fairways and traffic separation schemes (TSSs) to provide safe access routes for vessels proceeding to and from U.S. ports. The PWSA provides that such designation of fairways and TSSs must recognize, within the designated areas, the paramount right of navigation over all other uses.

The PWSA requires the Coast Guard to conduct a study of potential traffic density and the need for safe access routes for vessels before establishing or adjusting fairways or TSSs. Through the study process, we must coordinate with Federal, State, and foreign state agencies (as appropriate) and consider the views of maritime community representatives, environmental groups, and other interested stakeholders. A primary purpose of this coordination is, to the extent practicable, to reconcile the need for safe access routes with other reasonable waterway uses.

What are the timetable, study area, and process of this PARS? The Vessel Traffic Management Division (G–MWV) of Coast Guard Headquarters will conduct this PARS. The study will begin immediately and must be completed by September, 2005, in order for the Coast Guard and NMFS to prepare their required report to Congress by January, 2006.

The study area is divided into two regions described as follows:

1. *Northern region:* Cape Cod Bay; the area off Race Point at the northern end of Cape Cod (Race Point) and the Great South Channel.

2. *Southern region:* The area bounded to the north by a line drawn at latitude 31° 27′N (which coincides with the northernmost boundary of the mandatory ship reporting system) and to the south by a line drawn at latitude line 29° 45′N. The eastern offshore boundary is formed by a line drawn at longitude 81° 00′W and the western boundary is formed by the shoreline. Included in this area are the ports of Jacksonville and Fernandina, FL, and Brunswick, GA.

As part of this study, we will consider previous studies, analyses of vessel traffic density, and agency and stakeholder experience in and public comments on vessel traffic management, navigation, ship handling, and affects of weather. We encourage you to participate in the study process by submitting comments in response to this notice.

We will publish the results of the PARS in the **Federal Register**. The study may—

1. Recommend implementing the vessel routing measures identified in the NMFS ANPRM for the two areas;

2. Recommend creating vessel routing measures other than those proposed in the NMFS ANPRM for the two areas;

3. Validate existing vessel routing measures, if any, and conclude that no changes are necessary; or

4. Recommend changes be made to the existing vessel routing measures, if any, in order to reduce the threat of ship strikes of right whales.

The recommendations may lead to future rulemakings or appropriate international agreements.

Possible Scope of the Recommendations

We expect that information gathered during the study will identify any problems and appropriate solutions. The study may recommend that, in any or all of the study areas, all or some of the following items be accompished:

1. Maintain current vessel routing measures, if any.

2. Establish Traffic Separation Schemes (TSS) at the entrances to the identified ports.

3. Designate recommended or mandatory routes.

4. Create one or more precautionary areas.

5. Create one or more inshore traffic zones.

6. Create deep-draft routes.

7. Establish area(s) to be avoided (ATBA).

8. Establish, disestablish, or modify anchorage grounds.

9. Establish a Regulated Navigation Area (RNA) with specific vessel operating requirements to ensure safe navigation near shallow water.

10. Identify any other appropriate ships' routing measures to be used.

Questions

To help us conduct the port access route study, we request comments on the following questions, although comments on other issues addressed in this document are also welcome. In responding to a question, please explain your reasons for each answer and follow the instructions under ''Public Participation and Request for comments'' above.

1. What navigational hazards do vessels operating in the study areas face? Please describe.

2. Are there strains on the current vessel routing system, such as increasing traffic density? If so, please describe.

3. What are the benefits and drawbacks to modifying existing vessel routing measures, if any, or establishing new routing measures such as those described in the NMFS ANPRM? If so, please describe.

4. What impacts, both positive and negative, would changes to existing routing measures, if any, or new routing measures, such as those described in the NMFS ANPRM, have on the study area?

Dated: February 10, 2005.

Howard L. Hime,

Acting Director of Standards, Marine Safety, Security and Environmental Protection.

[FR Doc. 05–3117 Filed 2–17–05; 8:45 am]

BILLING CODE 4910–15–M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[OAR–2004–0490, FRL–7874–1]

RIN 2060–AM79

Standards of Performance for Stationary Combustion Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The EPA is proposing standards of performance for new stationary combustion turbines in 40 CFR part 60, subpart KKKK. The new standards would reflect changes in nitrogen oxides (NO_X) emission control technologies and turbine design since standards for these units were originally promulgated in 40 CFR part 60, subpart GG. The NO_X and sulfur dioxide (SO_2) standards have been established at a level which brings the emission limits up to date with the performance of current combustion turbines and their emissions.

DATES: Comments must be received on or before April 19, 2005, or 30 days after the date of any public hearing, if later.

Public Hearing. If anyone contacts EPA by March 10, 2005, requesting to speak at a public hearing, EPA will hold a public hearing on March 21, 2005. If you are interested in attending the public hearing, contact Ms. Eloise Shepherd at (919) 541–5578 to verify that a hearing will be held.

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

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- Agency Web site: *http://www.epa.gov/edocket.* EDOCKET, EPA's electronic public docket and comment system, is EPA's preferred method for receiving comments. Follow the on-line instructions for submitting comments.
- *E-mail:* Send your comments via electronic mail to *a-and-r-docket@epa.gov,* Attention Docket ID No. OAR–2004–0490.

• *Fax:* Fax your comments to (202) 566–1741, Attention Docket ID No. OAR–2004–0490.

• *Mail:* Send your comments to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode 6102T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. OAR–2004–0490. Please include a total of two copies. The EPA requests a separate copy also be sent to the contact person identified below (*see* **FOR FURTHER INFORMATION CONTACT**). In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for EPA, 725 17th St. NW., Washington, DC 20503.

• *Hand Delivery:* Deliver your comments to: EPA Docket Center (EPA/DC), EPA West Building, Room B108, 1301 Constitution Ave., NW., Washington DC, 20460, Attention Docket ID No. OAR–2004–0490. Such deliveries are accepted only during the normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. 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.epa.gov/edocket,* 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 EDOCKET, regulations.gov, or e-mail. The EPA EDOCKET and the Federal regulations.gov Web sites are ''anonymous access'' systems, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through EDOCKET or regulations.gov, your e-mail 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, 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 EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, 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 EPA's public docket visit EDOCKET on-line or see the **Federal Register** of May 31, 2002 (67 FR 38102).

Docket: All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket.* Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the Docket, EPA/DC, EPA West, Room B102, 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 EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jaime Pagan, Combustion Group, Emission Standards Division (C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711; telephone number (919) 541–5340; facsimile number (919) 541–5450; e-mail address ''*pagan.jaime@epa.gov.*''

SUPPLEMENTARY INFORMATION:

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. General Information

A. Does This Action Apply to Me?

Regulated Entities. Categories and entities potentially regulated by this action are those that own and operate new stationary combustion turbines with a peak rated power output greater than or equal to 1 megawatt (MW). Regulated categories and entities include:

Category	NAICS	SIC	Examples of regulated entities
Any industry using a new stationary combustion turbine as defined in the proposed rule.	2211	4911	Electric services.
	486210	4922	Natural gas transmission.
	211111	1311	Crude petroleum and natural gas.
	211112	1321	Natural gas liquids.
	221	4931	Electric and other services, combined.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility is regulated by this action, you should examine the applicability criteria in section 60.4305 of the proposed rule. For further information concerning applicability and rule determinations, contact the appropriate State or local agency representative. For information concerning the analyses performed in developing the New Source Performance Standards (NSPS), consult the contact person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. What Should I Consider as I Prepare My Comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through EDOCKET, regulations.gov or e-mail. Send or deliver information identified as CBI to only the following address: Mr. Jaime Pagan, c/o OAQPS Document Control Officer (Room C404–02), U.S. EPA, Research Triangle Park, NC 27711, Attention Docket ID No. 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 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.

