satisfy certain public hearing requirements	No analogous requirement.
No distinction made in treatment between health-based and welfare-based pollutants; states may consider remaining useful life and other factors regardless of type of pollutant.	Different provisions for health-based and welfare-based pollutants; state plans must be as stringent as the EPA's emission guidelines for health-based pollutants unless variance provision is invoked.

A. Regulatory Background

The Agency also is, in this action, clarifying the respective roles of the states and the EPA under section 111(d), including by finalizing revisions to the regulations implementing that section in 40 CFR part 60 subpart B. CAA section 111(d)(1) states that the EPA ''Administrator shall prescribe regulations which shall establish a procedure . . . under which each state shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance.'' [271] CAA section 111(d)(1) also requires the Administrator to ''permit the State in applying a standard of performance to any particular source

[271] *See* 42 U.S.C. 7411(d).

under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.''[272]

As the statute provides, the EPA's authorized role under CAA section 111(d)(1) is to develop a procedure for states to establish standards of performance for existing sources. Indeed, the Supreme Court has acknowledged the role and authority of states under CAA section 111(d): This provision allows ''each State to take the first cut at determining how best to achieve EPA emissions standards within its domain.'' [273] The Court addressed the statutory framework as implemented through regulation, under which the EPA promulgates emission guidelines and the states establish performance standards: ''For existing sources, EPA issues emissions guidelines; in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction, [42 U.S.C.] 7411(d)(1).'' [274]

As contemplated by CAA section 111(d)(1), states possess the authority and discretion to establish appropriate standards of performance for existing sources. CAA section 111(a)(1) defines ''standard of performance'' as ''a standard of emissions of air pollutants which reflects'' what is commonly referred to as the ''Best System of Emission Reduction'' or ''BSER''—*i.e.,* ''the degree of emission limitation achievable through the application of the *best system of emission reduction* which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.''[275]

In order to effectuate the Agency's role under CAA section 111(d)(1), the EPA promulgated implementing regulations in 1975 to provide a framework for subsequent EPA rules and state plans under CAA section 111(d).[276] The implementing regulations reflect the EPA's principal task under CAA section 111(d)(1), which is to develop a procedure for states to establish standards of performance for existing sources through state plans. The EPA is promulgating an updated version of the implementing regulations. Under the revised implementing regulations, the EPA effectuates its role by publishing ''emission guidelines'' [277] that, among other things, contain the EPA's determination of the BSER for the category of existing sources being regulated.[278] In undertaking this task, the EPA ''will specify different emissions guidelines . . . for different sizes, types and classes of . . . facilities when costs of control, physical limitations, geographic location, or similar factors make subcategorization appropriate.'' [279]

In short, under the EPA's revised regulations implementing CAA section 111(d), which tracks with the existing implementing regulations in this regard, the guideline documents serve to ''provide information for the development of state plans.'' [280] The ''emission guidelines,'' reflecting the degree of emission limitation achievable through application of the BSER determined by the Administrator to be adequately demonstrated, are the principal piece of information states rely on to develop their plans that establish standards of performance for existing sources. Additionally, the Act requires that the EPA permit states to consider, ''among other factors, the remaining useful life'' of an existing source in applying a standard of performance to such sources.[281]

Additionally, while CAA section 111(d)(1) clearly authorizes states to develop state plans that establish performance standards and provides states with certain discretion in determining appropriate standards, CAA section 111(d)(2) provides the EPA specifically a role with respect to such state plans. This provision authorizes the EPA to prescribe a plan for a state ''in cases where the State fails to submit a satisfactory plan.'' [282] The EPA therefore is charged with determining whether state plans developed and submitted under CAA section 111(d)(1) are ''satisfactory,'' and the new implementing regulations at 40 CFR 60.27a accordingly provide timing and procedural requirements for the EPA to make such a determination. Just as guideline documents may provide information for states in developing plans that establish standards of performance, they may also provide information for the EPA to consider when reviewing and taking action on a submitted state plan, as the new implementing regulations at 40 CFR 60.27a(c) reference the ability of the EPA to find a state plan as ''unsatisfactory because the requirements of (the implementing regulations) have not been met.'' [283]

B. Provision for Superseding Implementing Regulations

The EPA proposed to include a provision in the new implementing regulations that expressly allows for any emission guidelines to supersede the applicability of the implementing regulations as appropriate, parallel to a provision contained in the 40 CFR part 63 General Provisions implementing section 112 of the CAA. The EPA cannot foresee all of the unique circumstances and factors associated with particular future emission guidelines, and therefore different requirements may be necessary for a particular 111(d) rulemaking that the EPA cannot envision at this time. The EPA is finalizing this provision as proposed.

C. Changes to the Definition of ''Emission Guidelines''

The existing implementation regulations under 40 CFR 60.21(e) contain a definition of ''emission guidelines,'' defining them as guidelines which reflect the degree of emission reduction achievable through the application of the BSER which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities. This definition additionally references that emission guidelines may be set forth in 40 CFR part 60, subpart C, or a ''final guideline document'' published under 40 CFR 60.22(a). While the implementing regulations do not define the term ''final guideline document,'' 40 CFR 60.22 generally contains a number of requirements pertaining to the contents of guideline documents, which are intended to provide information for the development of state plans.[284] The preambles for both the proposed and final existing implementing regulations suggest that ''emission guidelines''

[272] *Id.*

[273] *Am. Elec. Power Co.* v. *Connecticut,* 131 S. Ct. 2527, 2539 (2011).

[274] *Id.* at 2537–38.

[275] 42 U.S.C. 7411(a)(1) (emphasis added).

[276] *See* 40 CFR part 60, subpart B (hereafter referred to as the ''implementing regulations'').

[277] *See* section IV.B. for the changes to the definition of ''emission guidelines'' as part of the EPA's new implementing regulations.

[278] *See* 40 CFR 60.22a(b) (''Guideline documents published under this section will provide information for the development of State plans, such as: . . . (4) An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated.'').

[279] 40 CFR 60.22(b)(5).

[280] 40 CFR 60.22a(b).

[281] 42 U.S.C. 7411(d)(1).

[282] *Id.* 7411(d)(2)(A).

[283] *See also* 40 FR 53343 (''If there is to be substantive review, there must be criteria for the review, and EPA believes it is desirable (if not legally required) that the criteria be made known in advance to the States, to industry, and to the general public. The emission guidelines, each of which will be subjected to public comment before final adoption, will serve this function.'').

[284] *See* 40 CFR 60.22(b).

would be guidelines provided by the EPA that reflect the degree of emission limitation achievable by the BSER. In the proposal for this action, the EPA described that it is important to provide information on such degree of emission limitation in order to guide states in their establishment of standards of performance as required under CAA section 111(d). However, the EPA also explained that it did not believe anything in CAA section 111(a)(1) or 111(d) compels the EPA to provide a presumptive emission standard that reflects the degree of emission limitation achievable by application of the BSER. Accordingly, as part of the proposed new implementing regulations, the EPA proposed to re-define ''emission guidelines'' as final guideline documents published under 40 CFR 60.22a(a) that include information on the degree of emission reduction achievable through the application of the BSER which (taking into account the cost of such reduction and any non-air quality health and environmental impact and energy requirements) the EPA has determined has been adequately demonstrated for designated facilities.

The EPA received substantial comments regarding this proposed change to the implementing regulations. Commenters contend that because CAA section 111(a)(1) requires the EPA to identify the BSER, it is also the EPA's statutory responsibility to identify the degree of emission limitation achievable through application of the BSER. According to commenters, the identification of a BSER without an accompanying emission limitation reflecting its application is an incomplete identification of the system of emission reduction itself, as it is the manner and degree of application of a system that often determines the quantity and cost of the emission reductions achieved, as well as any implications for energy requirements—factors that are statutorily a component of the BSER analysis delegated to the EPA.

The EPA has considered carefully these comments and is not finalizing the proposed changes to the definition of ''emission guidelines'' regarding the aspect of such guidelines reflecting the degree of emission limitation achievable through application of the BSER. The EPA is finalizing a definition of ''emission guidelines'' that requires them to reflect the degree of emission limitation of emission achievable through application of the BSER, as well as updates to the definition consistent with CAA section 111(a)(1) (*e.g.,* including a reference to ''energy requirements'' which was not present in the original definition). Relatedly, the EPA is not finalizing changes to proposed 40 CFR 60.21a(e) requiring the EPA in emission guidelines to provide *information* on the degree of emission limitation achievable through application of the BSER rather than such degree of emission limitation itself. While the statute is ambiguous as to whose role (*i.e.,* the EPA's or the states') it is to determine the degree of emission limitation achievable through application of the BSER in the context of standards of performance for existing sources, the EPA believes it is reasonable to construe this aspect of CAA section 111 as included within the EPA's obligation to determine the BSER. While states are better positioned to evaluate source-specific factors and circumstances in establishing standards of performance, the EPA agrees with commenters that because the EPA evaluates components such as cost of emission reductions and environmental impacts on a broader, systemwide scale when determining the BSER, if a state instead were to determine the degree of emission limitation achievable for the sources within its borders, these factors will naturally be re-balanced on a smaller scale than the EPA's calculation and likely re-define the BSER in the process. Under the cooperative federalism structure of CAA section 111, the EPA determines the BSER and the associated level of stringency (*i.e.,* the degree of emission limitation achievable through application of the BSER), but states may where appropriate relax this level of stringency when establishing standards of performance by accounting for source-specific factors such as remaining useful life. Accordingly, given the EPA's role in determining the BSER, the EPA is retaining the requirement from the original implementing regulations that emission guidelines reflect the degree of emission limitation achievable through application of the BSER, rather than finalizing the proposed change that emission guidelines provide information on such degree of emission limitation achievable.

