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INDUSTRIAL BOILER COMBUSTION MODIFICATION NO_x CONTROL: VOLUME I. ENVIRONMENTAL ASSESSMENT

By

K. J. Lim, C. Castaldini, and H. I. Lips

Acurex Corporation
Energy & Environmental Division
485 Clyde Avenue
Mountain View, California 94042

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Prepared for

EPA Project Officer -- J. S. Bowen
EPA Deputy Project Officer -- R. E. Hall
Industrial Environmental Research Laboratory
Office of Environmental Engineering and Technology
Research Triangle Park, North Carolina 27711

U.S. ENVIRONMENTAL PROTECTION AGENCY
OFFICE OF RESEARCH AND DEVELOPMENT
WASHINGTON, DC 20460

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PREFACE

This is the second in a series of special reports to be documented in the "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies" (NO_x EA). Specifically, this report documents the environmental assessment of NO_x combustion controls applied to industrial boilers. The NO_x EA, a 36-month program which began in July 1976, is sponsored by the Combustion Research Branch of the Industrial and Environmental Research Laboratory of EPA (IERL-RTP). The program has two main objectives: (1) to identify the multimedia environmental impact of stationary combustion sources and NO_x combustion modification controls applied to these sources, and (2) to identify the most cost-effective, environmentally sound NO_x combustion modification controls for attaining and maintaining current and projected NO_2 air quality standards to the year 2000.

The NO_x EA will assess the following combination of process parameters and environmental impacts:

- Major fuel combustion stationary NO_x sources: utility boilers, industrial boilers, gas turbines, internal combustion (IC) engines, and commercial and residential warm air furnaces. Other sources (including mobile and noncombustion) will be considered only to the extent that they are needed to determine the NO_x contribution from stationary combustion sources.
- Conventional and alternate gaseous, liquid and solid fuels
- Combustion modification NO_x controls with potential for implementation to the year 2000; other controls (flue gas cleaning, mobile controls) will be considered only to estimate the future need for combustion modifications
- Source effluent streams potentially affected by NO_x controls

- Primary and secondary gaseous, liquid, and solid pollutants potentially affected by NO_x controls
- Pollutant impacts on human health and terrestrial or aquatic ecology

To achieve the objectives discussed above, the NO_x EA program approach is structured as shown schematically in Figure P-1. The two major tasks are: Environmental Assessment and Process Engineering (Task B5), and Systems Analysis (Task C). Each of these tasks is designed to achieve one of the overall objectives of the NO_x EA program cited earlier. In Task B5, of which this report is a part, the environmental, economic, and operational impacts of specific source/control combinations will be evaluated. On the basis of this assessment, the incremental multimedia impacts from the use of combustion modification NO_x controls will be identified and ranked. Task C will in turn use the results of Task B5 to identify and rank the most effective source/control combinations to comply, on a local basis, with the current NO_2 air quality standards and projected NO_2 related standards.

As show in Figure P-1, the key tasks supporting Tasks B5 and C are Baseline Emissions Characterization (Task B1), Evaluation of Emission Impacts and Standards (Task B2), and Experimental Testing (Task B3). The arrows in Figure P-1 show the sequence of subtasks and the major interactions among the tasks. The oval symbols identify the major outputs of each task. The subtasks under each main task are shown on the figure from the top to the bottom of the page in roughly the same order in which they will be carried out.

As indicated above, this report is a part of the Process Engineering and Environmental Assessment Task. The goal of this task is to generate process evaluations and environmental assessments for specific source/control combinations. These studies will be done in order of descending priority. In the first year of the NO_x EA, all the sources and controls involved in current and planned NO_x control implementation programs were investigated. The "Preliminary Environmental Assessment of Combustion Modification Techniques" (Reference P-1) documented this effort and established a priority ranking based on source emission impact and potential for effective NO_x control, to be used in the current ongoing detailed evaluation.

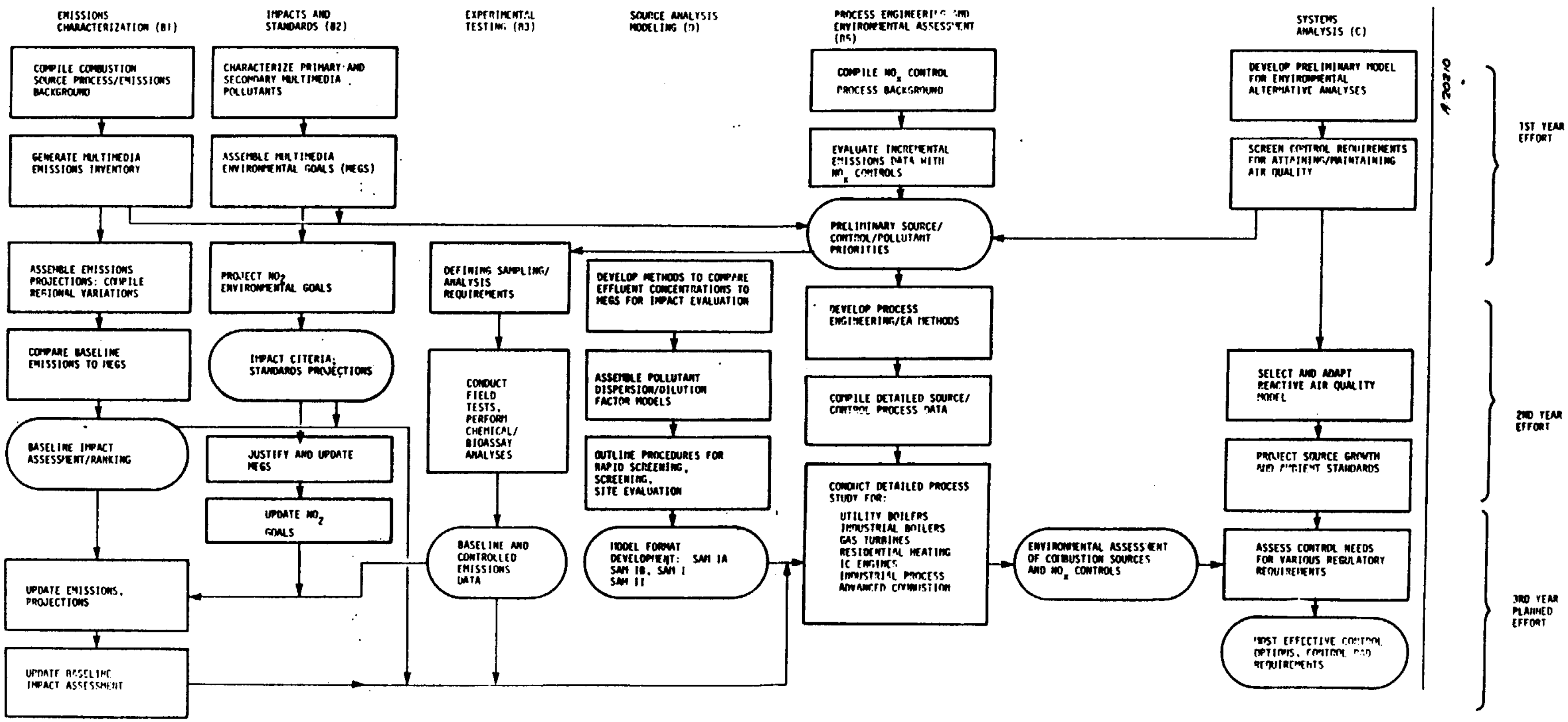

Figure P-1. NO_x EA approach.

This report presents the assessment of combustion modification NO_x controls for the second source category to be treated, industrial boilers. Other environmental assessment reports documented are:

- Environmental Assessment of Utility Boiler Combustion Modification NO_x Controls (Reference P-2)
- Environmental Assessment of Combustion Modification Controls for Stationary Gas Turbines (Reference P-3)
- Environmental Assessment of Combustion Modification Controls for Stationary Internal Combustion Engines (Reference P-4)
- Environmental Assessment of Combustion Modification Controls for Residential and Commercial Heating Systems (Reference P-5)

REFERENCES FOR PREFACE

P-1. Mason, H. B., et al., "Preliminary Environmental Assessment of Combustion Modification Techniques. Volume II: Technical Results," EPA-600/7-77-119b, NTIS-PB 276 681/AS, October 1977.

P-2. Lim, K. J., et al., "Environmental Assessment of Utility Boiler Combustion Modification NO_x Controls: Volume I. Technical Results; Volume II: Appendices," EPA-600/7-80-075a and b, April 1980.

P-3. Larkin, R., et al., "Combustion Modification Controls for Stationary Gas Turbines: Volume I. Environmental Assessment," EPA-600/7-81-122a, July 1981.

P-4. Lips, H. I., et al., "Environmental Assessment of Combustion Modification Controls for Stationary Internal Combustion Engines," EPA-600/7-81-127, July 1981.

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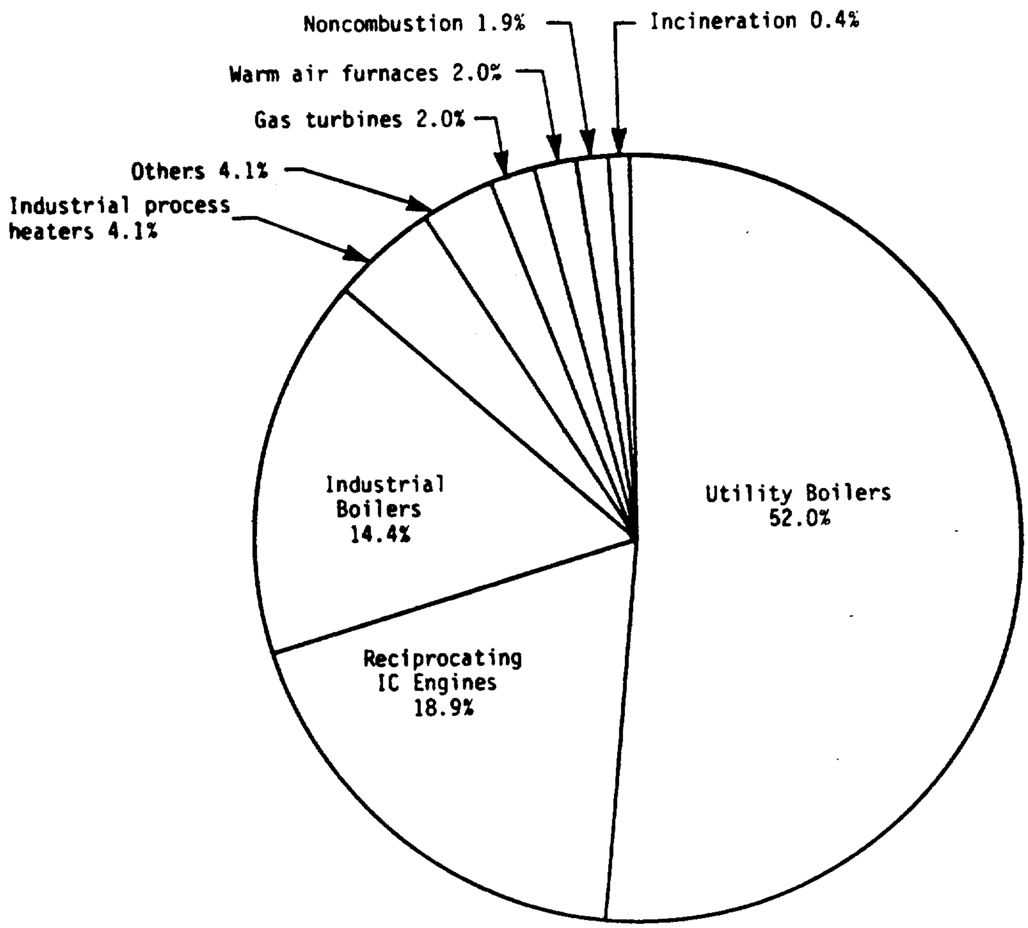
EXECUTIVE SUMMARY

S.1 INTRODUCTION

The 1970 Clean Air Act designated oxides of nitrogen (NO_x) as one of the criteria pollutants requiring regulatory controls to prevent potential widespread adverse health and welfare effects. To attain and maintain ambient air quality standards, the act mandated control of new mobile and stationary NO_x sources, each of which emits approximately half of the manmade NO_x nationwide. As shown in Figure S-1, industrial boilers represent the third largest contributor to total stationary source NO_x emissions. Indeed, industrial boilers were the origin of approximately 14 percent of all stationary NO_x emissions for the year 1977 (Reference S-1). The problem of NO_x emissions is expected to become more severe as impending shortages of oil and gas fuels force conversion to coal, which has the potential for higher NO_x emissions. In fact, the Powerplant and Industrial Fuel Use Act of 1978 and subsequent rules to implement that act may prohibit new major fuel-burning installations (MFBI) with an aggregate heat input capacity greater than or equal to 73 MW (250×10^6 Btu/hr) from burning oil or natural gas, except under extraordinary circumstances (Reference S-2). Furthermore, conversion of existing units to coal may possibly be encouraged through tax incentives.

Since the Clean Air Act, NO_x control techniques have been developed and implemented reducing emissions by a significant amount (20 to 60 percent) for a variety of source/fuel combinations, notably in the utility boiler sector. With increasingly stringent New Source Performance Standards (NSPS) established for utility boilers, the Environmental Protection Agency (EPA) is currently compiling and developing background information on industrial boilers with the intent of proposing NSPS (Reference S-3). State and local regulatory developments also point to increasing NO_x control implementation.



Total: 10.5 Tg/yr (11.6 x 10^6 tons/yr)

Figure S-1. Distribution of stationary anthropogenic NO_x emissions for the year 1977 (stationary fuel combustion) (Reference S-1).

This report provides an environmental assessment of NO_x control technology for coal-, oil-, and natural gas-fired industrial boilers. The effectiveness of controls in reducing NO_x emissions and their applicability to industrial boilers are reviewed. Demonstrated or expected operational or environmental impacts are highlighted, and energy and cost impacts are noted. The majority of the emissions data evaluated are drawn from References S-4 through S-15.

S.2 NO_x FORMATION MECHANISMS AND PRINCIPLES OF CONTROL

NO_x formed in combustion processes is usually due to either thermal fixation of atmospheric nitrogen in the combustion air, leading to thermal NO_x, or to the conversion of chemically bound nitrogen in the fuel, leading to fuel NO_x. For natural gas and distillate oil firing, nearly all NO_x emissions result from thermal fixation. With residual oil and coal, the contribution from fuel-bound nitrogen can be significant and, under certain operating conditions, predominant.

Both thermal and fuel NO_x appear to be kinetically or aerodynamically limited because emission rates are far below the levels that would prevail at equilibrium. Thus, the rate of formation of both thermal and fuel NO_x is dominated by combustion conditions and is amenable to suppression through combustion process modifications. Although the mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of oxygen with the fuel. Additionally, thermal NO_x is greatly increased by long residence time at high temperature. The modified combustion conditions and control concepts tried or suggested to limit NO_x formation include:

- Decrease primary flame zone O_2 level by:
  - Decreased overall O_2 level
  - Controlled mixing of fuel and air
  - Use of fuel-rich primary flame zone
- Decrease time of exposure at high temperature by:
  - Decreased peak temperature
  - Decreased adiabatic flame temperature through dilution
  - Decreased combustion intensity
  - Increased flame cooling

-- Controlled mixing of fuel and air or use of fuel-rich primary flame zone

-- Decreased primary flame zone residence time

Table S-1 relates these control concepts to applicable combustion process modifications and equipment types. The process modifications are further categorized according to their role in the control development sequence: operational adjustments, hardware modifications of existing equipment or through factory-installed controls, and major redesigns of new equipment. The controls for decreased O_2 are also generally effective for peak temperature reduction but have not been repeated.

In addition to these combustion modification concepts that suppress NO_x formation, postcombustion techniques which chemically control NO_x with a reducing agent such as ammonia are under development. These include both homogeneous noncatalytic and heterogeneous catalytic reduction systems. This study reviews only the ammonia injection process. Postcombustion flue gas treatment processes are evaluated in depth elsewhere (Reference S-16).

S.3 OVERVIEW OF NO_x CONTROL TECHNIQUES

The NO_x controls having possible application to industrial boilers include:

- Low excess air (LEA)
- Staged combustion (SC)
- Low NO_x burners (LNB)
- Flue gas recirculation (FGR)
- Reduced air preheat (RAP)
- Load reduction (LR) or reduced combustion intensity (furnace redesign)
- Ammonia injection (homogeneous reduction)

Low Excess Air

Reducing the excess air level in the furnace has generally been found to be an effective method of NO_x control for all fuels, reducing NO_x by 5 to 25 percent. In this technique, the combustion air is reduced to the minimum amount required for complete combustion, maintaining acceptable furnace cleanliness and steam temperature. With less oxygen available in the flame zone, both thermal and fuel NO_x formation is reduced. In addition, the reduced airflow reduces the

TABLE S-1. SUMMARY OF COMBUSTION PROCESS MODIFICATION CONCEPTS

Combustion Conditions	Control Concept	Effect on Thermal NO_x	Effect on Fuel NO_x	Primary Applicable Controls		
				Operational Adjustments	Hardware Modification	Major Redesign
Decrease Primary Flame Zone O_2 Level	Decrease overall O_2 level	Reduces O_2 rich, high NO_x pockets in the flame	Reduces exposure of fuel nitrogen intermediaries to O_2	Low excess air firing	Flue gas recirculation (FGR)	
	Delayed mixing of fuel and air	Flame cooling and dilution during delayed mixing reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burner adjustments	Low NO_x burners	Optimum burner/firebox design
	Primary fuel-rich flame zone	Flame cooling in low O_2, low temp. primary zone reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burners out of service; biased burner firing	Overfire air ports	Burner/firebox design for two stage combustion
Decrease Peak Flame Temperature	Decrease adiabatic flame temperature	Direct suppression of thermal NO_x mechanism	Ineffective	Reduced air preheat	Water injection, FGR	
	Decrease combustion intensity	Increased flame zone cooling yields lower peak temperature	Minor direct effect; indirect effect on mixing	Load reduction		Enlarged firebox, increased burner spacing
	Increased flame zone cooling/reduce residence time	Increased flame zone cooling yields lower peak temperature	Ineffective	Burner tilt		Redesign heat transfer surfaces, firebox aerodynamics

quantity of flue gas released per unit time resulting in an improvement in boiler efficiency. LEA, being the simplest NO_x control technique with the added benefit of improved boiler efficiency, is often the first technique implemented.

Staged Combustion

Staged combustion, through the use of overfire air (OFA) ports or burners-out-of-service (BOOS), seeks to control NO_x by carrying out initial combustion in a primary, fuel-rich combustion zone, then completing combustion, at lower temperatures, in a second, fuel-lean zone. The technique involves firing the active burners (or the combustion bed in the case of stokers) more fuel rich than normal while admitting the remaining combustion air through OFA or inactive burners (BOOS). SC is generally very effective for NO_x reduction and may be used with all fuels with reductions of up to 30 percent.

Low NO_x Burners

Low NO_x burners are generally designed to reduce flame turbulence, delay fuel-air mixing, and establish fuel-rich zones where combustion initially takes place. The longer, less intense flames produced with LNB's, as compared to those of conventional burners, result in lower flame temperatures that reduce thermal NO_x generation. Moreover, the reduced availability of oxygen in the initial combustion zone inhibits fuel NO_x conversion. LNB's represent a developing technology that promises highly effective NO_x control at a relatively low cost, with NO_x reductions of 40 to 60 percent projected.

Flue Gas Recirculation

Flue gas recirculation for NO_x control consists of extracting a portion of the flue gas and returning it to the furnace, admitting the flue gas through the burner windbox. FGR lowers the bulk furnace gas temperature and reduces oxygen concentration in the combustion zone. The former effect is probably dominant since FGR has been found to be most effective in reducing thermal NO_x. FGR has not been found to be an effective control method, considering the major equipment modification involved, for coal and residual oil, fuels for which fuel NO_x often predominates. Indeed, NO_x reductions of only 10 to 15 percent have been found for coal firing, but reductions of 40 to 70 percent have been achieved for distillate oil and gas. Addition of FGR to a boiler is a major modification: the fan, dampers, and controls as well as possibly having to increase existing fan capacity due to increased draft loss, can represent a large investment.

Reduced Air Preheat

Reducing the amount of combustion preheat lowers the primary combustion zone peak temperature, generally lowering thermal NO_x production as a result. It is an effective technique applicable to the clean fuels: distillate oil and natural gas. However, to prevent severe energy penalties, an economizer should be substituted when possible as a flue gas heat recovery device. RAP has not been found effective for coal-fired units.

Load Reduction

Reducing combustion intensity generally lowers thermal NO_x formation. Reduced combustion intensity can be brought about by load reduction in existing units and by use of an enlarged firebox in new units. NO_x reduction field test results on industrial boilers have been mixed, on a retrofit basis, but the technique is probably best implemented as an increased furnace plan area in new designs, based on results for new utility boilers.

Ammonia Injection

This technique reduces NO to N_2 and H_2O with injection of ammonia (NH_3) at flue gas temperatures ranging from 1070 to 1270K (1470^{o} to $1830^{o}F$). However, the method is very temperature-sensitive with maximum NO_x reductions occurring in a very narrow temperature window around 1240 $\pm$50K (1770^{o} $\pm 90^{o}F$). Addition of hydrogen can lower and thus extend the effective temperature window. An elaborate NH_3 (and possibly H_2) injection, monitoring, and control system is required. The application of this technique to flue gas from coal combustion has not been demonstrated in the field. Several industrial boilers in California are being fitted with ammonia injection as part of demonstration programs. Control effectiveness is projected to be 40 to 60 percent (References S-17 and S-18). Ammonia injection is a postcombustion technique under development, for possible application after conventional combustion modifications have already been applied, where additional NO_x reductions are required.

S.4 APPLICATION OF CONTROLS TO COAL-FIRED BOILERS

S.4.1 Pulverized Coal

Combustion modification NO_x controls have been successfully implemented on a limited number of industrial boilers. Representative equipment design types and typical baseline (uncontrolled) NO_x emissions from industrial boilers are listed in Table S-2. It should be noted that NO_x emissions are site specific, dependent on individual boiler/burner design differences, fuel properties, and local combustion conditions. Thus a particular boiler can exhibit an emission level outside the typical range indicated.

Of seven pulverized coal-fired units tested, baseline NO_x emissions ranged from 174 to 563 ng/J, with most data from 200 to 300 ng/J. No significant correlation of emission levels with (pulverized coal) boiler type (i.e., tangential versus wall-fired), coal properties, or operating conditions was evident from the limited data. For example, Figure S-2 shows that the fuel nitrogen content has no significant effect on NO_x emissions from coal-fired industrial boilers. Although undoubtedly fuel NO_x emissions increase with increasing fuel nitrogen content, the emissions increase is not proportional; furthermore, such effects are often overshadowed by boiler design and operating parameters. Indeed, Figure S-2 shows that the data for pulverized coal and spreader stoker units are clustered in the 200- to 300-ng/J heat input range, while other stoker types are clustered in the 100- to 200-ng/J range, all independent of fuel nitrogen content. All these units were generally operating at normal excess air levels.

Table S-3 lists the combustion modifications applicable to pulverized coal-fired industrial boilers. Combustion modifications for which no actual data exist for the industrial boiler size range have also been included, based on utility boiler experience which is much more extensive. Clearly, industrial boiler control test data are limited.

Low Excess Air

Low excess air operation is a relatively simple technique to implement. It is applicable to all boiler types and requires only reducing airflow to the burner windbox. However, in a multiburner unit, modifications to the windbox might be necessary to improve air distribution to individual burners during LEA operation. Lowering excess

TABLE S-2. REPRESENTATIVE INDUSTRIAL BOILERS AND TYPICAL BASELINE NO_x EMISSION LEVELS

Fuel	Boiler Type	Typical Size (Heat Input Capacity) MW (10^6 Btu/hr)	Average NO_x Baseline Emission Level ng NO_2/J (lb/10^6 Btu)
Pulverized coal	Single wall and tangential	59 (200)	285 (0.663)
Stoker coal	Spreader	44 (150)	265 (0.616)
	Underfeed	9 (30)	150 (0.349)
	Chain grate	22 (74)	140 (0.326)
Residual oil[a]	Firetube	4.4 (15)	115 (0.267)
	Watertube	44 (150)	160 (0.372)
Distillate oil	Firetube	4.4 (15)	70 (0.163)
	Watertube		
	Without air preheater	29 (100)	55 (0.128)
	With air preheater		90 (0.208)
Natural gas	Firetube	4.4 (15)	40 (0.093)
	Watertube		
	Without air preheater	29 (100)	45 (0.105)
	With air preheater		110 (0.255)

[a]Includes No. 5 and No. 6 fuel oils

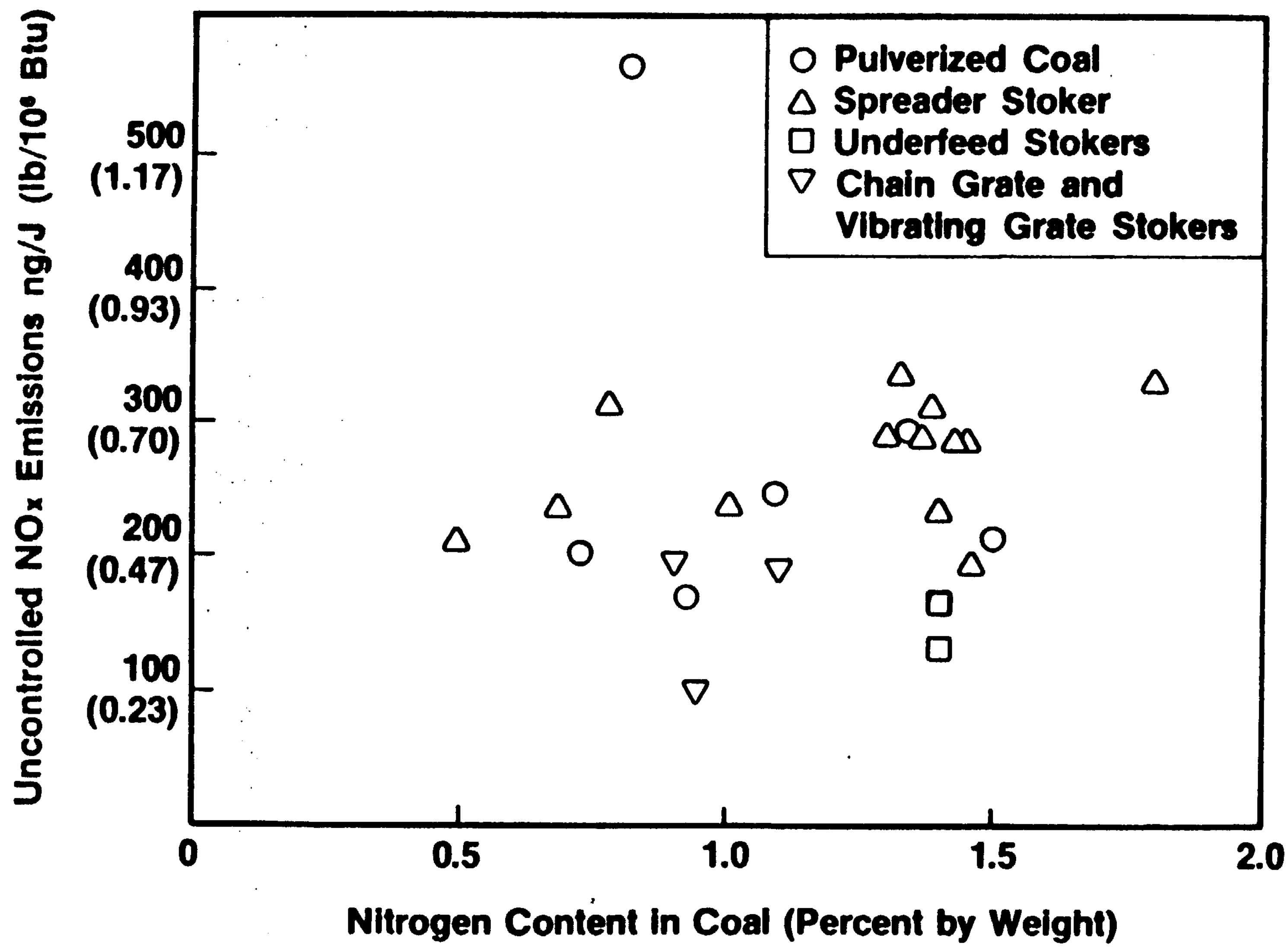


Figure S-2. Effect of fuel nitrogen content on NO_x emissions from coal-fired industrial boilers.

TABLE S-3. COMBUSTION MODIFICATION NO_x CONTROLS FOR PULVERIZED COAL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commercial Availability/ R&D Status	Comments
Low Excess Air (LEA)	Reduction of combustion air	7	0-25 (avg. 9)	Excess oxygen reduced to 5.2% on the average	Available	Added benefits of technique include increase in boiler efficiency, limited by increase in CO. HC and smoke emissions.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder firing fuel-rich.	2	27-39 (avg. 33)	Applicable only for boilers with minimum of 4 burners	Available. However, extensive engineering work necessary prior to implementation.	Limited by the number of burners available. Load reduction required in most cases. Possible increased slagging, corrosion.
Overfire Air Injection (OFA)	Secondary air from OFA ports above fuel rich firing burners		5-30	Burner stoichiometry as low as 100%	Commercially offered but not demonstrated for industrial size boilers	Requires installation of OFA ports, etc. Possible increased slagging, corrosion
Flue Gas Recirculation (FGR)	Recirculation of flue gas to burner windbox		0-20	Up to 25% of the flue gas recirculated	Not offered because relatively ineffective	Requires installation of FGR ducts, fan, etc. Can cause combustion instability. Burner windbox may need extensive modifications
Low NO_x Burner (LNB)	New burner designed utilizing controlled air-fuel mixing		45-60	Prototype LNB limited to size ranges above 29 MW (100×10^6 Btu/hr)	Still in the development stage. Prototype LNB available from major boiler mfrs.	Active R&D efforts underway

TABLE S-3. CONCLUDED

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commercial Availability/ R&D Status	Comments
Ammonia Injection	Injection of NH_3 in convective section of boiler		40-60	Limited by furnace geometry. NH_3 injection rate limited to 1.5 NH_3/NO.	Commercially offered but not demonstrated	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate.
Reduced Load	Reduction of fuel and air flow to the boiler.	6	Varies from 45% reduction to 4% increase in NO_x	Applicable to all boilers. Load can be reduced to 25% of capacity.	Available now but not implemented because of adverse operational impacts	Load reduction often not effective because of increase in excess O_2. Best implemented with increase in furnace size for new boilers.

air can reduce the safety margin for complete combustion. Hence, installation of an oxygen trim system may be necessary, in addition to the normal airflow controllers. Nevertheless, boiler efficiency gains with LEA should offset any additional hardware costs, and thus make LEA the most attractive NO_x control technique for first implementation (5 to 25 percent NO_x reduction). Figure S-3 shows the results of LEA tests on representative coal-fired industrial boilers. The slopes of the data bands indicate the relative effectiveness of LEA on each equipment category. It is seen that LEA is about equally effective for each category.

Staged Combustion

Staged combustion with OFA and LEA represents the best demonstrated, available control option for pulverized coal-fired industrial boilers, potentially reducing NO_x emissions by up to 30 percent. The LEA and OFA control system has primary advantage over the other control systems because of its commercial availability and its effectiveness. The cost of the system is not prohibitive when OFA ports are designed as a part of new boilers. In addition, careful operation of staged air injection is not expected to seriously affect emissions of other criteria pollutants. Burner stoichiometries in the range of 100 to 110 percent would be adequate to achieve a 20-percent NO_x reduction (Reference S-19). At these stoichiometry levels, oxidizing atmospheres would prevail in the furnace, thus minimizing concern over possible furnace slagging and boiler tube wastage. However, achieving more stringent NO_x control with combined LEA and OFA may require burner stoichiometries be reduced below 100 percent in some cases. This low burner stoichiometry level would cause reducing atmospheres in parts of the furnace, thus creating the potential for corrosion of water tubes, especially when firing high-sulfur coal (Reference S-20). Generally, boiler manufacturers do not recommend burner operation with stoichiometry below 100 percent primarily because of increased corrosion potential. Another potential adverse impact is that additional excess air may be required to ensure complete combustion, resulting in a decrease in boiler efficiency. However, experience with utility boilers indicates that these potential problems can be overcome with proper design and implementation (Reference S-20). Indeed, a recent 30-day, continuous monitoring test of

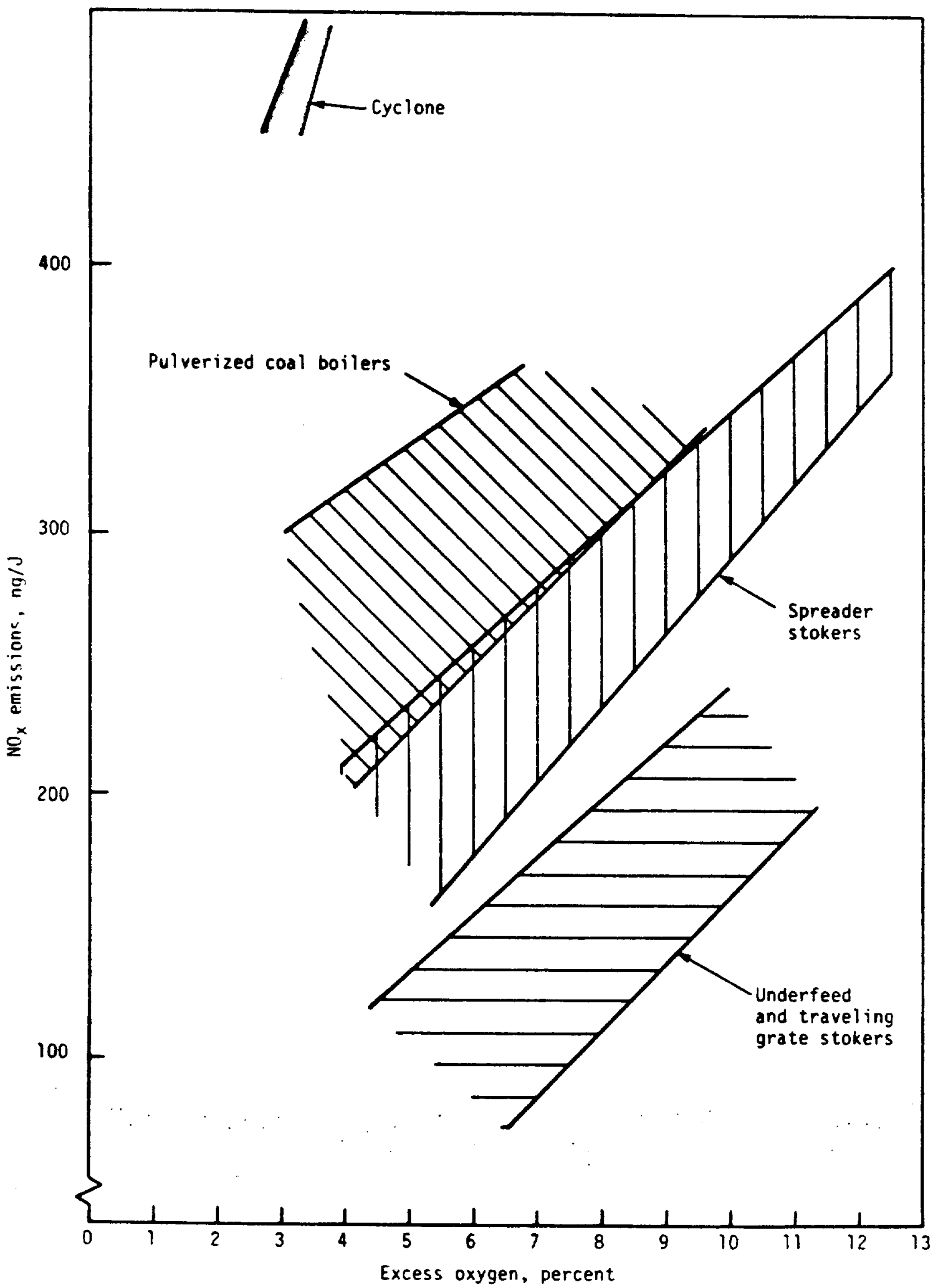


Figure S-3. Effect of excess oxygen on NO_x emissions from coal-fired boilers.

SC with LEA, at varying reduced boiler loads, demonstrated a 30-percent NO_x reduction with no adverse operational impacts (Reference S-15).

Burners out of service is the other technique that can be used to obtain SC. It is primarily considered for retrofit application. However, it is not a favored technique because of several limitations:

- Extensive engineering and testing on an individual boiler basis is required to determine the optimal BOOS pattern
- Selection of an effective BOOS pattern is sometimes not possible because pulverizers may serve burners located on two separate levels. The most effective BOOS pattern often involves only the top level of burners on air only.
- In many cases, burners/pulverizers that operate during BOOS cannot handle increased coal flow, necessitating a significant reduction in the boiler steam rating (e.g., 20-percent derate)
- Potential increased slagging and corrosion

Low NO_x Burners

Because of the possible operational problems associated with SC, a number of low NO_x burner designs are under development by commercial firms, with 40 to 60 percent NO_x control projected. An advanced design under study by EPA is the distributed fuel-air mixing concept, illustrated in Figure S-4. Field testing and application is scheduled for late 1982, with a target NO_x level of 86 ng/J (0.2 lb/10^6 Btu) (References S-21 and S-22).

In some applications, LNB's may have several advantages over other combustion modifications such as SC with OFA or BOOS. For example, one utility boiler manufacturer claims that LNB's will maintain the furnace in an oxidizing environment, minimizing slagging and reducing the potential for furnace corrosion when firing high-sulfur coal (Reference S-23). Also, more complete carbon utilization may be achieved due to better coal-air mixing in the furnace. Finally, lower oxygen levels may be obtained with all the combustion air admitted through the burners (Reference S-20).

Since the burners generally alter the flame configuration, care must be taken when applying the burners to existing boilers. For instance, some LNB's have a longer flame length. Such burners can be installed only in those boilers large enough to avoid cold wall

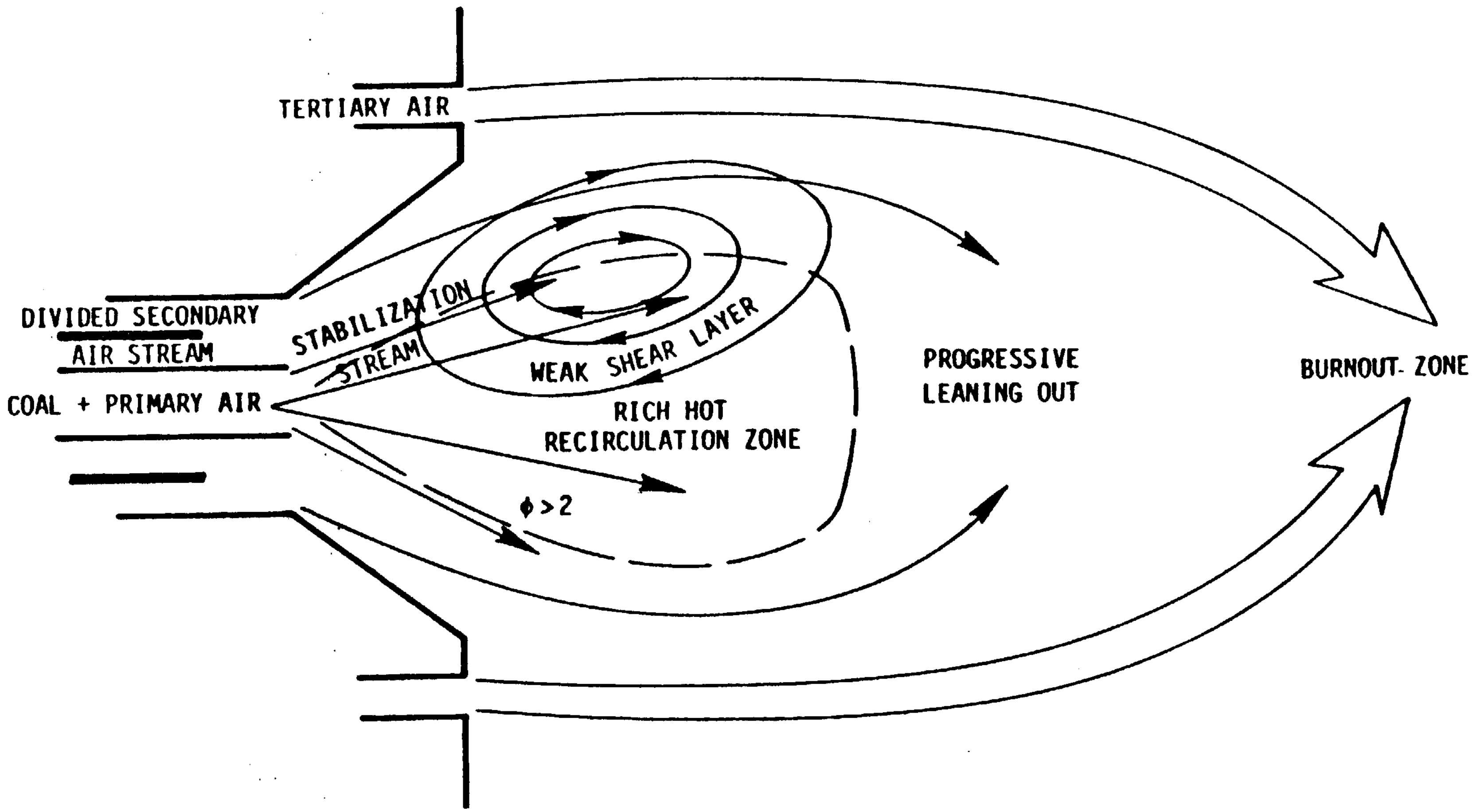


Figure S-4. Distributed fuel-air mixing concept (Reference S-22).

impingement. Once developed, however, low NO_x, coal-fired burners for industrial boilers could become the best control system because of the expected lower cost, higher NO_x reduction capability, and other operational advantages over SC.

Ammonia Injection

If additional control over and above boiler/burner modifications are needed (e.g., to meet stringent local regulations), ammonia injection is a commercially offered technique. A schematic is shown in Figure S-5. The technique has yet to be demonstrated on coal-fired boilers and is several times more costly than conventional combustion modifications. In addition, as a developing technology, there are several potential implementation and operational problems that need to be resolved:

- Optimal effectiveness for noncatalytic reduction of NO by NH_3 occurs over a very narrow temperature range; hence, the precise location of NH_3 injection ports is crucial
- Since the temperature profile in a boiler changes with load, NO_x control with NH_3 may dictate load restriction
- Emissions of NH_3 and byproducts
- Possible boiler equipment fouling by ammonium sulfates

However, the major strengths of the technique are its potential for high NO_x removal (40 to 60 percent), and its applicability as an additional control that can be combined with conventional combustion techniques for large NO_x reductions (References S-17 and S-18).

S.4.2 Stoker Coal

NO_x emissions from stokers are generally lower than those from pulverized coal. These lower emissions have been attributed to the lower combustion intensity and to the partial staged combustion that naturally occurs during combustion on fuel beds (Reference S-24).

As illustrated in Figure S-2, NO_x emissions from spreader stokers tend to be higher than those from other stoker designs. The coal in a spreader stoker boiler burns partly in a suspended state and partly on a moving or vibrating grate. The combustion of coal in the suspended state apparently causes NO_x emissions to be generally higher than for other stoker types that feed and combust coal directly on a moving grate. In addition, the higher heat release rates of spreader stokers probably also contribute to high NO_x emissions.

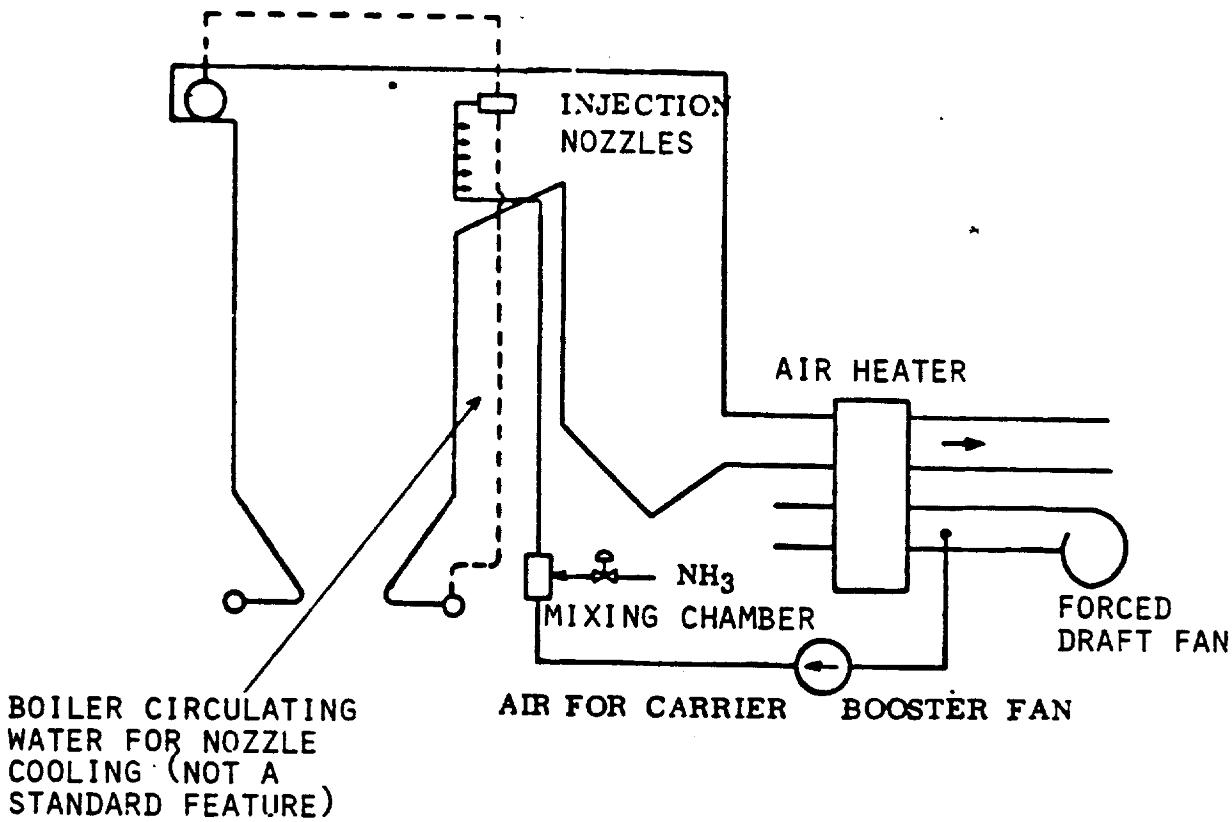


Figure S-5. Schematic diagram of an NH_3 injection system.

Four methods have been used to modify stoker coal combustion to reduce NO_x emissions. These methods are (1) reduced undergrate air or LEA, (2) OFA, (3) reduced heat input, and (4) RAP. Of these methods, only LEA firing has been demonstrated to be widely effective. Table S-4 summarizes the performance and limitations of each of these techniques.

Low Excess Air

Low excess air firing represents the only widely effective NO_x control technique for coal-fired stokers. Figure S-6 is a schematic of a spreader stoker furnace showing where combustion air is introduced in this type of boiler. OFA is generally controlled independently from undergrate air. LEA tests performed in the field consisted of reducing the undergrate airflow while maintaining the OFA flow close to normal operation.

A series of EPA field tests of 17 stokers indicate that the excess oxygen levels at baseline operating conditions averaged about 9 percent. During LEA tests, the average excess oxygen level was reduced to 6.4 percent. Such reduction lowered NO_x emission levels approximately 10 percent for each 1-percent reduction in excess oxygen. Indeed, data from an ongoing EPA-DOE-ABMA field test program involving 11 relatively new design stokers operating near the lower excess air level tend to support this general trend (Reference S-14).

The minimum achievable excess air is limited by several factors. Except for the water-cooled vibrating grate, the only cooling of the grate is by the flow of air. If this air is cut back too much, the grate can overheat. There is also the danger of creating local reducing zones and of forming harmful corrosion products as the air is cut back. Another problem noticed during field tests has been the formation of clinkers and increased CO emissions as the excess oxygen was reduced. However, test results indicate that if excess oxygen levels are maintained above 5 percent, CO emissions will tend to stay below 150 ppm.

Fuel combustion with lowest possible levels of excess air assures maximum boiler efficiency unless the air is decreased to the point where unburned carbon losses are greatly increased. From the limited amount of data it can be tentatively generalized that if the airflow is maintained such that the excess oxygen level is approximately above 6 percent, no serious operational or emission problem should result. Of course, this

TABLE S-4. COMBUSTION MODIFICATION NO_x CONTROLS FOR STOKER COAL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commercial Availability/ R&D Status	Comments
Low Excess Air (LEA)	Reduction of air flow under stoker bed	24	5-25	Excess O_2 limited to 5-6% minimum	Available now but need R&D on lower limit of excess air	Danger of overheating grate, clinker formation, corrosion, and high CO emissions
Staged Combustion (LEA + OFA)	Reduction of undergrate air flow and increase of overfire air flow	5	5-25	Excess O_2 limited to 5% minimum	Most stokers have OFA ports as smoke control devices but may need better air flow control devices	Need research to determine optimal location and orientation of OFA ports for NO_x emission control. Overheating grate, corrosion, and high CO emission can occur if undergrate airflow is reduced below acceptable level as in LEA.
Load Reduction (LR)	Reduction of coal and air feed to the stoker	13	Varies from 49% decrease to 25% increase in NO_x (average 15% decrease)	Has been used down to 25% load	Available	Only stokers that can reduce load without increasing excess air. Not a desirable technique because of loss in boiler efficiency.
Reduced Air Preheat (RAP)	Reduction of combustion air temperature	1	8	Combustion air temperature reduced from 473K to 453K	Available now if boiler has combustion air heater	Not a desirable technique because of loss in boiler efficiency
Ammonia Injection	Injection of NH_3 in convective section of boiler		40-60 (from gas- and oil-fired boiler experience)	Limited by furnace geometry. Feasible NH_3 injection rate limited to 1.5 NH_3/NO.	Commercially offered but not yet demonstrated	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate.

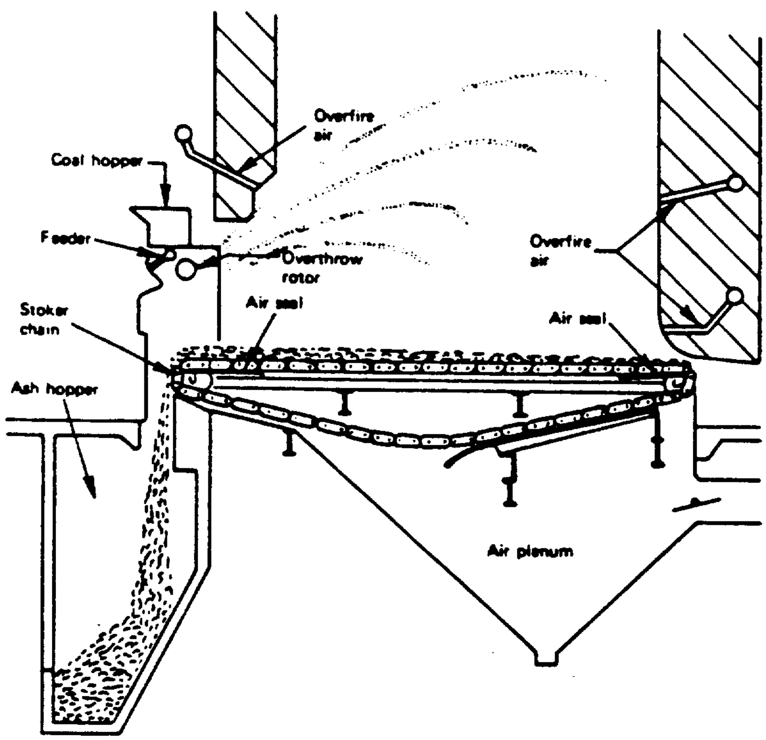


Figure S-6. Air injection in a traveling-grate spreader stoker (Reference S-24).

generalization would require verification. Indeed, the minimum excess oxygen level for a particular boiler could be higher than 6 percent. NO_x emission reductions of about 5 to 25 percent and increases in boiler efficiency of 1 percent can be expected with LEA provided fuel burnout does not change during the process.

Research and development work on redesigning the grate and stoker would be necessary if even lower excess oxygen levels are required. In addition, a solution to the clinker formation problem will also be needed for this type of operation.

Staged Combustion

One of the reasons NO_x emissions from stokers is lower than those from pulverized coal-fired boilers is the partial staged combustion nature of combustion of fuel beds (Reference S-25). Volatile matter leaves the fuel bed as the coal is fed into the grate and burns above the bed level. The solids are subsequently burned with lower combustion intensity.

An increased staged combustion effect beyond what seems to occur naturally in the stoker furnace seems difficult to obtain. However, augmented staged combustion control can be effected by injecting air above the fuel bed through the OFA ports and reducing the undergrate airflow.

Figure S-7 shows the relative location of these airflows. A reduction of 10 to 25 percent in NO_x has been achieved by this method without increasing CO emissions. However, most stokers have OFA ports originally designed for use as smoke control devices. Therefore, the location or orientation of the OFA ports may not be the optimum to achieve best NO_x reductions. For example, one test showed a 25-percent reduction in NO_x emissions by using two oil burners as OFA ports. However, these burner ports were located far above the existing stoker OFA ports. Other OFA tests, using only the existing OFA ports located closer to the fuel bed rather than the burner ports, lowered NO_x emission only 10 percent. The current EPA-DOE-ABMA field program has found little success with OFA on existing units (Reference S-14).

The OFA method suffers from the same potential problems as LEA because reduced undergrate airflow is absolutely necessary to achieve any staging effect. Therefore, limitations applicable to the technique of LEA such as grate overheating, corrosion, and clinker formation can also limit the application of the staged combustion technique. An ongoing

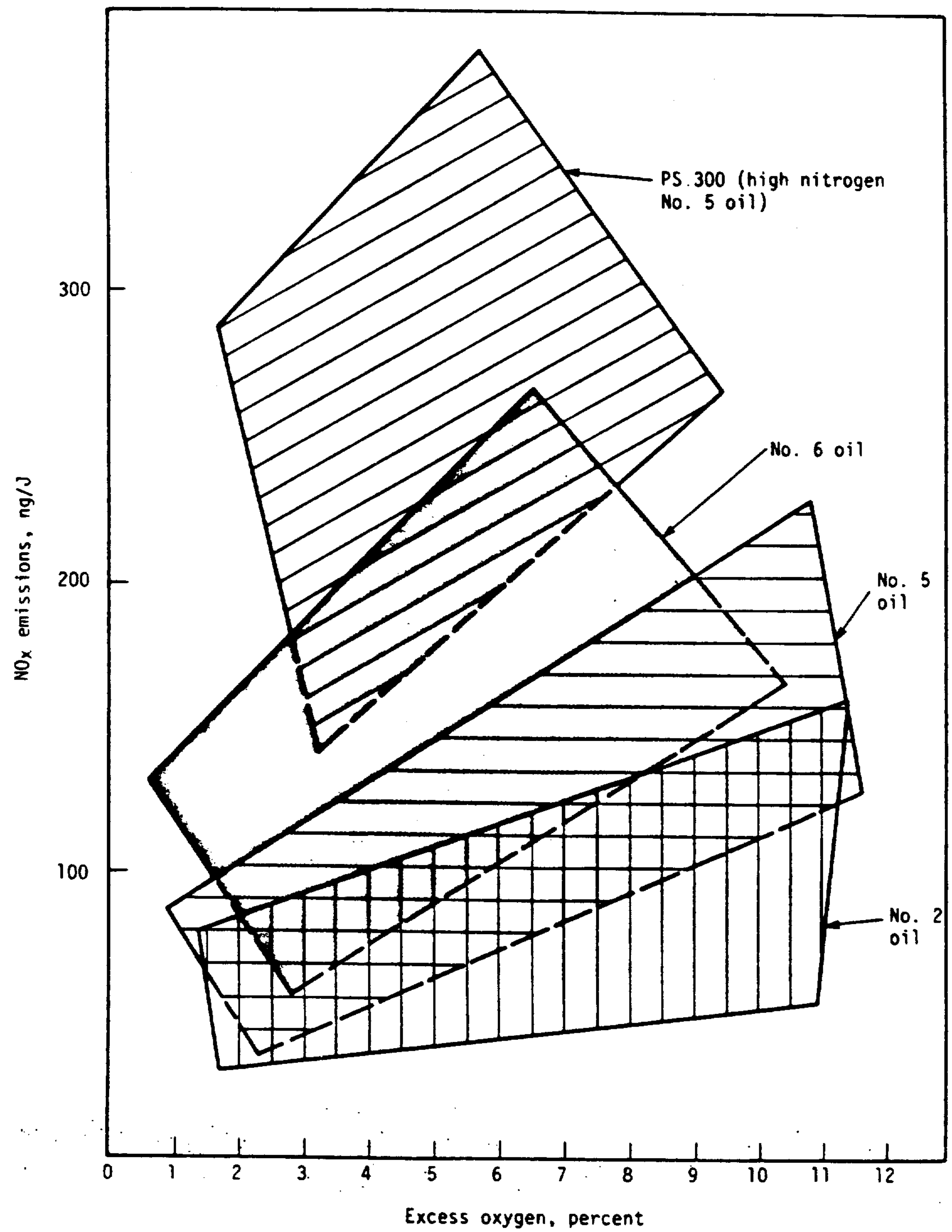


Figure S-7. Effect of excess oxygen on NO_x emission from distillate and residual oil-fired boilers

EPA-sponsored program is examining advanced stoker designs, including use of OFA for NO_x control (Reference S-26).

Ammonia Injection

Ammonia injection is potentially applicable although it has not yet been demonstrated on an industrial stoker. The boiler geometry and the flue gas temperature profile in a stoker should permit the implementation of the NH_3 injection process in a similar manner as for a pulverized coal-fired unit. Indeed, the discussion on performance and limitations of ammonia injection as noted earlier for pulverized coal firing is also applicable to stokers, and will not be repeated here.

S.5 APPLICATION OF CONTROLS TO OIL-FIRED BOILERS

Combustion modification NO_x controls have been successfully implemented on a limited number of oil-fired boilers, as for coal-fired units. Table S-5 summarizes the performance characteristics of potentially applicable controls. As noted earlier, low excess air firing is the only demonstrated control technique applicable to all industrial boilers. Figure S-7 gives a graphic presentation of the excess air test results. Although the test data of Table S-5 indicated that LEA is about equally effective on a percentage basis for both residual and distillate oil (about 11 percent NO_x reduction), Figure S-7 shows that absolute NO_x reductions are greater for the higher nitrogen, heavier fuels (data bands have steeper slope). This is, of course, expected because LEA is effective in reducing both fuel and thermal NO_x in the heavier fuels. Number 2 distillate oil produces primarily thermal NO_x.

S.5.1 Residual Oil

Baseline NO_x emissions from residual oil-fired firetube boilers are relatively low, averaging 115 ng/J (Table S-2). Low excess air operation should lower emissions by about 10 percent and also increase boiler efficiency. The same caution about possible increased CO and hydrocarbon emissions discussed for coal firing under low excess air applies here also. Low NO_x burners or staged combustion are the preferred alternatives if additional control is necessary. However, neither one is demonstrated for the firetube boiler design. Developing low NO_x burners may become the first control choice after LEA because of their potential for high NO_x reductions with the lowest boiler operational impact.

TABLE S-5. COMBUSTION MODIFICATION NO_x CONTROLS FOR OIL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	No. of Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)		Range of Application	Commercial Availability/ R&D Status	Comments
			Residual	Distillate Oil			
Low Excess Air (LEA)	Reduction of combustion air	22 residual oil boilers, 7 distillate oil boilers	0 to 28 (11 average) or 10 ng/J/ % O_2 reduction	0 to 24 (11 average) or 10 ng/J/ % O_2 reduction	Generally excess O_2 can be reduced to 2.5% representing a 3% drop from baseline	Available	Added benefits included increase in boiler efficiency. Limited by increase in CO, HC, and smoke emissions.
Staged Combustion (SC)	Fuel-rich firing burners with secondary combustion air ports	3 residual oil boilers, 1 distillate oil boiler	20 to 50	17 to 44	70-90% burner stoichiometries can be used with proper installation of secondary air ports	Technique is applicable on package and field-erected units. However, not commercially available for all design types.	Best implemented on new units. Retrofit is probably not feasible for most units especially packaged ones.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	8 boilers	10 to 30	N/A	Applicable only for boilers with minimum of 4 burners. Best suited for square burner pattern with top burner or burners out of service. Only for retrofit application.	Available. Retrofit requires careful selection of BOOS pattern and control of air flow.	Retrofit often requires boiler derating unless fuel delivery system is modified
Flue Gas Recirculation (FGR)	Recirculation of portion of flue gas to burners	1 distillate oil boiler, 2 residual oil boilers	15 to 30	58 to 73	Up to 25-30% of flue gas recycled. Can be implemented on all design types.	Available. Requires extensive modifications to the burner and windbox.	Best suited for new units. Costly to retrofit. Possible flame instability at high FGR rates.
Flue Gas Recirculation Plus Staged Combustion	Combined techniques of FGR and staged combustion	Only one packaged watertube boiler	25 to 53	73 to 77	Max. FGR rates set at 25% for distillate oil and 20% for residual oil	Combined techniques are still at experimental stage. Needs more R&D.	Retrofit may not be feasible. Best implemented on new units.

TABLE S-5. CONCLUDED

Control Technique	Description of Technique	No. of Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)		Range of Application	Commercial Availability/ R&D Status	Comments
			Residual	Distillate Oil			
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	17 residual oil-fired boilers, 7 distillate oil-fired boilers	33% decrease to 25% increase in NO_x	31% decrease to 17% increase in NO_x	Applicable to all boiler types and sizes. Load can be reduced to 25% of maximum.	Available now as a retrofit application. Better implemented with improved firebox design	Technique not effective when it necessitates an increase in excess O_2 levels. LR possibly implemented in new designs as reduced combustion intensity (enlarged furnace plan area).
Low NO_x Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation	Large number tested in Japan	20 to 50	20 to 50	New burners described generally applicable to all boilers. More specific information needed.	Commercially offered but not demonstrated	Specific emissions data from industrial boilers equipped with LNB are lacking
Ammonia Injection	Injection of NH_3 as a reducing agent in the flue gas	5 (4 Japanese installations, 1 domestic)	40 to 70	40 to 70	Applicable for large package and field-erected watertube boilers. May not be feasible for firetube boilers.	Commercially offered but not demonstrated	Elaborate NH_3 injection, monitoring and control system required. Possible load restrictions on boiler and air preheater fouling when burning high sulfur oil.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	2 residual oil-fired boilers	5 to 16	NA	Combustion air temp. can be reduced to ambient conditions (340K)	Available. Not implemented because of significant loss in thermal efficiency.	Application of this technique on new boilers requires installation of alternate heat recovery system (e.g., an economizer)

The generally larger watertube boilers with higher NO_x emissions (160 ng/J average) will also need the same controls: low excess air, low NO_x burners, and staged combustion. Staged combustion is a demonstrated technique for the large multiburner watertube boilers. However, if developing low NO_x burners are successful and achieve 40 to 60 percent reduction, down to 86 ng/J (0.2 $lb/10^6$ Btu), they should prove more cost effective. The only other alternative for stringent control is ammonia injection. Although demonstrated and in limited commercial operation for oil and gas firing in Japan, ammonia injection may be a more costly alternative for NO_x reduction than LNB or SC. In addition, operational problems and potential emissions of NH_3 and byproducts cause environmental concern.

It should be noted that the above discussed controlled emission levels for residual oil firing may be difficult to achieve for boilers firing high nitrogen content fuel (e.g., 0.3 weight percent nitrogen). Indeed, Figure S-8 indicates a possible trend of increasing total NO_x emissions with fuel nitrogen content, unlike the behavior exhibited by coal-fired boilers. A possible explanation may be the following: 1) the fractional conversion of fuel nitrogen to fuel NO_x increases with decreasing fuel nitrogen content, and 2) residual oil generally has a much lower fuel nitrogen content than does coal (Reference S-8).

It should also be noted from Figure S-8 that NO_x emissions from residual oil-fired boilers appear to be independent of combustion air preheat. This is expected because reduced air preheat is primarily effective for reducing thermal NO_x, but fuel NO_x dominates for the heavy oil.

S.5.2 Distillate Oil

NO_x emissions from distillate oil combustion are primarily from thermal NO_x formation. The relatively low uncontrolled baseline NO_x emissions of distillate oil-fired boilers (Table S-2) should permit achievement of very low controlled NO_x levels. These control levels can in most cases be met with commercially available combustion modification techniques. The preferred control systems are low excess air, reduced air preheat, flue gas recirculation, and low NO_x burners (under development), in that order, lowering NO_x down to about 65 ng/J (0.15 $lb/10^6$ Btu). Distillate oil- and natural gas-fired boilers not

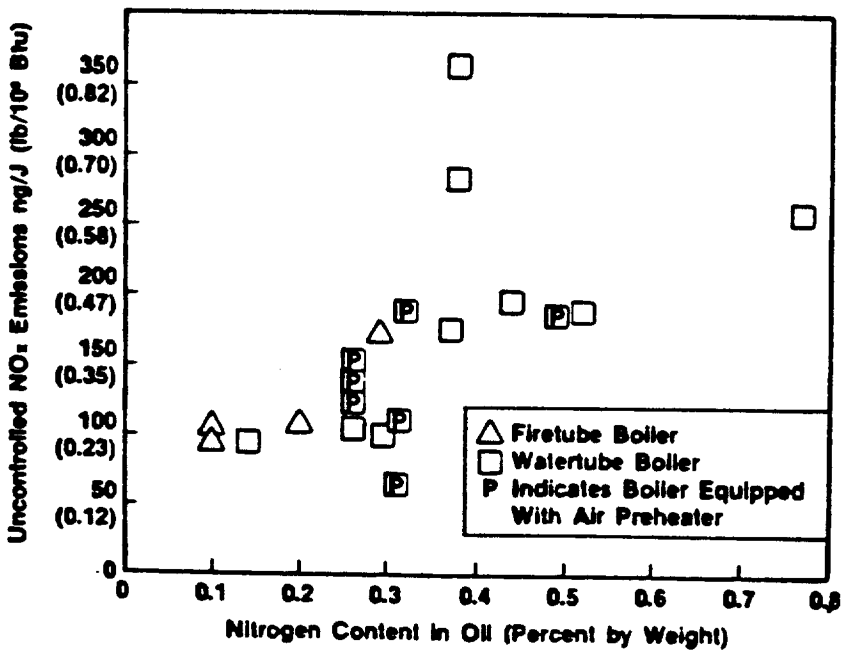


Figure S-8. Effect of fuel nitrogen content on NO_x emissions from residual oil-fired industrial boilers.

equipped with air preheaters (all firetubes, some watertubes) generally exhibited significantly lower average NO_x emissions than those with air preheaters, irrespective of boiler heat input capacity, as shown in Figure S-9. Although Figure S-9 would seem to indicate a general trend of higher NO_x emissions with increasing boiler capacity, the trend is probably due to factors other than capacity per se: design differences such as firetube systems for the smaller boilers and watertube systems for the larger, and air preheaters with larger units as well. Figure S-9 shows that bypassing an existing preheater substantially reduces NO_x (shown for natural gas, though similar behavior is expected for distillate oil). Those boilers without air preheat should be able to reach 43 ng/J (0.1 lb/10^6 Btu) with just flue gas recirculation, while air preheater-equipped boilers may require combined reduced air preheat and flue gas recirculation. Figure S-10 illustrates the high effectiveness (40 to 75 percent NO_x reduction) of flue gas recirculation for clean fuels (distillate oil and natural gas).

S.6 APPLICATION OF CONTROLS TO GAS-FIRED BOILERS

The NO_x emissions characteristics and control strategies for gas-fired boilers are nearly identical to those for distillate oil-fired units. Therefore, the previous discussion on distillate oil-firing is directly relevant here and will not be repeated. Table S-6 summarizes the potentially applicable techniques.

S.7 ENERGY IMPACT

Of the NO_x control methods available, LEA is the most fuel-efficient. LEA should be used with most control methods to increase thermal efficiency and reduce NO_x emissions. In general, combustion modification NO_x controls should only have a minor energy impact, usually less than 0.5 percent increase in energy consumption. In fact, with proper boiler design and control implementation, it might even be possible in some cases to significantly lower NO_x emissions and use less energy. The postcombustion NO_x control techniques under development are expected to increase energy usage by less than 1 percent.

S.8 COST IMPACT

The primary contributions of combustion modification controls to steam cost changes are the equipment modification costs and changes in thermal efficiency and fan power demand. In general, combustion

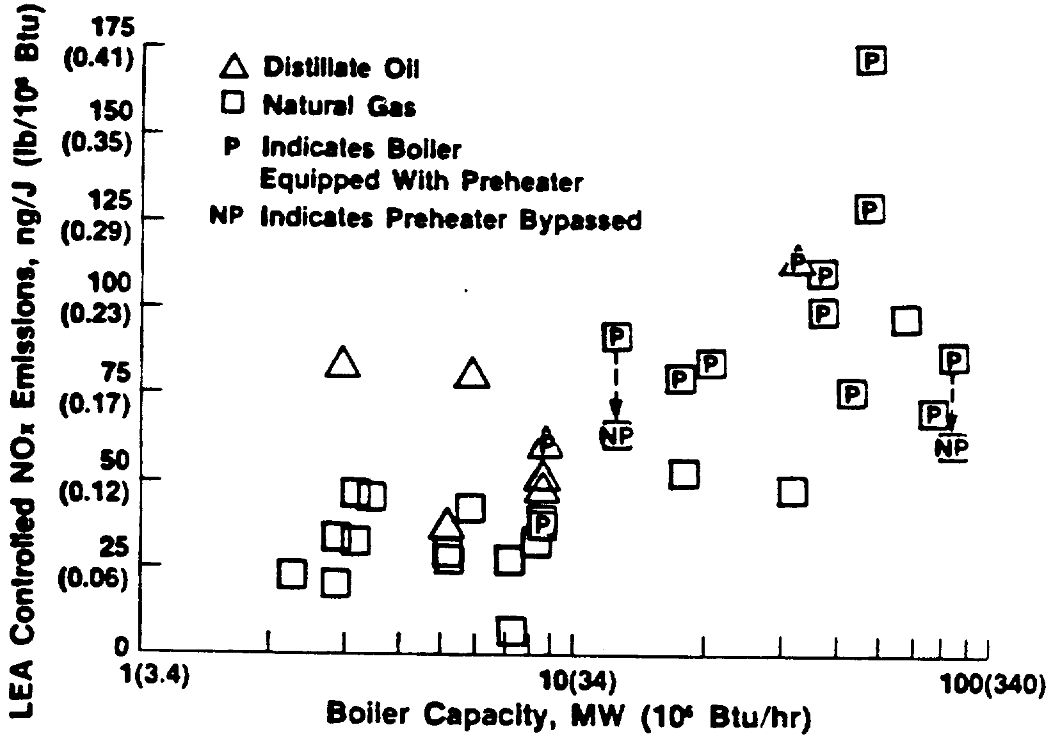


Figure S-9. Effect of combustion air preheat and boiler capacity on NO_x emissions from distillate oil- and gas-fired industrial boilers.

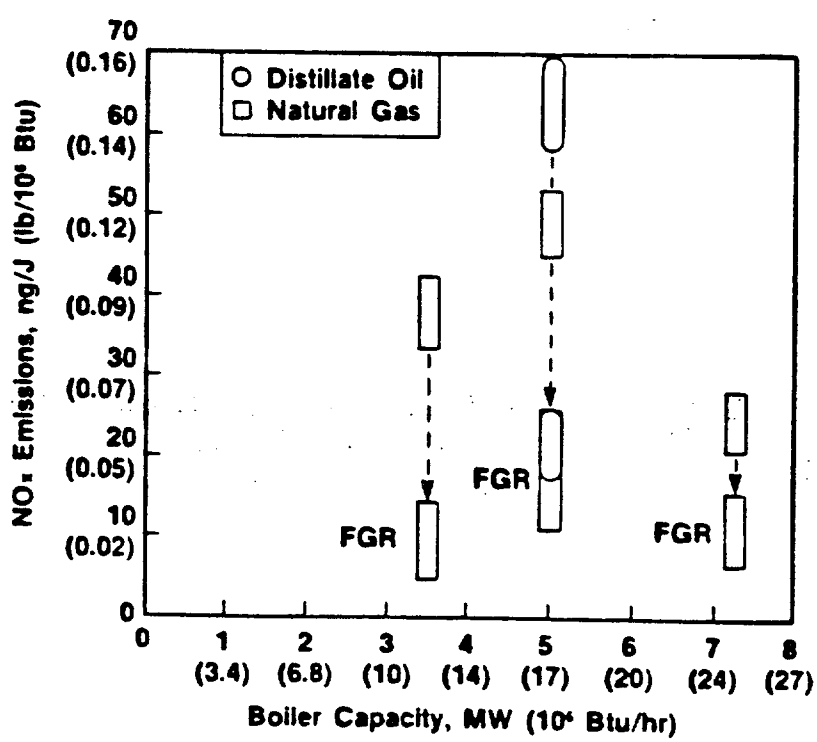


Figure S-10. Effect of flue gas recirculation on NO_x emissions from distillate oil- and gas-fired industrial boilers.

TABLE S-6. COMBUSTION MODIFICATION NO_x CONTROLS FOR GAS-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commercial Availability/ R&D Status	Comments
Low Excess Air (LEA)	Reduction in air-fuel ratio by reducing air flow to the windbox	28	-71 to 83 Average 10	Generally excess O_2 can be safely reduced to 3.0%. This reduction represents a 2.5% drop from baseline.	Method and control equipment currently available	Generally practiced because of increased boiler efficiency. Best NO_x reductions reported for large multiburner units.
Staged Combustion Air (SCA)	Fuel-rich firing burners with secondary combustion air ports	3	5 to 46	70 to 90% burner stoichiometries can be maintained. Applicable to all units, however requires extensive equipment modification.	Technique is still experimental, especially for small firetube and watertube units	Found to be less effective on firetube boilers than watertube boilers. Generally less effective for gas-fired units.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	3	17 to 44	Applicable only to multiburner units. Best suited for square burner pattern.	Technique is available. Retrofit application only. Requires careful selection of BOOS and control of air flow.	May require modification of gas delivery system and burners to avoid derating
Flue Gas Recirculation (FGR)	Recirculation of flue gas to the burner windbox. Requires motor, fan, and connecting ducting.	3	48 to 86	Flue gas recirculation rates possible up to 45%. Technique is applicable to all boiler types except ones equipped with ring burners.	Available now. Best suited for new boilers. Retrofit application would result in extensive burner modifications.	Flame instability problem is not severe except for ring burners. Minor burner modifications can guarantee stable flames. Most effective on watertube units.
Staged Combustion and Flue Gas Recirculation	Combined techniques of staged combustion air and FGR	1	76	Applicable to all boilers with same restrictions as individual techniques	FGR is an available technique. SCA for small package units is still at R&D stage.	No added benefit of SCA to FGR performance. Combined methods are not additive in their effect.

TABLE S-6. CONCLUDED

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commercial Availability/ R&D Status	Comments
Load Reduction (LR)	Reduction of both fuel and air flow to burners or design with enlarged firebox	21	32% decrease to 82% increase in NO_x (10.5% average reduction)	Tests to 20% of rated capacity. Applicable to all units.	Technique available. However, retrofit application is not feasible due to initial low load factor of industrial units.	Least effective on firetube boilers because of lower combustion intensity. Applicable for new watertube units with increased firebox size.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	2	20 to 55 ng/J per 50K reduction in air temperature	Applicable only on units equipped with air preheaters (large watertube units). This application is very limited.	Technique available but not implemented because of significant loss in efficiency	Implementation would require other designs to recover loss of heat. Technique is not desirable because of loss in efficiency.
Low NO_x Burners (LNB)	New burner designs with controlled air-fuel mixing and increased heat dissipation	N/A	20 to 50	New burners generally applicable to all boilers. More information is needed.	Commercially offered but not demonstrated	Specific emissions data from industrial boilers equipped with LNB are lacking
Ammonia Injection	Injection of NH_3 as a reducing agent in the flue gas	5 (4 Japanese, installations, 1 domestic)	40 to 70	Applicable for large package and field-erected watertube boilers. May not be feasible for firetube boilers.	Commercially offered but not demonstrated	Should be fewer problems than with coal- or oil-firing. Elaborate NH_3 system still required. Possible boiler load restrictions.

modification controls should be cost-effective means of control for industrial boilers, raising steam costs only 1 to 2 percent in most cases. However, the initial investment required, especially for smaller boilers, may be a large fraction of the cost of the boiler itself, up to 25 percent when controls are installed on a new boiler. Retrofit control costs, highly site specific, could be two to three times higher.

The postcombustion control techniques, because of higher capital equipment, raw material, and energy requirements, are significantly more costly. Ammonia injection is severalfold more costly than conventional combustion modifications, while flue gas treatment techniques are about an order of magnitude higher than combustion modifications. However, postcombustion controls are the only near-term option if extremely high NO_x reductions are required.

S.9 ENVIRONMENTAL IMPACT

To help quantify the potential change in environmental impact of an industrial boiler that switches from baseline to low NO_x firing, a source analysis model SAM IA (Reference S-27) was applied to the effluent data from the two stoker coal-fired industrial boilers tested in this study. EPA has been developing a series of source analysis models to define methods of comparing emission data to environmental objectives, termed Multimedia Environmental Goals (MEG's) (Reference S-28). The model selected for the level of data detail obtained from the industrial boiler tests was designed for rapid screening purposes. As such, it includes no treatment of pollutant transport or transformation. Goal comparisons employ threshold effluent stream concentration goals.

For purposes of screening pollutant emissions data to identify species requiring further study, a Discharge Severity (DS) is defined as follows:

$$DS_i = \frac{\text{Concentration of Pollutant } i \text{ in Effluent Stream}}{\text{DMEG of Pollutant } i}$$

The DMEG (Discharge Multimedia Environmental Goal) value, a threshold effluent concentration, is the maximum pollutant concentration considered safe for occupational exposure. When DS exceeds unity, more refined chemical analysis may be required to quantify specific compounds present.

To compare waste stream potential hazards, a Total Weighted Discharge Severity (TWDS) is defined as follows:

$$TWDS = (\Sigma_i \ DS_i) \times \text{Mass Flow Rate}$$

where the Discharge Severity is summed over all species analyzed. The TWDS is an indicator of output of hazardous pollutants and can be used to rank the needs for controls for waste streams. It can also be used as a preliminary measure of how well a pollutant control, say a combustion modification NO_x control, reduces the overall environmental hazard of the source.

The tests performed were both cooperative efforts with the EPA-DOE-ABMA field program on stoker emissions and efficiency improvement (Reference S-14). Site A was a traveling grate spreader stoker with a steam capacity of 38 kg/s (300,000 lb/hr) while Site B, also a spreader stoker, can produce 25 kg/s (200,000 lb/hr). Both boilers were tested in the baseline (normal) operation and low NO_x firing modes. The Site A low NO_x condition was increased overfire air at the same overall excess air level (actually LEA firing) as baseline. The Site B low NO_x mode was low excess air firing.

S.9.1 <u>Site A Environmental Test Results</u>

Table S-7 shows the results of the SAM IA evaluation of the flue gas composition data from Site A. Results are presented for uncontrolled operation (baseline) and controlled operation (low NO_x). The table shows MEG category DS for each firing condition for those components with DS greater than 1 in either test. DS values shown were calculated from air/health-based DMEGs.

The results presented in Table S-7 show that NO_x and SO_2 are potentially the most hazardous flue species. The sum of the DS values for these two species again comprises over 70 percent of the stream Total Discharge Severity) (TDS). The DS for SO_2 again fluctuates with day-to-day fuel sulfur content, masking the effects of the reduction of the NO_x DS with the application of NO_x control, so that stream TDS remains relatively constant with NO_x control application. Other species of potential concern include CO, SO_3 (vapor), and several trace elements. In this test, though, the SO_3 DS did not decrease with NO_x

TABLE S-7. FLUE GAS DISCHARGE SEVERITY: SITE A

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
NO_x	47	70	58
SO_2	53	63	85
CO	42	6.3	12
SO_3 (vapor)	53	5.8	35
Be	32	1.9	0.049
As	49	1.6	3.5
Fe	72	1.1	1.9
Carboxylic acids	8	1.0	1.8
Ti	41	0.34	3.7
Cd	82	0.61	1.7
Pb	46	0.38	1.2
Total stream		154	206

control and in fact increased sixfold. However, this increase may be within the accuracy of the analytical technique used to measure SO_3. Carboxylic acids are flagged here also.

Table S-8 shows stream TWDS for each stream under each firing mode tested. As was the case for the coal-fired utility boiler tested in the NO_x EA program (Reference S-20), the flue gas stream dominates the potential hazard of the source, with a WDS over two orders of magnitude larger than any other stream. In addition, the WDS's for the ash streams remain relatively constant with firing mode. Thus, changes in flue gas WDS will elicit corresponding changes in total source WDS. So it is concluded that the NO_x control tested does not, of itself, increase total source potential hazard.

S.9.2 Site B Environmental Test Results

Table S-9 shows the results of the SAM IA evaluation of the flue gas from the Site B unit. Results for the two modes of operation

TABLE S-8. WEIGHTED DISCHARGE SEVERITY: SITE A

Stream	Weighted Discharge Severity (kg/s)	
	Baseline	Low NO_x
Flue gas	6,600	7,900
Bottom ash	15	16
Mechanical collector hopper ash	1.7	1.8
ESP hopper ash	5.3	2.6
Total source	6,620	7,920

TABLE S-9. FLUE GAS DISCHARGE SEVERITY: SITE B

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
NO_x	47	68	38
SO_2	53	39	23
CO_2	42	35	27
As	49	18	20
B	68	2.2	2.5
SO_3 (vapor)	53	1.9	1.6
CO	42	1.4	0.88
Total Stream		168	114

(baseline and low NO_x) are presented. MEG category DS values for those compounds with DS greater than 1 in either test are displayed. These values were calculated on air/health DMEG's.

Conclusions drawn from the results presented in Table S-8 are analogous to those discussed above on the results in Table S-7. NO_x and SO_2 remain the potentially most hazardous species, accounting for over half the flue gas of stream TDS. Here, though, the DS for SO_2 (which varies exclusively with fuel sulfur content) drops in the low NO_x mode, so that stream TDS decreases with NO_x control application.

Other flue gas species with DS greater than 1 include CO_2, CO, SO_3 (vapor), and the trace elements As and B. The DS for SO_3 shows essentially no change with firing mode. In addition, for this test no organic category had a DS value greater than 1.

Table S-10 shows stream TWDS values for each stream under both firing modes tested. Previously stated conclusions hold here as well. The flue gas stream dominates the potential source hazard. The application of NO_x control reduces the hazard presented by NO_x. DS changes caused by day-to-day fuel composition changes are often of greater magnitude than the reduction in NO_x DS. Thus, NO_x control application reduces total source potential hazard in the absence of SO_2

TABLE S-10. WEIGHTED DISCHARGE SEVERITY: SITE B

Stream	Weighted Discharge Severity (kg/s)	
	Baseline	Low NO_x
Flue gas	7,160	3,640
Bottom ash	--[a]	7.7
Mechanical collector hopper ash	50	5.5
ESP hopper ash	1.9	3.7
Total source	7,210	3,660

[a]Bottom ash sample not taken for baseline test

considerations which are dependent on the fuel sulfur content and not on the NO_x control.

Bioassay tests performed on the bottom ash and ESP hopper ash from the Site B low NO_x test generally indicated negative mutagenicity and nondetectable toxicity. Only the ESP hopper ash elicited a positive response, giving a low toxicity result in the RAM assay.

S.9.3 General Comments on Environmental Impact

Based on a review of the emissions data from the two stoker coal-fired boilers tested in this program and published data from other coal-, oil-, and gas-fired industrial boilers, no serious environmental impacts are expected from applying combustion modification controls. However, more field testing is required to quantify and establish that statement. The limited field test data on incremental emissions indicate that pollutant emissions other than NO_x are generally unaffected by proper implementation of preferred combustion modification NO_x controls. Emissions of CO, unburned hydrocarbons, organics, and SO_2 are largely unaffected. There may be a possible, slight decrease of sulfate and particulate emissions; there also could be slight shifts in trace metal partitioning. However, all these potential effects appear to be quite secondary compared to the overall reductions in NO_x emissions with the proper application of controls. As far as postcombustion NO_x controls, current development efforts are addressing the potential problem of undesirable ammonia and byproduct emissions.

S.10 CONCLUSIONS

NO_x controls have been applied only to a limited extent in the industrial boiler sector. An exception is low excess air operation, which is often implemented for boiler efficiency gains. The general trends highlighted in this report are meant to be only guidelines; there will certainly be exceptions, and much research and development work remains to be done before NO_x control technology is well characterized for the wide diversity of industrial boiler design and equipment types.

However, it can be generally concluded that currently available combustion modification technology is capable of moderate reductions (10 to 25 percent) for coal- and residual oil-fired boilers, while major reductions (40 to 70 percent) are possible for distillate oil- and gas-fired units with minimal adverse operational or environmental impacts. Advanced techniques under development, such as low NO_x burners and ammonia injection, are potentially capable of more efficient operation and/or additional reductions.

EPA is currently sponsoring several field test programs demonstrating combustion modification NO_x controls for industrial boilers. These programs include identification of optimal combustion conditions for 11 stoker coal-fired boilers, sponsored jointly with the Department of Energy and ABMA (Reference S-14), and field demonstrations of a commercial low NO_x burner for both oil and gas firing (Reference S-29). The results from these studies should help fill some of the data gaps identified in this study. In addition, several other field tests of these and other combustion controls are underway, including 30-day continuous monitoring programs (Reference S-29). The results of these and other test programs should be monitored and incorporated in future updates of the assessment of combustion modification NO_x controls.

