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Environmental Protection Agency

40 CFR Part 60

Standards of Performance for New Stationary Sources; Industrial-Commercial-Institutional Steam Generating Units; Proposed Rule and Public Hearing

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2489-1]

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: This proposal would revise Subpart D of 40 CFR Part 60 as it currently pertains to emissions of particulate matter and nitrogen oxides from industial-commercial-institutional steam generating units. The proposed standards would limit emissions of particulate matter and nitrogen oxides from all new, modified, and reconstructed industrial-commercial-institutional steam generating units capable of combusting more than 29 MW (100 million Btu/hour) heat input. Under the proposed standards, emissions of particulate matter and nitrogen oxides would be reduced by an estimated 22,000 to 46,000 Mg (24,000 to 51,000 tons) per year and an estimated 11,000 to 28,000 Mg (12,000 to 31,000 tons) per year, respectively, from new, modified, and reconstructed industrial-commercial-institutional steam generating units built in the next 5 years.

Revised sulfur dioxide emission standards are currently under development for industrial-commercial-institutional steam generating units and will be the subject of a separate rulemaking action. Consequently, the sulfur dioxide emission standards under Subpart D of 40 CFR Part 60 would remain in effect for industrial-commercial-institutional steam generating units larger than 73 MW (250 million Btu/hour) heat input capacity until revised sulfur dioxide standards are proposed. Similarly, emissions of particulate matter from oil-fired industrial-commercial-institutional steam generating units with heat input capacities greater than 73 MW (250 million Btu/hour) would also continue to be regulated by Subpart D of 40 CFR Part 60 until revised standards for particulate matter emissions from oil-fired steam generators are proposed as part of the rulemaking to revise the sulfur dioxide emission standards. Electric utility steam generating units larger than 73 MW (250 million Btu/hour) heat input capacity would not be covered by the proposed standards. They would continue to be subject to separate standards under 40 CFR Part 60, Subpart Da.

The proposed standards would 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 intent of this rulemaking it to require new, modified, and reconstructed industrial-commercial-institutional steam generating units to achieve emission limits reflecting the best demonstrated technological system of continuous emission reduction, considering costs, nonair quality health and environmental impacts, and energy requirements.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments:* Comments must be received on or before September 17 1984. *Public Hearing:* A public hearing will be held on August 1, 1984, beginning at 10:00 a.m. Persons wishing to present oral testimony must notify Ms. Shelby Journigan at the address below by July 26, 1984.

ADDRESSES: *Comments:* Comments should be submitted (in duplicate if possible) to: Central Docket Section (LE-131), Attention: Docket Number A-79-02, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460.

Public Hearing: A public hearing will be held at the ERC Auditorium, Corner of Highway 54 and Alexander Drive, Research Triangle Park, N.C. Persons wishing to present oral testimony must notify Ms. Shelby Journigan, Standards Development Branch (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5624.

Background Information Documents: The background information documents (BID's) for the proposed standards may be obtained from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402, telephone number (202) 783-3238 (GPO stock number 055-000-00216-9). The background information documents include 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," and EPA-450/3-82-007 "Nonfossil Fuel Fired Industrial Boilers—Background Information." The price of the three-volume set is $28.00.

The cost reports for steam generating units and control devices may be obtained from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22161, telephone number (703) 487-4650 (NTIS stock number PB-83-119438). The cost reports include EPA-450/3-82-021 "Costs of Sulfur Dioxide, Particulate Matter, and Nitrogen Oxide Controls on Fossil Fuel/fired Industrial Boilers" (NTIS stock number PB-83-119438), and EPA-450/3-83-004 "Costs of Particulate Matter Controls for Nonfossil Fuel-fired Boilers" (NTIS stock number PB-83-19365). The price is $20.50 and $13.00, respectively, for each volume in printed copy, or $4.50 for a microfiche copy of each volume.

Information on spreader stoker steam generating units gathered in a three-volume joint study by the American Boiler Manufacturing Association (ABMA), Department of Energy (DOE), and Environmental Protection Agency (EPA) may also be obtained from the National Technical Information Service (NTIS stock number DE81030264-Vol. 1; DE81030265-Vol. 2; DE81030266-Vol. 3). These reports include DOE/ET/10386-T1 (Volumes 1, 2, and 3) "Emissions and Efficiency Performance of Industrial Coal Stoker Fired Boilers." The price is $26.50 each for volumes 1 and 2 and is $35.50 for volume 3 (printed copy). The cost of a microfiche copy of each volume is $4.50.

Docket: Docket Number A-79-02, containing supporting information used in developing the proposed standards, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

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 number (919) 541-5624.

SUPPLEMENTARY INFORMATION:

Preamble Outline

I. Proposed 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, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated (section 111(a)(1)).

The proposed standards would revise the particulate matter and nitrogen oxides emission limits in Subpart D of 40 CFR Part 60 for industrial-commercial-institutional steam generators over 73 MW (250 million Btu/hour) heat input capacity and would set new standards for industrial-commercial-institutional steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity. The proposed standards would not revise the standards for sulfur dioxide currently included in Subpart D of 40 CFR Part 60. The sulfur dioxide standards in Subpart D will continue to apply to industrial-commercial-institutional steam generating units of greater than 73 MW (250 million Btu/hour) heat input capacity.

The proposed standards apply to all new, modified or reconstructed industrial-commercial-institutional steam generators which have a capacity of more than 29 MW (100 million Btu/hour) heat input and which fire coal, oil, natural gas, wood, or municipal-type solid waste and mixtures of these fuels with and without other fuels. Electric utility steam generating units with greater than 73 MW (250 million Btu/hour) heat input capacity will continue to be covered under Subpart Da of 40 CFR Part 60.

Only those steam generating units with a heat input capacity of greater than 29 MW (100 million Btu/hour) for which construction, modification, or reconstruction is commenced after June 19, 1984 would be affected by the proposed standards. "Construction" is defined by 40 CFR 60.2 to mean "fabrication, erection or installation of an affected facility." *Sierra Pacific Power Co.* v. *EPA*, 647 F.2d 60 (9th Cir. 1981). The affected facility for this standard is the steam generating unit as defined in the proposed standards (§ 60.41b). "Commenced" is defined by 40 CFR 60.2 to mean "than an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification." The phrase "contractual obligation" means a contractual obligation that cannot be cancelled without incurring significant liability. *Potomac Electric Power Co.* v. *EPA, 650 F.2d 509, 513–515 (4th Cir. 1981).*

Particulate matter standards are proposed for coal- wood- and municipal-type solid waste-fired steam generating units, as well as for steam generating units firing mixtures including these fuels. For coal-fired steam generating units, the proposed particulate matter standard is 22 ng/J (0.05 lb/million Btu) heat input. For steam generating units which fire wood or municipal-type solid waste, the proposed particulate matter standard is 43 ng/J (0.10 lb/million Btu) heat input. For steam generating units which fire coal with wood, solid waste or other fuels, applicability of the proposed standard would be determined based on the amount of coal combusted relative to other fuels. Steam generating units which have an annual capacity factor for wood, solid waste or other fuels greater than 5 percent and which have an enforceable Federal, state or local operating permit which specifies that while the unit is operated, an annual capacity for wood, solid waste or other fuels is to be maintained above 5 percent, would be subject to the proposed particulate matter standard of 43 ng/J (0.10 lb/million Btu) heat input. If a steam generating unit combusts coal but has an annual capacity factor for wood, solid waste, or other fuel of 5 percent or less, or if there is no Federal, state or local operating permit, the proposed particulate matter standard of 22 ng/J (0.05 lb/million Btu) heat input would apply.

Steam generating units in the 29 through 73 MW (100 through 250 million Btu/hour) heat input capacity range that would have an annual capacity factor of 30 percent or less, based upon the combustion of coal, wood, or municipal-type solid waste, and which have an enforceable Federal, State or local operating permit limiting the annual capacity factor of the steam generating unit for these fuels to 30 percent or less on an annual basis, would be subject to a particulate matter standard of 86 ng/J (0.20 lb/million Btu) heat input.

The annual capacity factor for determining the applicable particulate matter standard would be calculated by dividing the actual annual heat input to the steam generator from firing coal, wood, solid waste or mixtures of these fuels by the potential annual heat input to the steam generating unit from all fuels. The potential annual heat input is defined as the product of the maximum rated heat input capacity (MW or million Btu/hour) times 8,760 hours per year.

The proposed opacity standard for all steam generating units firing coal, wood, or solid waste is 20 percent opacity (six-minute average).

Performance tests to determine compliance with the particulate matter emission limits would be conducted using Reference Method 5 or 17. 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 would be required for all steam generators. Semiannual reports of excess opacity would be required if any excess emissions are monitored during a 6-month period.

Nitrogen oxide (NO_x) standards are proposed for industrial-commercial-institutional steam generating units with a heat input capacity above 29 MW (100 million Btu/hour) which fire natural gas, oil, coal or mixtures of these fuels with or without other fuels.

The proposed NO_x emission limits are 301 ng/J (0.70 lb/million Btu) heat input for pulverized coal-fired steam generating units, 258 ng/J (0.60 lb/million Btu) heat input for spreader stoker coal-fired steam generating units, and 215 ng/J (0.50 lb/million Btu) for mass-feed stoker coal-fired steam generators. For lignite-fired steam generating units, the proposed NO_x standard is 258 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 proposed standard is 340 ng/J (0.80 lb/million Btu) heat input.

For natural gas-fired steam generating units and distillate oil-fired steam generating units, the proposed NO_x standard is 43 ng/J (0.10 lb/million Btu) heat input. For steam generating units firing mixtures including more than 5 percent (by heat input) natural gas or distillate oil on an annual basis with either wood or municipal-type solid waste, the proposed standard is 129 ng/J (0.30 lb/million Btu) heat input.

For steam generating units firing residual oil with a fuel nitrogen content of 0.35 weight percent or less, the proposed NO_x standard is 129 ng/J (0.30 lb/million Btu) heat input. The proposed NO_x standard is 172 ng/J (0.40 lb/million Btu) heat input for affected steam generating units firing residual oil with a fuel nitrogen content greater than 0.35 weight percent.

The proposed nitrogen oxides emission limits for steam generating units burning 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 combusted. For steam generating units which fire coal, oil, or natural gas in a mixture containing other fuels (except for mixtures of natural gas with wood or municipal-type solid waste) and for which the annual capacity utilization factor based on coal, oil, or natural gas or a mixture of these fuels is greater than 5 percent, the steam generating unit would be required to meet the NO_x standard for coal, oil, or natural gas, as applicable.

Under the proposed standards, gaseous or liquid byproducts and wastes that are produced during industrial processes and are combusted in steam generating units, whether for heat recovery or for disposal, are treated as either natural gas or residual oil. Gaseous byproducts or wastes are included in the definition of natural gas and affected facilities firing these substances are subject to the proposed NO_x emission limit of 43 ng/J (0.10 lb/million Btu) heat input. Liquid byproducts or wastes are included in the definition of residual oil and are subject to an emission limit based on their fuel nitrogen content. Affected facilities firing liquid byproducts and wastes having a fuel nitrogen content of 0.35 weight percent or less are subject to the proposed standard of 129 ng/J (0.30 lb/million Btu) heat input. Steam generating units combusting liquid byproducts and wastes having a fuel nitrogen content of greater than 0.35 weight percent are subject to a proposed standard of 172 ng/J (0.40 lb/million Btu) heat input.

Steam generating unit specific NO_x emission limits could be established for steam generating units combusting fuel mixtures containing nonhazardous high nitrogen content by-products/wastes if the owner or operator can demonstrate to the Administrator's satisfaction that the applicable NO_x standard cannot be achieved due to the nitrogen content of the by-product/waste. Unit specific NO_x emission limits could also be established for steam generating units combusting fuel mixtures containing by-products/wastes classified as hazardous under the Resource Conservation and Recovery Act (RCRA) due to their toxicity, reactivity, or corrosivity if the owner or operator can demonstrate to the Administrator's satisfaction that applicable Federal, State or local permit requirements for thermal destruction of these by-product/wastes would prevent achievement of the NO_x emission limits.

The proposed NO_x emission limits would not apply to modified steam generating units. These limits also would not apply to affected facilities which combust 5 percent or less (by heat input) coal, oil, or natural gas with other fuels, on an annual basis, and which are subject to an enforceable Federal, State or local permit requirement limiting the annual capacity of the steam generating unit for these fuels to 5 percent or less.

Steam generating units firing coal, oil or natural gas which have annual capacity utilization factors for coal, oil, natural gas, or mixtures of these fuels greater than 5 percent would be subject to the nitrogen oxides emission limits and would be required to conduct a performance test to determine compliance with the NO_x emission limits. Affected facilities with an annual capacity factor between 5 percent and 30 percent would be required to conduct a 30-day performance test when the steam generating unit begins operation. Following the initial compliance test, steam generating unit operating conditions would be monitored.

Affected facilities having an annual capacity factor for coal, oil or natural gas of greater than 30 percent (0.30) would be required to operate a continuous nitrogen oxides emissions monitor. The continuous monitoring system would be used to conduct the initial compliance test. Subsequently, data from the continuous NO_x monitoring system would be used to determine a 30-day rolling average NO_x emission rate each day, calculated as the arithmetic average of the hourly NO_x values available for the preceding 720 hours of steam generating unit operation. This 30-day average would be used to determine compliance on a continuous basis.

Steam generating units subject to the proposed nitrogen oxides standards and with an annual capacity factor for coal, oil, or natural gas between 5 and 30 percent would be required to monitor steam generating unit operating conditions. The owner or operator of an affected facility would submit a monitoring plan for review by EPA. Manufacturers of steam generating units may develop monitoring plans and provide them to owners or operators of steam generating units. The monitoring plans could subsequently be submitted by the owner or operator of the affected facility.

The conditions to be monitored under this plan are to be indicative of nitrogen oxides emissions control. The results from this monitoring will be recorded and used to determine when the nitrogen oxides emissions controls are operating properly or when some failure or malfunction in those controls indicate that a performance test should be conducted.

Owners or operators of steam generating units capable of firing more than 29 MW (100 million Btu/hour) heat input would be required to maintain records of the annual fuel consumption by fuel type. For oil-fired steam generating units, fuel oil records indicating the amount and nitrogen content of oils fired would also be maintained. Fuel specification data from the oil supplier may be used to determine fuel oil nitrogen content. If fuel oil blends are being fired, specifications may be prorated based on the ratio of the oils of different nitrogen content in the fuel blend. In all cases, records would be maintained for 2 years, after which they could be discarded. Records of continuous NO_x emission data also must be maintained for 2 years.

Steam generating unit owners or operators would be required to submit certain reports. The proposed regulation would require that EPA be notified of the intent to initiate operation of a new, modified, or reconstructed steam generator and that EPA be provided with the results of the initial performance test and performance evaluation of the continuous monitoring system, if applicable. In addition, semiannual reports of excess opacity and NO_x emissions (for those affected facilities employing continuous nitrogen oxides monitoring) would be required if any exceedance occurred during a semiannual period.

II. Summary of Environmental, Energy, and Economic Impacts

The environmental, energy, and economic impacts of the proposed standards are expressed as incremental differences between the impacts for industrial-commercial-industrial steam generators complying with the proposed standards and steam generators complying with current emission regulations (referred to as the baseline). These impacts vary considerably depending on the assumptions made with regard to future fuel prices. If future natural gas prices are assumed to be low relative to coal prices, a large proportion of the new industrial-commercial-institutional steam generator population would be expected to fire natural gas or oil. On the other hand, if future natural gas prices are assumed to be high relative to coal and oil prices, a large proportion of the new industrial-commercial-institutional steam generating units are expected to fire coal. Because coal combustion has the potential of emitting larger quantities of particulate matter and NO_x than natural gas or oil combustion, the greater the number of coal-fired steam generators projected to be subject to the proposed standards, the greater the environmental, energy, and economic impacts associated with the standards. Because the number of coal fired steam generating units projected varies with the price of natural gas, the national impact projections are discussed in terms of a range rather than as a single value.

The primary environmental impact resulting from the proposed standards is a significant reduction in the quantity of particulate matter and nitrogen oxides emitted from new industrial-commercial-institutional steam generators. It is estimated that between 1983 and 1988 approximately 800 new steam generators will be constructed that would be subject to the proposed standards. Depending on the mix of new natural gas-fired, oil-fired, and coal-fired steam generators, baseline emissions from new steam generators greater than 29 MW (100 million Btu/hour) heat input capacity would range from 35,000 to 71,000 Mg (39,000 to 78,000 tons) of particulate matter per year and from 71,000 to 127,000 Mg (78,000 to 140,000 tons) of nitrogen oxides per year in 1988. The proposed standards would reduce baseline particulate matter emissions from these new industrial-commercial-institutional steam generating units by 22,000 to 46,000 Mg (24,000 to 51,000 tons) and nitrogen oxides emissions by 11,000 to 28,000 Mg (12,000 to 31,000 tons) in 1988. This represents about a 60 percent reduction in the growth of particulate matter emissions and about a 10 to 40 percent reduction in the growth of nitrogen oxides emissions from new industrial-commercial-institutional steam generating units. The increase in liquid waste generation as a result of the proposed standard would be negligible. Solid waste generation would increase by less than 5 percent over baseline. Because of the availability of existing solid waste disposal methods, no adverse environmental impacts resulting from the disposal of solid waste are anticipated.

The economic impacts of the proposed standards have 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 generators, and the impact on the availability of capital to the firms purchasing steam generators.

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

On the national level, assuming increases in annualized costs are passed forward to product consumers and not absorbed by industry, the proposed standards would result in a projected average increase of no more than a 0.05 percentage point 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 proposed standards, product prices could increase by 0.05 to 0.40 percent in 1988. 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 proposed standards. Impacts on any given plant would likely be much less than these worst case examples under either assumption.

On a national basis, the proposed standards would increase the capital cost for new steam generators by a negligible amount. It is projected that the nationwide increase in annualized costs for producing steam from new generators subject to the proposed standards would range from about $30 to $62 million in 1988. This represents an increase of less than 0.7 to 1.4 percent over baseline annualized costs for producing steam from new generators.

The energy impacts of the proposed standards have been analyzed in terms of the impact on demand for coal as an industrial-commercial-institutional steam generator fuel and in terms of overall energy requirements of steam generator and pollution control equipment operation. Steam generating units that would be affected by the proposed standards are projected to demand approximately 580 million GJ (550 trillion Btu) of fossil fuels in 1988. Depending on the relative cost of natural gas and oil versus coal, it is projected that coal use in industrial-commercial-institutional steam generating units would range from 25 percent to 75 percent of this fossil fuel energy demand under baseline conditions. The wide range of projected coal penetration levels results from the sensitivity of fuel selection to projected natural gas and oil prices. Coal use in new industrial-commercial-institutional steam generating units under the proposed standards is projected to decrease by less than 5 percent of the total fossil fuel demand as compared to baseline levels over the full range of natural gas and oil prices considered.

The proposed particulate matter standards would increase the national electric energy requirements of new steam generating units by about 130 to 180 GWh/yr in 1988. This increased electrical energy requirement to operate air pollution control equipment could be met by combusting an additional 2.1 million GJ (2 trillion Btu) of fossil fuel at an electric utility power plant. This increased fuel use would be partially offset by fuel savings associated with low excess air operation, as required under the proposed NO_x standards. Without considering the potential energy savings resulting from low-excess air operation, the projected 2.1 million GJ (2 trillion Btu) per year increase in fossil fuel use would represent less than one half of one percent increase in the overall fuel consumption for new industrial-commercial-institutional steam generators.

III. Rationale

A. Selection of Source Category

On August 21, 1979, a priority list for development of future new source performance standards was published in accordance with sections 111(b)(1)(A) and 111(f)(1) of the Clean Air Act Amendments of 1977 This list identified 59 major stationary source categories for which new source performance standards would be established in the future. Fossil fuel-fired industrial steam generating units ranked eleventh on this priority list of sources judged to contribute significantly to air pollution which could reasonably be expected to endanger public health or welfare.

Of the 10 sources ranked above fossil fuel-fired industrial steam generating units on the priority list, 9 were major sources of volatile organic compound (VOC) emissions. Given the nonattainment status of many areas with respect to the national ambient air quality standard for ozone, major sources of VOC emissions were accorded a very high priority. The remaining source category ranked above fossil fuel-fired industrial steam generating units was stationary internal combustion engines, a major source of nitrogen oxides emissions. Consequently, fossil fuel-fired industrial steam generating units was the highest ranked source category for particulate matter and sulfur dioxide emissions and the second highest ranked source category for nitrogen oxides emissions on the priority list of source categories not regulated by NSPS.

