Title 40 - Protection of Environment

CHAPTER I - ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

Introduction

§ 60.5700b What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish emission standards limiting greenhouse gas (GHG) emissions from an affected steam generating unit or natural gas fired stationary combustion turbine. An affected steam generating unit or natural gas fired stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. State plans under the emission guidelines in this subpart are also subject to the requirements of subpart Ba. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or Ba of this part, the requirements of this subpart shall apply.

§ 60.5705b Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases (GHG). The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of § 51.166(b)(49)(ii), 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 § 51.166(b)(48) 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), 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, with respect to GHG 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.

§ 60.5710b Am I affected by this subpart?

If you are the Governor of a State in the United States with one or more affected EGUs that must be addressed in your state plan as indicated in § 60.5845b, 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 United States with no affected EGUs, or if all EGUs in your State are excluded from being affected EGUs per § 60.5850b, you must submit a negative declaration letter in place of the State plan.

§ 60.5715b What is the review and approval process for my plan?

The EPA will review your plan according to § 60.27a. The Administrator will have 12 months after the date the final plan or plan revision (as allowed under § 60.5785b) is found to be complete, to approve or disapprove such plan or revision or each portion thereof.

§ 60.5720b What if I do not submit a plan or my plan is not approvable?

(a) If you do not submit 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 affected EGUs not covered by an approved State 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 State plan.

§ 60.5725b 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).

§ 60.5730b Is there an approval process for a negative declaration letter?

No. 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, an affected EGU 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 State plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a State plan.

State Plan Requirements

§ 60.5740b What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (9) of this section in your plan submittal. The final plan must meet the requirements and include the information required under § 60.5745b, and must also meet any administrative and technical completeness criteria listed in § 60.27a(g)(2)-(3) of this part that are not otherwise specifically enumerated here.

(1) *Identification of affected EGUs.* Consistent with § 60.25a(a), you must identify the affected EGUs covered by your plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845b. In addition, you must include an inventory of CO_2 emissions from the affected EGUs. You must also identify the subcategory into which you have classified each affected EGU. States must subcategorize affected EGUs into one or more of the following subcategories:

- *(A) Long-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have not adopted enforceable commitments to cease operations by January 1, 2040.
- *(B) Medium-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date after December 31, 2031, and before January 1, 2040, and that are not near-term units.
- *(C) Near-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date after December 31, 2031, and before January 1, 2035, and elected to commit to adopt an annual capacity factor limit of 20 percent.
- *(D) Imminent-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date before January 1, 2032.
- *(E) Base load continental existing oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.
- *(F) Intermediate load continental existing oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.
- *(G) Low load (continental and non-continental) existing oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor less than 8 percent.
- *(H) Intermediate and base load non-continental existing oil-fired steam generating units,* consisting of non-continental oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent.
- *(I) Base load existing natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent
- *(J) Intermediate load existing natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.
- *(K) Low load existing natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor less than 8 percent.
- *(L) Carbon capture and storage ("CCS") existing combustion turbine generating units*, consisting of natural gas fired stationary combustion turbines that will comply with a standard of performance based on carbon capture and storage.
- (M) *Hydrogen co-fired existing combustion turbine generating unit*s, consisting of natural gas fired stationary combustion turbines that will comply with a standard of performance based on co-firing low-GHG hydrogen.

(2) *Standards of Performance.* You must include all standards of performance for each affected EGU according to § 60.5775b. Standards of performance must be established at a level of performance (CO_2 lb/MWh-gross) that does not exceed the level calculated through the use of the methods described in § 60.5775b(c), unless a State establishes a standard of performance pursuant to § 60.5775b(e).

(3) *Requirements for Subcategory Applicability*.

(i) You must include the following enforceable requirements to establish an affected EGU's applicability for each of the following subcategories:

(A) For medium-term existing coal-fired steam generating units, you must include a requirement to permanently cease operations by a date after December 31, 2031, and before January 1, 2040.

(B) For near-term existing coal-fired steam generating units, you must include a requirement to permanently cease operations by a date after December 31, 2031, and before January 1, 2035, and a requirement that annual capacity factor shall be limited to 20 percent.

