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Alternative Control Techniques Document-- NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers

Emission Standards Division

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ALTERNATIVE CONTROL TECHNIQUES DOCUMENT

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1. INTRODUCTION

Congress, in the Clean Air Act Amendments (CAAA) of 1990, amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

> [W]ithin 3 years after the date of the enactment of the CAAA, the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of . . . oxides of nitrogen which emit or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Industrial, commercial, and institutional (ICI) boilers have been identified as a category that emits more than 25 tons of oxides of nitrogen (NO_x) per year. This alternative control techniques (ACT) document provides technical information for use by State and local agencies to develop and implement regulatory programs to control NO_x emissions from ICI boilers. Additional ACT documents are being developed for other stationary source categories.

ICI boilers include steam and hot water generators with heat input capacities from 0.4 to 1,500 MMBtu/hr (0.11 to 440 MWt). These boilers are used in a variety of applications, ranging from commercial space heating to process steam generation, in all major industrial sectors. Although coal, oil, and natural gas are the primary fuels, many ICI boilers also burn a variety of industrial, municipal, and agricultural waste fuels.

It must be recognized that the alternative control techniques and the corresponding achievable NO_x emission levels presented in this document may not be applicable to every ICI boiler application. The furnace design, method of fuel firing, condition of existing equipment, operating duty cycle, site conditions, and other site-specific factors must be taken into consideration to properly evaluate the applicability and performance of any given control technique. Therefore, the feasibility of a retrofit should be determined on a case-by-case basis.

The information in this ACT document was generated through a literature search and from information provided by ICI boiler manufacturers, control equipment vendors, ICI boiler users, and regulatory agencies. Chapter 2 summarizes the findings of this study. Chapter 3 presents information on the ICI boiler types, fuels, operation, and industry applications. Chapter 4 discusses NO_x formation and uncontrolled NO_x emission factors. Chapter 5 covers alternative control techniques and achievable controlled emission levels. Chapter 6 presents the cost and cost effectiveness of each control technique. Chapter 7 describes environmental and energy impacts associated with implementing the NO_x control techniques. Finally, Appendices A through G provide the detailed data used in this study to evaluate uncontrolled and controlled emissions and the costs of controls for several retrofit scenarios.

2. SUMMARY

This chapter summarizes the information presented in more detail in Chapters 3 through 7 of this document. Section 2.1 reviews the diversity of equipment and fuels that make up the ICI boiler population. The purposes of this section are to identify the major categories of boiler types, and to alert the reader to the important differences that separate the ICI boiler population from other boiler designs and operating practices. This diversity of combustion equipment, fuels, and operating practices impacts uncontrolled NO_x emission levels from ICI boilers and the feasibility of control for many units. Section 2.2 reviews baseline NO_x emission reported for many categories of ICI boilers and highlights the often broad ranges in NO_x levels associated with boiler designs, firing methods, and fuels.

The experience in NO_x control retrofits is summarized in Section 2.3. This information was derived from a critical review of the open literature coupled with information from selected equipment vendors and users of NO_x control technologies. The section is divided into a subsection on combustion controls and another on flue gas treatment controls. As in the utility boiler experience, retrofit combustion controls for ICI boilers have targeted principally the replacement of the original burner with a low-NO_x design. When cleaner fuels are burned, the low-NO_x burner (LNB) often includes a flue gas recirculation (FGR) system that reduces the peak flame temperature producing NO_x. Where NO_x regulations are especially stringent, the operating experience with natural gas burning ICI boilers also includes more advanced combustion controls and techniques that can result in high fuel penalties, such as water injection (WI). As in the case of utility boilers, some boiler designs have shown little adaptability to combustion controls to reduce NO_x. For these units, NO_x reductions are often achievable only with flue gas treatment technologies for which experience varies.

Section 2.4 summarizes the cost of installing NO_x controls and operating at lower NO_x levels. The data presented in this document are drawn from the reported experience of technology users coupled with costs reported by selected technology vendors. This information is offered only as a guideline because control costs are always greatly influenced by numerous site factors that cannot be taken fully into account. Finally, Section 2.5 summarizes the energy and environmental impacts of low-NO_x operation. Combustion controls are often limited in effectiveness by the onset of other emissions and energy penalties. This section reviews the emissions of CO, NH_3, N_2O, soot and particulate.

2.1 ICI BOILER EQUIPMENT

The family of ICI boilers includes equipment type with heat input capacities in the range of 0.4 to 1,500 MMBtu/hr (0.11 to 440 MWt). Industrial boilers generally have heat input capacities ranging from 10 to 250 MMBtu/hr (2.9 to 73 MWt). This range encompasses most boilers currently in use in the industrial, commercial, and institutional sectors. The leading user industries of industrial boilers, ranked by aggregate steaming capacity, are the paper products, chemical, food, and the petroleum industries. Those industrial boilers with heat input greater than 250 MMBtu/hr (73 MWt) are generally similar to utility boilers. Therefore, many NO_x controls applicable to utility boilers are also candidate control

for large industrial units. Boilers with heat input capacities less than 10 MMBtu/hr (2.9 MWt) are generally classified as commercial/institutional units. These boilers are used in a wide array of applications, such as wholesale and retail trade, office buildings, hotels, restaurants, hospitals, schools, museums, government buildings, airports, primarily providing steam and hot water for space heating. Boilers used in this sector generally range in size from 0.4 to 12.5 MMBtu (0.11 to 3.7 MWt) heat input capacity, although some are appreciably larger.

Table 2-1

TABLE 2-1. ICI BOILER EQUIPMENT, FUELS, AND APPLICATIONS

Heat transfer configuration	Design and fuel type	Capacity range, MMBtu/hr[a]	% of ICI boiler units[b,c]	% of ICI boiler capacity[b,c]	Application[d]
Watertube	Pulverized coal	100-1,500+	**[e]	2.5	PH, CG
	Stoker coal	0.4-550+[f]	**	5.0	SH, PH, CG
	FBC[g] coal	1.4-1,075	**	**	PH, CG
	Gas/oil	0.4-1,500+	2.3	23.6	SH, PG, CG
	Oil field steamer	20-62.5	N.A.[h]	N.A.	PH
	Stoker nonfossil	1.5-1,000[f]	**	1.1	SH, PH, CG
	FBC nonfossil	40-345	**	**	PH, CG
	Other nonfossil	3-800	**	**	SH, PH, CG
Firetube	HRT coal	0.5-50	**	**	SH, PH
	Scotch coal	0.4-50	**	**	SH, PH
	Vertical coal	<2.5	**	**	SH, PH
	Firebox coal	0.4-15	**	**	SH, PH
	HRT gas/oil	0.5-50	1.5	1.5	SH, PH
	Scotch gas/oil	0.4-50	4.8	4.6	SH, PH
	Vertical gas/oil	<2.5	1.0	**	SH, PH
	Firebox gas/oil	<20	6.5	48	SH, PH
	HRT nonfossil	2-50	N.A.	N.A.	SH, PH

lists the various equipment and fuel combinations, the range in heat input capacity, and the typical applications. Passed boiler inventory studies were used to estimate the relative number and total firing capacity of each boiler-fuel category. Many of these boilers vary greatly in age and use patterns. Older units have outdated furnace configurations with greater refractory area and lower heat release rates. Newer designs focus on compact furnaces with tangent tube configurations for greater heat transfer and higher heat release rates. Newer furnaces also tend to have fewer burners, because of improvements in combustion control and better turndown capability, and better economics. This diversity of equipment requires a careful evaluation of applicable technologies. Many smaller ICI boilers often operate with little supervision, and are fully automated. Application of NO_x controls that would limit this operational flexibility may prove impractical. They can be found fully enclosed inside commercial and institutional buildings and in industry steam plants or completely outdoors in several industrial applications at refineries and chemical plants. The location of these boilers often influences the feasibility of retrofit for some control technologies because poor access and limited available space.

ICI boiler equipment is principally distinguished by the method of heat transfer of heat to the water. The most common ICI boiler types are the watertube and firetube units. Firetube boilers are generally limited in size to about 50 MMBtu/hr (15 MWt) and steam pressures, although newer designs tend to increase the firing capacity. All of these firetubes are prefabricated in the shop, shipped by rail or truck, and are thus referred to as packaged. Watertube boilers tend to be larger in size than firetube units, although many packaged single burner designs are well within the firetube capacity range. Larger, multi-burner watertubes tend to be field erected, especially older units. Newer watertubes also tend to be single burners and packaged. Steam pressures and temperatures for watertubes are generally higher than firetube units. Combustion air preheat is never used for firetube boiler configuration. Higher capacity watertube ICI boilers often use combustion air preheat. This is an important distinction because air preheat units tend to have higher NO_x levels.

As the type and sizes of ICI boilers are extremely varied, so are the fuel types and methods of firing. The most commonly used fuels include natural gas, distillate and residual fuel oils, and coal in both crushed and pulverized form. Natural gas and fuel oil are burned in single or multiple burner arrangements. Many ICI boilers have dual fuel capability. In smaller units, the natural gas is normally fed through a ring with holes or nozzles that inject fuel in the air stream. Fuel oil is atomized with steam or compressed air and fed via a nozzle in the center of each burner. Heavy fuel oils must be preheated to decrease viscosity and improve atomization. Crushed coal is burned in stoker and fluidized bed (FBC) boilers. Stoker coal is burned mostly on a grate (moving or vibrating) and is fed by various means. Most popular are the spreader and overfeed methods. Crushed coal in FBC boilers burns in suspension in either a stationary bubbling bed of fuel and bed material or in a circulating fashion. The bed material is often a mixture of sand and limestone for capturing SO_2. Higher fluidizing velocities are necessary for circulating beds which have become more popular because of higher combustion and SO_2 sorbent efficiencies. Where environmental emissions are strictly controlled and low grade fuels are economically attractive, FBC boilers have become particularly popular because of characteristically low NO_x and SO_2 emissions.

Although the primary fuel types are fossil based, there is a growing percentage of nonfossil fuels being burned for industrial steam and nonutility power generation. These fuels include municipal and agricultural wastes, coal mining wastes, and petroleum coke and special wastes such as shredded tires, refuse derived fuel (RDF), tree bark and saw dust, and black liquor from the production of paper. Solid waste fuels are typically burned in stoker or FBC boilers which provide for mass feed of bulk material with minimal pretreatment and the handling of large quantities of ash and other inorganic matter. Some industries also supplement their primary fossil fuels with hazardous organic chemical waste with medium to high heating value. Some of these wastes can contain large concentrations of organically bound nitrogen that can be converted to NO_x emissions. The practice of burning hazardous wastes in boilers and industrial furnaces is currently regulated by the EPA under the Resource Conservation and Recovery Act (RCRA).

2.2 NO_x FORMATION AND BASELINE EMISSIONS

NO_x is the high-temperature byproduct of the combustion of fuel and air. When fuel is burned with air, nitric oxide (NO), the primary form of NO_x, is formed mainly from the high temperature reaction of atmospheric nitrogen and oxygen (thermal NO_x) and from the reaction of organically bound nitrogen in the fuel with oxygen (fuel NO_x). A third and less important source of NO formation is referred to as "prompt NO," which forms from the rapid reaction of atmospheric nitrogen with hydrocarbon radical to form NO_x precursors that are rapidly oxidized to NO at lower temperatures. Prompt NO is generally minor compared to the overall quantity of NO generated from combustion. However, as NO_x emissions are reduced to extremely low limits, i.e., with natural gas combustion, the contribution of prompt NO becomes more important.

The mechanisms of NO_x formation in combustion are very complex and cannot be predicted with certainty. Thermal NO_x is an exponential function of temperature and varies with the square root of oxygen concentration. Most of the NO_x formed from combustion of natural gas and high grade fuel oil (e.g., distillate oil or naphtha) is attributable to thermal NO_x. Because of the exponential dependence on temperature, the control of thermal NO_x is best achieved by reducing peak combustion temperature. Fuel NO_x results from the oxidation of fuel-bound nitrogen. Higher concentrations of fuel nitrogen typically lead to higher fuel NO_x and overall NO_x levels. Therefore, combustion of residual oil with 0.5 percent fuel-bound nitrogen, will likely result in higher NO_x levels than natural gas or distillate oil. Similarly, because coal has higher fuel nitrogen content higher baseline NO_x levels are generally measured from coal combustion than either natural gas or oil combustion. This occurs in spite of the fact that the conversion of fuel nitrogen to fuel NO_x typically diminishes with increasing nitrogen concentration. Some ICI boilers, however, that operate at lower combustion temperature, as in the case of an FBC, or with reduced fuel air mixing, as in the case of a stoker, can have low NO_x emissions because of the suppression of the thermal NO_x contribution.

Test data were compiled from several sources to arrive at reported ranges and average NO_x emission levels for ICI boilers. Baseline data were compiled from test results on more than 200 ICI boilers described in EPA documents and technical reports. These data, representative of boiler operation at 70 percent capacity or higher, are detailed in Appendix A.

Table 2-2

TABLE 2-2. SUMMARY OF BASELINE NO_x EMISSIONS

Fuel	Boiler type	Uncontrolled NO_x range, lb/MMBtu	Average, lb/MMBtu
Pulverized coal	Wall-fired	0.46-0.89	0.69
	Tangential	0.53-0.68	0.61
	Cyclone	1.12[a]	1.12
Coal	Spreader stoker	0.35-0.77	0.53
	Overfeed stoker	0.19-0.44	0.29
	Underfeed stoker	0.31-0.48	0.39
	Bubbling FBC	0.11-0.81	0.32
	Circulating FBC	0.14-0.60	0.31
Residual oil	Firetube	0.21-0.39	0.31
	Watertube:		
	10 to 100 MMBtu/hr	0.20-0.79	0.36
	>100 MMBtu/hr	0.31-0.60	0.38
Distillate oil	Firetube	0.11-0.25	0.17
	Watertube:		
	10 to 100 MMBtu/hr	0.08-0.16	0.13
	>100 MMBtu/hr	0.18-0.23	0.21
Crude oil	TEOR steam generator	0.30-0.52	0.46
Natural gas	Firetube	0.07-0.13	0.10
	Watertube:		
	≤100 MMBtu/hr	0.06-0.31	0.14
	>100 MMBtu/hr	0.11-0.45	0.26
	TEOR steam generator	0.09-0.13	0.12
Wood	<70 MMBtu/hr	0.010-0.050	0.022
	≥70 MMBtu/hr	0.17-0.30	0.24
Bagasse		0.15[b]	0.15
MSW	Mass burn	0.40[b]	0.40
	Modular	0.49[b]	0.49

summarizes the range and average NO_x emissions from the various categories of ICI boilers investigated in this study. On an average basis, coal-fired ICI boilers emit the highest level of NO_x, as anticipated. Among the higher emitters are the wall-fired boilers with burners on one or two opposing walls of the furnace. Average NO_x levels were measured at approximately 0.70 lb/MMBtu. Next highest emitters are tangential boilers burning pulverized coal (PC). The burners on these units are located in the corners of the furnace at several levels and firing in a concentric direction.

Among the stokers, the spreader firing system has the highest NO_x levels than either the overfeed or underfeed designs. This is because a portion of the coal fines burn in suspension in the spreader design. This method of coal combustion provides for the greatest air-fuel mixing and consequently higher NO_x formation. FBC boilers emit significantly lower NO_x emissions than PC-fired units and are generally more efficient than stokers. The large variations in baseline NO_x levels for the FBC units are generally the result of variations in air distribution among FBC units. Newer FBC designs incorporate a staged air addition that suppresses NO_x levels. Also the type of bed material and SO_2

sorbent influence the level of NO_x generated. FBC units are, on average, the lowest NO_x emitters among coal burning ICI equipment.

Large variations in baseline NO_x levels are also shown for ICI boilers burning residual oil. For example, boilers with a capacity of less than 100 MMBtu/hr (29 MWt) can have emissions in the range of 0.20 to 0.79 lb/MMBtu, a factor of nearly 4. This is attributable predominantly to large variations in fuel nitrogen content of these fuel oils. NO_x emissions from distillate-oil- and natural-gas-fired ICI boilers are significantly lower due by and large to the burning of cleaner fuel with little or no fuel-bound nitrogen. It is also important to note that baseline emission levels for the larger boilers tend to be somewhat higher, on average. This is attributable to the higher heat release rate that generally accompanies the larger units in order to minimize the size of the furnace and the cost of the boiler. Also, another factor is the use of preheated combustion air with the larger boilers. Higher heat release rate and preheated combustion air increase the peak temperature of the flame and contribute to higher baseline NO_x levels. The AP-42 emission factors were used for some of the ICI boilers for which little or no data were available in this study.

2.3 CONTROL TECHNIQUES AND CONTROLLED NO_x EMISSION LEVELS

The reduction of NO_x emissions from ICI boilers can be accomplished with combustion modification and flue gas treatment techniques or a combination of these. The application of a specific technique will depend on the type of boiler, the characteristic of its primary fuel, and method of firing. Some controls have seen limited application, whereas certain boilers have little or no flexibility for modification of combustion conditions because of method of firing, size, or operating practices. Table 2-3

TABLE 2-3. EXPERIENCE WITH NO_x CONTROL TECHNIQUES ON ICI BOILERS

	Coal-fired			Oil-/natural-gas-fired			Nonfossil-fuel-fired		MSW-fired
NO_x control technique	Field-erected PC-fired	Stoker	FBC	Field-erected watertube	Packaged watertube	Packaged firetube	Stoker	FBC	Mass burn
BT/OT					X	X			
WI/SI					X	X			
SCA	X	X	X	X [a]	X		[b] X[a]	X	X [a]
LNB	X			X	X	X			
FGR				X	X	X			X
NGR	X	[b]							X[b]
SNCR	X	[b] X	X	X	X		X	X [b]	X
SCR	X	[b]	X[b]	X[b]					

BT/OT = Burner tuning/oxygen trim
WI/SI = Water injection/steam injection
SCA = Staged combustion air, includes burners out of service (BOOS), biased firing, or overfire air (OFA)
LNB = Low-NO_x burners
FGR = Flue gas recirculation
NGR = Natural gas reburning
SNCR = Selective noncatalytic reduction
SCR = Selective catalytic reduction
MSW = Municipal solid waste
[a]SCA is designed primarily for control of smoke and combustible fuel rather than NO_x. Optimization of existing SCA (OFA) ports can lead to some NO_x reduction.
[b]Limited experience.

lists the applicability of candidate NO_x control techniques for ICI boiler retrofit. Each "X" marks the applicability of that control to the specific boiler/fuel combination. Although applicable, some techniques have seen limited use because of cost, energy and operational impacts, and other factors.

NO_x emissions can be controlled by suppressing both thermal and fuel NO_x. When natural gas or distillate oil is burned, thermal NO_x is the only component that can be practically controlled due to the low levels of fuel N_2 in the distillate oil. The combustion modification techniques that are most effective in reducing thermal NO_x are particularly those that reduce peak temperature of the flame. This is accomplished by quenching the combustion with water or steam injection (WI/SI), recirculating a portion of the flue gas to the burner zone (FGR), and reducing air preheat temperature (RAP) when preheated combustion air is used. The use of WI/SI has thus far been limited to small gas-fired boiler applications in Southern California to meet very stringent NO_x standards. Although very effective in reducing thermal NO_x, this technique has not been widely applied because of its potential for large thermal efficiency penalties, safety, and burner control problems. FGR, on the other hand, has a wide experience base. The technique is implemented by itself or in combination with LNB retrofits. In fact, many LNB designs for natural-gas-fired ICI boilers incorporate FGR. LNB controls are available from several ICI equipment vendors. RAP is not a practicable technique because of severe energy penalties associated with its use, and for this reason it was not considered further in this document.

Thermal NO_x can also be reduced to some extent by minimizing the amount of excess oxygen, delaying the mixing of fuel and air, and reducing the firing capacity of the boiler. The first technique is often referred to as oxygen trim (OT) or low excess air (LEA) and can be attained by optimizing the operation of the burner(s) for minimum excess air without excessive increase in combustible emissions. The effect of lower oxygen concentration on NO_x is partially offset by some increase in thermal NO_x because of higher peak temperature with lower gas volume. OT and LEA are often impractical on packaged watertube and firetube boilers due to increased flame lengths and CO, and can lead to rear wall flame impingement, especially when fuel oil is fired. The second technique reduces flame temperature and oxygen availability by staging the amount of combustion air that is introduced in the burner zone. Staged combustion air (SCA) can be accomplished by several means. For multiple burner boiler, the most practical approach is to take certain burners out of service (BOOS) or biasing the fuel flow to selected burners to obtain a similar air staging effect. The third technique involves reducing the boiler firing rate to lower the peak temperature in the furnace. This approach is not often considered because it involves reducing steam generation capacity that must be replaced elsewhere. Also, with some fuels, gains in reduction of thermal NO_x are in part negated by increases in fuel NO_x that result by increases in excess air at reduced boiler load.

The reduction of fuel NO_x with combustion modifications is most effectively achieved with the staging of combustion air. By suppressing the amount of air below that required for complete combustion (stoichiometric conditions), the conversion of fuel nitrogen to NO_x can be minimized. This SCA technique is particularly effective on high nitrogen fuels such as coal and residual oil fired boilers, which may have high baseline emissions and would result in high reduction efficiencies. For PC, BOOS for NO_x reduction is not practical. Therefore, SCA is usually accomplished with the retrofit of internally air staged burner or overfire air ports. The installation of low-NO_x burners for PC- and residual-oil-fired boilers is a particularly effective technique because it involves minimal furnace modifications and retained firing capacity. Staged fuel burners in some packaged watertube boilers without membrane convective side furnace wall(s) may cause an increase in CO emissions at the stack, due to short circuiting of incomplete combustion products to the convective section. The installation of OFA ports for some boilers is not practicable. These boilers are principally firetube and watertube packaged designs and most PC-fired units. Large field-erected gas- and low-sulfur oil-fired ICI boilers are the best candidates for the application of OFA because these fuels are least susceptible to the adverse effects of combustion staging, such as furnace corrosion and unburned fuel emissions.

Another combustion modification technique involves the staging of fuel, rather than combustion air. By injecting a portion of the total fuel input downstream of the main combustion zone, hydrocarbon radicals created by the reburning fuel will reduce NO_x emission emitted by the primary fuel. This reburning technique is best accomplished when the reburning fuel is natural gas. Natural gas reburning (NGR) and cofiring have been investigated primarily for utility boilers, especially coal-fired units that are not good candidates for traditional combustion modifications such as LNB. Examples of these boilers are cyclones and stoker fired furnaces. Application of these techniques on ICI boilers has been limited to some municipal solid waste (MSW) and coal-fired stokers.

NO_x control experience for ICI boilers with flue gas treatment controls has been limited to the selective noncatalytic and catalytic reduction techniques (SNCR and SCR). Both techniques involve the injection of ammonia or urea in a temperature window of the boiler where NO_x reduction occurs by the selective reaction of NH_2 radicals with NO to form water and nitrogen. The reaction for the SNCR process must occur at elevated temperatures, typically between 870 and 1,090 °C (1,600 and 2,000°F) because the reduction proceeds without a catalyst. At much lower flue gas temperatures, typically in the range of 300 to 400 °C (550 to 750°F), the reaction requires the presence of a catalyst. SNCR is

particularly effective when the mixing of injected reagent and flue gas is maximized and the residence time of the gas within the reaction temperature is also maximized. These favorable conditions are often encountered in retrofit applications of SNCR on FBC boilers. The reagent is injected at the outlet of the furnace (inlet to the hot cyclone), where mixing is promoted while flue gas temperature remains relatively constant. Other applications of SNCR on stoker boilers burning a variety of fuels and waste fuels have also shown promise. SCR retrofit ICI applications in this country have been limited to a few boilers in California, although the technology is widely used abroad and several vendors are currently marketing several systems.

2.3.1 Combustion Modification Controls

Table 2-4

TABLE 2-4. SUMMARY OF COMBUSTION MODIFICATION NO_x CONTROL PERFORMANCE ON ICI WATERTUBE BOILERS

ICI boiler and fuel	NO_x control	Percent NO_x reduction	Controlled NO_x level, lb/MMBtu	Comments
PC, wall-fired	SCA	15-39	0.33-0.93	Limited applicability because of potential side effects.
	LNB	49-67	0.26-0.50	Technology transfer from utility applications.
	NGR	N.A.[a]	0.23-0.52	Limited experience. Technology transfer from utility applications.
	LNB+SCA	42-66	0.24-0.49	Technology transfer from utility applications.
PC, T-fired	SCA	25	0.29-0.38	Effective technique. Technology transfer from utility applications.
	LNB	18	0.36	LNCFS[b] utility firing system design with closed coupled OFA.
	NGR	30	0.23	Limited experience.
	LNB+SCA	55	0.20	LNCFS utility firing system design. Technology transfer from utility applications.
Spreader stoker	SCA	-1-35	0.22-0.52	Potential grate problems and high CO emissions.
	FGR+SCA	0-60	0.19-0.47	Limited applicability.
	RAP	32	0.30	Limited applicability.
	Gas cofiring	20-25	0.18-0.20	Only recent exploratory tests. NO_x reduction via lower O_2.
Coal-fired BFBC	SCA	40-67	0.10-0.14	SCA often incorporated in new designs.
Circulating coal-fired FBC	SCA	N.A.	0.05-0.45	SCA often incorporated in new designs.
	SCA+FGR	N.A.	0.12-0.16	Limited application for FGR.
Residual-oil-fired	LNB	30-60	0.09-0.23	Staged air could result in operational problems.
	FGR	4-30	0.12-0.25	Limited effectiveness because of fuel NO_x contribution.
	SCA	5-40	0.22-0.74	Techniques include BOOS[c] and OFA. Efficiency function of degree of staging.
	LNB+FGR	N.A.	0.23	Combinations are not additive in effectiveness.
	LNB+SCA	N.A.	0.20-0.40	Combinations are not additive in effectiveness.
Distillate-oil-fired	LNB	N.A.	0.08-0.33	Low-excess air burner designs.
	FGR	20-68	0.04-0.15	Widely used technique because of effectiveness.
	SCA	30	0.09-0.12	Limited applications except BOOS[c], Bias and selected OFA for large watertube.
	LNB+FGR	N.A.	0.03-0.13	Most common technique. Many LNB include FGR.
	LNB+SCA	N.A.	0.20	SCA also included in many LNB designs.
Natural-gas-fired	SCA	17-46	0.06-0.24	Technique includes BOOS[c] and OFA. Many LNB include SCA technique.
	LNB	39-71	0.03-0.17	Popular technique. Many designs and vendors available.
	FGR	53-74	0.02-0.10	Popular technique together with LNB.
	LNB+FGR	55-84	0.02-0.09	Most popular technique for clean fuels.
	LNB+SCA	N.A.	0.10-0.20	Some LNB designs include internal staging.

[a]N.A. = Not available. No data are available to determine control efficiency. See Appendix B for detailed individual test data.
[b]LNCFS = Low-NO_x Concentric Firing System by ABB-Combustion Engineering.
[c]BOOS is not applicable to single-burner packaged boilers and some multiburner units.

summarizes control efficiency and NO_x levels achieved with the retrofit of combustion modification techniques for watertube ICI boilers. The data base includes primarily commercial facilities that were retrofit to meet regulated NO_x limits. In addition. the data base also includes result obtained from controls installed for research and development of specific techniques. Details and references for this data base can be found in Appendices B and C of this document.

The most effective NO_x control techniques for PC-fired ICI boilers are LNB, NGR, and LNB+SCA. The average reduction achieved with the retrofit of LNB on seven ICI boilers was 55 percent with a controlled level of 0.35 lb/MMBtu. A combination of LNB plus overfire air (OFA) also achieved an average of 0.35 lb/MMBtu on eight ICI boilers. Lower NO_x emissions were achieved for tangentially fired boilers. Evaluation of retrofit combustion controls for coal-fired stokers revealed control efficiencies in the range of 0 to 60 percent. This wide range in control efficiency is attributed to the degree of staging implemented and method of staging. Typically, existing OFA ports on stokers are not ideal for effective NO_x staging. Furthermore, the long term effectiveness of these controls for stokers was not evaluated in these exploratory tests. The average NO_x reduction for eight stokers with enhanced air staging was 18 percent with a corresponding controlled NO_x level of 0.38 lb/MMBtu. Largest NO_x reductions were accompanied by large increases in CO emissions. Gas cofiring in coal-fired stokers, only recently explored, achieves NO_x reductions in the 20 to 25 percent range only by being able to operate at lower excess air.

Air staging in coal-fired FBC boilers is very effective in reducing NO_x from these units. FBCs are inherently low NO_x emitters because low furnace combustion temperatures preclude the formation of thermal NO_x.

Furthermore, the in-bed chemistry between coal particles, CO, and bed materials (including SO_2 sorbents) maintains fuel nitrogen conversion to NO at a minimum. The

control of NO_x is further enhanced by operating these boilers with some air staging. In fact, many new FBC designs, including circulating FBCs, come equipped with air staging capability especially for low NO_x emissions. Excessive substoichiometric conditions in the dense portion of the fluidized bed can result in premature corrosion of immersed watertubes used in bubbling bed design. Circulating FBC boilers are better suited for deep staging because these units do not use in-bed watertubes.

NO_x reductions and controlled levels for residual oil combustion are influenced by the nitrogen content of the oil, the degree of staging implemented, and other fuel oil physical and chemical characteristics. Because of these factors, NO_x control performance on this fuel is likely to vary, as shown in Table 2-4. Data on LNB for residual-oil-fired ICI boilers were obtained primarily from foreign applications. The average controlled NO_x level reported with LNB for residual-oil-fired ICI boilers is 0.19 lb/MMBtu based on 17 Japanese installations and one domestic unit equipped with Babcock and Wilcox (B&W) XCL-FM burner for industrial boilers.

The data base for distillate-oil- and natural-gas-fired boilers is much larger than that for residual-oil-fired units. This is because many of the distillate-oil- and natural-gas-fired applications are in California, where current regulations have imposed NO_x reductions from such units. Among the controls more widely used are LNB, FGR, and LNB with FGR. Many LNB designs also incorporate low excess air and FGR, internal to the burner or external in a more conventional application. The average NO_x reduction for FGR on natural-gas-fired boilers is approximately 60 percent from many industrial boilers, nearly all located in California. The average controlled NO_x level for FGR-controlled ICI watertube boilers is 0.05 lb/MMBtu or approximately 40 ppm corrected to 3 percent O_2. For distillate

oil, the average FGR-controlled level from watertube boilers is 0.08 lb/MMBtu or approximately 65 ppm corrected to 3 percent O_2. Average NO_x emissions controlled with LNB plus FGR are slightly lower than these levels.

Table 2-5 summarizes results of controls for firetube units. Controlled NO_x levels achieved on these boiler types are generally slightly lower than levels achieved on watertube units. For example, LNB+FGR recorded an average of about 0.033 lb/MMBtu or approximately 35 ppm corrected to 3 percent O_2. FGR by itself is also capable to achieve these low NO_x levels when burning natural gas. In addition to these combustion controls, both OT and WI have been retrofitted in combination on selected packaged industrial boilers in California to meet very low NO_x levels.

TABLE 2-5. SUMMARY OF COMBUSTION MODIFICATION NO_x CONTROL PERFORMANCE ON ICI FIRETUBE BOILERS

Fuel type	NO_x control	Percent NO_x reduction	Controlled NO_x level, lb/MMBtu	Comments
Residual-oil-fired	LNB	30-60	0.09-0.25	Staged air could result in operational problems.
	SCA	49	0.11	Technique generally not practical unless incorporated in new burner design.
Distillate-oil-fired	LNB	15	0.15	Several LNB designs are available. Most operate on low excess air.
	FGR	N.A.[a]	0.04-0.16	Effective technique for clean fuels.
Natural-gas-fired	SCA	5	0.08	Technique not practical unless incorporated in new burner design.
	LNB	32-78	0.02-0.08	Several LNB designs are available. Some include FGR or internal staging.
	FGR	55-76	0.02-0.08	Effective technique. Used in many applications in California.
	LNB+FGR	N.A.	0.02-0.04	Most popular technique for very low NO_x levels. Some LNB designs include FGR.
	Radiant LNB	53-82	0.01-0.04	Commercial experience limited to small firetubes.

[a]N.A. = Not available. No data are available to determine control efficiency. See Appendix B for detailed individual test data.

These controls offer the potential for economic NO_x control because of low initial capital investment compared to either FGR or LNB. NO_x reduction efficiencies and controlled levels have been reported in the range of about 55 to 75 percent depending on the amount of water injected and the level of boiler efficiency loss acceptable to the facility.

2.3.2 Flue Gas Treatment Controls

Application of flue gas treatment controls in the United States is generally sparse. Table 2-6

TABLE 2-6. SUMMARY OF FLUE GAS TREATMENT NO_x CONTROL PERFORMANCE ON ICI BOILERS

ICI boiler and fuel	NO_x control	Percent NO_x reduction	Controlled NO_x level, lb/MMBtu	Comments
PC, wall-fired	SNCR-Urea	30-83	0.15-0.40	Experience relies primarily on utility retrofits. Because of relatively higher NO_x, higher control efficiency is frequently achieved.
Coal-fired FBC	SCR	53-63	0.10-0.15	Limited applications to few foreign installations. No domestic experience.
Coal-Stoker	SNCR-Ammonia	50-66	0.15-0.18	Control levels achieved in combination with OFA controls.
Coal-Stoker	SNCR-Urea	40-74	0.14-0.28	Control levels achieved in combination with OFA controls.
Wood-fired stoker	SNCR-Ammonia	50-80	0.04-0.23	Vendors of technology report good efficiency for stoker applications irrespective of fuels.
	SNCR-Urea	25-78	0.09-0.17	
MSW stokers and mass burn	SNCR-Ammonia	45-79	0.07-0.31	Vendors of technology report good efficiency for stokers applications, irrespective of fuels.
	SNCR-Urea	41-75	0.06-0.30	
	SCR	53	0.05	Experience limited to one foreign installation.
Coal-fired FBC	SNCR-Ammonia	76-80	0.04-0.09	Technique is particularly effective for FBC boilers. Applications limited to California sites.
	SNCR-Urea	57-88	0.03-0.14	
Wood-fired FBC	SNCR-Ammonia	44-80	0.03-0.20	Technique is particularly effective for FBC boilers irrespective of fuel type. Applications limited to California sites.
	SNCR-Urea	60-70	0.06-0.07	
Wood-fired Watertube	SNCR-Urea	50-52	0.14-0.26	Limited application and experience.
	SCR	80	0.22	Only two known installations in the United States.
Natural-gas- and distillate-oil-fired watertube	SNCR-Ammonia	30-72	0.03-0.20	Limited application and experience.
	SNCR-Urea	50-60	0.05-0.10	
	SCR	53-91	0.01-0.05	Experience principally based on foreign and some southern California installations.

summarizes the range in NO_x reduction performance and controlled NO_x levels achieved with the application of SNCR and SCR. The data base assembled to produce these results includes both domestic and foreign installation whose results have been reported in the literature or were available from selected technology vendors. References and details are available in Appendix B.

The NO_x reduction efficiency of SNCR for PC-fired boilers is based on results from four boilers, one a small utility unit. For these boilers, NO_x reductions ranged from 30 to 83 percent and averaged 60 percent, with controlled NO_x levels in the range of 0.15 to 0.40 lb/MMBtu. SNCR performance is known to vary with boiler load because of the shifting temperature window. SNCR has been reported to be quite more effective for FBC and stoker boilers. In circulating FBC boilers in California, SNCR with either urea or ammonia injection, achieved an average NO_x reduction and controlled level of nearly 75 percent and 0.08 lb/MMBtu, respectively. SNCR results for 13 coal-fired stokers ranged from 40 to 74 percent reduction, with controlled NO_x levels between 0.14 and 0.28 lb/MMBtu. For stokers burning primarily waste fuels, including MSW mass burning equipment, several applications of SNCR resulted in NO_x reductions in the range of 25 to 80 percent, averaging about 60 percent, with controlled levels in the range of 0.035 to 0.31 lb/MMBtu.

2.4 COST AND COST EFFECTIVENESS OF NO_x CONTROL TECHNIQUES

A simplified costing methodology, based primarily on the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, was developed for this study. The capital control costs were based on costs reported by vendors and users of the NO_x control technologies and from data available in the open literature. The total

capital investment was annualized using a 10-percent interest rate and an amortization period of 10 years. Cost

effectiveness was calculated by dividing the total annualized cost by an NO_x reduction for each retrofit cost case using boiler capacity factors in the range of 0.33 to 0.80.

Table 2-7

TABLE 2-7. ESTIMATED COST AND COST EFFECTIVENESS OF NO_x CONTROLS (1992 DOLLARS)

Fuel type	Boiler type and size, MMBtu/hr	NO_x control technique	Estimated NO_x control level, lb/MMBtu[a]	NO_x reduction, tons/yr	Total capital investment, $/MMBtu/hr	Cost effectiveness, $/ton of NO_x
Pulverized coal	Watertube (400)	LNB	0.35	310	5,300	1,170-1,530
		SNCR	0.39	270	1,600-2,100	1,010-1,400
		SCR	0.14	490	20,000	3,400-4,200
Coal	FBC (400)	SNCR	0.08	210	1,600	890-1,030
	S. Stoker (400)	SNCR	0.22	270	1,100	1,300-1,500
Natural gas	Single burner packaged watertube (50)	OT+WI	0.06	5.8	530	710-820
		LNB	0.08	4.3	650-2,300	570-2,400
		LNB+FGR	0.06	5.8	2,100-4,700	1,600-4,400
		SCR	0.02	8.7	2,400-6,900	4,800-6,900
	Packaged firetube (10.5)	OT+WI	0.04	1.3	2,400	3,100-3,700
		OT+FGR	0.07	0.65	5,300	8,000-11,000
	Multiburner field-erected watertube (300)	OT+SCA[b]	0.15	53	190	210-240
		LNB	0.12	60	5,100-8,300	2,100-4,200
Distillate oil	Single burner packaged watertube (50)	LNB	0.10	3.3	2,300	460-1,900
		LNB+FGR	0.07	6.6	2,100-4,700	1,000-3,300
		SCR	0.03	25	2,400-6,900	3,900-5,500
	Packaged firetube (10.5)	OT+FGR	0.12	1.6	5,400	4,500-6,200
	Multiburner watertube (300)	LNB	0.10	72	5,100-8,300	3,100-6,300
Residual oil	Single burner packaged watertube (50)	LNB	0.19	19	2,300	240-1,000
		LNB+FGR	0.15	23	2,100-4,700	760-2,000
		SCR	0.06	33	2,400-6,900	2,000-2,900
	Firetube (10.5)	LNB	0.17	4.6	5,400	2,700-3,600
	Multiburner watertube (300)	LNB	0.19	120	5,100-8,300	1,600-3,300
Wood waste	Stoker (150)	SNCR	0.11	43	2,100-2,500	1,300-2,400
	FBC (400)	SNCR	0.11	61	970	1,500-1,600
MSW	Stoker (500)	SNCR	0.18	240	2,100-3,300	1,500-2,100

[a]Average levels calculated from the data base available to this study. Average levels do not necessarily represent what can be achieved in all cases.

[b]SCA is burners out of service.

Notes: Boiler capacity factor between 0.50 and 0.66. See Appendices D, E, F, and G for details of costing. Costs do not include installation of continuous emission monitoring (CEM) system. Annual NO_x reduction based on 0.50 capacity factor. Total capital investment from Appendices E through G.

summarizes the total investment cost and cost effectiveness of several retrofit scenarios. Overall, the total investment of controls varies from a minimum of about $100/MMBtu/hr for oxygen trim with operation of the boiler with BOOS for multi-burner watertubes, to an estimated $20,000/MMBtu/hr for the installation of SCR on a 400 MMBtu/hr (120 MWt) PC-fired boiler. The high costs of SCR retrofit were derived from estimates developed for small utility boilers, and are meant to be estimates because no domestic application of this technology was available at the time of this printing. Furthermore, costs of SCR systems have recently shown a downward trend because of improvements in the technology, increased number of applications, and competitiveness in the NO_x retrofit market.

Control techniques with the lowest investment cost are those that require minimum equipment modification or replacement. For example, the installation of an OT system coupled with WI for gas-fired firetubes and packaged watertube is typically much less than $35,000. Also the application of BOOS in multi-burner units may be a relatively low investment cost approach in reducing NO_x. These costs, however, do not consider the installation of emission monitoring instrumentation. The cost of CEM systems can easily outweigh the cost of NO_x controls for these packaged boilers. The cost effectiveness of WI controls for packaged boilers is anticipated to be low in spite of the associated efficiency losses. This is because an efficiency improvement was credited with the combined application of oxygen trim controls that can compensate for some of the losses of WI.

The installation of FGR, LNB, and LNB with FGR controls for both packaged and multi-burner field erected boilers burning natural gas or oil was estimated to range between $650/MMBtu/hr and $4,700/MMBtu/hr with

cost effectiveness as low as $240/ton to as high as $6,300/ton, depending on fuel

type and boiler capacity. The cost of SNCR is based on estimates provided by two vendors of the technology. For a 400 MMBtu/hr boiler, the investment cost can be as low as $1,100/MMBtu/hr for a stoker boiler burning coal, to $3,300/MMBtu/hr for an MSW unit burning stoker. The cost effectiveness of SNCR was calculated to range from as low as $1,010/ton to $2,400/ton depending on fuel and boiler type. SNCR costs are not likely to vary with type of reagent used (aqueous ammonia or urea).

Figures 2-1 through 2-4 illustrate how the cost effectiveness of these controls varies with boiler capacity. As anticipated, the larger the boiler size the more cost effective is the control. Also, costs increase much more rapidly for boilers below 50 MMBtu/hr in size.

2.5 ENERGY AND ENVIRONMENTAL IMPACTS OF NO_x CONTROL TECHNIQUES

Combustion modification controls to reduce NO_x emissions from ICI boilers can result in either increase or decreases in the emissions of other pollutants, principally CO emissions. The actual effect will depend on the operating conditions of the boiler's existing equipment and the sophistication of burner management system. As discussed earlier, many of these boilers especially the smaller packaged units are operated relatively with little supervision and with combustion safety margin which includes excessive amounts of combustion air to ensure efficient combustion. For these boilers, the installation of burner controls to reduce excess oxygen is likely to reduce NO_x emissions with some increase in CO emissions. For those boilers, that have poor air distribution to the active burners, a program of burner tuning with oxygen trim is likely to achieve both some reduction in NO_x and CO as well.

Figure 2-1. Cost effectiveness versus boiler capacity, PC wall-fired boilers.

Figure 2-3. Cost effectiveness versus boiler capacity, distillate-oil-fired boilers.

Table 2-8 lists CO emission changes that were recorded with the

TABLE 2-8. EFFECTS OF NO_x CONTROLS ON CO EMISSIONS FROM ICI BOILERS

Boiler and fuel type	NO_x control	NO_x reduction,%	CO emissions impact: Emissions at low NO_x, ppm	CO emissions impact: Average change, %
Coal-fired watertube	LNB	67	13-430	+800
	LNB+SCA	66	60-166	+215
Coal-fired stoker	SCA	31	429	+80
Coal-fired FBC	SCA	67	550-1,100	+86
Gas-fired packaged firetube	FGR	59-74	3-192	- 93 - -6.3
	LNB	32-82	0-30	-100 - -53
Gas-fired packaged watertube	FGR	53-78	20-205	-70 - +450
	LNB+FGR	55	2	-98
Distillate oil packaged watertube	FGR	20-68	24-46	+20 - +1,000
Distillate oil packaged firetube	LNB	15	13	+120
Residual oil watertube	FGR	4-30	20-145	0 - +1,400
	SCA	8-40	20-100	N.A.[a]

[a]N.A. = Not available.

Figure 2-2. Cost effectiveness versus boiler capacity, natural-gas-fired packaged watertube boilers.

Figure 2-4. Cost effectiveness versus boiler capacity, residual-oil-fired boilers.

application of combustion modification controls. The information shows that high CO emission are more prevalent when burning coal, especially with combustion controls such as LNB and SCA. Highest CO levels were recorded from the application of SCA for FBC boilers. CO emissions from combustion modifications for natural-gas- and oil-fired boilers are usually less than 200 ppm. Higher CO levels are likely to be recorded with the attainment of strict NO_x emission levels. In recognition of this, the South Coast Air Quality Management District (SCAQMD) in California permits 400-ppm CO levels for low-NO_x permits under its Rule 1146. Also, the American Boiler Manufacturers Association (ABMA) recommends 400-ppm CO levels when NO_x emissions from ICI boilers are lowered. Increases in particulate emissions and unburned carbon are other potential impacts of combustion modification NO_x control retrofits on oil- and coal-fired ICI boilers. Insufficient data are available to quantify these potential impacts, however.

Other potential environmental impacts can result from the application of SNCR and SCR control techniques. Both techniques can have ammonia emissions released to the atmosphere from the boiler's stack. Ammonia-based

SNCR or SCR can result in ammonia releases from the transport, storage, and handling of the chemical reagent. Data from technology vendors show that the level of unreacted ammonia emitted from the boiler's stack when either urea and ammonia-based processes are used is less than 40 ppm. The actual level of ammonia breakthrough will depend on how well the reagent feedrate is controlled with variable boiler loads and on the optimization of injection location and mixing of reagent with the flue gas. For some retrofits, especially packaged boilers, the injection of reagents at SNCR temperatures and the retrofit of SNCR reactors are difficult if not completely impractical.