However, a separate proposal is being made today to amend the priority list to include nonfossil fuel-fired steam generating units of all types (including incinerators with heat recovery) and commercial and institutional steam generating units. Analyses of emissions from existing steam generating units and future trends in steam generating unit fuel use indicate that emissions from coal combustion will be a significant source of pollution from new steam generating units due to future widespread use of coal as a steam generator fuel. Analyses also show that wood and solid waste are the most widely used nonfossil fuels in steam generating units and, therefore, could potentially be significant contributors to future air pollution. In addition, studies also show that large commercial and institutional steam generating units have essentially the same design, fuel capability, and emissions potential as industrial steam generators. Consequently, the proposed standards would cover both fossil and nonfossil fuel-fired steam generating units, as well as industrial, commercial and institutional steam generating units.

Fossil and nonfossil fuel-fired steam generators are a significant source of emissions of three major pollutants: particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x). As discussed in "Priorities for New Source Performance Standards Under the Clean Air Act amendments of 1977" (EPA-450/3-78-019), in the absence of the proposed standards, emissions from industrial-commercial-institutional steam generators with a heat input capacity of 3 through 73 MW (10 through 250 million Btu/hour) would contribute 18 percent of the total national particulate matter emissions from major sources and 24 percent of the total national nitrogen oxides emissions from major sources in 1990.

The expected construction of new coal- wood- and solid waste-fired steam generators as a result of plant expansions and replacement of natural gas- and oil-fired steam generators is the principal reason for the large growth in emissions from steam generators. New steam generators with heat input capacities greater than 29 MW (100 million Btu/hour) are expected to increase total additional fossil fuel demand by approximately 580 million GJ (550 trillion Btu) by 1988. Many of these new facilities will fire coal, creating an increased coal demand of 140 to 430 million GJ (130 to 410 trillion Btu) annually, or approximately 5 to 18 million Mg (5 to 20 million tons) of coal per year, over existing coal combustion levels. Combustion of other solid fuels (wood and solid waste) is also rapidly increasing due to their lower cost. These developments could result in significant increases in emissions if standards of performance are not established.

National ambient air quality standards have been established for particulate matter, sulfur dioxide, and nitrogen oxides because of their known adverse effects on public health and welfare. Impacts of these pollutants have been documented in criteria documents prepared under section 108 of the Clean Air Act. These effects are the primary basis for the determination that emissions from industrial-commercial-institutional steam generating units constitute a potential danger to public health and welfare. Also significant in this determination is the finding that many steam generating units will continue to be located in urban areas where a large population will be exposed to the emissions. From 25 to 50 percent of the projected number of new steam generating units will be replacements for existing natural gas-or oil-fired steam generating units, and many of the remaining steam generating units, representing new steam generating unit capacity, will also be located at existing plant sites. Therefore, the present concentration of steam generating units in industrialized urban areas will continue to contribute to local and regional air pollution. For these reasons the source category of industrial-commercial-institutional steam generating units was selected for development of standards of performance.

B. Selection of Pollutants, Fuels, and Affected Facilities

Particulate matter (PM) and nitrogen oxides (NO_x) would be the pollutants regulated under the proposed standards. Other pollutants emitted from steam generating units, including sulfur dioxide (SO_2), carbon monoxide (CO), hydrocarbons (HC), and other trace substances would not be covered under these proposed standards.

Table 1 indicates the uncontrolled quantity of pollutants emitted through the combustion of each of the fuels examined in the development of the proposed standards.

TABLE 1.—TYPICAL UNCONTROLLED EMISSION FACTORS FOR STEAM GENERATOR FUELS, NG/J (LB/MILLION BTU) HEAT INPUT

Fuel Type	PM	NO_x	SO_2	CO	HC	Trace metals [e]
Coal [a]	1,092 (2.54)	387 (0.90)	2,450 (5.70)	13 (0.03)	2 (0.005)	4 (0.009)
Oil (residual) [b]	96 (0.23)	[d] 170 (0.39)	1,400 (3.22)	14 (0.03)	3 (0.01)	0.07 (0.0002)
Oil (distillate) [c]	6 (0.01)	[d] 100 (0.23)	220 (0.51)	16 (0.04)	3 (0.01)	
Natural Gas	4 (0.01)	[d] 100 (0.23)	0.3 (0.001)	7 (0.02)	1 (0.003)	0 (0)
Wood	2,100 (4.88)	110 (0.25)	9 (0.02)			
Solid Waste	1,400 (3.22)	130 (0.31)	210 (0.49)			

[a] Based on high-sulfur (3.5 percent by weight), high-ash (10.6 percent by weight) coal burned in a spreader stoker coal-fired steam generating unit.
[b] Based on high-sulfur oil (3.0 percent by weight).
[c] Based on low-sulfur oil (0.5 percent by weight).
[d] Assumes no combustion air preheat.
[e] Based on lead to illustrate general level of trace metal emissions.

Steam generating units constitute a major stationary source of particulate matter emissions. Because particulate matter is a criteria pollutant and because of the large potential emission rate, it has been selected for regulation under the proposed standards of performance. Similarly, nitrogen oxides have been selected for regulation under the proposed standards of performance.

Sulfur dioxide emissions from industrial-commercial-institutional steam generating units have been selected for regulation under a separate proposal. As part of the deliberations on reauthorization of the Clean Air Act, amendments were introduced in the 97th Congress that would have changed the definition of standard of performance. Development of sulfur dioxide standards for industrial-commercial-institutional steam generating units was suspended shortly after the start of the 97th Congress in 1981, pending the outcome of the Clean Air Act amendments. However, amendments to the Act have not been adopted by Congress to date and, rather than continue to defer development of new source performance standards for sulfur dioxide, analysis of standards for sulfur dioxide emissions has been resumed. Sulfur dioxide emission standards for industrial-commercial-institutional steam generating units will be proposed as a separate rulemaking.

The potential impacts associated with this "phased" approach to proposing particulate matter and nitrogen oxides standards now and proposing sulfur dioxide standards in the future have been considered. There appears to be no reason for delaying the proposal of emission standards for particulate matter and nitrogen oxides while waiting for the sulfur dioxide standards to be developed. State sulfur dioxide standards now in effect would not interfere with compliance with today's proposed standards for particulate matter or nitrogen oxides. Similarly, when standards are proposed for sulfur dioxide, they would not be retroactive and would affect only new steam generating units built after that date. Since the standards will not affect steam generating units which have commenced construction prior to that time, this will assure that no unreasonable impacts occur. Any unforeseen impacts a sulfur dioxide standard may have on particulate matter and nitrogen oxides emissions control will be addressed at the time sulfur dioxide standards are proposed. In the interim, the present standards of performance limiting sulfur dioxide emissions from large fossil fuel-fired steam generating units (40 CFR Part 60, Subpart D) will remain in effect. No potential problems have been identified which might result from proposal of standards for particulate matter and nitrogen oxides today and proposal of standards for sulfur dioxide in the future.

Carbon monoxide and hydrocarbons were not selected for regulation due to their relatively low emission rates and the lack of any control technology for these pollutants which is reasonable in cost. Trace metals have not been selected for regulation under the proposed standards because of the lack of information on the performance of alternative control technologies to reduce these emissions. It is anticipated that the proposed particulate matter standard would result in significant reductions in trace metal emissions.

Trace amounts of radionuclides present in coal are also emitted by industrial-commercial-institutional steam generating units but are not a direct subject of these proposed regulations. Control of particulate matter emissions from coal-fired steam generating units to low levels is expected to bring about a corresponding reduction in emissions of radionuclides. Further discussion of the control of radionuclides from coal-fired steam generating units can be found in the Federal Register (48 FR 15085, April 6, 1983) as part of recently proposed standards for radionuclides under section 112 of the Act.

The proposed standards would limit emissions from steam generating units firing natural gas, residual and distillate oil, coal, wood, solid waste and fuel mixtures containing any of these fuels. Steam generating units or incinerators with heat recovery firing only municipal-type solid waste or steam generating units firing only wood (5 percent fossil fuel or less on an annual basis) would be covered by the proposed particulate matter standards, but not by the proposed nitrogen oxides standards. Similarly, steam generating units firing only oil or natural gas would be subject to the proposed standard for nitrogen oxides, but not to the proposed standards for particulate matter emissions. Emissions of particulate matter from the combustion of natural gas are low and therefore the costs of further emission control would be unreasonably high. Control of particulate matter from oil-fired steam generating units will be considered in the development of the sulfur dioxide standards.

The proposed standards would cover only industrial-commercial-institutional steam generating units with heat input capacities of greater than 29 MW (100 million Btu/hour). Analyses of the projected new steam generating unit population indicate that nearly all new steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity will be industrial-type steam generating units with only a few commercial and institutional steam generating units in this size range. The steam generating unit size limit of 29 MW (100 million Btu/hour) heat input capacity would, thus, include only the largest commercial and institutional steam generating units and would concentrate the scope of the proposed standards on industrial-type steam generating units.

In addition to differences in application, the type of steam generating unit fuels which are combusted in steam generating units above 29 MW (100 million Btu/hour) heat input capacity is markedly different from the type combusted in steam generating units below this size. Depending on future energy pricing scenarios, from 25 to 75 percent of all new steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity are expected to combust coal as the primary steam generating unit fuel. For units less than 29 MW (100 million Btu/hour) up to 90 percent of the fuel is expected to be natural gas or fuel oil. Additionally, the use of firetube-type steam generating units becomes more common for units of 29 MW (100 million Btu/hour) heat input capacity or less. Watertube-type steam generating units predominate among steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity.

Development of new source performance standards limiting emissions of sulfur oxides, nitrogen oxides, and particulate matter from steam generating units smaller than 29 MW (100 million Btu/hour) heat input capacity is planned. In this small steam generator size range, the type of unit used, the physical design characteristics of these units, the cost impacts of emission control systems on steam production costs, and the steam generation applications are often different than for larger steam generating units. Because these factors have been found to be materially different, a separate study for these smaller steam generating units is appropriate. This will assure that an adequate evaluation is conducted on the technical and economic factors associated with applying emission controls to smaller steam generating units.

C. Selection of Formats for Emission Limits

Three possible formats were considered for the emission limits in the proposed standards: (1) Concentration,

(2) emissions per unit of steam generating unit energy output, and (3) emissions per unit of steam generating unit heat input. The criteria used for selecting the format were: (1) The ability of the format chosen to reflect the application of the best system of emission reduction, and (2) the ease of monitoring and compliance testing.

A concentration format measures the ability of the control system to reduce the level of pollutants relative to the volume of flue gas and provides a direct measure of the performance of the control equipment. There is, however, the potential that the effectiveness of a concentration standard can be reduced by dilution of the exhaust gases discharged to the atmosphere with excess combustion air, thus lowering the concentration of pollutants emitted but not the total mass emitted. This problem can be corrected by using a concentration standard at a reference carbon dioxide or oxygen level. Use of such a correction, however, renders this format functionally equivalent to a mass per unit of heat input format with respect to measurements needed to determine compliance. Thus, a concentration format was not selcted for the proposed standards.

A format of emissions per unit of steam generating unit energy output would make the process of determining compliance with the proposed standards very complicated. A format of this type would require measurement of pollutant emissions followed by calculation of the steam generating unit energy output which would require measurements of the steam production rate, steam quality, and condensate return conditions. The cumulative effect of requiring all these measurements would be to complicate compliance testing and monitoring, increase the likelihood for error, and increase costs for compliance testing and monitoring without significant benefits.

It is suggested that this format would create an incentive to purchase more efficient steam generating units and to increase operational efficiency. However, an incentive to purchase more efficient steam generating units would exist in any case because less efficient steam generating units would have to combust more fuel and use a larger emission control device compared to more efficient steam generating units which would produce the same amount of steam while firing less fuel.

Using a mass per unit of energy output format, standards which are based on best systems of emissions reduction applied to less efficient steam generating units may not reflect the best system of emissions reduction when compared to more efficient steam generating units. This outcome may not be consistent with the basic requirements of section 111 of the Clean Air Act that standards of performance reflect the application to all affected facilities of the best systems of continuous emission reduction considering costs and other impacts. Adjusting standards in some manner to reflect application of the best systems of emission reduction on all steam generating units would render this format functionally equivalent to a mass per unit of heat input format. Therefore, a format of emissions per unit of energy output was not selected for the proposed standards; however, this would not in any way discourage the use of higher efficiency steam generating units.

A mass per unit of heat input format was selected for the proposed standards since this format directly relates the net quantity of pollutants emitted to the amount of fuel fired in the steam generating unit. Monitoring and emission testing used to determine compliance with standards written in this format would be based on established methods. Additionally, this format is consistent with other standards established for steam generators (Subparts D and Da of 40 CFR Part 60). The major feature of this format, however, is that the required degree of emission control would be the same for all similar steam generating units burning the same amounts of fuel.

Emission credits for cogeneration systems and for combined cycle units were also considered and are discussed under the *Cogeneration Steam Generators—Emission Credits* and the *Combined Cycle Steam Generators—Emission Credits* sections of this preamble (See **REQUEST FOR COMMENTS** section).

D. Selection of Demonstrated Emission Control Technology and Emission Limits Nitrogen Oxides

1. Introduction

Nitrogen oxides (NO_x) formed during fuel combustion are composed of thermal NO_x and fuel-nitrogen NO_x. Thermal NO_x is formed through a reaction between the nitrogen and oxygen present in the combustion air. In contrast, fuel-nitrogen NO_x is the result of a reaction between nitrogen present in the fuel and oxygen present in the combustion air.

Nitrogen and oxygen in the combustion air can combine to form thermal NO_x at the elevated temperatures found in steam generating unit flames. Increased formulation is due to two factors; high combustion temperatures and high concentrations of oxygen in the presence of nitrogen. Boiler operating and design conditions which elevate combustion temperatures include increasing design heat release rates, full load operation, and preheating combustion air. Fuel moisture, on the other hand, will lower combustion temperatures. This lower temperature is a result of the cooling effect created by the evaporation of the moisture as the fuel burns. High concentrations of oxygen in the presence of nitrogen exposed to the high combustion temperatures are generally associated with the use of large amounts of excess air introduced early in the combustion zone.

The fuel nitrogen component of NO_x emissions is generated by the reaction of nitrogen in the fuel with oxygen in the combustion air. The two steam generating unit operating conditions which contribute most to fuel-nitrogen NO_x formation are increased fuel nitrogen content and the presence of large amounts of excess air in the combustion region where the fuel nitrogen evolves from the fuel.

Because of the influence of fuel nitrogen content, various fuels fired in steam generating units have widely differing NO_x characteristics. For example, natural gas and distillate oils contain little, if any, fuel nitrogen. As a result, nearly all of the NO_x emissions produced by the combustion of these fuels is thermal NO_x. Accordingly, the uncontrolled emissions from firing these low nitrogen fuels are generally much lower than from firing residual oils and coal.

Residual oils and nonfossil fuels are characterized by varying, but generally greater, amounts of fuel nitrogen than natural gas or distillate oil. As a result of these higher fuel nitrogen levels, total NO_x emissions from firing residual oils are comprised of both thermal NO_x and fuel-nitrogen NO_x. Uncontrolled emissions from residual oil combustion are generally higher than for natural gas and distillate oil, but less than for coal. Nonfossil NO_x emissions are generally in the same range as those from gas and distillate oil fuels.

Coal contains a substantial amount of fuel nitrogen relative to natural gas and oil. Consequently, NO_x emissions resulting from coal combustion typically include both thermal NO_x and significant quantities of fuel-nitrogen NO_x. The level of NO_x emissions generated by coal combustion is also dependent on steam generating unit type. In order of increasing NO_x emissions, the three basic steam generating unit types used to fire coal are: mass-feed stokers, spreader stokers, and pulverized coal-fired steam generating units. The differences in NO_x emission characteristics are due primarily to the different combustion mechanisms employed in each steam generating unit type.

Mass-feed stoker coal-fired steam generating units (e.g., underfeed stokers and chaingrate stokers) generally have the lowest uncontrolled NO_x emissions. In this steam generating unit type, the coal [approximately 2 cm (3/4 in) in diameter] is pushed directly into a coal bed positioned in a retort or on a grate. All combustion occurs in the coal bed. Compared to the other two steam generating unit types, coal combustion is less intense and occurs relatively slowly in mass feed stokers. The reduced combustion intensity reduces combustion temperature and tends to result in lower NO_x emissions. Considerable burning occurs in the interior of the fuel bed where oxygen is locally deficient. This reduced oxygen availablility also reduces combustion intensity and further contributes to the lowering of NO_x emissions.

Spreader stoker steam generating units also employ coal beds for combustion; however, the coal [approximately 0.6 cm (1/4 in) in diameter] is introduced by a mechanism above the grate which throws the coal onto the grate. Coal combustion occurs in suspension above the grate as well as on the grate. Suspension burning tends to be more intense and results in higher NO_x emissions. In this regard, the combustion characteristics of spreader stokers are a hybrid of both the mass-feed stokers and pulverized coal-fired steam generating units. The NO_x emissions of spreader stokers are greater than those of mass-feed stokers but less than those of pulverized coal-fired steam generating units, reflecting this hybrid combustion characteristic.

Pulverized coal-fired steam generating units burn finely powdered coal [more than 75 percent of the coal is less than 75μ (.005 in) in diameter] in burners similar to a natural gas- or oil-fired burner. Combustion occurs in suspension in the steam generating unit firebox. This combustion is relatively intense compared to stoker steam generating units, and uncontrolled NO_x emissions from pulverized coal-fired steam generating units are the highest of all coal-fired steam generating unit types.

In summary, NO_x emission rates are influenced by both steam generating unit design and operating conditions and by fuel properties. The steam generating unit design and operating conditions that influence NO_x emissions most significantly are suspension-vs-grate combustion, levels and location of combustion air introduction, heat release rates, steam generating unit load, and degree of combustion air preheat. The fuel properties that influence NO_x emissions most significantly are fuel type, nitrogen content, and moisture content. The proposed NO_x standards were developed with careful consideration given to these and other factors.

Demonstrated Control Techniques. A variety of methods can be employed to control NO_x emissions. The lowest cost and most widely used techniques modify the combustion process to minimize NO_x formation. Other less common NO_x control techniques remove NO_x from the flue gas after its formation (flue gas treatment).

Flue (or combustion) gas treatment was reviewed as a NO_x control technique during development of the proposed standards. The flue gas NO_x cleanup technique currently receiving the most attention is selective catalytic reduction (SCR), in which combustion gases are passed over a catalyst to reduce NO_x emissions back to elemental nitrogen (N_2) and oxygen (O_2).

SCR is quite costly compared to combustion modification control techniques. Also, SCR has not yet been applied in the United States to full-scale steam generating units firing coals and high nitrogen oils which have the highest NO_x emissions potential. Technical and economic questions exist concerning the application of SCR to steam generating units which preclude a conclusion at this time that SCR is a universally demonstrated technology for the purpose of developing standards of performance limiting NO_x emissions from steam generating units.

Combustion modification control techniques have been applied to industrial-commercial-institutional steam generating units. The principal combustion modification NO_x control techniques which have received the most development are low excess air and low excess air/staged combustion. Other NO_x control techniques, however, such as reduced air preheat and flue gas recirculation have also been applied to industrial-commercial-institutional steam generating units.

Reduced combustion air preheat is a form of combustion modification that reduces NO_x formation. At present, steam generating units using preheated combustion air, heat the combustion air by heat exchange with the hot flue gas exiting the steam generating unit, thereby improving steam generating unit efficiency and thereby reducing fuel costs. As combustion air preheat temperature is increased, NO_x emissions generally increase because of increased flame temperatures. Reduced combustion air preheat reduces flame temperatures and thus serves to control the formation of thermal NO_x emissions.

Data from uncontrolled natural gas-fired steam generating units indicate that direct use of unheated ambient air achieves NO_x emission reductions in the range of 30 to 40 percent from NO_x emission levels where combustion air is preheated to 150°C (300°F). The technique of reduced combustion air preheat, however, is generally much less effective on coal- and residual oil-fired steam generating units where a large percentage of the NO_x emissions may be derived from the fuel-nitrogen content, and not from the thermal formation.

One area of concern with the use of reduced combustion air preheat as a NO_x control technique, however, is the potential energy penalty associated with certain applications. The costs associated with an energy penalty largely depend on whether a steam generating unit feedwater heater (economizer) can be used in the place of a combustion air preheater. Similar to combustion air preheaters, economizers increase steam generating unit efficiency by recovering heat from steam generating unit flue gases and using it to preheat the steam generating unit feedwater instead of preheating the inlet combustion air. This method of recovering waste heat improves steam generating unit efficiency without raising flame temperatures or increasing NO_x emissions.

If steam generating unit flue gas heat is recovered in an economizer rather than in a combustion air preheater, no costs would be associated with use of reduced (or no) air preheat as an NO_x control technique. The capital costs of economizers and combustion air preheaters are similar. Also, any loss in overall steam generating unit efficiency due to reduced combustion air preheat is offset by a gain in steam generating unit efficiency due to the preheating of steam generating unit feedwater, with no net change in efficiency.

