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Part V

Environmental Protection Agency

40 CFR Part 60

Standards of Performance for New Stationary Sources: Industrial-Commercial-Institutional Steam Generating Units and Fossil Fuel-Fired Steam Generating Units; Final Rules

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-3074-5]

Standards of Performance for New Stationary Sources; Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance limiting emissions of particulate matter and nitrogen oxides (NO_x) from industrial-commercial-institutional steam generating units were proposed in the **Federal Register** on June 19, 1984 (49 FR 25102). Today's action promulgates these standards. The standards implement section 111 of the Clean Air Act and are based on the Administrator's determination that industrial-commercial-institutional steam generating units cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of these standards is require all new, modified, and reconstructed industrial-commercial-institutional steam generating units to reduce emissions of particulate matter and (NO_x) to the levels achievable by the best demonstrated system of continuous emission reduction, considering costs, nonair quality health and environmental impacts, and energy requirements.

DATE: Effective November 25, 1986.

Under Section 307(b)(1) of the Clean Air Act, judicial review of the actions taken by this notice is available *only* by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under Section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later during civil or criminal proceedings to enforce these requirements.

Incorporation by Reference: The incorporation by reference of certain publications in these standards is approved by the Director of the Office of the Federal Register as of November 25, 1986.

ADDRESSES: Background information documents may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, (919) 541-2777.

Docket number A-79-02 is available for public inspection between 8:00 a.m. and 4:00 p.m. Monday through Friday at the Central Docket Section (LE-131), West Tower Lobby, Gallery 1, 401 M Street, SW., Washington, DC 20460.

See "**SUPPLEMENTARY INFORMATION**" for further details.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter on Mr. Walter Stevenson, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5624.

SUPPLEMENTARY INFORMATION:

Summary of Standards

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> * * * application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)(C)].

For convenience, this will be referred to as "best demonstrated technology."

Applicability

These new source performance standards (NSPS) apply to all new, modified, or reconstructed steam generating units with a heat input capacity greater than 29 MW (100 million Btu/hour) for which construction is commenced after June 19, 1984, except for electric utility steam generating units covered by 40 CFR Part 60 Subpart Da. The definition of "steam generating unit" includes all devices that combust fuel and produce steam, hot water, or heat other fluids which are used as heat transfer media. Fuel combustion units which function as process heaters are not covered if their primary purpose is to heat a fluid in order to initiate or promote a chemical reaction in which the fluid itself is a reactant or catalyst.

The owner or operator of any steam generating unit with a heat input capacity for any fuel or fuels greater than 29 MW (100 milion Btu/hour) must submit certain information as required by the General Provisions (§ 60.11), including notification of the date of initial unit startup, and must maintain certain fuel use records.

Particulate matter emission limits are established for coal-, wood-, and municipal solid waste-fired steam generating units and for steam generating units which fire fuel mixtures including these fuels. The NO_x emission limits are established for coal-, oil-, and gas-fired steam generating units and for steam generating units which fire fuel mixtures including these fuels. Steam generating units that fire fuels other than coal, wood, municipal-type solid waste, oil, or natural gas are not subject to the particulate matter or NO_x standards, as applicable, unless they fire mixtures containing significant amounts of coal, wood, municipal-type solid waste, oil, or natural gas on an annual basis, as defined in the standards.

The standards being adopted today do not revise the sulfur dioxide (SO_2) standards for coal- or oil-fired units or the particulate matter standards for oil-fired units under 40 CFR Part 60 Subpart D. Steam generating units having heat input capacities greater than 73 MW (250 million Btu/hour) constructed after August 18, 1971 remain subject to the SO_2 standard for coal- and oil-fired units and the particulate matter standards for oil-fired units under 40 CFR Part 60 Subpart D. When the SO_2 standards for coal- and oil-fired units and the particulate matter standard for oil-fired units proposed on June 19, 1986 under 40 CFR Part 60 Subpart Db are promulgated, all steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity constructed after June 19, 1986 will become subject to the new SO_2 and particulate matter standards, as well as to the applicable particulate matter and NO_x standards promulgated today. As previously mentioned, all new electric utility steam generating units constructed after September 18, 1978, with heat input capacities greater than 73 MW (250 million Btu/hour) are subject to the particulate matter, NO_x, and SO_2 standards under Subpart Da of 40 CFR Part 60.

New steam generating units meeting the applicability requirements under this subpart and the applicability requirements under Subpart J (Standards of performance for petroleum refineries, § 60 100) are subject to the NO_x and particulate matter standards under this subpart and the SO_2 standards under Subpart J (§ 60.104).

New steam generating units meeting the applicability requirements under this subpart and the applicability requirements under Subpart E (Standards of performance for incinerators; § 60.50) are subject to the NO_x and particulate matter standards under this subpart.

Particulate Matter Standards

The particulate matter standards apply to coal-, wood-, and municipal type solid waste-fired steam generating units, as well as to steam generating units firing mixtures which include these fuels. For coal-fired steam generating units, the promulgated particulate matter emission limit is 22 ng/J (0.05 lb/million Btu) heat input. For steam generating units that fire wood or municipal-type solid waste, the promulgated particulate matter emission limit is 43 ng/J (0.10 lb/million Btu) heat input.

For steam generating units that fire mixtures including coal, wood, or municipal-type solid waste, with or without other fuels, the applicability of the 43 ng/J (0.10 lb/million Btu) heat input or the 22 ng/J (0.05 lb/million Btu) heat input emission limit would be determined based on the amount of coal, wood, or municipal-type solid waste combusted. Steam generating units that combust coal with wood, municipal-type solid waste or other fuels, have an annual capacity factor for wood, municipal-type solid waste or other fuels greater than 10 percent, and have a Federally enforceable permit which specifies that the unit must be operated at an annual capacity factor for wood, municipal-type solid waste, or other fuels (except coal) above 10 percent, are subject to a particulate matter emission limit of 43 ng/J (0.10 lb/million Btu) heat input. If a steam generating unit combusts coal with wood, municipal-type solid waste, or other fuels and has an annual capacity factor for wood, municipal-type solid waste, or other fuels (except coal) of 10 percent or less, or does not have a Federally enforceable permit, a particulate matter emission limit of 22 ng/J (0.05 lb/million Btu) heat input applies.

Coal-, wood-, or municipal solid waste-fired steam generating units in the 29 through 73 MW (100 through 250 million Btu/hour) heat input capacity range constructed between June 19, 1984 and November 25, 1986 that have an annual capacity factor for coal, wood, or municipal-type solid waste or any mixtures of these fuels of 30 percent or less and have a Federally enforceable permit limiting the annual capacity factor for coal, wood, or municipal-type solid waste to 30 percent or less are subject to a particulate matter emission limit of 86 ng/J (0.20 lb/million Btu) heat input.

Wood-fired steam generating units in the 29 MW through 73 MW (100 million Btu/hour through 250 million Btu/hour) heat input capacity size range constructed after November 25, 1986 that have an annual capacity factor of more than 10 percent for wood and less than 30 percent for all fuels, and have obtained a Federally enforceable operating permit limiting the annual capacity factor to these levels are subject to a particulate matter emission limit of 86 ng/J (0.20 lb/million Btu) heat input. All municipal solid waste-fired steam generating units commencing construction, modification, or reconstruction after November 25, 1986 will be subject to a 43 ng/J (0.10 lb/million Btu) heat input particulate matter standard independent of annual capacity factor. All coal-fired steam generating units commencing construction, modification, or reconstruction after November 25, 1986 will be subject to a 22 ng/J (0.05 lb/million Btu) heat input standard independent of annual capacity factor.

The annual capacity factor for determining the applicable particulate matter standard is calculated by dividing the annual heat input to the steam generating unit from firing coal, wood, municipal-type solid waste, or mixtures of these fuels as specified in the Federally enforceable limitation, by the potential annual heat input to the steam generating unit. The potential annual heat input is defined as the product of the maximum rated continuous heat input capacity (MW or million Btu/hour) multiplied by 8,760 hours per year. The potential annual heat input is a constant for each unit and is not affected by the number of hours the unit is actually operated.

The opacity standard for all steam generating units firing coal, wood, solid waste, or mixtures of these fuels, with or without other fuels, is 20 percent opacity (6-minute average) with one 6-minute excursion per hour up to 27 percent per hour. The opacity standard applies at all times except during periods of startup, shutdown, or malfunction as provided for by the General Provisions [§ 60.11(c)].

Performance tests to determine compliance with the particulate matter emission limits are conducted using Reference Method 5 or 17. It is anticipated that proposed Reference Method 5B (50 FR 21963, May 29, 1985), if promulgated, will be an applicable test method under today's standards. Reference Method 3 would be used for gas analysis and Reference Method 1 for the selection of sampling points. Reference Method 9 (a 6-minute average of 24 observations) would be used to determine compliance with the opacity standard. Continuous opacity monitoring is required for all steam generating units except as provided for by the General Provisions [§ 60.11(b)] and excess emissions (opacity) reports are required to be submitted on a semiannual basis.

NO_x Standards

The NO_x standards being adopted today apply to steam generating units with a heat input capacity greater than 29 MW (100 million Btu/hour) that fire coal, oil, natural gas, or mixtures of these fuels.

The promulgated NO_x emission limits for coal-fired steam generating units are 300 ng/J (0.70 lb/million Btu) heat input for pulverized coal-fired steam generating units, 260 ng/J (0.06 lb/million Btu) heat input for spreader stoker coal-fired steam generating units and fluidized bed combustion steam generating units, and 210 ng/J (0.50 lb/million Btu) for mass-feed stoker coal-fired steam generating units and for all coal-derived fuels. Lignite-fired steam generating units are subject to a NO_x emission limit of 260 ng/J (0.60 lb/million Btu) heat input, except for lignite mined in North Dakota, South Dakota, or Montana that is combusted in a slag tap-type furnace for which the emission limit is 340 ng/J (0.80 lb/million Btu) heat input.

For natural gas and distillate oil-fired steam generating units with maximum design heat release rates of 730,000 J/sec-m^3 (70,000 But/hour-ft^3) or less, the NO_x standard is 43 ng/J (0.10 lb/million Btu) heat input. For natural gas-fired and distillate oil-fired steam generating units with maximum design heat release rates greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3), the NO_x standard is 86 ng/J (0.20 lb/million Btu) heat input. For natural gas or distillate oil-fired duct burners used in steam generating units that are components of combined cycle gas turbine systems, NO_x standards are 86 ng/J (0.20 lb/million Btu) heat input.

Steam generating units firing fuel mixtures that include natural gas or distillate oil with either wood or solid waste and that have an annual capacity factor for natural gas or distillate oil greater than 10 percent are subject to a NO_x emission limit of 130 ng /J (0.30 lb/million Btu) heat input.

For residual oil-fired steam generating units having maximum design heat release rates of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or less, the NO_x emission limit is 130 ng/J (0.30 lb/million Btu) heat input. For residual oil-fired steam generating units having maximum design heat release rates greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3), the NO_x emission limit is 170 ng/J (0.40 lb/million Btu) heat input. For residual oil-fired duct burners, NO_x standards are 170 ng/J (0.40 lb/million Btu) heat input.

The NO_x emission limits for steam generating units firing mixtures of coal, oil, or natural gas would be determined by proration of the NO_x standards based on the respective amounts of each fuel fired. For steam generating units that fire coal, oil, or natural gas in a mixture containing other fuels (except for mixtures of natural gas or distillate oil with wood or solid waste) and for which the annual capacity factor based on the total heat input from coal, oil, and natural gas is greater than 10 percent, the steam generating unit would be required to meet the NO_x standard for coal, oil, natural gas, or a mixture of these fuels, as applicable.

Steam generating units that fire mixtures of natural gas or distillate oil with gaseous byproduct/waste fuels from chemical plants or petroleum refineries are subject to the NO_x emission limit applicable to natural gas or distillate oil. Similarly, units that fire mixtures of residual oil and liquid byproduct/waste fuels from chemical plants or petroleum refineries are subject to the NO_x emission limit applicable to residual oil.

Owners or operators of steam generating units covered by these standards may apply in one of two ways for facility-specific NO_x emission limits if they are burning byproducts/wastes. If non-toxic wastes are fired, facility-specific NO_x emission limits will be proposed and promulgated in the **Federal Register** provided the owner or operator can demonstrate to the Administrator's satisfaction that the facility has installed best demonstrated NO_x control technology, but cannot achieve the applicable NO_x standard due to characteristics of the byproduct/waste, such as high nitrogen content, high heat content, or other characteristics affecting NO_x emissions. Such a demonstration may include test data that showed the facility complied with the NO_x standard when natural gas or oil was fired, as appropriate, but is unable to comply with the applicable NO_x standard when gaseous or liquid byproduct/wastes are fired. For units firing toxic waste a full waiver of the NO_x standard will be issued provided the demonstration shows compliance with all applicable federally enforceable destruction efficiency requirements. It is suggested that the demonstration test be incorporated into the initial 30-day compliance test, which is required to be completed within 180 days of initial unit startup. Although the NO_x standards promulgated today may be delegated to State or local agencies for enforcement, these provisions for facility-specific NO_x emission limits will not be delegated.

All steam generating units subject to the NO_x standards are required to perform an initial 30-day compliance test within 180 days of initial unit startup. After the initial compliance test or 180 days following initial unit startup, whichever comes first, compliance with the standards is determined in one of two ways, depending on the size of the unit and the fuel fired. First: (1) All steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity that fire coal or high nitrogen content residual oil (greater than 0.3 weight percent nitrogen), and (2) all steam generating units larger than 73 MW (250 million Btu/hour) heat input capacity that fire natural gas, distillate oil, or low nitrogen content residual oil (less than 0.3 weight percent) are required to install and operate a continuous emission monitoring system (CEMS) to measure NO_x emissions. The only exception to this is gas turbine combined cycle units equipped with duct burners where CEMS are not required.

The NO_x emission data will be used to calculate NO_x emissions on a 30-day rolling average basis. These data will be used to determine compliance with the NO_x standards; therefore, the quality assurance procedures for CEMS set forth under 40 CFR Part 60 Appendix F, Procedure 1, (49 FR 9676, March 14, 1984) when adopted will apply. NO_x compliance reports are required to be submitted on a quarterly basis.

Second, for steam generating units having heat input capacities between 29 MW and 73 MW (100 million Btu/hour and 250 million Btu/hour), and firing natural gas, distillate oil, or low nitrogen content residual oil (less than 0.3 weight percent) the owner or operator has an option of using either CEMS or monitoring steam generating unit operating conditions. In these applications, the CEMS data will not be used to determine direct compliance with the NO_x standards. The quality assurance procedures under 40 CFR Part 60 Appendix F would not apply. The CEMS data will be used to prepare excess emission reports which will be used primarily to determine if another 30-day compliance test is necessary. NO_x excess emission reports are required to be submitted on a semiannual basis.

As an alternative to CEMS for these units, the owner or operator of the facility may apply to the Administrator for approval to monitor steam generating unit operating conditions indicative of NO_x emission rates. An owner or operator applying for approval to monitor operating conditions shall submit a monitoring plan to the Administrator for review. Manufacturers of steam generating units may develop monitoring plans and provide them to owners or operators of steam generating units. The monitoring plans, with supporting operating and emission data, could subsequently be submitted by the owner or operator of the affected facility.

The plan submitted for review must outline how the conditions to be monitored can be used to predict NO_x emission rates. If approved by the Administrator, the results from monitoring operating conditions shall be recorded, used to predict NO_x emission rates, and the NO_x emission data submitted in semiannual excess emission reports. Additionally, a quarterly excess emissions report will be required to be submitted for any quarter that excess emissions occur. The excess emission reports will then be used primarily to determine if another 30-day compliance test should be conducted. It is suggested that the monitoring plan be developed during the initial 30-day compliance test which is required for all units. The standards being adopted today require that the monitoring plan be submitted within 360 days of initial unit startup.

Owners or operators of all steam generating units with heat input capacities greater than 29 MW (100 million Btu/hour) shall maintain records of annual fuel consumption by fuel type. For facilities in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range and combusting residual oil containing less than 0.30 weight percent nitrogen, fuel records must be maintained that indicate the nitrogen content of the residual oil fired. If fuel nitrogen content is not reported it will be assumed to be higher nitrogen content residual oil (equal to or greater than 0.30 percent nitrogen) and CEMS will be required. Appendix F will be applicable and the emissions data used to determine compliance on a continuous basis.

Fuel specification data from the oil supplier may be used to determine fuel nitrogen content in place of on-site testing. If liquid fuel blends are fired, specifications may be prorated based on the ratio of the liquid fuels of different nitrogen content in the fuel blend. In all cases, fuel records shall be maintained for 2 years. All facilities subject to the NO_x standards operating a CEMS or measuring unit operating conditions shall maintain records for 2 years.

The owners or operators of all steam generating units having heat input capacities greater than 29 MW (100 million Btu/hour) heat input must submit certain reports. The regulation requires notification of the intent to initiate operation of a new, modified, or reconstructed steam generating unit. Additionally, those facilities subject to the particulate matter or NO_x standards must submit results of the initial performance test and performance evaluation of the CEMS within 180 days of initial startup. For those facilities monitoring opacity, monitoring NO_x by CEMS, or monitoring NO_x by operating conditions, emissions reports must be submitted even if the standards were not exceeded during the reporting period. Also, units equipped with CEMS that are used for compliance determinations will be subject to the quality assurance requirements under 40 CFR Part 60, Appendix F, Procedure 1 when promulgated and shall submit CEMS quarterly quality assurance reports.

Environmental Impacts

The environmental impacts of the standards being adopted today are expressed as incremental differences in emissions between the current emission regulations (referred to as the baseline) and these standards. These impacts are based on the assumption that energy prices experienced in 1984/1985 will continue with only moderate price increases in future years. A consequence of this fuel price assumption is that a large proportion of the new industrial-commercial-institutional steam generating unit population (greater than 50 percent) will continue to fire natural gas or oil, and that coal-fired units are expected to be limited to principally base load units in the larger size range.

The new source performance standards for particulate matter and NO_x emission controls being adopted today will result in a range of emission reductions depending on the mix of fuels assumed to be fired. New source performance standards for SO_2 were recently proposed and affect the mix of fuel fired. The SO_2 standards, as proposed, are expected to increase the market share for natural gas-fired steam generating units from approximately 30 percent to about 55 percent. Because natural gas-fired steam generating units have lower particulate matter and NO_x emissions than either coal- or oil-fired units, decreased particulate matter and NO_x emissions result with the SO_2 standards in place.

A range of environmental impacts is presented. The lower estimate is based on the incremental change between the baseline regulations (State implementation plans and Subpart D new source performance standards) and the particulate matter and NO_x standards being adopted today. The upper estimate is based on the incremental change between the baseline regulations and the particulate matter and NO_x standards combined with the recently proposed new source performance standards for SO_2 (51 FR 22384, June 19, 1986), which would also apply to this category of steam generating units.