2. *Tips for Preparing Your Comments.* When submitting comments, remember to:

a. Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).

b. Follow directions. The EPA may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

c. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

d. Describe any assumptions and provide any technical information and/or data that you used.

e. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

f. Provide specific examples to illustrate your concerns, and suggest alternatives.

g. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

h. Make sure to submit your comments by the comment period deadline identified.

Docket. The docket number for the proposed NSPS (40 CFR part 60, subpart KKKK) is Docket ID No. OAR–2004–0490.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of the proposed rule is also available on the WWW through the Technology Transfer Network Website (TTN Web). Following signature, EPA will post a copy of the proposed rule on the TTN's 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. If you need more information regarding the TTN, call the TTN HELP line at (919) 541–5384.

II. Background Information

This action proposes NSPS that would apply to new stationary combustion turbines greater than or equal to 1 MW that commence construction, modification or reconstruction after February 18, 2005. The NSPS are being proposed pursuant to section 111 of the Clean Air Act (CAA) which requires the EPA to promulgate and periodically revise the NSPS, taking into consideration available control technologies and the costs of control. The EPA promulgated the NSPS for stationary gas turbines in 1979 (44 FR 52798). Since promulgation of the NSPS for stationary gas turbines, many advances in the design and control of emissions from stationary turbines have occurred. Nitrogen oxides and SO_2 are known to cause adverse health and environmental effects. The proposed standards represent reductions in the NO_X and SO_2 limits of over 80 and 93 percent, respectively. The output-based standards in the proposed rule would allow owners and operators the flexibility to meet their emission limit targets by increasing the efficiency of their turbines.

III. Summary of the Proposed Rule

A. Does the Proposed Rule Apply to Me?

Today's proposed standards would apply to new stationary combustion turbines with a power output at peak load greater than or equal to 1 MW. The applicability of the proposed rule is similar to that of existing 40 CFR part 60, subpart GG, except that the proposed rule would apply to new stationary combustion turbines, and their associated heat recovery steam generators (HRSG) and duct burners. A new stationary combustion turbine is defined as any simple cycle combustion turbine, regenerative cycle combustion turbine, or combined cycle steam/electric generating system that is not self-propelled and that commences construction, modification, or reconstruction after February 18, 2005. The new stationary combustion turbines subject to the proposed standards are exempt from the requirements of 40 CFR part 60, subpart GG. Heat recovery steam generators and duct burners subject to the proposed rule would be exempt from the requirements of 40 CFR part 60, subparts Da and Db.

B. What Pollutants Would Be Regulated?

The pollutants to be regulated by the proposed standards are NO_X and SO_2.

C. What Is the Affected Source?

The affected source for the proposed stationary combustion turbine NSPS is each stationary combustion turbine with a power output at peak load greater than or equal to 1 MW, that commences construction, modification, or reconstruction after February 18, 2005. Integrated gasification combined cycle (IGCC) combustion turbine facilities covered by subpart Da of 40 CFR part 60 (the Utility NSPS) are exempt from the requirements of the proposed rule.

D. What Emission Limits Must I Meet?

The format of the proposed standards for NO_X is an output-based emission limit in units of emissions mass per unit useful recovered energy, nanograms/Joule (ng/J) or pounds per megawatt-hour (lb/MW-hr). There are four subcategories, and thus four separate output-based NO_X limits. These are presented in Table 1 of this preamble. The output of the turbine does not include any steam turbine output and refers to the rating of the combustion turbine itself.

TABLE 1.—NO_X EMISSION STANDARDS (NG/J)

Combustion turbine fuel type	Combustion turbine size	
	<30 MW	≥30 MW
Natural gas	132 (1.0 lb/MW-hr)	50 (0.39 lb/MW-hr)
Oil and other fuel	234 (1.9 lb/MW-hr)	146 (1.2 lb/MW-hr)

We have determined that it is appropriate to exempt emergency combustion turbines from the NO_X limit. We have defined these units as turbines that operate in emergency situations. For example, turbines used to supply electric power when the local utility service is interrupted are considered to fall under this definition. In addition, we are proposing that combustion turbines used by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements be exempted from the NO_X limit. Given the small number of turbines that are expected to fall under this category and since there is not one definition that can provide an all-inclusive description of the type of research and development work that qualifies for the exemption from the NO_X limit, we have decided that it is appropriate to make these exemption determinations on case by case basis only.

The proposed standard for SO_2 is the same for all turbines regardless of size and fuel type. You may not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 73 ng/J (0.58 lb/MW-hr). You would be able to choose to comply with the SO_2 limit itself or with a limit on the sulfur content of the fuel. We are proposing this sulfur content limit to be 0.05 percent by weight (500 parts per million by weight (ppmw)).

E. If I Modify or Reconstruct My Existing Turbine, Does the Proposed Rule Apply to Me?

The proposed standards would apply to stationary combustion turbines that are modified or reconstructed after February 18, 2005. The guidelines for determining whether a source is modified or reconstructed are given in 40 CFR 60.14 and 60.15, respectively.

F. How Do I Demonstrate Compliance?

In order to demonstrate compliance with the NO_X limit, an initial performance test is required. If you are using water or steam injection, you must continuously monitor your water or steam to fuel ratio in order to demonstrate compliance and you are not required to perform annual stack testing to demonstrate compliance. If you are not using water or steam injection, you would conduct performance tests annually following the initial performance test in order to demonstrate compliance. Alternatively, you may choose to demonstrate continuous compliance with the use of a continuous emission monitoring system (CEMS) or parametric monitoring; if you choose this option, you are not required to conduct subsequent annual performance tests.

If you are using a NO_X CEMS, the initial performance test required under 40 CFR 60.8 may, alternatively, coincide with the relative accuracy test audit (RATA). If you choose this as your initial performance test, you must perform a minimum of nine reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest achievable) load. You must use the test data both to demonstrate compliance with the applicable NO_X emission limit and to provide the required reference method data for the RATA of the CEMS. The requirement to test at three additional load levels is waived.

G. What Monitoring Requirements Must I Meet?

If you are using water or steam injection to control NO_X emissions, you would have to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. Alternatively, you could use a CEMS consisting of NO_X and oxygen (O_2) or carbon dioxide (CO_2) monitors. During each full unit operating hour, each monitor would complete a minimum of one cycle of operation for each 15-minute quadrant of the hour. For partial unit operating hours, at least one valid data point would be obtained for each quadrant of the hour in which the unit operates.

If you operate any new turbine which does not use water or steam injection to control NO_X emissions, you would have to perform annual stack testing to demonstrate continuous compliance with the NO_X limit. Alternatively, you could elect either to use a NO_X CEMS or perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you would define at least four parameters indicative of the unit's NO_X formation characteristics, and you would monitor these parameters continuously;

(2) For any lean premix stationary combustion turbine, you would continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed combustion mode;

(3) For any turbine that uses SCR to reduce NO_X emissions, you would continuously monitor appropriate parameters to verify the proper operation of the emission controls; and

(4) For affected units that are also regulated under part 75 of this chapter, if you elect to monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in 40 CFR 75.19, the monitoring requirements of the turbine NSPS may be met by performing the parametric monitoring described in section 2.3 of appendix E of part 75 of this chapter or in 40 CFR 75.19(c)(1)(iv)(H).

Alternatively, you could petition the Administrator for other acceptable methods of monitoring your emissions. If you choose to use a CEMS or perform parameter monitoring to demonstrate continuous compliance, annual stack testing is not required.

If you operate any stationary combustion turbine subject to the provisions of the proposed rule, and you choose not to comply with the SO_2 stack limit, you would monitor the total sulfur content of the fuel being fired in the turbine. There are several options for determining the frequency of fuel sampling, consistent with appendix D to part 75 of this chapter for fuel oil; and the sulfur content would be determined and recorded once per unit operating day for gaseous fuel, unless a custom fuel sampling schedule is used. Alternatively, you could elect not to monitor the total sulfur content of the fuel combusted in the turbine, if you demonstrate that the fuel does not to exceed a total sulfur content of 300 ppmw. This demonstration may be performed by using the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or through representative fuel sampling data which show that the sulfur content of the fuel does not exceed 300 ppmw.