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SECTION 1
INTRODUCTION

This report assesses the operational, economic, and environmental impacts from applying combustion modification NO_x controls to industrial boilers. With more NO_x controls being implemented in the field and expanded control development anticipated for the future, there is currently a need to: (1) ensure that the current and emerging control techniques are technically and environmentally sound, and compatible with efficient and economical operation of systems to which they are applied, and (2) ensure that the scope and timing of new control development programs are adequate to allow stationary sources of NO_x to comply with potential air quality standards. The NO_x EA program addresses these needs by (1) identifying the incremental multimedia environmental impact of combustion modification controls, and (2) identifying the most cost-effective source/control combinations to achieve ambient NO_2 standards.

1.1 BACKGROUND

The 1970 Clean Air Act Amendments designated oxides of nitrogen (NO_x) as one of the criteria pollutants requiring regulatory controls to prevent potential widespread adverse health and welfare effects. Accordingly, in 1971, EPA set a primary and secondary National Ambient Air Quality Standard (NAAQS) for NO_2 of 100 $\mu g/m^3$ (annual average). To attain and maintain the standard, the Clean Air Act mandated control of new mobile and stationary NO_x sources, each of which currently emits approximately half of the manmade NO_x nationwide. Emissions from light duty vehicles (the most significant mobile source) were to be reduced by 90 percent to a level of 0.25 g NO_2/km (0.4 g/mile) by 1976. Stationary sources were to be regulated by EPA Standards of Performance for New Stationary Sources (NSPS), which are set as control technology becomes available. Additional standards required to attain air quality in the Air

Quality Control Regions (AQCR's) could be set for new or existing sources through the State Implementation Plans (SIP's).

Since the Clean Air Act, techniques have been developed and implemented that reduce NO_x emissions by a moderate amount (30 to 60 percent) for a variety of source/fuel combinations. In 1971, EPA set NSPS for large steam generators burning gas, oil, and coal (except lignite). Recently, more stringent standards for utility boilers burning bituminous and subbituminous coals have been promulgated, along with standards for lignite-fired utility boilers. In addition, NSPS have been proposed for stationary gas turbines and are currently being drafted for reciprocating internal combustion engines and intermediate size (industrial) steam generators. Local standards also have been set, primarily for new and existing large steam generators and gas turbines, as parts of SIP's in several areas with NO_x problems. This regulatory activity has resulted in reducing NO_x emissions from individual controlled sources by 30 to 60 percent. The number of controlled sources is increasing as new units are installed with factory equipped NO_x controls.

Emissions have been reduced comparably for light duty vehicles. Although the goal of 90 percent reduction (0.25 g NO_2/km) by 1976 has not been achieved, emissions were reduced by about 25 percent (1.9 g/km) for the 1974 to 1976 model years and now (1979) have been reduced by 50 percent to 1.25 g/km. Achieving the 0.25 g/km goal has been deferred indefinitely because of technical difficulties and fuel penalties. Initially, the 1974 Energy Supply and Environmental Coordination Act deferred compliance to 1978. The Clean Air Act Amendments of 1977 defined the 0.25 g/km emission level as a research goal and set the standard of 0.62 g/km (1 g/mile) for the 1981 model year and beyond. However, the EPA Administrator is required to review the 0.25 g/km goal, considering the cost and technical capabilities, as well as the need of such a standard to protect public health or welfare. A report to the Congress is due July 1980.

Because the mobile source emission regulations have been relaxed, stationary source NO_x control has become more important for maintaining air quality. Several air quality planning studies have evaluated the need for stationary source NO_x control in the 1980's and 1990's in view of recent developments (References 1-1 through 1-9, and 1-23). These studies all conclude that relaxing mobile standards, coupled with the continuing growth rate of stationary sources, will require more stringent stationary source controls than current and impending NSPS provide. This conclusion has been reinforced by projected increases in the use of coal in stationary sources. The studies also conclude that the most cost-effective way to achieve these reductions is by using combustion modification NO_x controls in new sources.

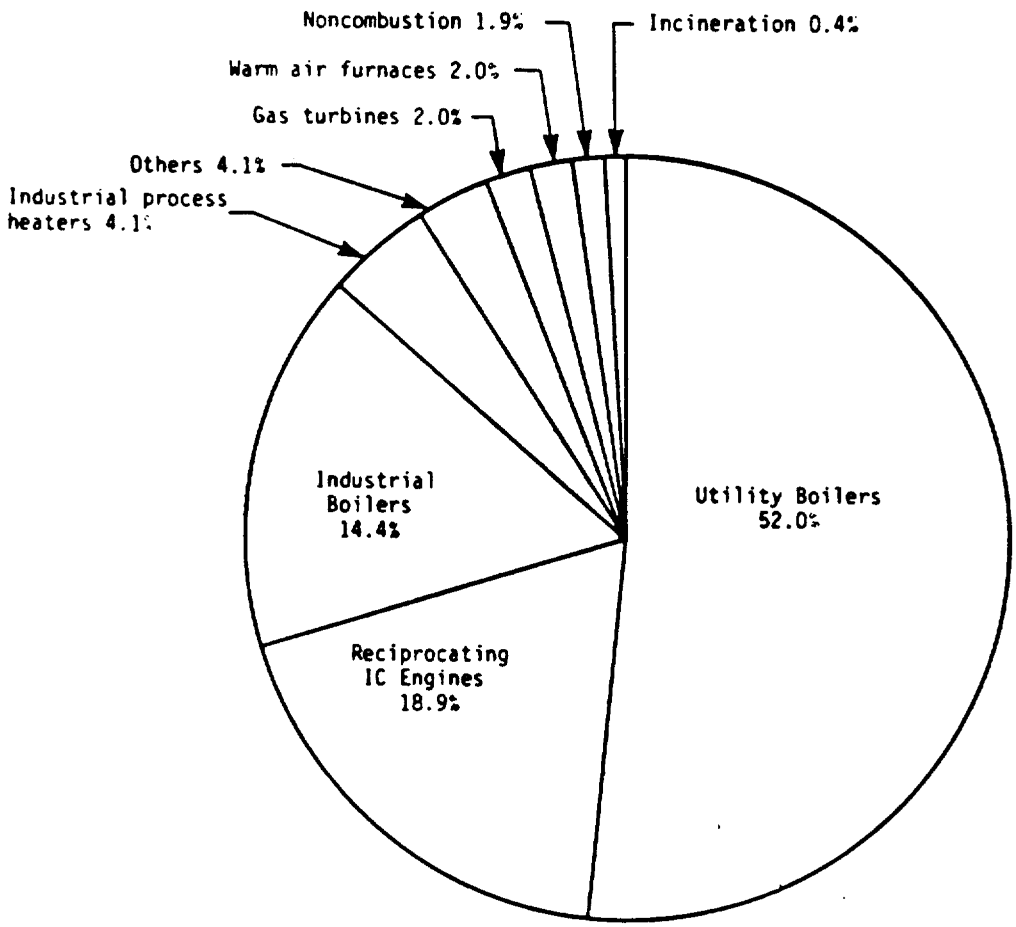
It is also possible that separate NO_x control requirements will be needed to attain and/or maintain additional NO_2 related standards. Recent data on the health effects of NO_2 suggest that the current NAAQS should be supplemented by limiting short term exposure (References 1-4 and 1-10 through 1-12). In fact, the Clean Air Act Amendments of 1977 require EPA to set a short term NO_2 standard for a period not to exceed 3 hours unless it can be shown that such a standard is not needed. EPA will probably propose a short term standard in 1980 when update of the NO_2 air quality criteria document (Reference 1-13) is completed (References 1-14 and 1-15).

EPA is continuing to evaluate the long range need for additional NO_x regulation as part of strategies to control oxidants or pollutants for which NO_x is a precursor, e.g., nitrates and nitrosamines (References 1-4, 1-10, and 1-14 through 1-17). These regulations could be source emission controls or additional ambient air quality standards. In either case, additional stationary source control technology could be required to assure compliance.

In summary, since the Clean Air Act, near term trends in NO_x control are toward reducing stationary source emissions by a moderate amount; hardware modifications in existing units or new units of conventional design will be stressed. For the far term, air quality projections show that more stringent controls than originally anticipated will be needed. To meet these standards, the preferred approach is to control new sources by using low NO_x redesigns.

1.2 ROLE OF INDUSTRIAL BOILERS

Industrial boilers are the second largest contributor of NO_x emissions in the U.S. Figure 1-1 shows that industrial packaged boilers were the origin of over 14 percent of all stationary source NO_x emissions for the year 1977 (Reference 1-18). Furthermore, NO_x



Total: 10.5 Tg/yr (11.6×10^6 tons/yr)

Figure 1-1. Distribution of stationary anthropogenic NO_x emissions for the year 1977 (Reference 2-17).

emissions are projected to increase unless adequate controls are developed (Reference 1-19). The problem will become more severe as impending shortages of oil and gas fuels force conversion to higher NO_x producing coal. In fact, the Powerplant and Industrial Fuel Use Act of 1978 (Reference 1-20) and the proposed rules to implement that Act (Reference 1-21) will prohibit all new major fuel burning installations (MFBI), including industrial boilers, with an aggregate heat input capacity of greater than 73 MW (250 x 10^6 Btu/hr) from burning oil or natural gas, except under extraordinary circumstances. Furthermore, conversion of existing units to coal may possibly be encouraged through tax incentives.

Given this background and their potential NO_x control, industrial boilers were selected as the second source category to be treated under the NO_x EA program. The "Preliminary Environmental Assessment of Combustion Modification Techniques" (Reference 1-8) concluded that modifying combustion process conditions is the most effective and widely used technique for achieving 20 to 70 percent reduction in oxides of nitrogen. Nearly all current NO_x control applications use combustion modifications. Other approaches, such as treating postcombustion flue gas, are being evaluated in depth in other programs for potential future use (Reference 1-22).

1.3 OBJECTIVE OF THIS REPORT

This report provides comprehensive, objective, and realistic evaluations and comparisons of the important aspects of the available combustion NO_x control techniques, using a common and uniform basis for comparison. The objective is to perform an environmental assessment of NO_x combustion modification techniques for industrial boilers to:

- Determine their impact on the achievement of selected environmental goals, based on a comprehensive analysis from a multimedia consideration
- Ascertain the effect of their application on boiler performance and identify potential problem areas
- Estimate the economics of their operation
- Estimate the limits of control achievable by combustion modification

- Identify further research and development and/or testing required to optimize combustion modification techniques and to upgrade their assessments

1.4 ORGANIZATION OF THIS REPORT

Evaluating the effectiveness and impacts of NO_x combustion controls applied to industrial boilers requires assessing their effects on both controlled source performance, especially as translated into changes in operating costs and energy consumption, and on incremental emissions of other pollutants as well as NO_x. To perform such an evaluation, it is necessary to:

- Characterize the source category with regards to equipment, fuels, and emissions (Section 2)
- Identify NO_x formation mechanisms and relate fuels to their emissions potential (Section 3)
- Evaluate the performance of current and potential NO_x control techniques available for implementation (Section 3)
- Assess the operational and cost impacts, including energy impacts, of implementing NO_x controls (Section 4)
- Evaluate the environmental impact of NO_x controls through the analysis of incremental emissions (Section 5)
- Make an overall assessment and ranking of control techniques for the major equipment/fuel categories (Section 6)
- Identify research and development needs (Section 6)

Section 7 summarizes the emission source test data.

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SECTION 2
SOURCE CHARACTERIZATION

This section presents a general characterization of the industrial boiler sector to aid in the assessment of combustion modification technology for NO_x control. Industrial boilers are defined here as coal-, oil- or natural gas-fired steam generators with heat input capacities generally ranging from 2.9 to 73 MW (10 to 250×10^6 Btu/hr). These boilers provide electrical or mechanical power, process heat, or a combination of these to a variety of industries.

This capacity range does not encompass all steam and hot water generators in the industrial sector. In fact, a recent population inventory estimates that boilers in the size category of 2.9 to 73 MW (10 to 250×10^6 Btu/hr) represent only 60 percent of the total units being used in industry (Reference 2-1). In addition, industrial boilers are not limited to coal, oil or natural gas fuels but also burn woodbark, black liquor, refinery gas and other waste fuels.

This environmental assessment report of NO_x controls treats only industrial boilers in the defined capacity range, primarily because large industrial boilers with capacities greater than 73 MW (250×10^6 Btu/hr) are generally similar to small utility boilers. Likewise, industrial boilers with heat input capacity less than 2.9 MW (10×10^6 Btu/hr) are generally categorized as commercial units primarily used for hot water and space heating functions.

Lim, et al., have assessed the performance, environmental and cost impacts of combustion modification NO_x controls for utility and large industrial boilers with heat input capacity as low as 73 MW (250×10^6 Btu/hr) (Reference 2-2). Also, commercial and residential boilers in the size range of 2.9 MW (10×10^6 Btu/hr) and lower will be treated in another environmental assessment report, as part of this overall NO_x EA program. Industrial boilers whose primary fuel is other than coal, oil or gas are not considered in this report because these boilers do not constitute a significant portion of the installed population (Reference 2-1).

The following sections describe the main characteristics of industrial boilers and also present a population inventory with estimated fuel consumption and uncontrolled NO_x emissions. Section 2.1 addresses those units primarily fueled by coal; Section 2.2 treats oil-fired boilers; and Section 2.3, gas-fired boilers.

2.1 COAL-FIRED BOILERS

In past years, the use of coal in industrial size boilers was generally avoided -- primarily because of the high capital cost of coal handling equipment relative to the cost of the boiler. In addition, because of air pollution concerns and the cost of air pollution abatement, few coal-fired boilers were sold compared with packaged oil- and gas-fired boilers. Battelle Columbus Laboratory has reported that the population of coal-fired industrial boilers declined from approximately 14 percent in 1965 to 4 percent in 1972 and 1973 (Reference 2-3).

However, recent governmental pressures coupled with the increasing cost of domestic and foreign oil and gas fuels have caused an apparent change in fuel combustion trends in the industrial boiler sector. A recent industrial boiler inventory indicated that coal-fired boilers in the size range of 2.9 to 73 MW (10 to 250 x 10^6 Btu/hr) accounted for 18 percent of the entire industrial boiler population in 1977 (Reference 2-1). The consumption of coal is expected to increase, especially for boilers in the size range from 29 to 73 MW (100 to 250 x 10^6 Btu/hr). Boilers burning coal as their primary fuel are expected to account for as much as 50 percent of the total industrial boiler population in the 1990's (Reference 2-3).

The growing dependence on coal will increase the environmental impact of industrial boilers on air quality. Coal is generally more polluting than oil or natural gas. The nitrogen, sulfur, and ash contents of coal give rise to significant NO_x, SO_2, and particulate emissions. In addition, trace elements in the coal ash contribute to pollutant emissions from the boiler. Based on the projected increase of industrial boilers burning coal and their associated significant increase in NO_x emissions, these sources will be primary targets for NO_x controls.

The following sections characterize coal-fired industrial boilers. Section 2.1.1 describes equipment types of typical industrial size boilers burning coal. Section 2.1.2 summarizes the results of a recent industrial boiler inventory in which the number and capacity of these units were calculated. Estimated coal consumption and NO_x emission inventory are presented in Section 2.1.3. Then Section 2.1.4 summarizes equipment trends.

2.1.1 Equipment Types

Coal-fired industrial boilers are primarily of watertube design. With this design, the heat of combustion is absorbed by water flowing through tubes which line the furnace walls and boiler passes. The furnace watertubes absorb primarily radiative heat while watertubes in the boiler passes recover heat from the combustion products by convective heat transfer. Coal can also be burned in firetube boilers. In these units the hot combustion gases pass through tubes immersed in boiler water. The firebox, as well as the tubes, is often also immersed in boiler water.

Coal-fired firetube boilers are not nearly as popular as coal-fired watertubes, primarily because firetubes are usually limited to approximately 5.8 MW (30 x 10^6 Btu/hr) heat input capacity. Below this capacity, coal has not constituted a popular fuel due to economic reasons. However, some manufacturers of firetube boilers are providing coal combustion capability on new units (Reference 2-4). Firebox firetubes are the most popular type of coal-fired firetube boilers.

The following discussion is restricted to coal-fired watertube boilers only, which presently constitute essentially the entire population of coal-fired industrial boilers.

Watertube industrial boilers burning coal can be classified in two major categories -- stokers and pulverized coal-fired units. The main difference between these two design types is the way the coal is burned and the size of the coal particles injected into the furnace. In a stoker, coal burns primarily on a stationary or moving grate, while the pulverized boiler burns coal entirely in a suspended state. The crushed coal fed to a stoker is approximately 0.02 m x 0.03 m (3/4 in x 1-1/4 in) in size (Reference 2-5), while in pulverized coal-fired units, as the name implies, the coal is pulverized to nearly a fine powder, 70 percent of the particles smaller than 74 micrometers across (200 mesh). Pulverized coal-fired industrial boilers are almost always field erected and are very similar to utility boilers. Their heat input capacity is usually greater than 29 MW (100×10^6 Btu/hr) primarily because of economic considerations. Stokers can, however, be both field erected or shop assembled (packaged). Typical capacities of stokers depend primarily on the individual design types.

The following subsections describe the major design characteristics of each of these industrial boiler types burning coal.

2.1.1.1 Stoker Fed Boilers

Stoker boilers account for nearly all (95 percent) coal-fired industrial boilers in the size range of 2.9 to 73 MW (10 to 250×10^6 Btu/hr) (Reference 2-1). Therefore, their contribution to industrial coal consumption and total NO_x emissions is considered significant.

Although stokers can be of different designs, they can all be classified by their method of introducing fuel to the furnace, namely (Reference 2-5):

- Spreader
- Underfeed
- Overfeed

The type of stoker used in an industrial plant depends primarily on steam capacity needed, the type of coal available for burning and its application. For example, spreader stokers are generally larger than all other stoker types, and thus are used where steam demand is high. In addition, they respond faster to load demand than other stokers. Spreader stokers can also burn the widest range of coals, while chain grate overfeed stokers require a coal with ash content of less than 15 percent and a high fusion ash temperature to prevent clinker formation.

Stoker boilers can be shop assembled or field erected. Shop assembled or packaged units come in sizes up to 15 MW (50×10^6 Btu/hr) (Reference 2-5). These units are usually preferred over field erected boilers of the same size because they are less expensive. In addition, packaged stokers often permit installation of less expensive particulate collection devices (Reference 2-5). Following are some detailed descriptions of these three stoker types.

Spreader Stokers

In spreader stokers, coal is injected midway into the furnace above a burning fuel bed. The coal feed mechanism provides a continuous, well distributed supply of fuel at a variable rate as required by the load demand. Spreader stokers can be distinguished according to the type of grate design: stationary and dumping grate, traveling grate, or vibrating grate. The stationary and dumping grates are used mostly in small and medium-sized boilers. The traveling grate illustrated in Figure 2-1 is generally used in large size spreader stokers.

Recommended maximum grate heat release rates measured as heat input per unit effective grate area are 2380 MW/m^2 (750×10^3 Btu/hr-ft^2) for spreader stokers with traveling grates, 1430 MW/m^2 (450×10^3 Btu/hr-ft^2)

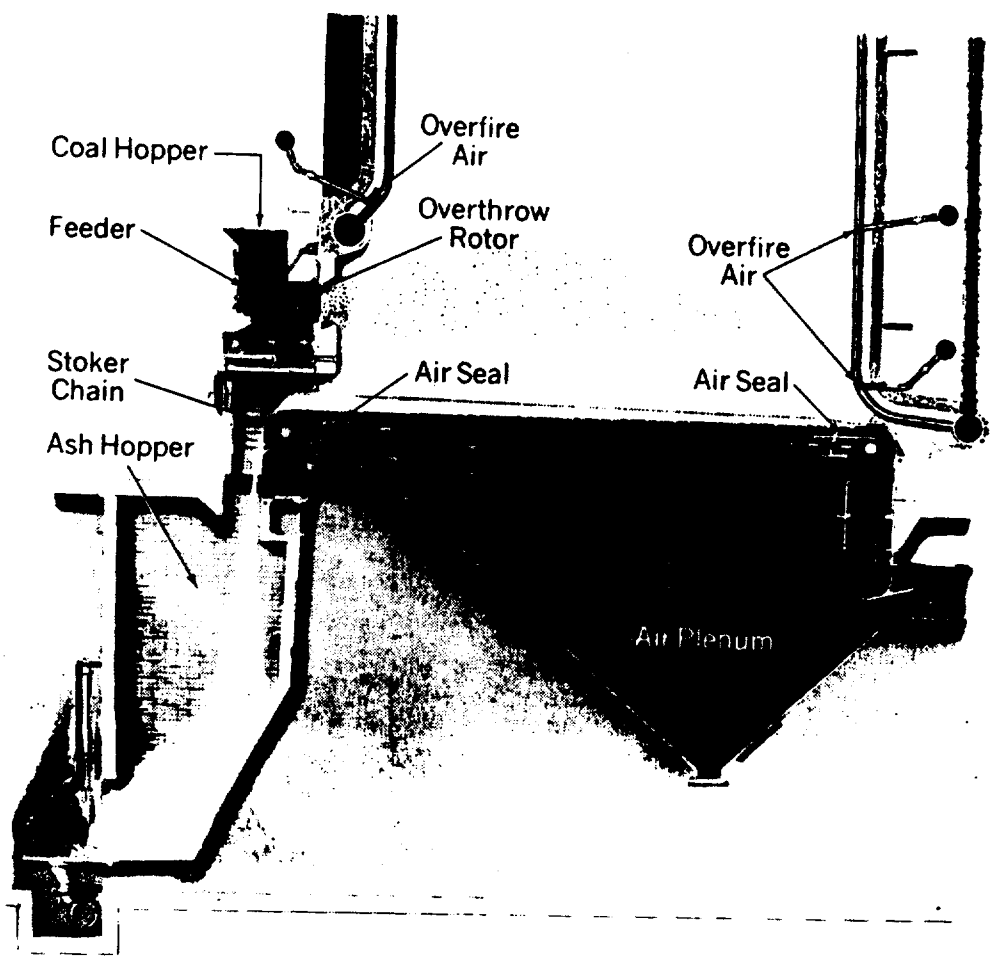

Figure 2-1. Traveling grate spreader stoker with front ash discharge (Reference 2-5).

for spreader stokers with stationary and dumping grates, and 2060 MW/m^2 (650×10^3 Btu/hr ft^2) for vibrating grate stokers (Reference 2-5). The traveling grate design is generally preferred by the industry because of its higher heat release rate. Injecting coal over the grate with a spreader mechanism allows for a combination of suspension burning and grate burning. However, the high heat release rate of spreader stokers is blamed for the generally higher NO_x emissions compared with other stoker types. In addition, suspension burning also causes a greater carryover of carbon-containing particulate matter compared with other stoker types. Thus, a flyash collector is generally provided with spreader stokers to collect these particles for reintroduction into the furnace.

Overfire air injection ports provide the high turbulence air necessary to maintain suspension and aid combustion. Overfire air ports placed in two rows in the furnace rear wall and one row in the furnace front wall inject air at a nominal pressure of 6.7 to 7.5 kPa (27 to 30 inches of water) (Reference 2-5).

Spreader stokers, especially ones with traveling grates, can burn a variety of coals including caking coals and high moisture lignite (Reference 2-6). Burning caking coals causes little problem in spreader stokers because the surface heating of the coal in suspension destroys the caking tendency. High moisture content coals such as lignite can also be easily burned in a spreader stoker. However, the use of coals with high surface moisture can cause feeding problems. The wet coal particles may stick to the feeder surface and cause uneven distribution of coal on the grate (Reference 2-7).

The use of spreader stokers as industrial equipment to burn coal has increased constantly in recent years. As noted earlier, of the various stoker designs, spreader stokers are particularly attractive because of their wide load swing capability. The increase in spreader stoker use will continue in the future as the availability of gas and oil decreases (Reference 2-1 and 2-3).

Underfeed Stokers

Underfeed stokers introduce coal through a retort beneath the burning fuel bed. These boilers can be classified into single retort horizontal-feed or multiple retort gravity feed types. Figures 2-2 and 2-3 show schematics of these two design types. In the single retort

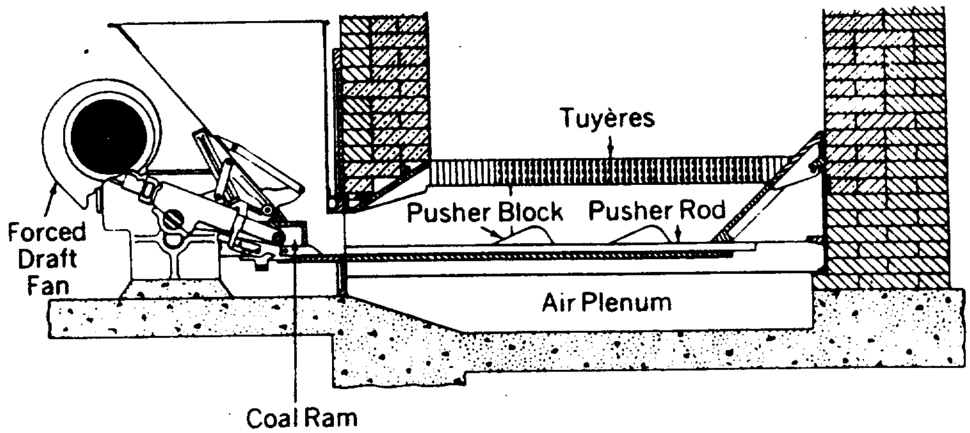

Figure 2-2. Single retort, horizontal-feed, side ash discharge underfeed stoker (Reference 2-5).

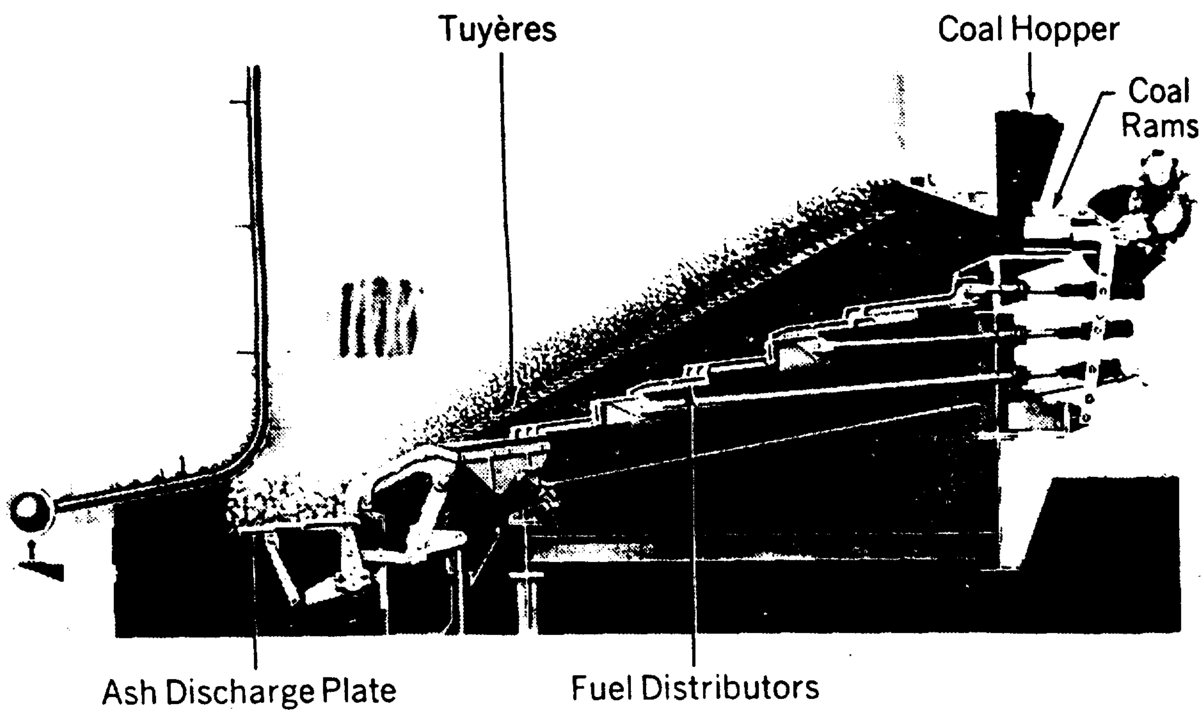

Figure 2-3. Multiple retort gravity-feed type of rear ash discharge underfeed stoker (Reference 2-5).

horizontal type underfeed stoker, the coal is fed from the hopper by a reciprocating ram, or from a screw conveyor on the small units, to a simple trough called the retort. The coal is moved toward the rear wall by small auxiliary pushers, then upward to spread over the air-admitting tuyeres. The rising coal then ignites when it comes in contact with the burning bed. The upward feeding of the coal pushes the fuel bed over the tuyeres, pushing the spent fuel to the side dumping grates. Overfire air is often used to prevent smoke emissions, especially at reduced boiler loads.

The single retort horizontal-type underfeed stokers are usually limited in size to 9 MW (30×10^6 Btu/hr) with burning rates of 1360 MW/m^2 (425×10^3 Btu/hr-ft^2) (Reference 2-5). Simple retort stokers have either stationary or moving grates. Those with stationary grates are usually of lower price for boilers in the range of 5 to 9 MW (12 to 20×10^6 Btu/hr) (Reference 2-4). However, moving grates can handle a larger variety of coals than the underfeed stokers with stationary grates. In addition, the underfeed stoker with a moving grate can be designed for higher capacities, up to 11 MW (35×10^6 Btu/hr) (Reference 2-4). Primary fuels used in single retort underfeed stokers are the Eastern caking bituminous coals and free burning Midwestern coals with ash fusion temperatures high enough to operate successfully in the thick fuel bed characteristic of all underfeed stokers.

In multiple retort inclined underfeed stokers, the coal is introduced through a coal hopper and ram fed to the inclined retorts and grates. The inclination of the retort and grates is usually 20 to 25 degrees. This type of stoker can be designed with a heat input capacity of over 146 MW (500×10^6 Btu/hr) at burning rates of up to 1920 MW/m^2 (600×10^3 Btu/hr ft^2) (Reference 2-5).

The multiple retort inclined underfeed stoker is still being used in industry for operation with relatively constant high loads. Smoke levels are low during this type of operation, especially when compared with spreader stokers. Overfire air injection is also provided as with the single and double retort designs, mainly to limit smoke emissions at low loads or for intermittent use during sudden increases in firing rate.

The most suitable coals for multiple retort stokers are those which have a tendency to cake but break into a porous fuel bed when agitated

(Reference 2-7). Generally, high ash fusion temperature coals are desirable because of their low potential for clinker formation which causes bed corrosion.

Overfeed Stokers

In these boiler types the coal is fed from above and onto a continuously moving bed. The coal entering the furnace on the grate at a preset thickness is heated by radiation from the furnace gases. The volatile matter of the coal is driven off by this heating action and ignition of the coal begins. The fuel continues to burn as it moves along the fuel bed, becoming progressively thinner until only ash remains. At the far end of the furnace the ash is discharged into an ash pit as the grates pass downward over a returning bend (Reference 2-6). There are two basic kinds of overfeed stokers:

- Chain grate or traveling grate
- Water cooled vibrating grate

These terms are synonymous with overfeed stokers. That is, often overfeed is not specified when, for example, chain grate or traveling grate are discussed. Also, the designation "chain grate" and "traveling grate" are often used interchangeably because these stoker types are essentially of the same design.

Figures 2-4 and 2-5 show typical chain grate and vibrating grate overfeed stokers respectively. One very noticeable characteristic of the vibrating grate stoker is the water cooled grate. This characteristic is significant because cooling of the grate is not solely dependent on the air flow as with other stoker types. Thus, the water cooled grate may permit low excess air levels otherwise not possible with non-water cooled grates. Low excess air operation, as will be discussed in Section 3, is an effective technique for reducing NO_x emissions from stokers.

The maximum burning rates of overfeed stokers range between 1120 and 1600 MW/m^2 (350 to 500 x 10^3 Btu/hr ft^2) depending on the type of coal and its ash and moisture characteristics (Reference 2-5). Recommended sizes for these boilers range between 6 and 44 MW heat input (20 to 150 x 10^6 Btu/hr) (Reference 2-8).

Overfire air injection is also provided in overfeed stokers. Generally, sets of overfire air injection jets are located on the front and rear furnace walls. The rear jets are positioned so that the air

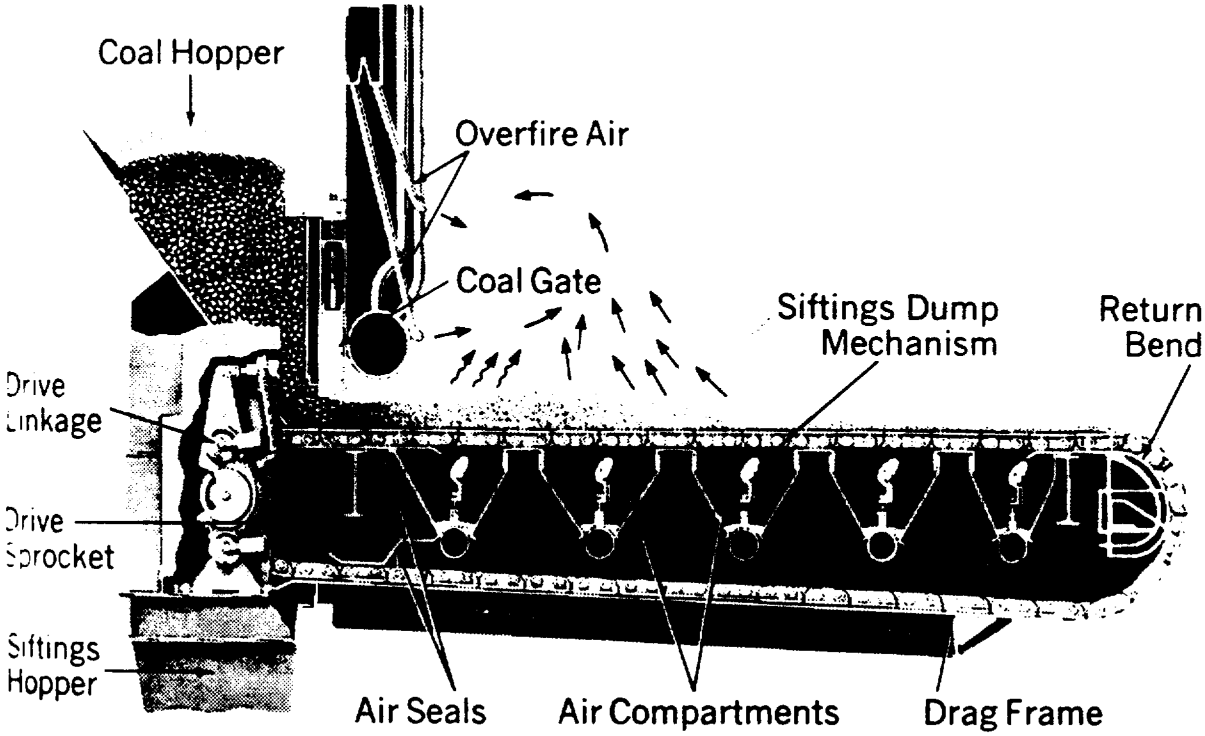

Figure 2-4. Chain grate overfeed stoker (Reference 2-5).

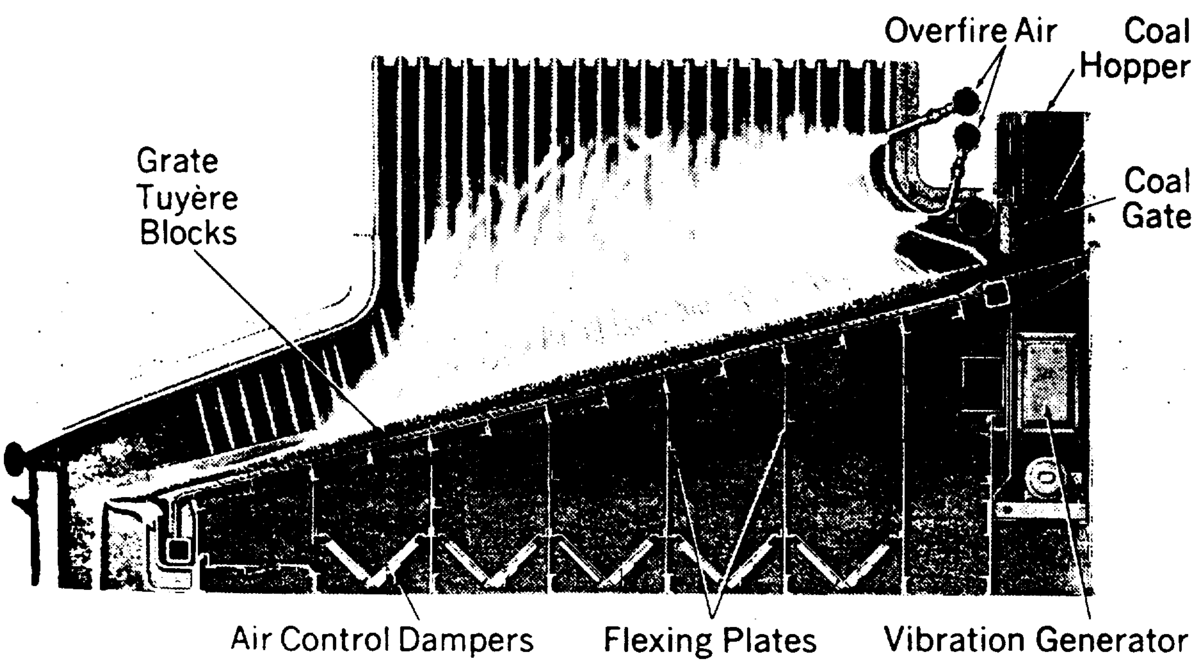

Figure 2-5. Water cooled vibrating grate stoker (Reference 2-5).

pushes the flame toward the front of the bed. The flame creates more intense radiation, facilitating the ignition and combustion of the incoming fuel. Front jets reverse the flow of gases in the horizontal direction promoting turbulence of the combustion gases above the bed. Overfire air is controlled independently from air flowing from under the grate.

Overfeed stokers generally burn a variety of fuels including lignite, subbituminous, free-burning bituminous and anthracite, provided the coal is sized properly (Reference 2-7). Chain grate stokers may be better suited to burn caking coals or coals which may form clinkers on the bed since chain grates move in a scissorlike manner which may prevent the formation of clinkers (Reference 2-7).

2.1.2 Pulverized Coal-Fired Boilers

Pulverized coal-fired boilers accounted for only approximately 8 percent of all installed coal-fired industrial boilers in 1977 (Reference 2-1). However, because pulverized coal-fired industrial boilers have generally high heat input capacities, the coal burned in these units amounts to almost 20 percent of total coal burned. The forecasted increase in coal consumption as an industrial fuel is expected to significantly increase the number of pulverized coal-fired units as well as stokers in the industrial sector (Reference 2-3). The increased use of pulverized coal-fired industrial boilers could have an adverse impact on total NO_x emissions from the industrial sector.

Pulverized coal-fired boilers currently installed are almost entirely limited to sizes larger than 29 MW (100×10^6 Btu/hr). Pulverized coal-fired boilers with heat input capacities lower than 29 MW (100×10^6 Btu/hr) require coal handling and pollution control equipment which increases the capital cost to as much as ten times that of a gas- or oil-fired industrial boiler of the same size. In addition, pulverized coal-fired boilers are not as compact as other industrial units, thus requiring larger installation space (Reference 2-9).

Combustion in pulverized coal-fired boilers takes place entirely while the coal is suspended in the furnace, as opposed to stoker firing where all or most of the coal burns on a grate. With suspension firing, the fuel and the air mix close to the burners. Primary air, which transports the coal to the burner, constitutes 10 to 20 percent of the total combustion air. Secondary air injected at the burner accounts for the remainder of the theoretical air needed for complete combustion plus any excess air amount. Pulverized coal-fired boilers are essentially all of the watertube design. These units are either field erected or packaged design. A recent inventory estimates that the packaged boilers account for only 14 percent of the population with field erected units making up the rest (Reference 2-1).

Pulverized coal-fired watertube boilers can be classified in four different types according to the location of the burners and the direction of coal injection into the furnace. These types are:

- Single and opposed wall
- Tangential
- Vertical
- Cyclone

Of these types, wall and tangential designs predominate. Although the coal burned in a cyclone furnace is not pulverized but crushed, this type of boiler is often categorized as a pulverized coal-fired design. Impact, vertical and cyclone units generally have heat input capacities greater than 73 MW (250×10^6 Btu/hr). However, these designs are no longer being commercially offered. Figures 2-6 and 2-7 show schematics of burner arrangement for the wall- and tangential-fired boilers. Figure 2-6 shows a single wall-fired boiler, with burners on one wall of the furnace and fuel injected horizontally into the furnace. Wall-fired boilers can be either single wall-fired (burners only on one wall) or opposed wall-fired (burners on two opposing walls). However, the opposed wall boilers are usually much larger than the 73 MW (250×10^6 Btu/hr) industrial boiler limit. In fact, these units are quite common in utility boiler designs with electrical generating capacity of 400 MW or more (Reference 2-2).

Tangential firing requires that the burners be located in the corners of the furnace as shown in Figure 2-7. The fuel and air are injected toward the center of the furnace to create a vortex that enhances fuel and air mixing. Tangential fired boilers are also very common in utility boiler designs (Reference 2-2).

Equipment characteristics and operation for these boiler types are very similar whether they are in the industrial or utility size category. In fact, large wall- and tangential-fired industrial boilers are often

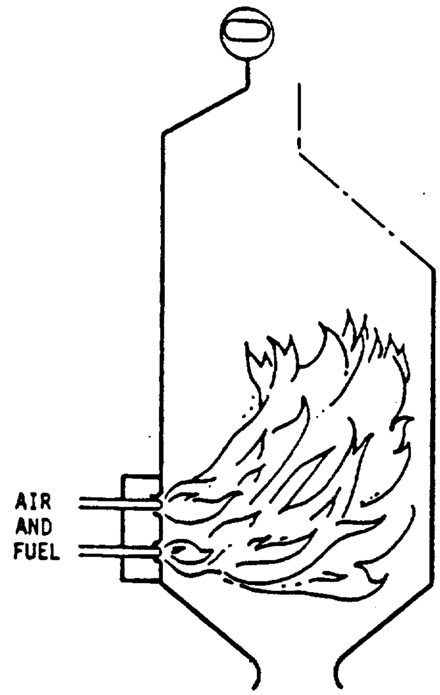

Figure 2-6. Wall firing

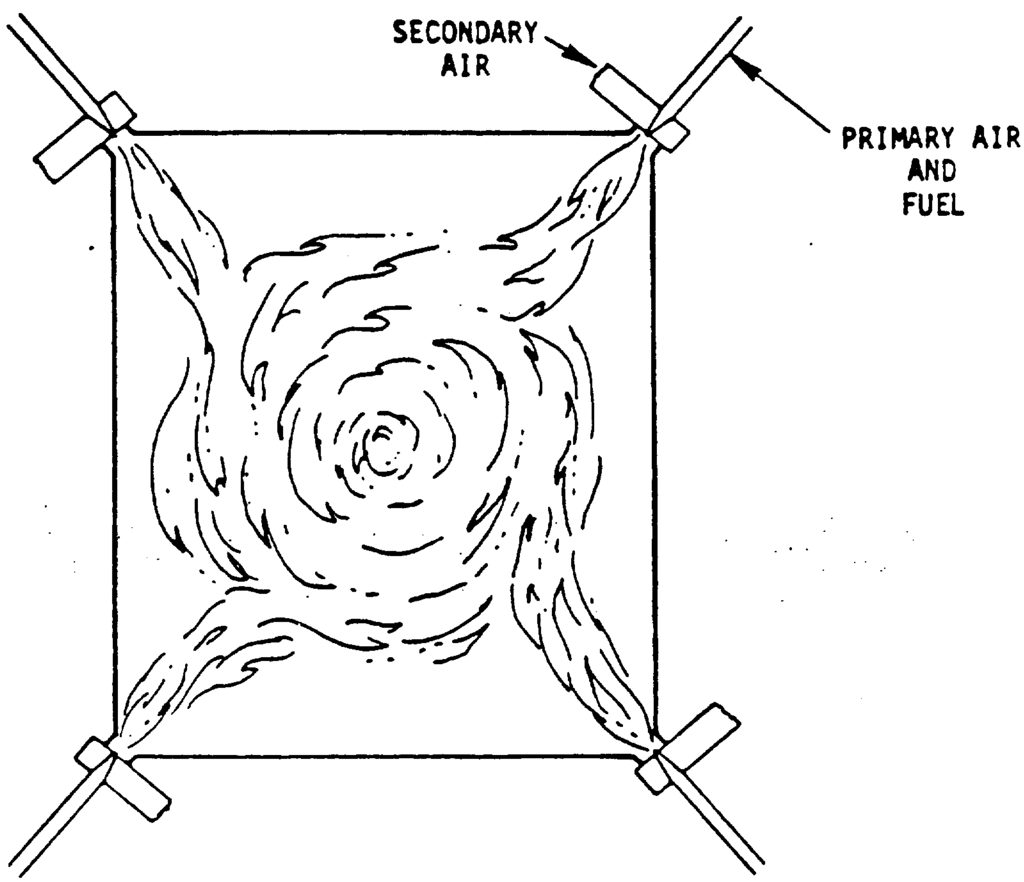

Figure 2-7. Tangential firing

categorized with the utility units of the same type because of their similarity. NO_x emissions and NO_x controls are also very similar as will be discussed in Section 3 of this report. Wall- and tangential-fired industrial boilers are nearly all field erected units. Packaged pulverized coal-fired industrial boilers, are, however, being introduced into the industrial boiler market by some manufactirers (Reference 2-9). These packaged boilers are bottom supported and have three drums. A schematic of such a unit is shown in Figure 2-8. Models as large as 23 MW (80×10^6 Btu/hr) heat input can be shipped by rail. The furnace of this boiler type is constructed such that the combustion gases do not make any turns. This design permits combustion of a variety of coals with reduced flyash deposition. In addition, the design permits installation of staged air injection ports for reduced NO_x emissions (Reference 2-9).

A study by Locklin, et al., forecasted that the population of pulverized coal-fired boilers in sizes between 2.9 and 73 MW (100 to 250×10^6 Btu/hr) will increase (Reference 2-3). This trend will result in pulverized coal-fired industrial boilers of this size range accounting for 40 percent of all installed industrial boilers by the year 1990 (Reference 2-3).

2.1.3 Coal Consumption and Emission Inventory

The capacity of industrial coal-fired boilers in place in 1977 was approximately 130,000 MW (444×10^9 Btu/hr) (Reference 2-1). Table 2-1 gives a breakdown of this total capacity for pulverized and stoker coal units in four size ranges. The results of this inventory for coal-fired boilers indicate that pulverized units are available only in sizes greater than 29 MW (100×10^6 Btu/hr). These boilers account for only 6 percent of all coal-fired industrial boilers. Stoker units are more available in the small size ranges, 2.9 to 15 MW (10 to 50×10^6 Btu/hr) than in the larger sizes. In fact, the number of stokers with capacity below 15 MW 50×10^6 Btu/hr) accounts for almost 70 percent of all stokers. The capacity of the larger units, however, accounts for 61 percent of the total installed capacity in 1977.

Table 2-2 breaks down the population of industrial stokers between field erected and packaged units. In addition, a distinction is made between the three types of stoker designs -- spreader, underfeed and overfeed. This table indicates that packaged stokers account for

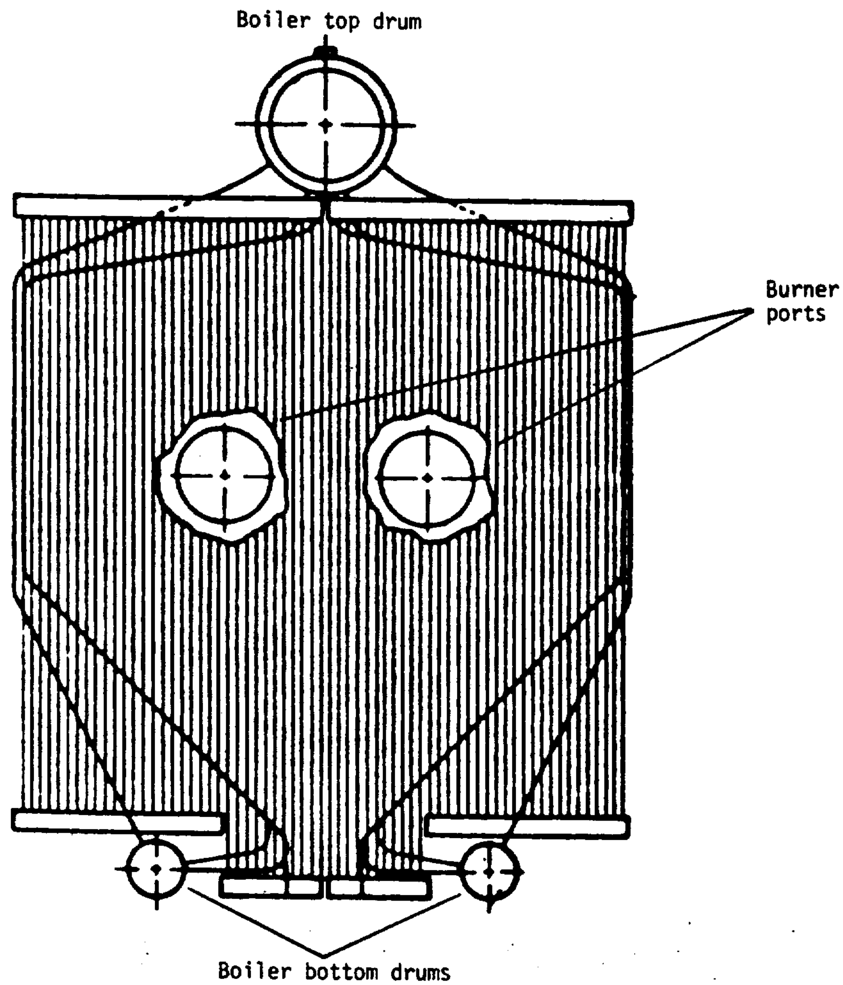

Figure 2-8. Shop-assembled boiler for pulverized-coal firing (Reference 2-9).
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TABLE 2-1. DISTRIBUTION OF COAL-FIRED INDUSTRIAL BOILERS IN PLACE IN 1977 (Reference 2-1)

Capacity MW (10^6 Btu/hr)	Total Number of Units (Total Boiler Capacity MW)		
	Pulverized Coal	Stoker Coal	Total
2.9 - 7.3 (10 - 25)	--	2,421 (12,230)	2,421 (12,230)
7.3 - 15 (25 - 50)	--	2,790 (30,950)	2,790 (30,950)
15 - 29 (50 - 100)	--	1,542 (33,610)	1,542 (33,610)
29 - 73 (100 - 250)	467 (20,510)	774 (32,900)	1,241 (53,410)
TOTAL 2.9 - 73 (10 - 250)	467 (20,510)	7,527 (109,690)	7,994 (130,200)

TABLE 2-2. DISTRIBUTION OF STOKER COAL-FIRED INDUSTRIAL BOILER POPULATION IN PLACE IN 1977 (Reference 2-1)

Capacity MW (10^6 Btu/hr)	Total Number of Units (Total Boiler Capacity, MW)						
	Field Erected Units			Packaged Units			Total
	Spreader	Underfeed	Overfeed	Spreader	Underfeed	Overfeed	
2.9 - 7.3 (10 - 25)	43 (210)	197 (970)	26 (120)	99 (500)	1,993 (10,110)	63 (320)	2,421 (12,230)
7.3 - 15 (25 - 50)	157 (1,760)	453 (5,040)	120 (1,320)	364 (4,070)	1,414 (15,650)	282 (3,110)	2,790 (30,950)
15 - 29 (50 - 100)	120 (2,610)	333 (7,470)	87 (1,880)	223 (4,830)	617 (13,330)	162 (3,490)	1,542 (33,900)
29 - 73 (100 - 250)	379 (16,200)	135 (5,650)	67 (2,840)	125 (5,390)	45 (1,880)	23 (940)	774 (32,900)
TOTAL 2.9 - 73 (10 - 250)	699 (20,780)	1,118 (19,130)	300 (6,160)	811 (14,790)	4,069 (40,970)	530 (7,860)	7,527 (109,690)

72 percent of the total number of stokers installed as of 1977. Underfeed stokers with heat input capacity smaller than 29 MW (100×10^6 Btu/hr) constituted the largest number of installed units. This finding by Devitt, et al., (Reference 2-1) contradicts previous estimates by Locklin, et al., who stated that underfeed stokers were the most popular only to a size of 4.6 MW (16×10^6 Btu/hr) (Reference 2-3).

The data in Table 2-2 also indicate that spreader stokers account for the majority (65 percent) of the stokers with capacity greater than 29 MW (100×10^6 Btu/hr). Also, of all field erected stokers, the spreader feed design is the most popular. Overfeed stokers account for only 15 percent of all installed units, most of which are of packaged design.

An estimated annual load factor was used in this report to calculate the coal consumption of industrial boilers. Annual load factor is a measure of boiler service usage; it is defined as the ratio of fuel quantity burned to the quantity that would be burned with the boiler generating continuously at full capacity. Recent load factors of 0.072 to 0.180 for coal-fired units in the size range of 2.9 to 73 MW (10 to 250×10^6 Btu/hr) were estimated by Devitt, et al. (Reference 2-1). Other load factors estimated by Locklin, et al., ranged from 0.426 to 0.524 (Reference 2-10).

Table 2-3 lists the coal consumption for coal-fired industrial boilers based on an average annual load factor of 0.18 derived from the data presented in the more recent citation, Reference 2-1. The total consumption of 0.6 EJ in 1977 can be compared with the estimate of 2.36 EJ calculated in another study for the 1971 base year (Reference 2-10). These figures indicate an apparent coal consumption decrease of 75 percent over the six year time span. In a third study, performed in the NO_x EA, the coal consumption for packaged industrial boilers was estimated for the base year of 1974 to be approximately 2.85 EJ (Reference 2-11). However, that figure cannot be directly compared with the total coal consumption estimated in this report because fuel consumption in Reference 2-11 was not limited to boilers in the 2.9 to 73 MW (10 to 250×10^6 Btu/hr) size category.

The large apparently anomalous decrease in coal consumption by the industrial sector in 1977 from the level estimated in 1971 may be partly

TABLE 2-3. ESTIMATED 1977 COAL CONSUMPTION FOR INDUSTRIAL BOILERS, EJ (10^{15} Btu) (Reference 2-1)

Fuel Type	Equipment Type	Boiler Capacity - MW (10^6 Btu/hr)				
		2.9 - 7.3 (10 - 25)	7.3 - 15 (25 - 50)	15 - 29 (50 - 100)	29 - 73 (100 - 250)	Total 2.9 - 73
Pulverized	All types	--	--	--	0.102 (0.108)	0.102 (0.108)
Stoker	Spreader	0.003 (0.003)	0.025 (0.026)	0.034 (0.036)	0.106 (0.112)	0.168 (0.177)
	Underfeed	0.044 (0.046)	0.088 (0.093)	0.096 (0.101)	0.037 (0.039)	0.264 (0.279)
	Overfeed	0.002 (0.002)	0.019 (0.020)	0.025 (0.026)	0.019 (0.020)	0.064 (0.068)
All Coals	All Boilers	0.048 (0.051)	0.132 (0.139)	0.155 (0.163)	0.264 (0.279)	0.60 (0.63)

due to inconsistencies in the earlier study as well as differing assumptions in the two studies. However, a decrease in coal consumption may actually be real for several related reasons:

- The decline in coal-fired boiler sales, especially in the early 1970's when environmental considerations and economics favored gas and oil combustion in place of coal
- Some fuel switching from coal to cleaner gas or oil fuels occurred under environmental pressures
- The phasing out of older coal-fired boilers and replacement with gas- or oil-fired ones

The recent shortages of natural gas and oil combined with political pressures to switch back to coal following the 1973 oil embargo have apparently not reversed the decline in coal consumption over the six year period from 1971 to 1977.

Total NO_x emissions from coal-fired industrial boilers for the year 1977 can be approximated using the coal consumption estimates of Table 2-3 and the average NO_x emission factors for the major firing types. Section 7 summarizes all the available field test NO_x emissions data along with the principal boiler/fuel characteristics of the units tested. Average NO_x emission factors were calculated from the data cited in Section 7, and summarized for the representative boiler/fuel types indicated in Tables 2-4, 2-9, and 2-13. However, since only a handful of units were tested in each category, the actual average NO_x emissions factor may actually be up to $\pm$20 percent of that reported here. Furthermore, individual boilers may have NO_x emissions up to 50 percent different from the average for its category. These trends are true for oil- and gas-fired data as well. A more extensive discussion of the variability of emissions factors is given elsewhere (Reference 2-12). In any event, these NO_x emissions factors along with the fuel consumption figures were combined in Table 2-4 to give the estimated total in 1977 NO_x emissions from coal-fired industrial boilers, as shown in that table.

The information in Table 2-4 indicates that spreader stokers contribute the largest amount of NO_x emissions, approximately 36 percent. Underfeed and pulverized units are second and third largest emitters with 32 and 24 percent, respectively. Overfeed stokers contribute the smallest amount, 7 percent.

TABLE 2-4. ESTIMATED 1977 NO_x EMISSIONS FOR COAL-FIRED INDUSTRIAL BOILERS

Fuel Type	Equipment Type	Coal Consumption EJ (10^{15} Btu)	Emission Factor[a] ng/J (lb/10^6 Btu)	NO_x Emissions Gg (10^3 tons)
Pulverized Coal	All types	0.102 (0.108)	285 (0.66)	32 (36)
Stoker Coal	Spreader	0.168 (0.177)	265 (0.62)	50 (55)
	Underfeed	0.264 (0.279)	150 (0.35)	44 (49)
	Overfeed	0.064 (0.068)	140 (0.33)	10 (11)
TOTAL	All Boilers	0.60 (0.63)	--	136 (151)

[a]Based on very limited data

2.1.4 Coal-Fired Equipment Trends

In the previously cited study, Locklin, *et al.* (Reference 2-3) estimated the 1971 installed coal-fired industrial boiler population and projected their inventory into the 1990's to evaluate trends for this fuel/equipment category. Table 2-5 lists the population, on a percentage basis, of industrial coal-fired boilers for 1971 together with the projected population in the 1990's from the Locklin, *et al.* study (Reference 2-3) and compares this to the 1977 estimates from Devitt, *et al.* (Reference 2-1).

The information listed in the table shows that the projected rapid trend toward a significant increase of spreader stokers with heat input capacities less than 29 MW (100 x 10^6 Btu/hr) by the 1990's has not yet begun. Underfeed stokers were still very popular in 1977 according to Devitt, *et al.* (Reference 2-1). However, Locklin, *et al.* (Reference 2-3) estimated that underfeed stokers will eventually be replaced by spreader stokers in this size category. Pulverized coal-fired units will still be essentially unavailable in sizes smaller than 29 MW (100 x 10^6 Btu/hr).

In the size category of 29 to 73 MW (100 to 250 x 10^6 Btu/hr), the trend toward a significant increase in pulverized coal-fired boilers has apparently already taken place in 1977, according to Devitt, *et al.* (Reference 2-1). Both Devitt, *et al.* and Locklin, *et al.* (Reference 2-3) predict a gradual decrease in spreader stokers in the greater than 29 MW (100 x 10^6 Btu/hr) size range. Also, Devitt, *et al.* confirmed the decrease in the number of installed underfeed stokers in this size category. The number of overfeed stokers will apparently increase at a relatively steady pace with the total coal-fired industrial boiler population through the 1990's. It should be pointed out that because Locklin, *et al.* used different size categories than Devitt, *et al.*, a direct comparison between the two boiler inventories was limited to only the two size ranges noted in Table 2-5.

2.2 OIL-FIRED BOILERS

Industrial boilers burning fuel oil as their primary fuel accounted for about 45 percent of all installed boiler capacity in 1977 (Reference 2-1). Oil-fired industrial equipment can be classified into two main categories, watertube and firetube. Watertube boilers can be either shop assembled

TABLE 2-5. ESTIMATED POPULATION TRENDS OF COAL-FIRED INDUSTRIAL BOILERS INSTALLED IN THE YEARS NOTED (PERCENTAGE BASIS)

Boiler Size	2.9 - 29 MW (10 - 100 x 10^6 Btu/hr)			29 - 73 MW (100 - 250 x 10^6 Btu/hr		
Survey Base Year/ Boiler Type	Locklin, *et al.*[a] 1971	Devitt, *et al.*[b] 1977	Locklin, *et al.*[a] 1990	Locklin, *et al.*[a] 1971	Devitt, *et al.*[b] 1977	Locklin, *et al.*[a] 1990
Pulverized Coal	-	-	-	16	38	47
Spreader Stoker	15 - 20	21	35 - 70	53	41	41
Underfeed Stoker	60 - 70	64	10 - 50	21	15	0
Overfeed Stoker	10 - 15	15	10 - 15	10	7	12

[a](Reference 2-3)

[b](Reference 2-1)

(packaged) or field erected. Firetube boilers, whether oil- or gas-fired, are rarely field erected because of their smaller size.

Oil-fired watertube boilers which are field erected are similar to pulverized coal-fired units. Those boilers strictly designed for oil firing differ from pulverized coal-fired boilers mainly in size. Oil-fired boilers are more compact than coal-fired boilers with the same heat input because of the more rapid combustion characteristics of fuel oil.

The following sections briefly describe watertube and firetube boiler designs with emphasis on typical capacity size ranges and equipment characteristics.

2.2.1 Watertube Boilers

As the name implies, watertube boilers are designed to flow water through the heat transfer tubes, instead of combustion products as in the firetube design. As previously mentioned, watertube boilers can be field erected or packaged design. There are almost 50 percent more packaged units than field erected units in the size range of 2.9 to 29 MW (10 to 100×10^6 Btu/hr) (Reference 2-1). However, above 29 MW (100×10^6 Btu/hr), field erected oil-fired watertubes are more popular than packaged watertubes, by nearly a factor of 4 (Reference 2-1). Generally, few oil-fired watertube boilers with size above 59 MW (200×10^6 Btu/hr) are shop assembled. The packaged boiler popularity in the size range below 29 MW (100×10^6 Btu/hr) is due primarily to low capital cost.

Packaged watertube boiler furnaces are designed to operate under positive pressure. However, furnace pressure in a large field erected watertube boiler is balanced or slightly negative.

There are two major types of packaged watertube designs, straight and bent tube boilers. Typical straight and bent tube boilers are shown in Figure 2-9. Horizontal and inclined tube boilers are no longer being manufactured, having been completely supplemented by firetubes in the smaller sizes and bent watertube boilers in the intermediate size range. The higher capital cost, poor accessibility for inspection and cleaning, and lower steam rate capabilities are the cause for the replacement of this boiler design. However, there are a large number of straight tube boilers still in operation.

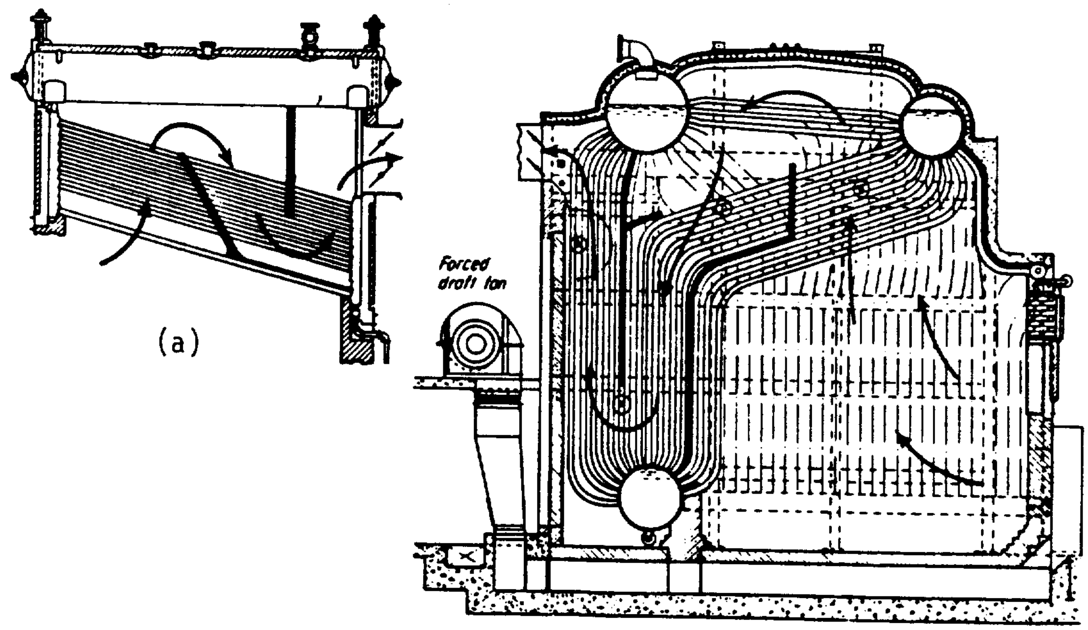

Figure 2-9. Inclined tube (a) and bent tube (b) boilers (Reference 2-13).
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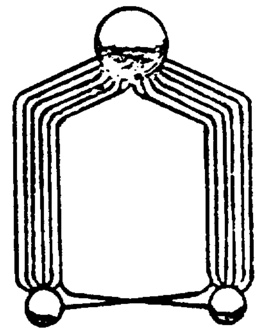
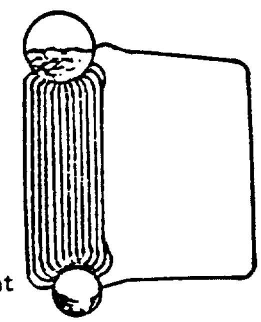
Horizontal bent tube boilers, the major type of watertube design, are classified by the number of drums, headroom, and tube configuration, with the latter being the most important distinguishing factor. In the boiler, each tube is connected to the steam drum and to a lower drum or header. Figure 2-10 shows the three most common tube/drum configurations in packaged watertube boilers. The figure shows that the watertubes are oriented vertically and enter the drum radially. Figure 2-11 illustrates tube location in a typical D-type bent tube packaged boiler. The furnace is of the waterwall type backed up with refractory. The tubes, which form the furnace waterwall, are an integral part of the boiler.

Packaged watertubes of the bent tube design in the size above 15 MW (50×10^6 Btu/hr) often have flue gas heat recovery devices consisting of either economizers or air preheaters. Field erected watertube boilers, larger than 59 MW (200×10^6 Btu/hr) are very similar to utility boilers. These multiburner facilities are available in the tangentially-fired design as well as the wall-fired type in the smaller units.

A-type has two small lower drums or headers. Upper drum is larger to permit separation of water and steam. Most steam production occurs in center furnace-wall tubes entering drum.



D-type allows much flexibility. Here the more active steaming risers enter drum near water line. Burners may be located in end walls or between tubes in buckle of the D, right angles to drum.



O-type is also a compact steamer. Transportation limits height of furnace, so, for equal capacity, longer boiler is often required. Floors of D and O types are generally tile-covered.

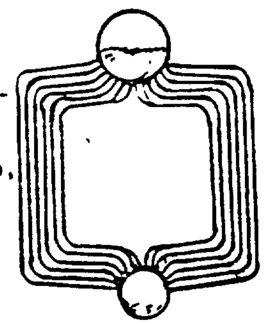


Figure 2-10. Types of bent tube packaged watertube boilers (Reference 2-13).
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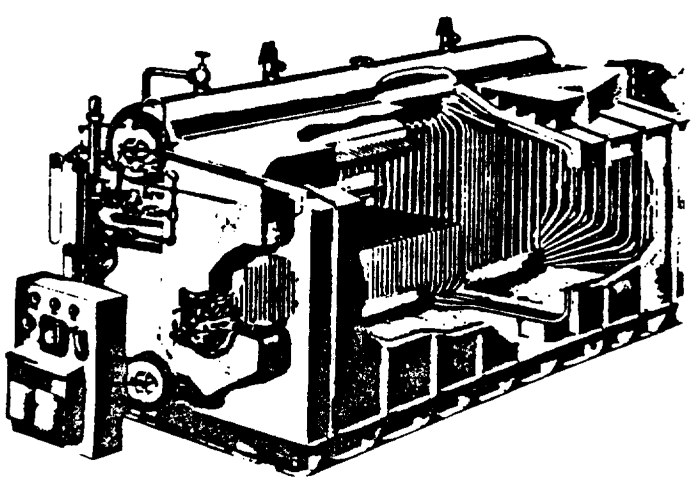

Figure 2-11. D-type bent tube configuration (Reference 2-13).
Reprinted with permission from POWER, June 1964.

2.2.2 Firetube Boilers

In a firetube boiler, the fuel is burned in a cylindrical furnace which is located inside a cylindrical pressure vessel. The combustion products are then directed through tubes which are submerged in water either above or below the furnace. The tubes are normally horizontal for firetube boilers above 2.9 MW (10×10^6 Btu/hr), the industrial size category. Depending on the capacity of the firetube, the hot flue gas may make up to four passes before exiting from the boiler.

Firetube boilers are usually limited in size to 8.7 MW (30×10^6 Btu/hr). However, some firetube designs have been built with heat input up to 12 MW (40×10^6 Btu/hr) (Reference 2-4). Firetube boilers in the industrial boiler size category can be classified in three different types, namely:

- Horizontal return tube (HRT)
- Firebox
- Scotch

The horizontal return tube (HRT) firetube is a two pass boiler. It was formerly the most popular of firetube boilers primarily because it could handle many types of fuels. In fact, so many of these units were fabricated that the HRT firetube today represents 56 percent of the firetube population with heat capacity above 2.9 MW (10^7 Btu/hr) (Reference 2-1). However, the trend in new firetube sales has long changed toward other firetube designs, primarily the scotch design because it is more versatile.

Firebox firetube boilers are constructed with an internal steel encased, water-jacketed firebox. These units are short and compact, employing at the most, three passes. The compact size of the firebox firetube calls for proper matching of the burner flame length and combustion volume. The greatest advantage of this boiler is its efficiency and the minimum floor space required for installation. Generally, firebox firetubes are limited in size to below 5.8 MW (20×10^6 Btu/hr).

The scotch firetube was developed 30 years ago based on the Scotch marine boiler and has since become one of the most popular firetube boilers. The trend toward increased use of this boiler type continues.

Figure 2-12 shows a typical oil-fired scotch boiler. Its design emphasizes compactness and limited head room. It is capable of gas, oil

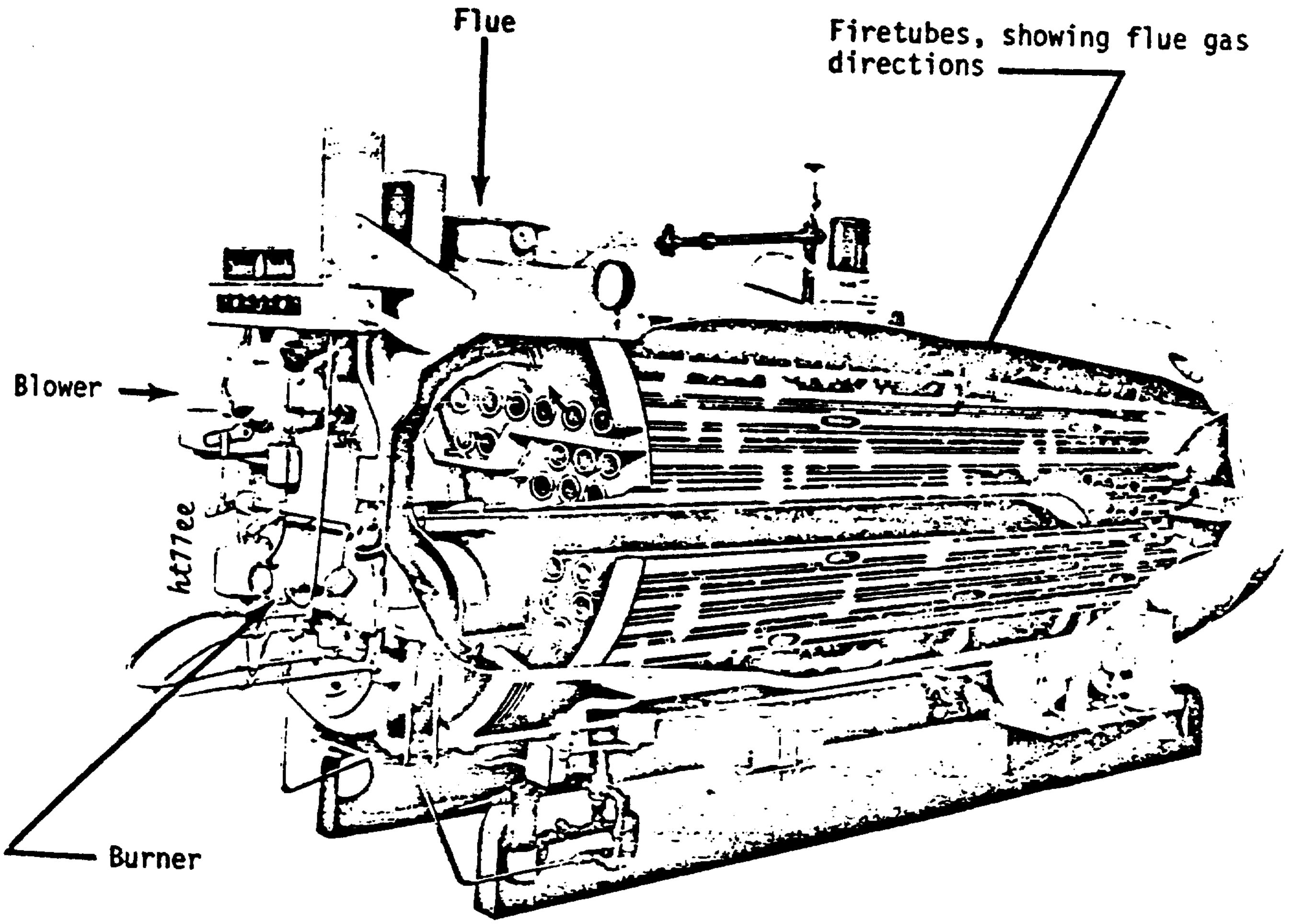

Figure 2-12. Four-pass scotch firetube boiler (Reference 2-13). Reprinted with permission POWER, June 1964.

or combination firing. Its capacity is normally limited to 7.3 MW (25×10^6 Btu/hr), however, scotch firetubes with heat input as high as 12 MW (40×10^6 Btu/hr) can be built (Reference 2-9).
Scotch firetubes can have either two, three, or four passes. The burner flame is contained in an elongated, water-cooled combustion chamber which also acts as the first pass. This characteristic is unique to this type of boiler. The rear wall of the furnace is either refractory-lined ("dry-back") or water-cooled ("wet-back") popular in the later versions. Due to the relatively small diameter firetubes and concomitant large pressure drop, three and four pass units generally require provision for mechanical draft.

Scotch firetubes are generally cheaper than watertube boilers without economizers in sizes up to 12 MW (40×10^6 Btu/hr). In addition, these firetube types offer advantages over watertubes such as (Reference 2-9):

- More rapid response to load swings
- Easier tube replacement
- Less installation space required
- Low susceptibility to cold-end and casing corrosion

Furthermore, thermal efficiencies of scotch firetubes are often higher than for watertubes because the heating surface of the scotch is approximately 40 percent more than for watertubes of the same size. The additional surface permits more heat transfer and lowers boiler exit flue gas temperature, which is conducive to higher thermal efficiency.

2.2.3 Atomization Methods

Fuel atomization refers to the transformation of a liquid oil into a spray. The large number of droplets in the spray serve to increase the fuel surface area exposed to combustion air. The droplet size distribution depends primarily on the type of atomization and the physical properties of the fuel such as viscosity.

Four techniques are used to atomize fuel oil, namely:

- Air atomization
- Steam atomization
- Mechanical atomization (oil pressure atomization)
- Rotary cup (atomization by centrifugal acceleration)

The type of atomization has been reported to have some effect on pollutant emissions, primarily particulates (Reference 2-14). Furthermore, the type of atomization also affects NO_x emissions to some extent (Reference 2-15). Section 3.3 will discuss some of these effects.

A study conducted for the EPA estimated the extent to which these atomization types are being used in oil-fired industrial boilers (Reference 2-3). Table 2-6, obtained from that study, indicates that air and rotary atomization is dominant in small boilers while steam atomization predominates in larger capacities. Pressure atomization is found in all industrial boiler size ranges, but only to a limited extent.

Steam and air atomized burners are essentially similar. In fact, a burner using steam atomization can also be used with air atomization. Table 2-6 indicates that the air atomizers are most popular for small packaged boilers. For larger boilers, air atomization is seldom used because of the high operating cost of supplying large volumes of high pressure air. Air atomization is used primarily with light oils while steam atomization is used with heavier residual oils. Fuel flow rate turndown is somewhat more limited with air atomization than for steam. In addition, steam atomizers can shape the flame better than can air atomizers.

TABLE 2-6. POPULATION BREAKDOWN OF INDUSTRIAL BOILERS BY BURNER TYPE (PERCENT BASIS) (REFERENCE 2-3)

Burner Type	Rated Capacity MW (10^6 Btu/hr)		
	2.9 - 4.7 (10 - 16)	4.7 - 29 (16 - 100)	29 - 73 (100 - 250)
Air Atomizing	40	15	5
Steam Atomizing	20	70	85
Pressure or Mechanical Atomizing	10	10	10
Rotary Cup	30	5	--

Oil firing with mechanical atomization is the simplest form of oil firing. However, the atomization requires fuel pressures much higher than for air or steam atomization. The high fuel oil supply pressure necessitates fuel return lines from each burner in order to control both pressure and fuel flow. Mechanical atomization can be used with both distillate and residual oils. It is best suited for steady loads and high fuel capacities. Firing at reduced load is limited with this type of atomization and, thus, it is not recommended for single burner packaged boilers. However, Table 2-6 shows that mechanical atomization is found just as frequently in small units as in large multiburner boilers.

In a rotary cup atomized oil burner, the fuel is atomized by centrifugal acceleration of a liquid to a high velocity and subsequent discharge into the furnace. This centrifugal acceleration is obtained by a number of devices located at the burner tip. The rotary cup is one of these devices; others are: flat or vaned disks, bowls or slotted wheels. Rotary atomizers are used primarily with oils with low viscosity, such as distillate oil. Also, they are used in small size packaged boilers equipped only with one burner.

2.2.4 Oil Consumption and Emission Inventory

Oil-fired industrial boilers in place in 1977 accounted for approximately 40 percent of the total industrial boiler capacity (Reference 2-1). These units are often equipped to burn natural gas or even coal as a secondary fuel. In fact, Locklin, *et al.* estimated that in 1971 industrial boilers with dual fuel capability, natural gas and oil, accounted for 26 percent of the entire population (Reference 2-3).

Table 2-7 lists the number of units and total boiler capacity for oil-fired industrial boilers in each specified capacity range. The inventory indicates that in 1977, the total number of residual oil-fired watertube boilers was over 5 times that of distillate oil-fired boilers. In fact, watertube boilers whose primary fuel was residual oil are always more numerous than distillate oil-fired watertubes in any size category. Packaged watertube boilers are more numerous than field erected units only in heat input capacities below 29 MW (100 x 10^6 Btu/hr).

In order to calculate the oil consumed in industrial boilers in the year 1977, estimated annual load factors are used as was done with coal-fired units. Load factors used are listed in Table 2-8 together with

TABLE 2-7. DISTRIBUTION OF OIL-FIRED INDUSTRIAL BOILER POPULATION IN PLACE IN 1977 (Reference 2-1)

Capacity MW (10^6 Btu/hr)	Total Number of Units (Boiler Capacity MW)						Total
	Field Erected Watertube		Packaged Watertube		Firetube		
	Residual Oil	Distillate Oil	Residual Oil	Distillate Oil	Residual Oil	Distillate Oil	
2.9 - 7.3 (10 - 25)	819 (3,900)	197 (880)	1,912 (9,110)	462 (2,080)	5,072 (26,051)	3,318 (17,050)	11,780 (59,071)
7.3 - 15 (25 - 50)	1,507 (16,060)	274 (2,780)	3,515 (37,500)	640 (6,530)	833 (9,148)	543 (5,980)	7,312 (77,998)
15 - 29 (50 - 100)	771 (16,640)	105 (2,340)	1,434 (30,880)	193 (4,370)	--	--	2,503 (54,230)
29 - 73 (100 - 250)	928 (39,990)	151 (6,620)	309 (13,330)	51 (2,230)	--	--	1,439 (62,170)
TOTAL 2.9 - 73 (10 - 250)	4,025 (76,590)	727 (12,620)	7,170 (90,820)	1,346 (15,210)	5,905 (35,199)	3,861 (23,030)	23,034 (253,469)

TABLE 2-8. ESTIMATED OIL CONSUMPTION BY INDUSTRIAL BOILER IN PLACE IN 1977, EJ (10^{15} Btu)

Fuel Type	Equipment Type	Load Factor	Boiler Capacity MW (10^6 Btu/hr)				
			2.9 - 7.3 (10 - 25)	7.3 - 15 (25 - 50)	15 - 29 (50 - 100)	29 - 73 (100 - 250)	TOTAL 2.9 - 73 (10 - 250)
Residual Oil	Watertube	0.174	0.057 (0.060)	0.241 (0.254)	0.206 (0.218)	0.206 (0.217)	0.710 (0.749)
	Firetube	0.182	0.114 (0.121)	0.041 (0.043)	--	--	0.155 (0.164)
Distillate Oil	Watertube	0.280	0.020 (0.021)	0.065 (0.068)	0.049 (0.051)	0.057 (0.060)	0.191 (0.200)
	Firetube	0.279	0.115 (0.121)	0.041 (0.044)	--	--	0.156 (0.165)
All Oils	All Boilers	0.20[a]	0.306 (0.323)	0.388 (0.409)	0.255 (0.269)	0.263 (0.277)	1.21 (1.28)

[a]Weighted average

total oil consumption. Load factors ranging from 0.174 to 0.280 were derived from the recent data of Devitt, et al. (Reference 2-1). Other load factors estimated by Putnam, et al. ranged from 0.33 to 0.37 for distillate and residual oil-fired units respectively (Reference 2-10).

The estimated total 1977 oil consumption of 1.21 EJ listed in Table 2-8 compares with approximately 2.6 EJ calculated by Putnam, et al., for the base year 1971 (Reference 2-10). These figures give an apparent consumption decrease of approximately 50 percent. However, this is probably due to different assumptions used in the two inventories, such as in load factors. In another study, the oil consumption for industrial packaged boilers was estimated at 4.46 EJ for the base year of 1974 (Reference 2-11). However, a direct comparison cannot be made between the 1974 and 1977 oil consumption estimates because packaged boilers with capacity smaller than 2.9 MW (10 x 10^6 Btu/hr) were included in the 1974 inventory (Reference 2-11).

Total NO_x emissions for 1977 can be estimated by multiplying NO_x emission factors by the fuel oil consumption listed in Table 2-8. Total NO_x emissions from oil-fired industrial boilers are presented in Table 2-9. NO_x emissions factors were obtained from a recent review of all available field test data (Reference 2-12). A distinction in emission factors was made between distillate oil-fired watertube boilers with heat input capacity above or below 15 MW (50 x 10^6 Btu/hr). This distinction was based on the assumption that watertube boilers with heat input capacity greater than 15 MW (50 x 10^6 Btu/hr) are often equipped with air preheaters. As will be discussed in later sections of this report, the preheated combustion air significantly increases the level of NO_x emitted from distillated oil-fired watertubes. However, NO_x emissions are not significantly affected by an air preheater when residual oil is burned.

The data clearly indicate that residual oil-fired industrial boilers are responsible for about 85 percent of the total NO_x emitted from oil-fired boilers. Firetube boilers which consumed the second largest quantity of fuel oil contributed approximately 18 percent of the total NO_x emissions.

TABLE 2-9. ESTIMATED 1977 NO_x EMISSIONS FROM OIL-FIRED INDUSTRIAL BOILERS

Fuel Type	Equipment Type	Capacity MW (10^6 Btu/hr)	Fuel Consumption EJ (10^{15} Btu)	NO_x Emission Factor ug/J (lb/10^6 Btu)	Total NO_x Emissions Gg (10^3 tons)
Residual Oil	Watertube	2.9 - 73 (10 - 250)	0.710 (0.749)	160 (0.37)	126 (138)
	Firetube	2.9 - 15 (10 - 150)	0.155 (0.164)	115 (0.27)	20 (22)
Distillate Oil	Watertube	15 - 73 (50 - 250)	0.106 (0.111)	90 (0.21)	10 (11)
	Watertube	2.9 - 15 (10 - 50)	0.085 (0.089)	55[a] (0.13)	5 (6)
	Firetube	2.9 - 15 (10 - 50)	0.156 (0.165)	70[a] (0.16)	12 (13)
All Oils	All Boilers	2.9 - 73 (10 - 250)	1.21 (1.28)	-	173 (190)

[a]Assumes not equipped with air preheaters

2.2.5 Oil-Fired Equipment Trends

In 1971 oil-fired industrial boilers accounted for 29 percent of the total industrial boiler capacity (Reference 2-10). In a more recent inventory, oil-fired units accounted for about 40 percent of the total installed capacity in the year 1977 (Reference 2-1). However, in both inventories it is not clear whether boilers with dual fuel capability, such as oil and natural gas, were included with oil-fired units or gas-fired units. Locklin, et al. (Reference 2-3) estimated that industrial boilers capable of dual fuel combustion ranged from 16 to 26 percent for the gas/oil combination to 0.5 percent for the oil/coal combination.