The primary environmental impacts resulting from the particulate matter and NO_x standards being adopted today are reductions in the quantity of particulate matter and NO_x emitted from steam generating units subject to these standards. It is estimated that between 1985 and 1990 approximately 725 new steam generating units will be constructed that would be subject to the standards. Baseline emissions from these new steam generating units will be 49,000 Mg (54,000 tons) of particulate matter per year and about 77,000 Mg (85,000 tons) of NO_x per year in 1990. The standards being adopted today are projected to reduce baseline particulate matter emissions by 16,000 to 22,000 Mg (18,000 to 24,000 tons) per year and NO_x emissions by 21,000 to 24,000 Mg (23,000 to 26,000 tons) per year in 1990. This represents about a 35 to 45 percent reduction in the growth of particulate matter emissions and about a 25 to 30 percent reduction in the growth of NO_x emissions from new steam generating units subject to these standards.

The solid and liquid waste impacts associated with the particulate matter and NO_x standards are minimal. Flyash disposal levels associated with existing State regulations and Subpart D new source performance standards are only incrementally increased as a result of the particulate matter standards adopted today. Further, the change in fuel use patterns resulting from the standards can actually reduce flyash levels where increased gas use displaces coal. Overall, the standards are projected to result in solid waste impacts ranging from a net reduction of about 9,000 Mg/year (10,000 tons/year) to a net increase of 13,000 Mg/year (14,000 tons/year). The liquid waste impacts associated with the particulate matter standards are minimal. Liquid waste production levels are projected to increase over baseline by about 19,000 m^3 (680,000 ft^3) per year, or approximately 1.5 percent.

Energy Impacts

The energy impacts of the standards have been analyzed in terms of the impact on demand for natural gas, oil, and coal and in terms of overall energy requirements of steam generating units covered by the standards. Steam generating units that would be affected by the standards are projected to demand approximately 525 million GJ (498 trillion Btu) of fossil fuels in 1990. It is projected that natural gas will comprise about 30 to 50 percent of the fuel used in steam generating units and residual oil will provide a substantial portion of the remainder. The particulate matter standards would increase the national electric energy requirements by about 146 GWh/year in 1990.

Cost Impacts

In analyzing the national cost impacts of the standards, only the costs resulting from the implementation of the particulate matter and NO_x standards have been considered in this rulemaking. On a national basis, the particulate matter and NO_x standards would increase the capital cost for new steam generating units by approximately 1 percent. The nationwide increase in annualized costs for producing steam from new steam generating units subject to the standards would be approximately $36 million in 1990. This represents an increase of less than 1 percent over baseline annualized costs for producing steam from new steam generating units. The magnitude of these cost impacts remains the same regardless of the SO_2 standards.

The national incremental cost effectiveness of the particulate matter standards over existing regulations is projected to range from approximately $1,025/Mg to $1,400/Mg ($930/ton to $1,270/ton) of particulate matter removed. The national incremental cost effectiveness of the NO_x standards over existing regulations is projected to range from $370/Mg to $640/Mg ($340/ton to $580/ton) of NO_x removed.

These impacts are presented as a range of values, showing the incremental cost effectiveness between the baseline and the particulate matter and NO_x standards adopted today, and between the baseline and the combined particulate matter, NO_x, and proposed SO_2 standards. Because of the fuel shifts which are projected to occur under the proposed SO_2 standards, different cost effectiveness levels result in each case.

Economic Impacts

The economic impacts of the standards have also been evaluated in terms of the nationwide capital expenditures for pollution control equipment, the increase in the annualized cost of producing steam, the resulting rise in the price of products produced by operators of steam generating units, and the impact on the availability of capital to the firms purchasing steam generating units.

In analyzing potential product price, profitability, and capital availability impacts associated with the standards, industries likely to experience the severest impacts and the conditions which would produce the most adverse impacts were chosen for examination. The standards being adopted today were found to have no significant adverse economic impacts on any of these industries.

On the national level, assuming increases in annualized costs are passed forward to product consumers and not absorbed by industry, the standards are projected to result in a projected average increase of less than a 0.05 percentage point average increase in the product price for any major steam user group examined, with smaller increases for industries using less steam. For those selected industries which have been judged likely to be most affected by the standards, product prices could increase by 0.05 to 0.40 percent. This projected product price increase is based on a "worst case" analysis assuming full cost pass-through. If no cost pass-through and full cost absorption by industry are assumed, no product cost increase would result, and the return on assets would decrease by 0.01 to 0.60 percentage point under the standards. Impacts on any given plant would likely be much less than these worst case examples under either assumption.

Public Participation

Prior to proposal, interested parties were advised by public notice in the **Federal Register** (47 FR 19786, May 7, 1982) of a meeting of the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) to discuss the standards recommended for proposal. This meeting was held on June 16 and June 17, 1982. The meeting was open to the public and each attendee was given an opportunity to comment on the standards recommended for proposal.

Subsequently, the standards were proposed on June 19, 1984 (49 FR 25102). The preamble to the proposed standards discussed the availability of the Background Information Documents (BID) which describe in detail the regulatory alternatives considered and the impacts of those alternatives. The BID's include EPA-450/3-82-006a "Fossil Fuel-Fired Industrial Boilers—Background Information for Proposed Standards Volume 1: Chapters 1-9," EPA-450/3-82-006b "Fossil Fuel-Fired Industrial Boilers—Background Information for Proposed Standards Volume 2: Appendices," and EPA-450/3-82-007 "Nonfossil Fuel-Fired Industrial Boilers—Background Information." Cost reports include EPA-450/3-82-021 "Costs of Sulfur Dioxide, Particulate Matter, and Nitrogen Oxide Controls on Fossil Fuel-Fired Industrial Boilers," and EPA-450/3-83-004 "Costs of Particulate Matter Controls for Nonfossil Fuel-Fired Boilers." Comments on the proposal were solicited and copies of the BID and cost reports were made available to interested parties.

To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held on August 15, 1984 at Research Triangle Park, North Carolina. The hearing was open to the public and each attendee was given an opportunity to comment on the proposed standards.

The comment period was from proposal date (June 19, 1984) to October 1, 1984. The written comments and oral statements have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the proposed standards.

Comments On Proposal

Discussed below are the more significant comments made by commenters.

Priority List

Two commenters requested that steam generating units with heat input capacities of less than 73 MW (250 million Btu/hour) be delisted from the category of "Fossil Fuel-Fired Steam Generators: Industrial Boilers." The commenters indicate the reasons for their request are (1) that steam generating units under 73 MW (250 million Btu/hour) heat input capacity are not significant air pollution sources; and (2) that these units are already adequately regulated by State regulations and other requirements of the Clean Air Act.

On August 21, 1979, a priority list for development of additional NSPS was published in accordance with sections 111(b)(1)(A) and 111(f)(1) of the Clean Air Act. This list identified 59 major stationary source categories that were not covered by NSPS, but that were judged to be "significant contributors" i.e., to contribute significantly to air pollution that could reasonably be expected to endanger public health or welfare. Fossil fuel-fired industrial steam generating units ranked eleventh on this priority list of sources for which NSPS would be established in the future.

Of the 10 sources ranked above fossil fuel-fired industrial steam generating units on the priority list, nine were major sources of volatile organic compound (VOC) emissions. Because there are many areas that have not attained the national ambient air quality standard for ozone, major sources of VOC emissions were accorded a very high priority. Of the remaining source categories, fuel-fired industrial steam generating units were the highest ranked source of particulate matter and SO_2 emissions, and the second highest ranked source of NO_x emissions. The industrial-commercial-institutional source category is a significant contributor and therefore an appropriate source category for regulation. There is no requirement that subcategories of a listed category or individual sources within a listed category also be "significant contributors." For this reason, the request for delisting fossil fuel-fired steam generating units with heat input capacities less than 73 MW (250 million Btu/hour) is denied.

Applicability

A number of commenters requested clarification on the types of facilities covered by the standards. The applicability requirements of the final standards have been clarified but remain basically the same as those in the proposal. All steam generating units with more than 29 MW (100 million Btu/hour) heat input capacity for which construction is commenced after June 19, 1984, except utility units covered under Subpart Da, are covered by Subpart Db. Except as noted below, the definition of "steam generating unit" includes all devices that combust fuel and produce steam, hot water, or a heat transfer fluid. Fuel combustion units which function as process heaters are not covered if their primary purpose is to heat a fluid in order to initiate or promote a chemical reaction in which the fluid itself is a reactant or catalyst.

Although the standards being adopted today apply to a wide range of industrial-commercial-institutional steam generating units, emission limits are established only for specified fuels or fuel mixtures. Particulate matter emission limits are established for coal, municipal-type solid waste, wood and mixtures of these fuels with other fuels, and NO_x emission limits are established for natural gas, distillate oil, residual oil, coal, and mixtures of these fuels with refinery and chemical plant byproduct/waste fuels. Industrial-commercial-institutional steam generating units firing other fuels would be required to report their startup and maintain certain fuel records, but would not be subject to the particulate matter or NO_x standards. These units may, however, be regulated under Prevention of Significant Deterioration (PSD) permit requirements.

The applicability date for the standards adopted today are June 19, 1984. The standards include one particulate matter standard for low annual capacity factor coal- and municipal solid waste-fired units build between June 19, 1984 and today, and a stricter standard for such low capacity units built after today. The particulate matter standard for low annual capacity factor coal-fired units constructed between June 19, 1984 and today is 190 ng/J (0.20 lb/million Btu) heat input, whereas the standard for such units constructed after today is 22 ng/J (0.05 lb/million Btu) heat input. The particulate matter standard for low annual capacity factor municipal solid waste-fired units constructed between June 19, 1984 and today is 190 ng/J (0.20 lb/milion Btu) heat input. However, for units constructed after today's date, the standard for low annual capacity factor municipal solid waste-fired units is the same as for all other municipal waste-fired units, which is 43 ng/J (0.10 lb/million Btu) heat input.

One commenter asked if the standards apply to exhaust gas incinerators at sulfur recovery units (e.g., Claus units). Emissions from sulfur recovery units at gas processing plants are covered under Subpart LLL of 40 CFR Part 60. Emissions from sulfur recovery units at petroleum refineries are covered under Subpart J. Although sulfur recovery unit tail gas incinerators may fire some natural gas, no tail gas incinerators large enough to meet the size requirements of the standards adopted today have been identified. Therefore, few, if any, exhaust gas incinerators at sulfur recovery units would be covered by the standards being adopted today.

Similarly, sewage sludge incinerators are not covered under these standards. Emissions from sewage sludge incinerators are regulated under Subpart O of 40 CFR Part 60.

Commenters questioned whether all municipal solid waste-fired units, including municipal waste incinerators, are covered. Municipal waste incinerators are currently regulated under Subpart E of 40 CFR Part 60. Subpart Db, as adopted, supersedes Subpart E to the extent that it regulates particulate matter emissions from municipal solid waste-fired incinerators that generate steam, hot water, or heat a heat transfer fluid and have a heat input capacity greater than 29 MW (100 million Btu/hour). A 29 MW (100 million Btu/hour) heat input capacity is equivalent to approximately a 230 Mg/day (250 tons/day) capacity municipal solid waste-fired unit. Municipal solid waste incinerators without heat recovery or that have a heat input capacity less than 29 MW (100 million Btu/hour) remain subject to 40 CFR Part 60 Subpart E.

Under the standards adopted today, incinerators with heat recovery are required to meet the particulate matter standard of 43 ng/J (0.10 lb/million Btu) heat input. Incinerators without heat recovery and incinerators with heat recovery below 29 MW (100 million Btu/hour) heat input in size remain subject to the Subpart E particulate matter emission limit of 0.18 g/dscm (0.08 gr/dscf), which is approximately equivalent to 73 ng/J (0.17 lb/million Btu) heat input.

It should be noted that, in addition to being subject to the standards promulgated today, incinerators combusting byproduct/wastes containing polychlorinated biphenyls (PCB's), including incinerators with and without heat recovery, are subject to regulations pertaining to PCB's promulgated under the Toxic Substances Control Act (TSCA) (40 CFR 761.70).

Lastly, commenters raised questions about what fuels actually comprise municipal-type solid waste. Only waste such as paper, wood, yard wastes, food wastes, plastic, leather, rubber, and other materials typically collected from residential or commercial properties are regulated.

Another commenter inquired about the coverage of process heaters using waste heat economizers. Process heaters equipped with a waste heat economizer are not covered under these standards if the primary purpose of the process heater is to heat a fluid in order to initiate or promote a chemical reaction in which the fluid itself is a reactant or catalyst. The regulations have been revised to clarify this point.

The effect of the proposed standards on catalytic cracking units at petroleum refiners was questioned by one commenter. Catalytic cracking units are covered under Subpart J of 40 CFR Part 60 and are not covered under these standards. The final regulation addresses this.

Inquiry was also made concerning the applicability of Subpart Db to auxiliary (e.g., startup) steam generating units at electric utility power plants. Although these standards apply primarily to steam generating units used in industrial, commercial, and institutional applications, the standards do apply to utility units with heat input capacities greater than 29 MW (100 million Btu/hour) that are not covered under Subpart Da of 40 CFR Part 60. Consequently, small auxiliary steam generating units located at electric utility power plants meeting the applicability requirements of today's standard but not Subpart Da are subject to the standards being promulgated today.

Several commenters expressed opinions about whether various fuels were covered under the emission standards. One commenter said that black liquor recovery steam generating units at pulp mills should not be covered. Black liquor is a byproduct at pulpmills and is fired in steam generating units to recover sodium bisulfate in the flyash. Black liquor recovery units are exempted from these standards if they do not fire regulated fuels, in which case they are covered under Subpart BB of 40 CFR Part 60 applicable to Kraft pulp mills. If black liquor recovery units have an annual capacity factor for fossil fuels greater than 10 percent, which is unlikely, they would be subject to the NO_x standards under this subpart.

Other commenters questioned if various coal-derived fuels were covered by the emission standards. Coal-derived gases, coal-derived liquids, coal-oil mixtures, and coal-water mixtures and other coal-derived fuels are covered and emissions from firing these fuels would be subject to the particulate matter and NO_x standards for coal-fired units. Coal and all coal-derived fuels, including both liquid and gaseous fuels, are being covered because there are demonstrated control technologies available to reduce emissions from the combustion of fuels in both forms.

Commenters questioned whether steam generating units firing mixtures of wood and natural gas would be subject to an emission limit of 130 ng/J (0.30 lb/million Btu) heat input under § 60.46b(a), or would be subject to some prorated emission limit under § 60.43b(b). The final NO_x standards have been revised to make it clear that units firing mixtures of wood and natural gas are subject to the 130 ng/J (0.30 lb/million Btu) heat input emission limit.

It should also be noted that today's **Federal Register** contains a separate notice incorporating the same 130 ng/J (0.30 lb/million Btu) heat input emission limit into Subpart D for units firing mixtures of wood and natural gas.

Particulate Matter

Coal-Fired Steam Generating Units. Commenters stated that the cost effectiveness of particulate matter controls for coal-fired steam generating units covered by this subpart is high relative to the cost effectiveness of particulate matter control on utility power plants and this represents a poor use of capital for environmental protection. Another commenter said the cost effectiveness of the proposed particulate matter standards is underestimated because the baseline emission level used in the cost analysis is higher than the actual emission levels generally allowed for these sources by State regulations.

With respect to the first comment, the analysis of the cost of the particulate matter standard for coal-fired steam generating units was based on the cost and performance capability of fabric filters on industrial-size units. The analysis showed that the cost effectiveness of applying particulate matter control varies as a function of steam generating unit size and that the cost effectiveness for smaller (i.e., industrial-size) steam generating units is higher than for larger units. However, this does not necessarily mean that either the standard for industrial-commercial-institutional units or the standard for utility units under Subpart Da is unreasonable.

Based on the cost of fabric filters, the incremental cost effectiveness of particulate matter control for a typical industrial-size steam generating unit [44 MW (150 million Btu/hour) heat input capacity] is estimated to be about $1,600/Mg ($1,500/ton) of pollutant removed over the next most effective technology. As expected, this cost effectiveness level is higher than for a typical utility-size unit which would experience an incremental cost effectiveness level of less than $550/Mg ($500/ton).

When selecting the particulate matter standard for utility steam generating units under Subpart Da, cost-effectiveness levels which might be considered unreasonable were not reached. The standard was limited by the technical performance level of ESP's and fabric filters rather than by cost effectiveness. If no particulate matter standards were adopted that exceeded the cost effectiveness levels of Subpart Da, few if any particulate matter standards would be possible because the large size of facilities covered by Subpart Da alone results in low cost-effectiveness levels.

The Clean Air Act does not require that the cost effectiveness of the standards for one source category be the same as the cost effectiveness of standards for other source categories (*Portland Cement Association v. Ruckelshaus* 486 F.2d. 375, 389–90 (D.C. Cir. 1973)). The Act requires only that the costs of the standards be considered reasonable by the Administrator for the individual category of facilities subject to regulation. In this case, the cost effectiveness of applying fabric filter or other equally effective particulate matter control technologies to industrial-commercial-institutional coal-fired units is considered reasonable.

The second comment was that a baseline particulate matter emission level of 260 ng/J (0.60 lb/million Btu) heat input is higher than the actual emission levels generally allowed by State regulations. The baseline emission level represents the emission reduction capability of single mechanical collectors. Although many States require the use of more efficient control systems, mechanical collectors are the control device universally required as a minimum under even the least stringent State implementation plan (SIP).

As discussed in the preamble to the proposed standards, two technical alternatives to this baseline for the control of particulate matter emissions were analyzed in terms of cost specific basis and cost effectiveness. Technical Alternative I was based on a moderate level of control [86 ng/J (0.20 lb/million Btu) heat input] achieved by sidestream separators, low pressure drop wet scrubbers, or low efficiency ESP's. Technical Alternative II was based on a high level of particulate matter control [22 ng/J (0.05 lb/million Btu) heat input] achieved by fabric filters and other equally effective control technologies.

The cost effectiveness of the proposed standards on an individual unit basis was analyzed in terms of the incremental cost effectiveness of each alternative level of control in relation to the next less stringent alternative. Therefore, the cost effectiveness of Technical Alternative I was estimated in relation to the cost effectiveness of single mechanical collectors capable of reducing particulate matter emissions to the baseline emission level of 260 ng/J (0.60 lb/million Btu) heat input or less. The cost effectiveness of Technical Alternative II, which coincided with the proposed standard, was estimated in relation to the cost effectiveness of sidestream separators capable of reducing particulate matter emissions to 86 ng/J (0.20 lb/million Btu) heat input or less (Technical Alternative I), rather than to the baseline level of 260 ng/J (0.60 lb/million Btu) heat input. This method of analysis provides an estimate of the marginal, or incremental, cost of control for an individual unit and is the most appropriate way to review increasingly stringent control options. Because the final particulate matter standard for coal-fired units (Technical Alternative II), is compared with the cost of Technical Alternative I and not the baseline costs, the assumed baseline control level is not a factor in the calculation of the incremental cost effectiveness of the standard as adopted. Thus, the commenter's concern that the assumed baseline particulate matter emission level was too low is not relevant to the results of the cost analysis for the incremental cost between Technical Alternatives I and II.

