

Title 40 - Protection of Environment

CHAPTER I - ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

APPLICABILITY

§60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences a modification after **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after **[INSERT DATE OF PUBLICATION IN FEDERAL REGISTER]**. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any coal-fired steam generating unit or IGCC that commences a modification after **[INSERT DATE OF PUBLICATION IN FEDERAL REGISTER]** that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commenced construction or reconstruction after **[INSERT DATE OF PUBLICATION IN FEDERAL REGISTER]** that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (9) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-

electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition 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.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, 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.

(5) [RESERVED]

(6) [RESERVED]

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO₂ emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO₂ emissions standards.

(8) [RESERVED]

(9) Your EGU derives 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.

EMISSION STANDARDS

§60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, 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 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, 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 40 CFR 71.2.

§60.5520a What CO₂ emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO₂ in excess of the applicable CO₂ emission standard specified in Table 1 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term “gross or net energy output” is used, the term that applies to you is “gross energy output.”

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term “gross or net energy output” is used, the term that applies to you is “net energy output.” Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in Table 1 of this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in Table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.*, uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO₂/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, low-GHG hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb

CO₂/MMBtu) or less (*e.g.*, non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under §60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO₂ emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See Table 1 of this subpart for the applicable CO₂ emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section. Any combustion turbine burning hydrogen fuel for compliance purposes must only combust low-GHG hydrogen.

(1) For each affected EGU subject to a CO₂ emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO₂ emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with §60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO₂ emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIP_{ng}) and the total heat input from all other fuels combined (HTIP_o) using one of the methods under §60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

$$CO_2 \text{ emissions standard} = \frac{(50 \times HTIP_{ng}) + (69 \times HTIP_o)}{HTIP_{ng} + HTIP_o}$$

Where:

CO₂ emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

HTIP_{ng} = the heat input in GJ (or MMBtu) from natural gas.

HTIP_o = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO₂/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO₂/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the

following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines

$$CO_2 \text{ emissions standard} = \left[BLER_L + \frac{BLER_S - BLER_L}{BLR_L - BLR_S} * (BLR_L - BLR_A) \right] * \left[\frac{HIER_A}{HIER_{NG}} \right]$$

Where:

CO₂ emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

BLER_L = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 350 kg CO₂/MWh-gross (770 lb CO₂/MWh-gross) or 360 kg CO₂/MWh-net (790 lb CO₂/MWh-net); 40 kg CO₂/MWh-gross (90 lb CO₂/MWh-gross) or 42 kg CO₂/MWh-net (97 lb CO₂/MWh-net); or 310 kg CO₂/MWh-gross (680 lb CO₂/MWh-gross) or 320 kg CO₂/MWh-net (700 lb CO₂/MWh-net) as applicable

BLER_S = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h) (410 kg CO₂/MWh-gross (900 lb CO₂/MWh-gross or 420 kg CO₂/MWh-net (920 lb CO₂/MWh-net))

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

HIER_A = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO₂/MMBtu). Not to exceed 69 kg/GJ (160 lb CO₂/MMBtu)

HIER_{NG} = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO₂/MMBtu)

(ii) For intermediate load combustion turbines:

$$CO_2 \text{ emissions standard} = ILER * \left[\frac{HIER_A}{HIER_{NG}} \right]$$

Where:

CO₂ emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO₂/MWh-gross) or 530 kg CO₂/MWh-net (1,160 lb CO₂/MWh-net) or 450 kg/MWh-gross (1,100 lb CO₂/MWh-gross) or 460 kg CO₂/MWh-net (1,110 lb CO₂/MWh-net) as applicable

HIER_A = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO₂/MMBtu). Not to exceed 69 kg/GJ (160 lb CO₂/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO₂/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.*, no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in §72.2 of this chapter), the first month of the initial compliance period shall be the first operating month (as defined in §60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) [RESERVED]

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in §60.5580a) after the calendar month in which emissions reporting is required to begin under §60.5555a(c)(3)(iii).