Increased energy consumption will result from the retrofit of most NO_x control techniques. For example, the injection of water or steam to chill the flame and reduce thermal NO_x will reduce the thermal efficiency of the boiler by 0.5 to 2 percent depending on the quantity of water used. Increases in CO emissions that can result form the application of certain controls such as WI, SCA, and LNB will also translate to increased fuel consumption. The application of FGR will require auxiliary power to operate the flue gas recirculation fan. Both SNCR and SCR have auxiliary power requirements to operate reagent feed and circulating pumps. Also, anhydrous ammonia-based SNCR and SCR require auxiliary power to operate vaporizers and for increased combustion air fan power to overcome higher pressure drop across catalysts. Additionally, increases in flue gas temperatures, often necessary to maintain the SCR reactor temperature constant over the boiler load, can translate into large boiler thermal efficiency losses. Oxygen trim and burner tuning will, on the other end, often result in an efficiency improvement for the boiler. This is because lower oxygen content in the flue gas translates to lower latent

heat loss at the stack. Estimates of increases and potential decreases in energy consumption are presented in Chapter 7.

3. ICI BOILER EQUIPMENT PROFILE

ICI boilers span a broad range of equipment designs, fuels, and heat input capacities. The feasibility of retrofitting existing ICI boilers with NO_x controls, and the effectiveness and costs of these controls, depend on many boiler design characteristics such as heat transfer configuration, furnace size, burner configuration, and heat input capacity. Many of these design characteristics are influenced by the type of fuel used such as natural gas, fuel oil, pulverized and stoker coal, and solid waste fuels. Uncontrolled NO_x emissions also vary significantly among the various fuels and boiler design types. Combustion modifications are the most common approach to reducing NO_x, but experience with many ICI boiler types is limited. FGT controls can substitute for combustion modifications or can provide additive NO_x reductions from controlled-combustion levels.

This chapter presents an overview of ICI boiler equipment to aid in the assessment of NO_x control technologies. A boiler is defined here as a combustion device, fired with fossil or nonfossil fuels, used to produce steam or to heat water. In most ICI boiler applications, the steam is used for process heating, electrical or mechanical power generation, space heating, or a combination of these. Smaller ICI boilers produce hot water or steam primarily for space heating. The complete boiler system includes the furnace and combustion system, the heat exchange medium where combustion heat is transferred to the water, and the exhaust system. There are roughly 54,000 industrial boilers currently in operation in the United States today, with new

units being added at the rate of about 200 per year. Of these new units , nearly 80 percent are sold as replacement units, thus the nation's industrial boiler population is growing only slightly. The leading user industries, ranked on the basis of aggregate steaming capacity, are the paper products industry , the chemical products industry, the food industry, and the petroleum industry.[1]

As a whole, ICI boilers span the range of heat input capacities fro m 0.4 to 1,500 MMBtu/hr (0.11 to 440 MWt). Table 3- 1

TABLE 3-1. ICI BOILER EQUIPMENT, FUELS, AND APPLICATIONS

Heat transfer configuration	Design and fuel type	Capacity range, MMBtu/hr[a]	% of ICI boiler units[b,c]	% of ICI boiler capacity[b,c]	Application[d]
Watertube	Pulverized coal	100-1,500+	**	2.5	PH, CG
	Stoker coal	0.4-550+[e]	**[f]	5.0	SH, PH, CG
	FBC[g] coal	1.4-1,075	**	**	PH, CG
	Gas/oil	0.4-1,500+	2.3	23.6	SH, PH, CG
	Oil field steamer	20-62.5	N.A.[h]	N.A.	PH
	Stoker nonfossil	1.5-1,000[e]	**	1.1	SH, PH, CG
	FBC nonfossil	40-345	**	**	PH, CG
	Other nonfossil	3-800	**	**	SH, PH, CG
Firetube	HRT coal	0.5-50	**	**	SH, PH
	Scotch coal	0.4-50	**	**	SH, PH
	Vertical coal	<2.5	**	**	SH, PH
	Firebox coal	0.4-25	**	**	SH, PH
	HRT gas/oil	0.5-50	1.5	1.5	SH, PH
	Scotch gas/oil	0.4-50	4.8	4.6	SH, PH
	Vertical gas/oil	<2.5	1.0	**	SH, PH
	Firebox gas/oil	<20	6.5	48	SH, PH
	HRT nonfossil	2-50	N.A.	N.A.	SH, PH
	Firebox nonfossil	2-20	N.A.	N.A.	SH, PH
Cast iron	Coal	<0.4-14	9.9	1.3	SH, PH
	Gas/oil	<0.4-14	72	9.6	SH, PH
Tubeless	Gas/oil	<0.4-4	N.A.	N.A.	SH, PH

gives the distribution of the major ICI boiler types currently in use. Figures 3-1 and 3-2 illustrate the range of heat input capacities applicable to various fuels, heat transfer configurations, and equipment types. Industrial boilers generally have heat input capacities ranging from 10 to 250 MMBtu/hr (2.9 to 73 MWt). This range encompasses most boilers currently in use in the industrial, commercial, and institutional sectors. Those industrial boilers with heat input capacities greater than 250 MMBtu/hr (73 MWt) are generally similar to utility boilers.[5] Therefore, many of the NO_x controls applicable to utility boilers are also candidate controls for large industrial boilers.

Boilers with heat input capacities less than 10 MMBtu/hr are generally classified as commercial/institutional units. These boilers are used in a wide array of applications, such as wholesale and retail trade, office buildings, hotels, restaurants, hospitals, schools, museums, and government facilities, primarily providing steam and hot water for space heating.[3] Boilers used in this sector generally range in size from 0.4 to 12.5 MMBtu/hr (0.11 to 3.7 MWt) heat input capacity, although some are appreciably larger.[6]

Figure 3-1. Occurrence of fuel types and heat transfer configurations by capacity.

Figure 3-2. Occurrence of ICI boiler equipment types by capacity.

As the types and sizes of ICI boilers are extremely varied, so too are the fuel types burned in these units. The most commonly used fuels include natural gas, distillate and residual fuel oils, and coal in both crushed and pulverized form. Although the primary fuel types used are fossil based, there is a growing percentage of nonfossil fuels being burned for industrial steam and nonutility power generation. The fuels' physical and chemical composition greatly influence the quantity and type of emissions produced, and the feasibility of certain types of NO_x controls, as will be discussed in Chapters 4 and 5.

The following sections describe the main characteristics of ICI boiler types used in the United States. Section 3.1 describes the three main heat transfer configurations of boilers. Section 3.2 addresses those units primarily fueled by coal. Section 3.3 discusses oil- and natural-gas-fired boilers. Finally, Section 3.4 describes nonfossil-fueled boilers.

3.1 BOILER HEAT TRANSFER CONFIGURATIONS

An important way of classifying boilers is by heat transfer configuration. The four major configurations are watertube, firetube, cast iron, and tubeless. In

a watertube boiler (Figures 3-3 and 3-4), combustion heat is transferred to

Figure 3-3. Simplified diagram of a watertube boiler. [9]

Figure 3-4. Watertube boiler. [10]

water

flowing through tubes lining the furnace walls and boiler passes. The furnace watertubes absorb primarily radiative heat, while the watertubes in the boiler passes gain heat by convective heat transfer. ICI watertube boilers span the entire range of ICI boiler capacities: 0.4 to 1,500 MMBtu/hr (0.11 to 440 MWt) heat input capacity.[7,8] They can be either packaged or field-erected, depending on their size. In general, most units greater than 200 MMBtu/hr heat input capacity are field-erected. Field-erected units are assembled onsite; these include all large multi-burner gas- and oil-fired boilers and most PC and stoker units. Packaged boilers are shipped by rail or flatbed truck as complete units. New gas- and oil-fired boilers as large as 150 MMBtu/hr (44 MWt) heat input capacity are typically shop-assembled and shipped as packaged units. Demand for packaged boilers peaked in the 1970s, when premium fuel restrictions and the rapidly escalating prices of oil and gas caused their decline. However, with government's repeal of its premium fuel use restrictions, and with greater availability and lowered prices of oil and gas, the packaged boiler is becoming increasingly popular.[11]

Figure 3-5. Simplified diagram of a firetube boiler.[15]

In a firetube boiler (Figures 3-5 and 3-6), the hot combustion gases flow through tubes immersed in the boiler water, transferring heat to the water. The firebox itself is also often immersed in the water. At high pressures, and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers, since, in the firetube units, the high-pressure steam is contained by the boiler walls rather than by multiple small diameter watertubes, which are inherently stronger.[6] As a consequence, ICI firetube boilers are typically small, with heat input capacities limited to less than 50 MMBtu/hr (15 MWt)[12], and steam pressures limited to 300 psig, although high-end steam pressures of 150 psig are more common. Firetubes are used primarily where loads are relatively constant.

Nearly all firetube boilers are sold as packaged units because of their relatively small size.

In a cast iron boiler, combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as

Figure 3-6. Firetube boiler.[16]

it moves upward through the tubes. Cast iron boilers produce low-pressure steam or hot water, and generally burn oil or natural gas.[13] They are used primarily in the residential and commercial sectors, and have heat input capacities up to 14 MMBtu/hr (4.1 MWt).[14]

The tubeless design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

3.2 COAL-FIRED BOILER EQUIPMENT TYPES

In 1977, 12 percent of all ICI boilers in the United States were coal-fired.[3] Coal has not been utilized in ICI boilers as extensively as oil or natural gas, chiefly due to cost-effectiveness considerations for the smaller units. Although the majority of coal-fired ICI boilers are smaller cast iron units, coal-fired firetube or cast iron boilers are not as common as oil- or natural-gas-fired firetube units. As discussed above, this is because firetube boilers are usually limited to 50 MMBtu/hr (15 MWt) heat input capacity. For smaller industrial and commercial units below this capacity, coal has not been a popular fuel because of the high capital cost of coal handling equipment relative to the costs of the boilers. Thus, most ICI boilers are fueled with oil or natural gas.

Nevertheless, there has been a market percentage increase in coal-fired boilers since the early 1970s. Of the total industrial boiler units purchased in 1971, only 0.5 percent were designed primarily for coal use. By 1980, coal-fired boilers claimed 13.7 percent of the new boiler market. With regards to the application of these coal-fired boilers, five industry groups consumed 66 percent of the total industrial coal used in 1980. These groups included the chemical products industry, the paper products industry, the food and kindred products industry, the primary metals industry, and the transportation equipment industry.[17]

3.2.1 Coal-fired Watertube Boilers

Coal-fired watertube boilers made up less than 1 percent of the total United States ICI boiler population in 1977, the last time an industrial boiler inventory was taken. Yet, due to their larger capacities, these units accounted for 14 percent of the total operating capacity.[18] Coal-fired watertube ICI boilers can be classified into three major categories: stokers, PC-fired units, and FBC boilers. The following subsections describe these types of boilers.

3.2.1.1 Stoker-firing Watertube Boilers

Stoker-firing systems account for approximately 90 percent of coal-fired watertube ICI boilers.[19] Stoker systems can be divided into three groups: underfeed stokers, overfeed stokers, and spreader stokers. These systems differ in how fuel is supplied to either a moving or stationary grate for burning. One important similarity among all stokers is that all design types use underfeed air to combust the coal char on the grate, combined with one or more levels of overfire air introduced above the grate. This helps ensure complete combustion of volatiles and low combustion emissions. Most stokers also utilize flyash reinjection to minimize the unburned carbon content in the flyash. Underfeed stokers were once the primary stoker type used in industrial and utility steam generation, but the high costs of maintenance and these units' slow response to varying loads have made them less competitive in the present market. Spreader stokers, however, are extremely popular in industry today, due in part to their wide fuel capability, discussed further below.[20]

Figure 3-7. Single-retort horizontal-feed underfeed stoker.[21]

Underfeed stokers are generally of two types: the horizontal-feed, side-ash-discharge type, shown in Figure 3-7; and the gravity-feed, rear-ash-discharge type, shown in Figure 3-8. The horizontal-feed, side-ash-discharge type of stoker is used primarily in small boilers supplying relatively constant steam loads of less than 30,000 lb/hr (~30 MMBtu/hr input).[21] As shown in Figure 3-7, coal is supplied from below the air-admitting surface of the grate into the bottom of a fuel bed, usually via a longitudinal channel called a retort. As additional coal is fed into the boiler with a ram or screw, the coal is forced to the top of the retort, where it spills onto a grate located on either side. Combustion air is supplied through tuyeres at the side grates, where combustion is completed. Overfire air is often supplied to the flame zone above the bed to provide more combustion air and turbulence for more

Figure 3-9. Overfeed chain-grate stoker.[21]

complete combustion.[22] These smaller underfeed stokers typically have one or two retorts. Maximum allowable burning rates are typically 425,000 Btu/hr per square foot of grate area.[21] Allowable burning rates determine the size of the grate area for a given heat input rate. The higher the burning rate the higher the intensity of combustion and thickness of the burning bed. The gravity-feed, rear-ash-discharge underfeed stoker often has multiple retorts. Typically, this type of stoker has a maximum 500 MMBtu/hr (146 MWt) heat input capacity.[21] In this type of stoker, coal is introduced through a coal hopper and is ram-fed to the inclined retorts and grates. The retorts and grates are typically inclined 20 to 25°. Maximum allowable fuel burning rates are 600,000 Btu/ft^2-hr.[21]

An overfeed stoker, shown in Figure 3-9, uses a moving grate assembly. Coal is fed from a hopper onto a continuous grate that conveys the coal into the furnace. As coal moves through the furnace on the grate, it passes over several air zones for staged burning. The air serves a dual purpose; it is used for combustion as well as for cooling the fuel bed and grate, preventing fusing of the coal. At the far end of the moving grate, combustion is completed and ash discharged to the bottom of the furnace. An adjustable gate at the coal feed point allows regulation of the depth of the fuel bed.[23,24] The three types of grates used with overfeed coal stokers are the chain, travelling, and water-cooled vibrating grates. These overfeed stoker systems are often referred to by the type of grate employed. Overfeed coal-fired systems typically range up to 350 MMBtu/hr (100 MWt) heat input capacity. Maximum fuel burning rates for overfeed stokers are roughly 500,000 Btu/ft^2-hr.[21]

In a spreader stoker, mechanical or pneumatic feeders distribute coal uniformly over the surface of a moving grate. In a typical spreader stoker boiler, shown in Figure 3-10

Figure 3-8. Multiple-retort gravity-feed underfeed stoker.[21]

, primary air is admitted evenly throughout the active grate area, providing some fuel bed cooling, while above the grate an overfire air system provides secondary air and turbulence. The injection of the fuel into the furnace and onto the grate combines suspension burning with a thin, fast-burning fuel bed. The amount of fuel burned in suspension depends primarily on fuel size and composition, among other factors. Generally, the finer the fuel and/or the higher its volatile matter content, the more energy released in suspension; the higher the moisture content, the more energy released on the grate.[24] Many spreader stoker units incorporate a flyash recirculation system, whereby unburned solids in the flyash are collected and recirculated back into the primary combustion chamber. Heat input capacities of spreader stokers typically range from 5 to 550 MMBtu/hr (1.5 to 160 MWt), although

Figure 3-10. Spreader stoker.[21]

there are a few units of 1,500 MMBtu/hr (440 MWt) or more.[18] Maximum fuel burning rates are highest for this stoker design, often reaching a maximum of 750,000 Btu/ft^2-hr.[21]

In general, stoker coal is fed crushed with a nominal size less than 2 inches. Overfeed and spreader stokers can be used to burn almost any type of coal or solid fuel, including wood, wood waste, and bagasse. Coking bituminous coals, however, are not used in overfeed stokers to avoid matting and restricting the airflow through the grate. Coking has little effect on the performance of spreader stokers.[8] Most packaged stoker units designed for coal firing are less than 100 MMBtu/hr (29 MWt) capacity.[25] Larger units are typically field-erected.

3.2.1.2 PC-fired Watertube Boilers

PC-fired boilers account for a small percentage of the ICI watertube boiler population. In 1977, they accounted for less than 1/10th of 1 percent of all installed ICI boiler units. However, they accounted for approximately 2.5 percent of total ICI boiler capacity.[18] This disparity is due to the fact that PC-fired boilers are almost entirely limited to sizes larger than 100 MMBtu/hr (29.3 MWt) heat input capacity. Below this level, the required coal-handling and pulverizing equipment can increase the capital cost of PC-fired units to as high as 10 times that of an oil- or natural-gas-fired industrial boiler of the same size.[26] Thus, when coal is the fuel of choice, stoker firing dominates in units below about 150 MMBtu/hr (44 MWt) heat input capacity. PC firing and FBC are usually the choices for larger boilers.[27] PC-fired ICI boilers are nearly all of watertube configuration, and the majority are field-erected.[26]

Combustion in PC-fired units takes place almost entirely while the coal is suspended, unlike in stoker units, in which most, if not all, of the coal burns on a grate. Finely ground coal (70 percent through 200 mesh) is typically mixed with primary combustion air and fed to the burner or burners,

Figure 3-11. Wall firing. [26]

whereupon it is ignited and mixed with secondary combustion air. Depending upon the location of the burners and the direction of coal injection into the furnace, PC-fired boilers can be classified into three different firing types

- Single- and opposed-wall, also known as face firing
- Tangential, also known as corner firing
- Cyclone

Of these types, wall and tangential configurations are the most common. [26]

Figure 3-11 shows a schematic of a single-wall-fired boiler. Wall-fired boilers can be either single-wall-fired, with burners on only one wall of the furnace firing horizontally, or opposed-wall-fired, with burners mounted on two opposing walls. However, opposed-wall boilers are usually much larger than 250 MMBtu/hr heat input capacity, and are much more common in utility rather than in industrial applications. [26]

Figure 3-12 shows a plan view of a tangential-firing configuration, with the burners mounted in the corners of the furnace. The fuel and air are injected toward the center of the furnace to create a vortex that enhances air/fuel mixing. Larger flame volumes and flame interaction contribute to characteristically lower NO_x levels from tangential firing. Tangential boilers, like opposed-wall boilers, are commonly used in utility applications.[26]

Cyclone furnaces are often categorized as PC-fired systems even though the coal burned in cyclones is crushed and not pulverized. These furnaces burn low-fusion-temperature coal crushed to a maximum particle size of about 4.75 mm (95 percent through 1/4 inch mesh).[8] The coal is fed tangentially, with primary air, into a horizontal cylindrical furnace. Smaller coal particles are burned in suspension, while larger particles adhere to a molten layer of slag on the combustion chamber wall. The larger particles remain in the slag until they are burned. Because of their intense furnace heat release rates, cyclones emit high levels of NO_x, and are generally more difficult to control with combustion modifications. Cyclone furnaces are not as widely used in the industrial sector as wall, tangential, or stoker systems.[8]

PC-fired boilers are also classified as either dry bottom or wet bottom, depending on whether the ash is removed in solid or molten state. This is an important differentiation with respect to NO_x emissions, as wet-bottom boilers generally operate at higher furnace temperatures and subsequently emit greater amounts of NO_x. Boiler designs in wet- and dry-bottom furnaces hinge on coal quality and ash fusion properties. Wet-bottom furnaces are also referred to as slag tap furnaces. In the ICI sectors, dry-bottom PC-fired boilers are much more widely used than wet-bottom boilers.[6,8]

3.2.1.3 FBC Watertube Boilers

FBC boilers, while not constituting a large percentage of the total ICI boiler population, have nonetheless gained popularity in the last decade, due primarily to their capabilities to burn a wide range of solid fuels and to use combined NO_x/SO_x controls within the furnace. FBC units generate steam for ICI facilities, cogenerators, independent power producers, and utilities. In the United States, FBCs in use in the industrial sector account for less than 10 percent of the total installed FBC generating capacity.[28]

There are two major categories of FBC systems: (1) atmospheric, operating at a slight negative draft, and (2) pressurized, operating at from 4 to 30 atmospheres (60 to 450 psig). Pressurized FBC (PFBC) systems are being demonstrated at two utility sites in the United States. No PFBC units are currently in operation in the ICI sector, and it is unlikely that such systems will be used for industrial applications in the near future, due to the developmental status of this technology. A recent market assessment report concluded that PFBCs are several

Figure 3-12. Tangential firing.[26]

years away from full commercialization in the utility industry, and that near-term opportunities for large industrial applications rest with atmospheric FBC technology.[28] Currently, only atmospheric FBC systems are used in the ICI sector.[29] Therefore, the remainder of this section describes atmospheric FBCs.

In a typical FBC boiler, solid, liquid, or gaseous fuel or fuels, together with a mixture of inert material (e.g., sand, silica, ash) and/or a sorbent such as limestone, are kept suspended by a steady upward flow of primary air through the fuel bed. This fuel bed fluidization promotes turbulence, which improves mixing of fuel and air, allowing the FBC to combust solid fuel at a substantially lower and more uniformly distributed temperature—typically 815 to 870°C (1,500 to 1,600°F) — compared to stoker or PC-fired boilers, where furnace temperatures can peak at 1,590 °C (2,900°F).

This lower temperature range provides two of the three main advantages of FBCs over conventional boiler units:

- Lower combustion temperatures result in less formation of thermal NO_x and allow use of sorbent to reduce SO_2 emissions
- Lower combustion temperatures are generally below the ash fusion temperatures of most fuels, resulting in less slagging and fouling of heat transfer surfaces
- FBCs are able to burn many types of fuels besides coal, including low-grade fuels such as petroleum coke, waste coal, municipal waste, and biomass materials

Flexible-fuel capability is inherent in FBC design, and the ability to efficiently burn low-grade fuels would generally be impractical without FBC technology. High combustion efficiencies are generally due to the long retention times of solids in the fluidized beds.[30]

Figure 3-13. Bubbling FBC schematic. [32]

FBCs are primarily watertube boilers, especially among the larger units, although firetube units are also available. In some FBCs — bubbling bed units, described below — additional watertubes are located within the fuel bed itself, oriented either horizontally or vertically. Steam output is controlled by manipulating the primary bed parameters of height, temperature, fuel input, and fluidization velocity—the velocity of the primary air through the bed.

Firetube FBC boilers are also available and in use. However, of the more than 50 FBC manufacturers worldwide, only 12 offer firetube designs in addition to the more conventional watertube systems. [31] This indicates the relative popularity of watertube FBC systems as compared to the less common firetube units.

Figures 3-13 and 3-14 show the two principal types of atmospheric FBC boilers, the bubbling bed and the circulating bed. The fundamental distinguishing feature between these types is the fluidization velocity. In the bubbling-bed design, the fluidization velocity is relatively slow, ranging between 5 and 12 ft/s, the idea being to minimize solid carryover into the convective passes of the boiler. In some units, relatively slow fluidization velocities allow watertubes to be placed within the bed itself, as long as tube erosion is not a problem. Circulating FBCs, however, employ fluidization velocities as high as 30 ft/s and actually promote the carryover or circulation of solids—fuel and bed material. Solids leaving the primary combustion zone are trapped by high-temperature cyclones and recirculated back to the primary combustion chamber. In some circulating-bed designs, a secondary combustion chamber is used to complete combustion of the fuel. The circulating FBC maintains a continuous, high-volume recycle rate that increases the fuel residence time compared to the bubbling-bed design.

Figure 3-14. Circulating FBC schematic.[32]

Because of this, circulating FBCs often achieve higher combustion efficiencies and better sorbent utilization in the control of SO_2 emissions than bubbling-bed units.[33] This is one reason why the bubbling bed FBC, still favored for small-scale boilers, is not as favored for large-scale industrial and utility applications.[33] Circulating FBCs have their heat exchange tubes downstream of the recirculating cyclone.

Of atmospheric FBCs currently in use in all sectors, including industrial, utility, independent power production, and cogeneration applications, coal is the primary fuel used, followed in descending order by biomass, coal waste, and municipal waste. Coal waste and municipal waste are not significant fuel types for larger FBC plants.[33] Of 157 non-utility FBC boilers in operation in the United States in 1991, 116 were of heat input capacities below 250 MMBtu/hr (73 MWt or 37 MWe), and of these, 51 burned coal exclusively.[2] Another 18 units burned coal in combination with wood, sludge, coke, or biomass. The coal-burning FBCs ranged between 8.4 and 235 MMBtu/hr heat input capacity (2.5 to 69 MWt, or 1.25 to 35 MWe output), and accounted for a relatively small amount of the total capacity of coal-fired ICI boilers. The largest coal-fired FBC unit in non-utility application in the United States has an approximate heat input capacity of 1,070 MMBtu/hr (315 MWt), generating 160 MWe of electric power at a cogeneration facility.[2]

From an economic standpoint, ICI FBC boilers that burn coal do not compete strongly with gas-fired units. For example, in the 200- to 600-MMBtu/hr (59- to 175-MWt or 30- to 90-MWe) size range, the capital costs of a coal-fired FBC boiler are 2 to 3 times higher than a conventional natural-gas-fired unit. The use of lower cost opportunity fuels, such as coke, biomass, wood waste, and low-grade coals, can provide sufficient economic incentive to offset higher initial capital costs. When used in electric power generating applications, FBC coal-fired power plants produce electricity at 1.5

to 3 times the cost of gas-based power generation.[34] Future growth in the ICI FBC boiler market is expected to occur mainly among units that burn fuels other than coal, such as waste fuels like wood and manure.

3.2.2 Coal-fired Firetube Boilers

Coal-fired firetube boilers represent a small portion of the ICI boiler population. In 1977, coal-fired firetube boilers accounted for only 10 percent of the industrial and commercial firetube boiler population in the United States, and only 1.5 percent of all ICI boilers.[35] The four most common types of firetube boilers used with coal are the horizontal return tubular (HRT), Scotch, vertical, and the firebox; however, the HRT boiler is generally used with gas or oil instead of coal. Virtually all coal-fired firetube boilers are packaged units. The following sections discuss these boiler types as well as other less common firetube boilers.

3.2.2.1 HRT Firetube Boilers

In a typical HRT boiler, the firetubes are horizontal and self-contained, with the combustion chamber separate. When solid fuel such as coal is used, it is fed through a feed chute onto grates in the primary combustion chamber. The combustion gases then pass through the firetubes of the boiler.

Most coal- and other solid-fuel-fired HRT boilers are two-pass designs. In a two-pass HRT boiler, shown in Figure 3-15

Figure 3-15. Two-pass HRT boiler.[38]

, primary and secondary combustion chambers are located beneath the boiler tank. The combustion gases flow over the bridge wall towards the rear of the boiler, heating the outer shell of the tank. At the rear of the boiler, the combustion gases then enter the firetubes. The gases flow through the firetubes, transferring additional heat to the water, and are then exhausted through the boiler stack.

HRT boilers come in various sizes, ranging from 0.5 to 50 MMBtu/hr (0.15 to 15 MWt) heat input capacity, with pressures of 15 to 250 psig. Some larger units are available that supply saturated steam at 300 psig. Firing of coal in HRT boilers is not as common as firing liquid or gaseous fuels, due to the possibility of scaling or slagging.

3.2.2.2 Scotch Firetube Boilers

A Scotch, or shell, boiler differs from the HRT boiler in that the boiler and furnace are contained in the same shell. In a two-pass unit, combustion occurs in the lower half, with the flue gases passing beneath the bottom of the water basin occupying the upper half. The gases then pass through the firetubes running through the basin. Scotch boilers also come in three- or four-pass configurations. The capacity of Scotch boilers ranges up to 50 MMBtu/hr (15 MWt) heat input, with pressures up to 300 psig, although more typical pressures are approximately 200 psig. Like HRT boilers, coal is not as commonly used in Scotch boilers due to slagging and scaling.[36] More common gas- and oil-fired Scotch units are shown in Figures 3-6 and 3-16

Figure 3-16. Four-pass gas-/oil-fired scotch boiler. [39]

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3.2.2.3 Vertical Firetube Boilers

Another common firetube design is the vertical boiler. A vertica l firetube boiler is a single-pass unit in which the firetubes come straight u p from the water-cooled combustion chamber loc ated at the bottom of the unit. F i g u r e 3 - 1 7

Figure 3-17. Exposed-tube vertical boiler. [37]

depicts an exposed-tube vertical boiler in which the firetubes exten d from the top of the furnace into the steam space. This causes the steam to b e superheated and reduces carryover of moisture. [37]

Figure 3-18

Figure 3-18. Submerged-tube vertical boiler. [37]

shows a submerged-tube vertical boiler in which the firetubes extend from the furnace to the tube sheet, which is below the water level. This design prevents the ends of the firetubes from overheating. A conical flue gas collector directs the flue gases to an exhaust stack. The submerged-tube boiler has essentially been discontinued, however, because the collector is difficult to build and tends to leak. [37]

Vertical boilers are small, with heat input capacities under 2.5 MMBtu/hr (0.73 MWt). However, they are capable of burning all types of fuels, including coal.

3.2.2.4 Firebox Firetube Boilers

Another type of firetube boiler is the firebox boiler. These units are constructed with an internal steel-encased, water-jacketed firebox. Firebox boilers are compact and employ, at most, three passes of combustion gases. Firebox firetube boilers are also referred to as locomotive, short firebox, and compact firebox boilers. A locomotive boiler is a single-pass horizontal firetube boiler; a short firebox boiler is a two-pass horizontal firetube unit; and a compact firebox boiler is a three-pass horizontal unit. [37]

Currently available coal-fired firebox units either employ mechanical underfeed stokers, or are capable of being hand-fired. They are generally limited in size to below 25 MMBtu/hr (7.3 MWt) heat input capacity. [40]

3.2.3 Cast Iron Boilers

Commercial cast iron boilers consist of several vertical sections of heat exchange tubes mounted above a firebox. Water enters each section at the bottom, and is heated or converted to steam as it passes upward through the heat exchange tubes. The capacity of a commercial cast iron boiler is determined by the number of heat exchange sections in the boiler.

In 1977, only 12 percent of the 1.5 million cast iron boilers in the United States were coal fired, and of these, 37 percent had heat input capacities of 0.4 MMBtu/hr (0.1 MWt) or higher. [41] The majority of cast iron boilers are below 0.4 MMBtu/hr (0.1 MWt) heat input capacity and are fueled by natural gas or fuel oil. All cast iron boilers are packaged units, as they are usually no greater than 14 MMBtu/hr (4.1 MWt) in heat input capacity, and, hence, are relatively small.

3.3 OIL- AND NATURAL-GAS-FIRED ICI BOILER EQUIPMENT TYPES

Oil- and natural-gas-fired ICI boilers accounted for 88 percent of the ICI boiler population in 1977. [3] These boilers are generally similar to coal-fired units, with the exception of stoker systems, which are not used to burn liquid or gaseous fuels. However, some boilers are designed with oil/gas burners and a solid fuel stoker system, to allow use of the most economically available fuel. Oil- and natural-gas-fired ICI boilers are similar; in fact, many are capable of firing both fuels either separately or in combination.

In smaller packaged units, single burners are usually employed, while larger field-erected boilers often have multiple burners. In older boilers, multiple-burner arrangements provided a means of controlling heat input in lieu of burner turndown capability. With advances in burner control and turndown capability—most new burners can maintain stable flames as low as 10 percent of capacity—the use of multiple burners in smaller units has declined. Most newer units smaller than 200 MMBtu/hr (59 MWt) heat input capacity have only one burner. Oil- and natural-gas-fired boiler types can be categorized as watertube, firetube, cast iron, or tubeless, and as either packaged or field-erected. Watertube boilers can either be shop-assembled (packaged) or field-erected. Firetube and cast iron boilers are nearly all packaged because of their smaller sizes.

In the smaller sizes and most commercial applications of ICI boilers, the packaged gas/oil fired Scotch firetube boiler predominates.[42] Almost all of these applications are for heating where loads do not fluctuate quickly. Boilers designed for low temperature (250 °F or less) and low pressure (15 psig and less) steam are the most widely used in residential, apartment, and commercial construction.[42]

3.3.1 Oil- and Natural-gas-fired Watertube Boilers

Oil- and natural-gas-fired watertube boilers come in a wide range of capacities, from small commercial units of 0.4 MMBtu/hr (0.1 MWt) heat input capacity, to very large industrial boilers of 1,500 MMBtu/hr (440 MWt) or heat input capacity or higher. However, in the ICI sector, most are smaller than 250 MMBtu/hr (73 MWt). Larger oil- and natural-gas-fired watertube boilers that are field-erected are similar to PC-fired units in firing configuration, but with smaller furnace volumes (higher heat release rate per unit volume or waterwall surface area). Units with heat input capacities greater than 150 MMBtu/hr (44 MWt) are typically wall-fired or tangential-fired with multiple burners. Field-erected watertube boilers strictly designed for oil firing are more compact than coal-fired boilers with the same heat input, because of the more rapid combustion characteristics of fuel oil. Field-erected watertube boilers fired by natural gas are even more compact due to the rapid combustion rate of the gaseous fuel, the low flame luminosity, and the ash-free content of natural gas.[43]

In general, field-erected watertube boilers are much more common than packaged units in the boiler size category above 100 MMBtu/hr (29 MWt) heat input capacity, whereas below this capacity, watertube boilers are usually packaged. There are, however, packaged watertube units as large as 250 MMBtu/hr (73 MWt) heat input capacity.

The major type of watertube design used in packaged oil/natural-gas-fired ICI boilers is the horizontal bent tube, classified by the number of drums, headers, and tube configuration, with the latter being the most distinguishing

Figure 3-19. Watertube design configurations. [44]

factor. Figure 3-19 shows the three most common tube configurations used in packaged units. The "A" type has two small lower drums, or headers, and a large upper drum for steam and water separation. Most steam production occurs in the center furnace wall tubes entering the drum. The "D" type, the most flexible design and the most widespread, has two drums and a large-volume combustion chamber that is easy to outfit with a superheater or economizer. The "O" configuration's symmetry exposes the least amount of tube surface to radiant heat.[11] Figure 3-20

Figure 3-20. D-type packaged boiler and watertubes.[45]

depicts a typical D-type packaged boiler, and its watertubes, equipped with a single oil/natural gas burner at the end.

3.3.2 Oil- and Natural-gas-fired Firetube Boilers

The most common types of firetube boilers used for oil and natural gas firing are the Scotch, the HRT, the vertical, and the firebox boilers. Available units range from 0.4 MMBtu/hr (0.1 MWt) to 50 MMBtu/hr (15 MWt) heat input capacity, although most in use in the ICI sector have capacities below 25 MMBtu/hr (7.3 MWt).[35] These firetube boilers almost always employ a single burner rather than multiple burners, and nearly all are packaged units.

Of these four types of firetube designs, the Scotch firetube boiler is the most common. In a four-pass Scotch boiler, such as that shown in Figure 3-16, the burner is located at the end of the unit. Combustion gases pass first through the furnace tube, which is an extension of the combustion chamber, to the end of the boiler, and then enter firetubes at the bottom of the unit. The flue gases then flow back toward the front of the unit, and then enter two more systems of firetubes located above the combustion chamber, before finally exhausting through the stack. A two-pass Scotch boiler is shown in Figure 3-6; this type of unit ranges from 1 MMBtu/hr to 30 MMBtu/hr (0.3 to 9 MWt) heat input capacity.

Oil- and natural-gas-fired HRT, vertical, and firetube boilers are similar in designs and capacities to the coal-fired units discussed earlier. They are essentially the same as the coal-fired firetube units, but differ in that burners rather than stoker systems are used.

3.3.3 Oil- and Natural-gas-fired Cast Iron Boilers

Although approximately 70 percent of ICI boilers are oil- or natural-gas-fired cast iron units, these systems comprise only about 10 percent of the total United States ICI boiler capacity. Two-thirds of these boilers are rated

below 0.4 MMBtu/ hr (0.1 MWt) heat input capacity. Most of them are used in the

commercial and institutional sectors to provide low-pressure steam or hot water. Cast iron boilers using oil or natural gas are similar in design to those described in Section 3.2.3.

3.3.4 Other Oil- and Natural-gas-fired Boilers

Another oil- and natural-gas-fired boiler currently in use is the three-pass vertical tubeless boiler, shown in Figure 3-2 1

Figure 3-21. Vertical tubeless boiler. [46]

. This boiler consists of a vertical, rigid steel pressure vessel enclosed inside another pressure vessel, with water in between. This assembly is itself enclosed within an insulated outer shell. The burner is mounted horizontally at the bottom of the boiler assembly, firing into the inner pressure vessel, which serves as a large primary radiant furnace. Flue gases pass up through the inner vessel, and then make second and third passes over convection fins mounted on the outside of the outer pressure vessel. Heat is transferred to the water located between the two pressure vessels. This type of boiler is packaged and is available in heat input capacities ranging from 0.25 to 4.2 MMBtu/hr (0.07 to 1.23 MWt). The largest units are roughly 6 feet in diameter and 9 feet in height.[46]

Boilers used in thermally enhanced oil recovery (TEOR) operations are referred to as TEOR steam generators. These units are typically packaged watertube boilers with heat input capacities from about 20 to 62.5 MMBtu/hr (5.9 to 18.3 MWt). Steam generators are typically cylindrical in shape and horizontally oriented, with watertubes arranged in a coil-like design. For a given size, there is little variability in the design or configuration of oil field steam generators.[47] Figure 3-22

Figure 3-22. TEOR steam generator.[49]

shows a typical oil field steam generator.

FBC boilers rely on coal, biomass, wood, and other solid fuels. Natural gas or oil is used primarily as either a startup fuel to preheat the fluidized bed, or as an auxiliary fuel when additional heat is required.[31,48]

3.3.5 Oil Burning Equipment

Natural-gas- and oil-fired boilers often use similar combustion equipment, and in fact, many units are capable of firing either fuel. The use of fuel oil, however, generally requires special equipment to "atomize" the fuel before

combustion. In some installations, this atomization equipment may play a key role in the combustion performance of the boiler unit. To burn fuel oil at the high rates required in most ICI boiler applications, it is necessary that the oil be atomized or dispersed into the furnace as a fine mist. This exposes a larger amount of oil particle surface for contact with the combustion air, assuring prompt ignition and rapid combustion.[50] The most common types of atomizers are steam and mechanical atomizers.

Steam atomizers, which may also be used with moisture-free compressed air, are the most widely used.[50] These types of atomizers produce a steam-fuel emulsion which, when released into a furnace, atomizes the oil through rapid expansion of the steam. Steam atomizers are available in sizes up to 300 MMBtu/hr (88 MWt) input. The steam and oil pressure required are dependent on the design of the steam atomizer, although maximum oil pressures can be as high as 300 psi and maximum steam pressures as much as 150 psi.[50] Oil pressures are much lower than for mechanical atomizers. The steam atomizer performs more efficiently over a wider load range than do mechanical atomizers.

In mechanical atomizers the pressure of the fuel oil itself is used as the means for atomization. The oil pressure required at the atomizer for maximum capacity typically ranges from 600 to 1,000 psi, depending on capacity, load range, and fuel grade.[50] Mechanical atomizers are available in sizes up to 180 MMBtu/hr (53 MWt) input.

The viscosity of the oil is the most important property affecting atomization in mechanical atomizers.[51] As viscosity increases, larger viscous forces must be overcome by the energy supplied to the nozzle. This detracts from the energy available for droplet breakup, resulting in coarser atomization and possible adverse affects on combustion efficiency.[51] Thus, for proper atomization and combustion, oil of grades higher than No. 2 must usually be heated to reduce its viscosity to 135 to 150 Saybolt Universal Seconds.[50]

F i g u r e 3 - 2 3

Figure 3-23. Effect of temperature on fuel oil viscosity.[51]

shows the effect of temperature on viscosity for No . 2 (distillate) through No. 6 (residual) fuel oils.

3.4 NONFOSSIL-FUEL-FIRED ICI BOILER EQUIPMENT TYPES

Nonfossil-fuel-fired boilers are commonly used in industries that generate combustible wastes from their industrial processes. In general, nonfossil-fuel-fired boilers include any boiler used in the production of steam or hot water from biomass, including wood wastes and bagasse, and general solid waste, including MSW, industrial solid waste (ISW), and RDF. The following subsections briefly describe the types of fuels burned and the most common types of nonfossil-fuel-fired boilers currently in use.

3.4.1 Wood-fired Boilers

Wood wastes are typically burned in boilers used in the paper and allied products industry, the forest products industry, and the furniture industry. Types of wood wastes are sawdust, sanderdust, wood chips, slats, and bark. Other sources of wood for fuel include discarded packing crates, wood pallets, and wood waste from construction or demolition activities.[52] Wood is often cofired with an auxiliary fossil fuel in larger boilers.

Stokers are the most common type of wood-firing systems in the United States. There are three types of wood-fired stokers: spreader, overfeed, and underfeed. In design, they are similar to the coal-fired stokers described earlier, and range from 1.5 MMBtu/hr (0.44 MWt) to greater than 1,430 MMBtu/hr (420 MWt) heat input capacity. Of larger wood-fired units of 150 MMBtu/hr (44 MWt) heat input capacity or greater, spreader stokers are the most widespread.[53] As in the coal-fired spreader stoker described earlier, fuel enters the furnace through a chute and is spread pneumatically or mechanically across the furnace, where part of the wood burns in suspension. The remainder of the fuel lands on a stationary or moving grate, where it is burned in a thin, even bed. A portion of the combustion air is injected under the grate to drive off the volatiles and burn the char, while the remainder is fed above the grate to complete combustion. Most stoker units are equipped with a flyash reinjection system.

Other methods used to fire wood are overfeed and underfeed stoker firing, gasification, pyrolysis, fuel cell firing, suspension firing, and FBC, though to a lesser degree than spreader stoker firing. Another type of boiler combustion system, the Dutch oven, is also in use, but has been essentially discontinued from new construction due to its low efficiency, high construction costs, and inability to follow load swings.[53] The overfeed stoker is the second most common method of wood firing after the spreader stoker.

Gasification is a method of firing wood waste or other biomass whereby the fuel is partially combusted to generate a combustible fuel gas rich in carbon monoxide and hydrogen, which is then burned. Heat to sustain the process is derived from exothermic chemical reactions, while the combustible components of the resulting gas are generated by endothermic reactions.[54] In essence, a gasification system behaves as a type of biomass burner. One manufacturer offers flyash gasification systems ranging from 4.2 to 33.5 MMBtu/hr (1.2 to 9.8 MWt) heat input capacity.

In pyrolysis, an organic fuel is introduced into a high-temperature environment with little oxygen. Thermal cracking of the fuel occurs, producing combustible gases that are then burned. One system uses a moving variable-speed grate to introduce the waste fuel to the pyrolytic gasification chamber, where the fuel is thermally cracked between 1,500 °F and 1,850 °F. The resulting combustible gases are then fired in an afterburner and the flue gases directed to the boiler passes. This system is available in heat input capacities from 14 to 57 MMBtu/hr (4.1 to 16.7 MWt).

In a fuel cell boiler, wood is piled on a stationary grate in a refractory-lined cell. Forced draft air is supplied to drive off the volatiles in the wood and burn the carbon. The volatiles are mixed with secondary and tertiary combustion air and pass into a second chamber where combustion is completed.[53] Fuel cell boilers range in heat input capacity from 3 MMBtu/hr (0.9 MWt) to 60 MMBtu/hr (17.6 MWt).

In suspension firing boilers, small-sized wood fuel, such as sanderdust, is typically blown into the furnace and combusted in mid-air. The small-sized fuels required by these boilers are typically cleaner and drier than other wood wastes, which can result in increased combustion efficiency and less ash entering the furnace. However, most of the ash that does enter the furnace is usually entrained in the flue gas. Most newer boilers utilize a flyash reinjection system to minimize the amount of unburned carbon in the flyash.

Wood is also fired in FBC boilers, which are detailed in Section 3.2.1.3. In 1991, 10 nonutility FBC boilers below 250 MMBtu/hr (73 MWt) heat input capacity and exclusively firing wood wastes were in use in the United States.[2] These ranged from a 40-MMBtu/hr (12-MWt or 6-MWe) boiler, at a timber company's cogeneration plant, to a 180-MMBtu/hr (53-MWt or 27-MWe) unit, used by an independent power producer. In an additional 29 units below 250 MMBtu/hr (73 MWt) heat input capacity, wood was fired in combination with other fuels, such as coal, oil, plastic, and other agricultural wastes. The largest single wood-fired FBC boiler had an electrical generating capacity of 220 MWe, roughly equivalent to 1,500 MMBtu/hr (440 MWt) heat input capacity. This unit was operated by an independent power producer, and is atypical in size. The next largest wood-fired FBC in the ICI sector was 345 MMBtu/hr (100 MWt or 51 MWe) heat input capacity. This is more typical of the ICI wood-fired FBC boiler range.[2]

It is fairly common practice to use an auxiliary fuel, particularly fossil fuel, in all types of wood-fired boilers. Approximately 50 percent of wood-fired boilers have some type of fossil fuel firing capability.[53] Fossil fuels are fired during startup operation, as an augmentation fuel, or alone when wood fuel is unavailable. Fossil fuels are used more frequently in larger wood-fired boilers than in smaller boilers below 100 MMBtu/hr (29 MWt) heat input capacity.

Wood-fired boilers are available in both firetube and watertube designs, and are packaged or field-erected. Typical firetube boilers used in wood firing are the HRT and the firebox. Wood-fired HRT boilers are usually no larger than 40 MMBtu/hr (12 MWt) heat input capacity, although some as large as 50 MMBtu/hr (15 MWt) have been built. Wood-fired firebox units generally range between 2 and 20 MMBtu/hr (0.6 to 6 MWt) heat input capacity. The firing methods discussed above are used with both firetube and watertube boilers.