Industrial boilers with multifuel capability are becoming increasingly more popular because of uncertainties in fuel supplies. In fact, often fuel flexibility is more desirable than improved boiler efficiency (Reference 2-9). Table 2-10 clearly shows the trend of boilers away from single fuel capabilities and toward dual fuel capability. This is especially evident in the oil/gas fuel combination. In fact, population trends in industrial boilers suggest that steam generators with oil/gas dual fuel combustion capability would account from 30 to 45 percent of the total installed capacity in the 1990's (Reference 2-3). The larger percentage would be reported in the smaller size boilers with heat input capacity of less than 4.7 MW (16 x 10^6 Btu/hr). Industrial boilers with oil/coal dual fuel combustion capability would account for 10 percent of all industrial boiler capacity in the size range from 29 to 73 MW (100 to 250 x 10^6 Btu/hr). Trends in oil burners indicate that in the 1990's steam atomization will account for over 90 percent of the total number of oil burners installed in watertube and firetube boilers with heat input capacities in the range from 4.7 to 73 MW (16 to 250 x 10^6 Btu/hr) (Reference 2-3). For boilers smaller than 4.7 MW (16 x 10^6 Btu/hr) air and steam atomization will each account for 40 percent of all oil-fired boilers with pressure or mechanical atomization making up the remaining 20 percent. Rotary cup burners will eventually be phased out as old units get replaced primarily with air and pressure atomization.

TABLE 2-10. ESTIMATED TRENDS BY FUEL CAPABILITY (PERCENTAGE BASIS) FOR INDUSTRIAL BOILERS (Reference 2-3)

Rated Capacity Size Range MW (10^6 Btu/hr)	2.9 - 4.7 (10 - 16)				4.7 - 29 (16 - 100)				29 - 73 (100 - 250)			
Year	1930's	1950's	1970's	1990's	1930's	1950's	1970's	1990's	1930's	1950's	1970's	1990's
Fuel Capability												
Oil Only	17	43	30	13	13	30	30	10	5	20	24	nil
Gas Only	5	20	30	6	10	30	30	4	5	20	24	nil
Coal Only	75	10	5	30	75	30	5	40	90	38	15	50
Oil/Gas	nil	25	30	45	nil	5	30	40	nil	10	25	30
Oil/Coal	--	--	--	--	--	--	--	--	nil	5	5	10
Gas/Coal	--	--	--	--	--	--	--	--	nil	5	5	5
Miscellaneous Fuels	3	2	5	6	2	5	5	6	nil	2	2	5

2.3 GAS-FIRED BOILERS

Gas-fired industrial boilers accounted for about 40 percent of the total industrial boiler capacity in 1977 (Reference 2-1). These units are quite similar in design to oil-fired boilers. In fact, many gas-fired boilers can also fire oil as a supplementary fuel.

The uncertain supplies of natural gas have required that dual fuel capability be installed in many industrial boilers. In 1973, 16 to 26 percent of all operating industrial boilers had combined natural and oil fuel combustion capability. These percentages are expected to increase to 30 to 45 percent in the 1990's as supplies of natural gas becomes still more uncertain.

2.3.1 Equipment Types

Gas-fired industrial boilers can also be distinguished by watertube and firetube designs. Field erected watertubes primarily designed for gas-firing are the most compact of all steam generators due to the rapid combustion of the gaseous fuel, the low flame luminosity, and the ash free content of natural gas. Packaged watertubes and firetubes with gas burners are very similar to their counterpart oil-fired packaged boilers. Figure 2-13 shows a schematic of a combined gas/oil-fired burner installed on a packaged watertube boiler (Reference 2-16). The perforated ring injects the gas concentrically in the burner throat. Oil is injected through an oil gun which is located along the axis of the burner to achieve a symmetric spray pattern in the boiler furnace. Spray guns are also available for natural gas fuel; however, they are less frequently encountered in small industrial boilers.

2.3.2 Natural Gas Consumption and Emission Inventory

Table 2-11 lists the population and heat input capacity distribution of industrial boilers in the four designated capacity categories. The data indicate that even though natural gas-fired firetube boilers accounted for nearly half of the installations, these units accounted for only 23 percent of the total installed heat input capacity in 1977.

Packaged watertube boilers are more common than field erected boilers except in the size category above 29 MW (100 x 10^6 Btu/hr) where field erected units account for 75 percent of the total installed capacity in the range 29 to 73 MW (100 to 250 x 10^6 Btu/hr).

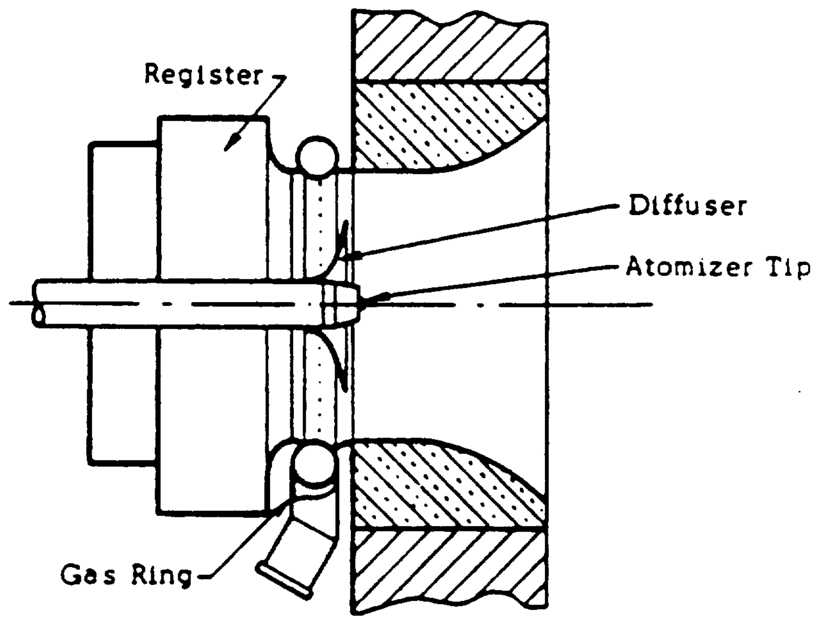

Figure 2-13. Schematic of dual fuel (oil/gas) burner installed in a packaged watertube boiler (Reference 2-16).

TABLE 2-11. DISTRIBUTION OF NATURAL GAS-FIRED INDUSTRIAL BOILER POPULATION IN PLACE IN 1977 (REFERENCE 2-1)

Capacity MW (10^6 Btu/hr)	Total Number of Units/Total Boiler Capacity MW			
	Field Erected	Packaged		Total
	Watertube	Watertube	Firetube	
2.9 - 7.3 (10 - 25)	760 (3,780)	1,775 (8,850)	8,345 (42,840)	10,880 (55,470)
7.3 - 15 (25 - 50)	1,459 (15,820)	3,404 (36,890)	1,518 (16,700)	6,381 (69,410)
15 - 29 (50 - 100)	979 (20,830)	1,816 (38,710)	--	2,795 (59,540)
29 - 73 (100 - 250)	1,189 (52,180)	397 (17,400)	--	1,586 (69,580)
TOTAL 29 - 73 (10 - 250)	4,387 (92,610)	7,392 (101,850)	9,863 (59,540)	21,642 (254,000)

Natural gas consumption is presented in Table 2-12. Watertube boilers consumed nearly 80 percent of total gas consumption in industrial boilers. Total estimated gas consumption of 2.35 EJ reported for 1977 compares with an approximate gas consumption of 3.79 EJ for the year 1971 (Reference 2-10). These two consumption figures indicate a 38 percent decrease in natural gas consumption, again probably due to differences in assumptions in the two studies rather than an actual decrease in consumption.

Estimated NO_x emissions from natural gas-fired industrial boilers based on reported NO_x emission factors (Reference 2-12) are listed in Table 2-13. Emissions from watertube units were separated between boilers with heat input greater and lower than 15 MW (50 x 10^6 Btu/hr) as was done for distillate oil-fired watertube boilers. Uncontrolled NO_x emissions from watertube boilers equipped with air preheaters are significantly higher than NO_x emissions from boilers not equipped with air preheaters (Reference 2-12). Total NO_x emissions from gas-fired boilers accounted for approximately 25 percent of the total NO_x emitted from industrial boilers in place in 1977.

2.3.3 Equipment Trends

Industrial boilers in the 1990's capable of burning natural gas will have almost entirely dual fuel capability. Most of these units will be capable of switching from oil to gas or vice versa (Reference 2-3). Table 2-10 clearly indicated that the trend in industrial boiler equipment design is away from single fuel capability especially for natural gas-fired boilers. Natural gas will, however, still be consumed in significant quantities in boilers with heat input capacities lower than 7.3 MW (25 x 10^6 Btu/hr) in the 1980's.

TABLE 2-12. ESTIMATED NATURAL GAS CONSUMPTION BY INDUSTRIAL BOILERS IN PLACE IN 1977, EJ (10^{15} Btu)

Equipment Type	Load Factor	Boiler Size Categories MW (10^6 Btu/hr)				
		2.9 - 7.3 (10 - 25)	7.3 - 15 (25 - 50)	15 - 29 (50 - 100)	29 - 73 (100 - 250)	Total 2.9 - 73 (10 - 250)
Watertube	0.38	0.107 (0.113)	0.492 (0.519)	0.553 (0.583)	0.643 (0.679)	1.79 (1.89)
Firetube	0.39	0.403 (0.425)	0.156 (0.164)	--	--	0.558 (0.589)
All Boilers	0.38[a]	0.510 (0.538)	0.648 (0.683)	0.553 (0.583)	0.643 (0.679)	2.35 (2.48)

[a]Weighted average load factor

TABLE 2-13. ESTIMATED 1977 NO_x EMISSIONS FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS

Equipment Type	Capacity MW (10^6 Btu/hr)	Fuel Consumption EJ (10^{15} Btu)	NO_x Emission Factor ng/J (lb/10^6 Btu)	Total NO_x Emissions Gg (10^3 tons)
Watertube[a]	2.9 - 15 (10 - 50)	0.599 (0.632)	45 (0.10)	29 (32)
Watertube	15 - 73 (50 - 250)	1.196 (1.262)	110 (0.256)	52 (57)
Firetube[a]	2.9 - 15 (10 - 50)	0.558 (0.589)	40 (0.09)	24 (26)
All Boiler Types	2.9 - 73 (10 - 250)	2.35 (2.48)		105 (115)

[a]Assumes not equipped with air preheater

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SECTION 3

EFFECTIVENESS, PERFORMANCE, AND APPLICABILITY OF NO_x CONTROLS

This section presents a survey of applicable combustion modifications to reduce NO_x emissions from industrial boilers. As such, this section provides a review of current available knowledge of the effectiveness, applicability and limitations of specific combustion modifications for each major equipment/fuel category in the industrial boiler sector. Major equipment and fuel categories for industrial boilers have been identified as follows:

- Coal-fired
  - -- Pulverized coal, field-erected watertube
  - -- Packaged and field erected stoker-fed watertube
- Oil-fired
  - -- Residual oil, packaged and field erected watertube
  - -- Residual oil, packaged firetube
  - -- Distillate oil, packaged and field erected watertube
  - -- Distillate oil, packaged firetube
- Gas-fired
  - -- Packaged and field erected watertube
  - -- Packaged firetube

The category of stokers includes packaged underfeed units and field erected spreader and chain grate units. These boiler categories include the standard boiler types identified in the NO_x EA and correspond to those adopted in a recent EPA study (Reference 3-1).

The main discussion on combustion modifications for NO_x control of industrial boilers is preceded by a brief overview of the mechanisms of NO_x formation and the basic concepts for its reduction.

3.1 NO_x FORMATION MECHANISM AND PRINCIPLES OF CONTROL

Oxides of nitrogen formed in combustion processes are usually due either to thermal fixation of atmospheric nitrogen in the combustion air, leading to "thermal NO_x", or to the conversion of chemically bound nitrogen in the fuel, leading to "fuel NO_x".* For natural gas and light distillate oil firing, nearly all NO_x emissions result from thermal fixation. With residual oil, crude oil, and coal, the contribution from fuel-bound nitrogen can be significant and, under certain operating conditions, predominant. A brief discussion of each of these two mechanisms of NO_x formation follows.

3.1.1 Thermal NO_x

The detailed chemical mechanism by which molecular nitrogen in the combustion air is converted to nitric oxide is not fully understood. In practical combustion equipment, particularly for liquid or solid fuels, the kinetics of the N_2-O_2 system are coupled to the kinetics of hydrocarbon oxidation and both are influenced, if not dominated, by effects of turbulent mixing in the flame zone. It is, however, generally accepted that thermal NO_x forms at high temperatures in an excess of O_2. The most widely accepted set of reactions that describes this phenomenon is the chain mechanism proposed by Zeldovich (Reference 3-2):

$$N_2 + O \rightleftarrows NO + N \qquad (3\text{-}1)$$

$$N + O_2 \rightleftarrows NO + O \qquad (3\text{-}2)$$

$$N + OH \rightleftarrows NO + H \qquad (3\text{-}3)$$

Reaction (3-1) has a large activation energy (317 kJ/mol) and is generally believed to be rate determining. Oxygen atom concentrations are assumed to have reached equilibrium according to:

$$O_2 + M \rightleftarrows O + O + M \qquad (3\text{-}4)$$

where M denotes any third substance (usually N_2).

Experimental measurements of NO formation in heated mixtures of N_2, O_2 and Ar at atmospheric pressures have shown that NO

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*The term NO_x includes all oxides of nitrogen, primarily NO and NO_2 However, field test data have shown that over 95 percent of the NO_x formed in steam generators leaves the stack as NO (Reference 3-22).

concentration is strongly dependent on temperature (Reference 3-3). Thermal NO_x formation is also dependent on the N_2 concentration, the residence time, and the square root of O_2 concentration according to the following equation (Reference 3-3):

$$\left[NO\right] = k_1 \exp\left(-k_2/T\right)\left[N_2\right]\left[O_2\right]^{1/2} t \qquad (3\text{-}5)$$

where: $\left[\;\right]$ = mole fraction

T = temperature (k)

t = residence time

k_1, k_2 = constants of the reaction rate coefficient

Therefore, the formation of thermal NO_x can be reduced by four tactics: (1) reduce nitrogen level, (2) reduce oxygen level, (3) reduce peak temperature, and (4) reduce time of exposure at peak temperature. In typical hydrocarbon-air flames, the N_2 mole fraction is of the order 0.7 and is relatively difficult to modify. Therefore, field practice has focused on reducing oxygen level, peak temperature, and time of exposure in the NO_x-producing region of the combustor (Reference 3-4). These parameters are in turn dependent on secondary combustion variables such as combustion intensity and internal mixing in the flame zone -- effects which are ultimately determined by primary equipment and fuel parameters over which the combustion engineer has some control.

Combustion modification techniques such as lowered excess air and staged combustion have been used to lower local O_2 concentrations. Flue gas recirculation and reduced air preheat have been used in boilers to lower peak flame temperatures. Flue gas recirculation reduces residence time at peak temperatures, although the primary effect is through temperature reduction and lowered O_2 concentration.

Controlling the mixing between fuel, combustion air and recirculated products has also been found to reduce thermal NO_x formation. Burner swirl, combustion air velocity, fuel injection angle and velocity, burner divergent angle and confinement ratio all affect the mixing between fuel combustion air and recirculated products. Unfortunately, generalizing these effects is difficult, because the interactions are complex. Increasing swirl, for example, may both increase entrainment of cooled combustion products (hence lowering peak temperatures) but it may also increase fuel/air mixing (raising local combustion intensity). Thus, the net effect of increasing swirl can be to either raise or lower NO_x emissions, depending on other system parameters (Reference 3-5).

3.1.2 Fuel NO_x

The role of fuel-bound nitrogen as a source of NO_x emissions from combustion sources has been recognized since 1968 (Reference 3-6). Although the relative contribution of fuel and thermal NO_x to total NO_x emissions from sources firing nitrogen-containing fuels has not been definitively established, recent estimates indicate that fuel NO_x is significant and may even predominate. In fact, laboratory studies under controlled operating conditions have shown that fuel NO_x can account for 50 percent of the total NO_x in residual oil firing and up to 80 percent for coal (Reference 3-7), even though only a small fraction of the fuel nitrogen may be converted, as discussed below. Therefore, as coal is increasingly used as a national energy source, the control of fuel NO_x will become more important.

The following discussion is directed mainly toward fuel NO_x formation from coal, though fuel NO_x is also a problem with other nitrogen-containing fuels as well. A recent review of published data indicated that, in general, anywhere from 20 to 90 percent of fuel nitrogen in oil is converted to NO_x while the percentage of fuel nitrogen converted to NO_x in coal ranges from 5 to 60 (Reference 3-5). Figure 3-1 illustrates the nitrogen content of various U.S. coals, expressed as ng NO_2 produced per Joule for 100 percent conversion of the fuel nitrogen. The figure clearly shows that if all coal-bound nitrogen was converted to NO_x, emissions for all coals would exceed the coal-fired utility boiler NSPS of 301 ng/J (0.7 lb/10^6 Btu) implemented in 1971. Fortunately, only a fraction of the fuel nitrogen is converted to NO_x for both oil and coal firing (Reference 3-8, 3-9). Furthermore, the percentage of fuel nitrogen conversion appears to decrease as the fuel nitrogen content increases. Recent data from combustion of coal in utility boilers exhibited fuel nitrogen conversion ranging from 6.5 percent to 15 percent, with the possible correlation of conversion increasing with the ratio of coal oxygen to coal nitrogen (References 3-10 and 3-11). An

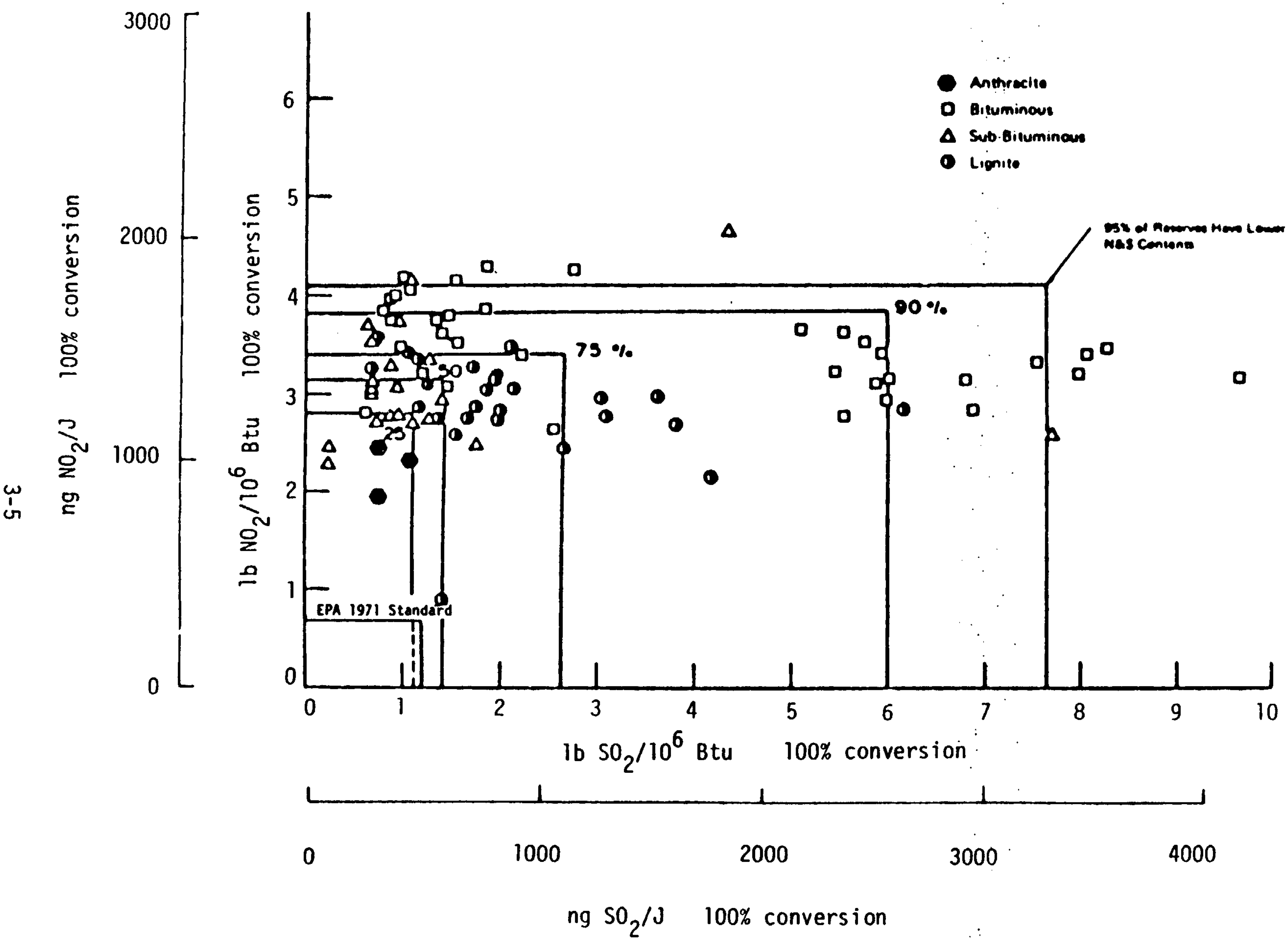

Figure 3-1. Nitrogen and sulfur content of U.S. coal reserves (Reference 3-9).

EPA field test program on industrial boilers confirmed the trend of increasing fractional conversion of fuel nitrogen with decreasing nitrogen content. An average conversion of 46 percent was found for residual oil, and nearly 100 percent for distillate oil (Reference 3-12).

Thus, although fuel NO_x emissions undoubtedly increase with increasing fuel nitrogen content, the emissions increase is not proportional (Reference 3-8). In fact, data on tangential coal-fired boilers indicate only a small increase in total NO_x emissions as fuel nitrogen increases. This is shown in Figure 3-2 (Reference 3-13). One recent report comparing two similar wall-fired utility boilers claimed a 23 percent reduction in fuel NO_x with a 15 percent reduction in fuel nitrogen, on a ng nitrogen/J heat input basis (Reference 3-14). However the lower NO_x producing coal also had a higher moisture content which would have tended to reduce NO_x emissions. The data collected on industrial boilers by Cato, et al., under an EPA sponsored field test program indicated that no direct correlation between total NO_x emissions and coal fuel nitrogen, per se, exists (Reference 3-12). The tentative generalizations that can be made at this time are that the higher nitrogen fuels do produce more NO_x in the order coal > residual oil > distillate oil > natural gas, but within a given fuel category, e.g., coal, no definite conclusions can be drawn. Since field experience is not definitive, a review of the current fundamental theories of fuel NO_x formation may be profitable in developing control strategy.

In general, fuel NO_x formation is the product of oxidation of the nitrogen in the volatiles and in the char of the coal. The oxidation of char nitrogen to NO proceeds much more slowly than the oxidation of volatilized nitrogen. In fact, based on a combination of experimental and empirical modeling studies, it is now believed that 60 to 80 percent of the fuel NO_x results from volatile nitrogen oxidation (References 3-8 and 3-15). Conversion of the char nitrogen to NO is in general lower, by factors of two to three, than conversion of total coal nitrogen (Reference 3-16).

Regardless of the precise mechanism of fuel NO_x formation, several general trends are evident, particularly for coal combustion. As expected, fuel nitrogen conversion to NO is highly dependent on the fuel/air ratio for the range existing in typical combustion equipment

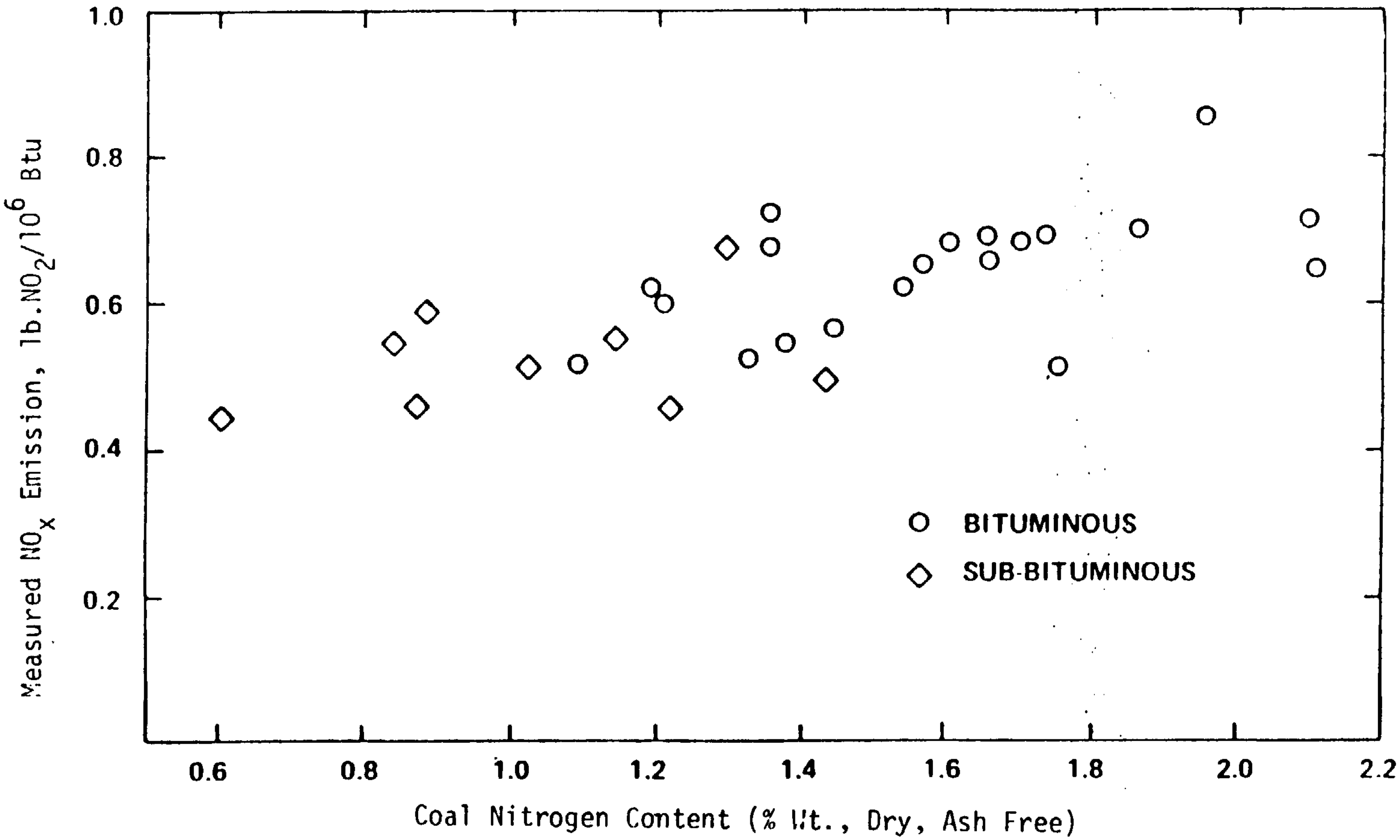

Figure 3-2. Nitric oxide emission as measured versus coal nitrogen content (Reference 3-13).

(Reference 3-17). This behavior is due largely to volatile NO formation, while oxidation of the char nitrogen is relatively insensitive to fuel/air changes.

In contrast to thermal NO_x, fuel NO_x production is relatively insensitive to small changes in combustion zone temperature (Reference 3-16). Char nitrogen oxidation appears to be a very weak function of temperature, and although the amount of nitrogen volatiles appears to increase as temperature increases, this is believed to be partially offset by a decrease in percentage conversion (Reference 3-16). Furthermore, operating restrictions severely limit the magnitude of actual temperature changes attainable in current systems.

As described above, fuel NO_x emissions are a strong function of fuel/air mixing. In general, any change which increases the mixing between the fuel and air during coal devolatilization will dramatically increase volatile nitrogen conversion and increase fuel NO. In contrast, char NO formation is only weakly dependent on initial mixing and therefore may represent a lower limit on the emission level which can be achieved through burner modifications (Reference 3-5).

In principle, the best strategy for fuel NO_x abatement combines low excess air firing, optimum burner design, and staged combustion. Assuming suitable stage separation, low excess air (LEA) may have little effect on fuel NO, but it increases system efficiency. Before using LEA firing, the need to get good carbon burnout and low CO emissions must be considered.

Optimum burner design ensures locally fuel-rich conditions during devolatilization, which promotes reduction of volatilized nitrogen compounds to N_2. Staged combustion produces overall fuel-rich conditions during the first 1 to 2 seconds and promotes the reduction of NO to N_2 through reburning reactions. High secondary air preheat also appears desirable, because it promotes more complete nitrogen volatilization in the fuel-rich initial combustion stage. This leaves less char nitrogen to be subsequently oxidized in the fuel-lean second stage. Unfortunately, it also tends to favor thermal NO formation, and at present there is no general agreement on which effect dominates (Reference 3-5).

3.1.3 Principles of Control

In summary of the above discussion, both thermal and fuel NO_x are far below the levels which would prevail at equilibrium at peak temperature. Thus, the rate of formation of both thermal and fuel NO_x is dominated by combustion conditions and is amenable to suppression through combustion process modifications. Although the mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of oxygen with the fuel. Additionally, thermal NO_x is greatly increased by increased residence time at high temperature. The modified combustion conditions and control concepts which have been tried or suggested to combat the formation mechanisms are as follows:

- Decrease primary flame zone O_2 level by:
  - -- Decreased overall O_2 level
  - -- Controlled mixing of fuel and air
  - -- Use of fuel-rich primary flame zone
- Decrease time of exposure at high temperature by:
  - -- Decreased peak temperature:
    - -- Decreased adiabatic flame temperature through dilution
    - -- Decreased combustion intensity
    - -- Increased flame cooling
    - -- Controlled mixing of fuel and air or use of fuel-rich primary flame zone
  - -- Decreased primary flame zone residence time
- Chemically reduce NO_x in post-flame region by:
  - -- Injection of reducing agent

Table 3-1 relates these control concepts to applicable combustion process modifications and equipment types. The process modifications are further categorized according to their role in the control development sequence: operational adjustments, hardware modifications of existing equipment or through factory installed controls, and, major redesigns of new equipment. The controls for decreased O_2 are also generally effective for peak temperature reduction but have not been repeated.

Table 3-2 summarizes the availability and status of the primary controls shown in Table 3-1 as applicable to the major boiler fuel type categories identified earlier. The following subsections review the status and performance of each of these applicable controls.

TABLE 3-1. SUMMARY OF COMBUSTION PROCESS MODIFICATION CONCEPTS (Reference 3-5)

Combustion Conditions	Control Concept	Effect on Thermal NO_x	Effect on Fuel NO_x	Primary Alplicable Controls		
				Operational Adjustments	Hardware Modification	Major Redesign
Decrease primary flame zone O_2 level	Decrease overall O_2 level	Reduces O_2 rich, high NO_x pockets in the flame	Reduces exposure of fuel nitrogen intermediaries to O_2	Low excess air firing	Flue gas recirculation (FGR)	
	Delayed mixing of fuel and air	Flame cooling and dilution during delayed mixing reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burner adjustments	Low NO_x burners	Optimum burner/firebox design
	Primary fuel-rich flame zone	Flame cooling in low O_2, low temp. primary zone reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burners out of service; biased burner firing	Overfire air ports	Burner/firebox design for two stage combustion
Decrease peak flame temperature	Decrease adiabatic flame temperature	Direct suppression of thermal NO_x mechanism	Ineffective	Reduced air preheat	Water injection, FGR	
	Decrease combustion intensity	Increased flame zone cooling yields lower peak temperature	Minor direct effect; indirect effect on mixing	Load reduction		Enlarged firebox, increased burner spacing
	Increased flame zone cooling/reduce residence time	Increased flame zone cooling yields lower peak temperature	Ineffective	Burner tilt		Redesign heat transfer surfaces, firebox aerodynamics
Chemically reduce NO_x in post flame region	Inject reducing agent	Decomposition	Decomposition		Ammonia injection possible on some units	Redesign convective section for NH_3 injection

TABLE 3-2. APPLICABILITY OF COMBUSTION MODIFICATION NO_x CONTROLS FOR MAJOR INDUSTRIAL BOILER EQUIPMENT/FUEL TYPES

Fuel	Coal		Oil and Natural Gas		
Equipment Type / Combustion Modification	Packaged and Field Erected Stokers	Field Erected Pulverized Coal	Field Erected Watertube	Packaged Watertube	Packaged Firetube
Low Excess Air (LEA)	Available but not implemented[a]	Available, implemented on limited basis	Available, implemented on limited basis	Available but not implemented	Available but not implemented
Load Reduction (LR)	Available but not implemented	Available but not implemented	Available but not implemented	Available but not implemented	Available but not implemented
Staged Combustion with Overfire Air Injection (OFA)	Available but not implemented	Available, implemented on limited basis	Available but not implemented	Not available R&D[b] status	Not available R&D[b] status
Staged Combustion with Burners out of Service (BOOS)[c]	Not applicable	Available but not implemented	Available but not implemented	Not applicable for single burner boilers	Not applicable
Flue gas Recirculation (FGR)	Not applicable	Not available. limited research	Available	Available	Available
Low NO_x Burners (LNB)	Not applicable	Not available. R&D[b] status	Commercially offered but not demonstrated	Commercially offered but not demonstrated	Commercially offered but not demonstrated
Ammonia Injection	Not available. Limited research	Commercially offered but not demonstrated	Commercially offered but not demonstrated	Commercially offered but not demonstrated	Commercially offered but not demonstrated
Reduced Air Preheat (RAP)[d]	Not available. Limited research	Available but not implemented: fuel penalty too high	Available[d]	Available[d]	Not applicable
New Furnace Design (Decreased Heat Release Rate)	Not available. Limited research	Available but not implemented	Not available. Limited research	Not available. Limited research	Not available. Limited research

[a]Means that control technique is commercially available, but is not presently being implemented for emission control.
[b]R&D, Research and Development.
[c]BOOS is considered a retrofit NO_x control measure.
[d]On certain new distillate oil - or natural gas-fired boilers, it may be possible to substitute an economizer for the air preheater, to lower NO_x emissions.

3.2 COAL-FIRED BOILERS

As noted previously, there are insufficient emissions data on coal-fired industrial boilers to warrant a breakdown of baseline or achievable control levels based on coal type. The few boiler and coal types tested are not adequate to establish the significance of any trends. In fact, data trends are often conflicting. Variations in emissions from boiler to boiler (of the same firing type, etc.) are often greater than possible variations due to coal type (see, for example, Table 7-2).

Of the four single wall pulverized coal-fired boilers analyzed in the EPA test program reported in References 3-19 and 3-20, three showed baseline (normal operation) emissions of 174, 216 and 244 ng/J (0.405, 0.502, and 0.567 lb/10^6 Btu) as NO_2 and the fourth showed baseline emissions of 563 ng/J (1.31 lb/10^6 Btu) as NO_2.* These boilers ranged in size from 46.7 to 117 MW (160 to 400 x 10^6 Btu/hr) with the fourth boiler having an input capacity of 76.2 MW (260 x 10^6 Btu/hr). The large baseline emissions of the fourth unit could not be explained by any significant differences in fuel properties, boiler characteristics, or operating conditions. One cyclone boiler tested emitted 494 ng/J (1.15 lb/10^6 Btu) as NO_2 at baseline (References 3-12 and 3-19). Cyclone boilers are generally large NO_x producers; thus these high NO_x levels are not surprising. A 66 MW (225 x 10^6 Btu/hr) and a 94 MW (320 x 10^6 Btu/hr) tangential coal-fired boiler were also tested. Baseline emissions were 234 and 296 ng/J (0.544 and 0.688 lb/10^6 Btu) as NO_2, respectively (Reference 3-19). Because of the small number of boilers tested and the small difference in the <u>average</u> NO_x emissions from tangential and single wall industrial boilers, their NO_x emissions will be averaged together in this discussion.

Emission data from industrial boilers burning pulverized coal are limited to the six units above. However, large industrial boilers are similar in design to utility boilers. Based on this similarity in design, a direct comparison of NO_x emissions can be made. Control techniques applicable to utility boilers can often be applied to large industrial boilers.

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*Note: NO_x emission data discussed in this report are all listed in Appendix A along with boiler and fuel characteristics.

Generally stokers emit lower uncontrolled NO_x emissions than pulverized coal-fired boilers. Reported baseline NO_x emissions vary from 153 to 336 ng/J (0.356 to 0.781 lb/10^6 Btu) as NO_2 for spreader stokers, 136 to 163 ng/J (0.317 to 0.379 lb/10^6 Btu) as NO_2 for underfeed stokers and 100 ng/J to 178 ng/J (0.233 to 0.414 ng/J) as NO_2 for chain grate stokers (References 3-12 and 3-19 through 3-21).

The following subsections summarize the NO_x control techniques via combustion modifications for these two major coal-fired industrial boiler types: pulverized coal and stokers.

3.2.1 Applicable Control Techniques for Pulverized Coal-Fired Boilers

Field test data on combustion modifications to reduce NO_x emissions from industrial boilers firing pulverized coal are very limited. However, due to the basic similarity in equipment design between the industrial and utility size boilers, applicable combustion modifications established for the smaller utility steam generators are also applicable for the larger industrial size units. Added limitations are present though when implementing these controls on the smaller boilers. These limitations are discussed for each of the control techniques.

Table 3-3 lists the combustion modifications which are applicable to pulverized coal-fired boilers. Combustion modifications for which no actual data exist for the industrial boiler size range have also been included. The effectiveness and limitations of these individual techniques are based on data reported for utility size boilers. The information on the number of industrial size boilers tested clearly shows that the data on control techniques for these units are indeed very limited. Compounding this fact, the boilers that were tested were only tested for a short period of time (<3 hours).

3.2.1.1 Low Excess Air

Reducing the excess air level in the furnace has generally been found to be an effective method for NO_x control. In this technique, the combustion air is reduced to the minimum amount required for complete combustion, while maintaining acceptable furnace cleanliness, and steam temperature. With less oxygen available in the flame zone, both thermal

TABLE 3-3. COMBUSTION MODIFICATION NO_x CONTROL FOR PULVERIZED COAL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commercial Availability/ R&D Status	Comments
Low Excess Air (LEA)	Reduction of combustion air.	7	0-25 (avg. 10)	Excess oxygen reduced to 5.2% on the average	Available	Added benefits of technique include increase in boiler efficiency, limited by increase in CO. HC and smoke emissions.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	2	27-39 (avg. 33)	Applicable only for boilers with minimum of 4 burners.	Available. However, extensive engineering work necessary prior to implementation.	Limited by the number of burners available. Load reduction required in most cases. Possible increased slagging, corrosion.
Overfire Air Injection (OFA)	Secondary air from OFA ports above fuel rich firing burners		5-30	Burner stoichiometry as low as 100%	Commercially offered but not demonstrated for industrial size boilers.	Requires installation of OFA ports, etc. Possible increased slagging, corrosion.
Flue Gas Recirculation	Recirculation of flue gas to burner windbox		0-20	Up to 25% of the flue gas recirculated.	Not offered because relatively ineffective.	Requires installation of FGR ducts, fan, etc. Can cause combustion instability. Burner windbox may need extensive modifications.
Low NO_x Burners (LNB)	New burner designed utilizing controlled air-fuel mixing		45-60	Prototype LNB limited to size ranges above 29 MW (100 x 10^6 Btu/hr)	Still in the development stage. Prototype LNB available from major boiler mfrs.	Active R&D efforts underway.
Ammonia Injection	Injection of NH_3 in convective section of boiler.		40-60	Limited by furnace geometry. NH_3 injection rate limited to 1.5 NH_3/NO	Commercially offered but not demonstrated	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate.
Reduced Load	Reduction of fuel and air flow to the boiler.	6	Varies from 45% reduction to 4% increase in NO_x	Applicable to all boilers. Load can be reduced to 25% of capacity.	Available now but not implemented because of adverse operational impacts	Load reduction often not effective because of increase in excess O_2. Best implemented with increase in furnace size for new boilers.

and fuel NO_x formation are reduced. In addition, the reduced airflow lowers the quantity of flue gas released resulting in an improvement in boiler efficiency.

Low excess air (LEA) operation is a relatively simple technique to implement. It is applicable to all boiler types and requires only reducing airflow to the burner windbox. However, in a multiburner unit, modifications to the windbox might be necessary to improve air distribution to individual burners during low excess air operation. Lowering excess air reduces the safety margin for complete combustion. Therefore, close monitoring of flue gas O_2 and CO may be necessary.

Figure 3-3 shows the results of LEA tests on representative coal-fired industrial boilers (References 3-12, 3-19, and 3-22). The slopes of the data bands indicate the relative effectiveness of low excess air firing on each equipment category. It is seen that LEA is about equally effective for each category.

Baseline excess oxygen levels for single wall and tangential pulverized coal-fired boilers investigated ranged from 4.5 to 8.6 percent and averaged 6.3 percent (References 3-19 and 3-20). In these boilers excess oxygen was reduced to 5.2 percent lowering NO_x emission by 8.6 percent on the average.

The lone cyclone boiler (117 MW, 400 x 10^6 Btu/hr) tested was the least amenable to excess oxygen reduction because of the initial low baseline O_2 level. The excess oxygen measured 3.4 percent at baseline and was reduced only to 3.1 percent for LEA firing. NO_x emissions were reduced 5 percent for this test (References 3-19 and 3-22).

These excess oxygen levels were probably not representative of the actual excess oxygen in the flue gas leaving the furnace. Air infiltration into the boiler ducts for balanced draft boilers can dilute the flue gas and cause oxygen readings to be higher than actual. However, field investigations found that these units were, in general, being fired with more than adequate excess air in order to assume complete combustion and provide a margin of safety.

Combustion with low excess air is a favorite NO_x control technique because it not only reduces NO_x by 25 ppm on the average for each percent reduction in excess oxygen, but it also increases boiler efficiency and furthermore is relatively easy to implement.

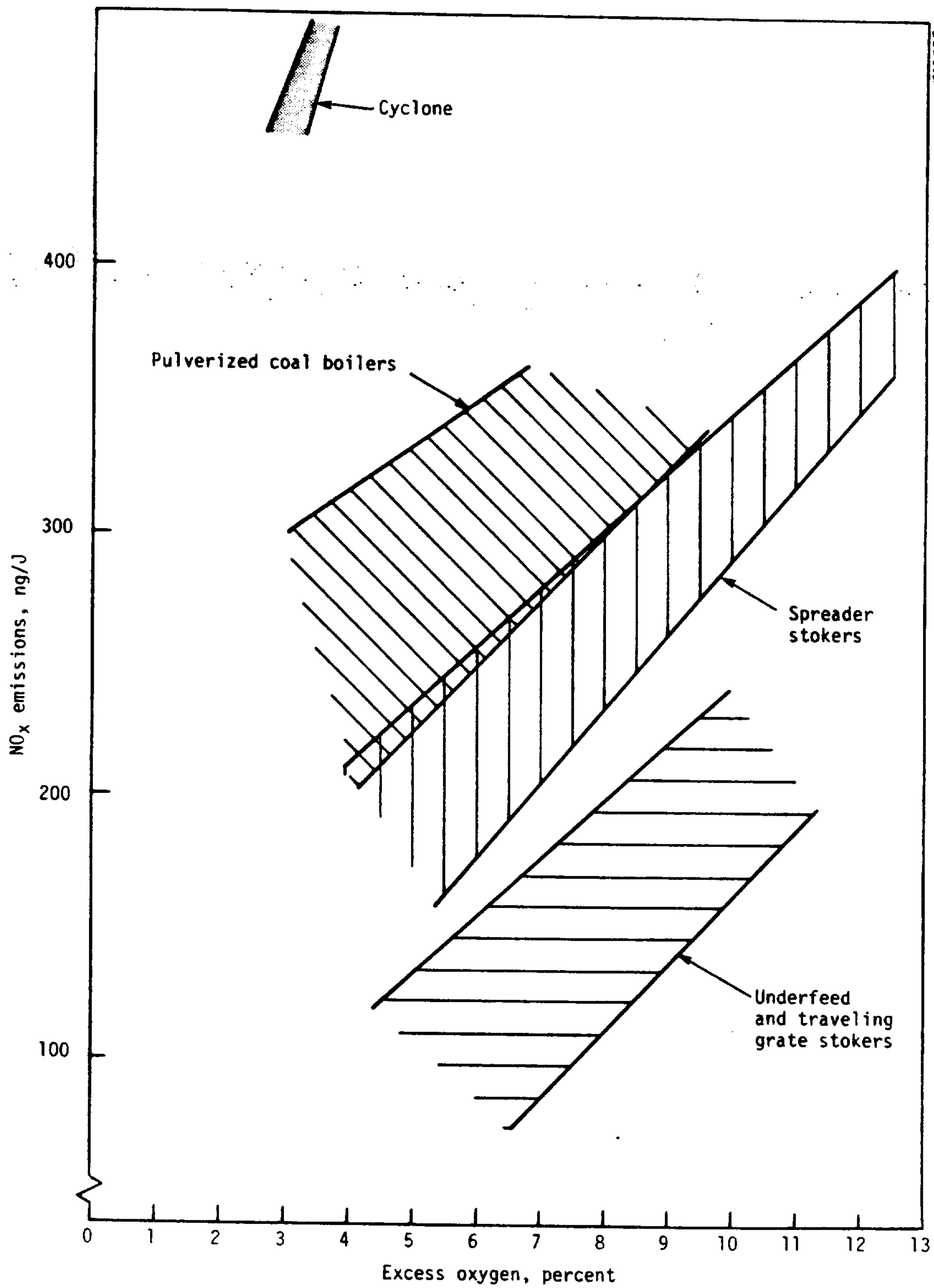

Figure 3-3. Effect of excess oxygen on NO_x emissions from coal-fired boilers (References 3-12, 3-19, and 3-22).

3.2.1.2 Overfire Air Injection (OFA)

The injection of air above the top burner level through OFA ports together with a reduction in airflow to the burners is one of two techniques used to obtain staged combustion in industrial size pulverized coal-fired boilers. The other technique, burners out of service, is discussed below in Section 3.2.1.3.

New utility tangential coal-fired boilers currently come equipped with overfire air ports to help meet 1971 NSPS for NO_x emissions. Overfire air ports on wall-fired boilers are not as common as for the tangentially fired units. However, Babcock and Wilcox (B&W) has recently installed two 190 MW (650 x 10^6 Btu/hr) pulverized coal-fired industrial boilers equipped with OFA ports and compartmented windboxes to limit NO_x emissions to 500 ppm at 3 percent excess O_2 (References 3-23 and 3-24). In these boilers, 105 percent of the total air requirement is added to the burners, 10 percent through the OFA ports. Automatic controls determine the difference between the total air requirements for the total fuel flow to the furnace and the total airflow to the individual burner compartments. This difference in airflow is then fed through the OFA ports.

The combination of the compartmented windbox and careful airflow control also improves the thermal efficiency of these new B&W units. B&W provides oxygen analyzers on all new coal-fired industrial boilers. Overfire air cannot be implemented on cyclone boilers because the cyclone furnace cannot be fired substoichiometrically.

No detailed OFA test data have been reported for pulverized coal-fired industrial boilers. Therefore the information listed in Table 3-3 reflects results from utility boiler testing (Reference 3-25). Overfire air has been very effective in reducing NO_x for boilers of this size. In fact, 30 percent reductions have been reported for utility boilers of the tangential firing type. Potential limitations of the technique include (References 3-26 and 3-27):

- Furnace tube wastage due to local reducing conditions when firing high sulfur coal
- Tendency for slag accumulation in the furnace
- Additional excess air may be required to ensure complete combustion resulting in a decrease in boiler efficiency

Overfire air is more attractive in original designs than in retrofit applications. Additional duct work, furnace penetration, and extra fan capacity may be required. In addition, physical obstructions outside of the boiler may make retrofit installation difficult and costly. There may also be insufficient height between the top row of burners and the furnace exit to permit accommodation of overfire air ports and the enlarged combustion zone created by the staged combustion technique (Reference 3-26).

3.2.1.3 Burners Out of Service (BOOS)

Burners out of service is the other technique used to obtain staged combustion in industrial pulverized coal-fired boilers. It is primarily employed as a retrofit NO_x control measure for existing utility sized boilers. Ideally, all of the fuel flow is diverted from a selected number of burners to the remaining firing burners. Since airflow is maintained relatively unchanged among all burners a staged combustion effect is obtained. For the technique to be significantly effective, it is often required that the top burners be set on air only. The technique, however, has several limitations for pulverized coal-fired boilers. These limitations can be summarized as follows:

- Extensive engineering and testing on an individual boiler basis is required to determine the optimal BOOS pattern
- Selection of an effective BOOS pattern is sometimes not possible because pulverizers may serve burners located on two separate levels. The most effective BOOS pattern often involves only the top level of burners on air only.
- In many cases burners/pulverizers which operate during BOOS cannot handle increased coal flow necessitating a significant reduction in the boiler steam rating
- Register adjustments are often necessary to divert some airflow from top burners to lower burners. If satisfactory staging conditions cannot be obtained simply by adjusting burner registers, a compartmented windbox becomes necessary.
- Potential increased slagging and corrosion

These limitation were clearly evident in the tests conducted on one pulverized coal-fired industrial size boiler (76 MW heat input) equipped with four burners in square matrix (Reference 3-12). To implement the BOOS technique the pulverizer serving the top two burners was shut off necessitating a 50 percent reduction in boiler load. In addition, airflow could not be easily controlled to individual burners so that burner swirl and coal air mixing were affected. The resultant NO_x reduction was 39 percent.

From this experience, it is evident that to implement the BOOS technique with this burner pattern and the number of available burners necessitates a reduction in the capacity of the boiler by up to 50 percent. It is expected that this will often be the case for industrial boilers because of the limited number of burners and pulverizers.

A more recent investigation applied biased burner firing (BBF) to a 4-burner 90 MW heat input pulverized coal-fired boiler (References 3-91 and 3-92). Biased burner firing is a variation of BOOS in which all burners are firing, but selected burners are firing fuel lean while the remaining ones fire fuel rich. For the particular boiler tested, BBF necessitated about a 20 percent boiler derate. At 70 percent load, BBF and low excess air achieved only a 15 percent NO_x reduction from baseline operation at the some load. However, a 30-day continuous NO_x monitoring test, using the combined NO_x controls of low excess air, BBF, and reduced load (load ranged from 20 to 83 percent MCR), gave an average NO_x reduction of 32 percent. The study cautioned that flame stability problems, although correctable, were encountered.

Since a reduction in boiler load is not desirable and often not feasible, BOOS is not always a viable technique. A potential alternative involves the installation of overfire air ports above existing burners if there is space for the overfire air ports (already discussed in Section 3.2.1.2).

3.2.1.4 Low NO_x Burners (LNB)

Prototype low NO_x pulverized coal-fired burners have been developed primarily for reducing NO_x emissions from utility boilers. Their principal characteristics are reduced flame turbulance, delayed fuel air mixing, and establishment of fuel-rich zones where combustion initially takes place (Reference 3-25). Prototype dual register burners developed by Babcock and Wilcox (B&W) (References 3-28 and 3-29) and the dual throat burners developed by Foster Wheeler (FW) (References 3-30 and 3-31) are being installed in new utility size coal-fired boilers. This technology applies only to wall-fired boilers. NO_x reductions reported in Table 3-3 are based on results from B&W and FW utility application testing because no industrial size low NO_x coal burner has yet been developed.

EPA, with a contract to Energy and Environmental Research Corporation (EER), is developing advanced low NO_x burner concepts such as distributed fuel/air mixing, as illustrated in Figure 3-4 (References 3-32 and 3-33). Field evaluation programs, also sponsored by EPA, involving several manufacturers and R&D groups, are being planned (Reference 3-34).

A low NO_x burner for industrial boiler application is under commercial development by Peabody Engineering Corporation. Peabody is constructing a variation of a standard dual register type burner. The 15 MW (50×10^6 Btu/hr) burner may become one of several burners to be tested in an EPA test program. Basically, the burner is designed to reduce the air in the primary combustion zone. The resultant reduced flame temperatures also serve to lower NO_x emissions. Once completed the burner presumably will not be restricted in size range and may be suitable for many pulverized coal facilities (Reference 3-33).

In some applications low NO_x burners may have several advantages over other combustion modifications such as staged combustion with OFA or BOOS. For example, one utility boiler manufacturer claims that low NO_x burners will maintain the furnace in an oxidizing environment, hence, minimizing slagging and reducing the potential for furnace corrosion when firing high sulfur coal (Reference 3-28). Also, more complete carbon utilization may be achieved due to better coal/air mixing in the furnace. Finally, lower oxygen levels may be obtained with all the combustion air admitted through the burners (Reference 3-25).

Since the burners generally alter the flame configuration, care must be taken when applying the burners to existing boilers. For instance, the dual register coal burners have a longer flame length. The burner can be installed only in those boilers which are large enough to avoid cold wall impingement.

In summary of the above, it is estimated that low NO_x burners for industrial size pulverized coal-fired steam generators is several years away.

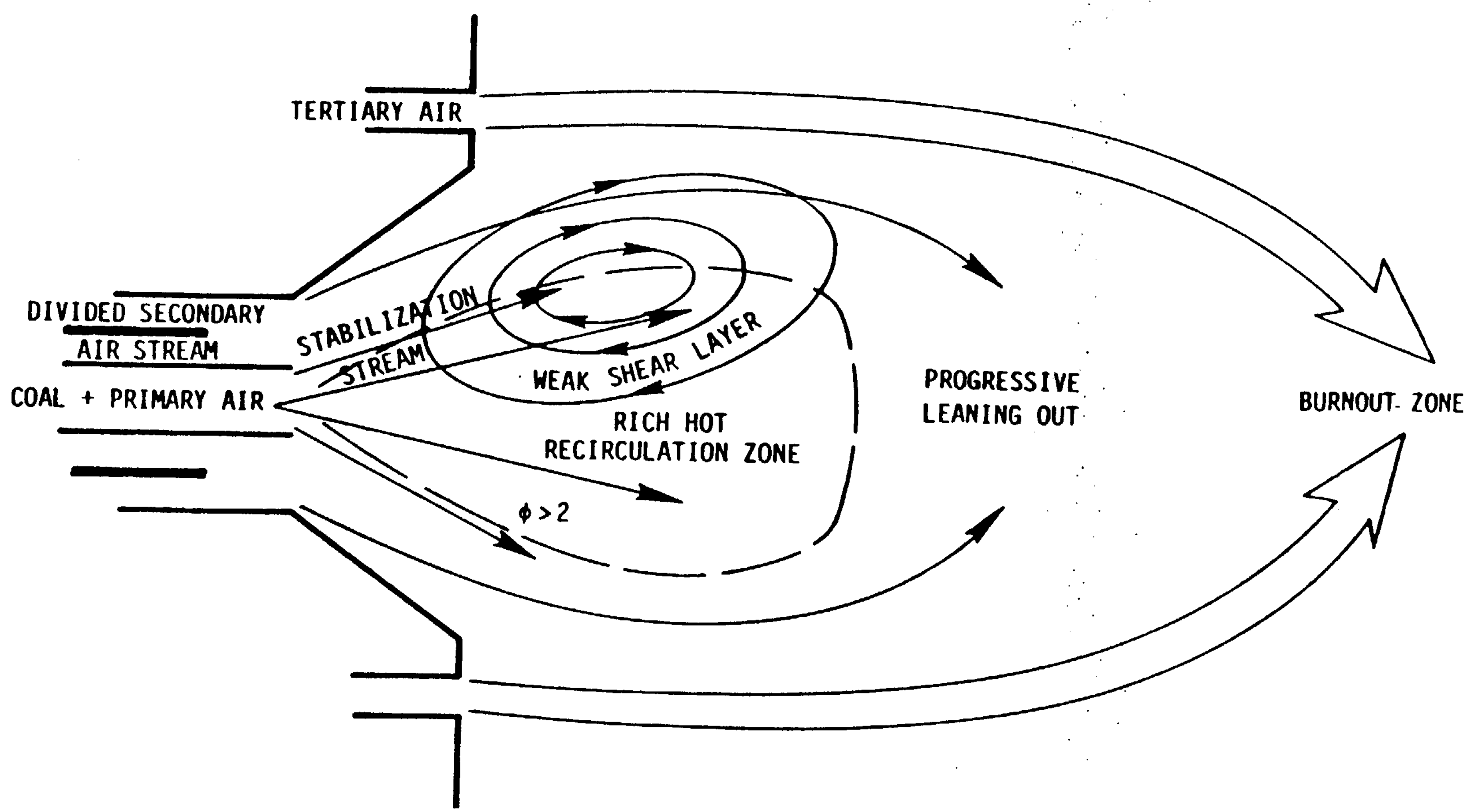

Figure 3-4. Distributed fuel/air mixing concept (Reference 3-30).

3.2.1.5 Flue Gas Recirculation (FGR)

Flue gas recirculation for NO_x control consists of extracting a portion of the flue gas from the economizer outlet and returning it to the furnace, admitting the flue gas through the burner windbox. Figure 3-5 shows a schematic of a typical FGR installation. Flue gas recirculation lowers the bulk furnace gas temperature and reduces oxygen concentration in the combustion zone (Reference 3-25).

Flue gas recirculation through the windbox and, to a lesser degree, through the furnace hopper has been found to be very effective for NO_x control on gas- and oil-fired utility boilers (References 3-27 and 3-36). However, the technique was relatively ineffective on coal-fired units because FGR mainly affects thermal NO_x, not fuel NO_x (Reference 3-38). Table 3-3 gives performance data on FGR with low excess air (LEA) on opposed wall coal-fired utility boiler. These data show that for this boiler, combined flue gas recirculation and low excess air can only reduce NO_x emissions by 20 percent (Reference 3-38). Similar results have been reported elsewhere (Reference 3-5). The technique of low excess air alone can often achieve similar reductions, as discussed earlier.

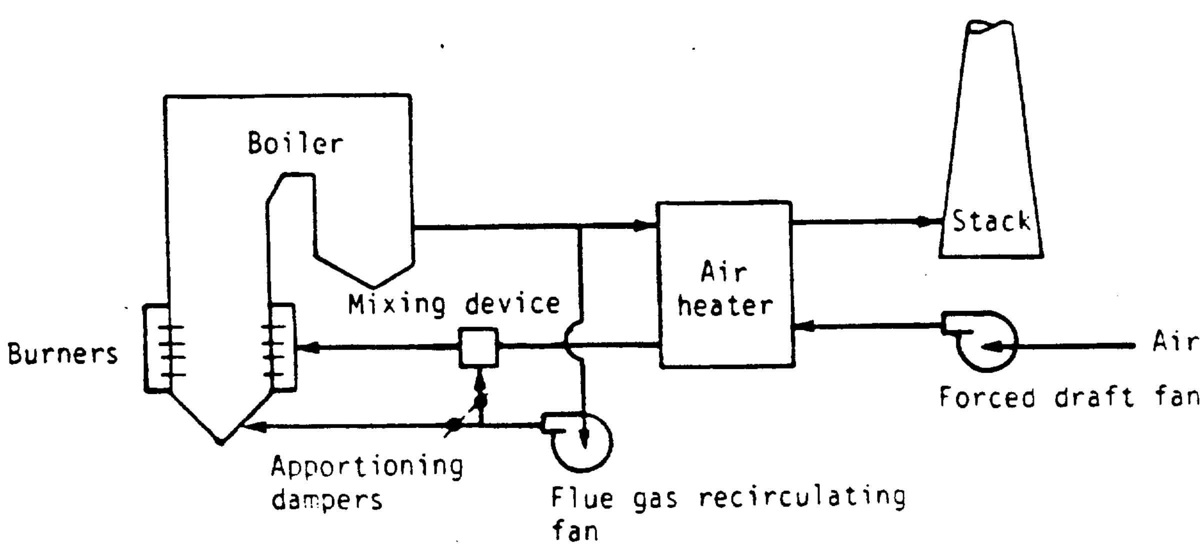

Figure 3-5. Typical flue gas recirculation system for NO_x control.

No data are available for pulverized coal-fired industrial units but as large industrial boilers are similar in design to utility boilers, performance of FGR is not expected to vary greatly from this result.

Flue gas recirculation for NO_x control is less costly for new designs than as a retrofit application. Retrofit installation of flue gas recirculation can be quite costly. The fan, flues, dampers, and controls as well as possibly having to increase existing fan capacity due to increased draft loss, can represent a large investment. In addition, the flue gas recirculation system itself may require a substantial maintenance program due to the high temperature environment experienced and potential erosion from entrained ash. Thus, the cost effectiveness of this method of NO_x control for pulverized coal-fired boilers has to be examined carefully when comparing it to other control techniques. In summary, the relatively small NO_x reductions obtained with FGR when firing coal may not warrant the large investment for both a retrofit case or installation of FGR on new industrial units.

3.2.1.6 Ammonia Injection

The process of injecting ammonia in the hot flue gas to reduce NO_x emissions has been patented under the trade name Thermal DeNO$_x$ by Exxon Research and Engineering Company (Reference 3-39). Experimental data have shown that NH_3 injection under well controlled laboratory conditions, can result in NO_x reductions as high as 90 percent (Reference 3-40). Figure 3-6 (Reference 3-41) shows a schematic of a retrofit application of an ammonia injection system on a large industrial size boiler. The technique acts by reducing NO to elemental nitrogen and oxygen with NH_3 at gas temperatures ranging from approximately 1070 to 1290K (1470 to 1856^{o}F). However, optimal NO reduction occurs over a very narrow temperature range, around 1240 $\pm$ 50K (1770 $\pm$ 90^{o}F).

The NO_x reduction effectiveness reported in Table 3-3 reflects results from full-scale application of the ammonia injection process in gas- and oil-fired industrial boilers in Japan (Reference 3-42). No full-scale application on a coal-fired unit has been tried. However, in sub-scale tests it was found that the flue gas environment from coal combustion does not markedly affect the effectiveness of the process any more than that relative to gas and oil combustion products (Reference 3-43).

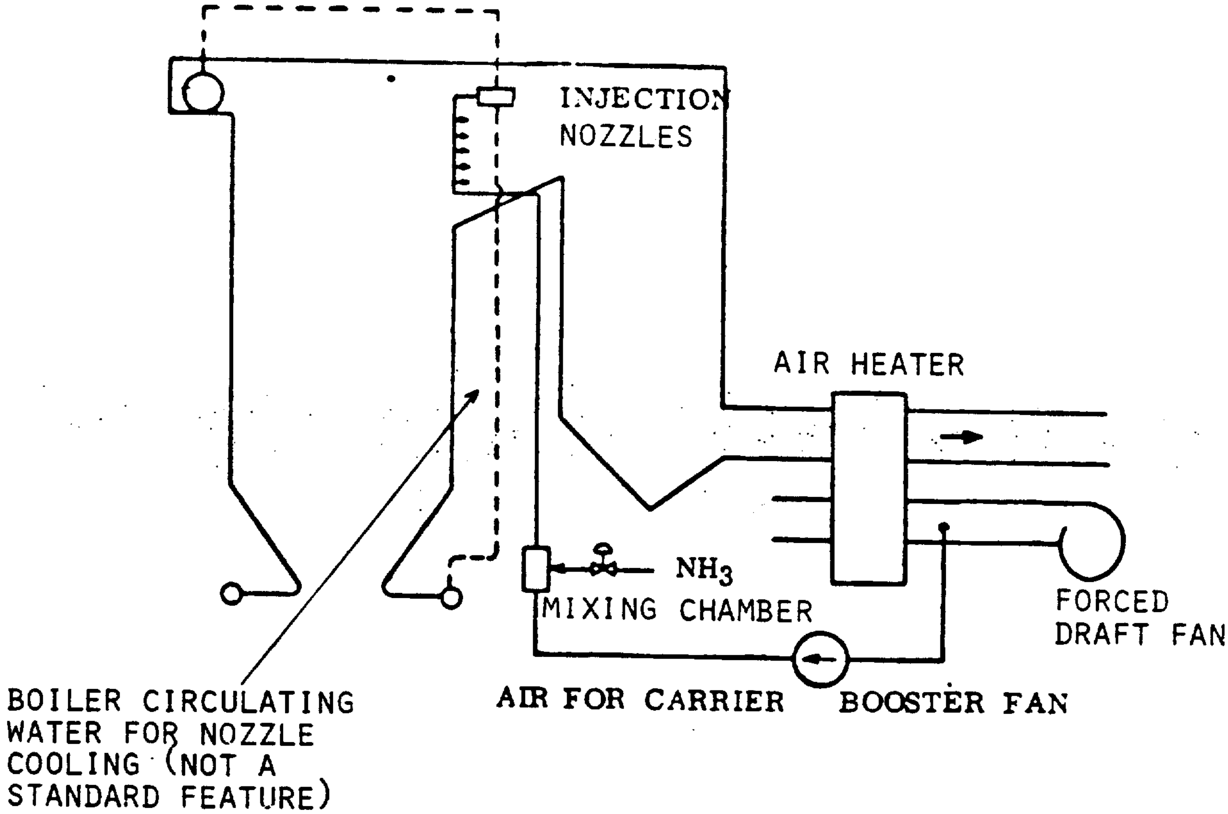

Figure 3-6. Schematic diagram of the NH_3 injection system (Reference 3-41).

Ammonia injection has numerous limitations which have so far prevented its full-scale commercialization as a NO_x reduction technique on coal-fired boilers. These limitations can be summarized as follows: (References 3-40, 3-42 and 3-44).

- Performance is very sensitive to flue gas temperature, and is maximized only within a 50K temperature gradient from the optimum temperature of about 1240K. This temperature sensitivity may require special procedures for load following boilers.
- Performance is very sensitive to flue gas residence time at optimum temperatures. High flue gas quench rates are expected to reduce process performance.
- Costs of the process can be much higher than for other combustion controls

- Successful retrofit application is highly dependent on the geometry of convective section
- Byproduct emissions such as ammonium bisulfate might cause operational problems, especially in coal-fired boilers

Although NH_3 injection is currently being commercially offered, it is not demonstrated technology. Therefore, it should be considered to be still at the development stage (Reference 3-45). This technique might prove to be, however, the only alternative in controlling NO_x emission from cyclone-fired boilers which are not amenable to other combustion modifications. Therefore, its use can potentially achieve NO_x emission levels which would otherwise not be obtainable with current state-of-the-art controls (Reference 3-42).

3.2.1.7 Load Reduction

Thermal NO_x formation generally increases as the volumetric heat release rate or combustion intensity increases (Reference 3-5). Reduced combustion intensity can be brought about by load reduction, or derating, in existing units and by use of an enlarged firebox in new units.

However, during field tests on industrial boilers burning pulverized coal, NO_x emissions were found to increase when these boilers were operated below 60 percent of capacity (Reference 3-12). A load reduction of approximately 30 percent from the baseline rating of 80 percent capacity increased NO_x emissions from three boilers by 13 percent on the average. The reduced heat input was accompanied in all cases by an increase in excess oxygen averaging 0.7 percent. One cyclone unit, however, showed a drop in NO_x emissions by 6 percent for a load reduction of 25 percent (Reference 3-22). Thus, it seems that in many cases any beneficial effects resulting from load reduction were offset by the increase in excess air required at the reduced load.

Reduced firing rate often leads to several operating problems. Aside from the limiting of capacity, low load operation usually requires higher levels of excess air to maintain steam temperature and to control smoke and CO emissions. The steam temperature control range is also reduced substantialy for those industrial boilers producing superheated steam. This will reduce the operating flexibility of the unit and its response to changes in load. The combined results are reduced operating efficiency due to higher excess air and reduced load following capability due to a reduction in control range (Reference 3-5).

When the unit is designed for a reduced heat release rate, the problems associated with derating are largely avoided. The use of an enlarged firebox produces NO_x reductions similar to load reduction on existing units. This technique of larger firebox has been implemented on new coal-fired utility boilers since about 1970 (Reference 3-25). Generally, the size of these fireboxes has increased 30 percent partly in response to 1971 NSPS for utility boilers and partly to facilitate combustion of lower grade coals (Reference 3-46). Therefore, the technique can also be considered available for large industrial size pulverized coal-fired boilers. Babcock and Wilcox (B&W) is currently considering lower furnace loading as one of several techniques for reducing NO_x emissions from their industrial boilers (Reference 3-47).

3.2.2 Applicable Control Techniques for Stokers

NO_x emissions from stokers are significantly lower than those from pulverized coal. These lower emissions have been attributed to the lower combustion intensity and to the partial staged combustion that naturally occurs during combustion on fuel beds (Reference 3-18).

Four methods have been used to modify the combustion of a stoker in order to reduce NO_x emissions. These methods are (1) reduced undergrate air or low excess air, (2) overfire air, (3) reduced air preheat, and (4) reduced heat input (References 3-19 through 3-22). Ammonia injection is potentially applicable although it has not yet been demonstrated on an industrial stoker. The boiler geometry and the flue gas temperature profile in a stoker should permit the implementation of the NH_3 injection process in a similar manner as for a pulverized coal-fired unit. Table 3-4 lists information on the performance and limitation of each of these techniques.

The information is based on limited data. A search for additional data from boiler manufacturers and researchers has not revealed any other applicable combustion modification for NO_x control for stokers (References 3-48 through 3-52).

3.2.2.1 Low Excess Air (LEA)

Figure 3-7 is a schematic of a spreader stoker furnace showing where combustion air is introduced in this type of boiler. Overfire air

TABLE 3-4. COMBUSTION MODIFICATION NO_x CONTROLS FOR STOKER COAL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commerical Availability/ R&D Status	Comments
Low Excess Air (LEA)	Reduction of air flow under stoker bed.	24	5-25	Excess O_2 limited to 5-6% minimum	Available now but need R&D on lower limit of excess air.	Danger of overheating grate, clinker formation, corrosion, and high CO emissions.
Staged Combustion (LEA + OFA)	Reduction of under grate air flow and increase of overfire air flow.	5	5-25	Excess O_2 limited 5% minimum.	Most stokers have OFA ports as smoke control devices but may need better air flow control devices.	Need research to determine optimal location and orientation of OFA ports for NO_x emission control. Overheating grate, corrosion and high CO emission can occur if under grate air flow is reduced below acceptable level as in LEA.
Reduced Load	Reduction of coal and air feed to the stoker.	13	Varies from 49% decrease to 25% increase in NO_x (average 15% decrease)	Has been used down to 25% load.	Available	Only stokers that can reduce load without increasing excess air. Not a desirable technique because of loss in boiler efficiency.
Reduced Air Preheat (RAP)	Reduction of combustion air temperature	1	8	Combustion air temperature reduced from 473K to 453K.	Available now if boiler has combustion air heater.	Not a desirable technique because of loss in boiler efficiency.
Ammonia Injection	Injection of NH_3 in convective section of boiler.		40-60 (from gas- and oil-fired boiler experience).	Limited by furnace geometry. Feasible NH_3 injection rate limited to 1.5 NH_3/NO	Commercially offered but not demonstrated.	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate.

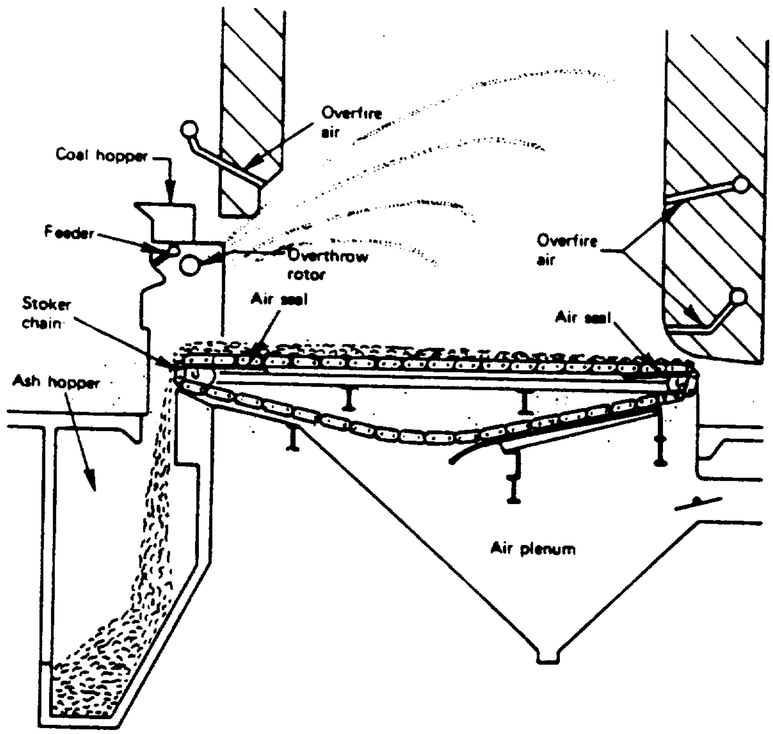

Figure 3-7. Air injection in a traveling-grate spreader stoker (Reference 3-18).

is generally controlled independently from undergrate air. Low excess air tests performed in the field consisted of reducing the undergrate airflow while maintaining the OFA flow approximately as in normal operation.

A series of EPA field tests of 17 stokers indicate that the excess oxygen levels at baseline operating conditions averaged about 9 percent (References 3-12, 3-19 through 3-22). During low excess air tests, the excess oxygen level was reduced to an average of 6.4 percent. Such a reduction lowered NO_x emission levels approximately 10 percent for each 1 percent reduction in excess oxygen (References 3-12, 3-21, 3-22, 3-52, and 3-55). Indeed, data from a recently completed EPA-DOE-ABMA field test program involving 11 relatively new design stokers operating near the lower excess air level tend to support this general trend (References 3-80 through 3-90). Figure 3-3 indicated that LEA is an effective method for stokers.

The minimum achievable excess air is limited by several factors. Except for the water-cooled vibrating grate, the only cooling of the grate is by the flow of air past it. If this air is cut back too much, the grate can overheat. There is also the danger of creating local reducing zones as the air is cut back and forming harmful corrosion products. Another problem noticed during field tests has been the formation of clinkers as the excess oxygen was reduced, the CO emissions tend to rise. However, test results indicate that if excess oxygen levels are maintained above 5 percent, CO emissions will tend to stay below 150 ppm (References 3-12, 3-19, 3-21, 3-53, and 3-94). Limited data show CO emissions for underfeed stokers to be less sensitive to excess air levels than for spreader stokers (References 3-12, 3-19 and 3-22).

Fuel combustion with lowest possible levels of excess air assures maximum boiler efficiency unless the air is decreased to the point where unburned carbon losses are greatly increased. From the limited amount of data it can be tentatively generalized that if the airflow is maintained such that the excess oxygen level measures approximately 6 percent, no serious operational or emission problems should result. Of course, this generalization would require verification. NO_x emission reductions of about 5 to 25 percent and increases in boiler efficiency of 1 percent can be expected provided fuel burnout does not change during the process (References 3-12 and 3-22).

Research and developmental work on redesigning the grate and stoker would be necessary if lower excess oxygen levels are required. In addition a solution to the clinker formation problem will also be needed for this type of operation.

3.2.2.2 Staged Combustion

One of the reasons NO_x emissions from stokers are lower than those from pulverized coal-fired boilers is the partial staged combustion nature of combustion in fuel beds (Reference 3-54). Volatile matter leaves the fuel bed as the coal is fed into the grate and burns above the bed level. The solids are subsequently burned with lower combustion intensity.

An increased staged combustion effect beyond what seems to occur naturally in the stoker furnace seems difficult to obtain. However, augmented staged combustion control can be effected by injecting air above the fuel bed through the overfire air ports (OFA) and reducing the undergrate airflow.

Figure 3-7 shows the relative location of these airflows. A reduction of 10 to 25 percent in NO_x has been achieved by this method without increasing CO emission (References 3-12, 3-19, 3-22 and 3-53). Most stokers have OFA ports as smoke control devices. However, the location or orientation of these OFA ports may not be the optimum in order to achieve best NO_x reductions. For example, one test showed a 25 percent reduction in NO_x emissions by using two oil burners as overfire air ports (Reference 3-22). However, these burner ports were located far above the existing stoker OFA ports. Other OFA tests, using only the existing OFA ports located closer to the fuel bed rather than the burner ports, lowered NO_x emissions only 10 percent.

This method suffers from the same disadvantages of LEA because reduced undergrate airflow is absolutely necessary to achieve any staging effect. Therefore limitations applicable to the technique of LEA such as grate overheating, corrosion, and clinker formation can also limit the application of the staged combustion technique.

3.2.2.3 Reduced Load

Underfeed stokers tend to produce lower NO_x emissions than spreader stokers. One reason has been attributed to the fact that underfeed stokers have larger fireboxes and consequently lower volumetric and surface heat release rates (References 3-12 and 3-22). Reducing the boiler load will lower the volumetric and surface heat release rate; therefore it is equivalent to having a larger firebox. One test on a spreader stoker showed a 10 percent reduction in NO_x emissions by reducing the load from 70 to 60 percent of maximum continuous rating (References 3-12 and 3-19). On most other tests as the load was reduced, the excess air had to be increased, causing a net rise in NO_x emissions. These results suggest that the technique will be effective in reducing NO_x emissions only if the excess air can be maintained at the original level measured during the higher load condition.

The technique, although an applicable one, has numerous possible disadvantages. These include derating of the boiler and loss in boiler efficiency as a consequence of the requirements to increase the excess air level (Reference 3-12).

3.2.2.4 Reduced Air Preheat (RAP)

There are only limited data on reduced air preheat applied to industrial stokers. Based on tests on only one boiler, a small reduction of the combustion air temperature from approximately 366 to 355K (200^{0}F to 180^{0}F) reduced NO_x emissions by an average of 8 percent (References 3-12 and 3-19). Some researchers claim that the coal bed preheats the air before the combustion occurs and thus defeats the purpose of the method (Reference 3-54). This technique is of course limited to stokers equipped with combustion air preheaters. Only larger (>29 MW, 100 x 10^6 Btu/hr) stokers tend to have air preheaters. In addition, significant losses in boiler efficiencies will occur if flue gas temperatures leaving the stack are increased as a consequence of bypassing air preheaters. Economizers could be added to avoid efficiency losses, though.

3.2.2.5 Ammonia Injection

Ammonia injection should be applicable to stoker boilers as well as pulverized coal-fired units. However, the geometry of the ducting in the convective section is crucial. The ammonia injection ports must be located in that portion of the furnace where the flue gas temperature ranges from 1070 to 1290K (1470 to 1860^{0}F).

The information on ammonia injection listed in Table 3-4 is the same as that in Table 3-3. The performance of the ammonia injection process has not been investigated on stokers; therefore the potential NO_x reductions listed in Table 3-4 are based on reported results on gas- and oil-fired industrial boilers (References 3-42).

3.3 OIL-FIRED BOILERS

Oil-fired industrial boilers fall into two major categories: firetube and watertube. Firetube boilers can be further divided into Scotch, horizontal return tube, and firebox designs. Watertube boilers are identified as either packaged or field-erected units. Packaged boilers, both watertube and firetube, are usually equipped with a single burner. Field-erected units are usually equipped with an array of burners and are generally of larger capacity than the packaged units.

Table 3-5 lists the baseline NO_x emissions from oil-fired industrial boilers measured during an extensive test program (Reference 3-12 and 3-22). Regardless of the boiler type, it is evident that boilers burning residual oil produce more NO_x emissions than the ones firing distillate oil.

TABLE 3-5. NO_x EMISSIONS AT BASELINE AND AT LOW EXCESS AIR FROM OIL-FIRED INDUSTRIAL BOILERS (References 3-12, 3-22, 3-56, and 3-57)

Equipment Type	No. Boilers Tested	Residual Oil				
		Baseline				Low Excess Air
		02 %	NO_x Emissions ng/J[a]	NO_x Emissions lb/10^6 Btu[a]	02 %	NO_x Reductions %
Firetube	5	5.2	95.5 - 170 (118.4)	0.222 - 0.395 (0.275)	3.2	7
Watertube W/O Air Preheat	9	5.9	87.5 - 362 (190)	0.203 - 0.843 (0.442)	4.0	13
Watertube W/ Air Preheat	8	5.8	66.8 - 188 (134)	0.155 - 0.438 (0.312)	4.6	12
All Boiler Types	22	5.7	66.8 - 362 (155)	0.155 - 0.843 (0.360)	4.0	11

Equipment Type	No. Boilers Tested	Distillate Oil				
		Baseline				Low Excess Air
		02 %	NO_x Emissions ng/J[a]	NO_x Emissions lb/10^6 Btua	02 %	NO_x Reductions
Firetube	2	5.4	96.5 - 107 (102)	0.224 - 0.248 (0.236)	3.2	18
Watertube W/O Air Preheat	3	5.5	44.7 - 59.5 (51.8)	0.103 - 0.138 (0.120)	3.2	6
Watertube W/ Air Preheat	2	5.4	69.0 - 102 (86.5)	0.160 - 0.237 (0.199)	4.5	12
All Boiler Types	7	5.8	44.7 - 107 (72.6)	0.104 - 0.248 (0.169)	3.7	11

[a]NO_x emissions are given as a range, with the average in parentheses. T-1749

Also for any particular class of boilers the range of NO_x emissions for residual oil is often wider than the range of emissions for distillate oil. The larger amount and variation of fuel nitrogen in the residual oil accounts for both these observations. Fuel analyses performed as a part of this test program showed that residual oil generally contained 0.10 to 1.0 percent fuel nitrogen while distillate oil contained less then 0.05 percent on the average (Reference 3-12).

Combustion modification NO_x control techniques for oil-fired boilers are as follows:

- Low excess air (LEA)
- Staged combustion air (SCA)
- Burners out of service (BOOS)
- Flue gas recirculation (FGR)
- Reduced air preheat (RAP)
- Load reduction (LR)
- Low NO_x burners (LNB)
- Ammonia injection

These techniques can be applied singly or in appropriate combination, especially for ammonia injection which can be implemented with any other combustion modification. Also, the BOOS technique can only be applied to multiburner units and is usually confined to retrofit applications. Table 3-6 summarizes the information on the performance, applicability and availability of these techniques for oil-fired industrial boilers. The following subsections highlight the major points of interest for each of the controls considered.

3.3.1 Low Excess Air (LEA)

Low excess air, as for coal-fired boilers, is an effective means of achieving reductions in NO_x with increased boiler efficiency for oil-fired units. The technique is applicable to all oil-fired industrial boilers and is easy to implement both in a retrofit case and in new boilers.

Firetube and small watertube industrial boilers are generally equipped with constant speed forced draft fans which supply air to the windbox. Air control is achieved by adjusting the vanes at the inlet to the fan. A reduction in airflow to the burner(s) is achieved by closing these vanes. The reduced air-fuel ratio lowers the excess air level in

TABLE 3-6. COMBUSTION MODIFICATION NO_x CONTROLS FOR OIL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	No. of Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)		Range of Application	Availability/ R&D Status	Comments
			Residual	Distillate Oil			
Low Excess Air (LEA)	Reduction of combustion air	22 residual oil boilers, 7 distillate oil boilers	0 to 28 11 average or 10 ng/J % O_2 reduction.	0 to 24 11 average or 10 ng/J % O_2 reduction.	Generally excess O_2 can be reduced to 2.5% representating a 3% drop from baseline.	Available.	Added benefits included increase in boiler efficiency. Limited by increase in CO, HC, and smoke emissions.
Staged Combustion Air	Fuel rich firing burners with secondary combustion air ports	3 residual boilers, 1 distillate oil boilers	20 to 50	17-44	70-90% burner stoichiometries can be used with proper installation of secondary air ports	Technique is applicable on package and field-erected units. However, not commercially available for all design types	Best implemented on new units. Retrofit is probably not feasible for most units especially packaged ones.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	8 boilers	10 to 30	N/A	Applicable only for boilers with minimum of 4 burners. Best suited for square burner pattern with top burner or burners out of service. Only for retrofit application.	Available. Retrofit requires careful selection of BOOS pattern and control of air flow.	Retrofit often requires boiler derating unless fuel delivery system is modified.
Flue Gas Recirculation (FGR)	Recirculation of portion of flue gas to burners	One distillate oil boilers. Two residual boilers.	15 to 30	58 to 73	Up to 25-30% of flue gas recycled. Can be implemented on all design types.	Available. Requires extensive modifications to the burner and windbox.	Best suited for new units. Costly to retrofit. Possible flame instability at high FGR rates.
Flue Gas Recirculation plus staged combustion	Combined techniques of FGR and staged combustion	Only one package watertube	25 to 53	73 to 77	Max. FGR rates set at 25% for distillate oil and 20% for residual oil.	Combined techniques are still at experimental stage. Needs more R&D.	Retrofit may not be feasible. Best implemented on new units.

TABLE 3-6. Concluded

Control Technique	Description of Technique	No. of Boilers Tested	Effectiveness of Control (Percent NO_x Reduction) Residual	Distillate Oil	Range of Application	Availability/ R&D Status	Comments
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	17 residual oil-fired boilers, 7 distillate oil-fired boilers	33% decrease to 25% increase in NO_x	31% decrease to 17% increase in NO_x	Applicable to all boiler types and sizes. Load can be reduced to 25% of maximum	Available now as a retrofit application. Better implemented with improved firebox design	Technique not effective when it necessitates an increase in excess O_2 levels, LR possible implemented in new designs as reduced combustion intensity (enlarged furnace plan area)
Low NO_x Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation.	Large number tested in Japan	20-50%	20-50%	New burners described generally applicable to all boilers. More specific information needed.	Commercially offered but not demonstrated.	Specific emissions data from industrial boilers equipped with LNB are lacking
Ammonia Injection	Injection of NH_3 as a reducing agent in the flue gas.	5 (4 Japanese installations, 1 domestic)	40-70%	40-70%	Applicable for large package and field-erected watertube boilers. May not be feasible for firetube boilers.	Commercially offered but not demonstrated.	Elaborate NH_3 injection, monitoring and control system required. Possible load restrictions on boiler and air preheater fouling when burning high sulfur oil.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	2 residual oil-fired boilers	5-16%	--	Combustion air temp. can be reduced to ambient conditions (340K)	Available. Not implemented because of significant loss in thermal efficiency.	Application of this technique on new boilers necessitated installation of heat recovery systems in the flue gas

the furnace. Large oil-fired multiburner watertube boilers are equipped with variable speed forced draft and often induced draft fans which can be controlled to vary the amount of airflow to the boiler. However, these units will probably require the use of compartmented windboxes in addition to fan control for even distribution of airflow to each burner.