MONITORING AND COMPLIANCE DETERMINATION PROCEDURES

§60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under §60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under §60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO₂ emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO₂ mass emission rate (tons/h), in accordance with the applicable provisions in §75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see §60.5555a(c)).

(b) You must determine the hourly CO₂ mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected coal-fired EGU or for an IGCC unit you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO₂ continuous emission monitoring system (CEMS) to directly measure and record hourly average CO₂ concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to §75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO₂ concentration, provided that your EGU does not use carbon separation (*e.g.*, carbon capture and storage), you may use data from a certified oxygen (O₂) monitor to calculate hourly average CO₂ concentrations, in accordance with §75.10(a)(3)(iii) of this chapter. If you measure CO₂ concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to §75.11(b) of this chapter. Alternatively, you 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.

(2) For each continuous monitoring system that you use to determine the CO₂ mass emissions, you 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.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO₂ mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO₂ mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for “valid operating hours”, as defined in §60.5540(a)(1).

(i) Begin with the hourly CO₂ mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to part 75 of this chapter (if CO₂ 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 CO₂ concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO₂ 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 CO₂.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO₂ to kg. Round off to the nearest kg.

(iv) The hourly CO₂ tons/h values and EGU (or stack) operating times used to calculate CO₂ mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO₂ mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO₂ mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in §60.5520a(d)(2), you may determine CO₂ mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to part 75 of this chapter to calculate the hourly CO₂ mass emission rate (tons/h). You 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 you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(3) For each “valid operating hour” (as defined in §60.5540(a)(1), multiply the hourly tons/h CO₂ mass emission rate from paragraph (c)(2) 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 CO₂. Then, multiply the result by 909.1 to convert from tons of CO₂ to kg. Round off to the nearest two significant figures.

(4) The hourly CO₂ tons/h values and EGU (or stack) operating times used to calculate CO₂ mass emissions are required to be recorded under §75.57(e) of this chapter and must be reported electronically under §75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO₂ mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO₂ emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under §60.107a(d) and convert this heat input to CO₂ emissions using Equation G-4 in appendix G to part 75 of this chapter.

(ii) You may use the procedure for determining CO₂ emissions during the compliance period based on the use of the Tier 3 methodology under §98.33(a)(3) of this chapter.

(d) Consistent with §60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.*, lb of CO₂ per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see §60.17). For a combined heat and power (CHP) EGU, as defined in §60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.*, hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will

need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (e.g., lb CO₂/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under §60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to part 75 of this chapter;

(ii) The procedures for monitoring heat input under §60.107a(d);

(iii) If you monitor CO₂ emissions in accordance with the Tier 3 methodology under §98.33(a)(3) of this chapter, you may convert your CO₂ emissions to heat input using the appropriate emission factor in table C-1 of part 98 of this chapter. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (F_c) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO₂ emissions to heat input using Equation G-4 in appendix G to part 75 of this chapter.

(e) Consistent with §60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross energy output. The Administrator may approve such alternate methods for apportioning the gross energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO₂ mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in Table 1 of this subpart, you may monitor the hourly CO₂ mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as “stack operating hours” (as defined in §72.2 of this chapter). If you attain compliance with the applicable emissions standard in §60.5520a at the common stack, each affected EGU sharing the stack is in compliance.

(2) As an alternative, or if the EGUs are subject to different emission standards in Table 1 of this subpart, you must either (1) monitor each EGU separately by measuring the hourly CO₂ mass emissions prior to mixing in the common stack or (2) apportion the CO₂ mass emissions based on the unit’s load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO₂ emissions. The

Administrator may approve such alternate methods for apportioning the CO₂ emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) 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), you must monitor the hourly CO₂ mass emissions and the “stack operating time” (as defined in §72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO₂ mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§60.5540a How do I demonstrate compliance with my CO₂ emissions standard and determine excess emissions?