Packaged watertube boilers are the most difficult of all boilers to fire with wood waste. This is because the furnaces of these boilers are relatively cold, with water walls on all sides, and because the furnaces are very narrow due to shipping requirements. Because of this cold environment, it is essential that the dry wood particles be small enough to burn out completely during the time it takes the particles to pass through the furnace. For most packaged watertube units, the particles should be no larger than 1/64 to 1/32 of an inch, depending upon the heat release rate.[55]

3.4.2 Bagasse-fired Boilers

Bagasse, an agricultural waste, is the fibrous residue left after processing sugar cane. It is used in sugar industry boilers in Hawaii, Florida, Louisiana, Texas, and Puerto Rico.[52] This fuel is available on a seasonal basis. Other agricultural wastes include nut hulls, rice hulls, corn cobs, olive pits, and sunflower seed hulls.

The earliest type of bagasse-burning furnace was the Dutch oven with flat grates. In this type of furnace, the bagasse was burned in a pile on a

Figure 3-24. Ward fuel cell furnace. [56]

refractory hearth and combustion air admitted to the pile around its circumference through tuyeres. However, this type of furnace resulted in high maintenance costs and was essentially discontinued from new installation. A more commonly used pile burning boiler is the fuel cell, described earlier. In one type of fuel cell boiler system, the Ward furnace, shown in Figure 3-24, bagasse is gravity-fed through chutes into individual cells, where it is burned from the surface of the pile with air injected into the sides of the pile. Additional heat is radiated to the pile from hot refractory, and combustion is completed in a secondary furnace. This type of design is considered one of the most reliable, flexible, and simple methods of burning bagasse.[56]

Recent trends in bagasse firing have been toward using spreader stoker systems. Bagasse spreader stoker boilers are similar in design to wood-fired spreader stokers, except that flyash reinjection is not normally used.[57] Spreader stokers require bagasse with a high percentage of fines and a moisture content not over 50 percent.[56]

Like most other waste-fueled boilers, bagasse-fired units typically use auxiliary fuels such as natural gas or fuel oil during startup or when additional capacity is required. Most operators minimize the amount of auxiliary fuel used, and typically less than 15 percent of the total annual fuel heat input to bagasse boilers comes from fossil fuels.[57] Bagasse-fired boilers range from 13 to 800 MMBtu/hr (3.8 to 230 MWt) heat input capacity.

3.4.3 Municipal Solid Waste (MSW)-fired Boilers

General solid waste consists of refuse and garbage from municipalities and industries. Boilers that fire general solid waste are found in manufacturing plants, district heating plants, municipal heating plants, and electric utilities. As mentioned earlier, general solid waste can be further classified as MSW, ISW, or as RDF.

MSW is made up of food wastes, rubbish, demolition and construction wastes, treatment plant wastes, and other special wastes. Combustible rubbish consists of material such as paper, cardboard, plastics, textiles, rubber, leather, wood, furniture, and garden trimmings. Treatment plant waste consists of sludge from water, wastewater, and industrial wastewater treatment facilities. Special wastes are roadside litter, dead animals, and abandoned vehicles. The exact makeup of MSW varies both seasonally and geographically. For example, more organic material is usually contained in MSW during the fall, especially in areas such as the northeast where many trees are deciduous. Typically, over one third of MSW in the United States is paper, with the next most abundant constituents being food wastes and garden trimmings.[58]

MSW-fired boilers can be categorized by heat input capacity as either small modular units or large mass-burning facilities. Small modular MSW-fired boilers range from 4.5 MMBtu/hr (1.3 MWt) to 38 MMBtu/hr (11 MWt) heat input capacity, while mass-burning units are as large as 290 MMBtu/hr (85 MWt).[59] Modular units have been in operation in the United States since the late 1960s, while most existing mass-burning facilities have been constructed since 1970.

A typical large mass-burning facility rated at 150 MMBtu/hr (44 MWt) heat input capacity and MSW throughput of 15 tons per hour is shown in Figure 3-25

Figure 3-25. Large MSW-fired boiler.[60]

. The facility includes a waterwall furnace and an overfeed stoker system. MSW is loaded by overhead crane into the feed chute, which deposits the waste onto the first grate, known as the "dry-out" grate. Ignition starts at the bottom of the dry-out grate and is continued on a second "combustion" grate. A third grate, the "burn-out" grate, provides final combustion of the waste before dumping the ash into the ash pit. Typical thermal efficiencies for this size of mass-burning boiler range between 60 and 70 percent.[60,61] Other variations of mass burn systems besides the waterwall furnace type are controlled air (pyrolysis) and refractory furnaces. Controlled-air MSW units received much developmental attention during the 1970s. Many of these units, however, were subsequently shut down due to operational or economic problems.[62]

Small modular units differ from the mass-burning boilers in that they are typically hopper- and ram-fed instead of crane-fed. These units are packaged and designed to allow installation of additional units as the need for further capacity increases. A typical modular boiler, shown in Figure 3-26

Figure 3-26. Modular MSW-fired boiler. [63]

, utilizes a furnace with a primary and secondary combustion chamber. MSW is fired at approximately 820 °C (1,500 °F) in the primary chamber and at 1,040 °C (1,900 °F) in the secondary chamber. An auxiliary burner is used in the secondary chamber whenever additional heat is required. This particular type of unit is an example of a controlled-air or "starved-air" boiler, as the air in the primary combustion chamber is below stoichiometric levels to reduce ash and fuel entrainment.[63]

3.4.4 Industrial Solid Waste (ISW)-fired Boilers

ISW is composed of those wastes, typically paper, cardboard, plastic, rubber, textiles, wood, agricultural waste, and trash, arising from industrial processes. The composition of ISW fuel at any one site is usually relatively constant because the industrial activities that generate the waste are usually well regulated. The average heating value of ISW is higher than MSW, about 17,000 kJ/kg (7,100 Btu/lb) compared to 11,000 kJ/kg (4,875 Btu/lb) as fired, and the ash content is less.[64]

ISW is fired in the same type of boiler systems as the modular units described above. These units encompass the same capacity range of the modular MSW-fired boilers, but can also be as large as 60 MMBtu/hr (17.6 MWt) heat input capacity. Large-mass burning boilers are not commonly used at industrial facilities; thus, ISW is usually only fired in mass-burning boilers when it is collected as part of MSW.[64]

3.4.5 Refuse-derived Fuel (RDF)-fired Boilers

RDF is fuel processed from general solid waste. Unlike MSW and ISW fuels, which are burned in the same form as they are received at the boiler site, RDF is generated by the sorting and processing of the general solid waste. Usually, noncombustibles, such as glass and metal, are removed and recycled, and the remainder of the refuse processed into pelletized or powdered form. RDF can be burned alone or in combination with coal or oil.[54] The most common use of RDF is as a substitute for part of the coal used in coal-fired stoker and PC boilers. However, a few stoker units burn RDF alone; these units are similar to standard coal-fired boilers.[64]

Both RDF-firing and mass burn systems were commonly used in early U.S. resource recovery plants. Currently, the majority of U.S. MSW firing units utilize mass burn and not RDF firing, due in part to the successful experience of mass burn plants in Germany, Switzerland, Japan, and a number of U.S. locations. Based on the number of plants in operation and the number being planned in the near future, mass burn is the MSW-firing system of choice, although RDF firing is still considered a viable technique, especially when refuse throughput is low to moderate, on the order of a few thousand tons per day.[62,65]

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4. BASELINE EMISSION PROFILES

NO_x is a high-temperature byproduct of the combustion of fuels with air. NO_x formation in flames has two principal sources. Thermal NO_x is that fraction of total NO_x that results from the high-temperature reaction between the nitrogen and oxygen in the combustion air. The rate of thermal NO_x formation varies exponentially with peak combustion temperature and oxygen concentration. Fuel NO_x is that fraction of total NO_x that results from the conversion of organic-bound nitrogen in the fuel to NO_x via a high-temperature reaction with oxygen in the air. The amount of nitrogen in the fuel, peak combustion temperature, oxygen concentration, and mixing rate of fuel and air influence the amount of fuel NO_x formed. When low-nitrogen fuels such as natural gas, higher grade fuel oils, and some nonfossil fuels are used, nearly all the NO_x generated is thermal NO_x. When coal, low-grade fuel oils, and some organic wastes are burned, fuel NO_x generally becomes more of a factor because of the higher levels of fuel-bound nitrogen available.

Aside from the physical and chemical characteristics of the fuels, many boiler design and operating parameters influence the formation of NO_x because they impact peak flame temperatures, fuel-air mixing rates, and oxygen concentrations. Principal among these are the heat release rates and absorption profiles in the furnace, fuel feed mechanisms, combustion air distribution, and boiler operating loads. For example, steam pressure and temperature requirements may mandate a certain heat release rate and heat absorption profile in the furnace which changes with the load of the boiler.

Solid fuels can be introduced into the furnace in several ways, each influencing the rate of mixing with combustion air and the peak combustion temperature. These parameters are very unit specific and vary according to the design type and application of each individual boiler. As described in Chapter 3, ICI boilers include a broad range of furnace types operating in a variety of applications and burning a variety of fuels ranging from clean burning natural gas to several types of nonfossil and waste fuels. Thus, NO_x emissions from ICI boilers tend to be highly variable.

This chapter discusses the primary factors influencing baseline NO_x levels and summarizes the baseline (uncontrolled) NO_x emission levels measured from a variety of ICI boiler and fuel combinations. Parameters affecting NO_x emissions from ICI boilers are discussed in Section 4.1, while compiled baseline emissions for ICI boilers are presented in Section 4.2 on the basis of boiler fuel type. Section 4.3 presents a summary of the information presented in this chapter.

4.1 FACTORS AFFECTING NO_x EMISSIONS FROM ICI BOILERS

The ranges in baseline NO_x emissions for ICI boilers are due to several factors including boiler design, fuel type, and boiler operation. These factors usually influence baseline NO_x in combination with each other, and often to different degrees depending on the particular ICI boiler unit. Thus, wide variations among ICI boiler NO_x emissions are common, even among similar boiler designs or fuel types. These factors are discussed in the following subsections.

4.1.1 Boiler Design Type

The firing type of the boiler influences the overall NO_x emission level. For example, for a given fuel, tangential field-erected units typically have a baseline level less than wall-fired boilers because of their inherent staging of fuel and air in a concentric fireball. This trend has been documented for utility-sized boilers.[1] Conversely, cyclone units generally have higher NO_x levels than wall-fired units due to their inherent turbulent, high-temperature combustion process, which is conducive to NO_x formation.[2] Even within a particular type of boiler, other design details may influence baseline NO_x. For example, in field erected PC wall-fired units, NO_x may vary depending upon whether a wet bottom or dry bottom furnace is used. Wet bottom furnaces have higher furnace temperatures to maintain the slag in a molten state, leading to greater thermal NO_x formation.[3]

In comparison, coal stokers have lower NO_x emissions than PC-fired units since the stokers inherently operate in a "staged combustion" configuration.[4] Staged combustion, which is discussed in greater detail in Chapter 5, relies on the reduction of the peak flame zone oxygen level to reduce formation of fuel NO_x, and is achieved by delaying — or staging — the addition of combustion air. Higher NO_x levels reported for spreader stokers are due to a portion of the fuel burning in suspension with more effective fuel/air mixing and higher combustion temperatures. In comparison, overfeed and underfeed stokers combust more of the coal on a grate where combustion is naturally staged, with a fuel rich zone close to the grate and a more fully mixed zone above the grate. Additionally, underfeed and overfeed units tend to have larger fireboxes and, consequently, lower heat release rates, resulting in lower peak temperatures and lower levels of thermal NO_x formation.[5]

The other major design type of solid-fuel-fired units, FBC boilers, report lower baseline NO_x emissions than similarly-sized wall-, tangential-, or cyclone-fired units, due mostly to the lower combustion temperatures used in FBCs. In FBC boilers, NO_x formation generally peaks in the lower part of the furnace and is reduced in the freeboard zone, where heterogeneous reducing reactions between char and NO_x occur.[6] Also, newer FBC designs are incorporating combustion air staging in their original configuration to achieve low emissions for permitting in strict environmental areas. In staged configurations, the lower part of the fluidized bed and furnace are kept at or below stoichiometry. The staged addition of combustion air results in lower NO_x levels compared to unstaged designs.

Regarding smaller packaged natural-gas- or oil-fired boilers, NO_x emissions generally depend more on fuel, heat release rate and capacity characteristics. In general, ICI boilers with higher heat release rates and higher capacities tend to have higher levels of NO_x. This is discussed in more detail in Section 4.1.3. For a given heat release rate and fuel type, however, there is no strong correlation between NO_x emissions and whether a packaged boiler is a firetube or a watertube design.

4.1.2 Fuel Characteristics

ICI boiler baseline NO_x emissions are highly influenced by the properties of the fuels burned. NO_x and other emissions will vary depending on whether natural gas, oil, coal, or nonfossil fuels are used. Additionally, among each of these fuel types, emissions will depend on highly variable factors such as fuel grade and fuel source. In particular, studies have shown that fuel nitrogen content — and for coal the oxygen content and the ratio of fixed carbon to volatile matter — are key factors influencing NO_x formation.[3,7-9]

Much attention has been given to the role of fuel-bound nitrogen in NO_x formation. For any given fuel, only a portion of the available fuel nitrogen is converted during combustion to fuel NO_x. Published data indicate that for coal burning, anywhere from 5 to 60 percent of the nitrogen is converted, whereas for other fuels as much as 80 percent of the fuel bound nitrogen is routinely converted.[10,11] In general, higher nitrogen fuels such as coal and residual oil have lower conversion rates, as shown in Figure 4-1

Figure 4-1. Conversion of fuel nitrogen.[11]

, but higher overall NO_x rates than lower nitrogen fuels such as distillate oil.[3] The nitrogen content of bituminous coals can vary from as low as 0.8 to as high as 3.5 percent by weight. Fuel oil is normally divided into distillate oil and residual oil. Distillate oil represents the lighter fraction of the distillation process, including No. 2 oil and diesel oil normally used in residential and commercial heating, internal combustion engines, and sometimes in larger boilers strictly regulated for SO_2 and NO_x emissions. Residual oil consists of the higher temperature fractions and still bottoms from the distillation process, including No. 4, 5, and 6 fuel oils often used in industrial and some commercial boilers.

Table 4-1 lists the range and average concentrations of nitrogen and sulfur in distillate, residual, and crude oils. The data were compiled from various sources, including emission test reports, to illustrate the variability of these fuel properties. Many areas will have oils with different values, these depending on many factors such as the type of crude, refinery processes (e.g., hydrodesulfurization), and blending. Clearly, the lighter oils contain much lower levels of fuel nitrogen and

TABLE 4-1. TYPICAL RANGES IN NITROGEN AND SULFUR CONTENTS OF FUEL OILS[a]

	Distillate oil (No. 2)		Residual oil (No. 6)	
	Nitrogen	Sulfur	Nitrogen	Sulfur
Average	<0.01	0.72	0.36	1.3
Low	<0.001	0.20	0.10	0.10
High	0.01	0.70	0.80	3.5
Standard deviation	0.005	0.20	0.17	0.90
Reference	13-15		9, 14, 16-20	

[a]All concentrations are percent by weight.

sulfur, thereby contributing significantly lower NO_x and SO_2 emissions. Distillate oil normally has less than 0.01-percent nitrogen content, whereas the fuel nitrogen content of residual oils typically ranges from 0.1 to 0.8 percent by weight, with an average of 0.36 percent based on the data used to compile Table 4-1.

Sulfur content is typically specified when residual oil is purchased. This is done to meet environmental regulations and to safeguard boiler equipment from acid corrosion. Although lower sulfur content generally means lower nitrogen, there is no apparent direct relationship between these two fuel oil parameters, as illustrated in Figure 4-2

. Because the deliberate denitrification of fuel oil is not a refinery practice, significant swings in the nitrogen content of residual oil occur even when sulfur content is limited to low levels.

The nitrogen content of natural gas can vary over a wide range, from zero to as high as 12.9 percent, depending on the source of the gas. Nitrogen in natural gas, however, does not contribute as much to the production of fuel NO_x as with liquid or solid fuels, the reason being that the nitrogen in natural gas is in its molecular form (N_2), as in the combustion air. In contrast, nitrogen in liquid or solid fuels is released in its atomic form (N) and reacts at relatively low temperatures with oxygen to form fuel NO_x.[12]

Figure 4-2. Fuel oil nitrogen versus sulfur for residual oil. (Data from several EPA- and EPRI-sponsored tests; see Table 4-1.)

Figure 4-3

Figure 4-3. Effect of fuel nitrogen content on total NO_x emissions.[9]

shows the effect of fuel nitrogen content on total NO_x emissions for 26 oil-fired and 15 coal-fired industrial boiler tests. For the oil-fired tests, in which both residual and distillate oils were burned, a clear correlation was seen between nitrogen content and NO_x, with higher NO_x levels reported for the higher nitrogen content oils. The field tests of coal-fired units, however, showed no direct correlation between total NO_x emissions and coal fuel nitrogen content, per se.[9] Similar results were also reported in a study comparing the use of low-sulfur western coal to the use of eastern bituminous coal in ICI boilers.[8] It is believed that while nitrogen content does play a key role in NO_x formation, as was seen in the oil tests, other coal fuel factors such as oxygen content also influence NO_x formation concurrently, masking any obvious correlation between coal fuel nitrogen

Figure 4-4. Fuel NO_x formation as a function of coal oxygen/nitrogen ratio and coal nitrogen content.[21]

and NO_x.

This was suggested by test results showing a possible linkage between the ratio of coal oxygen to coal nitrogen and the amount of NO_x formed. Figure 4-4 shows the results of a study of the effects of the coal oxygen/nitrogen ratio on fuel NO_x formation in tangential PC-fired boilers. The figure shows the relationship between fuel NO_x, coal nitrogen content, and the coal oxygen/nitrogen ratio. The data indicate slightly higher NO_x emissions for western sub-bituminous coal due to the higher coal oxygen/nitrogen ratio, despite the coal's lower fuel nitrogen content. On a broader scale, coal property data show that coals with high oxygen/nitrogen ratios generally have lower nitrogen contents. Thus, the two influences — higher NO_x due to higher oxygen content, and lower NO_x due to lower nitrogen content — would tend to balance one another resulting in reasonably similar fuel NO_x emissions for a variety of coal types.[7,21]

Another major coal factor influencing baseline NO_x formation is the fuel ratio, defined as the ratio of a coal's fixed carbon to volatile matter. Typically, under unstaged combustion conditions, lower fuel ratios (i.e. higher volatile content of the coal) correlate to higher levels of NO_x, because with higher volatile content coals, greater amounts of volatile nitrogen are released in the high temperature zone of the flame where sufficient oxygen is present to form NO_x.[3] Thus, considered by itself, higher volatile coal firing will tend to result in higher baseline NO_x levels.[22] It has been shown, however, that firing coal with high volatile content and lower fixed carbon generally results in less solid carbon to be burned out in the post-flame gases, meaning that the coal can be fired at lower excess air before combustible losses became a problem.[8] As discussed in Section 4.1.4, lower excess air requirements generally result in lower NO_x emissions. Thus, the higher NO_x levels associated with higher volatile coals may be balanced to a certain degree by the lower excess air capability provided.

The difference between average NO_x emission levels reported among various fuel oil types (i.e., residual versus distillate) lies primarily in the fact that residual oils are produced from the residue left after lighter fractions (gasoline, kerosene, and distillate oils) have been removed from crude oil. Residual oils thus contain high quantities of nitrogen, sulfur, and other impurities. As discussed, fuels with high nitrogen contents generally produce higher levels of fuel-bound NO_x than fuels with low nitrogen contents. Thus, with residual oil in particular, fuel NO_x makes up a greater portion of the total NO_x emitted. For any particular class of boilers, the range in 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 this.[23] Even within one type of fuel oil, large variations in NO_x emissions can be recorded due to the other factors discussed in this chapter. The variability in NO_x emissions between the boilers listed in Appendix A burning the same type of oil is chiefly due to variations in boiler heat release rates and operating conditions.

Besides distillate oil, many nonfossil fuel types are low-nitrogen-content fuels. Thus, NO_x emissions from ICI boilers fired on these fuels and on natural gas are almost entirely thermal NO_x, and the major factors which influence their NO_x levels are furnace heat release rate (related to capacity and operating load) and excess air level, both of which are discussed below.[24] While most wood burning boilers are stokers and are similar in design to coal-fired units, the relatively low nitrogen content of wood contributes to much lower fuel-bound NO_x formation than with coal. In general, with wood wastes the generation of particulates and other unburned combustibles is more of a concern than NO_x formation. The wood moisture content and wood fuel size are the two most important fuel quality factors influencing those emissions.[25]

Moisture content also plays an important role in the formation of uncombustible emissions in MSW firing. By its nature, MSW composition is highly dependent on the net waste contributions of residential and commercial waste producers, and on seasonal factors which may impact the amount and type of organic waste produced. For example, a period of high rainfall can result in increased moisture content in the MSW, with larger quantities of yard waste. These variables result in wide ranges in MSW composition and corresponding fuel properties. Studies have shown that the non-combustible content of MSW can range from 5 to 30 percent, the moisture content from 5 to 50 percent, and the heating value from about 7,000 to 15,000 kJ/kg (3,000 to 6,500 Btu/lb).[26] Nitrogen contents, too, are often highly variable depending on the source of MSW. Ultimate analyses of MSW from different parts of the United States have shown nitrogen contents ranging between 0.2 and 1.0 percent.[27-31] Thus, emissions from MSW-fired boilers will also tend to be highly variable.

4.1.3 Boiler Heat Release Rate

Boiler heat release rate per furnace area is another influential variable affecting NO_x formation. As heat release rate increases, so does peak furnace temperature and NO_x formation, as illustrated in Figure 4-5

Figure 4-5. Effect of burner heat release rate on NO_x emissions for coal and natural gas fuels.[16]

. Boiler heat release rate varies primarily with the boiler firing type, th e primary fuel burned, and the

operating load.[3] Additionally, boiler heat release rate per unit volume is often related to boiler capacity, as illustrated in Figure 4-6

Figure 4-6. Furnace heat release rate versus boiler size.[32]

. For example, among coal-fired boilers, PC-fired units are typically the largest in capacity. The data in Appendix A include PC-fired units from 111 to 640 MMBtu/hr (32.5 to 188 MWt) heat input capacity, whereas the coal stokers listed in Appendix A are generally smaller, ranging in size from 3 to 444 MMBtu/hr (0.88 to 130 MWt), with the vast majority being below 200 MMBtu/hr (59 MWt) capacity. These ranges are fairly representative of the capacity ranges discussed in Chapter 3. Compared to other coal-fired boiler designs, PC-fired units tend to have larger capacities, heat release rates, and, as shown by the data in Appendix A, generally higher baseline NO_x levels.

Among stoker units, the largest capacity stokers are spreader stokers as reflected in the Appendix A data. The majority of spreader stoker data came from units greater than 100 MMBtu/hr (29 MWt) in capacity, while the other two stoker types were usually less than 100 MMBtu/hr (29 MWt). While some large underfeed and overfeed stokers are in use in the ICI sector, these types of stokers commonly have lower heat input capacities, and, as indicated earlier, tend to have larger fireboxes. Consequently, overfeed and underfeed stokers generally have lower heat release rates per unit area, resulting in lower peak temperatures and lower levels of thermal NO_x formation than spreaders.[5]

Because packaged natural-gas- or oil-fired watertube boilers are available in higher capacities and heat release rates than firetubes, the high end of the ranges of reported baseline NO_x tends to be greater for the watertube designs. However, as noted in Section 4.1.1, there is no obvious correlation per se between NO_x emissions and whether a boiler is a firetube or a watertube.

4.1.4 Boiler Operational Factors

In addition to boiler design and fuel factors, the conditions under which a unit is operated also influence baseline NO_x levels. Chief among these operational factors are the amount of excess oxygen in the flue gases and the combustion air temperature. Excess oxygen refers to the oxygen concentration in the stack gases, and is dependent on the amount of excess air provided to the boiler for combustion.[33] Combustion air temperature, meanwhile, is dependent on the degree of air preheat used before the air is introduced into the furnace or burner. Air preheat is usually used to increase furnace thermal efficiency.

Numerous sources have discussed the typical relationship of excess oxygen levels and NO_x, wherein as excess oxygen in creases, so does NO_x.[34-37] This relationship is shown in Figure 4-7

Figure 4-7. Effect of excess oxygen and preheat on NO_x emissions, natural-gas-fired boilers.[39]

, which presents data for natural-gas-fired watertube and firetube boilers. The thermal efficiency advantages of operating boilers at low excess oxygen levels have long been known, as long as the boiler is operated with a certain margin of excess air above the minimum level required to avoid excessive combustible emissions formation (CO, particulate). Operation on low excess oxygen or air is therefore considered a fundamental part of good combustion management of boilers. However, many ICI boilers are typically fired with excess oxygen levels which are more than adequate to assure complete combustion and provide a margin of safety to the operator.[38] Thus, these units often are operated at unnecessarily high excess oxygen levels that result in unnecessarily high NO_x emissions and losses in efficiency. Utility boilers, on the other hand, are typically fired with a smaller safety margin of excess air, but these units are more closely monitored by operating personnel and are not as subject to such wide variations in load as ICI boilers.[38]

Figure 4-7 also shows the effect of using combustion air preheat. As shown, use of air preheat generally results in higher levels of NO_x. The level of combustion air preheat has a direct effect on the temperatures in the combustion zone, which, in turn, has a direct impact on the amount of thermal NO_x formed. More specifically, the greater degree that the air is preheated, the higher the peak combustion temperature and the higher the thermal NO_x.[40] Because the air preheat temperature primarily affects thermal NO_x formation, the use of air preheat has its greatest NO_x impact on fuels such as natural gas and distillate oils.[40,41] Boilers with combustion air preheat systems are usually larger than 50 MMBtu/hr in capacity, with preheat temperatures in the range of 120 to 340 °C (250° to 650°F).[41] In particular, many stoker boilers are equipped with air preheat.

4.2 COMPILED BASELINE EMISSIONS DATA — ICI BOILERS

This section presents compiled uncontrolled NO_x emissions data for ICI boilers. Where data were available, CO and total unburned hydrocarbon (THC) emissions are also reported. These baseline data were compiled from test results on more than 200 boilers described in EPA documents and technical reports. These data are detailed in Appendix A. Emission tests on these boilers were performed at greater than 70-percent boiler load in most cases.

4.2.1 Coal-fired Boilers

Table 4-2

TABLE 4-2. COMPARISON OF COMPILED UNCONTROLLED EMISSIONS DATA WITH AP-42 EMISSION FACTORS, COAL-FIRED BOILERS

	NO_x, lb/MMBtu[a]		CO, lb/MMBtu[a]		THC, lb/MMBtu[a]	
Boiler type	Compiled data[b]	AP-42	Compiled data	AP-42	Compiled data	AP-42
PC wall-fired	0.46-0.89	0.58-0.81	0.0-0.05	0.02-0.04	0.001-0.019[c,d]	0.004-0.007
PC tangential	0.53-0.68	0.58-0.81	0.0-0.14	0.02-0.04	0.004-0.009[c,d]	0.004-0.007
Cyclone	1.12	[e] 1.31[c,d]	0.0[e]	0.02-0.04	N.A.	0.004-0.007[f]
Spreader stoker	0.35-0.77	0.42-0.54	0.0-0.53	0.19-0.35	0.0-0.018	0.004-0.007
Overfeed stoker	0.19-0.44	0.29-0.41	0.001-1.65	0.35-0.42	0.022-0.024	0.004-0.007
Underfeed stoker	0.31-0.48	0.37-0.42	0.0-0.94	0.42-0.76	0.010	0.081-0.150
Bubbling FBC	0.11-0.81	N.A.	0.17-0.49	N.A.	N.A.	N.A.
Circulating FBC	0.14-0.60	N.A.	0.02-0.25	N.A.	N.A.	N.A.

[a]To convert to ppm @ 3% O_2, multiply by the following: NO_x, 740; CO, 1,215; THC, 2,130.
[b]See Appendix A for compiled data.
[c]Current AP-42 does not distinguish PC units by firing configuration, but by dry- versus wet-bottom.
[d]Includes utility boilers.
[e]Single data point.
[f]N.A. = Not available. No data available.

summarizes reported baseline NO_x, CO, and THC emission ranges for coal-fired boilers, and lists current AP-42 emission factors for comparison.[42-45] Industrial PC-fired boilers were among the highest emitters of NO_x. The emission level from a wet bottom cyclone fired industrial boiler was recorded at 1.12 lb/MMBtu. The data for dry-bottom boilers compiled for this study show a range in NO_x emissions from 0.46 to 0.89 lb/MMBtu. In comparison, AP-42 shows NO_x emissions for dry-bottom boilers in the range of 0.58 to 0.81 lb/MMBtu. However, the AP-42 factors include several utility boilers as no distinction is made among application for this class of boilers. For wet-bottom industrial PC-fired boilers, only one data point was obtained in this study.

Spreader stoker units averaged 0.60 lb/MMBtu (450 ppm) NO_x from a range of 0.40 to 1.08 lb/MMBtu (300 to 800 ppm). The other two stoker types, overfeed and underfeed, averaged 0.29 and 0.36 lb/MMBtu respectively (215 and 265 ppm). Emission data for spreader stokers compiled for this study show generally higher emission levels than suggested by current AP-42 emission factors.

FBC boilers are typically low NO_x emitters compared to PC-fired boilers and most spreader stokers, as the data indicate. This is due to several reasons, one of which is the lower combustion temperatures, as discussed in Chapter 3, and the use of staged combustion, as discussed in Section 4.1. As shown in Appendix A, available industrial coal-fired FBC data indicate an average NO_x emission level of 0.27 lb/MMBtu (200 ppm), for bubbling bed units, and 0.32 lb/MMBtu (240 ppm), for circulating FBC boilers. NO_x emissions ranged from 0.11 to 0.81 lb/MMBtu (80 to 600 ppm), for bubbling bed FBC units, and from 0.14 to 0.60 lb/MMBtu (105 to 445 ppm), for circulating FBC units. No AP-42 factors are currently available for industrial FBC boilers.

CO and THC emission data for all types of coal-fired boilers are highly variable. Average CO emission levels for PC wall-fired and spreader stoker units were generally in agreement with the AP-42 factors. For PC wall-fired units, CO ranged between 0 and 0.05 lb/MMBtu (0 to 60 ppm), while for spreader stokers, CO ranged between 0 and 0.53 lb/MMBtu (0 to 645 ppm). However, the measured CO emission levels for overfeed and underfeed stokers encompassed much wider ranges than reported in AP-42, ranging from 0 to 1.65 lb/MMBtu (0 to 2,000 ppm). Likewise, the THC emissions for overfeed stokers also differed greatly from the AP-42 values, averaging roughly 0.023 lb/MMBtu (50 ppm). Overfeed stoker THC data were available for only two units, however. This and the wide range of reported emission values indicates that available baseline CO and THC data from overfeed and underfeed stokers are generally inadequate. Circulating FBC boilers tend to have lower CO emissions than bubbling bed units, ranging from 0.02 to 0.25 lb/MMBtu (24 to 300 ppm). The bubbling bed units' CO levels were higher at 0.17 to 0.49 lb/MMBtu (205 to 595 ppm). The higher fluidization velocities and recirculation used in the circulating FBC units generally increase air/fuel mixing and combustion efficiency.

PC-fired boilers tend to emit less CO than stoker units. The data in Table 4-2 show CO emissions from PC wall-fired and tangential boilers ranging from 0 to 0.14 lb/MMBtu (0 to 170 ppm). CO emissions from the stoker units listed were higher, ranging from 0 to 1.65 lb/MMBtu (0 to 2,000 ppm). The use of pulverized coal allows better air/fuel mixing, increasing the combustion efficiency in the furnace which is evidenced by lower CO. In stoker units, however, coal combustion takes place on grates, and the combustion air supplied to the fuel bed generally does not allow as high combustion efficiencies. Spreader stokers, which burn some fuel in suspension and the remainder on grates, generally emit less CO than overfeed and underfeed stokers, although the CO data in Appendix A for underfeed stokers is suspect, as mentioned above. The combustion temperatures in stokers are also lower than in PC-fired units, contributing to higher levels of CO.

4.2.2 Oil-fired Boilers

T a b l e 4 - 3

TABLE 4-3. COMPARISON OF COMPILED UNCONTROLLED EMISSIONS DATA WITH AP-42 EMISSION FACTORS, OIL-FIRED BOILERS

Oil type and boiler capacity	NO_x, lb/MMBtu[a]		CO, lb/MMBtu[a]		THC, lb/MMBtu[a]	
	Compiled data[b]	AP-42	Compiled data	AP-42	Compiled data	AP-42
Residual Oil:						
Firetube units	0.21-0.39	0.37	0.0-0.023	0.033	0.002-0.014	0.011
Watertube units:						
10 to 100 MMBtu/hr	0.20-0.79	0.37	0.0-0.114	0.003	0.0-0.031	0.009
>100 MMBtu/hr	0.31-0.60	0.28-0.45	0.0-0.066	0.033	0.002-0.016	0.007
Distillate Oil:						
Firetube units	0.11-0.25	0.14	0.0-0.014	0.036	0.012[c]	0.004
Watertube units:						
10 to 100 MMBtu/hr	0.08-0.16	0.14	0.0-1.177	0.036	0.0-0.003	0.002
>100 MMBtu/hr	0.18-0.23	N.A.	0.0-0.837	N.A.	0.001-0.009	N.A.

[d]

gives baseline emission data for oil-fired ICI boilers, categorized by type of oil, boiler capacity, and heat transfer configuration. Residual-oil-fired boilers averaged approximately 0.36 lb/MMBtu (280 ppm) of NO_x, regardless of capacity, with NO_x ranging from 0.20 to 0.79 lb/MMBtu (160 to 625 ppm). Average baseline NO_x levels for distillate-oil-fired units were lower at approximately 0.15 lb/MMBtu (120 ppm). NO_x from the distillate-oil-fired units ranged from 0.08 to 0.25 lb/MMBtu (63 to 200 ppm). These data are in general agreement with AP-42 emission factors.

Reported CO emission levels for residual oil boilers were low, with the majority of units reporting CO levels below 0.030 lb/MMBtu (40 ppm). The baseline CO data for distillate-oil-fired watertube boilers, however, show wide variability, with units in the large capacity (greater than 100 MMBtu/hr) category emitting anywhere from 0 to 0.84 lb/MMBtu (0 to 1,090 ppm), while in the 10 to 100 MMBtu/hr capacity range, units emitted between 0 and 1.18 lb/MMBtu (0 and 1,530 ppm). CO emissions from distillate-oil-fired firetube units were low, under 0.015 lb/MMBtu (20 ppm). High levels of CO emissions from industrial boilers indicate, in part, poor burner tuning and maintenance levels for many of these units, which are often operated with little supervision and required maintenance.

Reported unburned THC emissions for residual-oil-fired boilers ranged from 0 to 0.031 lb/MMBtu (0 to 70 ppm), while for distillate-oil-fired units the range was between 0 and 0.022 lb/MMBtu (0 to 50 ppm). These are in general agreement with current AP-42 THC emission factors.

4.2.3 Natural-gas-fired Boilers

The data base compiled for this study indicated that baseline NO_x emission levels for natural-gas-fired firetube boilers ranged from 0.07 to 0.13 lb/MMBtu (58 to 109 ppm). For watertube units, NO_x ranged from 0.06 to 0.31 lb/MMBtu (50

TABLE 4-4. COMPARISON OF COMPILED UNCONTROLLED EMISSIONS DATA WITH AP-42 EMISSION FACTORS, NATURAL-GAS-FIRED BOILERS

Boiler type and capacity	NO_x, lb/MMBtu[a] Compiled data[b]	NO_x, lb/MMBtu[a] AP-42	CO, lb/MMBtu[a] Compiled data	CO, lb/MMBtu[a] AP-42	THC, lb/MMBtu[a] Compiled data	THC, lb/MMBtu[a] AP-42
Firetube units	0.07-0.13	0.095	0.0-0.784	0.019	0.004-0.117	0.0076
Watertube units:						
≤100 MMBtu/hr	0.06-0.31	0.13	0.0-1.449	0.033	0.0-0.023	0.0055
>100 MMBtu/hr	0.11-0.45	0.26-0.52	0.0-0.233	0.038	0.0-0.051	0.0016

[a]To convert to ppm @ 3% O_2, multiply by the following: NO_x, 835; CO, 1,370; THC, 2,400.
[b]See Appendix A for compiled data.

to 260 ppm) for units less than or equal to 100 MMBtu/hr capacity, and from 0.11 to 0.45 lb/MMBtu (95 to 375 ppm) for units greater than 100 MMBtu/hr capacity. As shown in Table 4-4, the low end of the emission range is well below the current AP-42 emission factors. This is due in part to emissions data obtained at reduced boiler load and emissions from smaller capacity boilers. As illustrated in Appendix A, NO_x emissions from natural-gas-fired boilers tend to increase with increasing boiler capacity.

Baseline CO emission levels show wide variability, ranging from 0 to 1.45 lb/MMBtu (0 to 1,990 ppm). The data indicate that for natural-gas-fired boilers less than or equal to 100 MMBtu/hr in capacity, CO emissions are often higher than in the current AP-42 emission factors. THC emissions ranged from 0 to 0.117 lb/MMBtu (0 to 280 ppm).

4.2.4 Nonfossil-fuel-fired Boilers

TABLE 4-5. AP-42 UNCONTROLLED EMISSION FACTORS FOR NONFOSSIL-FUEL-FIRED BOILERS

Fuel and equipment type	NO_x, lb/MMBtu	CO, lb/MMBtu	THC, lb/MMBtu
Wood Waste:			
Units with 50,000 to 400,000 lb/hr steam output (~70 to 580 MMBtu/hr heat input)	0.27 (0.17-0.30)[a]	0.38-4.52	0.16
Units with less than 50,000 lb/hr steam output (<70 MMBtu/hr heat input)	0.022 (0.010-0.050)[a]	0.38-4.52	0.16
Bagasse	0.15	N.A.[b]	N.A.
General Solid Waste:			
Mass burn municipal solid waste	0.4	0.24	0.012
Modular municipal solid waste	0.49	0.38	N.A.
Refuse derived fuel	0.36	0.26	N.A.

[a]Compiled data range, Appendix A.
[b]N.A. = Not available. No data available.

Table 4-5 shows AP-42 uncontrolled emission factors for wood waste-, bagasse-, and general solid waste-fired boilers. AP-42 NO_x emission factors for wood-fired units are 0.27 lb/MMBtu (190 ppm), for larger boilers, and 0.065 lb/MMBtu (50 ppm), for smaller units. The limited emissions data for wood-fired boilers in Appendix A show an NO_x range of 0.010 to 0.30 lb/MMBtu (7 to 220 ppm corrected to 3 percent O_2). Many of these boilers operate inefficiently with very high excess air levels, at times greater than 5 times the amount required for complete combustion. Bagasse-fired boilers generally emit low levels of NO_x, roughly 0.15 lb/MMBtu (105 ppm).

Boilers that burn general solid waste typically show higher NO_x levels than biomass-fueled units. The current AP-42 NO_x emission factors for MSW-fired units and RDF-fueled units are 0.4 to 0.49 lb/MMBtu (280 to 350 ppm) and

TABLE 4-6. AVERAGE NO_x EMISSIONS FROM MUNICIPAL WASTE COMBUSTORS[a]

Combustor type	Capacity (tons/day)	Uncontrolled NO_x emissions, ppm @ 7% O_2	
		Range	Average
Mass burn/refractory	56-375	59-240	155
Mass burn/rotary waterwall	100-165	146-165	156
Mass burn/waterwall	100-1,000	68-370	243
Refuse derived fuel (RDF)	300-1,000	195-345	270
Modular, excess air	50-120	105-280	140
Modular, starved air	36-90	86-280	215
All types	36-1,000	59-370	210

[a]Source of data: Reference 20.

0.36 lb/MMBtu (250 ppm), respectively. Uncontrolled CO emissions from these boilers are relatively high, 0.24 to 0.38 lb/MMBtu (280 to 440 ppm). Table 4-6 presents a detailed breakdown of NO_x emissions for municipal waste combustors (MWCs) by major equipment types. The data come from 52 combustion sources, each tested over a period of 1 to 3 hours. The average NO_x level of 210 ppm corrected to 7 percent O_2 translates into approximately 0.4 lb/MMBtu.

Nonfossil-fuel-fired FBC boilers burning wood waste, manure, and other agricultural waste byproducts had NO_x emissions ranging from 0.10 to 0.42 lb/MMBtu (70 to 300 ppm). This is lower than the coal-fired FBC emission levels because of the lower nitrogen contents of the nonfossil fuels.

AP-42 CO emission factors for all wood-fired boilers span a wide range, from 0.38 to 4.52 lb/MMBtu (440 to 5,200 ppm), due to several factors, including wood composition and boiler design type. Unburned THC emissions are significantly higher than levels measured in fossil-fuel-fired boilers. Reported AP-42 levels are 0.16 lb/MMBtu (327 ppm), on average.

4.2.5 Other ICI Boilers

There are limited baseline NO_x emissions data for small commercial and institutional boilers such as cast iron and tubeless units. This is due in part to the virtual lack of regulations on boilers in the capacity range below 10 MMBtu/hr (2.9 MWt), with the exception of recent rules adopted in Southern California in 1988 and 1990. Natural gas is the predominant fuel in this area for these combustion sources. Units of this capacity range, while numerous, have not historically been regulated due to their size; hence, little testing has been done to characterize their emissions.

Uncontrolled NO_x emissions from natural-gas-fired TEOR steam generators range between 0.09 and 0.13 lb/MMBtu (75 and 110 ppm), while for crude-oil-fired steam generators, baseline NO_x emissions generally range from 0.30 to 0.52 lb/MMBtu (240 to 400 ppm), depending on the nitrogen content of the crude oil.[46,47] Because there is less variability in the designs and configurations of TEOR steam generators, their NO_x emissions, for a given fuel, are usually less variable than other boilers.

4.3 SUMMARY

T a b l e 4 - 7

TABLE 4-7. SUMMARY OF BASELINE NO_x EMISSIONS

Fuel	Boiler type	Uncontrolled NO_x range, lb/MMBtu	Average, lb/MMBtu
Pulverized coal	Wall-fired	0.46-0.89	0.69
	Tangential	0.53-0.68	0.61
	Cyclone	1.12[a]	1.12
Coal	Spreader stoker	0.35-0.77	0.53
	Overfeed stoker	0.19-0.44	0.29
	Underfeed stoker	0.31-0.48	0.39
	Bubbling FBC	0.11-0.81	0.32
	Circulating FBC	0.14-0.60	0.31
Residual oil	Firetube	0.21-0.39	0.31
	Watertube:		
	10 to 100	0.20-0.79	0.36
	MMBtu/hr	0.31-0.60	0.38
	>100 MMBtu/hr		
Distillate oil	Firetube	0.11-0.25	0.17
	Watertube:		
	10 to 100	0.08-0.16	0.13
	MMBtu/hr	0.18-0.23	0.21
	>100 MMBtu/hr		
Crude oil	TEOR steam generator	0.30-0.52	0.46
Natural gas	Firetube	0.07-0.13	0.10
	Watertube:		
	≤100 MMBtu/hr	0.06-0.31	0.14
	>100 MMBtu/hr	0.11-0.45	0.26
	TEOR steam generator	0.09-0.13	0.12
Wood	<70 MMBtu/hr	0.010-0.050	0.022
	≥70 MMBtu/hr	0.17-0.30	0.24
Bagasse		0.15[b]	0.15
MSW	Mass burn	0.40[b]	0.40
	Modular	0.49[b]	0.49

summarizes baseline NO_x emissions for the major ICI boiler equipment categories discussed in Chapter 3. Coal-fired cyclone boilers generally emit the highest levels of NO_x, followed by PC wall-fired units, PC tangential boilers, coal-fired stokers, MSW-burning units, and crude-oil-fired TEOR steam generators. The lowest NO_x emissions are from boilers fired on natural gas, distillate oil, and wood fuels. NO_x emissions from coal-fired FBC and stoker boilers are generally lower than from PC-fired boiler types. In general, few data are available for ICI boilers less than 10 MMBtu/hr (2.9 MWt) in thermal capacity, which includes many fossil- and nonfossil-fuel-fired firetube units, cast iron units, and tubeless types.

With the exception of distillate-oil-fired units, the data show that for a given fuel, NO_x emissions from firetube boilers are lower than from watertube boilers. This is likely due to the fact that most watertube boilers have larger capacities than firetube units. As discussed above, as boiler capacity increases, NO_x emissions also increase in most cases.

Actual emissions from individual boilers vary widely by boiler heat release rate, fuel quality and type, boiler design type, and operating factors such as excess air level or load. Fuel type is a major factor influencing baseline NO_x levels. Listed in descending order of NO_x emissions, the fuels are pulverized coal, stoker coal, MSW, crude oil, residual oil, distillate oil, natural gas, wood, and bagasse. It is important to recognize that large variations in baseline (uncontrolled) NO_x levels are possible due to several boiler design and operational factors, including variations in the chemical makeup of the fuel. The most important fuel property that influences NO_x is the fuel nitrogen content, which determines to a large degree the amount of fuel NO_x that may be formed during combustion.