Other commenters stated that the less stringent particulate matter standard of 86 ng/J (0.20 lb/million Btu) heat input proposed for coal-fired units less than 73 MW (250 million Btu/hour) in size with an annual capacity factor for coal of 30 percent (0.30) or less was unjustified and should be removed so that all coal-fired units would be subject to the same standard. The purpose for proposing a separate, more lenient standard for low capacity factor units was to distinguish seasonal, standby, or low-load units from base-load type units in response to the higher cost-effectiveness levels associated with control of particulate matter emissions from these types of coal-fired steam generating units.

Further analysis indicates that relatively few new coal-fired low annual capacity factor units are likely to be constructed. This pattern is expected to continue in the future, especially in light of NSPS proposed for the control of SO_2 emissions from coal-fired industrial-commercial-institutional steam generating units (51 FR 22384, June 19, 1986). The few low annual capacity factor coal-fired units that may have been constructed in the absence of SO_2 standards will likely shift from firing coal to firing natural gas or fuel oil as the primary fuel as a result of the SO_2 standards. As a result, the impacts associated with the application of more stringent particulate matter standards are not likely to materialize for low annual capacity factor units.

The judgment that relatively few low annual capacity factor steam generating units are likely to be constructed to fire coal in the future is based on a comparison of the economics of firing coal versus oil or natural gas. The annualized cost for a typical coal-fired industrial steam generating unit (44 MW; 150 million Btu/hour heat input capacity) in a low capacity factor application will exceed the cost of a natural gas-fired or oil-fired steam generating unit by 50 to 100 percent. Consequently, coal is generally not competitive with oil or natural gas in steam generating units which operate at low annual capacity factors. In such cases, the economics clearly favor selection of oil or natural gas as the primary fuel, regardless of the cost of emission control systems. As a result, in instances where a low annual capacity factor unit is built, the less than 5 percent cost increase to apply the most efficient particulate matter control technology will not change steam generating unit economics.

When viewed on an annual basis, the incremental cost effectiveness of the most effective systems is comparatively high for low capacity factor units. However, during periods of operation, the emissions potential of such coal-fired units can be as great or greater than units with higher annual capacity utilization rates. Coal-fired steam generating units used for space heating, for example, are often operated on a seasonal basis at or near full capacity for several months each year. During these periods, the emission rates of such units will be comparable to similar sized coal-fired units operated yearround.

Additionally, an emission limit requiring use of high efficiency control systems uniformly on all coal-fired units will improve the enforceability of the standards. If any low capacity factor coal-fired units are built, there will be an inherent economic incentive to operate them at higher capacity factors as plant production expands or if the unit is subsequently used for cogeneration purposes. If the unit is operated at an annual capacity factor greater than 0.30 (30 percent) it would become subject to a more stringent standard, requiring retrofit of the unit with a high efficiency control system. In addition to requiring a permit revision, such a change would require additional resources to enforce applicable monitoring, reporting, recordkeeping and other compliance-related provisions.

In the final regulation, therefore, the same standard [22 ng/J (0.05 lb/million Btu) heat input] is applicable to lower annual capacity factor coal-fired units as to higher annual capacity factor units. In the final standards, all coal-fired units constructed after today's date with heat input capacities greater than 29 MW (100 million Btu/hour) are subject to a particulate matter standard of 22 ng/J (0.05 lb/million Btu) heat input, independent of annual capacity utilization rates.

Although few, if any, units are expected to be built, it would be inappropriate to require any units which may have been constructed since proposal, but prior to today, to retrofit particulate matter control technology to meet the lower standard. The emission limit of 86 ng/J (0.20 lb/million Btu) heat input is being maintained for low annual capacity factor units constructed during this interim period. As a result, the final standards specify that low annual capacity factor coal-fired units, if constructed between June 19, 1984 and today, are subject to a particulate matter standard of 86 ng/J (0.20 lb/million Btu) heat input.

Wood-Fired Steam Generating Units. One commenter stated that promulgation of the standard of 43 ng/J (0.10 1b/million Btu) heat input proposed for wood-fired steam generating units would discourage the use of wood fuels, and that existing State regulations for wood-fired units provide adequate environmental protection to meet national ambient air quality standards (NAAQS) for particulate matter. The commenter observed that particulate matter emissions from new wood-fired steam generating units would be about 10,000 Mg (11,000 tons) in 1989, or less than 0.2 percent of the national total emissions of particulate matte. from industrial-commercial-institutional steam generating units.

Also, the commenter contended that promulgation of the proposed standard would reduce the use of logging residues as fuels. This would increase open burning of logging residue in "slash fires," resulting in a net deterioration of air quality. Finally, the commenter suggested that wood-fired steam generating units be allowed to operate under existing State standards [130 to 170 ng/J (0.30 to 0.40 lb/million Btu) heat input], provided the facility demonstrated that more than 12 percent of the fuel fired was derived from logging residues.

Section 111 of the Clean Air Act requires NSPS to be based on the level of emissions achievable using best demonstrated technology. Basing a standard on best demonstated technology may result in an emission limit more stringent than a State regulation based on national ambient air quality standards (NAAQS) . Particulate matter emissions of 10,000 Mg/year (11,000 tons/year) are significant and can be controlled at a reasonable cost. If the suggested logic were followed, it could be concluded that few, if any, NSPS were necessary because most individual units only contribute a small fraction of the final emissions from the source category.

In addition, promulgation of the standards is not expected to cause more logging residue to be burned in open "slash fires" than is already being burned in this manner. The promulgated standards will result in only a minor increase in cost and there will remain an economic incentive for use of logging residues where available as opposed to other fuels.

Another commenter stated that basing the 43 ng/J (0.10 lb/million Btu) heat input particulate matter emission limit for wood-fired-steam generating units on ESP technology was inappropriate. This objection was based on emission data presented in the proposed standard that showed electrostatic granular filters (EGF) achieved particulate matter emission levels of 8.6 to 17.0 ng/J (0.02 to 0.04 lb/million Btu) heat input. This commenter also noted that fabric filters achieved a particulate matter emission level of 8.6 ng/J (0.02 lb/million Btu) heat input on two wood-fired steam generating units.

Both ESP's and EGF's are considered demonstrated particulate matter emission control technologies for wood-fired steam generating units. However, the particulate matter test data for EGF's are very limited. The proposed standard was based on careful consideration of text data available for ESP's and high pressure drop scrubbers applied to seven steam generating units firing wood and mixtures of wood and fossil fuels. In comparison, particulate matter test data were available from only two steam generating units using EGF's for control of particulate matter emissions. Because of the limited database, EGF's were not selected as the basis of the standard applicable to wood-fired steam generating units.

To date, fabric filters have been used infrequently on wood-fired steam generating units because of concern about potential fire hazards. New units with control interlocks appear to greatly reduce fire hazard. But, again, fabric filters have had limited application and test data are available from only two units.

For these reasons, the particulate matter standard for steam generating units firing wood or mixtures of wood and fossil fuels has not been changed and is based on application of ESP's or high pressure drop wet scrubbers. However, any technology, including EGF's or fabric filters, can be selected to comply with the standard being promulgated today.

Municipal Solid Waste-Fired Steam Generating Units. An emission limit of 43 ng/J (0.10 lb/million Btu) heat input was proposed for steam generating units firing municipal-type solid waste. The proposed emission limit was based on the performance of electrostatic precipitators (ESP's), as demonstrated in four Reference Method 5 particulate matter emission tests on units ranging in heat input capacity from 14 to 85 MW (47 to 290 million Btu/hour). The test data showed that particulate matter emissions decreased with increasing ESP collection area and that an emission limit of 43 ng/J (0.10 lb/million Btu) heat input could be achieved by use of ESP's with collection areas of at least 47 $m^2/(m^3/s)$ (240 ft^2/1,000 acfm).

Although these test data were the best available during the development of the proposed standards for municipal solid waste-fired units, these data are from units that began operation in the early 1970's. Interest in waste-to-energy facilities has been increasing in recent years and a number of new units are currently in planning or under construction for operation in the near future. These new facilities are using more effective and sophisticated control equipment designed to achieve even lower particulate matter emission levels than the proposed standard. In fact, several commenters suggested that emission levels for lower than the proposed standard are now achievable by the current generation of waste-to-energy facilities. This latest generation of facilities is generally being required by permits to operate at optimum combustion levels and install spray dryer/fabric filter technology.

Efforts have been underway since proposal to collect and evaluate additional data on the performance of the latest emission control systems for municipal waste-fired units. Some additional data have been obtained; however, it is too early to draw firm conclusions about the emission reduction capabilities of this more sophisticated generation of waste-to-energy facilities. Consequently, although it is recognized that lower emission levels may be achievable in the future as a result of rapidly evolving developments in the field of municipal waste-fired steam generating unit emission control technology, an emission limit of 43 ng/J (0.10 lb/million Btu) heat input is being promulgated.

As a result of these recent events and as part of a settlement agreement with the Natural Resources Defense Council concerning their petition over the Agency's decision not to regulate emissions of polycyclic organic matter (POM), a thorough study of municipal waste-fired facilities is actively underway. A document that identifies, to the extent data are available: (1) The lowest emission levels for organic compounds (including dioxin), toxic metals, acid gases, and particulate matter that have been achieved from municipal waste combustors on a commercial scale; (2) the feed characteristics, operating conditions, and control techniques associated with such emission levels; and (3) available monitoring techniques that can be used to determine whether emission levels from municipal waste-fired units reflect the lowest emission levels achieved on a commercial scale will be issued in the near future. By June, 1987, the Administrator will decide whether to regulate emissions from municipal waste-fired facilities further.

To aid in this effort, the Administrator requests any data or information available concerning the effectiveness and cost of various emission control systems for municipal waste combustion. In particular, comments are requested on the technological and economic feasibility of establishing a particulate matter emission limit of less than 43 ng/J (0.10 lb/million Btu) heat input based on use of spray dryer/fabric filter technology.

Comments were received stating that insufficient test data exist to establish particulate matter emission standards for units firing refuse-derived fuel (processed municipal-type solid waste). Comments indicated that variations in the moisture content and other characteristics of refuse-derived fuel result in considerable variation in particulate matter emission levels of these units.

The factors affecting the control of particulate matter emissions from units firing refuse-derived fuel and the test data supporting the proposed standard of 43 ng/J (0.10 lb/million Btu) heat input for such units have been reviewed further. The test data supporting the standard are representative of the range of fuel and steam generating unit operating conditions that can reasonably be expected for units fired with refuse-derived fuel. A review of these data and the factors affecting particulate matter emissions for these units supports the ability of well-designed, operated, and maintained ESP's with an adequate specific collection area to meet the standard.

Nitrogen Oxides

Natural Gas- And Distillate Oil-Fired Steam Generating Units. Numerous comments were received stating that the proposed NO_x emission limit of 43 ng/J (0.10 lb/million Btu) heat input for natural gas- and distillate oil-fired units was too stringent for the package steam generating units covered by the proposed standards. Some commenters questioned the technical achievability of the proposed standard for package gas- and oil-fired steam generating units. Others questioned the reasonableness of the cost of meeting the standard. Additionally, some commenters noted the proposed standard might preclude the use of combustion air preheat.

Package steam generating units are those which are prefabricated and transported to the site by rail or barge, rather than being constructed on-site. Package units are characterized by relatively fixed designs and furnace dimensions limited by rail or barge shipping restrictions. As a result, package natural gas- and oil-fired units are generally restricted to less than 59 to 73 MW (200 to 250 million Btu/hour) heat input capacity.

The proposed emission limit of 43 ng/J (0.10 lb/million Btu) heat input was based, in part, on vendor guarantees of the performance capabilities of staged combustion burners (SCB's). In general, vendors would not confirm the verbal guarantees they offered informally prior to proposal of the standards, especially with respect to large package steam generating units. Review of information included in the comments and analysis of the limited emission test data available on the performance of SCB's (also known as "low-NO_x burners") do, however, indicate that the proposed NO_x emission limits can be achieved. To do so, the volumetric heat release rate for the steam generating unit would have to be maintained below some defined level. The American Boiler Manufacturers Association commented that the volumetric heat release rate would have to be limited to 730,000 to 830,000 J/sec-m^3 (70,000 to 80,000 Btu/hour-ft^3) to allow low NO_x firing methods. Additionally, communications with one low-NO_x burner manufacturer indicated the unit heat release rate would have to be maintained below about 780,000 J/sec-m^3 (75,000 Btu/hour-ft^3) to allow SCB application. Since proposal, data have been obtained from two package steam generating units employing staged combustion technology. Analysis of these limited data indicated that SCB controls can be used to meet the proposed standard at heat release rates of less than about 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

As previously mentioned, package steam generating units covered by the standard are in the 29 to 73 MW (100 to 250 million Btu/hour) size range. Because these units are restricted in maximum outside dimensions, they typically have volumetric heat release rates that increase with increasing unit size. Typical heat release rates for package steam generating units range from about 776,000 J/sec-m^3 (75,000 Btu/hour-ft^3) for a 29 MW (100 million Btu/hour) unit up to about 983,000 J/sec-m^3 (95,000 Btu/hour-ft^3) for the largest package unit. Therefore, virtually all package gas- and oil-fired units covered by the standard being adopted today have design heat release rates in excess of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3). Units larger than 73 MW (250 million Btu/hour) heat input capacity are typically field-erected units and have heat release rates of less than 410,000 J/sec-m^3 (40,000 Btu/hour-ft^3).

Therefore, to meet the proposed standards using SCB controls, package steam generating units would have to be operated at less than full capacity in order to restrict their heat release rates to less than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3). An oversized boiler would have to be used to provide increased furnace volume to reduce the overall, volumetric heat release rate. Operation at partial load to maintain heat release rates at or below a certain ceiling is referred to as derate, and is calculated as the excess capacity that must be purchased to meet a steam demand while not exceeding a given heat release rate. As an alternative to derate, a single field-erected unit or a group of smaller packaged units could be used in place of a single package steam generating unit and little or no derate would be required. In any of the three cases, the cost of meeting a given steam demand would be higher than current conditions.

Data from both natural gas- and residual oil-fired package industrial steam generating units were gathered to determine how much derate would be needed to meet the proposed standards as a function of unit heat input capacity. Analysis of these data indicated that maintaining the maximum design heat release rate below a 730,000 J/sec-m^3 (75,000 Btu/hour-ft^3) level would require about 10 percent derate for a 29 MW (100 million Btu/hour) package unit and up to 30 percent derate for the largest package unit. The application of 30 percent derate to a typical 44 MW (150 million Btu/hour) package natural gas-fired steam generating unit would increase steam generating unit capital cost by 18 percent and annual operating costs by 2 percent. As a result, the incremental costs associated with meeting a NO_x emission limit of 43 ng/J (0.10 lb/million Btu) heat input based on the use of SCB controls over the costs associated with meeting a NO_x emission limit of 86 ng/J (0.20 lb/million Btu) based on the use of LEA alone leads to incremental cost effectiveness levels of more than $4,400/Mg ($4,000/ton) of NO_x removed. Consideration of the cost effectiveness of derate leads to the conclusion that the cost effectiveness of the proposed standard for package units covered by the standard is unreasonable. The cost effectiveness associated with NO_x standards based on the use of LEA, however, is considered reasonable because no derate is necessary and minimal cost impacts occur.

As discussed in the proposal, LEA is one of the most common forms of combustion modification and is directly applicable to industrial-commerical-institutional steam generating units. LEA operation involves reducing the excess combustion air to the minimum amount needed for complete combustion. Although effective on both fuel and thermal NO_x, emission test data indicate that LEA is most effective in reducing thermal NO_x, which is the principal source of NO_x emissions from natural gas and distillate oil because of their low fuel nitrogen contents.

A large amount of NO_x emission data was collected and analyzed on the performance of LEA prior to proposal. Since proposal, an emission test data set from an additional package unit with a high design heat release rate of approximately 1,035,000 J/sec-m^3 (100,000 Btu/hour-ft^3) was added to the database. The total database was re-analyzed to determine the NO_x emission level achievable by LEA under worst case conditions for the formation of NO_x, including high heat release rate and combustion air preheat. The results of this new analysis were essentially the same as for the analysis of LEA performance carried out prior to proposal. The results show that LEA is capable of reducing NO_x emissions from natural gas- and distillate oil-fired steam generating units without combustion air preheat to 86 ng/J (0.20 lb/million Btu) heat input or less on a 30-day rolling average basis and to 130 ng/J (0.30 lb/million Btu) heat input with combustion air preheat.

Review of information concerning steam generating unit sales over the past 5 years indicates that very few package steam generating units use combustion air preheat. As the name implies, combustion air preheat uses flue gas from the steam generating unit (and a heat exchanger) to preheat combustion air prior to combustion. The recovery of heat from the exhaust gases increases the overall thermal efficiency of the unit. Rather than use combustion air preheat, however, an economizer could be used to accomplish the same result. An economizer uses flue gas (and a heat exchanger) to preheat feedwater to the steam generating unit. Again, heat is recovered from the exhaust gases and an increase in thermal efficiency results. With either heat recovery option, the cost and complexity of the steam generator are increased. Additionally, space restrictions on shipment may preclude the units with preheat being shipped as one package. Because few package units use combustion air preheat and in those instances where an increase in thermal efficiency is desired, a reasonable alternative to combustion air preheat is available, the final standard will limit NO_x emissions from all natural gas- and distillate oil-fired steam generating units with heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or greater to 86 ng/J (0.20 lb/million Btu) heat input.

An emission limit of 43 ng/J (0.10 lb/million Btu) heat input is, however, achievable for steam generating units with heat release rates less than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3). For example field-erected units have a fire box large enough to accommodate the longer flame lengths associated with low NO_x firing methods without derate. Field-erected steam generating units also have typical design maximum heat release rates of less than 410,000 J/sec-m^3 (40,000 Btu/hour-ft^3). Therefore, an emission limit of 43 ng/J (0.10 lb/million Btu) heat input is being promulgated for natural gas- or distillate oil-fired steam generating units with maximum design heat release rates less than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

In summary, the final standards will limit NO_x emissions to 43 ng/J (0.10 lb/million Btu) heat input for units firing natural gas or distillate oil with maximum design heat release rates of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or less, and will limit NO_x emissions to 86 ng/J (0.20 lb/million Btu) heat input for units with maximum design heat release rates greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3). Because package units in the size range covered by the standard will typically have heat release rates in the range of 780,000 to 990,000 J/sec-m^3 (75,000 to 95,000 Btu/hour-ft^3), practically all package units covered by today's standards will be subject to the 86 ng/J (0.20 lb/million Btu) heat input standard. Because most, if not all, field-erected steam generating units will have maximum design heat release rates of less than 410,000 J/sec-m^3 (40,000 Btu/hour-ft^3), the 43 ng/J (0.10 lb/million Btu) heat input standard will, for the most part, apply to field-erected units.