(a) In accordance with §60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in §60.5520a(d)(2), you must demonstrate compliance with the applicable CO₂ emission standard in Table 1 of this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (7) of this section to calculate the CO₂ mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.*, either kg/MWh or kg/GJ). You must use the hourly CO₂ mass emissions calculated under §60.5535a(b) or (c), as applicable, and either the generating load data from §60.5535a(d)(1) for output-based calculations or the heat input data from §60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO₂ prior to combustion (*e.g.*, blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO₂ present in the fuel prior to combustion and exclude this portion of the CO₂ mass emissions from compliance determinations.

(1) Each compliance period shall include only “valid operating hours” in the compliance period, *i.e.*, operating hours for which:

- (i) “Valid data” (as defined in §60.5580a) are obtained for all of the parameters used to determine the hourly CO₂ mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and
- (ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

- (i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO₂ mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;
- (ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO₂ mass emissions or, if applicable, to determine the hourly heat input;

(iii) The total gross or net energy output ($P_{\text{gross/net}}$) or, if applicable, the total heat input is unavailable; or

(iv) Grace periods for delaying RATAs for any of the parameters used to determine the hourly carbon dioxide mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO₂ mass emissions by summing the valid hourly CO₂ mass emissions values from §60.5535a for all of the valid operating hours in the compliance period.

(5) *Sources subject to output based standards.* For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO₂ mass emissions, you must determine $P_{\text{gross/net}}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO₂ mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO₂ mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.*, zero) gross electrical, mechanical, or useful thermal output, you must use that hour 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.

(i) Calculate $P_{\text{gross/net}}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with §60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{\text{gross/net}} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_A}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad (\text{Eq. 2})$$

Where:

$P_{\text{gross/net}}$ = In accordance with §60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in §60.5540a(a)(1)) 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.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

(Pe)_A = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

(Pt)_{PS} = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (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)(ii) of this section in MWh.

(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 useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

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

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad (\text{Eq. 3})$$

Where:

Q_m = Measured useful thermal output flow in kg ((lb) for the operating hour.

H = Enthalpy of the useful thermal output 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.

(6) *Calculation of annual basis for standard.* Sources complying with energy output-based standards must calculate the basis (*i.e.*, denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with §60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under §60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO₂ mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO₂ mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO₂ mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO₂ mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(b) In accordance with §60.5520a, to demonstrate compliance with the applicable CO₂ emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO₂ mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO₂ emissions standard in Table 1 of this part, or the emissions standard calculated in accordance with §60.5525a(a)(2).

NOTIFICATION, REPORTS, AND RECORDS

§60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 of this subpart).

(b) You must prepare and submit notifications specified in §75.61 of this chapter, as applicable, to your affected EGUs.

(c) Owners and operators of combustion turbines that commence operation prior to January 1, 2031, must submit a notification by January 1, 2031 whether you elect to demonstrate early GHG reductions and affected EGU will comply with the 2032 and 2038 emission standards or your affected EGU will comply with the 2035 emissions standard.

(d) Owners and operators of combustion turbines that commence operation between January 1, 2031 and December 31, 2038, must submit a notification upon startup whether you elect to demonstrate early GHG reductions and affected EGU will comply with the 2032 and 2038 emission standards of performance or your affected EGU will comply with the 2035 emissions standard.

§60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by §60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO₂ mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO₂ mass emissions rate for the compliance period according to the procedures in §60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO₂ mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO₂ emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (*i.e.*, the total number of valid operating hours (as defined in §60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with §60.5520a, the CO₂ emissions standard (as identified in Table of this part) with which your affected EGU must comply; and

(vi) Consistent with §60.5520a, an indication whether or not the hourly gross or net energy output ($P_{\text{gross/net}}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with §60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this

chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with §75.64(a) of this chapter, *i.e.*, beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in §75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in §72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under §75.64(a) of this chapter, if that date occurs on or after **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with §75.4(j) of this chapter, §75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO₂ mass emission rates are calculated using maximum potential values are not “valid operating hours” (as defined in §60.5540(a)(1)), and shall not be used in the compliance determinations under §60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under §72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under §72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under §72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO₂ to meet the applicable emission limit, you 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂, and permanence of the CO₂ 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 CO₂ 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 CO₂ 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.