(C) For imminent-term existing coal-fired steam generating units, you must include a requirement to permanently cease operations by a date before January 1, 2032.

(ii) You must require that the owners or operators of existing steam-generating affected EGUs notify the state and EPA, and post on Carbon Pollution Standards for EGUs Websites, of final subcategory designations and corresponding standards of performance by July 1, 2029.

(iii) You must require that the owners or operators of existing combustion turbine affected EGUs must notify the state and EPA, and post on Carbon Pollution Standards for EGUs Websites, of the final subcategory designations and corresponding standards of performance by July 1, 2031.

(iv) For affected EGUs in the hydrogen co-fired existing combustion turbine subcategory that will comply with their applicable standards of performance by co-firing hydrogen, you must require that they co-fire low-GHG hydrogen.

(4) *Increments of Progress.* You must include legally enforceable increments of progress as required elements for affected EGUs within the following subcategories: long-term existing coal-fired steam generating units (§ 60.5775b(b)(1)); medium-term existing coal-fired steam generating units (§ 60.5775b(b)(2)); CCS subcategory existing combustion turbine generating units (§ 60.5775b(b)(12)); and hydrogen co-fired subcategory existing combustion turbine generating units (§ 60.5775b(b)(13)). State plans must assign calendar-date deadlines to each of the following increments of progress:

(i) Submittal of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration for each affected EGU in the state plan.

(A) For each affected unit within the medium-term existing coal-fired steam generating unit subcategory or hydrogen co-fired existing combustion turbine generating subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks the facility anticipates along the way.

(B) For each affected unit within the long-term existing coal-fired steam generating unit subcategory or CCS existing combustion turbine generating subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or front-end engineering and design (FEED) study.

(ii) Completion of awarding of contracts. The owner or operator of an affected EGU can demonstrate compliance with this increment of progress by submitting sufficient evidence that the appropriate contracts have been awarded.

(A) For each affected unit within the medium-term existing coal-fired steam generating unit subcategory or hydrogen co-fired existing combustion turbine generating subcategory, awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish boiler modifications.

(B) For each affected unit within the long-term existing coal-fired steam generating unit subcategory or CCS existing combustion turbine generating unit subcategory, 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.

(iii) Initiation of on-site construction or installation of emission control equipment or process change.
   (A) For each affected unit within the medium-term existing coal-fired steam generating unit subcategory, initiation of onsite construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.
   (B) For each affected unit within the hydrogen co-fired existing combustion turbine generating subcategory, initiation of onsite construction or installation of any boiler modifications necessary to enable hydrogen co-firing at a level of 30 percent on an annual average basis.
   (C) For each affected unit within the long-term existing coal-fired steam generating unit subcategory or CCS existing combustion turbine generating unit subcategory, initiation of onsite construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(iv) Completion of on-site construction or installation of emission control equipment or process change.
   (A) For each affected unit within the medium-term existing coal-fired steam generating unit subcategory, completion of onsite construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.
   (B) For each affected unit within the hydrogen co-fired existing combustion turbine generating subcategory, completion of onsite construction of any boiler modifications necessary to enable hydrogen co-firing at a level of 30 percent on an annual average basis.
   (C) For each affected unit within the long-term existing coal-fired steam generating unit subcategory or CCS existing combustion turbine generating unit subcategory, completion of onsite construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(v) Commencement of permitting actions related to pipeline construction. The owner or operator of an affected EGU must demonstrate that they have commenced permitting actions by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate each affected unit at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities.
   (A) For affected units within the medium-term existing coal-fired steam generating unit subcategory, this increment of progress applies to each affected EGU that adopts natural gas co-firing to meet the standard of performance and ensures timely completion of any pipeline infrastructure needed to transport natural gas to designated facilities.
   (B) For affected units within the hydrogen co-fired existing combustion turbine generating subcategory, this increment of progress applies to each affected EGU that adopts hydrogen co-firing to meet the standard of performance and ensures timely completion of any pipeline infrastructure needed to transport natural gas to designated facilities.
   (C) For affected units within the long-term existing coal-fired steam generating unit subcategory or CCS existing combustion turbine generating subcategory, this increment of progress applies to each affected EGU that adopts CCS to meet the standard of performance and ensure timely completion of CCS-related pipeline infrastructure.