If you choose to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters would be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit.

If you are required to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples would be collected during the performance test. For liquid fuels, the samples for the total sulfur content of the fuel must be analyzed using American Society of Testing and Materials (ASTM) methods D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01. For gaseous fuels, ASTM D1072–90 (Reapproved 1999); D3246–96; D4468–85 (Reapproved 2000); or D6667–01 must be used to analyze the total sulfur content of the fuel.

The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

H. What Reports Must I Submit?

For each affected unit for which you continuously monitor parameters or emissions, or periodically determine the fuel sulfur content under the proposed rule, you would submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions would be reported for all 4-hour rolling average periods of unit operation, including start-up, shutdown, and malfunctions where emissions exceed the allowable emission limit or where one or more of the monitored process or control parameters exceeds the acceptable range as determined in the monitoring plan.

IV. Rationale for the Proposed Rule

A. Why Did EPA Choose Output-Based Standards?

We have written the proposed standards to incorporate output-based NO_X and SO_2 limits. The primary benefit of output-based standards is that they recognize energy efficiency as a form of pollution prevention. The use of more efficient technologies reduces fossil fuel use and leads to reductions in the environmental impacts associated with the production and use of fossil fuels. Another benefit is that output-based standards allow sources to use energy efficiency as a part of their emissions control strategy. This provides an additional compliance option that can lead to reduced compliance costs as well as lower emissions.

Several States have initiated regulations or permits-by-rule for distributed generation (DG) units, including combustion turbines. States that have made efforts to regulate DG sources include California, Texas, New York, New Jersey, Connecticut, Delaware, Maine, and Massachusetts. Those State rules include emission limits that are output-based, and many allow generators that use combined heat and power (CHP) to take credit for heat recovered. For example, Texas recently passed a DG permit-by-rule regulation that gives facilities 100 percent credit for steam generation thermal output, and incorporates HRSG and duct burners under the same limit. The California Air Resources Board (CARB) also has output-based emission limits which allow DG units that use CHP to take a credit to meet the standards, at a rate of 1 MW-hr for each 3.4 million British thermal units (MMBtu) of heat recovered, or essentially, 100 percent. The draft rules for New York and Delaware also allow DG sources using CHP to receive credit toward compliance with the emission standards.

B. How Did EPA Determine the Proposed NO_X Limits?

Over the last several years NO_X performance in combustion turbines has improved dramatically. At the current time, lean premix turbines, or dry low NO_X, dominate the market for combustion turbines fired by natural gas. To determine the proposed NO_X limits, we evaluated stack test data for stationary combustion turbines of different sizes. The data provided us with information on actual NO_X emissions performance in relation to the size of the unit and the type of fuel being used. In addition, we obtained information from turbine manufacturers on the NO_X levels that they guarantee for their new stationary combustion turbines. We only used these manufacturer guarantees to confirm the NO_X levels observed in the stack test data that we studied.

We considered requiring the use of SCR in setting the limit for NO_X. However, we determined that the costs for SCR were high compared to the incremental difference in emission concentration. Newer large turbines without add-on controls can readily achieve 9 or 10 parts per million (ppm). The use of SCR might bring this level down to 2 to 4 ppm. In addition, SCR may be difficult to implement for turbines operating under variable loads. We determined that the incremental benefit in emissions reductions did not justify the costs and technical challenges associated with the addition and operation of SCR. Therefore, we did not base the NO_X emission limit on this add-on control. However, add-on control technologies may be required at the State or local level, for Prevention of Significant Deterioration (PSD) and New Source Review (NSR) programs.

We identified a distinct difference in the technologies and capabilities between small and large turbines. We found the breaking point between these two turbine types to be 30 MW. Smaller turbines have less space to install NO_X reducing technologies such as lean premix combustor design. In addition, the smaller combustion chamber of small turbines provides inadequate space for the adequate mixing needed for very low NO_X emission levels. The design differences between small and large turbines leads to different emission characteristics. When we examined data of NO_X emissions versus turbine size, there was a clear difference in NO_X emissions for turbines below and above 30 MW. In addition, manufacturer guarantees are, generally speaking, higher for smaller turbines, because of differences in design and technologies. The 30 MW cutoff is consistent with the manufacturer guarantees.

As explained below, the output-based NO_X limits being proposed are based on concentration levels that are achievable by new stationary combustion turbines without the use of add-on controls such as SCR. Also, it is important to note that the output-based limits were determined using thermal efficiencies typical of full-load operation.

Small Natural Gas Fired Turbines

We are proposing the NO_X limit for small (less than 30 MW) natural gas-fired turbines to be 132 ng/J, or 1.0 lb/MW-hr. This limit is based on a NO_X emission concentration of 25 ppm and a turbine efficiency of 30 percent. Multiple manufacturers guarantee 25 ppm NO_X for natural gas-fired turbines of all sizes, including those less than 30 MW. Since actual NO_X emissions are considerably lower than the guaranteed levels for most turbines, an emission limit based on a NO_X level of 25 ppm at 15 percent O_2 for small natural gas-fired turbines can readily be achieved without the use of additional controls. We also gathered many recent source tests, supporting the conclusion that the majority of new small natural gas-fired turbines can achieve NO_X levels lower than 25 ppm at 15 percent O_2 without the use of add-on controls. Regarding efficiency, a significant number of small turbines are simple cycle; therefore, we selected the baseline efficiency of 30 percent for small simple cycle natural gas-fired turbines.

Large Natural Gas Fired Turbines

We are proposing a NO_X emission limit of 50 ng/J (0.39 lb/MW-hr) for large natural gas-fired turbines (greater than or equal to 30 MW). The proposed NO_X output-based limit for large natural gas-fired turbines is based on a NO_X emission concentration of 15 ppm at 15 percent O_2 and a combined cycle turbine efficiency of 48 percent, which also equates to a NO_X emission concentration of 9 ppm at 15 percent O_2 and a simple cycle turbine at an efficiency of 29 percent. Many manufacturers guarantee NO_X emissions of 15 ppm at 15 percent O_2 for large natural gas-fired turbines, and a few even guarantee NO_X levels at or below 9 ppm at 15 percent O_2. In addition, we have gathered a number of source tests which confirm that these turbines can achieve these levels without the use of add-on controls. Therefore, this emission limit may be achieved by most large natural gas combustion turbines without the use of add-on controls. Other options for new turbine owners and operators include the following: Add a SCR add-on control device to a simple cycle turbine which does not have a low NO_X guarantee, or locate their turbine where the exhaust heat can be recovered as useful output (a combined cycle unit or CHP unit).

Distillate Oil Fired Turbines

Very few turbines sold today are solely distillate oil-fired. However, a significant number of turbines which primarily fire natural gas also have the capability to fire distillate oil. We are proposing a NO_X emission limit of 234 ng/J (1.9 lb/MW-hr) for small distillate oil-fired turbines, and 146 ng/J (1.2 lb/MW-hr) for large distillate oil-fired turbines. When firing distillate oil fuel, the majority of turbine manufacturers guarantee a NO_X emission level of 42 ppm at 15 percent O_2, regardless of turbine size. We confirmed through the analysis of recent source test reports provided by States that this level is achievable by the majority of new distillate oil-fired turbines without the use of add-on controls. The basis for the output-based emission limits for distillate oil-fired turbines is 42 ppm NO_X at 15 percent O_2; for small turbines, a 30 percent efficiency, and for large turbines, a 48 percent efficiency. The 30 percent efficiency for small oil-fired turbines is consistent with that of simple-cycle units, while the 48 percent efficiency for large oil-fired turbines is consistent with that of combined-cycle units. This approach is appropriate since there are almost no oil-fired simple-cycle turbines in the ''greater than 30 MW'' category. We would like to request comment on this issue and the appropriateness of the NO_X limits for oil-fired simple-cycle turbines that are greater than 30 MW. Furthermore, since according to our information, most of these simple-cycle turbines are used as peaking units, we would like to request comments on an alternative approach that allows large oil-fired peaking units to meet the same NO_X limit that applies to the small units.

