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Part III

Environmental Protection Agency

40 CFR Part 60
Standards of Performance for Stationary Gas Turbines; Standards of Performance for Stationary Combustion Turbines; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2004–0490; FRL–9695–6]

RIN 2060–AQ29

Standards of Performance for Stationary Gas Turbines; Standards of Performance for Stationary Combustion Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The EPA is proposing to amend the new source performance standards (NSPS) for stationary gas turbines and stationary combustion turbines. These amendments are primarily in response to issues raised by the regulated community. On July 6, 2006, the EPA promulgated amendments to the new source performance standards for stationary combustion turbines. On September 5, 2006, the Utility Air Regulatory Group filed a petition for reconsideration of certain aspects of the promulgated standards. The EPA is proposing to amend specific provisions in the NSPS to resolve issues and questions raised by the petition for reconsideration, and to address other technical and editorial issues. In addition, this proposed rule would amend the location and wording of existing paragraphs for clarity. The proposed amendments would increase the environmental benefits of the existing requirements because the emission standards would apply at all times. The proposed amendments would also promote efficiency by recognizing the environmental benefit of combined heat and power and the beneficial use of low energy content gases.

DATES: Comments must be received on or before October 29, 2012.

Public Hearing. If anyone contacts the EPA by September 10, 2012 requesting to speak at a public hearing, the EPA will hold a public hearing on or about September 13, 2012.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2004–0490, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: a-and-r-docket@epa.gov.*
- *Fax:* (202) 566–9744.
- *Mail:* Air and Radiation Docket, U.S. EPA, Mail Code 6102T, 1200 Pennsylvania Ave. NW., Washington, DC 20460. Please include a total of two copies.
- *Hand Delivery:* EPA Docket Center, Docket ID Number EPA–HQ–OAR–2004–0490, EPA West Building, 1301 Constitution Ave. NW., Room 3334, Washington, DC, 20004. Such deliveries are accepted only during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2004–0490. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through regulations.gov or email. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2004–0490. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through www.regulations.gov, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about the EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/dockets/.*

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air and Radiation Docket EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket is (202) 566–1742.

Public Hearing: If a public hearing is requested, it will be held at the EPA Facility Complex in Research Triangle Park, North Carolina or at an alternate site nearby. Contact Ms. Pamela Garrett at (919) 541–7966 to request a hearing, to request to speak at a public hearing, to determine if a hearing will be held, or to determine the hearing location.

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–4003, facsimile number (919) 541–5450, electronic mail (email) address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION: *Regulated Entities:* Entities potentially affected by this proposed action include, but are not limited to, the following:

Category	NAICS[1]	Examples of regulated entities
Industry	2211	Electric services.
	486210	Natural gas transmission.
	211111	Crude petroleum and natural gas.
	211112	Natural gas liquids.
	221	Electric and other services, combined.

[1] North American Industry Classification System (NAICS) code.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this proposed rule. To determine whether your facility is regulated by this proposed rule, you should examine the applicability criteria in §§ 60.4305 and 60.4310. If you have any questions regarding the applicability of this proposed rule to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

WorldWide Web (WWW): Following the Administrator's signature, a copy of the proposed amendments will be posted on the Technology Transfer Network's (TTN) policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg*. The TTN provides information and technology exchange in various areas of air pollution control.

Outline: The information presented in this preamble is organized as follows:

I. Background

On July 6, 2006, the EPA promulgated revised new source performance standards (NSPS) for stationary combustion turbines (subpart KKKK of 40 CFR part 60) applicable to stationary combustion turbines on which construction, modification or reconstruction is commenced after February 18, 2005 (71 FR 38482). The new standards in subpart KKKK reflect advances in turbine design and nitrogen oxide (NO_X) emission control technologies since the standards for these units were originally promulgated in 1979 in subpart GG of 40 CFR part 60 (44 FR 52798). The new standards also reflect the use of lower sulfur fuels.

A petition for reconsideration of the revised NSPS was filed by the Utility Air Regulatory Group on September 5, 2006. The EPA has decided to grant reconsideration of subpart KKKK to the extent specified in this proposed rule. The amendments proposed by this action address issues for which the petitioners specifically requested reconsideration (see docket entry EPA–HQ–OAR–2004–0490–0325) and other matters as described below.

As part of this action, the EPA is also proposing to amend other rule language to correct technical omissions, typographical errors, grammatical errors and to address various other issues that have been identified since promulgation. A significant issue identified since promulgation is the development of new stationary combustion technologies that are capable of burning a variety of low-British thermal units (Btu) gases. The amendments proposed in this action include amending the sulfur dioxide (SO_2) standard for all low-Btu gases similar to the biogas (i.e., landfill gas) standard currently in subpart KKKK. The proposed amendments would not change the EPA's original projections for this proposed rule's compliance costs, environmental benefits, burden on industry or the number of affected facilities. The EPA is also proposing limited conforming amendments to subpart GG.

Finally, the EPA is proposing to amend subpart KKKK to exempt some stationary combustion turbines from the emission standards in subpart KKKK. First, owners/operators of stationary combustion turbines that meet the applicability criteria of, and that are complying with the SO_2 standard in, either subpart J or Ja (standards of performance for petroleum refineries) would be exempt from complying with the otherwise applicable SO_2 standard in subpart KKKK. In addition, owners/operators of stationary combustion turbines covered that meet the applicability criteria of, and that are complying with the SO_2 and NO_X standards in subparts Ea, Eb, Cd, AAAA or BBBB (the municipal solid waste regulations) would be exempt from complying with the otherwise applicable SO_2 and NO_X standards in subpart KKKK.

II. Proposed Amendments

We are proposing to amend subparts GG and KKKK of 40 CFR part 60 to clarify the intent in applying and implementing specific rule requirements, to correct unintentional technical omissions and editorial errors, and address various other issues that have been identified since the promulgation of subpart KKKK. A summary of the proposed substantive amendments to the NSPS for stationary combustion turbines and the rationale for these amendments are below.

In addition, we are proposing to amend 40 CFR 60.17 (incorporations by reference) and republish subpart KKKK in its entirety. The proposed amendments include updating 40 CFR 60.17 to include additional test methods identified in subpart KKKK and revising the wording and writing style to clarify the requirements of the NSPS. We do not intend for these editorial revisions to substantively change any of the technical or administrative requirements of the subpart and have concluded that they do not do so. To the extent that we determine that the editorial revisions do effect any unintended substantive changes, we will correct the problem in taking final action on the proposed rule.

A. Applicability

We are proposing to make five amendments to the applicability of subpart KKKK of 40 CFR part 60. First, the combustion turbine engine (the air compressor, combustor and turbine sections) is the primary source of emissions from a stationary combustion turbine. However, due to the broad definition of the affected facility in subpart KKKK, the combustion turbine engine does not necessarily constitute the majority of the costs of a new stationary combustion turbine. The expanded definition of a stationary combustion turbine in subpart KKKK is intended to simplify compliance and recognize the environmental benefit of heat recovery at combined cycle and combined heat and power (CHP) facilities. It is not intended to change the circumstances in which a turbine engine is designated as new or reconstructed. However, under subpart KKKK it is not clear whether a CHP or combined cycle facility that replaces the turbine engine would be considered ''new'' or ''reconstructed.'' The existing language in subpart KKKK could be interpreted to mean that replacement of a turbine engine with a new turbine engine at an existing combined cycle or CHP facility not currently subject to subpart KKKK would result in the new turbine engine being subject to subpart GG. In that case, the heat recovery steam generator (HRSG) would continue to comply with the same boiler NSPS as prior to the turbine engine replacement and two NSPS would apply to the facility. It was clearly not the intent when subpart KKKK was promulgated that these turbine engines would only be subject to emission control technologies that were available in the 1970s. In this situation, combustion controls have the same cost effectiveness as other new or reconstructed turbine engines. In addition, compliance is minimally impacted by the design of the HRSG, so there is no reason that two pieces of equipment should not be combined. Since the subpart KKKK standards are input-based, with optional alternative output-based standards, the efficiency of the HRSG is not essential for demonstrating compliance. Further, the presence of duct burners should not significantly impact the emissions rate since typical low NO_X natural gas-fired duct burners contribute between 15 to 25 parts per million (ppm) NO_X corrected to 15 percent oxygen (O_2) and ultra low NO_X duct burners are available that only contribute approximately 3 ppm NO_X corrected to 15 percent O_2. Therefore, while we are maintaining the broad definition of an affected facility, we are proposing that for the purposes of determining applicability and if a stationary combustion turbine is ''new'' or ''reconstructed,'' only the combustion turbine engine itself will be considered. This approach reflects the environmental benefits of heat recovery and output-based standards and was the intent of the original rule. This rule as amended would make it clear that the replacement of a turbine engine at a CHP or combined cycle facility that is not currently subject to subpart KKKK with a new turbine engine would result in the establishment of a new stationary combustion turbine under subpart KKKK, as was intended when subpart KKKK was promulgated. Furthermore, the addition of a new turbine engine to an existing HRSG would result in the establishment of a new stationary combustion turbine under subpart KKKK that includes the existing heat recovery steam generating unit. However, the construction or reconstruction of a HRSG associated with a turbine engine covered by subpart GG would not result in the entire facility being subject to subpart KKKK. A positive aspect of this approach is that the most current subpart KKKK requirements would apply to turbine engines that are replaced at combined cycle and CHP facilities already subject to subpart KKKK.

In the event the final rule does not include this clarification, the stationary combustion engine replaced at an existing combined cycle or CHP facility would be covered by subpart GG, and the HRSG would be covered by the applicable steam generating unit NSPS. Subpart GG would be amended to include NO_X emission standards for turbine engines that are identical to those in Table 1 of subpart KKKK. The subpart GG SO_2 emission standards and the monitoring, testing and reporting requirements would also be amended to be identical to the requirements for simple cycle turbines subject to subpart KKKK. With this approach, subpart GG would have to be amended each time that the subpart KKKK standards are amended. To provide additional compliance flexibility, we would add the ability for owners/operators of new and reconstructed turbine engine replacements at existing combined cycle and CHP facilities to petition the Administrator to voluntarily comply with the new and reconstructed requirements, as applicable, in subpart KKKK as an alternative to demonstrating compliance with amended subpart GG and applicable boiler NSPS separately. This approach would provide an equivalent amount of environmental protection as the previously described approach. However, we have concluded that the previously described approach avoids petition requirement and would reduce the regulatory burden of the proposed rule. We specifically request comment on the level of environmental protection and regulatory burden for each approach. A disadvantage of this approach is that the most current subpart KKKK requirements would not apply to turbine engines that are replaced at combined cycle and CHP facilities already subject to subpart KKKK. We are requesting comment if this approach could be amended to assure that future amended subpart KKKK requirements would apply to new and reconstructed turbine engines.

Second, we are proposing to exempt owners/operators of stationary combustion turbines that meet the applicability requirements and that are complying with the SO_2 standard in either subparts J or Ja of 40 CFR part 60 (Standards of performance for petroleum refineries) from complying with the otherwise applicable SO_2 standard in subpart KKKK. The SO_2 standard in both subparts J and Ja is more stringent than in subpart KKKK, so this proposed amendment would simplify compliance for owner/operators of petroleum refineries without an increase in pollutant emissions. In addition, owners/operators of stationary combustion turbines covered that meet the applicability criteria of, and that are complying with, the SO_2 and NO_X standards in subparts Ea, Eb, Cd, AAAA or BBBB (the municipal solid waste regulations) would be exempt from complying with the otherwise applicable SO_2 and NO_X standards in subpart KKKK. The SO_2 standards in the municipal solid waste rules are more stringent than in subpart KKKK, so this proposed amendment would simplify compliance for owner/operators of petroleum refineries without an increase in pollutant emissions.

Third, we are proposing to exempt owners/operators of stationary combustion turbines that are subject to a federally enforceable permit limiting fuel to gaseous fuels containing no more than 20 grains of sulfur per 100 standard cubic feet (scf) and/or liquid fuels containing no more than 0.050 weight percent sulfur (500 ppm sulfur by weight) from the SO_2 standard. Both of these fuels have potential SO_2 emissions of less than 0.060 pounds per million British thermal units (lb/MMBtu) and would be in compliance with the SO_2 standard. The proposed amendment would reduce the burden for owners/operators burning natural gas and distillate oil of complying with subpart KKKK by limiting reporting and recordkeeping costs without increasing emissions.

Fourth, we are proposing to allow owners/operators of stationary combustion turbines currently covered by subpart GG and any associated steam generating unit subject to an NSPS to have the option to petition the Administrator to comply with subpart KKKK in lieu of complying with subpart GG and any associated steam generating unit NSPS. Since the applicability of subpart KKKK encompasses any associated heat recovery equipment, owners/operators would have the flexibility to comply with one NSPS instead of multiple NSPS. The Administrator will only grant the petition if he/she determines that compliance with subpart KKKK would be equivalent to, or more stringent than, compliance with subpart GG and any associated steam generating unit NSPS. For example, assuming equal amounts of fuel are combusted in the turbine and duct burners (HRSG), an existing oil-fired combined cycle combustion turbine subject separately to subpart GG and subpart Db of 40 CFR part 60 would have an equivalent combined NO_X emissions standard of approximately 65 parts per million (ppm). By contrast, the subpart KKKK NO_X standard for modified turbines burning fuels other than natural gas is 96 ppm. The Administrator would, therefore, deny the petition in such circumstances. We have concluded that this is only an issue for turbines burning fuels other than natural gas. Also, we are clarifying that if any solid fuel as defined in subpart KKKK is burned in the HRSG, the HRSG would be covered by the applicable steam generating unit NSPS and not subpart KKKK. We are not aware of any existing stationary combustion turbines that burn solid fuel in the HRSG, but the intent of this proposed rule is to cover only liquid and gaseous fuels. The amendment would prevent a large solid fuel-fired boiler from using the exhaust from a combustion turbine engine in order to avoid the requirements of the applicable steam generating unit NSPS.