(vi) For each affected unit within the long-term existing coal-fired steam generating unit subcategory or CCS existing combustion turbine generating subcategory, a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities.

(vii) For each affected unit within the hydrogen co-fired existing combustion turbine generating subcategory, a demonstration that the unit has secured access to hydrogen supplies sufficient to meet anticipated 2032 fuel needs. The demonstration must be consistent with the information provided in the final control plan and the pipeline specification included in the pipeline construction increment of progress.

(viii) Final compliance with the standard of performance as follows:

(A) For each affected unit within the medium-term existing coal-fired steam generating subcategory or long-term existing coal-fired steam generating subcategory, by January 1, 2030.

(B) For each affected unit within the hydrogen co-fired existing combustion turbine generating subcategory, by January 1, 2032.

(C) For each affected unit within the CCS existing combustion turbine generating unit subcategory, January 1, 2035.

Application of Increments of Progress for Certain Units Based on Selected Control Strategy. For any affected unit within (1) the long-term existing coal-fired steam generating unit subcategory or the CCS combustion turbine subcategory that will meet its applicable standard of performance using a control other than carbon capture and storage, (2) the medium-term existing coal-fired steam generating unit subcategory that will meet its applicable standard of performance using a control other than natural gas co-firing, or (3) the hydrogen co-fired combustion turbine subcategory that will meet its applicable standard of performance using a control other than co-firing low-GHG hydrogen, the state plan must include appropriate increments of progress consistent with 40 CFR 60.21a(h) specific to the affected unit's control strategy.

(5) *Milestones for Affected EGUs that Have Elected to Commit to Cease Operations.* State plans must include legally enforceable milestones for affected EGUs within the subcategories of imminent-term existing coal-fired steam generating units (§ 60.5775b(b)(4)), near-term existing coal-fired steam generating units (§ 60.5775b(b)(3)), and medium-term coal-fired steam generating unit (§ 60.5775b(b)(2)) subcategories, as follows:

(i) Five years before the date used to determine the applicable subcategory under these emission guidelines (the date that the affected EGU permanently ceases operations) or 60 days after state plan submission, whichever is later, the owner or operator of an affected EGU must submit an Initial Milestone Report to the applicable State administering authority that includes the following:

(A) A summary of the process steps required for the affected EGU to permanently cease operations by the enforceable date, including the approximate timing and duration of each step.

(B) A list of key milestones, metrics that will be used to assess whether each milestone has been met, and calendar day deadlines for each milestone. These milestones must include at least the following: notice to the official reliability authority (*e.g.*, regional transmission organization, balancing authority, public utility commission, or other applicable authority) of the federally enforceable retirement date; submittal of an official suspension filing (or equivalent filing) made to the affected EGU's reliability authority; and submittal of an official retirement filing (or equivalent filing) with the unit's reliability authority when the affected EGU has permanently ceased operations.

(C) An analysis of how the process steps, milestones, and associated timelines included in the Milestone Report compare to the timelines of similar units within the state that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines.

(D) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority, any integrated resource plan, as well as any filings with the SEC or notices to investors in which the plans for the affected EGU are mentioned.

(ii) For each of the remaining years prior to the date to permanently cease operations used to determine the applicable subcategory, the owner or operator of an affected EGU must submit an annual Milestone Status Report that addresses the following:

(A) Progress toward meeting all milestones and related metrics identified in the Initial Milestone Report; and

(B) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority to demonstrate compliance with or progress toward all milestones.

(iii) No later than six months following the date on which the affected EGU permanently ceased operations, the owner or operator of the affected EGU must submit a Final Milestone Status Report that documents what the unit has done to make the closure permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(iv) The owner or operator of an affected EGU with reporting milestones for enforceable commitments to permanently cease operations is required to post their initial Milestone Report, annual Milestone Status Reports, and final Milestone Status Report, including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the Carbon Pollution Standards for EGUs Website required by subsection (7) of this section within 30 business days of being filed.