The proposed output-based NO_X limits for oil-fired combustion turbines can be achieved when operating at loads near 100 percent, where the thermal efficiency tends to be the highest. However, at part-loads, there may be concern about higher output-based NO_X levels emitted due to the lower thermal efficiencies that are characteristic under those conditions. We request comment on the ability of oil-fired combustion turbines to meet the proposed NO_X limits under part-load operation.

Other Fuels

It is expected that few turbines would burn fuels other than natural gas and distillate oil. Turbines that burn other fuels would have to comply with the NO_X emission limit for distillate oil. We understand that there are concerns about certain fuels, such as landfill, digester and other waste gases, process, refinery or syn gases, and other alternative fuels. Of particular concern are the fuels that are of lower heating value or of highly variable heating value, that are in locations where these fuels would be flared or otherwise disposed without energy recovery. Landfill and digester gases have considerably lower heating values than natural gas, making it more difficult to comply with an output-based emission limit. If the installation of these turbines became impossible due to lack of ability to comply with the NSPS, these gases might otherwise just be vented to the atmosphere or flared, without the benefit of any useful energy recovery as would have been achieved with a combustion turbine. Because of these issues, we are requesting public comment on the output-based NO_X limit for alternative fuels.

Simple-Cycle and Combined-Cycle Combustion Turbines

Although we believe that proposing different NO_X limits for small and large turbines is appropriate, an alternative approach considered was to set different NO_X limits for simple-cycle and combined-cycle combustion turbines burning natural gas. Simple-cycle turbines are not able to recover exhaust heat as combined-cycle turbines do. As a result, the output-based NO_X levels of simple-cycle turbines will tend to be higher than those for combined-cycle units. Even though we have taken into account these differences between simple- and combined-cycle turbines in the proposed NO_X limits, we would like to request comment on this issue. If data is presented showing that it would be more appropriate to set different NO_X limits for simple-cycle and combined-cycle gas-fired turbines, rather than based on turbine size, we would consider a range of 0.2 lb/MW-hr to 0.6 lb/MW-hr.

Supporting data for the proposed NO_X limits were received from contacts with turbine manufacturers, State agencies and EPA Regional offices, the 2003 Gas Turbine World Handbook, the 2003–2004 Diesel and Gas Turbine Worldwide Catalog, NO_X performance tests, and State permit data. For more details regarding the supporting data used in this analysis, please consult the docket.

C. How Did EPA Determine the Proposed SO_2 Limit?

Because of the lower levels of sulfur in today's fuels, including distillate oil and natural gas, lower SO_2 emissions can be achieved. Low sulfur fuel oil (500 ppmw sulfur content or less) has recently become widely available, since it is required by EPA regulations on diesel fuels used for highway and non-road applications. In addition, ultra low sulfur (15 ppmw or less sulfur content) diesel fuel will become available over the next few years as more recent EPA rules for fuels used on highway and non-road applications come into effect. According to EPA estimates done for the Non-Road Diesel Rule (69 FR 38958), the cost differential to produce low sulfur (500 ppmw sulfur content) is only about 2.5 cents per gallon. It is expected that stationary combustion turbines burning low sulfur diesel fuel will have lower maintenance expenses associated with reduced formation of acid compounds inside the turbine. These lower maintenance expenses are expected to reduce or even eliminate the overall costs associated with the use of low sulfur fuel oil on stationary combustion turbines. For these reasons, we have set a SO_2 emission limit which corresponds to a 500 ppmw sulfur fuel content for distillate oil fuel. Natural gas also has naturally low levels of sulfur.

All owners and operators of new turbines are expected to comply with low sulfur content in fuel rather than stack testing for SO_2, since this option is significantly easier and less costly to perform than stack testing. In addition, if the levels are shown to be below 300 ppmw sulfur, fuel monitoring is not required. Fuels are often supplied with specifications which include stringent sulfur standards, requiring levels lower than 500 ppmw, oftentimes at or below the 300 ppmw range. If the fuel is demonstrated to be lower than 300 ppmw sulfur, you could use proof from the fuel vendor's tariff sheet or purchase contract in order to become exempt from monitoring your total sulfur content or SO_2 emissions. We believe that 300 ppmw provides an adequate margin of compliance. If your fuel is greater than 300 ppmw, you must follow a fuel monitoring schedule as outlined in the proposed rule.

D. What Other Criteria Pollutants Did EPA Consider?

In order to characterize the current emissions levels from new stationary combustion turbines, the Reasonably Achievable Control Technology (RACT), Best Available Control Technology (BACT) and Lowest Achievable Emissions Rate (LAER) Clearinghouse (RBLC) was queried to obtain data on permits for newly installed turbines. The EPA's AP–42 Emission Factors Background Document was also consulted for information on pollutant formation mechanisms. In addition, several turbine manufacturers were contacted to determine their guaranteed emission concentrations.

Emissions from combustion turbines are primarily NO_X and carbon monoxide (CO). Particulate matter (PM) is also a primary pollutant for combustion turbines using liquid fuels. While NO_X formation is strongly dependent on the high temperatures developed in the combustor, emissions of CO and PM are primarily the result of incomplete combustion. Ash and metallic additives in the fuel may also contribute to PM in the exhaust. Available emissions data in EPA's AP–42 indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Combustion turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. Information on each pollutant is listed below, including formation, control, and emission concentrations.

Carbon Monoxide

Carbon monoxide is a product of incomplete combustion. Carbon monoxide results when there is insufficient residence time at high temperature, or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at combustion turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In combustion turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the combustion turbine. For example, a combustion turbine operating under full load would experience greater fuel efficiencies, which will reduce the formation of CO.

Turbine manufacturers have significantly reduced CO emissions from combustion turbines by developing lean premix technology. Most of the newer designs for turbines incorporate lean premix technology. Lean premix combustion design not only produces lower NO_X than diffusion flame technology, but also lowers CO and volatile organic compounds (VOC), due to increased combustion efficiency. In the most recent version of AP–42 emission factors, (April 2000), CO emission factors for lean premix turbines are 9.9 e-2 lb/MMBtu, while for diffusion flame turbines, the CO emission factor is 3.2 e-1 lb/MMBtu. Virtually all new combustion turbines sold are lean premix combustor technology turbines. Siemens Westinghouse, Solar Turbines, and General Electric (GE) Heavy Duty Turbine manufacturers typically guarantee CO emissions from 9 to 50 ppm for natural gas, and 20 to 50 ppm for diesel fuel. On a case-by-case basis, some manufacturers will guarantee lower emissions for CO.

Stationary combustion turbines do not contribute significantly to ambient CO levels. Almost 80 percent of CO emissions nationwide result from on-road vehicles and non-road vehicles and engines. High levels of CO generally occur in areas that have heavy traffic congestion. Currently, there are only eight areas in the U.S. that are classified as non-attainment for CO. As a result, control measures for CO emissions from stationary combustion turbines historically have not been instituted nationwide. In California, for example, only one air district has a CO emission limit for combustion turbines. Because of advances in turbine technology and increases in thermal and combustion efficiencies, CO emissions from combustion turbines have been mostly regulated in local areas of non-attainment for CO.