Finally, we are requesting comment on how to address combustion turbine engines that are overhauled or refurbished off site in such a manner that neither the owner, operator nor manufacturer can identify which components have been replaced and, therefore, cannot conduct the otherwise required reconstruction analysis. The owner/operator of a turbine engine that is overhauled or refurbished in such a manner that each individual component of the engine is tracked would still perform the traditional reconstruction analysis, i.e., the owner/operator would compare the total cost of replacement components with the cost of a comparable new turbine engine. In general, a reconstructed facility is one which has had components replaced to the extent that the fixed capital costs of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. (See 40 CFR 60.15.)

We are requesting comment on two potential approaches for dealing with circumstances where there is insufficient information to determine which components of a particular combustion turbine engine have been replaced. The first approach would base the reconstruction test on changes to the combustor alone. (That is, the test would be whether the fixed capital cost of the replacement combustor exceeds 50 percent of the fixed capital cost that would be required to install a comparable new combustor.) The alternate approach would be based on the number of times a particular turbine engine has been refurbished. Potential language for both approaches is as follows:

1. An overhauled or refurbished turbine engine where neither the owner/operator nor manufacturer can identify which components have been replaced shall be considered reconstructed if the combustor itself is either replaced or reconstructed (as specified under § 60.15). When such information is known, an owner or operator of a turbine engine that is overhauled or refurbished shall perform a reconstruction analysis on the entire turbine engine as described under § 60.15.

The corresponding definition for a combustor would be:

A combustor means a component or area in a combustion turbine engine where fuel is added to the pressurized air molecules and combustion takes place. It is also known as a burner or flame can.

2. An overhauled or refurbished turbine engine where neither the owner/operator nor manufacturer can identify which components have been replaced during the most recent and previous two refurbishments shall be considered reconstructed. When such information is known, an owner or operator of a turbine engine that is overhauled or refurbished shall perform a reconstruction analysis on the turbine engine as described under § 60.15.

If this provision is adopted, it would provide an owner/operator with relative certainty that they could potentially operate a combustion turbine for approximately 90,000 hours, or over 10 years of continuous operation, before triggering the reconstruction provisions in subpart KKKK. (Assuming that turbine exchanges take place at approximately 30,000 operating hour intervals.) This approach would provide relative regulatory certainty for both the owner/operator of the combustion turbine and the turbine manufacturer.

We are also requesting comment on the frequency of an entire combustor replacement. It is our understanding that combustion liners and the fuel injection system are replaced at intervals similar to major overhauls, but that the combustor need not be replaced in entirety. If this is the case, then the ''combustor'' approach could inadvertently hinder emissions improvements by providing an incentive to replace only the critical components of the combustor instead of upgrading the entire combustor. A potential alternative approach would be to limit the applicability of the combustor to the combustion liner and fuel injection system such that once those components are replaced the combustion turbine would be considered reconstructed. Assuming the replacement intervals are similar to overhaul intervals, if we adopt this approach in the final rule, we would consider two replacements prior to triggering reconstruction.

Finally, we are requesting comment on whether a similar approach should be adopted for turbines that are overhauled onsite. It is our understanding that larger combustion turbines operating on natural gas have overhaul schedules of approximately every 50,000 operating hours. Under these assumptions, a combustion turbine could potentially operate continuously for over 17 years prior to triggering the amended reconstruction provision under subpart KKKK.

If we adopt reconstruction triggers that differ from the general provisions, we intend to maintain the qualification that it is technologically and economically feasible to meet the applicable standards for each combustion turbine that triggers the amended reconstruction provisions. Instances where it might not be economically feasible would be made on a case-by-case basis by the Administrator. Examples of situations where it might not be economically feasible to meet the emissions standard include low NO_X combustor designs being unavailable, turbine designs that are not compatible with water or steam injection, or demineralized water or steam required for NO_X control being unavailable.

In addition to the above proposed amendments to the applicability of Subpart KKKK to new, reconstructed, and modified stationary combustion turbines, we are proposing to exempt non-major sources subject to this NSPS from title V permitting requirements. Under the Clean Air Act (CAA) section 502(a), the EPA may exempt non-major sources subject to CAA section 111 (NSPS) standards from the requirements of title V if the EPA finds that compliance with such requirements is ''impracticable, infeasible, or unnecessarily burdensome'' on such sources. The EPA's finding to support exemption of non-major source stationary combustion turbines subject to Subparts GG and KKKK from the title V permitting requirements is available in the docket.

B. NO_X Emissions Standard

We are proposing to amend the NO_X emissions standard for stationary combustion turbines that burn multiple fuels. The existing rule bases the applicable NO_X standard on the total heat input to the stationary combustion turbine, including any associated duct burners, and the more stringent standard is only applicable if the total heat input is derived from at least 50 percent natural gas. However, fuel choice impacts combustion turbine engine NO_X emissions to a greater degree than it impacts such emissions from a duct burner. Therefore, we are proposing that the NO_X standard be based on the type of fuel being burned in the combustion turbine engine alone. The natural gas standard would apply at those times when the fuel input to the combustion turbine engine meets the definition of natural gas, regardless of the fuel, if any, that is burned in the duct burners.

We are also proposing to add a provision allowing for a site-specific NO_X standard for an owner/operator of a stationary combustion turbine that burns by-product fuels. The owner/operator would be required to petition the Administrator for a site-specific standard using a procedure similar to what is currently required by subpart Db of 40 CFR part 60 (the industrial boiler NSPS). We have concluded that this is appropriate since subpart KKKK now covers the HRSG that was previously covered by subpart Db.

Since startup and shutdowns are part of the regular operating practices of stationary combustion turbines, we are proposing that the NO_X emissions standard includes startup and shutdown emissions. Since periods of startup and shutdown are by definition periods of low load, the ''part-load standard'' would apply to all hours that contain a startup or shutdown event. Since the ''part-load standard'' is based on the emissions rate of a diffusion flame and not dry low NO_X (DLN) combustion controls, we have concluded this standard is appropriate. Through analysis of continuous emission monitoring system (CEMS) data, we have determined that including periods of startup and shutdown in the standard would not result in non-compliance with the standard. We analyzed NO_X continuous CEMS data from existing large and small turbines without post-combustion controls to reduce NO_X emissions. Even though many of these turbines were built prior to the applicability date of subpart KKKK, the theoretical compliance rate with a 4-hour rolling average including all periods of operation was greater than 99 percent for both large and small turbines. We were unable to determine if any of the potential excess emissions were a result of either malfunction of the NO_X CEMS or combustion control equipment, or identify all periods when the ''part-load standard'' would apply and the actual level of theoretical compliance would be higher. Even though the theoretical compliance rate is high when the NO_X emissions standard is determined directly, we are specifically requesting comment on whether to account for startup conditions by considering the first 30 minutes of operation ''part-load'' such that the part-load emissions rate would apply during that time period regardless of the actual load. Implementing this option increases the theoretical compliance rate.

Since we only used performance test data and did not analyze NO_X CEMS data in the original rulemaking, we are requesting comment on whether it is appropriate to extend the averaging time for simple cycle turbines to an operating day average. Emissions averages would only be determined for operating days with 3 or more hours of CEMS data that are not out-of-control. Data from operating days with less than 3 hours of CEMS data that are not out-of-control would be rolled over to the next operating day until 3 or more hours of data are available. Extending the averaging period to an operating daily average would increase the theoretical compliance rate. However, since combustion turbines using combustion controls tend to have a steady emissions profile, we have concluded that this approach would not result in an increase in emissions, and could lower compliance burden by reducing the reporting burden. An additional benefit of this approach is that all non out-of-control emissions data would be used in determining excess emissions. Under the current approach, any 4 operating hours with more than 1 hour of monitor downtime is reported as monitor downtime and the emissions from the remaining hours are excluded. We are not proposing a longer averaging period for a simple cycle turbine. If we were to use a longer averaging period for simple cycle turbines or determine compliance during startup, shutdown and part-load periods separately from full-load periods, the NO_X standards would be re-evaluated to determine appropriate standards. Furthermore, we are proposing to add a lb/MMBtu NO_X option that is equivalent to the ppm standard. This option would simplify compliance for some sources while providing the same level of environmental protection. Fourth, based on analysis of the CEMS data, we are proposing to change the classification of large/small for turbines operating at part-load. The existing rule divides large/small turbines operating at part-load based on the rated output of the turbine (i.e., turbines with outputs greater than 30 megawatts (MW) are considered large). This proposed amendment would divide large/small turbines operating at part-load based on the rated heat input (i.e., turbines with base load heat inputs greater 340 MMBtu per hour (MMBtu/h) would be considered large). A heat input rating of 340 MMBtu/h is approximately equivalent to an output rating of 30 MW, and this amendment would simplify compliance by making the measurement method for determination the large/small part-load subcategory consistent with how the other subcategories are determined. A detailed discussion of the NO_X CEMS data for both large and small turbines is available in the docket.

We have concluded that the net power supplied to the end user is a better indication of environmental performance than gross output from the power producer. Therefore, we intend to amend the optional output-based standard from gross to net output in the final rule. Net output is the combination of the gross electrical (or mechanical) output of the turbine engine and any output generated by the HRSG minus the parasitic power requirements. A parasitic load for a stationary combustion turbine is any of the loads or devices powered by electricity, steam, hot water or directly by the gross output of the stationary combustion turbine that does not contribute electrical, mechanical or thermal output. One reason for this amendment is that while combustion turbine engines that require high fuel gas feed pressures typically have higher gross efficiencies, they also often require fuel compressors that have potentially larger parasitic loads than combustion turbine engines that require lower fuel gas pressures. We have concluded that primary parasitic loads include the fuel compressor, pump, or heater, fans, inlet air cooling systems, control systems and post combustion controls. We are requesting comment on any additional loads that should be considered. To account for the parasitic loads, we intend to lower the efficiency assumptions used to generate the output-based standards. We have concluded that a 2.5 percent difference in efficiency is appropriate, but are requesting comment on the issue. As an alternative to continuously monitoring parasitic loads, we have concluded that estimating parasitic loads is adequate and would minimize compliance costs. A calibration would be required to determine the parasitic loads at four load points (< 25 percent load, 25–50 percent load, 50–75 percent load, and >75 percent load). Once the parasitic load curve is determined, the appropriate amount would be subtracted from the gross output to determine net output. We are requesting comment on this approach and whether a four-load test is appropriate or if a curve fit of three loads greater than 25 percent load is sufficient.

In addition, we are proposing to recognize the environmental benefit of electricity generated by CHP facilities to account for the benefit of on-site generation avoiding losses from the transmissions and distribution of the electricity. Actual line losses vary from location to location, but we are proposing a benefit of five percent avoided transmission and distribution losses when determining the electric output for CHP facilities. To avoid CHP facilities only providing a trivial amount of thermal energy from qualifying for the transmission and distribution benefit, we are proposing to restrict the 5 percent benefit to CHP facilities where at least 20 percent of the annual output is useful thermal output.

Finally, we are requesting comment on limiting the use of the 30-day average. The existing rule provides a 30-day averaging period for owners/operators of combined cycle and CHP turbines regardless of if they elect to comply with the input or output-based standard. However, based on the review of CEMS data, NO_X emissions from stationary combustion turbines are relatively stable in terms of ppm or lb/MMBtu and a 30-day averaging time for combined cycle and CHP facilities is not necessary. Owner/operators of any stationary combustion turbine (including combined cycle and CHP turbines) electing to comply with either of the input-based standards (ppm or lb/MMBtu) would be required to use the 4-hour (or daily) averaging period. The existing rule does not provide owner/operators of simple cycle turbines the option to demonstrate compliance using a 30-day average. We have concluded that few owner/operators of simple cycle turbines would elect to demonstrate compliance with the output-based standard, but as technology develops this might change in the future. Therefore, since output is the only relevant characteristic that varies significantly over short periods and a longer averaging period is necessary to account for periods of lower efficiency, we are requesting comment on using the 30-day averaging period for owner/operators of any stationary combustion turbine electing to demonstrate compliance with the output-based standard. Owner/operators of all stationary combustion turbines electing to demonstrate compliance with either the ppm or lb/MMBtu standards would use a 4-hour (or daily) averaging period.

C. SO_2 Emissions Standard

We are proposing to amend the rule language to clarify the intent of the rule in that if a source elects to perform fuel analysis to demonstrate compliance with the SO_2 standard, the initial test must measure all sulfur compounds (e.g. hydrogen sulfide, dimethyl sulfide, carbonyl sulfide and thiol compounds). Alternate test procedures can be used only if the measured sulfur content is less than half of the applicable standard. In addition, we are proposing to allow fuel blending to achieve the applicable SO_2 standard. Under the proposed language, an owner/operator of an affected facility would be able to burn higher sulfur fuels as long as the average fuel fired meets the applicable SO_2 standard at all times. Finally, the primary method of controlling SO_2 emissions is through selecting fuels containing low amounts of sulfur or through fuel pretreatment operations that can operate at all times. We are proposing that the SO_2 standard apply during periods of startup and shutdown.

In recognition that ultra-low sulfur diesel is available for transportation purposes in Hawaii, the Commonwealth of Puerto Rico and the Virgin Islands, we are removing these areas from the definition of noncontinental area. The only difference for owners/operators of affected stationary combustion turbines located in noncontinental areas is the ability to burn higher sulfur fuels. We have concluded that since these areas have low sulfur diesel oil available it is not appropriate to include these locations in the noncontinental area definition. This amendment would still allow the use of higher sulfur fuels in Guam, American Samoa, the Northern Mariana Islands and offshore platforms where lower sulfur fuels are not necessarily as readily accessible.