(6) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your plan all applicable monitoring, reporting and recordkeeping requirements, including initial and ongoing quality assurance and quality control procedures, for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860b.

(7) *State reporting.* You must include in your plan a description of the process, contents, and schedule for State reporting to the EPA about plan implementation and progress.

(8) *Carbon Pollution Standards for EGUs Websites*. You must require in your plan that owners or operators of affected EGUs establish a publicly accessible "Carbon Pollution Standards for EGUs Website" and that they post relevant documents to this website. State plans must require affected EGUs to post their subcategory designations and compliance schedules as well as any emissions data and other information needed to demonstrate compliance with a standard of performance to this website in a timely manner. State plans must also require affected EGUs with increments of progress to post those increments, the schedule required in the state plan for achieving them, and any documentation or other evidence necessary to demonstrate that they have been achieved to this website within 30 business days. State plans must require affected EGUs to post a report of any deviation from any federally enforceable increment of progress or milestone to this website within 30 business days. In addition, states must establish a website that displays the links to these websites for all affected EGUs in their state plan.

(9) *Meaningful Engagement*. You must conduct meaningful engagement with pertinent stakeholders during development of the state plan. You must demonstrate where and how you considered the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from a designated facility. This demonstration must include:

(i) A list of pertinent stakeholders;

(ii) A summary of the engagement conducted;

(iii) A summary of the stakeholder input provided, including information about the potential pollution impacts and benefits of control.

If a state plan submission does not meet the required elements for notice and opportunity for public participation, including requirements for meaningful engagement, this may be grounds for the EPA to find the submission incomplete or to disapprove the plan.

§ 60.5760b What are the timing requirements for submitting my State plan?

(a) You must submit a State plan with the information required under § 60.5740b by [INSERT DATE TWO YEARS FROM DATE OF PUBLICATION OF FINAL RULE].

(b) You must submit all information required under paragraph (a) of this section according to the electronic reporting requirements in § 60.5875b.

§ 60.5775b What standards of performance must I include in my plan?

(a) Standard(s) of performance for affected EGUs included under your plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The plan submittal must include the methods by which each standard of performance meets each of the following requirements:

(1) An affected EGU's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.
(2) An affected EGU'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 emission standard.
(3) An affected EGU's standard of performance is non-duplicative with respect to a State plan if it is not already incorporated as an emission standard in the State plan.
(4) An affected EGU's standard of performance is permanent if the emission standard must be met continuously, unless it is replaced by another emission standard in an approved plan revision, or the State demonstrates in an approvable plan revision.
(5) An affected EGU's standard of performance is enforceable if:
    (i) A technically accurate limitation or requirement, and the time period for the limitation or requirement, are specified;
    (ii) Compliance requirements are clearly defined;
    (iii) The affected EGUs are responsible for compliance and liable for violations identified;
    (iv) Each compliance activity or measure is enforceable as a practical matter, as defined by 40 CFR 49.167; and
    (v) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its emissions) and secure appropriate corrective actions: in the case of the Administrator, pursuant to CAA sections 113(a)-(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.

(c) Methodology for establishing presumptively approvable standards of performance, or presumptively approvable standards of performance, for affected EGUs in each subcategory.

(1) Long-term existing coal-fired steam generating units
    (i) BSER is CCS with 90 percent capture of CO_2.
    (ii) Degree of emission limitation is 88.4 percent reduction in emission rate (lb CO_2/MWh-gross)

(iii) Presumptively approvable standard of performance is an emission rate limit defined by an 88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.

(2) Medium-term existing coal-fired steam generating units
  (i) BSER is natural gas co-firing at 40 percent of the heat input to the unit
  (ii) Degree of emission limitation is a 16 percent reduction in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an emission rate limit defined by a 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline
  (iv) For units in this subcategory that have an amount of co-firing that is reflected in the baseline operation, states must account for such preexisting co-firing in adjusting the degree of emission limitation (e.g., for an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to 30 percent to reflect the preexisting level of natural gas co-firing).