D. Updates to Timing Requirements

The timing requirements in the existing implementing regulations for state plan submissions, the EPA's action on state plan submissions, and the EPA's promulgation of federal plans generally track the timing requirements for SIPs and federal implementation plans (FIPs) under the 1970 version of the CAA. The existing implementing regulations at 60.23(a)(1) require state plans to be submitted to the EPA within nine months after publication of final emission guidelines, unless otherwise specified in emission guidelines. Congress subsequently revised the SIP and FIP timing requirements in section 110 as part of the 1990 CAA Amendments. The EPA proposed to update accordingly the timing requirements regarding state and federal plans under CAA section 111(d) to be consistent with the current timing requirements for SIPs and FIPs under section 110.[285]

Commenters contend that premising the proposed longer timelines for state plans based on the timelines for SIPs and FIPs is inappropriate because CAA section 111(d) state plans are narrower in scope and less complex than section 110 SIPs for a number of reasons. According to commenters, these reasons include: (1) Because state plans cover one source category, whereas SIPs cover the different types of sources whose emissions must be reduced to meet an ambient air quality standard; (2) because sources under state plans are required to meet an emission standard expressed as a rate or mass limitation, whereas SIPs are required to assure that ambient air within a state stay below the NAAQS, which requires monitoring, modeling, and other complicated considerations; and (3) EPA already does a substantial percentage of the work for states in the first instance by determining the BSER and the degree of emission limitation achievable through application of the BSER.

While it is correct that the main requirement under CAA section 111(d) is for state plans to establish standards of performance for designated facilities, and that these existing-source performance standards are informed by the degree of emission limitation achievable through application of the BSER that EPA identifies, CAA section 111(d)(1)(B) also requires state plans to include measures that provide for the implementation and enforcement of such standards. The implementing regulations further clarify what those measures may be, such as monitoring, reporting, and recordkeeping requirements, but the regulations do not specify the types of measures that may satisfy those requirements (*e.g.,* what type of monitoring is adequate to measure compliance for a particular source category). Nor do the implementing regulations contain an exhaustive list of implementation and enforcement measures given that the nature of a specific state plan, or individual source subject to a state plan, may necessitate tailored implementation

[285] *See* 84 FR 44746–813.

and enforcement measures that the EPA has not, or cannot, prescribe.

Establishment of standards of performance under CAA section 111(d) state plans also may not be as straightforward as commenters suggest, as states have the authority to consider remaining useful life and other factors in applying a standard to a designated facility. While the EPA defines the degree of emission limitation achievable through application of the BSER, it is the state that must evaluate whether there are source-specific considerations which necessitate development of a different standard than the degree of emission limitation that the EPA identifies. Commenters do not provide any information suggesting development of such standards, or development of appropriate implementation and enforcement measures generally, would take some shorter period of time to formulate and adopt for submission of a state plan than the three years the EPA proposed. Therefore, for these reasons, commenters fail to recognize that while CAA section 111(d) is not the same as CAA section 110 in the scope of its requirements, state plans under CAA section 111(d) have their own complexities and realities that take time to address in the development of state plans.

To the contrary, it has been the EPA's experience over decades in the SIP context that states often do need and take much, if not all, of the three-year period under section 110 for the process of developing and adopting SIPs, even if a required SIP submission is relatively narrow in scope and nature. To the extent the EPA determines a shorter timeline is appropriate for the submission of state plans under CAA section 111(d), for example based on the nature of the pollution problem involved, the EPA has authority under the implementing regulations to impose a shorter deadline in specific emission guidelines. Relatedly, the EPA also proposed that it would be required to propose a federal plan ''within'' two years, and nothing in this provision precludes the EPA from promulgating a federal plan at any period within that span of two years if it deems appropriate.

For all of these reasons and based on its experience, the EPA believes it is at least reasonable to construe Congress's direction that it establish a procedure ''similar'' under that of CAA section 110 to authorize it to provide the same timing requirements for state and federal plans under CAA section 111(d) as Congress provided under CAA section 110, and indeed that this direction may indicate Congress's specific intention that the EPA adopt those same timing requirements. The EPA is finalizing, as part of new implementing regulations, a requirement that states adopt and submit a state plan to the EPA within three years after the notice of the availability of the final emission guidelines. Because of the amount of work, effort, and time required for developing state plans that include unit-specific standards, and implementation and enforcement measures for such standards, the EPA believes that extending the submission date of state plans from nine months to three years is appropriate. Because states have considerable flexibility in implementing CAA section 111(d), this timing also allows states to interact and work with the Agency in the development of their state plans and to minimize the chances of unexpected issues arising that could slow down eventual approval of state plans. The EPA notes that nothing in CAA section 111(d) or the implementing regulations preclude states from submitting state plans earlier than the applicable deadline. The EPA also is finalizing to give itself discretion to determine, in specific emission guidelines, that a shorter time period for the submission of state plans particular to that emission guidelines is appropriate. Such authority is consistent with CAA section 110(a)(1)'s grant of authority to the Administrator to determine that a period shorter than three years is appropriate for the submission of particular SIPs implementing the NAAQS.

Following submission of state plans, the EPA will review plan submittals to determine whether they are ''satisfactory'' pursuant to CAA section 111(d)(2)(A). Given the flexibilities CAA section 111(d) and emission guidelines generally accord to states, and the EPA's prior experience on reviewing and acting on SIPs under section 110, the EPA is extending the period for EPA review and approval or disapproval of plans from the four-month period provided in the 1975 implementing regulations to a twelve-month period after a determination of completeness (either affirmatively by the EPA or by operation of law, see section IV.F. for the new implementing regulations' treatment of completeness) as part of the new implanting regulations. This timeline will provide adequate time for the EPA to review plans and follow notice-and-comment rulemaking procedures to ensure an opportunity for public comment on the EPA's proposed action on a state plan.

The EPA additionally is extending the timing for the EPA to promulgate a federal plan from six months in the existing implementing regulations to two years, as part of the new implementing regulations. This two-year timeline is consistent with the FIP deadline under section 110(c) of the CAA. The EPA is finalizing provisions in the new implementing regulations [286] that provide that it has the authority to promulgate a federal plan within two years if it:

• Finds that a state failed to submit a plan required by emission guidelines and CAA section 111(d);

• Makes a finding that a state plan submission is incomplete, as described under the new completeness requirements and criteria in 40 CFR 60.27a(g); or

• Disapproves a state plan submission.

E. Compliance Deadlines

The previous implementing regulations required that any compliance schedule for state plans extending more than 12 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities.[287] However, as described in section IV.D, the EPA is finalizing updates to the timing requirements for the submission of, and action on, state plans. Consequently, it follows that the requirement for increments of progress also should be updated in order to align with the new timelines. Given that the EPA is finalizing a period of up to 18 months for its action on state plans (*i.e.,* 12 months from the determination that a state plan submission is complete, which could occur up to six months after receipt of the state plan), the EPA believes it is appropriate that the requirement for increments of progress should attach to plans that contain compliance periods that are longer than the period provided for the EPA's review of such plans. This way, sources subject to a plan will have more certainty that their regulatory compliance obligations would not change between the period when a state plan is due and when the EPA acts on a plan. Accordingly, the EPA is requiring that states include provisions for increments of progress where their state plans contain compliance schedules longer than 24 months from

[286] 40 CFR 60.27a(c).

[287] 40 CFR 60.24(e)(1).

the date when state plans are due for particular emission guidelines.

F. Completeness Criteria

Similar to requirements regarding determinations of completeness under CAA section 110(k)(1), the EPA is finalizing completeness criteria that provide the Agency with a means to determine whether a state plan submission includes the minimum elements necessary for the EPA to act on the submission. The EPA determines completeness simply by comparing the state's submission against these completeness criteria. In the case of SIPs under CAA section 110(k)(1), the EPA promulgated completeness criteria in 1990 at appendix V to 40 CFR part 51.[288] The EPA is adopting criteria similar to the criteria set out at section 2.0 of appendix V for determining the completeness of submissions under CAA section 111(d).

The EPA notes that the addition of completeness criteria in the framework regulations does not alter any of the submission requirements states already have under any applicable emission guidelines. The completeness criteria in this action are those that would generally apply to all plan submissions under CAA section 111(d), but specific emission guidelines may supplement these general criteria with additional requirements.

The completeness criteria that the EPA is finalizing in this action can be grouped into administrative materials and technical support. For administrative materials, the completeness criteria mirror criteria for SIP submissions because the two programs have similar administrative processes. Under these criteria, the submittal must include the following:

(1) A formal letter of submittal from the Governor or the Governor's designee requesting EPA approval of the plan or revision thereof;

(2) Evidence that the state has adopted the plan in the state code or body of regulations; or issued the permit, order, or consent agreement (hereafter ''document'') in final form. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date;

(3) Evidence that the state has the necessary legal authority under state law to adopt and implement the plan;

(4) A copy of the official state regulation(s) or document(s) submitted for approval and incorporated by reference into the plan, signed, stamped, and dated by the appropriate state official indicating that they are fully adopted and enforceable by the state. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The state's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submission must indicate the changes made to the approved plan by redline/strikethrough;

(5) Evidence that the state followed all applicable procedural requirements of the state's regulations, laws, and constitution in conducting and completing the adoption/issuance of the plan;

(6) Evidence that public notice was given of the plan or plan revisions with procedures consistent with the requirements of 40 CFR 60.23, including the date of publication of such notice;

(7) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23.; and

(8) Compilation of public comments and the state's response thereto.