For stationary combustion turbines combusting 50 percent or more biogas (based on total heat input) per calendar month, the existing Subpart KKKK establishes a maximum allowable SO_2 emissions standard of 65 nanograms (ng) SO_2 per joule (/J) (0.15 lb SO_2/MMBtu) heat input. This standard was set to avoid discouraging the development of energy recovery projects, which burn landfill gases to generate electricity in stationary combustion turbines (see 74 FR 11858, March 20, 2009). New stationary combustion technologies using other low-Btu gases are becoming commercially available. These technologies can burn low-Btu content gases recovered from steelmaking (e.g., blast furnace gas and coke oven gas), coal bed methane, closed landfills, etc. Similar to biogas, substantial environmental benefits can be achieved by using these low-Btu gases to generate electricity instead of flaring or direct venting to the atmosphere, as is now common practice. Therefore, we are proposing to expand the application of the existing 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input emissions standard to include stationary combustion turbines combusting 50 percent or more (on a heat input basis) of any gaseous fuels that have heating values less than 26 megajoules per standard cubic meter (700 Btu per scf) per calendar month.

To account for the environmental benefit of productive use and simplify compliance for low-Btu gases, we have concluded that it is appropriate to base the SO_2 standard on a fuel concentration basis as an alternative to a lb/MMBtu basis. The original subpart KKKK 2005 proposal (70 FR 8314) SO_2 standard was based on the sulfur content in distillate oil and included a sulfur standard of 0.05 percent by weight (500 ppm by weight (ppmw)). However, since we are proposing to exempt liquid fuels containing less than 0.050 weight percent sulfur from the SO_2 standard, we are proposing an alternate standard of 500 ppm by volume (ppmv). In general, emission standards are applied to a gaseous mixture are by volume (ppmv), not by weight (ppmw). Basing the standard on a volume basis would simplify compliance and minimize burden to the regulated community. Therefore, we are proposing a fuel specification standard of 650 milligrams per standard cubic meter (28 gr/100 scf) for low-Btu gases. This is approximately equivalent to a standard of 500 ppmv, and is in the units directly reported by most test methods.

D. Malfunction Affirmative Defense

The EPA has proposed standards in this proposed rule that apply at all times and is proposing to add an affirmative defense to civil penalties that are caused by malfunctions. The EPA's finding to support the malfunction affirmative defense is available in the docket.

E. Electronic Data Submittal

The EPA is proposing that owners/operators of stationary combustion turbines submit electronic copies of required performance test reports to the EPA's WebFIRE database. The EPA's finding to support this requirement is available in the docket.

F. Additional Proposed Amendments

We are also proposing several additional amendments. First, we have concluded that it is not appropriate to require an affected facility that is not currently in operation to startup to demonstrate compliance with the NSPS. Commencing operation strictly for the purposes of demonstrating compliance is an unnecessary cost and increases emissions. Therefore, we are proposing to exempt units that are out of operation at the time of the required performance test from conducting the required performance test until 45 days after the facility is brought back into operation.

Similarly, owner/operators of a combustion turbine that has operated 50 hours or less since the previous performance test was required to be conducted can request an extension of the otherwise required performance test from the appropriate EPA Regional Office until the turbine has operated over 50 hours. This provision is fuel specific and an owner/operator permitted to burn a backup fuel, but that rarely does so, can request an extension on testing on that particular fuel until it has been burned for over 50 hours.

In addition, for similar, separate affected facilities using identical control equipment, the Administrator or delegated authority may authorize a single emissions test as adequate demonstration for up to four other similar, separate affected facilities as long as: (1) The most recent performance test for each affected facility shows that performance of each affected facility is 75 percent or less of the applicable emissions standard; (2) the manufacturer's recommended maintenance procedures for each control device are followed; and (3) each affected facility conducts a performance test for each pollutant for which they are subject to a standard at least once every five years. DLN combustion controls are the primary method for compliance with the NSPS requirements and result in relatively stable emission rates. Furthermore, the DLN combustor is a fundamental part of a combustion turbine and as long as similar maintenance procedures are followed we have concluded that emission rates will likely be comparable between similar combustion turbines. Therefore, the additional compliance costs associated with testing each affected turbine would not result in significant emissions reductions.

Additionally, turbine engine performance can deteriorate with operation and age and operational parameters need to be verified periodically to assure proper operation of emission controls. Therefore, we are proposing to require facilities using the water or steam to fuel ratio as a demonstration of continuous compliance with the NO_X emissions standard to verify the appropriate ratio or parameters at a minimum of every 60 months. We have concluded this would not add significant burden since the majority of affected facilities are already required to conduct performance testing at least every five years through title V requirements or other state permitting requirements.

The existing rule does not state how multiple combustion turbine engines that are exhausted through a single HRSG would demonstrate compliance with the NO_X standard. Therefore, we are proposing procedures for demonstrating compliance when multiple combustion turbine engines are exhausted through a single HRSG and when steam from multiple combustion turbine HRSGs is used in a single steam turbine. Furthermore, the existing rule requires approval from the permitting authority for any use of the part 75 NO_X monitoring provisions in lieu of the specified part 60 procedures, but we concluded that approval is an unnecessary burden for facilities only using combustion controls. Therefore, we are proposing to allow sources using only combustion controls to use the parametric NO_X monitoring in part 75 to demonstrate continuous compliance without requiring prior approval. However, if the source is using post combustion control technology to comply with the requirements of the NSPS, then approval from the permitting authority is required prior to using the part 75 CEMS calibration procedures in place of the part 60 procedures.

Finally, for turbine engines replaced with an identical overhauled engine as part of an exchange program, we are proposing that the new turbine undergo a new performance test to verify proper operation, for owner/operators using water or steam to fuel ratio to verify the proper ratio, and for owner/operators using parametric monitoring to verify that the operating parameters are still valid.

G. Additional Request for Comments

Affected Facility. We are considering and requesting comment on amending the definition of the affected facility for systems with multiple combustion turbine engines. Specifically, we are requesting comment on treating multiple combustion turbine engines connected to a single generator, separate combustion turbines engines using a single HRSG and separate combustion turbine engines with separate HRSG that use a single steam turbine or otherwise combine the useful thermal output as single affected facilities. This approach would reduce burden to the regulated community by simplifying monitoring. We are also requesting comment on how the applicable emission standards would be determined and on how ''new'' and ''reconstruction'' would be defined. We are specifically requesting comment on basing the emission standards on either the base load rating of the largest single combustion turbine engine or the combined base load ratings of the combustion turbine engines. For an affected facility with multiple combustion turbine engines, we are requesting comment on considering the entire facility ''new'' or ''reconstructed'' if any combustion turbine engine is replaced with a new combustion turbine engine or reconstructed.

District Energy. We are considering and requesting comment on an appropriate method to recognize the environmental benefit of district energy systems. The steam or hot water distribution system of a district energy system located in urban areas, college and university campuses, hospitals, airports and military installations eliminates the need for multiple, smaller boilers at individual buildings. A central facility typically has superior emission controls and consists of a few larger boilers facilitating more efficient operation than numerous separate smaller individual boilers. However, when the hot water or steam is distributed, approximately two to three percent of the thermal energy in the water and six to nine percent of the thermal energy in the steam is lost, reducing the net efficiency advantage. We are requesting comment on whether it is appropriate to divide the thermal output from district energy systems by a factor (i.e., 0.95 or 0.90) that would account for the net efficiency benefits of district energy systems. This approach would be similar to the proposed approach to how the electric output for CHP is considered when determining regulatory compliance. We request that comments include technical analysis of the net benefits in support of any conclusions.

Jet Fuel. We realize that jet fuel is an available fuel for combustion turbines and are requesting comment on adding jet fuel to the definition of distillate oil. In the event we include jet fuel in the definition of distillate oil, we are also requesting the appropriate test method (i.e., ASTM method) that should be used to identify jet fuel.

Low-Btu Gases. We are considering and requesting comment on amending subpart KKKK to specifically exempt from the SO_2 emission standards stationary combustion turbines combusting over 50 percent or more per calendar month low-Btu gases. Since these by-product gases are a recovered waste that would otherwise be flared or vented rather than a newly supplied fossil fuel such as natural gas or fuel oil, the combusting of the low-Btu gases in a stationary combustion turbine to generate electricity does not increase SO_2 emissions to the atmosphere. Such an exemption would encourage the environmentally beneficial use of low-Btu by-product gases, and would reduce the burden to the owners/operators of these affected facilities by eliminating the need to demonstrate compliance with an SO_2 emissions standard. When the emissions associated with the displaced electric and useful thermal output are accounted for, there is a net reduction in emissions to the atmosphere.

III. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is, therefore, not subject to review under the Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011).

B. Paperwork Reduction Act

This action does not impose any new information collection burden. The amended reconstruction provisions would not significantly impact owners/operators of stationary combustion turbines within the next 5 years, and the other proposed amendments result in no changes to the information collection requirements of the existing standards of performance and would have no impact on the information collection estimate of projected cost and hour burden made and approved by the Office of Management and Budget (OMB) during the development of the existing standards of performance. Therefore, the information collection requests have not been amended. However, OMB previously approved the information collection requirements contained in the existing regulations (40 CFR part 60, subpart KKKK) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq., and has assigned OMB control number 2060–0582. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of the proposed amendments on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The required emissions control technology and other requirements have not been significantly changed. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives ''which minimize any significant economic impact of the rule on small entities.'' 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule.

Although this proposed rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless has tried to reduce the impact of this rule on small entities. The proposed amendments would allow flexibility in the timing of performance testing of idle turbines and fuel blending to achieve the SO_2 standards.

We therefore concluded that today's proposed rule would relieve regulatory burden for all affected small entities.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any 1 year. Since the best system of emissions reduction is unchanged and there are only minor proposed amendments to the performance testing, recordkeeping, monitoring and reporting requirements, the proposed amendments would not significantly impact the regulatory burden of this rule. Thus, this proposed rule is not subject to the requirements of sections 202 and 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. The proposed amendments would reduce the overall regulatory requirements of the rule.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This proposed rule will not impose substantial direct compliance costs on state or local governments; it will not preempt state law. Thus, Executive Order 13132 does not apply to this action.

In the spirit of Executive Order 13132, and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). The EPA is not aware of any stationary combustion turbine owned by an Indian tribe. Thus, Executive Order 13175 does not apply to this action.

The EPA specifically solicits additional comment on this proposed action from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is based solely on technology performance. The proposal is not expected to produce notable changes in criteria pollutant emissions or other pollutants but does encourage the current trend towards cleaner generation, helping to protect air quality and children's health. The agency recognizes that children are among the groups most vulnerable to climate change impacts and the public is invited to submit comments or identify peer reviewed studies relevant to this proposal based solely on technology.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (*e.g.,* materials specifications, test methods, sampling procedures and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency decides not use available and applicable VCS.

This proposed rulemaking does not involve any new technical standards. Therefore, the EPA did not consider the use of any VCS.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations.

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practical and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the United States.

The EPA has determined that this proposed rule would not have disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because it increases the level of environmental protection for all affected populations without having any disproportionately high adverse human health or environmental effects on any populations, including any minority, low-income or indigenous populations. This proposed rule would assure that all new stationary combustion turbines install appropriate controls to minimize health impacts to nearby populations.

To gain a better understanding of the source category and near source populations, the EPA conducted a demographic analysis on recent installations of combustion turbines selling >25 MW of power to identify any overrepresentation of minority, low income, or indigenous populations. This analysis only gives some indication of the prevalence of sub-populations that may be exposed to air pollution from the sources; it does not identify the demographic characteristics of the most highly affected individuals or communities, nor does it quantify the level of risk faced by those individuals or communities. The demographic analysis results and the details concerning their development are presented in the April 20, 2012, memorandum titled, *Environmental Justice Review,* a copy of which is available in the docket.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: June 22, 2012.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60, of the Code of the Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[AMENDED]

2. Section 60.17 is amended:

a. By revising paragraph (a)(9);
b. By revising paragraph (a)(16);
c. By revising paragraph (a)(18);
d. By revising paragraph (a)(22);
e. By revising paragraph (a)(25);
f. By revising paragraph (a)(40);
g. By revising paragraph (a)(50);
h. By revising paragraph (a)(57);
i. By revising paragraph (a)(59);
j. By revising paragraph (a)(61);
k. By revising paragraph (a)(64);
l. By revising paragraph (a)(68);
m. By revising paragraph (a)(71);
n. By revising paragraph (a)(72);
o. By revising paragraph (a)(75);
p. By revising paragraph (a)(76);
q. By revising paragraph (a)(81);
r. By revising paragraph (a)(88);
s. By revising paragraph (a)(106);
t. By revising paragraph (a)(107);
u. By revising paragraph (a)(108); and
v. By adding paragraphs (a)(109) through (a)(117).
w. By revising paragraph (h)(4);
x. By reserving paragraph (i);
y. By redesignating paragraph (m)(1) as paragraph (m)(4);
z. By revising paragraph (m)(2);
aa. By adding new paragraphs (m)(1) and (m)(3); and

bb. By revising newly redesignated paragraph (m)(4).

The revisions and additions read as follows.

§ 60.17 Incorporations by Reference.

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(a) * * *

(9) ASTM D129–11, Standard Test Method for Sulfur in Petroleum Products (General High Pressure Decomposition Device Method), IBR approved for § 60.4360(c).

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(16) ASTM D975–11, 11b, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.4420 of subpart KKKK of this part.