Residual Oil-Fired Steam Generating Units. Several commenters indicated they also believed the proposed NO_x standards for package residual oil-fired units were unreasonable. Specifically, commenters felt that staged combustion (SC) controls for reducing NO_x emissions from package units had not been demonstrated to meet the proposed emission limits of 130 ng/J (0.30 lb/million Btu) heat input for low nitrogen residual oil and 170 ng/J (0.40 lb/million Btu) heat input for high nitrogen residual oil for package steam generating units. Use of SC controls on package units would necessitate derating to accommodate the longer flame lengths associated with SC controls. Consequently, there could be a substantial cost penalty associated with meeting the emission limits as proposed. Commenters recommended that the proposed emission limits be increased to 170 ng/J (0.40 lb/million Btu) heat input for low nitrogen content oil and to 210 ng/J (0.50 lb/million Btu) heat input for high nitrogen content residual oils for package units.

Commenters, however, including two major industry trade associations (American Boiler Manufacturers Association and Council of Industrial Boiler Owners), specifically recommended promulgation of the proposed standard of 130 ng/J (0.30 million Btu/hour) heat input for low nitrogen residual oil-fired units and 170 ng/J (0.40 lb/million Btu) heat input for high nitrogen residual oil-fired units above 73 MW (250 million Btu/hour) heat input capacity.

In addition, one of the major steam generating unit manufacturers and one of the major burner manufacturers indicated their willingness to offer guarantees to achieve the proposed standards for units above 73 MW (250 million Btu/hour) in size. The support for the proposed standard as it applies to field-erected steam generating units by industry trade associations and manufacturers indicates that SC is recognized as being a NO_x control technique that can reduce NO_x emissions to the level of the proposed standards.

As evidenced by the recommendations of commenters, that the proposed standards should be promulgated for field-erected units, the issue posed in these comments is not the ability of demonstrated emission control techniques to reduce NO_x emissions from residual oils to the proposed levels, but the reasonableness of applying this technology to package units, given the costs associated with the required derate. To meet the proposed standards, most package residual oil-fired steam generating units in the 29 to 73 MW (100 to 250 million Btu/hour) heat input size range would have to be derated by 10 to 35 percent to accommodate the longer flame lengths associated with SC controls. The cost effectiveness of this approach to meeting the standards is up to $4,400/Mg ($4,000/ton) of NO_x reduction.

An alternative to derating as a means of meeting the proposed standards for residual oil would be to fire low nitrogen content residual oil, such as those containing less than 0.17 weight percent nitrogen. Analysis of the available NO_x emission data show that, without combustion air preheat, use of LEA controls alone are sufficient to meet the proposed NO_x standard when firing residual oils containing 0.17 weight percent nitrogen or less. Since LEA does not extend flame lengths, the proposed standards could be met firing very low nitrogen residual oils in large package units without any derating.

Information on the nitrogen content of residual oils sold in the United States is extremely limited. Information that is available is not current, but indicates that only about 10 to 15 percent of residual fuel oils have nitrogen contents of less than 0.17 weight percent. About a third of residual feul oils have nitrogen contents of less than 0.2 weight percent and about two-thirds of residual fuel oils have nitrogen contents of less than 0.3 weight percent. The availability of residual oils with very low nitrogen contents of 0.17 weight percent or less, therefore, could be quite limited.

An alternative to firing such extremely low nitrogen oils for meeting the proposed standards would be to switch from firing residual oil to firing natural gas. Switching to natural gas would avoid having to fire a very low nitrogen content residual oil or derating the unit. However, the cost effectiveness associated with this alternative is also fairly high, about $2,750/Mg ($2,500/ton) of NO_x reduction, because of fuel price differentials.

Consequently, in the final standards the emission limit for package residual oil-fired steam generating units has been set at 170 ng/J (0.40 lb/million Btu) heat input, independent of the nitrogen content of the residual oil fired. Compliance with a NO_x emission limit of 170 ng/J (0.40 lb/million Btu) heat input can be achieved with LEA alone without combustion air preheat when firing residual oils with nitrogen contents of about 0.3 weight percent or less. No derate would be necessary.

Most package residual oil-fired units do not use preheated combustion air. In addition, in those isolated cases where an owner/operator wanted to increase the thermal efficiency of a steam generating unit, economizers could be used to preheat feedwater rather than using preheated combustion air.

Since about two-thirds of residual fuel oils have nitrogen contents of less than 0.3 weight percent, fuel availability should not be a problem. Also, in today's residual fuel oil market, there is no apparent price premium for residual oils with nitrogen contents less than 0.3 weight percent, unless one focuses on residual oils with a very low nitrogen content (i.e., less than 0.17 weight percent). Therefore, there should be no increased costs associated with firing residual oils of less than 0.3 weight percent nitrogen in order to meet the standard.

Because the cost effectiveness of LEA controll for reducing NO_x emissions is negligible, the cost effectiveness of a 170 ng/J (0.40 lb/million Btu) heat input standard for package residual oil-fired units based on LEA and firing of residual oils with a nitrogen content of less than 0.3 weight percent is considered reasonable.

As mentioned above, the concerns expressed by commenters relative to SC controls and derate do not apply to field-erected steam generating units, which predominate in steam generating unit sizes above 73 MW (250 million Btu/hour) heat input capacity. Commenters expressed no objection to the proposed standards of 130 ng/J (0.30 lb/million Btu) heat input and 170 ng/J (0.40 1b/million Btu) heat input for low and high nitrogen residual oil, respectively, in the case of field-erected units.

The proposed standards for residual oil varied with the nitrogen content of the oil because fuel nitrogen is a major determinant of NO_x emissions from residual oil combustion and of the effectiveness of NO_x control techniques on residual oil-fired units. No distinction was made in the proposed standards between package and field-erected oil-fired steam generating units.

In the case of units above 73 MW (250 million Btu/hour) in size, the effect of the emission limit proposed for high nitrogen residual oil would have been to raise the existing standard applicable to these units. The existing 1971 standard for oil-fired units (Subpart D of 40 CFR Part 60) is 130 ng/J (0.30 lb/million Btu) heat input. It has been concluded that raising the standard for these units to 170 ng/J (0.40 lb/million Btu) heat input is unnecessary for three reasons.

First, as stated above, field-erected units are not restricted by the same furnace size limitations as package units and, therefore, can accommodate SC controls without the need for derate. Second, unlike for package units, staged combustion has been demonstrated to be effective in reducing NO_x emissions from field-erected units firing high nitrogen residual oil. Third, the existing standard has been in effect for over 15 years and there is no indication that it needs changing. In fact, no continuous emission monitoring data from field-erected units firing high nitrogen residual oil could be obtained because such units are generally exempt under § 60.45(b)(3) from a requirement to continuously monitor NO_x emissions due to having emissions during the performance test of less than 70 percent of the standard 86 ng/J (0.20 lb/million Btu) heat input.

Considering all of these factors, it appears there has been little problem meeting the longstanding Subpart D standard of 130 ng/J (0.30 lb/million Btu) heat input for high nitrogen residual oil-fired units that are field-erected and there is no need to change that standard. Therefore, the 170 ng/J (0.40 lb/million Btu) heat input standard proposed in 1984 for units greater than 73 MW (250 million Btu/hour) heat input capacity which fire high nitrogen residual oil has been replaced in the final standards. All residual oil-fired units larger than 73 MW (250 million Btu/hour) heat input capacity are subject to the same 130 ng/J (0.30 lb/million Btu) heat input emission limit.

As discussed above, steam generating units in the 29 MW to 73 MW (100 to 250 million Btu/hour) size range are generally package units and have heat release rates of 776,000 to 983,000 J/sec-m³ (75,000 to 95,000 Btu/hour-ft³). Field-erected units are predominant above 73 MW (250 million Btu/hour) hear input capacity and have heat release rates less than about 414,000 J/sec-m³ (40,000 Btu/hour-ft³). A mid-point between the two types of steam generating units that would distinguish between the two unit types would be about 720,000 J/sec-m³ (70,000 Btu/hour-ft³).

Consequently, the final standards limit NO_x emissions to 130 ng/J (0.30 1b/million Btu) heat input for all residual oil-fired units with maximum design heat release rates of 720,000 J/sec-m³ (70,000 Btu/hour-ft³) or less and to 170 ng/J (0.40 1b/million Btu) heat input for all residual oil-fired units with a miximum design heat release rate of greater than 720,000 J/sec-m³ (70,000 Btu/hour-ft³), independent of the nitrogen content of the residual oil being fired.

Spreader Stoker Steam Generating Units. Comments were received on the proposed standard limiting NO_x emissions from coal-fired spreader stoker steam generating units to 260 ng/J (0.60 1b/million Btu) heat input. Several commenters questioned the ability of spreader stoker steam generating units using preheated combustion air >150°C (300°F)] to meet the proposed standard. The commenters did not submit any new data showing that the NO_x standards are not achievable but they did reference a recent test at a 115 MW (400 million Btu/hour) coal-fired spreader stoker with preheated combustion air. This unit had been selected for testing because it represented the use of combustion air preheat on a spreader stoker with a very high heat release rate. Commenters stated that the data from these tests substantiate the need for a higher NO_x emission level for spreader stokers with preheated combustion air. One commenter suggested that a dual standard would be appropriate with the proposed standard of 260 ng/J (0.60 lb/million Btu) heat input applying to spreader stoker steam generating units not using combustion air preheat [<150°C (300°F)], and a standard of 300 ng/J (0.7 lb/million Btu) heat input applying to steam generating units using preheated combustion air [>150°C (300°F)]. The commenters also maintained that the proposed NO_x emission limit would force spreader stoker units with preheated combustion air to be designed for heat release rates much lower than typical design, thereby encouraging the preferential use of pulverized coal-fired units over use of spreader stoker units.

The results obtained from the referenced emissions test on the 115 MW (400 million Btu/hour) spreader stoker were analyzed to show the effect of combustion air preheat on NO_x emissions. The analysis showed that combustion air preheat temperature did not have a significant effect on NO_x emissions. The test results showed that combustion air preheat slightly lowered NO_x emissions in three of four paired data tests conducted.

Under full load operating conditions and with combustion air preheat, NO_x emissions at the tested unit exceeded 260 ng/J (0.60 lb/million Btu) heat input. However, further analysis of these data revealed that the relatively high NO_x emissions at this facility were due to the high grate heat release rate of this unit. This unit is more than 20 years old and the grate heat release rate is 2,600,000 J/sec-m² (818,000 Btu/hour-ft²) at full load. By comparison, the maximum design grate heat release rate for new spreader stoker steam generating units is approximately 2,200,000 J/sec-m² (700,000 Btu/hour-ft²). The manufacturer of the tested unit confirmed that the unit was designed with an atypically high grate heat release rate. Anaylsis of the test data indicated that if the grate heat release rate of this unit were lowered to less than 2,200,000 J/sec-m² (700,000 Btu/hour-ft²), NO_x emissions would be less than 260 ng/J (0.60 lb/million Btu) heat input.

The NO_x emissions data previously presented in the proposed standard were based on tests from 11 different spreader stoker steam generating units. Predicted average NO_x emissions for these steam generating units were in the range of 150 to 230 ng/J (0.34 to 0.54 lb/million Btu) heat input with an average of 200 ng/J (0.46 lb/million Btu) heat input. The comment that a 260 ng/J (0.60 lb/million Btu) heat input standard would force spreader stoker steam generating units using preheated combustion air to be designed for very low heat release rates is unsubstantiated. The use of preheated combustion air does not appear to noticeably affect NO_x emissions from spreader stoker units. Analyses of the data indicated that steam generating untis with design heat release rates within the normal range of design parameters can meet the standard.

Another commenter stated the upward adjustment of the test data 260 ng/J (0.60 lb/million Btu) heat input from 230 ng/J (0.54 lb/million Btu) heat input to account for variability in NO_x emissions did not reflect data from the other two tested units, which had long-term NO_x emissions ranging from 150 to 190 ng/J (0.36 to 0.44 lb/million Btu) heat input. This commenter suggested the emission level should be lowered to between 170 to 210 ng/J (0.40 to 0.50 lb/million Btu) heat input based on the long-term emissions of these units.

This comment reflects a misunderstanding of the method used to calculate the emission limit. The long-term NO_x data were analyzed to determine the variation in NO_x emissions from mean emission levels rather than to determine the applicable emission limit. Time series analysis was used to calculate the maximum 30-day average NO_x emission levels that would be expected to occur once every 10 years. This analysis concluded that the peak 30-day average emission rate would be expected to be about 7 percent greater than the mean emission rate. The 7 percent variability factor reflects a statistical projection and is not directly comparable to average NO_x emission data measured during the test program.

Pulverized Coal-Fired Steam Generating Units. Several comments were received concerning the proposed NO_x standard for pulverized coal-fired steam generating units. Many commenters noted that the NO_x standard for pulverized coal-fired steam generating units was based on NO_x emissions data from tangentially-fired pulverized coal-fired units larger than 147 MW (500 million Btu/hour) heat input capacity. The commenters stated that pulverized coal-fired units used in industrial applications would more likely be smaller wall-fired pulverized coal-fired units rather than tangentially-fired pulverized coal-fired units which are more commonly used for large utility units. The commenters questioned the ability of the more common wall-fired pulverized coal-fired units to achieve the proposed NO_x standard of 300 ng/J (0.70 lb/million Btu) heat input. To accommodate wall-fired units, it was recommended that the NO_x emission limit for pulverized coal-fired units be increased to 340 ng/J (0.80 lb/million Btu) heat input capacity.

In response to these comments, 90 days of continuous NO_x emission data were obtained from a 88 MW (300 million Btu/hour) heat input capacity wall-fired pulverized coal-fired unit with overfire air firing eastern bituminous coal. Data from a unit firing eastern bituminous coal were selected because previously collected emissions data showed higher potential NO_x emissions when eastern bituminous coal is fired than when western subbituminous coal is fired.

More than 1,200 hours of continuous NO_x emissions data from this unit were analyzed. The hourly NO_x emissions for the 90-day period ranged from 150 to 290 ng/J (0.35 to 0.68 lb/million Btu) heat input, and steam generating unit load for the period during which data were collected ranged from 38 to 90 percent. During the entire 90-day test period, the NO_x emissions averaged 210 ng/J (0.50 lb/million Btu) heat input and steam generating unit load averaged 49 percent. A regression analysis of the continuous NO_x emission data was conducted to predict mean NO_x emissions from this unit under operating conditions of 100 percent load and 4.8 percent O_2. This analysis predicted average NO_x emissions at 100 percent load to be 290 ng/J (0.67 lb/million Btu) heat input.

A time series statistical analysis of the data was conducted to determine the variability in NO_x emissions projected to occur over a 30-day period. This analysis predicted the peak 30-day NO_x emission levels to be about 9 ng/J (0.02 lb/million Btu) heat input higher than the mean. Therefore, the peak NO_x emissions based on a 30-day rolling average would be 300 ng/J (0.69 lb/million Btu) heat input. Therefore, the proposed NO_x standard of 300 ng/J (0.70 lb/million Btu) heat input is again demonstrated to be achievable and is being promulgated for all pulverized coal-fired steam generating units.

NO_x Control for Waste Fuels. Several commenters expressed concerns over the regulation of liquid and gaseous byproduct/waste fuels. These commenters said that, in many instances, the NO_x emission limits specified in the proposed standards could not be met when combusting these byproducts/wastes because of high nitrogen content or other properties. Several commenters also stated that insufficient data are available on emissions from steam generating units firing gaseous or liquid byproducts/wastes to demonstrate the achievability of the proposed NO_x standards. Commenters stated that the emission and combustion characteristics of byproducts/wastes are too variable and uncertain to justify their inclusion in the proposed NO_x standards. Finally, commenters objected that the definition of byproducts/wastes is too broad.

In response to these comments, several points need to be considered. First, the NO_x standards being promulgated today are not intended to encourage or discourage the firing of byproduct/wastes. The regulation of by-product waste firing is addressed by other regulations. For example, the firing of fuels containing polychlorinated biphenyls (PCB's) are regulated under the Toxic Substances Control Act (TSCA) (40 CFR 761.70). The TSCA regulations require that units firing fuels containing less than 500 ppm PCB demonstrate a 99.9 percent thermal destruction efficiency. Units firing fuels containing greater than 500 ppm PCB must demonstrate a 99.9999 percent thermal destruction efficiency.

Second, the proposed NO_x emission limits for byproducts/wastes are applicable only to steam generating units firing mixtures of natural gas or oil with byproduct/waste fuels. The purpose of these provisions is not only to control NO_x emissions from byproduct/waste fuel combustion, but also to make clear that the cofiring of byproducts/waste fuels with natural gas or oil will not have the unintended effect of exempting a steam generating unit from the NO_x emission limits that fire a minimum amount of other fuels.

Third, a comparison of data gathered from the steam generating units burning fuel mixtures including gaseous byproduct/waste fuels with data gathered from natural gas-fired units shows no discernible difference in NO_x emissions from the combustion of these two fuels. Similarly, a comparison of data gathered from steam generating units burning fuel mixtures including liquid byproduct/waste fuels with data gathered from residual oil-fired units shows no discernible difference in NO_x emissions from the combustion of these two fuels. The analysis of available data also indicates that NO_x control technologies that are effective in reducing NO_x emissions from steam generating units firing natural gas or residual oil are equally effective in reducing NO_x emissions from steam generating units firing gaseous byproduct/waste fuels or liquid byproduct/waste fuels, respectively. Consequently, it was concluded that the proposed NO_x standards for units burning natural gas should apply to units burning mixtures of natural gas and gaseous byproduct/waste fuels. Similarly, it was concluded that NO_x standards for units firing residual oil should apply to units burning mixtures of oil and liquid byproduct/waste fuels.

As discussed above, the NO_x emission limits for natural gas- and residual oil-fired steam generating units with heat release rates greater than 620,000 J/sec-m ^{3} (60,000 Btu/hour-ft ^{3}) have been revised to 86 ng/J (0.20 lb/million Btu) heat input and 170 ng/J (0.40 lb/million Btu) heat input, respectively. Consequently, the emission limits for steam generating units firing natural gas and gaseous byproduct/waste fuels and for units firing residual oil and liquid byproduct/waste fuels have been revised accordingly. The proposed NO_x emission limits have not been changed for steam generating units with low design heat release rates firing gaseous or liquid byproduct/waste fuels in combination with fossil fuels.