In addition, the technical support required for all plans must include each of the following:

(1) Description of the plan approach and geographic scope;

(2) Identification of each designated facility; identification of emission standards for each designated facility; and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility;

(3) Identification of compliance schedules and/or increments of progress;

(4) Demonstration that the state plan submission is projected to achieve emissions performance under the applicable emission guidelines;

(5) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and

(6) Demonstration that each emission standard is quantifiable, permanent, verifiable, and enforceable.

The EPA intends that these criteria generally be applicable to all CAA section 111(d) plans submitted on or after the date on which final new implementing regulations are promulgated, with the proviso that specific emission guidelines may provide otherwise.

Consistent with the requirements of CAA section 110(k)(1)(B) for SIPs, the EPA is finalizing that the EPA will determine whether a state plan is complete (*i.e.,* meets the completeness criteria) by no later than 6 months after the date, if any, by which a state is required to submit the plan. The EPA requires that any plan or plan revision that a state submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum completeness criteria, shall on that date be deemed by operation of law to be a complete state plan. Then, as previously discussed, the EPA relatedly is finalizing that the EPA will act on a state plan submission through notice-and-comment rulemaking within 12 months after determining a plan is complete either through an affirmative determination or by operation of law.

When plan submissions do not contain the minimum elements, the EPA will find that a state has failed to submit a complete plan through the same process as finding a state has made no submission at all. Specifically, the EPA will notify the state that its submission is incomplete and that it therefore has not submitted a required plan, and the EPA will also publish a finding of failure to submit in the **Federal Register**, which triggers the EPA's obligation to promulgate a federal plan for the state. This determination that a submission is incomplete and that the state has failed to submit a plan is ministerial in nature and requires no exercise of discretion or judgment on the Agency's part, nor does it reflect a judgment on the eventual approvability of the submitted portions of the plan.

G. Standard of Performance

As previously described, the implementing regulations were promulgated in 1975 and effectuated the 1970 version of the CAA as it existed at that time. The 1970 version of CAA section 111(d) required state plans to include ''emission standards'' for existing sources, and consequently the implementing regulations refer to this term. However, as part of the 1977 amendments to the CAA, Congress replaced the term ''emission standard'' in section 111(d) with ''standard of performance.'' The EPA has not since revised the implementing regulations to reflect this change in terminology. For clarity's sake and to better track with statutory requirements, the EPA is determining to include a definition of ''standard of performance'' as part of the new implementing regulations, and to consistently refer to this term as appropriate within those regulations in lieu of referring to an ''emission standard.'' In any event, the current definition of ''emission standard'' in the implementing regulations is incomplete and would need to be revised. For

[288] 55 FR 5830; February 16, 1990.

example, the definition encompasses equipment standards, which is an alternative form of standard provided for in CAA section 111(h) under certain circumstances. However, CAA section 111(h) provides for other forms of alternative standards, such as work practice standards, which are not covered by the existing regulatory definition of ''emission standard.'' Furthermore, the definition of ''emission standard'' encompasses allowance systems, a reference that was added as part of the EPA's CAMR.[289] This rule was vacated by the D.C. Circuit, and therefore this added component to the definition of ''emission standard'' had no legal effect because of the Court's vacatur. Consistent with the Court's opinion, the EPA signaled its intent to remove this reference as part of its MATS rule.[290] However, in the final regulatory text of that rulemaking, the EPA did not take action removing this reference, and it remains as a vestigial artifact.

For these reasons, the EPA is replacing the existing definition of ''emission standard'' with a definition of ''standard of performance'' that tracks with the definition provided for under CAA section 111(a)(1). This means a standard of performance for existing sources would be defined as a standard for emissions of air pollutants that reflects the degree of emission limitation achievable through the application by the state of the BSER which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. Several commenters expressed concern that the proposed definition of ''standard of performance'' in conjunction with the proposal to strike the reference to allowance-based systems precluded states from including mass-based standards of performance. Commenters misunderstand the EPA's proposal, which did not propose that the new definition of ''standard of performance'' itself would specify either rate-based or mass-based standards. As explained at proposal, the new definition is intended to track the definition of the same term in CAA section 111(a)(1), which does not specify that standards of performance must be rate or mass-based. Rather, the EPA may determine in particular emission guidelines the appropriate form of the standard that a state plan must include, based on considerations specific to those emission guidelines, such as the BSER determination, the nature of the pollutant and affected source-category being regulated, and other relevant factors. The EPA believes the term ''standard of performance'' alone does not require or preclude that the standard be in rate or mass-based form, whereas the prior definition of ''emission standard'' was actually more restrictive in that it specified rate-based standards and allowance-based systems, but it did not identify other mass-based standards (such as limits) as permissible.

Similarly, other commenters stated that the definition in the implementing regulations should be clarified to encompass unambiguously rates of any kind (*e.g.,* input-based or output-based), quantities, concentrations, or percentage reductions, consistent with statutory language. However, as previously described, the term ''standard of performance'' alone does not specify which form the standard must take, and such specification is appropriately made in a particular emission guideline depending on considerations such as the nature of the BSER, source category, and pollutant for that rule. Therefore, the EPA is finalizing the definition of ''standard of performance'' as proposed and clarifying that the definition alone does not preclude any form of rate or mass-based standards, but particular emission guidelines may specify the appropriate form of standards that a state plan under such guidelines can or cannot include.

The EPA is further finalizing a definition of standard of performance that incorporates CAA section 111(h)'s allowance for design, equipment, work practice, or operational standards as alternative standards of performance under the statutorily prescribed circumstances. The previous implementing regulations allowed for state plans to prescribe equipment specifications when emission rates are ''clearly impracticable'' as determined by the EPA. CAA section 111(h)(1), by contrast, allows for alternative standards such as equipment standards to be promulgated when standards of performance are ''not feasible to prescribe or enforce,'' as those terms are defined under CAA section 111(h)(2). Given the potential discrepancy between the conditions under which alternative standards may be established based on the different terminology used by the statute and existing implementing regulations, the EPA is establishing in the new implementing regulations the ''not feasible to prescribe or enforce'' language as the condition under which alternative standards may be established.

H. Remaining Useful Life and Other Factors Provisions

The EPA believes that the previous implementing regulations' distinction between public health-based and welfare-based pollutants is not a distinction unambiguously required under CAA section 111(d) or any other applicable provision of the statute. The EPA does not believe the nature of the pollutant in terms of its impacts on health and/or welfare impact the manner in which it is regulated under this provision. Particularly, 60.24(c) requires that for health-based pollutants, a state's standards of performance must be of equivalent stringency to the EPA's emission guidelines. However, CAA section 111(d)(1)(B) states that the EPA's regulations ''shall'' permit states to take into account, among other factors, a designated facility's remaining useful life when establishing an appropriate standard of performance. In other words, Congress explicitly envisioned under CAA section 111(d)(1)(B) that states could implement standards of performance that vary from the EPA's emission guidelines under appropriate circumstances. Notably, the pre-existing implementing regulations at § 60.24(f) contain a provision that allows for states to also apply less stringent standards on sources under certain circumstances.[291] However, this provision attaches to the distinction between health-based and welfare-based pollutants and is available to the states only under the EPA's discretion. This provision was also promulgated prior to Congress's addition of the requirement in CAA section 111(d)(1)(B) that the EPA permit states to take into account remaining useful life and other factors, and the terms of the regulatory provision and statutory provision do not match one another, meaning that this provision may not account for all of the factors envisioned under CAA section 111(d)(1)(B). Given all of these considerations, the EPA is finalizing in the new implanting regulations provisions that remove the distinction between health-based and welfare-based pollutants and associated requirements contingent upon this distinction. The EPA is also finalizing a new provision to permit states to take into account remaining useful life, among other

[289] 70 FR 28605.

[290] 77 FR 9304.

[291] The EPA is hereafter no longer referring to 40 CFR 60.24(f) or its corollary under the new implementing regulations as the ''variance provision.'' The EPA is instead using the phrase ''remaining useful life and other factors'' when referring to this provision, as this phrase is consistent with the terminology used in CAA section 111(d)(1) and better reflects the states' role and authority in establishing standards of performance under CAA section 111(d) generally.

factors, in establishing a standard of performance for a particular designated facility, consistent with CAA section 111(d)(1)(B).

Under this new ''remaining useful life and other factors'' provision, these following factors may be considered, among others:

- Unreasonable cost of control resulting from plant age, location, or basic process design;
- Physical impossibility of installing necessary control equipment; or
- Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

Given that there are unique attributes and aspects of each designated facility, it is not possible for the EPA to define each and every circumstance that states may consider when applying a standard of performance under CAA section 111(d); accordingly, this list is not intended to be exclusive of other source-specific factors that a state may permissibly take into account in developing a satisfactory plan establishing standards of performance for existing sources within its jurisdiction. Such ''other factors'' referred to under the remaining useful life and other factors provision may be ones that influence decisions to invest in technologies to meet a potential performance standard. Such other factors may include timing considerations like payback period for investments, the timing of regulatory requirements, and other unit-specific criteria. A state may account for remaining useful life and other factors as it determines appropriate for a specific source, so long as the state adopts a reasonable approach and adequately explains that approach in its submission to the EPA.