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(18) ASTM D1072–06, 06, Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.4360(c).

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(22) ASTM D1266–07, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for § 60.4360(c).

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(25) ASTM D1552–08, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for § 60.4360(c).

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(40) ASTM D2622–10, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4360(c).

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(50) ASTM D3246–11, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.4360(c).

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(57) ASTM D4057–06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4360(b).

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(59) ASTM D4084–07, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.4360(c).

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(61) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4360(b).

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(64) ASTM D4294–10, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4360(c).

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(68) ASTM D4468–85 (Reapproved 2011), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§ 60.335(b) and 60.4360(c).

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(71) ASTM D4810–88 (Reapproved 1999), 06, Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for § 60.4360(c).

(72) ASTM D5287–97 (Reapproved 2002), 08, Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for § 60.4360(b).

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(75) ASTM D5453–09, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.4360(c).

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(81) ASTM D6228–98 (Reapproved 2003), 10, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for § 60.4360(c).

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(88) ASTM D6667–10, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.4360(c).

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(106) ASTM D3699–08, Standard Specification for Kerosine, including Appendix Xl, (Approved September 1, 2008), IBR approved for §§ 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.4420 of subpart KKKK of this part.

(107) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices Xl through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.4420 of subpart KKKK of this part.

(108) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices Xl through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.4420 of subpart KKKK of this part.

(109) ASTM D240–09, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for § 60.4360(c).

(110) ASTM D396–10, Standard Specification for Fuel Oils, IBR approved for § 60.4420 of subpart KKKK of this part.

(111) ASTM D1826–94 (Reapproved 2010), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for § 60.4350(c).

(112) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, IBR approved for § 60.4360(c).

(113) ASTM D4809–09a, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for § 60.4360(c).

(114) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, IBR approved for § 60.4360(c).

(115) ASTM D5504–08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for § 60.4360(c).

(116) ASTM D6522–11, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 60.4400(a).

(117) ASTM D7164–05, 10, Standard Practice for On-line/At-line Heating Value Determination of Gaseous Fuels by Gas Chromatography, IBR approved for § 60.4360(c).

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(h) * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for § 60.56c(b), § 60.63(f), § 60.106(e), § 60.104a(d), (h), (i), and (j), § 60.105a(d), (f), and (g), § 60.106a(a), § 60.107a(a), (c), and (d), tables 1 and 3 of subpart EEEE, tables 2 and 4 of subpart FFFF, table 2 of subpart JJJJ, § 60.4415(b), § 60.2145 and (t), § 60.2710(s), (t) and (w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, and tables 2 and 3 to subpart MMMM.

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(i) [Reserved]

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(m) * * *

(1) Gas Processors Association Method 2166–05, Obtaining Natural Gas Samples for Analysis by Gas Chromatography, IBR approved for § 60.4360(b).

(2) Gas Processors Association Method 2172–09, Calculation of Gross Heating Value, Relative Density, Compressibility, and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer, IBR approved for § 60.4360(c).

(3) Gas Processors Association Method 2174–93, Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography, IBR approved for § 60.4360(b).

(4) Gas Processors Association Standard 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, IBR approved for §§ 60.105(b), 60.107a(b), 60.334(h), and 60.4360(c).

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Subpart GG—[Amended]

3. Section 60.330 is amended by revising paragraph (a) and adding paragraph (c) to read as follows:

§ 60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines not covered by subparts Da or KKKK of this part with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

* * * * *

(c) As an alternative to meeting the requirements of this subpart, an owner or operator can petition the Administrator (in writing) to comply with the requirements for modified units in subpart KKKK of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements for modified units in subpart KKKK of this part.

(d) If you are an owner or operator of a non-major source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as a non-major source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart, as applicable.

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

4. Part 60 is amended by revising subpart KKKK to read as follows:

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) You are subject to this subpart if you own or operate a stationary combustion turbine that commenced construction, modification, or reconstruction after February 18, 2005, and that has a base load rating equal to or greater than 2.9 megawatts (MW) (10 million British thermal units per hour (MMBtu/h)), except as provided for in § 60.4310. Any additional heat input from duct burners used with heat recovery steam generating units or fuel preheaters is not included in the heat input value used to determine the applicability of this subpart to a given stationary combustion turbine.

(b) For the purpose of this subpart, only the combustion turbine engine itself is used to determine whether the affected facility is new or reconstructed. Other equipment included in the definition of a stationary combustion turbine is not included when determining if a facility is new or reconstructed.

(c) A combustion turbine engine subject to this subpart is not subject to subpart GG of this part.

(d) Duct burners that do not burn any solid fuels when used with a heat recovery steam generating unit that is part of either a combined cycle combustion turbine or a combined heat and power (CHP) combustion turbine subject to this subpart are not subject to subpart D, Da, Db, or Dc of this part, as applicable.

(e) If you own or operate either a stationary combustion turbine (including a combined cycle combustion turbine or a CHP combustion turbine) that commenced construction, modification, or reconstruction on or before February 18, 2005, you may submit a written petition to the Administrator requesting that the stationary combustion turbine be allowed to comply with the applicable requirements for modified units under this subpart as an alternative to complying with subpart GG of this part, and with subparts D, Da, Db, and Dc of this part, as applicable. If the Administrator or delegated authority approves the petitioner's request, the affected facility must comply with the requirements for modified units under this subpart unless the combustion turbine engine is reconstructed or replaced with a new facility in the future.

(f) If you are an owner or operator of a non-major source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as a non-major source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart, as applicable.

§ 60.4310 What stationary combustion turbines are not subject to this subpart?

(a) An integrated gasification combined cycle electric utility steam generating unit subject to subpart Da of this part is not subject to this subpart.

(b) A stationary combustion turbine used in a combustion turbine test cell/stand as defined in § 60.4420 is not subject to this subpart.

(c) A stationary combustion turbine subject to subpart Ea, subpart Eb, or subpart AAAA of this part is not subject to this subpart.

(d) A stationary combustion turbine subject to an EPA approved State or Federal plan implementing under authority of Clean Air Act sections 111(d)/129 either subpart Cb or subpart BBBB of this part is not subject to this subpart.

Emission Standards

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxides (NO_X) and sulfur dioxide (SO_2).

§ 60.4320 What NO_X emissions standard must I meet?

(a) For each simple cycle stationary combustion turbine, except as provided for in paragraph (d) of this section, you must not discharge into the atmosphere from the affected facility any gases that contain NO_X in excess of the applicable emissions standard as determined on a 4-operating hour basis and according to the requirements specified in paragraph (c) of this section.

(b) For each combined-cycle combustion turbine or CHP combustion turbine except as provided for in paragraph (d) of this section, you must not discharge into the atmosphere from the affected facility any gases that contain NO_X into the atmosphere from the affected facility in excess of the applicable emissions standard on a 30-operating day basis and according to the requirements specified in paragraph (c) of this section.

(c) For the purpose of determining compliance with the applicable emissions standard in paragraphs (a) and (b) of this section, you must meet the requirements specified in paragraphs (c)(1) through (c)(4), as applicable to your affected facility.

(1) The NO_X emissions standard that is applicable to your affected facility shall be determined on an operating hour basis except as provided for in paragraph (c)(2) of this section. Determining the hourly NO_X emission standards for your affected facility requires recording hourly data and maintaining records according to the requirements in § 60.4390.

(2) As an alternative to the requirements specified in paragraph (c)(1) of this section, you may elect to use the lowest emissions standard determined using Table 1 of this subpart that is applicable to your affected facility for the entire required compliance period.

(3) During each operating hour when only natural gas is combusted in the combustion turbine engine, you must meet the applicable NO_X emissions standard determined using Table 1 of this subpart for a stationary combustion firing natural gas. During each operating hour when any fuel other than natural gas is combusted in the combustion turbine engine, you must meet the applicable NO_X emissions standard determined using Table 1 of this subpart for a stationary combustion firing fuels other than natural gas. If multiple fuels are combusted during a given operating hour, then the highest applicable NO_X emissions standard is applied for the entire operating hour.

(4) If you have two or more combustion turbine engines connected to a single electric generator, each of the combustion turbine engines must meet the applicable NO_X emissions standard determined using Table 1 of this subpart.

(d) Stationary combustion turbines specified in paragraphs (d)(1) through (3) of this section are exempt from the applicable NO_X emissions standard in paragraphs (a) and (b) of this section.

(1) An emergency combustion turbine, as defined in § 60.4420;

(2) A stationary combustion turbine used for research and development of equipment for combustion turbine emissions control techniques or efficiency improvements as determined by the Administrator or delegated authority on a case-by-case basis; and

(3) A stationary combustion turbine that combusts byproduct fuels for which a facility-specific NO_X emissions standard has been established by the Administrator according to the requirements of paragraphs (d)(3)(i) and (ii).

(i) You may request a facility-specific NO_X emissions standard by submitting a written request to the Administrator or delegated authority explaining why your affected facility when burning the byproduct fuel is unable to comply with the applicable NO_X emissions standard determined using Table 1 of this subpart.

(ii) If the Administrator approves the request, a letter will be sent to the facility describing the facility-specific NO_X emissions standard. You must use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(e) For affected facilities for which construction, modification, or reconstruction commenced before August 30, 2012, you must meet the NO_X emissions standard applicable under this section to your affected facility during all times when the affected facility is operating except during periods of startup, shutdown, or malfunction. For each affected facility for which construction, reconstruction, or modification commenced after August 29, 2012, you must meet the NO_X emissions standard applicable under this section to your affected facility during all times when the affected facility is operating (including periods of startup, shutdown, and malfunction).

§ 60.4330 What SO_2 emissions standard must I meet?

(a) For each stationary combustion turbine, except as provided for in paragraphs (b) through (g) of this section, you must not cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of either:

(1) 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output; or

(2) 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

(b) As an alternative to the requirements of paragraph (a) of this section, for each stationary combustion turbine combusting 50 percent or more low-Btu gas per calendar month based on total heat input using the higher heating value of the fuel, you may limit the sulfur content of the fuel to no more than either:

(1) 650 milligrams of sulfur per standard cubic meter (mg/scm) (28 grains (gr) of sulfur per 100 standard cubic feet (scf)); or

(2) 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

(c) For each stationary combustion turbine located in a noncontinental area, you must not cause to be discharged into the atmosphere from the affected facility any gases that contains SO_2 in excess of either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input.

(d) For each stationary combustion turbine for which the Administrator determines that the affected facility does not have access to natural gas and the removal of sulfur compounds from the fuel would cause more environmental harm than benefit, you must not cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of either:

(1) 780 ng/J (6.2 lb/MWh) gross energy output; or

(2) 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input.

(e) A stationary combustion turbine that is subject to SO_2 emission standards under either subpart J or Ja of this part is not subject to the SO_2 emission standards in this subpart.

(f) A combustion turbine that is subject to a federally enforceable requirement limiting the sulfur content of gaseous fuels combusted in the stationary combustion turbine to no more than 460 mg/scm (20 gr/100 scf) and/or for liquid fuels no more than 0.050 weight percent sulfur is not subject to the SO_2 emission standards in this subpart.

(g) For affected facilities for which construction, modification, or reconstruction commenced before August 30, 2012, you must meet the SO_2 emissions standard applicable under this section to your affected facility during all times when the affected facility is operating except during periods of startup, shutdown, or malfunction. For each affected facility for which construction, reconstruction, or modification commenced after August 29, 2012, you must meet the SO_2 emissions standard applicable under this section to your affected facility during all times when the affected facility is operating (including periods of startup, shutdown and malfunction).

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) If you own or operate a stationary combustion turbine subject to a NO_X emissions standard in § 60.4320, you must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400 or § 60.4405. Thereafter, unless you perform continuous monitoring consistent with §§ 60.4335, 60.4340(b), or 60.4345, you must conduct subsequent performance tests according to the applicable requirements in paragraphs (b)(1) through (b)(6) of this section.

(1) Except as provided for in paragraphs (b)(2) through (b)(5) of this section, you must conduct subsequent performance tests within 12 calendar months following the date the previous performance test was required to be conducted. Performance tests must be separated by a minimum of 9 calendar months.

(2) If the NO_X emission result from the most recent performance test is less than or equal to 75 percent of the NO_X emissions standard for the stationary combustion turbine, you may reduce the frequency of subsequent performance tests to 24 calendar months following the date the previous performance test was required to be conducted. Performance tests must be separated by a minimum of 21 calendar months. If the results of any subsequent performance test exceed 75 percent of the NO_X emissions standard for the stationary combustion turbine, you must resume annual performance testing.

(3) An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days after the next operating day. The delegated permitting authority must be notified of recommencement of operation consistent with § 60.4375(d).

(4) If you own or operate an affected facility that has operated 50 operating hours or less in total or with a particular fuel since the date the previous performance test was required to be conducted you may request an extension from the otherwise required performance test until after the affected facility has operated more than 50 operating hours in total or with a particular fuel since the date of the previous performance test was required to be conducted. A request for an extension under this paragraph must be addressed to the relevant air division or office director of the appropriate Regional Office of the U.S. EPA as identified in § 60.4(a) for his or her approval at least 30 calendar days prior to the date on which the performance test is required to be conducted. If an exemption is approved, a performance test must be conducted within 45 calendar days after the day the facility reaches 50 hours of operation since the date the previous performance test was required to be conducted. When the facility has operated more than 50 operating hours since the date the previous performance test was required to be conducted, the delegated permitting authority must be notified consistent with § 60.4375(e).

(5) For a facility at which a group consisting of no more than five similar stationary combustion turbines (i.e., same manufacturer and model number) is operated, you may request the use of a custom testing schedule by submitting a written request to the Administrator or delegated authority. The minimum requirements of the custom schedule include the conditions specified in paragraphs (5)(i) through (v) of this section.