Reduced combustion air preheat, however, could result in a cost penalty where alternative sources of waste heat are available in excess of the energy utilization capacity of preheating the steam generating unit feedwater. This situation may occur in large industrial plants with integrated energy systems such as petroleum refineries and chemical plants. In these instances, the most effective use of the available energy may require the use of both economizers to preheat feedwater and combustion air preheaters. Therefore, where large quantities of waste heat are available, the use of reduced combustion air preheat for NO_x emission control could preclude the recovery of waste energy. In such cases the cost-effectiveness of applying reduced combustion air preheat as an NO_x control technique can be quite poor for natural gas-fired steam generating units. As a result, while the proposed standard would not preclude the use of combustion air preheaters, the use of this control technique was not considered a reasonable basis for developing standards of performance when cost and energy impacts are taken into consideration.

Flue gas recirculation (FGR) is another form of combustion modification which has received some application to industrial-commercial-institutional steam generating units as a means of reducing NO_x emissions. This control technique involves extracting a portion of the flue gas and returning it to the steam generating unit firebox. FGR reduces the oxygen concentration in the combustion air by using oxygen-depleted flue gas as a portion of the combustion air and thereby reduces the combustion temperature. Experience suggests that FGR is most effective in suppressing thermal NO_x formation and has less effect on fuel-nitrogen NO_x formation. Consequently, FGR appears more suitable for steam generating units firing low nitrogen fuels, such as natural gas and distillate oil than for residual oil- and coal-fired steam generating units.

FGR systems are offered by one manufacturer of gas- and oil-fired steam generating units and one manufacturer of stoker coal-fired steam generating units. Each manufacturer has retrofitted several industrial-commercial-institutional steam generating units with FGR systems. Very limited data on two small gas- and oil-fired steam generating units [2.5 MW and 15 MW (8.6 and 50 million Btu/hr) heat input], however, appears to indicate that FGR achieves little NO_x reduction beyond the NO_x emission reduction capability of another and much more widely employed control technique referred to as low excess air (LEA), which is discussed below. Similarly, very limited data on one coal-fired spreader stoker steam generating unit also appears to indicate that FGR achieved minor NO_x emission reduction beyond that associated with the use of LEA alone on modern coal-fired spreader stoker generating units. FGR, on the other hand, appears to cost somewhat more than LEA. As a result, attention focused primarily on the use of LEA rather than FGR as an NO_x control technique to serve as the basis of standards of performance.

As mentioned above, one of the most common forms of combustion modification which is widely used in industrial-commercial-institutional steam generating units is operation of the steam generating unit at low excess air levels (LEA). With LEA, less oxygen is available in the flame zone and thus formation of both thermal and fuel-nitrogen NO_x is diminished. Although effective on both types of NO_x emissions, experience indicates that LEA is considerably more effective in reducing thermal NO_x. There is, however, a practical limit to the use of LEA. At extremely low air settings, problems may occur with combustion stability, and smoking could result from incomplete combustion. When firing coal, another potential problem resulting from unreasonably low excess air levels is coal ash slagging which can lead to steam generating unit operating constraints or maintenance problems. Within practical low excess air limits for good steam generating unit operation, however, LEA can significantly reduce NO_x emissions for any steam generating unit.

LEA control can be implemented by manual or automatic control (trim) of the steam generating unit combustion air (windbox) controls to maintain an appropriate air-to-fuel ratio at each steam generating unit load condition. LEA control can also be enhanced for steam generating units burning liquid or gaseous fuels by use of low excess air burners, which promote complete and stable combustion at very low excess air levels.

LEA exhibits two features which have encouraged its use on all types of coal- oil- and natural gas-fired steam generating units. The first feature is increased steam generating unit efficiency, which occurs because less excess combustion air is required to be heated in the steam generating unit during the combustion process.

The second feature is the ability of LEA to reduce NO_x formation in steam generating units firing a variety of fossil fuels, including natural gas, oil and coal and a variety of fossil fuel blends with wood and solid wastes. This versatility allows steam generating unit owners or operators to switch fuels or to fire various fuel mixtures and still obtain the energy and environmental benefits of LEA.

Generally, data from natural gas, distillate oil and stoker coal firing indicate the LEA achieves NO_x emission reductions of up to 30 percent depending on steam generating unit fuel and steam generating unit type. Consequently, LEA is considered a demonstrated NO_x control technique for the development of standards of performance limiting NO_x emissions from industrial-commercial-institutional steam generating units.

The final combustion modification technique evaluated was staged combustion (SC). Although SC is most effective in reducing fuel-nitrogen NO_x formation, SC is also effective in reducing thermal NO_x formation. Because of this broad influence on NO_x formation, SC has found application in a broad range of steam generator categories.

SC supresses NO_x emission formation by separating the combustion process into multiple stages, each varying by the availability of combustion air. With SC, the oxygen availability during the critical stages of combustion in minimized and the conversion of both atmospheric-nitrogen and fuel-nitrogen to NO_x is reduced. SC also delays a portion of the combustion process, thereby reducing the peak flame temperature and the formation of thermal NO_x. The application of low excess air plus staged combustion (LEA/SC) compounds the reduction of thermal NO_x and fuel-nitrogen NO_x emissions, thereby resulting in effective reduction of total steam generating unit NO_x emission.

SC controls can be implemented by two methods. One method, known as overfire air (OFA), involves diverting a fraction of the combustion air away from the burner, and injecting it into the flame from secondary air ports. These secondary air ports are typically located in the side of the stream generating unit downstream from the burners.

OFA controls are currently offered by several industrial-commercial institution steam generating unit manufacturers. Over the past several years, OFA controls have received limited application to natural gas and distillate oil fired steam generating units and wide application to pulverized coal- and residual oil-fired steam generating units. Due to this wide application of OFA to pulverized coal and residual oil fired steam generating units, the NO_x emission reduction capabilities of OFA controls are well documented for firing of these fuels and OFA controls are considered the preferred technology for achieving SC on pulverized coal- and residual oil-fired steam generating units.

The second method for achieving SC is through the use of staged combustion burners (SCB), which are often referred to as "low-NO_x" burners. SCB achieve staging of the combustion process by creating a core flame that is either oxygen or fuel deficient. The remaining air or fuel required to complete the combustion process is introduced by the burner in a cylindrical zone around the core flame. The specific mechanical designs of SCB vary by manufacturer, but are based on these staged combustion principles. In addition to reducing NO_x emission, SCB also greatly relduces the sensitivity of NO_x emissions from natural gas- and distillate oil-fired steam generating units to combustion air preheat.

SCBs are a relatively new NO_x control technology and are the result of several years of very active research and development. In addition, this technology will continue to be an area of active development and rapidly expanding application. This research and development has pursued SCB technology for all fuels fired with burners, including pulverized coal. However, the greatest emphasis has been on the development of SCB for the control of NO_x emissions from natural gas- and distillate oil-fired steam generating units in response to significant environmental problems occurring in locations such as California where natural gas and distillate oil fuels are commonly used. As a result of the rapid development of SCB, there are now a limited number of SCB applied to natural gas- and distillate oil-fired industrial-commercial-institutional steam generating units installed and operating in the U.S. Furthermore, there are four steam generating unit manufacturers and four burner manufacturers offering SCB's for field-erected and packaged steam generating units. Performance guarantees are being offered for SCB application to the combustion of natural gas and distillate oil.

Althought SCB for residual oil-fired steam generating units are commercially available from three vendors, the application of SCB to residual oil- and pulverized coal-fired steam generating units has largely been limited to pilot and demonstration applications. The establishment of performance capabilities for SCB on residual oil- and pulverized coal-fired units is complicated by the wide variability in composition exhibited by these two fuels. Because of these performance data limitations performance guarantees for SCB when applied to residual oil- and pulverized coal-fired steam generating units are limited, although one vendor will generatee NO_x emissions of 129 ng/J (0.30 lb/million Btu) heat input for residual oil with low nitrogen content.

SC control techniques have been shown to be a very effective NO_x emission control technique for natural gas- oil- and pulverized coal-fired steam generating units. The OFA method of SC has seen limited application on natural gas- and distillate oil-fired steam generating units and has seen widespread application for several years on residual oil- and pulverized coal-fired steam generating units. OFA is, therefore, considered a demonstrated control technique for purposes of developing standards of performance limiting NO_x emissions from natural gas- distillate oil-, residual oil- and pulverized coal-fired steam generating units. SCB, although a newer technology, has been the focus of much recent SC activity, particularly for distillate oil- and natural gas-fired steam generating units. SCB is considered a demonstrated control technique for the purpose of developing standards of performance limiting NO_x emissions from natural gas- and distillate oil-fired steam generating units. For residual oil- or pulverized coal-fired steam generating units, SCB technology is under active development but does not appear to have reached the point where it can be considered demonstrated and available for universal application to industrial-commercial-institutional steam generating units.

When LEA is applied in conjunction with SC, LEA/SC compounds the effectiveness of each technology, resulting in from 25 to 60 percent NO_x emission reductions from fossil fuel-fired steam generating units. Consequently, LEA and LEA/SC are considered demonstrated control techniques for the purpose of developing standards of performance limiting NO_x emissions from industrial-commercial-institutional steam generating units.

NO_x Emission Limits. As discussed above, after evaluating a number of NO_x control technologies currently in existence, the low excess air (LEA) and the low excess air-staged combustion (LEA/SC) modification techniques are considered to be demonstrated control technologies for the purpose of developing standards of performance for industrial-commercial-institutional steam generating units. The emission reduction capability and achievable emission limit for each combination of fuels and major type of steam generating units were determined based on the use of these control techniques.

Natural Gas/Distillate Oil-Fired Steam Generating Units. The evaluation of combustion modification controls for natural gas- and distillate oil-fired steam generating units focussed on two NO_x emission control technologies; LEA and LEA/SC. Because natural gas and distillate oil are both low nitrogen fuels, fuel-nitrogen NO_x formation is minimal and thermal NO_x formation composes the major source of NO_x emissions from firing these fuels. LEA has been shown to be quite effective in controlling thermal NO_x formation and consequently is quite effective in reducing NO_x emissions from steam generating units firing natural gas and distillate oil. However, in the last two years LEA/SC controls in the form of staged combustion burners (SCB) have been the focus of most NO_x emission control technology demonstration and application activities. SCB, when combined with LEA, has been shown to be more effective than LEA alone in reducing NO_x emissions from natural gas and distillate oil combustion.

A large amount of NO_x emission data covering a wide range of conditions was collected on the performance of LEA applied to natural gas- and distillate oil-fired steam generating units. Over 250 short-term test results were collected for approximately 24 natural gas- and distillate oil-fired steam generating units. These data were gathered using a continuous NO_x analyzer (chemiluminescent) with each test period ranging from a few minutes to several hours. The natural gas-fired steam generating units ranged in size from 6 to 117 NW (22 to 400 million Btu/hour) heat input capacity. The distillate oil-fired steam generating units ranged from 6 to 73 MW (22 to 250 million Btu/hour) heat input capacity. Some steam generating units had preheated combustion air, while others did not. Thus, the temperature of the combustion air entering the steam generating units ranged from 16°C to 360°C (60°F to 680°F). Boiler loads ranged from 18 percent to nearly 106 percent of rated capacity and excess oxygen levels ranged from 0.2 to 14.5 percent (1 to 200 percent excess air). Under these conditions, resulting short term NO_x emissions ranged from 13 to 237 ng/J (0.03 to 0.55 lb/million Btu) heat input.

The wide variability in the test data is due primarily to wide variations in steam generating unit test conditions. In some cases, the test conditions were not representative of adverse NO_x formation conditions such as high loads and high combustion air preheat temperatures. In other cases, the amount of excess air used was above the level that is consistent with reasonable LEA control. In order to characterize each steam generating unit's emissions under LEA controls, a method was developed which matched the emission data to their associated set of LEA operating conditions and then predicted NO_x emission. This method relied on statistical regressions that established a relationship between NO_x emissions and heat release rate (load), excess air level, and combustion air temperature (degree of combustion air preheat). After identifying the relationship, operating conditions were specified to represent LEA controls and high potential NO_x emissions (full load and maximum preheat temperature) and the NO_x emission level for steam generating unit under LEA control was estimated.

For natural gas- and distillate oil-fired steam generating units not using combustion air preheat, LEA reduced NO_x emissions to less than 69 ng/J (0.16 lb/million Btu) heat input. For steam generating units firing the same fuels but employing combustion air preheat, LEA reduced average NO_x emissions to less than 120 ng/J (0.28 lb/million Btu) heat input under worst case operating conditions.

These NO_x emission levels represent the mean performance of LEA under operating conditions which are conducive to high NO_x emissions. However, day-to-day variation around this mean can be expected. One method to address this variation is to average the data from more than one day of operation. NO_x emissions averaged over 30 days, for example, show much less variation than NO_x emissions averaged on a 24-hour basis.

Short-term variations in NO_x emission levels can be minimized by averaging emissions, but not eliminated completely. By performing time series analysis of long-term NO_x emission data from individual steam generating units, it is possible to quantify the amount of long-term variation remaining after averaging. No long-term NO_x data are available for the application of LEA to watertube natural gas- and distillate oil-fired steam generating units; however, long-term NO_x data were available and were analyzed for the application of LEA/SC to watertube residual oil-fired steam generating units. Since the composition of natural gas and distillate oil fuels are generally more consistent than residual oils, the analysis based upon residual oil represents a worst case situation and the variation in NO_x emissions resulting from the use of LEA would be smaller for steam generating units firing natural gas or distillate oil.

The long-term NO_x data for application of LEA/SC to residual oil-fired steam generating units (discussed in next section) indicate that variations above and below the mean NO_x emission level would be expected to be less than 8 percent when an averaging period of 30 days is used to analyze the data. This means that an NO_x emission level 8 percent higher than the mean NO_x emission level could be met consistently when using a 30-day period to average NO_x emission data.

Applying the results of this analysis of NO_x emission variation to the application of LEA to natural gas- and distillate oil-fired steam generating units leads to the conclusion that LEA is capable of reducing NO_x emissions from natural gas- and distillate oil-fired steam generating units without preheated combustion air to 86 ng/J (0.20 lb/million Btu) heat input or less on a 30-day rolling average basis. Similarly, LEA is capable of reducing NO_x emissions from natural gas- and distillate oil-fired steam generating units with preheated combustion air to 129 ng/J (0.30 lb/million Btu) heat input or less on a 30-day rolling average basis.

To evaluate the performance of LEA/SC NO_x emission controls on natural gas- and distillate oil-fired steam generating units, performance data was collected on both LEA/OFA and LEA/SCB systems. NO_x emission data were collected from two natural gas-fired steam generating units equipped with LEA/OFA controls. All data were gathered with a continuous NO_x emission monitor (chemiluminescent). The two steam generating units had heat input capacities of 165 MW and 230 MW (567 and 800 million Btu/hour) and were capable of combusting both natural gas and residual oil fuels (no residual oil data were available, however). A series of twelve short term tests ranging in length from 8 minutes to 25 minutes were conducted on each steam generating unit. NO_x emissions during these tests averaged 37 ng/J and 38 ng/J (0.086 and 0.089 lb/million Btu) heat input, respectively.

NO_x emission test data was also collected from five natural gas-fired steam generating units equipped with LEA/SCB. All data were gathered with a continuous NO_x analyzer (chemiluminescent). The five steam generating units ranged in size from 19 MW to 29 MW (65 to 100 million Btu/hour) heat input capacity. Two of the steam generating units were designed to fire only natural gas and three of the steam generating units were designed for both natural gas and distillate oil firing. Finally, four of the five units were packaged units and the fifth unit was a field erected unit.

The NO_x emission data consisted of three or more short term tests conducted on each of the five steam generating units at full load conditions. These data indicate that average NO_x emissions ranged from 30 ng/J to 38 ng/J (.07 to .09 lb/million Btu) heat input for natural gas firing and 43 ng/J (0.10 lb/million Btu) heat input for distillate oil firing.

The manufacturers of LEA/SCB and of steam generating units equipped with LEA/SCB were also contacted to determine what NO_x emission performance guarantees they offered. Four of the five manufacturers contacted are providing guarantees for their LEA/SCB units. Two of the guarantees offered were for achieving sustained NO_x emission levels of 17 to 34 ng/J (0.04 to 0.08 lb/million Btu) heat input when firing natural gas. The other two manufacturers are providing guarantees that their LEA/SCB units are capable of achieving sustained NO_x emission levels of 43 ng/J (0.10 lb/million Btu) heat input for natural gas firing. Finally, one manufacturer is also providing guarantees that their LEA/SCB are capable of achieving sustained NO_x emission levels of 43 ng/J (0.10 lb/million Btu) heat input for distillate oil-fired steam generating unit applications.

All emission control technologies exhibit some sensitivity to changes in combustion conditions, which result in variations in emission performance. However, these sensitivities to combustion conditions are greatly reduced when LEA/SC controls are applied to natural gas- and distillate oil-fired units due to the consistently high quality of these fuels and the combustion characteristics of LEA/SC controls. Any variations in NO_x emissions when LEA/SC controls can be further reduced by averaging the emission data for more than one day of operation. NO_x emissions when averaged over a 30-day period, exhibit much less variation than NO_x emissions averaged over a 24-hour period.

This analysis and assessment of the NO_x emission performance capabilities of the application of LEA/SC to natural gas- and distillate oil-fired steam generating units, the rapid development and continuing improvement in the performance characteristics of this technology, and the availability of NO_x emission performance guarantees from the vendors of this technology, indicates that LEA/SC will reduce NO_x emissions from steam generating units firing natural gas or distillate oil to 43 ng/J (0.10 lb/million Btu) heat input on a 30-day rolling average basis.

Residual Oil-Fired Steam Generating Units. The composition of residual oils varies considerably. Some residual oils contain very little fuel nitrogen, while others, derived from heavy crude oils, may have fuel nitrogen levels exceeding 0.5 weight percent. However, most residual oils have fuel nitrogen contents in the range of 0.1 to 0.4 weight percent.

The control technique most effective in reducing NO_x emissions from residual oil-fired steam generating units depends on the fuel nitrogen content of the oil. For residual oils with low fuel nitrogen levels, thermal NO_x predominates and LEA is the most effective NO_x control technique. At this fuel nitrogen level LEA/SC does not generally result in a further reduction in emissions. For residual oils with intermediate or high fuel nitrogen contents, fuel-nitrogen NO_x predominates and LEA/SC is distinctly the most effective control technique.

The data gathered for assessment of LEA and LEA/SC as control techniques for NO_x emissions from steam generating units firing residual oils consist of results from both short-term and long-term emission tests. These data were gathered using a continuous NO_x analyzer (chemiluminescent). The short-term test periods ranged from 30 minutes to 6 hours in duration. The long-term test data were collected from a residual oil-fired steam generating unit over a 29-day period.

The short-term NO_x data consist of over 150 tests (each test was less than 6 hours) performed on 12 residual oil-fired industrial steam generating units. Five steam generating units were tested under LEA/SC controls using overfire air ports (OFA). OFA has been the perferred technique for achieving LEA/SC on residual oil-fired steam generating units. These data were gathered in order to analyze the effect of LEA and LEA/SC on NO_x emissions from firing residual oil of varying fuel nitrogen contents using varying degrees of combustion air preheat. The steam generating units tested ranged in size from 6 to 59 NW (22 to 200 million Btu/hour) heat input capacity. Some of the steam generating units used preheated combustion air, while others did not. Thus, the temperature of the combustion air entering the steam generating unit ranged from 16°C to 310°C (60°F to 590°F). The steam generating units were operated at stem generating unit loads from 20 to 94 percent. The residual oil fired during these tests had fuel nitrogen levels ranging from 0.14 to 0.77 weight percent. The flue gas oxygen levels ranged from 0.9 to 13.3 percent (5 to 150 percent excess air). Under these conditions, NO_x emissions ranged from 60 to 335 ng/J (0.14 to 0.78 lb/million Btu) heat input.

These data were analyzed in the same manner as that employed to analyze the LEA data base for the natural gas- and distillate oil-fired steam generating unit data. Statistical regressions were performed to relate NO_x emissions to key steam generating unit operating conditions. These analyses showed that by far the most pronounced factor affecting the performance of LEA and LEA/SC was the fuel nitrogen content of the residual oil fired. From these analyses a strong correlation was established between the effectiveness of LEA and LEA/SC in reducing NO_x emissions and the fuel nitrogen content of the residual oil fired. When LEA is used alone, NO_x emissions are reduced but tend to increase in an almost linear fashion as the fuel nitrogen content of the residual oil increases. Thus, as the fuel nitrogen content of the residual oil increases, the effectiveness of LEA alone decreases.

When SC is used in combination with LEA, NO_x emissions also increase as the fuel nitrogen content of the residual oil increases, but at a much slower rate. Ultimately, there is little further increase in NO_x emissions as the residual oil fuel nitrogen content exceeds 0.4 weight percent. These relationships are consistent with the general view that LEA is quite effective in reducing thermal NO_x formation, but is much less effective in reducing fuel-nitrogen NO_x formation, and that SC in combination with LEA is very effective at reducing both thermal and fuel-nitrogen NO_x formation.

