



**WEST VIRGINIA SECRETARY OF STATE**

**MAC WARNER**

**ADMINISTRATIVE LAW DIVISION**

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6/24/2020 2:15:16 PM

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:**

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

Other	0	0	0
<b>2. Estimated Total Revenues</b>	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.**

45CSR44

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.

#### 45CSR44

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<sub>2</sub>" 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<sub>2</sub> 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<sub>2</sub>) 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<sub>2</sub> 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<sub>2</sub> 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.

45CSR44

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.

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

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<sub>2</sub> emitted per unit of energy (e.g. pounds of CO<sub>2</sub> 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<sub>2</sub> 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 through 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<sub>2</sub> emissions;

4.12.b.2. Monitoring methods to continuously and accurately measure all CO<sub>2</sub> emissions, CO<sub>2</sub> 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;

## 45CSR44

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<sub>2</sub> 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.

#### 45CSR44

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<sub>2</sub> emissions;

6.1.b.2. Monitoring methods to continuously and accurately measure all CO<sub>2</sub> emissions, CO<sub>2</sub> 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.