(i) Emissions from the most recent performance test for each individual affected facility are 75 percent or less of the applicable standard;

(ii) Each stationary combustion turbine uses the same emissions control technology;

(iii) Each stationary combustion turbine is operated in a similar manner;

(iv) Each stationary combustion turbine and its emissions control equipment are maintained according to the manufacturer's recommended maintenance procedures; and

(v) A performance test is conducted on each affected facility at least once every 5 calendar years.

(6) A stationary combustion turbine subject to a NO_X emissions standard in § 60.4320 that exchanges the combustion turbine engine for an overhauled combustion turbine engine

as part of an exchange program, must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400.

(c) Except as provided for in paragraphs (c)(1) or (2) of this section, for each stationary combustion turbine subject to a NO_X emissions standard in § 60.4320, you must demonstrate continuous compliance using a continuous emissions monitoring system (CEMS) for measuring NO_X emissions according to the provisions in § 60.4345. If your stationary combustion turbine is equipped with a NO_X CEMS, those measurements must be used to determine excess emissions.

(1) If your stationary combustion turbine uses water or steam injection but not post-combustion controls to meet the applicable NO_X emissions standard in § 60.4320, you may elect to demonstrate continuous compliance using either the pounds per million British thermal units (lb/MMBtu) or the part per million (ppm) standard according to the provisions in § 60.4335.

(2) If your stationary combustion turbine does not use water injection, steam injection, or post-combustion controls to meet the applicable NO_X emissions standard in § 60.4320, you may elect to demonstrate continuous compliance with either the lb/MMBtu or ppm standard according to the provisions in § 60.4340.

(d) An owner or operator of a stationary combustion turbine subject to an SO_2 emissions standard in § 60.4330 must demonstrate compliance using one of the methods specified in paragraphs (d)(1) through (4) of this section.

(1) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415. Thereafter, you must conduct subsequent performance tests within 12 calendar months following the date the previous performance test was required to be conducted. Performance tests must be separated by a minimum of 9 calendar months. An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days after the next operating day;

(2) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415. Thereafter, conduct subsequent fuel sulfur analyses using the applicable methods specified in § 60.4360 and at the frequency specified in § 60.4365;

(3) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415. Thereafter, maintain records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the initial and subsequent fuel combusted in your stationary combustion turbine at all times does not exceed applicable conditions specified in § 60.4370; or

(4) Conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4415. Thereafter, continue to monitor SO_2 emissions using a CEMS according to the requirements specified in § 60.4372.

(e) If you elect to comply with an input-based standard (lb/MMBtu) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_X and SO_2 emission standards according to the procedures specified in paragraphs (e)(1) or (2) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the fuel flow to the combustion turbine engine and any associated duct burners.

(2) For a configuration where two or more combustion turbine engines are exhausted through a heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit and the total fuel flow to each combustion turbine engine and any associated duct burners. The applicable emissions standard for the affected facility is equal to the most stringent emissions standard for any individual combustion turbine engine.

(f) If you elect to comply with an output-based standard (lb/MWh) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_X and SO_2 emission standards according to the procedures in paragraphs (f)(1), (2), or (3) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility.

(1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the total electrical, mechanical energy, and useful thermal output of the stationary combustion turbine (as applicable).

(2) For a configuration where two or more combustion turbine engines are exhausted through a single heat recovery steam generating unit, you must measure both the total emissions at the exhaust stack for the heat recovery steam generating unit, and the total electrical, mechanical energy, and useful thermal output of the heat recovery steam generating unit and each combustion turbine engine (as applicable). The applicable emissions standard for the affected facility is equal to the most stringent emissions standard for any individual combustion turbine engines.

(3) For a configuration where your combustion turbine engines are exhausted through two or more heat recovery steam generating units which serve a common steam turbine or steam header, you must measure both the emissions at the exhaust stack for each heat recovery steam generating unit and the total electrical or mechanical energy output of each combustion turbine engine (as applicable). To determine the gross energy output of the steam produced by the heat recovery steam generating unit, you must develop a custom method and provide information, satisfactory to the Administrator or delegated authority, apportioning the gross energy output of the steam produced by the heat recovery steam generating units to each of the affected stationary combustion turbines.

§ 60.4334 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in paragraphs §§ 60.4320 and 60.4330 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed; however, if you fail to meet your burden of proving all of the requirements in the affirmative defense, the affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis must also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator or delegated authority with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report, or excess emission report due after the initial occurrence of the violation of the relevant standard.

Monitoring

§ 60.4335 How do I demonstrate compliance with my NO_X emissions standard without using a NO_X CEMS if I use water or steam injection?

If you qualify and elect to demonstrate continuous compliance according to the provisions of § 60.4333(c)(1), you must install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel fired in the combustion turbine engine consistent with the requirements in § 60.4342. Water or steam only needs to be injected when a fuel is being combusted that requires water or steam injection for compliance with the applicable NO_X emissions standard.

§ 60.4340 How do I demonstrate compliance with my NO_X emissions standard without using a NO_X CEMS if I do not use water or steam injection?

(a) If you qualify and elect to demonstrate continuous compliance according to the provisions of § 60.4333(c)(2), you must demonstrate compliance with the NO_X emissions standard using the methods specified in either paragraphs (a)(1) through (3) of this section.

(1) Conduct performance tests according to requirements in § 60.4400;

(2) Monitor the NO_X emissions rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19; or

(3) Install, calibrate, maintain and operate an operating parameter continuous monitoring system according to the requirements specified in paragraph (b) of this section and consistent with the requirements specified in § 60.4342.

(b) Continuous operating parameter monitoring must be performed using the methods specified in paragraphs (b)(1) through (4) of this section as applicable to the stationary combustion turbine.

(1) Selection of the operating parameters used to comply with this paragraph must be identified in the performance test report, and are subject to the review and approval of the delegated permitting authority.

(2) For a lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode when low-NO_X operation is required to comply with the applicable emission NO_X standard.

(3) For a stationary combustion turbine other than a lean premix stationary combustion turbine, you must define parameters indicative of the unit's NO_X formation characteristics, and monitor these parameters continuously.

(4) You must perform the parametric monitoring described in section 2.3 in appendix E to part 75 of this chapter or in § 75.19(c)(1)(iv)(H).

§ 60.4342 How do I monitor NO_X control operating parameters?

(a) If you monitor steam or water to fuel ratio according to § 60.4335 or other parameters according to § 60.4340, the applicable parameters must be continuously monitored and recorded during the performance test, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations, and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must include the information specified in paragraphs (a)(1) through (6) of this section:

(1) Identification of the parameters to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls;

(2) Selected parameter ranges (or designated conditions) indicative of proper operation of the stationary combustion turbine NO_X emission controls, or describe the process by which such range (or designated condition) will be established;

(3) Explanation of the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable);

(4) Description of quality assurance and control practices used to ensure the continuing validity of the data;

(5) Description of the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred); and

(6) Justification for the proposed elements of the monitoring. If a

proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges.

(b) The ratio of water or steam to fuel and parameter continuous monitoring system ranges must be reestablished at least 60 calendar months following the previous calibration and each time the combustion turbine engine is replaced with an overhauled turbine engine as part of an exchange program. An affected facility that has not operated for 60 calendar days prior to the due date of a recalibration you are not required to perform the subsequent recalibration until 45 calendar days after the next operating day.

§ 60.4345 How do I demonstrate compliance with my NO_X emissions standard using a NO_X CEMS?

(a) Each CEMS measuring NO_X emissions used to meet the requirements of this subpart, must meet the requirements in paragraphs (a)(1) through (7) of this section.

(1) You must install, certify, maintain, and operate a NO_X monitor to determine the hourly average NO_X emissions in the units of the standard with which you are complying;

(2) If you elect to comply with the ppm emissions standard, you must also install a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor;

(3) If you elect to comply with an input-based emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow meter to continuously measure the heat input to the affected facility;

(4) If you elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate both a watt meter (or meters) to continuously measure the gross electrical output from the affected facility and a stack flow meter. If you have a CHP combustion turbine and elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate meters to continuously determine the total useful recovered thermal energy. For steam this includes flow rate, temperature, and pressure. If you have a direct mechanical dive application and elect to comply with the output-based emissions standard you must submit a plan to the Administrator or delegated authority for approval of how gross energy output will be determined.

(5) If you elect to comply with the part load NO_X emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow meter to continuously measure the heat input to the affected facility.

(6) If you elect to comply with the temperature dependent NO_X emissions standard, you must install, calibrate, maintain, and operate a thermometer to continuously monitor the ambient temperature.

(7) If you burn natural gas with fuels other than natural gas and elect to comply with the fuels other than natural gas NO_X emissions standard, you must install, calibrate, maintain, and operate a device to continuously monitor when a fuel other than natural gas fuel is combusted in the combustion turbine engine.

(b) Each NO_X CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part. The span value must be 125 percent of the highest applicable standard or highest anticipated hourly NO_X emissions rate. For stationary combustion turbines that do not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart, the delegated permitting authority may approve the use of the NO_X and diluent CEMS that are installed and certified according to appendix A of part 75 of this chapter in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13 of this part, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis.

(c) During each full operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour. For partial operating hours, at least one data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two data points (one in each of two quadrants) are required for each monitor.

(d) Each fuel flow meter must be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively fuel flow meters that meet the installation, certification, and quality assurance requirements in appendix D to part 75 of this chapter are acceptable for use under this subpart.

(e) Each watt meter, steam flow meter, and each pressure or temperature measurement device must be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(f) You must develop, submit to the delegated permitting authority for approval, maintain, and adhere to an on-site quality assurance (QA) plan for all of the continuous monitoring equipment you use to comply with this subpart. At a minimum, such a QA plan must address the requirements of §§ 60.13(d), (e), and (h) of this part. For the CEMS and fuel flow meters, the owner or operator of a stationary combustion turbine that does not use post combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart may, with approval of the delegated permitting authority, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 in appendix B to part 75 of this chapter in lieu of the requirements in § 60.13(d)(1).

§ 60.4350 How do I use the NO_X CEMS data to determine excess emissions?

(a) If you demonstrate continuous compliance using a CEMS for measuring NO_X emissions, excess emissions are defined as the applicable compliance period for the stationary combustion turbine (either 4-operating hours or 30-operating days), during which the average NO_X emissions from your affected facility measured by the CEMS is greater than the applicable maximum allowable NO_X emissions standard specified in § 60.4320 as determined using the procedures specified in this section that apply to your stationary combustion turbine.

(b) The NO_X CEMS data for each operating hour as measured according to the requirements in § 60.4345 must be used to determine the hourly average NO_X emissions. The hourly average for a given operating hour is the average of all data points for the operating hour. However, for any periods during which the NO_X, diluent, flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the hourly average NO_X emissions. All data points that are not collected during out-of-control periods must be used to determine the hourly average NO_X emissions.

(c) For each operating hour in which an hourly average is obtained, the data acquisition and handling system must calculate and record the hourly average NO_X emissions in units of ppm or lb/MMBtu, using the appropriate equation from EPA Method 19 in appendix A–7 of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(d) Correction of measured NO_X concentrations to 15 percent O_2 is only allowed if you elect to comply with the ppm standard in Table 1 of this subpart.

(e) Data used to meet the requirements of this subpart shall not include substitute data values derived from the missing data procedures of part 75 of this chapter, nor shall the data be bias adjusted according to the procedures of part 75 of this chapter.

(f) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. However, for any periods during which the flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the appropriate hourly average value

(g) Calculate the hourly average NO_X emissions rate, in units of the emissions standard under § 60.4320, using either ppm or lb/MMBtu for units complying with the input-based standard or equation 1 of this subpart for units complying with the output-based standard:

(1) For a stationary combustion turbine complying with an output-based emissions standard use Equation 1.

$$E = \frac{(NO_x)_h \times Q}{P} \qquad \text{(Eq. 1)}$$

Where:

E = Hourly NO_X emissions rate, in lb/MWh,

$(NO_X)_h$ = Average hourly NO_X emissions rate, in lb/MMBtu,

Q = Hourly heat input to the stationary combustion turbine, in MMBtu, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, an O_2 or CO_2 CEMS and a stack flow meter, or the methodologies in appendix F to part 75 of this chapter, and

P = Gross energy output of the stationary combustion turbine in MWh.

(2) The gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine engine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit, and the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, as calculated using Equations 2 and 3 of this subpart:

$$P = \frac{(Pe)t}{T} + \frac{(Pe)c}{T} + Ps + Po \qquad \text{(Eq. 2)}$$

Where:

P = Gross energy output of the stationary combustion turbine system in MWh,

$(Pe)_t$ = Electrical or mechanical energy output of the stationary combustion turbine in MWh,

$(Pe)_c$ = Electrical or mechanical energy output (if any) of the steam turbine in MWh,

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh, and

P_o = Other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the stationary combustion turbine.

T = Electric Transmission and Distribution Factor. Equal to 0.95 for CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis. Equal to 1.0 for all other combustion turbines.

$$P_s = \frac{Q_m \times H}{3.413 \times 10^6 \ Btu/MWh} \qquad \text{(Eq. 3)}$$

Where:

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh,

Q_m = Measured steam flow in lb,

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and

3.413×10^6 = Conversion factor from Btu to MWh.

(3) For mechanical drive applications complying with the output-based standard, use equation 4 of this subpart:

$$E = \frac{(NO_x)_m}{BL \times AL} \qquad \text{(Eq. 4)}$$

Where:

E = NO_X emissions rate in lb/MWh, $(NO_X)_m$ = NO_X emissions rate in lb/h,

BL = Manufacturer's base load rating of turbine, in MW, and

AL = Actual load as a percentage of the base load rating.