The regressions were used to match each of the short-term tests to a common set of steam generating unit operating conditions representing high NO_x emission potential and the use of LEA or LEA/SC, as applicable. For steam generating units firing low nitrogen residual oil (less than 0.2 weight percent fuel nitrogen) and employing LEA, 30-day average NO_x emissions did not exceed 116 ng/J (0.27 lb/million Btu) heat input. At this level of fuel nitrogen LEA/SC does not generally result in a further reduction in emissions. For steam generating units firing a medium nitrogen residual oil (0.2 to 0.35 weight percent fuel nitrogen) and employing LEA, average NO_x emissions were 158 ng/J (0.37 lb/million Btu) heat input or less. Using LEA/SC while firing a medium nitrogen residual oil resulted in 30-day average NO_x emissions which did not exceed 122 ng/J (0.28 lb/million Btu) heat input. Finally, for steam generating units firing a high nitrogen residual oil (greater than 0.35 weight percent fuel nitrogen) and employing LEA/SC, 30-day average NO_x emissions did not exceed 124 ng/J (0.29 lb/million Btu) heat input.

In addition to short-term NO_x emission test data, long-term NO_x emission data were also gathered on the performance of LEA and LEA/SC in reducing NO_x emissions from residual oil-fired steam generating units. The long-term data were collected with a continuous NO_x analyzer (chemiluminescent) from a 29 MW (100 million Btu/hour) heat input capacity steam generating unit over a 29-day period. During this test period, the steam generating unit fired residual oil having a fuel nitrogen content of 0.3 weight percent and was operated between 45 and 95 percent of steam generating unit capacity. For 16 days of the test period, this steam generating unit was controlled using LEA alone, with flue gas oxygen levels ranging from 6 to 11 percent (40 to 100 percent excess air). For the remainder of the period, LEA continued to be used while SC was implemented by removing one of the burners from service and by using the port for overfire air. This test provides a good indication of the preformance of LEA/SC. A new steam generating unit which is specifically designed for SC, however, would be expected to achieve even greater reductions in NO_x emissions because of the flexibility to locate staging air ports in optimal positions. NO_x emissions from this steam generating unit averaged 125 ng/J (0.29 lb/million Btu) heat input using LEA alone. With the addition of SC, average NO_x emissions were reduced to 99 ng/J (0.23 lb/million Btu) heat input.

These long-term NO_x data were analyzed to examine the ability of the 30-day averaging period to reduce the variation in NO_x emissions. Using time series analysis, the variation in NO_x emissions remaining after using a 30-day rolling average to calculate NO_x emission levels was found to be 8 percent. Using this factor to increase the average NO_x emission levels resulting from the analysis of the short-term NO_x emission data is sufficient to ensure that NO_x emissions calculated using a 30-day rolling average would be consistently under this level. As a result, this analysis indicates that for steam generating units firing residual oils with less than 0.35 weight percent fuel nitrogen, LEA/SC will reduce NO_x emissions to 129 ng/J (0.30 lb/million Btu) heat input or less when using a 30-day rolling average to calculate emissions. Some low fuel nitrogen residual oils will be able to meet this emission level using LEA controls. For steam generating units firing residual oil having a fuel nitrogen content greater than 0.35 weight percent, LEA/SC will reduce NO_x emissions to 172 ng/J (0.40 lb/million Btu) heat input or less when using a 30-day rolling average to calculate emissions.

Coal-Fired Mass-Feed Stoker Steam Generating Units. The analysis of NO_x

emissions data from coal-fired mass-feed stoker steam generating units examined the emission reduction potential of LEA. In general, SC has not been applied to mass-feed stoker steam generating units. The available data consist of approximately 150 short-term tests on 7 steam generating units. The steam generating units varied in heat input capacity from 16 to 79 MW (56 to 269 million Btu/hour).

During these tests, loads ranged from 32 to 104 percent of capacity. Coals fired varied in fuel nitrogen from 0.94 to 1.55 weight percent and moisture content varied from 2.7 to 12.3 percent. One steam generating unit employed a combustion air preheater which heated combustion air to 107° C (225° F); the remainder used ambient combustion air. At flue gas oxygen levels of 5.0 to 14 percent (30 to 170 percent excess air), NO_x emissions as measured by a continuous NO_x analyzer (chemiluminescent) varied from 73 to 224 ng/J (0.17 to 0.52 lb/million Btu) heat input.

Statistical regressions were used to correlate NO_x emissions with steam generating unit operating conditions. This regression analysis differed from that used in the natural gas- and oil-fired steam generating unit analysis discussed earlier in that correlations were developed for each individual steam generating unit rather than for the data set as a whole. Individual steam generating unit regressions were more appropriate because the response of NO_x emissions to changes in operating conditions was found to be more specific to individual steam generating unit design.

The steam generating unit specific correlations indicate that NO_x emissions are related primarily to excess air level and grate heat release rate (or steam generating unit load). While the data base for mass-feed stoker steam generating units is insufficient to investigate the effect of other operating variables, such as combustion air preheat and coal fuel nitrogen levels, statistical analysis of the NO_x data base for coal-fired spreader stoker steam generating units (discussed below), which are similar to mass-feed stoker steam generating units, concluded that the effect of these other variables is relatively insignificant.

The correlations predicted average NO_x emissions for each steam generating unit at maximum grate heat release rate (i.e., full load) under LEA conditions. This analysis predicted average NO_x emissions would range from 95 to 194 ng/J (0.22 to 0.45 lb/million Btu) heat input.

Based on this analysis, LEA operation will reduce average NO_x emissions from mass-feed stoker steam generating units to 194 ng/J (0.45 lb/million Btu) heat input or less. Although no long-term NO_x data from mass-feed stoker steam generating units are available, two long-term NO_x tests on spreader stoker steam generating units are available. The variability in NO_x emissions from coal-fired mass-feed stoker and spreader stoker steam generating units is expected to be similar. As discussed below, analysis of these long-term data indicates that the long-term variation in NO_x emissions is about 7 percent when using a 30-day rolling average to calculate NO_x emissions. Using this factor to increase the average NO_x emission levels resulting from analysis of the short-term NO_x data from mass-feed stoker steam generating units indicates that NO_x emissions calculated using a 30-day rolling average would be consistently below 215 ng/J (0.5 lb/million Btu) heat input. As a result, this analysis concludes that LEA will reduce NO_x emissions from mass-feed stoker steam generating units to 215 ng/J (0.50 lb/million Btu) heat input or less, using a 30-day rolling average to calculate emissions.

Coal-Fired Spreader Stoker Steam Generating Units. LEA has been the primary control technique employed on spreader stoker steam generating units to reduce NO_x emissions. SC controls have been employed on several spreader stoker steam generating units by diverting a greater portion of the undergrate combustion air to the overfire air ports located above the grate. Available NO_x emission data, however, do not indicate significant emission reductions beyond those achieved using LEA alone. For this reason, the analysis of spreader stoker NO_x emission control concentrated on LEA alone.

NO_x emission data were gathered from approximately 350 short-term tests (less than 3 hours per test) on 11 spreader stoker steam generating units to determine the effectiveness of LEA in reducing NO_x emissions. All data were gathered with a continuous NO_x analyzer (chemiluminescent). The short-term NO_x emission data gathered from 6 of the 11 spreader stoker steam generating units were gathered in a joint study by the American Boiler Manufacturing Association (ABMA), Department of Energy (DOE), and EPA. The results of this joint study were published recently by the ABMA in a three-volume document entitled "Emissions and Efficiency Performance of Industrial Coal Stoker Fired Boilers." (See *Background Information Documents* for details.)

The overall conclusions drawn in this joint study confirm the NO_x emission trends discussed in the data base contained in the Background Information Document. The study concluded that NO_x emissions increased with load and that this increase could be offset by lowering excess air levels as load is increased. The amount of NO_x emission decrease associated with lowering excess air varied from 9 to 29 ng/J (0.021 to 0.067 lb/million Btu) heat input for each 10 percent decrease in excess air at a fixed load. The study also concluded that staged combustion (SC) did not result in significant reductions in NO_x emissions for spreader stoker steam generating units and that variations in coal nitrogen contents from 0.75 to 1.5 weight percent also had no measurable effect on NO_x emissions.

The 11 spreader stoker steam generating units tested ranged in size from 28 to 105 MW (97 to 359 million Btu/hour) heat input capacity and were operated at loads from 30 to 100 percent during the tests. Coal nitrogen contents ranged from 0.82 to 1.8 weight percent and coal moisture ranged from 1.5 to 25.0 weight percent. Two steam generating units employed combustion air preheat, operating with combustion air temperature of 158°C (315°F) in one case and 149°C (300°F) in the other case.

As in the analysis for mass-feed stoker steam generating units, statistical regressions were developed for each individual steam generating unit correlating NO_x emissions to steam generating unit operating conditions. These correlations indicate that NO_x emissions are related primarily to excess air level and grate heat release rate (i.e., Btu/hour-ft^2). In addition, these correlations also indicate that no significant relationships exist between NO_x emissions and combustion air preheat level, coal fuel nitrogen content, or any other operating parameters of these spreader stoker-fired steam generating units.

Using these correlations, average NO_x emissions at maximum grate heat release rate (i.e., full load) were predicted for each steam generating unit under LEA conditions consistent with proper steam generating unit operation. Predicted average NO_x emissions for all steam generating units except one were in the range of 146 to 232 ng/J (0.34 to 0.54 lb/million Btu) heat input. Predicted emissions from the other spreader stoker steam generating unit were much higher at 340 ng/J (0.79 lb/million Btu) heat input.

An investigation was conducted to determine the cause of the anomalous emission characteristics of the one steam generating unit. A site visit was conducted and the investigation revealed that a number of operational changes have been made to this steam generating unit to improve its operation since the NO_x data were originally gathered. These changes improved steam generating unit operation and reduced NO_x emissions considerably. Additional continuous, long-term NO_x data were obtained for this steam generating unit and for an indentical companion steam generating unit covering a 1-month period. These new data show that NO_x emissions from these two steam generating units, after steam generating unit improvements, varied from 40 to 150 ng/J (0.11 to 0.40 lb/million Btu) heat input. A statistical correlation based on these data predict average NO_x emissions at maximum grate heat release rate to be 168 ng/J (0.39 lb/million Btu) heat input for each of the two steam generating units under LEA operating conditions.

The analyses indicate that LEA will reduce average NO_x emissions from spreader stoker steam generating units to 232 ng/j (0.54 lb/million Btu) heat input or less. To determine the variation in NO_x emissions, long-term NO_x emissions data were collected from two spreader stoker steam generating units using a continuous NO_x analyzer (chemiluminescent). The first steam generating unit was tested over a 30-day period at average daily loads between 55 and 80 percent of the 37 MW (125 million Btu/hour) rated heat input capacity. A coal analysis indicated an average fuel nitrogen content of 1.3 weight percent and an average coal moisture of 7 weight percent. The combustion air was not preheated. During the test period, NO_x emissions using LEA ranged from 155 to 189 ng/J (0.36 to 0.44 lb/million Btu) heat input.

The second spreader stoker steam generating unit was tested during a 20-day period with daily average loads between 32 and 60 percent of the 59 MW (200 million Btu/hour) rated heat input capacity. Coal analysis indicated an average fuel nitrogen content of 0.8 weight percent and an average moisture of 23 weight percent. This steam generating unit employed a combustion air preheater designed to heat combustion air to 177 °C (350 °F). Actual combustion air temperature during testing, however, was not recorded. During the test periods when LEA was applied (approximately 8 hours per day), NO_x emissions ranged from 189 to 232 ng/J (0.44 to 0.54 lb/million Btu) heat input.

A time series statistical analysis was conducted on the long-term NO_x emission data from the above two spreader stoker steam generating units and from the previously discussed two spreader stoker steam generating units that underwent operational changes. This statistical analysis determined the variability in NO_x emissions remaining after use of 30-day rolling average to calculate emissions. This analysis indicated a variability in NO_x emissions of about 7 percent. Using this factor to adjust the average NO_x emissions resulting from the analysis of the short-term NO_x data, NO_x emissions calculated using a 30-day rolling average are consistently below the proposed emission level. As a result, the analysis indicates that LEA will reduce NO_x emissions from spreader stoker steam generating units to 258 ng/j (0.60 lb/million Btu) heat input or less, using a 30-day rolling average to calculate emissions.

Pulverized Coal-Fired Steam generating units. To assess the performance of LEA/SC in reducing NO_x emissions from pulverized coal-fired steam generating units, 2 years of continuous NO_x emission data were gathered using a continuous NO_x analyzer (chemiluminescent) from two relatively new 88 MW (300 million Btu/hour) heat input capacity steam generating units having a single stack. During this long-term NO_x emissions test, steam generating unit loads for the two steam generating units ranged from 31 to 93 percent of rated capacity and averaged 78 percent for one steam generating unit and 58 percent for the other. A typical coal analysis showed a coal nitrogen content of approximately 1.6 weight percent and a moisture content of approximately 7 weight percent. Both steam generating units employed combustion air preheaters, and although actual combustion air temperatures were not recorded, each preheater was designed to heat combustion air to 272° C (522° F). During the 2-year test period, the daily NO_x emissions from this facility ranged from 130 to 335 ng/J (0.30 to 0.78 lb/million Btu) heat input. The monthly average NO_x emissions were all below 258 ng/J (0.6 lb/million Btu) heat input. Overall NO_x emissions for the entire 2-year test period averaged 228 ng/J (0.53 lb/million Btu) heat input.

Data were also analyzed for two pulverized coal-fired steam generating units tested over a 1-month period. For the 156 MW (535 million Btu/hour) heat input capacity steam generating unit, load ranged from 41 to 90 percent of capacity and stack O_2 levels ranged from 6.1 to 9.8 volume percent (44 to 84 percent excess air). For the 234 MW (800 million Btu/hour) heat input capacity steam generating unit, load ranged from 51 to 98 percent of capacity and stack O_2 levels ranged from 3.0 to 7.1 volume percent (17 to 54 percent excess air). NO_x emissions as measured by a continuous NO_x analyzer (chemiluminescent) ranged from 120 to 297 ng/J (0.28 to 0.69 lb/million Btu) for the two steam generating units, respectively. Over the 1-month time period, NO_x emissions averaged 203 ng/J and 220 ng/J (0.47 and 0.51 lb/million Btu), respectively.

A time series statistical analysis of the data from the two year test was conducted to determine the variability in NO_x emissions remaining after use of a 30-day rolling average to calculate emissions and reduce this variation. This analysis indicated a variability in NO_x emissions of about 69 ng/J (0.16 lb/million Btu). Using this factor to adjust the average NO_x emissions for each of the above four steam generating units provides an NO_x emission level achievable on a 30-day rolling average basis. This analysis showed that LEA/SC can reduce NO_x emissions from industrial sized pulverized coal-fired steam generators to 300 mg/J (0.70 lb/million Btu) heat input or less when NO_x emissions are calculated on a 30-day rolling average basis.

The long-term NO_x data collected are representative of the performance of LEA/SC in reducing NO_x emissions from pulverized coal-fired steam generating units under adverse operating conditions. For example, the coal fired in these steam generating units had a high nitrogen content (i.e., 1.6 weight percent compared to 0.5 to 1.5 weight percent for most coals) and a low moisture content (i.e., 7 weight percent compared to 3 to 30 weight percent for most coals). Both of these coal properties would contribute to high uncontrolled NO_x emissions from pulverized coal-fired steam generating units, thus representing adverse conditions in terms of the ability of LEA/SC to reduce NO_x emissions.

Examination of the data at different loads indicates on trends with respect to higher NO_x emissions at higher loads. This can be explained by the lower excess air levels feasible at higher loads. At high loads, steam generating unit combustion conditions are characterized by greater turbulence and correspondingly better mixing of fuel and air. Under these conditions, complete fuel combustion and safe steam generating unit operation can be maintained at lower excess air levels. In addition, both steam generating units incorporate combustion air preheat, reflecting relatively adverse operating conditions with respect to thermal NO_x formation.

The analyses, therefore, show, that LEA/SC can reduce NO_x emissions from industrial-sized pulverized coal-fired steam generating units to 301 ng/J (0.70 lb/million Btu) heat input or less when emissions are calculated on a 30-day rolling average basis.

Fossil Fuel Mixtures. NO_x control techniques are compatible and frequently employed in combination with one another to reduce NO_x emissions from firing of fossil fuels. This is especially the case with LEA and LEA/SC. These techniques are as applicable to steam generating units firing several fossil fuels simultaneously as they are to steam generating units firing fossil fuels individually. Therefore, the "mix" of LEA and SC employed to reduce NO_x emissions is directly related to the amount of each fossil fuel fired.

Because of the compatability of LEA with SC and because the required "mix" of these two control techniques is directly related to the amount of each fuel fired, NO_x emissions from steam generating units firing mixtures of fossil fuels can be controlled to levels proportionate to the NO_x emission limits for each fossil fuel alone. Thus, the NO_x emission limit for a specific fossil fuel mixture would be calculated as a weighted average, based on the percentage of fossil fuel heat input to the steam generating unit and the NO_x emission limits for each fossil fuel fired.

Fossil Fuel and Chemical By-Product/Waste Fuel Mixtures. Chemical by-products and wastes are frequently combusted in steam generating units used in the chemical and refining industries. These waste materials are not generally combusted alone but are fired in combination with fossil fuels. Chemical by-products and waste are combusted in steam generating units to dispose of these waste materials and to recover their heating value. The term "chemical by-products and wastes" includes refinery or process gas, combustible by-products, and various combustible wastes that may or may not be classified as hazardous under the Resource Conservation and Recovery Act (RCRA). NO_x emission data were analyzed for three categories of by-product/waste fuels fired in mixtures with fossil fuels: refinery or process gas; low nitrogen content liquid wastes; and high nitrogen content liquid wastes.

Refineries and chemical plants typically burn a blend of natural gas and nonhazardous by-product/waste gases which is characteristically termed "process gas" or "refinery gas." NO_x emission data was collected from seven steam generating units firing fossil fuel and process gas mixtures comprised of up to 50 volume percent by-product/waste gases. The capacities of these steam generating units ranged from approximately 16 to 170 MW (53 to 580 million Btu/hour) heat input with loads ranging from 46 to 113 percent of rated capacity. Five steam generating units had no combustion air preheat while two steam generating units had combustion air preheat temperatures ranging from 216°C to 321°C (420°F to 610°F). The approximate heating values of the process gases fired in these steam generating units ranged from 30 to 64 MJ/m³ (800 to 1,700 Btu/SCF) which compares to a natural gas heat value of approximately 40 MJ/m³ (1,050 Btu/SCF).

Flue gas from the seven process gas-fired steam generating units contained oxygen concentrations ranging from 1.2 to 12.0 percent by volume (5 to 130 percent excess air) and NO_x emission rates ranging from 56 to 280 ng/J (0.13 to 0.65 lb/million Btu) heat input. Data were collected using a continuous NO_x analyzer (chemiluminescent). Analysis of the NO_x emission data reveals a strong correlation between the higher NO_x emission rates and the higher combustion preheat temperatures and flue gas oxygen concentrations (excess air). These relationships are characteristic of thermal NO_x formation and are the same relationships exhibited by natural gas-fired steam generating units. (Thermal NO_x formation and control are discussed above in detail in the section on NO_x emission limits for natural gas- and distillate oil-fired steam generating units.) When NO_x emissions from the seven process gas-fired steam generating units were compared to the NO_x emissions from more than 30 natural gas-fired steam generating units under the same operating conditions, there were no discernible distinctions between the NO_x emissions from the two fuels. All 37 steam generating units responded in a like manner to LEA controls revealing that NO_x emissions from both fuels are generated by similar mechanisms and respond similarly to a given NO_x emission control technique.

The similar responses of both natural gas and process gas NO_x emissions to combustion conditions are attributable to both being comprised of thermal NO_x. Thus, the NO_x control techniques which are effective in reducing thermal NO_x emissions from steam generating units firing natural gas, will also be effective in reducing thermal NO_x emissions from steam generating units firing process gas. Similarly, the NO_x control techniques which are effective in reducing thermal NO_x emissions from steam generating units firing a mixture of natural gas and other fossil fuels, will also be effective in reducing thermal NO_x emissions from steam generating units firing mixtures of process gas with fossil fuels. The proposed standards, therefore, would limit NO_x emissions from steam generating units firing process gas to the same level as steam generating units firing natural gas. Additionally, the proposed standard for steam generating units firing mixtures of process gas and fossil fuels would limit NO_x emissions to the same levels as steam generating units firing mixtures of natural gas and other fossil fuels.