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5. NO_x CONTROL TECHNOLOGY EVALUATION

This chapter presents a survey of applicable control technologies to reduce NO_x emissions from ICI boilers. A review of current knowledge on the effectiveness, applicability, and limitations of specific control techniques is presented for each major fuel/equipment category discussed in Chapter 3. These categories are as follows:

- Coal-fired:
  - — PC, field-erected watertube
  - — Stoker coal, packaged and field-erected
  - — FBC
- Oil-fired:
  - — Residual oil, packaged and field-erected watertube
  - — Residual oil, packaged firetube
  - — Distillate oil, packaged and field-erected watertube
  - — Distillate oil, packaged firetube
  - — Crude oil, TEOR steam generator
- Natural-gas-fired:
  - — Packaged and field-erected watertube
  - — Packaged firetube
- Nonfossil-fuel-fired:
  - — Stoker-fed
  - — FBC

NO_x emissions data from more than 200 boilers were compiled from technical reports, NO_x control equipment manufacturer literature, and compliance and rule development records available at California's South Coast Air Quality Management District (SCAQMD). These data are tabulated in Appendix B. Most of the data were obtained from boilers operating in the ICI sectors. However, some small utility boilers were included in the data base of Appendix B because their heat input capacities are characteristic of large industrial boilers. The largest unit for which data are listed is a 1,250 MMBtu/hr PC-fired boiler. However, more than 90 percent of the units listed in Appendix B have heat capacities less than 400 MMBtu/hr. Most of the emissions data were obtained during short-term tests. Where noted, test data were collected from long-term tests based on 30-day continuous monitoring.

The control of NO_x emissions from existing ICI boilers can be accomplished either through combustion modification controls, flue gas treatment controls, or a combination of these technologies. Combustion modification NO_x controls such as SCA, LNB, and FGR modify the conditions under which combustion occurs to reduce NO_x formation. Flue gas treatment controls—principally SNCR and SCR — are applied downstream of the combustion chamber and are based upon chemical reduction of already formed NO_x in the flue gas. Other gas treatment controls, besides SNCR and SCR, that combine NO_x and SO_2 reduction are being developed. However, these controls are generally expensive and are currently targeted primarily for coal-fired utility boilers. Several demonstrations of these technologies are underway at electrical power plants under the U.S. Department of Energy (DOE) Clean Coal Technology (CCT) demonstration program and other programs sponsored by industry. With the exception of reburning and SCR-based technologies, these advanced controls are not discussed here because they are not likely to be applied to the ICI boiler population in the foreseeable future.

In this section, the main discussion of NO_x controls for ICI boilers is preceded by Section 5.1, which presents a brief overview of NO_x formation and basic concepts for its reduction by combustion modifications. Sections 5.2, 5.3, and 5.4 discuss combustion modification NO_x controls for coal-fired boilers, oil- and natural-gas-fired units, and nonfossil-fuel-fired boilers, respectively. Section 5.5 discusses flue gas treatment controls for ICI boilers.

5.1 PRINCIPLES OF NO_x FORMATION AND COMBUSTION MODIFICATION NO_x CONTROL

NO_x is formed primarily from the thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_x) or from the conversion of chemically bound nitrogen in the fuel (fuel NO_x). Additionally, a third type of NO_x, known as prompt NO, is often present, though to a lesser degree than fuel or thermal NO_x. For natural gas, distillate oil, and nonfossil fuel firing, nearly all NO_x emissions result from thermal fixation. With coal, residual oil, and crude oil firing, the proportion of fuel NO_x can be significant and, under certain boiler operating conditions, may be predominant.

The actual mechanisms for NO_x formation in a specific situation are dependent on the quantity of fuel bound nitrogen, if any, and the temperature and stoichiometry of the flame zone. Although the NO_x formation mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of fuel and combustion air. This rate of mixing may itself depend on fuel characteristics such as the atomization quality of liquid fuels or the particle fineness of solid fuels.[1] Additionally, thermal NO_x is greatly increased by increased residence time at high temperature, as mentioned earlier. Thus, primary combustion modification controls for both thermal and fuel NO_x typically rely on the following control strategies:

- Decrease primary flame zone O_2 level:
  - Decreased overall O_2 level
  - Controlled (delayed) mixing of fuel and air

- Use of fuel-rich primary flame zone

- **Decrease residence time at high temperature:**
  - **Decreased peak flame temperature:**
    - **Decreased adiabatic flame temperature through dilution**
    - **Decreased combustion intensity**
    - **Increased flame cooling**
    - **Controlled mixing of fuel and air**
    - **Use of fuel-rich primary flame zone**
  - **Decreased primary flame zone residence time**

T a b l e 5 - 1

TABLE 5-1. SUMMARY OF COMBUSTION MODIFICATION NO_x CONTROL APPROACHES

				Primary control techniques		
NO_x control approach	Control concept	Effect on thermal NO	Effect on fuel NO_x	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 N intermediaries to oxygen	LEA firing and OT	FGR	Low excess air burners
	Delayed mixing of fuel and air	Flame cooling and dilution during delayed mixing reduces peak temperature	Volatile fuel N reduces to N_2 in absence of oxygen	Burner adjustments and timing	LNB	Optimum burner/ firebox design
	Primary fuel-rich flame zone	Flame cooling in low O_2, low temperature primary zone reduces peak temperature	Volatile fuel N reduces to N_2 in absence of oxygen	BOOS; biased burner firing	OFA ports	Burner/firebox design for SCA
Decrease peak flame temperature	Decrease adiabatic flame temperature	Direct suppression of thermal NO_x mechanism	Minor	RAP	FGR, LNB, water injection	
	Decrease combustion intensity	Increased flame cooling; yields lower peak temperature	Minor direct effect; indirect effect on mixing	Load reduction	Enlarged firebox, increased burner spacing	Enlarged firebox, increased burner spacing
	Increase flame cooling; reduce residence time	Increased flame zone cooling; yields lower peak temperature	Minor	Burner tilt	WI or SI	Redesign heat transfer surface, firebox aerodynamics
Create secondary NO_x reducing zone	Use of low O_2 secondary combustion zone	Primary zone NO_x reduces to N_2 in absence of O_2	Primary zone NO_x reduces to N_2 in absence of O_2		OFA ports	Install reburning burners, OFA ports; replace tube wall panels, piping ductwork
Fuel switching	Burn higher quality fuel with low or no nitrogen content	Minor or slight increase because of higher temperature flame	Large NO_x reduction due to reduced fuel nitrogen conversion	Minor if dual-fuel capability exists		Only for installation of burner and fuel delivery system

shows the relationship between these control strategies and currently available combustion modification NO_x control techniques, which are categorized as either operational adjustments, hardware modifications, or techniques requiring major boiler redesign. The use of a secondary NO_x reduction combustion zone is also included in the table. This strategy is based on a secondary low oxygen reducing zone where NO_x is reduced to N_2. This is accomplished with secondary injection of fuel downstream of the primary combustion zone. This control technique is referred to as fuel staging, or reburning, and is discussed in greater detail in the following subsections. Additionally, fuel switching is also considered a viable combustion control because of the reduction or elimination of fuel NO_x with the burning or cofiring of cleaner fuels. Table 5-2

TABLE 5-2. EXPERIENCE WITH NO_x CONTROL TECHNIQUES ON ICI BOILERS

	Coal-fired			Oil-/natural-gas-fired			Nonfossil-fuel-fired		MSW-fired
NO_x control technique	Field-erected PC-fired	Stoker	FBC	Field-erected watertube	Packaged watertube	Packaged firetube	Stoker	FBC	Mass burn
BT/OT					X	X			
WI/SI					X	X			
SCA	X	X	X	X[a]	X	[b]	X[a]	X	X[a]
LNB	X			X	X	X			
FGR				X	X	X			X
NGR	X[b]								X[b]
SNCR	X[b]	X	X	X	X		X	X[b]	X
SCR	X[b]		X[b]	X[b]					

BT/OT = Burner tuning/oxygen trim
WI/SI = Water injection/steam injection
SCA = Staged combustion air, includes burners out of service (BOOS), biased firing, or overfire air (OFA)
LNB = Low-NO_x burners
FGR = Flue gas recirculation
NGR = Natural gas reburning
SNCR = Selective noncatalytic reduction
SCR = Selective catalytic reduction
MSW = Municipal solid waste

[a]SCA is designed primarily for control of smoke and combustible fuel rather than for NO_x control. Optimization of existing SCA (OFA) ports can lead to some NO_x reduction.

[b]Limited experience.

identifies combinations of NO_x controls and major boiler fuel type categories for which retrofit experience is available and documented.

Typically, the simplest boiler operational adjustments rely on the reduction of excess oxygen used in combustion, often referred to as BT/OT. Figure 5-1

NO t baseline operating conditions,

Figure 5-1. Effect of excess O_2 on $_x$ emissions for firetube boilers a shows the results of several tests to determine the effect of excess air levels on NO_x emissions from natural-gas and oil-fired firetube boilers.[2] These test results show that NO_x emissions can be reduced 10 to 15 percent when the stack excess oxygen concentration is lowered from 5 to 3 percent, measured in the flue gas on a dry basis. The actual amount of NO_x reduced by decreasing excess air varies significantly based on fuel and burner conditions. These reductions are due mainly to lower oxygen concentration in the flame, where NO_x formation is highest.

Although LEA operation can produce measurable reductions in NO_x, in this study, LEA will not be considered a separate control technology but a part of other retrofit technologies, since it accompanies the application of low NO_x combustion hardware such as low NO_x burners. Additionally, boiler operation with LEA is considered an integral part of good combustion air management that minimizes dry gas heat loss and maximizes boiler efficiency.[3] Therefore, most boilers should be operated on LEA regardless of whether NO_x reduction is an issue. However,

Figure 5-2. Changes in CO and NO_x emissions with reduced excess oxygen for a residual oil-fired watertube industrial boiler.[5]

excessive reduction in excess air can be accompanied by significant increases in CO. As illustrated in Figure 5-2, when excess air is reduced below a certain level, CO emissions increase exponentially. This rapid increase in CO is indicative of reduced mixing of fuel and air that results in a loss in combustion efficiency. Each boiler type has its own characteristic "knee" in the CO versus excess oxygen depending on several factors such as fuel type and burner maintenance. In general, along with LEA, the application of combustion modifications that reduce NO_x often result in reduced combustion efficiency (manifested by increased CO).

Another operational adjustment listed in Table 5-1, load reduction, when implemented, decreases the combustion intensity, which, in turn, decreases the peak flame temperature and the amount of thermal NO_x formed. However, test results have shown that with industrial boilers, there is only slight NO_x reduction available from this technique as the NO_x reduction effect of lowering the load is often tempered by the increase in excess air required at reduced load.[4] Higher excess air levels are often required with older single-burner units because high burner velocity promotes internal gas recirculation and stable combustion. Multiple-burner boilers generally provide a greater load turndown capability. Operating at reduced load is often infeasible for many ICI boilers because steam load is dictated by process steam demands and cannot be controlled independently. Reduced load on one boiler must be compensated for by increased load on another boiler, unless energy conservation measures permit a net reduction in fuel consumption. Therefore, reduced load operation is not considered as a viable retrofit NO_x control technology and will not be discussed further in this report.

Although the formations of fuel and thermal NO_x are generally predominant, a third type of NO_x, known as prompt NO, has also been reported. Prompt NO is so termed because of its early formation in the flame zone where the fuel and air first react, at temperatures too low to produce thermal NO_x. C_2 and CH radicals present in hydrocarbon flames are believed to be the primary sources of prompt NO because they react with atmospheric nitrogen to form precursors such as HCN and NH_3, which are rapidly oxidized to NO. The formation of prompt NO is greater in fuel-rich flames, and decreases with the increase in local O_2 concentrations.[6] Like fuel and thermal NO_x formation, prompt NO formation has been shown to be a function of flame temperature and stoichiometry. Prompt NO, however, generally accounts for smaller levels of NO_x than are due to thermal or fuel NO_x. For example, in utility boiler systems, prompt NO is assumed to be less than 50 ppm, while the thermal NO_x contribution can be as high as 125 to 200 ppm.[6]

In ICI boilers, prompt NO is believed to account for the first 15 to 20 ppm of NO_x formed during combustion.[7] The control of prompt NO is not typically targeted because of prompt NO's minor combustion to total NO_x. However, as NO_x limits for ICI boilers grow stricter, especially in areas such as the South Coast Air Basin of Southern California, the control of prompt NO is gaining more importance as evidenced by the development of new techniques, such as fuel induced recirculation, as discussed in Section 5.5.

The following sections discuss retrofit NO_x controls that are commercially available and the documented experience in NO_x reduction performance for each major ICI boiler and fuel category mentioned earlier.

5.2 COMBUSTION MODIFICATION NO_x CONTROLS FOR COAL-FIRED ICI BOILERS

Coal rank plays an important role in the NO_x reduction performance of combustion control technologies. Typically, controlled limits for low volatile bituminous coal differ from those attainable when burning high volatile subbituminous coal or lignites. However, the data available on coal-fired ICI boilers are insufficient to warrant a breakdown of achievable control levels based on coal type. Nearly all data compiled in this study were for boilers fired on bituminous coal. In comparison with ICI boilers fired on natural gas or oil, discussed in Section 5.3, there are relatively few reported emissions data for ICI coal-fired units operating with NO_x controls. This section includes data from 18 field operating PC-fired units, 11 stoker units, and 10 field operating FBC boilers. Large PC-fired industrial boilers are similar in design to utility boilers.[8] Thus, control techniques applicable to many utility boilers can often be applied to large industrial boilers as well. Data from three pilot-scale PC-fired facilities are also included in Appendix B, because their firing capacities are in the ICI boiler range and test results are considered indicative of the ICI boiler population. Additionally, combustion modification tests for bubbling bed FBC (BFBC) units include results obtained at pilot-scale facilities. Pilot-scale research on retrofit combustion modification NO_x control for FBC far exceeds published data on full-scale FBC installations. This is because commercial FBC boilers are relatively new, the majority having been installed after 1985, and many new units come already equipped with these controls. Little research on full-scale NO_x control retrofit technologies has been undertaken. Pilot-scale research provides an in-depth view into the mechanisms of NO_x formation and control in FBC. These data are used in this study to support conclusions with respect to NO_x reduction efficiencies and controlled limits.

Sections 5.2.1 through 5.2.3 summarize the combustion modification techniques applicable to the three major coal-fired industrial boiler types: PC, stokers, and FBC units.

5.2.1 Combustion Modification NO_x Controls for Pulverized Coal (PC)-fired ICI Boilers

Table 5-3

TABLE 5-3. COMBUSTION MODIFICATION NO_x CONTROLS FOR FULL-SCALE PC-FIRED INDUSTRIAL BOILERS

Control technique	Description of technique	Type of industrial boiler tested	% NO_x reduction	Controlled NO_x levels ppm @ 3% O_2, lb/MMBtu	Comments
SCA	Fuel-rich firing burners with secondary air injection	Wall-fired	15	691 (0.93)	OFA.
		Wall-fired	27	250 (0.34)	BOOS, reduced load.
		Wall-fired	39	651 (0.88)	OFA, reduced load.
		Tangential	25	211-280 (0.29-0.38)	
LNB	Wall-fired boiler — LNB with distributed air for controlled mixing	Wall-fired	49	280 (0.38)	Wall-fired boilers used staged air burners.
		Wall-fired	65	220 (0.30)	
	Tangential-fired boiler — uses air on wall concept for controlled mixing	Wall-fired	67	190-225 (0.26-0.34)	Tangential-fired boiler used low-NO_x concentric firing system (LNCFS).
		Wall-fired	49	370 (0.50)	
		Tangential	18	269 (0.36)	
Reburn with SCA (OFA)	Injection of coal, natural gas, or oil downstream of the burner area	Wall-fired w/coal reburn	N.A.[a]	170-250 (0.23-0.34)	SCA (OFA) used with reburn in all tests.
		Wall-fired w/coal reburn	N.A.	215-385 (0.29-0.52)	
		Tangential-fired w/oil reburn	30	167 (0.23)	
LNB+SCA	Combination of LNB and SCA control techniques	Wall-fired	42	180-360 (0.24-0.49)	Data for wall-fired units do not show benefit of adding SCA to LNB.
		Wall-fired	66	220-264 (0.30-0.36)	
		Wall-fired	N.A.	220-370 (0.30-0.50)	
		Wall-fired	60	275 (0.37)	
		Wall-fired	62	275 (0.37)	
		Wall-fired	65	275 (0.37)	
		Wall-fired	44	330 (0.45)	
		Tangential	55	148 (0.20)	

[a]N.A. = Not available. No baseline (uncontrolled) NO_x data available.

Note: References, and greater detail including baseline emissions, for these data are included in Appendix B.

summarizes test results of combustion modification techniques applicable to ICI PC-fired boilers. The table provides the ranges of percent NO_x reduction and the controlled NO_x levels achieved in these tests. More detailed data are contained in Appendix B. The following are brief discussions of each applicable control, the attained NO_x reduction efficiency attained and potential operational limits and impacts of retrofit on existing ICI boilers.

5.2.1.1 SCA

One approach to reducing NO_x, discussed in Section 5.1, is to decrease the primary flame zone oxygen level. The intent of SCA controls is to achieve a primary fuel-rich flame zone, where both fuel and thermal NO formations are suppressed, followed by an air-rich secondary zone where fuel combustion is completed. This is done by injecting air into the combustion zone in stages, rather than injecting all of it with the fuel through the burner. As a result, the primary flame zone becomes fuel-rich. SCA for PC-fired boilers includes two main techniques—OFA and BOOS.

OFA in PC-fired boilers typically involves the injection of secondary air into the furnace through OFA ports above the top burner level, coupled with a reduction in primary combustion airflow to the burners. OFA is applicable to both wall-fired and tangential-fired units. OFA is not applicable to cyclone boilers and other slagging furnaces because combustion staging significantly alters the heat release profile which changes the slagging rates and properties of the slag.[9] Additional duct work, furnace wall penetration or replacement, and extra fan capacity may be required when retrofitting boilers with OFA. To retrofit an existing PC-fired boiler with OFA involves installing OFA ports in the wall of the furnace and extending the burner windbox.

Data for two PC-fired boilers operating with and without OFA were obtained during this study. Using OFA, a 25 percent reduction in NO_x was achieved at the first unit, a tangential-fired unit at the Kerr-McGee Chemical Corporation facility in Trona, California. This unit was retrofitted with a separated OFA system in conjunction with an LNB system. Separated OFA refers to the use of a separate OFA windbox mounted above but not an integral part of the main windbox, as opposed to "close coupled" OFA which is injected within the main windbox just above the top elevation of fuel. Controlled NO_x emissions from this unit ranged from 211 to 280 ppm[a] (0.29 to 0.38 lb/MMBtu); this unit was also LNB-equipped. The second unit, a 325 MMBtu/hr wall-fired boiler, achieved 15 percent NO_x reduction using OFA. Controlled NO_x emissions from this unit were 690 ppm (0.93 lb/MMBtu). The NO_x reduction efficiencies of these two units are in agreement with OFA performance estimates for PC-fired utility boilers, which range between 15 and 30 percent NO_x reduction.[9,10]

Two principal design requirements for the installation of OFA ports in an existing PC-fired boiler must be met in order for the technology to effectively reduce NO_x without adversely affecting operation and equipment integrity. First, there must be sufficient height between the top row of burners and the furnace exit, not only to physically accommodate the OFA ports but also to provide adequate residence time for the primary stage NO to reduce to N_2, and adequate residence time for the second stage gases to achieve carbon burnout before exiting the furnace. In order to maximize NO_x reduction, previous studies have shown that the optimum location for OFA injection is 0.8 seconds (residence time of primary gas before OFA injection)

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[a]All ppm values in this study are referenced to 3 percent O_2.

above the top burner row.[11] Additionally, these studies have shown that to achieve carbon burnout, a minimum of 0.5 seconds residence time is required above the OFA ports.

The second design consideration for OFA retrofit is that good mixing of OFA with the primary combustion products must be achieved in order to ensure complete combustion and maximize NO_x reduction. Some important parameters affecting the mixing of OFA and first stage gases are OFA injection velocity, OFA port size, number, shape, and location; and degree of staging.[11] Thus, OFA port design is critical in determining the effectiveness of OFA in reducing NO_x. Additionally, OFA port design must, take into account the effects of port installation on the structural integrity of the boiler walls. Structural loads may be transferred from the firing walls to the side walls of the furnace, and OFA port shapes may be designed to minimize structural modifications. Given the magnitude of retrofitting PC-fired boilers with OFA and the moderate NO_x reduction efficiencies of 15 to 30 percent, OFA does not appear to be a primary retrofit technology for industrial sized PC-fired boilers. In general, the use of OFA is considered more feasible for new boilers than for retrofit applications.

The second major technique of staging combustion is BOOS, in which ideally all of the fuel flow is diverted from a selected number of burners to the remaining firing burners, keeping firing capacity constant. For maximum effectiveness, it is often the case that the top row of burners be set on air only, mimicking the operation of OFA discussed above (Figure 5-3). For PC-fired boilers, this means shutting down the pulverizer (mill), as fuel flow cannot be shut off at the individual burners as can be done with oil- and gas-fired units. This sometimes presents a problem when pulverizers serve burners located on two separate levels. With PC-firing, BOOS is commonly considered more of an operating practice for pulverizer maintenance than for

Figure 5-3. Effect of BOOS on emissions.

NO_x control, as pulverizers are routinely taken out of service because of maintenance requirements. The ability of boilers to operate units with one less pulverizer is generally very limited. For this reason, BOOS is not a popular control option for PC-fired units.

Data for two wall-fired units operating with one pulverizer out of service show NO_x reduction efficiencies of 27 and 39 percent. For one 230 MMBtu/hr boiler, NO_x was reduced from 340 ppm to 250 ppm (0.46 to 0.34 lb/MMBtu), while for a 260 MMBtu/hr unit, NO_x was reduced from 1,065 ppm to 651 ppm (1.44 to 0.88 lb/MMBtu).[12] However, in order to achieve the 39 percent reduction rate with the larger boiler, it was necessary for that particular boiler to be operated at 50 percent load reduction. Additionally, airflow could not be easily controlled to the individual burners so that burner swirl and coal air mixing were affected.[12] Operating at reduced load when using BOOS is often required for industrial sized units due to the limited number of burners and pulverizers.

In summary, data from three wall-fired boilers operating with SCA techniques of OFA and BOOS showed NO_x reduction ranges of 15 to 39 percent, while the single tangential-fired boiler with SCA showed 25 percent reduction (see Table 5-3). Although the two units operated with BOOS accounted for the higher NO_x reduction efficiencies of 27 and 39 percent, both had to be operated at significantly reduced load. Because industrial units have fewer burners and typically have more limited pulverizer-burner arrangements, BOOS is not considered a widely applicable control technique.

5.2.1.2 LNBs for PC-fired Boilers

LNBs, principally designed for utility boiler applications, have also been retrofitted to several large industrial boilers over the past decade. All major manufacturers of utility type boilers offer LNB for PC firing. Some of the larger manufacturers are ABB-Combustion Engineering, Babcock & Wilcox, Foster Wheeler, and Riley Stoker. In order to achieve low NO_x levels, LNBs basically incorporate into their design combustion techniques such as LEA, SCA, or recycling of combustion products. One of the most common types of LNB is the staged air burner.

Air staging in this type of LNB is accomplished by dividing the combustion air into two or more streams within the burner, delaying the mixing of fuel and air. A portion of the air is used to create a fuel-rich primary combustion zone where the fuel is only partially combusted. Secondary combustion of this unburned fuel occurs downstream of the primary burnout zone, where the remainder of burner air is injected. Peak combustion temperatures are also lower with the staged air burner because flames are elongated and some heat from the primary combustion stage is transferred to the boiler tubes prior to the completion of combustion. As discussed in Section 5.1, NO_x formation is reduced due to the lowering of the peak flame temperature, the delayed air/fuel mixing, and the low oxygen primary zone, where volatile fuel bound nitrogen compounds reduce to form N_2. Thus, both thermal and fuel NO_x are reduced.

One example of a staged air LNB is Foster Wheeler's Controlled Flow/Split Flame (CF/SF) LNB, which has been retrofitted to at least two

Figure 5-4. Foster Wheeler CF/SF LNB.[9]

industrial units. The CF/SF burner, shown in Figure 5-4, is an internally staged dual register burner. The outer register, where secondary air is injected, controls the overall flame shape while the inner register controls ignition at the burner throat and the air/fuel mixture in the primary substoichiometric region of the flame.[13] The newer version of the CF/SF burner also incorporates a split flame nozzle that forms four distinct coal streams. The result is that volatiles are driven off and are burned under more reducing conditions than would occur without the split flame nozzle.[9] CF/SF burners have been retrofitted to a 110,000 lb (steam)/hr (about 140 MMBtu/hr heat input) single wall-fired boiler at a Dupont chemical plant in Martinsville, Virginia. This unit, fired on bituminous coal, utilizes four CF/SF burners. Nearly 50 percent NO_x reduction was achieved, with average post-retrofit NO_x emissions of 280 ppm (0.38 lb/MMBtu). Post-retrofit CO emissions were 25 ppm. CF/SF burners were also retrofitted to a 125,000 lb/hr (about

150 MMBtu/hr heat input) four-burner, wall-fired steam boiler, where 65 percent NO_x reduction from baseline was achieved. Post-retrofit NO_x emissions at this site averaged 220 ppm (0.30 lb/MMBtu).[10] Figure 5-5 shows the NO_x reduction performance of these two units—labeled as numbers 4 and 5 in the figure—as well as several utility sized boilers.

Babcock & Wilcox's DRB-XCL burner also utilizes dual registers to achieve internal staged combustion. The major elements of this burner are its use of a conical diffuser to disperse the fuel, which produces a fuel-rich ring near the walls of the nozzle and a fuel-lean core. Reducing species are formed by partial oxidation of coal volatiles from primary air and limited secondary air. The reducing zone created in the fuel-lean core prevents NO_x formation

Figure 5-5. Performance of CF/SF LNB.[10]

during devolatilization, and the reducing species generated by oxidation decompose the formed NO_x as combustion continues.[14] In a DRB-XCL burner retrofit program to a 220,000 lb/hr (about 275 MMBtu/hr heat input) wall-fired boiler at the Neil Simpson Power Station in Wyoming, average NO_x emissions were reduced approximately 67 percent, when operating at the same excess air level. Controlled NO_x emissions for this unit ranged between 190 and 255 ppm (0.26 and 0.34 lb/MMBtu).[15]

Riley Stoker also manufactures a LNB for PC wall-fired units, known as the Controlled Combustion venturi (CCV™) burner. Figure 5-6

Figure 5-6. Riley low-NO_x CCV™ burner with secondary air diverter.[16]

depicts this burner, which uses a single register, unlike the dual register burners already discussed. The key element of this burner design is a patented venturi coal nozzle and low swirl coal spreader located in the center of the burner. The venturi nozzle concentrates fuel and air in the center of the coal nozzle, creating a fuel-rich zone. As in the CF/SF LNB, the coal/air mixture is divided into four distinct streams which then enter the furnace in a helical pattern. This produces very slow mixing of the coal with secondary air, which is injected through the single register. Devolatilization of the coal in the fuel-rich mixture occurs at the burner exit in a substoichiometric primary combustion zone, resulting in lower fuel NO_x formation. Thermal NO_x formation is suppressed by the reduction of peak flame temperature which results from the staged combustion.[16]

Riley's Tertiary Staged Venturi (TSV) burner is similar to the CCV burner but uses additional tertiary air and an advanced air staging (OFA) system for reducing NO_x emissions. This burner was developed for use on Riley's TURBO furnaces as well as downfired and arch fired boilers. These boilers are characterized by downward tilted burner firing, which lengthens the residence time of combustion products in the furnace. As such, the inherently long furnace retention time combined with gradual or distributed air/fuel mixing typically results in lower NO_x emissions than a conventional wall-fired unit operating at similar conditions with identical fuel.[16] TURBO furnaces are commonly used to burn low volatile coals such as anthracite, which require longer residence time for complete combustion. Figure 5-7 or turbo-furnace, down-fired and arch-

Figure 5-7. Riley low-NO_x TSV burner with advanced air staging f

shows a schematic of a TURBO furnace and the TSV LNB. Six TSV burners, in conjunction with OFA, were used in a 400,000 lb/hr (about 470 MMBtu/hr heat input) industrial TURBO furnace at a paper manufacturing facility in the Midwest. Firing bituminous coals, controlled NO_x emissions ranged between 220 and 370 ppm (0.30 and 0.50 lb/MMBtu).[17]

A different type of LNB has been developed for tangential-firing PC boilers, incorporated into the LNCFS system. The burner itself, manufactured by ABB Combustion

Engineering, is referred to as the Concentric Firing System (CFS). The CFS creates local staging by diverting a portion of secondary air horizontally away from the coal stream toward the furnace waterwall tubes. This delays the mixing of secondary air with the coal during the initial coal devolatilization stage of the combustion process, the stage when significant amounts of fuel nitrogen are typically released. Early ignition and devolatilization are achieved by using flame attachment coal nozzle tips. This early ignition and flame attachment feature provides greater control over volatile matter flame stoichiometry while enhancing flame stability and turndown.[18] The boiler at Kerr-McGee Chemical, mentioned in the above discussion on OFA, has been retrofitted with the LNCFS. Operating with the CFS LNB only, 18 percent NO_x reduction was achieved, to 269 ppm (0.36 lb/MMBtu). When the full LNCFS was used (CFS+OFA), NO_x reduction improved to 55 percent, with NO_x at 148 ppm or 0.20 lb/MMBtu.[18]

The LNBs discussed were originally designed for use on utility boilers. However, as evidenced by the above industrial experiences, in most cases the burners are also applicable to larger industrial PC-fired boilers. In some cases, as with the Neil Simpson unit retrofitted with B&W DRB-XCL burners, modifications to the burner walls were necessary to accommodate the larger LNBs. Furnace wall openings of the Neil Simpson unit were enlarged by replacing two furnace wall tube panels, each containing two burner throats.[15] In general, however, because there are already existing burner ports, LNB retrofits to PC-fired units do not require as much rework of the furnace walls as does installation of new OFA ports. However, significant modifications may be required for the windbox in order to improve air distribution with changes in the fuel ducting. Consideration must also be given to LNB flame characteristics such as shape and length to avoid flame impingement on the furnace walls. Because flames from staged combustion burners are often longer than from conventional burners, this may be a particularly important issue to small-volume furnaces.

NO_x emissions data for PC-fired units with LNB are summarized in Table 5-3. For four wall-fired units, NO_x reductions ranged between 49 and 67 percent, with controlled NO_x emissions of 190 to 370 ppm (0.26 to 0.50 lb/MMBtu). One tangential-fired unit experienced 18 percent reduction efficiency, with an NO_x level of 269 ppm (0.36 lb/MMBtu). Again, the minimum long-term NO_x level that can be reached with LNB retrofit depends on several factors, principally coal type, furnace dimension, boiler load, combustion air control, and boiler operating practice.

5.2.1.3 Reburn (Fuel Staging) with SCA, PC-fired Boilers

Reburning, also known as fuel staging, involves injecting a supplemental fuel into the main furnace above the primary combustion zone to produce a secondary combustion zone where a reducing atmosphere exists. The general idea is to provide a chemical path for the primary zone NO to convert to N_2 rather than NO_2. Hydrocarbon radicals formed during secondary combustion provide this chemical path; hence, some of the NO_x created in the primary combustion zone is reduced to molecular nitrogen. OFA is utilized in conjunction with reburning to complete combustion of supplemental fuel. Domestic experience in the ICI sector is nonexistent.

Reburning has been chiefly developed and applied to larger industrial boilers in Japan. Mitsubishi Heavy Industries (MHI) has developed the Mitsubishi Advanced Combustion Technology (MACT) process utilizing oil as the reburn fuel. Use of MACT in a 700,000 lb/hr (about 825 MMBtu/hr heat input) tangential-fired boiler at Taio Paper Company in Japan resulted in a 30-percent NO_x reduction to a level of 167 ppm (0.23 lb/MMBtu), during bituminous coal firing.[19] MACT has been used in at least eight other wall or tangential coal-fired industrial boilers in Japan, with capacities ranging between 170 and 200 MMBtu/hr. In the United States, except for several utility demonstration projects and pilot scale test programs, reburning has not been applied to any commercial facility. [20] The results from one pilot-scale test are included in Appendix B—a test conducted at the 6 MMBtu/hr B&W Small Boiler Simulator facility.

This test analyzed the NO_x reduction efficiencies of reburning in a cyclone furnace with three types of fuel—bituminous coal, residual oil, and natural gas. With the main burners of the furnace firing bituminous coal, NO_x reduction efficiencies of 54 to 65 percent were achieved. [21] Results showed that reburning with natural gas produced the best NO_x reduction and the lowest average NO_x emissions, between 235 and 420 ppm (0.32 and 0.57 lb/MMBtu). This was due to the low nitrogen content of natural gas. Use of natural gas as the reburning fuel also brings the added benefit of reducing SO_2 emissions. The use of coal as a reburn fuel resulted in the lowest NO_x removal efficiency. In general, the data suggest that the cleaner the reburn fuel, the more efficient the reburn process.

Prior to this pilot test, B&W had conducted a feasibility study of applying natural gas reburn technology to cyclone-fired boilers. Cyclone boilers are currently being used in both the utility and industrial sectors. Because cyclone boilers have a unique configuration that prevents the application of standard low-NO_x burner technology—combustion occurs within a water-cooled horizontally-tilted cylinder attached to the outside of the furnace—this study sought to assess the feasibility of retrofitting existing cyclone furnaces with reburn controls. Reburning technology prior to the pilot scale test had never been applied to cyclone-equipped boilers. From an industrial boiler standpoint, the most important result of this study was the conclusion that in general, it is unfeasible to retrofit cyclone boilers below 80 MWe capacity with natural gas reburn controls, which essentially excludes all but the largest industrial cyclones.[16] The reason for this is that cyclone units below this size range generally have insufficient furnace height to allow sufficient residence time for reburn and OFA to work effectively. For a 41 MWe boiler, it was determined that the furnace would have to be extended by over 50 percent, which is impractical.[16] From this study, it appears that gas reburn is most applicable to larger existing cyclone boilers.

Thus, reburn technology is generally not applicable for retrofit to smaller cyclone boilers in the ICI sector because of insufficient furnace heights. For wall-fired and tangential-fired units, however, natural gas or coal reburn may emerge as a viable NO_x control technique for industrial PC-fired units as indicated by utility demonstrations.

5.2.1.4 LNB with SCA

The use of LNBs with SCA (OFA) in PC-fired boilers combines the effects of staged burner combustion and staged furnace combustion. ABB-CE, B&W, and Foster Wheeler offer OFA with LNB systems for retrofit. OFA is an integral part of ABB-CE's LNCFS NO_x reduction package for tangential-fired boilers, and in fact is responsible for the majority of NO_x reduction achieved.[18] As mentioned earlier, in the Kerr-McGee boiler in California, 55 percent NO_x reduction was achieved with the LNCFS, combining OFA and the CFS LNB. Note that the NO_x reduction efficiencies for combined control techniques are not additive.

Emissions data for seven wall-fired units using LNB and SCA controls show NO_x reductions in the range of 42 to 66 percent (see Table 5-3). No baseline data were reported, however, for one of the seven units. This reduction range reflects LNB and SCA performance for six boilers. The 66 percent reduction efficiency was obtained on an industrial size 250 MMBtu/hr unit at Western Illinois Power Cooperative's (WIPCO) Pearl Station. Field tests showed that under normal operation, 50 percent reduction of NO_x was typically achieved while under carefully controlled conditions, the 66 percent NO_x reduction level was possible. Retrofit of four distributed mixing burners with tertiary air ports required replacement of the front wall, modifications to the windbox, replacement of the burner management system, and provision of an alternative support structure for the hopper.[22] Because of the extensive boiler modification required for this particular LNB+SCA system, it is generally intended for use in new boiler designs rather than in retrofit applications.

Controlled NO_x levels for these wall-fired units ranged between 180 and 370 ppm (0.24 and 0.50 lb/MMBtu). Generally, on utility boilers, NO_x reduction performance for this combination of controls can reach as high as 65 or 70 percent.[23] Thus, for large (greater than 250 MMBtu/hr) industrial boilers, this may be the maximum reduction achievable as well. However, insufficient data for PC-fired ICI boilers using LNB and SCA precludes reaching any definitive conclusions.

5.2.2 Combustion Modification NO_x Controls for Stoker Coal-fired ICI Boilers

The two most commonly used combustion modification NO_x controls for stoker coal-fired ICI boilers are SCA and FGR. A third combustion modification, RAP, has not been utilized as often. Gas cofiring with burners above the grate is under active evaluation. Table 5-4

TABLE 5-4. COMBUSTION MODIFICATION NO_x CONTROLS FOR STOKER COAL-FIRED INDUSTRIAL BOILERS

Control technique	Description of technique	Type of Stoker boiler tested	% NO_x reduction	Controlled NO_x levels ppm @ 3% O_2, lb/MMBtu	Comments
SCA	Reduction of combustion air under the grate and increase of overfire air flow	Spreader	6	350 (0.47)	Danger of grate overheating, clinker formation, corrosion, high CO emissions.
		Spreader	10	353 (0.48)	
		Spreader	26	237 (0.32)	
		Spreader	31	263 (0.36)	
		Spreader	35	369 (0.50)	
		Spreader	N.A.[a]	230-387 (0.31-0.52)	
		Overfeed	-1	166 (0.22)	
		Overfeed	N.A.	172-202 (0.23-0.27)	
FGR+SCA	Recirculation and mixing of stack flue gas with the undergrate or overgrate combustion air	Spreader	0	300-345 (0.41-0.47)	FGR primarily leads to NO_x reduction by lowering achievable excess O_2.
		Spreader	13	350 (0.47)	
		Spreader	60	140 (0.19)	
RAP	Reduce temperature of preheated combustion air	Spreader	32	219 (0.30)	Limited applicability to larger units with air preheaters. Reduces boiler efficiency.

summarizes the data compiled for stoker coal-fired ICI boilers with combustion modification NO_x controls. Available data are limited to 12 stoker units. The data show wide variability in NO_x control efficiency, ranging from -1 to 60 percent reduction. Controlled NO_x levels for spreader stokers with SCA ranged from 230 to 387 ppm (0.31 to 0.52 lb/MMBtu), while for spreaders with FGR+SCA, NO_x ranged from 140 to 350 ppm (0.19 to 0.47 lb/MMBtu). Data were available for only one spreader unit with RAP. This unit had a controlled NO_x level of 219 ppm (0.30 lb/MMBtu).

5.2.2.1 SCA

Stoker units naturally operate with a form of staged combustion due to their design. As the coal is fed onto the grate, volatile matter is driven from the fuel bed and burned above the bed level. The coal solids remaining are subsequently burned on a bed with lower combustion intensity. Because of this natural staging, NO_x emissions from stoker units are generally lower than those from PC-fired units of the same size.[24] As presented in Appendix A, uncontrolled NO_x emissions ranged from 341 to 659 ppm (0.46 to 30.89 lb/MMBtu) during nine tests of PC wall- and tangential-fired units ranging in size from 100 to 200 MMBtu/hr. For eight tests of similarly sized stoker units, uncontrolled NO_x levels ranged from 158 to 443 ppm (0.21 to 0.60 lb/MMBtu).

The availability of existing OFA ports offers the opportunity for increased air staging. Additional staging can be achieved by injecting more overfire air above the fuel bed while reducing the undergrate airflow. Using OFA, the boilers for which data were collected show a NO_x reduction range of zero to 35 percent, averaging 17 percent reduction. In two boilers, OFA did not affect NO_x. Controlled NO_x emissions ranged from 230 to 400 ppm (0.31 and 0.54 lb/MMBtu) for the spreader stokers tested and 166 to 202 ppm (0.22 to 0.27 lb/MMBtu) for the overfeed stokers. No data were collected for underfeed stoker type boilers in this study.

Many older stokers incorporate OFA ports as smoke control devices. Therefore, these OFA ports may not be optimally located for NO_x control purposes. For example, in one test, injection of OFA through oil burner ports high above the grate reduced NO_x by 25 percent. When OFA was injected through the actual OFA ports located closer to the grate, only 10 percent reduction was achieved.[25]

Because the use of SCA in stoker boilers requires reduced undergrate air flow for staging, there are certain operational limitations involved. First, with the exception of a water-cooled vibrating grate, the only grate cooling mechanism used in stoker units is the flow of combustion air under the grate. During SCA operation, if undergrate air is lowered too much, the grate can overheat. There is also the possibility of creating local reducing zones with low oxygen which may form harmful corrosion products.[25] Still another problem that may arise from reduced undergrate air firing is the formation of clinkers. For coals with low ash fusion temperatures, significant clinker formation can be caused by the excessively high bed temperatures resulting from combustion with insufficient amounts of excess air.[26] Thus, a minimum amount of undergrate air must be used to provide adequate mixing and cooling. As such, there is a limit to the degree of OFA used in stoker boilers and consequently achievable NO_x reduction.

5.2.2.2 FGR with SCA

The requirements of mixing and cooling when using SCA can be met to a certain degree by recirculating a portion of the flue gas to the furnace and mixing it with the fresh combustion air. One effect of FGR in stoker units is that recirculated flue gas dilutes the oxygen concentration of the combustion air, allowing boiler operators to lower the overall excess air level which consequently reduces formation of NO_x. FGR is primarily considered a thermal NO_x control technique, reducing NO_x by lowering the peak furnace temperature. Because temperatures in ICI stoker units are lower than in PC-fired units, thermal NO_x control has not been as high a priority for stoker coal-fired boilers.

Figure 5-8

Figure 5-8. Schematic diagram of stoker with FGR. [27]

Figure 5-9. FGR effects on excess O_2.[27]

depicts a schematic of a stoker boiler equipped with FGR. Flue gas is drawn from the entrance of the stack and mixed with the undergrate combustion air. This type of FGR system was used in a 100,000 lb/hr (125 MMBtu/hr heat input) spreader stoker fired on bituminous coal. Test results from this boiler illustrate the effect of FGR on allowable excess oxygen and consequently, its effects on NO_x. In this unit, minimum excess oxygen levels and boiler load were restricted by opacity. To prevent opacity from reaching unacceptable levels, pre-retrofit load was limited to 80 percent of capacity and the boiler was operated at minimum stack excess oxygen of 8 percent. Figure 5-9 illustrates the effect of adding FGR to the boiler on allowable excess oxygen. After retrofit, boiler operators could lower excess oxygen levels to as low as 3 percent, keeping opacity the same as pre-retrofit levels. Not only does this represent a significant increase in boiler efficiency, but because NO_x is dependent on the excess oxygen used, lower emission levels were achieved, as shown in Figure 5-10. Thus, at a constant load of 80 percent, using FGR allowed the excess oxygen level to be reduced from 8 percent to approximately 3.5 percent, resulting in a reduction of NO_x by as much as 60 percent. A controlled emission level of 140 ppm (0.19 lb/MMBtu) was measured.[27] Another spreader stoker unit also displayed similar characteristics when operated with FGR, experiencing 13 percent NO_x reduction. Less reduction was achieved in this unit because excess air was not reduced as much.[26] In a third spreader stoker, however, no NO_x reduction was achieved using FGR, since initial excess oxygen levels were already quite low at 4 percent. FGR did not allow the boiler operators to reduce oxygen concentration, thus resulting in no measurable change in NO_x emissions.[26]

FGR was also applied to an overfeed stoker, but test results showed the use of FGR on this boiler to be unsatisfactory. Unlike spreader stokers which utilize the entire length of the grate for primary combustion, overfeed stoker units often have shorter active grate combustion zones depending on the location of the furnace wall arch over the grate, as shown in Figure 5-11

Figure 5-10. NO emissions versus excess O_2, active stoker combustion zone.

Figure 5-11. Overfeed stokers with FGR.[26,27]

. The particular boiler tested had a very short active combustion zone limited to the front half of the grate, due to the location of its furnace arch. The lowering of excess oxygen in the combustion air with FGR caused the active combustion zone to lengthen beyond the furnace arch, resulting in flame quenching and impingement on the arch. Also, FGR caused unstable combustion at the front portion of the active combustion zone.[26] In contrast with overfeed

stokers, FGR's effect of lengthening the active combustion zone in spreader stokers is of little consequence because the length required for the coal to burn out is much shorter than the length of the fuel bed. [27]

In summary, the use of FGR in stoker coal-fired ICI boilers has been demonstrated successfully in a limited number of boilers. NO_x reduction on two of the spreader stokers ranged from 13 to 60 percent. For the overfeed stoker unit, FGR caused unsatisfactory combustion conditions including flame quenching, flame impingement, and unstable combustion. The primary effect of FGR is to allow reduction of the excess oxygen level of the boiler, thereby reducing NO_x emissions and increasing boiler efficiency. FGR has also been shown to be beneficial in dealing with grate overheating.