(h) For each simple cycle stationary combustion turbines, excess NO_X emissions are determined on a 4-operating hour averaging period basis using the NO_X CEMS data and procedures specified in paragraphs (h)(1) through (4) of this section as applicable to the NO_X emissions standard in Table 1 to this subpart.

(1) For each 4-operating hour period, compute the 4-operating hour rolling average NO_X emissions as the heat input weighted average of the hourly average of NO_X emissions for a given operating hour and the 3 operating hours immediately preceding that operating hour using the applicable equation in paragraphs (h)(2) through (4) of this section. If the 4-operating hour period contains more than one operating hour with no data points (one or more continuous monitors was out-of-control for the entire hour), report the 4-operating hour rolling average NO_X emissions rate determined for the period as occurring during a period with monitor downtime.

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating hour rolling average NO_X emissions rate and the applicable 4-operating hour rolling average NO_X emissions standard, calculated using hourly values from in Table 1, using Equation 5 of this subpart.

$$E = \frac{\sum_{i=1}^{4} (E_i \times Q_i)}{\sum_{i=1}^{4} Q_i} \quad \text{(Eq. 5)}$$

Where:

E = 4-operating hour rolling average NO_X emissions (lb/MMBtu or ng/J),

E_i = Hourly average NO_X emissions rate or emissions standard for operating hour ''i'' (lb/MMBtu or ng/J), and

Q_i = Total heat input to stationary combustion turbine for operating hour ''i'' (MMBtu or J as appropriate).

(3) If you elect to comply with the applicable output-based emissions rate standard, calculate the 4-operating hour rolling average NO_X emissions rate using equation 6–1 of this subpart. Calculate the applicable 4-operating hour rolling average NO_X emissions standard, calculated using hourly values from in Table 1, using Equation 6–2 of this subpart.

$$E = \frac{\sum_{i=1}^{4} (E_i \times Q_i)}{\sum_{i=1}^{4} P_i} \quad \text{(Eq. 6-1)}$$

Where:

E = 4-operating hour rolling average NO_X emissions rate (lb/MWh or ng/J),

E_i = Hourly average NO_X emissions rate for operating hour ''i'' (lb/MMBtu or ng/J),

Q_i = Total heat input to stationary combustion turbine for operating hour ''i'' (MMBtu or J as appropriate), and

P_i = Total gross energy output from stationary combustion turbine for operating hour ''i'' (MWh or J).

$$E = \frac{\sum_{i=1}^{4} (E_i \times P_i)}{\sum_{i=1}^{4} P_i} \quad \text{(Eq. 6-2)}$$

Where:

E = 4-operating hour rolling average NO_X emissions standard (lb/MWh or ng/J),

E_i = Hourly NO_X emissions standard for operating hour ''i'' (lb/MWh or ng/J), and

P_i = Total gross energy output from stationary combustion turbine for operating hour ''i'' (MWh or J).

(4) If you elect to comply with the applicable concentration standard using a numerical average, calculate both the 4-operating hour rolling average NO_X emissions rate and the applicable 4-operating hour rolling average NO_X emissions standard, calculated using hourly values from in Table 1, using Equation 7 of this subpart.

$$E = \frac{\sum_{i=1}^{4} (C_{ave\,i})}{4} \quad \text{(Eq. 7)}$$

Where:

E = 4-operating hour rolling average NO_X emissions (ppm), and

C_{avei} = 1-hour average NO_X concentration as determined using the procedure in § 60.13(h) or emissions standard for operating hour ''i'' (ppm).

(i) For each combined cycle combustion turbine and CHP combustion turbine, you must determine excess emissions on a 30 operating-day rolling average basis. The measured emissions rate is the NO_X emissions measured by the CEMS for a given operating day and the 29 operating days immediately preceding that day. Once each day, calculate a new 30-operating day average measured emissions rate using all hourly average values based on non out-of-control NO_X emission data for all operating hours during the previous 30-operating day operating period. Report any 30-operating day periods for which you have less than 75 percent data availability as monitor downtime. If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the measured emissions rate and emissions standard using Equation 8 of this subpart. If you elect to comply with the applicable output-based emissions rate standard, calculate the measured emissions rate using Equation 9–1 of this subpart and calculate the emissions standard using Equation 9–2 of this subpart. If you elect to comply with the applicable concentration standard using a numerical average, calculate the measured emissions rate and emissions standard using Equation 10 of this subpart.

$$E = \frac{\sum_{i=1}^{n} (E_i \times Q_i)}{\sum_{i=1}^{n} Q_i} \quad \text{(Eq. 8)}$$

Where:

E = 30-operating day rolling average NO_X measured emissions rate or emissions standard for combined cycle combustion turbines and CHP combustion turbines (lb/MMBtu or ng/J),

E_i = Hourly average NO_X emissions rate or emissions standard for non out-of-control operating hour ''i'' (lb/MMBtu or ng/J),

Q_i = Total heat input to stationary combustion turbine for non out-of-control operating hour ''i'' (MMBtu or J as appropriate), and

n = Total number of non out-of-control operating hours in the 30 operating-day period.

$$E = \frac{\sum_{i=1}^{n} (E_i \times Q_i)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 9-1)}$$

Where:

E = 30-operating day average NO_X measured emissions rate for combined cycle combustion turbines and CHP combustion turbines (lb/MWh or ng/J),

E_i = Hourly average NO_X emissions rate for non out-of-control operating hour ''i'' (lb/MMBtu or ng/J),

Q_i = Total heat input to stationary combustion turbine for non out-of-control operating hour ''i'' (MMBtu or J as appropriate),

P_i = Total gross energy output from stationary combustion turbine for non out-of-control operating hour ''i'' (MWh or J), and

n = Total number of operating non out-of-control hours in the 30 operating-day period.

$$E = \frac{\sum_{i=1}^{n} (E_i \times P_i)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 9-2)}$$

Where:

E = 30-operating day average NO_X emissions standard for combined cycle combustion turbines and CHP combustion turbines (lb/MWh or ng/J),

E_i = Hourly NO_X emissions standard for non out-of-control operating hour ''i'' (lb/MWh or ng/J),

P_i = Total gross energy output from stationary combustion turbine for non out-of-control operating hour ''i'' (MWh or J), and

n = Total number of operating non out-of-control hours in the 30 operating-day period.

$$E = \frac{\sum_{i=1}^{n} (C_{ave\,i})}{n} \quad \text{(Eq. 10)}$$

Where:

E = 30-operating day rolling average NO_X measured emissions rate or emissions standard for combined cycle combustion turbines and CHP combustion turbines (ppm),

C_{avei} = 1-hour average NO_X concentration as determined using the procedure in § 60.13(h) or emissions standard for non out-of-control operating hour ''i'' (ppm), and

n = Total number of operating hours in the 30 operating-day period.

§ 60.4360 How do I use fuel sulfur analysis to determine the total sulfur content of the fuel combusted in my stationary combustion turbine?

(a) If you elect to demonstrate compliance with a SO_2 emissions standard according to § 60.4333(d)(2), the fuel analyses may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency as determined by the delegated permitting authority using the sampling frequency specified in § 60.4365.

(b) Representative fuel analysis samples may be collected either manually or by an automatic sampling system. For automatic sampling, following ASTM D5287 (incorporated by reference, see § 60.17) for gaseous fuels or ASTM D4177 (incorporated by reference, see § 60.17) for liquid fuels. For reference purposes when manually collecting gaseous samples, see Gas Processors Association Standard 2166 (incorporated by reference, see § 60.17). For reference purposes when manually collecting liquid samples, see either Gas Processors Association Standard 2174 or the procedures for manual pipeline sampling in section 14 of ASTM D4057 (both of which are incorporated by reference, see § 60.17).

(c) Each collected fuel analysis sample must be analyzed for the total sulfur content of the fuel and heating value using the methods specified in paragraphs (c)(1) or (2) of this section, as applicable to the fuel type.

(1) For the sulfur content of liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see § 60.17). For the heating value of liquid fuels, ASTM D240 or D4809 (both of which are incorporated by reference, see § 60.17); or

(2) For the sulfur content of gaseous fuels, ASTM D1072, or alternatively D3246, D4468, or D6667 (all of which are incorporated by reference, see § 60.17). If the total sulfur content of the gaseous fuel during the most recent compliance demonstration was less than half the applicable standard, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used. For the heating value of gaseous fuels, ASTM D1826, or alternatively D3588, D4891, or D7164, or Gas Processors Association Standard 2172 (all of which are incorporated by reference, see § 60.17).

§ 60.4365 How frequently must I determine the fuel sulfur content?

(a) If you are complying with requirements in § 60.4360, the total sulfur content of all fuels combusted in each stationary combustion turbine subject to an SO_2 emissions standard in § 60.4330 must be determined according to the schedule specified in paragraphs (a)(1) or (2) of this section, as applicable to the fuel type, unless you determine a custom schedule for the stationary combustion turbine according to paragraph (b) of this section.

(1) *Liquid fuel.* Use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 in appendix D to part 75 of this chapter (*i.e.* flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with liquid fuel already in the intended storage tank).

(2) *Gaseous fuel.* If the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per operating day.

(b) *Custom schedules.* As an alternative to the requirements of paragraph (a) of this section, you may implement custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply using the procedures provided in either paragraph (b)(1) and (2) of this section. Either you or the fuel vendor may perform the sampling. As an alternative to using one of these procedures, you may use a custom schedule that has been substantiated with data and approved by the Administrator or delegated authority as a change in monitoring prior to being used to comply with the applicable standard in § 60.4330.

(1) You may determine and implement a custom sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) Obtain daily total sulfur content measurements for 30 consecutive operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content must be as specified in paragraph (b)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals provided the fuel source or supplier does not change. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable standard, follow the procedures in paragraph (b)(1)(iii) of this section. If any measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable standard, but none exceeds the applicable standard, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable standard, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring must continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable standard, are obtained. At that point, the applicable procedures of paragraph (b)(1)(ii) or (iii) of this section must be followed.

(2) You may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 in appendix D to part 75 of this chapter to determine and implement a sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) If the maximum fuel sulfur content obtained from any of the 720 hourly samples does not exceed half the applicable standard, then the minimum required sampling frequency must be one sample at 12 month intervals.

(ii) If any sample result exceeds half the applicable standard, but none exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iii) of this section.

(iii) If the sulfur content of any of the 720 hourly samples exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iv) of this section.

§ 60.4370 How do I demonstrate compliance with my SO_2 emissions standard using records of the fuel sulfur content?

(a) If you elect to demonstrate compliance with a SO_2 emissions standard according to § 60.4333(d)(3), you must maintain on-site records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the fuel combusted in your stationary combustion turbine at all times does not exceed the conditions specified in paragraph (b) through (e) of this section, as applicable to your stationary combustion turbine.

(b) If your stationary combustion turbine is subject to the SO_2 emissions standard in § 60.4330(a), then the fuel combusted must have a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) heat input or less.

(c) If your stationary combustion turbine is subject to the SO_2 emissions standard in § 60.4330(b), then the total sulfur content of the gaseous fuel combusted must be 650 (mg/scm) (28 gr/100 scf).

(d) If your stationary combustion turbine is subject to the SO_2 emissions standard in § 60.4330(c) or (d), the total sulfur content of the fuel combusted must be:

(1) For natural gas, 140 gr/100 scf or less.

(2) For fuel oil, 0.40 weight percent (4,000 ppmw) or less.

(3) For other fuels, potential SO_2 emissions of 180 ng/J (0.42 lb/MMBtu) heat input or less.

(e) Representative fuel sampling data following the procedures specified in section 2.3.1.4 or 2.3.2.4 in appendix D to part 75 of this chapter documenting that the fuel meets the part 75 requirements to be considered either pipeline natural gas or natural gas.

§ 60.4372 How do I demonstrate compliance with my SO_2 emissions standard and determine excess emissions using a SO_2 CEMS?

(a) If you demonstrate continuous compliance using a CEMS for measuring SO_2 emissions, excess emissions are defined as the applicable averaging period, either 4-operating hour or 30-operating day, during which the average SO_2 emissions from your stationary combustion turbine measured by the CEMS exceeds the applicable SO_2 emissions standard specified in § 60.4330 as determined using the procedures specified in this section that apply to your stationary combustion turbine.

(b) You must install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations at the outlet of your stationary combustion turbine, and record the output of the system.

(c) The 1-hour average SO_2 emissions rate measured by a CEMS must be expressed in ng/J or lb/MMBtu heat input and must be used to calculate the average emissions rate under § 60.4330.

(d) You must use the procedures for installation, evaluation, and operation of the CEMS as specified in § 60.13 and paragraphs (d)(1) through (3) of this section.

(1) Each CEMS must be operated according to the applicable procedures under Performance Specifications 1, 2, and 3 in appendix B of this part;

(2) Quarterly accuracy determinations and daily calibration drift tests must be performed according to Procedure 1 in appendix F of this part; and

(3) The span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the stationary combustion turbine if no SO_2 control device is used) must be 125 percent of either the highest applicable standard or highest potential SO_2 emissions rate of the fuel combusted.

(e) Correction of measured SO_2 concentrations to 15 percent O_2 is not allowed.

(f) If you have installed and certified a SO_2 CEMS that meets the requirements of part 75 of this chapter, the delegated permitting authority can approve that only quality assured data from the CEMS must be used to identify excess emissions under this subpart. You must report periods where the missing data substitution procedures in subpart D of part 75 are applied as monitoring system downtime in the excess emissions and monitoring performance report required under § 60.7(c).