V. Statutory and Executive Order Reviews

Additional information about these Statutory and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This final action is an economically significant action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the compliance cost, benefit, and net benefit impacts associated with this action in the analytical timeframe of 2023 to 2037. This analysis, which is contained in the Regulatory Impact Analysis (RIA) for this final action, is consistent with Executive Order 12866 and is available in the docket for this action.

In the RIA for this final action, the Agency provides a full benefit-cost analysis of an illustrative policy scenario representing ACE, which models HRI at coal-fired EGUs. This illustrative policy scenario, described in greater detail in section III.F above, represents potential outcomes of state determinations of standards of performance, and compliance with those standards by affected coal-fired EGUs. Throughout the RIA, the illustrative policy scenario is compared against a single baseline. As described in Chapter 2 of the RIA, the EPA believes that a single baseline without the CPP represents a reasonable future against which to assess the potential impacts of the ACE rule. The EPA also provides analysis in Chapter 2 of the RIA that satisfies any need for regulatory impact analysis that may be required by statute or executive order for the repeal of the CPP.

The EPA evaluates the potential regulatory impacts of the illustrative policy scenario using the present value (PV) of costs, benefits, and net benefits, calculated for the timeframe of 2023–2037 from the perspective of 2016, using both a three percent and seven percent end-of-period discount rate. In addition, the EPA presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. These specific snapshot years are 2025, 2030, and 2035.

The power industry's ''compliance costs'' are represented in this analysis as the change in electric power generation costs between the baseline and illustrative policy scenario, including the cost of monitoring, reporting, and recordkeeping. The EPA also reports the impact on climate benefits from changes in CO_2 and the impact on health benefits attributable to changes in SO_2, NO_X, and $PM_{2.5}$ emissions. More detailed descriptions of the cost and benefit impacts of these rulemakings are presented in section III.F above.

Table 9 presents the PV and equivalent annualized value (EAV) of the estimated costs, domestic climate benefits, ancillary health co-benefits, and net benefits of the illustrative policy scenario for the timeframe of 2023–2037, relative to the baseline. The EAV represents an even-flow of figures over the timeframe of 2023–2037 that would yield an equivalent present value. The EAV is identical for each year of the analysis, in contrast to the year-specific estimates presented earlier for the snapshot years of 2025, 2030, and 2035. Table 10 presents the estimates for the specific snapshot years of 2025, 2030, and 2035.

TABLE 9—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COSTS, DOMESTIC CLIMATE BENEFITS, ANCILLARY HEALTH CO-BENEFITS, AND NET BENEFITS, ILLUSTRATIVE POLICY SCENARIO, 3 AND 7 PERCENT DISCOUNT RATES, 2023–2037

[Millions of 2016$]

	Costs		Domestic climate benefits		Ancillary health co-benefits		Net benefits	
	3%	7%	3%	7%	3%	7%	3%	7%
Present Value	1,600	970	640	62	4,000 to 9,800	2,000 to 5,000	3,000 to 8,800	1,100 to 4,100.
Equivalent Annualized Value	140	110	53	6.9	330 to 820	220 to 550	250 to 730	120 to 450.

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector SO_2 and NO_X emissions and reflect the range based on adult mortality functions (*e.g.,* from Krewski et al. (2009) with Smith et al. (2009)[292] to Lepeule et al. (2012) with Jerrett et al. (2009)).[293]

[292] Smith, R.L., Xu, B., Switzer, P., 2009. Reassessing the relationship between ozone and short-term mortality in U.S. urban communities. Inhal. Toxicol. 21 Suppl 2, 37–61. *https://doi.org/10.1080/08958370903161612.*

[293] Jerrett, M., Burnett, R.T., Pope, C.A., Ito, K., Thurston, G., Krewski, D., Shi, Y., Calle, E., Thun, M., 2009. Long-term ozone exposure and mortality. N. Engl. J. Med. 360, 1085–95. *https://doi.org/10.1056/NEJMoa0803894.*

TABLE 10—COMPLIANCE COSTS, DOMESTIC CLIMATE BENEFITS, ANCILLARY HEALTH CO-BENEFITS, AND NET BENEFITS IN 2025, 2030, AND 2035, ILLUSTRATIVE POLICY SCENARIO, 3 AND 7 PERCENT DISCOUNT RATES

[Millions of 2016$]

	Costs		Domestic climate benefits		Ancillary health co-benefits		Net benefits	
	3%	7%	3%	7%	3%	7%	3%	7%
2025	290	290	81	13	390 to 970	360 to 900	180 to 760	84 to 630.
2030	280	280	81	14	490 to 1,200	460 to 1,100	300 to 1,000	200 to 860.
2035	25	25	72	13	550 to 1,400	510 to 1,300	600 to 1,400	500 to 1,200.

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector SO_2 and NO_X emissions and reflect the range based on adult mortality functions (*e.g.,* from Krewski et al. (2009) with Smith et al. (2009) to Lepeule et al. (2012) with Jerrett et al. (2009)).

In the decision-making process it is useful to consider the change in benefits due to the targeted pollutant relative to the costs. Therefore, in Chapter 6 of the RIA for this final action the Agency presents a comparison of the benefits from the targeted pollutant—CO_2—with the compliance costs. Excluded from this comparison are the benefits from changes in $PM_{2.5}$ and ozone concentrations from changes in SO_2, NO_X, and $PM_{2.5}$ emissions that are projected to accompany changes in CO_2 emissions.

Table 11 presents the PV and EAV of the estimated costs, benefits, and net benefits associated with the targeted pollutant, CO_2, for the timeframe of 2023–2037, relative to the baseline. In Table 11 and Table 12, negative net benefits are indicated with parenthesis.

TABLE 11—PRESENT VALUE AND EQUIVALENT ANNUALIZED VALUE OF COMPLIANCE COSTS, CLIMATE BENEFITS, AND NET BENEFITS ASSOCIATED WITH TARGETED POLLUTANT (CO_2), ILLUSTRATIVE POLICY SCENARIO, 3 AND 7 PERCENT DISCOUNT RATES, 2023–2037

[Millions of 2016$]

	Costs		Domestic climate benefits		Net benefits associated with the targeted pollutant (CO_2)	
	3%	7%	3%	7%	3%	7%
Present Value	1,600	970	640	62	(980)	(910)
Equivalent Annualized Value	140	110	53	6.9	(82)	(100)

Notes: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector SO_2 and NO_X emissions.

Table 12 presents the costs, benefits, and net benefits associated with the targeted pollutant for specific years, rather than as a PV or EAV as found in Table 11.

TABLE 12—COMPLIANCE COSTS, CLIMATE BENEFITS, AND NET BENEFITS ASSOCIATED WITH TARGETED POLLUTANT (CO_2) IN 2025, 2030, AND 2035, ILLUSTRATIVE POLICY SCENARIO, 3 AND 7 PERCENT DISCOUNT RATES

[Millions of 2016$]

	Costs		Domestic climate benefits		Net benefits associated with the targeted pollutant (CO_2)	
	3%	7%	3%	7%	3%	7%
2025	290	290	81	13	(210)	(280)
2030	280	280	81	14	(200)	(260)
2035	25	25	72	13	47	(11)

Notes: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector SO_2 and NO_X emissions.

Throughout the RIA for this action, the EPA considers a number of sources of uncertainty, both quantitatively and qualitatively. The RIA also summarizes other potential sources of benefits and costs that may result from these rules that have not been quantified or monetized.

B. Executive Order 13771: Reducing Regulation and Controlling Regulatory Costs

This action is expected to be an Executive Order 13771 regulatory action. Details on the estimated costs of this final rule can be found in the EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned the EPA ICR number 2503.04. A copy of the ICR can be found in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a state plan to limit CO_2 emissions from existing sources in the power sector. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart Ba.

Respondents/affected entities: 48—the 48 contiguous states;

Respondent's obligation to respond: The EPA expects state plan submissions from 43 of the 48 contiguous states and negative declarations from Vermont, California, Maine, Idaho, and Rhode Island.

Frequency of response: Yearly.

Total estimated burden: 192,640 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $21,500 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce the approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

D. Regulatory Flexibility Act (RFA)

After considering the economic impacts of this rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This final rule will not impose any requirements on small entities. Specifically, emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states develop and submit to the EPA plans that establish performance standards for existing sources within their jurisdiction, and it is those state requirements that could potentially impact small entities. Our analysis in the accompanying RIA is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As with the description in the RIA, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their state implementation plans.[294]

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments.

This action does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate or the private sector in any one year. Specifically, the emission guidelines proposed under CAA section 111(d) do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop state plans. The burden for states to develop state plans in the three-year period following promulgation of the rule was estimated and is listed in section IV.A. above, but this burden is estimated to be below $100 million in any one year. Thus, this rule is not subject to the requirements of section 203 or section 205 of the Unfunded Mandates Reform Act (UMRA).