(3) Near-term existing coal-fired steam generating units
  (i) BSER is routine methods of operation
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an emission rate limit (lb CO_2/MWh-gross) not to exceed the unit-specific baseline

(4) Imminent-term existing coal-fired steam generating units
  (i) BSER is routine methods of operation
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an emission rate limit (lb CO_2/MWh-gross) not to exceed the unit-specific baseline

(5) Base load continental existing oil-fired steam generating units
  (i) BSER is routine methods of operation and maintenance
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,300 lb CO_2/MWh-gross

(6) Intermediate load continental existing oil-fired steam generating units
  (i) BSER is routine methods of operation and maintenance
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,500 lb CO_2/MWh-gross

(7) Low load (continental and non-continental) existing oil-fired steam generating units do not have requirements.

(8) Intermediate and base load non-continental existing oil-fired steam generating units
  (i) BSER is routine methods of operation and maintenance
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)
  (iii) Presumptively approvable standard of performance is an emission rate limit (lb CO_2/MWh-gross) defined by the unit-specific baseline

(9) Base load existing natural gas-fired steam generating units
  (i) BSER is routine methods of operation and maintenance
  (ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross)

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,300 lb CO_2/MWh-gross

(10) Intermediate load existing natural gas-fired steam generating units

(i) BSER is routine methods of operation and maintenance

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO2/MWh-gross)

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,500 lb CO_2/MWh-gross

(11) Low load existing natural gas-fired steam generating units do not have requirements.

(12)CCS existing stationary combustion turbines

(i) BSER is CCS with 90 percent capture of CO_2

(ii) Degree of emission limitation is 89 percent reduction in emission rate (lb CO_2/MWh-gross)

(iii) Presumptively approvable standard of performance is an emission rate limit defined by an 89 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline

(13)Hydrogen co-fired existing stationary combustion turbines

(i) BSER is

i. hydrogen co-firing at a level of 30 percent by volume starting January 1, 2032

ii. hydrogen co-firing at a level of 96 percent by volume starting January 1, 2038

(ii) Degree of emission limitation is

i. 12 percent reduction in emission rate (lb CO_2/MWh-gross) starting January 1, 2032

ii. 88.4 percent reduction in emission rate (lb CO_2/MWh-gross) starting January 1, 2038

(iii) Presumptively approvable standard of performance is

i. an emission rate limit defined by a 12 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline starting January 1, 2032

ii. an emission rate limit defined by an 88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline starting January 1, 2038

(d) Methodology for establishing the unit-specific baseline of emission performance.

(1) A state shall use the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from the most representative continuous 8-quarter period from 40 CFR part 75 reporting within the 5 years immediately prior to [INSERT DATE OF PUBLICATION OF FINAL RULE].

(2) For the continuous 8 quarters of data, a state shall divide the total CO_2 emissions (in the form of pounds) over that continuous time period by the total gross electricity generation (in the form of MWh) over that same time period to calculate baseline CO_2 emission performance in lb CO_2 per MWh.

(e) *Remaining Useful Life and Other Factors (RULOF).* A state's consideration of RULOF to apply a less stringent standard to a particular EGU must meet the requirements of 40 CFR 60.24a, except as specifically superseded or amended as follows:

(1) Demonstrations that an affected EGU cannot reasonably apply the best system of emission reduction to achieve the degree of emission limitation determined by the EPA based on unreasonable cost of control resulting from plant age, location, or basic process design must consider cost as dollars/ton CO_2 reduced and dollars/MWh electricity generated.

(2) States wishing to rely on an affected EGU's anticipated change in operating conditions as the basis for using a different methodology to set an emissions baseline, when that different methodology results in a less stringent standard of performance, must use the RULOF mechanism in 40 CFR 60.24a.