§60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in §60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under §75.53(g) and (h) of this chapter;

(ii) Operating parameter records under §75.57(b)(1) through (4) of this chapter;

(iii) The records under §75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under §75.57(c)(3) of this chapter for continuous moisture monitoring systems;

- (v) The records under §75.57(e)(1) of this chapter, except for paragraph (e)(1)(x), for CO₂ concentration monitoring systems or O₂ monitors used to calculate CO₂ concentration;
 - (vi) The records under §75.58(c)(1) of this chapter, specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;
 - (vii) The records under §75.58(c)(4) of this chapter, specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;
 - (viii) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (a)(1) through (12) and (15), for CEMS;
 - (ix) The quality-assurance records under §75.59(a) of this chapter, specifically paragraphs (b)(1) through (4), for fuel flow meters; and
 - (x) Records of data acquisition and handling system (DAHS) verification under §75.59(e) of this chapter.
- (c) You must keep records of the calculations you performed to determine the hourly and total CO₂ mass emissions (tons) for:
- (1) Each operating month (for all affected EGUs); and
 - (2) Each compliance period, including, each 12-operating-month compliance period.
- (d) Consistent with §60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.
- (e) You must keep records of the calculations you performed to determine the percentage of valid CO₂ mass emission rates in each compliance period.
- (f) You must keep records of the calculations you performed to assess compliance with each applicable CO₂ mass emissions standard in Table 1 or 2 of this subpart.
- (g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).
- (h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

§60.5565a In what form and how long must I keep my records?

- (a) Your records must be in a form suitable and readily available for expeditious review.
- (b) You must maintain each record for 5 years after the date of conclusion of each compliance period.
- (c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

OTHER REQUIREMENTS AND INFORMATION

§60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

- (1) Approval of alternatives to the emission standards.
- (2) Approval of major alternatives to test methods.
- (3) Approval of major alternatives to monitoring.
- (4) Approval of major alternatives to recordkeeping and reporting.
- (5) Performance test and data reduction waivers under §60.8(b).

§60.5580a 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 subpart A (general provisions of this part).

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. Actual and potential heat input derived from non-combustion sources (e.g., solar thermal) are not included when calculating the annual capacity factor.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (e.g., solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388-99 (Reapproved 2004)^{e1} (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

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 (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit*, (also known as “cogeneration”) means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.*, electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.*, CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17), ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see §60.17), or an alternative approved by the Administrator.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D396-98 (incorporated by reference, see §60.17); diesel fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D975-08a (incorporated by reference, see §60.17); kerosene, as defined by ASTM International in ASTM D3699 (incorporated by reference, see §60.17); biodiesel as defined by ASTM International in ASTM D6751 (incorporated by reference, see §60.17); or biodiesel blends as defined by ASTM International in ASTM D7467 (incorporated by reference, see §60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.*, meets the applicability criteria)

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

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

- (1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.
- (2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;
- (3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not

applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU 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 the affected EGU 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 EGU during operation.

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

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

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 CO₂e/kg H₂), 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 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.

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 CO₂ content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (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-electric sales means:

- (1) The gross electric sales to the utility power distribution system minus purchased power; or
- (2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on an annual basis, the gross electric sales to the utility

power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales that result from a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities where 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.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (e.g., CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

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.

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 EGU(s) or auxiliary equipment.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

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 2.1.5, 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 to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO₂ emissions rate is higher than the applicable emissions standard located in Table 1 of this subpart.