Table 3-5 summarized the performance of the LEA technique on specific industrial boiler equipment types burning fuel oil. In general, the data show that LEA is equally effective on a percentage basis for residual and distillate oil-fired boilers. NO_x was reduced by approximately 11 percent for both fuels. The data also show that for residual oil-fired boilers LEA is slightly more effective when applied on watertube than on firetube units. The reverse is true for distillate oil-fired boilers. However, the data base is not sufficiently large to verify the significance of these trends.

Figure 3-8 gives a graphical presentation of the excess air test results. Though Table 3-5 indicated that LEA is about equally effective on a percentage basis for all oils tested, Figure 3-8 shows that absolute NO_x reductions are greater for the higher nitrogen, heavier fuels (data bands have steeper slope). This is, of course, expected because LEA is effective in reducing both fuel and thermal NO_x in the heavier fuels. Number 2 distillate oil produces primarily only thermal NO_x.

Reducing the excess oxygen in the flue gas by decreasing the airflow to the burner can lead to a rapid increase in CO, hydrocarbon and smoke emissions. However, the field test data for many boilers has shown that as long as the excess O_2 is maintained above 3.0 percent these emissions were not increased (Reference 3-19).

In addition to reducing NO_x emissions the technique of LEA is cost effective because it increases boiler efficiency. In fact, the thermal efficiency of all oil-fired units tested increased 0.7 percent on the average with LEA combustion (Reference 3-12).

Application of low excess air combustion requires not only means of adjusting airflow at various boiler loads, but also installation of flue gas O_2 and CO monitors. Attempts to adjust for LEA without controls may lead to a loss rather than a gain in efficiency. Alarms should also be installed to provide a safety system in case the airflow to the boiler is inadequate.

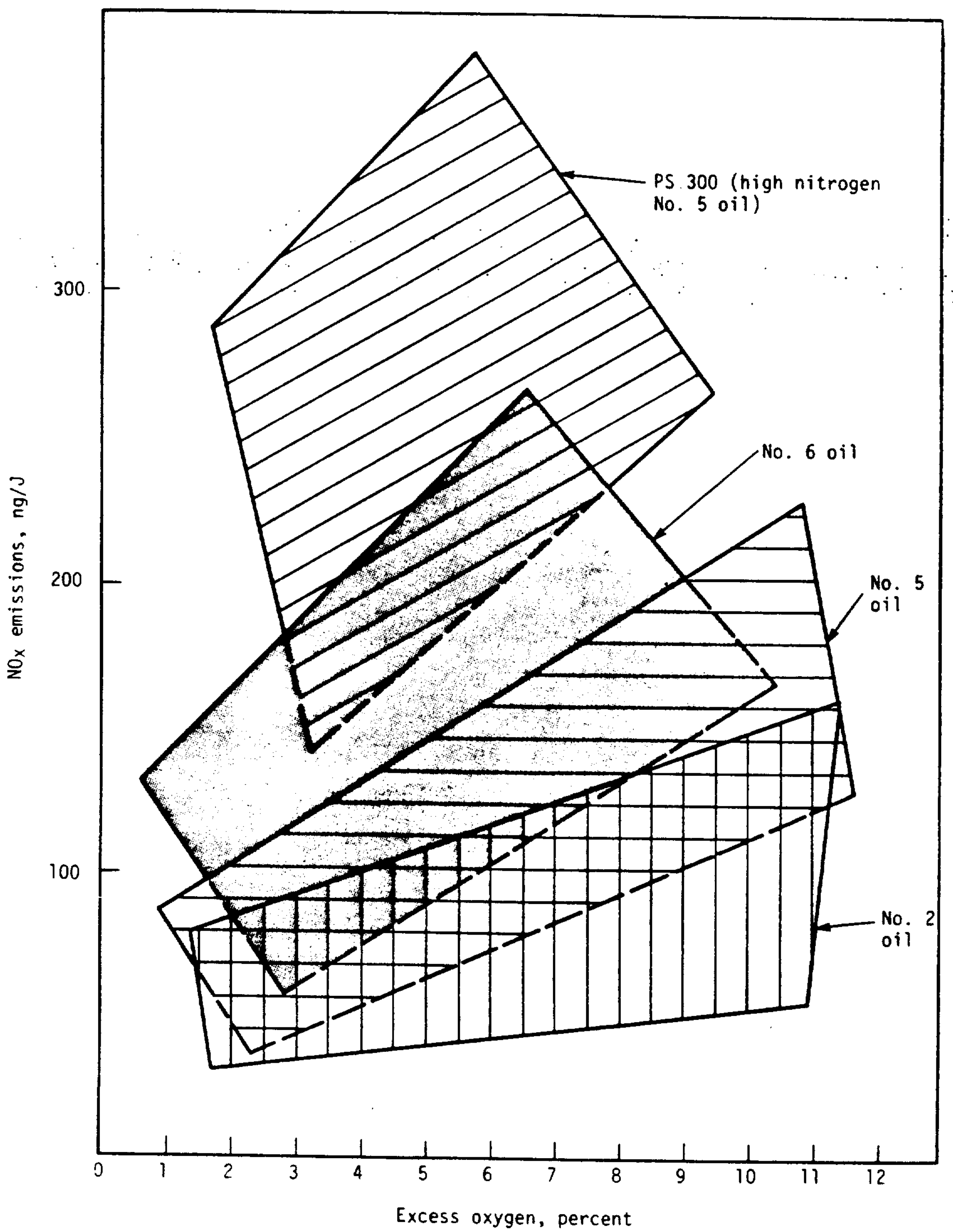

Figure 3-8. Effect of excess oxygen on NO_x emissions from distillate and residual oil-fired boilers (References 3-12, 3-22, and 3-57).

Low excess air combustion should be considered a standard operating practice for industrial boilers. In fact, because of the increased fuel efficiency the technique is often implemented strictly as a fuel economy device.

3.3.2 Staged Combustion

The concept of staged combustion consists of injecting secondary air downstream of a first stage combustion zone which is characterized by substoichiometric levels of combustion air. Stage combustion can be effected by use of secondary air ports/injectors or by burners out of service. Which of these techniques can be implemented on oil-fired boilers will depend on the type of furnace design.

The diversity of air injection systems designs applicable to oil-fired industrial boilers warrants a separate discussion for each of the major equipment design types previously identified.

3.3.2.1 Firetube Boilers

Figure 3-9 shows a schematic of an experimental retrofit application of the staged combustion technique, staged combustion air injection (SCA), on a firetube boiler burning residual oil.

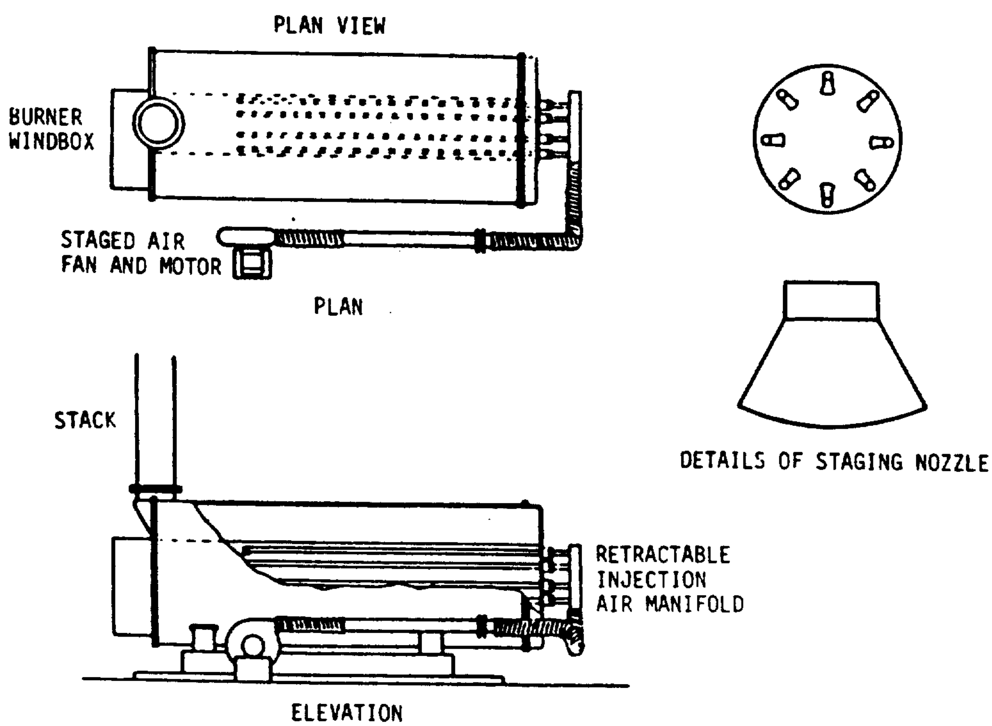

Figure 3-9. Schematic of staged combustion air injection for an oil- and gas-fired firetube boiler (Reference 3-56).

The retrofit design consists of eight stainless steel pipes connected through a ring mainfold to a forced draft fan. The air injection pipes penetrate the furnace opposite from the burner and are equipped with a "fish tail" orifice to assist in mixing the air with the combustion products. A separate fan provides air to the manifold independent of the burner air. This technique assures control of burner stoichiometry while supplying enough air downstream of the burner to complete combustion. The retractable injection nozzles permitted the analysis of the effect of injection air location on the performance of the staged combustion technique at various burner air-fuel ratios.

The retrofit design shown in Figure 3-9 represents a possible way of implementing SCA on firetube boilers. Alternate solutions would be to perforate the front or the side of the boiler to accommodate the injection nozzles.

Staged combustion test results are available only for residual oil. NO_x was reduced from 96.2 to 49 ng/J (0.224 to 0.114 lb/10^6 Btu) with a burner stoichiometry of 76 percent and the injection air ports located 2.5 firebox diameters downstream of the burner oil tip. The overall excess oxygen level was 4 percent. The boiler load was, however, reduced to 50 percent of capacity because combustion instabilities were encountered at high loads as the airflow through the windbox was reduced (References 3-56 and 3-57). It should be noted that these instabilities could be partly attributed to removal of burner baffles under the staged combustion tests. The significant NO_x reduction achieved indicates that the staged combustion technique can be very effective in reducing NO_x emissions from firetube boilers burning residual oil. This technique is expected to be less effective for distillate oil combustion because of the lower fuel NO_x formation with this fuel.

Staged combustion air injection should be considered still in the development stage for packaged boilers. More testing is required to resolve the combustion instability at the high boiler loads and to establish the reliability of the system for long-term operation. In addition, the design of the SCA system as shown in Figure 3-9 might not be feasible altogether because of operational complexity and incremental cost.

3.3.2.2 Packaged Watertube

Two retrofit designs of the staged combustion technique have been investigated for single burner packaged watertube boilers. Figures 3-10 and 3-11 show the schematic of two secondary air injection systems.

In the first retrofit application (Figure 3-10), the staged combustion air was injected from the side of the furnace. The application was possible because the configuration of the waterwalls was not of the tangent type. That is, refractory brick spacing existed between furnace waterwall tubes. Consequently air could be injected without having to modify or remove any of the furnace tubes. This type of waterwall tube design is not typical of oil boiler furnaces. Modern manufacturing methods utilize tangent tube construction for better radiant heat transfer.

Figure 3-11 shows an alternate method of injecting staged air combustion in a modern design "D" type package watertube boiler. Holes were drilled in the windbox and four retractable air injection lances were installed directly in the furnace. The tangent tube design of this furnace did not permit side air injection. The movable lances permitted injection of air at varying distances downstream of the burner. This injection system was designed for the purpose of conducting experimental tests and should not be considered as an established method of injecting secondary air in this boiler type. However, it may be possible to design the tube arrangement in new boilers such that air injection ports could be installed on the side of the furnace.

Results on the performance of staged combustion on single burner watertube boilers suggest that two conditions are required to achieve substantial NO_x reductions (References 3-12 and 3-59).

- Burner stoichiometries must be set between 90 and 100 percent. That is, airflow to the burner windbox must be below theoretical air needed for complete combustion.
- Secondary air must be injected sufficiently downstream from the burner exit to allow for cooling of combustion gases. This downstream distance varies with burner type and size.

Carefully installed and operated staged injection air will result in significant NO_x reductions (40-45 percent) from residual oil-fired package boilers. However, as in the case with firetube boilers it is

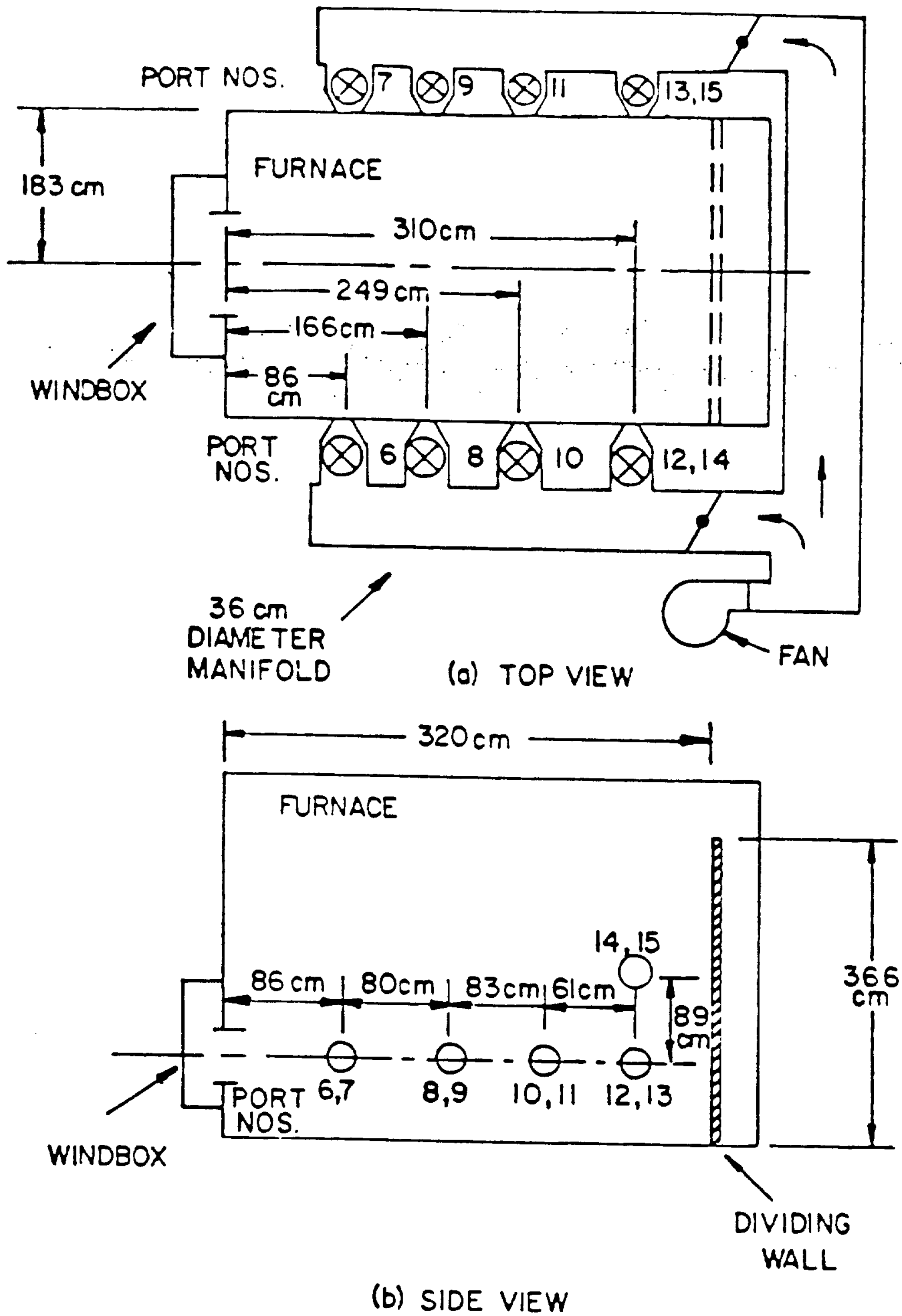

Figure 3-10. Schematic of staged air system installed for a single burner, residual, oil- or gas-fired packaged watertube oil-fired boiler (Reference 3-59).

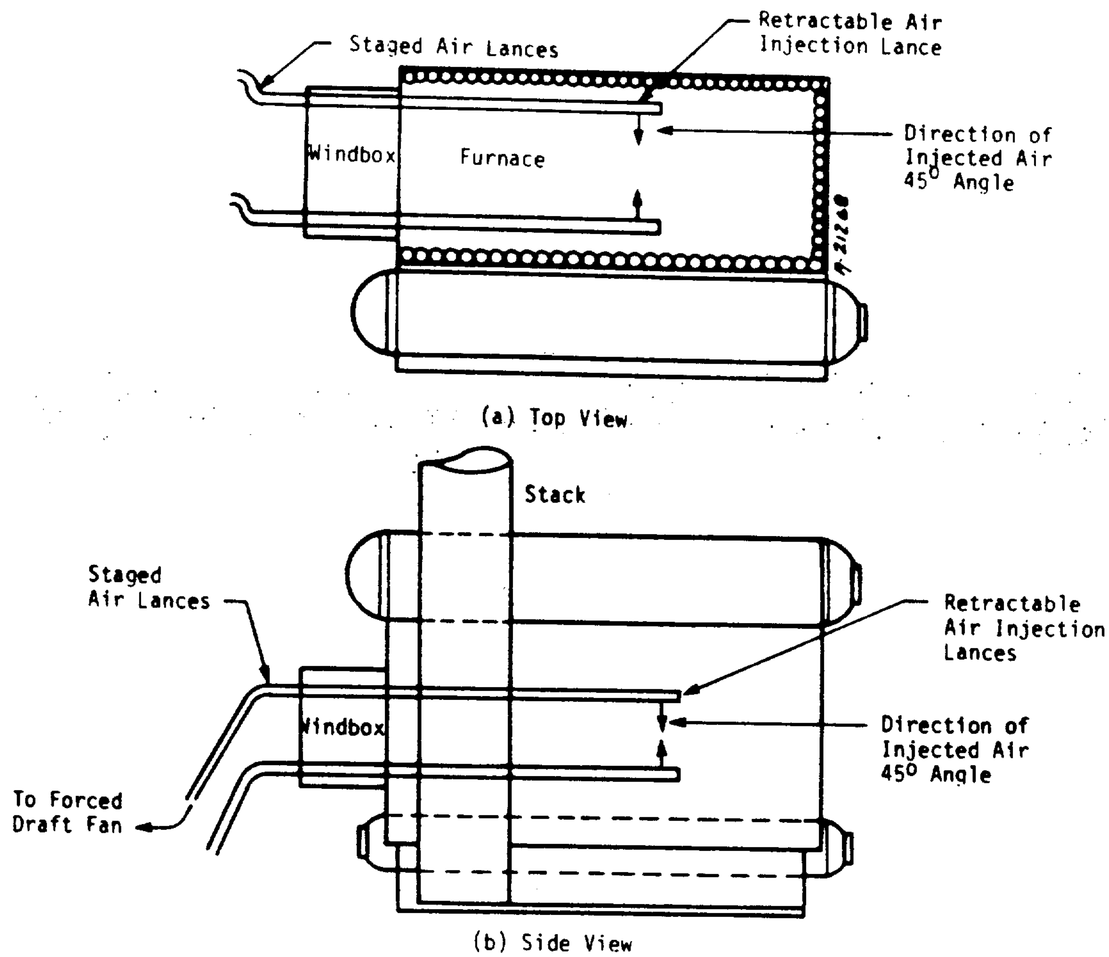

Figure 3-11. Schematic of staged air system installed on a residual oil-, distillate oil-, or gas-fired packaged watertube boiler (Reference 3-59).

estimated that more field data on the long term effects of SCA in these units is necessary before this technique can be considered demonstrated.

3.3.2.3 Field Erected Watertube

For field erected watertube boilers, normally equipped with more than one burner, staged combustion can be obtained with the techniques of overfire air (OFA) or burners out of service (BOOS).

The technique of OFA has already been described for coal-fired boilers (Section 3.2.1.2). Overfire air injection above the top burner level is applicable to new as well as existing oil-fired boilers. However, as in the case for coal-fired units the technique is more attractive in original designs than in retrofit applications for cost considerations. Information on NO_x reductions from oil-fired industrial boilers using OFA is very limited. However, application of the technique to utility boilers burning oil has resulted in 24 percent NO_x reduction (Reference 3-25). Overfire air is a viable NO_x reduction technique for new multiburner industrial units burning oil. Furthermore, it is considered demonstrated and commercially available.

Burners out of service is the simplest method of achieving staged combustion with these units. However, this technique is limited to retrofit applications. The method of implementing BOOS has already been described in Section 3.2.1.3 for coal-fired units. The application to oil-fired units is essentially the same except that oil-fired units have better control over the number or location of the burner(s) that can be used as air injection ports. This is possible for oil and also gas units because the fuel flow can be terminated at each individual burner and not at a set of burners as in the pulverized coal-fired units. Furthermore, fuel feed rates to the active burners can be adjusted over a broader range for oil- and gas-fired boilers. Numerous field test data on burners out of service have been gathered on industrial boilers. NO_x emissions were reduced 25 to 40 percent during these tests (References 3-12 and 3-22).

On existing units, operation with BOOS requires that the unit be derated unless modification to the fuel delivery system is made. In addition, adjustments to the airflow controls, such as burner registers, might also be required to achieve the required burner stoichiometry without increasing smoke and combustible emissions. Furthermore, there is no optimum BOOS pattern applicable to all existing boilers (Reference 3-12).

3.3.3 Flue Gas Recirculation (FGR)

Recycling a portion of the flue gas back to the primary combustion zone reduces NO formation by lowering the bulk furnace gas temperature and reducing oxygen concentration. Figures 3-12 through 3-14 show schematics of typical FGR retrofit applications on a firetube and two packaged watertube boilers, respectively. The systems are nearly identical consisting of an FGR fan assembly and associated ducting connecting the stack to the windbox.

One investigator reported that the technique is more effective for watertube boilers than for firetube boilers when burning the same fuel

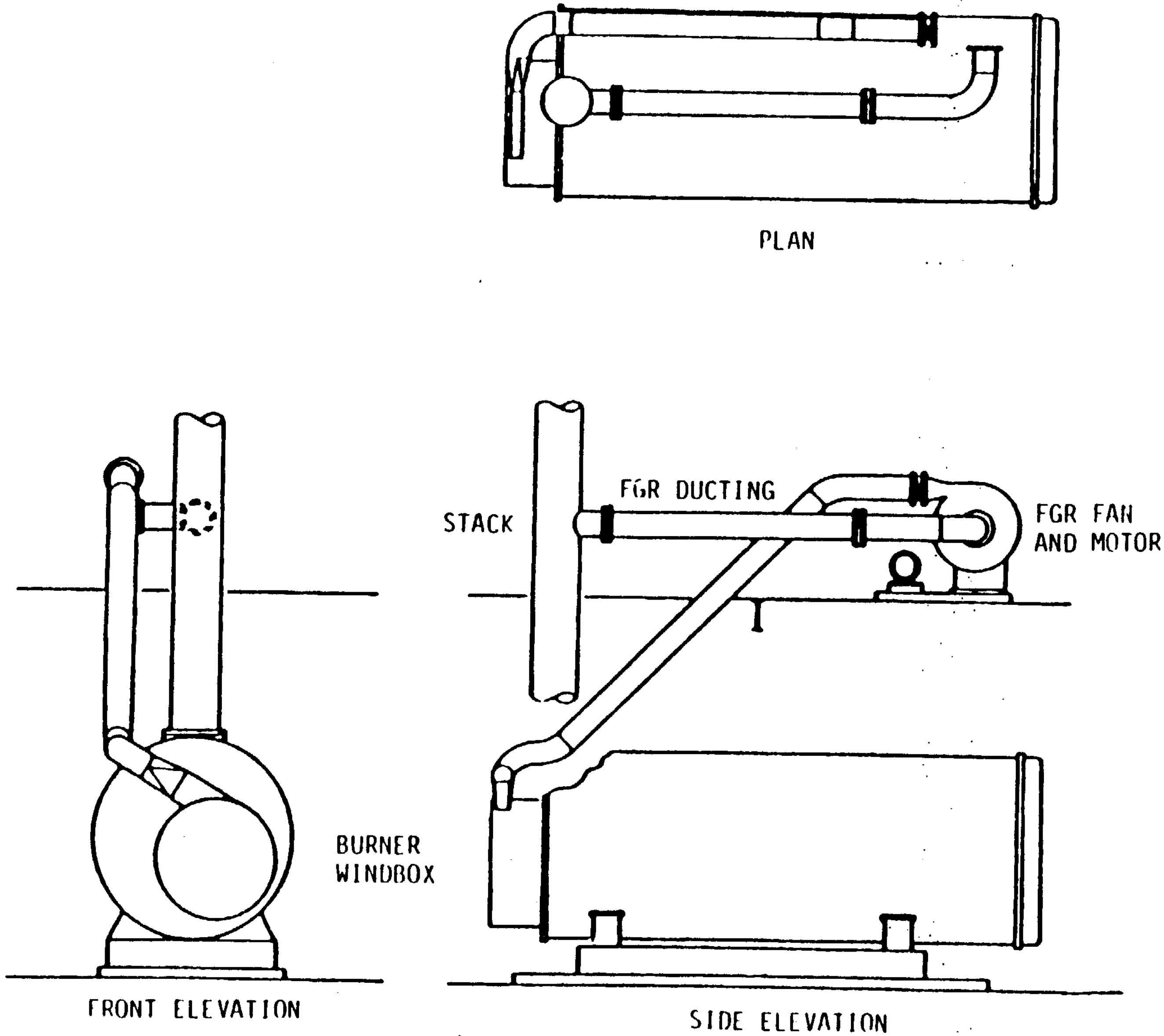

Figure 3-12. Layout of flue gas recirculation system for a residual oil- or gas-fired firetube boiler (Reference 3-56).

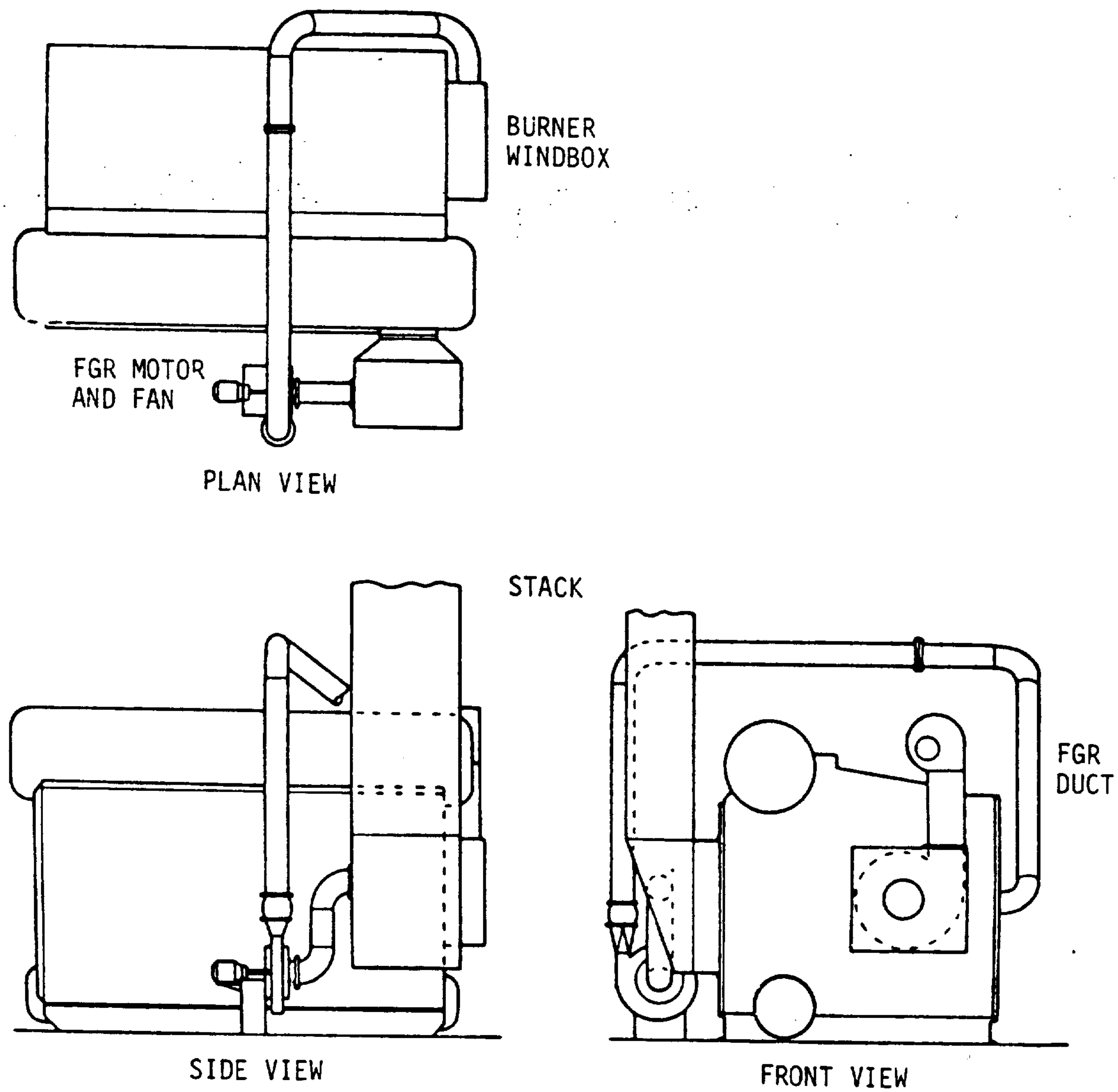

Figure 3-13. Layout of flue gas recirculation system for a residual oil- or gas fired packaged watertube boiler (Reference 3-56).

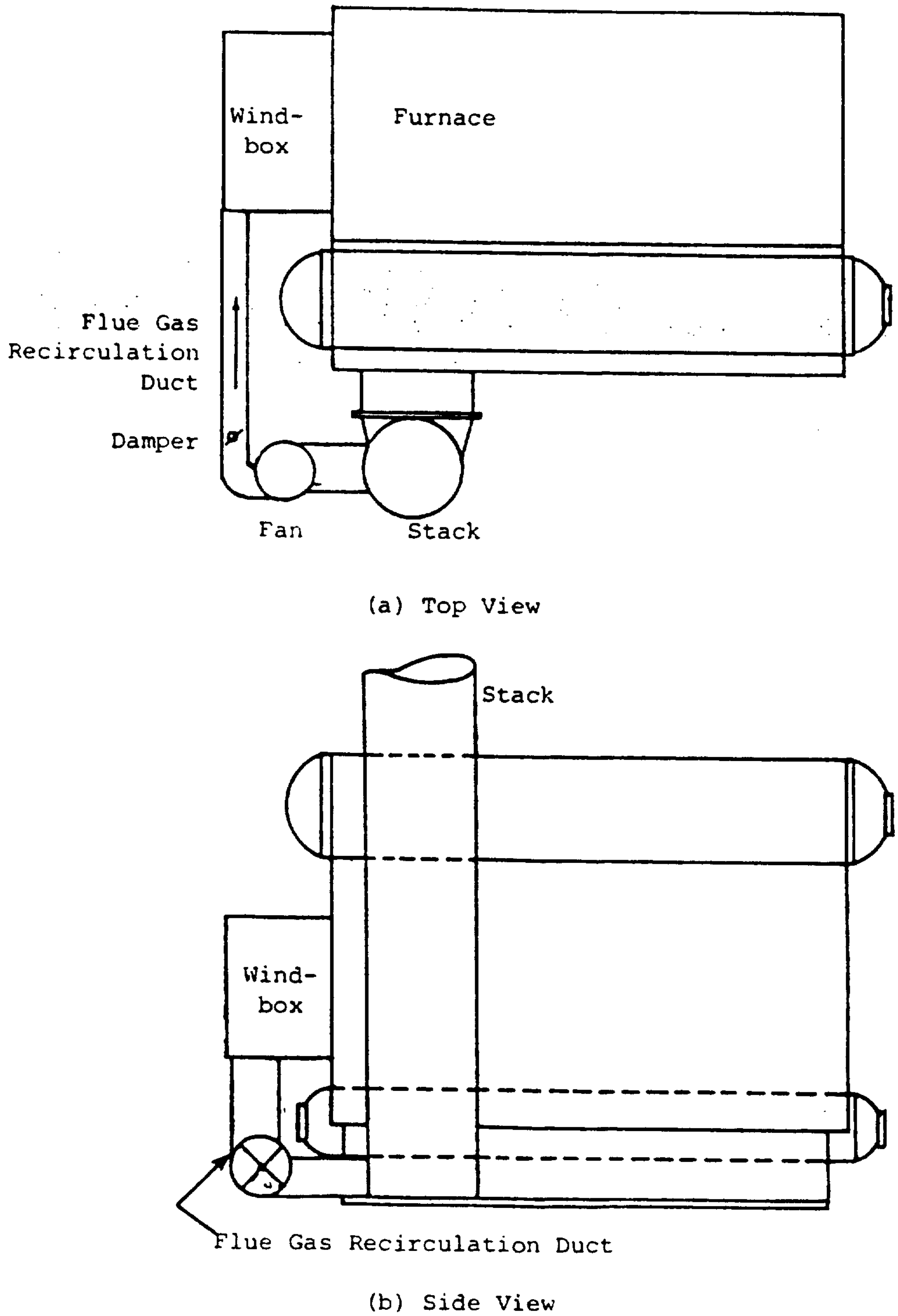

Figure 3-14. Layout of flue gas recirculation system for a residual oil-, distillate oil or gas-fired packaged watertube boiler (Reference 3-59).

because of the generally higher combustion intensity of the watertubes (Reference 3-56). However, NO_x reductions for both firetube and watertube units reached a maximum of 20 percent when burning a residual oil. Another investigator reported that FGR is more effective for steam atomized oil combustion than for air atomized oil combustion (References 3-12 and 3-59). In fact, in a watertube boiler burning steam atomized residual oil, maximum NO_x reduction was 20 percent. When burning the same oil with air atomization only 16 percent NO_x reduction was achieved.

For oil-fired boilers FGR is more effective when burning light distillate oil because thermal NO_x predominates. In fact, NO_x reductions of up to 73 percent were obtained with FGR when burning a No. 2 distillate oil (Reference 3-59).

In a retrofit application, flue gas recirculation rates approaching or above 30 percent can cause severe flame instability, flame pulsation, equipment vibration and blowouts. These problems were found to be significantly alleviated by extensive burner and windbox modifications (References 3-12 and 3-56).

In general, FGR is definitely an applicable control technique for oil-fired industrial boilers. It is most effective on boilers burning distillate oil. When burning residual oil, it is more effective with steam atomization systems. The technique is commercially available for new boilers for which burners have been designed to accommodate the additional flue gas flow. In fact, one manufacturer has recently installed two 14.7 MW (50 x 10^6 Btu/hr) units equipped with FGR systems in Southern California (References 3-60 and 3-61). No information on the performance on these units has been reported. However, the NO_x emissions of these units are designed to meet the stringent regulations of the South Coast Air Quality Management District of 225 ppm at 3 percent O_2 for oil combustion (approximately 126 ng NO_2/J).

3.3.4 Combined Flue Gas Recirculation and Staged Combustion

The packaged watertube boiler shown in Figures 3-11 amd 3-14 were also tested with combined SCA and FGR. Tests were run to determine whether the effectiveness of the two techniques are additive (References 3-12 and 3-59). Combining SCA with FGR gave no increased reduction over that with FGR or SCA alone when burning distillate oil. However, the combined techniques had a pronounced effect when burning residual oil. Thus staged combustion alone reduced NO_x emissions of residual oil 42 percent, FGR alone reduced NO_x emissions 11 percent while FGR with SCA reduced the NO_x emission 55 percent.

Fitting a boiler with both SCA and FGR may not prove to be cost effective. The combined technique is not considered commercially available because staged combustion is still experimental for firetube and packaged watertube boilers.

3.3.5 Reduced Air Preheat (RAP)

Reducing the amount of combustion air preheat lowers the primary combustion zone peak temperature, generally lowering thermal NO_x production as a result. The technique can be implemented only on boilers equipped with air preheaters. These boilers are of the watertube type and generally have designed heat input capacities of greater then 15 MW (50×10^6 Btu/hr) (Reference 3-12). No retrofit work is required in some instances.

As evidenced by the data contained in Table 3-5, distillate oil-fired watertube boilers equipped with air preheaters had higher baseline NO_x emissions than those units not equipped with air preheaters. Unit capacity was not a factor. No similar reduction occured for those units burning residual oil, perhaps because of the greater variation in fuel nitrogen content of the various oils being burned.

The data reported in Table 3-6 reflects results of RAP tests on two residual oil-fired boilers. For one boiler where initial baseline NO_x emissions were below 200 ppm at 3 percent O_2 the technique was ineffective. For the other boiler with initial baseline emissions over 330 ppm at 3 percent O_2, RAP reduced NO_x emissions at a rate of 18.8 ng/J (33.5 ppm) per 50K (90^oF) reduction in combustion air temperature (Reference 3-12).

Although available, the technique is rarely applied because very few industrial size oil-fired boilers are equipped with air preheaters. When RAP is implemented, the fuel penalty involved due to loss in efficiency can make the technique very unattractive. Reducing the air preheat temperatures as a means of reducing nitrogen oxide emissions from oil-firing will result in a decrease in boiler efficiency by about 2.5 percent per 50K (90^oF) increase in stack temperature (Reference 3-12 and 3-62). Because of this significant loss in boiler efficiency, the heat loss would have to be recovered if RAP is to be used as a NO_x control technique. Enlarging the surface area of existing economizers or installation of an economizer in place of an air preheater can be used to recover the heat loss due to the RAP technique for NO_x control. For new boilers, installation of an economizer is technically feasible and also offers economic advantages over the air preheater (Reference 3-63).

3.3.6 Load Reduction

Reducing boiler load is accomplished by reducing the heat input into the furnace. Both heat release rate and peak flame temperature are lowered, reducing the themal NO_x formation. However, the reduced mass flow through the burners at the reduced load condition can cause improper fuel-air mixing, thus creating CO and soot emissions with additional operational problems. This situation is alleviated by increasing the airflow to excess air levels higher than normally maintained at the higher boiler loads. This increase in airflow causes more oxygen availability, thus favoring increase in fuel NO_x formation. The net effect of reduced thermal NO and increased fuel NO is often no change in NO_x concentration in the flue gas.

This was essentially the result of the load reduction tests conducted in an EPA program on 24 oil-fired industrial boilers (References 3-12, 3-22 and 3-57). The data often show a split with increasing NO_x emissions in some boilers at reduced loads and decreasing emissions in others. For firetube boilers burning distillate oil, NO_x emission changes ranged from a 10 percent decrease to a 7 percent increase for each 10 percent load reduction. Five distillate oil-fired boilers without air preheat showed an average increase in NO_x emissions of 3.8 percent while the remaining two with air preheat showed an average decrease of 26 percent. NO_x emissions from firetube and watertube units burning residual oil showed average decreases in NO_x emissions regardless of whether the air was preheated or not.

Reducing boiler load will usually reduce the thermal efficiency of the boiler because of the increase in excess air needed to maintain good fuel air mixing. A more desirable way to achieve a reduction in combustion intensity would be to increase the size of the firebox. The enlarged firebox would provide reduced heat release rates without necessitating an increase in excess air levels. Naturally, larger firebox designs will only apply to new boilers. This technique is being implemented on utility size boilers (Reference 3-25).

3.3.7 Low NO_x Burners (LNB)

Low NO_x burners firing fuel oil can generally be classified by the method of fuel injection and the method of combustion air delivery. A recent EPA study (Reference 3-64) further classifies the burners as:

- Good-mixing*
- Divided flame
- Self-recirculating
- Staged-combustion
  - -- Two stage combustion
  - -- Off stoichiometric combustion

The good-mixing and divided flame type burners primarily reduce thermal NO_x, either by rapid quenching of the flame, or by an increase in the surface area of the flame for increased heat dissipation. The self-recirculation and various staged-combustion type burners reduce both thermal and fuel NO_x. This is accomplished through the recycling of combustion gas, which is lean in oxygen, or substoichiometric air injected in the primary combustion zone with stoichiometric and excess air added at the point of fuel discharge into the furnace.

Seven types of low NO_x burners for industrial boilers are presently under development or in commerical use in Japan. A summary of the limited information regarding each of these burners is presented in Table 3-7. Available information on the operations, performance, applicability and availability of each of these burners is discussed in the following sections. Unfortunately, actual emissions data for low NO_x burners for industrial boilers are generally not available. The percentage NO_x reductions presented here are only the expected performance as cited in the references, usually with no baseline emission levels given.

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*Controlled-mixing is probably a better term, but "good-mixing" was the term used in the EPA study and will be retained here.

TABLE 3-7. LOW NO_x BURNERS

Manufacturer Developer	Burner Type	Effectiveness of (Percent NO_x Reduction)	Applicability	Availability	Comments
Nippon/TRW	Good mixing[a]	17-23% w/heavy oil, fuel nitrogen content of 0.3%	Oil & gas	Commercialized early 1975 in Japan	Lower steam atomization but higher burner throat ΔP, High excess O_2
TRW/Civiltech	Good mixing[a]	17-23% w/heavy oil, fuel nitrogen content of 0.3%	Oil & gas	Late 1979	First generation burner tested in Japan. Second generation being developed for U.S.
Ishikawajima-Narima	Divided flame	30-50% reduction depending on application	Oil & gas	Commerically available in Japan (1973)	Requires burner tip modification only
Tokoyo Gas	Staged Combustion	50% reduction	Gas	Continuing development	Flame stability problems
Kawasaki	Staged Combustion	20-50% depending on fuel rate	Oil & gas	N/A	N/A
Coen	Staged Combustion	N/A	Oil & gas	Available on a very limited basis	Staged combustion design. All proprietary data
Energy and Environmental Research	Staged Combustion	Up to 50%	Oil	Still at R&D stage	Currently being tested in a field operating firetube

[a]Controlled mixing is probably a better term, but "good mixing" was the term used by the EPA study (Reference 3-64) and will be retained here.

Nippon/TRW Burner

The Nippon/TRW burner is designed to allow for an initial fuel-air mixing zone, established through precise control of the radial injection and atomization of the fuel into the combustion air. A second mixing zone allows for heterogenerous mixing of fuel droplets, followed by the primary flame front and post combustion zone (Reference 3-65).

The intermixing of fuel and air produces a radial conical flame pattern as shown in Figure 3-15. The combination of the recirculation of combustion products and good-mixing of fuel and air leads to reduced NO_x emissions by rapid quenching of the flame with cooler combustion gases. Figure 3-15 also shows the flame as being a thin annular configuration for increased heat dissipation and lower flame temperatures. Both phenomena reduce thermal NO_x production.

Figure 3-16 presents the results of the demonstration/commercialzation tests performed by Nippon/TRW. The sensitivity of NO_x emission concentrations as affected by fuel nitrogen is clearly seen. Figure 3-16 also demonstrates the low NO_x burner capabilities compared to a conventional burner. These tests were conducted after the burner was installed in an existing packaged boiler without modification to the safety control equipment, combustion air or fuel-handling system. Also shown are natural gas and distillate oil data from an LNB-equipped laboratory test furnace. The field test results show a 35 percent decrease in NO_x emissions for No. 2 fuel oil and a 30 percent decrease for heavy oil (analysis unknown). When the low NO_x burner was in operation, all NO_x emissions were below 220 ppm corrected at 3 percent excess oxygen (123 ng/J, 0.287 lb/10^6 Btu). The burner has been commercially available in Japan since early 1975 (Reference 3-66).

TRW/Civiltech Burner

The TRW/Civiltech burner represents the second generation burner being developed based on experience obtained with the Nippon/TRW LNB (Reference 3-67). Problems experienced during testing in Japan have led to a program to refine the original burner design. The second generation burner is being designed to achieve:

- Reasonably low excess air requirements during partial load operations

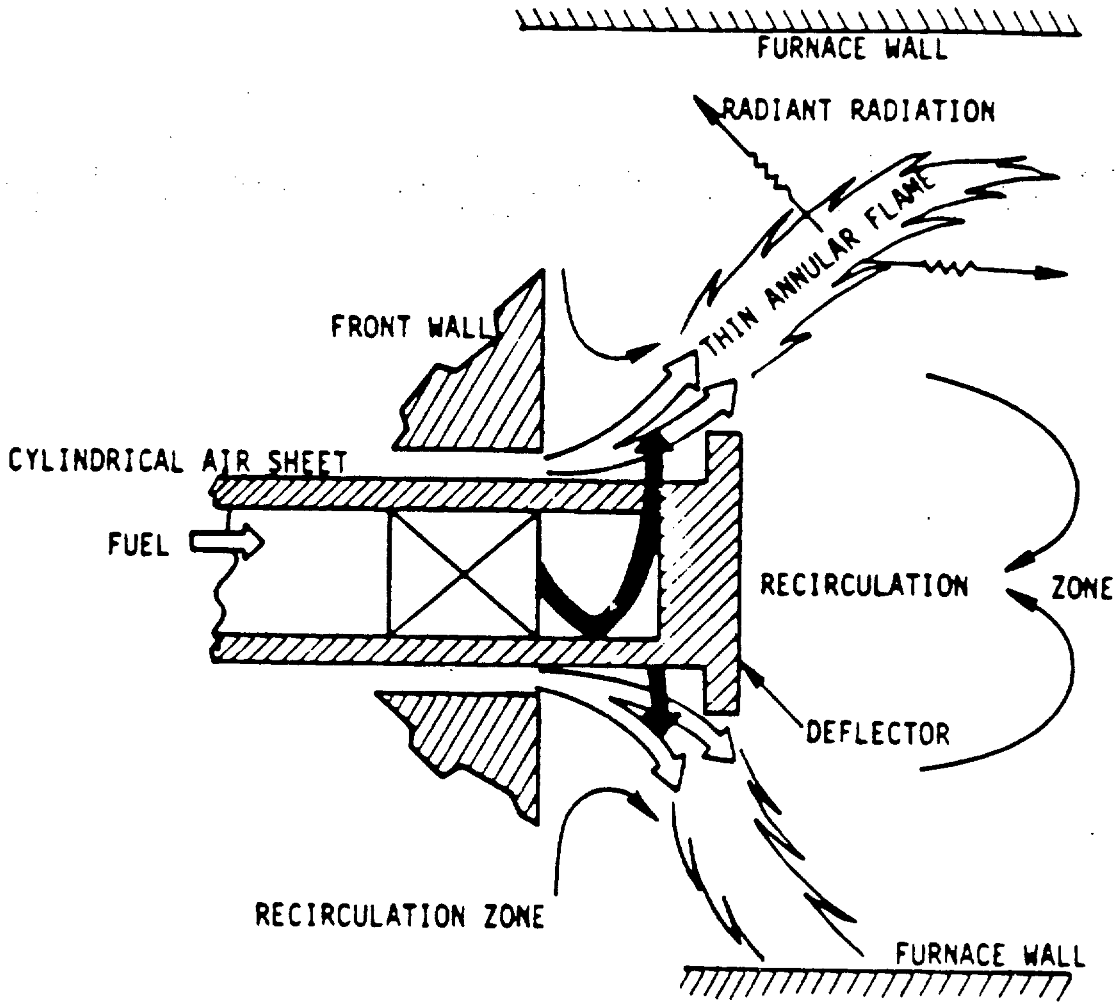


Figure 3-15. The Nippon/TRW burner (Reference 3-66).

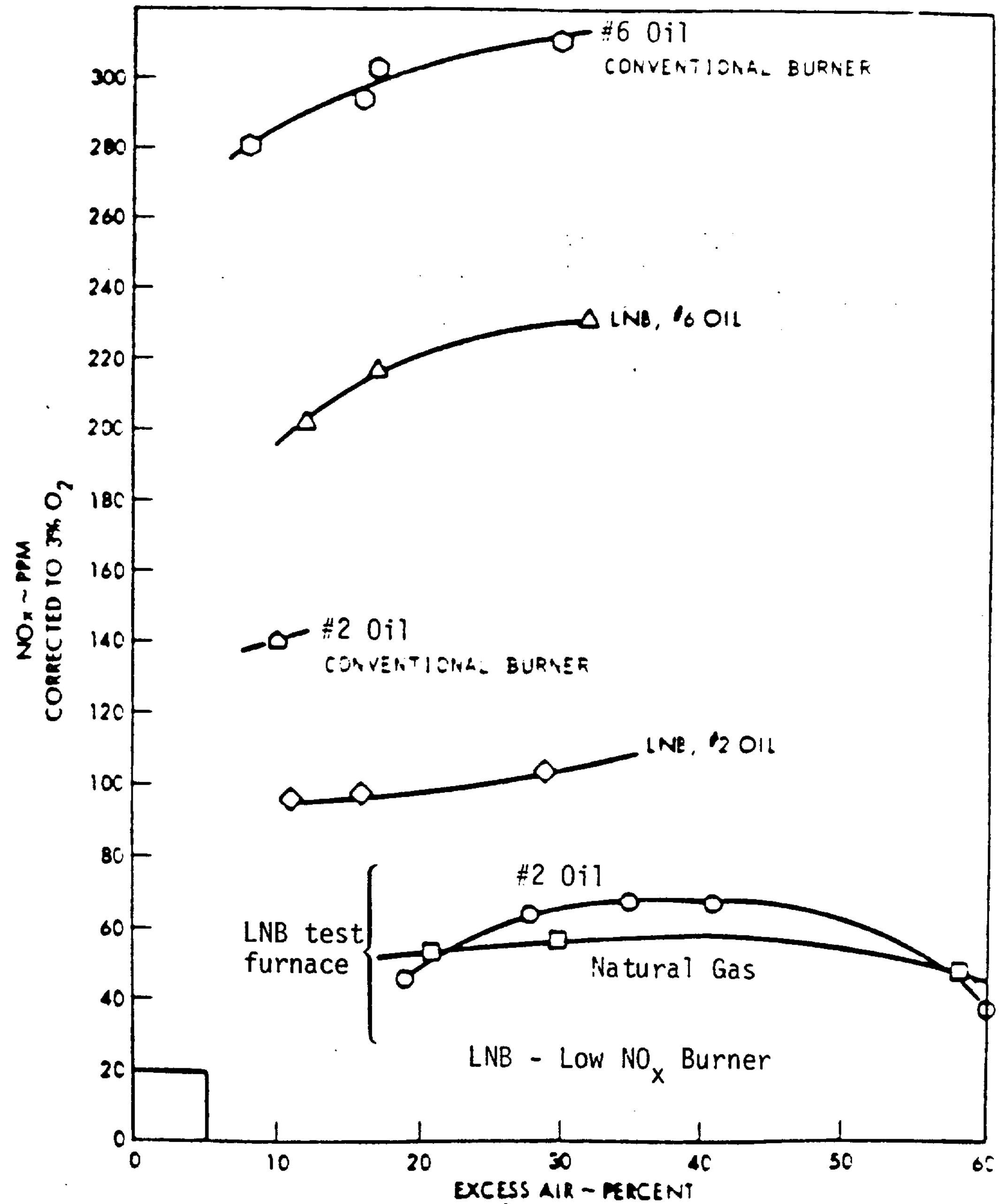


Figure 3-16. Performance results of the Nippon/TRW low NO_x burner (LNB) installed in a laboratory test furnace and in a packaged boiler (Reference 3-65).

- Wider range of applicability, with burner heat input capacities of 3 to 73 MW (10 to 250 x 10^6 Btu/hr)

The TRW burner is currently being commercially offered, though as yet undemonstrated. A preliminary timetable calls for commercial application by about 1980 (References 3-65, 3-67, and 3-77). An EPA-sponsored field demonstration is currently underway and actual operating data should soon be available (Reference 3-78).

Ishikawajima-Harima Heavy Industries (IHI) Burner

Ishikawajima-Harima Heavy Industries developed several burner configurations which are effective in reducing NO_x. The basic principle of the burners is a divided flame, as shown in Figure 3-17. The flame produced has a radial conical pattern which increases the radiation surface area and the rate of heat dissipation. The reduced flame temperature results in reductions in NO_x emissions.

The burner variations shown in Figure 3-17 were tested on a furnace simulator. The results are shown in Figure 3-18. NO_x emissions are shown to be reduced by 30 to 50 percent from conventional burners. Field tests on large boilers, 130 MW (400 x 10^6 Btu/hr) and larger have also been conducted and the results are presented in Figure 3-19. It is significant to note that combinations of NO_x reduction capability of the IHI burner are reduced as the use of other control methods, such as flue gas recirculation or staged combustion is increased.

The burner is commercially available for oil and gas fuel applications. The primary advantage to this burner is that it requires only the replacement of the conventional burner tip with the IHI flame divider, a minor modification.

Tokoyo Gas Company Burner

Tokoyo Gas company developed one of the first two-stage combustion type burners (Reference 3-69). The principle of the burner is shown in Figure 3-20. The primary air ports admit a predetermined air volume followed by stoichiometric addition as shown.

Experimental test results showed the presence of HCN and NH_3 intermediates, the radicals which Fenimore determined were precursors to the formation of "prompt NO" (Reference 3-70). To reduce the concentration of these radicals, a catalyst was inserted between the first and second combustion zones. The burner operates at the limit of

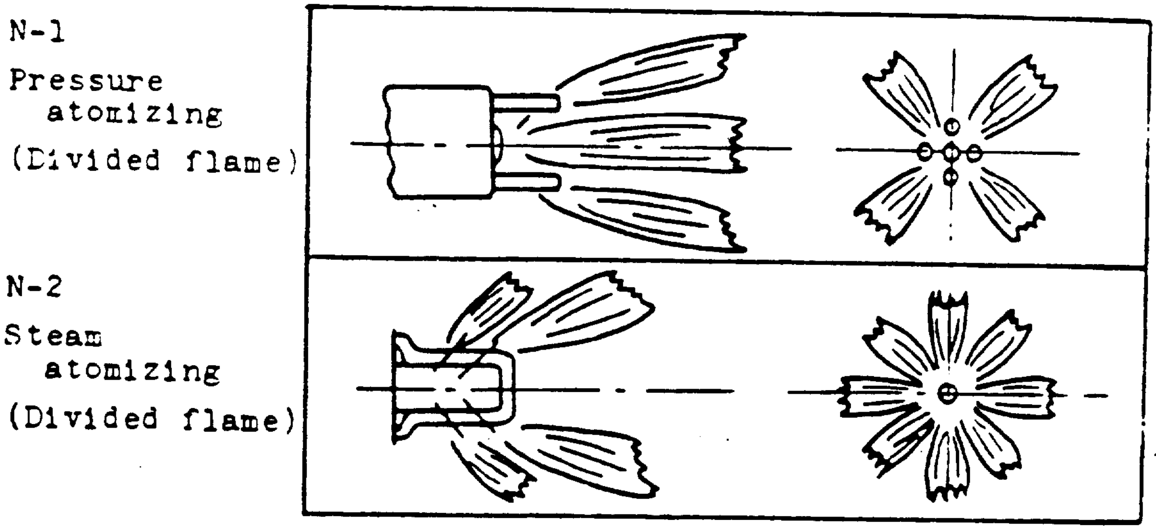
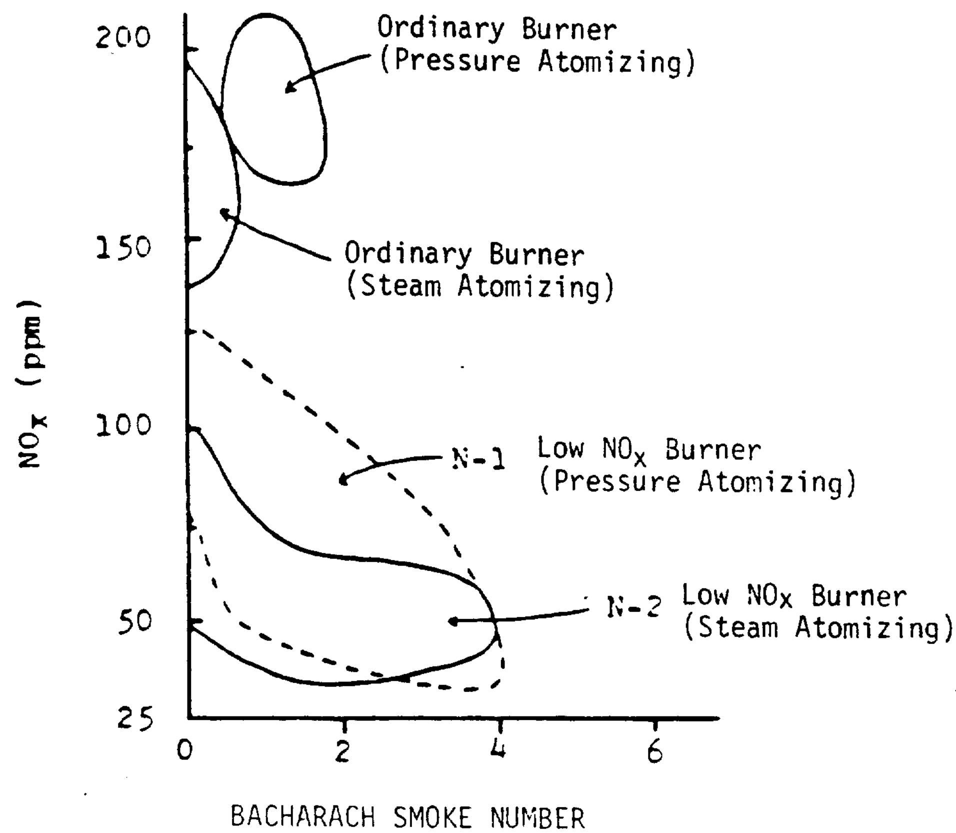
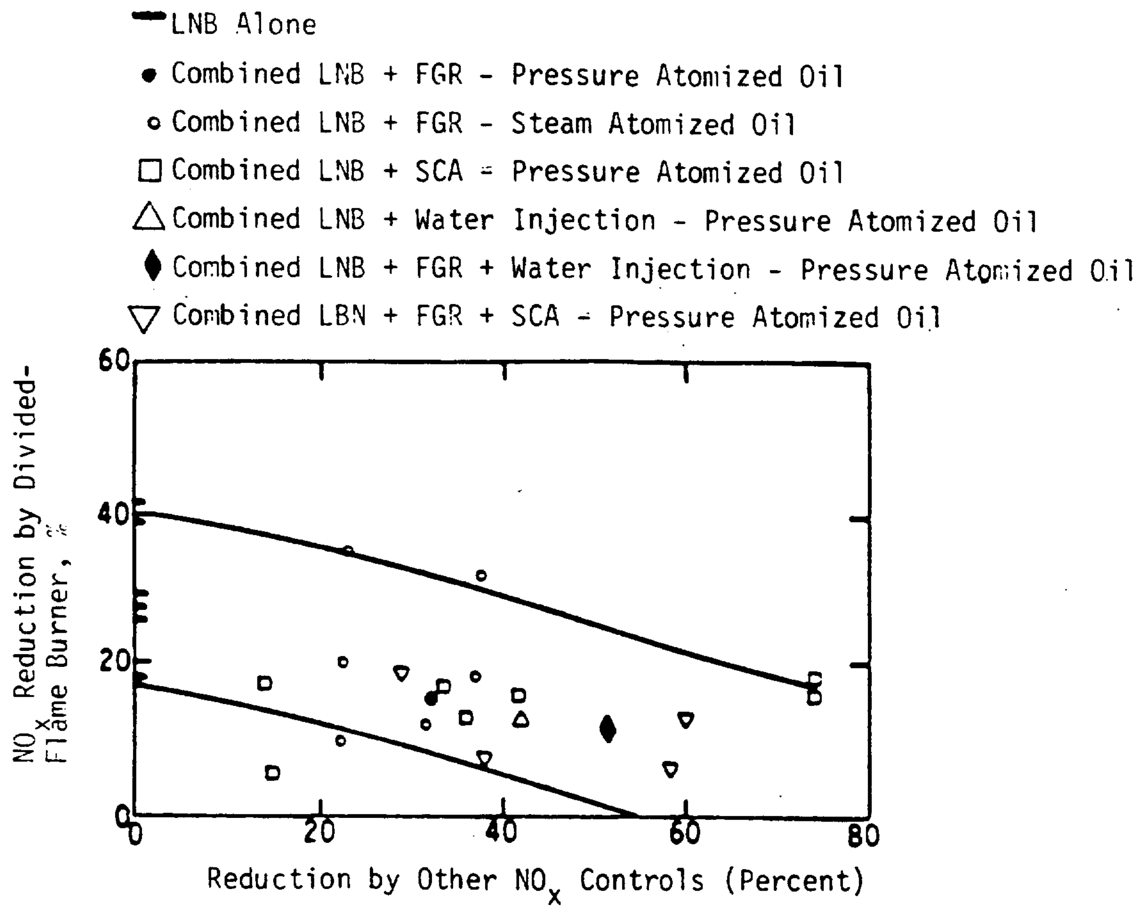


Figure 3-17. Ishikawajima-Harima divided flame burner (Reference 3-68).



NOTE: Enclosed regions represent data bands.

Figure 3-18. Effect of flame division on NO_x and smoke concentrations (Ishikawajima-Harima burner) (Reference 3-68).



LNB = Low NO_x Burner
FGR = Flue Gas Recirculation
SCA = Staged Combustion Air

Figure 3-19. Effect of combined combustion modifications NO_x controls on the performance of the Ishikawajima-Harima low NO_x burner (Reference 3-68).

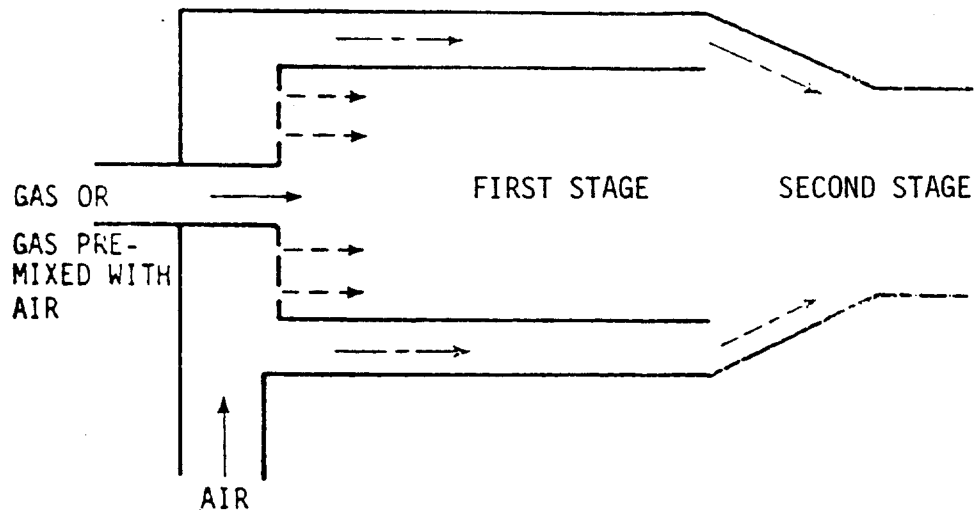


Figure 3-20. Schematic of Tokoyo Gas Company two-stage combustion type burner for low NO_x formation (Reference 3-64).

fuel-rich combustion, resulting in some flame stability problems (Reference 3-69).

Tests conducted on a firetube boiler with a capacity of 5.5 MW (18.6×10^6 Btu/hr) resulted in NO_x emissions approximately 50 percent of those from conventional burners. Because of the flame stability problems, however, the burner is still in the development stages (Reference 3-69).

Kawasaki Heavy Industries Burner

A two-staged combustion burner, utilizing a precombustion zone, has been designed by Kawasaki Heavy Industries (Reference 3-64). The precombustion chamber is placed in the windbox with secondary combustion air added at the point of discharge into the furnace, as shown in Figure 3-21. The injection of the fuel oil results in an eddy effect, as in self-recirculating burners, resulting in fuel rich combustion. The fuel is vaporized and partially combusted. Secondary air is added, at the desired overall stoichiometry, at the burner tip. Reportedly, this configuration reduces both thermal and fuel NO_x. The degree of reduction is shown in Figure 3-22.

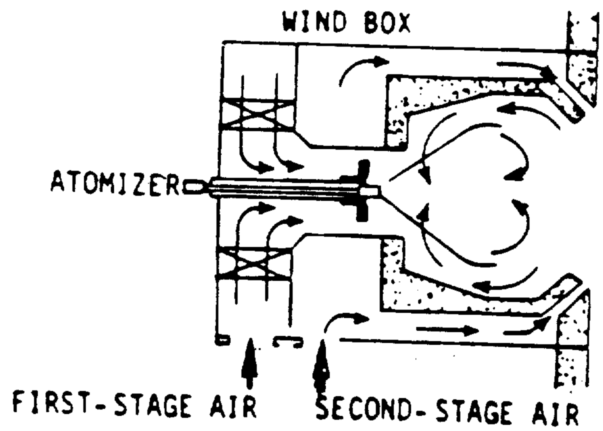


Figure 2-21. Kawasaki two-stage combustion-type burner for oil (Reference 3-64).

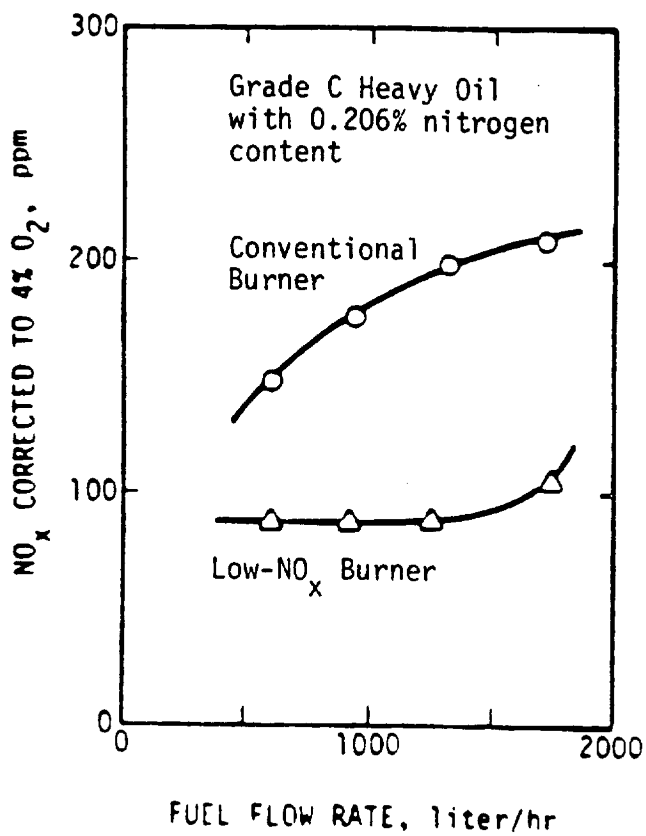


Figure 3-22. Effect of Kawasaki low NO_x burner on NO_x emissions (Reference 3-64).

Coen Burner

All test and descriptive information regarding the Coen low NO_x burner is considered proprietary (Reference 3-71). The information given was limited to burner concept (staged combustion) and applicable fuels (gas and oil). It was also stated that the burner was commercially available on an extremely limited basis. The flame is elongated, making the application to existing boilers difficult without substantial derating. All burners sold will be tested as part of a burner development program. Widespread commerical availability is not expected in the near future (Reference 3-71).

Energy and Environmental Research Co. (EER)/EPA Burner

EER recently tested an oil-fired low NO_x burner in a firetube boiler. Reductions in NO_x emission levels of greater than 50 percent were achieved without the need to modify the boiler in any way (Reference 3-72). Apparently the burner has not been fully demonstrated because additional testing is underway to investigate the effect of oil atomization. Preliminary bench-scale experiments with nitrogen containing fuel oils indicate that those atomization designs which yield more rapid vaporization of the fuel in the primary zone result in lower NO_x emissions (Reference 3-79). These preliminary results are encouraging and hold promise for the future.

3.3.8 Ammonia Injection

The noncatalytic reduction of NO in the flue gas with NH_3 is commercially available in Japan. Four industrial steam generators ranging in size from 41 to 252 MW (140 to 860 x 10^6 Btu/hr) have been successfully retrofitted in Japan. Reported NO_x reductions ranging from approximately 40 to 65 percent depending on the temperature of the injection location (Figure 3-23).

Since the commercial application of ammonia injection process in Japan, one domestic application on an oil recovery boiler in Southern California has taken place. Reported NO_x reductions ranged from 50 to 70 percent with the unit burning a heavy crude oil (Reference 3-73). The technique is particularly attractive because it can be used in combination with any other combustion modification. Thus, significant NO_x reductions can be achieved.

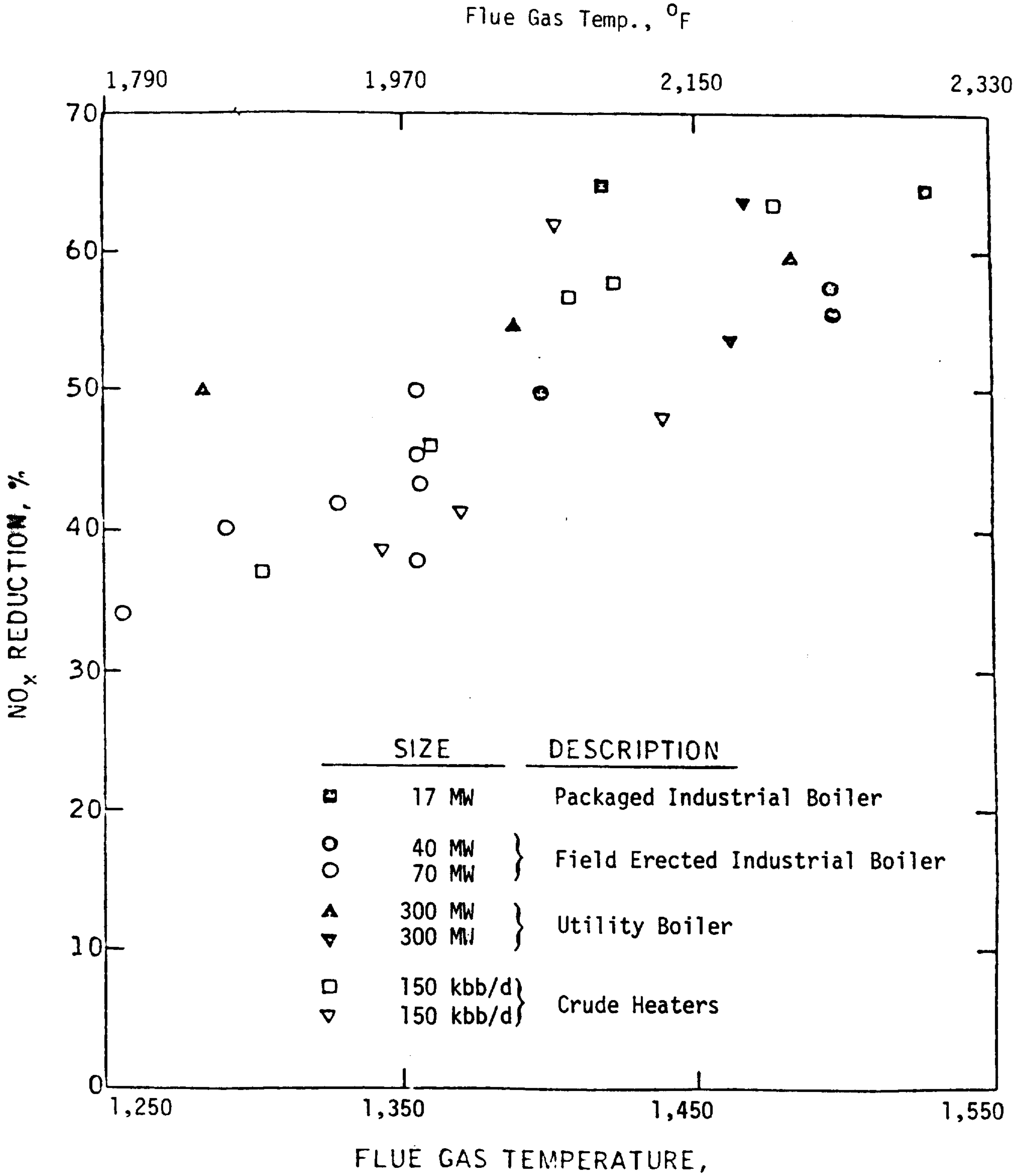


Figure 3-23. Ammonia injection system performance on commercial units as functions of temperature (Reference 3-74).

For firetube boilers the injection system would need to be placed in the firebox as it is shown in Figure 3-24 because optimum temperatures occur at this location. The system represents an experimental retrofit application for a pilot scale test program. For watertube boilers the injection system will have to be located at the entrance of the convective section where flue gas temperatures are optimum for the NO reduction reaction to occur.

Due to the expected high cost of this technique compared with other combustion modifications, the ammonia injection process will probably not be practical on small size boilers such as firetubes and package watertubes. In addition, since these industrial units are generally not base loaded, that is they do not operate at a steady continuous load, the variable heat input will cause significant flue gas temperature fluctuations which will reduce the performance of the control technique. From an operational standpoint, the ammonia injection process is best suited for units burning low sulfur oil. The absence of SO_3 in the flue gas will eliminate the concern for corrosive deposits caused by the formation of ammonium sulfates.

3.4 GAS-FIRED BOILERS

Gas-fired industrial boilers are of the same basic design as oil-fired boilers. In fact, approximately one-fourth of all industrial boilers are capable of burning gas and oil individually or in combination (Reference 3-48). Gas-fired boiler designs are categorized as firetubes, and packaged or field-erected watertubes. Of the total population of installed units, gas-fired firetubes comprise 11.3 percent, packaged watertubes 8.6 percent and field-erected watertubes 13.6 percent (Reference 3-1).

Table 3-8 lists baseline NO_x emission from gas-fired industrial boilers tested by EPA (References 3-12, 3-22 and 3-57). The data show a definite increase in NO_x emissions for boilers equipped with air preheaters. There appears to be no difference between NO_x emissions of firetube boilers and those of small single burner watertube boilers without air preheat.

All of the combustion modifications applicable for oil-fired units are also applicable to boilers burning natural gas. Table 3-9 summarizes

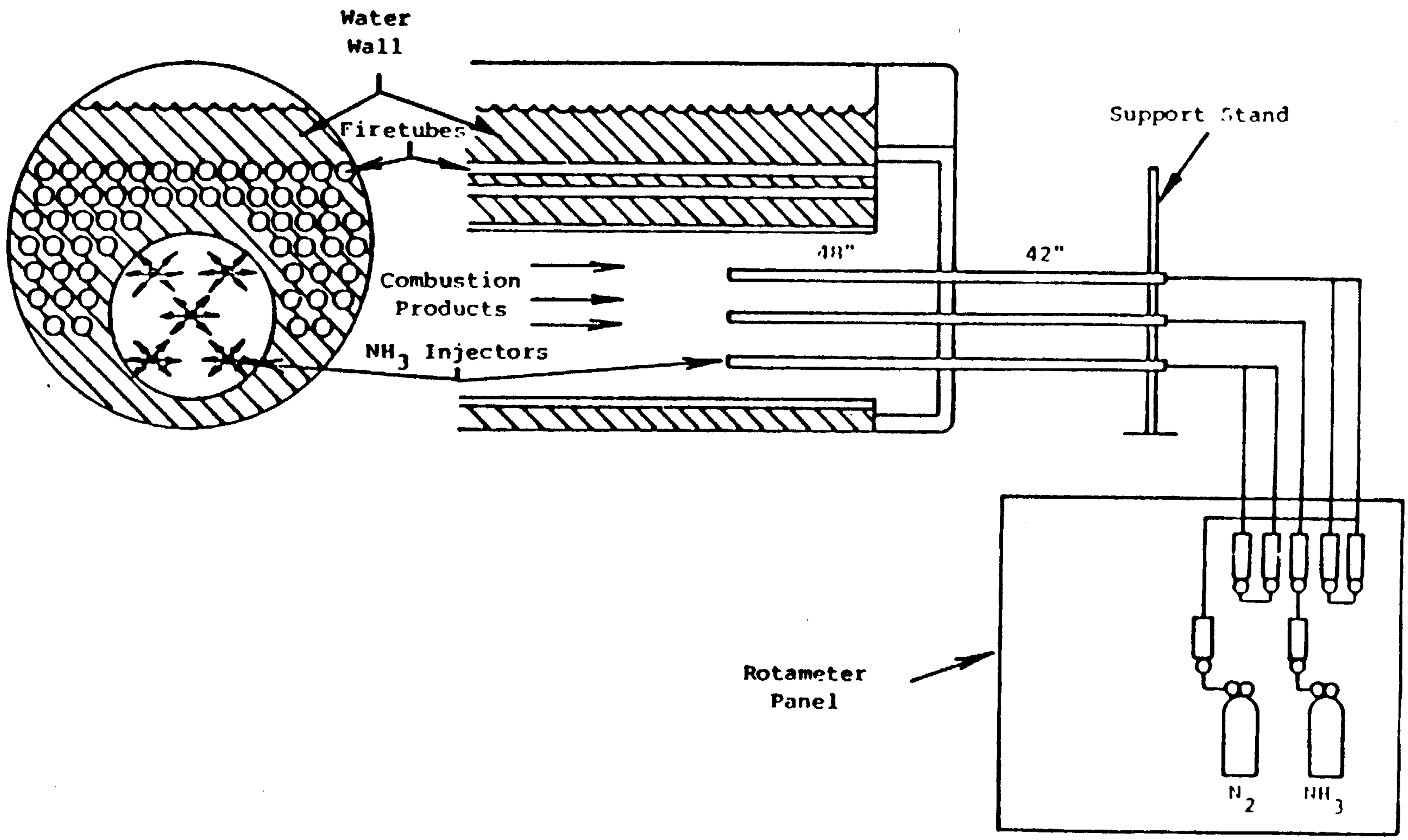


Figure 3-24. Schematic of ammonia injection system on a firetube boiler (Reference 3-19).

TABLE 3-8. BASELINE NO_x EMISSION FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS

Type of Boiler	Number of Boilers	Excess O_2 (Weighted Average)	Range of NO_x Emissions ng/J (Weighted Average)	Range of NO_x Emissions lb/10^6 Btu (Weighted Average)
Firetube	8	3.6 - 11.5 (6.5)	28.6 - 55.1 (41.0)	0.066 - 0.128 (0.095)
Watertube without air preheat	9	2.9 - 8.9 (5.3)	30.1 - 97.9 (50.0)	0.070 - 0.228 (0.116)
Watertube with air preheat	11	1.9 - 13.1 (5.7)	49.0 - 190.1 (113)	0.114 - 0.444 (0.263)

TABLE 3-9. COMBUSTION MODIFICATION NO_x CONTROLS FOR GAS-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commerical Availability/ R&D Status	Comments
Low Excess Air (LEA)	Reduction in air-fuel ratio by reducing air flow to the windbox	28	-71 to 83 Average 10	Generally excess O_2 can be safely reduced to 3.0%. This reduction represents a 2.5% drop from baseline.	Method and control equipment currently available.	Generally practiced because of increased boiler efficiency. Best NO_x reductions reported for large multiburner units.
Staged combustion air (SCA)	Injection of secondary air downstream of the burner(s) in the direction of the flue gas path	3	5 to 46	70-90% burner stoichiometries can be maintained. Applicable to all units, however requires extensive equipment modification.	Technique is still experimental especially for small firetube and watertube units.	Found to be less effective on firetube boilers than watertube boilers. Generally less effective for gas-fired units.
Burners out of Service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	3	17 to 44	Applicable only to multiburner units. Best suited for square burner pattern.	Technique is available. Retrofit application only. Requires careful selection of BOOS and control of air flow.	May require modification of gas delivery system and burners to avoid derating.
Flue Gas Recirculation (FGR)	Recirculation of flue gas to the burner windbox. Requires motor, fan and connecting ducting.	3	48 to 86	Flue gas recirculation rates possible up to 45%. Technique is applicable to all boiler types except ones equipped with ring burners	Available now. Best suited for new boilers. Retrofit application would result in extensive burner modifications.	Flame instability problem is not severe except for ring burners. Minor burner modifications can guarantee stable flames. Most effective on watertube units.
Staged combustion and Flue Gas Recirculation (FGR)	Combined techniques of staged combustion air and FGR	1	76	Applicable to all boilers with some restrictions as individual techniques.	FGR is an available technique. SCA for small package units is still at R&D stage.	No added benefit of SCA to FGR performance. Combined methods are not additive in their effect.

TABLE 3-9. Concluded

Control Technique	Description of Technique	Number of Industrial Boilers Tested	Effectiveness of Control (Percent NO_x Reduction)	Range of Application	Commerical Availability/ R&D Status	Comments
Load Reduction (LR)	Reduction of both fuel and air flow to burners. Or design with enlarged firebox.	21	32% decrease to 82% increase in (10.5% average reduction)	Tests to 20% of rated capacity. Applicable to all units.	Technique available. However, retrofit application is not feasible due to initial low load factor of industrial units.	Least effective on firetube boilers because of lower combustion intensity. Applicable for new watertube units with increased firebox size.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater.	2	20 to 55 ng/J/temperature per 50K reduction in air temp.	Applicable only on units equipped with air preheaters (large watertube units). This application is very limited.	Technique available but not implemented because of significant loss in efficiency.	Implementation would require other designs to recover loss of heat. Technique is not desirable because of loss in efficiency.
Low NO_x Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation.	N/A	20 to 50	New burners generally applicable to all boilers. More information is needed.	Commercially offered but not demonstrated.	Specific emissions data from industrial boilers equipped with LNB are lacking.
Ammonia Injection	Injection of NH_3 as a reducing agent in the flue gas.	5 (4 Japanese, installations, 1 domestic)	40 to 70	Applicable for large package and field-erected watertube boilers. May not be feasible for firetube boilers.	Commercially offered but not demonstrated.	Should be fewer problems than with coal- or oil-firing. Elaborate NH_3 system still required. Possible boiler load restrictions.

the available information on the performance, applicability and availability of these techniques for gas-fired units.

The following subsections highlight the major points of interest for each of the techniques considered.

3.4.1 Low Excess Air (LEA)

Implementation of LEA firing on gas-fired units is similar to that on oil-fired units because the boiler equipment is essentially the same. Low excess air reduces NO_x emissions approximately 12 percent for firetube boilers, 8 percent for watertube boilers without preheated air and about 15 percent for watertube boilers with preheated air. Figure 3-25 shows, as expected, that low excess air firing is more effective for boilers with air preheat because LEA would reduce the amount of preheated air, hence, lowering combustion intensity and reducing NO_x formation. Documented test data show that excess oxygen level could in general be reduced to around 3.0 percent without excessive emissions of CO or HC (References 3-12, 3-22, and 3-57).

In summary, LEA is a moderately effective NO_x control technique for gas-fired boilers. Furthermore, combustion with LEA remains desirable because of increased boiler efficiency.

3.4.2 Staged Combustion Air (SCA)

Staged combustion air on gas-fired boilers is applied in the same manner as on oil-fired boilers. The firetube and single burner watertubes for which SCA was implemented with oil firing were also used to investigate the effectiveness of the technique for gas firing. SCA on gas-fired multiburner watertubes was also investigated implementing the BOOS technique. The following sections summarize the performance, applicability and availability of the various methods of implementing SCA on the major gas-fired industrial boilers.

3.4.2.1 Firetube Boilers

A schematic of the staged air injection system for firetube boilers was shown in Figure 3-9. In the EPA study, NO_x emissions were reduced 25 percent at a burner stoichiometry of 90 percent and overall excess air of 2.9 percent (Reference 3-57). Secondary air was most effective when injected downstream of the burner at a distance equivalent to 1.5 firebox diameters.

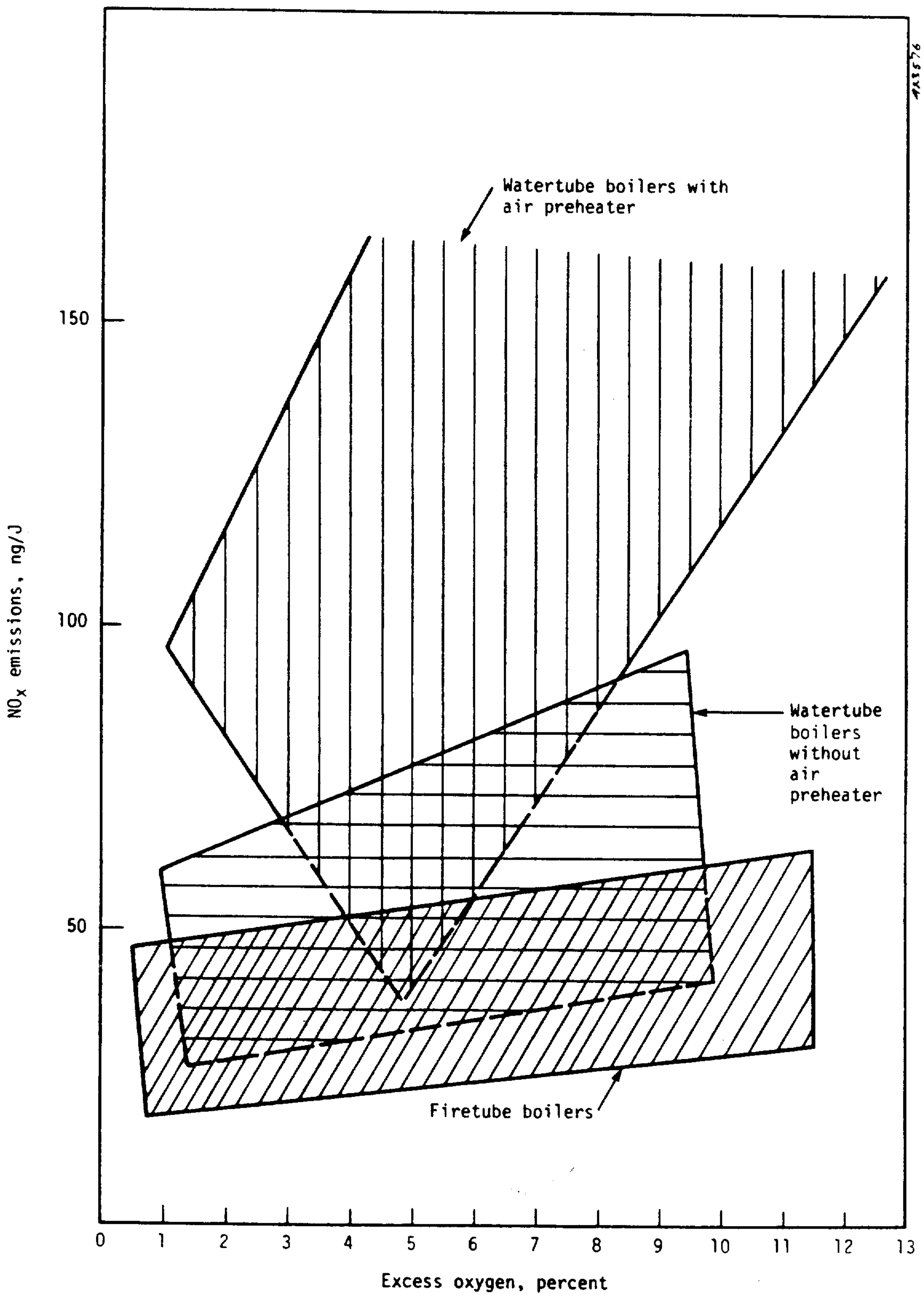


Figure 3-25. Effect of excess oxygen on NO_x emissions from natural gas-fired boilers (References 3-12, 3-22, and 3-57).