Liquid by-products/wastes are generally cofired in steam generating units with natural gas. Data were collected from two steam generating units firing mixtures of natural gas and low nitrogen liquid by-products/wastes. One steam generating unit was rated at 25 MW (85 million Btu/hour) heat input capacity and the other rated at 73 MW (250 million Btu/hour) heat input capacity. The test data covered steam generating unit load ranging from 103 to 125 percent capacity in one case and 76 to 114 percent capacity in the other. Neither steam generating unit was equipped for operation using staged combustion (SC) and neither used preheated combustion air. However, both steam generating units applied various degrees of low excess air (LEA). Flue gas O_2 content ranged from 1.2 to 3.4 percent (6 to 9 percent excess air) for the 25 MW (85 million Btu/hour) heat input capacity steam generating unit and from 2.0 to 4.6 percent (10 to 27 percent excess air) for the 73 MW (250 million Btu/hour) heat input capacity steam generating unit.

Data were collected for the combustion of natural gas alone and for the combustion of mixtures of natural gas and these liquid by-products/wastes. The mixtures contained 4 to 11 percent of the waste on a total heat input basis. The waste had a heating value of 46 kJ/g (20,000 Btu/lb) and was composed primarily of C_2 to C_{10} alkanes, alkenes, and dienes.

Analysis of NO_x emissions both with and without cofiring of the liquid by-product/waste with natural gas indicates that the presence of the waste had little effect on NO_x emission levels, nor on the ability of LEA controls to reduce NO_x formation. In all cases where this waste was cofired with natural gas, including tests using LEA controls, NO_x emissions were identical to those that would be generated by the corresponding mixture of natural gas and low nitrogen residual oil.

When combusting low nitrogen liquid by-products/wastes, as with the combusting of low-nitrogen residual oil, NO_x emissions are composed primarily of thermal NO_x. As discussed earlier, the factors which impact thermal NO_x formation most are combustion temperature and excess oxygen levels. Because the majority of low nitrogen liquid by-product/waste fuels will have heat contents analogous to or lower than residual oil (i.e., less than 40 kJ/g (18,000 Btu/lb), the majority of these fuels will result in combustion temperatures and, hence, thermal NO_x emissions similar to or lower than NO_x emissions from low-nitrogen residual oil combustion. Similarly, NO_x emission control techniques which are effective in the reduction of thermal NO_x emissions from low-nitrogen residual oil combustion will also be effective in the reduction of thermal NO_x emissions from low nitrogen liquid by-product/waste fuel combustion.

Consequently, NO_x emissions resulting from cofiring low nitrogen content liquid chemical by-products/wastes with fossil fuels are not significantly different from NO_x emissions resulting from firing low-nitrogen residual oil alone or with other fossil fuels. Similarly, the firing of these liquid by-products/wastes with fossil fuels does not reduce the effectiveness of NO_x control techniques in limiting NO_x emissions.

As a result, NO_x emissions from low nitrogen liquid chemical by-products/wastes cofired with fossil fuels can be reduced to the same NO_x emission levels as would be required for steam generating units firing low-nitrogen residual oil or cofiring mixtures of low-nitrogen residual oil with other fossil fuels.

Data on the combustion of natural gas and a high nitrogen liquid by-product/waste were also collected. These data were collected on the same two natural gas steam generating units described above which cofired natual gas with low nitrogen chemical by-product/waste. The nitrogen content of the high nitrogen liquid by-product/waste was 11.5 weight percent. These wastes had a heating value of 26.7 kJ/g (11,500 Btu/lb) and were composed primarily of nitrobenzene, benzene, and aniline. The test data covered steam generating unit loads ranging from 95 to 126 percent capacity for the 25 MW (85 million Btu/hour) heat input capacity steam generating unit and 64 to 114 percent capacity for the 73 MW (250 million Btu/hour) heat input capacity steam generating unit. Flue gas O_2 content ranged from 1.2 to 3.6 percent (6 to 20 percent excess air) and from 1.7 to 5.9 percent (8 to 39 percent excess air) for the two steam generating units, respectively.

When cofiring natural gas with this high nitrogen liquid by-product/waste, NO_x emissions increased significantly compared to NO_x emissions when natural gas was fired alone. NO_x emissions ranged from 159 to 228 ng/J (0.37 to 0.53 lb/million Btu) heat input, while cofiring this waste with natural gas in concentrations of 3 to 9 percent (based on heating value).

As shown by these data, the presence of nitrogen in liquid by-product/waste fuels increases NO_x emissions in a manner similar to the effect of nitrogen in residual oils. The relationship of nitrogen content and NO_x emissions has been well established for residual oils, with higher fuel nitrogen contents resulting in higher NO_x emissions. This relationship is discussed above in the section on NO_x emission controls for residual oil-fired steam generating units. Nitrogen present in liquid by-product/waste fuels in general contributes to NO_x formation according to similar chemical reactions and mechanisms as nitrogen in residual oils. Thus, the same NO_x control techniques which are effective for reducing NO_x emissions from steam generating units cofiring mixtures of high nitrogen residual oils with other fossil fuels are effective for steam generating units cofiring high nitrogen liquid by-products/wastes with fossil fuel.

To ensure that the standards for high-nitrogen liquid by-product/wastes based on high-nitrogen residual oils are not unreasonable, provisions are included within the standards for petitioning the Administrator to establish an individually tailored NO_x standard for specific steam generating units, where it can be shown to the Administrator's satisfaction that NO_x emissions from firing such specific mixtures in the steam generating unit cannot be reduced to the levels necessary to comply with the proposed standard.

Under RCRA, waste materials may be listed as hazardous due to corrosivity, reactivity, flammability, or toxicity. Enforcement guidelines for the combustion of hazardous waste-derived fuels in steam generating units were recently published (Federal Register, 48 FR 11157, March 16, 1983). These guidelines distinguish between recycling and disposing of hazardous wastes in steam generating units. Combustion in steam generating units of hazardous wastes having a heating value comparable to or greater than that of low energy commercial fuels, such as wood or low-grade subbituminous coal, constitutes recycling and presently would not be subject to RCRA requirements. The combustion in steam generating units of hazardous wastes with lower heating values, however, constitutes disposal and would be subject to RCRA provisions requiring 99.99 percent destruction of hazardous wastes.

Wastes listed as hazardous due to corrosivity or reactivity are not likely to be fired in steam generating units because of the destructive threat they present to the steam generating unit and to its downstream equipment. Wastes classified as hazardous due to flammability alone are easy to combust due to their flammable properties and are candidate fuels for cofiring with fossil fuels. Additionally, wastes classified as hazardous due to both flammability and toxicity may also have relatively high heating values and under proper steam generating unit operating conditions would not require combustion at unusually high temperatures or high excess oxygen levels to ensure complete destruction (Federal Register, 48 FR 11160, March 16, 1983, Appendix A). For these reasons, the impact on NO_x emissions of firing hazardous wastes with fossil fuels in steam generating units would, in most cases, be no different than the impact on NO_x emissions of firing nonhazardous wastes with fossil fuels in steam generating units.

Some toxic wastes may be difficult to destroy by thermal means and, as a result, may require high combustion temperatures and high excess air levels to ensure complete destruction. These combustion conditions would preclude the application of demonstrated NO_x control techniques. In these cases, however, incinerators are generally better suited to achieving these combustion conditions and ensuring complete toxic waste destruction than are steam generating units. Steam generating units are designed to provide steam for various end uses and are not designed specifically to destroy wastes although high destruction efficiencies can frequently be achieved in steam generating units. Incinerators, on the other hand, can be designed specifically to achieve whatever combustion conditions are necessary to ensure high destruction efficiencies. As a result, in many cases hard to destroy toxic wastes may need to be disposed of in incinerators, rather than steam generating units, to ensure complete thermal destruction.

Since many hazardous wastes which will be combusted in steam generating units are not any more difficult to destroy than nonhazardous wastes and the combustion of many hazardous wastes in steam generating units constitutes recycling which would not be subject to specific RCRA destruction requirements at this time, the proposed standards would limit NO_x emissions from steam generating units firing mixtures of hazardous wastes and fossil fuels to the same levels as steam generating units firing mixtures of nonhazardous wastes and fossil fuels. To ensure that these standards are not unresonable or do not have any adverse effects, however, provisions are included within the standards for petitioning the Administrator to establish an individually tailored NO_x standard for specific steam generating units firing mixtures of toxic, corrosive, or reactive hazardous wastes and fossil fuels, where it can be shown, to the Administrator's satisfaction, that NO_x emissions cannot be reduced to the levels necessary to comply with the proposed standards while simultaneously complying with other applicable Federal, State, or local requirements for achieving specific waste destruction efficiencies.

Nonfossil Fuels and Fossil/Nonfossil Fuel Mixtures. Because of the generally lower nitrogen content and lower combustion temperature of most nonfossil fuels, the formation of NO_x during the combustion of these fuels is characteristically less than that experienced in coal-fired steam generating units. The lower nitrogen content results in less fuel-nitrogen NO_x formation. The lower combustion temperature results in lower thermal NO_x formation. These two factors combine to reduce uncontrolled NO_x emissions from nonfossil fuel firing to considerably lower levels than those emitted by coal-fired steam generating units and most residual oil-fired steam generating units. Emissions levels are similar to uncontrolled NO_x emissions from natural gas-fired steam generating units.

Nonfossil fuel-fired steam generating units can experience flame stability problems due to the high moisture content of the fuel, the variable heating value of the fuel, and other factors. In order to compensate for these problems, nonfossil fuel-fired steam generating units are typically operated at higher excess air levels than fossil fuel-fired steam generating units. Since combustion modification techniques, such as LEA, could aggravate the flame stability problems associated with firing of nonfossil fuels, they have not received wide application to such steam generating units to reduce NO_x emissions. As a result, NO_x control techniques are not proposed for steam generating units firing nonfossil fuels alone.

Nonfossil fuels and fossil fuels, however, are frequently cofired in industrial-commercial-insitutional steam generating units, and it is expected that many new steam generating units, and it is expected that many new steam generating units will be capable of firing a mixture of such fuels. As the proportion of fossil fuels in a fuel mixture increases, the NO_x emission characteristics of the steam generating unit tend to resemble those of fossil fuel-fired steam generating units and also become more amenable to NO_x control through combustion modification techniques, such as LEA and LEA/SC.

To determine the effectiveness of combustion modification on reducing NO_x emissions from the cofiring of nonfossil fuel and natural gas, NO_x emission data were gathered on two spreader stoker steam generating units equipped with LEA firing wood and natural gas. Emission data were obtained on these steam generating units using continuous NO_x monitors (chemiluminescent) over a period ranging in length from 1 to 10 hours. In addition, test data were also obtained using Reference Method 7 The two steam generating units were 220 and 236 MW (752 and 806 million Btu/hour) heat input capacity in size, and they were operated at 54 to 104 percent of steam generating unit load capacity during the tests. The natural gas/wood fuel mixtures fired ranged from 1 to 40 percent natural gas on a heat input basis. The wood nitrogen contents ranged from 0.10 to 0.14 weight percent and the wood moisture contents ranged from 42 to 50 percent. Both steam generating units preheated combustion air to approximately 260° C (500° F). At excess air levels of 17 to 78 percent, NO_x emissions varied from 82 to 138 ng/J (0.19 to 0.32 lb/million Btu) heat input. However, if only data obtained while the steam generating unit was operated under LEA conditions are considered, NO_x emission levels ranged from 82 to 120 ng/J (0.19 to 0.28 lb/million Btu) heat input. These data show that NO_x emissions from wood/natural gas mixtures can be controlled to a level of 129 ng/J (0.30 lb/million Btu) heat input or less.

No steam generating units have been identified that cofire distillate oil/nonfossil fuel mixtures. However, all NO_x emission test results indicate that distillate oil and natural gas form similar NO_x emissions and that these emissions respond similarly to LEA controls. NO_x emissions from combustion of nonfossil fuel/distillate oil mixtures in steam generating units therefore, can be controlled to NO_x levels similar to NO_x emission levels for nonfossil fuel/natural gas mixtures, or to a level of 129 ng/J (0.30 lb/million Btu) heat input or less.

Similarly no data are available on steam generating units firing mixtures of nonfossil fuels and residual oil with NO_x controls such as LEA or SC. As discussed above and below, however, NO_x control techniques are as applicable to steam generating units firing nonfossil/fossil fuel mixtures as they are to steam generating units firing fossil fuel alone. Therefore, NO_x emission control techniques are capable of reducing NO_x emissions from steam generating units firing mixtures of nonfossil fuel and low nitrogen residual oil to 129 ng/J (0.30 lb/million Btu) heat input and from units firing mixtures of nonfossil fuels and high nitrogen residual oil to 172 ng/J (0.40 lb/million Btu) heat input.

NO_x emission control techniques have also been applied to steam generating units firing mixtures of coal and nonfossil fuels. Tests were conducted on a 45 MW (153 million Btu/hour) heat input capacity spreader stoker steam generating unit firing a wood/bark mixture with coal to determine NO_x emissions from mixed fuel-firing and the performance of LEA in reducing these emissions. These NO_x emission data were obtained using a continuous NO_x monitor (chemiluminescent). The steam generating unit load was 85 to 97 percent during testing. The wood/bark nitrogen content varied from 0.18 to 0.21 weight percent and the coal nitrogen content varied from 1.33 to 1.49 weight percent. The wood/bark moisture content varied from 52 to 61 weight percent and the coal moisture content varied from 7.4 to 7.5 weight percent. NO_x emissions from this steam generating unit were 168 ng/J (0.39 lb/million Btu) heat input when fired with a mixture of 20 percent wood/bark and 80 percent coal (based on heat input). NO_x emissions increased as the percentage of coal in the fuel mixture increased. At normal operating excess air levels, the highest NO_x emissions occurred when only coal was fired in the steam generating unit and were 232 ng/J (0.54 lb/million Btu) heat input. These tests also showed that for the mixture of approximately 20 percent wood/bark and 80 percent coal (based on heat input) the use of LEA resulted in a reduction in NO_x emissions. For example, reducing the excess air level from about 80 percent to an LEA level of about 50 percent reduced NO_x emissions from 250 ng/J (0.58 lb/million Btu) heat input to a level of 122 ng/J (0.28 lb/million Btu) heat input.

Data on NO_x emissions were also obtained on two spreader stoker steam generating units firing mixtures of coal and solid waste in the form of refuse-derived fuel (RDF). Emission data were obtained using Reference Method 7. The steam generating units are located at the same site and are 43 and 56 MW (146 and 191 million Btu/hour) heat input capacity in size. They were operated at loads from 59 to 98 percent during testing. These two steam generating units fired different coals and the same RDF. The average coal moisture contents were 11 and 16 weight percent and the average RDF moisture content was 23 weight percent. The average RDF nitrogen content was 0.42 weight percent. The coal nitrogen contents were not measured. Both steam generating units used ambient temperature combustion air. The excess air levels during testing ranged from 40 to 128 percent.

The results from these tests show that as the percentage of heat input to the steam generating unit from the solid waste increases, NO_x emissions decrease. This change is due to the decrease in combustion temperatures caused by the lower heat content of the solid waste and the evaporation of moisture contained in the solid waste. Average NO_x emissions from these two steam generating units ranged from 80 to 133 ng/J (0.19 to 0.31 lb/million Btu) heat input when no RDF was fired with the coal. When heat input mixtures of 16 to 32 percent RDF were fired, average NO_x emissions were reduced to 76 to 131 ng/J (0.18 to 0.30 lb/million Btu) heat input. When the percentage of RDF was increased to a range of 40 to 68 percent of the heat input, average NO_x emissions were reduced to 50 to 106 ng/J (0.12 to 0.25 lb/million Btu) heat input.

Analysis of these data on NO_x emissions from steam generating units firing nonfossil fuel/coal mixtures indicates that NO_x emissions from steam generating units firing such fuel mixtures are lower than emissions from steam generating units firing coal alone. In addition, analysis of these data also confirms that NO_x control techiques are as applicable to steam generating units firing coal/nonfossil fuel mixtures as they are to steam generating units firing coal alone. Therefore, it is concluded that NO_x emission controls will reduce NO_x emissions from steam generating units firing mixtures of nonfossil fuels and coal to 215 ng/J (0.50 lb/million Btu) heat input for mass/feed stoker steam generating units, 258 ng/J (0.60 lb/million Btu) heat input for spreader stoker steam generating units, and 301 ng/J (0.70 lb/million Btu) heat input for pulverized coal-fired steam generating units.

Nonfossil fuel fired steam generating units may have auxiliary burners to fire natural gas or oil and in some cases, to fire pulverized coal. Generally, the primary purpose of these burners is to serve as a "pilot" flame during combustion, if necessary, in order to maintain flame stability, or to provide additional heat input into the steam generating unit if sufficient nonfossil fuel is unavailable to provide the desired level of heat input. Additionally, these burners may be used to maintain steam production if the nonfossil fuel firing system is inoperative. For nonfossil fuel fired steam generating units in which fossil fuel is used to maintain flame stability, the amount of fossil fuel fired is quite small in comparison to the amount of nonfossil fuel fired. In such cases, the fossil fuel fired frequently represents less than 5 percent of the annual heat input capacity of the steam generating unit. In addition, since the fossil fuel is being fired to maintain flame stability, the application of NO_x control techniques, which generally aggravate flame stability problems, is frequently not possible. Consequently, the proposed NO_x standards include an exemption for nonfossil/fossil fuel fired steam generating units with an annual heat input capacity factor, based on the combustion of fossil fuel (i.e. fossil fuel heat input divided by total heat input), of less than 5 percent.

Summary. In summary, LEA or LEA/SC are considered demonstrated systems of continuous NO_x emission reduction for the range of steam generating unit types and fuels covered by the proposed standards. The specific technological basis for the proposed NO_x standards and the applicable NO_x emission limits depends on the particular fuel or fuel mixture combusted. Table 2 summarizes the technology on which the proposed NO_x standards are based and their corresponding NO_x emission levels for each steam generating unit type and fuel covered.

TABLE 2.—SUMMARY OF DEMONSTRATED NO_x Control Techniques and Achievable Emission Limits

Fuel/steam generator type	Demonstrated technology	Proposed emission limits ng/J (lb/million Btu) total heat input
Natural gas/distillate oil	LEA/SC	43 (0.10).
Low nitrogen residual oil[a]	LEA/SC	129 (0.30).
High nitrogen residual oil	LEA/SC	172 (0.40).
Mass-feed stoker coal	LEA	215 (0.50).
Spreader stoker coal[b]	LEA	258 (0.60).
Pulverized coal (other than lignite).	LEA/SC	301 (0.70).
Pulverized lignite	LEA/SC	258 (0.60).
Pulverized lignite mined in North Dakota, South Dakota, or Montana and fired in a slag tap furnace.	LEA/SC	340 (0.80).
Nonfossil/fossil fuel mixtures.	Applicable technology for fossil fuel.	Applicable value for fossil fuel.

[a] Residual oil with a fuel nitrogen content of 0.35 weight percent or less.
[b] Includes fluidized bed combustion.

2. Particulate Matter

Introduction. An important aspect of the development of the proposed particulate matter standards is the recognition that the design and controlled emission characteristics of various steam generating units differ substantially. Different steam generator fuels contain different levels of ash and the design of the firing mechanism in coal-fired units affect the amount of fly ash generated and carried from the steam generating unit by entrainment in the flue gas stream.

Of the major steam generator fuels, natural gas inherently emits less particulate matter than others. The uncontrolled particulate matter emissions from firing natural gas without controls are less than 9 ng/J (0.02 lb/million Btu) heat input.

The particulate emission characteristics of most fuel oils are greater than for natural gas and vary with the ash and sulfur content of the oil, the carbon residue formed during combustion, and the firing mechanism of the steam generating unit. The uncontrolled particulate matter emissions from the combustion of distillate oil are most similar to those for natural gas-fired steam generating units, however, for residual oil (such as a typical Number 6 fuel oil) the ash content of the oil is usually higher and the uncontrolled particulate matter emissions are greater than for distillate oils. Also, the uncontrolled emissions from oil-fired steam generating units are significantly affected by burner design and operation.

Coal and nonfossil fuels have significantly higher uncontrolled particulate matter emissions than either natural gas or oil. The firing of these fuels characteristically results in emissions of from 860 to 2000 ng/J (2 to 7 lb/million Btu) heat input, depending on the type of steam generating unit, the quality of the fuel, and the operating load conditions. A pulverized coal-fired steam generating unit, for instance, typically has particulate matter emissions three times as high as a mass-feed stoker unit firing the same quantity of a similar coal. If the ash content of the coal is raised, the uncontrolled particulate matter emissions from either type of steam generator would be increased. Similarly, uncontrolled particulate matter emissions from nonfossil fuel-fired steam generating units will increase substantially if the moisture or ash content of the fuel is increased.

In summary, uncontrolled particulate matter emissions are significantly influenced by both fuel characteristics and steam generating unit characteristics. Important fuel characteristics include fuel type, ash content, sulfur content, and moisture content. Characteristics which can significantly influence uncontrolled particulate matter emissions from steam generating units include unit design, excess air setting, and operating load.

Demonstrated Control Technologies. Flue gas cleaning is the most widely employed approach used for the control of particulate matter emissions. Flue gas cleaning techniques employed to control particulate matter emissions from steam generating units include various types of mechanical collectors, sidestream separators, wet scrubbers, electrostatic granular bed filters, electrostatic precipitators, and fabric filters.