Any new major stationary source or major modification located in an area attaining the National Ambient Air Quality Standard (NAAQS) is subject to PSD requirements and must conduct an analysis to ensure the application of BACT. Similarly, if the source is in a non-attainment area, it is subject to non-attainment NSR and must conduct an analysis to ensure the application of LAER. The RBLC provides State agencies with the best technologies and emission rates determined by other States on a nationwide basis. Several BACT and LAER determinations in the RBLC included the use of an oxidation catalyst to control CO emissions from stationary combustion turbines. Out of the 42 permits for CO for combustion turbines reported since January 2003, 15 required the use of oxidation catalysts for CO reduction. Other requirements included good combustion practices and good combustion design. Emission limitations ranged from 2 ppm to 14 ppm for CO with the use of oxidation catalysts, and 4 ppm to 132 ppm CO for good combustion practices and design.

Based on the available information, we propose that no CO emission limitations be developed for the combustion turbine NSPS. With the advancement of turbine technology and more complete combustion through increased efficiencies, and the prevalence of lean premix combustion technology in new turbines, it is not necessary to further reduce CO in the proposed rule. Because of these advances, the addition of an oxidation catalyst would be cost prohibitive, on a dollar per ton basis, relative to the limited additional emissions reductions to be realized. However, individual States may continue to evaluate CO limits on a case-by-case basis, as has been done historically and as has been required in the NSR Program.

Volatile Organic Compounds

Volatile organic compounds are also products of incomplete combustion. These compounds are discharged into the atmosphere when fuel remains unburned or is burned only partially during the combustion process. The pollutants commonly classified as VOC can encompass a wide spectrum of organic compounds, some of which are hazardous air pollutants. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolized volatile organic emissions. Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

Owners of combustion turbines have improved combustion practices to increase combustion efficiency in the turbine, thereby limiting the unburned fuel. In addition, lean premix technology has significantly reduced VOC emissions from combustion turbines by increasing the combustion efficiency. Because of better combustion practices, and the prevalence of lean premix combustion technology in new turbines, it is not necessary to regulate VOC in the proposed rule. Therefore, we propose that no VOC emission limitations be developed for the combustion turbine NSPS.

Particulate Matter

Particulate matter emissions from turbines result primarily from carryover of noncombustible trace constituents in the fuel. Particulate matter emissions are negligible with natural gas firing due to the low sulfur content of natural gas. Emissions of PM are only marginally significant with distillate oil firing because of the low ash content. The sulfur content of distillate fuel is decreasing due to requirements from other regulations such as the non-road diesel engine rule. Particulate matter emissions from distillate oil-fired turbines would decrease even further as the sulfur content of distillate oil decreases. Furthermore, there are very few new turbines that solely fire distillate oil. A fraction have the ability to fire distillate oil (dual-fuel units), but generally speaking, most owners and operators fire natural gas the majority of the time.

A review of the BACT and LAER determinations in the RBLC since January of 2003 showed that no add-on controls were required to limit PM for any of the turbines. Permit requirements included the use of clean fuel or good combustion practices. Emission limitations required by permits in the RBLC database with permit dates after January of 2003 ranged from 9 pounds per hour (lb/hr) to 27 lb/hr for PM for natural gas, and 27 to 44 lb/hr for PM for diesel-fired turbines. General Electric is the only manufacturer who provides PM guarantees on their heavy duty turbines, and these guarantees ranged from 3 lb/hr to 15 lb/hr for natural gas, and 6 lb/hr to 34 lb/hr for diesel fuel.

As fuels continue to get cleaner, PM would be greatly reduced. In addition, the NO_X limits set forth in the proposed rule would also limit PM emissions by reducing nitrate formation. Therefore, we feel that an emission limitation for PM emissions from stationary combustion turbines is not necessary.

E. How Did EPA Determine Testing and Monitoring Requirements for the Proposed Rule?

Monitoring provisions in subpart GG of 40 CFR part 60 only addressed turbines that used water injection for NO_X control. Over the years, EPA has approved on a case-by-case basis alternative monitoring methods for turbines that do not use water injection for NO_X control, since this technology has become increasingly archaic. Some requested the use of a NO_X CEMS, since the turbines had these monitoring systems already in place for other regulatory requirements, such as the acid rain regulations or PSD/NSR permits. In the July 8, 2004 amendments to subpart GG of 40 CFR part 60, Stationary Gas Turbine NSPS (69 FR 41346), we added the option to utilize a NO_X CEMS in place of water to fuel ratio monitoring. We also included in the July 8, 2004 final rule a provision allowing sources to use CEMS to monitor their NO_X emissions for turbines that do not use water or steam injection.

In today's action, we are proposing monitoring requirements similar to those in 40 CFR part 60, subpart GG. For turbines that do not use water or steam injection, we are proposing annual stack testing to demonstrate continuous compliance. We considered other monitoring requirements, including CEMS and parametric monitoring. However, costs were high compared to costs for annual stack testing and annual stack testing provides a reliable means of demonstrating compliance. Therefore, annual stack testing is an appropriate monitoring method, and would help ensure continuous compliance with the new NO_X limits.

We also considered the use of portable analyzers as monitoring requirements. Recent testing by EPA has shown portable analyzers to be a reliable method of monitoring emissions, and they are believed to be as good as the traditional EPA method tests. Costs are comparable to EPA method tests. Portable analyzers are, therefore, a viable option to traditional method stack tests and the proposed rule allows the use of ASTM D6522–00 to measure the NO_X concentration during performance testing.

Many of the large turbines in the utility sector are already equipped with NO_X CEMS for compliance with other regulations, such as 40 CFR part 75. It is appropriate to allow the use of NO_X CEMS to demonstrate compliance with the proposed rule, particularly when they are already installed on-site for other regulatory purposes. Continuous emission monitoring systems are, therefore, the natural choice for these large turbines, and we are allowing the use of data from these certified CEMS for demonstrating compliance instead of an annual stack test.

Also, we included additional options for owners and operators to establish parameters which would be appropriate to monitor in order to correlate NO_X emissions with these data. Historically, some turbines have used parametric monitoring for compliance with 40 CFR part 75 requirements. For example, the owner/operator of a lean premix turbine might establish during the initial performance test that when the turbine is running in the lean premix mode, it is in compliance. Certain parameters, such as load or combustion temperature, might let the owner or operator know when the turbine is in compliance. Another option is for owners or operators to petition the Administrator for approval of another monitoring strategy.

F. Why Are Heat Recovery Steam Generators Included in 40 CFR Part 60, Subpart KKKK?

For sources that are combined cycle turbine systems using supplemental heat, turbine NO_X emissions would be measured after the duct burner, since emissions and output associated with duct burners are included in the NO_X emission limit. Any combined cycle units that are subject to the NO_X CEMS requirements for 40 CFR part 75 would most likely have installed the CEMS after the duct burner, on the HRSG stack. Another reason to require measurement of NO_X emissions after the duct burner is that add-on NO_X control systems, such as SCR, are generally located after the duct burner. Turbine NO_X performance testing should be conducted after the NO_X control device and would, therefore, include any emissions from the duct burner.

In addition, all of the data that we have gathered where emissions were tested with and without duct burner firing show that duct burners have little to no effect on NO_X emissions. Minimal additions and reductions were noted in several recent source tests, as well as an EPA sponsored test conducted by the EPA's Emissions Measurement Center. Thus, it is appropriate to include heat recovery sources such as duct burners in the proposed rule.

G. What Emission Limits Must I Meet if I Fire More Than One Type of Fuel?

New combustion turbines that fire both natural gas and distillate oil (or some other combination of fuels) are required to meet the corresponding emission limit for the fuel being fired in the turbine at that time.

H. Why Can I No Longer Claim a Fuel-Bound Nitrogen Allowance?

We are not including a fuel-bound nitrogen allowance in the proposed rule. In subpart GG of 40 CFR part 60, this provision allowed sources to claim a credit for nitrogen content in their fuel, up to a certain limit, attributing a part of their NO_X emissions to the fuel. We concluded that this provision is outdated since the nitrogen content of fuel is now lower than it has been in the past and is no longer an issue. The vast majority of new turbines are fired by natural gas. Many of these turbines are permitted to fire only pipeline quality natural gas, which is virtually nitrogen free. We do not anticipate any new turbines needing to utilize the fuel-bound nitrogen allowance, and are, therefore, not proposing it.