Because many of the concerns expressed about regulation of byproduct/waste fuels centered on the achievability of the proposed emission limit of 43 ng/J (0.10 lb/million Btu) heat input, which was based on the standard for natural gas and distillate oil, revision of that emission limit upward to 86 ng/J (0.20 lb/million Btu) heat input for steam generating units with high heat release rates is expected to resolve most of the concerns about regulation of byproduct/waste fuels.

Section 60.44b(c) of the final rule incorporates a procedure that the owner or operator of an affected facility firing nonhazardous byproduct/waste fuels can use to petition the Administrator for a facility-specific NO_x emission limit. In order to obtain a facility-specific NO_x emission limit, the owner or operator of the facility must present sufficient evidence to the Administrator to demonstrate that the facility is unable to meet the NO_x emission limits due to the characteristics of the byproducts/wastes, such as high nitrogen content, high heat value, or other factors. As a part of this evidence, the owner or operator of the steam generating unit must demonstrate compliance with the applicable emission limit when firing only natural gas or residual oil, as appropriate. This is necessary to determine excess air levels and other operating conditions representative of the best demonstrated technology. If the facility is capable of complying with the emission limit while firing natural gas or residual oil using the best demonstrated technology, but not capable of complying while firing a fuel mixture including the byproduct/waste under the same conditions, the Administrator will establish an individual NO_x emission limit for that steam generating unit reflecting the level of NO_x emission reduction achievable when firing the byproduct/waste.

The final rule also incorporates a procedure that the owner or operator of a steam generating unit which combusts a fuel mixture including toxic waste, as determined under the Resource Conservation and Recovery Act (RCRA), can use to petition the Administrator for a facility-specific waiver from the NO_x emission limits. In order to obtain a facility-specific waiver, the owner or operator must present sufficient evidence to the Administrator to support the contention that the facility is unable to meet the NO_x emission limit and still achieve the level of thermal destruction of the toxic byproduct/waste required by RCRA.

The procedures for applying for this facility-specific emission limit or waiver are set out in the final rule. Because each application for a site-specific standard or waiver will entail a different set of waste characteristics and steam generating unit designs, greater standardization of forms or procedures is not practical. Instead, each application will be evaluated on its individual merits. The authority to establish a facility-specific NO_x standard or waiver will not be delegated by the Administrator. Petitions must be submitted directly to EPA and the establishment of site-specific standards will not be delegated.

After reviewing the definition of byproduct/waste in the proposed standard, it was determined that the definition should be revised to reflect more accurately the intention of the regulation and the nature of the data on which it is based. These data were drawn from steam generating units which combust byproducts/wastes from chemical plants and refineries, and it is byproducts/wastes from these sources which are intended to be regulated by the standard. Consequently, the definition of byproduct/waste has been revised to specify that the byproducts/wastes covered by the definition extend only to those which are produced at chemical plants and refineries. Chemical plants and refineries are defined as facilities which are classified by the Department of Commerce under Standard Industrial Classification (SIC) codes 28 and 29, respectively.

NO_x Control For Wood/Natural Gas-Fired Steam Generating Units. The proposed standards included a NO_x emission limit of 130 ng/J (0.30 lb/million Btu) heat input for steam generating units firing mixtures of natural gas and wood if more than 5 percent fossil fuel is fired on an annual basis. Commenters stated that the 5 percent criterion was not realistic because it did not account for the need to periodically increase fossil fuel use to account for fluctuations in wood availability and wood characteristics. Based on these comments, the annual capacity factor for fossil fuel for exemption from the NO_x standards has been increased from 5 percent to 10 percent.

Also, a separate notice is being published elsewhere in today's **Federal Register** promulgating the amendment changing the NO_x emission limit under Subpart D for units firing mixtures of wood and natural gas to 130 ng/J (0.30 lb/million Btu) heat input.

Status Of Alternative Technologies. One comment was made regarding flue gas recirculation (FGR) as a form of combustion modification to reduce NO_x emissions. The commenter stated that FGR could achieve lower NO_x emissions that use of only LEA. The limited data available at the time of proposal did not allow FGR to be analyzed or considered as a basis of the proposed standard. Since the standard was proposed, additional data indicate that FGR may be capable of greater reductions in NO_x emissions that was previously expected. These data also indicate that FGR is most effective in suppressing thermal NO_x formation, which is the predominant NO_x formation mechanism during the combustion of natural gas and distillate oil. Presently, insufficient data are available to base the final standard solely on FGR technology. Use of FGR for reducing NO_x emissions is neither precluded nor discouraged by the promulgated standards. In addition to LEA or other technologies, FGR may be used to achieve the NO_x emission limits being promulgated today.

One comment addressed the discussion in the proposal concerning NO_x flue gas treatment systems, including selective catalytic reduction (SCR). SCR refers to the process in which combustion gases are mixed with ammonia and passed over a catalyst to reduce NO_x emissions to elemental nitrogen and water. The commenter felt that although SCR was discussed as a method to reduce NO_x emissions, inadequate consideration had been given to other types of NO_x flue gas treatment systems.

The commenter is correct in noting that there are other types of NO_x flue gas treatment systems in addition to SCR. Current post-combustion NO_x control research in the United States is focused on processes that have both NO_x and SO_x removal capability. Included among these advanced removal processes is a flue gas treatment process which uses a copper oxide acceptor material to remove both NO_x and SO_x from flue gas. There is also a fluidized bed version of the same flue gas treatment process. The electron beam process is a dry process where ammonia is added to the flue gas which is then bombarded with an electron beam, removing NO_x and SO_x in the process. This concept is being examined for NO_x removal alone and in combination lime spray dryers for SO_2 removal. These types of post-combustion NO_x controls are being investigated at several bench scale and pilot unit projects in the United States. However, the processes being investigated are not commercially established and are not considered demonstrated technologies for the purpose of developing standards of performance limiting NO_x emissions from industrial-commercial-institutional steam generating units.

Another NO_x control process which is commercially available is selective noncatalytic reduction (SNR), a dry process involving a gas-phase reaction between NO_x and injected ammonia without the use of a catalyst. Ammonia is injected directly into the furnace with the furnace temperature driving the reduction reactions. This process is more difficult to control and is less efficient than SCR. Most applications of SNR are retrofits on oil refinery process heaters. There have also been several commercial applications of SCR to industrial-commercial-institutional steam generating units firing both oil and natural gas. However, SCR and SNR entail considerable costs. Therefore, although SNR and SCR are considered demonstrated technologies, they were not chosen as bases for these standards.

NO_x Monitoring. A variety of comments were received concerning continuous emission monitoring sytems (CEMS) for NO_x. Commenters suggested that steam generating units should not be required to install a NO_x CEMS if during the 30-day performance test NO_x emission levels are 10 to 30 percent below the applicable NO_x emission limit. Other commenters maintained that continuous NO_x monitoring was unnecessary for units regulated. Several comments stated that the cost of a CEMS is excessive for steam generating units having heat unit capacities less than 73 MW (250 million Btu/hour) and that these costs were underestimated in the proposed standard. One commenter suggested that conventional stack

testing be allowed as an alternative to continuous monitoring for natural gas- and oil-fired units with heat input capacities less than 73 MW (250 million Btu/hour).

After reviewing the comments, several alternative options for NO_x emission monitoring were considered. Among the factors taken into consideration were the type of fuel being burned, the size of the steam generating unit, the type of NO_x control technology required, and associated cost effectiveness. The NO_x monitoring requirements in the promulgated standard have been revised from those proposed to reflect the results of these analyses.

Under the proposed standard, CEMS were required on all units subject to the NO_x standards. However, an option was provided allowing units having an annual capacity factor for regulated fuels of less than 30 percent to monitor steam generating unit operating conditions indicative of NO_x emissions in lieu of continuous monitoring of NO_x emissions. Under the promulgated standards, CEMS continue to be required; however, the optional monitoring of operating conditions in place of CEMS has been revised. Under the promulgated standards, the operating condition monitoring option is available for units having less than 73 MW (250 million Btu/hour) heat unit capacity and which are combusting natural gas, distillate oil, or low nitrogen content residual oil (less than 0.30 weight percent nitrogen).

This data would be used to judge proper unit operations and need for a compliance test, but it would not be used for direct enforcement of the standard. For units: (1) Having heat input capacities greater than 73 MW (250 million Btu/hour) or (2) any units combusting coal or high nitrogen content residual oil (greater than 0.30 weight percent nitrogen) greater than 29 MW (100 million Btu/hour) heat input capacity, the CEMS, as proposed, remains the reference test method and the data are used to determine compliance with the NO_x standard. However, it should be noted that under the General Provisions [40 CFR 60.13(i)], any source, including for example natural gas-fired units larger than 73 MW (250 million Btu/hour) heat input capacity, can apply for approval to monitor alternative parameters which can be used to predict NO_x emissions in place of direct monitoring of NO_x emissions by CEMS. If an application to measure alternative parameters is approved, the predicted NO_x emission rates derived from the parametric data will be used to determine direct compliance with the NO_x standard just as if monitoring by CEMS had occurred.

Under the promulgated standards, all steam generating units subject to the NO_x emission limits are required to conduct an initial 30-day performance test using a CEMS. This test will serve as the initial performance test required under § 60.8. Thereafter, (1) all steam generating units greater than 73 MW (250 million Btu/hour) heat input capacity, and (2) all steam generating units greater than 29 MW (100 million Btu/hour) heat input capacity firing coal or high nitrogen residual oil, must install and operate a CEMS [unless approval to monitor operating conditions under § 60.13(i) has been obtained]. The data from the CEMS (or from monitoring operating conditions, as applicable) are used to determine a 30-day rolling average NO_x emission rate calculated as the arithmetic average of the hourly NO_x values for the preceding 30 steam generating unit operating days. CEMS in these applications will be subject to the requirements set forth in 40 CFR Part 60 Appendix F, Procedure 1 when these requirements are promulgated. Appendix F, Procedure 1 will require the owner or operator of a CEMS to perform periodic accuracy and drift assessments of the system. For this class of steam generating units, the NO_x emission data (or the predicted NO_x emission rates from the parametric data) are used to determine compliance with the NO_x standards and a quarterly compliance report is required.

For steam generating units with heat input capacities of less than 73 MW (250 million Btu/hour) firing natural gas, distillate oil, or low nitrogen content residual oil, a CEMS is also used to conduct the initial 30-day compliance test after unit startup. Thereafter, as stated above, the owner or operator of the facility can elect to install and operate: (1) A CEMS, or (2) a system to monitor steam generating unit operating conditions and predict NO_x emissions rates. The CEMS data or the predicted NO_x emission rates derived from the optional operating conditions monitoring data will be used to prepare excess emission reports which are required to be submitted on a semiannual basis. Additionally, a quarterly excess emissions report is required for any quarter that any excess emissions occur. Because a CEMS in this application is not used for direct compliance, the requirements of 40 CFR Part 60 Appendix F, Procedure 1 do not apply. However, a 30-day performance test using CEMS may be required by the appropriate enforcement authority at any time.

If operating conditions are monitored in lieu of installing a CEMS, operating conditions such as stem generating unit load, O_2 levels, or degree of staging (i.e., ratio between primary air and secondary air and/or tertiary air or flue gas recirculation rate) shall be used to predict NO_x emission rates. Other steam generating unit operating conditions may also be monitored. The standards require that the owner or operator of a steam generating unit wishing to use the alternative monitoring procedure submit a plan to the Administrator along with the initial performance test report. The plan shall specify the conditions to be monitored, the variation expected in these conditions with operating load, the data to be used to determine that these conditions are indicative of NO_x emission control, the relationship that will be used to predict NO_x emission rates from the operating conditions that will be monitored, and the procedures and formats to be followed in monitoring and recordkeeping.

Manufacturers of steam generating units may develop and provide to steam generating unit owners, monitoring plans for common steam generating unit designs. These plans must also be supported by actual operating and emission data from the affected facility and would subsequently be submitted by the owner or operator of the steam generating unit. If approved, the owner or operator of the facility shall maintain records of the operating conditions, including steam generating unit load, identified in the plan. Monitoring data and predicted NO_x emissions rates will be submitted in a quarterly excess emission report.

Reporting

All natural gas-, distillate oil-, residual oil-, and coal-fired steam generating units having heat input capacities greater than 73 MW (250 million Btu/hour) are required to use CEMS subject to Appendix F, Procedure 1, and are required quarterly compliance reports to allow direct enforcement of the NO_x standards on a continuing basis. All coal-fired and high nitrogen content residual oil-fired steam generating units having heat input capacities greater than 29 MW (100 million Btu/hour) are also required to use CEMS subject to Appendix F, Procedure 1, and submit quarterly compliance reports to allow direct enforcement of the NO_x standards on a continuous basis. Natural gas-, distillate oil-, and low nitrogen content residual oil-fired steam generating units having heat input capacities from 100 to 250 million Btu/hour are required to submit semiannual excess emission reports; however, a quarterly excess emissions report is required for each quarter that excess emissions occur. Appendix F, Procedure 1 would not apply if CEMS are used on these units.

Under both the proposed and promulgated NO_x standards, certain residual oils must be analyzed for nitrogen content. Specifically, steam generating units in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range firing low nitrogen content residual oil must report fuel nitrogen content. If fuel analysis data are not reported the oil will be assumed to be high in nitrogen content and use of a CEMS subject to the requirements of Appendix F, Procedure 1 is required. The nitrogen content can be measured by the owner or operator of the steam generating unit using American Society for Testing and Materials Method D3431–80 (incorporated by reference—see § 60.17). Fuel specification data can be obtained from fuel suppliers and provided in place of on-site fuel sampling and analysis.

Several commenters claimed that small manufacturing facilities do not have personnel capable of operating, calibrating, and maintaining NO_x CEMS. In response to this issue, owners and operators of steam generating units were surveyed to gather information concerning service personnel requirements associated with installation and operating of CEMS. The survey indicated that, in most cases, vendor training of plant personnel was provided on-site and typically lasted 1 day to 1 week. Also, a number of companies provide CEMS operating and maintenance services. The costs of employing outside specialists to provide routine service of NO_x CEMS were calculated and incorporated into the NO_x monitoring costs. The burden associated with installing, operating, and maintaining a NO_x CEMS, whether through on-site training of plant personnel or through contracts with outside specialists, is reasonable.

It should be noted that small manufacturing facilities would be expected to use steam generating units having heat input capacities less than 73 MW (250 million Btu/hour). For units having heat input capacities less than 73 MW (250 million Btu/hour), only coal- and high nitrogen content residual oil-fired steam generating units must use a CEMS. For natural gas-, distillate oil-, or low nitrogen content residual oil-fired steam generating units having heat input capacities less than 73 MW (250 million Btu/hour), use of the process monitoring option would preclude the need for a CEMS.

One comment stated that the proposed data availability requirement is too lenient. The proposed standard would have allowed an affected facility 5 calendar days to initiate servicing of an out-of-service CEMS and 15 calendar days to return the monitor to service. The commenter recommended that 75 percent valid data be required for each 30-day period. Several other comments concerned the level of reliability of NO_x CEMS.

In response to these comments, the standard has been changed to incorporate minimum data capture requirements. Minimum data capture requirements are necessary because monitors undergo periods of downtime and are not available 100 percent of the time. Minimum data capture requirements provide for downtime, but limit the amount of data permitted to be lost before supplemental sampling is required. The requirements provide the owner or operator with time to maintain and calibrate the CEMS, correct minor malfunctions, and, if necessary, arrange for supplemental sampling, while at the same time providing sufficient data for compliance determinations. Minimum data capture requirements also prevent the possibility of an affected facility operating for unreasonably long periods without collecting data.

Under the minimum data capture requirements, affected facilities are required to obtain at least 22 days of valid NO_x emission data for every 30-day period, that is, 75 percent data capture. Well operated and maintained CEMS will routinely operate better than the proposed data requirements and supplemental sampling should rarely be required.

Supplemental sampling, if necessary to meet the minimum data requirements, can be achieved with a standby CEMS, Reference Method 7, Reference Method 7A, or other approved methods.

If the minimum amount of data is not obtained for any 30-day rolling average period, reasons for failure to obtain sufficient data and a description of corrective action taken must be included in the quarterly report, along with all the information needed to calculate the 30-day rolling average values according to Method 19, section 7.

The minimum CEMS data requirements are related to proper maintenance and operation of the CEMS, not whether NO_x emission rates are calculated. In all cases, even if minimum data requirements are not met, a 30-day rolling average NO_x emission rate is calculated using all available hourly NO_x data to determine continuous compliance or excess emissions, as applicable.

Interpollutant Effects of NO_x Control. Several comments on the proposed NO_x emission limits noted that application of combustion modification techniques such as LEA and SC could lead to an increase in emissions of other pollutants. Of particular concern are increased emissions of carbon monoxide (CO), particular matter (PM), and hydrocarbons (HC).

Comments received on the interpollutant effects may have derived largely from concerns over the proposed standard for package steam generating units, which was based on LEA/SC technology. As discussed earlier in this preamble, the final standard applicable to package units is based on LEA rather than LEA/SC technology. The final standard for field-erected units is based on use of LEA/SC technology. As a result of this change in the standard, the analysis of the interpollutant effects of NO_x controls focused on use of LEA in package steam generating units and on use of LEA/SC in field-erected units.

From a technical viewpoint, the greater the reduction in excess air, the greater the reduction in NO_x emissions. It is also true, however, that at unreasonably low excess air levels, emissions of CO, PM, and HC can increase, indicating the onset of inefficient and unsafe combustion conditions. Under proper LEA operation, the excess air level is controlled to prevent operation at unacceptably low O_2 conditions that would result in an increase in emissions of CO, HC, or PM. Increases in emissions of these pollutants are associated with incomplete combustion. Increases in the CO emission level can indicate increases in emissions of other incomplete combustion products.

An analysis of CO emission data from package and field-erected units was undertaken to investigate the impact of the final standards on the emissions of incomplete combustion products. Under normal steam generating unit operating conditions, CO levels are maintained below 200 ppm. The use of unreasonably low excess air levels can result in CO concentrations exceeding 1,000 ppm, which is unacceptable.

For natural gas-fired steam generating units using LEA, carbon monoxide emission data were available from 5 tests on 1 natural gas-fired package unit having a heat input capacity of 42 MW (140 million Btu/hour). At operating O_2 levels ranging from 2 to 3 percent, which are representative of proper LEA operation, average CO levels remained less than 100 ppm representing acceptable operation. As operating O_2 levels were reduced to 1 percent, the CO level reached 1,300 ppm.