Mechanical collection is a well-established technology which uses centrifugal separation to remove particles from a gas stream. Mechanical collectors have been widely used for years to control particulate matter emissions from steam generating units firing coal and wood. More recently, they have been used as flue gas precleaning devices located upstream of more efficient particulate matter control devices.

Most mechanical collectors consist of multiple small cyclone collectors connected in a paralell arrangement (multiclone). A variation of this technology consists of two mechanical collectors connected in series. This latter configuration is frequently referred to as a double mechanical collector. This arrangement typically achieves lower particulate matter emission levels than a single mechanical collector.

The effectiveness of mechanical collectors is highly variable depending on collector design, steam generator operating load, uncontrolled emission level, particle size, collector maintenance, fly ash properties. Mechanical collector performance can deteriorate significantly under low load operating conditions and when the device is not properly maintained. Operation at low loads results in reduced flue gas velocity through the collector tubes, which reduces centrifugal separation effects, and, consequently, lowers the particulate matter collection efficiency. This lower collection efficiency is of concern because industrial-commercial-institutional steam generating units are not commonly operated at constant full load conditions.

Mechanical collectors must also be protected from temperature excursions below the dew point with as much care as would be required for more sophisticated particulate collection technologies. If the flue gas temperature in the collector falls below the dew point, the mechanical collector tubes can become plugged from the bridging of damp fly ash particles. If this would happen the mechanical collector rapidly fills with fly ash and the collection efficiency quickly and substantially deteriorates.

To maintain the collection efficiency of mechanical collectors, frequent maintenance is often needed due to air leakage into the ductwork and erosion of the internal mechanical collector structure by the abrasive fly ash. Air leakage and erosion of the internal structure tend to disturb the cyclonic flow pattern which is vital to mechanical collector performance. Air leakage may also lead to reentrainment of particles previously collected. In both cases, the particulate matter control efficiency of the mechanical collector is significantly reduced.

Particulate matter emissions data indicate that single mechanical collectors applied to coal-fired and nonfossil fuel-fired steam generating units generally show reductions of 50 to 90 percent. However, these removal efficiencies are principally associated with particles larger than 10 microns. Mechanical collectors are relatively ineffective for collection of smaller particles, typically achieving reductions of only 35 to 50 percent for particles with mean diameters smaller than 10 microns. These sizes of particles are in the inhalable range and, therefore, have the greatest potential for adverse health impacts.

Mechanical collectors are a demonstrated particulate matter emission control technology. However, even the most lenient existing air pollution control regulations limit particulate matter emissions to levels that require use of single mechanical collectors. In fact, many existing State or local air pollution control regulations limit particulate matter emissions to levels that can only be met through the use of more efficient particulate matter control technologies, such as electrostatic precipitators or fabric filters. Consequently, single mechanical collectors were considered as the "baseline" against which the incremental costs and benefits of standards based on more efficient particulate matter emission control technologies were analyzed and assessed. Double mechanical collectors are a demonstrated control technology for purposes of establishing proposed particulate matter standards; however, due to their limited effectiveness in controlling particulate matter emissions compared to other demonstrated technologies, the application of double mechanical collectors is considered appropriate only in limited circumstances.

Sidestream separators (a technology also known as hopper evacuation) are modified mechanical collectors in which a fraction of the flue gas stream (about 20 percent) is withdrawn from the mechanical collector ash hopper and is passed through a small fabric filter. By drawing flue gases from the ash hopper, fly ash reentrainment from the ash hopper is reduced. Application of sidestream separator control technology has generally been limited to retrofitting of existing steam generating units which are equipped with mechanical collectors and provides a means of upgrading mechanical collector performance. Sidestream separators have been applied to a limited number of new steam generating units, and they are now being offered as a single, integrated control system by at least one vendor.

The available particulate matter emission control performance data for sidestream separators applied to stoker steam generating units firing coal indicate an improvement in performance in comparison to mechanical collectors. For typical stoker bituminous coals containing 4 to 10 percent ash, collection efficiency can be improved to between 90 and 97 percent through the use of a sidestream separator arrangement. Sidestream separators result in more efficient removal of small particles than mechanical collectors. The limited particle size data available indicate sidestream separators remove approximately 70 to 80 percent of particles with a mean diameter of less than 10 microns. In addition, sidestream separators can be operated with a constant air flow level through the fabric filter, thereby increasing the ratio of gas through the baghouse at reduced load and offsetting any deterioration in mechanical collector performance characteristics. Over the full operating range, sidestream separators represent a method of improving mechanical collector performance; however, the mechanical collector component of a sidestream separator must be well maintained to assure low overall emission rates. The small fabric filter used in the sidestream separator arrangement cannot offset poor performance of inadequately maintained mechanical collectors.

Although the effectiveness of sidestream separators has been demonstrated in applications to coal-fired stoker steam generating units, sidestream separators have not been applied on the several other types of steam generating units that would be regulated by the proposed standards (i.e., pulverized coal-fired units, wood-fired units, or solid waste-fired units). Sidestream separator performance on the coal-fired stoker steam generating units tested would not be expected to be representative of performance on pulverized coal-fired units due to the differences in particulate matter emission characteristics of pulverized coal-fired units compared to stoker units. Changes in factors that may affect the reentrainment and capture of the particles being evacuated from the mechanical collector hopper, such as uncontrolled particulate matter emission rates, the size distribution of the steam generating unit fly ash, and the particle composition could alter sidestream separator performance. Because mass loadings, particle size distribution, and particle composition, are not the same for all steam generating unit types, it is difficult to extrapolate the performance of this technology to pulverized coal- wood- or solid waste-fired steam generating units. Consequently, sidestream separators can only be considered a demonstrated particulate matter emission control technology for the purpose of developing standards of performance limiting emissions from coal-fired stoker steam generating units.

A wet scrubber uses an aqueous stream to remove particulate matter from a gas stream. Wet particulate mater scrubber systems (venturi scrubbers) may use water as a scrubbing medium for controlling particulate matter emissions from steam generating units firing wood, or mixtures of wood and coal containing limited amounts of coal. Wet scrubbers using alkaline scrubbing liquids (flue gas desulfurization systems) can be used on coal-fired steam generating units. Even if used for particulate matter emission control alone, an alkaline scrubbing liquid is necessary for coal-fired steam generating units to neutralize the sulfur dioxide or sulfur trioxide removed by the scrubber. Without neutralization, the recycled scrubbing liquid would become increasingly acidic and could lead to scrubber corrosion problems. Steam generating units firing mixtures of coal and wood do not have to adjust scrubber alkalinity/acidity (pH) with as much care because the fly ash from wood combustion is alkaline and, within limitations, will neutralize the sulfur dioxide or sulfur trioxide removed.

The wet scrubber is usually preceded by a mechanical collector to minimize scrubber erosion, to reduce the total particular matter collected as sludge, and to improve the overall particulate matter collection efficiency of the control system.

A disadvantage of wet particulate matter scrubbers relative to dry collection systems is the generation of a liquid waste stream which must be disposed of properly. However, environmentally acceptable methods of waste stream disposal are currently in use. Wet scrubbers are considered a demonstrated particulate matter emission control technology for the purpose of developing standards of performance to limit particulate matter emissions from industrial-commercial-institutional steam generating units firing wood, coal and mixtures of these fuels.

Electrostatic granular filtration (EGF) is a technology in which particulate matter is collected as the flue gas passes through a bed of electrically charged gravel. The electric field helps to collect particulate matter on the surface of the gravel.

There are approximately 10 electrostatic granular filters (EGF's) in operation on wood-fired or wood/coal-fired steam generating units at nine different facilities. Based on an evaluation of the limited particulate matter test data available, EGF's in combination with mechanical collectors are capable of reducing uncontrolled particulate matter emissions from wood-fired units by up to 99.5 percent. To date, users of EGF's have not reported any major operating or maintenance problems. The performance of EGF's on wood-fired steam generating units is comparable to that of electrostatic precipitators.

EGF's have been applied to a few steam generating units firing fuels other than wood, such as municipal solid waste and coal. However, limited particulate matter emission data are currently available for EGF's applied to steam generating units firing any fuel other than wood. Therefore, for the purpose of developing standards of performance, EGF's are considered a demonstrated particulate matter emission control technology only for wood-fired steam generating units.

Electrostatic precipitators (ESP's) are in commercial use for the control of particulate matter emissions from industrial steam generating units firing coal, oil, wood and, more recently, from steam generating units firing municipal-type solid waste. ESP's remove particulate matter from steam generating unit flue gases by electrically charging the suspended particles and precipitating them onto a collection plate.

ESP's have been shown in particulate matter emission tests to achieve reductions in uncontrolled particulate matter emissions up to 99.5 percent. Such reductions have been achieved on a wide range of steam generating unit types and fuels, including difficult applications such as the collection of high resistivity fly ash from low sulfur coal combustion.

A principal design factor affecting the performance of ESP's is the specific collection area, expressed as the ratio of the collector plate surface area to the flue gas flow rate. For any given steam generating unit and fuel type, a larger collection area will provide improved ESP particulate matter collection efficiency. For a given ESP design, the ratio of collection area to steam generating unit flue gas flow will increase under reduced steam generator load operating conditions. ESP's with adequate collector areas for high steam generating unit loads, therefore, will perform efficiently at low loads as well. Thus, the particulate matter emission control performance of ESP's tends to increase as operating load decreases.

The performance of ESP's is significantly superior to mechanical collectors and sidestream separators, especially with respect to control of smaller particles. Tests of two pulverized coal-fired steam generators firing low sulfur coal, for example, showed ESP's to have removal efficiencies of 99 percent for particulate matter with a mean particle diameter of less than 10 microns. In addition, ESP's offer considerable operating flexibility to steam generating unit owners and operators who may wish to retain the capability to combust fuel mixtures, such as wood/coal, wood/oil, coal/solid waste, or other fossil/nonfossil fuel mixtures. ESP's are applicable to each of these fuels and fuel mixtures. ESP's therefore, are considered a demonstrated particulate matter emission control technology for the purpose of developing standards of performance limiting such emissions.

Fabric filters (also known as baghouses) are a particulate matter control technology that has been used on an increasing number of steam generating units in recent years. A fabric filtration system is one which directs particle-laden flue gas through a number of fabric bags where the particulates collect as a filter cake on the bag surface. Since the late 1960's, over 100 fabric filters have been installed on pulverized and spreader stoker coal-fired steam generating units. Fabric filters have had limited application to wood-fired units (approximately seven steam generating units) and have only been used in one pilot project on a municipal-type solid waste-fired unit.

On coal-fired steam generating units, fabric filters can achieve particulate matter emissions reductions of 99.5 percent or more over uncontrolled particulate matter emission levels for a wide range of steam generator designs, operating conditions, and fuel characteristics. Fabric filters have also been shown to be one of the most efficient of the particulate matter control techniques in controlling small particles, achieving more than 99 percent removal efficiency for particles smaller than 10 microns in diameter. Fabric filters have been shown to be one of the most versatile high efficiency particulate matter emission control technologies and can readily be applied to steam generating units firing a wide range of coals. For coal-fired steam generating units equipped with fabric filters, fuel flexibility is limited to a greater extent by steam generator design constraints than by fabric filter limitations.

A principal design factor affecting the performance of fabric filters is the air-to-cloth (A/C) ratio, which represents the volume of flue gas treated in relation to the total surface area of the filters. Generally, the operating pressure drop and fabric filter bag life improves as the A/C ratio decreases. For a given total cloth area, the A/C ratio will decrease as flue gas flow is decreased under reduced load operating conditions. Thus, fabric filters with adequate cloth areas for high loads will perform as well or better at low loads.

Fabric filters, therefore, are a demonstrated particulate matter control technology for the purpose of developing standards of performance for coal-fired steam generating units.

Particulate Matter Emission Data. After evaluating a wide range of particulate matter emission control technologies, fabric filters, electrostatic precipitators, wet scrubbers, electrostatic granular filters, and sidestream separators are the five technologies considered demonstrated for the purpose of developing standards of performance limiting particulate matter emissions from industrial-commercial-institutional steam generating units. Based on these technologies, the emission reduction capability and achievable emission limits for each combination of fuel and steam generator design were determined.

Natural Gas-fired Steam Generating Units. The uncontrolled particulate matter emissions from the combustion of natural gas in steam generators are very low. Uncontrolled particulate matter emission levels of less than 9 ng/J (0.02 lb/million Btu) heat input are typical of natural gas-fired steam generating units. Because of these low uncontrolled particulate matter emission levels, the application of any particulate matter control technology to natural gas-fired steam generating units would entail unreasonable costs, and no further consideration was given to the development of standards of performance to limit particulate matter emissions from units firing natural gas.

Oil-fired Steam Generating Units. The uncontrolled emissions of particulate matter from oil-fired steam generating units vary depending on the characteristics of the oil being fired. For distillate oil, which typically has a low ash content, the uncontrolled particulate matter emission levels are similar to those of natural gas-fired steam generating units. For higher ash residual oils, uncontrolled particulate matter emission levels are typically in the range of 10 to 65 ng/J (0.02 to 0.15 lb/million Btu) heat input, although some residual oils, particularly those with high sulfur contents, have considerably higher uncontrolled particulate matter emission levels, up to 21 ng/J (0.5 lb/million Btu) heat input. Uncontrolled particulate matter emissions from firing high ash residual oil, however, are about an order of magnitude less than those associated with uncontrolled emissions from the firing of solid fossil fuels (such as coal) or solid nonfossil fuels (such as wood or solid waste). Although these emissions are sufficient to consider development of standards of performance, the application of "add-on" postcombustion particulate matter controls to oil-fired steam generating units is quite costly per unit of particulate matter emissions collected due to the relatively low uncontrolled emission rate. Consequently, the most cost-effective approach (and most common approach) to the control of particulate matter emissions from oil-fired units is the use of a low ash, low sulfur oil. The use of a low ash, low sulfur oil is also presently considered to be the most cost-effective approach for control of sulfur dioxide emissions from oil-fired steam generating units.

As discussed earlier, sulfur dioxide standards for industrial-commercial-institutional steam generating units are being developed separately. Because of the relationship between control of particulate matter emissions and sulfur dioxide emissions from oil-fired units (i.e., control of both pollutants relies primarily on the use of low ash, low sulfur oils), consideration will be given to standards of performance limiting particulate matter emissions from oil-fired steam generator during development of the standards for sulfur dioxide. In the interim, the current particulate matter standards contained in 40 CFR Part 60 Subpart D for oil-fired steam generating units above 73 MW (250 million Btu/hour) heat input capacity will remain in effect.

Coal-Fired Steam Generating Units. In order to assess the performance of double mechanical collectors on coal-fired stoker steam generating units, particulate matter emissions were reviewed from nine units equipped with double mechanical collectors. These data were gathered using Reference Method 5 procedures. The steam generating units ranged in size from 25 to 62 MW (84 to 211 million Btu/hour) heat input capacity, and were operated during the emissions tests at loads ranging from 33 to 100 percent of capacity. Analyses of the coal fired in seven of these units showed ash contents ranging from 4.8 to 10.3 weight percent. Fuel analyses at the remaining two sites were not available. The average particulate emissions ranged from 77 to 125 ng/J (0.18 to 0.28 lb/million Btu).

These data represent the performance of double mechanical collectors on coal-fired stoker steam generating units at both high and low loads. Also, some of these tests were performed while the steam generating unit was operated under swing loads. These data, therefore, represent the performance of double mechanical collectors tested under the most adverse steam generating unit conditions.

To assess the performance of sidestream separators applied to stoker boilers, particulate matter emissions data were gathered by Reference Method 5 on seven coal-fired stoker boilers which ranged in heat input capacity from 15 to 66 MW (50 to 225 million Btu/hour). During these tests, boiler loads ranged from 33 percent of capacity to over 100 percent of capacity. The bituminous coal fired varied from 4.3 to 10.0 weight percent and sulfur content varied from 0.7 to 2.1 weight percent. Average particulate matter emissions ranged from 52 to 77 ng/J (0.12 to 0.18 lb/million Btu) heat input.

These data represent the performance of sidestream separators on bituminous coal-fired stoker boilers at both low and high loads. At high loads the uncontrolled particulate matter emissions are highest. At low loads the mechanical collector portion of the sidestream separator is least efficient. Thus, both high and lows loads may present relatively adverse conditions with respect to sidestream separator performance. The test data are representative of both of these conditions.

In order to assess the performance of fabric filters on coal-fired stoker steam generating units, particulate matter emission data from four units equipped with fabric filters were reviewed. These data were gathered using Reference Method 5 test procedures. These steam generator ranged in size from 24 to 68 MW (80 to 227 million Btu/hour) heat input capacity, were operated during the emissions tests at steam generating unit loads ranging from 77 to 99 percent of total capacity, and fired coal having ash contents of 5.5 to 10.2 percent. At operating fabric filter air-to-cloth ratios of 1.2 to 1.8 cm/s (2.3 to 3.6 ft/min), the average particulate matter emissions from each of these coal-fired stoker units were less than 12 ng/J (0.03 lb/million Btu) heat input.

In order to analyze the effectiveness of fabric filters in controlling particulate matter emissions from industrial-commercial-institutional pulverized coal-fired steam generating units, particulate matter emission data gathered by Reference Method 5 from two pulverized coal-fired units were evaluated. These units have capacities of 94 to 98 MW (313 to 325 million Btu/hour) heat input and were operated at loads of 100 and 83 percent, respectively, during the testing. At operating air-to-cloth ratios of 1.1 to 0.8 cm/s (2.2 to 1.7 ft/min), the fabric filters on these steam generating units reduced the average particulate matter emissions to 8 and 16 ng/J (0.019 and 0.037 lb/million Btu) heat input, respectively.

These data represent the performance of fabric filters on stoker and pulverized coal-fired steam generating units at high operating load conditions. At high operating loads, the air-to-cloth ratio is increased because a larger quantity of flue gas is introduced into the baghouse while the filter area remains constant. The operating loads presented in these data, therefore, represent the performance of the fabric filters tested under the most adverse load conditions.

Particulate matter emission data were gathered using Reference Method 5 on the performance of ESP's on five coal-fired stoker steam generating units which ranged in size from 27 to 110 MW (93 to 375 million Btu/hour) heat input capacity. These units were tested at operating load conditions of 52 to 106 percent of the steam generator capacity and fired coal having sulfur contents of 0.54 to 1.0 percent and ash contents of 5.4 to 12 percent. The operating specific collections areas of the ESP's ranged from 25.2 to 124.8 $m^2/(m^3/s)$ (128 to 634 ft^2/1,000 acfm). Under these conditions, the average particulate matter emissions from each of the five steam generating units were less than 21 ng/J (0.05 lb/million Btu) heat input.

Particulate matter emission data were also gathered by Reference Method 5 from ESP's applied to six different industrial-commercial-institutional pulverized coal-fired steam generating units. These tests were conducted on units having a heat input capacity of 110 to 158 MW (375 to 537 million Btu/hour) and operating at 73 to 100 percent of the steam generator capacity. The coals fired in these tests were all similar and averaged approximately 1 percent in sulfur content and 12 percent in ash content. The ESP's had operating specific collection areas of 18.9 to 71.6 $m^2/(m^3/s)$ (96 to 364 ft^2/1,000 acfm). Average particulate matter emissions for each test were 21 ng/J (0.05 lb/million Btu) heat input or less. A seventh pulverized coal-fired unit controlled by an ESP was tested by Reference Method 5. This steam generating unit had a heat input capacity of 158 MW (537 million Btu/hour). At loads of 95 to 98 percent of capacity and an operating specific collection area of 17.7 $m^2/(m^3/s)$ (90 ft^2/1,000 acfm), average particulate matter emissions from this steam generating unit were 30 ng/J (0.07 lb/million Btu) heat input. This higher level of emissions is due to the very low specific collection area of the ESP.

One characteristic of flue gas particulate matter which can make control and collection by ESP's difficult is high electrical resistivity. As the sulfur content of coal decreases, the resistivity of the particulate matter in the steam generating unit flue gas increases, requiring a larger collection area for effective electrostatic precipitation. The sulfur content of the coal combusted during the tests reported above was 0.54 to 1.0 percent by weight, which represents low sulfur levels for most industrial-commercial-institutional steam generating units. Further, the high operating load conditions which were included in many of these tests effectively lowered the ratio of the flue gas flow rate to the collection plate area of the ESP. As this ratio is lowered, the effectiveness of the ESP decreases. Because the steam generating units tested fired low sulfur content coal and were operated at high loads, the test results represent the performance of ESP's under adverse conditions.

Fossil Fuel Mixtures. Fossil fuel mixtures fired in steam generating units include various combinations of coal, oil, and natural gas. ESP's can be applied to units firing coal with oil or natural gas. Since oil and natural gas are inherently cleaner burning fuels than coal, the uncontrolled particulate matter emissions from firing mixtures of coal with oil or natural gas or both are reduced from the uncontrolled particulate matter emissions from firing coal alone. The use of ESP's on steam generating untis firing mixtures of coal with oil or natural gas or both, therefore, will reduce particulate matter emissions to levels less than the emission levels achieved through the use of ESP's on units firing coal alone.