Table 1 of Subpart TTTTa of Part 60—CO₂ Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After [INSERT DATE OF PUBLICATION] (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO ₂ Emission standard
<p>Newly constructed or reconstructed stationary combustion turbine that:</p> <ul style="list-style-type: none"> Supplies more than its design efficiency times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis The owner or operator has submitted notification that the combustion turbine shall comply with the 2035 standard of performance 	<p>For 12-operating month averages beginning before January 2035, 350 to 540 kg CO₂/MWh (770 to 1,200 lb CO₂/MWh) of gross energy output; or 360 to 550 kg CO₂/MWh (790 to 1,220 lb CO₂/MWh) of net energy output as determined by the procedures in §60.5525.</p> <p>For 12-operating month averages beginning after December 2034, 40 to 60 kg CO₂/MWh (90 to 130 lb CO₂/MWh) of gross energy output; or 42 to 64 kg CO₂/MWh (97 to 139 lb CO₂/MWh) of net energy output as determined by the procedures in §60.5525.</p>
<p>Newly constructed or reconstructed stationary combustion turbine that:</p> <ul style="list-style-type: none"> Supplies more than its design efficiency times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis The owner or operator has submitted notification that the combustion turbine shall comply with the 2032 and 2038 standards of performance 	<p>For 12-operating month averages beginning before January 2032, 350 to 540 kg CO₂/MWh (770 to 1,200 lb CO₂/MWh) of gross energy output; or 360 to 550 kg CO₂/MWh (790 to 1,220 lb CO₂/MWh) of net energy output as determined by the procedures in §60.5525.</p> <p>For 12-operating month averages beginning after December 2031 and before January 2038, 310 to 480 kg CO₂/MWh (680 to 1,100 lb CO₂/MWh) of gross energy output; or 320 to 480 kg CO₂/MWh (700 to 1,070 lb CO₂/MWh) of net energy output as determined by the procedures in §60.5525.</p> <p>For 12-operating month averages beginning after December 2037, 40 to 60 kg CO₂/MWh (90 to 130 lb CO₂/MWh) of gross energy output; or 42 to 64 kg CO₂/MWh (97 to 139 lb CO₂/MWh) of net energy output as determined by the procedures in §60.5525.</p>
<p>Newly constructed or reconstructed stationary combustion turbine that supplies greater than 20% of its potential electric output and its design efficiency times its potential electric output or less as net-electric sales on both a 12-operating month and a 3-year rolling average basis</p>	<p>For 12-operating month averages beginning before January 2032, 520 to 700 kg CO₂/MWh (1,150 to 1,530 lb CO₂/MWh) of gross energy output; or 530 to 690 kg CO₂/MWh (1,160 to 1,550 lb CO₂/MWh) of net energy output as determined by the procedures in §60.5525.</p>

	For 12-operating month averages beginning after December 2031, 450 to 590 kg CO ₂ /MWh (1,000 to 1,290 lb CO ₂ /MWh) of gross energy output; or 460 to 600 kg CO ₂ /MWh (1,010 to 1,300 lb CO ₂ /MWh) of net energy output as determined by the procedures in §60.5525.
Newly constructed or reconstructed stationary combustion turbine that supplies 20% or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis	Between 50 to 69 kg CO ₂ /GJ (120 to 160 lb CO ₂ /MMBtu) of heat input as determined by the procedures in §60.5525.

Table 2 of Subpart TTTTa of Part 60—CO₂ Emission Standards for Affected Steam Generating Units or IGCC That Commenced Modification After [INSERT DATE OF PUBLICATION IN FEDERAL REGISTER]

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO ₂ Emission standard
Modified steam generating unit	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO ₂ emission rate (from 2002 to the date of the modification)

Table 3 to Subpart TTTTa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§60.1	Applicability	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5580a.
§60.3	Units and Abbreviations	Yes	

§60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in §60.7(a)(1) and (3) and to keep records of malfunctions in §60.7(b), if applicable.
§60.8(a)	Performance tests	No	
§60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods
§60.8(c) – (f)	Conducting performance tests	No	
§60.9	Availability of Information	Yes	
§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	
§60.12	Circumvention	Yes	
§60.13 (a) – (h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary	

		combustion turbines)	
§60.15	Reconstruction	Yes	
§60.16	Priority list	No	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	Does not apply to notifications under §75.61 or to information reported through ECMPS.