This rule is also not subject to the requirements of section 203 of UMRA because, as described in 2 U.S.C. 1531–38, it contains no regulatory requirements that might significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

F. Executive Order 13132: Federalism

The EPA has concluded that this action may have federalism implications because it might impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. The development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule, as well as time to work with state legislatures as appropriate, and develop a plan submittal. The Agency understands the burden that these actions will have on states and is committing to providing aid and guidance to states through the plan development process. The EPA will be available at the states initiative to provide clarity for developing plans, including standard of performance setting and compliance initiatives.

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. It would not impose substantial direct compliance costs on tribal governments that have designated facilities located in their area of Indian country. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for designated facilities. The EPA notes that this final rule does not directly impose specific requirements on EGU sources, including those located in Indian country; before developing any standards of performance for existing sources on tribal land, the EPA would consult with leaders from affected tribes. This action also will not have substantial direct costs or impacts on the relationship between the federal government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as

[294] *See American Trucking Ass'n* v. *EPA,* 175 F.3d 1029, 1043–45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the action.

Executive Order 13175 requires the EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' The EPA has concluded that this action does not have tribal implications as specified in E.O. 13175. It would not impose substantial direct compliance costs on tribal governments that have designated facilities located in their area of Indian country. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for designated facilities. This action also will not have substantial direct cost or impacts on the relationship between the federal government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175.

Consistent with EPA Policy on Consultation and Coordination with Indian Tribes, the EPA consulted with tribal officials during the development of this action to provide an opportunity to have meaningful and timely input. On August 24, 2018, consultation letters were sent to 584 tribal leaders that provided information and offered consultation regarding the EPA's development of this rule. On August 30, 2018, the EPA provided a presentation overview on the Proposal: Affordable Clean Energy (Rule) on the monthly National Tribal Air Association/EPA Air Policy call. At the request of the tribes, two consultation meetings were held: One with the Navajo Nation on October 11, 2018, and one with the Samish Indian Nation on October 16, 2018. The Samish Indian Nation opened their consultation to other tribes—also participating in this meeting for informational purposes only were seven tribes (Blue Lake Rancheria, Cherokee Nation Environmental Program, La Jolla Band of Luiseño Indians, Leech Lake Band of Ojibwe, Muscogee (Creek) Nation Office of Environmental Services, Nez Perce Tribe, The Quapaw Tribe) and the National Tribal Air Association. In the meetings, the tribes were presented information from the proposal. The tribes asked general clarifying questions and indicated that they would submit formal comments. Comments on the proposal were received from the Navajo Nation, the Samish Indian Nation, Blue Lake Rancheria, Leech Lake Band of Ojibwe, Nez Perce Tribe, and the National Tribal Air Association, in addition to the Keweenaw Bay Indian Community, the Fond du Lac Band, the 1854 Treaty Authority, and the Sac and Fox Nation. Tribal commenters insisted on meaningful government-to-government consultation with potentially impacted tribes, and that the final rule require states to consult with indigenous and vulnerable communities as they develop state plans. More specific comments can be found in the docket.

H. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is subject to Executive Order 13045 because it is an economically significant regulatory action as defined by Executive Order 12866. The EPA believes that this action will achieve CO_2 emission reductions resulting from implementation of these emission guidelines, as well as ozone and $PM_{2.5}$ emission reductions as a co-benefit, and will further improve children's health.

Moreover, this action does not affect the level of public health and environmental protection already being provided by existing NAAQS, including ozone and $PM_{2.5}$, and other mechanisms in the CAA. This action does not affect applicable local, state, or federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action, which is a significant regulatory energy action under Executive Order 12866, is likely to have a significant effect on the supply, distribution, or use of energy. Specifically, the EPA estimated in the RIA that the rule could result in more than a one percent decrease in coal production in 2025 (or a reduction of more than a 5 million tons per year) and less than a one percent reduction in natural gas use in the power sector (or more than a 25 million MCF reduction in production on an annual basis). The energy impacts the EPA estimates from these rules may be under- or over-estimates of the true energy impacts associated with this action. For more information on the estimated energy effects, please refer to the RIA for these rulemakings, which is in the public docket.

J. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

K. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action is unlikely to have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). The EPA believes that this action will achieve CO_2 emission reductions resulting from implementation of these final guidelines, as well as ozone and $PM_{2.5}$ emission reductions as a co-benefit, and will further improve environmental justice communities' health as discussed in the RIA.

With regards to the repeal, Chapter 2 of the RIA explains why the EPA believes that the power sector is already on path to achieve the CO_2 reductions required by the CPP, therefore the EPA does not believe it would have any significant impact on EJ effected communities.

With regards to ACE, as described in Chapter 4 of the RIA, the EPA finds that most of the eastern U.S. will experience PM and ozone-related benefits as a result of this action. While the EPA expects areas in the southeastern U.S. to experience a modest increase in fine particle levels, areas including the Midwest will experience reduced levels of PM, yielding significant benefits in the form of fewer premature deaths and illnesses. On balance, the positive benefits of this action significantly outweigh the estimated disbenefits.

Moreover, this action does not affect the level of public health and environmental protection already being provided by existing NAAQS, including ozone and $PM_{2.5}$, and other mechanisms in the CAA.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

VI. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, and 307(d)(1)(V) of the CAA, as amended (42 U.S.C. 7411, 7601, 7607(d)(1)(V)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: June 19, 2019.

Andrew R. Wheeler,

Administrator.

Therefore, 40 CFR chapter I is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 2. Add subpart Ba to read as follows:

Subpart Ba—Adoption and Submittal of State Plans for Designated Facilities

Sec.

§ 60.20a Applicability.

(a) The provisions of this subpart apply upon publication of a final emission guideline under § 60.22a(a) if implementation of such final guideline is ongoing as of July 8, 2019 or if the final guideline is published after July 8, 2019.

(1) Each emission guideline promulgated under this part is subject to the requirements of this subpart, except that each emission guideline may include specific provisions in addition to or that supersede requirements of this subpart. Each emission guideline must identify explicitly any provision of this subpart that is superseded.

(2) Terms used throughout this part are defined in § 60.21a or in the Clean Air Act (Act) as amended in 1990, except that emission guidelines promulgated as individual subparts of this part may include specific definitions in addition to or that supersede definitions in § 60.21a.

(b) No standard of performance or other requirement established under this part shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 112, Part C or D, or any other authority of this Act), or a standard issued under State authority.

§ 60.21a Definitions.

Terms used but not defined in this subpart shall have the meaning given them in the Act and in subpart A of this part:

(a) *Designated pollutant* means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

(b) *Designated facility* means any existing facility (see § 60.2) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility (see § 60.2).

(c) *Plan* means a plan under section 111(d) of the Act which establishes standards of performance for designated pollutants from designated facilities and provides for the implementation and enforcement of such standards of performance.

(d) *Applicable plan* means the plan, or most recent revision thereof, which has been approved under § 60.27a(b) or promulgated under § 60.27a(d).

(e) *Emission guideline* means a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22a(a), which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator has determined has been adequately demonstrated for designated facilities.

(f) *Standard of performance* means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated, including, but not limited to a legally enforceable regulation setting forth an allowable rate or limit of emissions into the atmosphere, or prescribing a design, equipment, work practice, or operational standard, or combination thereof.

(g) *Compliance schedule* means a legally enforceable schedule specifying a date or dates by which a source or category of sources must comply with specific standards of performance contained in a plan or with any increments of progress to achieve such compliance.

(h) *Increments of progress* means steps to achieve compliance which must be taken by an owner or operator of a designated facility, including:

(1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency;

(2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification;

(3) Initiation of on-site construction or installation of emission control equipment or process change;

(4) Completion of on-site construction or installation of emission control equipment or process change; and

(5) Final compliance.

(i) *Region* means an air quality control region designated under section 107 of the Act and described in part 81 of this chapter.

(j) *Local agency* means any local governmental agency.

§ 60.22a Publication of emission guidelines.

(a) Concurrently upon or after proposal of standards of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft emission guideline containing information pertinent to control of the designated pollutant from designated facilities. Notice of the availability of the draft emission guideline will be published in the **Federal Register** and public comments on its contents will be invited. After consideration of public comments and upon or after promulgation of standards of performance for control of a designated pollutant from affected facilities, a final emission guideline will be published and notice of its availability will be published in the **Federal Register**.

(b) Emission guidelines published under this section will provide information for the development of State plans, such as:

(1) Information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant.

(2) A description of systems of emission reduction which, in the

judgment of the Administrator, have been adequately demonstrated.

(3) Information on the degree of emission limitation which is achievable with each system, together with information on the costs, nonair quality health environmental effects, and energy requirements of applying each system to designated facilities.

(4) Incremental periods of time normally expected to be necessary for the design, installation, and startup of identified control systems.

(5) The degree of emission limitation achievable through the application of the best system of emission reduction (considering the cost of such achieving reduction and any nonair quality health and environmental impact and energy requirements) that has been adequately demonstrated for designated facilities, and the time within which compliance with standards of performance can be achieved. The Administrator may specify different degrees of emission limitation or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

(6) Such other available information as the Administrator determines may contribute to the formulation of State plans.

(c) The emission guidelines and compliance times referred to in paragraph (b)(5) of this section will be proposed for comment upon publication of the draft guideline document, and after consideration of comments will be promulgated in subpart C of this part with such modifications as may be appropriate.

§ 60.23a Adoption and submittal of State plans; public hearings.

(a)(1) Unless otherwise specified in the applicable subpart, within three years after notice of the availability of a final emission guideline is published under § 60.22a(a), each State shall adopt and submit to the Administrator, in accordance with § 60.4, a plan for the control of the designated pollutant to which the emission guideline applies.