(3) States determining a source-specific BSER based on RULOF for an affected EGU must reasonably analyze the following control options:

(i) For an affected EGU in the long-term existing coal-fired steam generating unit subcategory: CCS to achieve a less stringent degree of emission limitation and natural gas co-firing at different levels, starting at 40 percent.

(ii) For an affected EGU in the medium-term existing coal-fired steam generating unit subcategory: natural gas co-firing at different levels.

(iii) For an affected EGU in the CCS existing combustion turbine subcategory: first demonstrate that the affected EGU cannot comply with the presumptive standard of performance for the hydrogen co-fired combustion turbine subcategory. If applicable, then analyze CCS to achieve a less stringent degree of emission limitation, comprehensive turbine upgrades, and smaller efficiency improvements.

(iv) For an affected EGU in the hydrogen co-fired existing combustion turbine subcategory: first demonstrate that the affected EGU cannot comply with the presumptive standard of performance for the CCS existing combustion turbine subcategory. If applicable, then analyze lower percentages of hydrogen co-firing, comprehensive turbine upgrades, and smaller scale efficiency improvements.

(4) These emission guidelines do not provide an imminent or outermost retirement date for consideration of an affected EGU's remaining useful life.

(5) Standards of performance applied pursuant to a RULOF determination must be in the form of lb CO_2/MWh electricity generated.

(f) State plans must demonstrate that they achieve equivalent stringency as would be achieved if each affected EGU was achieving the applicable presumptive standard of performance, accounting for any application of less-stringent standards of performance based on remaining useful life and other factors.

(g) Your state plan may provide for affected EGUs to comply with their standards of performance in the aggregate, for example through emissions trading or averaging, subject to the requirement in subsection (f) of this section.

§ 60.5785b What is the procedure for revising my plan?

EPA-approved State 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 all applicable requirements of subpart Ba of this part. If one (or more) of plan elements in § 60.5740b require revision, the state must submit a plan revision pursuant to 40 CFR 60.28a.

Applicability of Plans to Affected EGUs

§ 60.5840b 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, affected EGU 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 State plan to implement and enforce the emission guidelines contained in this subpart by [INSERT DATE TWO YEARS FROM DATE OF PUBLICATION OF FINAL RULE], or the EPA disapproves State plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5720b, applicable to each affected EGU within the State that commenced construction on or before January 8, 2014.

§ 60.5845b What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your plan are:

(1) Any affected EGUs that were in operation or had commenced construction on or before January 8, 2014;

(2) Natural gas fired stationary combustion turbines that commenced construction or reconstruction before [INSERT DATE OF PUBLICATION IN FEDERAL REGISTER].

(3) Coal-fired steam generating units that commenced a modification before [INSERT DATE OF PUBLICATION IN FEDERAL REGISTER].

(b) An affected EGU is a steam generating unit or natural gas fired stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) through (2) of this section, as applicable, except as provided in § 60.5850b.

(1) Serves a generator capable of selling greater than 25 MW to a utility power distribution system; and

(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).

§ 60.5850b What EGUs are excluded from being affected EGUs?

EGUs that are excluded from being affected EGUs are:

(a) Natural gas fired stationary combustion turbines with an electric generating capacity equal to or less than 300 MW or with an electric generating capacity of more than 300 MW and that operate at an annual capacity factor equal to or less than 50 percent.

(b) New or reconstructed EGUs that are subject to 40 CFR part 60 subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date;

(c) Modified EGUs that are subject to 40 CFR part 60 subpart TTTTa of this part as a result of commencing modification after the TTTTa applicability date;

(d) 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 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output or 219,000 MWh;

(e) Non-fossil fuel units (*i.e.,* units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(f) CHP units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater;

(g) 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;

(h) Municipal waste combustor units subject to 40 CFR part 60, subpart Eb;

(i) Commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or

(j) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

§ 60.5860b What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my plan for affected EGUs?