Wood-Fired Steam Generating Units. The performance of double mechanical collectors in reducing particulate matter emissions from wood-fired steam generating units was examined. Very little emission test data are available, however, to evaluate these systems on wood-fired units. As a result, no conclusions about their performance can be made from a review of emissions data collected under test conditions. Based on a review of factors affecting the control of particulate matter emissions from wood-fired units, the performance of double mechanical collectors is believed to be comparable to the performance of these devices on coal-fired steam generating units. Therefore, for purposes of the proposed standards, double mechanical collectors are considered capable of achieving an emission level of 129 ng/J (0.30 lb/million Btu) heat input on wood-fired units.

To evaluate the performance of wet scrubbers in reducing particulate matter emissions from wood-fired steam generating units, particulate matter emisssion tests were conducted using Reference Method 5 on 13 spreader stoker units firing 100 percent wood. These untis ranged in size from 20 to 70 MW (57 to 230 million Btu/hour) heat input capacity. The wood burned during the tests included bark, wood scraps, hog fuel (a wood/bark mixture), sanderdust, and pulverized wood residue. The reported fuel moisture contents ranged from 45 to 65 weight percent and the ash contents ranged from 0.7 to 3.2 weight percent. During 11 of the tests, fly ash was reinjected from the mechanical collector precleaner back to the generator firebox for burnout. Nine of these tests were conducted on low pressure drop impingement and fixed throat venturi scrubbers with pressure drops of 1.5 to 2.0 kPa (6 to 8 inches of water) and loads which ranged from 56 to 104 percent of the steam generating unit capacity. The other four tests were conducted on units operating at average loads of 91 to 100 percent of design capacity and controlled with adjustable throat venturi scrubbers operating at medium pressure drops of 3.8 to 6.5 kPa (15 to 26 inches of water). The average particulate matter emissions from the low pressure drop scrubbers tests ranged from 30 to 90 ng/J (0.07 to 0.21 lb/million Btu) heat input. Average particulate matter emissions from the four tests on scrubbers using medium pressure drops were significantly lower, ranging from 22 to 30 ng/J (0.05 to 0.07 lb/million Btu) heat input.

To evaluate the performance of ESP's on wood-fired steam generating units, emissions tests were performed on two spreader stoker units using Reference Method 5. These steam generating units fired 100 percent wood in the form of bark, sanderdust, and hog fuel. The first unit had a heat input capacity of 49 MW (168 million Btu/hour) and fired bark supplemented with sanderdust. During testing, operating unit load conditions ranged from 64 to 67 percent of design capacity. The moisture content of the fuel was not available. All of the fly ash from the mechanical collector was reinjected into the steam generator. The average operating specific collection area was 45 $m^2/(m^3/s)$ (230 $ft^2/1000$ acfm). The average particulate matter emissions were 30 ng/J (0.07 lb/million Btu) heat input. The second steam generating unit had a heat input capacity of 236 MW (806 million Btu/hour). During testing, the average load ranged from 88 to 95 percent, and hog fuel with a typical moisture content of 42 weight percent was fired. Fly ash from the mechanical collector was reinjected into the steam generating unit. The average operating specific collection area was 89 $m^2/(m^3/s)$ (453 $ft^2/1000$ acfm). The average particulate emisisons were 26 ng/J (0.06 lb/million Btu) heat input.

Two spreader stoker steam generating units firing wood/coal mixtures and equipped with a single ESP were tested using Reference Method 5. Operating loads during the test ranged from 84 to 90 percent of the design capacities of 112 and 151 MW (382 and 517 million Btu/hour) heat input. These units fired a mixture of 25 percent wood bark and 75 percent coal, and employed fly ash reinjection. The wood bark had a moisture content of 46 weight percent and an ash content of 1.8 weight percent. The coal ash content was 11.7 weight percent and the sulfur content was 0.81 weight percent. The ESP was operated at an average collection area of 63 $m^2/(m^3/s)$ (320 $ft^2/1000$ acfm). Controlled particulate matter emissions from these steam generating units were less than 22 ng/J (0.05 lb/million Btu) heat input.

Two tests were also conducted on an ESP applied to the combined flue gas streams of a pulverized coal-fired steam generating unit and a spreader stoker unit which had heat input capacities of 56 MW (192 million Btu/hour) and 93 MW (320 million Btu/hour), respectively. These steam generating units cofired from 80 to 100 percent wood bark/sawdust with coal. Average moisture contents of the wood were 42 and 28 weight percent, and the ash contents were 4.4 and 5.9 weight percent, respectively. The ash content of the coal was 7.1 weight percent for the first test and 17.7 weight percent for the second test. The sulfur content of the coal fired was 0.7 percent for the first test and 0.5 weight percent for the second test. Fly ash reinjection was used on the spreader stoker steam generating unit. During the first test, operating loads for this system were 48 to 49 percent for the pulverized coal unit and 87 to 88 percent for the spreader stoker. During the second test, the steam generating units were operated at 76 to 88 and 45 to 52 percent of capacity, respectively. At average operating collection areas of 89 to 118 $m^2/(m^3/s)$ (452 to 600 $ft^2/1000$ acfm), particulate matter emissions from this combined system were reduced to less than 30 ng/J (0.07 lb/million Btu) heat input.

An ESP was also tested on a 280 MW (950 million Btu/hour) heat input capacity spreader stoker steam generating unit firing a mixture of 64 percent bark/sawdust and 36 percent residual oil. This test was performed at a load of 76 percent of design capacity and an ESP operating specific collection area of 90 $m^2/(m^3/s)$ (456 $ft^2/1000$ acfm). Fly ash reinjection was used during this test. The average particulate matter emissions were determined to be less than 13 ng/J (0.03 lb/million Btu) heat input.

Particulate matter emission test data were collected for a wood-fired steam generating unit controlled with dual mechanical collectors followed by an electrostatic granular filter (EGF). The steam generating unit was a 210 MW (716 million Btu/hour) heat input capacity spreader stoker steam generating unit which operated at a unit load range of 62 to 118 percent of rated capacity. This unit fired wood and bark with a moisture content of 49 to 58 weight percent and an ash content of 1.8 to 2 weight percent. Operating at average pressure drops of 0.7 to 1.7 kPa (3 tp 7 inches of water), the EGF achieved average emission of 9 to 17 ng/J (0.02 to 0.04 lb/million Btu).

Two sites with wood-fired steam generating units which controlled particulate matter emission using a fabric filter were tested using Reference Method 5. One site had a single 11 MW (38 million Btu/hour) heat input capacity spreader stoker unit operating at a load of 73 to 77 percent and firing wood bark with a moisture content of 47 weight percent and an ash content of 2.7 weight percent. The fabric filter on this steam generating unit operated at an air-to-cloth ratio of 1.9 cm/s (3.66 ft/min). There was no fly ash reinjection during this test. The average particulate matter emissions from this steam generating unit were less than 9 ng/J (0.02 lb/million Btu) heat input. The other site had three dutch oven-type wood-fired units which fired salt-laden hog fuel. These steam generating units operated at 86 to 99 percent of their combined 67 MW (230 million Btu/hour) heat input capacity. Moisture content of the fuel was 57 weight percent and the ash content was 1.5 weight percent. The flue gases of the three steam generating units were combined and ducted through a fabric filter for particulate matter control. Fly ash reinjection was not used. At an average air-to-cloth ratio of 1.5 cm/s (2.98 ft/min), the average particulate matter emissions from these steam generating units were 9 ng/J (0.02 lb/million Btu) heat input.

The particulate matter emission data discussed above were obtained from steam generating units firing wood, or cofiring wood with other fuels, both with and without fly ash reinjection. Fly ash reinjection effectively increases the amount of particulate matter entering the steam generating unit, placing a greater demand on the capacity of the particulate matter control device.

In addition, the effectiveness of the particulate matter control devices tested is reduced in some instances by an increase in emissions due to the high moisture content of the wood. The highest moisture content of the wood burned during these tests was approximately 65 weight percent, which is the highest moisture content expected of wood fired in steam generating units. High moisture content in the wood results in an increase in the gas velocity through the steam generating unit as water evaporates from the fuel and increases the flue gas exhaust volumetric flow rate. This higher gas velocity which results cause more particles to be entrained in the flue gas, which increases the uncontrolled emission rate. In addition, high fuel moisture content reduces the gas temperature and lowers the thermal efficiency of the steam generating unit, requiring higher fuel feed rates (and undergrate air intake) to maintain steam production. These two factors increase particulate matter emissions by increasing the concentration of particles in the steam generating unit and entraining them in the flue gas as air is forced through the combustion zone. Thus, conditions of fly ash reinjection and high wood moisture content are representative of the most adverse conditions which are expected to be encountered during the operation of wood-fired steam generating units.

Solid Waste-Fired Steam Generating Units. ESP's are the most widely used particulate matter control devices on steam generating units firing municipal solid waste. Four Reference Method 5 particulate matter emission tests were collected for steam generating units ranging in heat input capacity from 14 to 85 MW (47 to 290 million Btu/hour) which fire municipal solid waste and which are controlled by ESP's. The tests on these four steam generating units were conducted at loads ranging from 76 to 90 percent of capacity. Moisture contents of the solid waste fire at three of the four steam generating units were measured at 20, 27, and 27 percent, respectively, and the ash contents were 22, 22, and 31 percent, respectively. No fuel analysis was available for the remaining steam generating unit. The steam generating units tested are overfeed stoker units which are the only large units commonly used to burn municipal solid waste. The ESP's showed a range of particulate matter emissions from a high of 86 ng/J (0.20 lb/million Btu) heat input at an average specific collection area of 27 $m^2/m^3/s$) (139 ft^2/1000 acfm), down to 22 ng/J (0.05 lb/million Btu) heat input at an average specific collection area of 113 $m^2/(m^3/s)$ (570 ft^2/1000 acfm). The data also showed that particulate matter emissions decreased with increasing ESP collection area and that with ESP collection areas larger than 47 $m^2/(m^3/s)$ (240 ft^2/1000 acfm), average particulate matter emissions were less than 43 ng/J (0.10 lb/million Btu) heat input.

A test to determine the performance of ESP's on steam generating units firing refuse-derived fuel (produced from processing and drying MSW) was conducted using Reference Method 5. The steam generating unit selected was a spreader stoker with a heat input capacity of 97 MW (332 million Btu/hour). The steam generating unit was operated at 72 to 92 percent of capacity during the test. The solid waste fired in this unit was a wet pulp refuse-derived fuel having both a high moisture content of 51 weight percent and a high ash content of 7.9 weight percent. Operating with a collection area of 64 $m^2/(m^3/s)$ (326 ft^2/1000 acfm), the ESP reduced particulate matter emissions from this steam generating unit to an average of 30 ng/J (0.07 lb/million Btu) heat input.

The above data indicate that ESP's can reduce particulate matter emissions from steam generating units firing municipal-type solid waste and refuse-derived fuels to levels below 43 ng/J (0.10 lb/million Btu) heat input. Particulate matter emission data presented earlier also indicate that ESP's can reduce particulate matter emissions from coal-fired steam generating units to levels considerably below 43 ng/J (0.10 lb/million Btu) heat input. Controlling particulate matter emissions from steam generating units firing a mixture of these fuels presents no greater problems than controlling emissions from steam generating units firing these fuels separately. Consequently, ESP's can reduce particulate matter emissions from steam generating units firing mixtures of these fuels to less than 43 ng/J (0.10 lb/million Btu) heat input.

Visible Emissions. Data on the opacity of visible emissions from industrial-commercial-institutional steam generating units were gathered from units firing coal, wood, solid waste, and mixtures containing these fuels. These visible emissions data were gathered using both manual observations (Reference Method 9) and in-stack transmissometers. These data, which are summarized in Table 3, include coal-fired stoker steam generators controlled by ESP's, fabric filters, and sidestream separators; pulverized coal-fired steam generators controlled by ESP's and fabric filters; wood and wood/coal cofired steam generators controlled by ESP's and fabric filters; and solid waste-fired stoker steam generators controlled by ESP's. Visible emissions data from steam generating units equipped with wet scrubbers are not included because of the interference with opacity caused by water droplets in the flue gas. Such interference makes visible emission measurement ineffective as a technique for monitoring the performance and operation of a wet scrubbing system.

TABLE 3.—SUMMARY OF VISIBLE EMISSIONS DATA

Steam generator type	Control system	Test method	Emission level ng/J (lb/million Btu) heat input	Maximum 6-minute opacity observation	Average of all 6-minute opacity observations	Number of 6-minute observations*
Coal-fired stokers	Fabric filter	EPA method 9	4-22 (0.01-0.05)	0.6	01	30
	Fabric filter	Transmissometer	4-17 (0.01-0.04)	NR	010	NR
	ESP	EPA method 9	4 (0.01)	3	01	
	Sidestream separator	EPA method 9	43-63 (0.10-0.15)	15	01	61
	Sidestream separator	Transmissometer	52-77 (0.12-0.18)	NR	04	NR
Pulverized coal-fired	Fabric filter	EPA method 9	13-17 (0.03-0.04)	01	NR	10
		Transmissometer	4-13 (0.01-0.03)	NR	0	NR
Wood/coal cofired stoker	ESP	EPA method 9	8-23 (0.02-0.05)	18.8	01	76
Salt-laden wood dutch oven	Fabric filter	EPA method 9	4-13 (0.01-0.03)	13.5	04	89
Solid waste-fired stoker	ESP	EPA method 9	NR	14.4	04	60
Refuse derived fuel-fired stoker	ESP	EPA method 9	17-26 (0.04-0.06)	12.5	04	20

*No overlapping observations included. Twelve minutes of opacity data (48 observations) would provide 2 opacity observations (6 minute average).
NR=Not reported.

Analysis of these data focused on identification of a level of visible emissions which would provide a clear indication of a malfunction or improper operation and maintenance of the control device. Because of the relatively low opacity levels achieved at all facilities tested (individual 6-minute average levels approaching zero percent opacity for fabric filters on coal-fired stoker units and up to 18.8 percent for ESP's on combination wood/coal-fired stoker units), a single visible emissions level of 20 percent opacity would be appropriate to provide a clear indication of a malfunction or improper operation and maintenance or a particulate matter control device.

Summary. In summary, ESP's have been identified as a demonstrated control technology for particulate matter emissions from steam generating units firing coal, wood, solid waste, and mixtures of these fuels. In addition, fabric filters have been identified as a demonstrated technology for the control of particulate matter emissions from coal-fired steam generators, and wet scrubbers have been identified as a demonstrated technology for the control of particulate matter emissions from steam generators firing coal, wood, and mixtures of these fuels. Electrostatic granular filters are a demonstrated technology for wood and sidestream separators are a demonstrated control technology for coal-fired stoker steam generating units. Double mechanical collectors are a demonstrated technology for coal and for wood-fired units. These technologies and the emission reductions they are capable of achieving are summarized in Table 4.

TABLE 4.—SUMMARY OF DEMONSTRATED PARTICULATE MATTER TECHNOLOGIES AND ACHIEVABLE EMISSION LEVELS

Fuel	Demonstrated technology	Achievable emission levels: ng/J (lb/million Btu) heat input	Achievable emission levels: Opacity percent (maximum 6-minute average)
Technical alternative I:			
Coal	Sidestream separator/	86 (0.20)	20
	Low efficiency ESP	86 (0.20)	20
	Double mechanical collector	129 (0.30)	20
Wood	Low pressure drop scrubber/	86 (0.20)	NA
	Low efficiency ESP	86 (0.20)	20
	Double mechanical collector	129 (0.30)	20
Solid waste	Low efficiency ESP	86 (0.20)	20
Fuel mixtures	Low pressure drop scrubber/	86 (0.20)	NA
	Low efficiency ESP	86 (0.20)	20
	Double mechanical collector	129 (0.30)	20
Technical alternative II:			
Coal	Fabric filter/	22 (0.05)	20
	High efficiency ESP	22 (0.05)	20
Wood	Medium pressure drop scrubber/	43 (0.10)	NA
	High efficiency ESP	43 (0.10)	20
	Electrostatic granular filters	43 (0.10)	20
Solid waste	High efficiency ESP	43 (0.10)	20
Fuel mixtures	High efficiency ESP	43 (0.10)	20

NA=Not applicable.

As shown in Table 4, these emission control technologies lead to two principal technical alternatives, either of which could serve as the basis for standards of performance. Technical Alternative I represents a lower cost, moderate level of emission control, and involves the use of sidestream separators, double mechanical collectors, low efficiency ESP's, and low pressure drop wet scrubbers for steam generating units in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity range. Application of these control technologies would result in particulate emissions of 86 ng/J (0.20 lb/million Btu) heat input or less from steam generating units firing coal, wood, solid waste, or mixtures of these fuels, except in the case of double mechanical collectors where emissions of 129 ng/J (0.30 lb/million Btu) heat input or less would result.

Technical Alternative II represents a higher cost, higher degree of emission control, and involves the use of high efficiency ESP's, fabric filters, medium pressure drop wet scrubbers, or EGF's. Application of these control technologies would reduce particulate matter emissions to 22 ng/J (0.05 lb/million Btu) heat input or less from coal-fired steam generating units and 43 ng/J (0.10 lb/million Btu) heat input or less from steam generating units firing wood, solid waste, and mixtures of fuels containing coal, wood, and solid waste.

3. Consideration of Demonstrated Control Technology Costs

Control technology cost impacts on individual steam generating units were evaluated in three ways. The first analysis examined the increased capital cost resulting from application of each of the demonstrated technologies. The second analysis examined the increased annualized cost resulting from use of these technologies. This impact included annual fixed capital charges as well as annual operating and maintenance costs. The third way cost impacts were evaluated was in terms of cost-effectiveness, or the cost per ton of pollutant removed. In each of these three approaches, cost impacts were analyzed for each demonstrated technology in terms of the incremental difference between costs required under current regulations applicable to industrial steam generating units (i.e., the regulatory baseline) and costs required for each demonstrated control technology.

The financial parameters used in the analysis include an amortization period of 15 years for the steam generating unit and control systems and a "real" cost of capital of 10 percent in constant dollars. A "real" rather than a "nominal" cost of capital was used in the analysis in order to avoid having to make adjustments for varying inflation rates. For example, an assumed inflation rate of 8 percent and a 10 percent "real" cost of capital is equivalent to an 18 percent "nominal" cost of capital. All costs were calculated in mid-1982 dollars.

Nitrogen Oxides. With respect to the control of nitrogen oxides, industrial-commercial-institutional steam generating units above 73 MW (250 million Btu/hour) heat input capacity are regulated by existing standards of performance under 40 CFR Part 60 (Subpart D). For coal- and residual oil-fired steam generating units above this size, the demonstrated NO_x control techniques discussed earlier are essentially the same as those currently required to comply with the existing Subpart D standards of performance. The proposed standards for natural gas-fired and distillate oil-fired steam generating units are based upon the application LEA/SC technology, which would represent a change in the current basis for the NO_x standards for units above 73 MW (250 million Btu/hour) heat input capacity. However, as discussed below, any cost increase would be minimal. As a result, there would be little or no cost associated with the application of the demonstrated NO_x control techniques to natural gas-, oil- or coal-fired steam generating units above 73 MW (250 million Btu/hour) heat input capacity.

The analysis of the cost impacts of the demonstrated NO_x control techniques, therefore, focused on steam generating units above 73 MW (250 million Btu/hour) heat input capacity. In this size range, only five State implementation plans (SIP's) currently limit NO_x emissions from fossil fuel-fired steam generating units. Therefore, the regulatory baseline was assumed to be no NO_x control.

As discussed above, the control techniques considered to be demonstrated for the purpose of developing standards of performance for industrial-commercial-institutional steam generating units are LEA and LEA/SC. Rather than being add-on control technologies, LEA and LEA/SC are combustion modification NO_x control techniques which require continual monitoring and adjustment of steam generating unit operation. These demonstrated NO_x control techniques call for close and continued attention to steam generating unit operation and frequent adjustment of such parameters as excess air levels and the distribution of either combustion air or fuel between the primary and secondary combustion zones within the firebox (i.e., staging of the combustion process) to ensure effective NO_x emission reduction in response to changes in steam generating unit operation. As a result, the most effective means of ensuring operation in a manner consistent with optimal control of NO_x emissions is direct measurement of emissions in the flue gas with an NO_x monitor.

For the purpose of developing standards of performance, LEA is considered the only demonstrated NO_x control technique for reducing NO_x emissions from mass-feed and spreader stoker coal-fired steam generating units. The cost associated with use of this control technique would not have a major impact on the total capital or annualized cost of a new steam generating unit using LEA controls. For example, the capital cost of an LEA combustion air trim system and a continuous NO_x monitoring system, including installation cost, is approximately $80,000. Use of LEA, therefore, would increase the $11.6 million capital cost of a new coal-fired 44 MW (150 million Btu/hour) heat input capacity spreader stoker steam generating unit about 0.7 percent.