5.2.2.3 RAP

RAP is limited to stokers equipped with combustion air preheaters. Usually only larger stokers with heat input capacities greater than 100 MMBtu/hr tend to have air preheaters. [28] RAP is not commonly used in such boilers because significant losses in boiler efficiency occur when the flue gas bypasses the air preheaters. In bypassing the preheaters, recoverable heat from the flue gas is not utilized and the temperature of the flue gas leaving the stack is increased unless major equipment modifications are made to the heat transfer surfaces. Available emissions data for RAP is limited to one spreader stoker boiler. Reduction of preheated combustion air temperature reduced NO_x by 32 percent. [28] Because of its limited applicability and negative effects on boiler efficiency, RAP is not considered a primary NO_x control method for stoker coal-fired ICI boilers.

5.2.2.4 Natural Gas Cofiring

Gas cofiring for stokers has only recently been investigated for improving boiler operation and reducing emissions. The technique involves burning a fraction of the total fuel, typically 5 to 15 percent, as natural gas above the grate. The cofiring improves boiler efficiency through reduced excess air, lower LOI in ash, and reduced flue gas exit temperature. The reduced excess air lowers NO_x levels. Recent tests on a spreader stoker have shown that NO_x emissions can be reduced by 20 to 25 percent.[29] More tests are planned.

5.2.3 Combustion Modification NO_x Controls for Coal-fired Fluidized-bed Combustion (FBC) ICI Boilers

In FBC boilers, the fuel is burned at low combustion temperatures, 790 to 900°C (1,450 to 1,650°F). At these low temperatures, NO_x formation is limited to the conversion of fuel nitrogen (fuel NO_x). At these low combustion temperatures, studies have shown little correlation between temperature and NO_x emission, thus combustion modification NO_x controls for FBC boilers focus on the control of fuel NO_x.[30,31] The principal combustion modification controls used for NO_x reduction in FBC boilers are staged combustion, control of bed temperature, and FGR. Table 5-5

TABLE 5-5. NO_x CONTROL TECHNIQUES FOR FBC BOILERS[30]

Control technique	Control mechanism	Application limits	Potential limitations
SCA	Staged combustion reduces oxygen for conversion of volatile nitrogen; promotes heterogeneous NO reduction with CO over char; causes increase in CaO char concentration in dense bed	Secondary/primary air ratio limited by fluidization requirements in FBC and reheat steam temperatures	Increase in CO emissions, carbon loss, and reduced sulfur capture primarily in FBC under severe staging (SR_1<0.8); excessive steam temperature
Control of dense bed temperature	Lower bed temperature reduces volatile nitrogen conversion and increases heterogeneous reduction between char and formed NO	Bed temperature is tied to fuel reactivity (ratio of volatiles/fixed carbon). Higher bed temperature or an increase in residence time is required for low reactivity coal. Optimum temperature is between 1,500 and 1,600°F for high sulfur capture.	Excessive temperature reduction increases CO and carbon loss (efficiency reduction), necessitating longer gas residence time for char combustion, especially with low reactivity coal

summarizes the performance and process requirements of these three techniques. Each of these control approaches is discussed in the following subsections. Process variables that impact NO_x formation are also discussed. As indicated earlier, most combustion modification research for FBC has been conducted on pilot scale facilities. Available data from full-scale units are limited; thus, the pilot-scale data offer the greatest insights into the control mechanisms and NO_x reduction potential of these controls.

5.2.3.1 SCA in Coal-fired FBC Boilers

SCA is widely accepted as the most effective combustion modification control for reducing NO_x from FBC boilers. Nearly all new commercial FBC units come equipped with overfire air ports along the free board section of the combustor to inject secondary and sometimes tertiary combustion air.[32] The primary objective of using SCA in an FBC boiler is to reduce NO_x formation by operating the fluidized bed of a bubbling FBC (BFBC) boiler, or the lower portion of a circulating FBC (CFBC) boiler under substoichiometric conditions. Additionally, secondary air injection at high levels in the furnace help ensure good carbon, CO, and hydrocarbon burnout.[33]

SCA is generally more effective for high to medium volatile coals than for low volatile fuels such as anthracite. High-volatile-content fuels, also described as high-reactivity fuels (reactivity being defined as the ratio of volatile matter to fixed carbon), contain larger amounts of fuel nitrogen in the volatile matter. When introduced to the combustor, these fuels undergo thermal decomposition and quickly release the organically bound nitrogen in the volatile matter, whereupon it combines to form NO in the presence of oxygen. By using SCA, which lowers the excess oxygen level in the dense portion of the fluidized bed, this conversion of volatile nitrogen to NO is suppressed. For lower volatile fuels, the amount of fuel nitrogen in the volatile fraction is also lower. For these fuels, conversion of char nitrogen to

Figure 5-12. Effect of SCA on NO_x and CO emissions, Chalmers University.[34]

NO_x dominates the overall fuel NO_x, and nitrogen is released at a muc h slower rate which is a function of the char combustion rate. Thus, SCA has less of a NO_x reducing effect for these lower reactivity fuels. [33]

NO_x reductions due to SCA in coal-fired FBC boilers have bee n reported on the order of 40 percen t for full scale units in the ICI sector. [34] For example, Figure 5-12 shows th e effects of SCA on NO_x and CO emissions for a 16 MWe BFBC boiler firing bituminous coal at

Chalmers University in Sweden. Keeping the total excess air between 20 and 23 percent, NO_x was reduced 40 percent from 125 to 75 ppm (0.17 to 0.10 lb/MMBtu) when 20 percent of the total air supply was injected through OFA ports. When the proportion of air injected as secondary air was increased to 25 percent, NO_x reduction from baseline was only slightly more than 40 percent. Meanwhile, CO emissions more than doubled from a baseline level of 270 ppm to 565 ppm.[34] NO_x reduction efficiencies of as high as 60 to 70 percent have also been reported in several pilot-scale tests.[32] For instance, at the TNO Research facility in Sweden, tests conducted on a 14 MMBtu/hr BFBC unit with SCA showed 67 percent NO_x reduction.[35] Pilot-scale tests, however, generally involve much higher amounts of staging—i.e., lower primary zone stoichiometries—than are practically achieved in full scale units, due to concerns over combustion efficiency, corrosion of watertubes, and refractory integrity.[32]

Besides the amount of SCA used and fuel type, the location of the OFA ports can also have a significant impact on NO_x reduction. Several tests have shown that the greater the distance to the secondary air ports, the greater is the NO suppression.[36-38] This is due to the increased residence time between the primary and secondary air injection stages. However, there are practical limits on how high in the freeboard the OFA can be introduced without affecting combustion efficiency, corrosion, and steam temperature control. Additionally, because of the different rates of fuel nitrogen conversion for low- or high-reactivity coals mentioned earlier, in order to maximize NO_x reduction the optimal secondary air location must be specifically designed for each type of fuel used, as well as for fuel with different size distributions.

Reported NO_x emission levels for FBC units with SCA have been highly variable depending on the capacity, fuel type, OFA port location, and design type (i.e., CFBC or BFBC) of the boilers. For instance, controlled NO_x

TABLE 5-6. REPORTED CONTROLLED NO_x EMISSION LEVELS, FULL-SCALE, COAL-FIRED FBC BOILERS

Control technique	FBC boiler type	Controlled NO_x level, ppm @ 3% O_2, lb/MMBtu
SCA	Circulating	39-245 (0.05-0.33)
	Circulating	51-335 (0.07-0.45)
	Circulating	100 (0.14)
	Circulating	103-155 (0.14-0.21)
	Circulating	280 (0.38)
	Bubbling bed	75 (0.10)
	Dual bubbling bed	100 (0.14)
FGR+SCA	Circulating	90-116 (0.12-0.16)
	Circulating	100-115 (0.14-0.16)

emissions from a 222 MMBtu/hr CFBC unit fired on bituminous coal ranged from 51 to 335 ppm (0.07 to 0.45 lb/MMBtu), while an identical unit fired on brown coal emitted 103 to 155 ppm (0.14 to 0.21 lb/MMBtu) of NO_x.[33] Another CFBC unit, rated at 140 MMBtu/hr and firing bituminous coal, emitted 280 ppm (0.38 lb/MMBtu) NO_x.[39] Data obtained for full-scale units showed controlled NO_x emissions ranging from 39 to 335 ppm for five CFBC boilers, and 75 to 100 ppm for two BFBC units. These data are tabulated in Table 5-6. Other sources have reported practical NO_x limits achieved with SCA to be between 80 and 130 ppm (0.11 and 0.18 lb/MMBtu) for CFBC and 100 to 200 ppm (0.14 to 0.27 lb/MMBtu) for BFBC boilers.[32]

5.2.3.2 Bed Temperature Control

The temperature within FBC boilers is determined primarily by the combustion requirements of the coal and the temperature required to maximize sulfur capture. The optimum temperature range for sulfur capture is 800 and 850 °C (1,470 to 1,560 °F).[40] In this range, the sulfur capture can be as high as 98 percent depending on the Ca/S ratio, sorbent reactivity and size, residence time, and ash recirculation rate.

Low bed combustion temperature lowers the formation of thermal NO_x. The effects of bed temperature on NO_x formation for a pilot-scale BFBC was reported to be about 2 to 3 ppm NO_x reduction for every 10 °C in temperature drop.[41] Figure 5-13 shows this effect, as well as the bed temperature's effect on CO emissions, which increase as temperature is lowered. The effects of

Figure 5-13. NO_x and CO versus bed temperature, pilot-scale BFBC.[41]

Figure 5-14. Effect of bed temperature on NO_x and CO, Chalmers University.[34]

bed temperature on NO_x and CO are shown in Figure 5-14 for the full-scale 16 MWe BFBC test unit at Chalmers University, showing 54 percent NO_x reduction when bed temperature was lowered from 880 to 780 °C (1,620 to 1,440°F). This equates to 13 ppm NO_x reduction per 10 °C temperature drop, a greater effect than was experienced with the pilot-scale unit. The difference in temperature dependence is most likely due to differences in furnace geometry and the type of coal used. Unlike the pilot-scale results shown in Figure 5-13, CO emissions at Chalmers did not increase with lowered bed temperature, remaining fairly constant at 270 ppm.[34] For a CFBC pilot unit, the effect of bed temperature on NO_x reduction was 8 ppm reduction per 10 °C.[42] Similarly, tests conducted at the former 110 MWe CFBC Nuclear Power Station showed roughly 10 ppm NO_x reduction per 10 °C temperature drop in the bed.[43]

Although lowering bed temperature has shown measurable reductions in NO_x, the lowering of bed and freeboard gas temperatures is not considered a primary NO_x control method. Steam temperature control, sulfur capture, and combustion efficiency usually do not allow bed and freeboard temperatures much lower than 815 °C (1,500 °F).[40] Under staged combustion, lower bed and freeboard temperatures are not generally desired since temperature affects the rate of gas-solid catalytic reactions intended to reduce NO_x.

5.2.3.3 FGR in Coal-fired FBC Boilers

FGR through the air distribution plate in a FBC boiler is not a widely accepted NO_x control technology, or one that has received much research effort to date.[40] In general, FGR allows operation with reduced combustion oxygen levels in the dense portion of the bed, contributing to NO_x reduction. To some extent, FGR also reduces thermal NO_x by lowering the peak combustion temperature. When FGR is used in combination with SCA, the primary mechanism that results in NO_x reduction is the gas temperature drop in the lower portion of the bed combined with a localized reduction in the oxygen concentration. However, thermal NO_x reduction in FBC is not as high a priority as the control of fuel NO_x. FGR application in FBC has been limited for the most part to pilot scale research. However, test results reported for two full scale CFBC units with SCA and FGR show a marked NO_x reduction efficiency of nearly 70 percent for FGR rates in excess of 30 percent. Controlled NO_x emissions ranged from 90 to 116 ppm (0.12 to 0.16 lb/MMBtu).[33] These data are listed in Table 5-6 and in Appendix B.

Several disadvantages of applying FGR to CFBC units have been identified[33]:

- Combustion efficiency and sulfur retention are generally lowered
- Larger combustor, backpassing boiler chamber, greater bag house capacity, and fan size are required
- Greater power consumption is required for additional equipment
- Boiler capital and operating costs are increased

Because of these potential adverse side effects, FGR is generally not considered a viable NO_x control technology for FBC boilers.[40]

5.2.3.4 Other Process Variables Affecting NO_x

The actual NO_x levels achieved by combustion modification or other controls will depend on several process variables which can influence NO_x emissions in FBC boilers. These variables can be grouped into three major categories: chemical and physical coal properties, chemical and physical properties of sorbent and bed material, and FBC operational variables.

Coal Properties

Two important coal properties are the reactivity and size. Lower reactivity coals emit lower levels of NO_x under both staged and unstaged conditions, due to the catalytic properties of char in reducing formed NO, and because of the rapid oxidation of volatile nitrogen to NO.[43] However, coals with low reactivity, and, hence, lower volatile content, are generally burned less efficiently in FBC boilers than high reactivity coals. Also, SCA is not as effective in reducing NO_x when low reactivity coals are burned, as discussed in Section 5.2.3.1. Generally, an increase in coal size tends to reduce NO_x and improve thermal efficiency. NO_x is reduced due to the reduced surface area of the char which acts as a catalyst in NH_3 oxidation to NO in the presence of excess oxygen.[44] Thermal efficiency tends to improve as a result of the lower levels of elutriated coal leaving the bed.[44]

NO_x emissions also depend on the nitrogen content of the volatile fraction of the coal being used, generally increasing as this nitrogen content increases. Under staged combustion, fuel nitrogen conversion is significantly reduced from typically 6 to 7 percent to as low as 1.5 to 2.5 percent, depending on the degree of staging. Thus, the effect of nitrogen content on NO_x emissions will tend to be less under staged conditions than for unstaged combustion.

The sulfur content of the coal does not in itself have any effect on NO_x emissions. Indirectly, however, the use of high-sulfur coals requires more limestone sorbent to suppress SO_2 emissions, which will likely increase NO_x unless the FBC boiler is operated with some degree of air staging. This is because under oxygen rich conditions, excessive calcined limestone (CaO) acts as a catalyst in the oxidation of NH_3 to NO, increasing the conversion rate of volatile nitrogen to NO.[44] With combustion staging, CO levels in the dense portion of the bed reduces formed NO over char and CaO surfaces.

Sorbent/Bed Material

NO_x emissions are also affected by the chemical and physical properties of the bed material and sorbent used for sulfur capture. An increase in Ca/S ratio for improved sulfur capture, for example, will increase NO_x, especially under unstaged combustion conditions, as discussed earlier. CFBC boilers utilize lower Ca/S levels than do BFBC units, and thus tend to emit less NO_x. With staged combustion, however, the effect of Ca/S ratio on NO formation is reduced due to the catalytic effect of CaO and CaS on NO_x reduction in the presence of high concentrations of CO.

Operational Variables

Several operational variables have been reported to affect NO_x formation, including ash recirculation, coal distribution in the bed, and fluidization velocity. Of these, ash recirculation has the most effect. When CaO concentrations in the ash are low and char and $CaSO_4$ concentrations are high, a net reduction in NO_x is achieved with increased ash recycle. The $CaSO_4$ acts as a catalyst in oxidation of NH_3 and reduction in NO in the freeboard section of the furnace, according to localized temperature and concentration of NH_3 and O_2.[45] This was demonstrated in a 125 MMBtu/hr BFBC boiler in Japan, where the use of ash reinjection resulted in a 67 percent NO_x reduction, from 90 to 30 ppm (0.12 to 0.04 lb/MMBtu).[41]

Data on the effect of coal distribution in the bed are generally sparse and inconclusive. In small pilot-scale combustors, improved bed uniformity has been shown to increase NO_x. However, under staged conditions, it is likely that better distribution of the coal and increasing the bed depth will offer improved NO_x control and more efficient operation, although the reduction is anticipated to be small.[46]

The effect of fluidization velocity on NO_x emissions from FBC boilers is generally small. At constant high excess air levels, an increase in fluidizing velocity has shown a small effect on NO_x. When overall excess air is kept low, the effect is relatively insignificant.[46]

In summary, NO_x emissions from FBC boilers are influenced by several design and process parameters to such an extent that NO_x levels can vary significantly from one unit to the next. For a given type of FBC design, coal properties such as nitrogen content and reactivity; and FBC operating conditions such as bed temperature, ash recirculation, and coal distribution; are principal variables affecting NO_x. Additionally, the sulfur content of the coal together with the required amount of sulfur capture determine the amount of sorbent used, which in turn influences NO_x. Sorbent reactivity and size distribution also play important roles in NO_x emissions since they affect calcium utilization in the fuel bed. Of the combustion modification NO_x control techniques examined in this section, SCA is the most widely applicable and cost-effective method.

5.3 COMBUSTION MODIFICATION NO_x CONTROLS FOR OIL- AND NATURAL-GAS-FIRED ICI BOILERS

Combustion modification NO_x controls for full-scale oil- and natural-gas-fired ICI boilers have been implemented primarily in California. Most of the retrofit activity has been in response to local air districts' rules restricting NO_x emissions from boilers and process heaters. For example, SCAQMD Rules 1146 and 1146.1 regulate NO_x emissions from boilers as small as 2 MMBtu/hr in capacity. Rule 1146 restricts NO_x emissions from ICI boilers with heat input capacities of 5 MMBtu/hr or more to 40 ppm (0.05 lb/MMBtu), unless the unit is greater than or equal to 40 MMBtu/hr capacity and has more than a 25 percent annual capacity factor, in which case NO_x emissions are limited to 30 ppm. Rule 1146.1 mandates a 30 ppm (0.04 lb/MMBtu) limit for ICI boilers of at least 2 MMBtu/hr capacity but less than 5 MMBtu/hr. Additionally, several districts restrict NO_x from boilers used in the petroleum refining industry. It should be noted that these limits are possible in Southern California only because of the reliance on clean burning natural gas and light distillate oil. Applicable controls include WI/SI; FGR; LNB; SCA, including BOOS and OFA; and a combination of these.

The control of NO_x from fuel oil combustion relies on the suppression of both fuel and thermal NO_x, while with natural gas combustion, NO_x control focuses primarily on thermal NO_x only. In order to achieve this suppression, control methods involve combustion staging or reduction of peak flame temperature. Applicable combustion modification control techniques are SCA, including BOOS and OFA; use of LNBs; FGR; and combinations of these techniques. As explained earlier in this chapter, load reduction, reduced air preheat, and low excess air firing are not considered independent or viable control technologies. Fuel switching has traditionally not been viewed as a control technology. However, the switching from coal to oil or gas and from high-nitrogen residual oil to lighter oil fractions or gas have come under increased consideration in regional and seasonal NO_x compliance options. Fuel switching is discussed in this section along with more traditional combustion modification controls.

Tables 5-7

TABLE 5-7. COMBUSTION MODIFICATION NO_x CONTROLS FOR FULL-SCALE NATURAL-GAS-FIRED INDUSTRIAL BOILERS

Control technique	Description of technique	Number of industrial boilers tested	% NO_x reduction	Controlled NO_x levels ppm @ 3% O_2, lb/MMBtu	Comments
WI	Water injected into the flame in amounts equivalent to a fraction of the fuel.	Watertube—2[a]	50-77	35-45 (0.04-0.056)	Thermal efficiency loss of 0.5 to 2.5%. Often implemented with OT, LNB, or BOOS. CO increase is expected. Experience limited to Southern California.
SCA	Fuel-rich firing burners with secondary air injection.	Watertube—5[b] Watertube—7[c] Firetube—1[b]	17-46 N.A.[d] 5	50-200 (0.06-0.24) 67-170 (0.08-0.20) 67 (0.08)	Includes BOOS and OFA. BOOS applies to multi-burner units only.
LNB	LEA burners operate at lower oxygen concentrations. Staged combustion burners control mixing of primary combustion air and fuel. Also have radiant ceramic fiber burner which reduces peak furnace temperature.	Watertube—18[b] Watertube—177[c] Watertube—21[g] Firetube—5[b] Firetube—2[g]	39-71 (for 5 boilers)[e] N.A. N.A. 32[e] N.A.	25-140 (0.03-0.17) 30-170 (0.04-0.20)[f] <40 (<0.05) 23-68 (0.03-0.08) <40 (<0.05)	LEA LNBs more applicable to single-burner systems. Staged air burners could result in flame impingement on furnace walls of smaller units.
Radiant LNB	Flameless premix ceramic radiant burner	Firetube—6	53-82	9-30 (0.01-0.036)	Special design LNB limited to firetube applications (<10 MMBtu/hr).
FGR	Recirculation and mixing of stack flue gas with burner combustion air.	Watertube—20[b] Watertube—13[c] Firetube—57	53-74 (for 2 boilers)[e] N.A. 55-76 (for 10 boilers)[e]	18-67 (0.02-0.08) 30-85 (0.04-0.10) 16-61 (0.02-0.08)	Requires motor, fan, and connecting ducting. Reported NO_x data is for FGR rates of 10 to 30%.
LNB+FGR	Combination of LNB and FGR control techniques.	Watertube—22[b] Watertube—50[c] Firetube—5[b]	55-84 (for 5 boilers)[e] N.A. N.A.	13-39 (0.02-0.05) 25-170 (0.03-0.20) 20-37 (0.02-0.04)	Combined methods are not additive in their effectiveness.
LNB+SCA	Combination of LNB and SCA control techniques.	Watertube—9[c]	N.A.	85-170 (0.10-0.20)	Applicable principally to multi-burner boilers.

and 5-8 summarize the information available on the performance an d

TABLE 5-8. COMBUSTION MODIFICATION NO_x CONTROLS FOR OIL-FIRED INDUSTRIAL BOILERS

Control technique	Description of technique	Number of industrial boilers tested	% NO_x reduction	Controlled NO_x levels ppm @ 3% O_2, lb/MMBtu	Comments
LNB	Staged combustion burners control mixing of primary combustion air and fuel	Residual WT, FT-18[a,b]	30-60	69-200 (0.09-0.25)	Staged air burners could result in flame impingement on furnace walls of smaller units.
		Residual WT-24[c]	N.A.[d]	80-475 (0.10-0.60)[e]	
		Distillate WT-7[b]	N.A.	60-119 (0.08-0.15)	
		Distillate WT-71[c]	N.A.	65-260 (0.08-0.33)[f]	
		Distillate FT-1[b]	15	120 (0.15)	
FGR	Recirculation and mixing of stack flue gas with combustion air	Residual WT-2[b]	4-30	91-197 (0.12-0.25)	Requires motor, fan, and connecting ducting. Reported data are for FGR rates of 10 to 30%.
		Residual WT-1[c]	N.A.	275 (0.35)	
		Distillate WT-6[b]	20-68	28-120 (0.04-0.15)	
		Distillate WT-2[c]	N.A.	240 (0.30)	
		Distillate FT-11[b]	N.A.	28-126 (0.04-0.16)	
SCA	Fuel-rich firing burners with secondary air injection	Residual WT-11[b]	5-42	157-588 (0.20-0.74)	Includes BOOS and OFA. BOOS applicable for boilers with multiple burners only. Firetube test experimental.
		Residual WT-3[c]	N.A.	160-240 (0.20-0.30)	
		Residual FT-1[b]	49	90 (0.11)	
		Distillate WT-1[b]	30	77 (0.10)	
		Distillate WT-3[c]	N.A.	70-95 (0.09-0.12)	
LNB+FGR	Combination of LNB and FGR control techniques	Residual WT-1[b]	N.A.	180 (0.23)	Combined methods are not additive in their effectiveness.
		Residual WT-4[c]	N.A.	80-435 (0.10-0.55)	
		Distillate WT-10[b]	N.A.	20-103 (0.03-0.13)	
		Distillate WT-26[c]	N.A.	30-200 (0.04-0.25)	
LNB+SCA	Combination of LNB and SCA control techniques	Residual WT-11[c]	N.A.	160-315 (0.20-0.40)	Applicable principally to multi-burner boilers.
		Distillate WT-6[c]	N.A.	160 (0.20)	

[a]WT = watertube; FT = firetube. Watertube boilers include both single-burner packaged (PKG-WT) boilers and multi-burner field-erected (FE-WT) boilers.
[b]Data primarily from test reports. See Appendix B.
[c]Data from Coen Company. See Appendix C. NO_x levels are not necessarily actual. Often represent vendor-guaranteed levels.
[d]N.A. = Not available. No baseline (uncontrolled) NO_x data available.
[e]Range for 90 percent of units listed in Appendix C.
[f]Range for 96 percent of units listed in Appendix C.

applicability of these techniques for natural-gas-fired and oil-fired ICI boilers, respectively. For natural-gas-fired boilers, more data were available for watertube units equipped with LNB or combined LNB and FGR. Controlled NO_x levels for these units ranged from as low as 13 ppm (0.02 lb/MMBtu) to as high as 170 ppm (0.20 lb/MMBtu). The limited data available for gas-fired watertube units with SCA show controlled NO_x levels of 50 to 200 ppm (0.06 to 0.24 lb/MMBtu). Controlled NO_x emissions from gas-fired firetube units, most equipped with FGR, ranged from 15 to 68 ppm (0.02 to 0.08 lb/MMBtu).

The data presented in Table 5-8 also show wide variability in controlled NO_x levels. For example, units fired on distillate oil with LNB showed NO_x ranging from 60 to 260 ppm (0.08 to 0.33 lb/MMBtu). With combined LNB and FGR, NO_x ranged from 30 to 200 ppm (0.04 to 0.25 lb/MMBtu).

The following subsections, 5.3.1 through 5.3.7, describe each of these methods as they are applied to both oil and natural gas combustion. Although differences in fuel type are acknowledged and affect NO_x emission levels, in general the control equipment and techniques used for oil and natural gas firing are similar. In fact, a large percentage of industrial boilers are capable of burning gas and oil individually or in combination.[47] All data collected for this section are contained in Appendix B. Additionally, data provided by Coen Company and

Tampella Power Corporation are contained in Appendix C. These data include emission levels based on vendor guarantees, and actual recorded emissions.

5.3.1 Water Injection/Steam Injection (WI/SI)

WI/SI are effective control techniques for reducing thermal NO_x in natural-gas-fired ICI boilers. When water or steam are injected in the flame, they reduce the peak flame temperature and the oxygen concentration. The quenching of the flame reduces the NO_x by as much as 75 percent, depending on the amount of water or steam injected. Less water than steam is needed to achieve the same quenching effect because of the heat of vaporization required to change water into steam.

WI has seen very limited application in Southern California, where NO_x emission regulations are the most stringent. Because of low initial cost, the technique is considered particularly effective for small single-burner packaged boilers operated infrequently.[48] In these applications, the oil gun positioned in the center of the natural gas ring burner is used to inject the water at high pressure. The amount of water injected normally varies between 25 and 75 percent of the natural gas feedrate, on a mass basis.

Figure 5-15. As the rate of water injection increases, NO_x decreases.[48]

Figure 5-15 illustrates the general trend of NO_x reduction with water injection rate. However, the technique has some important environmental and energy impacts. For example, CO emissions increase because of the quenching effect on combustion, and the thermal efficiency of the boiler decreases because the moisture content of the flue gas increases, contributing to greater thermal losses at the stack. Another concern related to the technique is its potential for unsafe combustion conditions that can result from poor feedrate control.

5.3.2 Low-NO_x Burners (LNBs) in Natural-gas- and Oil-fired ICI Boilers

LNBs for natural-gas- and oil-fired ICI units are becoming more widespread as the technology has been commercialized and improved, and as regulatory requirements become stricter. LNBs in the ICI sector have been applied primarily to packaged watertube ICI boilers, and to a lesser extent, to packaged firetube and field erected watertube boilers. Most of the available data are from gas-fired boilers located in California. Some of the principal types of LNB available are staged combustion burners, relying on either staged air or staged fuel, LNB with FGR, and ceramic fiber burners. Additionally, another type of burner known as the cyclonic combustion burner has recently been introduced. Major manufacturers of staged combustion burners for ICI sized boilers include Coen Company, Inc., Faber Burner (Tampella Power), Todd Combustion, Peabody, Riley Stoker, Industrial Combustion, and the John Zink Company. Alzeta Corporation has developed the radiant ceramic burner, while York-Shipley has recently introduced the cyclonic burner, both of which are for use primarily in smaller packaged firetube boilers.

There are also burners known as LEA burners, which reduce NO_x formation by operating at low oxygen concentrations. An added benefit of LEA burners is improved thermal efficiency. When compared to conventional burners, however, these burners provide moderate reductions in NO_x, reportedly on the order of 10 to 25 percent reduction.[49] The primary benefits of LEA burners are their increased efficiency and fuel saving characteristics. Because of the greater difficulty in achieving equal air distribution in multiple burner systems, LEA burners are generally more applicable to single burner systems.

The data in Tables 5-7 and 5-8 indicate that ICI boiler LNB experience includes the reported NO_x levels and reduction efficiencies shown in Table 5-

TABLE 5-9. REPORTED NO_x LEVELS AND REDUCTION EFFICIENCIES IN ICI BOILERS WITH LNBs

Fuel	Performance levels
Residual oil	30-60% 0.09-0.60 lb/MMBtu
Distillate oil	N.A.[a] 0.08-0.33 lb/MMBtu
Natural gas conventional burners	32-71% 0.03-0.20 lb/MMBtu
Natural gas radiant burners	53-82% 0.01-0.036 lb/MMBtu

[a]N.A. = Not available.

9, exclusive of LNB vendor data from Appendix C. There are many factors that affect the level of NO_x achieved with these burners. The nitrogen content of residual oil, the heat release rate, and the amount of combustion air preheat combined with level of FGR used for gas fuel are among the more critical factors contributing to the wide range in controlled NO_x levels. The following subsections highlight the principal design features of LNB types.

5.3.2.1 Staged Combustion Burners

Staged combustion burners, the most common type of LNB, achieve lower NO_x emissions by staging the injection of either air or fuel in the near burner region. Hence, staged combustion burners may be further classified as either staged air burners or staged fuel burners. Staged air burners have been applied to watertube boilers since 1979.[50] Figure 5-16

Figure 5-16. Staged air LNB. [53]

is a schematic of a typical staged air burner, in which primary, secondary, and tertiary (denoted as staged air in the figure) air are injected into the burner. As the figure notes, the division of combustion air reduces the oxygen concentration in the primary burner combustion zone, lowering the amount of NO formed and increasing the amount of NO reducing agents. Secondary and tertiary air complete the combustion downstream of the primary zone, lowering the peak temperature and reducing thermal NO_x formation. Besides the basic staged air burner shown, there are variations on staged air burners which incorporate internal recirculation of combustion products to aid in NO_x reduction.

Due to the staging effect of staged air burners, flame lengths tend to be longer than those of conventional burners.[51] This is of particular concern for packaged units because there is the possibility that flame impingement will occur on the furnace walls, resulting in tube failure and corrosion. Additionally, staged air burners are often wider and longer than conventional burners, requiring significant modifications to existing waterwalls and windboxes. Burner size may also be an important factor when assessing the feasibility of retrofitting boilers located in restricted spaces.

Staged fuel burners are a slightly more recent development in staged combustion LNBs. These burners were originally developed for use on process heaters in the refining and petrochemical industries, and hence have been applied primarily to process heaters rather than boilers. Figure 5-17

Figure 5-17. Staged fuel LNB. [52]

is a schematic of a staged fuel burner, manufactured by the John Zink Company. Here, combustion air is introduced without separation and instead the fuel is divided into primary and secondary streams. Despite the high oxygen concentration in the primary combustion zone, thermal NO_x formation is limited by low peak flame temperatures which result from the fuel-lean combustion. Quenching of the flame by the high excess air levels also occurs, further limiting the peak flame temperatures and providing active reducing agents for NO_x reduction.[52] Inerts from the primary zone then reduce peak flame temperatures and localized oxygen concentration in the secondary combustion zone, thereby reducing NO_x formation. An advantage of staged fuel burners over staged air burners is that they tend to have shorter flame lengths, decreasing the likelihood of flame impingement.[54]

Data collected on natural-gas- and oil-fired ICI boilers with staged air LNBs show a wide range in performance and emission levels. For natural gas firing, NO_x reductions of 39 to 71 percent were reported for three existing and one new watertube boiler. Controlled NO_x levels for these and 10 other gas-fired watertube boilers, five of which were existing units retrofitted with LNBs, ranged from 25 ppm (0.03 lb/MMBtu), for a 10 MMBtu/hr boiler in Taiwan, to 140 ppm (0.17 lb/MMBtu), for a 100 MMBtu/hr floor firing unit in Germany. This range is quite wide due to differences in boiler design, capacity, and burner type. An example of the levels of performance achievable with different burners is that when a different LNB was tested in the German boiler mentioned above, the controlled NO_x level was 112 ppm (0.13 lb/MMBtu) instead of 140 ppm (0.17 lb/MMBtu).[55]

All but one of the above 14 units were packaged. The only field-erected unit, a 380 MMBtu/hr dual burner unit at Luz-Segs II in California, reported a controlled NO_x level of 80 ppm (0.10 lb/MMBtu) when retrofitted with an LNB.[56] Test results from one gas-fired firetube unit at Fort Knox retrofitted with a

staged air burner showed a 32 percent reduction in NO_x, from 100 ppm down to 68 ppm (0.12 to 0.08 lb/MMBtu). No other data are available for firetube units with staged air LNB.

Additional data supplied by Coen Company (see Appendix C) for 177 natural-gas-fired LNB installations showed guaranteed or actual NO_x levels typically between 30 and 170 ppm (0.04 to 0.20 lb/MMBtu) with LNB.[57] These data include emissions levels for boilers of various types and sizes, ranging from packaged to field erected units producing 25,000 to 520,000 lb/hr of steam (approximately 30 to 600 MMBtu/hr heat input). All units used Coen DAF LNBs. Appendix C also contains a list of 23 Tampella Power Corp. Faber LNB installations that reportedly emit 40 ppm NO_x (0.05 lb/MMBtu) or less when firing natural gas. All of these boilers are packaged units ranging from 9,000 to 100,000 lb/hr steam capacity.[58]

For smaller industrial gas-/oil-fired boilers, Riley Stoker has also introduced the Axial Staged Return (ASR™) flow burner, the Axial Flame Staged (AFS™) burner, and the Swirl Tertiary Staged (STS™) burner. The ASR burner is based on patented Deutsche Babcock technology that uses axial staging of primary and secondary air streams and internal recirculation

Figure 5-18. Low-NO_x ASR burner.[59]

of self-aspirated hot furnace gases. The burner, illustrated in Figure 5-18, has a maximum design capacity of 275 MMBtu/hr, with controlled NO_x levels in the 20 to 30 ppm (0.025 to 0.035 lb/MMBtu) range when firing natural gas with 12 to 30 percent FGR assistance.[59] The AFS burner incorporates axial stagin g of primary and secondary air and staged fuel addition. Th e burner, illustrated i n F i g u r e 5 - 1 9

, has a firing capacity in the 20 to 40 MMBtu/hr range.[59] With FGR addition, NO_x emissions in the 30 to 40 ppm (0.035 to 0 .048 lb/MMBtu) range have been

Figure 5-19. AFS air- and fuel-staged burner.[59]

Figure 5-20. Riley Stoker STS burner.[59]

reported in full-scale retrofits.[59] The STS burner, illustrated in Figure 5-20, is designed for retrofit on multiple burner wall-fired boilers with 500 °F air preheat. In one full-scale STS burner retrofit at a paper mill, reported NO_x emissions ranged from 90 to 110 ppm (about 0.1 to 0.13 lb/MMBtu) with high air preheat and heat release rate and without FGR.[59]

In summary, LNB NO_x reduction efficiencies for natural-gas-fired boilers including one firetube boiler and five watertube units range from 32 to 71 percent, in agreement with previously reported performance levels for natural gas firing. LNB reduction efficiencies for 13 additional watertube units listed in Appendix B could not be computed because of a lack of baseline (uncontrolled) emissions data. Controlled NO_x emissions for the 18 watertube units ranged from 25 to 30 ppm (0.03 to 0.04 lb/MMBtu), for the smaller units (10 to 31 MMBtu/hr input), and from 58 to 140 ppm (0.07 to 0.17 lb/MMBtu), for the remaining boilers, which ranged in size from 45 to

380 MMBtu/hr input. Controlled NO_x emissions reported by two LNB manufacturers for nearly 200 units ranged between 30 and 170 ppm (0.04 to 0.20 lb/MMBtu). Some burner manufacturers have reported NO_x reduction efficiencies of anywhere from 50 to

90 percent. In fact, several manufacturers guarantee NO_x emissions below 40 ppm (0.05 lb/MMBtu) when firing natural gas in smaller industrial packaged boilers, primarily in response to the SCAQMD regulations in California. For example, Faber, a division of Tampella Power, guarantees less than 40 ppm NO_x on any burner system and will guarantee less than 30 ppm (0.04 lb/MMBtu) of NO_x on a case-by-case basis.[60] Similarly, Coen Company states that less than 30 ppm of NO_x will be emitted from its Micro-NO_x® LNB.[61] Performance levels of less than 20 ppm are achievable on a case-by-case basis.

For oil firing with staged air LNBs, data were collected for 84 boilers firing distillate oil and 46 boilers firing residual oil. The distillate-fuel-fired boilers with staged air LNBs showed controlled NO_x levels of 60 to 260 ppm (0.08 to 0.33 lb/MMBtu). The 25 domestic units fired on No. 6 residual oil (fuel nitrogen contents of 0.14 to 0.3 percent) had controlled emissions of 80 to 475 ppm (0.10 to 0.60 lb/MMBtu). Due to a lack of baseline uncontrolled emissions data for these domestic units, it was not possible to calculate NO_x reduction efficiencies for the boilers. Additionally, overall performance results of 17 firetube and watertube boilers in Japan firing residual oil have been reported. For these units, which ranged in size from 5 to 40 MMBtu/hr, test results showed NO_x reductions between 30 and 60 percent, with controlled emissions between 69 and 185 ppm (0.09 and 0.23 lb/MMBtu).[62]

The retrofit of LNBs usually involves removing the original burner and bolting the LNB in. Most LNBs for ICI boilers are designed as self-contained units to allow easy bolt-on retrofit without boiler tube wall modifications. For applications where new fan or ducting equipment are desired, some manufacturers offer complete packaged burner units, in which the retrofit burner is combined with combustion controls, flame safeguard equipment, fuel piping, and a combustion air fan. These are sold together as factor y assembled, self-contained packages.

5.3.2.2 Ceramic Fiber Burners

Alzeta Corporation has developed a ceramic fibe r burner known as the Pyrocore® burner, applicable for use in gas-fired packaged boilers of up to 10 MMBtu/hr input. Although applicable to both wa tertube and firetube units, the Pyrocore burner has b een demonstrated primarily in firetube boilers and process heaters. This burner, depicted in Figure 5-2 1

Figure 5-21. Pyrocore LNB schematic. [63]

, is a gas-fired infrared (IR) burner. An IR burner uses energy released from the fuel to elevate the temperature of the radiant surface of the burner, which in turn emits energy in the form of IR radiation. In the Pyrocore burner, fuel gas is premixed with combustion air before entering the burner. The mixture passes through a porous burner material and is ignited, establishing a thin combustion layer in contact with the surface. Because the surface material is cooled by the incoming air/ fuel mixture and the material has a low thermal conductivity, radiant temperatures of 1,700 to 2,000 °F occur only on the outer surface.[63] The low combustion temperature limits thermal NO_x formation.

Field tests of this burner retrofitted to a 3.3 MMBtu/hr firetube boiler at Hall Chemical in Ohio showed NO_x reduction of 78 percent, with controlled emission levels of 15 ppm (0.02 lb/MMBtu). Another field test conducted on an 8 MMBtu/hr boiler retrofitted with the Pyrocore burner showed 53 percent reduction in NO_x, to a controlled level of 24 ppm (0.03 lb/MMBtu), while a third test on a 2 MMBtu/hr unit resulted in a controlled emission level of 17 ppm. On the average, results from five field tests and one laboratory test showed that NO_x was reduced by 71 percent and CO by 94 percent.[64] To date, most burners supplied by Alzeta have been designed to achieve less than 30 ppm NO_x at full rated load, although the actual emissions for many are reported to be below 20 ppm. Currently, the single-burner applications of this burner are limited to small packaged boilers of less than 20 MMBtu/hr because of physical limits on the size of the radiant burner. Structural issues are the major concern with larger applications. Further research and tests are being conducted to extend the

Pyrocore burner's applicability to larger firetube and watertube boilers, including the use of multiple burners.

Additional research is currently focusing on the use of lower surface firing rates, moderate temperature environments, and modest excess air to attain ultra-low NO_x levels of 9 ppm and below. Alzeta Corporation and Zurn Industries have recently commissioned an ultra-low-NO_x boiler, the Radiant Cell Boiler™, that utilizes the Alzeta flameless Pyrocore radiant burners and has a reported capability of 9 ppm of NO_x and less than 50 ppm of CO.[65]

5.3.2.3 Other LNBs

An LNB type known as a cyclonic burner has recently been developed by York-Shipley for packaged firetube boilers. The burners are available up to 16.6 MMBtu/hr heat input. In cyclonic combustion, high tangential velocities are used in the burner to create a swirling flame pattern in the furnace. This causes intense internal mixing as well as recirculation of combustion gases, diluting the temperature of the near-stoichiometric flame and lowering thermal NO_x formation. The tangential flame causes close contact between combustion gases and the furnace wall, adding a convective component to the radiant heat transfer within the furnace. The increased heat transfer and low excess air operation of the cyclonic burner result in increased boiler efficiency.

To achieve ultra-low NO_x levels, a small quantity of low-pressure steam is injected into the burner, which further reduces the local flame temperature and NO_x formation. Testing revealed that NO_x emissions during natural gas firing could be reduced from 70 ppm to less than 20 ppm without affecting burner stability, low excess air operation, or turndown performance. However, the use of steam did result in a boiler heat efficiency loss of roughly 5 percent.[66] The cyclonic burner is available as a stand-alone retrofit burner with a bolt-on feature. However, no retrofit emissions data were obtained during this study.

5.3.3 Flue Gas Recirculation (FGR) in Natural-gas- and Oil-fired ICI Boilers

FGR involves recycling a portion of the combustion gases from the stack to the boiler windbox. These low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature and the residence time at peak flame temperature. These effects result in reduced thermal NO_x formation. However, there is little effect on fuel NO_x emissions. The amount of NO_x reduction achievable depends primarily on the fuel nitrogen content and amount of FGR used. Other thermal NO_x control concepts similar to FGR are such control techniques as WI and SI, in which water, rather than recirculated flue gas, is used as an inert substance to lower the peak flame temperature. FGR is much more commonly used, however.

FGR is currently being used on a number of watertube and firetube boilers firing natural gas. Only limited NO_x reduction efficiency data are available, however, as baseline (uncontrolled) NO_x data for most units are unreported. Data for four natural-gas-fired watertube boilers equipped with FGR show a range in NO_x reduction of 53 to 74 percent, while for 10 gas-fired firetube units with FGR, NO_x reduction efficiency ranged from 64 to 76 percent. In all, controlled NO_x emission data were collected for a total of 33 gas-fired watertube and 57 gas-fired firetube units operating with FGR. Four of the watertube units and 26 of the firetube units were identified as retrofit applications. Controlled NO_x levels ranged from 20 to 85 ppm (0.02 to 0.10 lb/MMBtu) for the watertube units and 16 to 37 ppm (0.02 to 0.04 lb/MMBtu) for the firetube boilers. FGR rates were typically on the order of 20 percent during these tests. However, one firetube unit—which achieved 68 percent reduction—was run on 30 percent FGR during the emissions test.

Boilers are usually not operated with more than 20 percent FGR due to flame stability considerations.[67]

NO_x reduction efficiency data for oil-fired units with FGR are also very limited. In one test program, a single boiler was fired on both residual oil and distillate oil, using FGR and keeping all other variables constant. NO_x was reduced by 68 percent for distillate oil firing, yet was only reduced by 11 percent when residual oil was used. These data illustrate that FGR is more effective when used with low nitrogen content fuels such as natural gas or distillate oil, since FGR is more effective in controlling thermal NO_x rather than fuel NO_x. The 68 percent reduction was obtained with a relatively high FGR rate of 28 percent. Another boiler firing distillate oil reported NO_x reduction of only 20 percent, using 10 percent FGR. Available data are too limited to estimate typical NO_x reduction efficiencies for oil-firing boilers with FGR. In general, however, thermal NO_x reductions from distillate-oil-fired boilers with FGR are somewhat less than from natural-gas-fired units.[68] This is due to the greater potential for flame instability and emissions of unburned combustibles from distillate-oil-fired units, which limits the practical rate of FGR that can be used. Controlled NO_x emissions for distillate oil firing with FGR were between 28 and 240 ppm (0.04 to 0.30 lb/MMBtu) for 19 boilers. For three units firing residual oil, controlled NO_x levels ranged from 125 to 275 ppm (0.16 to 0.35 lb/MMBtu).

When compared to the number of LNB or combined LNB and FGR installations listed in Tables 5-7 and 5-8, the number of watertube boilers equipped only with FGR is relatively small. In general, for retrofit cases to existing packaged watertube ICI boilers, FGR is rarely applied without the installation of a new LNB as well. This is because the performance of many older burner systems tend to be adversely affected when an inert such as fuel gas is injected into the combustion zone.[57] Oxygen trim systems have been

Figure 5-22. FGR system for gas- or oil-fired boiler. [71]

installed to allow use of an existing burner with FGR and LNB together. Thus, the most common combustion modification NO_x controls for packaged watertube boilers are either LNB or combined LNB and FGR. FGR systems have been applied more commonly to smaller firetube units. A typical FGR system is shown in Figure 5-22. In order to retrofit a boiler with FGR, the major additional equipment needed are a gas recirculation fan and ducting. Major companies that supply FGR equipment for packaged gas- and oil-fired boilers are Cleaver Brooks, Coen Company, Industrial Combustion, Keeler (Tampella Power), and Todd Combustion.