(a) Your plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (8) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet emission standards must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) For rate-based emission standards, only "valid operating hours,", *i.e.,* full or partial unit (or stack) operating hours for which:

(i) "Valid data" (as defined in § 60.5880b) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; data obtained from flow monitoring bias adjustments are not considered to be valid data; and data provided or not provided from monitoring instruments that have not met the required frequency for relative accuracy audit testing are not considered to be valid data and

(ii) The corresponding hourly gross energy output value is also valid data (**Note:** For operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based emission standards, the owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.,* carbon capture and storage (CCS)), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (*e.g.,* from sorbent injection), this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If CO_2 concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F-11 in appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values from paragraph (a)(3)(ii) of this section.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and appendices A and B to part 75 of this chapter.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G-4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(5) For rate-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis gross electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with gross electric output to determine gross energy output. The owner or operator must use the following procedures to calculate gross energy output, as appropriate for the type of affected EGU(s).

(i) Determine P_{net} the hourly net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, *i.e.,* full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate P_{net} for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{\text{TDF}} + [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,]$$

WHERE:
P_{NET} = NET ENERGY OUTPUT OF YOUR AFFECTED EGU FOR EACH VALID OPERATING HOUR (AS DEFINED IN 60.5860b(a)(2)) IN MWh.
$(PE)_{ST}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF STEAM TURBINES IN MWh.
$(PE)_{CT}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF STATIONARY COMBUSTION TURBINE(S) IN MWh.
$(PE)_{IE}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF YOUR AFFECTED EGU'S INTEGRATED EQUIPMENT THAT PROVIDES ELECTRICITY OR MECHANICAL ENERGY TO THE AFFECTED EGU OR AUXILIARY EQUIPMENT IN MWh.
$(PE)_{A}$ = ELECTRIC ENERGY USED FOR ANY AUXILIARY LOADS IN MWh.
$(PT)_{PS}$ = USEFUL THERMAL OUTPUT OF STEAM (MEASURED RELATIVE TO SATP CONDITIONS, AS APPLICABLE) THAT IS USED FOR APPLICATIONS THAT DO NOT GENERATE ADDITIONAL ELECTRICITY, PRODUCE MECHANICAL ENERGY OUTPUT, OR ENHANCE THE PERFORMANCE OF THE AFFECTED EGU. THIS IS CALCULATED USING THE EQUATION SPECIFIED IN PARAGRAPH (a)(5)(V) OF THIS SECTION IN MWhH.
$(PT)_{HR}$ = NON-STEAM USEFUL THERMAL OUTPUT (MEASURED RELATIVE TO SATP CONDITIONS, AS APPLICABLE) FROM HEAT RECOVERY THAT IS USED FOR APPLICATIONS OTHER THAN STEAM GENERATION OR PERFORMANCE ENHANCEMENT OF THE AFFECTED EGU IN MWh.
$(PT)_{IE}$ = USEFUL THERMAL OUTPUT (RELATIVE TO SATP CONDITIONS, AS APPLICABLE) FROM ANY INTEGRATED EQUIPMENT IS USED FOR APPLICATIONS THAT DO NOT GENERATE ADDITIONAL STEAM, ELECTRICITY, PRODUCE MECHANICAL ENERGY OUTPUT, OR ENHANCE THE PERFORMANCE OF THE AFFECTED EGU IN MWh.

TDF = ELECTRIC TRANSMISSION AND DISTRIBUTION FACTOR OF 0.95 FOR A COMBINED HEAT AND POWER AFFECTED EGU WHERE AT LEAST ON AN ANNUAL BASIS 20.0 PERCENT OF THE TOTAL GROSS OR NET ENERGY OUTPUT CONSISTS OF ELECTRIC OR DIRECT MECHANICAL OUTPUT AND 20.0 PERCENT OF THE TOTAL NET ENERGY OUTPUT CONSIST OF USEFUL THERMAL OUTPUT ON A 12-OPERATING MONTH ROLLING AVERAGE BASIS, OR 1.0 FOR ALL OTHER AFFECTED EGUS.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

WHERE:
Q_M = MEASURED STEAM FLOW IN KILOGRAMS (KG) (OR POUNDS (LBS)) FOR THE OPERATING HOUR.
H = ENTHALPY OF THE STEAM AT MEASURED TEMPERATURE AND PRESSURE (RELATIVE TO SATP CONDITIONS OR THE ENERGY IN THE CONDENSATE RETURN LINE, AS APPLICABLE) IN JOULES PER KILOGRAM (J/KG) (OR BTU/LB).
CF = CONVERSION FACTOR OF 3.6×10^9 J/MWH OR 3.413×10^6 BTU/MWh.