For distillate oil-fired steam generating units using LEA, data were available from 1 test on 1 package unit having a heat input capacity of 29 MW (100 million Btu/hour). At an operating O_2 level of 2.5 percent, the average CO level was less than 50 ppm. No data were available for operation at O_2 levels less than 2.5 percent.

For residual oil-fired steam generating units using LEA, CO emissions data were available from 3 tests on 1 package unit having a heat input capacity of 29 MW (100 million Btu/hour). At operating O_2 levels ranging from 2 to 3 percent, average CO emissions were less than 50 ppm. No data were available for operation of O_2 levels less than 2 percent.

The review of these data indicates that within proper LEA limits associated with good steam generating unit operation, LEA operation does not increase emissions of CO outside of normal operating conditions. Therefore, LEA applied to package steam generating units does not lead to incomplete combustion products (CO, HC, PM, etc.).

Under the 1971 NO_x standards (Subpart D) and under the final standards being adopted today, SC will be used as a NO_x control technique for field-erected units firing high nitrogen content fuels such as coal or residual oil. Another data review focused on CO emissions from field-erected oil- and coal-fired units. Baseline emissions when SC (overfire air) was not in use were compared to emissions during SC operation.

For six residual oil-fired field-erected units having heat input capacities greater than 73 MW (250 million Btu/hour), emissions of CO averaged about 100 ppm without SC in use. With SC in use CO levels averaged about 100 ppm. There was no incremental increase in CO emissions due to SC for the field-erected units firing residual oil.

For two pulverized coal-fired field-erected units having heat input capacities greater than 73 MW (250 million Btu/hour), emissions of CO averaged less than 100 ppm without SC in use. With SC in use, CO emissions averaged less than 100 ppm. There was no incremental increase in CO emissions due to SC for the field-erected units firing coal.

Similar to LEA, the review of LEA/SC applications to field-erected units also concluded that no noticeable increases in emissions of incomplete combustion products occurred.

In summary, the final standards are based on the application of LEA to package steam generating units, and the application of LEA/SC to field-erected units. The application of these technologies will not result in increases in emissions of incomplete combustion products.

National Impacts

Environmental Impacts. Several commenters stated that the emission reductions associated with the proposed NSPS for industrial-commercial-institutional steam generating units have been overestimated. Specifically, the commenters believe that the number of new steam generating units projected for construction during the first 5 years of the standard is too high. Also, the commenters stated that the emission levels that would occur in the absence of an NSPS have been exaggerated.

Over 600 new coal-, oil-, and natural gas-fired industrial-commercial-institutional steam generating units were projected to be constructed over the 5-year period 1985–1990. These projected new units were used in estimating the national impacts of the standards based on the Industrial Fuel Choice Analysis Model (IFCAM), which relies on inputs drawn from the Midterm Energy Forecasting System (MEFS) developed by the Energy Information Administration of the Department of Energy. These estimates included a breakout of industrial demands for these fossil fuels by region and by fuel type. Additionally, 120 new wood- and municipal solid waste-fired steam generating units are projected to be built during this same time period. The estimated growth of wood- and municipal solid waste-fired units is based on historical steam generating unit population growth data, as well as on growth projections by vendor and other industry sources. In combination, 720 coal, oil, natural gas, wood and municipal-type solid waste units are projected to be covered by the standard in its first 5 years of application.

These projections are considered to be reasonable estimates of the number of new steam generating units to be constructed during the first 5 years of these standards. If this number proves to be overestimated, as contended by the commenters projected reductions in particulate matter and NO_x emissions may be diminished, but the costs of the standards on a nationwide basis will also be proportionally reduced. The relationship between total national costs and total national emission reductions (national cost effectiveness) would remain basically unaffected by the change in the number of new steam generating units.

The baseline used to calculate the emission reductions achieved under the particulate matter and NO_x emission limits for steam generating units is also derived from the IFCAM model. The inputs to the model which form the baseline are the individual State implementation plan (SIP) regulations and the Subpart D NSPS which were adopted in 1971. For nonfossil fuel-fired steam generating units, the same approach as discussed above was used, but the calculations were done manually because IFCAM only analyzes impacts from firing fossil fuels (coal, oil and natural gas). As discussed in the preamble to the proposed standards, the use of SIP regulations and Subpart D rather than PSD permit requirements to determine the baseline emission levels may result in the impacts of the standards both in emission reductions and costs being somewhat overstated. However, the relative assessment of the costs of the standard relative to the emission reductions, on a nationwide basis, would not be affected by the baseline values chosen for comparison. Additionally, if PSD requirements were used as a baseline it would make the analysis less accurate and more difficult because it would require an estimate to be made of what PSD permit requirements would be with and without an NSPS in place. SIP regulations do not have to be based on assumptions and are clearly defined.

Another commenter stated that the proposed standards would have the effect of discouraging the retirement of old, less efficient steam generating units with higher emissions and delaying their replacement with new, energy efficient units with lower emissions. The particulate matter and NO_x standards being adopted today are not expected to have a significant effect on the retirement of older steam generating units. Other factors, such as the cost of fuels, the physical condition of the steam generating unit, and the steam requirements of the industrial processes being served by the unit will play a much greater role in the decision to replace a steam generating unit than will the standards being adopted today.

Other commenters stated that the particulate matter emission reductions achieved through the proposed standards would be insignificant, constituting only a few tenths of a percent of the total national particulate matter and NO_x emissions. As a consequence, these commenters suggest that the proposed standards are unnecessary.

As discussed above, the category of industrial-commercial-institutional steam generating units has been listed as a "significant contributor" under Section 111 of the Clean Air Act. Section 111 requires promulgation of standards reflecting best demonstrated technology for this source category. Industrial-commercial-institutional steam generating units, as a source category, are the second largest source of particulate matter and NO_x emissions in the nation, ranking only behind utility power plant steam generating units. Further, they are the largest source of particulate matter emissions listed in the NSPS priority list adopted in 1980. In 1990, new steam generating units are projected to emit 49,000 Mg (54,000 tons) of particulate matter per year in the absence of these standards. More than 16,000 Mg to 22,000 Mg (17,000 tons to 24,000 tons), of particulate matter reduction are expected to result from today's standards. In addition, the steam generating units being regulated are major sources of particulate matter emissions, in many cases, individually emitting 90 Mg (100 tons) or more of particulate matter per year. For these reasons, particulate matter emissions from industrial-commercial-institutional steam generating units are appropriate sources for regulation under Section 111 of the Clean Air Act.

Industrial-commercial-institutional steam generating units are also the second highest ranking source category for NO_x emissions on the 1980 priority list of source categories not already regulated by NSPS. In 1990, new steam generating units are projected to emit 77,000 Mg (85,000 tons) of NO_x per year in the absence of the standards. Of this amount, more than 21,000 Mg to 24,000 Mg (23,000 tons to 26,000 tons), are expected to be eliminated due to the NO_x standards adopted today. In addition, the steam generating units being regulated are major sources of NO_x, in many cases individually emitting 90 Mg (100 tons) or more of NO_x per year. For these reasons, NO_x emissions from industrial-commercial-institutional steam generating units are appropriate sources for regulation under Section 111 of the Clean Air Act.

Three commenters urged that a more thorough assessment be performed of the relative impacts of the proposed standards compared to existing State regulatory programs. The commenters questioned whether the proposed NSPS will result in any significant improvement in air quality.

The adoption of these standards will result in improvements in air quality in two respects. First, it is projected that the standards will result in a reduction in particulate matter and NO_x emissions of more than 16,000 Mg to 22,000 Mg (17,000 tons to 24,000 tons) and 21,000 Mg to 24,000 Mg (23,000 tons to 26,000 tons) per year, respectively, from a baseline emission level estimated from current State and Federal regulations. Second, today's standards will assure that the best demonstrated control technology is applied to all new units and that air pollution resulting from future growth will be minimized. To the extent that some States may already require a similar level of control, the estimates of emission reductions, as well as the estimates of the costs and economic impacts of emission control, would be diminished.

Energy Impacts. Several commenters stated that the proposed standards do not promote energy efficiency. Specifically, they believe that the standards will discourage the preheating of combustion air, will make it difficult to operate steam generating units at low excess air levels when using staged combustion, and will restrict the use of alternative fuels, such as gaseous and liquid byproducts/wastes.

The standards are not expected to have an adverse effect on the use of energy efficient steam generating unit technologies. As discussed above, the NO_x standards adopted today for coal-fired steam generating units can be achieved whether the units use combustion air preheat or not. Natural gas- and oil-fired steam generating units, which are typically package units, are not commonly designed to include combustion air preheat. If greater efficiency is desired, steam generating unit feedwater preheat can be substituted for combustion air preheat.

Operation at LEA levels is included in the basis for each of the NO_x emission limits being adopted today. LEA operation applied to any facility affected by these standards will improve energy efficiency. Additionally, available data show that those facilities which also use SC for NO_x emission control can use that technology in combination with LEA while achieving efficient steam generating unit operation.

Finally, alternative fuels are neither encouraged nor discouraged as stream generating unit fuels by the particulate matter or NO_x standards being adopted today. Existing differences in terms of either costs or availability will not be affected by these standards.

Economic Impacts. Commenters stated that the financially depressed steam generating unit and burner markets will be subjected to excessive economic risks and further market decline if the standards force the premature use of SC controls on package natural gas- and distillate oil-fired steam generating units.

As discussed previously, the proposed NO_x emission limit of 43 ng/J (0.10 million Btu/hour) heat input for package natural gas- and distillate oil-fired steam generating units with high heat release rates has been revised. As adopted today, the emission limit for these units will be 86 ng/J (0.20 lb/million Btu) heat input. This revised standard is based on the use of LEA to control NO_x emissions, rather than on the use of SC control technology. With this revision, the concerns expressed by the commenters concerning the widespread use of SC technology and the effects of the standards on package steam generating units have been addressed.

Other Considerations

Proration of Emission Limits. One commenter stated that steam generating units capable of firing multiple fuels are designed according to the combustion requirements of the most difficult fuel to be fired, and that NO_x emission control techniques ar compromised in this situation. Therefore, the commenter stated that the NO_x limits applicable to steam generating units firing mixtures of fossil fuels should not be based on the achievable emission levels for individual fuels in the mixture.

As mentioned above, LEA and SC are the two basic combustion modification techniques which have formed the basis of the NO_x standards for this source category. LEA is effective in controlling NO_x formation during the combustion of fuels with low nitrogen contents, such as natural gas. SC is effective in controlling NO_x formation during the combustion of high nitrogen content fuels, such as coal. These two techniques are compatible and may be use simultaneously on the same steam generating unit to control NO_x emissions from the firing of mixtures of high nitrogen and low nitrogen content fossil fuels. Because of this compatibility and because the effectiveness of each technique is related to the amount of each fuel fired, NO_x emission limits from the firing of mixtures of fossil fuels can be controlled to levels proportionate to the emission levels achievable for each fossil fuel alone. Therefore, the emission limit for steam generating units firing mixtures of fissil fuels is based on the prorated contribution of each fuel to the total heat input to the unit.

Emission Credits for Cogeneration. Several commenters urged the inclusion in the standard of emission credits for cogeneration steam generating units used in cogeneration systems. These commenters stated that the granting of emissions credits to industrial-commercial-institutional steam generating units which also generate electricity (cogenerate) would encourage the development of cogeneration, resulting in regional decreases in fuel usage and emissions of particulate matter and NO_x.

As stated in the preamble to the proposed rule, these standards are not intended to either encourage or discourage cogeneration systems. Emission credits for cogeneration systems are not being allowed for the following reasons. First, an emission limit for cogeneration facilities which included a emission credit would not reflect the best technological system of emission control, as required by Section 111 of the Clean Air Act. As required by the Act, these standards are based on technological systems that have been determined to offer the greatest emission reductions achievable at reasonable cost and energy impacts. To grant emission credits for cogeneration facilities would allow the use of less than best demonstrated technology.

Second, the construction and operation of cogeneration systems does not guarantee net emission reductions in all cases. In those cases where the cogeneration unit would meet more restrictive emission standards than the displaced utility unit, emission reductions would occur. However, in those cases where the cogeneration system fires fuel which is inherently more polluting than the fuels fired in the utility steam generating unit being displaced, or where the cogeneration facility is subject to a higher emission limit, cogeneration units may result in a net increase rather than a net decrease in emissions.

Third, the implementation of an emission credit would not result in cost savings in proportion to the emission increases that would result. For example, a 15 percent cogeneration credit applied to coal-fired steam generating units would raise the applicable particulate matter emission limit from 22 ng/J (0.05 lb/million Btu) heat input to 25 ng/J (0.06 lb/million Btu) heat input. The incremental cost-effectiveness of this reduction in the stringency of the standard is $2,230/Mg ($2,030/ton) for a coal-fired steam generating unit controlled by an ESP. For a coal-fired steam generating unit controlled by a fabric filter, there is no change in cost effectiveness resulting from the recognition of a credit for cogeneration. For wood- or solid waste-fired steam generating units, a 15 percent credit would raise the particulate matter emission limit from 43 ng/J (0.10 lb/million Btu) heat input to 49 ng/J 0.12 lb/million Btu) heat input. The incremental cost-effectiveness of this reduction in stringency for a solid waste-fired steam generating unit controlled by an ESP is less than $1,650/Mg ($1,500/ton). In summary, there would be no significant difference in the design or in the cost of an ESP or fabric filter applied to a cogeneration unit whether the emission credit was granted or not.

For cogeneration units subject to emission limits for NO_x, combustion modification techniques can be implemented at little or no cost to the steam generating unit owner or operator. No significant economic benefits would result from allowing such a credit against the NO_x emission limit. Credits would, however, allow for NO_x emission increases with no cost savings.

Under the final standards, cogeneration units are neither discouraged or encouraged and, therefore, emission credits for cogeneration steam generating units are not granted under this standard for the reasons discussed above. Any site-specific benefits that may occur through cogeneration can be considered in the Prevention of Significant Deterioration (PSD) program which specifically addresses the site-specific impacts of air pollution sources.

Fluidized Bed Combustion. Several commenters questioned if the proposed standards would apply to fluidized bed combustion (FBC) units, and requested clarification on the applicable NO_x emission limit. Under the proposed standard, FBC units are subject to a NO_x emission limit of 258 ng/J (0.60 lb/million Btu) heat input [§ 60.43b(a)(3)(ii)]. The bases for this emission limit included NO_x emissions data presented in the "Technology Assessment Report for Industrial Boiler Applications: Fluidized Bed Combustion" (EPA-600/7-79-178e), "Fossil Fuel-Fired Industrial Boilers—Background Information Volume 1: Chapters 1-9" (EPA-450/3-82-006a), and "Fossil Fuel-Fired Industrial Boilers—Background Information Volume 2: Appendices" (EPA-450/3-82-006b).

A review of these data confirmed that an emission limit of 260 ng/J (0.60 lb/million Btu) heat input is appropriate for FBC units. Therefore, under the promulgated standard, FBC units are subject to a NO_x emission limit of 260 ng/J (0.60 lb/million Btu) heat input.

Reference Method 5B. Currently, the performance of particulate matter control techniques is measured with Reference Method 5. However, Reference Method 5 has been found to be subject to interference by sulfur trioxide (SO_3) when measurements are taken downstream of a wet flue gas desulfurization (FGD) system. The SO_3 effectively increases measured particulate matter emissions above true values. As a result, a new reference method is under development—Reference Method 5B—that greatly reduces the problem of SO_3 interference. This new reference method was proposed on May 29, 1985 (50 FR 21863) and as discussed in the proposal would apply to Subpart Db.

Reference Method 5B consistently results in equivalent or lower particulate matter emission measurements, with the most significant reduction being observed when measuring particulate matter emissions in gases containing high SO_3 levels. A comparative analysis shows a 35 to 50 percent reduction in measured particulate matter emissions when Reference Method 5B is used in place of Reference Method 5 to measure the performance of ESP's when firing fuels which result in high concentrations of SO_3 in the flue gas.

At this time the standards being promulgated today do not include Reference Method 5B because Reference Method 5B has not yet been adopted. However, when Reference Method 5B is adopted it will be an applicable test method under Subpart Db for measuring particulate matter emissions downstream from a wet FGD system.

Similarly, the standards being promulgated today do not require compliance with Appendix F, Procedure 1. When these new quality assurance procedures are finalized, they will apply to units covered under this subpart.

Duct Burners. Commenters noted that duct burners associated with steam generating units used in combined cycle gas turbine systems may have difficulty meeting a 43 ng/J (0.10 lb/million Btu) heat input standards under all load conditions. Duct burners are smaller package systems and generally have heat input capacities less than 73 MW (250 million Btu/hour). NO_x formation in duct burners is influenced by the temperature and O_2 content of the gas turbine exhaust. The gas turbine exhaust used for combustion air is about 760°C (1400°F), which would suggest a high potential for thermal NO_x formation. However, the turbine exhaust gases are very low in O_2 content, which would tend to reduce the formation of thermal NO_x.

Based on a review of the NO_x emissions data available from duct burners, the final standards limiting NO_x emissions from duct burners firing natural gas and distillate oil is established as 86 ng/J (0.20 lb/million Btu) heat input and 170 ng/J (0.40 lb/million Btu) heat input when residual oil is combusted. Following a review of the data, the proposed standards appeared overly restrictive and may not be achievable over all operating conditions. Under the final standards, owners and operators of duct burners are also required to conduct a performance test when requested by the Administrator. However, CEMS are not required and compliance testing on a continuous basis is not specified.

Owners and operators of duct burners are also required to conduct a performance test. Reference Method 20, which is the reference method for determining NO_x emissions from stationary gas turbines, will be used to monitor NO_x emissions during the initial and subsequent performance tests.

For the performance test, NO_x emissions will be monitored simultaneously at the gas turbine exhaust and steam generating unit outlet. The average NO_x concentration measured at the gas turbine exhaust location will be subtracted from the average NO_x concentration measured at the steam generating unit outlet in order to determine the incremental increase of NO_x emissions attributable to the duct burner.

In order to test the steam generating unit at maximum heat input capacity, the duct burner will be operated at 100 percent load, and the gas turbine will be operated at the rate needed to achieve maximum steam production.

Background Information Document. The background information documents (BID) for the standards being adopted today may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to EPA-450/382-82-006a "Fossil Fuel-Fired Industrial Boilers—Background Information Volume 1: Chapters 1-9, EPA-450/3-006b "Fossile Fuel-Fired Industrial Boilers—Background Information Volume 2: Appendices," EPA-450/3-82-007 "Nonfossil Fuel-Fired Industrial Boilers—Background Information," and EPA-450/3-86-003 "Fossil and Nonfossil Fuel-Fired Industrial Boilers—Background Information for Promulgated PM and NO_x Standard Volume 3." Volumes 1 and 2 of the BID contain technical data that served as the bases of the proposal. Volume 3 of the BID contains: (1) A summary of all the public comments made on the proposed standards, and (2) the final Environmental Impact Statement, which summarizes the impacts of the final standards.