(2) At any time, each State may adopt and submit to the Administrator any plan revision necessary to meet the requirements of this subpart or an applicable subpart of this part.

(b) If no designated facility is located within a State, the State shall submit a letter of certification to that effect to the Administrator within the time specified in paragraph (a) of this section. Such certification shall exempt the State from the requirements of this subpart for that designated pollutant.

(c) The State shall, prior to the adoption of any plan or revision thereof, conduct one or more public hearings within the State on such plan or plan revision in accordance with the provisions under this section.

(d) Any hearing required by paragraph (c) of this section shall be held only after reasonable notice. Notice shall be given at least 30 days prior to the date of such hearing and shall include:

(1) Notification to the public by prominently advertising the date, time, and place of such hearing in each region affected. This requirement may be satisfied by advertisement on the internet;

(2) Availability, at the time of public announcement, of each proposed plan or revision thereof for public inspection in at least one location in each region to which it will apply. This requirement may be satisfied by posting each proposed plan or revision on the internet;

(3) Notification to the Administrator;

(4) Notification to each local air pollution control agency in each region to which the plan or revision will apply; and

(5) In the case of an interstate region, notification to any other State included in the region.

(e) The State may cancel the public hearing through a method it identifies if no request for a public hearing is received during the 30 day notification period under paragraph (d) of this section and the original notice announcing the 30 day notification period states that if no request for a public hearing is received the hearing will be cancelled; identifies the method and time for announcing that the hearing has been cancelled; and provides a contact phone number for the public to call to find out if the hearing has been cancelled.

(f) The State shall prepare and retain, for a minimum of 2 years, a record of each hearing for inspection by any interested party. The record shall contain, as a minimum, a list of witnesses together with the text of each presentation.

(g) The State shall submit with the plan or revision:

(1) Certification that each hearing required by paragraph (c) of this section was held in accordance with the notice required by paragraph (d) of this section; and

(2) A list of witnesses and their organizational affiliations, if any, appearing at the hearing and a brief written summary of each presentation or written submission.

(h) Upon written application by a State agency (through the appropriate Regional Office), the Administrator may approve State procedures designed to insure public participation in the matters for which hearings are required and public notification of the opportunity to participate if, in the judgment of the Administrator, the procedures, although different from the requirements of this subpart, in fact provide for adequate notice to and participation of the public. The Administrator may impose such conditions on his approval as he deems necessary. Procedures approved under this section shall be deemed to satisfy the requirements of this subpart regarding procedures for public hearings.

§ 60.24a Standards of performance and compliance schedules.

(a) Each plan shall include standards of performance and compliance schedules.

(b) Standards of performance shall either be based on allowable rate or limit of emissions, except when it is not feasible to prescribe or enforce a standard of performance. The EPA shall identify such cases in the emission guidelines issued under § 60.22a. Where standards of performance prescribing design, equipment, work practice, or operational standard, or combination thereof are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such standards, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

(1) Test methods and procedures for determining compliance with the standards of performance shall be specified in the plan. Methods other than those specified in appendix A to this part or an applicable subpart of this part may be specified in the plan if shown to be equivalent or alternative methods as defined in § 60.2.

(2) Standards of performance shall apply to all designated facilities within the State. A plan may contain standards of performance adopted by local jurisdictions provided that the standards are enforceable by the State.

(c) Except as provided in paragraph (e) of this section, standards of performance shall be no less stringent than the corresponding emission guideline(s) specified in subpart C of this part, and final compliance shall be required as expeditiously as practicable, but no later than the compliance times specified in an applicable subpart of this part.

(d) Any compliance schedule extending more than 24 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. Unless otherwise specified in the applicable subpart, increments of progress must include, where practicable, each increment of progress specified in § 60.21a(h) and must include such additional increments of progress as may be necessary to permit close and effective supervision of progress toward final compliance.

(e) In applying a standard of performance to a particular source, the State may take into consideration factors, such as the remaining useful life of such source, provided that the State demonstrates with respect to each such facility (or class of such facilities):

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

(f) Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing:

(1) Standards of performance more stringent than emission guidelines specified in subpart C of this part or in applicable emission guidelines; or

(2) Compliance schedules requiring final compliance at earlier times than those specified in subpart C of this part or in applicable emission guidelines.

§ 60.25a Emission inventories, source surveillance, reports.

(a) Each plan shall include an inventory of all designated facilities, including emission data for the designated pollutants and information related to emissions as specified in appendix D to this part. Such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable standards of performance. As used in this subpart, ''correlated'' means presented in such a manner as to show the relationship between measured or estimated amounts of emissions and the amounts of such emissions allowable under applicable standards of performance.

(b) Each plan shall provide for monitoring the status of compliance with applicable standards of performance. Each plan shall, as a minimum, provide for:

(1) Legally enforceable procedures for requiring owners or operators of designated facilities to maintain records and periodically report to the State information on the nature and amount of emissions from such facilities, and/or such other information as may be necessary to enable the State to determine whether such facilities are in compliance with applicable portions of the plan. Submission of electronic documents shall comply with the requirements of 40 CFR part 3 (Electronic reporting).

(2) Periodic inspection and, when applicable, testing of designated facilities.

(c) Each plan shall provide that information obtained by the State under paragraph (b) of this section shall be correlated with applicable standards of performance (see § 60.25a(a)) and made available to the general public.

(d) The provisions referred to in paragraphs (b) and (c) of this section shall be specifically identified. Copies of such provisions shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act; and

(2) The State demonstrates:

(i) That the provisions are applicable to the designated pollutant(s) for which the plan is submitted, and

(ii) That the requirements of § 60.26a are met.

(e) The State shall submit reports on progress in plan enforcement to the Administrator on an annual (calendar year) basis, commencing with the first full report period after approval of a plan or after promulgation of a plan by the Administrator. Information required under this paragraph must be included in the annual report required by § 51.321 of this chapter.

(f) Each progress report shall include:

(1) Enforcement actions initiated against designated facilities during the reporting period, under any standard of performance or compliance schedule of the plan.

(2) Identification of the achievement of any increment of progress required by the applicable plan during the reporting period.

(3) Identification of designated facilities that have ceased operation during the reporting period.

(4) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of plan development but began operation during the reporting period.

(5) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(6) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

§ 60.26a Legal authority.

(a) Each plan or plan revision shall show that the State has legal authority to carry out the plan or plan revision, including authority to:

(1) Adopt standards of performance and compliance schedules applicable to designated facilities.

(2) Enforce applicable laws, regulations, standards, and compliance schedules, and seek injunctive relief.

(3) Obtain information necessary to determine whether designated facilities are in compliance with applicable laws, regulations, standards, and compliance schedules, including authority to require recordkeeping and to make inspections and conduct tests of designated facilities.

(4) Require owners or operators of designated facilities to install, maintain, and use emission monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such facilities; also authority for the State to make such data available to the public as reported and as correlated with applicable standards of performance.

(b) The provisions of law or regulations which the State determines provide the authorities required by this section shall be specifically identified. Copies of such laws or regulations shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act; and

(2) The State demonstrates that the laws or regulations are applicable to the designated pollutant(s) for which the plan is submitted.

(c) The plan shall show that the legal authorities specified in this section are available to the State at the time of submission of the plan. Legal authority adequate to meet the requirements of paragraphs (a)(3) and (4) of this section may be delegated to the State under section 114 of the Act.

(d) A State governmental agency other than the State air pollution control agency may be assigned responsibility for carrying out a portion of a plan if the plan demonstrates to the Administrator's satisfaction that the State governmental agency has the legal authority necessary to carry out that portion of the plan.

(e) The State may authorize a local agency to carry out a plan, or portion thereof, within the local agency's jurisdiction if the plan demonstrates to the Administrator's satisfaction that the local agency has the legal authority necessary to implement the plan or portion thereof, and that the authorization does not relieve the State of responsibility under the Act for carrying out the plan or portion thereof.

§ 60.27a Actions by the Administrator.

(a) The Administrator may, whenever he determines necessary, shorten the period for submission of any plan or plan revision or portion thereof.

(b) After determination that a plan or plan revision is complete per the requirements of § 60.27a(g), the Administrator will take action on the plan or revision. The Administrator will, within twelve months of finding that a plan or plan revision is complete, approve or disapprove such plan or revision or each portion thereof.

(c) The Administrator will promulgate, through notice-and-comment rulemaking, a federal plan, or portion thereof, at any time within two years after the Administrator:

(1) Finds that a State fails to submit a required plan or plan revision or finds that the plan or plan revision does not satisfy the minimum criteria under paragraph (g) of this section; or

(2) Disapproves the required State plan or plan revision or any portion thereof, as unsatisfactory because the applicable requirements of this subpart or an applicable subpart under this part have not been met.

(d) The Administrator will promulgate a final federal plan as described in paragraph (c) of this section unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such federal plan.

(e)(1) Except as provided in paragraph (e)(2) of this section, a federal plan promulgated by the Administrator under this section will prescribe standards of performance of the same stringency as the corresponding emission guideline(s) specified in the final emission guideline published under § 60.22a(a) and will require compliance with such standards as expeditiously as practicable but no later than the times specified in the emission guideline.