(vi) For rate-based standards, sum all of the values of P_{net} for the valid operating hours (as defined in paragraph (a)(2) of this section). Then, divide the total CO_2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values for the valid operating hours to determine the CO_2 emissions rate (lb/net MWh).

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emissions standard, the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected EGUs and the operating time must be expressed as “stack operating hours” (as defined in § 72.2 of this chapter).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the “stack operating time” (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(8) Consistent with § 60.5775b or § 60.5780b, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) [Reserved]

(c) Your plan must require the owner or operator of each affected EGU covered by your plan to maintain the records, for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's emission standard under § 60.5775b.

(ii) Copies of all reports submitted to the State under paragraph (c) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(d) Your plan must require the owner or operator of an affected EGU covered by your plan to include in a report submitted to you the information in paragraphs (d)(1) through (4) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO_2 emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour;

(ii) The net electric output and the net energy output (P_{net}) values for each valid operating hour;

(iii) The calculated CO_2 mass emissions (lb) for each valid operating hour;

(iv) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours; and

(v) The calculated CO_2 mass emission rate (lbs/net MWh).

(3) [Reserved]

(4) For each affected EGU the report must also include the applicable emission standard and demonstration that it met the emission standard. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate in units of the emission standard.

(e) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a plan that are required under § 60.5740b if applicable.

(f) If an affected EGU captures CO_2 to meet the applicable emission limit, the owner or operator must report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98 subpart RR or subpart VV, if injection occurs on-site;

(2) Assure that the captured CO_2 is transferred to a facility that reports in accordance with the requirements of 40 CFR part 98 subpart RR or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

Recordkeeping and Reporting Requirements

§ 60.5865b 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.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that is used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860b.

(c) If your State has a requirement for all hourly CO_2 emissions and net generation information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in part 75 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 10 years from the date the record is used to determine compliance with an emissions standard or plan requirement. Each record must be in a form suitable and readily available for expeditious review.

§ 60.5875b 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.

(b) All 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 must be reported through EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States that claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539-01, 4930 Old Page Rd., Durham, NC 27703.

(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 [INSERT DATE TWO YEARS FROM DATE OF PUBLICATION OF FINAL RULE] deadline for plan submittal so that the official will have the ability to submit the initial or final plan submittal 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 SPeCS. 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. Following initial plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable plan components, including State plan backstop measures. 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.

(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.

Definitions

§ 60.5880b 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 A, Ba, TTTT, and TTTTa, of this part.

Affected electric generating unit or *Affected EGU* means a steam generating unit or stationary combustion turbine that meets the relevant applicability conditions in section § 60.5845b.

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. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal-fired steam generating unit means an electric utility steam generating unit or IGCC unit that meets the definition of "fossil fuel-fired" and that burns coal for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, or that retains the capability to fire coal after December 31, 2029.

Combined cycle unit means 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.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

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.

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

Low-GHG Hydrogen means hydrogen (or a hydrogen derived fuel such as ammonia) produced through a process that results in a well-to-gate GHG emission rate of less than 0.45 kilograms of CO2 equivalent per kilogram of hydrogen produced (kg CO_2e/kg H_2), determined using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation model (GREET model).

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

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. 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 CO_2 content or heating value.

Natural gas-fired steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired or oil-fired steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal after December 31, 2029.

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 standard ambient temperature and pressure 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 affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.,* steam delivered to an industrial process for a heating application).

Oil-fired steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that is not a coal-fired steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, and that no longer retains the capability to fire coal after December 31, 2029.

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 emission 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. A stationary combustion turbine that burns any solid fuel directly 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.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

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 affected EGU, to directly enhance the performance of the affected EGU (*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 affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.4, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.