Docket. A docket, number A-79-02, containing information considered in development of the promulgated standards, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at the Central Docket Section (LE-131), West Tower Lobby, Gallery 1, 401 M Street, SW., Washington, DC 20460. A reasonable fee may be charged for copying.

Administrative

The docket is an organized and complete file of all the information considered in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking process. The docketing system is intended to allow members of the public and affected industries to identify and locate documents readily and to participate effectively in the rulemaking process. The statements of basis and purpose of the proposed and promulgated standards, the responses to significant comments, and the contents of the docket (except for interagency review materials) will serve as the record in case of judicial review [Section 307(d)(7)(A)].

The effective date of regulation is November 25, 1986. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities for which construction or modification was commenced after the date of proposal (49 FR 25102, June 19, 1984).

As prescribed by section 111, the promulgation of these standards is based on the Administrator's determination that industrial-commercial-institutional steam generating units contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

This regulation will be reviewed 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to ensure that cost was carefully considered in determining the best demonstrated technology. Portions of the economic impact assessment are included in the BID and additional information is included in the Docket.

The information collection requirements associated with this regulation (Sections 60.7, 60.11, 60.13, 60.44b, 60.45b, 60.46b) have been approved by the Office of Management and Budget (OMB) under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq* and have been assigned OMB control number 2060-0072.

Under Executive Order 12291, the Administrator is required to judge whether a regulation is a "major rule" and therefore subject to the requirements for preparation of a regulatory impact analysis (RIA). It has been determined that this regulation would result in none of the adverse economic effects set forth in section 1 of the Order as grounds for finding a regulation to be a "major rule." The industry-wide increase in annualized costs in the fifth year after the standards would go into effect would be less than $40 million, less than the $100 million established as the first criterion for a major regulation in the Order. The projected average increase in product prices of no more than 0.05 percent associated with the standards would not be considered a "major increase in costs or price" specified as the second criterion in the Order. The economic analysis of the standards' effects on the industry did not indicate any significant adverse effects on competition, investment, productivity, employment, innovation, or the ability of the U.S. firms to compete with foreign firms (the third criterion in the Order). Therefore, this regulation is not a "major rule" under Executive Order 12291. This rule has been submitted to OMB for review under Executive Order 12291.

The Regulatory Flexibility Act of 1980 requires the identification of potentially adverse impacts of Federal regulations upon small business entities. The Act specifically requires the completion of a Regulatory Flexibility Analysis in those instances where small business impacts are possible. Because these standards impose no adverse economic impacts on small businesses, a Regulatory Flexibility Analysis has not been conducted.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the proposed rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements, Incorporation by reference.

Dated: October 1, 1986.

Lee M. Thomas,
Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Authority: 42 U.S.C. 7411, 7414 and 7601(a).

2. 40 CFR Part 60 is amended by adding a new Subpart Db consisting of §§ 60.40b through 60.49b as follows:

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Sec.

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

§ 60.40b Applicability and definition of affected facility.

(a) The affected facility to which this subpart applies is each steam generating unit for which construction modification, or reconstruction is commenced after June 19, 1984, and which has a heat input capacity from fuels combusted in the steam generating unit of more than 29 MW (100 million Btu/hour), except as provided under paragraphs (b) through (f) of this section.

(b) Coal-fired steam generating units meeting both the applicability requirements under this subpart and the applicability requirements under Subpart D (Standards of performance for fossil fuel-fired steam generators; § 60.40) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under Subpart D (§ 60.43).

(c) Oil-fired steam generating units meeting both the applicability requirements under this subpart and the applicability requirements under Subpart D (Standards of performance for fossil fuel-fired steam generators; § 60.40) are subject to the nitrogen oxides standards under this subpart and the sulfur dioxide and particulate matter standards under Subpart D (§ 60.42 and § 60.43).

(d) Steam generating units meeting the applicability requirements under this subpart and the applicability requirements under Subpart J (Standards of performance for petroleum refineries; § 60.104) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under Subpart J (§ 60.104).

(e) Steam generating units meeting both the applicability requirements under this subpart and the applicability requirements under Subpart E (Standards of performance for incinerators; § 60.50) are subject to the nitrogen oxides and particulate matter standards under this subpart.

(f) Steam generating units meeting the applicability requirements under Subpart Da (Standards of performance for electric utility steam generating units; § 60.40a) are not subject to this subpart.

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

"Annual capacity factor" means the ratio between the actual heat input to a steam generating unit from the fuels listed in § 60.43b(a) or § 60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours at the maximum steady state design heat input capacity.

"Byproduct/waste" means any liquid or gaseous substance produced at chemical manufacturing plants or petroleum refineries, except natural gas, distillate oil, or residual oil, which is combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purposes of this subpart.

"Chemical manufacturing plants" means industrial plants which are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

"Coal" means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388–77, Standard Specification for Classification of Coals by Rank (incorporated by reference—see § 60.17). Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures and coal-water mixtures, are included in this definition for the purposes of this subpart.

"Cogeneration system" means a power system which simultaneously produces both electrical (or mechanical) and thermal energy from the same energy source.

"Combined cycle system" means a system where a gas turbine provides exhaust gas to a heat recovery steam generating unit.

"Distillate oil" means fuel oils which contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oils number 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396–78, Standard Specifications for Fuel Oils (incorporated by reference—see § 60.17).

"Duct burner" means a device which combusts fuel and which is placed in the exhaust duct of a stationary gas turbine to allow the firing of additional fuel before the exhaust gas enters a heat recovery steam generating unit.

"Federally enforceable" means all limitations and conditions which are enforceable by the Administrator, including those requirements developed pursuant to 40 CFR Parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 and 40 CFR 51.24.

"Fluidized bed combustion steam generating unit" means a device wherein fuel and solid sorbent are distributed onto or into a bed, or series of beds, of aggregate for combustion and these materials together with solid products of combustion are forced upward in the device by the flow of combustion air and the gaseous products of combustion.

"Full capacity" means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

"Heat input" means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or gas turbine exhaust gases.

"Heat release rate" means the steam generating unit design heat input capacity (in MW or Btu/hour) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

"Heat transfer medium" means any material which is used to transfer heat from one point to another point.

"High heat release rate" means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3).

"Lignite" means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388–77, Standard Specification for Classification of Coals by Rank (incorporated by reference—see § 60.17).

"Low heat release rate" means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hour-ft^3) or less.

"Mass-feed stoker steam generating unit" means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

"Maximum heat input capacity" means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

"Municipal-type solid waste" means refuse, more than 50 percent of which is municipal-type waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

"Natural gas" means a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal hydrocarbon constituent is methane.

"Oil" means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

"Petroleum refinery" means industrial plants which are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

"Process heater" means a device which is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

"Pulverized coal-fired steam generating unit" means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units.

"Residual oil" means crude oil, fuel oils number 1 and 2 which have a nitrogen content of greater than 0.05 weight percent, and all fuel oils number 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396–78, Standard Specifications for Fuel Oils (incorporated by reference—see § 60.17).

"Spreader stoker steam generating unit" means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

"Steam generating unit" means a device which combusts any fuel or byproduct/waste to produce steam or to heat water of any other heat transfer medium. This term includes any municipal-type waste incinerator with a heat recovery steam generating unit or any steam generating unit which combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters.

"Steam generating 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 steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

"Wet scrubber system" means any emission control device which mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter or sulfur dioxide.

"Wood" means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

§ 60.42b [Reserved]

§ 60.43b Standard for particulate matter.

(a) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility which combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases which contain particulate matter in excess of the following emission limits:

(1) 22 nanograms per joule (0.05 lb/million Btu) heat input;

(i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 nanograms per joule (0.10 lb/million Btu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a Federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 nanograms per joule (0.20 lb/million Btu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less,

(iii) Has a Federally enforceable requirement limiting operation of the affected facility to an annual capacity factor 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984 and before November 25, 1986.

(b) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility which combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases which contain particulate matter in excess of the following emission limits:

(1) 43 nanograms per joule (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 nanograms per joule (0.20 lb/million Btu) heat input if

(i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood,

(ii) Is subject to a Federally enforceable requirement limiting operation of the affected facility to an annual capacity factor 30 percent (0.30) or less for wood, and

(iii) Has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility which combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases which contain particulate matter in excess of the following emission limits:

(1) 43 nanograms per joule (0.10 lb/million Btu) heat input;

(i) If the affected facility combusts only municipal-type solid waste, or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 nanograms per joule (0.20 lb/million Btu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less,

(ii) has a maximum heat input capacity of 73 MW (250 million Btu/hour) or less,

(iii) Has a Federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) for municipal-type solid waste, or municipal-type solid waste and other fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984 but before November 25, 1986.

(d) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum design heat input capacity.

(e) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility subject to the particulate matter emission limits under paragraphs (a), (b) or (c) of this section shall cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

§ 60.44b Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility subject to the provisions of this section which combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases which contain nitrogen oxides in excess of the following emission limits:

[Figures in parentheses represent lb/million Btu heat input]

Fuel/Steam generating unit type	Nitrogen oxide [1]
(1) Natural gas and distillate oil, except (4):	
(i) Low heat release rate	43(0.10)
(ii) High heat release rate	86(0.20)
(2) Residual oil:	
(i) Low heat release rate	130(0.30)
(ii) High heat release rate	170(0.40)
(3) Coal:	
(i) Mass-feed stoker	210(0.50)
(ii) Spreader stoker and fluidized bed combustion	260(0.60)
(iii) Pulverized coal	300(0.70)
(iv) Lignite, except (v)	260(0.60)
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340(0.80)
(vi) Coal-derived synthetic fuels	210(0.50)
(4) Duct burner used in a combined cycle system:	
(i) Natural gas and distillate oil	86(0.20)
(ii) Residual oil	170(0.40)

[1] Emission limits nanograms per joule heat input.

(b) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility which simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases which contain nitrogen oxides in excess of a limit determined by use of the following formula:

$$E_{NOx} = [(EL_{go} \times H_{go}) + (EL_{ro} \times H_{ro}) + (EL_c \times H_c)] / Ht$$

where:

E_{NOx} is the nitrogen oxides emission limit,

EL_{go} is the appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil,

H_{go} is the heat input from combustion of natural gas or distillate oil,

EL_{ro} is the appropriate emission limit from paragraph (a)(2) for combustion of residual oil,

H_{ro} is the heat input from combustion of residual oil,

EL_c is the appropriate emission limit from paragraph (a)(3) for combustion of coal,

H_c is the heat input from combustion of coal, and

Ht is the total heat input to the steam generating unit from combustion of coal, oil, and natural gas.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever comes first, no owner or operator of an affected facility which simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases which contain nitrogen oxides in excess of the emission limit for the coal or oil, or mixture of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a Federally enforceable requirement which limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility which simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases which contain nitrogen oxides in excess of 130 nanograms per joule (0.30 lb/million Btu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent or less and is subject to a Federally enforceable requirement which limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility which simultaneously combusts coal, oil, or natural gas with byproduct/wastes shall cause to be discharged into the atmosphere from that affected facility any gases which contain nitrogen oxides in excess of an emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a Federally enforceable requirement which limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_{NOx} = [(EL_{go} \times H_{go}) + (EL_{ro} \times H_{ro}) + (EL_c \times H_c)] / Ht$$

where:

E_{NO_x} is the nitrogen oxides emission limit,
EL_{go} is the appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil,
H_{go} is the heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste.
EL_{ro} is the appropriate emission limit from paragraph (a)(2) for combustion of residual oil,
H_{ro} is the heat input from combustion of residual oil and/or liquid byproduct/waste.
EL_c is the appropriate emission limit from paragraph (a)(3) for combustion of coal,
H_c is the heat input from combustion of coal, and
Ht is the total heat input to the steam generating unit from combustion of natural gas, oil, coal, and byproduct/waste.

(f) Any owner or operator of an affected facility which combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a nitrogen oxides emission limit which shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as nitrogen oxides emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific nitrogen oxides emission limit pursuant to this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) or for residual oil in paragraph (a)(2), as appropriate, by conducting a 30-day performance test as provided in § 60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) or for residual oil in paragraph (a)(2), as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under subparagraph (i).

(2) The nitrogen oxides emission limits for natural gas or distillate oil in paragraph (a)(1) or for residual oil in paragraph (a)(2), as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific nitrogen oxides emission limit will be established at the nitrogen oxides emission level achievable when the affected facility is combusting coal, oil, natural gas and byproduct/waste in a manner which the Administrator determines to be consistent with minimizing nitrogen oxides emissions.

(g) Any owner or operator of an affected facility which combusts hazardous waste (as defined by 40 CFR Part 261 or 40 CFR Part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the nitrogen oxides emission limit which applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on nitrogen oxides emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the nitrogen oxides emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable Federally enforceable requirement preclude compliance with the nitrogen oxides emission limits of this section. The nitrogen oxides emission limits for natural gas or distillate oil in paragraph (a)(1) or for residual oil in paragraph (a)(2), as appropriate, is applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).)

§ 60.45b [Reserved]

§ 60.46b Compliance and performance testing for particulate matter and nitrogen oxides.

(a) The particulate matter emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The nitrogen oxides emission standards under § 60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section.

(c) Compliance with the nitrogen oxides emission standards under § 60.44b shall be determined through performance testing as described in paragraph (e) or (f) of this section.

(d) The following procedures and reference methods are used to determine compliance with the standards for particulate matter emissions under § 60.43b.

(1) Reference Method 3 is used for gas analysis when applying Reference Method 5 or Reference Method 17.

(2) Reference Method 5 or Reference Method 17 shall be used to measure the concentration of particulate matter and the associated moisture content as follows:

(i) Reference Method 5 at all facilities; or

(ii) Reference Method 17 at facilities where the stack gas temperature at the sampling location does not exceed an average temperature of 160°C (320°F). Reference Method 17 shall not be used at affected facilities with wet scrubber systems if the effluent gas is saturated or laden with water droplets.

(3) Reference Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Reference Method 5, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160°C (320°F).

(5) For determination of particulate emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Reference Method 5 or Reference Method 17 by traversing the duct at the same sampling location.

(6) For each run using Reference Method 5 or Reference Method 17, the emission rate expressed in nanograms per joule heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F_c factor, and

(iii) The dry basis emission rate calculation procedure contained in Reference Method 19 (Appendix A).

(7) Reference Method 9 is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for nitrogen oxides required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring nitrogen oxides under § 60.48(b).

(i) For the initial compliance test, nitrogen oxides from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the nitrogen oxides emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(ii) Following the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility which fires coal or which fires residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the nitrogen oxides emission standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(iii) Following the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility which has a heat input capacity greater than 73 MW (250 million Btu/hour) and which fires natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the nitrogen oxides standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxide emission data for the preceding 30 steam generating unit operating days.

(iv) Following the date on which the initial performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility which has a heat input capacity of 73 MW (250 million Btu/hour) or less and which fires natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the nitrogen oxides standards under § 60.44b through the use of a 30-day performance test when requested by EPA. During periods when performance tests are not requested by EPA, nitrogen oxides emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and to prepare excess emission reports, but will not be used to determine compliance with the nitrogen oxides emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 steam generating unit operating days.

(v) If the owner or operator of an affected facility which fires residual oil does not sample and analyze the residual oil for nitrogen content, as specified in § 60.49b(e), the requirements of paragraph (iii) of this section apply and the provisions of paragraph (iv) of this section are inapplicable.

(f) To determine compliance with the emission limit for nitrogen oxides required by § 60.44b(a)(4) for duct burners used in combined cycle systems, the owner or operator of an affected facility shall conduct the performance test required under § 60.8 using the nitrogen oxides and oxygen measurement procedures in 40 CFR Part 60 Appendix A, Method 20. During the performance test, one sampling site shall be located as close as practical to the exhaust of the turbine, as provided by section 6.1.1 of Reference Method 20. A second sampling site shall be located at the outlet to the steam generating unit. Measurements of nitrogen oxides and oxygen shall be taken at these two sampling sites simultaneously during the performance test. The nitrogen oxides emission rate from the combined cycle system shall be calculated by subtracting the nitrogen oxides emission rate measured at the sampling site at the outlet from the turbine from the nitrogen oxides emission rate measured at the sampling site at the outlet from the steam generating unit.

§ 60.47b [Reserved]

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) The owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

(b) Except as provided in paragraphs (g) and (h) of this section, the owner or operator of an affected facility subject to the nitrogen oxides standard of § 60.44b(a) shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides emissions discharged to the atmosphere and record the output of the system.

(c) The continuous monitoring systems required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in nanograms per joule or lb/million Btu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(b). At least 2 data points must be used to calculate each 1-hour average.

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities burning coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities burning coal, oil, or natural gas, the span value for nitrogen oxides is determined as follows:

Fuel	Span values for nitrogen oxides (PPM)
Natural gas	500
Oil	500
Coal	1,000
Combination	$500(x+y)+1,000z$

where:

x is the fraction of total heat input derived from natural gas,

y is the fraction of total heat input derived from oil, and

z is the fraction of total heat input derived from coal.

(3) All span values computed under paragraph (e)(2) of this section for burning combinations of regulated fuels are rounded to the nearest 500 ppm.

(f) When nitrogen oxides emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Reference Method 7, Reference Method 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility which has a heat input capacity of 73 MW (250 million Btu/hour) or less, and which has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section, or

(2) Monitor steam generating unit operating conditions and predict nitrogen oxides emission rates as specified in a plan submitted pursuant to § 60.49b(c).

(h) The owner or operator of an affected facility which is subject to the nitrogen oxides standards of § 60.44b(a)(4) is not required to install or operate a continuous monitoring system to measure nitrogen oxides emissions.

(Approved by the Office of Management and Budget under control number 2060-0072)

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) Identification of the fuels to be combusted in the affected facility, and

(2) The design heat input capacity and, if applicable, a copy of any Federally enforceable requirement which limits the annual capacity factor for any fuel or mixture of fuels listed in § 60.43b, or for any fuel or mixture of fuels listed in § 60.44b.

(3) [Reserved]

(4) [Reserved]

(b) For facilities subject to the particulate matter and nitrogen oxides emission limits under § 60.43b and § 60.44b, the performance test data from the initial performance test and the performance evaluation of the continuous emission monitors (using the applicable performance specifications in Appendix B) shall be submitted to the Administrator by the owner or operator of the affected facility.