(g) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(h) Calculate the hourly average SO_2 emissions rate, in units of the emissions standard under § 60.4330, using lb/MMBtu for units complying with the input-based standard or using equation 11 of this subpart for units complying with the output-based standard:

(1) For simple-cycle operation:

$$E = \frac{(SO_2)_h \times Q}{P} \quad \text{(Eq. 11)}$$

Where:

E = Hourly SO_2 emissions rate, in lb/MWh,

$(SO_2)_h$ = Average hourly SO_2 emissions rate, in lb/MMBtu,

Q = Hourly heat input rate to the stationary combustion turbine, in MMBtu, measured using the fuel flow meter(s), *e.g.,* calculated using Equation D–15a in appendix D to part 75 of this chapter, an O_2 or CO_2 CEMS and a stack flow meter, or the methodologies in appendix F to part 75 of this chapter, and

P = Gross energy output of the stationary combustion turbine in MWh.

(2) The gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the stationary combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit, and the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, as calculated using Equations 12 and 13 of this subpart.

$$P = \frac{(Pe)t}{T} + \frac{(Pe)c}{T} + Ps + Po \quad \text{(Eq. 12)}$$

Where:

P = Gross energy output of the stationary combustion turbine system in MWh,

$(Pe)_t$ = Electrical or mechanical energy output of the stationary combustion turbine in MWh,

$(Pe)_c$ = Electrical or mechanical energy output (if any) of the steam turbine in MWh,

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh, and

P_o = Other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the stationary combustion turbine.

T = Electric Transmission and Distribution Factor. Equal to 0.95 for CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis. Equal to 1.0 for all other combustion turbines.

$$P_s = \frac{Q_m \times H}{3.413 \times 10^6 \; Btu/MWh} \quad \text{(Eq. 13)}$$

Where:

P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh,

Q_m = Measured steam flow rate in lb,

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and

3.413×10^6 = Conversion factor from Btu to MWh.

(3) For mechanical drive applications complying with the output-based standard, use equation 14 of this subpart:

$$E = \frac{(SO_2)_m}{BL \times AL} \quad \text{(Eq. 14)}$$

Where:

E = SO_2 emissions rate in lb/MWh,

$(SO_2)_m$ = SO_2 emissions rate in lb/h,

BL = Manufacturer's base load rating of turbine, in MW, and

AL = Actual load as a percentage of the base load rating.

(i) For stationary combustion turbines other than combined cycle combustion turbines and CHP combustion turbines, you must determine excess emissions on a 4-operating hour rolling average basis. The ''4-operating hour rolling average SO_2 measured emissions rate'' is the SO_2 emissions measured by the CEMS for a given operating hour and the 3 consecutive operating hours immediately preceding that hour expressed in the units appropriate for the SO_2 emissions standard that is applied to your stationary combustion turbine. Each operating hour, calculate the 4-operating hour rolling average SO_2 measured emissions rate using all of the non out-of-control SO_2 emission data obtained during the previous 4-operating hour operating period. If the 4-operating hour period contains more than one operating hour with no data points (one or more CEMS was out-of-control for the entire hour), report the 4-operating hour rolling average SO_2 emissions rate determined for the period as occurring during a period with monitor downtime. If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the measured emissions rate and the emissions standard using Equation 15 of this subpart. If you elect to comply with the applicable output-based emissions standard, calculate the measured emissions rate using Equation 16–1 of this subpart and calculate the emissions standard using Equation 16–2 of this subpart.

$$E = \frac{\sum_{i=1}^{4} (E_i \times Q_i)}{\sum_{i=1}^{4} Q_i} \quad \text{(Eq. 15)}$$

Where:

E = 4-operating hour rolling average SO_2 measured emissions rate or emissions standard for stationary combustion turbines other than combined cycle combustion turbines and CHP combustion turbines (lb/MMBtu or ng/J),

E_i = Hourly average SO_2 emissions rate or emissions standard for non out-of-control operating hour ''i'' (lb/MMBtu or ng/J), and

Q_i = Total heat input to stationary combustion turbine for non out-of-control operating hour ''i'' (MMBtu or J as appropriate).

$$E = \frac{\sum_{i=1}^{4} (E_i \times Q_i)}{\sum_{i=1}^{4} P_i} \quad \text{(Eq. 16-1)}$$

Where:

E = 4-operating hour rolling average SO_2 measured emissions rate for stationary combustion turbines other than combined cycle combustion turbines and CHP combustion turbines (lb/MWh or ng/J),

E_i = Hourly average SO_2 emissions rate for non out-of-control operating hour ''i'' (lb/MMBtu or ng/J),

Q_i = Total heat input to stationary combustion turbine for non out-of-control operating hour ''i'' (MMBtu or J as appropriate), and

P_i = Total gross energy output from stationary combustion turbine for non out-of-control operating hour ''i'' (MWh or J).

$$E = \frac{\sum_{i=1}^{4} (E_i \times P_i)}{\sum_{i=1}^{4} P_i} \quad \text{(Eq. 16-2)}$$

Where:

E = 4-operating hour rolling average SO_2 emissions standard for stationary combustion turbines other than combined cycle combustion turbines and CHP combustion turbines (lb/MWh or ng/J),

E_i = Hourly SO_2 emissions standard for non out-of-control operating hour ''i'' (lb/MMBtu or ng/J), and

P_i = Total gross energy output from stationary combustion turbine for non out-of-control operating hour ''i'' (MWh or J).

(ii) For combined cycle combustion turbines and CHP combustion turbines, you must determine excess emissions on a 30 operating-day rolling average basis. The excess emissions level is the heat input weighted-average of the SO_2 emissions measured by the CEMS for a given operating day and the 29 operating days immediately preceding that day. Once each day, calculate a new 30-operating day average measured emissions rate using all hourly average values based on non out-of-control SO_2 emission data for all operating hours during the previous 30-operating day operating period. Report any 30-operating day periods for which you have less than 75 percent data availability as monitor downtime. If you elect to comply with the applicable heat input-based emissions standard, calculate the measured emissions rate and emissions rate using Equation 17 of this subpart. If you elect to comply with the applicable output-based standard, calculate the measured emissions rate using Equation 18–1 of this subpart and calculate the emissions standard using Equation 18–2 of this subpart.

$$E = \frac{\sum_{i=1}^{n} (E_i \times Q_i)}{\sum_{i=1}^{n} Q_i} \quad \text{(Eq. 17)}$$

Where:

E = 30-operating day rolling average SO_2 measured emissions rate or emissions standard for combined cycle combustion turbines and CHP combustion turbines (lb/MMBtu or ng/J),

E_i = Hourly average SO_2 emissions rate or emissions standard for non out-of-control operating hour ''i'' (lb/MMBtu or ng/J),

Q_i = Total heat input to stationary combustion turbine for non out-of-control operating hour ''i'' (MMBtu or J as appropriate), and

n = Total number of non out-of-control operating hours in the 30 operating-day period.

$$E = \frac{\sum_{i=1}^{n} \left(E_i \times Q_i\right)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 18-1)}$$

Where:

E = 30-operating day average SO_2 measured emissions rate for combined cycle combustion turbines and CHP combustion turbines (lb/MWh or ng/J),

E_i = Hourly average SO_2 measured emissions rate for non out-of-control operating hour ''i'' (lb/MMBtu or ng/J),

Q_i = Total heat input to stationary combustion turbine for non out-of-control operating hour ''i'' (MMBtu or J as appropriate),

P_i = Total gross energy output from stationary combustion turbine for non out-of-control operating hour ''i'' (MWh or J), and

n = Total number of non out-of-control operating hours in the 30 operating-day period.

$$E = \frac{\sum_{i=1}^{n} \left(E_i \times P_i\right)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 18-2)}$$

Where:

E = 30-operating day average SO_2 emissions standard for combined cycle combustion turbines and CHP combustion turbines (lb/MWh or ng/J),

E_i = Hourly SO_2 emissions standard for non out-of-control operating hour ''i'' (lb/MWh or ng/J),

P_i = Total gross energy output from stationary combustion turbine for non out-of-control operating hour ''i'' (MWh or J), and

n = Total number of non out-of-control operating hours in the 30 operating-day period.

Recordkeeping and Reporting

§ 60.4375 What reports must I submit?

(a) An owner or operator of a stationary combustion turbine that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, must submit reports of excess emissions and monitor downtime, according to § 60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction.

(b) An owner or operator of a stationary combustion turbine that performs performance tests to demonstrate compliance with this subpart must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test, except as specified in paragraph (c) of this part.

(c)(1) Within 60 days after the date of completing each performance test (see § 60.8) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(2) Within 60 days after the date of completing each CEMS performance evaluation test (see § 60.13), you must submit the relative accuracy test audit data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool as mentioned in paragraph (c)(1) of this section. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically to EPA's CDX.

(3) All reports required by this subpart not subject to the requirements in paragraphs (c)(1) and (2) of this section must be sent to the Administrator or delegated authority at the appropriate address listed in § 63.13. The Administrator or delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator or delegated authority retains the right to require submittal of reports subject to paragraphs (c)(1) and (2) of this section in paper format.

(d) The notification requirements of § 60.8 apply to the initial and subsequent performance tests.

(e) An owner or operator of an affected facility complying with § 60.4333(b)(3) must notify the delegated permitting authority within 15 calendar days after the facility recommences operation.

(f) An owner or operator of an affected facility complying with § 60.4333(b)(4) must notify the delegated permitting authority within 15 calendar days after the facility has operated more than 50 operating hours since the date the previous performance test was required to be conducted.

§ 60.4380 How are NO_X excess emissions and monitor downtime reported?

(a) For reports required under § 60.4375(a), periods of excess emissions and monitor downtime for stationary combustion turbines using water or steam to fuel ratio monitoring are reported as specified in paragraphs (a)(1) through (3) of this section.

(1) An excess emission that must be reported is any operating hour for which the 4-operating hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, is less than the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320, as established during the most recent performance test. Any operating hour during which no water or steam is injected into the turbine when the specific conditions require water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime that must be reported is any operating hour in which water or steam is injected into the turbine, but the parametric data needed to determine the steam or water to fuel ratio are unavailable or out-of-control.

(3) Each report must include the average steam or water to fuel ratio,

average fuel consumption, and the stationary combustion turbine load during each excess emission.

(b) For reports required under § 60.4375(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (b)(1) through (3) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating hour or 30-operating day rolling average NO_X emissions rate exceeds the applicable emissions standard in § 60.4320 as determined in § 60.4350.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters are either missing or out-of-control: NO_X concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

(3) For hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponded to the highest emissions standard.

(c) For reports required under § 60.4375(a), periods of excess emissions and monitor downtime for stationary combustion turbines using combustion parameters or parameters that document proper operation of the NO_X emission controls excess emissions and monitor downtime are reported as specified in paragraphs (c)(1) and (2) of this section.

(1) Excess emissions that must be reported are each 4-operating hour rolling average in which any monitored parameter (as averaged over the 4 operating-hour period) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) Periods of monitor downtime that must be reported are each operating hour in which any of the required parametric data are either not recorded or are out-of-control.

§ 60.4385 How are SO_2 excess emissions and monitor downtime reported?

(a) If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitor downtime are defined as follows:

(1) For samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, excess emissions occur each operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the stationary combustion turbine exceeds the applicable standard and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur standard.

(2) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent, 0.15 weight percent, or 0.40 weight percent as applicable. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been combusted, you may resume using the as-delivered sampling option.

(3) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(b) If you choose the option to maintain records of the fuel sulfur content, excess emissions are defined as any period during which you burn a fuel that you do not have appropriate fuel records or that fuel contains sulfur greater than the applicable standard.

(c) For reports required under § 60.4375(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (c)(1) through (2) of this section.

(1) An excess emission that must be reported is any unit operating period in which the 4-operating hour or 30-operating day rolling average SO_2 emissions rate exceeds the applicable emissions standard in § 60.4330 as determined in § 60.4372.

(2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters are either missing or out-of-control: SO_2 concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes.

§ 60.4390 What records must I maintain?

(a) You must maintain records of your information used to demonstrate compliance with this subpart as specified in § 60.7.

(b) An owner or operator of a stationary combustion turbine that uses the other fuels, part-load, or low temperature NO_X standards in the compliance demonstration must maintain concurrent records of the hourly heat input, percent load, ambient temperature, and emissions data as applicable.

(c) An owner or operator of a stationary combustion turbine that uses the tuning NO_X standard in the compliance demonstration must identify the hours on which the maintenance was performed and a description of the maintenance.

(d) An owner or operator of a stationary combustion turbine that demonstrates compliance using the output-based standard must maintain concurrent records of the total gross energy output and emissions data.

(e) An owner or operator of a stationary combustion turbine that demonstrates compliance using the water or steam to fuel ratio or a parameter continuous monitoring system must maintain continuous records of the appropriate parameters.

(f) An owner or operator of a stationary combustion turbine complying with the fuel based SO_2 standard must maintain records of the results of all fuel analyses or a current, valid purchase contract, tariff sheet, or transportation contract.

§ 60.4395 When must I submit my reports?

Consistent with § 60.7(c), all reports required under § 60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct performance tests to demonstrate compliance with my NO_X emissions standard if I do not have a NO_X CEMS?

(a) You must conduct the performance test according to the requirements in § 60.8 and paragraphs (b) through (d) of this section.

(b) You must use the methods in either paragraph (b)(1) or (2) of this section to measure the NO_X concentration for each test run.