I. Why Isn't My IGCC Turbine Covered in 40 CFR Part 60, Subpart KKKK?

We consider gasification as an emissions control technology for solid fuels. Therefore, we consider it appropriate to cover combustion turbines fueled by gasified coal under the Utility NSPS. Combustion turbines fueled by gasified coal and not meeting the heat input requirements of the Utility NSPS would be covered by the proposed rule under the ''other fuel'' category.

V. Environmental and Economic Impacts

In setting the standards, the CAA requires us to consider alternative emission control approaches, taking into account the estimated costs and benefits, as well as the energy, solid waste and other effects. The EPA requests comment on whether it has identified the appropriate alternatives and whether the proposed standards adequately take into consideration the incremental effects in terms of emission reductions, energy and other effects of these alternatives. The EPA will consider the available information in developing the final rule.

A. What Are the Air Impacts?

We estimate that approximately 355 new stationary combustion turbines will be installed in the United States over the next 5 years and affected by the rule, as proposed. No more than ten of these units may need to install add-on controls to meet the NO_X limits required under the rule, as proposed. However, these ten new turbines will already be required to install add-on controls to meet NO_X reduction requirements under PSD/NSR. Thus, we concluded that the NO_X and CO reductions resulting from the rule, as proposed, will essentially be zero. The expected SO_2 reductions as a result of the rule, as proposed, would be approximately 830 tons per year (tpy) in the 5th year after promulgation of the standards.

Although we expect the proposed rule to result in a slight increase in electrical supply generated by unaffected sources (*e.g.* existing stationary combustion turbines), we do not believe that this will result in higher NO_X and SO_2 emissions from these sources. Other emission control programs such as the Acid Rain Program and PSD/NSR already promote or require emission controls that would effectively prevent emissions from increasing. All the emissions reductions estimates and assumptions have been documented in the docket to the proposed rule.

B. What Are the Energy Impacts?

We do not expect any significant energy impacts resulting from the rule, as proposed. The only energy requirement is a potential small increase in fuel consumption, resulting from back pressure caused by operating a add-on emission control device, such as an SCR. However, most entities would be able to comply with the proposed rule without the use of any add-on control devices.

C. What Are the Economic Impacts?

The EPA prepared an economic impact analysis to evaluate the impacts the proposed rule would have on combustion turbines producers, consumers of goods and services produced by combustion turbines, and society. The analysis showed minimal changes in prices and output for products made by the industries affected by the proposed rule. The price increase for affected output is less than 0.003 percent, and the reduction in output is less than 0.003 percent for each affected industry. Estimates of impacts on fuel markets show price increases of less than 0.01 percent for petroleum products and natural gas, and price increases of 0.04 and 0.06 percent for base-load and peak-load electricity, respectively. The price of coal is expected to decline by about 0.002 percent, and that is due to a small reduction in demand for this fuel type. Reductions in output are expected to be less than 0.02 percent for each energy type, including base-load and peak-load electricity.

The social costs of the rule, as proposed, are estimated at $0.4 million (2002 dollars). Social costs include the compliance costs, but also include those costs that reflect changes in the national economy due to changes in consumer and producer behavior in response to the compliance costs associated with a regulation. For the proposed rule, changes in energy use among both consumers and producers to reduce the impact of the regulatory requirements of the rule lead to the estimated social costs being less than the total annualized compliance cost estimate of $3.4 million (2002 dollars). The primary reason for the lower social cost estimate is the increase in electricity supply generated by unaffected sources (*e.g.* existing stationary combustion turbines), which offsets mostly the impact of increased electricity prices to consumers. The social cost estimates discussed above do not account for any benefits from emission reductions associated with the proposed rule.

For more information on these impacts, please refer to the economic impact analysis in the public docket.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), we must determine whether a regulatory action is ''significant'' and, therefore, subject to review by OMB and the requirements of the Executive Order. The Executive Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligation of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has notified EPA that it considers this a ''significant regulatory action'' within the meaning of the Executive Order. The EPA submitted this action to OMB for review. Changes made in response to OMB suggestions or recommendations would be documented in the public record.

B. Paperwork Reduction Act

The information collection requirements in the proposed rule have been submitted for approval to OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned ICR No. 2177.01.

The proposed rule contains monitoring, reporting, and recordkeeping requirements. The information would be used by EPA to identify any new, modified, or reconstructed stationary combustion turbines subject to the NSPS and to ensure that any new stationary combustion turbines comply with the emission limits and other requirements. Records and reports would be necessary to enable EPA or States to identify new stationary combustion turbines that may not be in compliance with the requirements. Based on reported information, EPA would decide which units and what records or processes should be inspected.

The proposed rule would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after [date the final rule is published in the **Federal Register**]) is estimated to be 20,542 labor hours per year at an average total annual cost of $1,797,264. This estimate includes performance testing, continuous monitoring, semiannual excess emission reports, notifications, and recordkeeping. There are no capital/start-up costs or operation and maintenance costs associated with the monitoring requirements over the 3-year period of the ICR.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9 and 48 CFR chapter 15.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for the ICR under Docket ID No. OAR–2004–0490. See information under the **ADDRESSES** section of this preamble to find instructions for sending comments to this docket and for viewing comments submitted to the docket. Also, you can send comments to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Please include the EPA Docket ID No. and OMB control number in any correspondence.

Since OMB is required to make a decision concerning the ICR between 30 and 60 days after February 18, 2005, a comment to OMB is best assured of having its full effect if OMB receives it by March 21, 2005. In the final rule, EPA will respond to any OMB or public comments on the information collection requirements contained in the proposed rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedures 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 today's rule on small entities, small entity is defined as: (1) A small business whose parent company has fewer than 100 or 1,000 employees, depending on size definition for the affected North American Industry Classification System (NAICS) code, or fewer than 4 billion kilowatt-hours (kW-hr) per year of electricity usage; (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. It should be noted that small entities in 1 NAICS code would be affected by the proposed rule, and the small business definition applied to each industry by NAICS code is that listed in the Small Business Administration (SBA) size standards (13 CFR part 121).

After considering the economic impacts of today's proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. We have determined, based on the existing combustion turbines inventory and presuming the percentage of small entities in that inventory is representative of the percentage of small entities owning new turbines in the 5th year after promulgation, that one small entity out of 29 in the industries impacted by the proposed rule will incur compliance costs (in this case, only monitoring, recordkeeping, and reporting costs since control costs are zero) associated with the proposed rule. This small entity owns one affected turbine in the projected set of new combustion turbines. This affected small entity is estimated to have annual compliance costs of 0.3 percent of its revenues. The proposed rule is likely to also increase profits for the small firms and increase revenues for the many small communities (in total, 28 small entities) using combustion turbines that are not affected by the proposed rule as a result of the very slight increase in market prices. For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis in the docket.

Although the proposed rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of the rule on small entities. In the proposed rule, the Agency is applying the minimum level of control and the minimum level of monitoring, recordkeeping, and reporting to affected sources allowed by the CAA. In addition, as mentioned earlier in this preamble, new turbines with capacities under 1 MW are not subject to the proposed rule. This provision should reduce the size of small entity impacts. 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

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost effective, or least burdensome alternative that achieves the objective of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

The EPA has determined that the proposed rule contains no Federal mandates 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. Thus, the proposed rule is not subject to the requirements of sections 202 and 205 of the UMRA. In addition, EPA has determined that the proposed rule contains no regulatory requirements that might significantly or uniquely affect small governments because they contain no requirements that apply to such governments or impose obligations upon them. Therefore, the proposed rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires us to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' are defined in the Executive Order to include regulations that 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.''