(2) Upon application by the owner or operator of a designated facility to which regulations proposed and promulgated under this section will apply, the Administrator may provide for the application of less stringent standards of performance or longer compliance schedules than those otherwise required by this section in accordance with the criteria specified in § 60.24a(e).

(f) Prior to promulgation of a federal plan under paragraph (d) of this section, the Administrator will provide the opportunity for at least one public hearing in either:

(1) Each State that failed to submit a required complete plan or plan revision, or whose required plan or plan revision is disapproved by the Administrator; or

(2) Washington, DC or an alternate location specified in the **Federal Register**.

(g) Each plan or plan revision that is submitted to the Administrator shall be reviewed for completeness as described in paragraphs (g)(1) through (3) of this section.

(1) *General.* Within 60 days of the Administrator's receipt of a state submission, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria for completeness have been met. Any plan or plan revision that a State submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria. Where the Administrator determines that a plan submission does not meet the minimum criteria of this paragraph, the State will be treated as not having made the submission and the requirements of § 60.27a regarding promulgation of a federal plan shall apply.

(2) *Administrative criteria.* In order to be deemed complete, a State plan must contain each of the following administrative criteria:

(i) A formal letter of submittal from the Governor or her designee requesting EPA approval of the plan or revision thereof;

(ii) Evidence that the State has adopted the plan in the state code or body of regulations; or issued the permit, order, consent agreement (hereafter ''document'') in final form. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date;

(iii) Evidence that the State has the necessary legal authority under state law to adopt and implement the plan;

(iv) A copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan, including indication of the changes made (such as redline/strikethrough) to the existing approved plan, where applicable. The submittal must be a copy of the official state regulation or document signed, stamped and dated by the appropriate state official indicating that it is fully enforceable by the State. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The State's electronic copy must be an exact duplicate of the hard copy. If the regulation/document provided by the State for approval and incorporation by reference into the plan is a copy of an existing publication, the State submission should, whenever possible, include a copy of the publication cover page and table of contents;

(v) Evidence that the State followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption and issuance of the plan;

(vi) Evidence that public notice was given of the proposed change with procedures consistent with the requirements of § 60.23a, including the date of publication of such notice;

(vii) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the State's laws and constitution, if applicable and consistent with the public hearing requirements in § 60.23a;

(viii) Compilation of public comments and the State's response thereto; and

(ix) Such other criteria for completeness as may be specified by the Administrator under the applicable emission guidelines.

(3) *Technical criteria.* In order to be deemed complete, a State plan must contain each of the following technical criteria:

(i) Description of the plan approach and geographic scope;

(ii) Identification of each designated facility, identification of standards of performance for the designated facilities, and monitoring, recordkeeping and reporting requirements that will determine compliance by each designated facility;

(iii) Identification of compliance schedules and/or increments of progress;

(iv) Demonstration that the State plan submittal is projected to achieve emissions performance under the applicable emission guidelines;

(v) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and

(vi) Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

§ 60.28a Plan revisions by the State.

(a) Any revision to a state plan shall be adopted by such State after reasonable notice and public hearing. For plan revisions required in response to a revised emission guideline, such plan revisions shall be submitted to the Administrator within three years, or shorter if required by the Administrator, after notice of the availability of a final revised emission guideline is published under § 60.22a. All plan revisions must be submitted in accordance with the procedures and requirements applicable to development and submission of the original plan.

(b) A revision of a plan, or any portion thereof, shall not be considered part of an applicable plan until approved by the Administrator in accordance with this subpart.

§ 60.29a Plan revisions by the Administrator.

After notice and opportunity for public hearing in each affected State, the Administrator may revise any provision of an applicable federal plan if:

(a) The provision was promulgated by the Administrator; and

(b) The plan, as revised, will be consistent with the Act and with the requirements of this subpart.

Subpart UUUU [Removed]

■ 3. Remove subpart UUUU.

■ 4. Add subpart UUUUa to read as follows:

Subpart UUUUa—Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units

Introduction

Sec.

Introduction

§ 60.5700a What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish standards of performance limiting greenhouse gas (GHG) emissions from an affected steam generating unit. An affected steam generating unit for the purposes of this subpart, is referred to as a designated facility. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subpart A or Ba of this part, the requirements of this subpart will apply.

§ 60.5705a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The emission guidelines for greenhouse gases established in this subpart are heat rate improvements which target achieving lower carbon dioxide (CO_2) emission rates at designated facilities.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of § 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from facilities regulated in the plan, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2 of this chapter, with respect to greenhouse gas emissions from facilities regulated in the plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 71.2 of this chapter.

§ 60.5710a Am I affected by this subpart?

If you are the Governor of a State in the contiguous United States with one or more designated facilities that commenced construction on or before January 8, 2014, you are subject to this action and you must submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the contiguous United States with no designated facilities for which construction commenced on or before January 8, 2014, in your State, you must submit a negative declaration letter in place of the State plan.

§ 60.5715a What is the review and approval process for my plan?

The EPA will review your plan according to § 60.27a to approve or disapprove such plan or revision or each portion thereof.

§ 60.5720a What if I do not submit a plan, my plan is incomplete, or my plan is not approvable?

(a) If you do not submit a complete or an approvable plan the EPA will develop a Federal plan for your State according to § 60.27a. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of designated facilities not covered by an approved plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a plan.

§ 60.5725a In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a State plan submittal or a negative declaration letter (if applicable).

§ 60.5730a Is there an approval process for a negative declaration letter?

The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the **Federal Register**. If, at a later date, a designated facility for which construction commenced on or before January 8, 2014 is found in your State, you will be found to have failed to submit a plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that designated facility until you submit, and the EPA approves, a State plan.

State Plan Requirements

§ 60.5735a What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (4) of this section in your plan submittal. The final plan must meet the requirements of, and include the information required under, § 60.5740a.

(1) *Identification of designated facilities.* Consistent with § 60.25a(a), you must identify the designated facilities covered by your plan and all designated facilities in your State that meet the applicability criteria in § 60.5775a. In addition, you must include an inventory of CO_2 emissions from the designated facilities during the most recent calendar year for which data is available prior to the submission of the plan.

(2) *Standards of performance.* You must provide a standard of performance for each designated facility according to § 60.5755a and compliance periods for each standard of performance according to § 60.5750a. Each standard of performance must reflect the degree of emission limitation achievable through application of the heat rate improvements described in § 60.5740a. In applying the heat rate improvements described in § 60.5740a, a state may consider remaining useful life and other factors, as provided for in § 60.24a(e).

(3) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each designated facility.* You must include in your plan all applicable monitoring, reporting and recordkeeping requirements for each designated facility and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5785a.

(4) *State reporting.* Your plan must include a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress, including information required under § 60.5795a.

(b) You must follow the requirements of subpart Ba of this part and demonstrate that they were met in your State plan.

§ 60.5740a What must I include in my plan submittal?

(a) In addition to the components of the plan listed in § 60.5735a, a state plan submittal to the EPA must include the information in paragraphs (a)(1) through (8) of this section. This information must be submitted to the EPA as part of your plan submittal but will not be codified as part of the federally enforceable plan upon approval by EPA.

(1) You must include a summary of how you determined each standard of performance for each designated facility according to § 60.5755a(a). You must include in the summary an evaluation of the applicability of each of the following heat rate improvements to each designated facility:

(i) Neural network/intelligent sootblowers;

(ii) Boiler feed pumps;

(iii) Air heater and duct leakage control;

(iv) Variable frequency drives;

(v) Blade path upgrades for steam turbines;

(vi) Redesign or replacement of economizer; and

(vii) Improved operating and maintenance practices.

(2)(i) As part of the summary under paragraph (a)(1) of this section regarding the applicability of each heat rate improvement to each designated facility, you must include an evaluation of the following degree of emission limitation achievable through application of the heat rate improvements:

TABLE 1 TO PARAGRAPH (A)(2)(I)—MOST IMPACTFUL HRI MEASURES AND RANGE OF THEIR HRI POTENTIAL (%) BY EGU SIZE

HRI Measure	< 200 MW		200–500 MW		>500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved Operating and Maintenance (O&M) Practices	Can range from 0 to > 2.0% depending on the unit's historical O&M practices.					

(ii) In applying a standard of performance, if you consider remaining useful life and other factors for a designated facility as provided in § 60.24a(e), you must include a summary of the application of the relevant factors in deriving a standard of performance.

(3) You must include a demonstration that each designated facility's standard of performance is quantifiable,

permanent, verifiable, and enforceable according to § 60.5755a.

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

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

(A) Annual generation;

(B) CO_2 emissions;

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

(D) Fixed and variable operations and maintenance costs;

(E) Heat rates; and

(F) Electric generation capacity and capacity factors.

(ii) A timeline for implementation.

(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.

(5) Your plan submittal must include certification that a hearing required under § 60.23a(c)on the State plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission, pursuant to the requirements of § 60.23a(g).

(6) Your plan submittal must include supporting material for your plan including:

(i) Materials demonstrating the State's legal authority to implement and enforce each component of its plan, including standards of performance, pursuant to the requirements of §§ 60.26a and 60.5740a(a)(6);

(ii) Materials supporting calculations for designated facility's standards of performance according to § 60.5755a; and

(iii) Any other materials necessary to support evaluation of the plan by the EPA.

(b) You must submit your final plan to the EPA according to § 60.5800a.

§ 60.5745a What are the timing requirements for submitting my plan?

You must submit a plan with the information required under § 60.5740a by July 8, 2022.