(c) The owner or operator of each affected facility subject to the nitrogen oxides standard of 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions pursuant to the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan which identifies the operating conditions to be monitored under § 60.48b(g)(2) and the records to be maintained under § 60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and nitrogen oxides emission rates (i.e., nanograms per joule or pounds per million Btu heat input). Steam generating unit operating conditions include, but are not limited to, degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas oxygen level);

(2) Include the data and information which the owner or operator used to identify the relationship between nitrogen oxides emission rates and these operating conditions;

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(j). If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan.

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of all fuels fired during each day and calculate the annual capacity factor for coal, oil, natural gas, wood, and municipal-type solid waste for each calendar quarter.

(e) For affected facilities which fire residual oil having a nitrogen content of 0.3 weight percent or less; have heat input capacities of 73 MW (250 million Btu/hour) or less; and monitor nitrogen oxides emissions or steam generating unit operating conditions pursuant to § 60.48b(g), the owner or operator shall maintain records of the nitrogen content of the oil fired in the affected facility and calculate the average fuel nitrogen content on a per calendar quarter basis. The nitrogen content shall be determined using ASTM Method D3431-80, Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons (incorporated by reference—see § 60.17), or fuel specification data obtained from fuel suppliers. If residual oil blends are being fired, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For facilities subject to the opacity standard under § 60.43b, the owner or operator shall maintain records of opacity.

(g) For facilities subject to nitrogen oxides standards under § 60.44b, the owner or operator shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date.

(2) The average hourly nitrogen oxides emission rates (nanograms per joule or pounds per million Btu heat input) measured or predicted.

(3) The 30-day average nitrogen oxides emission rates (nanograms per joule or lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days.

(4) Identification of the steam generating unit operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(h) The owner or operator of any affected facility in any category listed below in paragraphs (h)(1) and (h)(2) of this section is required to submit excess emission reports for any calendar quarter during which there are excess emissions from the affected facility. If there are no excess emissions during the calendar quarter, the owner or operator shall submit a report semiannually stating that no excess emissions occurred during the semiannual reporting period.

(1) Any affected facility subject to the opacity standards under § 60.43b(e) or to the operating parameter monitoring requirements under § 60.13(i)(1).

(2) Any affected facility which is subject to the nitrogen oxides standard of § 60.44b; fires natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 percent or less; and has a heat input capacity of 73 MW (250 million Btu/hour) or less, and is required to monitor nitrogen oxides emissions on a continuous basis pursuant to § 60.48b(g)(1) or steam generating unit operating conditions pursuant to § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average nitrogen oxides emission rate, as determined pursuant to § 60.46b(e), which exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for nitrogen oxides pursuant to § 60.48(b) shall submit a quarterly report containing the information recorded pursuant to paragraph (b) of this section.

(j) [Reserved]

(k) [Reserved]

(l) [Reserved]

(m) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(Approved by the Office of Management and Budget under control number 2060–0072)

3. Section 60.17 is amended by revising paragraphs (a)(1) and (a)(10) and adding paragraph (a)(47), as follows:

§ 60.17 Incorporation by reference.

* * * * *

(a) * * *

(1) ASTM D388–77, Standard Specification for Classification of Coals by Rank, incorporation by reference (IBR) approved for §§ 60.41(f), 60.45(f)(4)(i), (ii), (vi), 60.41a, 60.251 (b), (c), 60.41b.

* * * * *

(10) ASTM D396–78, Standard Specification for Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), 60.41b.

* * * * *

(47) ASTM D3431–80, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons (microcoulometric method), IBR approved for § 60.49(e).

[FR Doc. 86–25585 Filed 11–24–86; 8:45 am]

BILLING CODE 6560-50-M

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40 CFR Part 60

[AD-FRL-3109-1]

Standards of Performance for New Stationary Sources; Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action amends the priority list for regulation under section 111 of the Clean Air Act by expanding the source category of industrial fossil fuel-fired steam generators to cover all steam generators, including both fossil and nonfossil fuel-fired steam generators, as well as steam generators used in industrial, commercial, and institutional applications. This amendment is based on the Administrator's determination that industrial-commercial-institutional steam generating units contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of this action is to include nonfossil fuel-fired and commercial/institutional steam generatingunits in the source category for which standards of performance are beingpublished elsewhere in today's **Federal Register**.

DATE: Effective November 25, 1986.

Under section 307(b)(1) of the Clean Air Act, judicial review of theactions taken by this notice is available only by the filing of a petition for review in the U.S Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: The background information documents may be obtained from the U.S. EPA Library (MD–35), Research Triangle Park, North Carolina 27711, (919) 541–2777.

Docket number A–79–02 is available for public inspection between 8:00 a.m. and 4:00 p.m. Monday through Friday at EPA's Central Docket Section (LE–131), West Tower Lobby, Gallery 1, 401 M Street, SW., Washington, DC.

See "**SUPPLEMENTARY INFORMATION**" for further details.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter or Mr. Walter Stevenson, Standards Development Branch, Emission Standards and Engineering Division (MD–13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541–5578.

SUPPLEMENTARY INFORMATION: The Clean Air Act establishes a program under section 111 to develop standards of performance for new sources within categories of stationary sources which the Administrator determines may contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Such source categories are referred to as "significant contributors." Section 111(f) of the Clean Air Act, added by the 1977 Clean Air Act Amendments, requires that the Administrator publish a list of categories of major stationary sources which are significant contributors and for which standards of performance for new sources are to be promulgated.

This list, which identifies major source categories in order of priority for development of regulations, was proposed in the **Federal Register** on August 31, 1978, and promulgated on August 21, 1979 (40 CFR 60.16, 44 FR 49222). Of the 59 source categories on the list, the category "Industrial Fossil Fuel-Fired Steam Generators: Industrial Boilers" is listed as number 11.

Today's action amends the priority list by revising the title of this source category to "Industrial-Commercial-Institutional Steam Generating Units." This change deletes the references to the type of fuel combusted, to the distinction between steam generating unit application, and to the type of steam generator.

As amended, this source category includes any device or system which combusts fuel which results in the production of steam (or hot water), including incinerators with heat recovery, combined cycle steam generators, cogeneration systems and small electric utility steam generating units. All of these types of steam generators exhibit emission characteristics which are similar in quantity and type. Furthermore, the emission control devices which have been found to be effective on steam generating units are also effective in reducing emissions from other types of steam generators. Therefore, the scope of the source category is expanded to include all types of steam generating units except those covered under Subpart Da.

Public Participation

This amendment to the priority list was proposed in the **Federal Register** on June 19, 1984 (49 FR 25156). Public comments were solicited at the time of proposal. Notice of a public hearing was also given to provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standard. No requests to present oral testimony were received.

The public comment period was from June 19, 1984 to September 17, 1984. Two comment letters were received and were given consideration.

Significant Comments and Changes to the Proposed Standard

Two commenters requested that steam generating units with heat input capacities less than 73 MW (250 million Btu/hour) be delisted from the new category of "Industrial-Commercial-Institutional Steam Generating Units." The commenters indicated that the reasons for their request are: (1) That steam generating units under 73 MW (250 million Btu/hour) heat input capacity are not significant air pollution sources; and (2) that these units are already adequately regulated by State regulations and other requirements of the Clean Air Act.

The Administrator has determined that fossil and nonfossil fuel-fired industrial, commercial, and institutional steam generating units should be classified together as one source category for the purpose of the priority listing. These steam generating units emit similar pollutants, fire the same fuels, and may employ the same emission control techniques. Their impacts on human health are similar and the Administrator has determined, pursuant to the provisions of section 111(b)(1)(A), that the inclusion of industrial, commercial, and institutional steam generating units in one source category is warranted.

The industrial-commercial-institutional source category is a significant contributor and an appropriate source category for regulation. There is no requirement that each subcategory of a listed category or each individual source also be significant contributors. For this reason, the request that fossil and nonfossil fuel-fired steam generating units with heat input capacities less than 73 MW (250 million Btu/hour) be delisted from the source category of industrial-commercial-institutional steam generating units is denied.

Background Information Document

The background information documents (BID) for the promulgated standards under Subpart Db that contain background information related to this action may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919)541-2777. Please refer to EPA-450/3-82-006a "Fossil Fuel-Fired Industrial Boilers—Background Information Volume 1: Chapters 1-9", EPA-450/3-82-006b "Fossil Fuel-Fired Industrial Boilers—Background Information Volume 2: Appendices, EPA-450/3-82-007 "Nonfossil Fuel-Fired Industrial Boilers—Background Information," and EPA-450/3-86-003 "Fossil and Nonfossil Fuel-Fired Industrial Boilers—Background Information for Promulgated PM and NO_x Standards." The BID Volumes 1 and 2 contain technical and source emission data, as well as analyses of regulatory alternatives and economic and environmental impacts. The BID for the promulgated standards contains a summary of all the public comments made on the proposed Subpart Db standards and includes a summary of public comments received concerning this action, and the final Environmental Impact Statement, which summarizes the impacts of the Subpart Db standards.

Docket. A docket, number A-79-02, contains supporting information considered in development of standards of performance for steam generating units. The docket is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (LE-131), West Tower Lobby, Gallery 1, 401 M Street, SW., Washington, DC. A reasonable fee may be charged for copying.

Administrative

The docket is an organized and complete file of all the information considered in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and responses to significant comments, the contents of the docket, except for interagency review materials, will serve as the record in case of judicial review [Section 307(d)(7)(A)]. This docket contains supporting information used in developing the 40 CFR Part 60 Subpart Db standards.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under section 111(b) of the Act. Because this action does not promulgate a new source performance standard, an economic impact assessment was not prepared.

There are no information collection requirements associated with this amemdment to the priority list.

Under Executive Order 12291, the Administrator is required to judge whether a regulation is a "major rule" and therefore subject to the requirements of a regulatory impact analysis (RIA). This amendment would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule." This action has been submitted to OMB for review under Executive Order 12291.

The Regulatory Flexibility Act of 1980 requires the identification of potentially adverse impacts of Federal regulations upon small business entities. The Act specifically requires the completion of a Regulatory Flexibility Analysis in those instances where small business impacts are possible. Because this action imposes no adverse economic impacts, a Regulatory Flexibility Analysis has not been conducted.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the proposed rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements, Incorporation by reference.

Dated: October 31, 1986.

Lee M. Thomas,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Authority: 42 U.S.C. 7411 and 7601(a).

2. 40 CFR Part 60, Subpart A, §60.16 is amended by revising item 11 as follows:

§ 60.16 Priority list.

* * * * *

11. Industrial-Commercial-Institutional Steam Generating Units.

* * * * *

[FR Doc. 86–25586 Filed 11–24–86; 8:45 am]

BILLING CODE 6560–50–M

40 CFR Part 60

[AD–FRL–3109–2]

Standards of Performance for New Stationary Sources; Fossil Fuel-Fired Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance limiting nitrogen oxides (NO_x) emissions from steam generating units firing mixtures of natural gas and wood were promulgated under Subpart D of 40 CFR Part 60 in the **Federal Register** on November 22, 1976 (41 FR 51397). This action amends the NO_x emission limit for steam generating units firing mixtures of natural gas and wood to make it consistent with the NO_x emission limit for this same fuel mixture under Subpart Db of 40 CFR Part 60 which is being promulgated in a separate document in today's **Federal Register.** The amended emission limit of 129 ng/J (0.30 lb/million Btu) heat input for units firing mixtures of natural gas and wood replaces the NO_x emission limit of 86 ng/J (0.20 lb/million Btu) heat input which was adopted in 1976 (41 FR 51397). The amended emission limit applies to all Subpart D steam generating units firing mixtures of natural gas and wood that commenced construction after August 17, 1971.

EFFECTIVE DATE: November 25, 1986.

Under section 307(b)(1) of the Clean Air Act, judicial review of the actions taken by this notice is available only by the filing of a petition for review in the U. S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: Background information documents may be obtained from the U.S. EPA Library (MD–35), Research Triangle Park, North Carolina 27711, (919) 541–2777.

Docket number A–79–02 is available for public inspection between 8:00 a.m. and 4:00 p.m. Monday through Friday at EPA's Central Docket Section (LE–131), West Tower Lobby, Gallery 1, 401 M Street, SW., Washington, DC 20460.

See "**SUPPLEMENTARY INFORMATION**" for further details.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter or Mr. Walter Stevenson, Standards Development Branch, Emission Standards and Engineering Division (MD–13), U. S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541–5578.

SUPPLEMENTARY INFORMATION:

The Standards

Under 40 CFR Part 60 Subpart D, particulate matter, NO_x and sulfur dioxide emission limits are established for fossil fuel-fired steam generating units having heat input capacities greater than 73 MW (250 million Btu/hour) that commenced construction after August 17, 1971. The standards under Subpart D apply to units firing fossil fuel alone or firing mixtures of fossil fuel and wood. Today's action would amend the NO_x emission standard for units firing mixtures of natural gas and wood. Prior to today's amendment, NO_x emissions from steam generating units firing mixtures of natural gas and wood were limited to 86 ng/J (0.20 lb/million Btu) heat input. Since promulgation of 40 CFR Part 60 Subpart D in 1976 (41 FR 51397), a number of steam generating units firing mixtures of natural gas and wood have been constructed. Results from extensive emission tests indicate a NO_x emission limit of 86 ng/J (0.20 lb/million Btu) heat input is not achievable on a continuous basis for units firing mixtures of natural gas and wood.

Therefore, this action amends the NO_x standard for steam generating units subject to 40 CFR Part 60 Subpart D, which fire mixtures of natural gas and wood to 129 ng/J (0.30 lb/million Btu) heat input. The technical database supporting this emission limit is discussed in 40 CFR Part 60 Subpart Db (which is being promulgated in a separate document in today's **Federal Register**).

This amendment applies to all steam generating units firing mixtures of natural gas and wood that are larger than 73 MW (250 million Btu/hour) heat input capacity and that commenced construction after August 17, 1971. Without such a change, natural gas- and wood-fired steam generating units constructed after June 19, 1984 would be subject to a 129 ng/J (0.30 lb/million Btu) heat input NO_x emission limit under 40 CFR Part 60 Subpart Db, while older units constructed between August 17, 1971 and June 19, 1984 (Subpart D) would be subject to a more restrictive NO_x emission limit of 86 ng/J (0.20 lb/million Btu) heat input. The amended NO_x standard being promulgated today corrects that inconsistency.

Environmental, Energy, and Economic Impacts

The environmental, energy, and economic impacts associated with the promulgated standard are discussed in the preamble to Subpart Db (standards of performance for industrial-commercial-institutional steam generating units) which is printed separately in today's **Federal Register.**

Public Participation

This amendment to Subpart D was proposed and published in the **Federal Register** on December 2, 1985 (50 FR 49422). Public comments were solicited at the time of proposal. Notice of a public hearing was also given to provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standard. No requests to present oral testimony were received.

The public comment period was from December 2, 1985 to February 18, 1986. Four comment letters were received and were given consideration.

Significant Comments and Changes to the Proposed Standard

Comments on the proposed standard were received from industry and industrial trade associations. All of the comments endorsed the adoption of the proposed amendment. Consequently, the NO_x emission limit being amended today is the same as the proposed amendment [129 ng/J (0.30 lb/million Btu) heat input] for affected facilities firing mixtures of natural gas and wood.

Background Information Document. The background information documents (BID) for the promulgated standards under Subpart Db that contain background information related to this action may be obtained from the U.S. EPA Library (MD–35), Research Triangle Park, North Carolina 27711, telephone number (919) 541–2777. Please refer to EPA–450/3–82–006a "Fossil Fuel-Fired Industrial Boilers—Background Information Volume 1: Chapters 1–9," EPA–450/3–82–006b "Fossil Fuel-Fired Industrial Boilers—Background Information Volume 2: Appendices," EPA–450/3–82–007 "Nonfossil Fuel-Fired Industrial Boilers—Background Information," and EPA–450/3–86–003 "Fossil and Nonfossil Fuel-Fired

Industrial Boilers—Background Information for Promulgated PM and NO_x Standards." The BID Volumes 1 and 2 contain technical and source emission data, and analyses of regulatory alternatives and economic and environmental impacts. The BID for the promulgated standards contains a summary of all the public comments made on the proposed Subpart Db standards and includes a summary of public comments received concerning this action, and the final Environmental Impact Statement, which summarizes the impacts of the standards.

Docket. A docket, number A–79–02, contains supporting information considered in development of the Subpart Db promulgated standards and includes a review of data pertaining to the proposed amendment that were not available in 1976 when 40 CFR Part 60 Subpart D was adopted. The docket is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (LE–131), West Tower Lobby, Gallery 1, 401 M Street, SW., Washington, DC 20460. A reasonable fee may be charged for copying.

Administrative

The docket is an organized and complete file of all the information considered in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and responses to significant comments, the contents of the docket, except for interagency review materials, will serve as the record in case of judicial review [Section 307(d)(7)(A)]. A discussion of the technical database supporting the proposed amendment to 40 CFR Part 60 Subpart D can be reviewed in Docket No. A–79–02. This docket contains supporting information used in developing the 40 CFR Part 60 Subpart Db standards and includes a review of data that were not available in 1976 when 40 CFR Part 60 Subpart D was adopted.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for the promulgation or substantial revision of any new source standard of performance promulgated under Section 111(b) of the Act. Because this revision is not substantial, an economic impact assessment was not prepared. However, an economic assessment was previously prepared for 40 CFR Part 60 Subpart D which considered other regulatory alternatives. All aspects of the assessment were considered in the formulation of the 40 CFR Part 60 Subpart D standards to ensure that cost was carefully considered in determining the best demonstrated technology. Under this action the best demonstrated technology remains the same; therefore, there is no additional economic impact. The economic impact assessment is included in the BID for the proposed 40 CFR Part 60 Subpart D standards.

There are no information collection requirements associated with this amendment to 40 CFR Part 60 Subpart D. Information collection requirements associated with 40 CFR Part 60 Subpart D have previously been approved by the Office of Management and Budget (OMB) under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* and were assigned OMB control number 2060–0026.

Under Executive Order 12291, the Administrator is required to judge whether a regulation is a "major rule" and therefore subject to the requirements of a regulatory impact analysis (RIA). This amendment would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule." This action has been submitted to OMB for review under Executive Order 12291.

The Regulatory Flexibility Act of 1980 requires the identification of potentially adverse impacts of Federal regulations upon small business entities. The Act specifically requires the completion of a Regulatory Flexibility Analysis in those instances where small business impacts are possible. Because this action imposes no adverse economic impacts, a Regulatory Flexibility Analysis has not been conducted.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the proposed rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements, Incorporation by reference.

Dated: October 31, 1986.

Lee M. Thomas,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Authority: 42 U.S.C. 7411 and 7601(a).

2. 40 CFR Part 60, § 60.44 is amended by revising paragraphs (a)(1) and (a)(2) as follows:

§ 60.44 Standards for nitrogen oxides.

(a) * * *

(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.

(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

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[FR Doc. 86–25587 Filed 11–24–86; 8:45 am]
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