(1) Measure the NO_X concentration using EPA Method 7E in appendix A–4 of this part or EPA Method 20 in appendix A–7 of this part. In addition, when only natural gas is being combusted ASTM D6522 (incorporated by reference, see § 60.17) can be used instead of EPA Method 20 in appendix

A–7 of this part to determine the oxygen content in the exhaust gas. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A–1 of this part, and measure and record the electrical and thermal output from the unit. Then, use Equation 19 of this subpart to calculate the NO_X emissions rate:

$$E = \frac{1.194 \times 10^{-7} \times (NO_x)_c \times Q_{std}}{P} \quad \text{(Eq. 19)}$$

Where:

E = NO_X emissions rate, in lb/MWh,
1.194×10^{-7} = Conversion constant, in lb/dscf-ppm,
$(NO_X)_c$ = Average NO_X concentration for the run, in ppm,
Q_{std} = Average stack gas volumetric flow rate, in dscf/h, and
P = Average gross electrical and mechanical energy output of the stationary combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for CHP operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation or to enhance the performance of the stationary combustion turbine, in MW, calculated according to § 60.4350.

(2) Measure the NO_X and diluent gas concentrations, using either EPA Method 7E in appendix A–4 of this part and EPA Method 3A in appendix A–2 of this part, or EPA Method 20 in appendix A–7 of this part. In addition, when only natural gas is being combusted ASTM D6522 (incorporated by reference, see § 60.17) can be used instead of EPA Method 3A in appendix A–2 of this part or EPA Method 20 in appendix A–7 of this part to determine the oxygen content in the exhaust gas. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O_2 or CO_2 CEMS along with a stack flow meter, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard measure the electrical, mechanical, and thermal output of the unit. Use EPA Method 19 in appendix A–7 of this part to calculate the NO_X emissions rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 of this subpart in § 60.4350(f) to calculate the NO_X emissions rate in lb/MWh.

(c) You must use the methods in either paragraph (c)(1) or (2) of this section to select the sampling traverse points for NO_X and (if applicable) diluent gas.

(1) You must select the sampling traverse points for NO_X and (if applicable) diluent gas according to EPA Method 20 in appendix A–7 of this part or EPA Method 1 in appendix A–1 of this part (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(2) As an alternative to paragraph (c)(1) of this section, you may select the sampling traverse points for NO_X and (if applicable) diluent gas according to requirements in paragraphs (c)(2)(i) and (ii) of this section.

(i) You perform a stratification test for NO_X and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) in appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you use the following alternative sample point selection criteria for the performance test specified in paragraphs (c)(2)(ii)(A) through (

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For a stationary combustion turbine subject to a NO_X emissions standard greater than 15 ppm at 15 percent O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For a stationary combustion turbine subject to a NO_X emissions standard less than or equal to 15 ppm at 15 percent O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(d) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of the base load rating. You may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 60 minutes.

(1) If the stationary combustion turbine combusts both natural gas and fuels other than natural gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle or CHP combustion turbine with supplemental heat (duct burner), you must measure the total NO_X emissions downstream of the duct burner. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 in appendix A–7 of this part or EPA Method 7E in appendix A–4 of this part run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320 NO_X emissions standard.

(4) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or

(as described in § 60.4405) as part of the initial performance test of the affected unit.

(5) The ambient temperature must be greater than 0 °F during the performance test. The delegated permitting authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

§ 60.4405 How do I conduct a performance test if I use a NO_X CEMS?

(a) If you use a CEMS the performance test must be performed according to the procedures specified in paragraph (b) of this section.

(b) The initial performance test must use the procedure specified in paragraphs (b)(1) through (4) of this section.

(1) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of the base load rating. You may perform testing at the highest achievable load point, if at least 75 percent of the base load rating cannot be achieved in practice. The ambient temperature must be greater than 0 °F during the RATA runs. The delegated permitting authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

(2) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard, measure the electrical and thermal output from the unit.

(3) Use the test data both to demonstrate compliance with the applicable NO_X emissions standard under § 60.4320 and to provide the required reference method data for the RATA of the CEMS described under § 60.4342.

(4) Compliance with the applicable emissions standard in § 60.4320 is achieved if the sum of the NO_X emissions divided by the heat input (or gross energy output) for all the RATA runs, expressed in units of lb/MMBtu or lb/MWh, does not exceed the emissions standard.

§ 60.4415 How do I conduct performance tests to demonstrate compliance with my SO_2 emissions standard?

(a) An owner or operator of an affected facility complying with the fuel based standard must submit fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) to satisfy the requirements of § 60.8.

(b) An owner or operator of an affected facility complying with the SO_2 emissions standard must conduct the performance test by measuring the SO_2 emissions in the stationary combustion turbine exhaust gases using the methods in either paragraph (b)(1) or (2) of this section.

(1) Measure the SO_2 concentration using EPA Methods 6, 6C, 8 in appendix A–4 of this part, or EPA Method 20 in appendix A–7 of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, ''Flue and Exhaust Gas Analyses,'' manual methods for sulfur dioxide (incorporated by reference, see § 60.17) can be used instead of EPA Method 6 in appendix A–4 of this part or EPA Method 20 in appendix A–7 of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A–1 of this part, and measure and record the electrical and thermal output from the unit. Then use Equation 20 of this subpart to calculate the SO_2 emissions rate:

$$E = \frac{1.664 \times 10^{-7} \times (SO_2)_c \times Q_{std}}{P} \quad \text{(Eq. 20)}$$

Where:

E = SO_2 emissions rate, in lb/MWh,

1.664×10^{-7} = Conversion constant, in lb/dscf-ppm,

$(SO_2)_c$ = Average SO_2 concentration for the run, in ppm,

Q_{std} = Average stack gas volumetric flow rate, in dscf/h, and

P = Average gross electrical and mechanical energy output of the stationary combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for CHP operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation or to enhance the performance of the stationary combustion turbine, in MW, calculated according to § 60.4350(f)(2).

(2) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 in appendix A–4 of this part and EPA Method 3A in appendix A–2 of this part, or EPA Method 20 in appendix A–7 of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see § 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O_2 or CO_2 CEMS along with a stack flow meter, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output based standard measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A–7 of this part to calculate the SO_2 emissions rate in lb/MMBtu. Then, use Equations 11 and, if necessary, 12 and 13 of this subpart in § 60.4372 to calculate the SO_2 emissions rate in lb/MWh.

Definitions

§ 60.4420 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.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Base load rating means 100 percent of the manufacturer's design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Byproduct means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas and fuel oil) and combusted in a stationary combustion turbine. Gaseous substances with CO_2 levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to generate steam that is used exclusively to create additional power output in a steam turbine.

Combined heat and power (CHP) combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to heat water or another medium, generate steam for useful purposes other than exclusively for additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine engine means the air compressor, combustor, and turbine sections of a stationary combustion turbine.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry standard cubic foot (dscf) means the quantity of gas, free of uncombined water, that would occupy a volume of 1 cubic foot at 293 Kelvin (20.0 °C) and 101.325 kPa of pressure.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for maintenance checks and readiness testing to retain their status as emergency combustion turbines, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X or SO_2 emissions rate are higher than the applicable emissions standard in § 60.4320 or § 60.4330; (2) the total sulfur content of the fuel being combusted in the affected facility or the SO_2 emissions exceeds the standard specified in § 60.4330; or (3) the recorded value of a particular monitored parameter, including ration of water or steam to fuel, is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator or delegated authority, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fuel oil means a fluid mixture of hydrocarbons that maintains a liquid state at ISO conditions. Additionally, fuel oil must meet the definition of either distillate oil or residual oil as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17) or diesel fuel as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17).

Gross useful energy output means:

(1) For simple cycle and combined cycle combustion turbines, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s).

(2) For a CHP combustion turbine, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process).

(3) For a CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis, the gross useful work performed is the gross electrical or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process).

Heat recovery steam generating unit (HRSG) means a unit where the 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 electric utility steam generating unit (IGCC) means an electric utility steam generating unit that burns solid-derived fuels in a combined-cycle combustion turbine. No solid fuel is directly combusted in the unit during operation.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.325 kilopascals (kPa) pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Low-Btu gas means biogas or any gas with a heating value of less than 26 megajoules per standard cubic meter (MJ/scm) (700 Btu/scf).

Natural gas means a fluid mixture of hydrocarbons, composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 MJ/scm (950 and 1,100 Btu/scf), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 460 mg/scm (20.0 gr/100 scf) or less of total sulfur. Finally, natural gas does not include any gaseous fuel produced in a process which might result in highly variable heating value.

Noncontinental area means Guam, American Samoa, the Northern Mariana Islands, or offshore platforms.

Offshore turbine means a stationary combustion turbine located on a platform in an ocean.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial operating hour.

Out-of-control period means any period beginning with the quadrant corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the quadrant corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

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

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.

Stationary combustion turbine means all equipment, including but not limited to the combustion turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems, heat recovery system, steam turbine, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components. 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.

Standard cubic foot (scf) means the quantity of gas that would occupy a volume of 1 cubic foot at 293 Kelvin (20.0 °C) and 101.325 kPa of pressure.

Standard cubic meter (scm) means the quantity of gas that would occupy a volume of 1 cubic meter at 293 Kelvin (20.0 °C) and 101.325 kPa of pressure.

Turbine tuning means planned maintenance of a lean premix combustion turbine engine involving adjustment of the operating configuration to maintain proper combustion dynamics. Turbine tuning is limited to 30 hours annually.

Useful thermal output means the thermal energy made available for processes and applications other than electrical or mechanical generation or to enhance the performance of the stationary combustion turbine (i.e., the thermal energy made available for use in any industrial or commercial process or used in any heating application). Useful thermal output for this subpart is measured relative to the enthalpy of the thermal output in its most prevalent form at ISO conditions (e.g., liquid water).

TABLE 1 TO SUBPART KKKK OF PART 60—NITROGEN OXIDE EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

[All numerical values have two significant figures]

Combustion turbine type	Combustion turbine heat input at base load rating (HHV)	NO_X emissions standard	Alternate NO_X emissions standard in ppm at 15 percent O_2
New turbine firing natural gas, electric generating	≤ 15 MW (50 MMBtu/h)	67 ng/J (0.16 lb/MMBtu) heat input or 290 ng/J of gross energy output (2.3 lb/MWh).	42
New turbine firing natural gas, mechanical drive	≤ 15 MW (50 MMBtu/h)	160 ng/J (0.37 lb/MMBtu) heat input or 690 ng/J of gross energy output (5.5 lb/MWh).	100
New turbine firing natural gas	> 15 MW (50 MMBtu/h) and ≤ 250 MW (850 MMBtu/h).	40 ng/J (0.093 lb/MMBtu) heat input or 150 ng/J of gross energy output (1.2 lb/MWh).	25
New, modified, or reconstructed turbine firing natural gas.	> 250 MW (850 MMBtuh).	24 ng/J (0.056 lb/MMBtu) heat input or 54 ng/J of gross energy output (0.43 lb/MWh).	15
New turbine firing fuels other than natural gas, electric generating.	≤ 15 MW (50 MMBtu/h)	160 ng/J (0.38 lb/MMBtu) heat input or 710 ng/J of gross energy output (5.6 lb/MWh).	96
New turbine firing fuels other than natural gas, mechanical drive.	≤ 15 MW (50 MMBtu/h)	250 ng/J (0.59 lb/MMBtu) heat input or 1,100 ng/J of gross energy output (8.7 lb/MWh).	150
New turbine firing fuels other than natural gas	> 15 MW (50 MMBtu/h) and ≤ 250 MW (850 MMBtu/h).	120 ng/J (0.29 lb/MMBtu) heat input or 470 ng/J of gross energy output (3.7 lb/MWh).	74
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 250 MW (850 MMBtu/h).	73 ng/J (0.17 lb/MMBtu) heat input or 160 ng/J of gross energy output (1.3 lb/MWh).	42
Modified or reconstructed turbine	≤ 15 MW (50 MMBtu/h)	250 ng/J (0.59 lb/MMBtu) heat input or 1,100 ng/J of gross energy output (8.7 lb/MWh).	150
Modified or reconstructed turbine firing natural gas.	> 15 MW (50 MMBtu/h) and ≤ 250 MW (850 MMBtu/h).	67 ng/J (0.16 lb/MMBtu) heat input or 250 ng/J of gross energy output (2.0 lb/MWh).	42
Modified or reconstructed turbine firing fuels other than natural gas.	> 15 MW (50 MMBtu/h) and ≤ 250 MW (850 MMBtu/h).	160 ng/J (0.38 lb/MMBtu) heat input or 600 ng/J of gross energy output (4.8 lb/MWh).	96

TABLE 1 TO SUBPART KKKK OF PART 60—NITROGEN OXIDE EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES—Continued

[All numerical values have two significant figures]

Combustion turbine type	Combustion turbine heat input at base load rating (HHV)	NO_X emissions standard	Alternate NO_X emissions standard in ppm at 15 percent O_2
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of the base load rating, turbines operated during periods of turbine tuning, startup, or shutdown, modified and reconstructed offshore turbines, or turbines operating at temperatures less than minus 17 °C.	≤ 100 MW (340 MMBtu/h).	250 ng/J (0.59 lb/MMBtu) heat input or 1,100 ng/J of gross energy output (8.7 lb/MWh).	150
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of the base load rating, turbines operated during periods of turbine tuning, startup, or shutdown, modified and reconstructed offshore turbines, or turbines operating at temperatures less than minus 17 °C.	> 100 MW (340 MMBtu/h).	160 ng/J (0.38 lb/MMBtu) heat input or 610 ng/J of gross energy output (4.8 lb/MWh).	96
Heat recovery units operating independent of the combustion turbine engine.	All sizes	86 ng/J (0.20 lb/MMBtu) heat input or 110 ng/J of gross energy output (0.90 lb/MWh).	50

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