§ 60.5750a What schedules and compliance periods must I include in my plan?

The EPA is superseding the requirement at § 60.22a(b)(5) for EPA to provide compliance timelines in the emission guidelines. Each standard of performance for designated facilities regulated under the plan must include a compliance period that ensures the standard of performance reflects the degree of emission limitation achievable though application of the heat rate improvements used to calculate the standard. The schedules and compliance periods included in a plan must follow the requirements of § 60.24a.

§ 60.5755a What standards of performance must I include in my plan?

(a) You must set a standard of performance for each designated facility within the state.

(1) The standard of performance must be an emission performance rate relating mass of CO_2 emitted per unit of energy (*e.g.* pounds of CO_2 emitted per MWh).

(2) In establishing any standard of performance, you must consider the applicability of each of the heat rate improvements and associated degree of emission limitation achievable included in § 60.5740a(a)(1) and (2) to the designated facility. You must include a demonstration in your plan submission for how you considered each heat rate improvement and associated degree of emission limitation achievable in calculating each standard of performance.

(i) In applying a standard of performance to any designated facility, you may consider the source-specific factors included in § 60.24a(e).

(ii) If you consider source-specific factors to apply a standard of performance, you must include a demonstration in your plan submission for how you considered such factors.

(b) Standards of performance for designated facilities included under your plan must be demonstrated to be quantifiable, verifiable, permanent, and enforceable with respect to each designated facility. The plan submittal must include the methods by which each standard of performance meets each of the requirements in paragraphs (c) through (f) of this section.

(c) A designated facility's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.

(d) A designated facility's standard of performance is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the standard of performance.

(e) A designated facility's standard of performance is permanent if the standard of performance must be met for each compliance period, unless it is replaced by another standard of performance in an approved plan revision.

(f) A designated facility's standard of performance is enforceable if:

(1) A technically accurate limitation or requirement and the time period for the limitation or requirement are specified;

(2) Compliance requirements are clearly defined;

(3) The designated facility responsible for compliance and liable for violations can be identified;

(4) Each compliance activity or measure is enforceable as a practical matter; and

(5) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if a designated facility does not meet its standard of performance based on its emissions) and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a) through (h), in the case of a State, pursuant to its plan, State law or CAA section 304, as applicable, and in the case of third parties, pursuant to CAA section 304.

§ 60.5760a What is the procedure for revising my plan?

EPA-approved plans can be revised only with approval by the Administrator. The Administrator will approve a plan revision if it is satisfactory with respect to the applicable requirements of this subpart and any applicable requirements of subpart Ba of this part, including the requirements in § 60.5740a. If one (or more) of the elements of the plan set in § 60.5735a require revision, a request must be submitted to the Administrator indicating the proposed revisions to the plan.

§ 60.5765a What must I do to meet my plan obligations?

To meet your plan obligations, you must demonstrate that your designated facilities are complying with their standards of performance as specified in § 60.5755a.

Applicability of Plans to Designated Facilities

§ 60.5770a Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State. However, designated facility owners or operators must comply with the plan that a State develops to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a plan to implement and enforce the emission guidelines contained in this subpart by July 8, 2022, or the date that EPA disapproves a final plan, the EPA will implement and enforce a Federal plan, as provided in § 60.27a(c), applicable to each designated facility within the State that commenced construction on or before January 8, 2014.

§ 60.5775a What designated facilities must I address in my State plan?

(a) The EGUs that must be addressed by your plan are any designated facility that commenced construction on or before January 8, 2014.

(b) A designated facility is a steam generating unit that meets the relevant applicability conditions specified in paragraphs (b)(1) through (3) of this section, as applicable, of this section except as provided in § 60.5780a.

(1) Serves a generator connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net (*i.e.,* capable of selling greater than 25 MW of electricity).

(2) Has a base load rating (*i.e.,* design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

(3) Is an electric utility steam generating unit that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years.

§ 60.5780a What EGUs are excluded from being designated facilities?

(a) An EGU that is excluded from being a designated facility is:

(1) An EGU that is subject to subpart TTTT of this part as a result of commencing construction, reconstruction or modification after the subpart TTTT applicability date;

(2) A steam generating unit that is subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less;

(3) A stationary combustion turbine that meets the definition of a simple cycle stationary combustion turbine, a combined cycle stationary combustion turbine, or a combined heat and power combustion turbine;

(4) An IGCC unit;

(5) A non-fossil unit (*i.e.,* a unit that is capable of combusting 50 percent or more non-fossil fuel) that has always limited the use of fossil fuels to 10 percent or less of the annual capacity factor or is subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(6) An EGU that serves a generator along with other steam generating unit(s), IGCC(s), or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less;

(7) An EGU that is a municipal waste combustor unit that is subject to subpart Eb of this part;

(8) An EGU that is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part; or

(9) A steam generating unit that fires more than 50 percent non-fossil fuels.

(b) [Reserved]

§ 60.5785a What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my plan for designated facilities?

(a) Your plan must include monitoring, recordkeeping, and reporting requirements for designated facilities. To satisfy this requirement, you have the option of either:

(1) Specifying that sources must report emission and electricity generation data according to part 75 of this chapter; or

(2) Including an alternative monitoring, recordkeeping, and reporting program that includes specifications for the following program elements:

(i) Monitoring plans that specify the monitoring methods, systems, and formulas that will be used to measure CO_2 emissions;

(ii) Monitoring methods to continuously and accurately measure all CO_2 emissions, CO_2 emission rates, and other data necessary to determine compliance or assure data quality;

(iii) Quality assurance test requirements to ensure monitoring systems provide reliable and accurate data for assessing and verifying compliance;

(iv) Recordkeeping requirements;

(v) Electronic reporting procedures and systems; and

(vi) Data validation procedures for ensuring data are complete and calculated consistent with program rules, including procedures for determining substitute data in instances where required data would otherwise be incomplete.

(b) [Reserved]

Recordkeeping and Reporting Requirements

§ 60.5790a What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan. After the effective date of the plan, States must keep records of all information relied upon in support of any continued demonstration that the final standards of performance are being achieved.

(b) You must keep records of all data submitted by the owner or operator of each designated facility that is used to determine compliance with each designated facility emissions standard or requirements in an approved State plan, consistent with the designated facility requirements listed in § 60.5785a.

(c) If your State has a requirement for all hourly CO_2 emissions and generation information to be used to calculate compliance with an annual emissions standard for designated facilities, any information that is submitted by the owners or operators of designated facilities to the EPA electronically pursuant to requirements in part 75 of this chapter meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records at a minimum for 5 years from the date the record is used to determine compliance with a standard of performance or plan requirement. Each record must be in a form suitable and readily available for expeditious review.

§ 60.5795a What are my reporting and notification requirements?

You must submit an annual report as required under § 60.25a(e) and (f).

§ 60.5800a How do I submit information required by these Emission Guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section unless you submit through the procedure described in paragraph (f) of this section.

(b) All negative declarations, State plan submittals, supporting materials that are part of a State plan submittal, any plan revisions, and all State reports required to be submitted to the EPA by the State plan may be reported through EPA's electronic reporting system to be named and made available at a later date.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the

Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the July 8, 2022, deadline for plan submittal so that the official will have the ability to submit a plan in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to the EPA electronic reporting system. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization, and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all plan components designated as federally enforceable must also be submitted in an editable version.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable plan components. The editable copy of any such submitted plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by EPA.

(f) If, in lieu of the requirements described in paragraphs (b) through (e) of this section, you choose to submit a paper copy or an electronic version by other means you must confer with your EPA Regional Office regarding the additional guidelines for submitting your plan.

Definitions

§ 60.5805a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts TTTT, A, and Ba of this part.

Air Heater means a device that recovers heat from the flue gas for use in pre-heating the incoming combustion air and potentially for other uses such as coal drying.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions.

Boiler feed pump (or *boiler feedwater pump*) means a device used to pump feedwater into a steam boiler at an EGU. The water may be either freshly supplied or returning condensate produced from condensing steam produced by the boiler.

CO_2 emission rate means for a designated facility, the reported CO_2 emission rate of a designated facility used by a designated facility to demonstrate compliance with its CO_2 standard of performance.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit* (also known as ''cogeneration'') means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period means a discrete time period for a designated facility to comply with a standard of performance.

Designated facility means a steam generating unit that meets the relevant applicability conditions in section § 60.5775a, except as provided in § 60.5780a.

Economizer means a heat exchange device used to capture waste heat from boiler flue gas which is then used to heat the boiler feedwater.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material to create useful heat.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Intelligent sootblower means an automated system that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup at a steam generating unit.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Nameplate capacity means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous State under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the designated facility divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.,* steam delivered to an industrial process for a heating application).

Neural network means a computer model that can be used to optimize combustion conditions, steam temperatures, and air pollution at steam generating unit.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine engine exhaust gases for purposes other than enhancing the performance of the stationary combustion turbine itself.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the designated facility, to directly enhance the performance of the designated facility (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the designated facility. Useful thermal output for designated facility(s) with no condensate return (or other thermal energy input to the designated facility(s)) or where measuring the energy in the condensate (or other thermal energy input to the designated facility(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Designated facility(s) with meaningful energy in the condensate return (or other thermal energy input to the designated facility) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Variable frequency drive means an adjustable-speed drive used on induced draft fans and boiler feed pumps to control motor speed and torque by varying motor input frequency and voltage.

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