The impact of the use of LEA to reduce NO_x emissions on the annualized costs of new spreader stoker steam generating units firing coal varies depending on the fuel saving achieved by LEA. Since LEA decreases stack gas heat losses by minimizing excess combustion air levels, it reduces fuel use. For example, the annualized cost of a 44 MW (150 million Btu/hour) heat input capacity spreader stoker coal-fired steam generating unit (including fuel costs) is about $6 million under the regulatory baseline. The annualized cost to operate and maintain an LEA combustion air trim system and an NO_x monitoring system is about $50,000. Without taking potential fuel savings into account, the use of LEA, therefore, would result in a 0.8 percent increase in the annualized costs of these steam generating units. If fuel savings are taken into account, however, the net annualized costs of the LEA combustion air trim system and the NO_x monitoring system decrease to about $25,000 for the spreader-stoker coal-fired steam generator. Thus, the overall impact of the proposed standards would be a 0.3 percent increase in the annualized costs associated with a 44 MW (150 million Btu/hour) heat input capacity spreader-stoker coal-fired steam generating unit.

For new steam generating units firing residual oil, the only NO_x control techniques considered demonstrated for the purpose of developing standards of performance are LEA/SC. In the case of LEA/SC, certain design modifications to the steam generating unit firebox in addition to installation of SC combustion air distribution systems may be necessary to accommodate SC in packaged high nitrogen residual oil-fired steam generating units.

In order to meet rail car shipping size limitations, packaged oil-fired steam generating units are constrained with respect to maximum firebox size. Use of LEA/SC, however, generally enlarges the size of the flame within a steam generating unit firebox. To accommodate the use of LEA/SC, some packaged residual oil-fired steam generating units may need to be redesigned or derated in order to avoid potential flame impingement problems. The extent of the redesign of the firebox or of the steam generating unit derating required will vary considerably depending on the existing steam generating unit designs. Based on a survey of packaged oil-fired steam generating unit manufacturers and vendors, in the absence of firebox redesign most steam generating units would need to be derated by 15 percent or less to accommodate SCA.

Assuming a derating of 15 percent, the use of LEA/SC, including the cost of LEA combustion air trim and staged combustion air distribution systems in addition to NO_x monitors, would increase the capital cost of a 44 MW (150 million Btu/hour) heat input capacity packaged residual oil-fired steam generating unit by about $265,000. This represents an increase of about 9 percent in the approximately $3.0 million cost of this steam generating unit. The annualized cost impact for this unit, however, would be much smaller. Taking into account the fuel savings associated with the use of LEA/SCA, the annualized costs of the steam generating units would be increased by about $32,000. Compared to annualized costs of about $5.8 million for this steam generating unit under the regulatory baseline, this represents an increase of only 0.5 percent.

Other alternatives, however, are available for packaged residual oil-fired steam generating units to reduce NO_x emissions to levels equivalent to the use of LEA/SC. One alternative is to minimize the adjustments needed in the firebox dimensions by using staged combustion burners (SCB's) rather than over-fire air (OFA) to incorporate LEA/SC into the steam generating unit. SCB's can in most instances be incorporated into steam generating unit designs with minimal increases in firebox dimensions. One manufacturer of small packaged steam generating units has indicated that currently available SCB's could be installed and operated with no modification to firebox dimensions. A second packaged steam generating unit manufacturer has indicated that minimal (30 to 60 cm (1 to 2 ft) increase in length) changes in firebox dimensions would be required.

The only NO_x control technique considered demonstrated for the purpose of developing standards of performance for new pulverized coal-fired steam generating units is also LEA/SC. The potential cost impacts of the use of LEA/SC on pulverized coal-fired steam generating units are less than those on residual oil-fired steam generating units. The primary reason for this is that pulverized coal-firing results in a large flame in all cases and requires a relatively large firebox even without SCA. In addition, most pulverized coal-fired steam generating units are larger than 73 MW (250 million Btu/hour) heat input capacity and consequently are subject to the existing standards of performance under 40 CFR Part 60 (Subpart D). These standards were adopted in 1971 and manufacturers and vendors of pulverized coal-fired steam generating units have long since incorporated the changes necessary to accommodate LEA/SC into their basic designs. As a result, the only additional costs associated with the use of SC on pulverized coal-fired steam generating units are the costs associated with the combustion air distribution system (i.e., ductwork, registers).

The use of LEA/SC, including the cost of LEA combustion air trim and SC combustion air distribution systems in addition to an NO_x monitor, would increase the capital costs of a 44 MW (150 million Btu/hour) heat input capacity pulverized coal-fired steam generating unit by about $117,000. This represents an increase in the $14 million capital cost of this steam generating unit under the regulatory baseline of about 0.8 percent. Taking into account the fuel savings associated with the use of LEA/SCA the annualized costs of this pulverized coal-fired steam generating unit would increase by about $52,000, which is equivalent to a 0.8 percent increase.

For new steam generating units firing natural gas and distillate oil, the NO_x control techniques considered demonstrated for the purpose of developing standards of performance are LEA and LEA/SC. Both techniques would require the use of oxygen trim to optimize performance. The use of LEA/SC would cost slightly more than the use of LEA alone since the application of LEA/SC to natural gas—and distillate oil-fired steam generating units would require the use of the more sophisticated staged combustion burners (SCB). Adjustments in firebox dimensions required to apply SC through use of SCB's would be minimal in most cases.

The use of LEA or SCB's including the cost of LEA combustion air trim, SCB's, and NO_x monitors would increase the capital cost of a 44 MW (150 million Btu/hour) heat input capacity packaged natural gas-fired steam generating unit by about $77,000. This represents an increase of about 2.6 percent in the approximately $2.9 million cost of this steam generating unit. When fuel savings are taken into account, the costs of the LEA trim, SCB's, and NO_x monitors are offset, resulting in negligible overall cost impacts. Similar impacts would occur in the case of distillate oil-fired steam generating units.

For all types of steam generating units, the impact of the proposed NO_x standards on both the capital costs and the annualized costs associated with LEA or LEA/SC varies with the size of the unit. The discussion above presents costs for steam generating units with heat input capacities of 44 MW (150 million Btu/hour). This represents the mean size of the range of steam generating unit sizes impacted by the proposed standards. For steam generating units above 44 MW (150 million Btu/hour) heat input capacity, the impact of the proposed standards on the capital costs and the annualized costs of the steam generating unity would represent a smaller percentage of steam generating unit costs. Similarly, for steam generating units at the lower end of the affected range, 29 MW (100 million Btu/hour) heat input capacity, the impact of the proposed standards on the capital costs and the annualized costs of the steam generating unit increases slightly from costs presented above. For example, capital and annualized cost increases associated with the use of LEA on a 29 MW (100 million Btu/hour) spreader stoker are 1.0 and 0.8 percent, respectively, as compared to increases of 0.8 and 0.3 percent, respectively, for a 44 MW (150 million Btu/hour) spreader stoker.

The cost-effectiveness associated with the use of the domonstrated NO_x control technologies was also examined. For a 44 MW (150 million Btu/hour) heat input capacity mass-feed or spreader-stoker steam generating unit firing coal, the cost-effectiveness of the use of LEA to reduce NO_x emissions is less than $510/Mg ($460/ton) of NO_x. The fuel savings associated with the use of LEA and the costs associated with the LEA combustion air trim system, SCB's and NO_x monitor are included in this value. The cost-effectiveness of the use of LEA/SC to reduce NO_x emissions from a 44 MW (150 million Btu/hour) steam generating unit firing residual oil or pulverized coal is about $790/Mg ($720/ton) of NO_x for residual oil and about $450/Mg ($10/ton) of NO_x for pulverized coal. As above, the fuel savings associated with the use of LEA and the costs associated with the LEA combustion air trim and the OFA system or SCB's, including the costs of an NO_x monitor, are incorporated in these values. The cost-effectiveness of the use of LEA or LEA/SC to reduce NO_x emissions from a 44 MW (150 million Btu/hour) steam generating unit firing natural gas or distillate oil is negligible. Included in this determination are fuel savings associated with the use of LEA and costs associated with the LEA combustion air trim system, the SCB's, and a NO_x monitor. Cost effectiveness is negligible because the fuel savings offset the costs of control.

The cost-effectiveness of applying these control techniques to reduce NO_x emissions also varies with steam generating unit size. As the size of the steam generating unit increases, the cost-effectiveness of these control techniques improves. Conversely, as the size of the steam generating unit decreases, the cost-effectiveness of these control techniques deteriorates. Consequently, for steam generating units above 44 MW (150 million Btu/hour) heat input capacity the cost-effectiveness of NO_x control associated with the demonstrated NO_x control techniques improves above the values cited above. For stream generating units below 44 MW (150 million Btu/hour) heat input capacity, however, the cost-effectiveness deteriorates from the values cited above.

The cost-effectiveness of applying these control techniques to reduce NO_x emissions also varies with the annual capacity factor of the steam generating unit. As the annual capacity factor increases, the cost-effectiveness of these control techniques improves and as the annual capacity factor decreases, the cost-effectiveness deteriorates. In particular, for steam generating units with annual capacity factors less than 30 percent (0.30), the cost-effectiveness of NO_x control deteriorates rapidly, with cost-effectiveness as high as $2,800/Mg ($2,500/ton) of NO_x reduction for 29 MW (100 million Btu/hr) heat input capacity coal— oil—, or natural gas-fired units with annual capacity factors of less than 30 percent (0.30). The principal factor which would increase the cost-effectiveness would be the relatively constant cost for operation of the continuous NO_x monitoring system, independent of steam generating unit operating levels.

Since the cost-effectiveness appears to be significantly greater for low capacity factor steam generating units, an alternative to the use of NO_x monitors is included in the proposed standards for steam generating units with low capacity factors. This alternative would allow low capacity factor steam generating units to monitor operating parameters of the steam generating unit, rather than NO_x emissions. Monitoring NO_x emissions directly assures optimal NO_x control and compliance with NO_x emission limits. Although the monitoring of operating parameters such as flue gas oxygen levels yields less exacting results, emission levels will be reduced by monitoring operating parameters and maintaining these parameters within certain narrow ranges. However, the full reductions in NO_x emissions will not be achieved by monitoring operating parameters. As a result, this alternative is only included in the proposed standards where the use of NO_x monitors leads to high cost-effectiveness values associated with NO_x control.

Particulate Matter. Existing State implementation plans (SIP's) limit emissions of particulate matter from most steam generating units which would be covered by the proposed standards. The level of particulate matter control required by SIP's varies considerably by steam generator size and by State. The majority of States have emission control requirements which become more stringent as steam generator size increases. Compliance with SIP's however, requires the use of mechanical collectors as a minimum for combustion of solid fuels. To reflect the minimum level of control uniformly required by all States, the use of single mechanical collectors was selected as the regulatory baseline for considering the cost impacts of various control technologies on individual steam generating units.

This assumption illustrates the comparative costs of different control alternatives; however, it tends to overstate the true cost impact of the proposed standards in many instances. In the case of more stringent SIP's, use of fabric filters, ESP's, or medium pressure drop wet scrubbers is required at present. Also, many SIP's currently require new wood-fired steam generating units to install medium pressure drop wet scrubbers or ESP's in order to meet existing State requirements. For municipal-type solid waste, ESP's are being installed almost exclusively on all new steam generating units to meet existing particulate matter emission limits. Altogether, several hundred fabric filters, ESP's, and medium pressure drop wet scrubbers have already been installed on industrial-commercial-institutional steam generating units of the size and type covered by this proposal to meet State emission limits.

Site specific construction/operating permit requirements also limit emissions of particulate matter from steam generating units covered by the proposed standards. For example, site specific emission limits as determined through prevention of significant deterioration (PSD) and new source review (NSR) requirements are often more stringent than required under a SIP. Based upon a review of the data available for recent PSD and NSR permits for non-utility coal-fired steam generating units, nearly all new units are currently being required to install an emission control technology more effectve than single mechanical collectors, and many units are being required to meet emmission control requirments as stringent as, or more stringent than, the proposed standards.

As a reflection of actual permit determinations, control levels derived from PSD or NSR requirements could also be used as a baseline for considering the impacts of the proposed standards. A baseline control level based upon PSD or NSR requirements would reduce the projected cost impact of the proposed standards. In areas where site-specific PSD or NSR requirements have been at least as stringent as the proposed standards, negligible cost impacts would result from the proposed standards. In fact, the only significant cost impacts resulting from the proposed standards would be for those steam generating units having less then 73 MW (250 million Btu/hour) heat imput capacity where the use of fabric filters, ESP's, wet scrubbers, or sidestream separators would be required in lieu of mechanical collectors. In order to identify and appropriately consider the cost of the proposed standards, the mechanical collector baseline which is reflective of SIP regulations was used for the cost analysis.

As outlined earlier, two technical alternatives for the control of particulate matter emissions could serve as the basis for particulate matter standards, and the costs presented in this analysis reflect the costs associated with each alternative. Technical Alternative I is based on a moderate level of particulate matter emisison control as achieved by sidestream separators, low pressure drop wet scrubbers, or low efficiency ESP's and is associated with an 86 ng/J (0.20 lb/million Btu) heat input emission level. Technical Alternative II is based on a high level of particulate matter control as achieved by high efficiency ESP's, fabric filters, or medium pressure drop wet scrubbers, and is associated with a 22 ng/J (0.05 lb/million Btu) heat input emission level for coal-fired steam generating units and a 43 ng/J (0.10 lb/million Btu) heat imput emmission level for wood-fired steam generating units, solid waste-fired steam generating units, or mixed fuel-fired steam generating units.

A typical coal-fired 44 MW (150 million Btu/hour) heat input capacity steam generation unit costs approximately $11.9 million with minimum particulate matter controls under the regulatory baseline. A wood-fired 44 MW (150 million Btu/hour) heat input capacity steam generating unit costs approximately $3.9 million under the regulatory baseline. To comply with standards based on Technical Alternative I, a 44 MW (150 million Btu/hour) heat input capacity coal-fired spreader stoker steam generating unit would incur an addtitional captial cost of $240,000 to install a sidestream separator. A 44 MW (150 million Btu/hour) heat input capacity wood-fired steam generating unit would incur a capital cost of $732,000 for a low pressure drop wet scrubber. These increases represent a 2.0 percent and 8.2 percent increase, respectively, in the capital cost of these steam generating units as compared to the regulatory baseline.

To comply with standards based on Technical Alternative II, a $1.2 million capital cost (over baseline) would be incurred by a 44 MW (150 million Btu/hour) heat input capacity coal-fired spreader stoker steam generating unit for fabric filter control. This represent a 10.1 percent increase in the capital cost of the steam generating unit. In the case of a 44 MW (150 million Btu/hour) heat input capacity wood-fired steam generating unit, a capital cost of $871,000 would be incurred for a high energy wet scrubber and would represent a 9.7 percent increase in the capital cost of the steam generating unit as compared to the regulatory baseline.

In order to purchase and operate the emission control technology based upon Technical Alternative I, a 44 MW (150 million Btu/hour) heat input capacity coal-fired spreader stoker steam generating unit would incur an additional annualized cost of $71,000 per year, and a 44 MW (150 million Btu/hour) heat input capacity wood-fired steam generating unit would incur an additional annulized cost of $264,000 per year. For a coal-fired steam generating unit, this repersents a 1.2 percent increase in annualized costs over a regulatory baseline cost of $5.8 million per year. For a wood-fired steam generating unit, this represents a 4.9 to 7.7 percent increase in annualized cost over a regulatory baseline cost of $3.4 to $5.4 million per year depending on the economic value of wood waste ($/million Btu).

To comply with standards based on Technical Atemative II, a 44 MW (150 million Btu/hour) heat input capacity coal-fired spreader stoker steam generating unit would incur increased annualized costs of $283.000 per year, which is an increase of 4.9 percent over the regulatory baseline. A 44 MW (150 million Btu/hour) heat input capacity wood-fired steam generating unit would incur increased annualized costs of $318,000 per year, which is an increase of 5.9 to 9.3 percent over the regulatory baseline, depending on the wood fuel value assumed.

The precentage increases in both capital and annualized costs cited above for Technical Alternative I and Technical Alternative II are relatively constant with respect to variations in steam generating unit size. Thus, the percentage increases presented above are representative of the range of steam generating unit sizes covered by the proposed particulate matter standards.

Even though the percentage increases in capital and annualized costs remain relatively constant for all steam generating unit sizes, the incremental cost-effectiveness of applying the demonstrated particulate matter control technologies to different size steam generating units varies significantly with steam generating unit size. This variance occurs because uncontrolled particulate matter emissons vary linearly with steam generator size for a given steam generator while the costs of particulate matter control do not. In addition, the cost-effectiveness of particulate matter control is influenced by the different steam generator designs representative of different size steam generating units.

In the range of 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity, spreader stoker systems represents the predominant design for the combustion of solid fuel, although some mass-feed units may be present. Above 73 MW (250 million Btu/hour) heat input capacity, pulverized coal-fired steam generating units represent the predominate design for coal firing, although wood-fired steam generating units continue to utilize the spreader stoker design. With increasing steam generating unit size, the increased fuel consumption rate and fuel costs justify the use of more complicated, more expensive, and more efficient steam generator designs.

Due to the unique characteristics of each of these steam generator designs, particulate matter emissions differ, with the emissions from spreader stoker steam generating units being inherently lower than those from pulverized coal-fired steam generating units. Because the cost-effectiveness of air pollution control systems is measured in terms of the cost ($) per Mg (ton) of pollutant removed, the inherently different baseline emission characteristics of each of these steam generator designs lead to significant differences in the cost-effectiveness of particulate matter emission control.

The cost-effectiveness of particulate matter controls for various coal-fired steam generating units is given in Table 5 for each technical alternative. Table 5 also compares the relative cost-effectiveness for Technical Alternative I and Technical Alternative II. Except for steam generating units with heat input capacities greater than 73 MW (250 million Btu/hour), the cost per Mg (ton) of particulate matter removed is generally lower for the less effective and less costly control systems associated with Technical Alternative I. For pulverized coal-fired steam generating units, which are characteristic of steam generating units above 73 MW (250 million Btu/hour) heat input capacity, sidestream separators are not demonstrated. For this reason, Technical Alternative I assumes the use of an ESP which is comparable in cost to a fabric filter. As a result, the cost effectiveness of Technical Alternative I and Technical Alternative II is essentially the same for this size range above 73 MW (250 million Btu/hour) heat input capacity.

TABLE 5.—INCREMENTAL COST-EFFECTIVENESS OF PARTICULATE MATTER CONTROLS ON COAL-FIRED STEAM GENERATING UNITS

Steam generator size MW (million Btu/hr) heat input capacity	Steam generator type	Technical alternative I (lower level of control)		Technical alternative II (higher level of control)	
		Cost-effectiveness		Cost-effectiveness	
		Dollars per million removed*	Dollars per ton removed	Dollars per million removed	Dollars per ton removed
29 (100)	Spreader stoker	630	(570)	1,542	(1,400)
44 (150)	Spreader stoker	560	(510)	1,400	(1,300)
73 (250)	Spreader stoker	520	(470)	1,300	(1,200)
73 (250)	Pulverized coal-fired	750	(680)	740	(670)
117 (400)	Pulverized coal-fired	580	(530)	660	(600)

E. Selection of Regulatory Alternatives

The technology and cost considerations discussed above lead to two principal regulatory alternatives which could serve as the basis for standards of performance to limit particulate matter and NO_x emissions from industrial-commercial-institutional steam generating units.

The consideration of regulatory alternatives focused on the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range. This size range represents the "heart" of the coal-fired industrial-commercial-institutional steam generating unit population.

To illustrate clearly the differences between the regulatory alternatives which could be selected as the basis of the proposed standards of performance for industrial-commercial-institutional steam generating units, two specific regulatory alternatives were analyzed in depth for their environmental, energy, and economic impacts. The principal difference between these two alternatives is the technical basis selected for standards of performance limiting emissions of particulate matter from steam generating units between 29 MW (100 million Btu/hour) and 73 MW (250 million Btu/hour) heat input capacity. Regulatory Alternative A is the lower cost alternative and the standards limiting particulate matter emissions for steam generating units in this size range would be based primarily on Technical Alternative I (i.e., use of sidestream separators, low efficiency ESP's or low pressure drop wet scrubbers). Regulatory Alternative B is the higher cost alternative and the standards limiting particulate matter emissions from steam generating units between 29 MW (100 million Btu/hour) and 73 MW (250 million Btu/hour) heat input capacity would be based primarily on Technical Alternative II (i.e., use of fabric filters, high efficiency ESP's or high pressure drop scrubbers). In both regulatory alternatives, the standards for particulate matter would be based on Technical Alternative II for steam generating units of greater than 73 MW (250 million Btu/hour) heat unit capacity.

In addition to the variations in the cost-effectiveness of emission control with steam generating unit size and steam generating unit type that were