5.3.4 Fuel Induced Recirculation (FIR)

Fuel induced recirculation (FIR) is a control technology for natural-gas-fired boilers recently introduced by the John Zink and Holman Boiler Companies. FIR involves the recirculation of a portion of the boiler flue gas and mixing it with the gas fuel at some point upstream of the burner. Although FIR has not yet been widely applied, it has been demonstrated commercially in an industrial unit in California, achieving NO_x emission readings as low as 17 ppm with little adverse affect on CO emissions.[69]

The primary difference between FIR and FGR is that in FIR the flue gas is mixed with the fuel stream, whereas in FGR the flue gas is recirculated into the combustion air. By diluting the fuel prior to combustion, which lowers the volatility of the fuel mixture, FIR reduces the concentration of hydrocarbon radicals that produce prompt NO.[6] Additionally, FIR reduces thermal NO_x in the same manner as FGR, by acting as a thermal diluent. Thus, one of the main benefits of FIR technology is that it impacts both prompt NO and thermal NO_x formation in gas-fired boilers.

A second fundamental feature of FIR is that flue gas recirculation is induced using the natural gas dynamics of the burner flow streams, without additional equipment such as recirculation fans. According to the manufacturer, FIR tends to be self-adjusting at various firing rates, as natural gas introduction is dependent on the mass and pressure of the fuel.[70]

5.3.5 Staged Combustion Air (SCA) in Natural-gas- and Oil-fired ICI Boilers

Staged combustion for oil- and natural-gas-fired boilers in the ICI sector consists of injecting a portion of the total combustion air downstream of the fuel-rich primary combustion zone. Staged combustion can be accomplished using secondary OFA or side-fired air ports, or by using the BOOS technique. The applicability of OFA, side-fired air, or BOOS (collectively grouped under the term SCA) depends primarily on the type of furnace design involved — i.e., watertube or firetube — and the size of the boiler. Generally, SCA is not considered viable for retrofit to packaged boiler units due to installation difficulties. The following subsections summarize the performance, applicability, and availability of the various methods of implementing SCA on the major types of natural-gas- or oil-fired ICI boilers.

5.3.5.1 Firetube Boilers

SCA is not considered a primary NO_x control method for existing firetube boilers because of the major modifications required to retrofit staged air to these boilers.[72] BOOS is not applicable because these units rarely have more than one burner. Side-fired air application is difficult as retrofit requires penetration of the firetube boiler water shell. Performance data are available only for one experimental application of side-fired air to a 12 MMBtu/hr firetube boiler fired on residual oil and natural gas. In this test program, sponsored by the U.S. EPA, secondary air was injected at the rear of the furnace opposite the burner through eight pipes connected to a forced-draft fan. In this way the secondary air was independent of the primary burner air. Test results for residual oil firing showed that NO_x was reduced from 177 ppm to 90 ppm (0.22 to 0.11 lb/MMBtu), a 49 percent reduction in NO_x. During these residual oil combustion tests, the burner was operated at 76 percent of stoichiometric conditions, and the overall excess oxygen level was 4 percent.[73] However, boiler load was reduced to 50 percent due to combustion instabilities at high loads.

Tests conducted on the same boiler but firing natural gas at 71 percent load had almost no effect on NO_x, showing only 5 percent NO_x reduction, from 70 to 67 ppm (0.084 to 0.080 lb/MMBtu). NO_x reduction for gas-firing may not have been as high as the residual oil-firing case because of the slightly higher test load and because the burner oxygen level was higher, at 90 percent stoichiometry. Also, because natural gas combustion emits lower levels of

NO_x than residual oil firing to begin with, it is generally more difficult to achieve as much percentage NO_x reduction with natural gas.

5.3.5.2 Packaged Watertube Boilers

Packaged watertube boilers generally use only one burner, so BOOS is not applicable as a means of achieving staged combustion. As was the case with firetube boilers, retrofit of SCA to smaller packaged watertube units is generally not considered a primary NO_x control option due to the difficulty of retrofitting SCA hardware. Hence, experience on these units has been limited. Data are available for two experimental retrofit applications of SCA in single-burner oil- and gas-fired packaged watertube units. The first application, in a 22 MMBtu/hr unit (Location 19), involved the injection of secondary air through four steel lances which were inserted through the windbox and the refractory firing face. At 83 percent load, NO_x emissions were reduced by 29 percent (controlled NO_x = 157 ppm or 0.20 lb/MMBtu) when residual oil was fired, by 30 percent (controlled NO_x = 77 ppm or 0.10 lb/MMBtu) when distillate oil was fired, and by 46 percent (controlled NO_x = 50 ppm or 0.07 lb/MMBtu) when natural gas was fired.[74]

At the second site, identified as "Location 38," secondary air was injected into a 56 MMBtu/hr boiler through any of 10 SFA ports. This unit was equipped with combustion air preheating, which could vary the temperature from roughly 65 to 176 °C (150 to 350 °F). At operating conditions of 89 percent load, 2.3 percent excess oxygen, and 14 percent SCA flow, NO_x was reduced by 42 percent from the baseline, when residual oil was fired. During natural gas firing, staged combustion resulted in a reduction of 32 percent from the baseline conditions at 2.4 percent excess oxygen and 14 percent SCA.[74] Results from these two applications showed that in order to maximize NO_x reduction using SCA in packaged watertube units, it is necessary to operate the burner at substoichiometric levels, and secondary air must be injected sufficiently downstream of the burner exit to allow for cooling of combustion gases. These types of SCA retrofits on full-scale packaged watertube boilers are generally not considered practical from installation and operational standpoints.

5.3.5.3 Field-erected Watertube Boilers

For field-erected watertube boilers equipped with more than one burner, staged combustion can be achieved by using OFA, BOOS, or biased burner firing. Biased burner firing consists of firing certain burners fuel-rich while other burners are fired fuel-lean. This may be accomplished by maintaining normal air distribution to the burners while adjusting fuel flow so that more fuel is sent to desired burners. Usually, the upper row of burners is fired fuel-lean, but this varies from boiler to boiler.

BOOS is more applicable as an NO_x control technique for natural-gas- and oil-fired boilers than it is for coal-fired units. As mentioned previously, with PC-fired ICI boilers the mill-burner arrangement usually determines which burners can be taken out of service. For this reason, BOOS is more often used as a maintenance operation than a direct NO_x control method. In contrast, with oil or natural gas firing, burners can be shut off individually or fuel flow adjusted to achieve optimum biased burner firing or BOOS operation.

For large wall-fired units, BOOS or biased firing are attractive first level retrofit NO_x control techniques because few equipment modifications are required. For natural gas firing, data compiled for three industrial boilers with BOOS showed NO_x reductions ranging from 17 to 44 percent, with an average of 29 percent reduction from uncontrolled NO_x levels. Controlled NO_x emissions from these units, ranging in size from 60 to 120 MMBtu/hr, were between 117 and 200 ppm (0.14 and 0.27 lb/MMBtu).[75] For residual oil firing, data from nine boilers using BOOS showed NO_x reduction efficiencies of 5 to 40 percent.

The wide range in control efficiencies is attributed to several factors, including the burner arrangement, the percentage of burners taken out of service, and the overall excess air. Some burner arrangements are more effective in reducing NO_x with BOOS. For example, a square burner matrix is more effective than an arrangement in which all of the burners are located at the same level. Another controlling factor is stoichiometry of the active burners.

Although operation with BOOS can measurably reduce NO_x, the operating performance of the boiler can be somewhat degraded because of the need to increase excess air in order to control CO, hydrocarbon, and smoke emissions.[76] Adjustments to the airflow controls, such as burner registers, may be required to achieve the desired burner stoichiometry without increasing these emissions. Also, operation with BOOS usually requires that the unit be derated unless modification to the fuel delivery system is made.[77]

Data on NO_x reductions from field-erected oil- or gas-fired ICI boilers using OFA are very limited. Controlled emissions from two units firing residual oil were from 160 to 180 ppm (0.20 to 0.23 lb/MMBtu).[57] Application of the technique to utility boilers in California has reportedly resulted in average NO_x reductions of 24 percent for oil and nearly 60 percent for gas.[78] Generally, OFA is applicable only to large furnaces with sufficient volume above the burners to allow complete combustion and steam temperature control. Because of required hardware modifications, OFA for large gas and oil wall-fired units is often not a preferred retrofit control as BOOS can offer similar reduction efficiency at less cost.[79]

5.3.6 Combined Combustion Modification NO_x Controls for Natural-gas- and Oil-fired ICI Boilers

Many retrofits have utilized combinations of the above combustion modification methods. The most demonstrated combination is the use of LNB with FGR. As mentioned earlier, retrofit of combined LNB and FGR controls to existing packaged boilers is often more feasible than using FGR alone. Also, combined retrofit of FGR and LNB to ICI boilers is considered by some to be a way of meeting stringent NO_x control regulations without using flue gas treatment controls.[80] Data have been collected for 101 natural-gas-fired units, 44 distillate-oil-fired boilers, and 13 residual-oil-fired boilers (see Appendices B and C). All were watertube boilers, the majority located in California. Many of the California boilers were existing units retrofitted with LNB/FGR controls.

NO_x reduction efficiencies of 55 to 84 percent were reported for five units firing natural gas. No baseline uncontrolled NO_x data were available for the other boilers; thus, reduction efficiencies could not be calculated. Nearly all California units reported controlled NO_x emissions at or below 40 ppm (0.05 lb/MMBtu), while the non-California units reported NO_x levels between 40 and 170 ppm (0.05 to 0.20 lb/MMBtu). For the distillate-oil-firing units, baseline uncontrolled NO_x levels were not available; thus, NO_x reduction efficiencies could not be determined. Controlled emissions ranged from 30 to 200 ppm (0.04 to 0.25 lb/MMBtu). For the residual-oil-firing units, controlled NO_x levels were between 80 and 435 ppm (0.10 to 0.55 lb/MMBtu).

While some experience has been obtained in combining SCA with LNB or FGR, these have involved new or experimental test units. In general, applications of SCA with LNB or FGR are limited to new units because of the costs involved in installing SCA in existing units, especially in packaged boilers. The use of SCA with an LNB in a new 140 MMBtu/hr natural-gas-fired watertube boiler resulted in controlled NO_x emissions of 64 ppm (0.08 lb/MMBtu), while in a new 150 MMBtu/hr residual-oil-fired boiler the controlled NO_x level was 175 ppm (0.22 lb/MMBtu).[81] Coen Company reports controlled NO_x emissions from 85 to 170 ppm (0.10 to 0.20 lb/MMBtu) for nine boilers with LNB and SCA, firing natural gas or distillate oil. For 11 units firing residual oil, NO_x ranged from 160 to 315 ppm (0.20 to 0.40 lb/MMBtu).[57] In general, however, the retrofit of SCA is applicable mainly to large industrial boilers.

5.3.7 Fuel Switching

Because fuel-bound nitrogen plays such an important role in total NO_x emissions from fuel combustion in boilers, switching from high-nitrogen fuels, such as coal or residual oil, to lower nitrogen fuels, such as distillate oil or natural gas, is a strategy that can be as effective in reducing NO_x as any other combustion control. Low-nitrogen fuels, such as distillate oil and natural gas, can be used to displace a fraction of the coal or residual oil, or replace them entirely. In either case, significant NO_x reductions are possible. For example, the cofiring of natural gas with coal in utility boilers has reduced NO_x emissions by a minimum of 10 to 30 percent, depending on the boiler, coal, cofiring configuration, and amount of gas firing.[82] The use of 33 percent natural gas in a gas cofiring configuration in the top row of burners of a PC-fired boiler (representing a more strategic way to maximize NO_x reduction efficiency with reburning techniques) can result in larger NO_x reductions reaching 35 to 60 percent from uncontrolled levels.[82] Figure 5-23 ions.

Figure 5-23. Effects of cofiring on NO_x emiss [82]

TABLE 5-10. EFFECTS OF SWITCHING FROM RESIDUAL OIL TO DISTILLATE FUEL ON INDUSTRIAL BOILERS

Fuel type	Fuel nitrogen, % weight	NO_x emissions @ 3% O_2
Residual oil	0.44	350
Distillate oil	0.006	65
Residual oil	0.27	298
Distillate oil	0.015	127
Residual oil	0.20	186
Distillate oil	0.014	84

illustrates NO_x reduction as a function of gas cofiring rate, expressed as a percentage of total heat input, measured during six full-scale utility boiler cofiring field tests. These results are applicable, in theory, to large PC-fired industrial boilers.

The replacement of high-nitrogen residual oil with a lower nitrogen fuel or natural gas is also very effective in reducing NO_x. To illustrate, the data shown in Table 5-10 were obtained from industrial boilers firing a residual oil first, and then switching to a distillate fuel.[2] NO_x reductions ranged from about 50 to 80 percent for reductions in fuel oil nitrogen of

TABLE 5-11. ESTIMATES OF NO_x REDUCTIONS WITH FUEL SWITCHING

Base fuel	Replacement fuel	Quantity used, %	Estimated NO_x reduction, %
PC	Natural gas	10-20 10-20 (reburning zone) 100	10-30 30-60 60-70
Residual oil with 0.6% N	Natural gas	100	50-80
	Distillate oil	100	50-80
	Residual oil with 0.3% N	100	30-40

Note: All emissions data were obtained from short-term tests.

approximately 0.19 to 0.436 percent by weight. If all the recorded NO_x reduction is attributed to the drop in fuel nitrogen, about 55 to 65 ppm reduction in NO_x results from each 0.1 percentage point reduction in the nitrogen content of the oil. Table 5-11 lists estimates of NO_x reductions attainable from ICI boilers cofiring or switching to a cleaner fuel.

In addition to natural gas and low-nitrogen fuel oil, the Shell Oil Company is marketing a proprietary liquid fuel for industrial boilers. This proprietary fuel is similar to distillate oil in thermal energy and physical properties, but contrary to distillate oil it contains essentially no fuel-bound nitrogen (3 to 9 ppm). Therefore, its NO_x emissions are similar to those achievable with natural gas.[83] Short-term performance with this proprietary fuel show FGR-controlled emissions in the range of 18 to 35 ppm corrected to 3 percent O_2 (0.022 to 0.042 lb/MMBtu). It is used as a standby liquid fuel for many boilers in Southern California in cases where natural gas is curtailed.

5.3.8 Combustion Modification NO_x Controls for Thermally Enhanced Oil Recovery (TEOR) Steam Generators

NO_x controls for TEOR steam generators have also been implemented primarily in California, due to stringent NO_x emission regulations. For instance, in Kern County, California, over 2,000 oil field steam generators are in use, the majority fired on crude oil.[84,85] Other fuels used in these boilers include natural gas and refinery gas. Nearly all units in Kern County utilize some form of combustion modification NO_x control, including OT systems, LNB, or FGR.[84]

5.3.8.1 OT Systems

OT systems or controllers limit the excess oxygen during combustion to reduce the formation of NO_x. It has been reported that these devices typically reduce the formation of NO_x from small steam generators (<35 MMBtu/hr input capacity) by 15 to 25 percent.[86] Controlled NO_x emissions from 71 tests conducted on small crude-oil-fired steam generators in Kern County ranged from 166 to 398 ppm (0.21 to 0.50 lb/MMBtu).[87] For larger units greater than 35 MMBtu/hr (most 62.5 MMBtu/hr), Kern County data from 326 tests showed controlled NO_x levels ranging between 174 and 340 ppm (0.22 and 0.43 lb/MMBtu). No uncontrolled data were reported for these units; thus, it was not possible to report actual NO_x reduction efficiencies. However, assuming a typical uncontrolled NO_x level of 300 ppm (0.38 lb/MMBtu), as reported in References 49 and 88 for large TEOR units in Kern County, average NO_x reduction on the order of 17 percent was achieved. It should be remembered that this is only an average value, based on average emission levels and average reported baseline levels. Actual NO_x reduction efficiencies may have been significantly higher or lower depending on the fuel characteristics, combustion conditions, and design type of each unit. The average levels are illustrative to a certain degree, however, as most TEOR steam generators are similar in design and all of the units tested fired Kern County crude.[84]

5.3.8.2 LNBs with SCA and OT

LNB systems, which generally are used with O_2 controllers, have been applied primarily to large (35 to 62.5 MMBtu/hr) crude oil-fired steam generators. The most effective and widely used LNB systems also incorporate SCA, usually using sidefire air injection. In fact with TEOR steam generators it is common to describe a combined LNB+SCA system as either an LNB or an SCA system.[86,87,89] Figure 5-24

Figure 5-24. North American LNB on oil field steam generator.[92]

Figure 5-25. Process Combustion Corporation toroidal combustor. [90]

depicts one type of LNB+ SCA system, manufactured by the North American Company, the principal vendor of LNB systems for TEOR steamers. This burner system is being used on over 100 crude oil-fired generators in Kern County. Minor modifications are made to a standard burner and secondary air injection nozzles are inserted around the circumference of the furnace at various locations in the radiant heat transfer section. In a 62.5 MMBtu/hr steam generator, 28 secondary air injection ports are used, positioned 17 to 27 feet downstream of the burner. In most applications of this burner system, O_2 controllers are used to keep excess oxygen at the stack below 2 percent. NO_x emission levels of 100 to 160 ppm (0.13 to 0.20 lb/MMBtu) have been reported when crude oil is fired, representing 50 to 70 percent NO_x reduction when compared to unstaged conventional North American burners. [89]

Another type of LNB system applicable for retrofit to TEOR steam generators is the single toroidal combustor, developed by Process Combustion Corporation (Figure 5-25). The single toroidal combustor is a two-stage burner in which approximately one-third of the fuel is combusted under highly reducing, turbulent conditions inside a precombustion chamber. The remaining two-thirds of the fuel is combusted in a secondary burnout zone at the entrance to the steam generator. The second stage is arranged so that the addition and mixing of 5 to 10 percent secondary excess air takes place in the high-velocity jet of flame emitted from the chamber throat inside the firebox.[90] The vigorous internal recirculation and mixing within the fuel-rich precombustion chamber aids in NO_x reduction, while combustion gases are entrained into the high-velocity flame of the secondary combustion zone, lowering the peak flame temperature. Results of 50 separate field tests using this burner showed average NO_x reductions of 60 percent, with average emissions of 125 ppm (0.16 lb/MMBtu) for 62.5 MMBtu/hr sized units and 150 ppm (0.19 lb/MMBtu) for 25 to 30 MMBtu/hr units. Controlled NO_x levels ranged from 90 to 225 ppm (0.11 to 0.28 lb/MMBtu).[91]

A third type of LNB for TEOR steam generators utilizes a split flame arrangement, whereby an inner fuel-rich diffusion flame is separated from and outer fuel-lean premix flame by a blanket of recirculated flue gas. This burner, the MHI PM low-NO_x burner, illustrated schematically in Figure 5-26

Figure 5-26. The MHI PM burner nozzle. [93]

, was retrofitted to a 62.5 MMBtu/hr crude-oil-fired steam generator as part of an EPA-sponsored test program on a demonstration unit. No additional TEOR steamers have been retrofitted with this burner. Full-load NO_x emissions of 110 ppm (0.14 lb/MMBtu) were obtained with what were deemed "acceptable" smoke and CO emissions (<100 ppm CO). This compares to emissions of approximately 300 ppm (0.38 lb/MMBtu) measured from an identical generator equipped with a conventional burner.[93] Thus, NO_x was reduced by 63 percent.

Most LNB retrofit experiences have been with crude-oil-fired units larger than 35 MMBtu/hr. Results from 134 tests conducted on such units in Kern County show controlled NO_x levels of 87 to 232 ppm (0.11 to 0.29 lb/MMBtu). Because no baseline data were available, it was impossible to calculate NO_x reduction efficiencies for these tests. However, these controlled emissions may be compared to the generally accepted average baseline of 300 ppm for Kern County crude oil firing.[84,88] For illustrative purposes, comparing average controlled emissions to this average baseline, 59 percent NO_x reduction was achieved with LNB systems. Again, however, it must be remembered that actual efficiencies may have varied significantly from unit to unit. Limited test data are available for natural gas fired units equipped with LNB. Data for two 62.5 MMBtu/hr gas-fired generators showed NO_x reductions of 8 and 28 percent.

Because of the limited data, however, no conclusions can be drawn about typical reduction efficiencies for LNB gas firing.

LNB systems have also been applied on a very limited basis to steam generators smaller than 35 MMBtu/hr. Reported NO_x emission reductions range from 30 to 60 percent for these units.[86] The limited application of LNB to small generators is due to the longer and wider flame produced by the LNB and the geometry of small steam generators. Because the radiant section in small generators is shorter in length and diameter than the radiant section in large generators, flame impingement is more of a problem.[86] Thus, LNB retrofits are primarily applicable to TEOR steam generators larger than 35 MMBtu/hr.

5.3.8.3 FGR and OT

FGR systems have been applied to TEOR steam generators on a more limited basis than LNB systems. Results from Kern County tests of 36 crude-oil-fired steam generators with FGR and O_2 trim showed controlled NO_x levels similar to those obtained with LNB systems, ranging from 79 to 264 ppm (0.10 to 0.33 lb/MMBtu).[87] Thus, for crude oil firing, FGR controls appear as effective as LNB systems in reducing NO_x. For natural gas firing, tests of three large units using FGR in combination with LNB measured controlled emission levels of 25 to 35 ppm (0.03 to 0.04 lb/MMBtu). NO_x reduction for two of these units ranged from 50 to 68 percent. For these particular units, these reductions in NO_x represent significant improvement over NO_x reduction efficiencies obtained using LNB alone.[56,88] Data are too limited, however, to characterize the performance of FGR controls used with natural-gas-fired TEOR steam generators.

5.3.9 Gas Fuel Flow Modifiers

In addition to the combustion techniques discussed thus far, a device known as a gas turbulator has been demonstrated to reduce NO_x formation in natural-gas-fired packaged boilers. Originally designed to produce savings in fuel consumption, the turbulator is a small stainless steel venturi incorporating strategically placed fins. The turbulator is inserted in the gas pipe directly upstream of the burner, creating highly turbulent fuel flow. This turbulence facilitates the bonding of hydrocarbon particles with the oxygen molecules of the combustion air, resulting in increased combustion efficiency.[94] Fuel savings typically range between 2 and 10 percent, but have been as high as 35 percent.[95]

From an NO_x standpoint, the more efficient turbulent mixing of the fuel and air results in lower excess air requirements for efficient combustion, producing lower levels of NO_x.[94,95] The only turbulator-related NO_x emissions data available to date are for a 33.5 MMBtu/hr natural-gas-fired firetube boiler at Duncan Boiler Service, Inc., in Kenner, Louisiana. At this site, the use of a turbulator raised full-load boiler efficiency by 3 percent, and the improved air/fuel mixing reduced the required excess oxygen by 27 percent. Consequently, NO_x emissions were reduced from 58 to 35 ppm at 3-percent oxygen, a 40-percent decrease.[96]

5.4 COMBUSTION MODIFICATIONS FOR NONFOSSIL-FUEL-FIRED ICI BOILERS

Application of combustion modification NO_x controls to nonfossil-fuel-fired ICI boilers is very limited. Many waste-fuel-fired boilers are not easily modified to reduce NO_x without compromising combustion efficiency and byproduct emissions. Furthermore, nonfossil fuels include a variety of waste fuels with varying combustion characteristics and pollutant profiles. Consequently, adaptation of conventional combustion controls can be difficult and very site-specific. Currently, more attention has focused on the application of flue gas treatment controls to nonfossil-fuel-fired ICI boilers, especially in California, where flue gas treatment controls have been applied to at least 17 units fired on wood or MSW. These applications are discussed in Section 5.3.

Combustion modification retrofit experience has been limited to the use of SCA. In one wood-/natural-gas-fired overfeed stoker unit, equipped with four gas burners as well as a traveling grate for wood firing, staged combustion was achieved by removing one of the four gas burners from service. Although 20 percent NO_x reduction was achieved, it should be noted that combustion modification was applied to the gas burners without any change to the wood-firing stoker system. This control approach would not be possible on boilers without supplemental gas firing. Difficulties were experienced with fluctuating bark flows, resulting in unsteady combustion conditions.[74]

Applications of combustion modifications to new nonfossil-fuel-fired units involve MSW-fired boilers equipped with FGR and natural gas reburn controls. Gas reburn for MSW boilers is being developed by Riley Stoker and Takuma Company, for NO_x control purposes and to suppress the formation of air toxic organics and combustible emissions.[97] In a 45 MMBtu/hr overfeed stoker MSW facility in Minnesota, NO_x emissions were reduced by 40 percent using FGR. When natural gas reburn was used in combination with FGR, NO_x was reduced by 60 percent, to a controlled level below 50 ppm. CO emissions were also decreased by 50 percent, to levels below 25 ppm. Natural gas reburn represented 12 to 15 percent of the total heat input, and FGR rates during these tests were roughly 8 percent.[97] Test results from a pilot-scale MSW-fired stoker boiler equipped with FGR and natural gas reburn showed 49 percent NO_x reduction efficiency, utilizing 17 percent FGR.[98,99] Because of the limited documented experiences regarding the retrofit of combustion modifications to existing nonfossil-fuel-fired boilers, no meaningful conclusions can be reached as far as NO_x control effectiveness or feasibility.

5.5 FLUE GAS TREATMENT NO_x CONTROLS FOR ICI BOILERS

NO_x control with flue gas treatment involves the reduction of NO_x in the flue gas by injecting a chemical reducing agent into the post-combustion region of a combustion unit. The reducing agents, primarily ammonia and urea, convert the NO in the flue gas to molecular nitrogen at high temperatures, between 870 and 1,100 °C (1,600 and 2,000 °F), without a catalyst. When a catalyst is used, this conversion takes place at a lower temperature range, roughly 300 and 425 °C (575 to 800 °F). Flue gas treatment methods without a catalyst are SNCR, while those with a catalyst are termed SCR. These methods are discussed in the following subsections.

Retrofitting these technologies to boilers typically involves installation of reagent injection nozzles, reagent storage and control equipment, and, in the case of SCR, catalytic reactors. Because flue gas treatment NO_x reduction efficiency depends in large part on flue gas temperature, injection nozzle placement is limited to those locations where acceptable process temperatures are present. Generally, in packaged ICI boilers, available locations for reagent injection and catalyst placement are further limited by space considerations. These units may also operate with wide ranges in boiler steam load that cause flue gas temperature shifts outside the optimum temperature window. Injection of reagents outside the optimum reaction temperature window results in lowered NO_x reduction efficiency and emissions of unreacted ammonia. SNCR and SCR controls have been applied primarily to larger boilers or new packaged boilers because these applications offer better control of temperature window and steady load demands.

5.5.1 Selective Noncatalytic Reduction (SNCR)

Two primary types of SNCR control technologies are currently available for retrofit to ICI boilers. The first is based on the use of ammonia

(NH_3) as the reducing agent, while the second, more recently introduced, is based on the use of urea (NH_2CONH_2). Several urea-based systems have been patented and are commercially offered by several domestic vendors. The following subsections briefly describe the experience to date using these controls on ICI boilers. Available data for SNCR application to industrial boilers are contained in Appendix B and summarized in Table 5-12. Generally, similar NO_x reduction efficiencies were obtained whether ammonia or urea was used. For ammonia injection, NO_x reduction ranged from 50 to 80 percent, depending on fuel type. For urea-based systems, most reported NO_x reduction efficiencies also fell within this range, although some were as low as 25 percent and as high as 88 percent. Experience with SNCR on smaller capacity boilers is minimal. Low-load operation and frequent load changes on such boilers pose additional complexities on the retrofit of SNCR for these boilers.

5.5.1.1 Ammonia-based SNCR

Exxon Research and Engineering Company developed and patented an ammonia-based SNCR process known as Thermal DeNO$_x$®. The Thermal DeNO$_x$ process is based on a gas phase homogeneous reaction between NO_x and ammonia which produces molecular nitrogen and water at high temperature. In this process, aqueous or anhydrous ammonia is vaporized and injected into the flue gas through wall-mounted nozzles at a location selected for optimum reaction temperature and residence time. The optimum reaction temperature range for this process is 870 to 1,100 °C (1,600 to 2,000°F), although this can be lowered to 700 °C (1,300°F) with additional injection of gaseous hydrogen.[100] At temperatures above 1,100 °C (2,000°F), ammonia injection becomes counterproductive, resulting in additional NO formation. Below 870°C (1,600°F), the reaction rate drops and undesired amounts of ammonia are carried out in the flue gas. Unreacted ammonia is

TABLE 5-12. SNCR NO_x CONTROL FOR ICI BOILERS

Reagent	Description of technique	Fuel type	Number of industrial boilers tested	% NO_x reduction	Controlled NO_x levels: ppm @ 3% O_2	Controlled NO_x levels: lb/MMBtu	Comments
Ammonia	Injection of ammonia into flue gas to chemically reduce NO_x	Natural gas/oil	11 FE-WT[a]	50-72	25-160	0.03-0.20	Temperature window between 870 and 1,100°C (1,600 and 2,000°F). Most data are for Thermal $DeNO_x$®.
			5 PKG-WT[b]	30-65	N.A.[c]	N.A.	
		Coal	4 FBC	76-80	30-65	0.04-0.087	
			4 stoker	50-66	110-132	0.15-0.18	
			1 PC[d]	57	135	0.18	
		Wood	10 stoker	50-80	25-160	0.035-0.23	
			8 FBC	44-80	24-140	0.035-0.20	
		MSW	13 stoker	45-79	48-195	0.068-0.28	
Urea	Injection of urea into flue gas to chemically reduce NO_x	Natural gas/oil	7 FE-WT	50-60	41-104	0.049-0.13	Most data are for NOxOUT®.
		Coal	4 FBC	57-88	21-106	0.028-0.14	
			4 PC	30-83	110-300	0.15-0.41	
			9 stoker	40-74	105-210	0.14-0.28	
		Wood	14 stoker	25-78	60-118	0.084-0.17	
			2 PKG-WT	50	178-187	0.24-0.26	
			2 FBC	60-70	45-50	0.063-0.070	
			1 cell	52	96	0.14	
		MSW	13 stoker	41-75	44-210	0.062-0.30	

[a]FE-WT = field-erected watertube.
[b]PKG-WT = packaged watertube.
[c]N.A. = Not available in reference source used.
[d]Boiler burning coke in Japan.

commonly referred to as ammonia slip, breakthrough, or carryover.[101] The amount of ammonia slip also depends in part on the amount of ammonia injected. Although the chemical reaction requires one mole of NH_3 for each mole of NO, the NH_3/NO_x ratio used is usually greater than 1 to avoid an undesired reaction which results in formation of NO.[100] NH_3/NO_x ratios of 4 to 1 have been reported in fluidized bed applications.[102] Ratios used are usually greater than 1 due to competing reactions at the temperatures involved.

The Thermal $DeNO_x$ process has been applied to a number of boilers firing both fossil and nonfossil fuels. In the U.S., most Thermal $DeNO_x$ applications have been on new units, many located in California. At least two retrofit applications on wood-fired industrial boilers have also been reported, one to a 375 MMBtu/hr wood-fired stoker unit and one to a 210 MMBtu/hr boiler, also a wood-fired stoker.[100] Both retrofits resulted in 50 percent NO_x reduction, with controlled emissions of 45 and 50 ppm (0.06 and 0.07 lb/MMBtu).

Overall, experience with ammonia-based SNCR on both new and existing units has shown the following results, listed in Table 5-12. NO_x reduction ranged from 50 to 80 percent for 10 wood-firing stokers and between 44 and 80 percent for eight wood-firing FBC units. For 13 MSW-fired units, NO_x reduction ranged from 45 to 79 percent, while for four coal-fired FBC units, 76 to 80 percent reductions were achieved. Several natural-gas-fired furnaces experienced 30 to 72 percent NO_x reduction. In addition to these applications, it has been reported that ammonia-based SNCR has been used on over 100 TEOR steam generators burning crude oil in Kern County, achieving reductions of approximately 70 percent.[103] Thus, for all applications, ammonia-based $DeNO_x$ reduced NO_x by roughly 30 to 80 percent. The upper range of NO_x reduction efficiency range is more characteristic of boilers operating at steady load such as cogeneration FBC units.

Achievable NO_x reductions for an individual boiler depend on the flue gas temperature, the residence time at that temperature, the initial NO_x concentration, the NH_3/NO_x ratio, the excess oxygen level, and the degree of ammonia/flue gas mixing. Also, stratification of both temperature and NO_x in the flue gas can affect the performance of the SNCR control.[104] The optimum placement of SNCR injectors requires a detailed mapping of the temperature profile in the convective passes of the boiler, because of the narrow temperature window. According to Exxon, the Thermal $DeNO_x$ process has no measurable effect on CO, CO_2, or SO_x emissions.[100]

The feasibility of retrofitting an existing boiler with SNCR often hinges on the ability to accommodate injection nozzles at a location where flue gas temperatures and residence time are optimum for the reaction to take place. In field-erected boilers, the ammonia is usually injected into either a superheater tube bank or between a superheater tube bank and the steam generator tube bank,[103] while, for a typical wood-fired stoker boiler, injectors are usually located before the first superheater coil. In a coal or wood-fired CFBC boiler, ammonia injectors are usually located after the cyclone to avoid high solids and NH_3 recirculation.[100] Smaller units, especially packaged watertube and firetube boilers, have limited space and access for the injection nozzles.

5.5.1.2 Urea-based SNCR

Originally developed by the Electric Power Research Institute (EPRI), a newer SNCR technology for flue gas treatment NO_x control utilizes urea as a reagent rather than ammonia. One urea-based SNCR process, known by the trade name of NOxOUT®, is offered by Nalco Fuel Tech, Inc., and its licensees (Foster Wheeler, Wheelabrator Air Pollution Control, Research Cottrell, Todd Combustion, RJM Corporation, and several others internationally). Other vendors, such as Applied Utility Systems and Noell, Inc., have also developed and installed urea-based SNCR processes. In the NOxOUT process, an aqueous solution containing urea and chemical enhancers is injected into the furnace or boiler at one or more locations, depending on the boiler type and size. The urea reacts with NO_x in the flue gas to produce nitrogen, carbon dioxide, and water. The main advantage of urea injection over ammonia injection is that urea is a nontoxic liquid that can be safely stored and handled.

Like ammonia injection, NOxOUT is effective only within a certain temperature range. Without the use of chemical enhancers, urea injection effectively reduces NO_x at temperatures between 900 and 1,150 °C (1,650 and 2,100°F). Residence time at temperature of interest is important. By using proprietary enhancers and adjusting concentrations, greater NO_x reduction efficiency can be achieved over a wider temperature window. If the urea is released at too high a temperature, the chemical species can actually be oxidized to form NO_x. Below this temperature, urea reacts with NO_x to form undesired amounts of ammonia. Table 5-12 lists NO_x reduction efficiencies of 25 to 88 percent, reported for different types of boilers burning coal, oil, MSW, and wood which have been retrofitted with urea injection. As with Thermal $DeNO_x$, actual reduction performance is highly dependent on temperature, amount of reagent used, and level of reagent/NO_x mixing.[105] Most of the commercial experience includes MSW-, wood-, and coal-fired stokers, and gas-fired boilers and incinerators. These applications have been on new and existing units. Successful demonstrations are documented on oil- and coal-fired boilers in the utility industry. NO_x reductions of as low as 10 percent to as high as 76 percent have been recorded for utility boilers. An average NO_x reduction performance of 45 percent is estimated for PC-fired boilers.[106] Due to residence time and temperature constraints, small packaged watertube and firetube boilers with fluctuating steam loads are difficult applications, and require case-by-case determinations for cost and performance levels.

5.5.2 Selective Catalytic Reduction (SCR)

The SCR process takes advantage of the selectivity of ammonia to reduce NO_x to nitrogen and water at lower temperature in the presence of a catalytic surface. Two catalyst formulations are denoted "base metal," this category including oxides of titanium, molybdenum, tungsten, and vanadium, and zeolites, which are alumina-silicate-based. These formulations may include other components that impart structural stability. Catalysts come in various shapes and sizes, according to the particular application. Gaseous ammonia is injected with a carrier gas, typically steam or compressed air, into the flue gas upstream of the catalyst. The ammonia/flue gas mixture enters the catalyst, where it is distributed through the catalytic bed. The flue gas then leaves the catalytic reactor and continues to the exit stack or air preheater. SCR technology is capable of achieving similar NO_x reductions as

Thermal DeNO$_x$ SNCR using a much smaller amount of ammonia, due to the positive effects of the lower reaction temperature and the selective catalyst.[101] Because of this, ammonia slip tends to be less with SCR than with SNCR.

SCR operates most efficiently at temperatures between 300 and 425 °C (575 and 800 °F) and when the flue gas is relatively free of particulate matter, which tends to contaminate or "poison" the catalytic surfaces.[101,107] Recent catalyst formulations can resist poisoning and abrasion in flue gas environments with high ash loading and trace metals, while maintaining NO$_x$ reduction performance. Typically, the catalytic reactor is located ahead of the air heater, to take advantage of the temperature regime. Sometimes, however, the reactor may be placed just ahead of the stack and downstream of particulate collection devices, avoiding catalyst contamination. In most cases, however, such placement requires reheating of the flue gas to meet temperature requirements, impacting the cost of the system. To avoid reheat requirements, some manufacturers are currently developing or have already developed special low-temperature catalysts which can be used at temperatures as low as 200 °C (400 °F).[107]

TABLE 5-13. SELECTED SCR INSTALLATIONS, CALIFORNIA ICI BOILERS

Boiler ID	Boiler type	Capacity, MMBtu/hr	Fuel used	Controlled NO_x emissions: ppm @ 3% O_2	Controlled NO_x emissions: lb/MMBtu
Darling-Delaware	PKG-WT[a]	110	Natural gas/ propane	9	0.011
Fletcher Oil and Refining	Unknown	49	Distillate oil	20	0.025
Lockheed	PKG-WT	N.A.[b]	Natural gas/ distillate oil	9	0.011
Kalkan Foods, Inc.	PKG-WT	78.6	Natural gas/ methanol	9	0.011
Ultramar Refinery	PKG-WT	N.A.	Refinery gas	11	0.011
Southern California Edison	Unknown	107 MWe	Natural gas	20	0.024

[a]PKG-WT = Packaged watertube boiler.
[b]N.A. = Not available.

SCR has seen very limited application on domestic ICI boilers. Table 5-13 shows a selected list of SCR applications on industrial boilers in California. A more complete list of SCR installations on ICI boilers is included in Appendix B. Most of the industrial applications of this control technology have been in Japan, where much of the original SCR technology development took place. Within the industrial sector, SCR has been applied primarily to gas- or oil-fired units, as well as a few PC-fired units or coal-fired BFBCs. SCR has not yet been demonstrated in CFBC units or stoker coal-fired boilers. However, it was recently announced that SCR will be incorporated into the design of a 220 MWe stoker coal-fired power plant in Virginia, as well as a 125 MWe CFBC in Sweden.[108,109] Major suppliers of SCR cat alysts include MHI, Babcock Hitachi, Corm etech, Engelhard, Johnson Matthey, and Norton.

Table 5-14 summarizes performance data for SCR applications t o boilers in the ICI sector. Data from Japanese oil-fired industrial boiler s retrofitted with SCR show NO_x reductions ranging from 85 to 90 percent . These units had controlled NO_x levels between 17 and 25 ppm (0.02 an d 0.03 lb/MMBtu), operating with flue gas treatment temperatures of 300 t o 370°C (575

TABLE 5-14. SCR NO_x CONTROLS FOR ICI BOILERS

Description of technique	Fuel type	Number of industrial boilers tested	% NO_x reduction	Controlled levels: ppm @ 3% O_2	Controlled levels: lb/MMBtu	Comments
Injection of ammonia into flue gas to chemically reduce NO_x	Oil	7	85-90	17-25	0.022-0.032	Temperature window between 300 and 425°C (575 and 800°F).
	Natural Gas	3	53-80	9-46	0.011-0.055	
	Coal	2	53-63	72-110	0.097-0.15	
	Ref. gas	4	83-94	9-11	0.011-0.013	
	MSW	1	53	36	0.051	
	Wood waste	2	80	154	0.22	

to 700°F).[109] Specific information was not available on the types of oil fired in these boilers or on boiler operating conditions; therefore, these reported NO_x levels should not be used to extrapolate controlled NO_x levels for all oil-fired boilers.

Similar reduction efficiencies of 83 and 94 percent were obtained on units firing refinery gas.[110] One of these units was located in Japan, the others at a California refinery. Results from tests conducted on three natural-gas- and two coal-fired boilers with SCR showed more moderate reduction efficiencies of 53 to 80 percent. Likewise, a single MSW-fired unit experienced 53 percent NO_x reduction with SCR.[101] In summary, NO_x reduction efficiencies with SCR have been reported in the range between 53 and 90 percent. Available data are too limited, however, to allow any correlations between fuel type, boiler type, and SCR effectiveness to be made.

The retrofit of SCR to an existing boiler requires far more extensive modifications than does SNCR, as the SCR reactor must be placed in the existing flue gas path where the temperature is sufficiently high for efficient NO_x control. This is in addition to the required installation of reagent injectors and storage and control equipment. The difficulty in retrofitting SCR to existing boilers was reflected in the compliance plans put forth by petroleum refiners in California's South Coast Air Basin, in response to the SCAQMD Rule 1109. Rather than retrofit existing boilers with SCR, many refiners instead opted to replace their old boilers with new units already incorporating SCR.[111] Because catalysts lose their effectiveness over time due to contamination or clogging of catalyst pores, they must be replaced periodically. On large boilers, it has been reported that catalyst replacement may be necessary every 1 to 5 years, depending on the application and the level of contaminants in the fuel.[112]

5.6 SUMMARY OF NO_x REDUCTION PERFORMANCE

Table 5-15. Summary of NO$_x$ reduction efficiencies and controlled NO$_x$ (continued)

Boiler and fuel	NO$_x$ control	Range in performance: Reduction efficiency, %	Range in performance: Controlled NO$_x$, lb/MMBtu	Average performance[a]: Reduction efficiency, %	Average performance[a]: Controlled NO$_x$, lb/MMBtu
Gas-fired MBWT[e,f]	SCA (BOOS)	17-46	0.06-0.24	31	0.15
	LNB[g]	38-52	0.10-0.17	46	0.12
	SNCR	50-72	0.03-0.19	58	0.10
	SCR[h]	N.A.[c]	0.024	N.A.	0.024
	LNB+SCA	N.A.	0.10-0.20	N.A.	0.15
Distillate firetube	LNB[h]	15	0.15	15	0.15
	FGR	N.A.	0.04-0.16	N.A.	0.12
Distillate SBWT[d,e]	LNB	N.A.	0.08-0.33	N.A.	0.10
	FGR	20-68	0.04-0.15	44	0.08
	LNB+FGR	N.A.	0.03-0.13	N.A.	0.07
	SCR[h]	N.A.	0.011	N.A.	0.011
Residual oil firetube	LNB[i]	30-60	0.09-0.25	40	0.17
Gas-fired firetube	LNB	32-78	0.02-0.08	50	0.03
	Radiant LNB	53-82	0.011-0.036	71	0.02
	FGR	55-76	0.02-0.08	65	0.07
	LNB+FGR	N.A.	0.02-0.04	N.A.	0.03
Gas-fired SBWT[d,e]	WI	50-77	0.04-0.056	64	0.05
	FGR	53-74	0.02-0.08	64	0.05
	LNB[i]	46-71	0.03-0.11	58	0.08
	LNB+FGR	55-84	0.018-0.09	76	0.06
	SCR	80-91	0.011-0.06	85	0.024

(continued)

TABLE 5-15. SUMMARY OF NO$_x$ REDUCTION PERFORMANCE

Boiler and fuel	NO$_x$ control	Range in performance: Reduction efficiency, %	Range in performance: Controlled NO$_x$, lb/MMBtu	Average performance[a]: Reduction efficiency, %	Average performance[a]: Controlled NO$_x$, lb/MMBtu
PC-fired boilers: all firing types with wall or corner burners	SCA	15-39	0.35-0.93	27	0.62
	LNB	18-67	0.26-0.50	35	0.35
	Reburn+OFA	30-65	0.23-0.52	32	0.34
	LNB+SCA	42-66	0.24-0.49	60	0.38
	SNCR	30-83	0.15-0.40	45	0.39
Coal-fired stokers	SCA	-1-35	0.22-0.52	18	0.38
	FGR+SCA	0-60	0.19-0.47	24	0.34
	SNCR	40-74	0.14-0.28	58	0.22
Coal-fired FBC	SCA	40-67	0.05-0.45	58	0.18
	FGR+SCA	N.A.[c]	0.12-0.16	N.A.	0.14
	SNCR	57-88	0.03-0.14	74	0.08
	SCR	53-63	0.10-0.15	60	0.12
Residual oil SBWT[d,e]	LNB	30-60	0.09-0.23	40	0.19
	FGR	4-30	0.12-0.25	15	0.17
	LNB+FGR[h]	N.A.	0.23	N.A.	0.23
Residual oil MBWT[e,f]	SCA	5-40	0.22-0.74	20	0.34
	LNB[j]	30-60	0.09-0.23	40	0.19
	LNB+SCA[h]	N.A.	0.22	N.A.	0.22
	SCR	58-90	0.025-0.15	83	0.045
Wood-fired stoker	SNCR	25-80	0.04-0.23	58	0.13
Wood-fired FBC	SNCR	44-80	0.035-0.20	64	0.09
MSW-fired stoker	SNCR	41-79	0.06-0.31	60	0.18

[a]Arithmetic averages of reported control efficiency NO$_x$ levels with specified controls. Values do not necessarily reflect emission targets that can be achieved in all cases.

[b]Average NO$_x$ reduction is based on utility boiler PC experience.

[c]N.A. = Not available.

[d]SBWT = Single-burner watertube. Also referred to as packaged watertube (PKG-WT).

[e]Data for gas- and oil-fired watertube boilers are limited to performance reported in Appendix B, exclusive of equipment vendor data reported in Appendix C.

[f]MBWT = Multi-burner watertube. Also referred to as field-erected watertube (FE-WT).

[g]Most LNB applications include FGR.

[h]Only one data point available.

[i]Experience relies primarily on Japanese industrial installations.

[j]No data available. NO$_x$ levels assumed to be on the same order as those reported for single-burner packaged watertubes.

levels for each boiler, fuel, and control combination investigated in this report. Arithmetic average performances are listed, but care must be used in interpreting them. Because these are averages, the data do not represent the NO_x control performance attainable in all cases. Actual performance will be influenced by several factors, including fuel type, degree of control applied, and the boiler's design and operating condition. Because coal and residual oil can vary in nitrogen content and other properties, the actual NO_x level achieved with these fuels will be very much a function of these fuel properties. Certainly, the degree of FGR and air staging applied,

or the amount of ammonia or urea reagent used, will influence the percent reduction efficiency and the NO_x level achieved.

NO_x from pulverized coal combustion in industrial boilers with LNB controls was shown to be controlled to levels ranging from 0.26 to 0.50 lb/MMBtu. These data include results for both tangential- and wall-fired boilers. The average, 0.35 lb/MMBtu, is lower than reported average control levels for utility boilers.[113] Therefore, this average efficiency should be used cautiously, considering the limited data available to this study. Other data show SNCR to be quite effective in reducing NO_x from coal- and waste-fuel-fired FBC and stoker boilers. Average levels for these sources controlled with either ammonia or urea range from 0.08 to 0.22 lb/MMBtu. For gas- and distillate-oil-fired ICI boilers, FGR and LNB controls operating alone or in combination can attain NO_x levels averaging 0.02 to 0.15 lb/MMBtu. Data on residual oil are somewhat more sparse. NO_x control levels from residual-oil-fired boilers are largely influenced by the nitrogen content of the fuel. Combustion controls for these boilers show average controlled levels ranging from 0.17 to 0.34 lb/MMBtu.

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6. COSTS OF RETROFIT NO_x CONTROLS

This chapter evaluates the economic impacts of controlling NO_x from existing ICI boilers. Costing methodologies and assumptions are discussed in Section 6.1. Section 6.2 presents the costs calculated for various NO_x controls retrofitted to ICI boilers. Section 6.3 discussed the capital and total annual costs of NO_x controls. Section 6.4 presents the cost effectiveness of NO_x controls. Supporting documentation, including costing spreadsheets, are included as appendices. Appendix D contains cost effectiveness data for the boilers and control systems analyzed, scaled from annual cost data of Appendices E, F, and G. The latter appendices contain detailed cost analysis spreadsheets developed from actual data provided by vendors, boiler owners, and regulatory agencies.

Whenever possible, cost data from actual retrofit projects were used to develop the cost effectiveness figures presented in Section 6.4. When key cost figures from actual projects were unavailable or not accounted for, however, the cost algorithms and assumptions described in Section 6.1 were used to supplement the available cost data.

6.1 COSTING METHODOLOGY

The costing methodology used in this study is based primarily on the U.S. EPA's OAQPS Control Cost Manual,[1] although certain cost components have been modified specifically for this study, based on conventional costing practice and actual cost data. Costs of retrofit NO_x controls for ICI boilers can be divided into two major cost categories — capital investment costs and annual operations and maintenance (O&M) costs. Capital costs are the total investment necessary to purchase, construct, and make operational a control system. O&M costs are the total annual costs necessary to operate and maintain the control system, above what was required to operate the pre-retrofit boiler without NO_x control. Each of these cost categories can be further subdivided into individual cost components. Section 6.1.1 discusses capital cost components, Section 6.1.2 discusses elements of O&M costs, and Section 6.1.3 describes the methodology for evaluating a control technology's overall cost effectiveness based on these capital and O&M costs.

6.1.1 Capital Costs of Retrofit NO_x Controls

Capital costs of NO_x controls include both direct and indirect cost components. Direct capital costs are expenses required to purchase equipment for the control system, referred to as purchased equipment costs, as well as those expenses required for installing the equipment in the existing boiler, known as direct installation costs. Indirect capital costs are costs entailed in the development of the overall control system, but not attributable to a specific equipment item. These costs are also referred to as indirect installation costs. In addition to direct and indirect components of capital investment costs, contingency costs are also added to account for unpredictable expenses. Figure 6-1

Figure 6-1. Elements of total capital investment cost. [1]

illustrates these principal elements of total capital investment and lists common sub-elements which comprise them. The major capital cost elements are described in detail below.

All costs in this chapter and the appendices are presented in 1992 dollars. When available cost data were referenced to other years, the Chemical Engineering Plant Cost Index was used to convert costs to 1992 dollars.[2-4]

6.1.1.1 Purchased Equipment Costs

Purchased equipment costs include the costs of primary control equipment, such as low-NO_x burners, FGR fans, or catalytic converters; auxiliary control equipment; instrumentation; and applicable sales taxes and shipping charges. When data were provided, the cost of CEM equipment was also included in the purchased equipment cost. For this study, instrumentation, tax, and freight charges were estimated as being 18 percent of the total primary and auxiliary equipment costs.[1]

6.1.1.2 Direct Installation Costs

The second major component of direct capital costs, direct installation costs include both labor and materials costs for foundations, supporting structures, piping, insulation, painting, handling and erection, and electrical work. Direct installation costs vary considerably from site to site and depend on such factors as availability of space, the amount of boiler modification that must be done to accommodate the control system, and existing facilities. Although direct installation costs may vary widely, they were estimated as 30 percent of purchased equipment cost in this study, unless an actual cost figure was provided. This is towards the low end of reported ranges for direct installation cost.[1,5] When direct installation cost data for new boiler applications were provided by vendors, the figures were doubled to account for additional retrofit expenses.[1,6] Costs of research and development and the cost of lost production during installation and startup were not included in direct installation cost.

6.1.1.3 Indirect Installation Costs

Indirect installation costs consist of engineering costs, construction and field expenses, construction fees, and expenses associated with startup, performance tests, and permitting. When actual cost data were unavailable, these costs were estimated to be approximately 33 percent of the purchased equipment cost.[1] For SCR retrofits, indirect installation was estimated as 66 percent of purchased equipment cost to account for additional engineering and construction requirements.

6.1.1.4 Contingencies

Contingency costs were added to capital cost estimates to account for additional expenses due to such things as price changes, small design changes, errors in estimation, strikes, or adverse weather conditions. These are unpredictable costs likely to occur.[5] In the cost spreadsheets of Appendices E, F, and G, contingency costs were estimated primarily as 20 percent of the total direct and indirect capital cost.[7,8] Cost estimates obtained from selected control vendors already included contingencies. To avoid double accounting, no additional contingency costs were added.

6.1.1.5 Other Capital Costs

Other costs which may be included as capital costs are expenditures for site preparation, buildings, land, and working capital. Site preparation costs are sometimes accounted for in direct installation costs, and in most cases are unreported. Additional buildings are usually not required for retrofit NO_x control systems for ICI boilers, except in cases where existing facilities are absolutely unable to accommodate additional equipment installation. For the purposes of this study, site preparation and building costs were listed in the cost spreadsheets, but were only used if sources provided costs for these items.

Working capital is a fund set aside to cover the initial O&M costs of labor, fuel, chemicals, and other materials for a given time, usually on the order of 90 days.[7] This fund is primarily used in cost analyses for large systems which require significant amounts of utilities, O&M labor, and materials.[1] Because most of the control systems considered in this study do not require large amounts of utilities, O&M labor and materials, working capital costs were not included in this study. Costs of additional land were also not included since most retrofit control systems do not require much space. These omissions are consistent with U.S. EPA OAQPS costing methodologies.[1]

6.1.2 Annual Operations and Maintenance (O&M) Costs

Annual O&M costs of NO_x control systems are classified as either direct or indirect annual costs. For this study, O&M costs were considered to be costs resulting from the use of the NO_x control equipment only, and are separate from the annual O&M costs of the existing boiler. Figure 6-2

Figure 6-2. Elements of total annual O&M cost. [1]

displays common elements of annual O&M costs. Included as direct annual O&M costs are expenses for labor and maintenance materials, utilities such as electricity or steam, fuel or chemicals which may be required for the control system, and waste disposal which may be required with SCR system catalysts. With FGR NO_x control systems, boiler fuel consumption may actually decrease due to increased boiler efficiency, resulting in an overall fuel savings. Two sources estimated fuel savings of 1 to 2 percent when FGR was retrofitted.[9,10] In the cost calculations of Appendices E, F, and G, fuel savings of 1 percent were included for all FGR systems.

Prices for fuels and electricity in the U.S. were obtained from Energy User News.[11] The cost of electricity was estimated as $0.05/kWh, while the cost per MMBtu for natural gas, distillate oil, and residual oil were estimated as $3.63, $4.83, and $2.35, respectively. The price of bulk anhydrous ammonia used for ammonia injection systems was estimated at $250 per ton, while the price of bulk urea was estimated at $220 per ton.[12]

Indirect annual O&M costs include overhead, administrative charges, property taxes, and insurance. Following the cost methodology developed by OAQPS, overhead charges were estimated as 60 percent of the annual labor and maintenance materials costs, while administrative, property tax, and insurance costs were estimated as 4 percent of the total capital investment cost described in Section 6.1.1.[1]

TABLE 6-1. ASSUMPTIONS FOR ESTIMATING CAPITAL AND ANNUAL O&M COSTS

Cost element	Cost assumption
Direct capital costs	
NO_x control equipment	Given
Instrumentation	10% of equipment cost
Sales taxes	3% of equipment cost
Freight	5% of equipment cost
Total = Purchased Equipment Cost (PEC)	
Direct installation cost	30% of PEC
Site preparation	0 unless given
Buildings	0 unless given
Indirect capital costs	
Engineering	10% of PEC [a]
Construction and field expenses	10% of PEC [a]
Construction fee	10% of PEC [a]
Startup	2% of PEC [a]
Performance test	1% of PEC [a]
Contingency	20% of direct and indirect capital costs
O&M costs	
FGR fuel savings	1% of boiler fuel cost
Overhead	60% of labor and maintenance material cost
Administrative	2% of total capital cost
Property tax	1% of total capital cost
Insurance	1% of total capital cost

[a]Increased by a factor of 2 for SCR installations.

Table 6-1 summarizes the assumptions made for estimating capital and O&M costs for retrofit NO_x control systems. When developing a NO_x control cost spreadsheet based on data from a particular reference source, these estimates were used whenever data were not provided by the source.

6.1.3 Total Annualized Cost and Cost Effectiveness

Total capital investment and total annual O&M costs may be combined to give a total annualized cost. Total capital investment is converted into uniform annual capital recovery costs which represent the payments necessary to repay the capital investment over a given time period at a given interest rate. This is done by multiplying the total capital investment cost by a capital recovery factor. For this analysis, a 10-percent interest rate and an amortization period of 10 years was assumed for the NO_x control systems, which results in a capital recovery factor of 0.1627.[13] The interest rate of 10 percent was selected as a typical constant dollar rate of return on investment to provide a basis for calculation of annualized capital investment cost. Although 10 years was chosen as the capital amortization period, other periods could have been selected if desired, as long as the same amortization period is used when comparing costs of different control systems. When the annualized capital cost is added to the total annual O&M costs discussed in Section 6.1.2, the resulting figure is the total annualized cost of the NO_x control system.

In order to compare the cost effectiveness of different controls on a given boiler, the total annualized cost of each control system was divided by the amount of NO_x removed by the system over 1 year. The amount of NO_x removed from a boiler is a function of the achievable NO_x reduction of the control system and of the annual capacity of that unit. An annual capacity factor represents the ratio of the amount of heat input a unit uses in a year to the amount it could have used if it was operated at full rated capacity 24 hours a day, 365 days per year. For the purposes of this study, it was assumed that all boilers, when operated, ran at full rated capacity, as opposed to being run at half load, for example. However, the annual capacity factors of all boilers were assumed to be less than 1.

The actual amount of boiler operating time over a year typically depends on the boiler size and application. For example, smaller capacity boilers used in commercial or institutional sectors are often operated intermittently, providing power for daily needs of office buildings, schools, etc. as needed. On the other hand, larger units located in large manufacturing facilities may operate almost continuously during the workweek. To illustrate the effect of capacity factor on NO_x control cost effectiveness, cost effectiveness was calculated for each boiler test case at capacity factors of 0.33, 0.5, 0.66, and 0.8. While data for the complete range of capacity factors are presented in the appendices, the summary tables in this chapter show cost effectiveness calculated for the mid-range capacity factors of 0.5 and 0.66 only.

To estimate the amount of NO_x removed by a control system per year, pre-retrofit and post-retrofit NO_x emission levels must be known, in addition to the boiler capacity factor and heat input capacity rating. Assumed baseline NO_x levels were selected for each fuel and boiler type based on data

TABLE 6-2. BASELINE (UNCONTROLLED) NO_x EMISSIONS USED FOR COST CASES

Fuel	Boiler type	Baseline NO_x, lb/MMBtu[a]
Natural gas	Firetube	0.12
	Watertube	
	10 to <75 MMBtu/hr	0.16
	75 to 150 MMBtu/hr	0.18
	>150 to <350 MMBtu/hr	0.24
	350 to <750 MMBtu/hr	0.30
	≥750 MMBtu/hr	0.40
Distillate oil	All	0.20
Residual oil	All	0.38
Pulverized coal	Wall-fired	0.70
Coal	Spreader stoker	0.53
Coal	FBC	0.32
Wood	Stoker	0.25
Wood	FBC	0.25
Wood/natural gas	Stoker	0.20
Paper	Packaged watertube	0.50
MSW	Stoker	0.40

[a]To convert to ppm at 3 percent O_2, multiply by the following factors: natural gas, 835; distillate oil, 790; residual oil, 790; coal, 740; wood, 710; paper, 710; MSW, 705 (approximate).

contained in Appendices A and B and summarized in Table 4-7 of Chapter 4. Table 6-2 lists the average baseline NO_x levels assumed for the purposes of calculating cost effectiveness. For natural-gas-fired watertube boilers, five boiler size categories were considered in the retrofit cost analyses. Average baseline NO_x emissions increase with boiler size because of the higher heat release rate and greater thermal NO_x formation. NO_x reduction efficiencies for each type of control were selected based on data contained in Chapter 5 and Appendix B, and are listed in Table 6-3

. These NO_x reduction efficiencies are assumed levels only; actual NO_x reduction performance of particular control systems may vary depending on boiler, fuel, and operating characteristics, as discussed in Chapter 5.

Total annualized costs are divided by the amount of NO_x emission reduction per year to obtain the cost effectiveness in terms of dollars per ton of NO_x reduced. As stated earlier, all costs in this analysis are expressed in terms of 1992 dollars.

TABLE 6-3. NO_x REDUCTION EFFICIENCIES USED FOR COST CASES

NO_x control technology	Applicable boiler equipment	NO_x reduction efficiency, % [a]
BT/OT	PKG-WT and FT	15
BT/OT and WI	PKG-WT and FT	65
BOOS with OT	FE-WT	50
BOOS/WI with OT	FE-WT	75
LNB	PC: wall-fired	50
	Nat. gas/oil: PKG-WT, FE-WT [b]	50
FGR	Nat. gas/oil: PKG-FT [c]	40
LNB and FGR	Nat. gas/oil: PKG-WT	60
SNCR	PC: wall-fired	45
	Coal: FBC	75
	Coal: Stoker	58
	Nonfossil: stoker, PKG-WT, FBC	55
SCR	PC: wall-fired	80
	Nat. gas/oil: PKG-WT	85

[a]See Chapter 5 and Appendix B.
[b]PKG-WT = packaged watertube; FE-WT = field-erected watertube.
[c]PKG-FT = packaged firetube.

TABLE 6-4. NO_x CONTROL COST EFFECTIVENESS CASES

Fuel type	Boiler type	Boiler capacity, MMBtu/hr	NO_x control technology	Cost data reference
PC	Wall-fired	250-750	LNB	14
		250-750	SNCR-ammonia	16
		250-750	SNCR-urea	17
		250-750	SCR	15
Coal	FBC	250-750	SNCR-urea	18
	Spreader stoker	250-750	SNCR-urea	17
Natural gas/distillate oil/residual oil	Packaged watertube	10-250	OT	19
	Packaged watertube	10-250	OT+WI	19
	Packaged firetube	3-34	OT	19
	Packaged firetube	3-34	OT+WI	19
	Packaged firetube	3-34	FGR	20
	Packaged watertube	10-250	LNB	6,14
	Packaged watertube	10-250	LNB+FGR	6,14,21
	Packaged watertube	10-250	SCR	9,22
	Field-erected wall-fired	250-750	LNB	14
Nonfossil fuel	Stoker	50-500	SNCR-urea	16
	Packaged watertube	10-250	SNCR-urea	16
	FBC	250-750	SNCR-ammonia	23

6.2 NO_x CONTROL COST CASES AND SCALING METHODOLOGY

NO_x control cost cases were selected based on the prevalence of control system applications to specific types and sizes of boilers and on the availability of cost data. Table 6-4 lists the cost cases analyzed and data sources from which various cost figures, principally capital and annual costs, were obtained. Cost data were compiled primarily from published reports and communications with selected boiler operators and control system manufacturers. Cost data for PC-fired boilers were limited to LNB, SNCR, and SCR control technologies. Capital and O&M costs for LNB and SCR were provided by the Council of Industrial Boiler Owners (CIBO) [14], and recent costs were developed for small utility PC-fired boilers.[15] Cost estimates for SNCR with urea and ammonia reagents were provided by vendors of these technologies. Experience with NO_x controls for ICI PC-fired boilers is generally very sparse; therefore, these cost estimates should be used with caution. Data on NO_x controls for FBC boilers were limited to SNCR, since combustion staging is usually integrated into the original FBC boiler design and operation. For firetube boilers, data were also limited primarily to FGR only. Cost estimates of WI+OT for firetube boilers were based on the data reported for packaged watertube boilers.

Raw data from the referenced sources listed were used to calculate the annual cost effectiveness figures presented in Appendices E, F, and G. Cost effectiveness estimates for each of the NO_x control cost cases were then obtained from these values, using the logarithmic scaling law known as the "six-tenths power rule," to account for differences in boiler capacity size.[5] Cost effectiveness was calculated for each cost case, using each applicable source of raw cost data. For example, the cost effectiveness of LNB used in 10 to 250 MMBtu/hr (2.9 to 73 MWt) natural-gas-fired packaged watertube units was calculated using annual costs derived from References 6 and 14, each of which provided data on more than one LNB retrofit project. Each individual retrofit project was used to calculate a cost effectiveness value. Results obtained for each cost case from each source are contained in Appendix D. The ranges in cost effectiveness obtained from all sources are summarized in the following subsections. In all, cost data for 42 different boiler/NO_x control configurations were used to develop these ranges, varying in boiler type, size, fuel, and NO_x control technology.

Most of the data obtained were for natural-gas-fired units, in part because of boiler retrofit activity in California's South Coast Air Basin, where natural gas is the primary fuel used. Cost effectiveness figures for distillate- and residual-oil-fired units were estimated using the annual costs for natural-gas-fired units. Appropriate baseline NO_x levels for fuel oil firing were used to calculate annual NO_x reduction. For FGR, fuel oil prices were used to estimate the annual fuel savings.

6.3 CAPITAL AND TOTAL ANNUAL COSTS OF NO_x CONTROLS

Table 6-5

TABLE 6-5. CAPITAL AND TOTAL ANNUAL COSTS OF RETROFIT NO_x CONTROLS FOR ICI BOILERS, 1992 DOLLARS

Boiler type, size, and fuel	NO_x control	Controlled NO_x, lb/MMBtu[a]	Capital cost, $/MMBtu/hr	Total annual cost, $/yr/MMBtu/hr[b]	Reference
400 MMBtu/hr PC-fired wall-fired watertube	LNB	0.35	5,300	1,220	14
	SNCR	0.28	1,600-2,100	950-1,200	16,17
	SCR	0.14	20,000	5,800	15
400 MMBtu/hr FBC	SNCR	0.08	1,600	680	18
400 MMBtu/hr stoker	SNCR	0.22	1,100	1,200	17
10.5 MMBtu/hr oil/gas firetube	OT+WI	0.04 (Gas)	2,400	690	19
	OT+FGR	0.07 (Gas) 0.12 (No. 2 oil)	5,400	1,100	20
50 MMBtu/hr oil/gas packaged watertube	OT+WI	0.06 (Gas)	530	210	19
	LNB	0.08 (Gas) 0.10 (No. 2 oil) 0.19 (No. 6 oil)	650-2,300	340-420	6,14
	LNB+FGR	0.06 (Gas) 0.07 (No. 2 oil) 0.15 (No. 6 oil)	2,100-4,700	430-890	6,14,21
	SCR	0.02 (Gas) 0.03 (No. 2 oil) 0.06 (No. 6 oil)	2,400-6,900	1,500-1,900	9,22
300 MMBtu/hr oil/gas field-erected watertube	OT+SCA (BOOS)	0.15 (Gas)	190	96	19
	LNB	0.12 (Gas) 0.10 (No. 2 oil) 0.19 (No. 6 oil)	5,100-8,300	990-1,500	14
150 MMBtu/hr wood-fired stoker	SNCR	0.11	2,100-2,500	500-800	16
400 MMBtu/hr wood-fired FBC	SNCR	0.11	970	590	23
500 MMBtu/hr MSW stoker	SNCR	0.18	2,100-3,300	940-1,100	15

[a]Arithmetic average of reported NO_x control performance. Not indicative of levels achievable in all cases.
[b]Calculated based on 0.66 capacity factor or 5,460 operating hours per year at the boiler capacity.
Note: All estimates are rounded to two significant figures.

summarizes the capital and total annualized costs of retrofit controls on selected "model" size boilers. The table also lists the anticipated NO_x control levels applicable to each control technology and model boiler. This information corresponds to data presented in Chapter 5. The total annualized cost includes the payments for the initial investment and the recurring direct and indirect O&M costs. The references indicate the sources of the capital cost data, and, in some cases, the O&M cost data, used in the analysis. As indicated earlier, when the reference cost data were for a different year or size of boiler, the capital costs were first updated to 1992 base year and then adjusted for boiler size using the "six-tenths" power law. That is:

$$Capital\ cost_2 = \left[\frac{(MMBtu/hr)_2}{(MMBtu/hr)_1}\right]^{0.6} Capital\ cost_1 \qquad (6\text{-}1)$$

The ranges in both capital and operating costs indicate that the references provided more than one cost case from which data could be extrapolated to the model boilers.

The reported capital cost of retrofit NO_x controls has been found to vary by two orders of magnitude, from the low cost of BOOS ($190/MMBtu) and WI ($530/MMBtu), on small- to medium-sized gas-fired boilers, to the high estimate for SCR retrofit ($20,000/MMBtu/hr), on PC-fired boilers. As shown, even the cost of SCR shows some large variations. Estimates from vendors and installers of the technology indicated that SCR can cost as little as $2,400 to $6,900/MMBtu for a relatively small gas-fired industrial boiler of 50 MMBtu/hr capacity (about 24 MWt), compared to an estimate of $20,000/MMBtu based on estimates from a comparable-sized utility boiler.[15] However, because of the lack of experience with SCR on coal-fired industrial boilers, it is difficult to draw any definitive conclusions with respect to the actual retrofit cost of SCR on these boiler types. Recent experience with utility boilers indicates that the cost of SCR has lowered due to technology improvements and market competition. These benefits are likely to transfer into the industrial boiler sector.

Where applicable, the capital cost of SNCR has been found to be in the same range as the capital costs of such combustion controls as LNB and FGR. Both SNCR-urea and SNCR-ammonia estimates were based on costs provided by vendors, and escalated to account for boiler size differences. For example, for a PC-fired 800 MMBtu/hr (234 MWt) boiler, the capital cost for SNCR-ammonia was estimated by Exxon to be about $900/MMBtu/hr.[16] For an 812 MMBtu/hr (238 MWt) tangential boiler, the capital cost for SNCR-urea was estimated by Nalco Fuel Tech to be about $600/MMBtu/hr.[17], while a smaller, 400 MMBtu/hr boiler will require an investment of $830,000.[17] Figure 6-3

Figure 6-3. Total capital cost reported by Exxon for SNCR-ammonia on a variety of industrial boilers.

plots the actual or estimated capital cost for the Thermal $DeNO_x$ process for several boiler types. These costs were prepared by Exxon Research and Engineering (ER&E) for new and retrofit installations on large, >250 MMBtu/hr (73 MWt), industrial and utility boilers burning a variety of fuels, including waste fuels.[24,25] These data show the exponential increase in capital cost with decreasing boiler size (boiler capacity is plotted on a logarithmic scale).

6.4 COST EFFECTIVENESS OF NO_x CONTROLS

This section presents the cost effectiveness of various NO_x controls retrofitted to a range of ICI boilers, using the costing methodology and assumptions discussed earlier. Section 6.4.1 describes the boiler NO_x control cases analyzed, and Sections 6.4.2 through 6.4.6 discuss the cost analyses results.

6.4.1 NO_x Control Cost Effectiveness: Coal-fired ICI Boilers

TABLE 6-6. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, COAL-FIRED ICI BOILERS

Boiler type	Boiler capacity, MMBtu/hr	NO_x control technology	Controlled NO_x level, lb/MMBtu	Cost effectiveness, \$/ton NO_x removed[a,b]
PC wall-fired	250	LNB	0.35	1,340-1,760
	400	LNB	0.35	1,170-1,530
	500	LNB	0.35	1,090-1,430
	750	LNB	0.35	980-1,280
	250	SNCR-ammonia	0.39	1,360-1,450
	400	SNCR-ammonia	0.39	1,310-1,400
	500	SNCR-ammonia	0.39	1,300-1,370
	750	SNCR-ammonia	0.39	1,270-1,330
	250	SNCR-urea	0.39	1,120-1,340
	400	SNCR-urea	0.39	1,040-1,240
	500	SNCR-urea	0.39	1,010-1,190
	750	SNCR-urea	0.39	960-1,130
	250	SCR	0.14	3,800-4,800
	400	SCR	0.14	3,400-4,200
	500	SCR	0.14	3,200-4,000
	750	SCR	0.14	3,000-3,700
CFBC	250	SNCR-urea	0.08	960-1,130
	400	SNCR-urea	0.08	890-1,030
	500	SNCR-urea	0.08	860-980
	750	SNCR-urea	0.08	810-920
Spreader stoker	250	SNCR-urea	0.22	1,360-1,440
	400	SNCR-urea	0.22	1,320-1,380
	500	SNCR-urea	0.22	1,300-1,360
	750	SNCR-urea	0.22	1,280-1,320

[a]Capacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.
[b]1992 dollars.

Table 6-6 summarizes the results obtained for coal-fired ICI boilers retrofitted with various NO_x controls. The cost effectiveness values presented here and in all subsequent tables and figures in this chapter were calculated using capacity factors of 0.50 to 0.66. These capacity factors were chosen as mid-range capacity levels for this analysis, although it is likely that small ICI boilers such as packaged firetube units will have capacity factors less than 0.50.[7] In all cost cases, costs per ton of NO_x control were higher as the capacity factor decreased, due to the reduced amount of NO_x removed. Thus, costs for boilers with capacity factors such as 0.33 will be higher than those presented in this section. See Appendix D for calculated cost effectiveness values for capacity factors of 0.33 and 0.80.

Figure 6-4

Figure 6-4. Cost effectiveness versus boiler capacity, PC wall-fired boilers.

graphically shows the relationship of cost effectiveness and boiler capacity for NO_x controls retrofitted to PC wall-fired boilers. The cost estimates depicted are based on data from a detailed cost study for a 766 MMBtu/hr (224 MWt) PC wall-fired unit.[14] Cost estimates for other boiler sizes were extrapolated using the 0.6 power law for capital cost and a proportional dependence for O&M cost. The data show reduced costs per ton of NO_x removed as boiler capacity increases, due to greater amounts of NO_x removed and economies of scale. SNCR controls were the most cost effective per ton of NO_x removed, with costs ranging from a low of $950 per ton of NO_x removed, for a 750 MMBtu/hr (220 MWt) unit, to a high of $1,340 per ton, for a smaller, 250 MMBtu/hr (73 MWt) unit. The difference in cost effectiveness between SNCR with urea and SNCR with ammonia is well within the margin of error for this cost analysis.

LNB controls required greater expenditures for equivalent NO_x removal, ranging from $980 to $1,760 per ton of NO_x removed. LNB costs were developed based on estimates provided by CIBO.[14] SCR has the highest costs per ton of NO_x removal, ranging from $4,610 to $7,810 per ton of NO_x. These estimates were also developed from EPA cost estimates for a 100 MWe utility boiler.[15] Recent trends in SCR applications have shown significant decreases in capital investment for this technology. However, due to the lack of experience in SCR application on PC-fired boilers, the actual cost of this control option is speculative at this stage. Overall, on a per-ton of NO_x removed basis of comparison, SNCR controls were the most cost effective for PC wall-fired boilers.

It should be noted that the controlled NO_x levels achieved using LNB were higher than those achieved using SNCR or SCR. This lower reduction efficiency, coupled with higher capital costs, results in higher cost effectiveness for LNB technology. For SCR controls, the most expensive cost elements were purchased equipment cost and annual chemical or catalyst replacement costs. SCR catalyst replacement was based on a 4-year catalyst life. Both capital and O&M SCR costs are in line with EPA estimates for small PC-fired utility boilers. In general, costs per ton of NO_x control for tangential-fired PC boilers may be expected to be slightly higher than those estimated for the PC wall-fired units, since baseline NO_x levels are generally lower for tangential firing, and, hence, the amount of NO_x removed will be slightly lower.

6.4.2 NO_x Control Cost Effectiveness: Natural-gas-fired ICI Boilers

Cost effectiveness estimates were made for packaged watertube, packaged firetube, and field-erected wall-fired units firing natural gas, and are summarized in Table 6-7

TABLE 6-7. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, NATURAL-GAS-FIRED ICI BOILERS

Boiler type	Boiler capacity, MMBtu/hr	NO_x control technology	Controlled NO_x level, lb/MMBtu	Cost effectiveness, \$/ton NO_x removed[a,b]
Packaged watertube (single-burner)	10	WI+OT	0.06	960-1,160
	25	WI+OT	0.06	800-940
	50	WI+OT	0.06	710-820
	100	WI+OT	0.06	570-650
	150	WI+OT	0.06	540-610
	250	WI+OT	0.08	380-430
	10	LNB	0.08	990-4,300
	25	LNB	0.08	720-3,070
	50	LNB	0.08	570-2,390
	100	LNB	0.09	410-1,670
	150	LNB	0.09	360-1,450
	250	LNB	0.12	240-920

[a]Capacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.
[b]1992 dollars.

(continued)

TABLE 6-7. (continued)

Boiler type	Boiler capacity, MMBtu/hr	NO_x control technology	Controlled NO_x level, lb/MMBtu	Cost effectiveness, \$/ton NO_x removed [a,b]
Packaged watertube (single-burner) (continued)	10	LNB+FGR	0.06	2,630-7,630
	25	LNB+FGR	0.06	1,930-5,510
	50	LNB+FGR	0.06	1,540-4,350
	100	LNB+FGR	0.07	1,110-3,090
	150	LNB+FGR	0.07	990-2,730
	250	LNB+FGR	0.10	650-1,760
	10	SCR	0.02	7,400-10,090
	25	SCR	0.02	5,730-8,010
	50	SCR	0.02	4,830-6,880
	100	SCR	0.03	3,040-5,350
	150	SCR	0.03	2,690-4,990
	250	SCR	0.04	1,810-3,460
Packaged firetube	2.9	WI+OT	0.04	4,190-5,240
	5.2	WI+OT	0.04	3,600-4,450
	10.5	WI+OT	0.04	3,050-3,720
	20.9	WI+OT	0.04	2,640-3,180
	33.5	WI+OT	0.04	2,410-2,890
	2.9	FGR+OT	0.07	26,570-35,410
	5.2	FGR+OT	0.07	15,160-20,380
	10.5	FGR+OT	0.07	7,970-10,830
	20.9	FGR+OT	0.07	4,520-6,100
	33.5	FGR+OT	0.07	3,000-4,080
Field-erected wall-fired (multiple-burner)	100	BOOS+OT	0.09	440-510
	250	BOOS+OT	0.12	280-330
	400	BOOS+OT	0.15	210-240
	500	BOOS+OT	0.15	210-240
	750	BOOS+OT	0.20	150-170
	100	BOOS+WI+OT	0.05	750-820
	250	BOOS+WI+OT	0.06	530-570
	400	BOOS+WI+OT	0.08	410-440
	500	BOOS+WI+OT	0.08	400-430
	750	BOOS+WI+OT	0.10	300-310
	250	LNB	0.12	3,030-6,210
	400	LNB	0.15	2,070-4,210
	500	LNB	0.15	1,920-3,900
	750	LNB	0.20	1,690-3,400

[a]Capacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.
[b]1992 dollars.

. Cost data for 26 different boilers were used to derive these estimates. Section 6.4.2.1 describes the results obtained for packaged watertube units equipped with WI+OT, LNB, LNB+FGR, and SCR. Section 6.4.2.2 presents cost effectiveness estimates for packaged firetube units retrofitted with WI+OT, and FGR controls, and Section 6.4.2.3 discusses field erected wall-fired units retrofitted with LNB. These estimates do not include the cost of purchasing and maintaining a fully instrumented CEM system to monitor compliance with an emission limit. The impact of CEMs on these costs is discussed in Section 6.4.6.

6.4.2.1 Natural-gas-fired Packaged Watertube Boilers

NO_x control cost data for natural-gas-fired packaged (single-burner) watertube boilers are more available than for othe r boiler and fuel types, primarily due to retrofit activity in California. Cost data from four boilers were used to estimate costs of WI and LNB retrofit, while data from six units were used to estimate combined LNB and FGR retrofit costs. SCR retrofit cost estimates were based on data supplied by a major manufacturer of SCR systems, with experience in stalling SCR systems on packaged boilers rated as small as 66,000 lb steam/hr (8.3 kg/s).

As tabulated in Table 6-7 and shown in Figure 6- 5

Figure 6-5. Cost effectiveness versus boiler capacity, natural-gas-fired packaged watertube boilers.

, cost effectiveness estimates for packaged watertube units fired by natural gas were highest for SCR NO_x control and lowest for LNB and WI+OT, with LNB+FGR falling in between. WI+OT is considered cost-competitive with LNB because of its low initial capital investment. In spite of the thermal efficiency loss of 0.5 to 1.0 percent associated with WI, this technique can be cost effective especially for small boilers with a low capacity factor.

As was the case with coal-fired units, costs per ton of NO_x reduction decreased with increased boiler capacity, due to the increased amount of NO_x removed from the larger units and general economies of scale. For packaged watertube units, the effect of boiler capacity on cost effectiveness becomes significant below about 50 MMBtu/hr (15 MWt) capacity. For units smaller than this capacity, costs of NO_x control increase rapidly as capacity decreases, especially when SCR is used. The costs per ton of NO_x control for a 250 MMBtu/hr (73 MWt) single-burner packaged boiler with LNB are much lower than those estimated for a multiple-burner field-erected unit of similar size. Some of the discrepancy between the figures can be attributed to the different data sources; however, the principal reason lies in the number of burners to be retrofitted. A field-erected unit with four or more burners, for example, will tend to require capital equipment and installation costs several times higher than a single-burner unit.

On average, LNB+FGR control costs per ton of NO_x removed were twice as high as for LNB and WI+OT, while SCR control costs per ton of NO_x removed were 3 times higher. Cost effectiveness of WI+OT ranged from $380 to $1,160 per ton of NO_x removed. Cost effectiveness for LNB controls ranged from $240 to $4,300 per ton of NO_x removed, across the capacity range of 10 to 250 MMBtu/hr (2.9 to 73 MWt). LNB+FGR cost effectiveness ranged from about $650 to $7,630/ton, while SCR had the highest range in cost per ton of NO_x

removed, approximately $1,810 to $10,090/ton. The high-end costs of these ranges were for the smallest, 10 MMBtu/hr (2.9 MWt) units at a 0.50 capacity factor. Because it is likely that many units this small are operated at even lower capacity factors, actual costs of NO_x control may be much higher than these estimates. For these lower capacity factor boilers, controls with a high initial capital investment, such as SCR, LNB, and LNB+FGR, are particularly penalized when compared on a cost-effectiveness basis.

Figure 6-5 illustrates the overall trend of cost effectiveness with boiler capacity. The enclosed areas reflect the ranges in cost and are representative of the uncertainty in these estimates. Cost-effectiveness ranges for LNB and for LNB+FGR overlap, due to the wide range of cost effectiveness values obtained. These cost-effectiveness data illustrate the potential variability in the costs of retrofitting boilers with NO_x controls, which are highly dependent on site-specific installation and operating factors. Figure 6-6

Figure 6-6. Cost effectiveness versus boiler capacity, natural-gas-fired packaged watertube boilers using SCR controls.

illustrates the variability of the cost effectiveness of SCR controls, assuming various catalyst lifetimes. As catalyst life increases, cost effectiveness slowly decreases.

6.4.2.2 Natural-gas-fired Firetube Boilers

Cost data were obtained for retrofitting WI+OT and FGR+OT controls to packaged firetube units ranging in size from approximately 3 to 34 MMBtu/hr (0.9 to 10 MWt) capacity. The data for FGR+OT controls were obtained from a distributor of industrial boilers and NO_x control systems, and are based on experiences with nearly 20 units operating with FGR.[20] Costs for WI+OT are based on recently reported NO_x retrofit experiences in Southern California.[19]

FGR+OT is one of the most common retrofit NO_x control strategies for natural-gas-fired firetube units, besides LNB or combined LNB and FGR. Costs per ton of NO_x removed for these units firing natural gas were relatively high, ranging from $3,000 to $35,410, with the highest costs being for units 5 MMBtu/hr (1.5 MWt) and smaller. The most significant cost components for these cost cases were equipment and installation costs. The costs of NO_x control for a 10 MMBtu/hr (2.9 MWt) firetube unit retrofitted with FGR+OT are relatively similar to the high-end costs estimated for a 10 MMBtu/hr (2.9 MWt) watertube unit retrofitted with LNB and FGR, as discussed above. Although no cost estimates were made for firetube units retrofitted with LNB or LNB+FGR controls, it is likely that cost effectiveness for these control cases will be comparable to those estimated for packaged watertube units of similar capacity.

The estimated costs for WI+OT for these firetube boilers are based on a retrofit investment of $35,000, irrespective of boiler size, and an efficiency penalty of 1.0 percent. It is difficult to predict the actual thermal efficiency impact in a retrofit situation. The actual impact will depend on current unit operating practices; given a poor operating condition with high excess air combustion, the retrofit of this control may, in some cases, result in an improvement. However, it was considered prudent to associate an efficiency loss with the use of WI in spite of potential gains with an OT control. As shown in Table 6-7, the estimated cost for this control strategy is similar to that for LNB retrofit, but still slightly higher than comparable controls for watertube units. This is due to lower baseline NO_x levels for firetube boilers compared with watertube units (see Table 6-2).

6.4.2.3 Natural-gas-fired Field-erected Wall-fired Boilers

The implementation of BOOS or biased firing and WI on large multi-burner gas-fired boilers will depend on the number of burners available and the load requirements of the boiler. Units with several burners with small heat input ratings per burner offer the greater opportunity for implementation of these effective control techniques. Where possible, the retrofit of BOOS and BOOS+WI+OT is likely to be the more cost effective options in spite of thermal efficiencies, here assumed to range between 0.25 and 1.0 percent. The lower the capacity factor of these boilers, the more cost-competitive these controls may prove to be. Estimates in this study range between about $150 and $510 per ton for BOOS+OT, and between $300 and $820 per ton for BOOS+WI+OT.

Cost estimates per ton of NO_x removed for natural-gas-fired field-erected units with LNB, listed in Table 6-7, range from $1,690 to $6,210 per ton of NO_x removed for boilers ranging in size from 250 to 750 MMBtu/hr (73 to 220 MWt). The costs per ton of NO_x control for a multiple-burner field-erected 250 MMBtu/hr (73 MWt) unit are much higher than the costs estimated for a single-burner packaged unit due to greater capital equipment and installation costs as discussed in Section 6.4.2.1. Although the listed cost effectiveness ranges are for a capacity factor as low as 0.50, most field-erected units have factors closer to 0.66.[7] The high end of the cost effectiveness ranges listed in Table 6-7 represent a 0.50 capacity factor. If considering a 0.66 capacity factor only, the high-end cost effectiveness estimates are roughly 25 percent lower. The estimates presented are based on capital cost data supplied for two boilers retrofitted with LNB.[14]

6.4.3 NO_x Control Cost Effectiveness: Fuel-oil-fired ICI Boilers

As discussed earlier, NO_x control cost effectiveness estimates for fuel-oil-firing units were made based on cost data for natural-gas-fired boilers, using appropriate baseline NO_x emission levels and fuel oil prices. Tables 6-8

TABLE 6-8. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, DISTILLATE-OIL-FIRED ICI BOILERS

Boiler type	Boiler capacity, MMBtu/hr	NO_x control technology	Controlled NO_x level, lb/MMBtu	Cost effectiveness, \$/ton NO_x removed[a,b]
Packaged watertube (single burner)	10	LNB	0.10	790-3,440
	25	LNB	0.10	580-2,450
	50	LNB	0.10	460-1,910
	100	LNB	0.10	370-1,500
	150	LNB	0.10	330-1,310
	250	LNB	0.10	280-1,110
	10	LNB+FGR	0.08	1,900-5,900
	25	LNB+FGR	0.08	1,340-4,210
	50	LNB+FGR	0.08	1,030-3,280
	100	LNB+FGR	0.08	800-2,580
	150	LNB+FGR	0.08	690-2,250
	250	LNB+FGR	0.08	580-1,910
	10	SCR	0.03	5,920-8,070
	25	SCR	0.03	4,590-6,410
	50	SCR	0.03	3,860-5,500
	100	SCR	0.03	2,740-4,820
	150	SCR	0.03	2,420-4,490
	250	SCR	0.03	2,170-4,150
Packaged firetube	2.9	FGR+OT	0.12	15,640-20,940
	5.2	FGR+OT	0.12	8,800-11,930
	10.5	FGR+OT	0.12	4,490-6,200
	20.9	FGR+OT	0.12	2,410-3,360
	33.5	FGR+OT	0.12	1,500-2,150
Field-erected wall-fired (multiple burner)	250	LNB	0.10	3,630-7,450
	400	LNB	0.10	3,100-6,320
	500	LNB	0.10	2,880-5,850
	750	LNB	0.10	2,530-5,100

[a]Capacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.
[b]1992 dollars.

TABLE 6-9. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, RESIDUAL OIL-FIRED ICI BOILERS

Boiler type	Boiler capacity, MMBtu/hr	NO_x control technology	Controlled NO_x level, lb/MMBtu	Cost effectiveness, \$/ton NO_x removed[a,b]
Packaged watertube	10	LNB	0.19	420-1,810
(single burner)	25	LNB	0.19	300-1,290
	50	LNB	0.19	240-1,010
	100	LNB	0.19	190-790
	150	LNB	0.19	170-690
	250	LNB	0.19	150-580
	10	LNB+FGR	0.23	1,220-3,320
	25	LNB+FGR	0.23	920-2,430
	50	LNB+FGR	0.23	760-1,950
	100	LNB+FGR	0.23	640-1,580
	150	LNB+FGR	0.23	580-1,400
	250	LNB+FGR	0.23	520-1,220
	10	SCR	0.06	3,110-4,240
	25	SCR	0.06	2,420-3,370
	50	SCR	0.06	2,030-2,900
	100	SCR	0.06	1,440-2,530
	150	SCR	0.06	1,270-2,360
	250	SCR	0.06	1,140-2,190
Packaged firetube	2.9	FGR+OT	0.23	8,560-11,350
	5.2	FGR+OT	0.23	4,960-6,600
	10.5	FGR+OT	0.23	2,690-3,590
	20.9	FGR+OT	0.23	1,600-2,100
	33.5	FGR+OT	0.23	1,120-1,460
Field-erected wall-fired (multiple burner)	250	LNB	0.19	1,910-3,920
	400	LNB	0.19	1,630-3,330
	500	LNB	0.19	1,520-3,080
	750	LNB	0.19	1,330-2,680

[a]Capacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.
[b]1992 dollars.

watertube boilers. NO_x controls that use water injection were not considered for oil-fired units because of lack of experience and greater operational and environmental impacts that are likely with these fuels compared with natural gas. Comparative cost results for the different NO_x control technologies are similar to those obtained for natural-gas-fired units, as expected, with SCR showing the highest costs per ton of NO_x removed and LNB showing the lowest. Like the cost estimates for natural gas firing, LNB+FGR control costs were, on average, twice as high as the costs of LNB controls, while SCR controls were 3 times as high.

Overall costs of NO_x control per ton removed are lower for fuel oil firing than for natural gas firing due to higher baseline NO_x emission levels, and, hence, greater amounts of NO_x removal per MMBtu heat input. As discussed for natural gas-fired boilers, the cost effectiveness discrepancy between a 250 MMBtu/hr (73 MWt) packaged boiler and a 250 MMBtu/hr (73 MWt) field-erected unit equipped with LNB is primarily due to the greater capital equipment and installation costs associated with retrofitting multiple burners rather than a single burner. Multiple-burner field-erected boilers are likely to benefit from selected BOOS. Where applicable, this technique can result in considerable NO_x reduction at much lower cost than LNB retrofit.

6.4.4 NO_x Control Cost Effectiveness: Nonfossil-fuel-fired ICI Boilers

Limited cost data were available for nonfossil-fuel-fired boilers retrofitted with NO_x controls. For this reason, cost estimates could only be made for the application of SNCR controls to several types of nonfossil-fuel-fired boilers. Data were obtained directly from leading SNCR system manufacturers, and reflect cost experiences for nine different installations. NO_x control performance and cost are considered the same regardless of the reagent used. Typical applications use either ammonia or urea

TABLE 6-10. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, NONFOSSIL-FUEL-FIRED ICI BOILERS

Boiler type	Fuel type	Boiler capacity, MMBtu/hr	NO_x control technology	Controlled NO_x level, lb/MMBtu	Cost effectiveness, \$/ton NO_x removed [a,b]
Stoker	Wood	50	SNCR-urea	0.11	1,810-3,130
		150	SNCR-urea	0.11	1,270-2,380
		250	SNCR-urea	0.11	1,080-2,130
		350	SNCR-urea	0.11	980-2,000
		500	SNCR-urea	0.11	890-1,870
	MSW	50	SNCR-urea	0.18	3,390-3,800
		150	SNCR-urea	0.18	1,890-2,790
		250	SNCR-urea	0.18	1,690-2,450
		350	SNCR-urea	0.18	1,580-2,270
		500	SNCR-urea	0.18	1,470-2,090
Packaged watertube	Paper	10	SNCR-urea	0.23	2,220-3,520
		25	SNCR-urea	0.23	1,780-2,710
		50	SNCR-urea	0.23	1,550-2,270
		100	SNCR-urea	0.23	1,370-1,930
		150	SNCR-urea	0.23	1,280-1,770
		250	SNCR-urea	0.23	1,190-1,610
BFBC	Wood	250	SNCR-ammonia	0.11	1,560-1,750
		350	SNCR-ammonia	0.11	1,480-1,650
		400	SNCR-ammonia	0.11	1,450-1,600
		500	SNCR-ammonia	0.11	1,390-1,530
		750	SNCR-ammonia	0.11	1,110-1,310

[a]Capacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.
[b]1992 dollars.

in aqueous solution. Table 6-10 summarizes the cost effectiveness ranges for these boilers. Cost effectiveness estimates made for wood-fired stokers with urea injection are comparable to those calculated for wood-fired FBC boilers with ammonia injection, ranging between \$890 and \$2,130 per ton of NO_x removed for boilers 250 to 500 MMBtu/hr (73 to 146 MWt). The range in cost effectiveness for MSW-fired stokers of the

same capacity retrofit with urea injection is $1,470 and $2,450 per ton of NO_x removed. For wood- or MSW-fired boilers smaller than 250 MMBtu/hr (73 MWt) but at least 50 MMBtu/hr (15 MWt), SNCR control costs ranged from approximately $1,270 to $3,800 per ton of NO_x removed. Cost estimates for similarly sized paper-fired units were lower, ranging from $1,280 to roughly $2,270 per ton of NO_x removed.

6.4.5 NO_x Control Cost Effectiveness: Oil-fired Thermally Enhanced Oil Recovery (TEOR) Steam Generators

No cost analyses were performed for NO_x controls for TEOR steam generators. However, it has been estimated that for a 25 MMBtu/hr (7.3 MWt) crude-oil-fired TEOR unit, annual costs would be $52,000 for LNB retrofit, $88,000 for SNCR, and $400,000 for SCR.[26] Based on these estimates, and assuming a baseline NO_x emission level of 0.38 lb/MMBtu (see Chapter 4) and the NO_x reduction efficiencies listed in Table 6-3, cost effectiveness is $3,790 per ton of NO_x removed for LNB at 0.66 capacity factor, $8,000/ton for SNCR, and $19,400/ton for SCR.

6.4.6 Cost Effect of Continuous Emissions Monitoring (CEM) System

Addition of a CEM system to an NO_x control retrofit package can increase the costs of NO_x control. For example, Table 6-11 shows the cost effect of adding a CEM system to a natural-gas-fired packaged watertube boiler, equipped with LNB or with LNB and FGR. The cost estimates are based on data from one source, for a 265 MMBtu/hr (77.7 MWt) unit, that showed a total CEM system capital cost of roughly $200,000, including installation.[14] Average cost increased by roughly 65 percent when a CEM system was included. While it is not possible to draw conclusions from one source about the extent to which CEM systems will increase costs, the data nevertheless show that CEM cost impact is considerable. For small-capacity boilers, in particular, the additional cost of CEM may be disproportionately large when compared to the overall cost of the boiler itself. At least one California air district requires CEM systems only for boilers that are 40 MMBtu/hr (12 MWt) or greater in capacity.[27]

TABLE 6-11. NO_x CONTROL COST EFFECTIVENESS WITHOUT/WITH CEM SYSTEM, NATURAL-GAS-FIRED ICI BOILERS[a]

Boiler type	Boiler capacity, MMBtu/hr	NO_x control technology	Controlled NO_x level, lb/MMBtu	Cost effectiveness without CEM, $/ton NO_x removed[b,c]	Cost effectiveness with CEM, $/ton NO_x removed[b,c]
Packaged	10	LNB	0.08	3,260-4,300	5,410-7,140
watertube	25	LNB	0.08	2,320-3,070	3,850-5,080
	50	LNB	0.08	1,810-2,390	3,000-3,960
	100	LNB	0.09	1,260-1,670	2,090-2,760
	150	LNB	0.09	1,100-1,450	1,830-2,410
	250	LNB	0.12	700-920	1,160-1,530
	10	LNB+FGR	0.06	3,700-5,000	5,480-7,360
	25	LNB+FGR	0.06	2,530-3,460	3,800-5,140
	50	LNB+FGR	0.06	1,900-2,620	2,890-3,930
	100	LNB+FGR	0.07	1,260-1,760	1,950-2,680
	150	LNB+FGR	0.07	1,050-1,500	1,660-2,290
	250	LNB+FGR	0.10	630-910	1,020-1,420

[a]Based on data contained in Reference 19, for a 265 MMBtu/hr (7.7 MWt) natural-gas-fired unit.
[b]Capacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.
[c]1992 dollars.

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7. ENVIRONMENTAL AND ENERGY IMPACTS

This chapter presents environmental and energy impacts for the NO_x emissions control techniques described in Chapter 5. These control techniques are specific to certain boiler and fuel equipment, as shown in Table 7-1

TABLE 7-1. EXPERIENCE WITH NO_x CONTROL TECHNIQUES ON ICI BOILERS

	Coal-fired			Oil-/natural-gas-fired			Nonfossil-fuel-fired		MSW-fired
NO_x control technique	Field-erected PC-fired	Stoker	FBC	Field-erected watertube	Packaged watertube	Packaged firetube	Stoker	FBC	Mass burn
BT/OT					X	X			
WI/SI					X	X			
SCA	X	X	X	X [a]	X		[b] X[a]	X	X [a]
LNB	X			X	X	X			
FGR				X	X	X			X
NGR	X	[b]							X[b]
SNCR	X	[b] X	X	X	X		X	X [b]	X
SCR	X	[b]	X[b]	X[b]					

BT/OT = Burner tuning/oxygen trim
WI/SI = Water injection/steam injection
SCA = Staged combustion air, includes burners out of service (BOOS), biased firing, or overfire air (OFA)
LNB = Low-NO_x burners
FGR = Flue gas recirculation
NGR = Natural gas reburning
SNCR = Selective noncatalytic reduction
SCR = Selective catalytic reduction
MSW = Municipal solid waste
[a]SCA is designed primarily for control of smoke and combustible fuel rather than NO_x. Optimization of existing SCA (OFA) ports can lead to some NO_x reduction.
[b]Limited experience.

. For example, LNB is not applicable to stoker and FBC boilers. WI and FGR are rarely considered when burning coal in any type of industrial combustion equipment. Similarly, among ICI boilers reburning with natural gas has only limited application potential to boilers burning municipal solid waste or stoker coal. Flue gas treatment controls have limited application experience, especially for SCR, on small boilers and boilers burning fuels other than natural gas. SNCR, instead, is generally limited to application on larger boilers with the greatest performance success recorded on FBC boilers.

This chapter is organized in four major sections. Section 7.1 presents the air pollution impacts, Section 7.2 the solid waste disposal impacts, Section 7.3 the water pollution impacts, and Section 7.4 the energy impacts.

7.1 AIR POLLUTION

7.1.1 NO_x Reductions

Control techniques presented in this document can result in significant NO_x reductions for selected ICI boilers. The actual NO_x reduction that can be achieved at each site will depend on many factors including the extent of the equipment upgrade, the degree of control applied, and the boilers current configuration such as furnace size, number of burners and burner matrix. For example, the amount of flue gas recirculated has a strong influence on the percent NO_x reduction. Also, the amount that can be safely recirculated will depend on the optimization of the burner design in order to maintain safe flame conditions, and low emissions of other pollutants such as CO. In another example, the amount of SCR catalyst that can be retrofit may depend on site accessibility. Many ICI boilers are often located inside buildings making access for large retrofit difficult at best.

Table 7-2

TABLE 7-2. NO_x EMISSIONS REDUCTION FROM MODEL BOILERS

Boiler type and size, MMBtu/hr		Baseline NO_x lb/MMBtu	Baseline NO_x Tons/yr (0.50 CF[a])	NO_x control technique	Control NO_x level, lb/MMBtu	NO_x reduction %	NO_x reduction Tons/yr (0.33 CF)	NO_x reduction Tons/yr (0.50 CF)	NO_x reduction Tons/yr (0.66 CF)
PC	400	0.70	610	BT/OT	0.62	15	46	70	93
				LNB	0.35	50	200	310	400
				NGR	0.28	60	240	370	490
				SNCR	0.39	45	180	270	360
				SCR	0.14	85	320	490	650
Stoker coal	250	0.53	290	SCA	0.42	20	40	60	79
				SNCR	0.29	45	86	130	170
FBC coal	400	0.32	280	SCA	0.19	40	75	110	150
				SNCR	0.13	75	110	170	220
FE-WT gas	300	0.26	150	BT/OT	0.20	15	13	20	26
				SCA	0.15	35	35	53	69
				LNB	0.12	55	60	92	120
				LNB+FGR	0.10	60	69	110	140
				SNCR	0.10	60	69	110	140
				SCR	0.04	85	95	140	190
FE-WT No. 2 oil	300	0.21	140	BT/OT	0.18	15	13	20	26
				SCA	0.13	40	35	53	69
				LNB	0.10	50	48	72	95
				LNB+FGR	0.08	60	56	85	110
				SNCR	0.10	50	48	72	95
				SCR	0.03	80	78	120	160
FE-WT No. 6 oil	300	0.38	250	BT/OT	0.32	15	26	34	52
				SCA	0.29	25	39	59	78
				LNB	0.19	50	82	120	160
				FGR	0.34	10	17	26	35
				LNB+FGR	0.15	60	100	150	200
				SCR	0.08	80	130	200	260
PK-WT gas	50	0.14	15	BT/OT	0.12	15	1.4	2.2	2.8
				WI/SI	0.06	55	5.8	8.8	12
				LNB	0.08	45	4.3	6.6	8.7
				LNB+FGR	0.06	57	5.8	8.8	12
				SNCR	0.07	50	5.1	7.7	10
				SCR	0.02	85	8.7	13	17
PK-WT No. 2 oil	50	0.13	14	BT/OT	0.11	15	1.4	2.2	2.8
				LNB	0.10	25	2.2	3.3	4.3
				FGR	0.07	45	4.3	6.6	8.6
PK-WT No. 6 oil	50	0.36	39	BT/OT	0.31	15	3.6	5.5	7.2
				LNB	0.19	45	12	19	25
				LNB+FGR	0.15	60	15	23	30
				SCR	0.06	85	22	33	43
FT gas	15	0.10	3.3	BT/OT	0.09	15	0.22	0.33	0.44
				WI/SI	0.04	65	1.3	2.0	2.6
				LNB	0.08	20	0.43	0.66	0.87
				FGR	0.07	30	0.65	1.0	1.3
				LNB+FGR	0.03	70	1.5	2.3	3
FT No. 2 oil	15	0.17	5.6	BT/OT	0.15	15	0.43	0.66	0.86
				LNB	0.09	50	1.7	2.6	3.5
				FGR	0.12	30	1.1	1.6	2.2
FT No. 6 oil	15	0.31	10	BT/OT	0.26	15	1.1	1.6	2.2
				LNB	0.17	45	3.0	4.6	6.1
Stoker nonfossil	150	0.24	79	SNCR	0.11	55	28	43	56
FBC nonfossil	200	0.25	110	SNCR	0.11	55	40	61	80
Mass MSW	500	0.40	440	NGR	0.16	60	170	260	350
				SNCR	0.18	55	160	240	320

[a]CF = capacity factor.

lists the anticipated NO_x reductions that can be achieved on a yearly basis with the retrofit of candidate control techniques. These estimates are based on "model size"

boilers, baseline emissions presented in Chapter 4, and NO_x reduction potentials presented in Chapter 5. Thus, a 400 MMBtu/hr (73 MWt) circulating FBC boiler burning coal with a baseline level of 0.32 lb/MMBtu could successfully employ SNCR to reduce emission levels to approximately 0.10 lb/MMBtu, corresponding to 210 tons/yr NO_x reduction at a capacity factor of 0.50.

7.1.2 CO Emissions

The CO emissions from ICI boilers are normally near zero, with the exception of a few boilers that have poor combustion air control or burner problems.[1] In an extensive study of industrial boilers' emissions, oil-fired units were found to have the lowest baseline CO emissions than either coal- or gas-fired units. This was attributed to higher excess air levels typically used to avoid visible smoke emissions when oil is burned.[1] CO emissions are generally caused by poor fuel-air mixing, flame quenching, and low residence time at elevated temperatures. Additionally, in some ICI furnace designs, CO emissions can also occur because of furnace gas leaks between furnace tubes.

The modification of combustion conditions aimed at reducing NO_x formation can result in increases in emissions of CO and hydrocarbons. This is because controls that reduce peak flame temperature and delay the mixing of fuel and air for NO_x reduction can cause some incomplete combustion of the fuel. However, the actual impact of NO_x control retrofits often depends on the operating conditions of the ICI boiler and the extent of improvements made to the combustion control system. In some cases, combustion NO_x control can also result in lower emissions of CO and other unburned fuel emissions.

Tables 7-3

TABLE 7-3. CO EMISSION CHANGES WITH NO_x CONTROL RETROFIT — COAL-FIRED BOILERS

Boiler type	NO_x control	NO_x reduction, %	CO emissions impact: Baseline/low NO_x, ppm	CO emissions impact: Average change, %	Reference
WT	LNB	67	20-27/13-420	+800	2
	LNB+SCA	66	35/60-166	+215	3
Cyclone	NGR	65	30/30	0	4
Spreader stoker	SCA (OFA)	31	231-252/429	+80	5
		10	313/300	-4	6
		26	0/49	NA[a]	1
FBC	SCA	67	387-500/550-1,100	+86	7

[a]NA = Not applicable.

TABLE 7-4. CO EMISSION CHANGES WITH NO_x CONTROL RETROFIT — GAS-FIRED BOILERS

Boiler type	NO_x control	NO_x reduction, %	CO emissions impact: Baseline/ low NO_x, ppm	CO emissions impact: Average change, %	Reference
PKG-FT	FGR	59	16/13	-18	8
	FGR	73	205/77	-62	9
	FGR	71	205/192	-6.3	9
	FGR	64	205/103	-50	9
	FGR	74	205/84	-59	9
	FGR	67	23/3	-87	8
	FGR	73	105/7	-93	8
	FGR	76	205/67	-67	9
	FGR	69	205/49	-76	9
	FGR	73	51/12	-76	10
	LNB	82	9/9	0	11
	LNB	53	51/24	-53	12
	LNB	32	39/8	-80	13
	LNB	78	856/30	-97	11
	LNB	NA[a]	342/30	-91	11
	LNB	NA	205/0	-100	11
	LNB	NA	9/9	0	12
PKG-WT	FGR	74	205/62	-70	9
	FGR	62	20/20	0	14
	FGR	78	10/55	+450	14
	FGR	53	205/205	0	9
	FGR	73	14/22	+57	10
	FGR	56	132/77	-42	10
	LNB+FGR	55	60-125/2	-98	15

[a]NA = Not applicable.

TABLE 7-5. CO EMISSION CHANGES WITH NO_x CONTROL RETROFIT — OIL-FIRED BOILERS

Oil/boiler type	NO_x control	NO_x reduction, %	CO emissions impact: Baseline/low NO_x, ppm	CO emissions impact: Average change, %	Reference
Distillate/WT	FGR	68	4/46	+1,000	16
	FGR	20	20/24	+20	14
Distillate/FT	LNB	15	6/13	+120	13
Residual/WT	FGR	4	20/20	0	14
	FGR	30	10/145	+1,400	14
	SCA (BOOS)	8	0/100	NA[a]	1
	SCA (BOOS)	40	0/20	NA	1

[a]NA = Not applicable.

through 7-5 list changes in emissions of CO measured following the retrofit of selected controls. These data can also be found in Appendix A of this document. As shown in Table 7-3, LNB, SCA and NGR controls achieved NO_x reductions in the range of 10 to 67 percent, with lowest reductions reported for the spreader stoker. Emissions of CO increased in nearly all cases, except for the retrofit of NGR on the cyclone boiler and one minor application of OFA for 10 percent reduction in NO_x in the spreader stoker. The implementation of staged air will typically result in increased CO emissions .

Data on the effect of NO_x controls on CO emissions from natural gas-fired ICI boilers were limited to the retrofit of FGR, LNB and FGR+LNB controls. Bulk dilution of combustion mixtures with FGR is limited by flame instability and reduced flammability. Slightly higher

excess air levels at high rates of FGR (typically 15 to 20 percent) coupled with improved burner settings often can result in decreased CO emissions in addition to lower NO_x.

The data in Table 7-4 suggest that baseline CO emission levels from these units ranged from 9 to 856 ppm, and that the application of these controls, along with an increase in excess air, resulted in a reduction of CO in most cases. The average CO reduction for these retrofits was nearly 70 percent. One of the boilers with an initial low CO level, 10 ppm, showed an increase in CO to 55 ppm when FGR was implemented. In another application, the CO level in the low-NO_x configuration increased to only 22 ppm. Excess air is an important operational parameter that determines the level of CO emissions following the retrofit of NO_x controls. As suggested above, most of the reductions in CO levels from these gas-fired boilers resulted from increases in excess air. Low-NO_x firing with LNB typically causes an increase in CO at equivalent excess air levels. Also, there is the possibility of CO emissions occurring due to gas leaks between tubes from furnace to convective section.

Figure 7-1. Changes in CO and NO_x emissions with reduced excess oxygen for a residual-oil-fired watertube industrial boiler. [17]

Figure 7-1 illustrates the dependence of CO emissions on excess air. The rapid increase in CO is indicative of reduced fuel and air mixing that often accompanies low-NO_x combustion controls such as LNB and SCA. Each boiler type has its own characteristic "knee" in CO versus excess oxygen, depending on several factors such as fuel type and burner maintenance. California's SCAQMD permits CO levels up to 400 ppm from ICI boilers when NO_x emissions are reduced to strict levels. [18] Also, the ABMA recommends an equivalent permitted level for CO for ICI boilers retrofitted with combustion controls. [19]

As shown in Table 7-5, the limited data base on fuel oil-fired ICI boilers indicates that baseline CO emission levels for these selected boilers were below 20 ppm. When NO_x controls such as LNB, FGR, and BOOS were applied, the CO emission levels increased in nearly all cases. The increase in

CO, however, did not result in emission levels greater than 200 ppm, considered a safe limit for boiler operation.

7.1.3 Other Air Pollution Emissions

Other air pollution emissions that are a concern when NO_x controls are applied to ICI boilers are: ammonia (NH_3) and nitrous oxide (N_2O), unburned hydrocarbon (HC), particulate matter (PM), and air toxic emissions. Ammonia and N_2O emissions are associated with the use of the SNCR process, primarily, and with SCR to a lesser extent. With either urea or ammonia hydroxide, unreacted ammonia emissions escape the SNCR temperature window resulting in direct emissions to the atmosphere. When sulfur-bearing fuels are burned, these emissions also pose an operational concern because of cold end corrosion and reduced heat transfer due to ammonium sulfate deposits. N_2O emissions are often a byproduct of the SNCR reaction, and, because of this, some N_2O emissions are likely with the process. In fact, the emissions have been reported with all reagents, particularly with urea reagents.[20] Some urea-based SNCR processes offer proprietary additives to minimize N_2O and NH_3 emissions.

SNCR vendors have paid particular attention to minimizing the breakthrough of unreacted ammonia considering the potentially negative impacts on the operation of the boiler. This is typically accomplished by careful selection of the injection location, method of injection to maximize mixing and residence time, and by careful control of reagent use with boiler load and operating conditions. Table 7-6

TABLE 7-6. AMMONIA EMISSIONS WITH UREA-BASED SNCR RETROFIT [a]

Fuel/boiler type	NO_x reduction, %	Ammonia emission level, ppm	Reference
Coal/CFBC	57	<18	21
	70	<10	21
	30	<5	21
Wood/stoker	50	<40	21
	60	<27	21
	25	<21	21
	47	<10	21
	35	<21	21
	50	<40	21
	52	<30	21
MSW/mass	69	<25	21
	48	<10	21
	60	<10	21
	75	22	22
	70	17	21
	41	<5	21
	60	<7	21
	60	12	22
	60	<15	21
	50	<21	21
	58	22	22
Paper/PKG-WT	50	<10	21
Fiber/PKG-WT	50	<10	21

[a]Test data are included in Appendix A.

lists NH_3 slip levels reported for several retrofit installations. Boilers best suited for retrofit of SNCR are FBC, bubbling and circulating designs. Stokers and mass burning equipment have also been targets for application of SNCR because combustion modifications have traditionally been limited and ineffective. In spite of large NO_x reductions achieved in the units with the retrofit of SNCR, typically in the range of 50 to 70 percent, NH_3 slip levels have been reported mostly in the range of less than 30 ppm, and often less than 20 ppm. Monitoring of NH_3 emissions is often difficult because direct on line measurement methods are only now being introduced into the market place and are often very expensive, therefore not a part of the monitoring system at these facilities.

Figure 7-2. Pilot-scale test results, conversion of NO_x to N_2O (NO_i = 300 ppm, N/NO = 2.0).[20]

Pilot-scale and field tests have clearly shown that a portion of the NO_x reduced by the SNCR process is merely transformed into N_2O emissions. Figure 7-2 illustrates the amount of N_2O produced in relation to the amount of NO_x reduction with three types of SNCR chemicals: cyanuric acid, urea, and ammonia. These test results obtained in a pilot-scale facility, show that nearly 30 percent of the NO_x reduced can actually be transformed to N_2O with urea, less when using ammonia. Cyanuric acid is not a preferred chemical because of its obvious disadvantage in N_2O formation compared with the other two more popular SNCR chemicals. In addition, cyanuric acid is 6 to 8 times more expensive than urea.

Increases in HC, PM and air toxic emissions are primarily of concern with the application of combustion modification controls. Information on HC and air toxic emissions is sparse at best. However, the limited data suggest that HC emissions do not change when NO_x

controls are implemented. HC emissions are the result of poor combustion conditions such as inefficient fuel-air mixing, low temperatures, and short residence time. These emissions are most often preceded by large increases in CO, soot, and unburned carbon content. Thus, by limiting CO, smoke and unburned carbon in the flyash, HC emissions are also suppressed, and changes with retrofit of NO_x controls become imperceptible.

A comprehensive test program in the mid-1970s reported on the effect of combustion modification controls for industrial boilers. The results of this program revealed the following trends with respect to filterable PM[23]:

- LEA reduced PM emissions on the order of 30 percent
- SCA, including BOOS, increased PM by 20 to 95 percent
- Burner adjustments and tuning had no effect on PM. However, the lower CO emission levels generally achieved with these adjustments would tend to lower PM as well.
- FGR resulted in an increase in PM from oil-fired packaged boilers by 15 percent over baseline levels

Information on the effects of LNB on PM is unavailable. However, newer burner designs have improved combustion air control and distribution. These features tend to compensate for the potential increase in PM from oil- and coal-burning equipment due to delayed mixing and lower peak temperatures that are needed to suppress NO_x formation.

7.2 SOLID WASTE DISPOSAL

NO_x reduction techniques that have a potential impact on the disposal of solid waste are combustion controls for PC-fired boilers and flue gas treatment systems for all applicable boilers. Combustion controls for PC-fired boilers are principally LNB and LNB+OFA. These controls can result in an increase in the carbon content of flyash that can preclude its use in cement manufacturing. Although primarily a practice of coal-fired power plants, the use of flyash for cement manufacturing reduces the ash disposal requirements. The impact of increased carbon content in the flyash from ICI boilers can result in an ash disposal requirement where one did not exist before. The environmental and economic impact of this requirement cannot be easily quantified.

An increase in flyash disposal can also occur with the use of flue gas treatment NO_x controls such as SNCR and SCR on coal-fired boilers. Both of these control options use ammonia-based reagents to reduce NO to N_2 and water. Excessive use of reagent can result in ammonia slip emissions, as discussed in Section 7.1.3. This excessive ammonia condenses on the flyash and, when present in quantities exceeding the odor threshold, would preclude its use as a cement additive. The likelihood or extent of this potential problem is not known because there is little experience in this country with the use of either SNCR or SCR for coal-fired boilers, especially PC-fired industrial boilers.

Finally, one potential solid waste impact is the result of catalyst replacement when the SCR process is used. With continuous use, the catalyst material will become less active. That is, the efficiency of the catalyst in reducing NO_x will gradually deteriorate. When this happens, the catalyst material must be replaced. This is often accomplished by replacing layers of individual modules starting with the most exposed layer (at the inlet), until all the catalyst material is finally replaced. Performance guarantees for SCR catalysts are often set at 3 years, or 24,000 hours, for natural-gas-fired applications, and 2 years, or 16,000 hours, for oil and coal applications. However, some catalysts have shown longer life, 8 to 10 years, when applied on clean-burning fuel.[24]

The disposal of spent catalyst can present a potential environmental impact because some of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations under RCRA and its amendments. For example, vanadia and titania catalysts are considered hazardous material. However, recent industry trends have shown that these material are readily regenerable. In fact, many catalyst vendors recycle this material thus avoiding any disposal problem for the user. Some of the catalysts, especially those that use rare earth material such as zeolites, are not hazardous and their disposal does not present an adverse environmental impact.

7.3 WATER USAGE AND WASTEWATER DISPOSAL

The only increase in water use is associated with the use of WI or SI and potentially with the use of flue gas treatment NO_x controls, especially SNCR. The use associated with WI or SI injection is an obvious one. The amount of water used does often not exceed 50 percent of the total fuel input on a weight basis. This is because excessive use of flame quenching with water can result in high emissions of CO and high thermal efficiency loss. Therefore, a 50 MMBtu/hr (15 MWt) boiler would use approximately 600,000 gal (2.2 million L) of water per year when operating with a 50 percent capacity factor.

An increase in water use and wastewater disposal requirement could result from the use of SNCR techniques, either urea or ammonia based. This is because ammonia slip when combined with SO_3 in the flue gas will form corrosive salts that deposit on heat transfer surfaces such as air heaters. These deposits must be removed to minimize pressure drop and material corrosion. Air heater acid washing could become more frequent. This practice would result in greater generation of wastewater requiring treatment and disposal. However, urea-based SNCR can actually use wastewater as reagent dilution water prior to injection, thus minimizing the amount of wastewater generated. Increased air heater washing has not been reported in the more than 80 combustion sources equipped with SNCR in the United States.

7.4 ENERGY CONSUMPTION

This section discusses the energy consumption associated with NO_x control techniques for ICI boilers. Energy consumption can come in various forms: a boiler fuel consumption penalty caused by reduced thermal or combustion efficiency; an increase in electrical power to operate fans and pumps; an increase in fuel consumption due to reheat of flue gas; an increase in energy for treatment and disposal of solid or liquid wastes generated by the control technology. Some controls offer the potential for a reduction in energy consumption. Trimming the excess oxygen necessary to assure complete combustion is the most noted of these energy savings techniques. Others include the installation of economizers and air preheaters to recover waste heat in some older and smaller boilers. However, contrary to oxygen trim, these other techniques do not offer a potential for NO_x reduction as well.

7.4.1 Oxygen Trim (OT)

ICI boilers are operated at various excess air levels, ranging from about 10 to over 100 percent of the theoretical amount of air needed to complete combustion. Some amount of excess air is required regardless of fuel burned and method of burning because fuel and air do not perfectly mix and the residence time in the combustion chamber is not infinite. This additional air provides a safe method to increase flame turbulence and assure near complete combustion of fuel. The type of fuel burned and the method of burning determines the minimum amount of excess air required for safe and near complete combustion. For example, the following minimum excess O_2 levels are considered typical for these fuels[25]:

- Natural gas, 0.5 to 3.0 percent
- Oil fuels, 2.0 to 4.0 percent
- Pulverized coal, 3.0 to 6.0 percent
- Coal stoker, 4.0 to 8.0 percent

Generally, excessive combustion air are found in poorly maintained, unattended boilers. This added air provides some measure of safety for burning all the fuel, especially when the operation of boilers is poorly supervised. In many such instances, burner tuning and combustion control adjustments and equipment improvements can be readily made that reduce the amount of excess air resulting in a thermal efficiency improvement and reduced NO_x emissions without compromising the safety of the operation of the unit. Qualified boiler and burner engineers and consultants can upgrade key components of the combustion air control system, including the installation of monitors for O_2 and CO levels in the stack.

Figure 7-3. Curve showing percent efficiency improvement per every 1 percent reduction in excess air. Valid for estimating efficiency improvements on typical natural gas, No. 2 through No. 6 oils, and coal fuels. [25]

Figure 7-3 illustrates the efficiency improvement that can be obtained by reducing excess combustion air in ICI boilers. For example, a 10-percent reduction in excess air (say, from O_2 of 3.5 to 2.0 percent) would result in an efficiency improvement of approximately 0.6 percent when the stack temperature is at 200 °C (400 °F). For a natural-gas-fired boiler with a capacity of 150 MMBtu/hr and a capacity factor of 0.5, this improvement will result in fuel savings of about 3.7 million ft^3 of natural gas per year or about $13,600/yr savings. Algebraically, the relationship between boiler efficiency and excess air can be expressed as follows[26]:

$$\Delta E = \frac{(T - 70)}{63.1} \; x \; \frac{\%EA}{89.5} \qquad (7\text{-}1)$$

Where:

T = stack temperature in °F

% EA = the change in percent excess air

The reduction in excess air, however, can result in some increase in unburned fuel primarily in the form of CO emissions, when gas or fuel oil is burned, and in unburned carbon in the flyash, when coal is burned. Increased emissions of CO have a detrimental effect on the efficiency, as illustrated in Figure 7-4. For example, the example boiler describe above operating at 2.0 percent oxygen might have an increase in CO to about 350 ppm, measured on a dry basis in the flue gas. This amount of CO would reduce the efficiency gain of 0.6 percent described above by about 0.1 percent. Besides this efficiency loss, the air quality impact of increased CO must be considered. The objective of boiler/burner tuning, however, is to reduce excess air without increasing CO emissions or unburned carbon, as discussed in Chapter 5. Algebraically, the relationship between boiler efficiency and CO can be expressed as follows[26]:

$$\Delta E = \frac{CO}{3{,}682} \; x \left(1 + \frac{\%EA}{89.5} \right) \qquad (7\text{-}2)$$

Where:

T = stack temperature in °F

% EA = the change in percent excess air

7.4.2 Water Injection/Steam Injection (WI/SI)

The injection of water or steam in the burner zone to reduce peak flame temperature and NO_x will have a detrimental impact on the efficiency of the boiler. Figure 7-5 illustrates the relationship between the amount of water or steam injected and the reduction in the thermal efficiency of the boiler. The data were developed using standard American Society of Mechanical Engineers (ASME) boiler efficiency calculation procedures.[27] The amount of water injected is typically in the range of 20 to 50 percent of the fuel input on a weight basis. Higher injection levels can cause large increases in CO and HC emissions. The corresponding loss in thermal efficiency when using water is in the range of about 1 to 2.5 percent. The efficiency loss when using an equivalent amount of steam is lower. However, the NO_x reduction efficiency is also lower.

7.4.3 Staged Combustion Air (SCA)

The operation of an ICI boiler with staged combustion air, whether BOOS or OFA, will likely not require additional energy. Taking selected burners out of service will not influence the air distribution. Also any increase in fan power associated with the operation of OFA ports will likely be compensated, for the most part, with reduction of air flow at the original burners.

Figure 7-4. Unburned carbon monoxide loss as a function of excess O_2 and carbon monoxide emissions for natural gas fuel.[28]

7.4.4 Low-NO_x Burners (LNBs)

Minor or no increases in energy consumption are anticipated with the retrofit of LNB technology. This is because newer LNB designs operate at lower excess air levels, thus requiring lower fan power. Some increases in windbox pressures are likely with some retrofits because of

Figure 7-5. Energy penalty associated with the use of WI or SI for NO_x control in ICI boilers.

higher gas velocities and more register control. This increase in pressure drop will tend to increase fan power somewhat, or compensate for the reduction in energy consumption at lower combustion air levels.

7.4.5 Flue Gas Recirculation (FGR)

The retrofit of FGR requires the installation of a fan to recirculate a portion of the hot flue gas back to the burner(s). The operation of the fan will result in an increase in energy consumption. Figure 7-6

Figure 7-6. Estimated energy consumption in FGR use.

illustrates the calculated power requirements with the use of FGR. The relationship between power consumption and FGR rate is based on the following equation:

$$= (0.5)\ (8{,}760\ hr/yr)\ (0.0013558\ kW/ft{-}lb)\ (FGR\ ft^3/s)\ (\Delta P\ l \qquad (7\text{-}3)$$

Where:

0.5 = The capacity factor

ΔP = Assumed to be 10 inches of water to account for efficiency loss

Some additional energy penalty will also be incurred with an increase in pressure drop in the windbox. However, any additional penalty is minor compare to the energy consumption for the FGR fan.

7.4.6 Selective Noncatalytic Reduction (SNCR)

Energy consumption in the SNCR process is related to pretreatment and injection of ammonia-based reagents and their carrier gas or liquids. Liquid ammonia or urea are injected in liquid form at high pressures to ensure efficient droplet atomization and dispersion. In some Thermal DeNO$_x$ installations, anhydrous ammonia is stored in liquid form under pressure. The liquid ammonia must be vaporized with some heat, mixed with carrier gas (air or steam) and then injected for adequate mixing. The amount of electricity used depends on whether the process uses air or steam for carrier gas. If steam is used, less electricity is needed but power consumption must take into consideration the amount of steam used.

Data supplied by Exxon suggest that the amount of electricity needed for the Thermal DeNO$_x$ Process is on the order of 1.0 to 1.5 kW for each MWt of boiler capacity (or 0.29 to 0.44 kW/MMBtu/hr) when using compressed air as the carrier medium.[29] The actual amount of electricity will depend on the baseline NO$_x$ emission level, the NH$_3$/NO ratio used, and the NO$_x$ reduction target. Therefore, a 250 MMBtu/hr (73 MWt) boiler operating with a capacity factor of 0.5 will use approximately:

$$kW/MMBtu/hr \times 250\ MMBtu/hr \times 0.5 \times 8{,}760\ hr/yr = 319{,}740 \qquad (7\text{-}4)$$

which corresponds to about $16,000/yr electricity cost. For steam-assisted ammonia injection, electricity use reduces to about 0.2 to 0.3 kW/MWt or 0.05 to 0.08 kW/MMBtu/hr boiler capacity. The amount of steam used is on the order of 25 to 75 lb/hr/MWt. In general, ammonia is most economically injected using compressed air rather than steam. Data supplied by Nalco Fuel Tech suggest that the urea-based SNCR process uses much lower levels of electricity than either ammonia-based SNCR or

SCR. Typical auxiliary power requirements for an ICI boiler using urea-based SNCR ranges from 20 to 60 kW.[30]

7.4.7 Selective Catalytic Reduction (SCR)

Energy consumption for the use of SCR systems consists of three principal areas: (1) the energy needed to store, pretreat and inject the chemical reagent ammonia or ammonia hydroxide; (2) the increased fan power to overcome the added pressure drop of the catalyst reactor in the flue gas; and (3) the thermal efficiency loss associated with maintaining the catalyst reactor temperature within the specifications for optimum performance at variable boiler load. The energy to store, pretreat, and inject the reagent is equivalent to that of an SNCR system. Estimates of increased pressure drop across the catalyst vary with the various catalyst vendors and applications, primarily fuel. Typically, the pressure drop across a catalyst is on the order of 3 to 6 inches of water. Figure 7-7

Figure 7-7. Estimated increase in energy consumption with SCR pressure drop.

illustrates the energy consumption associated with the additional pressure drop. The relationship between energy consumption and pressure drop across the catalyst is based on the following equation:

$$= (\Delta P \; in \; H_2O)\left(0.0361 \; \frac{lb}{in^2} \; in \; H_2O\right)\left(144 \; \frac{in^2}{ft^2}\right)\left(Q \; \frac{ft^3}{s}\right)\frac{0.5}{0.85} \times \qquad (7\text{-}5)$$

Where:

ΔP = Pressure drop across catalyst, in inches of water

Q = Flue gas flowrate in actual ft^3/s

Finally, the third potentially large source of energy consumption is the result of increased flue gas temperature at the stack at low boiler loads. This increase in stack temperature is associated with the bypass of heat exchange areas or increased fuel consumption to maintain the catalyst at optimum reaction temperature. Figure 7-8 illustrates the loss in boiler thermal efficiency as stack temperature increases. For example, at 20 percent excess air level the thermal efficiency loss is approximately 1.2

Figure 7-8. Curve showing percent efficiency improvement per every 10 °F drop in stack temperature. Valid for estimating efficiency improvements on typical natural gas, No. 2 through No. 6 oils, and coal fuels. [25]

percent for an increase in flue gas temperature of 50 °F. From an efficiency effect standpoint, each 10 °F increase in stack temperature is equivalent to a 583-ppm increase in CO emissions. Whether a facility will incur in this energy penalty will depend on the retrofit configuration, the boiler's load cycle, and the operating temperature window of the catalyst.

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APPENDIX A. ICI BOILER BASELINE EMISSION DATA

This appendix lists baseline NO_x, CO, and unburned THC data for more than 200 ICI boilers. The data were obtained primarily from published technical papers and EPA documents summarizing data from numerous test programs. Boiler data are listed by fuel type, with the exception of FBC boilers which are listed separately. More detailed data may be obtained by referring directly to the individual references.

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APPENDIX B. CONTROLLED NO_x EMISSION DATA

This appendix lists controlled emissions data for boilers used in the ICI sector. Where appropriate, data for small utility boilers and representative pilot-scale units are also included. The data were compiled primarily from technical reports, EPA documents, compliance records, and manufacturers' literature, as listed in the references at the end of this appendix. Additional low-NO_x performance data specific to low-NO_x burners (LNB) marketed by Coen Company, of California, and Tampella Power Corporation, Faber Burner Division, of Pennsylvania, are in Appendix C. Boiler emissions data are listed by fuel type and whether the NO_x control method used was a combustion modification or a flue gas treatment method.

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APPENDIX C. LOW-NO_x INSTALLATION LISTS, COEN COMPANY AND TAMPELLA POWER CORP.

(Note: NO_x levels reported in the Coen list are not necessarily those achieved with the Coen low-NO_x burner, but often represent NO_x guarantees. Actual levels may be lower.)

FABER BURNER — LOW-NO_x BURNER PROJECTS
40 ppm OR LESS — FIRING NATURAL GAS

	Quantity	Boiler capacity	Boiler manufacturer
Tampella Power Williamsport, PA	1	17,500 pph	TP — Package
International Business Machines San Jose, CA	1	36,000 pph	TP — Package
Formosa Plastics Co. Point Comfort, TX	2 3	35,000 pph 55,000 pph	TP — Package
Miller Brewing Co. Irwindale, CA	4	50,000 pph	TP — Package
Veterans Administration Medical Center Sheridan, WY	1	12,500 pph	TP — CP
Veterans Administration Medical Center Los Angeles, CA	1	45,000 pph	B&W — Package
Veterans Administration Medical Center Des Moines, IA	1 2	20,000 pph 15,000 pph	B&W — Package
General Motors Proving Grounds Milford, MI	2	50,000 pph	(1) B&W — Package (1) TP — Package
Armstrong World Industries South Gate, CA	1	9,000 pph	TP — CP
Nationwide Boiler Co. Fremont, CA	2	75,000 pph	Nebraska — Package
Canadian Forces Base Halifax, Nova Scotia	1	60,000 pph (No. 6 oil)	TP — Package
Hershey Chocolate Hershey, PA	3	40,000 pph	TP — Package
Kimberly Clark Fullerton, CA	1	40,000 pph	B&W — Package
Farmer John Vernon, CA	3	23,000 pph 12,000 pph	(1) CE — Marine (2) B&W — Package
3M Corporation Camarillo, CA	2	30,000 pph 22,000 pph	Nebraska — Package Trane — Package
Georgia Pacific Buena Park, CA	1	30,000 pph	TP — Package
Medical Center Co. Cleveland, OH	1	100,000 pph	Nebraska — Package
Sunkist Growers Ontario, CA	1	40,000 pph	B&W — Package
Luzerne County Wilkes-Barre, PA	3	17,500 pph	TP — Package

APPENDIX D. SCALED COST EFFECTIVENESS VALUES

The following tables present cost effectiveness figures for the cost cases analyzed in Chapter 6 and listed in Table 6-4. These costs are based on the annual costs calculated in Appendices E, F, and G for 46 different boiler, fuel, and NO_x control combinations. To estimate cost effectiveness for the boiler capacities listed in this appendix, which in most cases differ from the actual capacities of the 42 boilers cases, the logarithmic relationship known as the "six-tenths" power rule was used (Reference 5 of Chapter 6). Cost estimates for distillate- and residual oil-firing were based on the annual costs of natural gas-fired boilers calculated in Appendix E, using appropriate baseline NO_x emission values and fuel prices.

This appendix contains the following tables:

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APPENDIX E. ANNUAL FIT NO_x CONTROLS: NATURAL-GAS-FIRED ICI BOILERS

This appendix contains cost spreadsheets for natural-gas-fired boilers retrofitted with various NO_x controls. The spreadsheets are based on data from actual boiler retrofit experiences or studies. Capital annualization for all analyses are based on a 10-year amortization period and a 10-percent interest rate. All costs presented are in 1992 dollars. For further information on the methodology and assumptions made in these cost analyses, see Chapter 6.

This appendix contains cost spreadsheets for the following boilers:

APPENDIX F. ANNUAL COSTS OF RETROFIT NO_x CONTROLS: COAL-FIRED ICI BOILERS

This appendix contains cost spreadsheets for coal-fired boilers retrofitted with various NO_x controls. The spreadsheets are based on data from actual boiler retrofit experiences or studies. Capital annualization for all analyses are based on a 10-year amortization period and a 10 percent interest rate. All costs presented are in 1992 dollars. For further information on the methodology and assumptions made in these cost analyses, see Chapter 6.

This appendix contains cost spreadsheets for the following boilers:

APPENDIX G. ANNUAL COSTS OF RETROFIT NO_x CONTROLS: NONFOSSIL-FUEL-FIRED ICI BOILERS

This appendix contains cost spreadsheets for nonfossil-fuel-fired boilers retrofitted with various NO_x controls. The spreadsheets are based on data from actual boiler retrofit experiences or studies. Capital annualization for all analyses are based on a 10-year amortization period and a 10-percent interest rate. All costs presented are in 1992 dollars. For further information on the methodology and assumptions made in these cost analyses, see Chapter 6.

This appendix contains cost spreadsheets for the following boilers:

For a given cost case, cost estimates were calculated using all applicable boiler cases, in order to compare costs provided by different sources. For example, for natural gas-fired packaged watertube boilers with LNB, cost effectiveness was calculated using the annual costs developed for three different boilers listed in Appendix E. The results are presented on the following page for each of the three units.