The proposed rule 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. Thus, Executive Order 13132 does not apply to the proposed rule.

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

Executive Order 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' ''Policies that have tribal implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes.''

The proposed rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. We do not know of any stationary combustion turbines owned or operated by Indian tribal governments. However, if there are any, the effect of the proposed rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to the proposed rule.

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

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, we must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives.

The proposed rule is not subject to Executive Order 13045 because it is not an economically significant action as defined under Executive Order 12866.

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

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the

Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1) (i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a ''significant energy action.'' Although the proposed rule is considered to be a significant regulatory action under Executive Order 12866, it is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy.

An increase in petroleum product output, which includes increases in fuel production, is estimated at less than 0.01 percent, or about 600 barrels per day based on 2004 U.S. fuel production nationwide. A reduction in coal production is estimated at 0.00003 percent, or about 3,000 short tons per year based on 2004 U.S. coal production nationwide. The reduction in electricity output is estimated at 0.02 percent, or about 5 billion kW-hr per year based on 2000 U.S. electricity production nationwide.

Production of natural gas is expected to increase by 4 million cubic feet (ft^3) per day. The maximum of all energy price increases, which include increases in natural gas prices as well as those for petroleum products, coal, and electricity, is estimated to be the 0.04 percent increase in peak-load electricity rates nationwide. Energy distribution costs may increase by no more than the same amount as electricity rates. We expect that there will be no discernable impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies.

Also, the increase in cost of energy production should be minimal given the very small increase in fuel consumption resulting from back pressure related to operation of add-on emission control devices, such as SCR. All of the estimates presented above account for some passthrough of costs to consumers as well as the direct cost impact to producers. Therefore, we conclude that the rule, as proposed, will not have a significant adverse effect on the supply, distribution, or use of energy. For more information on these estimated energy effects, please refer to the economic impact analysis for the proposed rule. This analysis is available in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

The proposed rule involves technical standards. The EPA cites the following methods in the proposed rule: EPA Methods 1, 2, 3A, 7E, 19, and 20 of 40 CFR part 60, appendix A; and Performance Specifications (PS) 2 of 40 CFR part 60, appendix B.

In addition, the proposed rule cites the following standards that are also incorporated by reference (IBR) in 40 CFR part 60, section 17: ASTM D129–00, ASTM D1072–90 (Reapproved 1999), ASTM D1266–98, ASTM D1552–01, ASTM D2622–98, ASTM D3246–81 or –92 or –96, ASTM D4057–95 (Reapproved 2000), ASTM D4084–82 or –94, ASTM D4177–95 (Reapproved 2000), ASTM D4294–02, ASTM D4468–85 (Reapproved 2000), ASTM D5287–97 (Reapproved 2002), ASTM D5453–00, ASTM D5504–01, ASTM D6228–98, ASTM D6522–00, ASTM D6667–01, and Gas Processors Association Standard 2377–86.

Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods/ performance specifications. No applicable voluntary consensus standards were identified for EPA Method 19. The search and review results have been documented and are placed in the docket for the proposed rule.

In addition to the voluntary consensus standards EPA uses in the proposed rule, the search for emissions measurement procedures identified 11 other voluntary consensus standards. The EPA determined that nine of these 11 standards identified for measuring air emissions or surrogates subject to emission standards in the proposed rule were impractical alternatives to EPA test methods/performance specifications for the purposes of the proposed rule. Therefore, the EPA does not intend to adopt these standards. See the docket for the reasons for the determinations of these methods.

Two of the 11 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the proposed rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, ''Flow Measurement by Velocity Traverse,'' for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, ''Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters,'' for EPA Method 2.

Sections 60.4345, 60.4360, 60.4400 and 60.4415 of the proposed rule discuss the EPA testing methods, performance specifications, and procedures required. Under 40 CFR 63.7(f) and 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures.

List of Subjects in 40 CFR Part 60

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

Dated: February 9, 2005.

Stephen L. Johnson,

Acting Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60, of the Code of 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.*

2. Part 60 is amended by adding subpart KKKK to read as follows:

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines for Which Construction Is Commenced After February 18, 2005 or for Which Modification or Reconstruction is Commenced on or After [Date 6 Months After Date Final Rule Is Published in the Federal Register]

Introduction

Sec.

Applicability

Emission Limits

Monitoring

Reporting

Performance Tests

Definitions

Tables to Subpart KKKK of Part 60

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions for new stationary combustion turbines that were constructed, modified or reconstructed after February 18, 2005.

Applicability

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

(a) If you are the owner or operator of a stationary combustion turbine with a power output at peak load equal to or greater than 1 megawatt (MW), which commences construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only power output from the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any associated recovered heat or steam turbine output should not be included when determining your peak power output. However, this subpart does apply to emissions from any associated heat recovery steam generators (HRSG) and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da and Db of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in § 60.4420(g), are exempt from the nitrogen oxides (NO_X) emission limits in § 60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in § 60.4320 on a case-by-case basis as determined by the Administrator.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

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

§ 60.4320 What emission limits must I meet for nitrogen oxides (NO_X)?

You must meet the emission limits for nitrogen oxides specified in Table 1 to this subpart.

§ 60.4325 What emission limits must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If you are burning natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when you are burning distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

You must comply with one or the other of the following conditions:

(a) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 73 nanograms per Joule (ng/J) (0.58 pounds per megawatt-hour (lb/MW–hr)), or

(b) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur in excess of 0.05 percent by weight (500 parts per million by weight (ppmw)).

Monitoring

§ 60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, 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 being fired in the turbine.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2))

monitor, to determine the hourly NO_X emission rate in pounds per million British thermal units (lb/MMBtu); and

(2) Install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) Install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For cogeneration units, install, calibrate, maintain, and operate meters for steam flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/hr).

§ 60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with § 60.4400 to demonstrate continuous compliance.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§ 60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define at least four parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed (low-NO_X) combustion mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, if you elect to monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in § 75.19(c)(1)(iv)(H).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A to part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in § 60.13(e)(2), during each full unit 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, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

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

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

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in § 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in § 60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of lb/MMBtu, using the appropriate equation from method 19 in appendix A to 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.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under § 60.7(c).

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

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under § 60.4320, using the following equation:

(1) For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MW-hr,

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

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/hr, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the turbine in MW.

(2) For combined-cycle operation, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical energy

generated by the turbine, the additional electrical energy (if any) generated by the heat recovery steam generator, and 100 percent of the total thermal energy output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps \qquad \text{(Eq. 2)}$$

Where:

$(Pe)_t$ = electrical energy output of the turbine in MW,

$(Pe)_c$ = electrical energy output (if any) of the heat recovery steam generator) in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MW-hr}} \qquad \text{(Eq. 3)}$$

Where:

Ps = thermal energy of the steam, expressed as equivalent electrical energy, in MW,

Q = measured steam flow rate in lb/hr,

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

3.413×10^6 = conversion from Btu/hr to MW.

(3) For mechanical drive applications, use the following equation:

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

Where:

E = emissions in lb/MW–hr,

$(NO_X)_m$ = nitrogen oxides emission rate in lb/hr,

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

AL = actual load as a percentage of the base load.

(g) Use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in § 60.4380(b)(1).

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§ 60.4335 and 60.4340 must be monitored during the performance test required under § 60.8, 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:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

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

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe 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),

(6) Submit 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. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (*e.g.*, for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in § 75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in § 75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.0250 weight percent (250 ppmw), ASTM D4084–82, 94, D5504–01, or D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference—see § 60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed 300 ppmw total sulfur. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content of the fuel is 300 ppmw or less; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 300 ppmw. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, 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 of 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 fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in § 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

Reporting

§ 60.4375 What reports must I submit?