As in the case for oil-fired firetubes, more testing is needed to assess the feasibility of this technique. The probable high cost, both as a retrofit and a new boiler design feature associated with the modest NO_x reductions, make SCA unattractive for gas-fired firetube boilers.

3.4.2.2 Packaged Watertube Boilers

NO_x emissions from the "D" type watertube boiler (Figure 3-11) with staged combustion averaged 6 percent of baseline levels. The optimum location of the injected air was found to be at a distance of at least 1.2 m (4 feet) from a gas gun burner. Only marginally better NO_x reduction was achieved by increasing this distance to 2.1 m (7 feet) (References 3-12 and 3-59).

NO_x reductions for the other single burner watertube boiler (Figure 3-10) averaged only approximately 30 percent when the secondary air was injected at approximately 1 m (3 feet) and 3 m (9 feet) from the burner exit plane. Injection of secondary air between 1 and 3 meters from the ring burner caused only a slight reduction in NO_x emissions (References 3-12 and 3-59).

Staged combustion was less effective for the second watertube boiler because the combustion air was preheated. The high preheat temperatures reduced the effectiveness of SCA in lowering thermal NO_x. When the primary combustion air temperature was reduced, NO_x emissions were reduced 69 percent with staged air injection (Reference 3-59).

The same study also indicated that the type of gas burner -- gun or ring -- influenced the location of the secondary injection air for optimum NO_x reductions. For the gun type burner, NO_x emissions decreased as the air was injected further away from the burner exit plane. This reduction levels off at a distance corresponding to approximately 7 cm per thousand Joules of heat input. For the ring type burner, NO_x reduction peaked at two staged air injection locations: 0.8 and 3.0 meters approximately. These distances correspond to approximately 2 and 7 cm per thousand Joules of heat input respectively. Thus, for the ring burner, it seems that the staged air could also be injected much closer to the burner with similar NO_x reduction results (References 3-12 and 3-59).

Staged combustion air for small gas-fired watertube boilers is still at the experimental stage. More pilot and field studies are necessary to confirm some of the trends described above to define safe operating limits of the technique when the boiler is operating at various loads.

3.4.2.3 Multiburner Watertube

Staged combustion can be implemented on multiburner units by utilizing overfire air ports or by the BOOS method. For gas-fired boilers BOOS reduced NO_x emissions to a maximum of 30 percent by terminating the fuel flow to half of the available burners (Reference 3-12).

As in the case with oil firing the optimum BOOS selection varies from boiler to boiler. Similarly, limitations such as boiler derate when many burners are set on air only are also applicable to gas-fired units as for oil-fired units. Operational impact such as corrosion and soot formation are very much reduced with gas-fired boilers.

3.4.3 Flue Gas Recirculation (FGR)

Three natural gas-fired boilers were retrofitted with FGR in two EPA test programs (References 3-12, 3-57, and 3-59). Figures 3-12 through 3-14 showed schematics of the FGR system in two applications. In all cases the burner windbox was breached to install the FGR duct. The recycled flue gas was mixed with both primary and secondary air.

The firetube boiler had a gas "ring" burner embedded in the refractory throat (see Figure 3-26). Apparently, this burner permitted flue gas recirculation rates up to 55 percent without flame instability. Nitrogen oxide reductions were approximately 50 percent for 25 percent FGR and 70 percent for 50 percent FGR. Excess carbon monoxide emissions reached significant levels only at very low (less than 1.5 percent) excess O_2 levels (Reference 3-57).

For the 73 MW (250×10^6 Btu/hr) "D" type boiler, NO_x reductions on the order of 70 percent were achieved with FGR rates as high as 45 percent. Flame stability could apparently be maintained with the typical gas fired "ring" burner installed in this small watertube unit. Figure 3-27 shows a schematic of the burner (Reference 3-57).

The third packaged watertube boiler retrofitted with FGR was a 5 MW "D" type unit equipped with a ring burner similar to the one shown in Figure 3-27. Use of FGR caused severe flame stability problems even at low recirculation rates. These problems were alleviated by using a gas gun burner instead of the ring type. However, flue gas recirculation rates were still limited to 20 percent. Using the gas burner, NO_x

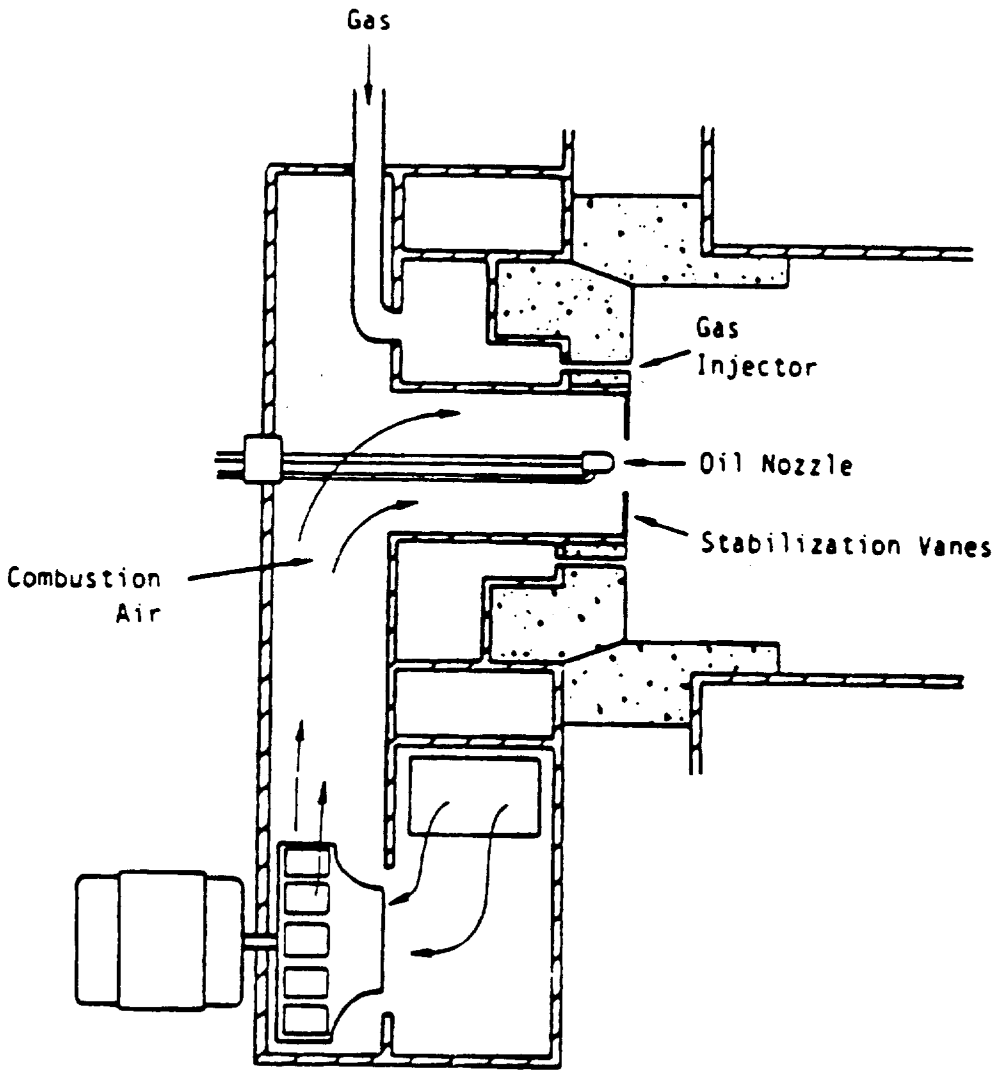


Figure 3-26. Schematic of the windbox burner arrangement of a firetube burner (Reference 3-57).

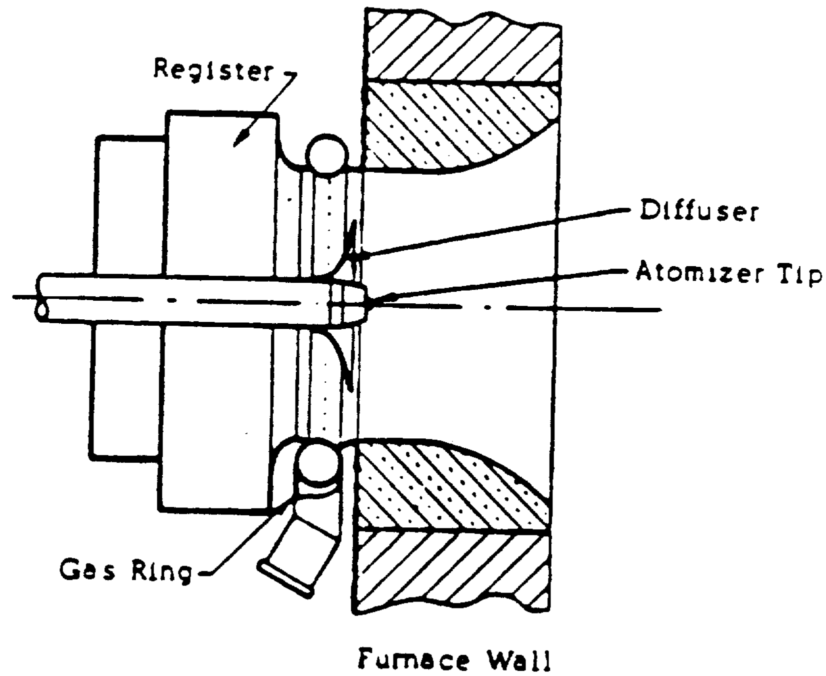


Figure 3-27. Schematic of register burner installed in a watertube boiler (Reference 3-57).

emissions were reduced 52 percent with 8 percent FGR and 75 percent with 20 percent FGR (Reference 3-59).

There seems to be no clear trend between gas burner type and flame stability with FGR. However, it is evident that FGR installation will necessitate, in most cases, substantial burner modifications to alleviate the flame instability.

Flue gas recirculation for gas-fired industrial boilers is definitely available and is an effective technique. However, use of FGR may necessitate
use of different burner configuration.

3.4.4 Combined Flue Gas Recirculation and Staged Combustion

Data for natural gas are limited to only one boiler, the 5 MW (17.5×10^6 Btu/hr) "D" type packaged unit discussed above (References 3-12 and 3-59). These data indicate that the addition of staged air injection does not further decrease NO_x emissions beyond the levels achieved with FGR (76 percent).

The combined FGR and SCA does not present any operational impact in addition to those caused by the single application of either technique. However, there is no incentive in adding SCA to FGR when there is no additional NO_x reduction.

3.4.5 Load Reduction

Load reduction gave an average NO_x emission reduction of 3.4 percent for firetubes; 6.4 percent for watertube boilers without air preheaters and 34.9 percent for boilers with air preheat (References 3-12 and 3-59). In these latter cases, with air preheat, the reduction in boiler load also produced a reduction in combustion air temperature.

In general, reduced boiler load is not as effective for gas-fired boilers as for oil-fired units. Reduced heat release rates via larger firebox design or new units does not appear promising based on these results. Reduced load often requires increased excess O_2 which can negate any drop in NO_x emissions.

3.4.6 Reduced Air Preheat (RAP)

Measurements of the effects of windbox temperature on gas-fired boilers were conducted in an EPA study (Reference 3-12). The following general conclusions were drawn:

- NO_x emissions decrease significantly with reduced combustion air temperature
- The effect of air temperature is more pronounced for larger burners
- The overall thermal efficiency of the boiler is reduced with reduced air preheat

Reduction of combustion air temperature is a very effective NO_x control technique for gas-fired boilers. Emissions were reduced 20 ng/J for each 50K reduction in combustion air temperature for two watertube boilers.

The application of RAP is limited to boilers equipped with air preheaters. These units are all of the watertube design type and are usually greater than 15 MW of heat input (50×10^6 Btu) (Reference 3-12). Overall efficiency of the unit may be maintained by adding an economizer (Reference 3-63).

3.4.7 Low NO_x Burners (LNB)

Available low NO_x burners are applicable to gas-fired as well as oil-fired boilers. Detailed performance data of the burners described in Section 3.3.7 are very limited for natural gas combustion.

The good mixing and divided flame burners which primarily reduce thermal NO_x could perform better with natural gas combustion. However, no data are available to quantify this.

Since the oil-fired LNB can also operate with natural gas, this NO_x control technique can be considered commercially available. However, the commercialization has been limited mainly to Japanese installations. Continuing research and development effort in U.S. is directed primarily toward oil-fired burners.

However, a recent 30-day test of a commercial low NO_x burner on a 30 MW heat input gas-fired boiler showed much promise (Reference 3-90). The average NO_x emission level was 33 ng/J at the high load condition and 44 ng/J at low loads (13 MW). Tests on an adjacent, identical boiler with standard burners produced NO_x emissions of 113 ng/J at boiler loads greater than 13 MW and 95 ng/J at less than 13 MW.

3.4.8 Ammonia Injection

The design and application of the ammonia injection process does not vary significantly with the fuel burned. Therefore, the basic design of the injection system shown in Figure 3-6 for a coal-fired watertube boiler is also applicable to gas-fired boilers. Application to the smaller firetube units would be similar to that of Figure 3-24, as discussed in Section 3.3.8 for oil-fired units.

The ammonia injection process should be easier to operate and maintain with gas firing. This advantage is due primarily to the less severe flue gas environment from combustion of natural gas. For example, the absence of sulfur oxides eliminates the possibility of ammonium sulfate formation. In addition, the absence of particulate emissions will reduce the maintenance of the injection grid to remove accumulated deposits. Finally, gas-fired boilers do not produce water wall deposits like those in coal- and residual oil-fired boilers and thus the fluctuation in flue gas temperatures caused by these deposits is eliminated.

Ammonia injection is a control technology which is commercially offered but not demonstrated. The effectiveness varies from 40 to 70 percent NO_x reduction depending on the application (Figure 3-23). As in the case of oil-fired units, ammonia injection will probably not be suitable for small units such as firetubes and package watertubes because of the significant incremental cost to the equipment and to its operation. In addition, many small units operate at continuously changing loads depending on plant steam demand. The variation in load will cause temperature fluctuations which degrade the performance of the process.

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SECTION 4

OPERATIONAL AND COST IMPACTS OF NO_x CONTROLS

The feasibility of combustion modifications for controlling nitrogen oxides emissions is in part dependent on the operational impact and the cost of those modifications. The effects which combustion modifications have on boiler operation, including energy consumption, and on incremental costs are evaluated in this section. Operational impacts are discussed in Section 4.1; incremental costs are dealt with in Section 4.2.

The assessment of these impacts is based on comparisons between baseline or normal operating conditions and those under low NO_x conditions. Unfortunately, due to the lack of detailed process and operating data for industrial boilers, extensive quantitative comparisons could not be performed. However, many of the potential adverse impacts identified for utility boiler modifications may also be of concern for industrial boilers. Thus much of the discussion here is qualitative, based on limited short term tests, and relies heavily on utility boiler experience.

4.1 OPERATIONAL IMPACT OF NO_x CONTROLS

The major factors to be considered in evaluating the operational impact of combustion modifications are boiler thermal efficiency, flame stability, boiler load, corrosion rate and slagging. These and other factors that reflect boiler operation can often be affected to some extent when combustion is altered for NO_x control. However, based on utility boiler experience, these potential operational impacts can be kept minimal with proper engineering and implementation.

The evaluation of the potential impact of combustion modification NO_x controls on corrosion rate and slagging of boiler tubes or air heaters often requires long term boiler testing. Since only short term tests were generally performed during recent field programs on industrial boilers, the information on corrosion and slagging is essentially non-existent. However, the time allotted for each field test generally allowed for an evaluation of operational impacts on efficiency, flame stability, boiler load and other potential short term impacts which were immediately evident to the field test crew. This present assessment will, thus, deal primarily with the short term operational impacts, including thermal efficiency, flame stability and boiler load, caused by combustion modifications for NO_x control.

This section is organized by control method. In Sections 4.1.1 through 4.1.7, each method discussed in Section 3 is evaluated for its effect on coal-, oil-, and gas-fired boilers. Because boiler tune-ups or minor burner changes do not affect NO_x emissions to any significant extent, operational impacts of these controls are not discussed here.

Table 4-1 summarizes the potential operational impact of each combustion modification technique. Each is discussed in turn in the following.

4.1.1 Low Excess Air (LEA)

Low excess air is the simplest of all NO_x control techniques, and one which also saves fuel as shown in Figure 4-1. Virtually all boilers tested show an increase of about 0.5 percent in efficiency for each 1 percent decrease in excess oxygen, although in a few isolated cases, LEA did not increase efficiency for natural-gas-fired units (References 4-2, 4-3, 4-4). Low excess air (LEA) operation also tends to reduce SO_3 formation, and thus may decrease corrosion in oil- and coal-fired boilers (References 4-1, 4-13).

The extent to which LEA can be used as a NO_x control technique is limited in all boilers by eventual increases in CO, HC, and smoke emissions as the excess air is lowered. The lower the excess air level, the greater the danger that fluctuations in load demand, fuel feed rates, air feed rates, fuel heating value, etc. can cause smoke emissions or incomplete combustion. Normal practice is to operate the boiler with an high excess air so that fluctuations do not cause the excess oxygen to decrease below the critical level that will cause operational problems. The installation of an oxygen trim system will usually allow operation at a lower excess air level (Reference 4-11). The oxygen trim system samples

TABLE 4-1. SUMMARY OF POTENTIAL OPERATIONAL IMPACTS OF NO_x CONTROLS ON INDUSTRIAL BOILERS

NO_x Control Technique	Potential Operational Impacts				Retrofit Equipment and Boiler Modifications which Alleviate Impacts
	Thermal and Overall Efficiency[a]	Flame and Combustion Stability	Boiler Heat Input Capacity	Corrosion and Fouling	
Low Excess Air (LEA)	Approximately 0.5% gain in thermal efficiency for 1% drop in excess O_2	Approximate limit of 3% excess O_2 for gas-firing boiler, 2% for oil-firing, and 4% for pulverized coal-firing before flame becomes unstable or incomplete combustion results with standard burner types	No effect	For stokers, limit of about 6% excess O_2 because grate can overheat, and corrosion potential, clinker formation can increase	O_2 trim system, windbox adjustments, new burner type
Staged Combustion Air (SCA)					
1. Burners out of Service (BOOS)	Small decrease in efficency (<1%)	None expected	Possible derate of up to 50% for coal-firing unless burners and fuel delivery system modified	Slagging, corrosion potential may increase for coal-fired boilers	Primarily retrofit control. O_2 trim system, windbox adjustments may need new burner tips and fuel delivery system changes
2. Sidefire Air (SFA) or Overfire Air (OFA)	Small decrease in efficiency (<1%), depends on air injection port location and fuel fired; additional fan power may be required	Approximate 90% lower limit on burner air stoichiometry	No effect	Slagging, corrosion potential may increase for coal-fired boilers. For stokers, possible grate overheat and clinker formation	O_2 trim system, windbox adjustments, and air injection ports. Several air port locations may be needed to accommodate fuel switching
Flue Gas Recirculation (FGR)	Tests showed up to 1% decrease, should be less on new unit; also force draft fan power use increases	Recirculation limit of about 45% for gas, 30% for oil, and 25% for coal before flame becomes unstable; gas-fired unit may require different burner type	Possible small derate	May increase corrosion potential	New duct work, windbox adjustment, probable larger FD fan, new burner air registers, gas flow controls

[a]LEA operation is recommended whenever possible to improve thermal efficiency.

TABLE 4-1. Concluded

No_x Control Technique	Potential Operational Impacts				Retrofit Equipment and Boiler Modifications which Alleviate Problems
	Thermal and Overall Efficiency[a]	Flame and Combustion Stability	Boiler Heat Input Capacity	Corrosion and Fouling	
Low NO_x Burners (LNB)	Probably no effect on thermal efficiency, one type of LNB may require more fan power use	Most LNB systems change flame shape and some allow lower than normal excess O_2 levels	No effect	Appears to be no effect	New burners, perhaps windbox and O_2 trim system
Reduced Air Preheat (RAP)	Large decrease in efficiency (>1%)	No problems expected. (RAP only recommended for distillate oil and gas fuels)	No effect	Appears to be no effect	Economizers should be used instead of air preheater if possible
Load Reduction	No effect unless excess air increased substantially	May require increased excess air to maintain stable flame	Reduced	Appears to be no effect	Viable technique only if steam plant has excess steam capacity
Ammonia Injection	Slight decrease in efficiency. (Increased energyconsumption ~0.25%)	No effect	No effect	Possible increased corrosion potential in economizer or air preheater when firing sulfur-containing fuels	Because of load changes could require several NH_3 injection ports

[a]LEA operation is recommended whenever possible to improve thermal efficiency.

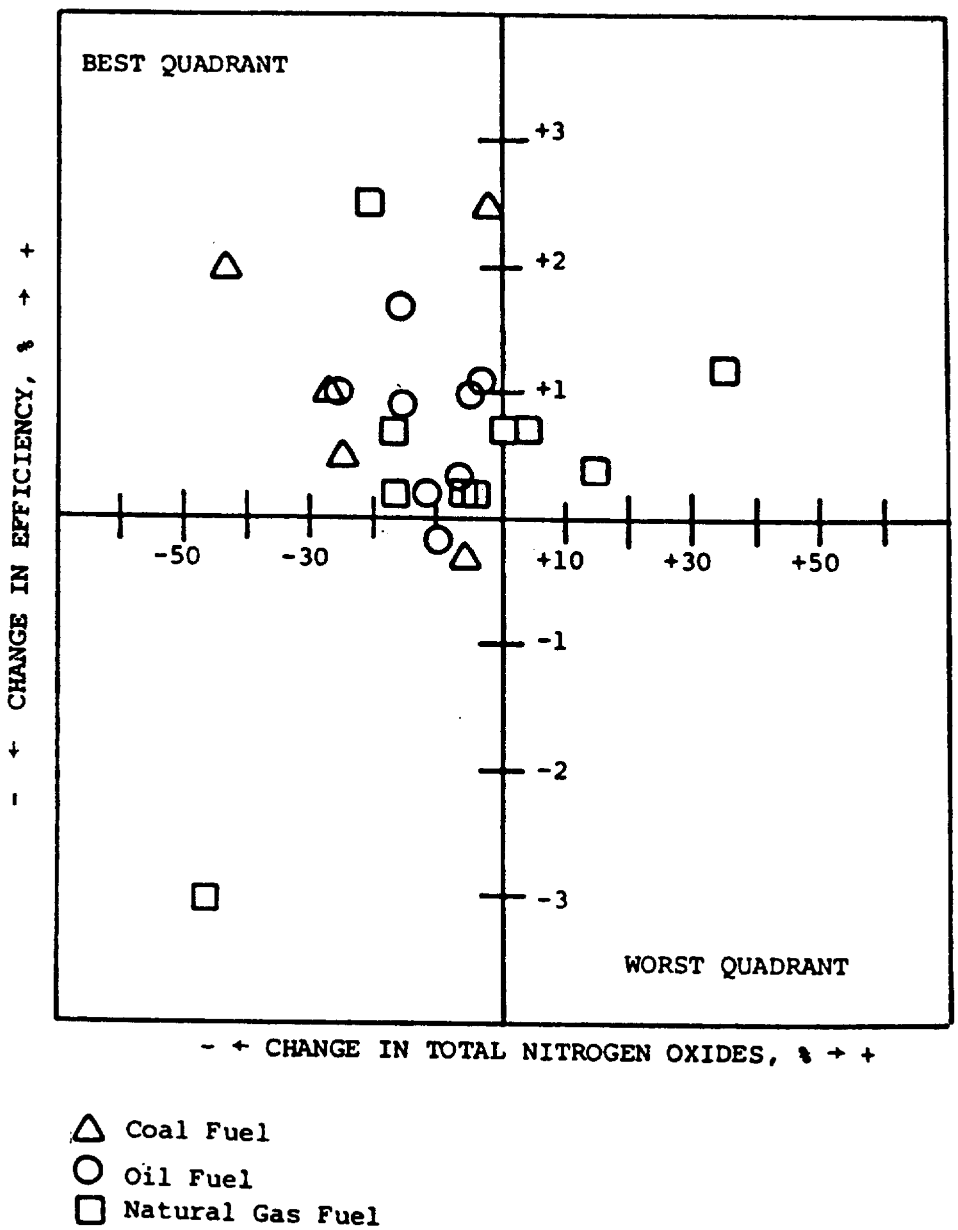


Figure 4-1. Effect of reducing the excess combustion air on boiler efficiency (References 4-3 and 4-19)

the oxygen level in the flue gas and then corrects the air flow rate. This is in addition to the normal air flow controllers. For boilers other than stokers, if the excess oxygen is decreased below a minimum level, combustion may be incomplete or the flame may become unstable. Thus, performance of the trim system becomes more critical.

When LEA is used on multiburner units, adjustments to the windbox may be required in addition to the installation of an O_2 trim system. Test data to date indicate that the lower limit for safety and ease of operation appears to be 4 percent excess oxygen for pulverized coal-fired, 3 percent for oil-fired, and 2 percent for gas-fired boilers. With stokers, there are some unique problems involved with low excess air operation. Except for stokers equipped with water-cooled vibrating grates, most stokers are cooled by the flow of air past the grate. If this air is cut back significantly in LEA operation, the grate can overheat. Even with water-cooled vibrating grates, it is uncertain whether stokers can operate at any lowered excess air for long periods of time (Reference 4-14). Along with the problem of overheating, recent stoker tests have shown excessive clinker formation as the air is cut back (References 4-6 and 4-43). Furthermore, there is a danger of increased corrosion caused by local reducing zones if the excess air is decreased too much. Because of these constraints, the safe lower excess oxygen level for stokers appears to be about 6 percent. However, this tentative conclusion is based on limited data from short term tests.

4.1.2 Staged Combustion Air (SCA)

The two techniques most often used to achieve staged combustion are burners out of service (BOOS), overfire air (OFA) or sidefire air (SFA). In packaged boilers, the secondary air usually must be injected from the side of the furnace (SFA). In coal-fired boilers, field erected boilers, and some packaged boilers, the secondary air is usually injected as overfire air. Burners out of service is used as a retrofit on multiburner boilers while OFA or SFA can be used as a retrofit or on new boilers. Both techniques may require an oxygen trim system such as that discussed for the LEA method.

4.1.2.1 Burners Out of Service (BOOS)

Because BOOS is limited to multiburner boilers, it is used only on the larger industrial boilers. With BOOS, some modifications must be made to the windbox to allow one or more burners to operate on air only. In some cases, a modification of the windbox may be required. For pulverized coal-fired industrial boilers, the fuel must be cut off to at least two burners in most cases, since one pulverizer usually feeds at least two burners (Reference 4-3). If the burners fed by the same pulverizer are on different levels, then the technique may not be effective. For oil- and gas-fired units, new flame scanners and detectors may become necessary to accommodate the hazy flames and obscure flame zones inherent with staged combustion.

For pulverized coal-fired units, the pulverizers supplying the active burners may not be able to handle the increased load. As a result, either increasing pulverized capacity (which is usually not practical) or derating of the boiler may be necessary. BOOS can also cause increased slagging and corrosion due to local reducing conditions. For oil- and gas-firing, BOOS may require the boiler to be derated unless the burners are retrofitted with new tips that allow the burners to handle more fuel flow.

As shown in Figure 4-2, from the small number of tests completed to date, BOOS operations by itself appears to have very little effect on thermal efficiency (References 4-2, 4-3, and 4-10).

4.1.2.2 Overfire (OFA) and Sidefire Air (SFA)

Besides BOOS, staged combustion may also be achieved by OFA or SFA. Use of secondary air ports does not require derating the boiler. For an existing boiler, it may, however, require a costly retrofit if there is not a convenient location for air injection ports. For new large multiburner units, adding OFA ports should not be difficult under normal circumstances. And for single burner units and stokers, OFA or SFA ports are the only way to achieve staged combustion. However, staged combustion methods for small packaged boilers are only in the development stage. The O_2 trim system for low excess air firing described in Section 4.1.1 can also be used with OFA or SFA ports to help offset possible boiler efficiency losses and reduce the need for boiler operator attention. Some modification to the windbox may also be required with staged combustion.

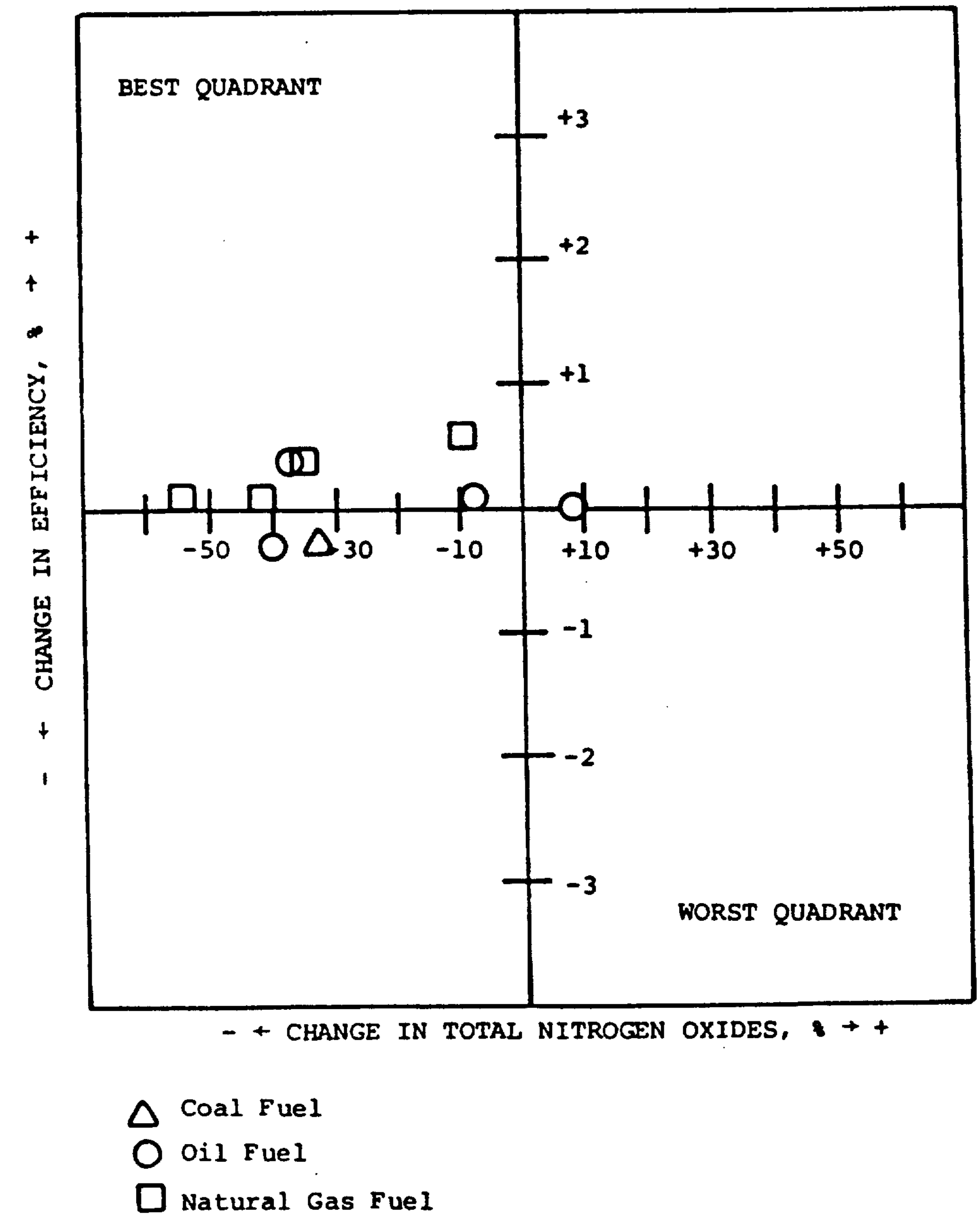


Figure 4-2. Effect of operating with burners out of service on boiler efficiency (References 4-3 and 4-19).

Operating a boiler with a fixed amount of OFA or SFA can lead to some of the same disadvantages experienced with LEA, except that smoke, CO, and HC emissions can be better controlled. In tests to date, the effect of OFA or SFA on efficiency has been mixed, ranging from a small gain to a 3 percent decrease. These changes in efficiency appear to be dependent on the location of the OFA or SFA ports and the particular boiler tested (Reference 4-3). It should be possible to locate these air ports at locations which minimize decreases in efficiency while maintaining low NO_x emissions. Because of the additional duct work required with OFA ports, more fan power may be needed. Utility boiler data show about 0.1 percent of boiler heat input was required to supply increased fan power use (Reference 4-1). This was in addition to about a 0.25 percent loss in overall boiler efficiency. Figure 4-3 summarizes changes in efficiencies for staged combustion operation in industrial boilers and illustrates the wide range of test results achieved so far. In practice, LEA operation is recommended with SCA operation when possible to increase thermal efficiency.

The following paragraphs review additional fuel-specific impacts of staged combustion using secondary air ports.

Coal-Fired Boilers

For pulverized coal-fired boilers, there is concern over potential increased corrosion and slag formation due to possible local reducing conditions with OFA operation (References 4-15 and 4-16). However, on utility boilers, OFA ports are commonly used with no major problems (Reference 4-1). Burner stoichiometrics in the range of 100 to 110 percent would be adequate to achieve a 20 percent NO_x reduction (Reference 4-44). At these stoichiometry levels oxidizing atmospheres would prevail in the furnace, thus minimizing concern over possible furnace slagging and boiler tube wastage. However greater NO_x reductions may require burner stoichiometries below 100 percent in some cases. These low burner stoichiometry levels would cause reducing atmospheres in parts of the furnace, thus creating the potential for corrosion in furnace tubes (Reference 4-1).

Most stoker-fired boilers have OFA ports as smoke control devices. As tests have shown (Reference 4-2), these ports are not necessarily in the best location for NO_x control; but proper relocation should not

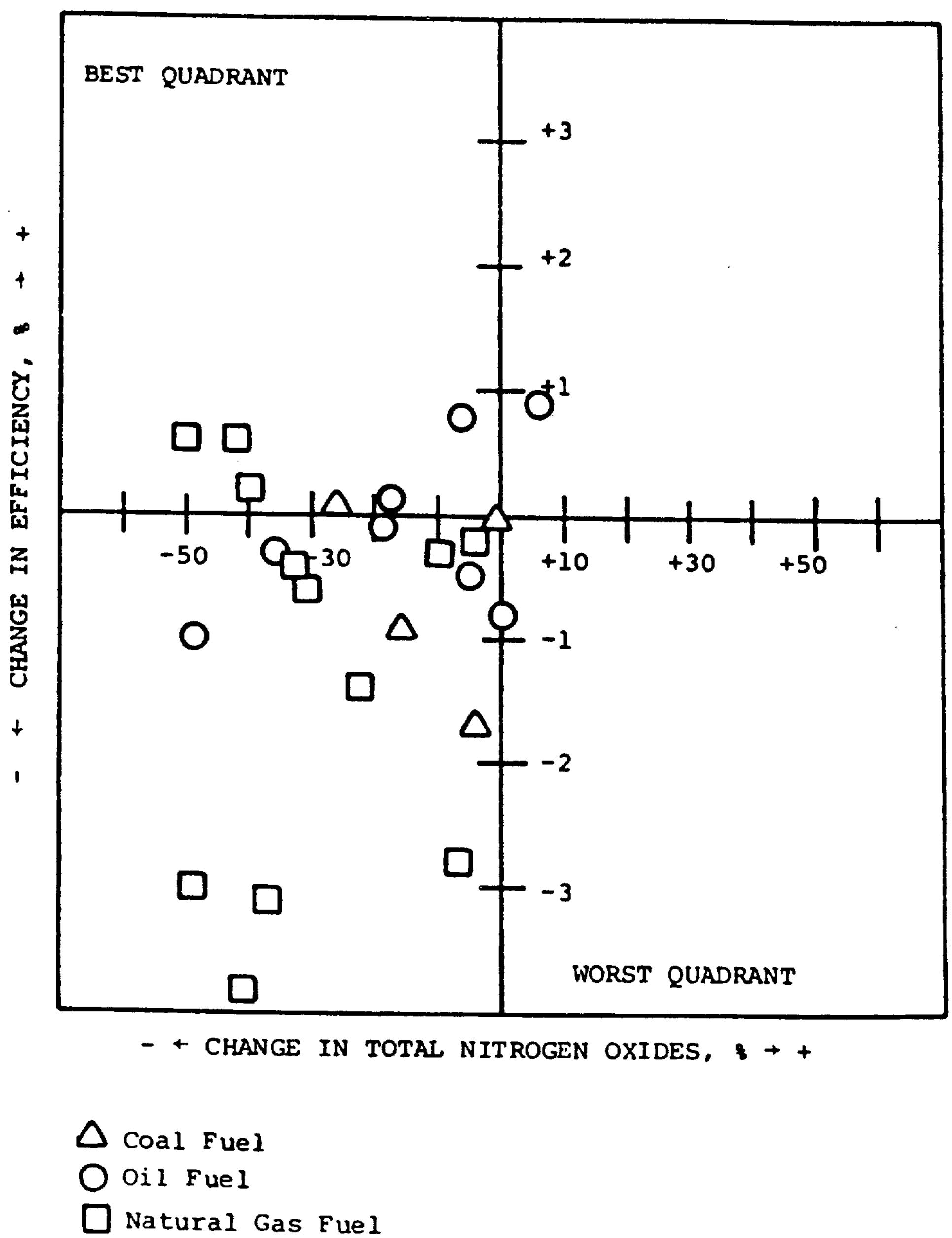


Figure 4-3. Effect of staged combustion air on boiler efficiency (References 4-3, 4-7 and 4-19).

cause any adverse operational impacts. Because undergrate air may be reduced with staged combustion in stokers, OFA has some of the same potential disadvantages as LEA. These disadvantages include the possibility of overheating the grate, increased corrosion, and clinker formation. Short of new stoker designs, these problems are best controlled by limiting the degree to which the undergrate air is reduced. Tests on stokers have shown that by carefully controlling excess air and overfired air, a 1 percent gain in efficiency can be achieved (Reference 4-6).

Results from the two stoker coal-fired boilers studied in this NO_x EA program with low excess air firing and increased OFA showed efficiency increases of about 2 percent. No_x emissions were reduced by 18 percent for one boiler with increased OFA while the other boiler achieved a 37 percent reduction with LEA, with no major adverse operational impact on either boiler. However, these were short-term tests of 5- to 6-hour duration (References 4-6 and 4-52). Details of the test program are summarized in Section 5.7.

Oil- and Gas-Fired Boilers

As in the case of BOOS operation, staged combustion with OFA or SFA can result in hazy flames and/or obscure flame zones when firing oil or gas, perhaps necessitating new flame detectors and scanners.

The firebox configuration of packaged oil- and gas-fired boilers often requires that sidefire air rather than overfire air be used to achieve staged combustion. The optimum location of the port(s) depends on both the burner type, fuel being fired and boiler load. Since packaged boilers may fire more than one type of fuel and with varying load, SFA ports in several locations may be required. In this case, sidefire air can be injected in different ports as fuels are switched. Using a single location for the SFA port is feasible when several fuels are to be fired -- but only at the sacrifice of achieving the lowest possible NO_x levels or highest boiler efficiency. But since some boiler users switch only infrequently, this may be a viable option for NO_x control.

In practice, the air to the burner(s) cannot, in general, be cut back lower than 90 percent of stoichiometric (References 4-7 through 4-10). Levels below this limit can result in flame stability problems.

The location of SFA ports can affect boiler efficiency. Tests on boilers retrofitted with SFA showed efficiency drops of 1 to 2 percent with SFA applied indiscriminately. However, a unit with SFA ports as original equipment showed essentially no loss in efficency indicating that with proper design and installation, it may be possible to use SFA on a new unit without losing efficiency (References 4-3, 4-6, 4-9 and 4-10).

4.1.3 Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) is a very effective technique for reducing NO_x emissions from combustion of clean fuels such as distillate oil and natural gas. As discussed in Section 3, NO_x reductions of 40 to 75 percent have been possible. For residual oil-firing, FGR is considered only moderately effective (15 to 30 percent) considering the extensive equipment modifications required. FGR has been shown to not be very effective for pulverized coal-firing (Reference 4-46), and has apparently not been attempted for stoker coal-fired boilers. In reviewing the literature, only one reference to possible application of FGR to stokers was found. In that instance, the researcher postulated that the stoker bed flame would be unstable under FGR operation because of low local O_2 levels (Reference 4-17). The following discussion of operational impacts of FGR is addressed primarily toward oil- and gas-firing.

Flame stability appears to be the biggest potential problem with FGR. Since FGR increases gas flow rate beyond the rate most conventional equipment is designed to handle, the windbox and/or burner may need to be modified. Retrofitting FGR on a conventional industrial boiler while retaining the original burner without modification may lead to flame stability problems at high rates of gas recirculation (References 4-7 and 4-10).

One manufacturer stated that modifying the burner register is usually sufficient to allow the boiler to handle the increased gas flow (Reference 4-18). However in one reported retrofit case, the burner had to be switched from a ring type natural gas burner to a gun type to maintain flame stability (Reference 4-7). This may have been an isolated incident. In one retrofit, there were vibration problems, but they were apparently due to system design rather than an inherent FGR limitation (Reference 4-7). FGR may also require a larger forced draft (FD) fan and can increase the power requirements of the fan. According to utility boiler data, an increase of 0.25 percent of boiler heat input could be required (Reference 4-1).

In tests run to date, FGR had only a small effect on boiler thermal efficiency. As shown in Figure 4-4, some tests showed as much as a 1 percent decrease. Most, however, were of the order 0 to 0.5 percent decrease. Also the limits to the amount of flue gas that can be recirculated imposed by flame instability were found to be 45 percent for gas-firing, 30 percent for oil-firing, and 25 percent for pulverized coal-firing (References 4-1, 4-3, 4-7, 4-10, 4-19). These maximum FGR rates correspond roughly to maximum NO_x reductions of 75 percent, 70 percent, and 20 percent, respectively.

In many FGR applications, additional flow controls may be needed to ensure that the oxygen level in the combustion air is adequate for complete combustion. Insufficient oxygen levels may be avoided by keeping the percent flue gas recirculated at a constant value and using an O_2 trim system to add additional control to the air flow. The oxygen trim system measures the O_2 after combustion, not the amount before combustion like a true combustion air sensor would.

Increased gas flows caused by FGR may also increase erosion in the boiler, especially for coal and residual oils due to entrainment of flyash particles (References 4-20 through 4-22). For FGR retrofits, available space for the extra ducting required could be a problem and potentially make retrofitting FGR very difficult.

4.1.4 Low NO_x Burners (LNB)

At present, low NO_x burners for industrial boilers are generally in the development stage; commercial application has been extremely limited. An EPA research program for the development of a coal-fired industrial LNB is well underway (Reference 4-46). Based on the performance of utility boiler low NO_x burners, no major adverse operational impacts are expected. The furnace may need to be enlarged to accommodate the expanded flame zone that is characteristic of low NO_x burners (Reference 4-1). Thus retrofit application of LNB's may not always be feasible.

Some forms of oil- and gas-fired low NO_x burner technology have been applied to a limited extent in Japan. In addition, commercial

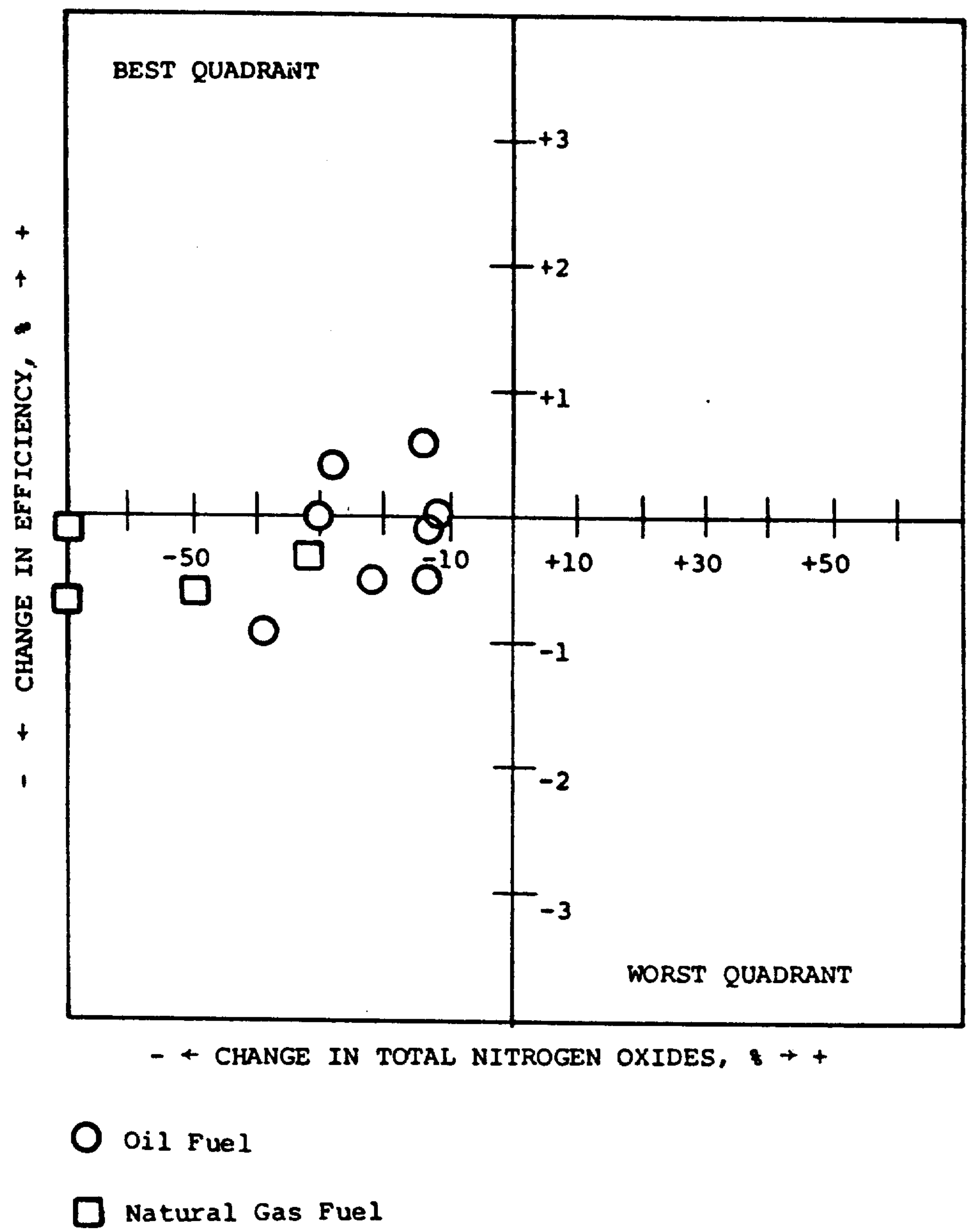


Figure 4-4. Effect of flue gas recirculation on boiler efficiency. (Reference 4-3, 4-7, 4-8, and 4-19)

application of a U.S. LNB system is imminent. As discussed in Section 3, recently released EPA 30-day field test results on a commercial gas-fired low burner system were quite promising, with 54 to 70 percent NO_x reductions and no significant adverse operational impacts (Reference 4-51). However, it is worth reviewing the more extensive Japanese experience with oil- and gas-fired LNB systems (References 4-23, 4-27, and 4-28). Unfortunately, well-documented performance data are not available. Furthermore, the applicability of the Japanese LNB systems to U.S. industrial boilers has not been established.

According to Japanese reports, the safety and stability of some available LNB systems are uncertain (References 4-23, 4-27, and 4-28). Some burners appear to have problems with flame flash back and blow out. However, these may be developmental problems for which a solution can be found. On retrofit units, data from Japan indicate a danger of flame impingement. This problem is due to the fact that some LNB's make use of an elongated flame for greater heat dissipation. This flame may impinge on the back wall of the boiler causing hot spots and possible tube failures. Japanese tests also seem to indicate that some LNB may require a change in the windbox on retrofit units.

The operating characteristics of various LNB appear to vary widely. The TRW/Civiltech burner gives a fatter flame, which may require increased burner spacing in a multiburner boiler to minimize flame interactions (References 4-23 through 4-26). The earlier TRW/Nippon burner required increased excess air. The Ishikawajimi-Harima Heavy Industries (IHI) burner requires changes only to the burner tips, but gives an increased pressure drop across the burner. This could require a larger FD fan (References 4-23, 4-27 and 4-29). Because of a precombustion zone, the Kawasaki Heavy Industries burner requires an insulated windbox (References 4-23 and 4-28).

Finally, low NO_x burners are not expected to have a significant impact on boiler thermal efficency in new unit installations. In fact some improvements in efficiency may be possible with use of lower excess air (Reference 4-24). However, retrofit LNB may entail some efficiency loss, based on utility boiler experience (Reference 4-1).

4.1.5 Reduced Air Preheat (RAP)

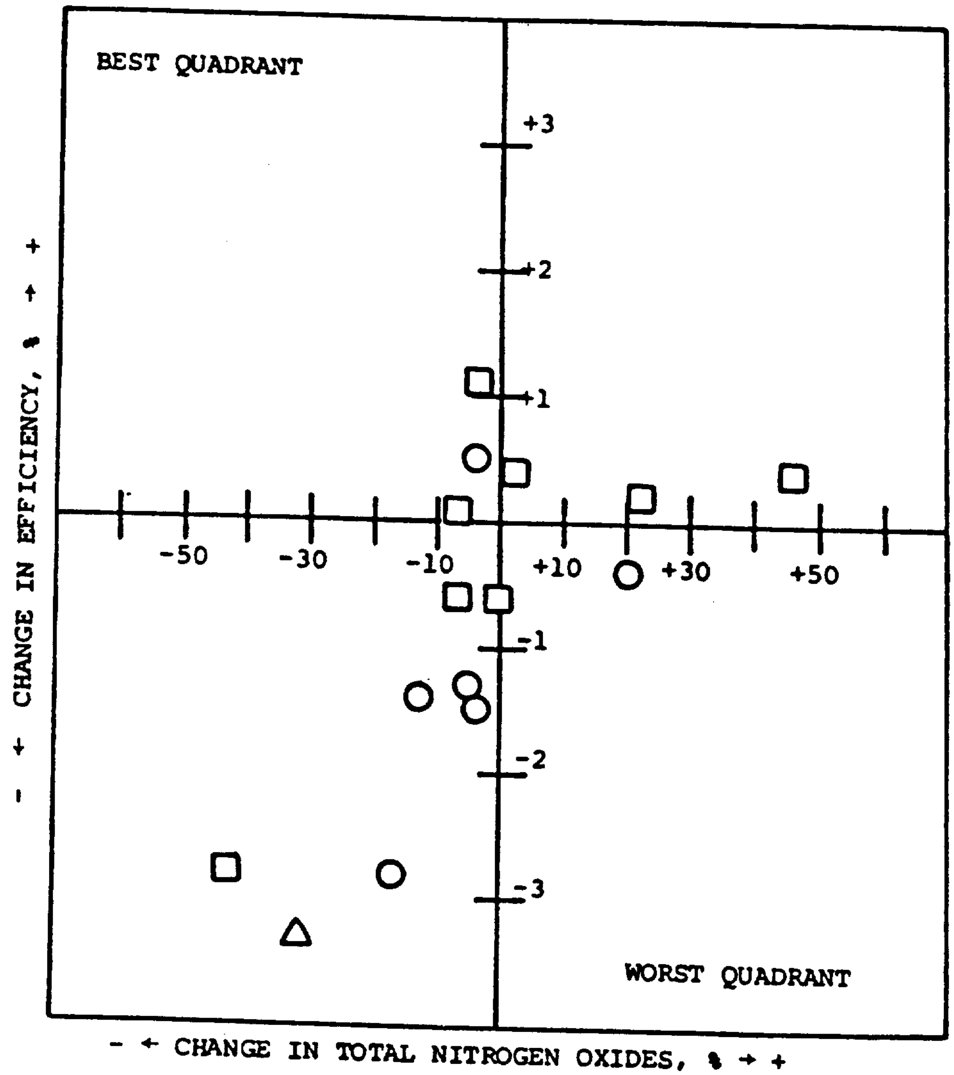
As discussed in Section 3, reducing combustion air preheat is a very effective means of lowering NO_x emissions from combustion of clean fuels, distillate oil and natural gas, by 20 to 55 percent (based primarily on gas data). In fact, industrial boilers not equipped with air preheaters were found to have average baseline NO_x emission levels approximately half of those from boilers with air preheaters, regardless of heat input capacity. Thus it would appear that RAP is an effective technique. However, RAP has been demonstrated to cause severe losses in overall boiler efficiency of up to 3 percent, as the representative data of Figure 4-5 indicate (References 4-2 through 4-4).

One possible solution to this problem is to enlarge the surface area of an existing economizer or installing an economizer instead of an air preheater as part of the design of a new boiler. Replacing the air heater with an economizer permits lower combustion air temperatures without a loss in efficiency (References 4-11, 4-12 and 4-38). Note however, that this may require extensive engineering design changes, even though there are boilers currently available that rely on an economizer rather than an air preheater to recover sensible heat from the flue gas (Reference 4-38).

Although air preheaters tend to cause less corrosion problems than economizers in boilers firing high-sulfur fuel, economizers are still generally preferred to preheaters (References 4-11 and 4-42). Economizers generally cost roughly the same as preheaters, and require less FD fan power because of lower pressure drop. However, a disadvantage economizers suffer is that they require larger installation areas.

4.1.6 Load Reduction

The applicability of load reduction as a NO_x control technique is limited to boilers utilized at steam plants with spare capacity. In addition, when the load is reduced beyond a certain point in most boilers, the excess air must be increased to prevent flame stability problems causing a loss in efficiency (References 4-2 through 4-4). Furthermore, the increased excess air may negate any potential NO_x reductions with reduced load. For new boilers, building larger fireboxes, thereby reducing combustion intensity, appears to be a way of achieving the effects of load reduction without a loss in efficiency.



△ Coal Fuel

○ Oil Fuel

□ Natural Gas Fuel

Figure 4-5. Effect of combustion air preheat temperature on boiler efficiency (References 4-3 and 4-19)

4.1.7 Ammonia Injection

There are several operational problems associated with ammonia injection on industrial boilers. First, smaller boilers may not have the available space for installation of the requisite injection ports. Since the effectiveness of the method depends largely on injecting the NH_3 at the proper flue gas temperature, fluctuating loads may require several different injection locations. Complex temperature and ammonia sensors and feedback control systems for the injectors may be required. Furthermore, with sulfur-containing fuels, the formation of ammonium sulfates can cause plugging of an air preheater or corrosion of boiler parts. In addition, if this technique is improperly used, unacceptable ammonia emission levels can be released to the atmosphere. Ammonia injection remains as a technology still under development. Full scale demonstrations of the technology, especially with flue gas environments from coal-firing, will be required to assess its many potential operation problems.

4.1.8 Summary of Operational Impacts

It should be emphasized that the potential operational impacts of NO_x controls on industrial boilers as discussed in the preceding subsections are based on limited data. Thus the concerns identified represent only potential concerns. Currently, application of NO_x controls to industrial boilers is very limited. In fact, many of the controls discussed here are still in the development stage or not demonstrated for a particular industrial size boiler category. There have apparently been few tests to determine the long term effects of combustion modification NO_x controls on boiler efficency, corrosion, maintenance, and other operational factors. However, based on utility boiler experience, preferred combustion modification NO_x controls should have no major adverse operational impacts, if these controls are properly designed and implemented. A possible exception is ammonia injection, which does not have any utility boiler experience to draw upon and may still require several more years of development before definitive conclusions can be made.

4.2 COST IMPACT OF NO_x CONTROLS

The effect of NO_x controls on the costs of owning and operating a boiler is of major concern to the industrial boiler user. In the evaluation of incremental cost of NO_x controls for industrial boilers, the cost of boiler systems with controls are compared to the costs of uncontrolled systems. Section 4.2.1 reviews the components that go into control costs, while Section 4.2.2 reviews the cost basis and assumptions.

4.2.1 Components of Control Costs

Nitrogen oxides control techniques can have two major cost components. First, the control methods will usually require additional hardware, increasing the cost of the boiler to the user. Second, the cost of producing steam will probably be increased due both to the increased capital charge to be annualized (referred to as annualized capital cost) and any changes in operating, maintenance, and energy costs (referred to collectively as annualized operating costs). The cost of producing steam will not always rise with addition of controls; for example, as will be shown later, low excess air operation can decrease the cost of steam in some cases.

The capital and operating costs of NO_x controls discussed here are engineering estimates based on limited published costs and discussions with equipment vendors. The largest component of operating costs is often increased energy consumption. These changes in energy consumption were discussed in Section 4.1 and estimated values are used in projecting the changes in steam cost due to NO_x controls.

Indeed, it has been found for NO_x controls for utility boilers that losses in boiler efficiency (increased fuel consumption) can add up to over half the cost-to-control (Reference 4-1). For example, a 0.25 percent loss in boiler efficiency with staged combustion can translate to one third of the control cost. Unfortunately, these changes in boiler efficiency with NO_x controls have not been precisely established for utility or industrial boilers. Therefore, although equipment and operating costs were investigated in as great detail as available data permit, the large unknown in energy costs should be noted when discussing control costs. In other words, a very small variation in boiler efficiency loss can lead to a very large fluctuation in control costs. In many cases, then, a detailed discussion of equipment cost estimates, etc. can become moot.

Since NO_x control techniques are not widely used on industrial boilers, very little is known about long term operation. Thus one area of concern is how NO_x controls affect day-to-day operation. Industrial boilers are operated with a minimal amount of operator attention and run under changing loads. Therefore the combustion modifications that are made for NO_x control may also require that the boiler control system (e.g., air and fuel flow controls) be modified. The cost of an additional boiler control system has been estimated and included in the presented prices, but without long term tests, a true modification cost cannot be given. Also, since the actual costs depend on site and use of boiler, only estimated prices for a typical boiler can be given.

4.2.2 Cost Basis

Table 4-2 summarizes the simplified cost basis used in evaluating NO_x controls. Capital costs represent the initial investment for the control: equipment and installation costs. On an annualized basis, the initial investment can be levelized into capital recovery charges and combined with taxes and insurance to comprise annualized capital charges. Annualized capital charges plus annual operating costs give the total cost to control per year.

TABLE 4-2. COST BASIS FOR EVALUATING NO_x CONTROLS

- Capital Costs (Initial Investment)
  - Equipment Costs
  - Installation Costs, Indirect
    - Engineering
    - Construction and Field Expense
    - Construction Fees
    - Start-up
    - Performance Test
  - Installation Costs, Direct
  - Contingencies
- Annualized
  - Capital Charges (Fixed Costs)
    - Capital Recovery
    - Taxes
    - Insurance
  - Operating Costs
    - Utilities
    - Raw Materials
    - Operating Labor
    - Maintenenace
    - Fuel Costs

Since experience with industrial boiler NO_x controls is very limited, a detailed breakdown of the costs into the various capital and operational cost components as illustrated in Table 4-2 was not always possible. The analysis relied heavily on estimates from equipment vendors and published data from utility boiler experience. Where information was lacking, engineering estimation rules as outlined in Reference 4-31 were used. Costs were collected from various sources and extrapolated to the boiler size under consideration. Using engineering judgment, a typical cost was estimated from these extrapolated values.

Following EPA guidelines for new technologies (Reference 4-48), the reliability of the cost estimate presented here is estimated to be no better than plus or minus 30 percent except for ammonia injection and low NO_x burners. Since these last two techniques represent untried technology, the reliability of their costs is estimated to be plus or minus 100 percent.

In calculating the costs of control systems, several assumptions were made. The annualized capital charges were taken to be 20 percent of the total installed cost of the combustion modification, and the annualized operating labor and maintenance costs were taken to be 5 percent of the total installed cost. The 20 percent includes 4 percent for general and administrative expenses, taxes, and insurance and a capital recovery factor of 16 percent. The utility industry typically uses 5 percent annualized operating labor and maintenance cost for NO_x combustion modification techniques for utility boilers (Reference 4-49). Since there is no long term operating experience with combustion modifications for industrial boilers, it was decided to use 5 percent as a first estimate.

An industrial boiler is assumed to be 82 percent efficient without an air preheater or economizer and 84 percent efficient with one except for a pulverized coal-fired boiler, which is assumed to be 87 percent efficient (References 4-4 and 4-51). To generate one kilogram of steam requires 2.56 MJ (1100 Btu/lb of steam) of heat. The load factors and fuel costs given by Devitt, et al. (Reference 4-31) were used in the cost analysis. Devitt reported average load factors of 45 percent for boilers smaller than 7000 kg steam/hr (15,000 lb steam/hr) and 60 percent for the larger sizes. The fuel prices used are \$2.84/GJ for No. 2 oil, \$2.65/GJ for No. 6 oil (\$2.21/GJ for the fuel itself plus a 20 percent charge for heating the fuel when firing and keeping the storage tank warm), \$1.85/GJ for natural gas, and \$1.10/GJ for low sulfur coal. The fuel prices, as well as all other costs presented here, are in 1978 dollars.

In the following discussion, costs to modify the boiler are given as a percentage of the boiler's installed cost, while the steam costs include the entire steam plant. The total steam plant costs more than that of the boiler alone because it includes additional equipment such as the smoke stack and water treatment system. The boiler and steam production costs used are from a report by Devitt presented to the EPA-OAQPS (Reference 4-31). Except for adding an O_2 trim system and ammonia injection, retrofit costs were assumed to be twice that of installing NO_x controls on a new unit as was found by one author for a small industrial boiler (Reference 4-10). It should be reiterated that the control costs presented in this section, as well as achievable NO_x control levels, are based on very limited data.

The cost data will be presented in tables in which the capital and annualized incremental costs and cost effectiveness of NO_x controls will be summarized. The costs are incremented from the costs of the basic uncontrolled systems. In the tables, the annualized incremental costs were calculated by the following formulas (units of mills/10^3 kg steam).

Total Annual Cost = Annualized Fixed Costs Plus Operating Cost

Annualized Fixed Costs =

$$\frac{\text{(Total Installed Cost of Control)(0.2)(1000)}}{\text{(Hours/yr) (Load Factor) (Boiler Capacity, } 10^3 \text{ kg steam/hr}}$$

Operating Cost = Fuel + Raw Materials + Utilities + Operating Labor + Maintenance

$$\text{where Fuel Cost} = \frac{\text{(Thermal Efficiency Change)(GJ/}10^3\text{kg steam)(mills/GJ)}}{\text{(Boiler Efficiency)}}$$

$$\text{Utilities Costs} = \frac{\text{(Fan Efficiency Loss)(Boiler Heat Input)(26 mills/kwh)}}{\text{(0.65) (Boiler Capacity, } 10^3 \text{ kg steam/hr}}$$

and Operating Labor and Maintenance Cost =

$$\frac{\text{(Total Installed Cost of Control)(0.05)(1000)}}{\text{(Hours/yr)(Load Factor)(Boiler Capacity, } 10^3 \text{ kg steam/hr}}$$

Overhead charges have already been incorporated into the labor and maintenance costs. Thermal efficiency and fan power changes are discussed later in this section. The cost effectiveness of a NO_x control technique is calculated by the following formula:

$$\text{Cost effectiveness} = \frac{\text{(Total Annualized Cost)(Boiler Capacity, } 10^3\text{kg steam/hr)}}{\text{(Heat Input)(Emission Change)}}$$

where Emission Change = Baseline NO_x level - NO_x Control Level

Thus cost effectiveness has units of \$/kg NO_x reduced.

The control cost estimates will be listed by control technique for each of seven representative boilers. The boiler/control options that were not deemed effective in Section 3 are not treated here. Table 4-3 lists the representative industrial boilers and their respective average baseline NO_x emission levels. The representative boilers are based on a survey performed by Devitt for EPA (Reference 4-31).

4.2.3 Low Excess Air (LEA)

Low excess air operation may require an oxygen trim system. Recall from Section 4.1.1 that this is a refinement to the normal air flow control system to allow unattended operation at lower than normal excess air levels. Several manufacturers and publications have listed prices for installing an oxygen trim system (References 4-11, 4-33 through 4-35). Assuming a 1 percent gain in thermal efficiency for LEA operation, except for distillate oil and natural gas where a 0.5 percent gain is assumed, the incremental cost of steam has been calculated and listed in Table 4-4. The capital cost for retrofitting this control could be 50 percent higher. The actual cost is very dependent on the particular boiler being modified. It will be noted that addition of an LEA system could significantly (10 percent) increase the initial cost of a new small packaged boiler.

TABLE 4-3. REPRESENTATIVE INDUSTRIAL BOILERS AND BASELINE NO_x EMISSION LEVELS FOR COST ANALYSIS

Fuel	Boiler Type	Typical Size (Heat Input Capacity) MW (10^6 Btu/hr)	Average NO_x Baseline Emission Level ng NO_2/J (lb/10^6 Btu)
Pulverized Coal	Single Wall and Tangential	59 (200)	285 (0.663)
Stoker Coal	Spreader	44 (150)	265 (0.616)
	Underfeed	9 (30)	150 (0.349)
	Chain Grate	22 (74)	140 (0.326)
Residual Oil[a]	Firetube	4.4 (15)	115 (0.267)
	Watertube	44 (150)	160 (0.372)
Distillate Oil	Firetube	4.4 (15)	70 (0.163)
	Watertube		
	Without air preheater	29 (100)	55 (0.128)
	With air preheater		90 (0.208)
Natural Gas	Firetube	4.4 (15)	40 (0.093)
	Watertube		
	Without air preheater	29 (100)	45 (0.105)
	With air preheater		110 (0.255)

[a]Includes No. 5 and No. 6 fuel oils

Table 4-4 shows that in most cases, LEA operation will have a beneficial effect on steam costs. Steam price is not lowered for the firetube boiler because there is only a small base to spread the fixed costs over. In all cases, it may be possible to gain increases in thermal efficiency greater than 1 percent if the excess air can be lowered even more than assumed. This would further lessen the economic impact of LEA operation.

4.2.4 Staged Combustion Air (SCA)

Staged combustion air operation, whether with overfire air (OFA) or sidefire air (SFA), will probably need an oxygen trim system as was required for LEA operation. Stokers normally have OFA ports as smoke control devices and thus there is no additional charge for installing these ports on stokers. Future tests might show that the standard port loctions on stokers are not optimal for NO_x control. Relocation of these ports or installation of additional air ports specifically designed for NO_x control would then increase the price of a stoker coal-fired boiler. For the other boiler types, it is also assumed that only one row of air injection ports are needed.

Table 4-5 lists the estimated cost impact of SCA operation. These costs were calculated assuming a 0.5 percent decrease in thermal efficiency except for stokers where no change in thermal efficiency was assumed and pulverized coal units where a 0.25 percent decrease is used. It is also assumed that fan power use increases by a value equal to 0.1 percent of boiler heat input. The capital costs listed are engineering estimates based on vendor estimates and published quotes (References 4-10, 4-33, 4-36). The capital cost for retrofitting would be about twice that for incorporating the control in a new unit design (Reference 4-10). The actual cost of retrofitting SCA will be dependent on the particular boiler being modified.

From the cost calculations, it appears that SCA has a greater effect on the smaller capacity boilers. This is because as a percent of boiler cost, the incremental capital charge is larger for the smaller boilers. Recall from Section 4.1.2 that the actual effect on thermal efficiency is both dependent on the air port location and the fuel being fired. Thus, it is probably possible to design and operate the boiler so

TABLE 4-4. ESTIMATED COST OF LOW EXCESS AIR OPERATION FOR NEW BOILERS

Type	Heat Input MW (10^6 Btu/hr)	Percent NO_x Reduction	Capital Cost 1000 $	Annualized Costs			Percent Change in Cost Of	
				Fixed	Operating	Total	Boiler	Steam
				mills/ 10^3 kg steam	mills/ 10^3 kg steam	mills/ 10^3 kg steam		
Pulverized Coal	59 (200)	15	27	13 (6)[a]	-28 (-13)	-15 (-7)	0.4	-0.1
Spreader Stoker	44 (150)	15	22	16 (7)	-31 (-14)	-15 (-7)	0.5	-0.1
Chain Grate Stoker	22 (75)	15	17	26 (12)	-28 (-13)	-2 (-1)	1.2	0
Underfeed Stoker	9 (30)	15	14	54 (24)	-23 (-10)	21 (14)	1.5	0.1
Residual Oil Watertube	44 (150)	20	17	12 (5)	-75 (-34)	-63 (-29)	1.9	-0.5
Residual Oil Firetube	4.4 (15)	15	9	91 (41)	-59 (-27)	32 (14)	9.0	0.1
Distillate Oil Watertube	29 (100)	10	14	16 (7)	-41 (-19)	-25 (-11)	3.4	-0.2
Distillate Oil Firetube	4.4 (15)	10	9	91 (41)	-26 (-12)	65 (29)	9.0	0.2
Natural Gas Watertube	29 (100)	5	14	16 (7)	-25 (-11)	-9 (-4)	4.0	-0.2
Natural Gas Firetube	4.4 (15)	5	9	91 (41)	-11 (-5)	80 (36)	9.0	0.3

[a]Numbers in parentheses are in units of mills/10^3 lb stream

TABLE 4-5. ESTIMATED COST OF STAGED COMBUSTION OPERATION FOR NEW BOILERS

Type	Heat Input MW (10^6 Btu/hr)	Percent NO_x Reduction	Capital Cost 1000 $	Annualized Costs			Percent Change in Cost Of	
				Fixed	Operating	Total	Boiler	Steam
				mills/ 10^3 kg steam	mills/ 10^3 kg steam	mills/ 10^3 kg steam		
Pulverized Coal	59 (200)	25	47	24 (11)[a]	47 (21)	71 (32)	0.8	0.6
Spreader Stoker	44 (150)	20	22	16 (7)	4 (2)	20 (9)	0.5	0.1
Chain Grate Stoker	22 (75)	15	17	26 (12)	6 (3)	32 (15)	1.2	0.2
Underfeed Stoker	9 (30)	15	14	54 (24)	12 (5)	66 (29)	1.5	0.3
Residual Oil Watertube	44 (150)	35	32	23 (10)	80 (36)	103 (46)	5.5	1.2
Residual Oil Firetube	4.4 (15)	25	19	193 (88)	117 (53)	310 (141)	21.0	1.2
Distillate Oil Watertube	29 (100)	30	26	29 (13)	84 (38)	113 (51)	7.0	1.2
Natural Gas Watertube	29 (100)	30	27	29 (13)	69 (31)	98 (44)	7.0	1.5

[a]Numbers in parentheses are in units of mills/10^3 lb stream

that the thermal efficiency is better than that assumed in calculating the cost. This would lessen the economic impact of NO_x control by staged combustion.

4.2.5 Flue Gas Recirculation (FGR)

Flue gas recirculation will require the duct work needed for recirculating a portion of the flue gas back from the stack to the burner. In addition, a force draft fan, windbox modifications, and burner changes may be required because of the increased gas flow through the boiler. For ease of operation, a combustion gas analyzer and control system is recommended but an oxygen trim system with a fixed flue gas reciruclation ratio may be sufficient.

Table 4-6 lists the estimated incremental costs for FGR for distillate oil-fired and natural gas-fired boilers. The values listed were calculated assuming a 0.5 percent decrease in thermal efficiency and a 0.25 percent boiler heat input fan power usage increase. The capital costs of FGR listed are engineering estimates based on one published report and one manufacturer's estimate (References 4-10 and 4-37). Because of locating the extra duct work, the force draft fan and modifications to the windbox and burners, the retrofit cost will be very site dependent. On an average retrofit, FGR is expected to cost about twice that for new boilers, according to Heap (Reference 4-10).

The effect on steam price caused by using FGR can be high with estimated increases in steam costs ranging from 1.4 to 5 percent. It may be possible to design the boiler so that the loss in thermal efficiency is less than the 0.5 percent which was assumed in the calculations, resulting in a smaller increase in steam price. It may even be possible to operate under LEA conditions and gain an increase in thermal efficiency.

One problem with using FGR on natural gas/oil boilers is that oil firing may be limited to distillate oil when natural gas is unavailable. Flue gas recirculation is a much more effective NO_x control technique for distillate oil than residual oil firing. This could force the boiler user to fire the more expensive distillate oil when natural gas is not available and stringent NO_x regulations must be met.

4.2.6 Low NO_x Burners (LNB)

Since low NO_x burners are still in the developmental stage, costs are not yet firmly established. For new boilers, incremental capital

TABLE 4-6. ESTIMATED COST OF FLUE GAS RECIRCULATION OPERATION FOR NEW BOILERS

Type	Heat Input MW (10^6 Btu/hr)	Percent NO_x Reduction	Capital Cost 1000 $	Annualized Costs			Percent Change in Cost Of	
				Fixed	Operating	Total	Boiler	Steam
				mills/ 10^3 kg steam	mills/ 10^3 kg steam	mills/ 10^3 kg steam		
Distillate Oil Watertube	29 (100)	40	26	29 (13)[a]	135 (61)	164 (74)	7.0	1.7
Distillate Oil Firetube	4.4 (15)	40	19	192 (87)	175 (80)	367 (167)	21.0	1.2
Natural Gas Watertube	29 (100)	40	26	29 (13)	120 (54)	150 (67)	7.0	2.4
Natural Gas Firetube	4.4 (15)	40	19	192 (87)	159 (72)	351 (159)	21.0	1.7

[a]Numbers in parentheses are in units of mills/10^3 lb stream

costs would be affected by the difference in price between a low NO_x burner and a standard burner plus the cost of an oxygen trim system if needed. A different and perhaps more costly windbox may also be needed. One cost estimate for coal-fired low NO_x burners for utility boiler application was reported to be about that for conventional coal burners (References 4-1 and 4-37). Most low NO_x burners should allow LEA operation which would keep the economic impact of LNB to a minimum. Thus, it seems likely that LNB operation will cost no more than SCA operation and, in fact, may have an even smaller effect on steam price than SCA. With LEA operation, LNB will probably be more efficient than SCA operation and the additional capital costs required by LNB is expected to be no more than for SCA operation.

4.2.7 Reduce Air Preheat (RAP)

Reduced air preheat is a very effective NO_x control technique for distillate oil- and natural gas-fired boilers. However lowering combustion air preheat without recovering the sensible heat loss can result in boiler efficiency losses of up to 3 percent, raising steam costs by as much as 2 percent in some cases. Hence RAP is not an attractive option unless an economizer is designed in place of an air preheater on a new boiler. In the latter case, there should be no significant economic impact, on either initial boiler cost or steam production costs (References 4-11, 4-12, and 4-38). However, replacement of an air heater with an economizer is not attractive on an existing unit because of the associated extensive design and engineering changes required.

4.2.8 Load Reduction

There is no economic impact when using load reduction unless the lost steam capacity must be replaced. Purchasing a new boiler to compensate for this loss would be prohibitively expensive. In addition, if the boiler load is reduced to the point where the excess air must be increased to maintain a stable flame, the thermal efficiency will be reduced. In that case, the price of steam would rise. Furthermore, the additional excess air may actually increase NO_x emissions.

At alternative method for load reduction is to increase the size of the firebox design in a new boiler. Obviously, this would entail extensive engineering efforts and increased materials and construction costs. The concept of an enlarged firebox is only in the development stage for industrial boilers.

4.2.9 Ammonia Injection (Thermal $DeNO_x$)

Ammonia injection is not a demonstrated technology and the effect of a fluctuating load on the effectiveness of this technique is not fully understood. Several ammonia injection ports and controls to switch between ports as the temperature changes will probably be required. Recall from Section 4.1.7 that the reduction of NO_x by NH_3 is only effective over a narrow temperature "window." The amount of NH_3 injected will also need to be varied as the load changes because the total amount of NO_x present in the combustion gases will be changing. This will require a complex system of temperature probes, NO_x and NH_3 sensors, and NH_3 injection port controllers.

Only a few sources give cost data for the ammonia injection control technique and they are for utility boilers (References 4-39 through 4-41). Extrapolating down to an industrial size boiler, the capital cost for installing ammonia injection on a 59 MW input (200×10^6 Btu/hr) pulverized coal boiler is estimated to be about $236,000, about a 4 percent increase over the cost of an uncontrolled boiler. The incremental steam cost is estimated to be 220 mills/10^3 kg steam (100 mills/10^3 lb steam) or a 2.5 percent increase in steam price. Because of the large error in extrapolating from an utility size boiler down to an industrial size boiler, the above price estimates have very large uncertainties.

Of the NO_x control techniques investigated, NH_3 injection is the most expensive, due mainly to the cost of ammonia and the associated ammonia handling and injection system. If load fluctuations and fuel sulfur problems do not make the technique impractical (see Section 4.1.7), NH_3 injection could be technically feasible. However, it will cause a large increase in steam price and thus would only be recommended where very strict NO_x regulations must be met. Ammonia injection itself should have very little impact on the boiler thermal efficiency.

4.2.10 Summary of Cost Impacts

As is the case of operational impacts of NO_x controls on industrial boilers, the cost impacts discussed here are based on very limited data. NO_x controls are not in active use on industrial boilers, and many of the techniques represent undemonstrated technology for that boiler size category.

However, some tentative conclusions can be made. A review of the data in the previous sections and Table 4-7 will show that larger absolute NO_x reductions are achieved at lower cost with pulverized coal-fired boilers than with other fuels. (Notice that the costs cited in Table 4-7 are those incurred just to achieve the listed control level. Further application of the control technique could result in lower NO_x levels at a lower cost effectiveness.) There are two principal reasons for this: (1) The pulverized coal-fired boilers tend to have higher baseline NO_x emission levels and hence a given percentage reduction results in a higher absolute NO_x reduction and (2) these boilers have a larger base (heat input or steam output capacity) over which to spread the cost of the control. As expected, for all fuels, lower NO_x emissions require greater control cost, with the exception of low excess air.

Specific comments on the cost impact of control options follow:

- Low excess air operation, in many cases, will actually lower steam costs due to the increase in thermal efficiency. In general, LEA operation is recommended for use with other control techniques to lessen their cost impact and to give higher NO_x reductions.
- Staged combustion causes an estimated small decrease in steam cost but with careful design and operation, this estimated cost can probably be reduced.
- Flue gas recirculation, though costly, is the most effective for the clean fuels, distillate oil and natural gas. Again, optimal design and operation will probably lower the cost.
- Low NO_x burners hold the promise of being the most cost-effective technique. However, they are still under development.
- Economizers are recommended for those boilers where either an air preheater or economizer may be installed.
- Ammonia injection appears to be a viable option only in those cases where very stringent NO_x emission standards must be met. Its high cost makes it a candidate control to be added

TABLE 4-7. COST-EFFECTIVENESS OF NO_x CONTROLS

Type	Control Level ng/J ($lb/10^6$ Btu)	Control Technique	Control Cost mills/ 10^3 kg Steam	Cost Effectiveness \$/kg NO_x Reduced
Pulverized Coal	285 (0.663)	Baseline	--	--
	258 (0.6)	LEA	0	0
	215 (0.5)	OFA	70	0.3
	172 (0.4)	OFA + LNB	~140	~0.4
	129 (0.3)	OFA + NH_3 injection	~275	~0.5
Spreader Stoker	265 (0.616)	Baseline	--	--
	215 (0.5)	OFA	20	0.1
	129 (0.3)	NH_3 injection	~220	~0.5
Residual Oil Watertube	160 (0.372)	Baseline	--	--
	129 (0.3)	LEA	-60	-0.6
	86 (0.2)	LNB	~170	~0.7
Distillate Oil Firetube	70 (0.163)	Baseline	--	--
	65 (0.15)	LEA	65	0.2
	43 (0.1)	FGR	367	1.2
Natural Gas Firetube	40 (0.093)	Baseline	--	--
	24 (0.06)	FGR	350	2.0

after conventional combustion modifications have been applied. Besides, developmental problems need to be solved.

In summary, based on preliminary cost projections, combustion modification NO_x controls, once proven and demonstrated, should be a cost effective means of control for industrial boilers, raising steam costs up to only 1 or 2 percent in most cases. However, the initial investment required may be a large fraction of the cost of the boiler itself, up to 21 percent when controls are installed as part of a new boiler, and up to 40 percent when retrofitting controls on an existing boiler.

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SECTION 5

ENVIRONMENTAL IMPACT OF NO_x CONTROLS

Modification of the combustion process for NO_x control can alter the emission rates of other pollutants. These changes, referred to as incremental emissions, could potentially lead to adverse environmental effects. Therefore, a key consideration of all NO_x control development programs must be the effects on emission levels of the criteria pollutants: carbon monoxide (CO), unburned hydrocarbons (UHC), particulate, and sulfur oxides (SO_x), and the SO_2/SO_3 ratio. Also of concern in recent control development programs are the noncriteria pollutants, trace metals and polynuclear aromatic hydrocarbons.

This section presents the expected effect of combustion modification NO_x controls on the criteria and noncriteria pollutants. These postulations are further supported by a review of the possible formation mechanisms for each pollutant. However, data are insufficient to completely describe the effect of the NO_x control and the resulting incremental emissions. The data that are available are presented as a function of boiler and fuel type.

Finally, as a step toward quantifying how low NO_x firing affects the environmental impact of a combustion source, a Source Analysis Model, SAM IA, was applied to the results from the two industrial coal-fired stokers tested under this NO_x EA program.

5.1 IDENTIFICATION OF THE MAJOR ENVIRONMENTAL CONCERNS

The alternative NO_x control systems for the major boiler/fuel categories were discussed in Section 3. Table 5-1 presents the potential effect each modification will have on incremental emissions. A review of Table 5-1 shows that:

- Increased CO and vapor phase hydrocarbon emissions are of major concern only when excess air levels are lowered

TABLE 5-1. POSTULATED EFFECT OF COMBUSTION MODIFICATIONS ON INCREMENTAL EMISSIONS FROM INDUSTRIAL BOILERS.

Combustion Modification	Resulting Combustion Conditions	CO	Vapor Phase HC	Sulfate	Organics
Low excess air	Reduced local O_2 concentration; decreased gas velocities; increased furnace residence time	Increased	Increased	Decreased overall because of lowered O_2 availability	Possibly increased
Staged combustion	Reduced local O_2 concentration; reduced peak flame temperature; increased convection zone temperature; delayed flame zone mixing	Possibly increased	Possibly increased	Possibly decreased because of decreased convection zone catalysis (less volatile metal redistribution)	Possibly increased
Flue gas recirculation	Reduced local O_2 concentration; reduced peak flame temperature; reduced furnace residence time; increased gas velocities; more turbulent flame; increased convective zone temperature	Possibly increased	Possibly increased	Possibly decreased	Possibly increased
Reduced air preheat	Reduced peak flame temperature; decreased gas velocities; increased furnace residence times; increased local O_2 concentration	No effect	No effect	Possibly decreased	Possibly increased
Ammonia injection	Increased local NH_3 concentration	No effect	No effect	Possibly increased through near plume solution catalysis	Decreased with decreased particle emissions; no effect otherwise
Low NO_x burners	Delayed fuel-air mixing; off-stoichiometric combustion	Possibly increased	Possibly increased	Possibly decreased because of less potential for SO_2 oxidation	Possibly increased due to greater carbonaceous particle formation

TABLE 5-1. (Concluded)

Combustion Modification	Particulate		Trace Metals	
	Size Distribution	Mass Emissions	Segregating	Nonsegregating
Low excess air	Possible trend to larger sizes	Possibly decreased because of increased bottom and ash fallout and internal deposition	Unknown effect: possible increase due to increased volatility but possible decrease with internal deposition	Possibly reduced because of reduced mineral particle emissions and internal particle deposition
Staged combustion	Possible trend to larger sizes	Unknown effect: possible increase due to soot formation; possible decrease due to larger particles and convection zone depositon and slagging	Possibly decreased because of decreased repartitioning to small particles	Possibly reduced due to larger particles (more carbon) and convection zone slagging
Flue gas recirculation	Probably no effect	Possibly increased due to increased velocities and possibility of soot formation	Possibly decreased because of decreased repartitioning to small particles	Possibly increased with increased particle emissions
Reduced air preheat	Probably no effect	Possibly increased due to less bottom slagging	Possibly reduced because of less concentration in small particles	Possibly increased with increased particle emissions
Reduced load	Probably no effect	Probably no net effect	Possibly reduced because of less concentration in small particles	Probably no effect
Ammonia injection	Trend to smaller particles (NH_4HSO_4 aerosol)	Possibly decreased with ESPs because of conditioning; increased otherwise	Possibly increased because larger fraction of small particles	Decreased with decreased particle emissions; no effect otherwise
Low NO_x burners	Trend to larger particles	Possibly increased because of greater soot formation	Possibly decreased because of overall trend to larger particles more easily controlled	Possibly decreased because larger particles more easily controlled

- Sulfate emission levels are expected to decrease or remain unchanged with all controls except staged combustion and ammonia injection (which alters the form of SO_3 to NH_3HSO_4)
- Changes in emitted particle size distribution are expected only when operating with low excess air, staged combustion or low NO_x burners. In these instances the production of larger particles is expected.
- Increased particulate mass emissions are of potential concern when flue gas recirculation, staged combustion, or low NO_x burners are used
- Condensible organic emissions are likely to increase with all combustion NO_x controls except ammonia injection
- Decreased segregating trace metal emissions are possible when using staged combustion, flue gas recirculation, or ammonia injection. Segregating species are those that partition to smaller particle sizes.
- Nonsegregating trace metal emissions are only of potential concern when implementing flue gas recirculation and reduced air preheat

The following subsection discusses the formation mechanism for each pollutant as a function of the combustion conditions.

Obviously care must be taken when quantifying impacts of NO_x controls. A careful balance between reduced NO_x and increased incremental emissions must be maintained to minimize the total impact on ambient environmental goals.

5.2 FORMATION MECHANISMS OF MAJOR POLLUTANTS

Since incremental emissions are sensitive to the same combustion conditions as NO_x, an understanding of the formation mechanisms of these incremental pollutants will permit a better appreciation of how NO_x control conditions affect these combustion generated pollutants. Such knowledge can aid in the interpretation of the limited field test data available and provide informed speculation on how NO_x controls act. Subsection 5.2.1 reviews the formation mechanism of the criteria pollutants: carbon monoxide, unburned hydrocarbons, particulate, and sulfur oxides. (Nitrogen oxides formation has already been discussed in

Section 2.) Subsection 5.2.2 discusses the formation mechanisms of the noncriteria pollutants: trace metals and condensible organics.

5.2.1 Criteria Pollutants -- Formation Mechanisms

Carbon Monoxides

The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can result in incomplete combustion. These include:

- Insufficient oxygen availability
- Poor fuel/air mixing
- Cold wall flame quenching
- Reduced combustion temperature
- Decreased combustion gas residence time
- Load reduction (reduced efficiency)

Since various combustion modifications for NO_x reduction can produce one or more of the above conditions, the possibility of increased CO emissions is a concern for environmental, energy efficiency, and operational reasons. Flue gas CO emission concentrations in excess of 2000 ppm can severely damage equipment from explosions in flue gas exit passages, though efficiency constraints would preclude such levels to be attained.

Unburned Hydrocarbons

Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, ethyl benzene, etc.) (References 5-2 and 5-3). Condensed phase organic compounds are discussed in Section 5.3.

Like CO, UHC occur due to incomplete combustion. Therefore, any combustion modification which reduces the combustion efficiency will most likely increase the concentrations of vapor phase hydrocarbons. These pollutants are of environmental concern because of their role in the atmospheric reactions which lead to photochemical smog (Reference 5-1).

Total Particulate

Gas-fired combustion equipment produces negligible amounts of particulate matter. The quantity of emissions increases when distillate oil and residual oil are used and the greatest quantity is emitted when coal is the primary fuel (Reference 5-4).

Particulate emissions from oil-fired units can be composed of soot (condensed organic matter) and ash (incombustible mineral matter). Coal particulate emissions are largely ash, and occasionally contain some unburned carbonaceous residue. The composition of the particulate generated in the combustor can affect mass emissions. This is due primarily to the relationship between composition and particle size, and the particulate control device employed for particle removal. In addition, some trace element emissions depend on the particle size distribution. Finally, polycyclic organic matter (POM) emissions from combustion sources occur largely as solid phase carbonaceous residue.

The formation of particulates in a combustion source is closely related to combustion aerodynamics, the mechanisms of fuel/air mixing, and the effects of these factors on combustion gas temperature-time history. The optimum conditions for reducing particulate formation (intense, high temperature flames as produced in high turbulence and rapid fuel/air mixing) are not the conditions for suppressing NO_x formation. Therefore, most attempts to design low-NO_x combustors have been compromised by the need to limit the formation of particulates.

Particulate emissions are subdivided into expected particle size distribution and particulate mass emissions. When NO_x controls are applied to reduce combustion efficiency, condensible organic matter (soot) can increase. If the combustion modification results in a reducing atmosphere rather than an oxidizing atmosphere, ash emissions may decrease due to increased slag formation (in pulverized coal units) and internal deposition of ash.

Particle size distribution can affect the emissions of trace metals. Some trace metals segregate to the smaller particle sizes. If combustion modifications reduce particle sizes, segregating trace metals emissions can increase. In general, the more complete the combustion, the smaller the particle size distribution. Therefore, loss of combustion efficiency can result in increased mass emissions from the boiler and increased particle size (Reference 5-1). Larger particles are more easily removed by pollution control devices. Boilers equipped with these devices may reduce mass emissions from the stack when combustion efficiency is reduced.

Sulfur Oxides

Ambient sulfate levels are of increasing concern in regions with large numbers of combustion sources firing sulfur-bearing coal and oil. Although the direct health effects of high ambient sulfate levels are currently unclear (Reference 5-5), high sulfate aerosol concentrations decrease visibility and aggravate acid precipitation.

Ambient sulfates are generally comprised of directly emitted sulfates (primary sulfates) and those derived from the atmospheric oxidation of sulfur dioxide, SO_2 (secondary sulfates). The criteria pollutant, sulfur dioxide, is emitted when sulfur-containing fuel is burned. In fact, up to 98 percent of all sulfur entering the boiler may be discharged as SO_2. Thus combustion modifications are not expected to affect the discharge of SO_2. The primary concern for incremental emissions, then, is to control the ratio of primary sulfate to SO_2 (SO_4/SO_2). The sulfate present may exist as either sulfuric acid (H_2SO_4) or as metal or ammonium sulfates.

The precise mechanisms for the formation of sulfates are not completely understood. However, two processes contribute to final flue gas sulfate levels. The first is homogeneous SO_2 oxidation in the flame through the reaction:

$$SO_2 + O + M = SO_3 + M \qquad (5\text{-}1)$$

where M is a third body molecule. Although SO_2 is the thermodynamically favored product at high temperatures, it is currently thought that some SO_3 is formed through Equation (5-1). Subsequent rapid gas quenching then freezes the system into a nonequilibrium state. Any SO_3 formed through this reaction will, at reduced temperatures, combine with available water vapor to form sulfuric acid. This sulfuric acid will then adsorb onto available particulate matter or, in the absence of sufficient particulate matter, condense as an acid mist.

The second important sulfate formation mechanism is catalyzed heterogeneous SO_2 oxidation in postcombustion regions by flue gas particulate and internal boiler deposits. Several potential oxidation catalysts exist in suspended and deposited flue gas particulate, including vanadium, nickel, iron, manganese oxides, and carbon (soot).

Based on the above, it is possible to speculate how NO_x controls might affect primary sulfate production. Reduced oxygen availability should definitely decrease primary sulfate emissions. Thus, NO_x controls which decrease local oxygen availability should lower sulfate emission levels. It is difficult to identify the effects of combustor temperature time history on sulfate production. This is because not much is known about in situ catalytic mechanisms and their relative importance to homogeneous SO_2 oxidation. Since trace metals present in the gas stream catalytically oxidize SO_2 to SO_3, combustion conditions which facilitate volatilization-condensation and partitioning of these metals, such as high peak flame temperatures, should promote SO_2 conversion. Conversely, combustion controls which lower peak flame temperature should decrease sulfate production.

5.2.2 Noncriteria Pollutants -- Formation Mechanisms

Organics

The term organics here is used to refer to those species not included in the criteria pollutant class of unburned vapor phase hydrocarbons. These remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known variously as polycyclic organic matter (POM) or polynuclear aromatic hydrocarbons (PNA or PAH).

Although polycyclic organic matter can conceivably be formed in the combustion of any hydrocarbon fuel, it is considered more of a problem when associated with soot (carbonaceous particulate) emissions from coal- and oil-fired combustion equipment. Polycyclic organic matter are especially prevalent in the emissions from coal burning, because a large fraction of the volatile matter in coal (coal tar) preexists as POM.

Although the formation mechanism of POM in flames is complex and variable, it is possible to form a relatively clear picture of the overall reaction. In a reducing atmosphere at temperatures around 2,000K (conditions common in the center of flames), radical species of the form, HC=CH and RCH=CH, can rapidly combine and form large polynuclear aromatic molecules through radical chain propagation (References 5-3, 5-6). As combustion gas cools and chain propagation is quenched, a variety of POM species can remain when combustion is incomplete. Upon further cooling, these species condense and are emitted largely as soot or high carbon content particulate.

It is important to again note that although POM formation is possible during methane combustion, the formation of these large aromatic molecules is facilitated by the presence of higher molecular weight radicals. Thus, POM production is of only minor concern in gas-fired systems, of some concern in oil-fired systems, and of greatest concern in coal-fired equipment. Whatever the combustion source, POM emissions should increase under conditions of poor combustion efficiency. Since NO_x combustion controls can lead to inefficient combustion and soot formation if not carefully applied (especially low excess air and staged combustion), implementation of these controls can lead to increased POM formation.

A few comments are in order here concerning an extremely toxic subclass of polynuclear aromatic hydrocarbons, the polychlorinated and polybrominated biphenyls (PCBs and PBBs). A theoretical assessment of PCB formation in combustion sources (Reference 5-7) concluded that, although PCB formation is thermodynamically possible during coal and residual oil (fuels which contain some chlorine) combustion, it is unlikely due to short reaction residence times and low chlorine concentrations. If PCBs are formed, they would be expected to occur under conditions which promote POM emissions. However, PCBs have not been found in conventional combustion source emissions. The most likely combustion source would be those combustion systems that fire wastes.

Trace Elements

Emissions of trace metals are a concern for combustion sources firing coal and residual oil. They are a lesser problem in sources firing distillate fuels since trace metal concentrations in distillate oils are generally much lower than those in residual oils. Trace metals from stationary sources are emitted to the atmosphere with the flue gas either as a vapor or condensed on particulate. The quantity of any given metal emitted, in general, depends on:

- Its concentration in the fuel
- The combustion conditions in the boiler

- The type of particulate control device used, and its collection efficiency as a function of particle size
- The physical and chemical properties of the element itself

It has become widely recognized that some trace metals concentrate in certain waste particle streams from a boiler (bottom ash, collector ash, flue gas particulate), while others do not (References 5-8 through 5-14). The most logical explanation for this segregation involves a volatilization-condensation mechanism (Reference 5-8). Certain metals have boiling points sufficiently high that they are not volatilized in the combustion zone. Instead, they form a melt of relatively uniform concentration, which becomes both bottom ash or slag, and flyash. Thus, these elements, termed Class I, remain in a condensed phase throughout the boiler and show little partitioning with particle size. By contrast, other metals have boiling points below peak combustion temperatures, so they are volatilized in the combustion zone and do not become incorporated in the slag. As combustion gases cool by traveling through the boiler, these elements, termed Class II, either form condensation nuclei or condense onto other available solid surfaces (predominantly preexisting Class I ash particles). Since the available surface area to mass ratio increases as particle size decreases, these elements concentrate in small particles. Finally, metals such as mercury (Hg) and to some extent selenium (Se), remain vaporized through the stack and are emitted as flue gas vapor components. These are referred to as Class III metals.

By understanding trace metal partitioning and concentration in fine particulate, it is possible to postulate the effects of NO_x combustion controls on incremental trace metal emissions. Several NO_x controls for boilers reduce peak flame temperatures (staged combustion, flue gas recirculation, reduced air preheat, load reduction, and water injection). The volatilization-condensation theory predicts that if the combustion temperature is reduced, less Class II metals will initially volatilize, hence less will be available for subsequent condensation. Under these conditions (lowered flame temperature), it is expected that less Class II metal (the segregating trace metals) will be redistributed to small particulate. Therefore, in boilers with particulate controls, lowered volatile metal emissions should result due to improved particulate removal. Flue gas emissions of class I metals (the nonsegregating trace metals) should remain relatively unchanged.

Lowered local O_2 concentrations are also expected to affect segregating metal emissions from boilers with particle controls. Lowered O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions Class II metals should remain in the vapor phase into the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class I metals should be unaffected. This behavior is expected when low excess air is implemented. Other combustion NO_x controls which decrease local O_2 concentrations (staged combustion and flue gas recirculation) also reduce peak flame temperature. For these, the effect of lowered combustion temperature is expected to predominate.

The effect of NO_x combustion controls on segregating metal emissions from combustion sources without particle collection devices should be minimal at best. Particle redistribution will not affect mass emissions because all particulate produced is emitted from these sources. However, since trace metal condensation on internal boiler surfaces undoubtedly occurs, conditions which decrease the extent of Class II metal volatilization (lowered peak flame temperature) should cause a slight decrease in segregating metal emissions. Conversely, conditions which increase metal volatility (low local O_2 concentrations) should cause slight increases in volatile metal emissions (Reference 5-1).

5.3 ENVIRONMENTAL IMPACTS OF NO_x CONTROLS FOR COAL-FIRED BOILERS

Coal-fired industrial boilers have been grouped into four equipment categories as follows:

- Field erected, pulverized coal.
- Field erected, stoker, spreader stoker
- Field erected, stoker, chain grate stoker
- Packaged, stoker, underfeed stoker

Table 5-2 presents incremental emission data from recently completed field test programs (References 5-15 and 5-19 through 5-21). Included in this test series were stoker type industrial boilers. Data from these are presented in Table 5-3. The information from these tables is presented graphically in Figures 5-1 and 5-2.

TABLE 5-2. INCREMENTAL EMISSIONS FROM PULVERIZED COAL-FIRED INDUSTRIAL BOILERS (References 5-15 and 5-20)

Boiler Test Series	System: Actual/Design Heat Input MW (10^6 Btu/hr)	System: Boiler Type	System: NO_x Control (Excess O_2, %)	NO_x Emissions: ng/J	NO_x Emissions: Incremental Change, ng/J	Criteria Emissions[a]: Pollutant	Criteria Emissions[a]: ng/J	Criteria Emissions[a]: Incremental Change, ng/J
A	117/146 (400)/(500)	Watertube Single Wall	Baseline (8.6)	216		CO	29	
						UHC	--	
						SO_3	--	
						PART	1140	
	114/146 (130)/(500)		Low Excess Air (8.1)	212	-4	CO	47	+18
						UHC	--	--
						SO_3	--	--
						PART	--	--
B	38/76 (130)/(260)	Watertube Single Wall	Baseline (7.4)	563		CO	0	
						UHC	--	
						SO_3	6	
						PART	2288	
	38/76 (130)/(260)		Low Excess Air (6.6)	529	-34	CO	0	0
						UHC	--	--
						SO_3	--	--
						PART	--	--
C	53/65 (180)/(220)	Watertube Tangential	Baseline (5.3)	234		CO	0	
						UHC	4	
						SO_3	5	
						PART	511	
	53/65 (180)/(220)		Low Excess Air (4.5)	222	-12	CO	--	--
						UHC	1	-3
						SO_3	--	--
						PART	--	--

[a]No data available on noncriteria emissions

TABLE 5-2. Concluded

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
D	76/94 (260)/(320)	Watertube Tangential	Baseline (5.8)	296		CO	0	
						UHC	2	
						SO_3	9	
						PART	834	
	76/94 (260)/(320)		Low Excess Air (4.8)	303	+7	CO	0	0
						UHC	1	-1
						SO_3	--	--
						PART	--	--
E	38/67 (130)/(230)	Watertube Single Wall	Baseline (4.5)	201		CO	11	--
						UHC	90	--
						SO_3	4.7	--
						PART	--	--
	38/67 (130)/(230)		Low Excess Air (3.4)	152	-49	CO	12	+1
						UHC	5.4	-3.6
						SO_3	2.2	-2.5
						PART	2895	--
F	33/47 (112)/(160)	Watertube Single Wall	Baseline (5.1)	174		CO	23.2	
						UHC	10	
						SO_3	21.7	
						PART	1194	
	33/7 (112)/(160)		Low Excess Air (3.4)	136	-38	CO	4.2	+19
						UHC	14	+4
						SO_3	0	-21.7
						PART	995	-199

[a]No data available on noncriteria emissions

TABLE 5-3. INCREMENTAL EMISSIONS FROM STOKER COAL-FIRED INDUSTRIAL BOILERS (References 5-15 and 5-20)

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
G	30/62 (103)/(210)	Watertube Chain Grate	Baseline (9.5)	100		CO	9	
						UHC	5	
						SO_3	--	
						PART	176	
	29/62 (100)/(210)		Low Excess Air (9.0)	75	-25	CO	22	+13
						UHC	11	+6
						SO_3	--	--
						PART	161	-15
	31/62 (105)/(210)		Low Excess Air (8.7)	77	-23	CO	20	+11
						UHC	4	-2
						SO_3	--	--
						PART	--	--
H	24/36 (81)/(125)	Watertube Spreader Stoker	Baseline (6.2)	196		CO	0	
						UHC	--	
						SO_3	20	
						PART	1320	
	24/36 (81)/(125)		Overfire Air (6.1)	145	-51	CO	18	+18
						UHC	--	--
						SO_3	--	--
						PART	--	--
	24/36 (81)/(125)		Low Excess Air (4.7)	142	-54	CO	8	+8
						UHC	--	--
						SO_3	--	--
						PART	847	-473

[a]No data available on noncriteria emissions

TABLE 5-3. Continued

Boiler Test Series	System: Actual/Design Heat Input MW (10^6 Btu/hr)	System: Boiler Type	System: NO_x Control (Excess O_2, %)	NO_x Emissions: ng/J	NO_x Emissions: Incremental Change, ng/J	Criteria Emissions[a]: Pollutant	Criteria Emissions[a]: ng/J	Criteria Emissions[a]: Incremental Change, ng/J
I	14/17 (48)/(60)	Watertube Underfeed Stoker	Baseline (6.6)	163		CO UHC SO_3 PART	0 -- 23 --	
	13/17 (45)/(60)		Low Excess Air (4.9)	115	-48	CO UHC SO_3 PART	0 -- -- --	0 -- -- --
	13/17 (45)/(60)		Baseline (9.8)	137		CO UHC SO_3 PART	0 -- -- 1647	
	13/17 (45)/(60)		Low Excess Air (7.0)	123	-14	CO UHC SO_3 PART	119 -- --	+119 -- --
J	32/39 (109)/(135)	Watertube Spreader Stoker	Baseline (7.0)	226		CO UHC SO_3 PART	10 5 15 1587	
	33/39 (112)/(135)		Low Excess Air (4.9)	205	-21	CO UHC SO_3 PART	47 2 --	+37 -3 --
K	12/15 (40)/(50)	Watertube Spreader Stoker	Baseline (8.0)	284		CO UHC SO_3 PART	9 2 15	
	12/15 (40)/(50)		Low Excess Air (5.8)	202	-82	CO UHC SO_3 PART	7 4 -- 279	-2 +2 -- -219

[a]No data available on noncriteria emissions

TABLE 5-3. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
L	17/22 (60)/(75)	Watertube Spreader Stoker	Baseline (7.8)	284		CO UHC SO_3 PART	34 2 28 140	
	18/22 (62)/(75)		Low Excess Air (5.9)	237	-47	CO UHC SO_3 PART	22 4 -- 123	-12 +2 -- +17
M	35/44 (120)/(150)	Watertube Spreader Stoker	Baseline (10.2)	338		CO UHC SO_3 PART	0 -- 36 1649	
	35/44 (120)/(150)		Low Excess Air (8.9)	228	-50	CO UHC SO_3 PART	0 -- -- --	0 -- -- --
N	47/67 (160)/(230)	Watertube Spreader Stoker	Baseline (10.8)	334		CO UHC SO_3 PART	0 -- 4 361	
	44/67 (150)/(230)		Low Excess Air (8.9)	220	-114	CO UHC SO_3 PART	0 -- -- --	0 -- -- --
	42/67 (143)/(230)		High Excess Air (HEA) (12.6)	241	-93	CO UHC SO_3 PART	0 -- 13 317	0 -- +9 -44

[a]No data available on noncriteria emissions

TABLE 5-3. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
P	18/29 (60)/(100)	Watertube Spreader Stoker	Baseline Montana Coal (10.9)	312		CO UHC SO_3 PART	205 -- 10 447	
	18/29 (60)/(100)		Low Excess Air Montana Coal (6.5)	206	-106	CO UHC SO_3 PART	17 -- -- 388	-188 -- -- --
	18/29 (60)/(100)		Baseline Illinois Coal (10.0)	289		CO UHC SO_3 PART	18 -- 9 674	
	18/29 (60)/(100)		Low Excess Air Illinois Coal (7.8)	258	-31	CO UHC SO_3 PART	0 -- -- 455	-18 -- -- -219
Q	24/47 (83)/(160)	Watertube Spreader Stoker	Baseline Montana Coal (8.6)	326		CO UHC SO_3 PART	53 -- 14 --	
	23/47 (79)/(160)		Low Excess Air Montana Coal (7.7)	183	-53	CO UHC SO_3 PART	48 -- -- 5803	-5 -- -- --
	31/47 (107)/(160)		Baseline Illinois Coal (8.6)	287		CO UHC SO_3 PART	17 -- -- --	
	32/47 (110)/(160)		Low Excess Air Illinois Coal (6.6)	241	-46	CO UHC SO_3 PART	33 -- -- 234	-84 -- -- --

[a]Cyclone outlet only

TABLE 5-3. Concluded

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
R	13/23 (46)/(80)	Watertube Spreader Stoker	Baseline 2/3 Illinois, 1/3 Montana Coal (9.4)	207		CO UHC SO_3 PART	61 -- 133 1209	
	13/23 (46)/(80)		Low Excess 2/3 Illinois, 1/3 Montana Coal (8.0)	239	+32	CO UHC SO_3 PART	33 -- 44 987	-28 -- -89 -222
S	5/13 (17)/(45)	Watertube Vibrating Grate Stoker	Baseline Western Coal (9.8)	199		CO UHC SO_3 PART	18 -- -- --	
	5/13 (17)/(45)		Low Excess Western Coal (7.3)	152	-47	CO UHC SO_3 PART	8 -- -- --	-10 -- -- --

[a]No data available on noncriteria emissions

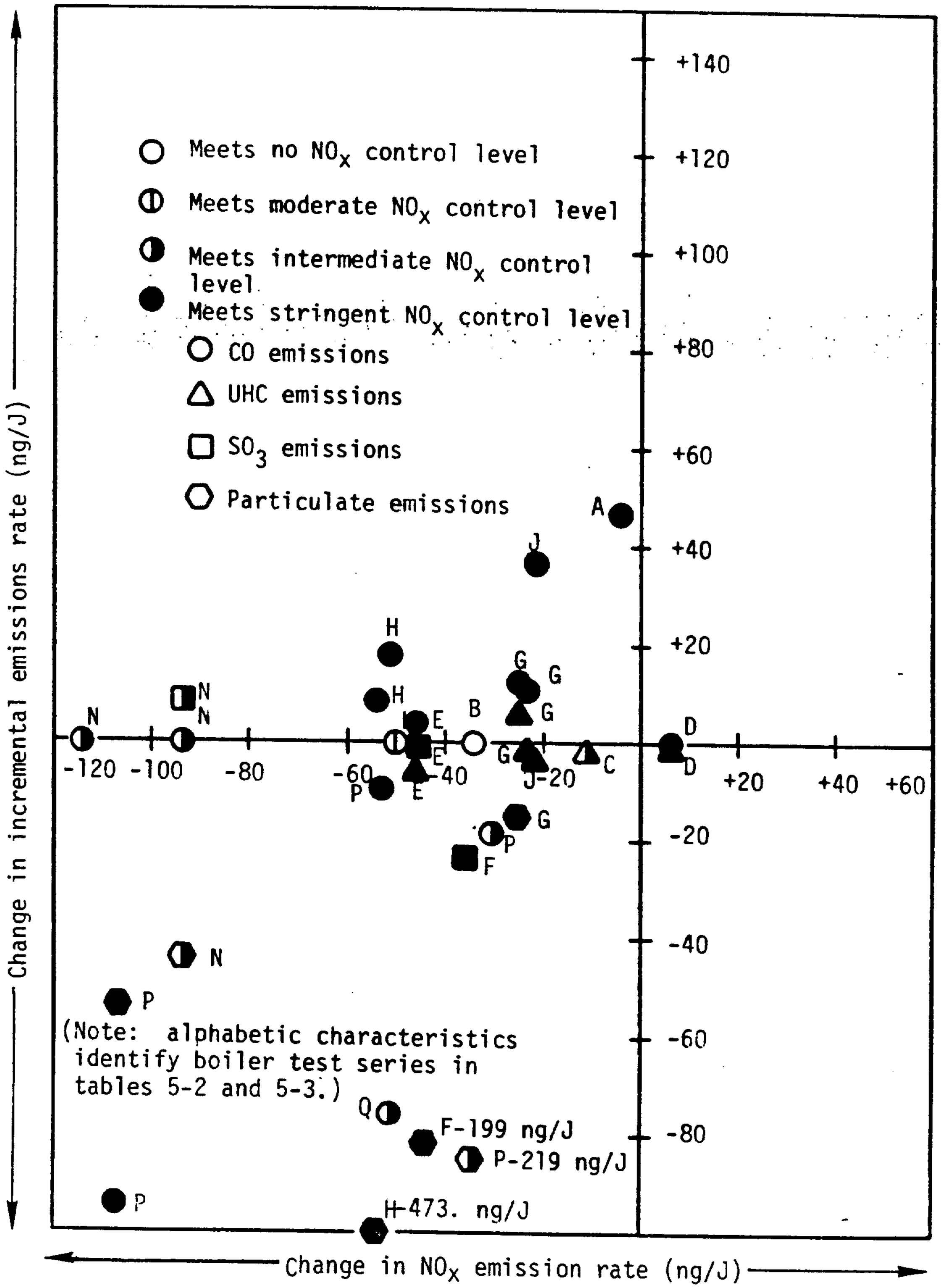

Figure 5-1. Change in incremental emissions from coal-fired industrial boilers >29 MW (100 x 10^6 Btu/hr).

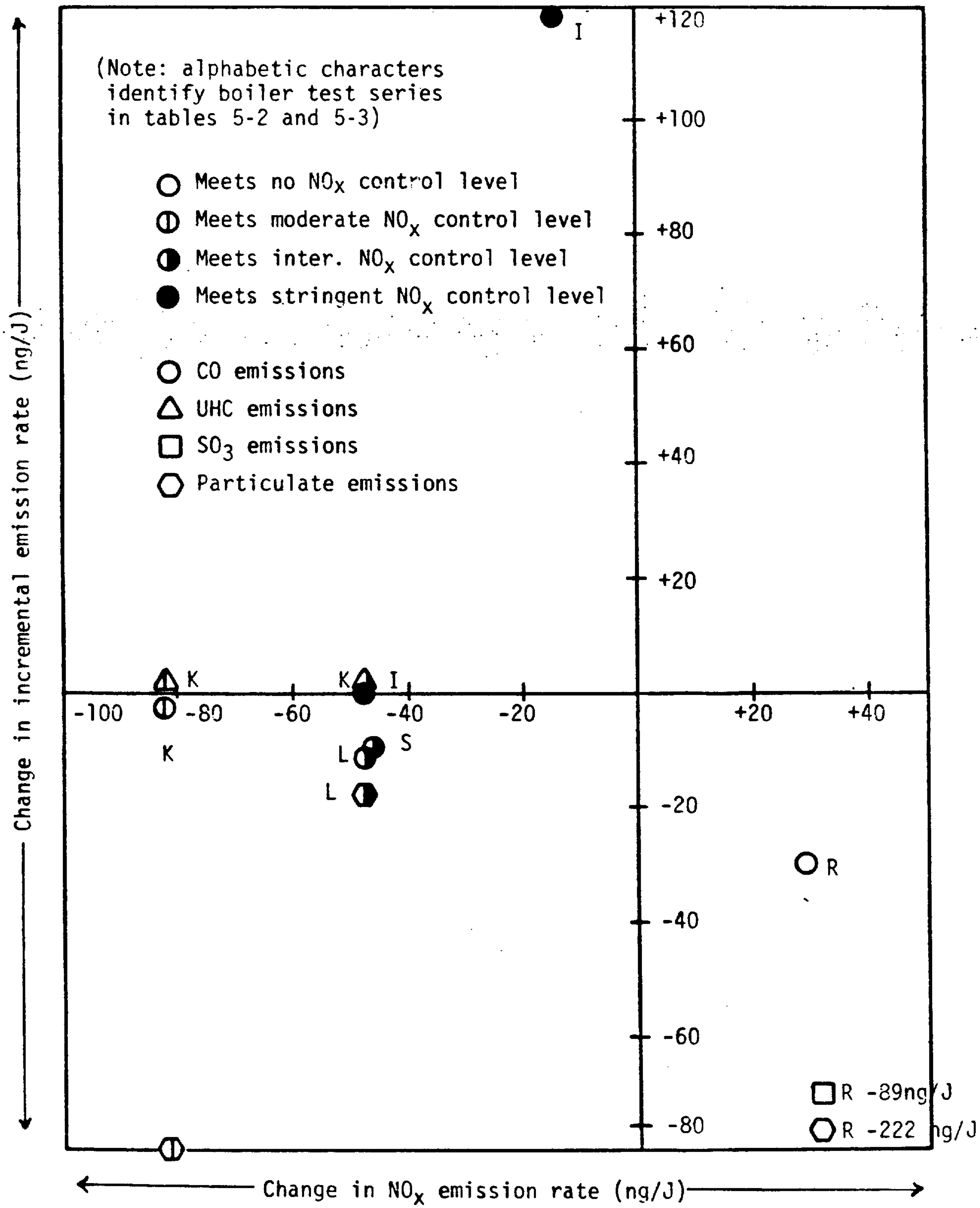

Figure 5-2. Change in incremental emissions from coal-fired industrial boilers <29 MW (100 x 10^6 Btu/hr).

The changes in incremental emissions, as affected by NO_x controls, depend on the extent to which a particular control is applied. Therefore, to facilitate the data evaluation, moderate, intermediate, and stringent NO_x control levels were identified for each major boiler/fuel category. These achievable NO_x control levels are further discussed in the next section.

All tests used low excess air for NO_x control except test series H which included one overfire air test and test N which included one high excess air test. In nearly all cases, CO emissions increased slightly, as predicted. Unburned vapor phase hydrocarbon emissions fluctuated between increases and decreases. There appears to be a decrease in SO_3 emissions with reduced excess air, as expected, though the data are sparse.

Comparative particulate tests generally show a decrease with NO_x control in particulate emissions following a particulate control device. Reduced excess air was expected to increase particle size. This would make the particles easier to collect in particulate control devices. Since the boilers in the comparative tests were equipped with dust control devices, it appeared that the predicted effect was correct. However, particulate sampling at the boiler outlet (upstream of any particulate collection devices) of the two stoker coal-fired boilers tested in this NO_x EA program showed lower particulate emissions with NO_x control (see Section 5.7.1).

The particle size distribution of the ash emitted from a boiler is also expected to increase with low excess and overfire air NO_x control. This is due to a slight decrease in combustion efficiency. Table 5-4 presents test data collected downstream of a dust collection device during one field test program (Reference 5-16). Though other tests were conducted, these data were the only comparative test data identified. A clear shift to larger particle size is noted. These data, coupled with the results from Figures 5-1 and 5-2, further suggest improved dust removal device efficiency and reduced particulate mass emissions from the stack. Results from the two stoker coal-fired boilers tested in this program show a slight or no shift to larger size particles (References 5-23 and 5-24).

Data collected during a coal-fired boiler test program (Reference 5-16) are in accordance with the trace metal partitioning theory discussed in Section 5-3. Figure 5-3 illustrates the partitioning of low-volatility iron, moderately volatile cobalt, and highly volatile copper.

TABLE 5-4. EFFECT OF OVERFIRE AIR NO_x CONTROL ON PARTICLE SIZE DISTRIBUTION[a] FOR A COAL-FIRED CHAIN GRATE STOKER (Reference 5-16)

Fuel Type	Burner Type	Test Load MW	NO_x ng/J	Impact Flow $cm^3\ s^{-1}$	D_{50} Cycl. m	Actual D_{50} of Stage No.[b] 1 µm	2 µm	3 µm	4 µm	5 µm	Cyclone mg	Cyclone, Stage and Filter Catch: Stage No. 1 mg	2 mg	3 mg	4 mg	5 mg	Filter mg	Total Catch mg	Comments
Coal	Grate	31	85.5	24.6	15.6	3.5	2.1	1.4	0.70	0.35	10.39	1.056	0.780	0.660	0.340	0.600	0.572	14.60	Baseline no soot
Coal	Grate	29	--	23.6	15.1	3.5	2.1	1.4	0.71	0.35	10.82	0.200	0.276	0.472	2.10	3.26	1.29	18.42	Low NO_x no soot

T-1451

[a]Particle size distribution determined by use of a Brink model "B" cascade impactor

[b]D_{50} identifies the size fraction in microns. Particulates with an aerodynamic diameter greater than the D_{50} cut point will be captured. Increasing stage number corresponds to decreasing particle size.

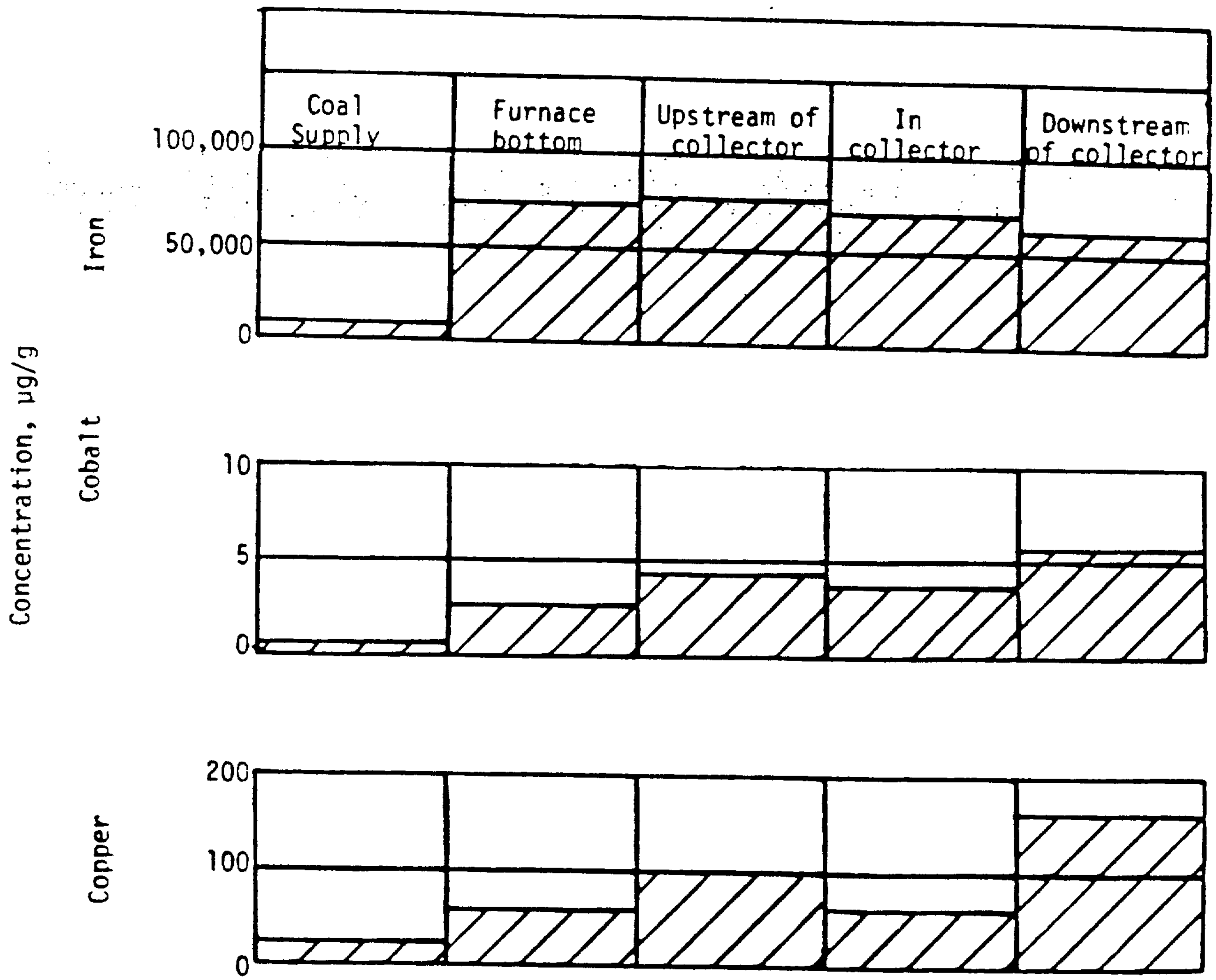

Figure 5-3. Partitioning of elements based on effluent location for a coal-fired industrial boiler (Reference 5-16).

Test data collected during the same test program (Reference 5-16) support the trace metal segregation theory as discussed in Section 5.3. As shown in Figure 5-4, the concentration of the volatile element antimony increased as the particle size decreased. The concentration of less volatile manganese remains relatively evenly distributed between particulate fractions.

The data presented above, indicate that NO_x control techniques which alter the overall boiler temperature profile, or change the particulate mass emissions or particle size distribution can affect the concentration of trace metals emitted from the collector. The NO_x EA stoker coal test results showed only slight differences in trace element partitioning between low NO_x and baseline operation (References 5-23 and 5-24).

Tests for polycyclic organic matter (POM) have been conducted (Reference 5-16). The data from a stoker coal-fired boiler (chain grate) are presented in Table 5-5. As shown, the data are incomplete due to the lack of sufficient gas stream samples for analyses. Though organic species are present, their general trend as a function of NO_x control is not known. The NO_x EA stoker test results indicated an increase in flue gas organic emissions with NO_x control (see Section 5.7.1).

The above emission data were presented for combustion modifications only. Low NO_x burners and ammonia injection are still in the development stages. Actual incremental emission data are not available.

5.4 ENVIRONMENTAL IMPACTS OF NO_x CONTROLS FOR RESIDUAL OIL-FIRED BOILERS

Oil-fired industrial boilers fall into two major equipment categories. These are packaged watertube and firetube boilers. Table 5-6 presents incremental emission data collected during two recent test programs (References 5-15 and 5-17). This information is presented graphically in Figures 5-5 through 5-8. As shown, all low NO_x control conditions that meet any of the recommended control levels result in an increase in CO emissions. Generally, the more the NO_x emissions are reduced, the higher the CO emission rate. As with coal-fired boilers, hydrocarbon levels from oil-fired boilers remain relatively unchanged.

The trend of decreasing sulfate emissions with excess O_2 level noted for coal-fired boilers also holds for residual oil-fired boilers. One test from Series H and two tests from Series G indicate that operation with higher O_2 levels produce greater quantities of SO_3.

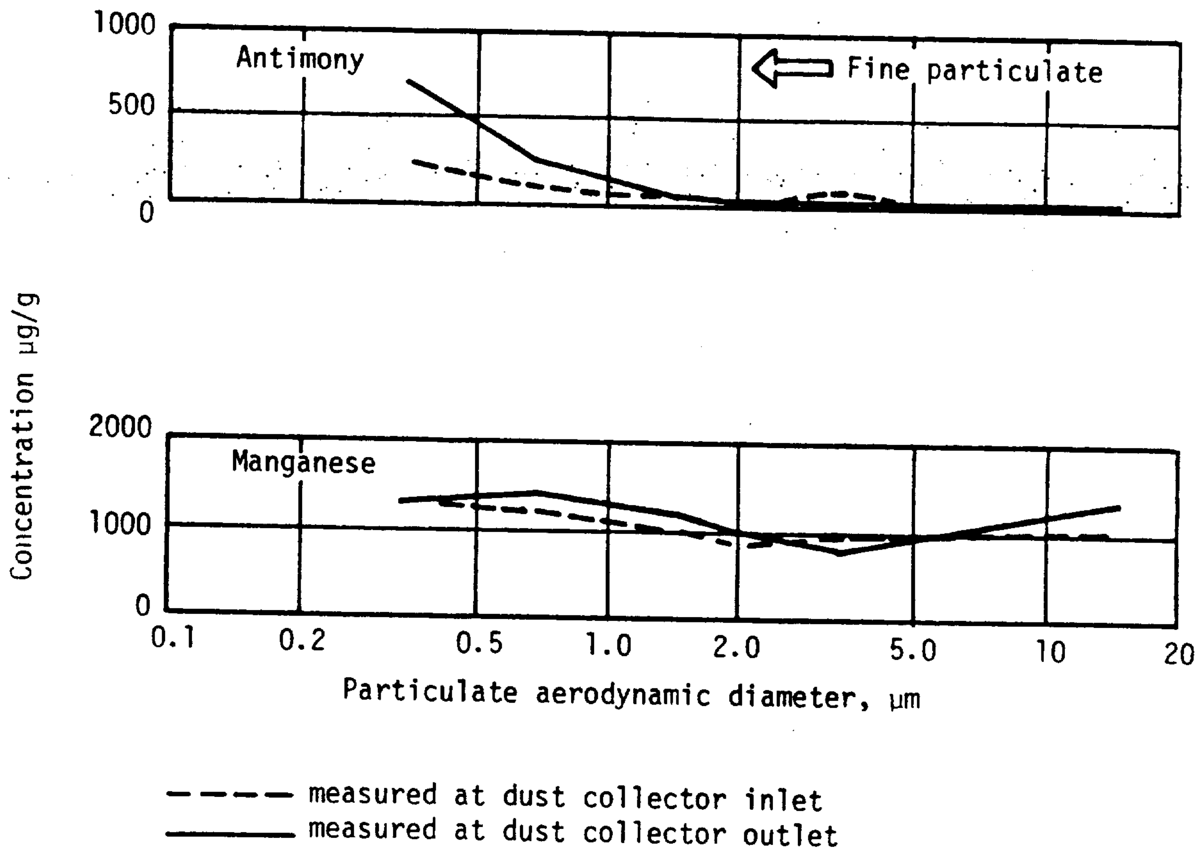

Figure 5-4. Trace element concentration in fine particulate (Reference 5-16).

TABLE 5-5. EMISSION RATES OF POLYCYCLIC ORGANIC MATTER (POM) FROM A COAL-FIRED CHAIN-GRATE STOKER BOILER (Reference 5-16)

Run No.	POM	In Coal		In Hopper Ash		In Stack Gases			
						Particulate		Vapor	
		g	%	g	%	g	%	g	%
9	7,12 Dimethylbenz(a)anthracene	None detected		None detected		Insufficient sample		None detected	
10		None detected		2.26	--	Insufficient sample		Trace	
11		None detected		1.39	--	Insufficient sample		None detected	
9	Benzo(a)pyrene	109	100	37	34	Insufficient sample		None detected	
10		245	100	92.6	38	Insufficient sample		None detected	
11		18.8	100	651	3462	Insufficient sample		None detected	
9	3 Methylcholanthrene	None detected		None detected		Insufficient sample		None detected	
10		None detected		None detected		Insufficient sample		None detected	
11		None detected		None detected		Insufficient sample		None detected	
9	Dibenz(a,h)anthracene	610	100	None detected		Insufficient sample		None detected	
10		822	100	None detected		Insufficient sample		None detected	
11		673	100	None detected		Insufficient sample		None detected	

TABLE 5-6. INCREMENTAL EMISSIONS FROM RESIDUAL OIL-FIRED BOILERS
(Reference 5-15)

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
A	35/44 (120)/(150)	Watertube	Baseline (5.0)	165		CO	0	
						UHC	7	
						SO_3	--	
						Part.	--	
	35/44 (120)/(150)		Low Excess Air (3.1)	138	-27	CO	0	0
						UHC	5	-2
						SO_3	--	--
						Part.	--	--
B	8/20 (27)/(68)	Watertube	Baseline (5.3)	115		CO	0	
						UHC	--	
						SO_3	--	
						Part.	140	
	8/20 (27)/(68)		Low Excess Air (4.9)	101	-14	CO	10	+10
						UHC	--	--
						SO_3	--	--
						Part.	--	--
C	18/23 (61)/(79)	Watertube	Baseline (3.3)	148		CO	0	
						UHC	2	
						SO_3	--	
						Part.	780	
	19/23 (64)/(79)		Low Excess Air (2.7)	143	-5	CO	70	+70
						UHC	2	0
						SO_3	--	--
						Part.	--	--

[a]No data available on noncriteria emissions

TABLE 5-6. Continued

Boiler Test Series	System: Actual/Design Heat Input MW (10^6 Btu/hr)	System: Boiler Type	System: NO_x Control (Excess O_2, %)	NO_x Emissions: ng/J	NO_x Emissions: Incremental Change, ng/J	Criteria Emissions[a]: Pollutant	Criteria Emissions[a]: ng/J	Criteria Emissions[a]: Incremental Change, ng/J
D	9/12 (32)/(40)	Watertube	Baseline (4.3)	109		CO	0	
						UHC	3	
						SO_3	12	
						Part.	62	
	9/12 (32)/(40)		Low Excess Air (4.0)	98	-11	CO	9	+9
						UHC	0	-3
						SO_3	--	--
						Part.	41	-21
E	10/13 (36)/(45)	Watertube	Baseline (3.0)	183		CO	0	
						UHC	0	
						SO_3	2	
						Part.	46	
	11/13 (37)/(45)		Low Excess Air (1.6)	136	-47	CO	41	+41
						UHC	5	+5
						SO_3	--	--
						Part.	--	--
	10/13 (36)/(45)		Overfire Air (2.9)	97	-86	CO	19	+19
						UHC	4	4
						SO_3	--	--
						Part.	59	+13
	10/13 (36)/(45)		Overfire Air (3.0)	90	-93	CO	31	+31
						UHC	0	0
						SO_3	--	--
						Part.	--	--

[a]No data available on noncriteria emissions

TABLE 5-6. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
F	4.1/5.0 (14)/(17)	Watertube	Baseline (3.1)	95		CO UHC SO_3 Part.	0 0 -- 13	
	4.1/5.0 (14)/(17)		Low Excess Air (0.9)	70	-25	CO UHC SO_3 Part.	34 -- -- --	+34 -- -- --
	4.1/5.0 (14)/(17)		Overfire Air (2.4)	61	-34	CO UHC SO_3 Part.	53 1 -- --	+53 +1 -- --
	4.1/5.0 (14)/(17)		Overfire Air (3.25)	102	+7	CO UHC SO_3 Part.	0 0 -- --	0 0 -- --
	4.1/5.0 (14)/(17)		Overfire Air (3.1)	75	-20	CO UHC SO_3 Part.	0 3 -- 12	0 3 -- -2
	4.1/5.0 (14)/(17)		Baseline (2.9)	91		CO UHC SO_3 Part.	0 0 2 13	
	4.1/5.0 (14)/(17)		Low Excess Air (2.25)	77	-14	CO UHC SO_3 Part.	48 0 -- --	+48 0 -- --

[a]No data available on noncriteria emissions

TABLE 5-6. Continued

Boiler Test Series	System			NO_x Emissions		Criteria Emissions[a]		
	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
F (Cont.)	4.1/5.0 (14)/(17)	Watertube	Overfire Air (3.0)	84	-7	CO UHC SO_3 Part.	27 13 -- --	+27 +13 -- --
	4.1/5.0 (14)/(17)		Overfire Air (2.9)	73	-18	CO UHC SO_3 Part.	10 0 -- --	+10 0 -- --
G	4.1/5.0 (14)/(17)	Watertube	Baseline (3.0)	122		CO UHC SO_3 Part.	1 2 4 36	
	4.1/5.0 (14)/(17)		Low Excess Air (1.0)	84	-38	CO UHC SO_3 Part.	62 4 3 26	+61 +2 -1 -10
	4.1/5.0 (14)/(17)		Overfire Air (3.1)	85	-37	CO UHC SO_3 Part.	8 1 3 32	+7 -1 -1 -4
H	11/13 (38)/(45)	Watertube	Baseline (2.9)	146		CO UHC SO_3 Part.	8 - 22 66	
	11/13 (38)/(45)		Low Excess Air (1.6)	107	-39	CO UHC SO_3 Part.	21 -- 10 44	+13 -- -12 -22

[a]No data available on noncriteria emissions

TABLE 5-6. Concluded

Boiler Test Series	System: Actual/Design Heat Input MW (10^6 Btu/hr)	System: Boiler Type	System: NO_x Control (Excess O_2, %)	NO_x Emissions: ng/J	NO_x Emissions: Incremental Change, ng/J	Criteria Emissions[a]: Pollutant	Criteria Emissions[a]: ng/J	Criteria Emissions[a]: Incremental Change, ng/J
H (Cont.)	11/13 (38)/(45)	Watertube	Overfire Air (3.0)	86	-60	CO UHC SO_3 Part.	10 -- -- --	+2 -- -- --
I	5.3/8.8 (18)/(30)	Watertube	Baseline (9.3)	184		CO UHC SO_3 Part.	<10 -- -- --	
	5.3/8.8 (18)/(30)		Low Excess Air (7.6)	174	-10	CO UHC SO_3 Part.	<10 -- -- --	0 -- -- --
	5.3/8.8 (18)/(30)		Low Excess Air (5.5)	156	-28	CO UHC SO_3 Part.	<10 -- -- --	0 -- -- --
	5.5/8.8 (19)/(30)		Low Excess Air (4.5)	127	-57	CO UHC SO_3 Part.	<10 -- -- --	0 -- -- --
	5.5/8.8 (19)/(30)		Low Excess Air (4.3)	140	-44	CO UHC SO_3 Part.	<10 -- -- --	0 -- -- --
	5.5/8.8 (19)/(30)		Low Excess Air (4.2)	94	-90	CO UHC SO_3 Part.	1232 -- -- --	+1232 -- -- --
	5.3/8.8 (18)/(30)		Low Excess Air (3.6)	113	-71	CO UHC SO_3 Part.	103 -- -- --	+103 -- -- --

[a]No data available on noncriteria emissions

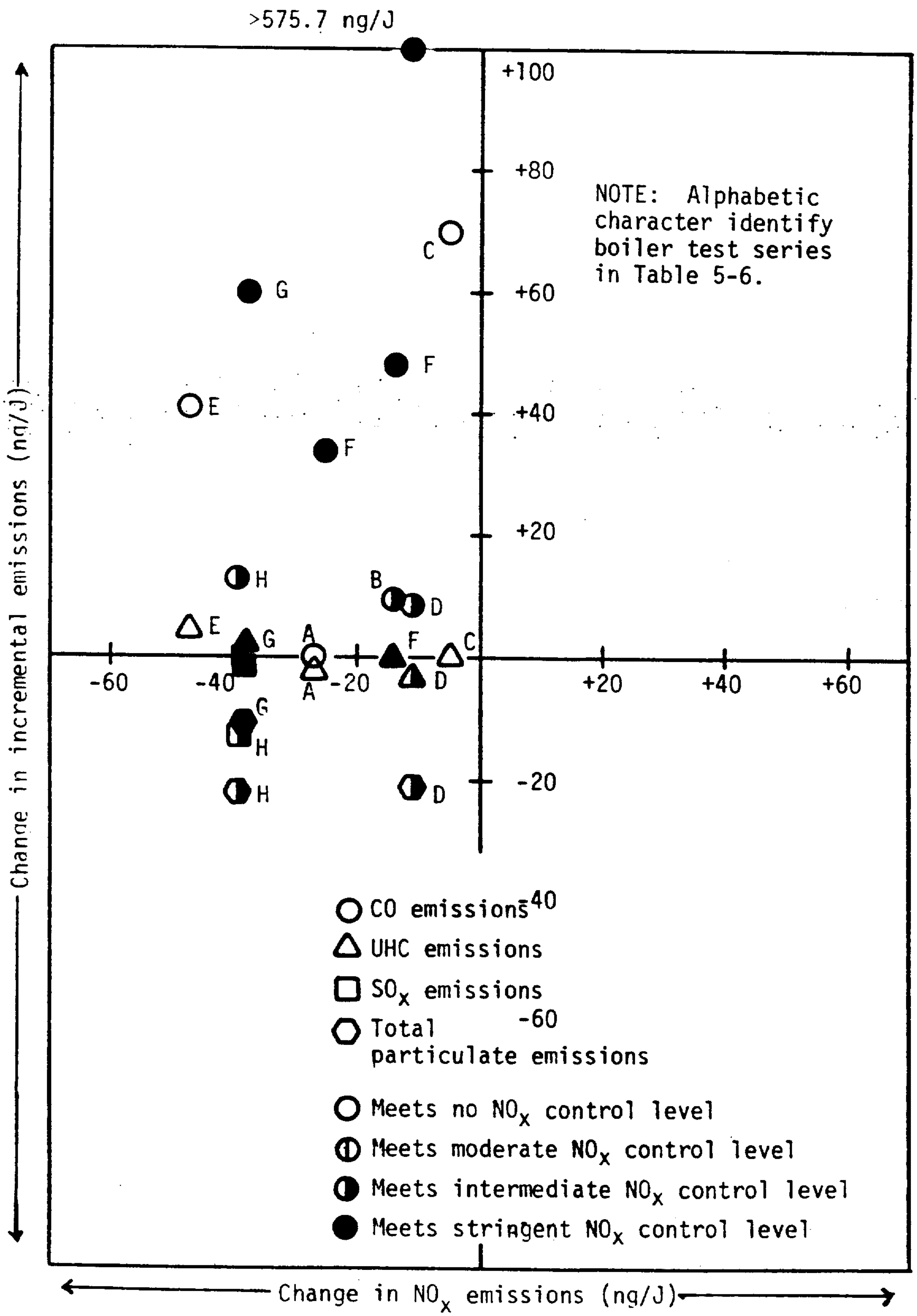

Figure 5-5. Change in incremental emissions with low excess air NO_x control for residual oil-fired watertube industrial boilers (References 5-15 and 5-17).

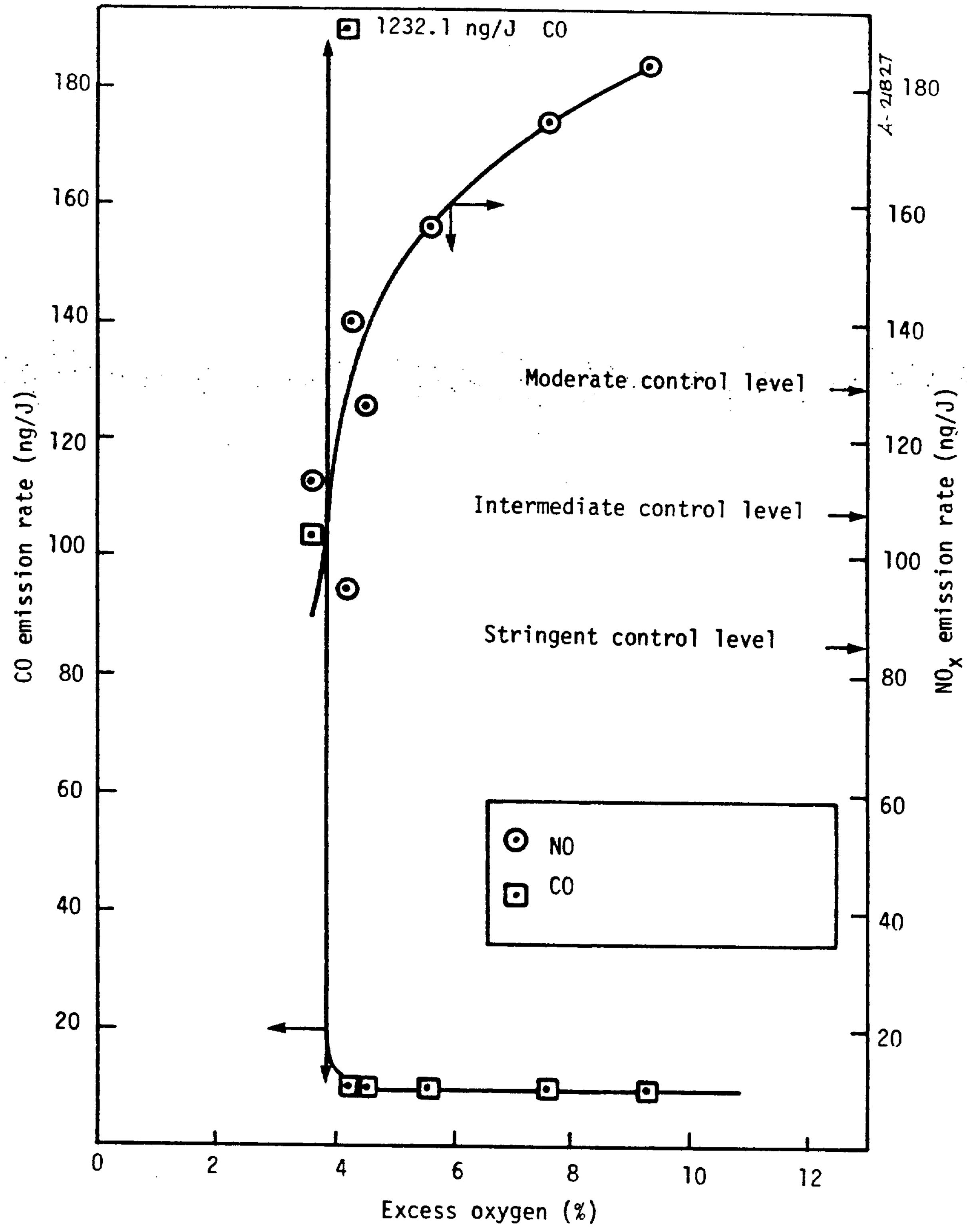

Figure 5-6. Changes in CO and NO_x emissions with reduced excess oxygen for a residual oil-fired watertube industrial boiler (Reference 5-17).

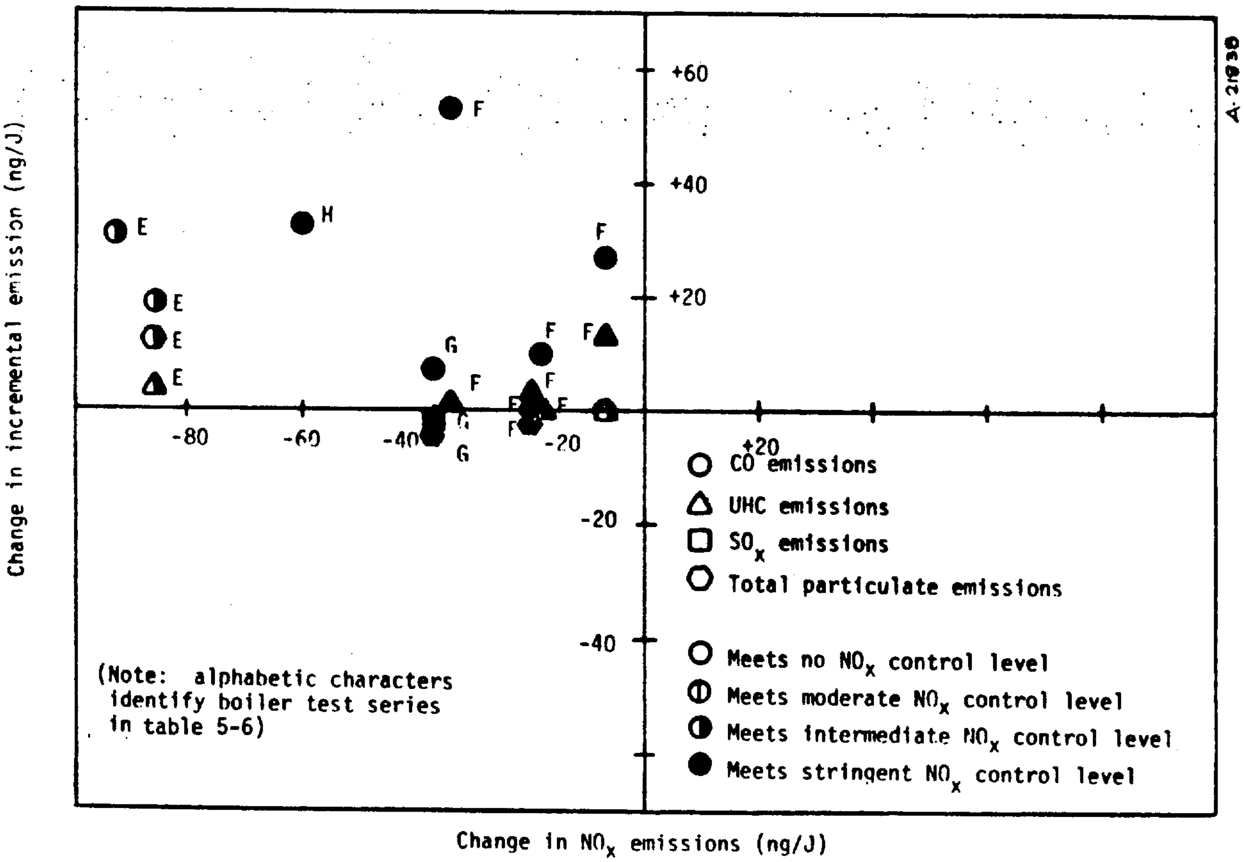

Figure 5-7. Change in incremental emissions with overfire air NO_x control for residual oil-fired watertube industrial boilers (References 5-15 and 5-17).

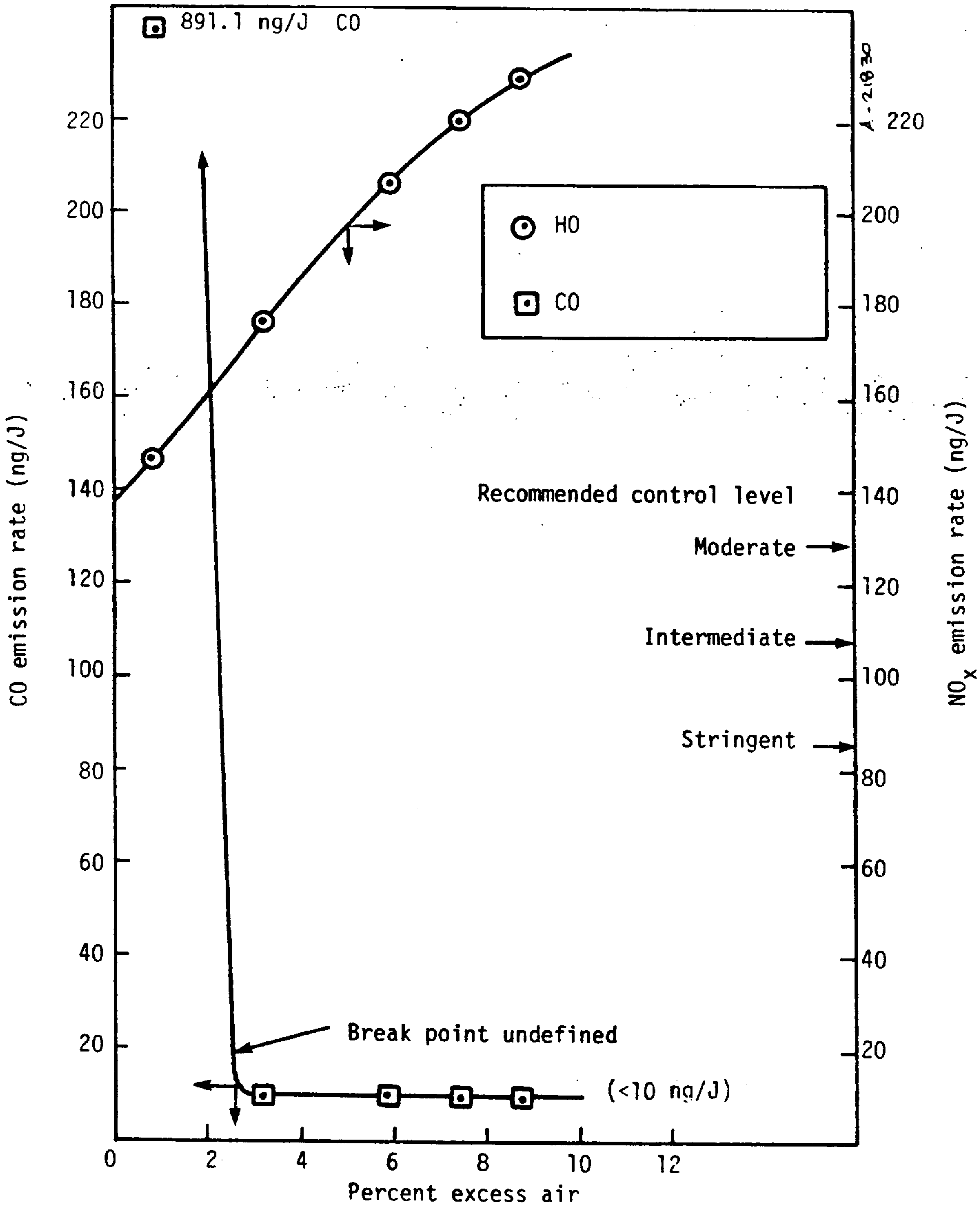

Figure 5-8. Change in CO and NO_x emissions with decreasing excess oxygen for a residual oil-fired firetube industrial boiler (Reference 5-17).

Finally, as was true with the coal-fired boilers, Figure 5-5 shows that particulate emissions for boilers with dust control devices are reduced with low excess air firing. This is most likely due to increased particle size resulting from reduced combustion completeness, making the particles easier to catch.

Test data collected on a watertube boiler (Reference 5-17) over a range of excess oxygen levels is presented in Figure 5-6. This figure shows the reductions in NO_x with decreasing excess oxygen levels. Complete combustion occurs until the oxygen level is reduced to approximately 4.25 percent. The emission rate of CO then climbs sharply. The data presented in Figure 5-5 show a significantly more scattered relationship between CO and NO_x emissions than Figure 5-6 suggests. However, it is reasonable to conclude that each boiler has similar emission characteristics, but fuel/air mixing, fuel nitrogen concentrations, flame temperatures, and many other variables, are responsible for the data scatter.

The effect of overfire air on incremental emissions is shown in Figure 5-7. The emission rate of CO is generally increased with decreasing NO_x emission rates. The emission rates of UHC remain the same or are increased only slightly.

Overfire air (staged combustion) reduces the excess oxygen available for reaction in the primary combustion zone of the boiler. Since less oxygen is available for reaction under these conditions, a reduction in sulfate emissions in the primary zone could be expected. Addition of secondary combustion air may quench the reaction, resulting in reduced overall SO_3. Figure 5-7 shows decreases in sulfate emissions on both tests conducted. (The potential for trace metal catalytic oxidation will be discussed later in this section.)

Finally, the trend established in Figures 5-1 and 5-5 of reduced particulate emissions with NO_x control, has one exception, test condition E. The boiler located at this test site did not have a dust control device. Since reduced combustion efficiency results in increased particulate size and emission rate, this facility would be expected to have increased particulate emissions without a dust control device, as noted.

A set of size distribution tests were conducted during the field test series reported in Reference 5-16. It was found that the combustion of oil fuel produced a larger proportion of particulates having an aerodynamic diameter less than 3 m than did coal fuel. A comparison of Table 5-4 for coal and Table 5-7 for residual oil shows this trend.

Other data collected during various low NO_x control conditions were reported in References 5-15 and 5-18. The data are presented in Figures 5-9 through 5-11. Generally an increase in particle size as excess air levels are decreased can be seen, though test number 132 on Figure 5-10 does not follow this overall trend. The remaining combustion modifications and combinations of modifications also indicate an increased particle size with NO_x control but the degree of change is mixed.

A recently completed field test program on an oil-fired industrial boiler (Reference 5-18) is the only source of organic emission data identified. The organic species proved very difficult to identify, with most sample quantities insufficient to allow for analysis.

No polychlorinated biphenyls (PCB) were identified during the oil tests. The concentration of polycyclic organic matter (POM) contained in the various sample train fractions is shown in Table 5-8. The most complete analysis was obtained from the organic sorbent (XAD-2) resin. The results of these tests are presented in Table 5-9. The results show a significant reduction in POM in the XAD-2 resin for the low NO_x test compared to that for baseline conditions. The test results are definitely not in line with the expected trends. However, without complete analysis of all fractions, a conclusion concerning the total gas stream cannot be made.

Trace element emission data are also limited. The same study which provided the POM data, above, provided the trace element data reported below (Reference 5-18). A combination of reduced excess air, staged combustion, and flue gas recirculation resulted in an increase in particulate emissions of from 30 to 50 percent over baseline conditions. Tables 5-10 through 5-12 present the results of the element partitioning study as a result of the increased particulate loading. Comparison of test 3 (low NO_x) with test 2 (baseline) indicates that calcium, chromium, iron, manganese, titanium and zinc were increased by 10 to 90 percent in the solid particulate less than 3 micrometers. These same

TABLE 5-7. EFFECT OF OVERFIRE AIR NO_x CONTROL ON PARTICLE SIZE DISTRIBUTION[a] FOR A RESIDUAL OIL-FIRED WATERTUBE BOILER (Reference 5-16)

Fuel Type	Burner Type	Test Load MW	NO_x ng/J	Impact Flow $cm^3\ s^{-1}$	D_{50} Cycl. µm	Actual D_{50} of Stage No.[b] 1 µm	2 µm	3 µm	4 µm	5 µm	Cyclone, Stage and Filter Catch: Cyclone mg	Stage Number 1 mg	2 mg	3 mg	4 mg	5 mg	Filter mg	Total Catch mg	Comments
No. 6	Steam	9.4	111	22.6	--	3.62	2.17	1.45	0.72	0.36	None	2.812	1.616	0.668	0.456	0.312	2.700	8.564	Baseline
No. 6	Steam	9.4	97.6	22.7	--	3.61	2.17	1.44	0.72	0.36	None	3.112	1.372	0.596	0.332	0.196	2.344	7.952	Low NO_x

[a]Particle size distribution determined by use of a Brink model "B" cascade impactor
[b]D_{50} identifies the size fraction in micrometers. Particulates with an aerodynamic diameter greater than the D_{50} cut point will be captured. Increasing stage number corresponds to decreasing particle size.

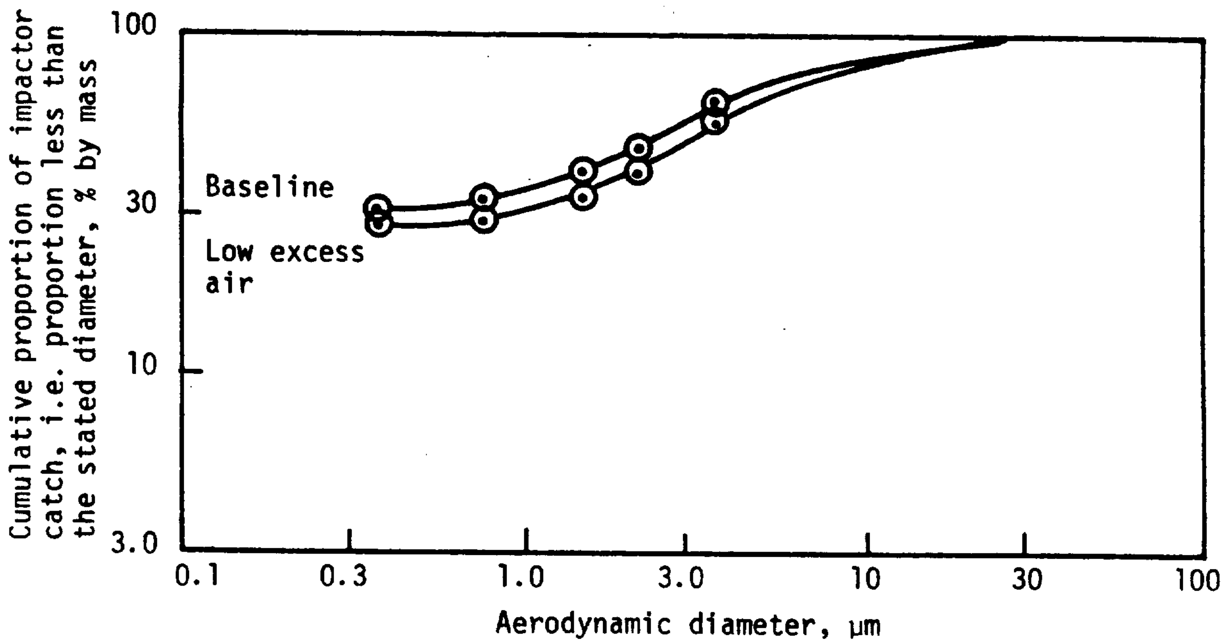

Figure 5-9. Effect of low excess air NO_x control on particle size distribution for a residual oil-fired watertube industrial boiler (Reference 5-15).

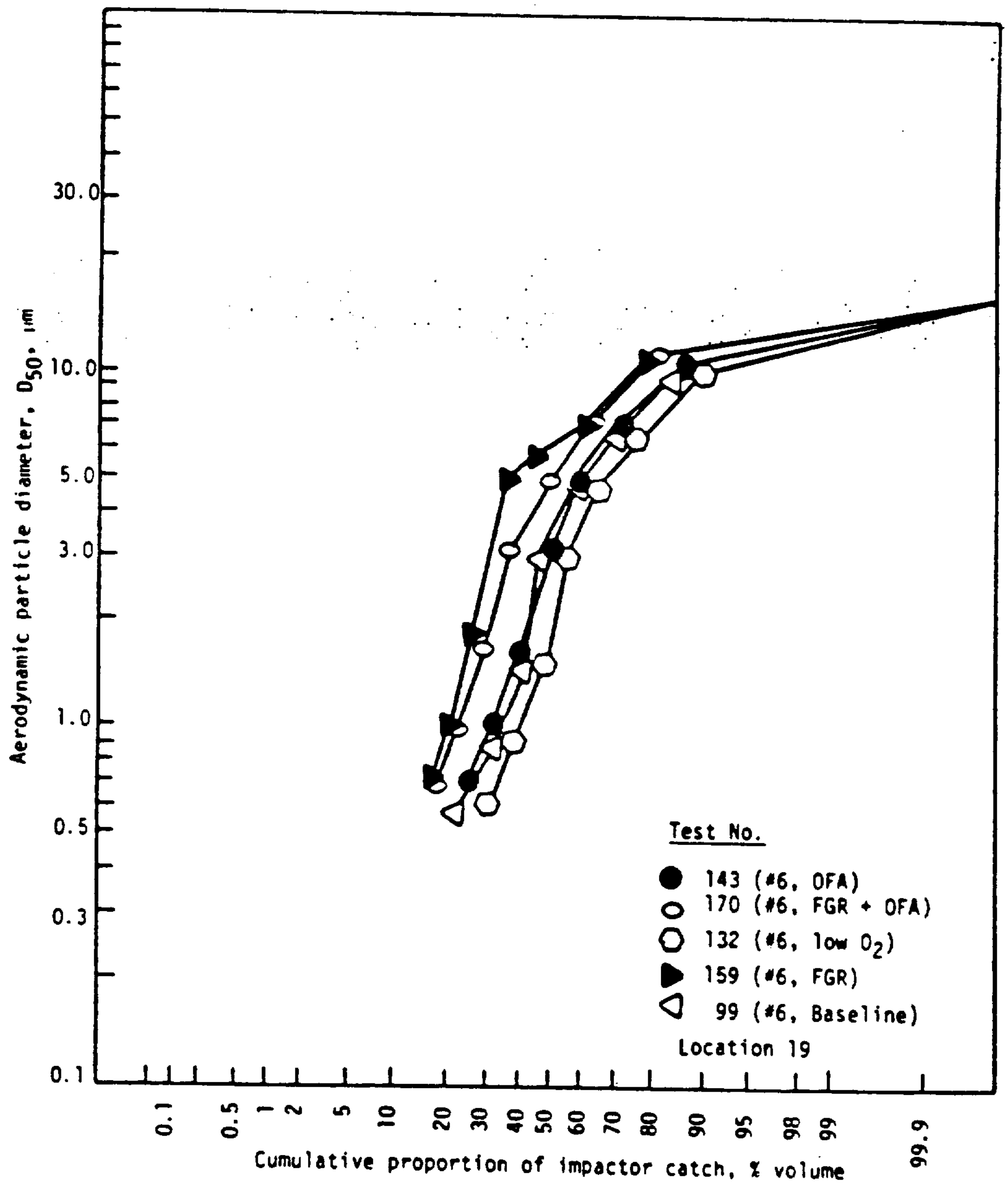

Figure 5-10. Effect of NO_x controls on particle size distribution for a residual oil-fired watertube industrial boiler (Reference 5-18).

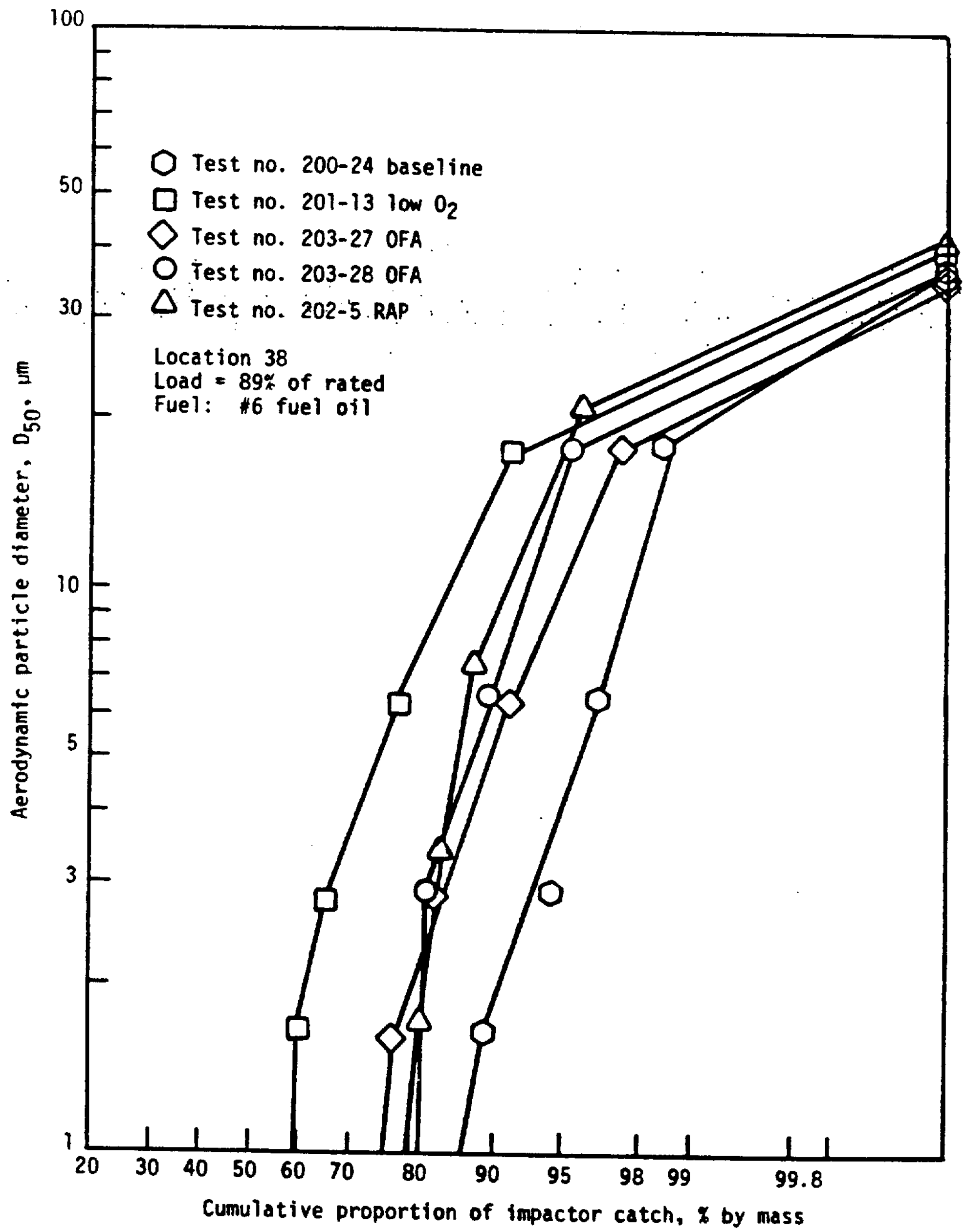

Figure 5-11. Effect of NO_x controls on particle size distribution for a residual oil-fired watertube industrial boiler (Reference 5-18).

TABLE 5-8. EFFECT OF COMBINED LOW EXCESS AIR, STAGED COMBUSTION, AND FLUE GAS RECIRCULATION ON POLYCYCLIC ORGANIC MATTER (POM) EMISSIONS FROM A RESIDUAL OIL-FIRED INDUSTRIAL BOILER (Reference 5-18)

Sample Train Fraction	Polycyclic Organic Matter (POM)					
	Test Number[a]					
	2-Baseline		3-Low NO_x		4-Low NO_x	
	μg/g	μg/m^3	μg/g	μg/m^3	μg/g	μg/m^3
10 μm solids	IS[b]	--	1	0.1	IS	--
3 μm solids	IS	--	IS	--	IS	--
1 μm solids	IS	--	IS	--	IS	--
Filters	IS	--	IS	--	IS	--
Solids section wash	NR[c]	--	NR	--	NR	--
XAD-2 resin	0.005	0.04	0.0008	0.006	<0.1	<0.8
Organic module rinse	IS	--	1.45	50	IS	--
Condensate	<0.001	<0.24	0.002	0.5	NR	--
Impinger 1-3	--	--	--	--	--	--

[a]Test 1 results were obtained using a fuel with a different analysis.
[b]Insufficient sample.
[c]Not recorded.

TABLE 5-9. EFFECT OF NO_x CONTROL ON POLYCYCLIC ORGANIC MATTER (POM) EMISSIONS FROM A RESIDUAL OIL-FIRED BOILER: XAD-2 RESIN SAMPLE (Reference 5-18)

POM Component[b]	Baseline		Low NO_x[a]	
	ng POM / g Particulate	ng POM / m^3 Flue Gas	Ng POM / g Particulate	ng POM / m^3 Flue Gas
Anthracene	3.2	24	0.45	3.4
Phenanthrene	--	--	0.02	0.1
Methyl Anthracenes	0.2	1.6	0.12	0.9
Fluoranthene	1.2	9.0	0.13	0.9
Pyrene	0.05	0.4	0.05	0.4
Benzo(c)phenanthrene	0.002	0.02	--	--
Chrysene	0.03	0.19	0.004	0.05
Benzo Fluoranthenes	0.007	0.05	0.007	0.05
Benz(a)pyrene	0.004	0.032	--	--
Benz(e)pyrene	0.004	0.032	--	--
Total POM	4.74	35.5	0.78	5.58

[a]Low NO_x condition: combined low excess air, staged combustion, and flue gas recirculation.

[b]Analysis by gas chromatography/mass spectrometry.

TABLE 5-10. EFFECT OF COMBINED LOW EXCESS AIR, STAGED COMBUSTION, AND FLUE GAS RECIRCULATION ON TRACE SPECIES EMISSIONS FROM A RESIDUAL OIL-FIRED INDUSTRIAL BOILER (Reference 5-18)

	Total Emission Concentrations by Atomic Absorption, μg/m³			Total Emission Concentrations by Spark Source Mass Spectrometry, μg/m³	
Test	2	3[a]	4[a]	2	3
Condition	Baseline	Low NO_x	Low NO_x	Baseline	Low NO_x
Antimony	< 380	< 540	< 350	11	160
Arsenic	6.5 < 15	59 < 64	55	6.5	6 < 12
Barium	95 < 210	640 < 740	800 < 850	MC[b]	640
Beryllium	< 6	< 8.9	< 6	0.055 < 3	0.3 < 2
Cadmium	13	4.8 < 12	1.1 < 6	7.5 < 13	0.09 < 5
Calcium	650	2000	440 < 460	2000 < MC	67 < MC
Chromium	750	740	530	960	500
Cobalt	65 < 130	79 < 150	18 < 85	8 < MC	94
Copper	32	39 < 44	95	49	130
Iron	4300	4700	3100	1300 < MC	1100
Lead	45 < 70	9.9 < 21	< 15	52 < 67	54
Manganese	70	99	65	69	64
Mercury	< 1.9	0.06 < 21	2	NR[c]	NR
Nickel	1300 < 1400	1600	2200	180 < MC	240 < MC
Selenium	< 12	9.9 < 290	< 11	2 < 5	100 < 110
Tellurium	< 300	< 450	< 290	0.04 < 3	0.2 < 3
Tin	< 750	< 1000	< 700	0.4 < 8	12
Titanium	70 < 1600	120 < 2500	20 < 100	53	580
Vanadium	3200 < 3400	3400 < 3600	2400	8 < MC	9 < MC
Zinc	370	810	3300	MC	680
Chloride	12000	3500	6000	4.3	2100
Fluoride	170 < 180	64 < 79	24 < 33	23	170
Nitrates	130	110 < 120	85	--	--
Sulfates	18000	18000	21000	--	--

[a] Tests 3 and 4 are duplicate runs.
[b] MC -- Major component, exceeds maximum measurable quantity (about 1,000 μg/g for spark source mass spectrometry).
[c] NR -- Not reported.

TABLE 5-11. TRACE SPECIES EMISSIONS FROM A RESIDUAL OIL-FIRED INDUSTRIAL BOILER UNDER BASELINE CONDITIONS (TEST 2) (Reference 5-18)

Sample Type	Nozzle, Probe, 10 µm Cyclone Solids		3 µm Cyclone Solids		1 µm Cyclone Solids		Filters		Solid Section Wash	
Sample Number	566		716		720		538		19-2A	
Sample Weight/Vol.	1.6620 g		0.4441 g		0.2196 g		0.4157 g		1605 ml	
Units	µg/g	µg/m³	µg/g	µg/m³	µg/g	µg/m³	µg/g	µg/m³	µg/ml	µg/m³
Antimony	< 38	< 3.2	< 210	< 4.7	< 250	< 2.7	< 500	< 10	< 0.5	< 40
Arsenic	< 1.5	< 0.13	33	0.73	< 10	< 0.11	200	4.2	0.019	1.4
Barium	38	3.2	460	10	6030	66	800	17	< 0.1	< 8
Beryllium	< 0.8	< 0.065	< 4.2	< 0.093	< 5	< 0.055	< 10	< 0.2	< 0.005	< 0.4
Cadmium	0.9	0.065	< 4.2	< 0.093	< 5	< 0.055	< 10	< 0.2	0.005	0.4
Calcium	1900	160	1900	42	3500	38	4800	100	0.49	39
Chromium	72	6	140	3.1	310	3.4	240	5	0.09	7.2
Cobalt	120	10	310	6.7	940	10	1600	33	< 0.2	< 16
Copper	46	3.8	50	1.1	100	1.1	460	9.6	0.06	4.8
Iron	5400	450	7200	160	32000	350	21000	440	2.6	210
Lead	150	13	< 20	< 0.44	< 25	< 0.27	1000	21	0.14	11
Manganese	51	4.3	75	1.7	210	2.3	250	5.2	0.17	14
Mercury	< 0.03	< 0.0025	< 0.17	< 0.0038	< 0.3	< 0.0022	< 0.4	< 0.008	< 0.005	< 0.4
Nickel	1900	160	2200	49	9000	99	30000	620	0.77	62
Selenium	< 1.5	< 0.13	< 8	0.19	< 10	< 0.11	< 20	< 0.42	< 0.01	0.8
Tellurium	< 38	< 3.2	< 210	< 4.7	< 250	< 2.7	< 500	< 10	< 0.3	< 24
Tin	< 76	< 6.3	< 420	< 9.3	< 500	< 5.5	<1000	< 21	< 1	< 80
Titanium	< 460	< 38	<1200	< 27	2500	27	<3000	< 62	< 1	< 80
Vanadium	6300	520	10000	220	43000	470	89000	1800	2.5	200
Zinc	400	33	400	8.9	1300	14	4900	100	1.7	140
Chloride	279	23	NES	NES	NES	NES	11600	240	2.1	170
Fluoride	205	17	134	3	909	10	< 2	< 0.04	< 0.1	< 8
Nitrates	113	9.4	NES	NES	NES	NES	39.5	0.82	0.24	19
Sulfates	14200	1200	NES	NES	NES	NES	457000	9500	7.0	560

NES: Indicates not enough sample.

TABLE 5-12. TRACE SPECIES EMISSIONS FROM A RESIDUAL OIL-FIRED INDUSTRIAL BOILER UNDER LOW NO_x CONDITIONS (TEST 3)[a] (Reference 5-18)

Sample Type	Nozzle, Probe, 10 μm Cyclone Solids		3 μm Cyclone Solids		1 μm Cyclone Solids		Filters		Solid Section Wash	
Sample Number	722		723		726		539		19-3A	
Sample Weight/Vol.	2.4163 g		1.0724 g		0.2120 g		0.9974 g		1839 ml	
Units	μg/g	μg/m^3	μg/g	μg/m^3	μg/g	μg/m^3	μg/g	μg/m^3	μg/ml	μg/m^3
Antimony	< 50	< 6	< 2500	< 130	< 830	< 9	< 170	< 8	< 0.5	< 46
Arsenic	4	0.5	< 100	< 5	< 33	< 0.4	33	1.6	0.01	0.[illegible]
Barium	480	57	< 1000	< 53	< 330	< 4	730	36	< 0.1	< 9
Beryllium	< 1	< 0.12	< 50	< 3	< 17	< 0.2	< 3.3	< 0.2	< 0.005	< 0.5
Cadmium	< 1	< 0.12	< 50	< 3	< 17	< 0.2	< 3.3	< 0.2	< 0.005	< 0.5
Calcium	1900	230	3500	190	3000	31	3100	150	15	1400
Chromium	69	8	950	50	300	3.1	180	8.9	0	0
Cobalt	104	12	450	24	300	3.1	807	40	< 0.2	< 18
Copper	43	5	< 50	< 3	< 150	< 2	200	9.9	0.11	10
Iron	5200	620	4400	230	6500	68	20000	1000	1.8	160
Lead	NES	--	NES	--	NES	--	NES	--	0.11	10
Manganese	49	6	200	11	117	1.2	160	7.9	0.16	15
Mercury	0.5	0.06	< 2	< 0.1	< 0.67	< 0.007	< 0.13	< 0.006	< 0.005	< 0.5
Nickel	970	120	1700	90	3000	31	13000	640	0.5	46
Selenium	< 2	0.24	< 5000	< 270	< 33	< 0.4	< 6.7	< 0.3	0.04	3.6
Tellurium	< 50	6	< 2500	< 130	< 830	< 9	< 170	< 8	< 0.3	< 27
Tin	< 100	12	< 5000	< 270	< 1700	< 18	< 330	< 16	< 1	< 91
Titanium	600	72	< 15000	< 800	5000	52	< 1000	< 49	< 1	< 91
Vanadium	5400	650	7000	370	14000	150	43000	2100	1.4	130
Zinc	281	34	250	13	350	3.7	3000	150	0.49	45
Chloride	< 30	< 4	< 97	< 5	NES	--	1700	84	< 0.5	< 46
Fluoride	54	6.5	NES	--	NES	--	< 1	< 0.05	< 0.1	< 9
Nitrates	43	5.1	67	3.6	NES	--	46	2.3	0.26	24
Sulfates	8910	1100	14000	740	NES	--	170000	8400	12	1100

NES: Indicates not enough sample.

[a]Low NO_x condition: combined low excess air, staged combustion, and flue gas recirculation.

elements, plus barium, cobalt, and copper were increased by over 20% in the total amount of solid particulate collected.

Comparison of the concentration of arsenic, cobalt, copper, iron, manganese, nickel, vanadium, zinc, chloride and sulfates at each size fraction shows a clear shift in concentration towards the smaller particle sizes during low NO_x operation. The remaining species were not present in sufficient quantities to allow an assessment.

It appears that, for this particular boiler, an increase in trace metal emissions, in proportion to increased particulate, occurs with increased NO_x control. A shift towards increased trace metal concentration in smaller particulate can also be seen.

The NO_x control data, unfortunately, are still very limited, presenting information only on a combination of control technologies, and only for one boiler. More data must be collected before firm conclusions can be presented.

The above emission data were presented for combustion modifications only. Low NO_x burners and ammonia injection are still in the development stages. Actual incremental emission data are not available.

Due to the comparative high cost of this technique, the ammonia injection process will probably not be feasible on small size boilers such as firetubes and package watertubes unless stringent emission levels are required. In addition, since these industrial units are generally not base loaded, that is they do not operate at a steady continuous load, the variable heat input will cause significant flue gas temperature fluctuations which will reduce the performance of the control technique.

5.5 ENVIRONMENTAL IMPACTS OF NO_x CONTROLS FOR DISTILLATE OIL AND NATURAL GAS-FIRED BOILERS

Distillate oil and natural gas-fired industrial boilers are generally packaged firetube boilers. Table 5-13 presents the incremental emission data available for distillate oil-fired boilers. Table 5-14 presents the incremental emission data available for natural gas-fired boilers.

Figure 5-12 presents the data for CO emissions with the various types of NO_x control techniques for distillate oil fuels. Carbon monoxide emissions increase in all cases where NO_x reductions occurred. Flue gas recirculation resulted in the largest decrease in NO_x emission

TABLE 5-13. INCREMENTAL EMISSIONS FROM DISTILLATE OIL-FIRED INDUSTRIAL BOILERS (References 5-15 and 5-17)

Boiler Test Series	System: Actual/Design Heat Input MW (10^6 Btu/hr)	System: Boiler Type	System: NO_x Control (Excess O_2, %)	NO_x Emissions: ng/J	NO_x Emissions: Incremental Change, ng/J	Criteria Emissions[a]: Pollutant	Criteria Emissions[a]: ng/J	Criteria Emissions[a]: Incremental Change, ng/J
A	6.7/9.7 (23)/(33)	Watertube	Baseline (5.9)	66		CO	0	
						UHC	--	
						SO_3	7	
						PART	20	
	7.0/9.7 (24)/(33)		Low Excess Air (2.8)	57	-9	CO	6	+6
						UHC	--	--
						SO_3	--	--
						PART	--	--
B	26/32 (89)/(110)	Watertube	Baseline (5.7)	115		CO	0	
						UHC	--	
						SO_3	8	
						PART	10	
	26/32 (89)/(110)		Low Excess Air (3.8)	--	--	CO	0	0
						UHC	--	--
						SO_3	--	--
						PART	--	--
C	2.0/2.9 (7)/(10)	Firetube	Baseline (7.2)	121		CO	0	
						UHC	24	
						SO_3	1	
						PART	23	
	1.5/2.9 (5)/(10)		Low Excess Air (3.6)	85	-36	CO	0	0
						UHC	5	-19
						SO_3	--	--
						PART	--	--
D	4.1/5.3 (14)/(18)	Watertube	Baseline (3.6)	37		CO	17	
						UHC	--	
						SO_3	6	
						PART	17	

[a]No data available on noncriteria emissions

TABLE 5-13. Continued

Boiler Test Series	System: Actual/Design Heat Input MW (10^6 Btu/hr)	System: Boiler Type	System: NO_x Control (Excess O_2, %)	NO_x Emissions: ng/J	NO_x Emissions: Incremental Change, ng/J	Criteria Emissions[a]: Pollutant	Criteria Emissions[a]: ng/J	Criteria Emissions[a]: Incremental Change, ng/J
D (Cont.)	4.1/5.3 (14)/(18)	Watertube	Low Excess Air (2.6)	34	-3	CO UHC SO_3 PART	158 -- -- --	+141 -- -- --
	4.1/5.3 (14)/(18)		Baseline (30)	54	--	CO UHC SO_3 PART	0 1 -- --	
	4.1/5.3 (14)/(18)		High Excess Air (4.3)	55	+1	CO UHC SO_3 PART	0 3 6 8	0 +2 -- --
	4.1/5.3 (14)/(18)		Low Excess Air (1.6)	44	-10	CO UHC SO_3 PART	60 2 -- --	+60 +1 -- --
	3.5/5.3 (12)/(18)		Baseline (4.3)	47	--	CO UHC SO_3 PART	0 -- -- 9	-- -- -- --
	3.5/5.3 (12)/(18)		Low Excess Air (3.7)	46	-1	CO UHC SO_3 PART	0 -- -- --	0 -- -- --
E	4.7/5.7 (16)/(20)	Firetube	Baseline (5.8)	126	--	CO UHC SO_3 PART	0 6 4 14	
	4.1/5.9 (14)/(20)		Low Excess Air (2.7)	76	-50	CO UHC SO_3 PART	0 17 -- --	0 +11 -- --

[a]No data available on noncriteria emissions

Table 5-13. Continued

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
F	4.1/5.3 (14)/(18)	Watertube	Baseline (3.1)	66		CO	3	
						UHC	1	
						SO_3	1	
						PART	25	
	4.1/5.3 (14)/(18)		Low Excess Air (1.2)	55	-11	CO	62	+59
						UHC	1	0
						SO_3	3	+2
						PART	15	-10
	4.1/5.3 (14)/(18)		Flue Gas Recirculation (0.85) (28.4 % FGR)	17	-49	CO	7	+4
						UHC	1	+0
						SO_3	5	+4
						PART	5	-20
	4.4/5.3 (15)/(18)		Flue Gas Recirculation (0.7) (27.9 % FGR)	19	-47	CO	24	+21
						UHC	1	0
						SO_3	--	--
						PART	--	--
	4.1/5.3 (14)/(18)		Overfire Air (3.1)	54	-12	CO	12	+9
						UHC	1	0
						SO_3	1	0
						PART	12	-13
	4.4/5.3 (15)/(18)		Overfire Air (3.2)	55	-11	CO	8	5
						UHC	0	-1
						SO_3	--	--
						PART	--	--
G	5.0/8.2 (17)/(28)	Watertube	Baseline (5.3)	51		CO	31	
						UHC	--	
						SO_3	12	
						PART	13	
	5.9/8.2 (20)/(28)		Low Excess Air (4.7)	47	-4	CO	51	+20
						UHC	--	--
						SO_3	--	--
						PART	--	--

[a]No data available on noncriteria emissions

TABLE 5-13. Concluded

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
H	20/58 (68)/(200)	Watertube	Baseline (4.4)	58		CO UHC SO_3 PART	0 0 -- 12	
			Overfire Air (5.4)	55	-3	CO UHC SO_3 PART	0 0 -- --	0 0 -- --

[a]No data available on noncriteria emissions

TABLE 5-14. INCREMENTAL EMISSIONS FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS (Reference 5-17)

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
A	5.0/7.9 (17)/(27)	Watertube	Baseline (2.2)	40		CO	21	
						UHC	--	
						SO_3	--	
						Part.	--	
	7.0/7.9 (24)/(27)		Low Excess Air (0.9)	38	-2	CO	152	+131
						UHC	--	--
						SO_3	--	--
						Part.	--	--
B	32/46 (110)/(157)	Watertube	Baseline (5.3)	79		CO	0	
						UHC	22	
						SO_3	--	
						Part.	--	
	35/46 (120)/(157)		Low Excess Air (3.2)	82	+3	CO	3	+3
						UHC	12	-13
						SO_3	--	--
						Part.	--	--
	35/46 (120)/(157)		Reduced Air Preheat (5.2)	81	+2	CO	0	0
						UHC	12	-10
						SO_3	--	--
						Part.	--	--
C	7.9/20 (27)/(70)	Watertube	Baseline (5.7)	108		CO	0	
						UHC	0	
						SO_3	--	
						Part.	--	
	7.9/20 (27)/(70)		Low Excess Air (3.7)	85	-23	CO	4	+4
						UHC	0	0
						SO_3	--	--
						Part.	--	--
	7.9/20 (27)/(70)		Reduced Air Preheat (5.6)	100	-8	CO	0	0
						UHC	--	--
						SO_3	--	--
						Part.	--	--

[a]No data available on noncriteria emissions

TABLE 5-14. Continued

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
D	22/38 (76)/(130)	Watertube	Baseline (7.1)	82		CO	62	
						UHC	--	
						SO_3	--	
						Part.	--	
	22/38 (76)/(130)		Reduced Air Preheat (7.1)	83	+1	CO	70	+12
						UHC	--	--
						SO_3	--	--
						Part.	--	--
	24/35 (82)/(120)		Baseline (4.4)	117		CO	0	
						UHC	--	
						SO_3	--	
						Part.	--	
	24/35 (82)/(120)		Low Excess Air (2.2)	111	-1	CO	0	0
						UHC	--	--
						SO_3	--	--
						Part.	--	--
E	57/73 (193)/(250)	Watertube	Baseline (2.6)	96		CO	100	
						UHC	7	
						SO_3	--	
						Part.	--	
	59/73 (200)/(250)		Reduced Air Preheat (2.6)	71	-25	CO	112	+12
						UHC	--	--
						SO_3	--	--
						Part.	--	--
	59/73 (200)/(250)		Reduced Air Preheat (2.5)	95	-1	CO	99	-1
						UHC	--	--
						SO_3	--	--
						Part.	--	--

[a]No data available on noncriteria emissions

TABLE 5-14. Continued

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
F	12/13 (40)/(45)	Watertube	Baseline (1.9)	112		CO UHC SO_3 Part.	0 2 -- --	
	12/13 (40)/(45)		Low Excess Air (1.35)	93	-19	CO UHC SO_3 Part.	279 0 -- --	-279 -2 -- --
	12/13 (40)/(45)		Reduced Air Preheat (1.75)	120	+8	CO UHC SO_3 Part.	9 2 -- --	+9 0 -- --
	10/13 (35)/(45)		Reduced Air Preheat (1.6)	63	-49	CO UHC SO_3 Part.	9 0 -- --	+9 -2 -- --
	10/13 (35)/(45)		Overfire Air (3.4)	82	-30	CO UHC SO_3 Part.	6 0 -- --	+6 -- -- --
	10/13 (35)/(45)		Overfire Air (2.9)	52	-60	CO UHC SO_3 Part.	11 -- -- --	+11 -- -- --
G	4.1/5.3 (14)/(18)	Watertube	Baseline (3.2)	30		CO UHC SO_3 Part.	3 1 -- --	

[a]No data available on noncriteria emissions

TABLE 5-14. Continued

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
G (Cont.)	4.1/5.3 (14)/(18)	Watertube	Low Excess Air (2.0)	29	-1	CO UHC SO_3 Part.	25 -- -- --	+22 -- -- --
	4.1/5.3 (14)/(18)		Flue Gas Recirculation (2.9)	19	-11	CO UHC SO_3 Part.	0 0 -- --	-3 -1 -- --
	3.8/5.3 (13)/(18)		Flue Gas Recirculation (2.75)	8	-22	CO UHC SO_3 Part.	37 13 -- --	+34 +12 -- --
	4.1/5.3 (14)/(18)		Overfire Air (2.8)	39	+9	CO UHC SO_3 Part.	0 0 -- --	-3 -1 -- --
	4.1/5.3 (14)/(18)		Overfire Air (2.4)	27	-3	CO UHC SO_3 Part.	3 0 -- --	0 -1 -- --
H	12/13 (40)/(45)	Watertube	Baseline (1.6)	82		CO UHC SO_3 Part.	43 -- -- --	
	12/13 (40)/(45)		Low Excess Air (1.25)	71	-11	CO UHC SO_3 Part.	619 -- -- --	576 -- -- --

[a]No data available on noncriteria emissions

TABLE 5-14. Continued

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
H (Cont.)	12/13 (40)/(45)	Watertube	Overfire Air (2.25)	57	-25	CO	38	-5
						UHC	--	--
						SO_3	--	--
						Part.	--	--
	12/13 (40)/(45)		Reduced Air Preheat (2.2)	62	-20	CO	3	-40
						UHC	--	--
						SO_3	--	--
						Part.	--	--
	12/13 (40)/(45)		Overfire Air (2.25)	53	-29	CO	85	-42
						UHC	--	--
						SO_3	--	--
						Part.	--	--
I	4.1/5.3 (14)/(18)	Watertube	Baseline (3.0)	49		CO	1	
						UHC	1	
						SO_3	--	
						Part.	--	
	4.1/5.3 (14)/(18)		Flue Gas Recirculation (3.2) (20.3% FGR)	12	-37	CO	6	+5
						UHC	1	0
						SO_3	--	--
						Part.	--	--
	4.1/5.3 (14)/(18)		Flue Gas Recirculation (2.5) (19.9% FGR)	11	-38	CO	5	+4
						UHC	0	-1
						SO_3	--	--
						Part.	--	--
	4.1/5.3 (14)/(18)		Baseline (3.2)	46		CO	6	
						UHC	1	
						SO_3	--	
						Part.	--	

[a]No data available on noncriteria emissions

TABLE 5-14. Continued

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
I (Cont.)	4.1/5.3 (14)/(18)	Watertube	Low Excess Air (1.1)	44	-2	CO UHC SO_3 Part.	208 0 -- --	+302 -1 -- --
	4.1/5.3 (14)/(18)		Overfire Air (2.8)	25	-21	CO UHC SO_3 Part.	91 0 -- --	+85 0 -- --
	4.1/5.3 (14)/(18)		Flue Gas Recirculation (3.3)	13	-33	CO UHC SO_3 Part.	5 0 2 3	-1 0 -- -1
J	2.5/3.5 (8.5)/12)	Firetube	Baseline (7.1)	87		CO UHC SO_3 Part.	19 -- -- --	
	2.2/3.5 (7.5)/(12)		Low Excess Air (6.6)	90	+3	UHC UHC SO_3 Part.	50 -- -- --	+31 -- -- --
	2.2/3.5 (7.5)/(12)		High Excess Air (7.8)	90	+3	CO UHC SO_3 Part.	55 -- -- --	+36 -- -- --
K	5.8/7.3 (20)/(25)	Watertube	Baseline (10.3)	64		CO UHC SO_3 Part.	25 -- -- --	

[a]No data available on noncriteria emissions

TABLE 5-14. Concluded

System				NO_x Emissions		Criteria Emissions[a]		
Boiler Test Series	Actual/Design Heat Input MW (10^6 Btu/hr)	Boiler Type	NO_x Control (Excess O_2, %)	ng/J	Incremental Change, ng/J	Pollutant	ng/J	Incremental Change, ng/J
K (Cont.)	5.8/7.3 (20)/(25)	Watertube	Low Excess Air (7.6)	67	+3	CO UHC SO_3 Part.	27 -- -- --	+2 -- -- --
	5.8/7.3 (20)/(25)		Low Excess Air (9.4)	68	+4	CO UHC SO_3 Part.	31 -- -- --	+6 -- -- --
	5.8/7.3 (20)/(25)		Low Excess Air (6.1)	65	+1	CO UHC SO_3 Part.	36 -- -- --	+11 -- -- --
	5.8/7.3 (20)/(25)		Low Excess Air (5.0)	59	-5	CO UHC SO_3 Part.	883 -- -- --	+858 -- -- --

[a]No data available on noncriteria emissions

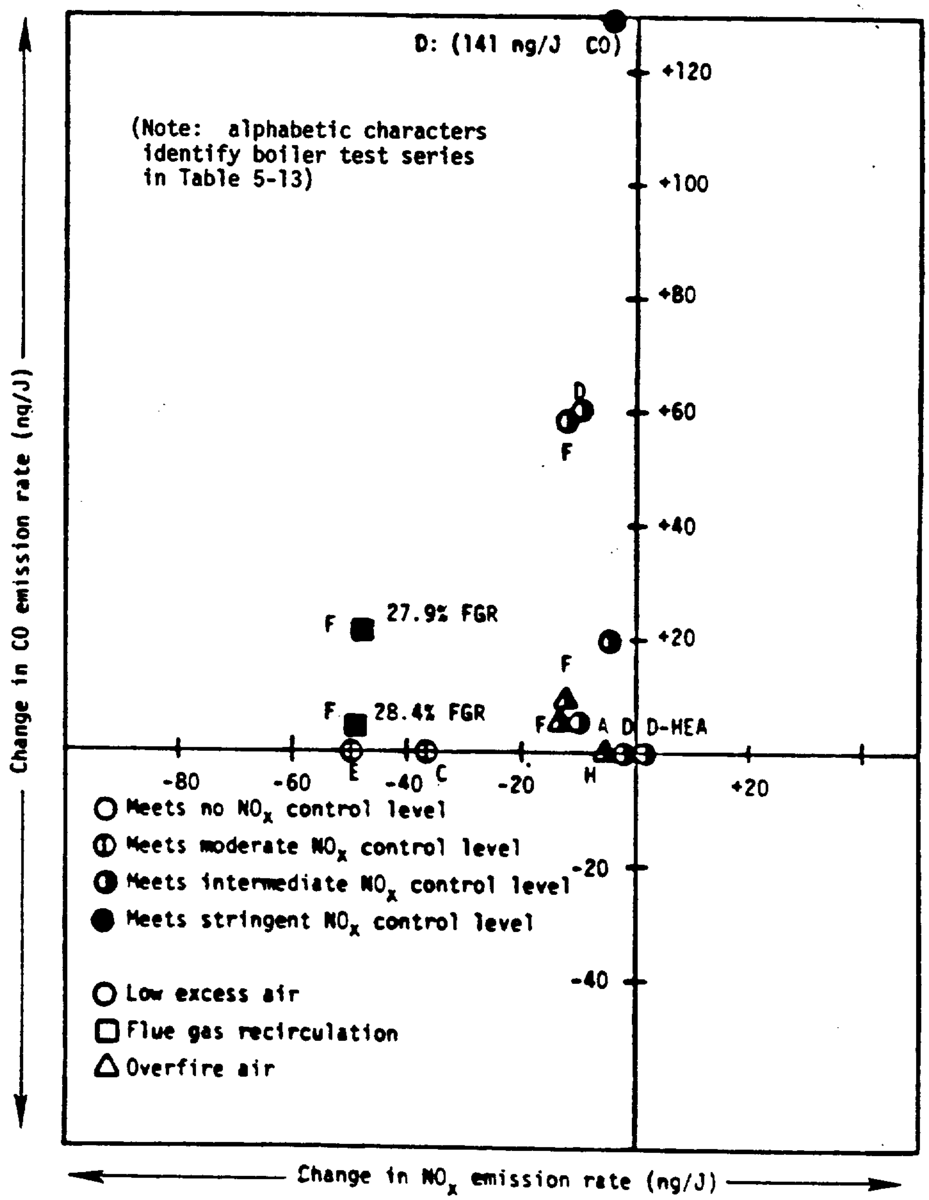

Figure 5-12. Change in CO emission rate with NO_x control for distillate oil-fired industrial boilers (References 5-15 and 5-17).

rate and met the stringent control level in both cases. All other control types met the intermediate control level, with CO emissions varying from no change to substantial increase. Low excess air resulted in the largest CO increases.

Figure 5-13 presents the incremental emission data for unburned vapor phase hydrocarbons from distillate oil-fired boilers. Generally there appears to be no change with NO_x emission reduction.

Data on the emissions for natural gas-fired boilers are presented in Figure 5-14. Low excess air NO_x control results in the largest incremental increases in CO emissions. However, the NO_x emissions are generally reduced to only moderate or intermediate levels. The best control technique for reaching the required NO_x levels without severe incremental emissions impact is flue gas recirculation. All other control techniques are mixed in their ability to control NO_x and their effects on other emissions. Figure 5-15 presents additional CO emission data for gas-fired boilers as a function of low excess air levels. As with coal and residual oil, a point is reached where CO emissions begin to increase rapidly. It is readily apparent that, with this technique, a small incremental decrease in NO_x beyond this point results in a large change in CO emissions at the lower excess oxygen levels.

Figure 5-16 presents the emission rates of unburned hydrocarbons. The quantity of data is very limited. Generally, however, very slight changes are noted with the various NO_x control techniques.

Particulate emissions from natural gas-fired boilers were reported as typically 1.72 to 3.01 ng/J (0.004 to 0.007 $lb/10^6$ Btu) in Reference 5-19. The reporting of particulate emissions during later test work with various NO_x techniques were omitted due to the low emission rates. Distillate oil-fired boilers emitted 8.6 to 17.2 ng/J (0.02 to 0.04 $lbs/10^6$ Btu) in the same test series. Particulate emissions data (Table 5-13) are plotted in Figure 5-17. Once again, as noted with coal- and residual oil-firing, particulate emissions decrease with NO_x control. Since each of the boilers tested was equipped with a dust control device, this could indicate an increase in particle size under low NO_x conditions and improved dust control device efficiency. Table 5-15 confirms the shift

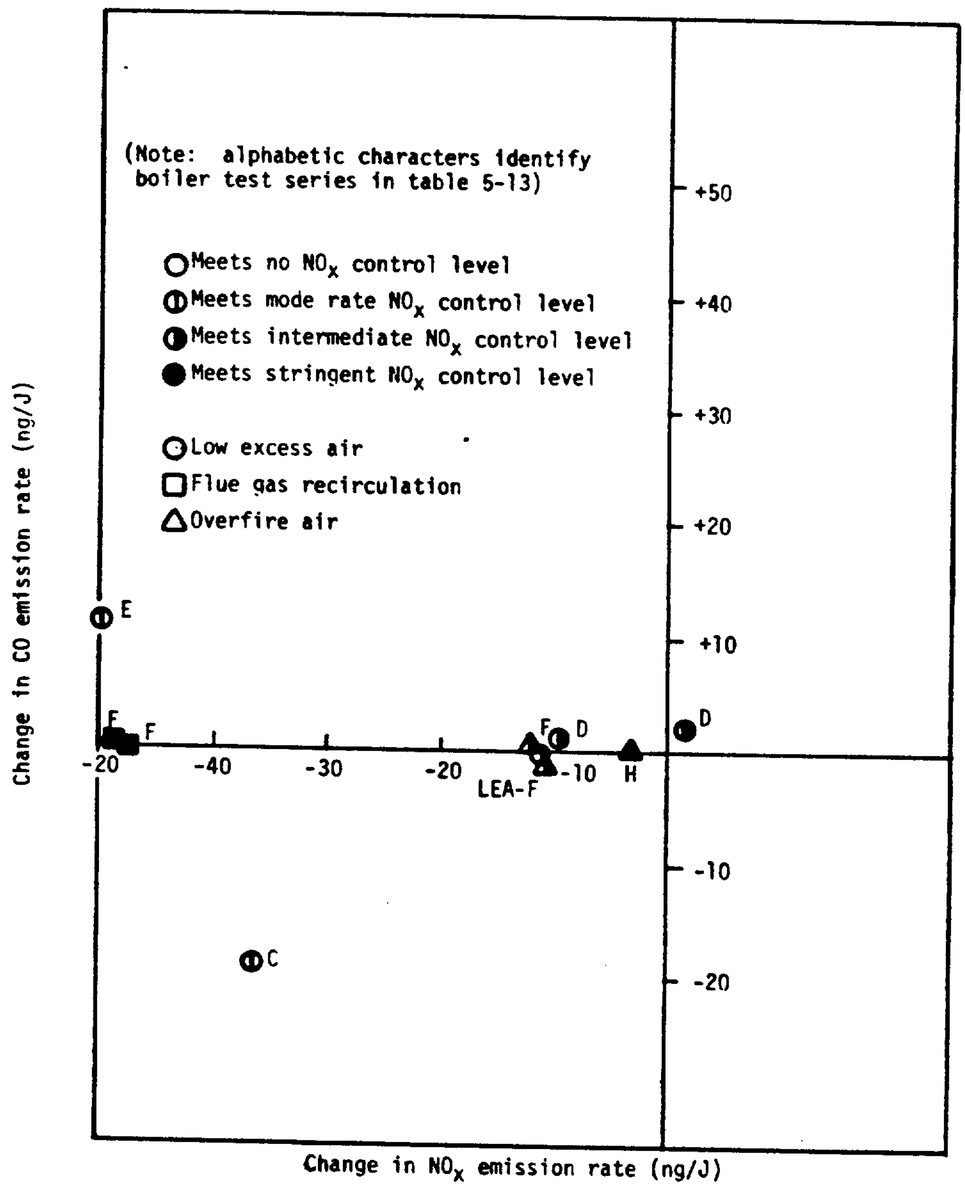

Figure 5-13. Change in UHC emission rate with NO_x control for distillate oil-fired industrial boilers (Reference 5-15 and 5-17).

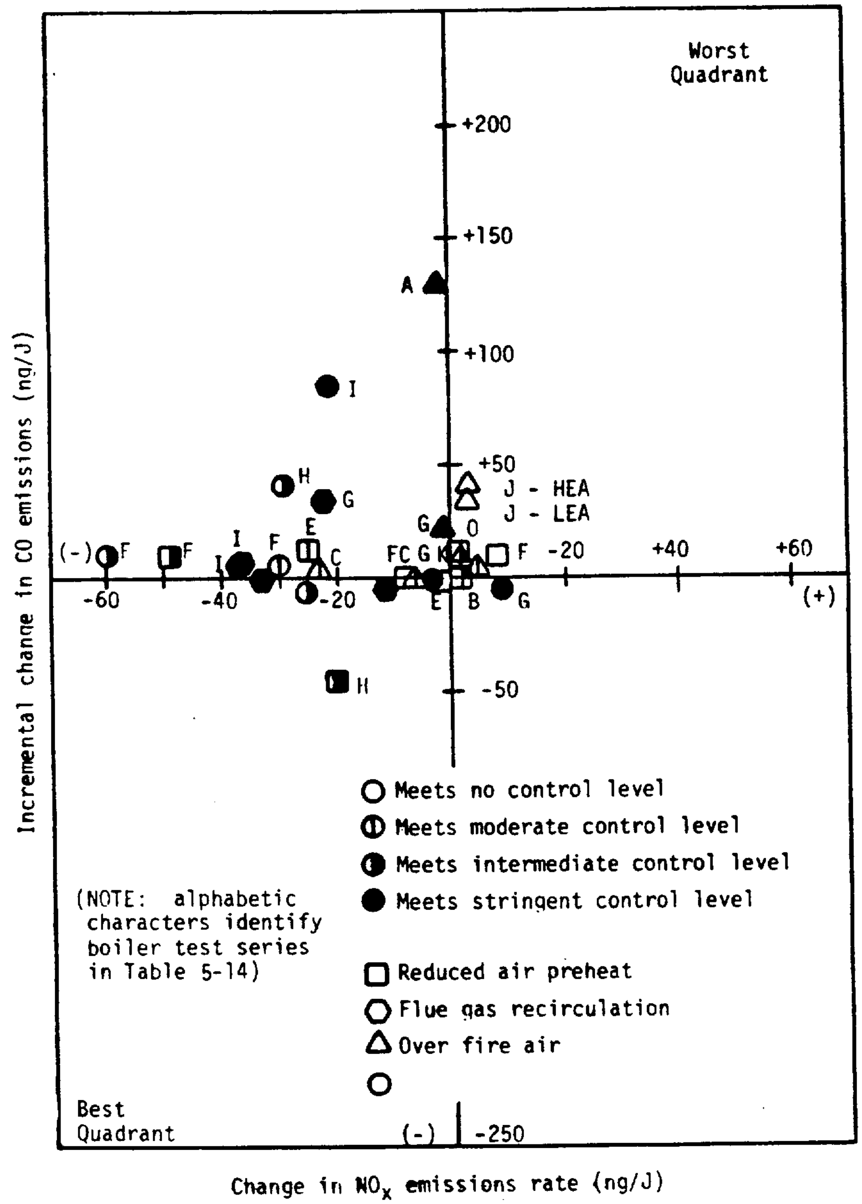

Figure 5-14. Change in CO emissions with NO_x control for a gas-fired industrial boiler (Reference 5-17).

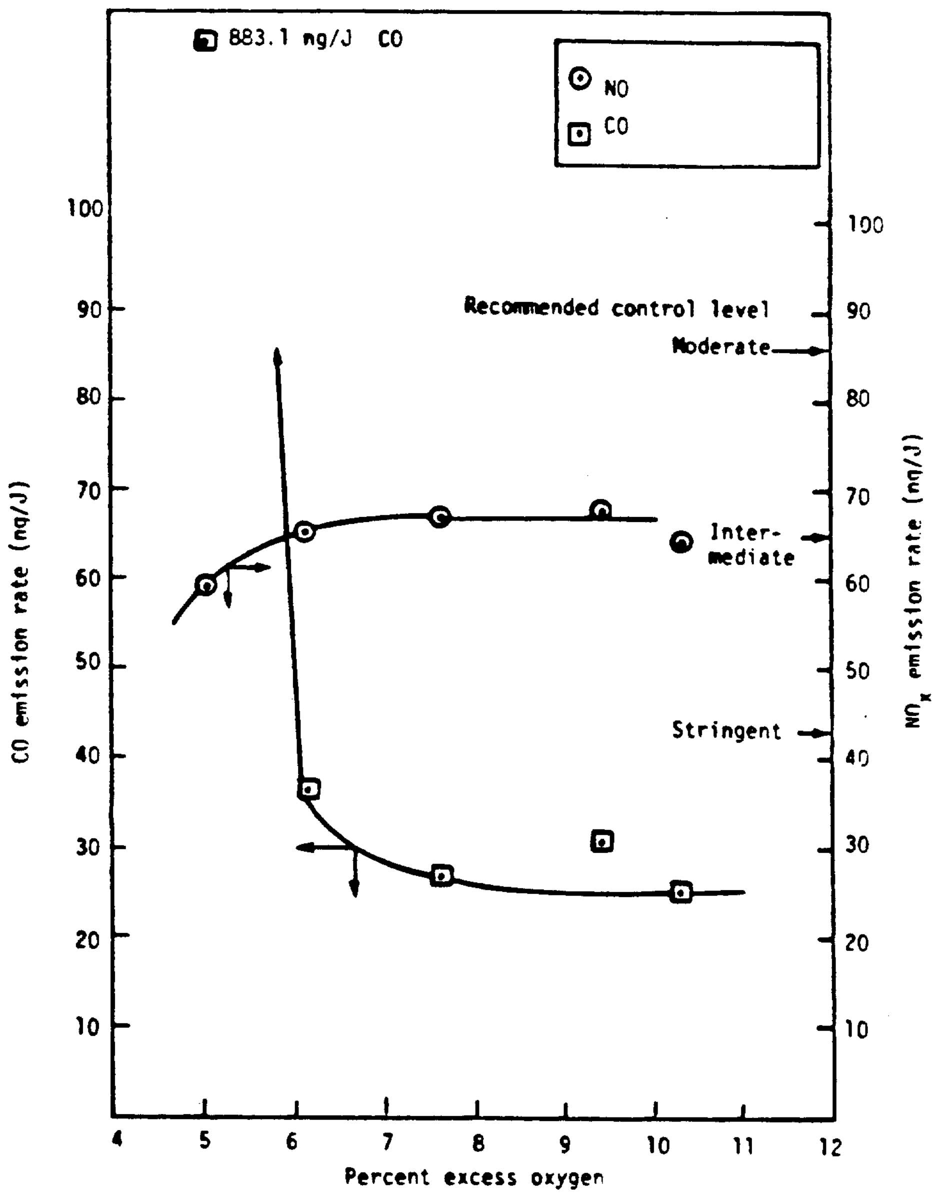

Figure 5-15. Changes in CO and NO_x emissions with reduced excess oxygen for a gas-fired watertube industrial boiler (Reference 5-17).

TABLE 4.5-1

SUMMARY OF METHODS EVALUATION*

Method	Sampling Protocol				Analytical Protocol				
	Efficiency	Specificity (interferences)	Cost	Flexibility	Specificity	Cost	Sensitivity	Flexibility, Dynamic Range, Others	Other Carbonyls
Spectrophotometric									
Chromotropic acid	●	--	●	●	--	●	--	--	0
Pararosaniline	●	--	●	●	--	●	--	--	0
MBTH	●	0	●	●	0	●	--	--	●
Acetylacetone (Nash)	0	●	●	●	●	●	--	--	0
AHMT	●	0	●	●	0	●	--	--	0
Chromatographic									
GC-MS	●	--	●	●	--	0	●	--	0
DNPH-GC	●	●	●	●	●	●	●	--	●
DNPH-HPLC	●	●	●	●	●	●	●	●	●
Bisulfite-GC	●	--	●	●	0	●	0	--	●
Dansyl-HPLC	●	●	●	●	●	●	●	●	●
Oxazolidine-GC	●	--	●	●	--	●	0	--	0
Spectroscopic									
Infrared	--	--	--	--	●	0	--	--	0
Differential ultraviolet	--	--	--	--	●	0	●	●	0
Other Active Sampling Methods									
Ion chromatography	--	0	●	--	0	●	0	--	**
Chemiluminescence	●	0	●	●	0	●	●	--	0
Passive Methods									
Bisulfite	●	--	●	0	--	●	0	--	0

*● good, 0 poor, --intermediate, or no data, or does not apply.
** Acetaldehyde only.

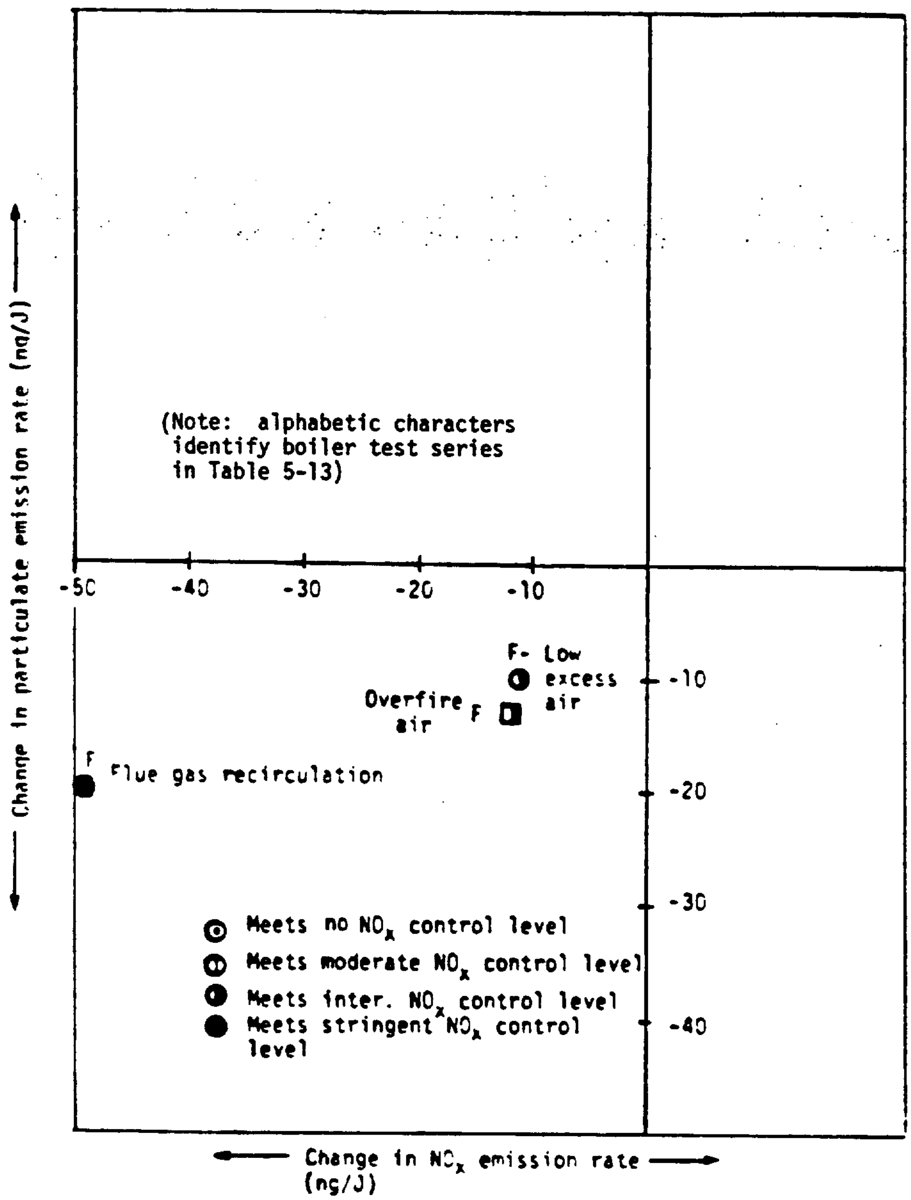

Figure 5-17. Change in particulate emissions with NO_x control for a distillate oil-fired watertube industrial boiler (Reference 5-15).

TABLE 5-15. EFFECT OF OVER FIRE AIR NO_x CONTROL ON PARTICLE SIZE DISTRIBUTION FOR A DISTILLATE OIL-FIRED WATERTUBE INDUSTRIAL BOILER (Reference 5-16)

Fuel Type	Burner Type	Test Load MW	NO_x ng/J	Impact Flow $cm^3\ s^{-1}$	D_{50} Cycl. μm	Actual D_{50} of Stage No.[b] 1 μm	2 μm	3 μm	4 μm	5 μm	Cyclone, Stage and Filter Catch: Cyclone mg	Stage No. 1 mg	2 mg	3 mg	4 mg	5 mg	Filter mg	Total Catch mg	Comments
No. 2	Steam	16	49.4	28.3	--	3.2	1.9	1.3	0.64	0.32	None	96.9	7.55	0.408	0.756	0.008	0.368	105.6	Lower Load
No. 2	Steam	18	--	28.3	--	3.2	1.9	1.3	0.64	0.32	None	5.60	0.148	0.064	1.032	0.024	0.192	7.06	Low NO_x
No. 2	Steam	18	--	28.3	--	3.2	1.9	1.3	0.64	0.32	None	10.6	3.57	0.788	0.62	0.034	0.20	15.842	Baseline

[a]Particle size distribution determined by use of a Brink model "B' cascade impactor
[b]D_{50} identifies the size fraction in micrometers. Particulates with an aerodynamic diameter greater than the D_{50} cut point will be captured. Increasing stage number corresponds to decreasing particle size.

Schumaker, M.B. and S.T. Weiss. 1981. "Health effects of indoor formaldehyde exposure." Presented at the International Symposium on Indoor Air Pollution, Health and Energy Conservation, Amherst, MA, 13-16 October.

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Traynor, G.W., M.G. Apte, J.R. Girman and C.D. Hollowell. 1981. Indoor air pollution from domestic combustion appliances, Lawrence Berkeley Laboratory, Berkeley, CA, Report No. LBL-12886.

Tuazon, E.C., A.M. Winer, J.N. Pitts Jr. 1981. "Trace pollutant concentrations in a multiday smog episode in the California South Coast Air Basin by long path length Fourier transform infrared spectroscopy," Environmental Science and Technology 15(10):1232-1237.

Woodbury, M. and C. Zenz. 1978. "Formaldehyde vapor problems in homes from chipboard and foam insulation." Presented to the Wisconsin Department of Health, Education and Welfare Committee to Coordinate Toxicology and Related Programs, 24 October.

Yocom, J.E. 1982. "Indoor-outdoor air quality relationships: a critical review," Journal of the Air Pollution Control Association 32(5):500-520.

boilers are expected to capture a major portion of the coal-fired boiler, indeed industrial boiler, market. Thus, two coal-fired traveling grate spreader stoker boilers were selected for testing in the NO_x EA field test program. These tests were both cooperative efforts with the EPA-DOE-ABMA field program on stoker emissions control and efficiency improvement (Reference 5-22). Section 5.7.1 summarizes the NO_x EA emission test results while Section 5.7.2 applies a source analysis model to assess the environmental impact of applying NO_x controls.

5.7.1 Emissions Results

For identification purposes, the first stoker tested was called Site A, the second Site B. Site A was a Foster Wheeler Ltd. boiler combined with a Detroit Stoker traveling grate spreader stoker. The Foster Wheeler steam generator was designed to produce 38 kg/s (300,000 lb/hr) of saturated steam at a pressure of 2.3 MPa (320 psig). Site B was a Riley boiler equipped with a Riley spreader stoker, with a continuous rating of 25 kg/s (200,000 lb/hr) of steam at a pressure of 1.38 MPa (185 psig) and temperature of 533K (500^{o}F). At both sites the NO_x EA field test program consisted of a baseline (normal operation) test and a test under low NO_x conditions. The Site A low NO_x condition was increased over-fire air at the same overall excess air level (actually LEA firing) as baseline. Site B was a low excess air, low NO_x test. Details of the boilers and the test program results are given in References 5-23 and 5-24.

Site A

Table 5-16 shows flue gas vapor species concentration data at the ESP outlet for the two firing conditions. As noted, NO_x emissions were reduced 18 percent under low NO_x conditions. Emission levels of CO, SO_2, and SO_3 all increased under low NO_x firing. However, the increases in sulfur species emissions were probably due to measurement difficulties or inhomogeneities in coal composition, rather than due to changes in firing mode.

Table 5-17 shows particulate load data at the boiler outlet and the ESP outlet. As the table shows, particulate load decreased at the boiler outlet for low NO_x firing, but increased at the ESP outlet, with a corresponding decrease in overall (air heater hopper, mechanical collector, ESP) particle collection efficiency.

TABLE 5-16. FLUE GAS COMPOSITION AT ESP OUTLET: SITE A

	Baseline	Low NO_x
NO_x, ng/J as NO^2	233	192
ppm[a]	382	315
SO_2, ng/J	300	407
ppm[a]	353	479
SO_3, ng/J	2.1	13
ppm[a]	2.0	12
CO, ppm[a]	243	483
O_2, percent dry	6.4	6.5

[a]3 percent O_2, dry.

TABLE 5-17. METHOD 5 PARTICULATE CONCENTRATION: SITE A

	Baseline	Low NO_x
Boiler Outlet		
μg/J	9.86	5.76
g/dscm	26.9	14.5
ESP Outlet		
μg/J	0.013	0.024
g/dscm	0.040	0.063
Overall Collection Efficiency (percent)	99.85	99.57

Table 5-18 shows summary organic analysis results of the flue gas and flue gas SASS samples taken at the ESP outlet. As noted, flue gas organic ($>C_7$) emissions increased under low NO_x firing. Infrared analysis results of sample extracts indicated the presence of carboxylic acids and some aromatics in the baseline extract, and aromatics and possibly an amide in the low NO_x extract.

TABLE 5-18. ORGANIC ANALYSIS RESULTS (mg/dscm): SITE A

	Baseline	Low NO_x
C_1 - C_6 HC (as CH_4)	48.9	-[a]
Total $>C_7$ Organics	1.00	1.79

[a]Data not available

Table 5-19 summarizes flue gas emissions for all components analyzed, including trace elements. For these latter species, within analytical accuracy, emission levels generally remain relatively unchanged with firing mode.

Ash steam composition data are shown in Tables 5-20 through 5-22. As the tables show, ash trace element composition did not vary with firing condition. It is interesting to note, though, that bottom ash nitrate levels (oxidized nitrogen) apparently decreased, and ammonium (reduced nitrogen) levels increased for the low NO_x test. In addition, organic species levels were higher in the low NO_x bottom ash than in the baseline bottom ash, although the baseline mechanical hopper ash had higher organic content than the low NO_x mechanical hopper ash.

Infrared analyses of ash sample extracts indicated that carboxylic acids, esters, or ethers were present in bottom ash samples, and that only aliphatic hydrocarbons were present in ESP hopper ash samples. No information on the organic speciation of mechanical hopper ash samples could be derived because IR spectra obtained were weak.

TABLE 5-19. FLUE GAS COMPOSITION AT ESP OUTLET (μg/dscm): SITE A

	Baseline	Low NO_x
NO_x	6.32×10^5	5.21×10^5
SO_2	8.18×10^5	1.10×10^6
SO_3	5.78×10^3	3.45×10^4
CO	2.46×10^5	4.80×10^5
Particulate	4.0×10^4	6.3×10^4
Antimony	<19	<3.17
Arsenic	3.19	<7.03
Barium	424	70.3
Beryllium	3.76	<0.0965
Bismuth	<24.3	<6.69
Boron	91.4	349
Cadmium	6.06	<17.1
Chromium	17.2	148
Cobalt	9.19	<48.1
Copper	28.5	<97.7
Iron	1.09×10^3	1.9×10^3
Lead	<57.4	<178
Manganese	31.8	<77.3
Mercury	<0.0370	<0.0157
Molybdenum	10.2	<8.02
Nickel	34.3	<142
Selenium	32.4	45.3
Tellurium	1.11	<5.53
Thallium	<34.3	<374
Tin	8.36	<218
Titanium	1.22	578
Vanadium	8.72	<17.2
Zinc	62.7	35.2
Organics (>C_7)	$1.00 \times 10_3$	1.79×10^3
Methane	4.89×10^4	--

TABLE 5-20. BOTTOM ASH COMPOSITION ($\mu g/g$): SITE A

	Baseline	Low NO_x
Antimony	<0.60	<0.70
Arsenic	2	3
Barium	240	150
Beryllium	0.80	1.3
Bismuth	<40	<40
Boron	<5	<5
Cadmium	<1	<1
Chromium	24	26
Cobalt	<5	<6
Copper	42	35
Iron	3.0×10^4	3.1×10^4
Lead	<20	<20
Manganese	540	560
Molybdenum	<1	<2
Nickel	8	<7
Selenium	<0.40	2.10
Tellurium	<0.80	<0.90
Thallium	<50	<60
Tin	520	390
Titanium	4.2×10^3	4.0×10^4
Vanadium	<20	<20
Zinc	17	19
Chloride	<32.9	<36
Fluoride	5.58	6.10
Cyanide	<2.65	<2.90
Nitrate	3.17×10^4	1.45×10^4
Sulfate	26	19
Ammonium	23.1	97
Organics (>C_7)	<1.9	33.3

TABLE 5-21. MECHANICAL HOPPER ASH COMPOSITION ($\mu g/g$): SITE A

	Baseline	Low NO_x
Antimony	<0.60	<0.60
Arsenic	2	2
Barium	9	9
Beryllium	0.540	0.97
Bismuth	<40	<40
Boron	<4	<4
Cadmium	<1	<1
Chromium	3.1	5.9
Cobalt	<5	<5
Copper	8	15
Iron	3.3×10^3	6.7×10^3
Lead	<20	<20
Manganese	70	150
Molybdenum	<1	<1
Nickel	<6	11
Selenium	1	1.5
Tellurium	<0.80	<0.80
Thallium	<50	<50
Tin	2	<2
Titanium	350	810
Vanadium	<20	<20
Zinc	4	10
Chloride	<37.4	<30
Fluoride	19	48.3
Cyanide	<3.02	<2.76
Nitrate	—	9.21×10^4
Sulfate	<6	37
Ammonium	23.5	18.4
Organics ($>C_7$)	328	<12.4

TABLE 5-22. ESP HOPPER ASH COMPOSITION (μg/g): SITE A

	Baseline	Low NO_x
Antimony	4.3	5.2
Arsenic	36	38
Barium	120	140
Beryllium	5	4.8
Bismuth	<40	<40
Boron	<4	<4
Cadmium	<1	3
Chromium	27	34
Cobalt	27	21
Copper	120	140
Iron	2.6×10^4	2.4×10^4
Lead	110	120
Manganese	550	500
Molybdenum	7	8
Nickel	53	50
Selenium	5.5	6.8
Tellurium	<0.80	<0.80
Thallium	<50	50
Tin	8	8
Titanium	4.0×10^3	3.6×10^3
Vanadium	30	35
Zinc	350	390
Chloride	<38.9	<34.2
Fluoride	6.89	15.2
Cyanide	<3.13	<2.76
Nitrate	9.90×10^3	3.13×10^4
Sulfate	224	83
Ammonium	27.9	48.9
Organics (>C_7)	75.5	70.5

Site B

The test program at Site B encompassed testing under normal (baseline) and low excess air (low NO_x) operation. Low NO_x operation achieved a 37 percent reduction in NO_x at the economizer outlet. Table 5-23 shows flue gas vapor species concentration data at the economizer outlet for the two firing conditions. As noted, NO_x emissions decreased 37 percent under LEA operation, while CO levels remained relatively unchanged. This is because CO levels were deliberately held below 65 ppm throughout the test program. This was done by reducing the excess air level until increases in CO were seen, then increasing the excess air level slightly to provide a comfortable operating margin.

TABLE 5-23. FLUE GAS COMPOSITION AT ECONOMIZER OUTLET: SITE B

	Baseline	Low NO_x
NO_x, ng/J as NO_2	210	131
ppm[a]	343	215
SO_2,[b] ng/J	227	121
ppm[a]	267	142
SO_3,[b] ng/J	1.1	0.9
ppm[a]	1.0	0.8
CO, ppm[a]	65	36
CO_2, percent dry	11.6	13.2
O_2, percent dry	8.1	6.0

[a] 3 percent O_2, dry.
[b] By Shell-Emeryville method at ESP outlet: may be in error

Results of the sulfur species analyses were inconclusive in that errors in the concentration values obtained by the Shell-Emeryville method used were suspected.

Particulate testing showed that LEA firing resulted in lower particulate emissions, as shown in Table 2-24. ESP collection efficiency was approximately the same in baseline and low NO_x modes.

Table 5-25 shows summary organic analysis results of the flue gas, and flue gas SASS samples taken at the ESP outlet. As the table shows, flue gas organic emissions did show an increase with low NO_x firing. Infrared analysis of the sample extracts indicated the presence of aliphatic hydrocarbons, ethers, esters, and carboxylic acids in the extracts from both tests.

Table 5-26 summarizes flue gas emissions for all species analyzed, including trace elements. For these latter species, no real trends in emission levels with firing mode were apparent.

TABLE 5-24. METHOD 5 PARTICULATE CONCENTRATION (μg/J): SITE B

	Baseline	Low NO_x
Boiler Outlet	7.31	5.82
ESP Outlet	0.008	0.010
Overall Collection Efficiency (percent)	99.89	99.83

TABLE 5-25. ORGANIC ANALYSIS RESULTS (mg/dscm): SITE B

	Baseline	Low NO_x
C_1 - C_6 HC (as CH_4)	12.7	57.2
Total $>C_7$ Organics	0.92	1.37

TABLE 5-26. FLUE GAS COMPOSITION AT ESP OUTLET (μg/dscm): SITE B

	Baseline	Low NO_x
NO_x	4.7×10^5	3.4×10^5
SO_2	5.0×10^5	3.0×10^6
SO_3	1.9×10^3	1.6×10^3
CO	5.4×10^4	3.5×10^4
CO_2	2.1×10^8	2.4×10^8
Particulate	1.9×10^4	2.9×10^4
Antimony	3.5	3.5
Arsenic	35	39
Barium	170	2.7
Beryllium	1.2	0.25
Bismuth	2.6	3.2
Boron	$<6.8 \times 10^3$	7.8×10^3
Cadmium	<1.2	5.2
Chromium	61	20
Cobalt	23	5.8
Copper	64	0.050
Iron	280	<71.2
Lead	<1.2	<0.50
Manganese	12	11
Mercury	2.4	1.3
Molybdenum	320	210
Nickel	2.6×10^3	2.4×10^3
Selenium	13	13
Tellurium	2	<3
Thallium	2	<2.2
Tin	9.5	<8.8
Titanium	<55	<49
Vanadium	130	18
Zinc	9.7	<0.058
Organics ($>C_7$)	920	1.37×10^3
Methane	1.27×10^4	5.72×10^4

Ash stream composition data are shown in Tables 5-27 through 5-29. The tables show that, within analytical accuracies, ash trace element or organic concentrations did not vary significantly with firing mode. Infrared analyses of ash sample extracts indicated the presence of aliphatic and aromatic hydrocarbons, esters, and carboxylic acids in the bottom ash sample, aliphatics in the mechanical collector hopper ash sample, and possibly an ester or carboxylic acid in the ESP hopper ash samples.

Bioassays were performed on the bottom ash and ESP hopper ash from the low NO_x test. Results are shown in Table 5-30. As the table shows, negative mutagenicity and nondetectable toxicity results were the rule. Only the ESP hopper ash elicited a positive response, giving a low toxicity result in the RAM assay. Details are given in Reference 5-24.

5.7.2 Source Analysis Model Results

To help quantify the change in potential environmental impact of a boiler which switches from baseline to low NO_x operation, a source analysis model was applied to the emissions data from the Site A and B tests. EPA has been developing a series of source analysis models to define methods of comparing emission data to environmental objectives, termed multimedia environmental goals (MEG's) (Reference 5-25). The model selected for the level of data detail obtainable was SAM IA, designed for rapid screening purposes. As such, it includes no treatment of pollutant transport or transformation (Reference 5-26). Goal comparisons employ threshold effluent stream concentration goals, termed discharge multimedia environmental goals (DMEG's).

For the purposes of screening pollutant emissions data to identify species requiring further study, a discharge severity (DS) is defined as follows:

$$DS_i = \frac{\text{Concentration of Pollutant i in Effluent Stream}}{\text{DMEG of Pollutant i}}$$

The DMEG value, the threshold effluent concentration, is the maximum pollutant concentration considered safe for occupational exposure. When DS exceeds unity, more refined chemical analysis may be required to quantify specific compounds present.

TABLE 5-27. BOTTOM ASH COMPOSITION (μg/g): SITE B[a]

	Low NO_x
Antimony	<0.60
Arsenic	<2
Barium	<10
Beryllium	<0.20
Bismuth	19
Boron	$<2.0 \times 10^3$
Cadmium	0.84
Chromium	110
Cobalt	16
Copper	96
Iron	2.0×10^4
Lead	5.8
Manganese	460
Mercury	<0.70
Molybdenum	<3
Nickel	48
Selenium	<0.30
Tellurium	3.5
Thallium	<3
Tin	210
Titanium	8.9×10^3
Vanadium	190
Zinc	11
Chloride	<19.8
Fluoride	<0.10
Cyanide	<2.50
Nitrate	2.7
Sulfate	359
Ammonium	9.1
Organics ($>C_7$)	120
Alkanes	15
Fluoranthene	0.015
Phenanthrene/anthracene	0.60

[a]Baseline sample not taken

TABLE 5-28. MECHANICAL COLLECTOR HOPPER ASH COMPOSITION (μg/g): SITE B

	Baseline	Low NO_x
Antimony	<0.60	<0.60
Arsenic	2	<2
Barium	83	370
Beryllium	24	3
Bismuth	<0.80	<1
Boron	5.0×10^3	$<2.0 \times 10^3$
Cadmium	0.030	0.49
Chromium	$<9.0 \times 10^3$	64
Cobalt	34	<0.10
Copper	46	24
Iron	1.4×10^4	8.0×10^3
Lead	420	6.9
Manganese	310	250
Mercury	<0.090	<0.70
Molybdenum	<0.50	<3
Nickel	40	30
Selenium	<1	<0.30
Tellurium	<0.60	0.50
Thallium	<5	<3
Tin	200	62
Titanium	2.4×10^3	1.4×10^3
Vanadium	54	7.1
Zinc	24	22
Chloride	<19.9	<20
Fluoride	2.60	6.20
Cyanide	<2.50	<2.50
Nitrate	<0.300	<0.300
Sulfate	1.24×10^3	849
Ammonium	<2.50	<2.50
Organics ($>C_7$)	61	6

TABLE 5-29. ESP HOPPER ASH COMPOSITION (μg/g): SITE B

	Baseline	Low NO_x
Antimony	27	31
Arsenic	740	590
Barium	4.4×10^3	2.8×10^3
Beryllium	77	69
Bismuth	<0.60	11
Boron	$<2.0 \times 10^3$	2.7×10^3
Cadmium	<1	3
Chromium	<0.40	<0.30
Cobalt	<0.030	<0.020
Copper	0.62	0.76
Iron	30	31
Lead	<0.090	<0.090
Manganese	0.21	0.26
Mercury	<0.20	0.20
Molybdenum	21	26
Nickel	<0.70	<0.60
Selenium	84	120
Tellurium	<0.50	<0.40
Thallium	<4	<4
Tin	33	45
Titanium	14	8.50
Vanadium	4.6	3.8
Zinc	0.57	0.82
Chloride	<20	<19.9
Fluoride	38.1	62.2
Cyanide	<0.150	<0.560
Nitrate	1.8	4.80
Sulfate	1.1×10^4	2.3×10^4
Ammonium	0.180	450
Organics ($>C_7$)	73	257

TABLE 5-30. BIOASSAY RESULTS: SITE B LOW NO_x SAMPLES

Sample	Test				
	Microbial Mutagenesis	RAM Cytotoxity	RAT	Freshwater Algae	Freshwater Fish
Bottom Ash	Neg	ND	ND	ND	ND
ESP Hopper Ash	Neg	L	ND	--	--

To compare waste stream potential hazards, a weighted discharge severity (WDS) is defined as follows:

$$WDS = (\sum_i DS_i) \times \text{Stream Mass Flow Rate}$$

where the DS's are summed over all species analyzed. The WDS is an indicator of output of hazardous pollutants and can be used to rank the needs for controls for waste streams. It can also be used as a preliminary measure of how well a pollutant control, say a combustion modification NO_x control, reduces the overall environmental hazard of the source. An extensive exposition of SAM IA and list of DMEG's are presented in Reference 5-26 and will not be repeated here.

Site A

Table 5-31 shows the results of the SAM IA evaluation of the flue gas composition data from Site A. Results are presented for uncontrolled operation (baseline) and controlled operation (low NO_x). The table shows MEG category DS for each firing condition for those components with DS greater than 1 in either test. DS values shown were calculated from air/health-based DMEG's. Tables 5-32 through 5-34 show corresponding results for the bottom ash, mechanical collector hopper ash, and the ESP hopper ash, respectively. DS values in these tables are based on land/health DMEG's.

The results presented in Table 5-31 show that NO_x and SO_2 are the potentially most hazardous flue species. The sum of the DS values for these two species again comprises over 70 percent of the stream total discharge severity (TDS). The DS for SO_2 again fluctuates with day-to-day fuel sulfur content, masking the effects of the reduction of

TABLE 5-31. FLUE GAS DISCHARGE SEVERITY: SITE A

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
NO_x	47	70	58
SO_2	53	63	85
CO	42	6.3	12
SO_3 (vapor)	53	5.8	35
Be	32	1.9	0.049
As	49	1.6	3.5
Fe	72	1.1	1.9
Carboxylic acids	8	1.0	1.8
Ti	41	0.34	3.7
Cd	82	0.61	1.7
Pb	46	0.38	1.2
Total stream		154	206

TABLE 5-32. BOTTOM ASH DISCHARGE SEVERITY: SITE A

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
Fe	72	100	100
Mn	71	11	11
Sn	45	1.7	1.3
Total stream		115	118

TABLE 5-33. MECHANICAL COLLECTOR HOPPER ASH DISCHARGE SEVERITY: SITE A

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
Fe	72	11	22
Mn	71	1.4	3.0
Total stream		14.1	27.6

TABLE 5-34. ESP HOPPER ASH DISCHARGE SEVERITY: SITE A

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
Fe	72	87	80
Mn	71	11	10
Pb	46	2.2	2.4
Ni	76	1.2	1.1
Total stream		105	98

the NO_x DS with the application of NO_x control, so that stream TDS remains relatively constant with NO_x control application. Other species of potential concern include CO, SO_3 (vapor), and several trace elements. In this test, though, the SO_3 DS did not decrease with NO_x control and in fact increased sixfold. However, this increase may be within the accuracy of the analytical technique used to measure SO_3. Carboxylic acids are flagged here also, under the conservative assumption that all the organic material in the flue gas was maleic acid, the most toxic organic material found in this test.

Tables 5-32 through 5-34 indicate that, for the ash streams, discharges of Fe and Mn represent the greatest potential hazard. Still the DS values for these remain relatively constant with firing mode. Pb is flagged of concern in the ESP hopper ash only, suggesting that it becomes concentrated to potentially hazardous levels on passage through the unit.

Table 5-35 shows stream total WDS for each stream under each firing mode tested. As was the case for the coal-fired utility boiler tested in the NO_x EA program (Reference 5-27), the flue gas stream dominates the potential hazard of the source, with a WDS over two orders of magnitude larger than any other stream. In addition, the WDS's for the ash streams remain relatively constant with firing mode. Thus, changes in flue gas WDS will elicit corresponding changes in total source WDS. So, it is concluded that the NO_x control tested does not, of itself, increase total source potential hazard.

TABLE 5-35. WEIGHTED DISCHARGE SEVERITY: SITE A

Stream	Weighted Discharge Severity (kg/s)	
	Baseline	Low NO_x
Flue gas	6,600	7,900
Bottom ash	15	16
Mechanical collector hopper ash	1.7	1.8
ESP hopper ash	5.3	2.6
Total source	6,620	7,920

Site B

Table 5-36 shows the results of the SAM IA evaluation of the flue gas from the Site B unit. Results for the two modes of operation (baseline and low NO_x) are presented. MEG category DS values for those compounds with DS greater than 1 in either test are displayed. These values were calculated based on air/health DMEG's. Tables 5-37 through 5-39 show corresponding results for the ash streams evaluated, with DS values here based on land/health DMEG's.

Conclusions drawn from the results presented in Table 5-37 are analogous to those discussed above on the results in Table 5-31. NO_x and SO_2 remain the potentially most hazardous species, accounting for over half the flue gas of stream TDS. Here, though, the DS for SO_2 (which varies exclusively with fuel sulfur content) drops in the low NO_x mode, so that stream TDS decreases with NO_x control application.

Other flue gas species with DS greater than 1 include CO_2, CO, SO_3 (vapor), and the trace elements As and B. The DS for SO_3 shows essentially no change with firing mode. In addition, for this test no organic category had a DS value greater than 1.

Tables 5-37 and 5-38 indicate that discharges of Fe, Mn, Cr, Be, and Ni are the potentially hazardous ones for the bottom and mechanical collector hopper ash streams from this source as well. (No bottom ash sample was taken in the Site B baseline test, so no comparisons with firing mode are possible here.) Interestingly, some new species not flagged previously (coal-fired source ash streams, Se, and condensed sulfate) appear in Table 5-39.

Table 5-40 shows stream total WDS values for each stream under both firing modes tested. Previously stated conclusions hold here as well. The flue gas stream dominates potential source hazard. The application of NO_x control reduces the hazard presented by NO_x. DS changes caused by day-to-day fuel composition changes are often of greater magnitude than the reduction in NO_x DS. Thus, NO_x control application reduces total source potential hazard in the absence of SO_2 considerations which are dependent on the fuel sulfur content and not on the NO_x control.

TABLE 5-36. FLUE GAS DISCHARGE SEVERITY: SITE B

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
NO_x	47	68	38
SO_2	53	39	23
CO_2	42	35	27
As	49	18	20
B	68	2.2	2.5
SO_3 (vapor)	53	1.9	1.6
CO	42	1.4	0.88
Total stream		168	114

TABLE 5-37. BOTTOM ASH DISCHARGE SEVERITY: SITE B

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
Fe	72	--[a]	67
Mn	71	--	9.2
Cr	68	--	2.2
Ni	76	--	1.1
Total stream		--	82.1

[a]Bottom ash sample not taken for baseline test

TABLE 5-38. MECHANICAL COLLECTOR HOPPER ASH DISCHARGE SEVERITY: SITE B

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
Cr	68	180	1.3
Fe	72	47	27
Pb	46	8.4	0.14
Mn	71	6.2	5.0
Be	32	4.0	0.83
Total stream		249	36.3

TABLE 5-39. ESP HOPPER ASH DISCHARGE SEVERITY: SITE B

Component	MEG Category	Discharge Severity	
		Baseline	Low NO_x
As	49	15	12
Be	32	13	12
Se	54	8.4	12
Ba	36	4.4	2.8
$SO_4^=$ (condensed)	53	3.7	77
Total stream		45	117

TABLE 5-40. WEIGHTED DISCHARGE SEVERITY: SITE B

Stream	Weighted Discharge Severity (kg/s)	
	Baseline	Low NO_x
Flue gas	7160	3640
Bottom ash	--[a]	7.7
Mechanical collector hopper ash	50	5.5
ESP hopper ash	1.9	3.7
Total source	7210	3660

[a]Bottom ash sample not taken for baseline test.

5.8 SUMMARY

Tables 5-41 through 5-44 compare the recommended NO_x control techniques, the levels of control achievable, and the resulting incremental changes in other pollutant emissions. Where actual data are not available, a postulated effect is presented.

Carbon monoxide levels generally increase with NO_x control. Actual test data show unburned hydrocarbon emissions to be decreased more often than increased, though the data are variable. Sulfate emissions decrease with decreasing oxygen content; particulate emissions decrease, possibly due to an increase in particle size which results in an increase in particulate control device collection. The best NO_x control method for industrial boilers firing coal appears to be low excess air, but information is too limited to be conclusive. Staged combustion (overfire air) has the smallest effect on incremental emissions from residual oil-fired boilers. It also appears to be the best method for distillate oil-fired units. And finally, for natural gas, flue gas recirculation and overfire air appear to be the best methods available.

Incremental emissions are potentially increased by NO_x controls. More data are needed to quantify the incremental emissions for each control technique and to determine if any significant environmental impact may result.

TABLE 5-41. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM COAL-FIRED INDUSTRIAL BOILERS

Boiler	NO_x Control Technique	Level of Control	Change in Incremental Emissions			
			CO	UHC	SO_3	Particulate
Coal-Fired Boiler ≥ 29 MW	Low Excess Air	Moderate	+	-	(-)	-[a]
		Intermediate	+		-	-[a]
		Stringent	+	v	-	-[a]
	Overfire Air	Intermediate	+	(+)	(-)	-[a]
		Stringent	+	+	-	-[a]
	Low NO_x Burners	Stringent	(+)	(+)	(-)	(-)[a]
	Ammonia Injection[b]	Stringent	(NE)	(NE)	(+)	(NE)
Coal-Fired Boilers < 29 MW	Low Excess Air	Intermediate	-	+	(-)	-
		Stringent	v	(+)	(-)	(-)[a]

( ) No data available
\- Some decrease
\+ Some increase
v Variable results
NE No effect
[a]Could be actual decrease or just more efficient collection of larger particles
[b]Ammonia injection may cause ammonia and byproduct emissions

TABLE 5-42. POSTULATED EFFECT OF NO_x CONTROLS ON INCREMENTAL EMISSIONS FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS

NO_x Control Technique	Level of Control	Change in Incremental Emissions			
		CO	UHC	SO_3	Particulate
Low Excess Air	Moderate	+	(+)	(-)	-[a]
	Intermediate	+	v	-	-[a]
	Stringent	++	v	-	-[a]
Overfire Air	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	+	+	(-)	-[a]
	Stringent	+	+	-	-[a]
Low NO_x Burners	Intermediate	(+)	(+)	(-)	(-)[a]
	Stringent	(+)	(+)	(-)	(-)[a]
Ammonia Injection[b]	Stringent	(NE)	(NE)	(+)	(NE)

( ) No data available
- Some decrease
+ Some increase
++ Significant increase
v Variable results
NE No Effect
a Assuming dust control devices are utilized. Otherwise could be (+)
b Ammonia injection may cause ammonia and byproduct emissions

TABLE 5-43. POSTULATED EFFECT OF NO_x CONTROLS ON INCREMENTAL EMISSIONS FROM DISTILLATE OIL-FIRED INDUSTRIAL BOILERS

NO_x Control Technique	Level of Control	Change in Incremental Emissions			
		CO	UHC	SO_3	Particulate
Low Excess Air	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	++	-	(-)	(-)[a]
	Stringent	(++)	(+)	(-)	(-)[a]
Flue Gas Recirculation	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	(+)	(+)	(-)	(-)[a]
	Stringent	+	+	(-)	(-)[a]
Overfire Air	Moderate	(+)	(+)	(-)	(-)[a]
	Intermediate	+	+	(-)	-[a]
	Stringent	+	+	-	-[a]
Reduced Air Preheat	Intermediate	(NE)	(NE)	(-)	(+)
	Stringent	(NE)	(NE)	(-)	(+)
Low NO_x Burners	Stringent	(+)	(+)	(-)	(-)[a]

( ) No data available
- Some decrease
+ Some increase
++ Significant increase
NE No Effect
[a] Assuming dust control devices are utilized. Otherwise could be (+)

TABLE 5-44. POSTULATED EFFECT OF CANDIDATE NO_x CONTROL SYSTEMS ON INCREMENTAL EMISSIONS FROM GAS-FIRED INDUSTRIAL BOILERS

NO_x Control Technique	Level of Control	Change in Incremental Emissions[a]	
		CO	UHC
Low Excess Air	Moderate	+	(+)
	Intermediate	+	-
	Stringent	+	(+)
Flue Gas Recirculation	Moderate	(+)	(+)
	Intermediate	(+)	(+)
	Stringent	-	(+)
Overfire Air	Moderate	+	(+)
	Intermediate	+	(+)
	Stringent	-	-
Reduced Air Preheat	Moderate	+	-
	Intermediate	+	(+)
	Stringent	+	(+)
Low NO_x Burners	Stringent	(+)	(+)

( ) No data available
- Some decrease
+ Some increase
++ Significant increase
[a] SO_3 and particulate not present in natural gas combustion products

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SECTION 6

CONCLUSIONS

Modifying the combustion process conditions appears to be the most cost-effective and promising method of effecting 20 to 70 percent reductions in NO_x emissions from industrial boilers. However, combustion modification NO_x controls are currently not in active use for industrial boilers. In fact the available data on the performance of these controls are based primarily on short term field tests of retrofit applications on a limited number of boilers. Tables 6-1, 6-2, 6-3 and 6-4 summarize the effectiveness, operational, cost, and environmental impact, and availability of the most promising control techniques for pulverized coal-, stoker coal-, residual oil-, distillate oil-, and natural gas-fired boilers.

6.1 PREFERRED CONTROL ALTERNATIVES

Preferred alternative emission control systems which achieve moderate, intermediate, and stringent levels of NO_x control were selected. These control levels were based on uncontrolled baseline emission levels and the capabilities of combustion modification controls. The control levels are somewhat arbitrary, and are introduced mainly to facilitate the discussion of control options for the various boiler/fuel categories. Moderate control represents that level which is achievable applying currently available technology. Stringent control is a technology-forcing level and represents the most rigorous control which might be achieved through acceleration of ongoing R&D efforts. The stringent control option encompasses technology expected to be commercially available within 5 years. Intermediate control is a level between moderate and stringent. It should be emphasized that the above definitions were used only as a guide.

Tables 6-5 through 6-9 summarize the candidates for best control systems and emission levels achievable for each of the major industrial boiler/fuel categories. Selection criteria for these candidate best control systems were based on the effectiveness, commercial availability or R&D status, operation impact, and reliability of each system. Energy, environmental, and cost impacts were also considered.

Results to date indicate that low excess air (LEA) or overfire air (OFA) form the best system for moderate (301 ng/J) and intermediate (258 ng/J) NO_x control for pulverized coal-fired industrial boilers. However, those boilers with high baseline NO_x emissions may need to use a combination of OFA and LEA to achieve the intermediate control level. Staged combustion combined with low excess air can achieve the stringent control level of 215 ng/J. Alternative controls include low NO_x burners (LNB) and ammonia injection; however these latter two techniques are still under development.

Spreader stokers are the only major stoker boiler types with average uncontrolled NO_x emissions as high as 258 ng/J. Low excess air and overfire air constitute the best candidate control system capable of reductions to 215 ng/J. Any NO_x reduction beyond this level can only be achieved with NH_3 injection, possibly down to 129 ng/J. The other major stoker types, chain grate and underfeed, have average uncontrolled NO_x emissions below 172 ng/J. Control of these units to 129 ng/J is possible with LEA.

The candidate best control systems for residual oil-fired industrial boilers are low excess air, low NO_x burners, and staged combustion. Low NO_x burners, once developed are expected to reduce NO_x emissions to the stringent level (86 ng/J). Staged combustion is not a demonstrated technique and may not be feasible for the smaller packaged boilers. An alternative control is NH_3 injection. Candidate best control systems for distillate oil- or gas-fired boilers are reduced air preheat, flue gas recirculation, and low NO_x burners, in that order, lowering NO_x to 65 ng/J. Reduced air preheat combined with flue gas recirculation or with low NO_x burners may potentially reduce NO_x emissions to 43 ng/J. The preferred method of reduced air preheat is to substitute, if possible, an economizer in place of an air preheater in a new boiler design.

TABLE 6-1. PROMISING SYSTEMS OF NO_x EMISSIONS REDUCTION FOR PULVERIZED COAL-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 25	Increased boiler efficiency.	Increased efficiency offsets capital and operating costs.	Possible increased CO and organic emissions.	Available
Overfire Air	5 - 30	Possible increased slagging, corrosion. Perhaps slight decrease in boiler efficiency.	Major modification. Marginal increase in cost for new units.	Possible increased particulate and organic emissions.	Commercially offered but not demonstrated for this boiler/fuel category
Reduced Combustion Intensity	10 - 25[c]	None. Best implemented as increased furnace plan area in new designs.	Major modification. Marginal increase in cost for new units.	None	Technology transfer required from utility industry
Low NO_x Burners	45 - 60	None expected.	Potentially most cost-effective.	None expected.	1981 - 1983
NH_3 Injection	40 - 60	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modifications.	Possible emissions of NH_3 and byproducts.	Commercially offered but not demonstrated

[a]Effectiveness based on control applied singly

[b]Incremental cost impact noting capacity/cost of boiler to which control is applied.

[c]Based on utility boiler experience

TABLE 6-2. PROMISING SYSTEMS FOR NO_x EMISSIONS REDUCTION FOR STOKER COAL-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 25	Possible grate overheat, clinker formation, increased corrosion. Close operator attention required.	Increased efficiency should partially offset costs.	Possible increased CO, organic, and particulate emissions.	Available
Overfire Air	5 - 25	Possible grate overheat, clinker formation, increased corrosion. Close operator attention required. Perhaps slight decrease in boiler efficiency.	Major modification of grate and OFA, probably costly. Present units have OFA for smoke control only.	Possible increased CO, organic, and particulate emissions.	R&D
NH_3 Injection	40 - 60	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modifications.	Possible emissions of NH_3 and byproducts.	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly.

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

TABLE 6-3. PROMISING SYSTEMS OF NO_x EMISSIONS REDUCTION FOR RESIDUAL OIL-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 20	Increased boiler efficiency.	Increased efficiency partially offsets costs.	Possible increased CO and organic emissions.	Available
Staged Combustion	20 - 50	Perhaps slight decrease in boiler efficiency.	Major modification, perhaps costly.	Possible increased particulate and organic emissions.	Commercially offered but not demonstrated for this boiler/fuel category
Low NO_x Burners	20 - 50	None expected.	Potentially most cost-effective.	None expected.	Commercially offered but not demonstrated
NH_3 Injection	40 - 70	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modification.	Possible emissions of NH_3 and byproducts.	Commercially offered but not demonstrated

[a]Effectiveness based on control applied singly.

[b]Incremental cost impact noting capacity/cost of boiler to which control is applied.

TABLE 6-4. PROMISING SYSTEMS OF NO_x EMISSIONS REDUCTION FOR DISTILLATE OIL- AND GAS-FIRED BOILERS

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Environmental Impact	Availability
Low Excess Air	5 - 15 (oil), 5 - 10 (gas)	Increased boiler efficiency.	Increased efficiency should offset some of costs.	Possible increased CO and organic emissions.	Available
Staged Combustion	20 - 40 (oil), 25 - 45 (gas)	Perhaps slight decrease in boiler efficiency.	Major modification, probably costly.	Possible increased organic emissions.	Commercially offered but not demonstrated for this boiler/fuel catetory
Flue Gas Recirculation	40 - 70 (oil) 45 - 75 (gas)	Possible flame instability. Can be eliminated with proper engineering/testing.	Major modification, probably costly.	Possible increased organic emissions.	Available
Reduced Air Preheat	20 - 55 (gas)	Replacing air preheater with economizer in new designs.	None, other than engineering redesign of new units (if necessary).	None	Available
Low NO_x Burners	20 - 50	None expected.	Potentially most cost-effective.	None expected.	Commercially offered but not demonstrated

[a]Effectiveness based on control applied singly.

[b]Incremental cost impact noting capacity/cost of boiler to which control is applied.

TABLE 6-5. BEST CONTROL SYSTEMS FOR PULVERIZED COAL-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control		
		Moderate 301 ng/J (0.7 lb/10^6 Btu)	Intermediate 258 ng/J (0.6 lb/10^6 Btu)	Stringent 215 ng/J (0.5 lb/10^6 Btu)
Pulverized Coal-Fired	285 (0.663)[b]	No control necessary[c]	1. Low excess air 2. Overfire air*	1. Overfire air* 2. Low NO_x burner*** 3. Ammonia injection[d]**

[a]Low excess air operation is recommended practice whenever controls are required. However combination of LEA and OFA is not recommended for pulverized coal tangential units (see Section 4). T-1759

[b]Wide range of baseline emissions reported (see Section 3)

[c]Some units may require low excess air.

[d]NH_3 injection required only for those units with unusually high baseline emissions.

*Commercially offered but not demonstrated for this boiler/fuel category.

**Commercially offered but not demonstrated.

***Under research and development.

TABLE 6-6. BEST CONTROL FOR STOKER COAL-FIRED INDUSTRIAL BOILERS

Boiler Equipment Type	Baseline NOx Emissions ng/J (lb/106 Btu)	Level of Control		
		Moderate 215 ng/J (0.5 lb/106 Btu)	Intermediate 172 ng/J (0.4 lb/106 Btu)	Stringent 129 ng/J (0.3 lb/106 Btu)
Spreader Stoker	265(0.616)	Low excess air/overfire air***	Ammonia injection**	Ammonia injection**
Chain Grate	140(0.326)	No control necessary	No control necessary	Low excess air
Underfeed	150(0.349)	No control necessary	No control necessary	Low excess air

**Commercially offered but not demonstrated.

***Under research and development.

TABLE 6-7. BEST CONTROL SYSTEMS FOR RESIDUAL OIL-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control: Moderate 129 ng/J (0.3 lb/10^6 Btu)	Intermediate 108 ng/J (0.25 lb/10^6 Btu)	Stringent 86 ng/J (0.2 lb/10^6 Btu)
Firetube	115 (0.267)	No control necessary	Low excess air	1. Low NO_x burners** 2. Staged combustion***
Watertube	160 (0.372)	1. Low excess air 2. Low NO_x burners** 3. Staged combustion*	1. Low NO_x burners** 2. Staged combustion*	1. Low NO_x burners** 2. Ammonia injection**

[a]Low excess air is recommended practice whenever controls are required.

*Commercially offered but not demonstrated for this boiler/fuel category.
**Commercially offered but not demonstrated.
***Research and development.

TABLE 6-8. BEST CONTROL SYSTEM FOR DISTILLATE OIL-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J (lb/10^6 Btu)	Level of Control: Moderate 86 ng/J (0.2 lb/10^6 Btu)	Intermediate 65 ng/J (0.15 lb/10^6 Btu)	Stringent 43 ng/J (0.1 lb/10^6 Btu)
Firetube	70 (0.163)	No control necessary	Low excess air	1. Flue gas recirculation 2. Low NO_x burners**
Watertube not equipped with air preheater	55 (0.128)	No control necessary	No control necessary	1. Flue gas recirculation 2. Low NO_x burners** 3. Staged combustion
Watertube equipped with air preheater	90 (0.209)	Low excess air	1. Reduced air preheat 2. Flue gas recirculation 3. Low NO_x burners** 4. Staged combustion*	1. Reduced air preheat + Flue gas recirculation 2. Reduced air preheat + Low NO_x burners**

[a]Low excess air operation is recommended practice whenever controls are required

*Commercially offered but not demonstrated for this boiler/fuel category.
**Commercially offered but not demonstrated.

TABLE 6-9. BEST CONTROL SYSTEMS FOR NATURAL GAS-FIRED INDUSTRIAL BOILERS[a]

Boiler Equipment Type	Baseline NO_x Emissions ng/J ($lb/10^6$ Btu)	Level of Control		
		Moderate 86 ng/J (0.2 $lb/10^6$ Btu)	Intermediate 65 ng/J (0.15 $lb/10^6$ Btu)	Stringent 43 ng/J (0.1 $lb/10^6$ Btu)
Firetube	40 (0.093)	No control necessary	No control necessary	No control necessary
Watertube not equipped with air heater	45 (0.105)	No control necessary	No control necessary	Low excess air
Watertube equipped with air heater	110 (0.256)	1. Reduced Air Preheat 2. Flue Gas Recirculation 3. Staged Combustion Air* 4. Low NO_x Burners**	1. Reduced Air Preheat + Flue Gas Recirculation 2. Reduced Air Preheat + Low NO_x Burners 3. Reduced Air Preheat + Staged Combustion Air*	1. Reduced Air Preheat + Flue Gas Recirculation 2. Reduced Air Preheat + Low NO_x Burners** 3. Reduced Air Preheat + NH_3 injection**

[a]Low excess air operation is recommended practice whenever controls are required.

*Commercially offered but not demonstrated for this boiler/fuel category.
**Commercially offered but not demonstrated.

6.2 OPERATIONAL IMPACT

Possible operational impacts with NO_x controls have been summarized in Tables 6-1 through 6-4. The major potential impacts are increased slagging and corrosion for coal-firing, and slight decreases in boiler thermal efficiency for all fuels. Controls for stokers are not well developed, and the only available technique, LEA/OFA, can lead to severe clinker formation if applied to extreme. Ammonia injection may suffer implementaion difficulties and fouling problems. In general, however, with proper engineering, development, and implementation, the preferred combustion modification NO_x controls should not have major adverse operational impacts if the controls are applied judiciously as they become fully developed.

6.3 COST IMPACT

The primary contributions of combustion modification NO_x controls to steam cost changes are the equipment modification costs and changes in thermal efficiency and fan power demand. For firetube boilers, annualized equipment costs are usually higher than costs due to efficiency or fan power demand changes. For watertube boilers, the opposite is usually true. For both firetube and watertube boilers, all costs are important and any factor that can lower any of these costs will be beneficial. In many cases, using the lowest possible excess air will lower the cost impact. Of course, the boiler should be designed to give the highest possible thermal efficiency and lowest fan power requirements. Careful design can result in better fuel efficiency than was assumed in the calculations presented in this assessment.

Of the NO_x controls covered, low excess air is the method recommended to be first considered since it can reduce fuel costs. Low NO_x burners are a promising technique since they should allow both low NO_x and LEA operation, and thus save fuel while lowering NO_x emissions. Staged combustion is the next best method, unless fuel switching problems make it impractical, since the optimal air port location is fuel dependent. If staged combustion cannot be used, flue gas recirculation is the next most cost-effective technique. Ammonia injection is the least cost effective technique and load changing may make it impractical. Also, whenever possible, an economizer is preferred over an air preheater as a fuel saving device since it does not raise NO_x levels.

In summary, combustion modification NO_x controls, once proven and demonstrated, should be a cost effective means of control for industrial boilers raising steam costs up to only 1 to 2 percent in most cases. However, the initial investment required, especially for small boilers, may be a large fraction of the cost of the boiler itself, up to 25 percent when controls are installed on a new boiler and up to 50 percent when retrofitting the controls on an existing boiler. Factory installed controls on new boilers should prove more cost effective than retrofit controls.

6.4 ENVIRONMENTAL IMPACT

In general, no serious environmental impacts are expected for the preferred control techniques recommended in this report. However, more field testing is required to quantify and establish that statement.

Carbon monoxide levels generally increase with NO_x control, although this can be minimized if not eliminated with judicious application of the control. Actual test data show unburned hydrocarbon emissions to be decreased more often than increased, though the data are variable. Sulfate emissions decrease with decreasing oxygen content; particulate emissions decrease possibly due to an increase in particle size resulting in improved particulate control device collection efficiency. The best NO_x control device for industrial boilers firing coal appears to be low excess air, but information is too limited to be conclusive.

Staged combustion (overfire air) has the smallest effect on incremental emissions from residual oil-fired boilers. It also appears to be the best method for distillate oil-fired units. And finally for natural gas, flue gas recirculation and staged combustion appear to be the best methods available.

Incremental emissions can potentially be increased by NO_x controls. More data are needed to quanitify the incremental emissions for each control technique and to determine if any significant environmental impact may result.

6.5 RECOMMENDATIONS FOR FURTHER INVESTIGATION

EPA is currently sponsoring several field test programs demonstrating combustion modification NO_x controls for industrial boilers. These programs include identification of optimal combustion conditions for 11 stoker coal-fired boilers, sponsored jointly with the Department of Energy and ABMA (References 6-1 and 6-2), and field demonstrations of a commercial low NO_x burner for both oil- and gas-firing (References 6-3 and 6-4). The results from these studies should help fill some of the data gaps identified in this study. In addition, several other field tests of these and other combustion controls are underway, including 30-day continuous monitoring programs (Reference 6-4). The results of these and other test programs should be monitored and incorporated in future updates of the assessment of combustion modification NO_x controls.

REFERENCES FOR SECTION 6

6-1. Gabrielson, J. E., et al., "Field Tests of Industrial Stoker Coal-fired Boilers for Emissions Control and Efficiency Improvement - Site A," EPA-600/7-78-136a, NTIS PB-285-972/AS, July 1978.

6-2. Langsjoen, P. L., et al., "Test Results of Modern Coal Fired Stoker Boilers for Emissions and Efficiency," presented at the American Power Conference, Chicago, IL, April 23-25, 1979.

6-3. Matthews, B. J., TRW, Inc., Redondo Beach, California, Letter to W. Peters, EPA IERL-RTP, NC, March 23, 1979.

6-4. Hall, R. E., IERL-RTP, NC, Telecommunication with K. J. Lim, Acurex Corporation, May 18, 1979.

SECTION 7
EMISSION SOURCE TEST DATA

This section contains the experimental data recorded on tests of various NO_x emission controls conducted on industrial boilers. Data selection and test methods are summarized. These data (References 7-1 through 7-9) were used to generate the baseline and controlled NO_x emission levels presented in the preceding sections of this report.

7.1 CRITERIA FOR SELECTION

A brief description of the data selection procedure follows in Section 7.1.1. Section 7.1.2 summarizes the test methods used.

7.1.1 Data Selection

Where possible, the data selected from published tests had to meet certain prescribed criteria to be included in the NO_x control technology assessment. These criteria included:

- Well planned and controlled experimental conditions in which only the parameter under investigation was allowed to vary. All other important parameters were held as constant as practically possible.
- Characterization and documentation of all major parameters and conditions during the test, such as fuel analysis, and boiler and burner design and operating variables.
- Representative boilers with representative baseline emissions. In some cases, however, very limited data did not permit a determination of representativeness. These cases have been noted in the text of this report.
- Reasonableness of the data. In some cases extreme values are given, as these were the only data available. These values are generally noted and this section contains, in addition to the parameters associated with these data, other data which support more moderate values, if available.

- Reliability and reproducibility of the data. In many cases, because of the very limited number of tests run, reproducibility could not be confirmed.

7.1.2 Test Methods

The two major investigative groups, KVB and Ultrasystems, used both wet chemical and instrumental methods. For instance, one group (KVB) used EPA Method 5 for particulate matter and EPA Method 9 for opacity. For sulfur oxides they used the Shell-Emeryville wet chemical procedure and for the remaining gases they used instruments obtained from a variety of manufacturers. The other group, Ultrasystems, principally used instrumentation to measure concentration. Selection of the methods used by both companies were primarily based on:

- Portability. All boilers investigated were in the field;
- Cost. Despite their high initial cost, most instruments if properly calibrated and maintained are more cost-effective than the wet analytical methods they replace;
- Reliability. Properly calibrated and maintained instruments are generally far more reliable than the wet methods they replace.

Table 7-1 lists the types of monitors employed by the two principal groups of investigators and their operating principles. A brief synopsis of the errors associated with the measurement of each of the pollutants follows. Only those for NO/NO_x are presented. The reader is referred to References 7-2 and 7-4 for a complete discussion of the methods employed.

Nitrogen oxides concentrations were measured by a Thermo Electron model 10A analyzer. The functional basis of the instrument is the chemiluminescent reaction of NO and O_3 to form NO_2 in an excited state. When excited NO_2 molecules revert to their ground state, light emission results. The resulting chemiluminescence is monitored through an optical filter by a high sensitivity photomultiplier tube. The output of the photomultiplier is electronically processed so it is linearly proportional to the NO concentration.

Because the analyzer is sensitive only to NO, total NO_x is determined by reducing any NO_2 in the sample to NO. Reduction is thermal, the gas being passed through a thermally insulated

TABLE 7-1. EMISSION MEASUREMENT INSTRUMENTATION

Emission	Symbol	KVB (References 7-4 and 7-5)		Ultrasystems (Reference 7-2)	
		Measurement Method	Equipment Manufacturer and Model Number	Measurement Method	Equipment Manufacturer and Model Number
Nitric oxide	NO	Chemiluminescent	Thermo Electron 10A	Chemiluminescent	Thermo-Electron[c]
Oxides of nitrogen	NO_x	Chemiluminescent	Thermo Electron 10A	Chemiluminescent	Thermo-Electron[c]
Carbon monoxide	CO	Spectrometer	Beckman 865	Spectrometer	MSA LIRA-303
Carbon dioxide	CO_2	Spectrometer	Beckman 864	--	--
Oxygen	O_2	Polarographic	Teledyne 325A	Polarographic	Theta Sensor[d]
Hydrocarbons	HC	Flame ionization	Beckman 402	--	--
Sulfur dioxide and trioxide	SO_2 SO_3	Absorption/ titration	KVB Equipment Company	Electrochemical[e]	Theta Sensor
Total particulate matter	PM	EPA Method 5	Joy Manufacturing Company	--	--
Particulate size	--	Visual counting Cascade impactor	Millipore Corporation[a] XX50 Monsanto-Brink[b]	--	--
Smoke spot	K	Reflectance Photometric	Research Applicance Company G2R-100	Visual	Bacharach
Opacity	--	EPA Method 9	--	--	--

[a] Reference 7-4.
[b] References 7-3, 7-5.
[c] Backup measurements made with Theta Sensor US-6000 analyzer.
[d] Backup measurements made with Teledyne 320AX.
[e] SO_2 only.

resistance-heated stainless steel coil. NO_2 can be obtained by taking the difference in readings with and without the converter in operation, and assuming that $NO + NO_2 = NO_x$.

The specifications of the instrument are presented below:

Accuracy	1% of full scale
Span stability	± 1% of full scale in 24 hours
Zero stability	± 1 ppm in 24 hours
Power requirements	115 ± 10V, 60 Hz, 1,000 watts
Response	90% of full scale in 1 second (NO_x mode), 0.7 sec (NO mode)
Output	4 - 20 ma
Sensitivity	0.5 ppm
Linearity	± 1% of full scale
Vacuum detector operation	
Range	2.5, 10, 25, 100, 250, 1,000, 2,500, 10,000 ppm full scale

Other criteria pollutants are listed in Table 7-1 along with the instrument or test method used. The reader is referred to Section 6 for a listing of the criteria pollutant emission data associated with NO_x controls, and to References 7-2 and 7-4 for a discussion of the instruments and/or techniques employed.

7.2 EMISSION SOURCE TEST DATA FOR COAL-FIRED BOILERS

Coal-fired industrial boilers have been tested during several EPA sponsored field investigations (References 7-4, 7-5 and 7-7 through 7-9). These include six pulverized coal-fired units, one cyclone, twelve spreader stokers, two underfeed stokers, two chain grate stokers and a vibrating grate stoker. Tables 7-2 through 7-4 present the results of NO_x emission controls as applied to pulverized coal and cyclone boilers; Tables 7-5 through 7-8 present the results for various stokers. The fuel heat value noted in all the data tables refers to the higher heating value.

The measurement of nitrogen oxides and the errors associated with these measurements have been described in Section 7.1. The direct experimental readings were in parts per million. These were corrected to the nominal 3 percent oxygen level and further corrected for water. The

TABLE 7-2. NO_x EMISSION TEST DATA FROM PULVERIZED COAL-FIRED INDUSTRIAL BOILERS WITH LOW EXCESS AIR (LEA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
53.5/65.9 (182)/(225)	LEA[e] 5.3-4.5	26.57[f] (11,430)	1.40	4.20	9.36	1	234 (0.544)	--	--	222 (0.517)	5	Intermediate	# 12-24, T[g], WT[h]	--	7-1
76.2/93.8 (260)/(320)	LEA 5.8-4.8	25.94 (11,160)	1.34	2.74	11.58	1	296 (0.688)	--	--	303 (0.704)	-2	--	# 12-20, T, WT	--	7-1
38.1/76.2 (130)/(260)	LEA 7.4-6.6	27.58 (11,863)	0.83	1.15	10.5	1	563 (1.31)	--	--	529 (1.23)	6	--	# 31-7, SW, WT	--	7-1
117/147 (400)/(500)	LEA 8.6-8.1	28.59 (12,300)	1.50	1.36	14.48	1	216 (0.502)	--	--	212 (0.493)	2	Stringent	# 13-2, SW, WT	Multifuel Furnace	7-1
38.0/67.2 (130)/(230)	LEA 4.5-3.4	21.70 (9,336)	0.73	0.81	10.04	1	201[i] (0.467)	--	--	152[i] (0.353)	25	Stringent	Alma #3, SW, WT	--	7-7
38.0/67.2 (130)/(230)	LEA 6.1-4.0	25.04 (10,776)	1.09	3.68	14.49	1	244[i] (0.567)	--	--	197[i] (0.458)	19	Stringent	Alma #3, SW, WT	--	7-7
32.8/46.7 (112)/(160)	LEA 5.1-3.4	24.9 (10,741)	0.93	0.32	6.89	1	174[i] (0.401)	--	--	136[i] (0.316)	22	Stringent	Fremont #6 SW, WT	--	7-7
93.8/117 (320)/(400)	LEA 3.4-3.1	30.66 (13,190)	1.55	2.92	7.78	1	494 (1.15)	--	--	470 (1.09)	5	--	#20-42, Cy, WT		7-1

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f] MJ/kg (Btu/lb) as received.
[g] T, tangential; SW, single wall; Cy, cyclone
[h] WT, watertube.
[i] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

TABLE 7-3. NO_x EMISSION TEST DATA FROM PULVERIZED COAL-FIRED INDUSTRIAL BOILERS WITH BURNERS-OUT-OF-SERVICE (BOOS)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[h] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
18.8/76.2 (64)/(260)	BOOS,[e]	27.58[f] (11,863)	0.83	1.15	10.5	1	618 (1.44)	--	--	378 (0.88)	39	--	# 31-7, SW,[g] WT[h]	Only 32% NO_x reduction when compared to baseline at 50% load	7-1
38.1/67.2 (130)/(230)	BOOS,[i]	25.04 (10.776)	1.09	3.68	14.49	1	197 (0.458)	--	--	144 (0.335)	27	Stringent	Alma #3 SW, WT	4% excess O_2	7-7

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Burner pattern 2 X 2, top row firing air only.
[f] MJ/kg (Btu/lb) as received.
[g] SW, single wall.
[h] WT, watertube.
[i] Burner pattern 2 X 2, top right firing air only.
[j] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

TABLE 7-4. NO_x EMISSION TEST DATA FROM PULVERIZED COAL-FIRED INDUSTRIAL BOILERS WITH LOAD REDUCTION (LR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[h] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
--/93.8 --/(320)	LR[e] 94-62	25.94[f] (11,160)	1.34	2.74	11.58	1	209 (0.486)	--	--	144 (0.335)	31	Stringent	# 12-20, T9, WT[g]	4% excess O_2	7-1
--/147 --/(500)	LR 92-64	28.59 (12,300)	1.50	1.36	14.48	1	233 (0.541)	--	--	197 (0.458)	15	Stringent	# 13-2, SW, WT	9% excess O_2	7-1
--/76.2 --/(260)	LR 50-25.4	27.58 (11,863)	0.83	1.15	10.5	1	592 (1.38)	--	--	618 (1.44)	-4	--	# 31-7, SW, WT	7% excess O_2	7-1
--/117 --/(400)	LR 100-60	30.66 (13,190)	1.55	2.92	7.78	1	489 (1.14)	--	--	459 (1.07)	6	--	# 20-42, WT	Cyclone 3% excess O_2	7-1
--/672 -/(230)	LR 87-57	25.04 (10,776)	1.09	3.68	14.49	1	246[i] (0.573)	--	--	197[i] (0.458)	20	Stringent	Alma #3 SW, WT	4% excess O_2	7-7
--/672 -/(230)	LR 74-41	21.70 (9,336)	0.73	0.81	10.04	1	283[i] (0.659)	--	--	157[i] (0.365)	45	Stringent	Alma #3 SW, WT	5% excess O_2	7-7
--/46.9 -/(160)	LR[e] 83-41	25.3 (10,889)	1.25	1.48	9.19	1	264[i] (0.613)	--	--	184[i] (0.428)	30	Stringent	Fremont #6 SW, WT	5.4% excess O_2	7-7
--/46.9 -/(160)	LR 72-44	24.9 (10,741)	0.93	0.32	6.89	1	155[i] (0.360)	--	--	158[i] (0.367)	-2	Stringent	Fremont #6 SW, WT	4.2% excess O_2	7-7

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[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent rated load, first value is high load (baseline); second value is low load.
[f] MJ/kg (Btu/lb) as received.
[g] SW, single wall.
[h] WT, watertube.
[i] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

TABLE 7-5. NO_x EMISSION TEST DATA FROM COAL-FIRED INDUSTRIAL STOKERS WITH LOW EXCESS AIR (LEA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics: Heat Value	% N	% S	% Ash	Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu): Low	High	Average	Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
32.2/39.6 (110)/(135)	LEA[e] 6.5-5.3	29.50[f] (12,690)	1.40	2.94	4.77	1	235 (0.547)	--	--	216 (0.502)	8	Intermediate	# 11-1, SS[g]		7-1
22/39.6 (75)/(135)	LEA 9.0-6.5	29.50 (12,690)	1.40	2.94	4.77	1	263 (0.612)	--	--	219 (0.510)	17	Intermediate	# 11-1, SS	Low Load	7-1
35.2/44.0 (120)/(150)	LEA 10.3-8.9	30.47 (13,110)	1.33	1.58	7.99	1	336 (0.781)	--	--	287 (0.668)	15	Moderate	# 14-1, SS		7-1
44.2/58.6 (151)/(200)	LEA 10.6-8.9	30.96 (13,320)	1.80	0.86	10.36	1	330 (0.767)	--	--	219 (0.509)	34	Intermediate	# 14-4, SS		7-1
11.7/14.6 (40)/(50)	LEA 8.0-5.8	31.96 (13,750)	1.45	0.76	6.75	1	284 (0.660)	--	--	202 (0.469)	29	Moderate	# 21-2, SS		7-1
17.9/22 (61)/(75)	LEA 7.8-5.5	32.08 (13,800)	1.43	1.55	6.94	1	283 (0.658)	--	--	219 (0.509)	22	--	# 21-3, SS		7-1
24.0/36.6 (82)/(125)	LEA 6.2-4.7	30.06 (12,293)	1.46	1.16	9.71	1	196 (0.456)	--	--	142 (0.330)	28	Stringent	# 30-8, SS		7-1
51.9/87.9 (177)/(300)	LEA 4.3-2.7	25.35 (10,365)	1.01	1.05	7.00	1	239[h] (0.556)	--		180[h] (0.419)	75	Stringent	Site A, SS		7-8
59.8/87.9 (204)/(300)	LEA 5.2-3.4	25.89 (10,588)	--	--	5.21	1	293[h] (0.681)	--	--	215[h] (0.500)	27	Stringent	Site A, SS		7-8
52.7/58.6 (180)/(200)	LEA 7.0-3.2	31.31 (13,469)	1.38	0.81	7.48	1	309[h] (0.719)	--	--	173[h] (0.402)	44	Stringent	Site B, SS		7-9
17.6/29.3 (60)/(100)	LEA 10.9-6.5	20.2 (8,704)	0.78	0.73	8.29	1	312[h] (0.726)	--	--	206[h] (0.479)	34	Stringent	UW-Madison # 2, SS		7-7

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent level discussed in Section 3.
[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f] MJ/kg (Btu/lb) as received.
[g] SS, spreader stoker; UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.
[h] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

Continued

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TABLE 7-5. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[h] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average				
17.6/29.3 (60)/(100)	LEA[e] 10.0-7.8	27.9[f] (12,006)	1.30	3.07	9.60	1	289[h] (0.672)	--	--	258[h] (0.600)	11	Intermediate	UW-Madison # 2, SS[g]	7-7
23.7/46.9 (81)/(160)	LEA 8.6-7.7	19.5[f] (8,408)	0.68	1.15	9.12	1	236[h] (0.549)	--	--	183[h] (0.426)	22	Stringent	Willmar #3 SS	7-7
31.6/46.9 (108)/(160)	LEA 8.6-6.6	28.9 (12,448)	1.37	2.28	7.76	1	287[h] (0.667)	--	--	241[h] (0.560)	16	Intermediate	Willmar #3 SS	7-7
13.5/23.4 (46)/(80)	LEA 9.4-8.0	25.2 (10,842)	0.48	1.59	7.68	1	207[h] (0.481)	--	--	239[h] (0.556)	-13	--	Fairmont #3 SS	7-7
13.2/17.6 (45)/(60)	LEA 6.6-4.9	26.99 (11,610)	1.40	0.86	9.51	1	163 (0.379)	--	--	117 (0.272)	28	Stringent	# 15-32-10, UFS	7-1
13.5/17.6 (46)/(60)	LEA 9.8-8.0	26.99 (11,610)	1.40	0.86	9.51	1	136 (0.317)	--	--	161 (0.375)	-18	Intermediate	# 15-32-13, UFS	7-1
31.4/63.0 (107)/(215)	LEA 9.5-8.2	27.60 (11,873)	0.94	3.05	13.7	1	100 (0.233)	--	--	96.5 (0.225)	4	Stringent	# 35-6, CGS	7-1
5.0/13.2 (17)/(45)	LEA 9.8-7.3	24.1 (10,378)	0.91	0.83	3.92	1	199[h] (0.462)	--	--	152[h] (0.353)	24	Intermediate	UW Stout # 2, VGS	7-7

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[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f] MJ/kg (Btu/lb) as received.
[g] SS, spreader stoker, UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.
[h] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

TABLE 7-6. NO_x EMISSION TEST DATA FROM COAL-FIRED INDUSTRIAL STOKERS WITH OVERFIRE AIR (OFA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
24/36.6 (82)/(125)	OFA	30.06[e] (12,293)	1.46	1.16	9.71	2	196 (0.455)	180 (0.419)	195 0.453)	188 (0.436)	4	Stringent	# 30-8, SS[f]	All tests conducted at 6% excess O_2	7-1
24/36.6 (82)/(125)	OFA	30.06 (12,293)	1.46	1.16	9.71	1	196 (0.455)	--	--	145 (0.337)	26	Stringent	# 30-8, SS	OFA ports plus redundant gas jets	7-1
30.5/63.0 (104)/(215)	OFA	27.60 (11,873)	0.94	3.05	13.7	2	100 (0.233)	91.6 (0.213)	101 (0.236)	96.5 (0.225)	4	Stringent	# 35-6, CGS	9% excess O_2	7-1
28/63.0 (95)/(215)	OFA	27.60 (11,873)	0.94	3.05	13.7	2	89.8 (0.209)	96.5 (0.225)	106 (0.247)	101 (0.235)	-13	Stringent	# 35-6, CGS	10% excess O_2	7-1
44.0/58.6 (150)/(200)	OFA	30.96 (13,320)	1.80	0.06	10.36	4	330 (0.767)	177 (0.411)	234 (0.544)	215 (0.499)	35	Stringent	# 14-4, SS	11% excess O_2	7-1
66.2/87.9 (226)/(300)	OFA	23.92 (10,289)	0.95	0.36	7.88	1	254 (0.591)	--	--	227 (0.528)	10	Stringent	Site A, SS	6% excess O_2	7-8
30.8/46.9 (105)/(160)	OFA	19.5 (8,408)	0.68	1.15	9.12	1	2369 (0.549)	--	--	2339 (0.542)	1	Intermediate	Willmar #3 SS	9% excess O_2	7-1

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] MJ/kg (Btu/lb) as received.
[f] SS, spreader stoker, UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.
[g] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

TABLE 7-7. NO_x EMISSION TEST DATA FROM COAL-FIRED INDUSTRIAL STOKERS WITH LOAD REDUCTION (LR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
--/44.0 --/(150)	LR[e] 100-80	30.47[f] (13,110)	1.33	1.58	7.99	1	346 (0.806)	--	--	338 (0.786)	2	--	# 14-1, SS[g]	9.5 % excess O_2	7-1
--/58.6 --/(200)	LR 100-80	30.96 (13,320)	1.80	0.86	10.36	1	365 (0.850)	--	--	331 (0.770)	9	--	# 14-4, SS	10.8 % excess O_2	7-1
--/58.6 --/(200)	LR 76-50	30.96 (13,320)	1.80	0.86	10.36	1	386 (0.897)	--	--	282 (0.655)	27	Moderate	# 14-4, SS	13% excess O_2	7-1
--/36.6 --/(125)	LR 65.6-38.4	30.06 (12,293)	1.46	1.16	9.71	1	196 (0.455)	--	--	119 (0.277)	39	Stringent	# 30-8, SS	6.2-7.4% excess O_2	7-1
--/29.3 --/(100)	LR 90-60	20.2 (8,704)	0.78	0.73	8.29	1	274[h] (0.636)	--	--	219[h] (0.509)	20	Intermediate	UW-Madison # 2, SS	7.75-7.9% excess O_2	7-7
--/29.3 --/(100)	LR 90-60	27.9 (12,006)	1.30	3.07	9.60	1	325[h] (0.756)	--	--	289[h] (0.673)	11	Moderate	UW-Madison # 2, SS	10.0-10.3% excess O_2	7-7
--/87.9 --/(300)	LR 77-59	24.5 (10,547)	1.01	1.05	6.09	1	367[h] (0.854)	--	--	261[h] (0.607)	29	Moderate	Site A, SS	5.1-5.2% excess O_2	7-8
--/46.9 --/(160)	LR 70-47.6	28.9 (12,448)	1.37	2.28	7.76	1	331[h] (0.769)	--	--	219[h] (0.509)	34	Intermediate	Willmar #3 SS	8.4% excess O_2	7-7
--/46.9 --/(160)	LR 67-49	19.5 (8,408)	0.68	1.15	9.12	1	234[h] (0.543)	--	--	183[h] (0.426)	22	Stringent	Willmar # 3 SS	7.8% excess O_2	7-7
--/23.4 --/(80)	LR 73.5-61	28.8 (12,441)	1.35	2.51	8.24	1	201[h] (0.468)	--	--	171[h] (0.397)	15	Intermediate	Fairmont # 3 SS	8.1% excess O_2	7-7
--/23.4 --/(80)	LR 76-57.5	25.2 (10,842)	0.48	1.59	7.68	1	227[h] (0.529)	--	--	239[h] (0.556)	-5	--	Fairmont # 3 SS	8.0% excess O_2	7-7
--/4.0 --/(13.5)	LR 64.4-42.3	24.5 (10,515)	0.81	0.61	5.14	1	181[h] (0.421)	--	--	128[h] (0.299)	29	Stringent	St. Johns # 2 SS	15.2% excess O_2	7-7

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent load; first value is high load (baseline), second value is low load.
[f] MJ/kg (Btu/lb) as received.
[g] SS, spreader stoker, UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.
[h] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

Continued

TABLE 7-7. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics: Heat Value	% N	% S	% Ash	Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu): Low	High	Average	Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
--/4.0 --/13.5	LR[e] 62-43.5	30.5[f] (13,123)	0.95	0.58	5.29	1	265[h] (0.617)	--	--	196[h] (0.455)	26	Moderate	St. Johns # 2 SS9	15.5% excess O_2	7-7
--/17.6 --/(60)	LR 100-78	26.99 (11,610)	1.40	0.86	9.51	1	195 (0.453)	--	--	181 (0.421)	7	Moderate	# 15-32-10, UFS	6% excess O_2	7-1
--/17.6 --/(60)	LR 78-53	26.99 (11,610)	1.40	0.86	9.51	1	181 (0.421)	--	--	114 (0.264)	37	Stringent	# 15-32-13, UFS	10.5% excess O_2	7-1
--/63.0 --/(215)	LR 56-44	27.60 (11,873)	0.94	3.05	13.7	1	94.7 (0.220)	--	--	79.4 (0.185)	16	Stringent	# 35-6, CGS	8.3% excess O_2	7-1
--/63.0 --/(215)	LR 49-32	27.60 (11,873)	0.94	3.05	13.7	1	94.1 (0.219)	--	--	118 (0.274)	-25	Stringent	# 35-6, CGS	11% excess O_2	7-1
--/17.6 --/(60)	LR 58-25	21.5 (9,276)	1.10	0.72	5.1	2	187[h] (0.435)	94.5[h] (0.220)	97.1[h] (0.226)	95.8[h] (0.223)	49	Stringent	UW-Eau Claire # 1, CGS	10.6% excess O_2	7-7
--/17.6 --/(60)	LR 45-25	28.8 (12,382)	1.24	2.79	8.03	2	184[h] (0.428)	128[h] (0.299)	147[h] (0.343)	138[h] (0.321)	25	Intermediate	UW-Eau Claire # 1, CGS	Baseline load at 10.9% excess O_2 Reduced load at 8% excess O_2	7-7
--/13.2 --/(45)	LR 67-26	23.6 (10,142)	0.91	0.83	3.92	1	101[h] (0.235)	--	--	126[h] (0.293)	-25	Stringent	UW-Stout # 2 VGS	7.8-7.9% excess O_2	7-7
--/13.2 --/(45)	LR 67-44	28.0 (12,023)	1.28	2.81	7.25	1	120[h] (0.279)	--	--	120[h] (0.279)	0	Stringent	UW-Stout # 2 VGS	8.2% excess O_2	7-7

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent load; first value is high load (baseline), second value is low load.
[f] MJ/kg (Btu/lb) as received.
[g] SS, spreader stoker, UFS, underfeed stoker; CGS, chain grate stoker; VGS, vibrating grate stoker.
[h] Estimate only, NO_x values assume NO_2 is 5% of total (only NO was measured).

TABLE 7-8. NO_x EMISSION TEST DATA FROM COAL-FIRED INDUSTRIAL STOKERS WITH REDUCED AIR PREHEAT (RAP)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
24/36.6 (82)/(125)	RAP[e] 366.5-354.3	30.06[f] (12,293)	1.46	1.16	9.71	1	196 (0.455)	--	--	162 (0.377)	17	Stringent	# 30-8, SS[g]	6% excess O_2
24.2/36.6 (82.5)/(125)	RAP 369.4-355.4	30.06 (12,293)	1.46	1.16	9.71	1	132 (0.307)	--	--	134 (0.311)	-2	Stringent	# 30-8, SS	5% excess O_2

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] First value, temperature (K) of baseline combustion air; second value, temperature (K) of RAP combustion air.
[f] MJ/kg (Btu/lb) as received.
[g] SS, spreader stoker.

results were then converted into an input specific value, ng/J or lb/10^6 Btu by:

a. Knowing the higher heating value (HHV) of the fuel and the amount of fuel consumed in a given period of time, or

b. Knowing the size of the boiler (the number of pounds of steam produced in a given period of time and the exact relationship between this with the HHV of the fuel, i.e., boiler efficiency).

As fuel consumption was not well documented, the unit conversion constants used by the investigators (References 7-4 and 7-5) were based on (b) from which they obtained a constant for each type of fuel for the conversion.

7.3 EMISSION SOURCE TEST DATA FOR OIL-FIRED INDUSTRIAL BOILERS

Tables 7-9 through 7-15 summarize the results of various NO_x emission controls as applied to a series of boilers burning residual oil. The data were obtained from a large number of tests run on industrial boilers under various EPA programs (References 7-1 through 7-6). The criteria used for selecting these data are listed in Section 7.1.

Residual oils employed in these tests consisted of No. 5 and No. 6 fuel oil and two others, NSF oil and PS 300 oil, which both qualify on the basis of viscosity as No. 5 oils. In addition to the effects of low excess air on boilers burning residual oil, Table 7-9 shows the effects of two differing No. 6 oils on the NO_x emissions of a watertube industrial boiler. The fuel characteristics columns exemplify the differences in fuels that, due to viscosity, are both labeled as No. 6 oils.

Data on NO_x emission controls as applied to boilers burning distillate oil are contained in Tables 7-16 through 7-20. The tests were selected because they best fitted the criteria for selection listed in Section 7.1. All of the data resulted from two EPA sponsored field investigations and one subsequent study of a boiler with major modifications (References 7-1, 7-3 through 7-5).

All distillate oils used were classified as No. 2. All had comparable heating values and sulfur, nitrogen, and ash contents. The fuel heat value noted in all the data tables refers to the higher heating value.

7.4 EMISSION SOURCE TEST DATA FOR GAS-FIRED INDUSTRIAL BOILERS

Emission source test data for NO_x controls on industrial boilers burning natural gas are presented in Tables 7-21 through 7-27. A large number of tests were conducted using this fuel under various EPA sponsored programs (References 7-1 through 7-5). The criteria whereby these tests were chosen as representative were presented in Section 7-1. The fuel heat value noted in all the data tables refers to the higher heating value.

TABLE 7-9. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH LOW EXCESS AIR (LEA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
2.0/2.1 (6.7)/(7)	LEA[e] 5.4-3.9	42.49[f] (18,280)	0.27	1.85	0.038	1	170 (0.395)	--	--	143 (0.333)	16	--	# 23-1, FT[g]	No. 6 oil	7-1
3.2/3.1 (10.9)/(10.5)	LEA 3.2-1.9	43.61 (18,760)	0.20	1.30	0.26	1	104 (0.243)	--	--	99.3 (0 .231)	5	Intermediate	# 24-TY, FT	No. 5 oil	7-1
5.1/5.3 (17.4)/(18)	LEA 7.2-3.7	42.31 (18,200)	0.10	1.46	0.007	2	95.4 (0.222)	88.1 (0.205)	105 (0.244)	96.5 (0.224)	-1	Intermediate	# 26-1, FT	No. 5 oil	7-1
3.5/3.2 (11.9)/(11)	LEA 4.1-3.7	42.31 (18,200)	0.10	1.46	0.007	1	106 (0.245)	--	--	106 (0.245)	0	Intermediate	# 26-2, FT	No. 5 oil	7-1
1.6/3.5 (53)/(12)	LEA 6.1-2.0	--	--	--	--	1	117 (0.273)	--	--	95.9 (0.223)	18	Intermediate	# ECCC, FT	No. 5 oil	7-2
2.3/3.5 (7.9)/(12)	LEA 5.9-3.2	--	--	--	--	1	116 (0.270)	--	--	99.3 (0.231)	14	Intermediate	# ECCC, FT	No 5 oil Higher load	7-2
4.2/5.1 (14.2)/(17.5)	LEA 4.0-2.2	42.49 (18,280)	0.44	2.80	0.044	2	195 (0.454)	155 (0.360)	160 (0.373)	158 (0.367)	19	--	# 19-1, WT	No. 6 oil	7-1
4.1/5.1 (14.1)/(17.5)	LEA 3.1-0.9	45.01 (19,365)	0.14	0.37	0.009	1	94.8 (0.220)	--	--	69.6 (0.162)	27	Stringent	# 19-1, WT	Different No. 6 oil	7-1
15/23 (51)/(80)	LEA 5.7-4.0	43.00 (18,500)	0.37	1.49	0.019	1	174 (0.404)	--	--	155 (0.361)	11	--	# 20-4, WT	No. 6 oil	7-1
10.5/13.2 (36)/(45)	LEA 3.0-1.6	44.69 (19,227)	0.49	0.19	0.08	1	183 (0.426)	--	--	136 (0.317)	26	--	# 38-2, WT	No. 6 oil	7-1
5.7/7.3 (19.5)/(25)	LEA 5.5-3.6	--	--	--	--	1	87.5 (0.203)	--	--	63.4 (0.147)	28	Stringent	# ECCC, WT	No. 5 oil	7-2
3.7/5.6 (12.5)/(19.2)	LEA[e] 7.6-7.1	43.54[f] (18.730)	0.26	1.59	0.065	1	112 (0.260)	--	--	105 (0.244)	6	Intermediate	# 15-123-1, WT[g]	NSF oil (No. 5 oil)	7-1

[a] All reported tests were short-term (3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] First value, temperature (K) of baseline combustion air; second value, temperature (K) of RAP combustion air.
[f] MJ/kg (Jtu/lb).
[g] FT, firetube; WT, watertube.

TABLE 7-9. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics: Heat Value[f]	% N	% S	% Ash	Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu): Low	High	Average	Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification[g]	Remarks	Reference
29.3/36.6 (100)/(125)	LEA 6.4-4.6	--	0.52	1.15	0.026	1	189 (0.440)	--	--	178 (0.414)	6	--	# 2-6, WT	PS 300 oil (No. 5 oil)	7-1
24.3/29.3 (83)/(100)	LEA 9.3-5.9	42.62 (18,333)	0.77	1.29	0.10	1	257 (0.598)	--	--	225 (0.523)	12	--	# 27-1, WT	PS 300 oil (No. 5 oil)	7-1
15.2/19.0 (52)/(65)	LEA 4.7-3.6	44.0 (18,930)	0.29	1.03	0.043	1	106 (0.247)	--	--	105 (0.244)	1	Intermediate	# 16-2, WT	No. 6 oil	7-1
21.1/26.4 (72)/(90)	LEA 7.4-7.0	42.82 (18,420)	0.26	1.04	0.031	1	138 (0.321)	--	--	121 (0.282)	12	Moderate	# 18-2, WT	No. 6 oil	7-1
23.4/30.8 (80)/(105)	LEA 6.3-5.3	43.96 (18,910)	0.26	1.03	0.032	1	142 (0.330)	--	--	116 (0.269)	18	Moderate	# 18-3, WT	No. 6 oil	7-1
34.9/46.9 (119)/(160)	LEA 7.2-6.0	43.96 (18,910)	0.26	1.03	0.032	1	133 (0.309)	--	--	131 (0.304)	2	--	# 18-4, WT	No. 6 oil	7-1
8.5/20.5 (29)/(70)	LEA 5.3-4.9	--	--	--	--	1	115 (0.267)	--	--	101 (0.235)	12	Intermediate	# 28-1, WT	No. 6 oil	7-1
35.5/44.0 (121)/(150)	LEA 5.0-3.1	42.34 (18,213)	0.31	2.74	0.03	1	66.8 (0.155)	--	--	68.4 (0.159)	-2	Stringent	# 29-5, WT	No. 6 oil	7-1
9.4/11.7 (32)/(40)	LEA 4.3-3.8	43.64 (18,773)	0.30	1.91	0.07	1	109 (0.254)	--	--	100 (0.234)	8	Intermediate	# 37-2, WT	No. 6 oil	7-1
16.4/25 (56)/(85)	LEA 7.6-5.4	--	0.32	0.35	0.010	1	188 (0.438)	--	--	145 (0.337)	23	--	# 7-3, WT	No. 5 oil	7-1
13.8/17.3 (47)/(59.2)	LEA 5.0-2.3	--	0.38	0.63	0.014	1	362 (0.843)	--	--	301 (0.699)	17	--	# 2-2, WT	PS 300 oil (No. 5 oil)	7-1
15.2/19.0 (52)/(65)	LEA 5.7-3.4	--	0.38	0.63	0.014	1	280 (0.651)	--	--	250 (0.581)	11	--	# 2-4, WT	PS 300 oil (No. 5 oil)	7-1

[a] All reported tests were short-term (3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Excess oxygen, %, first value is high excess air (baseline) condition; second value is low excess air condition.
[f] MJ/kg (Btu/lb).
[g] FT, firetube; WT, watertube.

TABLE 7-10. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH STAGED COMBUSTION AIR (SCA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
1.8/3.5 (6)/(12)	SCA[e] ϕ = 0.76	44.679 (19,219)	0.26	0.32	0.01	1	96.2 (0.224)	--	--	49.0 (0.114)	49	Stringent	# ECCC, FT[h]	No. 5 oil 2% excess O_2 Lance depth 2.5 diameters	7-2
1.8/3.5 (6)/(12)	SCA[e] ϕ = 0.65	44.67 (19,219)	0.26	0.32	0.01	2	96.2 (0.224)	51.9 (0.121)	51.9 (0.121)	51.9 (0.121)	46	Stringent	# ECCC, FT	No. 5 oil 4.4% excess O_2 Lance depth 2.5 diameters	7-2
4.0/5.1 (13.7)/(17.5)	SCA[f] ϕ_B = 1.03	43.82 (18,780)	0.23	0.60	0.034	1	120 (0.280)	--	--	84.9 (0.197)	29	Stringent	# 19-1, WT	No. 6 oil 3.1% excess O_2 Lance depth 1.5 m	7-3
4.2/5.1 (14.5)/(17.5)	SCA[f] ϕ_B >1	43.82 (18,780)	0.23	0.60	0.034	1	120 (0.280)	--	--	70 (0.162)	42	Stringent	# 19-1, WT	No. 6 oil 1.9% excess O_2 Lance depth 2.1 m	7-3
11.1/13.2 (38)/(45)	SCA[f] ϕ_B >1	42.92 (18,466)	0.31	1.88	0.05	1	168[i] (0.390)	--	--	97.4[i] (0.227)	42	Intermediate	# 38-2, WT	No. 6 oil 3.3% excess O_2	7-3

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] ϕ = Burner stoichiometry.
[f] ϕ_B = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air fuel at the burner.
[g] MJ/kg (Btu/lb).
[h] FT, firetube; WT, watertube.
[i] NO only.

TABLE 7-11. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH BURNERS OUT OF SERVICE (BOOS) (Reference 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
13.8/17.3 (47)/(59.2)	BOOS	--[e]	0.38	0.63	0.014	2	363 (0.845)	294 (0.684)	346 (0.807)	320 (0.744)	12	--	# 2-2, WT[f]	Two rows of 3 burners, staggered, middle top burner on air only: PS 300 (No. 5 oil)
14.9/19.0 (51)/(65.0)	BOOS	--	0.38	0.63	0.014	1	275 (0.640)	--	--	248 (0.577)	10	--	# 2-4, WT	Two rows of 3 burners, staggered, middle bottom burner on air only. PS 300 (No. 5 oil)
14.4/24.9 (49)/(85)	BOOS	--	0.32	0.35	0.010	2	192 (0.446)	139 (0.322)	153 (0.356)	146 (0.340)	24	--	# 7-3, WT	Single row of 4 burners, a middle burner on air only. (No. 5 oil)
34.9/46.9 (119)/(160)	BOOS	43.96 (18,910)	0.26	1.03	0.032	1	133 (0.309)	--	--	94.2 (0.219)	29	Intermediate	# 18-4, WT	Two rows of 2 burners one top burner on air only (No. 6 oil)
22.3/30.8 (76)/(105)	BOOS	43.96 (18,910)	0.26	1.03	0.032	7	134 (0.311)	122 (0.283)	128 (0.321)	127 (0.296)	5	Moderate	# 18-3, WT[f]	Two rows of 2 burners, one top on air only. No. 6 oil. Excess O_2 6%.
17.6/26.4 (60)/(90)[g]	BOOS	42.82 (18,420)	0.26	1.04	0.031	1	138 (0.321)	--	--	98.2 (0.228)	29	Intermediate	# 18-2, WT	One row of 3 burners, center burner on air only. No. 6 oil
8.5/20.5 (29)/(70)	BOOS	--	--	--	--	3	128 (0.299)	125 (0.291)	137 (0.244)	130 (0.303)	-2	Moderate	# 28-1, WT	One row of 3 burners, center burner on air only. No. 6 oil. Excess O_2 6%
21/44 (70)/(150)	BOOS	42.34[e] (18,213)	0.31	2.74	0.03	1	145 (0.337)	--	--	104 (0.243)	28	Intermediate	# 29-5, WT[f]	Two burners top burners on air only. No. 6 oil. Excess O_2 5.5%

[a] All reported tests were short-term (3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] MJ/kg (Btu/lb).
[f] WT, watertube.
[g] Baseline at 71 x 10^6 Btu/hr, 7.4% excess O_2; BOOS at 60 x 10^6 Btu/hr, 8.2% excess O_2.

TABLE 7-12. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH FLUE GAS RECIRCULATION (FGR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
1.2/3.5 (4)/(12)	FGR, 23%[e]	44.37[f] (19,091)	0.22	0.44	0.09	2	98.1 (0.288)	95.4 (0.222)	100 (0.233)	97.7 (0.227)	0	Intermediate	# ECCC, FT[g]	No. 5 oil	7-2
1.2/3.5 (4)/(12)	FGR, 40%	44.37 (19,091)	0.22	0.44	0.09	3	9.99 (0.232)	83.0 (0.193)	95.9 (0.223)	88.6 (0.206)	11	Intermediate	# ECCC, FT	No. 5 oil	7-2
1.2/3.5 (4)/(12)	FGR, 53%	44.37 (19,091)	0.22	0.44	0.09	1	94.8 (0.220)	--	--	63.4 (0.147)	33	Stringent	# ECCC, FT	No. 5 oil	7-2
1.8/3.5 (6)/(12)	FGR, 29%	44.37 (19,091)	0.22	0.44	0.09	1	108 (0.251)	--	--	82.5 (0.192)	24	Stringent	# ECCC, FT	No. 5 oil	7-2
1.8/3.5 (6)/(12)	FGR, 40%	44.37 (19,091)	0.22	0.44	0.09	1	108 (0.251)	--	--	81.9 (0.190)	24	Stringent	# ECCC, FT	No. 5 oil	7-2
3.1/3.5 (10.5)/(12)	FGR, 20%	44.37 (19,091)	0.22	0.44	0.09	2	95.9 (0.223)	66.2 (0.154)	71.8 (0.167)	69.0 (0.160)	28	Stringent	# ECCC, FT	No. 5 oil	7-2
2.9/7.3 (10)/(25)	FGR, 21%	44.60 (19,188)	0.19	0.40	0.01	3	53.9 (0.125)	43.8 (0.102)	52.4 (0.122)	47.0 (0.109	13	Stringent	# ECCC, WT	No. 5 oil	7-2
1.9/7.3 (6.5)/(25)	FGR, 17%	44.60 (19,188)	0.19	0.40	0.01	2	68.4 (0.159)	50.5 (0.117)	58.9 (0.137)	55.0 (0.128)	20	Stringent	# ECCC, WT	No. 5 oil	7-2
4.4/7.3 (15)/(25)	FGR, 8%	44.60 (19,188)	0.19	0.40	0.01	3	66.8 (0.155)	65.1 (0.151)	71.2 (0.166)	67.9 (0.158)	-2	Stringent	# ECCC, WT	No. 5 oil	7-2
4.4/7.3 (15)/(25)	FGR, 24%	44.60 (19,188)	0.19	0.40	0.01	1	66.8 (0.155)	--	--	65.1 (0.151)	3	Stringent	# ECCC, WT	No. 5 oil	7-2
4.2/5.1 (14.4)/(17.5)	FGR, 20%	45.0 (18,365)	0.14	0.37	0.009	1	95 (0.221)	--	--	81 (0.188)	15	Stringent	# 19-1, WT	Steam atomization No. 6 oil	7-2
4.2/5.1 (14.4)/(17.5)	FGR, 16%	45.0 (19,365)	0.14	0.37	0.009	1	90 (0.209)	--	--	83 (0.193)	8	Stringent	# 19-1, WT	Air atomization No. 6 oil	7-1

[a] All reported tests were short-term (3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Mass percent flue gas recirculated
[f] MJ/kg (Btu/lb).
[g] FT, firetube; WT, watertube

TABLE 7-13. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH COMBINED FLUE GAS RECIRCULATION AND STAGED COMBUSTION AIR (FGR/SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.3/5.1 (14.6)/(17.5)	FGR, 23.1[e] SCA, ϕ_B = 1.01[f]	43.849 (18,850)	0.22	0.60	0.026	1	120 (0.280)	--	--	90.5 (0.210)	25	Intermediate	# 19-1, WT[h]	No. 6 oil 4.2% excess O_2 Lance depth 1.2 m
4.3/5.1 (14.6)/(17.5)	FGR, 23% SCA, ϕ_B = 1.1	43.68 (18,780)	0.23	0.60	0.034	1	130 (0.303)	--	--	69 (0.16)	53	Stringent	# 19-1, WT	No. 6 oil 2.9% excess O_2 Lance depth 2.1 m
4.3/5.1 (14.6)/(17.5)	FGR, 19.6% SCA, ϕ_B = 1.21	43.68 (18,780)	0.23	0.60	0.034	1	130 (0.303)	--	--	65 (0.151)	50	Stringent	# 19-1, WT	No. 6 oil 1.5% excess O_2 Lance depth 1.2 m

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Mass percent flue gas recirculation.
[f] ϕ_B = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air fuel ratio at the burner.
[g] MJ/kg (Btu/lb).
[h] WT, watertube.

TABLE 7-14. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH REDUCED AIR PREHEAT (RAP) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
9.1/13.2 (31)/(45)	RAP[e] 430-350	44.69[f] (19,227)	0.49	0.19	0.08	1	183 (0.425)	--	--	153 (0.355)	16	--	38-2, WT[g]	No. 6 oil Excess O_2 3%
9.4/11.7 (32)/(40)	RAP 381.5-315.4	45.07 (19,390)	0.30	1.91	0.07	1	109 (0.254)	--	--	104 (0.241)	5	Moderate	37-2, WT	No. 6 oil Excess O_2 4%

a All reported tests were short-term (<3 hr).
b NO_x emissions determined by chemiluminescence in all cases.
c Based on average of all tests.
d Moderate, intermediate or stringent levels discussed in Section 3.
e First value, temperature (K) of baseline combustion air; second value temperature (K) of RAP combustion air.
f MJ/kg (Btu/lb).
g WT, watertube boiler

TABLE 7-15. NO_x EMISSION TEST DATA FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS WITH LOAD REDUCTION (LR) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics: Heat Value	% N	% S	% Ash	Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu): Low	High	Average	Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
-/5.0 -/(17)	LR[e] 126-71	43.77[f] (18,830)	0.28	1.72	0.055	1	120 (0.279)	--	--	104 (0.241)	13	Intermediate	# 15-2-1, FT[g]	RSF (No. 5) oil Excess O_2 7%
-/3.1 -/10.5)	LR 104-62	43.61 (18,760)	0.20	1.30	0.26	1	104 (0.243)	--	--	97.6 (0.227)	6	Intermediate	# 24-TV, FT	No. 5 oil Excess O_2 2.5%
-/5.3 -/(18)	LR 98-42	42.31 (18,200)	0.10	1.46	0.007	1	99.9 (0.232)	--	--	86.4 (0.201)	14	Stringent	# 26-1, FT	No. 5 oil, air atomization Excess O_2 7.3%
-/5.3 -/(18)	LR 96-39	42.31 (18,200)	0.10	1.46	0.007	1	90.9 (0.211)	--	--	87.0 (0.202)	4	Stringent	# 26-1, FT	No 5 oil, steam atomization. Excess O_2 7%
-/3.2 -/(11)	LR 77-38	42.31 (18,200)	0.10	1.46	0.007	1	99.9 (0.232)	--	--	90.9 (0.211)	10	Intermediate	# 26-2, FT	No. 5 oil Excess O_2 7.5%
-/24.9 -/(85)	LR 69-46	--	0.32	0.35	0.010	1	185 (0.429)	--	--	141 (0.329)	24	--	# 7-3, WT	No. 5 oil Excess O_2 7.7% Preheated air
-/26.4 -/(90)	LR 80-46	42.82 (18,420)	0.26	1.04	0.031	1	160 (0.372)	--	--	108 (0.250)	33	Intermediate	# 18-2, WT	No. 6 oil. Excess O_2 8.5%. Preheated air.
-/30.8 -/(105)	LR 76-44	44.00 (18,930)	0.29	1.03	0.043	1	176 (0.410)	--	--	123 (0.287)	30	Moderate	# 18-3, WT	No. 6 oil. Excess O_2 7.6%. Preheated air.
-/46.9 -/(160)	LR 75-45	44.00 (18,930)	0.29	1.03	0.043	1	144 (0.335)	--	--	180 (0.419)	-25	--	# 18-4, WT	No. 6 oil. excess O_2 8%. Preheated air.

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent rated load, first value is high load, second value is low load.
[f] MJ/kg (Btu/lb).
[g] FT, firetube; WT, watertube.

TABLE 7-15. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
-/44 -/(150)	LR[e] 79-47	42.33[f] (18,213)	0.31	2.74	0.03	1	165 (0.384)	--	--	145 (0.337)	12	--	# 29-5, WT[g]	No. 6 oil. excess O_2 5%. Preheated air.
-/17.3 -/(59)	LR 100-81	--	--	0.63	0.014	1	241 (0.560)	--	--	225 (0.523)	7	--	# 2-2, WT	PS 300 (No. 5) oil. Excess O_2 3%
-/19.0 -/(65)	LR 77-68	--	--	0.63	0.014	1	264 (0.614)	--	--	270 (0.628)	-2	--	# 2-4, WT	PS 300 (No. 5) oil. Excess O_2 3%
-/36.6 -/(125)	LR 80-30	--	0.52	1.15	0.026	1	215 (0.500)	--	--	197 (0.458)	8	--	#2-6, WT	PS300 (No. 5) oil. Excess O_2 7%
-/5.1 -/(17.5)	LR 83-55	42.49 (18,280)	0.44	2.80	0.044	1	219 (0.510)	--	--	210 (0.489)	4	--	#19-1, WT	No. 6 oil. Excess O_2 6%
-/23.4 -/(80)	LR 75-41	43.14 (18,560)	0.37	1.53	0.032	1	184 (0.428)	--	--	155 (0.361)	16	--	#20-4, WT	No. 6 oil. Excess O_2 6%
-/29.3 -/(100)	LR 85-55	42.62 (18,333)	0.77	1.29	0.10	1	257 (0.598)	--	--	246 (0.573)	4	--	#27-1, WT	PS 300 (No. 5) oil Excess O_2 9%
-/3.5 -/(12)	LR 92-46	44.34 (19,075)	0.04	0.67	0.04	1	120 (0.280)	--	--	110 (0.255)	8	Moderate	#ECCC, FT	No. 5 oil. Excess O_2 4% (Reference 7-2).
-/7.3 -/(25)	LR 74-26	44.40 (19,099)	0.15	0.75	0.02	1	71.2 (0.165)	--	--	68.3 (0.159)	4	Stringent	#ECCC, WT	No. 5 oil Excess O_2 4.5% (Reference 7-2).

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent rated load, first value is high load, second value is low load.
[f] MJ/kg (Btu/lb)
[g] FT, firetube; WT, watertube

TABLE 7-16. NO_x EMISSION TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH LOW EXCESS AIR (LEA) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
1.6/2.9 (5.5)/(10.0)	LEA[e] 5.6-3.6	--[f]	--	0.23	--	1	96.5 (0.224)	--	--	85.8 (0.200)	11	Moderate	#3-2, FT[g]	No air preheat.
2.7/5.9 (9.3)/(20.0)	LEA 5.2-2.7	--	--	0.30	--	1	107 (0.248)	--	--	81.3 (0.189)	24	Moderate	#4-4, FT	No air preheat.
5.4/8.5 (18.5)/(29.0)	LEA 5.9-4.5	45.19 (19,440)	0.045	0.40	0.003	1	54.4 (0.127)	--	--	51.6 (0.120)	5	Intermediate	#1-1, WT	No air preheat.
7.0/8.5 (24.0)/(29.0)	LEA 3.8-2.7	45.19 (19,440)	0.045	0.40	0.003	1	48.2 (0.112)	--	--	47.7 (0.111)	1	Intermediate	#1-1, WT	Higher load. No air preheat.
4.2/8.5 14.5/(29.0)	LEA 8.2-5.1	45.19 (19,440)	0.045	0.40	0.003	1	59.5 (0.138)	--	--	51.6 (0.120)	11	Intermediate	#1-2, WT	No air preheat.
6.9/8.8 23.5/(30)	LEA 5.9-2.8	--	0.031	0.22	0.001	1	69.0 (0.160)	--	--	58.3 (0.136)	16	Intermediate	#1-3, WT	
4.1/5.1 (14)/(17.5)	LEA 3.6-2.6	45.26 (19,470)	0.006	0.06	0.001	1	37.0 (0.086)	--	--	35.9 (0.083)	3	Stringent	# 19-1, WT[g]	Steam atomization. No air preheat.
4.1/5.1 (14)/(17.5)	LEA 3.0-1.6	45.26 (19,470)	0.006	0.06	0.001	1	51.0 (0.119)	--	--	50.5 (0.117)	1	Intermediate	# 19-1, WT	Air atomization. No air preheat.
3.4/5.1 (11.6)/(17.5)	LEA 4.3-3.7	45.26 (19,470)	0.006	0.06	0.001	1	46.0 (0.107)	--	--	46.0 (0.107)	0	Intermediate	# 19-1, WT	Mechanized atomization. No air preheat.
25.8/32.2 (88)/(110)	LEA 5.7-3.8	44.95 (19,340)	0.01	0.18	0.004	1	102 (0.236)	--	--	93.7 (0.218)	8	--	# 17-T-8, WT	

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Excess oxygen, %; first value is high excess air (baseline) condition; second value is low excess air condition.
[f] MJ/kg (Btu/lb).
[g] FT, firetube; WT, watertube.

TABLE 7-17. NO_x EMISSION TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH FLUE GAS RECIRCULATION (FGR) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.3/5.1 (14.6)/(17.5)	FGR, 28%[e]	45.61[f] (19,610)	0.008	0.14	0.001	2	67.4 (0.157)	17.4 (0.040)	18.5 (0.043)	18.0 (0.042)	73	Stringent	#19-1, WT[g]	Excess O_2 0.8% No air preheat.
4.3/5.1 (14.6)/(17.5)	FGR, 15%	45.78 (19,680)	<0.001	0.10	<0.001	1	~59 ~(0.14)	--	--	25 (0.058)	58	Stringent	#19-1, WT	Excess O_2 1% No air preheat.

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Mass percent flue gas recirculated.
[f] MJ/kg (Btu/lb).
[g] WT, watertube.

TABLE 7-18. NO_x EMISSION TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH STAGED COMBUSTION AIR (SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.3/5.1 (14.5)/(17.5)	SCA, ϕ_B = 1.04[e]	45.61[f] (19,610)	0.008	0.14	0.001	2	66.0 (0.153)	54.0 (0.126)	55.1 (0.128)	54.6 (0.127)	17	Intermediate	#19-1, WT[g]	Excess O_2 3.1%. Lance depth, 1.8 m.
4.3/5.1 (14.5)/(17.5)	SCA, ϕ_B = 1.10	45.78 (19,680)	<0.001	0.10	<0.001	1	66.0 (0.153)	--	--	29.0 (0.068)	44	Stringent	#19-1, WT	Excess O_2 2.6%. Lance depth 2.1 m.
4.3/5.1 (14.5)/(17.5)	SCA, ϕ_B = 1.10	45.78 (19,680)	<0.001	0.10	<0.001	1	56 (0.13)	--	--	39 (0.091)	30	Stringent	#19-1, WT	Excess O_2 3%. Lance depth, 2.1 m. No air preheat.

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] ϕ_B = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air-fuel ratio at burner.
[f] MJ/kg (Btu/lb).
[g] WT, watertube.

TABLE 7-19. NO_x TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH COMBINED FLUE GAS RECIRCULATION AND STAGED COMBUSTION AIR (FGR/SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.3/5.1 (14.6)/(17.5)	FGR, 26.3%[e] SCA, ϕ_B = 1.10[f]	--	--	--	--	1	67.4 (0.157)	--	--	18.0 (0.042)	73	Stringent	#19-1, WT[h]	Excess O_2 3.5%. Lance depth, 1.2 m. No air preheat.
4.3/5.1 (14.6)/(17.5)	FGR, 26% SCA ϕ_B = 1.1	45.619 (19,610)	0.008	0.14	0.001	1	67.4 (0.157)	-	-	16 (0.036)	77	Stringent	#19-1, WT	Excess O_2 2.5%. Lance depth, 2.1 m. No air preheat.

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Mass percent flue gas recirculated.
[f] Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air-fired ratio at the burner.
[g] MJ/kg (Btu/lb).
[h] WT, watertube.

TABLE 7-20. NO_x EMISSION TEST DATA FROM DISTILLATE (NO. 2) OIL-FIRED INDUSTRIAL BOILERS WITH LOAD REDUCTION (LR) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
-/2.9 -/(10.0)	70-30[e]	--[f]	--	0.23	--	1	95.9 (0.223)	--	--	86.4 (0.201)	10	Moderate	#3-2, FT[g]	Excess O_2 7% No air preheat.
-/5.9 -/(20)	92.5-46.5	--	--	0.30	--	1	106 (0.247)	--	--	108 (0.252)	-2	--	#4-4, FT	Excess O_2 6.4% No air preheat.
-/8.5 -/(29)	81-64	45.19 (19,440)	0.045	0.40	0.003	1	44.3 (0.103)	--	--	51.6 (0.120)	-17	Intermediate	#1-1, WT	Excess O_2 4%. No air preheat.
-/8.5 -/(29)	66-50	45.19 (19,440)	0.045	0.40	0.003	1	48.8 (0.113)	--	--	51.6 (0.120)	-6	Intermediate	#1-2, WT	Excess O_2 5%. No air preheat.
-/58.6 -/(200)	45-18	45.07 (19,390)	0.013	0.31	0.001	1	58.3 (0.136)	--	--	60.6 (0.141)	-4	Intermediate	#36-6, WT	Excess O_2 increased from 3.3% to 9.0%. No air preheat.
-/46.3 -/(158)	89-73	--	0.018	0.23	0.005	1	151 (0.351)	--	--	104 (0.241)	31	-	#6-3, WT	Excess O_2 5%.
-/32.2 -/(110)	80-30	44.96 (19,340)	0.01	0.18	0.004	1	114 (0.265)	--	--	88.6 (0.206)	22	Moderate	#17-TB, WT	Excess O_2 8%.

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Percent rated load, first value is high load (baseline), second value is low load.
[f] MJ/kg (Btu/lb).
[g] FT, firetube; WT, watertube

TABLE 7-21. NO_x EMISSION TEST DATA FROM GAS-FIRED INDUSTRIAL BOILERS WITH LOW EXCESS AIR (LEA)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics: Heat Value	% N	% S	% Ash	Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu): Low	High	Average	Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
1.46/2.9 (5.0)/(10.0)	LEA[e] 8.0-3.6	36.65[f] (1108)	--	--	--	1	51.0 (0.119)	--	--	33.7 (0.078)	34	Stringent	# 3-2, FT[g]	No air preheat	7-1
4.1/5.9 (14.0)/(20)	LEA 6.8-0.7	36.65 (1108)	--	--	--	1	55.1 (0.128)	--	--	40.3 (0.094)	27	Stringent	# 4-4, FT	No air preheat	7-1
2.6/5.9 (9.0)/(20)	LEA 6.8-1.2	36.65 (1108)	--	--	--	1	52.5 (0.122)	--	--	43.3 (0.101)	18	Stringent	# 4-4, FT	Low load No air preheat	7-1
2.3/2.9 (8.0)/(10.0)	LEA 5.1-1.9	36.65 (1108)	--	--	--	1	28.6 (0.066)	--	--	20.4 (0.047)	29	Stringent	# 5-248-3, FT	No air preheat	7-1
1.9/2.3 (6.4)/(8.0)	LEA 11.0-3.2	36.65 (1108)	--	--	--	1	31.6 (0.074)	--	--	24.0 (0.056)	24	Stringent	# 5-248-1, FT	No air preheat	7-1
3.6/3.1 (12.4)/(10.5)	LEA 4.1-3.1	31.96 (966)	--	--	--	1	31.6 (0.074)	--	--	32.6 (0.076)	-3	Stringent	# 24-IV, FT	No air preheat	7-1
5.0/5.3 (17.2)/(18)	LEA 7.2-2.7	31.89 (964)	--	--	--	1	29.6 (0.069)	--	--	38.8 (0.090)	-31	Stringent	# 26-1, FT	No air preheat	7-1
3.05/3.2 (10.4)/(11)	LEA 3.6-2.9	31.89 (964)	--	--	--	1	47.9 (0.111)	--	--	48.4 (0.113)	-1	Intermediate	# 26-2, FT	No air preheat	7-1
1.1/3.5 (3.8)/(12)	LEA 11.5-8.0	--	--	--	--	1	53.6 (0.124)	--	--	44.9 (0.104)	16	Intermediate	# ECCC, FT	No air preheat	7-2
2.0/3.5 (6.8)/(12)	LEA 9.0-6.5	--	--	--	--	1	52.0 (0.121)	--	--	45.9 (0.107)	12	Intermediate	# ECCC, FT	No air preheat	7-2

[a]All reported tests were short-term (<3 hr).
[b]NO_x emissions determined by chemiluminescence in all cases.
[c]Based on average of all tests.
[d]Moderate, intermediate or stringent levels discussed in Section 3.
[e]Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f]MJ/m^3, (Btu/ft^3)
[g]FT, firetube; WT, watertube.

TABLE 7-21. Continued

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics: Heat Value	% N	% S	% Ash	Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu): Low	High	Average	Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
6.9/8.5 (23.5)/(29)	LEA 4.5-1.9[e]	36.65[f] (1108)	--	--	--	1	36.7 (0.085)	--	--	33.1 (0.077)	10	Stringent	# 1-1, WT[g]	No air preheat	7-1
5.0/8.5 (17.0)/(29)	LEA 6.4-2.2	36.65 (1108)	--	--	--	1	37.7 (0.088)	--	--	39.8 (0.093)	-6	Stringent	# 1-2, WT	No air preheat	7-1
3.2/7.3 (11.0)/(25)	LEA 8.9-5.0	36.65 (1108)	--	--	--	1	41.8 (0.097)	--	--	7.14 (0.0166)	83	Stringent	# 5-716-3, WT	No air preheat	7-1
25/32 (87)/(110)	LEA 8.1-2.0	37.35 (1129)	--	--	--	1	47.9 (0.111)	--	--	82.1 (0.191)	-71	Moderate	# 10-5, WT	No air preheat	7-1
4.1/5.1 (14)/(17.5)	LEA 3.2-2.0	33.84 (1023)	--	--	--	1	30.1 (0.070)	--	--	28.0 (0.065)	7	Stringent	# 19-1, WT	No air preheat	7-1
47/59 (160)/(200)	LEA 3.7-1.3	27.50 (831)	--	--	--	1	97.9 (0.228)	--	--	97.4 (0.227)	1	--	# 39-8108, WT	No air preheat	7-1
2.9-4.1/7.3 (10-14)/(25)	LEA 6.3-2.4	--	--	--	--	2	34.7 (0.081)	30.6 (0.071)	31.1 (0.072)	30.9 (0.072)	11	Stringent	# ECCC, WT[g]	No air preheat	7-2
7.0/8.8 (24)/(30)	LEA 5.7-2.7	36.65 (1108)	--	--	--	1	49.0 (0.113)	--	--	39.3 (0.091)	20	Stringent	# 1-3, WT		7-1
40/47 (135)/(160)	LEA 3.8-2.6	37.35 (1129)	--	--	--	1	191 (0.402)	--	--	173 (0.402)	9	--	# 9-8C-6, WT		7-1
23/38 (77)/(130)	LEA 6.6-6.1	34.73 (1050)	--	--	--	1	105 (0.253)	--	--	100 (0.234)	4	--	# 32-4, WT		7-1
44/73 (150)/(250)	LEA 6.5-3.7	34.63 (1047)	--	--	--	1	96.4 (0.224)	--	--	87.2 (0.203)	10	Moderate	# 34-2, WT		7-1
12/13 (40)/(45)	LEA 1.9-1.4	33.81 (1011)	--	--	--	1	112 (0.261)	--	--	92.8 (0.216)	17	--	# 38-2, WT		7-1

[a]All reported tests were short-term (<3 hr).
[b]NO_x emissions determined by chemiluminescence in all cases.
[c]Based on average of all tests.
[d]Moderate, intermediate or stringent levels discussed in Section 3.
[e]Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f]MJ/m^3 (Btu/ft^3)
[g]FT, firetube; WT, watertube

TABLE 7-21. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
16/19.0 (53)/(65.0)	LEA[e] 4.5-3.0	36.65[f] (1108)	--	--	--	1	43.9 (0.102)	--	--	43.9 (0.102)	0	Stringent	# 2-4, WT[g]	No air preheat	7-1
14.5/18 (49.4)/(60)	LEA 5.2-2.5	37.35 (1129)	--	--	--	1	53.0 (0.123)	--	--	56.1 (0.130)	-6	Intermediate	# 10-4, WT	No air preheat	7-1
35/46.3 (120)/(158)	LEA 13.1-10.8	33.65 (1108)	--	--	--	1	168 (0.391)	--	--	127 (0.295)	24	--	# 6-3, WT		7-1
13.5/18 (46)/(60)	LEA 2.6-1.4	37.35 (1129)	--	--	--	1	123 (0.286)	--	--	80.1 (0.186)	35	Moderate	# 9-BC-1, WT		7-1
53.9/65.9 (184)/(225)	LEA 6.1-4.4	51.21 (1548)	--	--	--	1	102 (0.237)	--	--	70.9 (0.165)	30	Moderate	# 12-24, WT		7-1
8.8/21 (30)/(70)	LEA 5.7-3.7	37.3 (1000)	--	--	--	1	100 (0.234)	--	--	84.7 (0.197)	22	Moderate	# 28-1, WT		7-1
35/44 (120)/(150)	LEA 5.3-3.2	37.3 (1000)	--	--	--	1	76 (0.177)	--	--	81.6 (0.190)	-4	Moderate	# 29-5, WT		7-1
24/35 (83)/(120)	LEA 4.4-2.2	39.1 (1051)	--	--	--	1	117 (0.273)	--	--	111 (0.258)	5	--	# 32-1, WT		7-1

[a] All reported tests were short-term (<3 hr).
[b] NO_x emissions determined by chemiluminescence in all cases.
[c] Based on average of all tests.
[d] Moderate, intermediate or stringent levels discussed in Section 3.
[e] Excess oxygen, %, first value is high excess air (baseline) condition, second value is low excess air condition.
[f] MJ/m^3, (Btu/ft^3).
[g] FT, firetube, WT, watertube.

TABLE 7-22. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH STAGED COMBUSTION AIR (SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
2.5/3.5 (8.5)/(12)	SCA[e] ϕ = 57%	--	--	--	--	1	36.3 (0.084)	--	--	34.5 (0.080)	5	Stringent	# ECCC, FT[h]	Overall excess O_2: 2.9% (SCA), 1.9% (baseline) (Ref. 7-2) No air preheat
1.2/3.5 (4)/(12)	SCA[e] ϕ = 129%	--	--	--	--	1	28.0 (0.065)	--	--	23.6 (0.055)	16	Stringent	# ECCC, FT	Overall excess O_2: 7.6% (SCA), 8.0% (baseline) (Ref. 7-2) No air preheat
4.3/5.1 (14.5)/(17.5)	SCA[f] ϕ_B = 0.97%	38.69 (1035)	--	--	--	1	45.9 (0.107)	--	--	25.0 (0.058)	46	Stringent	# 19-1, WT	Lance at 2.1 m Overall excess O_2 2.8% No air preheat
11.3/13.2 (38.7)/(45)	SCA[f] ϕ_B = NA	37.7 (1011)	--	--	--	1	82.1 (0.191)	--	--	56.6 (0.132)	31	Intermediate	# 38-2, WT	Overall excess O_2 2.25%

[a]All reported tests were short-term (<3 hr).
[b]NO_x emissions determined by chemiluminescence in all cases.
[c]Based on average of all tests.
[d]Moderate, intermediate or stringent levels discussed in Section 3.
[e]ϕ = Burner stoichiometry.
[f]ϕ_B = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air-fuel ratio at the burner.
[g]MJ/m^3 (Btu/ft^3).
[h]FT, firetube, WT, watertube.

TABLE 7-23. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH FLUE GAS RECIRCULATION (FGR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
1.75/3.5 (6)/(12)	FGR 30%[e]	--	--	--	--	3	41 (0.095)	10 (0.023)	14 (0.032)	13 (0.030)	68	Stringent	# ECCC, FT[f]	Excess O_2 4% No air preheat	7-2
1.75/3.5 (6)/(12)	FGR 50%	--	--	--	--	3	41 (0.095)	8.2 (0.019)	9.2 (0.021)	8.9 (0.021)	79	Stringent	# ECCC, FT	Excess O_2 4% No air preheat	7-2
1.75/3.5 (6)/(12)	FGR 30%	--	--	--	--	1	33 (0.077)	--	--	9.2 (0.021)	72	Stringent	# ECCC, FT	Excess O_2 1.2% No air preheat	7-2
1.75/13.5 (6)/(12)	FGR 50%	--	--	--	--	3	33 (0.077)	3.1 (0.0071)	6.6 (0.015)	4.4 (0.010)	86	Stringent	# ECCC, FT	Excess O_2 3.5% No air preheat	7-2
2.3/3.5 (8)/(12)	FGR 55%	--	--	--	--	3	36 (0.084)	5.2 (0.012)	7.0 (0.016)	6.0 (0.014)	84	Stringent	# ECCC, FT	Comparatively high load. Excess O_2 2%. No air preheat	7-2
2.0/7.3 (7)/(25)	FGR, 12%	--	--	--	--	3	27 (0.062)	12 (0.028)	16 (0.036)	14 (0.031)	48	Stringent	# ECCC, WT	Excess O_2 1-3% No air preheat	7-2
2.0/7.3 (7)/(25)	FGR, 25%	--	--	--	--	3	27 (0.062)	6.6 (0.015)	10 (0.023)	8.2 (0.019)	70	Stringent	# ECCC, WT	Excess O_2 1-3% No air preheat	7-2
2.8/7.3 (9.5)/(25)	FGR, 22%	--	--	--	--	2	22 (0.050)	7.0 (0.016)	9.2 (0.021)	8.1 (0.019)	63	Stringent	# ECCC, WT	Excess O_2 1.2-2.6% No air preheat	7-2
4.2/5.1 (14.5)/(17.5)	FGR, 8%	34.249 (1035)	--	--	--	2	52 (0.121)	21 (0.049)	29 (0.067)	25 (0.058)	52	Stringent	# 19-1, WT	Excess O_2 1.5-3.1% No air preheat	7-3
4.2/5.1 (14.5)/(17.5)	FGR, 20%	34.24 (1035)	--	--	--	2	45.9 (0.107)	11.2 (0.026)	12.2 (0.028)	11.7 (0.027)	75	Stringent	# 19-1, WT	Excess O_2 2.5-3.2% No air preheat	7-3

[a]All reported tests were short-term (<3 hr).
[b]NO_x emissions determined by chemiluminescence in all cases.
[c]Based on average of all tests.
[d]Moderate, intermediate or stringent levels discussed in Section 3.
[e]Mass percent flue gas recirculated.
[f]FT, firetube, WT, watertube.
[g]MJ/m^3 (Btu/ft^3)

TABLE 7-24. NO_x TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH COMBINED FLUE GAS RECIRCULATION AND STAGED COMBUSTION (FGR/SCA) (REFERENCE 7-3)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
4.0/5.1 (13.7)/(17.5)	FGR, 17.8%[e] SCA, ϕ_B = 0.86[f]	34.249 (1035)	--	--	--	1	45.9 (0.107)	--	--	11.2 (0.026)	76	Stringent	# 19-1, WT[h]	Overall excess O_2 3.3% No air preheat

[a]All reported tests were short-term (<3 hr).
[b]NO_x emissions determined by chemiluminescence in all cases.
[c]Based on average of all tests.
[d]Moderate, intermediate or stringent levels discussed in Section 3.
[e]Mass percent flue gas recirculated.
[f]ϕ_B = Equivalence ratio, defined as ratio of stoichiometric air-fuel ratio to actual air-fuel ratio at the burner.
[g]MJ/m^3 (Btu/ft^3).
[h]WT, watertube.

TABLE 7-25. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH LOAD REDUCTION (LR)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
--/2.9 --/(10)	LR 100-50[e]	36.65[f] (1108)	--	--	--	1	46.4 (0.108)	--	--	51.0 (0.119)	-10	Intermediate	# 3-2, FT[g]	No air preheat	7-1
--/5.8 --/(20)	LR 92.5-45	36.65 (1108)	--	--	--	1	52.5 (0.122)	--	--	52.5 (0.122)	0	Intermediate	# 4-4, FT	No air preheat	7-1
--/2.9 --/(10)	LR 100-50	36.65 (1108)	--	--	--	1	28.6 (0.067)	--	--	30.1 (0.070)	-5	Stringent	# 5-248-3, FT	No air preheat	7-1
--/2.3 --/(80)	LR 100-40	36.65 (1108)	--	--	--	1	39.2 (0.091)	--	--	28.0 (0.065)	29	Stringent	# 5-248-1, FT	No air preheat	7-1
--/3.8 --/(13.0)	LR 95/32	31.96 (966)	--	--	--	1	31.6 (0.073)	--	--	34.7 (0.081)	-10	Stringent	# 24-TV, FT	No air preheat	7-1
--/5.8 --/(20.0)	LR 62.5-21	31.99 (967)	--	--	--	1	43.9 (0.102)	--	--	37.2 (0.087)	15	Stringent	# 25-1, FT	No air preheat	7-1
--/3.2 --/(11)	LR 47-25	31.89 (964)	--	--	--	1	43.9 (0.102)	--	--	43.4 (0.101)	1	Stringent	# 26-2, FT	No air preheat	7-1
--/5.2 --/(18)	LR 95.6-42.8	31.89 (964)	--	--	--	1	29.6 (0.069)	--	--	27.5 (0.064)	7	Stringent	# 26-1, FT	No air preheat	7-1
--/8.4 --/(29)	LR 83-64	36.65 (1108)	--	--	--	1	41.8 (0.097)	--	--	42.8 (0.100)	-2	Stringent	# 1-1, WT	Excess O_2 3% No air preheat	7-1
--/8.4 --/(29)	LR 62-26	36.65 (1108)	--	--	--	1	39.3 (0.091)	--	--	52.0 (0.121)	-32	Intermediate	# 1-1, WT	Excess O_2 8% No air preheat	7-1
--/8.4 --/(29)	LR 85-59	36.65 (1108)	--	--	--	1	39.3 (0.091)	--	--	39.8 (0.093)	-1	Stringent	# 1-2, WT	No air preheat	7-1
--/7.3 --/(25)	LR 80-44	36.65 (1108)	--	--	--	1	38.8 (0.090)	--	--	7.1 (0.017)	82	Stringent	# 5-716-3, WT	No air preheat	7-1

[a]All reported tests were short-term (<3 hr).
[b]NO_x emissions determined by chemiluminescence in all cases.
[c]Based on average of all tests.
[d]Moderate, intermediate or stringent levels discussed in Section 3.
[e]Percent load; first value is high load (baseline), second value is low load.
[f]MJ/m^3 (Btu/ft^3).
[g]FT, firetube; WT, watertube.

TABLE 7-25. Concluded

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks	Reference
		Heat Value	% N	% S	% Ash			Low	High	Average					
--/32.2 --/(110)	LR 98-27[e]	42.1[f] (1129)	--	--	--	1	63.2 (0.147)	--	--	54.6 (0.127)	14	Intermediate	# 10-5, WT[g]	Excess O_2 7% No air preheat	7-1
--/5.1 --/(17.5)	LR 91-70	38.1 (1023)	--	--	--	1	28.6 (0.066)	--	--	30.6 (0.071)	-7	Stringent	# 19-1, WT	Excess O_2 3% No air preheat	7-1
--/29.3 --/(100)	LR 75-20	36.4 (976)	--	--	--	1	57.6 (0.134)	--	--	51.5 (0.120)	11	Intermediate	# 27-1, WT	Excess O_2 6.8% No air preheat	7-1
--/17.6 --/(60)	LR 101-82	42.1 (1129)	--	--	--	1	58.7 (0.136)	--	--	55.1 (0.128)	6	Intermediate	# 10-4, WT	Excess O_2 3.8% No air preheat	7-1
--/7.3 --/(25)	LR 78-41	--	--	--	--	1	33.2 (0.077)	--	--	35.4 (0.082)	-7	Stringent	# ECCC, WT	No air preheat	7-2
--/3.5 --/(12)	LR 73-31	--	--	--	--	1	45.9 (0.107)	--	--	45.0 (0.105)	2	Stringent	# ECCC, FT	No air preheat	7-2
--/46.3 --/(158)	LR 95-39	36.65 (1108)	--	--	--	1	178 (0.415)	--	--	53.0 (0.123)	70	Intermediate	# 6-3, WT	Excess O_2 12.5%	7-1
--/46.9 --/(160)	LR 94-79	42.1 (1129)	--	--	--	1	206 (0.479)	--	--	181 (0.421)	12	--	# 9-BC-6, WT	Excess O_2 4%	7-1
--/18 --/(60)	LR 98-57	42.1 (1129)	--	--	--	1	125 (0.290)	--	--	70.4 (0.164)	44	Moderate	# 9-BC-1, WT	Excess O_2 2%	7-1
--/65.9 --/(225)	LR 100-58	37.8 (1016)	--	--	--	1	104 (0.241)	--	--	89.8 (0.209)	14	Moderate	# 12-24, WT	Excess O_2 5.5%	7-1

[a]All reported tests were short-term (<3 hr).
[b]NO_x emissions determined by chemiluminescence in all cases.
[c]Based on average of all tests.
[d]Moderate, intermediate or stringent levels discussed in Section 3.
[e]Percent load; first value is high load (baseline), second value is low load.
[f]MJ/m^3 (Btu/ft^3).
[g]FT, firetube; WT, watertube.

TABLE 7-26. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH REDUCED AIR PREHEAT (RAP) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb $NO_2/10^6$ Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
58.6/73.2 (200)/(250)	RAP[e] 383-303	39.0[f] (1047)	--	--	--	1	94.9 (0.221)	--	--	70.9 (0.165)	25	Moderate	# 34-2, WT[g]	Excess O_2 2.7%
44/73.2 (150)/(250)	RAP 391-308	39.0 (1047)	--	--	--	1	108 (0.250)	--	--	58.7 (0.136)	45	Intermediate	# 34-2, WT	Excess O_2 4.7%
11/13 (39)/(45)	RAP 550-480	37.7 (1011)	--	--	--	1	112 (0.261)	--	--	63.2 (0.147)	44	Intermediate	# 38-2, WT	Excess O_2 1.7%

[a]All reported tests were short-term (<3 hr).
[b]NO_x emissions determined by chemiluminescence in all cases.
[c]Based on average of all tests.
[d]Moderate, intermediate or stringent levels discussed in Section 3.
[e]Combustion air temperature (K), first value is baseline, second is reduced air preheat temperature.
[f]MJ/m^3 (Btu/ft^3).
[g]WT, watertube.

TABLE 7-27. NO_x EMISSION TEST DATA FROM NATURAL GAS-FIRED INDUSTRIAL BOILERS WITH BURNERS OUT OF SERVICE (BOOS) (REFERENCE 7-1)

Actual/Design Heat Input MW (10^6 Btu/hr)	Control Method	Fuel Characteristics				Number of Tests[a]	Baseline NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)	Controlled NO_x Emissions[b] ng NO_2/J (lb NO_2/10^6 Btu)			Percent NO_x Reduction[c]	Control Level Supported[d]	Boiler Identification	Remarks
		Heat Value	% N	% S	% Ash			Low	High	Average				
13.5/17.6 (46)/(60)	BOOS	42.1[e] (1129)	--	--	--	3	123 (0.287)	96.9 (0.225)	107.1 (0.249)	102.5 (0.238)	17	--	# 9-BC-1, WT[f]	Two rows of two[g] burners, one upper BOOS burner on air only. Excess O_2 3%
8.5/20.5 (29)/(70)	BOOS	37.3 (1000)	--	--	--	3	108 (0.251)	49 (0.113)	70 (0.619)	60.3 (0.140)	44	Intermediate	# 28-1, WT	One row of three burners. Center burner on air only. Excess O_2 5.5%.
17.9/35.2 (61)/(120)	BOOS	39.1 (1050)	--	--	--	2	106 (0.246)	74 (0.172)	80 (0.186)	77 (0.179)	27	Moderate	# 32-1, WT	Two rows of two burners, both upper burners on air only. Excess O_2 4.4%

[a]All reported tests were short-term (<3 hr).
[b]NO_x emissions determined by chemiluminescence in all cases.
[c]Based on average of all tests.
[d]Moderate, intermediate or stringent levels discussed in Section 3.
[e]MJ/m^3 (Btu/ft^3).
[f]WT, watertube.
[g]BOOS load, 41 x 10^6 Btu.

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16. ABSTRACT The report gives results of an environmental assessment of combustion modification techniques for coal-, oil-, and gas-fired industrial boilers, with respect to NOx control reduction effectiveness, operational impact, thermal efficiency impact, capital and annualized operating costs, and effect on emissions of pollutants other than NOx. Major industrial boiler design types and equipment trends are reviewed. Currently available control techniques can reduce NOx 10-25% for coal- and residual-oil-fired boilers, and 40-70% for distillate-oil- and gas-fired units with minimal adverse operating impacts. Controls should increase steam costs by only 1-2%, but the initial investment required could be significant, up to 20% on a new boiler and easily up to 40% on a retrofit. Detailed Level 1 tests on two stoker-coal-fired boilers indicate that combustion modification reduces the potential environmental hazard of the source by lowering NOx emissions, without significant effect on the emissions of other pollutants.

17. KEY WORDS AND DOCUMENT ANALYSIS

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