For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

§ 60.4380 How are excess emissions and monitor downtime defined for NO_X?

For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§ 60.4335(b) and 60.4345:

(1) An hour of excess emissions is any unit operating hour in which the 4-hour rolling average NO_X emission rate exceeds the applicable emission limit in § 60.4320. For the purposes of this subpart, a ''4-hour rolling average NO_X emission rate'' is the arithmetic average of the average NO_X emission rate in ng/J (lb/MW-hr) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 1 of the 4 hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

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

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit 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 combustion turbine exceeds 0.05 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) 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. 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 burned, you may resume using the as-delivered sampling option.

(c) 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.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under § 60.7(c) must be postmarked by the 30th day following the end of each calendar quarter.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?

(a) You must conduct an initial performance test, as required in § 60.8.

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using Method 7E or Method 20 in appendix A to this part or ASTM D6522–00. Also, concurrently measure the stack gas flow rate, using Methods 1 and 2 in appendix A to this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = NO_X emission rate, in lb/MW-hr

1.194 x 10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run,

in ppmQ_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross energy output of the turbine, in MW (for simple-cycle operation), or, for combined-cycle operation, the sum of all electrical and thermal output from the unit, in MW, calculated according to § 60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either Methods 7E and 3A, or Method 20 in appendix A to this part, or ASTM Method D6522–00. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use Method 19 in appendix A to this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the NO_X emission rate in lb/MW–hr.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following Method 20 or Method 1 (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.

(3) Notwithstanding the requirements in paragraph (a)(2) of this section, you may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X (and, if applicable, diluent) concentrations, is within +/ · 10 percent of the mean concentration 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) If each of the individual traverse point NO_X (and, if applicable, diluent) concentrations, is within +/ · 5 percent of the mean concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(b) The performance test must be done at four load levels, *i.e.*, either within +/ · 5 percent of 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the combustion turbine, including the minimum point in the operating range and 90 to 100 percent of peak load. You may perform testing at the highest achievable load point, if 90 to 100 percent of peak load cannot be achieved in practice. Three test runs are required at each load level. The minimum time per run is 20 minutes.

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

(2) For a combined cycle turbine system with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine.

(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, ASTM D6522–00 (incorporated by reference, see § 60.17), or EPA Method 7E 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 emission limit.

(4) Compliance with the applicable emission limit in § 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in § 60.4320.

(5) 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.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under § 60.4345, then the initial performance test required under § 60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine relative accuracy test audit (RATA) reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest achievable) load.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under § 60.4320 and to provide the required reference method data for the RATA of the CEMS described under § 60.4335.

(d) The requirement to test at three additional load levels is waived.

(e) Compliance with the applicable emission limit in § 60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of lb/MW-hr, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with § 60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287–97 (2002) for natural gas or ASTM D4177–95 (2000) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057–95 (2000). At least one fuel sample must be collected during each load condition. Analyze the samples for the total sulfur content of the fuel using:

(1) For liquid fuels, ASTM D129–00, or alternatively D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01; or

(2) For gaseous fuels, ASTM D 1072–90 (Reapproved 1999), or alternatively D3246–96; D4468–85 (Reapproved 2000); or D6667–01.

(b) The fuel analyses required under paragraph (a) of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency.

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.

Base load means the load level at which a combustion turbine is normally operated.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to heat water or generate steam.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

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 before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output-based on the lower heating value of the fuel.

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 the purpose of maintenance checks and readiness testing, 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 the NO_X emissions are higher than the applicable emission limit in § 60.4320; the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.4330; or the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the combustion turbine. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (*i.e.*, thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

ISO standard conditions means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals 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 unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 ppmw total sulfur, and 338 ppmv at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 Btu and 1100 Btu per standard cubic foot.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO standard conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases to heat water or generate steam.

Stationary combustion turbine means any simple cycle combustion turbine, regenerative cycle combustion turbine or a combined cycle steam/electric generating system that is not self-propelled. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12:00 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.

Unit 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 unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, *i.e.*, total thermal energy made available for processes and applications other than electrical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kiloPascals (kPa) of pressure.

Table to Subpart KKKK of Part 60

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

For the following stationary combustion turbines:	With a peak load capacity of:	You must meet the following nitrogen oxides limit, given in ng/J of useful output:
Natural gas-fired turbine	< 30 MW	132 (1.0 lb/MW-hr)
Natural gas-fired turbine	≥ 30 MW	50 (0.39 lb/MW-hr)
Distillate oil and fuels other than natural gas-fired turbine	< 30 MW	234 (1.9 lb/MW-hr)
Distillate oil and fuels other than natural gas-fired turbine	≥ 30 MW	146 (1.2 lb/MW-hr)

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FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[DA 05–289; MB Docket No. 05–35; RM–11134]

Radio Broadcasting Services; Charlotte and Jackson, MI

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: This document requests comments on a petition for rule making filed by Rubber City Radio Group (''Petitioner''), licensee of Station WJXQ(FM), Channel 291B, Jackson, Michigan. Petitioner requests that the Commission reallot Channel 291B from Jackson to Charlotte, Michigan. This request is filed to maintain a first local service at Charlotte, Michigan. If this petition is granted it will eliminate a potential conflict between two licensees in another rulemaking proceeding (MB Docket No. 03–222) who propose to move from Charlotte to two other cities in Michigan. The two proposals in that proceeding are not in technical conflict, but would conflict with the Commission's policy of maintaining local service in a community that might otherwise lose local transmission service. Petitioner will retain the same transmitter site when its station is reallotted to Charlotte. The coordinates for Channel 291B at Charlotte, Michigan are 42–23–28 NL and 84–37–22 WL, with a site restriction of 30 kilometers (16.1 miles) southeast of Charlotte.

DATES: Comments must be filed on or before March 28, 2005, and reply comments on or before April 12, 2005.

ADDRESSES: Secretary, Federal Communications Commission, 445 12th Street, SW., Room TW–A325, Washington, DC 20554. In addition to filing comments with the FCC, interested parties should serve Petitioner's counsel, as follows: Mark N. Lipp, Esq. and Scott Woodworth, Esq., Vinson & Elkins LLP; 1455 Pennsylvania Ave., NW., Suite 600; Washington, DC 20004–1008.

FOR FURTHER INFORMATION CONTACT: R. Barthen Gorman, Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Notice of Proposed Rule Making, MB Docket No. 05–35, adopted February 2, 2005, and released February 4, 2005. The full text of this Commission decision is available for inspection and copying during regular business hours in the FCC's Reference Information Center at Portals II, 445 12th Street, SW., CY–A257, Washington, DC 20554. This document may also be purchased from the Commission's duplicating contractors, Best Copy and Printing, Inc., Portals II, 445 12th Street, SW., Room CY–B402, Washington, DC 20554, telephone 1–800–378–3160 or *http://www.BCPIWEB.com*. This document does not contain proposed information collection requirements subject to the Paperwork Reduction Act of 1995, Public Law 104–13. In addition, therefore, it does not contain any proposed information collection burden ''for small business concerns with fewer than 25 employees,'' pursuant to the Small Business Paperwork Relief Act of 2002, Public Law 107–198, *see* 44 U.S.C. 3506(c)(4).

The provisions of the Regulatory Flexibility Act of 1980 do not apply to this proceeding.

Members of the public should note that from the time a Notice of Proposed Rule Making is issued until the matter is no longer subject to Commission consideration or court review, all *ex parte* contacts are prohibited in Commission proceedings, such as this one, which involve channel allotments. *See* 47 CFR 1.1204(b) for rules governing permissible *ex parte* contacts.

For information regarding proper filing procedures for comments, *See* 47 CFR 1.415 and 1.420.

List of Subjects in 47 CFR Part 73

Radio, Radio broadcasting.

For the reasons discussed in the preamble, the Federal Communications Commission proposes to amend 47 CFR part 73 as follows: