OVERVIEW OF ENVIRONMENTAL PROTECTION AGENCY'S

NO_x CONTROL TECHNOLOGY FOR STATIONARY COMBUSTION SOURCES

by

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ABSTRACT

An overview of the Environmental Protection Agency's nitrogen oxides control technology program is presented. Topics discussed include the role of stationary sources and their NO_x contribution, the state-of-the-art of NO_x control including combustion modification and flue gas cleaning technologies and implementation costs, future goals and possible new approaches. Environmental Protection Agency's standards and local regulations are reviewed.

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INTRODUCTION

Stationary combustion sources continue to contribute about half of the total man-made nitrogen oxides (NO_x) in the United States. Recent estimates indicate that over 11 million tons* of NO_x were emitted from fossil fuel combustion in stationary sources in 1972. Because of their quantity and potential for widespread adverse health effects, NO_x is among the atmospheric pollutants for which regulatory controls have been established by the U. S. Environmental Protection Agency (EPA). Authority for the promulgation and enforcement of source performance standards and National Ambient Air Quality Standards (NAAQS) came with passage of the 1970 Clean Air Act. The Act additionally provides for an EPA research program to develop cost-effective, commercially viable NO_x control technology for both new and existing stationary combustion sources. Toward that goal, the Combustion Research Section of the Control Systems Laboratory of EPA is actively engaged in a program of contract and in-house studies to develop NO_x combustion control technology for a variety of sources. EPA's current activity in flue gas treatment for NO_x is proceeding at a low level and is primarily directed toward catalytic methods for NO_x reduction.

*It is EPA policy to use Metric units; however, in this paper English units are used for convenience. See attached conversion table.

AUTHORITY FOR NO_x STANDARDS

The Clean Air Act of 1970 required that the Administrator promulgate national ambient air quality standards for those pollutants "which in his judgment have an adverse effect on public health and welfare." In addition, the Clean Air Act directed the Administrator to promulgate standards of performance with respect to the emission of air pollutants for those new stationary sources which he determines "may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare."

Prior to publication of a nitrogen oxides criteria document and in response to the directive of the Clean Air Act of 1970 that a reduction of nitrogen oxides emissions of at least 90 percent be achieved for light duty motor vehicles by 1976, a nitrogen oxide Federal motor vehicle emission standard of 0.4 g/mile was adopted. Subsequently, the publication of the nitrogen oxides air quality criteria document set in motion the mechanism for development of the National Ambient Air Quality Standards (NAAQS) which were promulgated in 1971.[1]

Nitrogen oxides were identified as an air pollutant having an adverse effect on public health and welfare. Within this category of chemical compounds, there are only two nitrogen oxides which are of significance in the atmosphere. These are nitric oxide (NO) and nitrogen dioxide (NO_2); the combination of these two major species is referred to under the general classification of nitrogen oxides, represented by the symbol NO_x. NO is the predominant form emitted by

most combustion processes, accounting for approximately 95% of the total NO_x from the combustion of fossil fuels. Some chemical processes (such as nitric acid manufacture) and certain combustors (such as gas turbines), however, may emit significant amounts of NO_2 directly.

Nitric oxide, once it is in the atmosphere, is converted to NO_2. One mechanism of conversion is thermal oxidation which proceeds at a slow rate. A second mechanism is the photochemical conversion involving NO_2, reactive hydrocarbons and ultraviolet energy from sunlight. This latter reaction is rapid and produces undesirable oxidants, as byproducts, which result in smog formation under certain conditions.

NATIONAL AMBIENT AIR QUALITY STANDARDS

In establishing a basis for ambient air quality standards, analyses of available information on atmospheric chemistry and on the effects of nitrogen oxides on man, plants and materials disclosed two main points. The first is that NO is rapidly converted to NO_2 in the atmosphere, and secondly, that NO_2 is by far the more hazardous oxide form.

The adverse effects of NO_2 at ambient concentrations on human beings were highlighted as the result of an epidemiological appraisal of NO_2 conducted by Shy in Chattanooga, Tennessee.[2] The results of this study indicated adverse health effects contributable after exposure to ambient levels of NO_2 at 0.1 ppm for 1 hour. This preliminary indication provided the basis for the statutory mobile source standard of 0.4 g/mile. Further analysis of the data led to the conclusion that

an annual average NO_2 concentration greater than 113 $\mu g/m^3$ (0.06 ppm) has the potential for adverse effects on respiratory performance. This became the basis for the NAAQS.

The NAAQS for NO_2 were set in 1971 as required by the Clean Air Act of 1970. The primary standard is based on a level which is required to protect the public health, and the secondary standard is based on a level which is requisite to protect the public welfare from any known or anticipated adverse effect associated with the presence of air pollutants in the ambient air. Both standards were set at 100 micrograms per cubic meter for NO_2.

Questions related to the reliability and accuracy of the analytical method used in the Chattanooga study have cast doubt on the 100 $\mu g/m^3$ NAAQS, and the issue has not yet been resolved. Indications are that the annual average NAAQS may be retained but that this may be supplemented by a short term exposure standard as well. As a result of reevaluation of the levels of NO_2 based on more reliable analytical methods, it appears that only four Air Quality Control regions (AQCRs) now exceed the NAAQS.[3] In addition another four AQCRs are near the standard and remain a potential future problem. These problem areas are all in regions of high population density so the NO_x problem at present is essentially an urban problem.

NEW SOURCE PERFORMANCE STANDARDS

The Clean Air Act requires that emission control standards "reflect the degree of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated." The approach to setting Federal standards for stationary sources is to determine a priority ranking of sources to be controlled based on: 1) magnitude of contribution to the total emission of a given pollutant, 2) available information on control technology, 3) projected growth, and 4) impact of Federal standards relative to existing State standards. The sources have been grouped into five priority categories to establish the order in which standards would be set. The two sources of NO_x which fell into the Priority I category were steam generators of greater than 250 x 10^6 Btu/hr. input and nitric acid plants. Other NO_x sources to be regulated included stationary gas turbines, stationary internal combustion engines, and steam generators between 10 x 10^6 and 250 x 10^6 Btu/hr. input.

Steam Generators

The New Source Performance Standards (NSPS) for fossil fuel fired steam generators over 250 x 10^6 Btu/hr. input cover any source on which construction or modification was commenced after August 17, 1971. The boilers which fall into this category are mostly utility boilers for electric power generation although some large field erected industrial steam-raising boilers are included. Along with the NO_x standards, levels for particulate matter and sulfur oxides were also included. The

particulate standard is 0.1 lb. per million Btu input (maximum 2 hr. average) for filterable particulate. The sulfur oxides (SO_x) standard is 0.8 and 1.2 lbs. SO_2 per million Btu for liquid and solid fuels, respectively. The NO_x standards are a function of fuel type as shown in Table 1.

Nitric Acid Plants

The NSPS for NO_x for nitric acid plants was set at 3 lbs. (expressed as NO_2) per ton of acid produced. A 10% opacity standard was also included.

Gas Turbines

Publication of the New Source Performance Standards for stationary gas turbines is planned for December, 1974. After comments are received and the standards are finalized, promulgation is anticipated during the first half of 1975. Although the original goal was 0.2 lb. NO_x (as NO_2) per million Btu input for all fuels, it now appears that different standards may be established for gas and oil fired units. Current target levels for stationary gas turbines of over 1.5 million Btu/hr. (about 125 hp) are 75 ppm NO_x (15% excess oxygen) for oil fired units and 55 ppm NO_x (15% excess oxygen) for gas fired units.

Other Sources

At least two other sources are under consideration for promulgation of NSPS. These possible sources to be controlled include stationary internal combustion engines and steam generators (coal, oil and gas

fired) between 10 x 10^6 and 250 x 10^6 Btu/hr. input. Lignite fired steam generators of over 250 x 10^6 Btu/hr. may also be added to the list.

Table 1

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

FOR STATIONARY COMBUSTION SYSTEMS

(Fossil Fuel Fired Steam Generating Units with Input Greater Than 250 x 10^6 Btu/hr.)

	Standard	
Fuel Type	lb. $NO_2/10^6$ Btu(2 hr. avg.)	ppm (3% excess O_2 dry basis)**
Gas	0.2	168
Oil	0.3	230
Coal	0.7	500
Mixed* Fuels	$\frac{X(0.2) + Y(0.3) + Z(0.7)}{X + Y + Z}$	

* X = % of total heat input derived from gas
Y = % of total heat input derived from oil
Z = % of total heat input derived from coal

** Based on typical average fuel heating values

STATE AND LOCAL STANDARDS

The Clean Air Act provides for State or political subdivisions to impose and enforce standards for control or abatement of air pollutants except that these standards may not be less restrictive than the Federal requirements if necessary to meet the NAAQS. The Los Angeles Air Pollution Control District (LAAPCD) established Rule 68 which set standards for existing gas and oil fired utility boilers of greater than 1,775 x 10^6 Btu/hr. input and has been in effect since December 31, 1971. A more stringent Rule 68 level of control becomes effective December 31, 1974. The Rule 68 levels are shown in Table 2. EPA has proposed to supplement Rule 68 to cover the boilers which range between 250 x 10^6 and 1,775 x 10^6 Btu/hr. as shown in Table 3. Essentially the same EPA regulations have been proposed for several other California and New York Air Pollution Control Districts.

Perhaps the most restrictive regulation in existence anywhere is the LAAPCD's Rule 67, which places a limit of 140 lbs. NO_2 per hour regardless of unit size. As an example under this rule, a 315 MW utility boiler can only emit 42 ppm NO_x (corrected to 3% oxygen). The Scattergood 3 unit of the Los Angeles Department of Water and Power is currently undergoing initial testing and is projected to meet this emission level.

Table 2

RULE 68: LOS ANGELES COUNTY NO_x STANDARDS FOR EXISTING BOILERS GREATER THAN 1775 x 10^6 BTU/HR HEAT INPUT

Fuel Type	Standard	
	In Effect	NO_2, ppm*
Gas	Before 12/31/74	225
	After 12/31/74	125
Oil, Coal	Before 12/31/74	325
	After 12/31/74	225

*Concentration is calculated at 3% excess O_2, dry basis

Table 3

STANDARDS PROPOSED BY EPA FOR EXISTING

BOILERS IN LOS ANGELES COUNTY*

Fuel Type	Boiler (type firing)	Standard	
		lb. $NO_2/10^6$ Btu	NO_2, ppm**
Gas	Tangential	0.2	168
	Front Wall	0.4	336
	Horizontally opposed	0.6	504
Oil	Tangential	0.3	230
	Front Wall	0.4	307
	Horizontally opposed	0.6	460

*For boilers greater than 250 x 10^6 Btu/hr. but less than 1775 x 10^6 Btu/hr.

**Concentration is calculated at 3% excess O_2, dry basis

STRATEGY FOR MEETING NAAQS

Provision was made to apply available NO_x control technology to stationary sources in order to achieve the NAAQS if the reduction in automotive NO_x emission levels of 0.4 g/mile was insufficient to meet the standards. It has been very difficult to meet this automotive standard and the control technology to achieve this level is costly and has imposed a significant fuel penalty. Thus EPA's Office of Air Quality Planning and Standards (OAQPS) has conducted a study analyzing the most effective means for achieving the NAAQS considering control and fuel penalty costs as well as air quality. As a result, OAQPS has recommended that the automotive standard be revised to 2.0 g NO_x per mile and that more stringent NO_x emission controls be placed on new and existing stationary sources as required in air quality control regions not meeting NAAQS. This recommended strategy is currently undergoing review prior to any formalized action in changing the earlier mandate.

The attainment of the NAAQS for nitrogen oxides will require achieving a balance of emissions control for both mobile and stationary sources. If the recommended OAQPS strategy is adopted, it would require that in certain AQCR's more stringent controls would have to be placed on new and existing stationary sources to achieve the NAAQS. Considering national annual growth rate patterns and future expansion of transportation and industry, it would be necessary to implement even more stringent NSPS for major stationary NO_x sources in the 1980-1985 period. This will require increased R&D in both combustion control and effluent treatment technology.

It is assumed that present standards can be met with current stationary source technology (CSST). However, more effective NO_x control technology than that currently available will be required within the next five years to ensure meeting the NAAQS is all AQCR's and the more stringent NSPS which are anticipated. This need for a maximum stationary source technology (MSST) program for attaining adequately low levels of NO_x in the future provides the major basis for the EPA's Control Systems Laboratory (CSL) NO_x control technology program.

CSL NO_x CONTROL TECHNOLOGY DEVELOPMENT PROGRAM

The current program for stationary NO_x control technology has been developed over the past seven years and is based on growing information relative to the definition of the problem, the most effective and economical strategies to be followed in meeting the standards, and our increased knowledge of the causes of the problem and the effectiveness of various approaches to NO_x emissions reduction. A systems study of the NO_x problem area five years ago provided the preliminary background and initial direction to the program. This early investigation indicated that 1) the major stationary sources of NO_x emissions were fossil fueled combustion systems and 2) the most effective means of control for near-term solutions of the problem would be the application of combustion modification techniques to minimize the formation of the nitrogen oxides. Although the recommended program was oriented strongly to the development and evaluation of combustion modification techniques, consideration was also given to flue gas cleaning methods. These latter

methods were believed to hold promise for application to specialized cases where high NO_x concentrations are present or very low levels of NO_x emissions are required.

The CSL program is divided into two separate parts. The major emphasis is directed to the development of combustion modification techniques for controlling NO_x emissions while a separate and much smaller effort is investigating effluent treatment methods for removal of NO_x.

Combustion Modification Technology

The NO_x combustion control program is a systems program concerned with the control of combustion generated pollutants from all types of stationary combustion sources. Although the primary pollutant emphasis was defined as NO_x control, it is known that NO_x combustion modification techniques, unless properly applied, could lead to serious problems of emissions of products of incomplete combustion. Some of the potential control techniques also appear to have the possibility of decreasing process efficiency. Secondary emphasis therefore is placed on the control of the products of incomplete combustion, such as carbon monoxide (CO), unburned hydrocarbons (UHC), carbon particulate, and smoke, and on process efficiency. A program guideline is that the NO_x control technology should not produce an increase in products of incomplete combustion, and should not adversely affect efficiency but, if possible, should actually increase it.

The program includes a number of separate projects which fall generally into four separate areas:

1) field testing and survey activities,
2) fundamental combustion research studies,
3) fuels research and development, and
4) process research and development.

A general discussion of these various areas of activity is included below to aid in understanding the program.

Field Testing and Survey Studies

The field testing and survey studies are designed to determine what can be done currently to control NO_x emissions. This work is generally performed by R and D organizations on commercial equipment and closely involves the cooperation of manufacturers, users and trade associations. These groups provide technical and financial assistance, make available test sites, and modify equipment or operating practices and schedules to accommodate test programs. In addition to developing trends and providing directional recommendations for industry to minimize emissions with today's technology, the work also defines problem areas and delineates where the R&D efforts should be concentrated. These studies are the initial efforts in the development of control technology and provide very near-term control technology. They develop the information on available state-of-the-art NO_x control technology to be passed along to other potential users who may not yet have adopted these control measures.

Fundamental Combustion Research Studies

The fundamental combustion research studies are designed to provide basic combustion theory and a detailed understanding of the formation of pollutants and their reactions in the combustion process. The studies consider the variations related to differences in fuels, combustion systems, and operating conditions. The goal of these studies is to provide a solid scientific basis for the rational development of effective control technology so that reliance on empirical approaches is minimized. As the role of chemical and physical factors and the influence of combustion process variables on pollutant formation become known, it should be possible to more readily postulate viable theories for NO_x control technology.

The fundamental combustion studies underway and planned for the future generally fall into three categories, namely, the chemistry of pollutant formation, the aerodynamics or physical factors affecting pollutant formation, and mathematical simulations or modelling of pollutant formation in combustion processes. Work in the first two categories investigates the basic components involved in the formation and destruction of pollutants in combustion processes and flames. These results provide the basis and input for the third category of mathematical simulations which will be used ultimately in all program areas.

Fuels Research and Development

The fuels research and development studies are designed to develop generalized combustion control technology which is applicable to the optimum control of NO_x emissions from the combustion of both conventional fossil fuels and future fuels. These engineering R&D studies examine the feasibility of the concepts which may be generated as a result of the fundamental combustion research studies. They are conducted on versatile experimental combustion systems and will define the generalized combustion control concepts and technology for the combustion of various fuels. This work will provide the optimum goal for practical NO_x control. When technically and economically feasible control techniques have been identified and generalized combustion control technology has been developed as a result of these studies, the technologies will be adjudged ready for application scale-up and more thorough investigation in practical systems.

Process Research and Development

The process research and development portion of the combustion modification program is planned to assess the application of optimum NO_x control technology to both traditional and advanced combustion systems. The work generally involves studies of control techniques as applied to commercial or prototype combustion systems and requires close cooperation with industry to achieve the desired results. The studies are planned to develop design information, to assess technical

performance, to generate cost information, and to identify problems relative to the application and use of the technology. Specific results of the work in this area include design and operational guidance manuals that can be used by manufacturers and users to control NO_x emissions by combustion modifying techniques. The results of the studies in this category provide the basis for the future demonstration of combustion control technology for major emission sources.

Maximum Stationary Source Technology (MSST) Program Planning

In view of anticipated changes in NO_x control strategy based on recommendations of the OAQPS to relax the automotive NO_x emission standards and to require more stringent NO_x controls for stationary sources, a project has been initiated to define the MSST program. The Aerotherm/Acurex Corporation was given the task of assisting CSL in developing a coordinated MSST program for NO_x control technology development. Three major objectives set forth for this task were: 1) to ensure that the CSL NO_x program directly responds to the needs of the OAQPS; 2) to delineate those sources which are being covered by current stationary source technology (CSST) and to define the reasonably expected controlled emissions obtainable through CSST, and 3) to define additional efforts (tasks), potential further NO_x reductions, and sources covered by the MSST. Among several auxiliary segments of this task, one involved estimating costs for a total budget required for achieving the MSST program.

The status of this effort is well advanced but results were not complete (draft final report) at the time this paper was prepared.

Although most of the effort to date has emphasized the combustion of fossil fuels in conventional combustion systems identified as the major emission sources (e.g., utility boilers, industrial boilers, commercial and residential heating systems), future effort is expected to expand into new areas. Work will be increased in the area of utilization of mixed fossil and waste fuels and of new alternate fuels as they are developed. Consideration will be given to a wider range of conventional combustion equipment, including stationary gas turbines, stationary internal combustion engines, and industrial process furnaces. In addition, newer concepts of combustion will be evaluated for their potential for low NO_x emissions. This work will include investigations of catalytic combustion systems and of advanced power cycles. In general, the program should provide the combustion control technology to minimize NO_x and other combustion-related emissions from a broad range of existing and new point and area combustion sources while simultaneously maintaining acceptable or improved combustion process efficiency. The effort, while stressing the development of control technology, will also provide assessments of the effect on the environment of practical applications of these controls.

Effluent Treatment Technology

The Esso Systems Study[5] on NO_x control identified a number of candidate effluent treatment techniques (e.g., sulfuric acid scrubbing, alkaline scrubbing, molecular sieve absorption and catalytic reduction). Early preliminary studies of sulfuric acid scrubbing and alkaline scrubbing, considering such variables as NO concentration, NO to NO_2 ratio, and scrubbing agent, indicated that these scrubbing processes alone were not feasible methods.[30,31] With sulfuric acid scrubbing, mass transfer rates were quite low leading to very large contact equipment and high costs. NO_2 absorption with alkaline scrubbing appeared feasible but mass transfer rates with sorbents for flue gas desulfurization were relatively slow, indicating similar problems. In addition, preliminary studies regarding oxidation of NO to NO_2 indicated that ozone production capital and operating costs would be quite expensive and require high power consumption. Being explored at present are catalytic NO_x control with the use of reductants and molecular sieve absorption. Demonstration of the technique of molecular sieve absorption is underway at 2 nitric acid plants. This technology is not applicable to combustion flue gases due to preferential sorption of the moisture in the flue gas.

Future efforts in the development of NO_x effluent treatment are anticipated to continue in three major areas relating to NO_x reduction:

Evaluation of the selective reduction of NO with platinum catalyst and ammonia as a reductant will be continued on a utility boiler firing low-sulfur distillate oil. The effects of operating time on catalyst performance will be evaluated and methods of extending the life of the catalyst will be investigated.

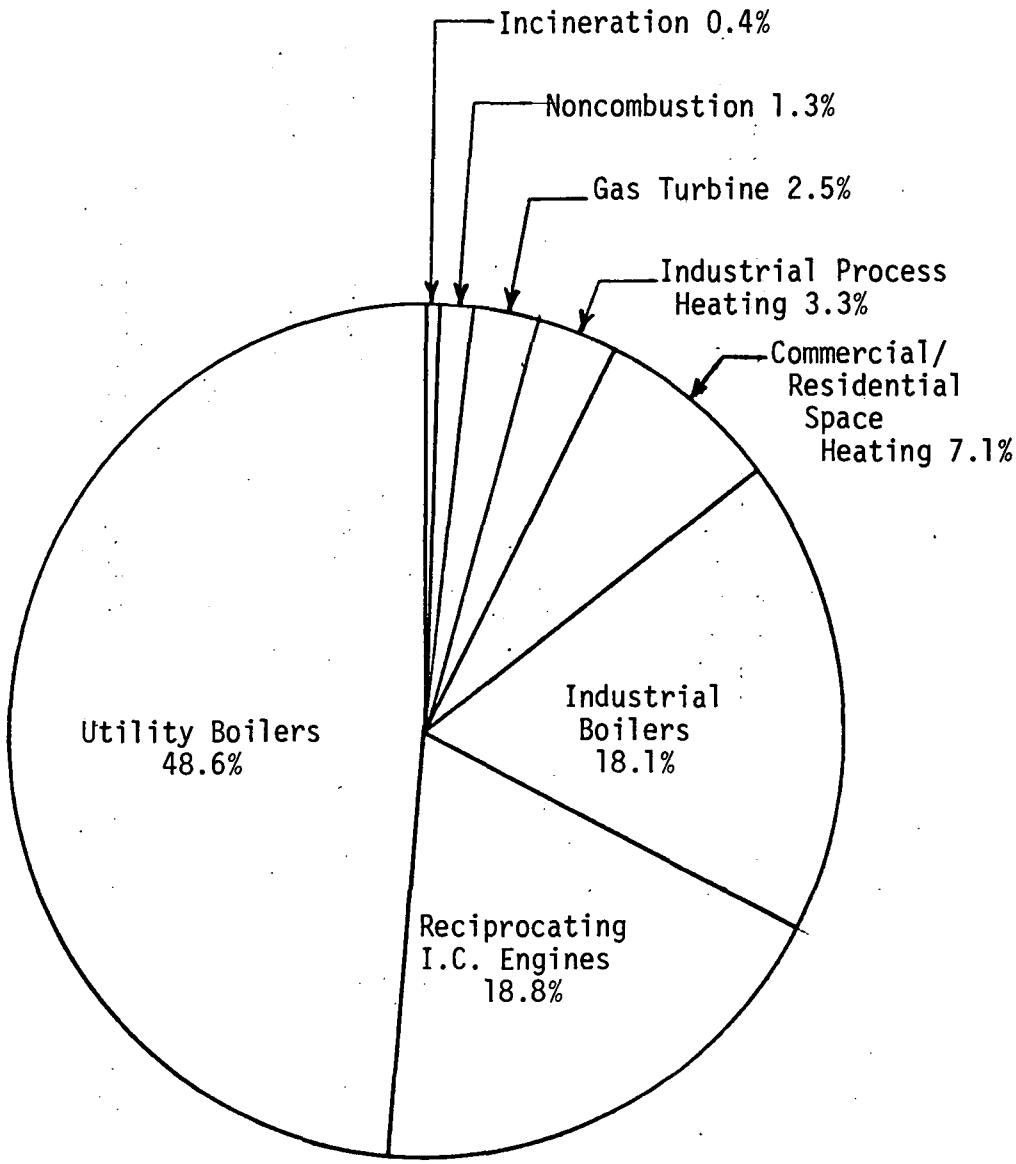
The technology of non-noble metal catalysts for NO_x reduction will be investigated further for applicability to combustion units firing SO_x producing fuels. This activity will include additional laboratory scale evaluations to provide design criteria and cost information. These evaluations will include selective NO_x reduction with NH_3 and nonselective reduction with H_2 and CO. Based on results, process evaluations may be conducted at larger scales.

Feasibility studies and experimental evaluations will be conducted on promising processes which simultaneously remove SO_x and NO_x from combustion flue gases. Processes with possible application include Esso/B&W, Shell/UOP and Chiyoda Thoroughbred 102. In addition, applications of effluent treatment technology will continue to be surveyed with particular attention paid to Japan where efforts have been intense.

SOURCES AND LEVELS OF NO_x EMISSIONS

A recently completed EPA-sponsored study[4] has updated and refined prior 1968 estimates by Esso[5] of NO_x emissions from stationary sources. Figure 1 shows the major stationary sources and their NO_x contribution. Utility boilers are the major NO_x source, accounting for over 48% of the nearly 11.7 million tons emitted. Stationary reciprocating internal combustion (I.C.) engines and gas turbines collectively accounted for over 21% of the total. Industrial boilers contributed over 18% and residential and commercial heating accounted for slightly over 7%. Another NO_x source was process heating at over 3%. Collectively, these five sources account for over 98% of the man-made NO_x from stationary sources, the remainder coming from non-combustion sources and incineration. The significance of the NO_x emission update is that since the 1968 studies, stationary engines (I.C. and gas turbines) have moved from third to second place as a result of refined emission factors and better estimates of installed capacity. Additionally, the total stationary source NO_x has increased by over two million tons with the majority of the increase coming from utility boilers.

Table 4 is a summary of total NO_x emissions from stationary fuel-user sources. It shows that the major NO_x contributors are coal fired utility boilers. The split between total NO_x from gas and coal combustion is about equal, even though the total usage of gas is significantly higher than coal. This is due primarily to the influence



Source	Estimated NO_x Emissions Tons/Year
Utility Boilers	5,670,000
Reciprocating I.C. Engines	2,189,000
Industrial Boilers	2,108,000
Commercial/Residential Heating	826,800
Industrial Process Heating	390,200
Gas Turbines	291,000
Noncombustion	149,000
Incineration	41,000
TOTAL	11,665,000

Fig. 1. Total NO_x emitted in the U.S. from stationary sources, 1972.[4]

Table 4

SUMMARY OF TOTAL NO_x EMISSIONS FROM FUEL-USER SOURCES (1972)[4]

Source	NO_x Production, 10^6 tons/yr (percent of total)				Cumulative Percentage
	Gas	Oil	Coal	Totals by Source	
Utility Boilers	1.114(9.55)	0.768(6.58)	3.788(32.47)	5.670(48.61)	48.61
I.C. Engines					
Reciprocating	1.873(16.06)	0.316(2.71)	-	2.189(18.77)	67.38
Gas Turbines	0.172(1.47)	0.119(1.02)	-	0.291(2.49)	69.87
Industrial Boilers	0.495(4.24)	1.098(9.41)	0.515(4.41)	2.108(18.07)	87.94
Commercial/Residential Heating	0.3308(2.84)	0.467(4.00)	0.029(0.25)	0.8268(7.09)	95.03
Process Heating	0.1855(1.59)	0.149(1.28)	0.0553(0.47)	0.3902(3.35)	98.38
Non-Combustion	-	-	-	0.149(1.28)	99.66
Incineration	-	-	-	0.041(0.35)	100
Totals by Fuel	4.1703(35.75)	2.9174(25.01)	4.3873(37.61)	11.665(100)	

of fuel nitrogen conversion to NO_x in coal (and oil). This phenomenon will be discussed later.

Table 5 provides a perspective summary of fuel use by combustion sources. The fuel usage for process heating (furnaces, kilns, etc.) is a crude estimate. However, the overall distribution of fuel use by source is reasonably accurate. It shows that gas usage was nearly twice that of coal. It is expected that coal usage will increase significantly in future years as a result of our national energy situation. Utility boilers were the largest users of fuel with commercial and residential heating being a very close second.

Table 5

SUMMARY OF FUEL USE BY COMBUSTION SOURCE (1972)[4]

	Fuel Used, 10^{15} Btu/yr (percent of Total)			
Source	Gas*	Oil	Coal	Totals by Source
Utility Boilers	3.8(8.6)	2.6(5.9)	8.4(19.0)	14.8(33.5)
Commercial and Residential Heating	7.9(17.9)	5.9(13.3)	0.2(0.4)	14.0(31.6)
Industrial Boilers	4.5(10.2)	5.5(12.4)	1.8(4.1)	11.8(26.7)
I.C. Engines and Gas Turbines	1.7(3.9)	0.5(1.1)	--------	2.2(5.0)
Process Heating	0.7(1.6)	0.6(1.4)	0.1(0.2)	1.4(3.2)
Totals by Fuel	18.6(42.2)	15.1(34.1)	10.5(23.7)	44.2(100)

*Includes Liquified Gas

Despite its second place position in terms of fuel use, NO_x emissions from commercial and residential heating were ranked fourth. This is due primarily to the comparatively low emissions from this source category and the fact that they generally fire the cleaner fuels (gas and No. 2 oil). Gas turbines and I.C. engines, despite their low ranking in terms of fuel use, were second in terms of NO_x production due to their high emission levels and widespread use.

It is important that when analogies are drawn between fuel use and source that full consideration be given to population factors (i.e., number of units) and relative emissions between sources and fuels.

This type of information is especially helpful in planning R&D programs for combustion control of NO_x from stationary sources. The overall NO_x ranking provides direction as to the major source categories requiring control. Further breakdown by fuel type gives additional insight for control strategies. Still further refinement by equipment type and fuel allows individualized assessment of control technology.

MECHANISMS OF NO FORMATION

Before discussing the types of NO_x control technologies that are presently available, it is worth reviewing the mechanisms by which NO is formed. An evaluation of the background data has led to the conclusion that NO formed in the combustion of fuels can occur by two

principal mechanisms: (1) high temperature fixation of molecular nitrogen in the combustion air to yield "thermal NO", and (2) conversion of chemically bound nitrogen in the fuel to yield "fuel NO".

The important reactions and kinetic rate constants associated with thermal NO were initially identified by Zeldovich in 1948[6] and have subsequently been studied by other investigators. The rate of formation of thermal NO is exponentially dependent on temperature and has a one-half power dependence on oxygen concentration. In practice, the actual levels of thermal NO ultimately formed are a function of additional factors, e.g., air/fuel mixing patterns, heat release/removal rates, and fuel injector design.

Recently, the importance of fuel NO has become apparent. Initial investigations by Shaw[7] indicated that nitrogenous compounds added to gaseous fuels could be converted to NO. Work by Martin[8] using distillate oil doped with varying concentrations of several nitrogenous compounds gave insight as to the degree of nitrogen conversion to NO. This work showed that the fraction of bound nitrogen converted to NO decreased with increasing nitrogen content although the absolute magnitude of the NO increased. Additionally this work showed that the degree of conversion increased with increasing excess air. It was postulated that fuel nitrogen was relatively insensitive to temperature and strongly dependent on oxygen availability. Turner [9] obtained similar results in a modified package boiler using residual oil with naturally occurring fuel nitrogen. Investigations by Heap

et al.[10] attributed NO formation in coal flames to conversion of volatile nitrogen compounds present in coal. Experiments by Pershing[11] confirmed the dominance of fuel NO in residual oil and coal flames by substituting a 21% oxygen/79% argon atmosphere for the combustion air. This recent work additionally served to confirm the temperature insensitivity of fuel nitrogen conversion.

As a consequence of prior experimental work it becomes important to give due consideration to the type of fuel being burned before selecting a combustion modification technique for NO_x control. A discussion of available combustion modification techniques follows.

NO_x COMBUSTION CONTROL TECHNOLOGY FOR BOILERS

Low Excess Air Combustion

Low excess air combustion is one of the most promising and widely applicable combustion modification techniques for reducing NO_x. It has been used successfully with all fuels and employed on a variety of furnace types. By reducing oxygen availability at the burner(s), both thermal and fuel NO can be reduced. The actual degree of NO_x reduction is a function of furnace design, fuel type and overall excess air. When employing this technique, the lowest practical excess air levels are generally dictated by a need to limit products of incomplete combustion (CO, hydrocarbons and smoke) or to prevent operating problems such as boiler vibrations, slagging and fireside corrosion.

Flue Gas Recirculation

The use of flue gas recirculation (FGR) in combustion processes is not a new technique. Its principal use, at least in utility boilers, is for steam temperature control. For that application, the flue gas is recirculated to the furnace bottom. To be useful as a NO_x control technique, FGR must be directed through the burners into the primary combustion zone. Its effect on reducing NO_x is two-fold: (1) the flame zone temperature is reduced by the recirculating flue gases, and (2) the concentration of oxygen available for NO production is reduced. The thermal effect is generally considered to be more important. Since FGR will reduce thermal NO primarily, its use is generally restricted to gas fired systems or to very low nitrogen fuels (e.g., distillate oils) where fuel nitrogen conversion is not particularly significant. The technique can be expensive since a high temperature fan and additional ductwork is required. Typical FGR rates of 15 to 30% have been employed. Burner stability problems can occur at higher rates. Application of FGR to existing boilers can adversely affect steam side performance because of the increased gas velocities through the convective passes of the boiler and load reduction may be necessary to maintain gas velocities within design limits. Additionally, space limitations on existing boilers may make installation of FGR difficult.

Water or Steam Injection

The use of water or steam injection into the combustion zone can reduce thermal NO since its effect is to reduce flame temperature. Its use would be restricted to gas or distillate oil fired systems where thermal NO predominates. It may be somewhat more effective on a mass basis than flue gas recirculation for reduction of thermal NO. The installation cost is quite low especially on gas fired systems equipped for standby oil firing since the oil guns provide a convenient point for injection and only a pump and piping is required. However, in the case of boilers, a severe penalty occurs in operating costs because of the increase in gas flow through the boiler and latent heat losses in the stack. It could be used as a "trimming" technique to maintain acceptable NO_x levels for gas and distillate oil fired systems. The maximum amount of water injection that could be used would be about 50 pounds of water per million Btu fired. This would impose an efficiency penalty of at least 5%.

Staged Combustion

Staged combustion for utility boilers was developed in the late 1950's cooperatively by Southern California Edison (SCE) and the Babcock & Wilcox Company. The study led to the investigation of burners operating with 90 to 95% of stoichiometric air through the burners with the balance of the combustion air admitted through "NO" ports located above the burners. Later work by SCE and KVB Engineering produced a modification to staged combustion known as "off-stoichiometric firing".

The technique involves firing lower sets of burners fuel rich and upper burners either fuel lean or on air only. A variation of this technique, "biased firing", operates burners in staggered configurations of fuel rich and either fuel lean or on air only. Staged combustion is effective in reducing both thermal and fuel NO_x emissions because of limited oxygen and lower flame temperatures in the primary combustion zone, and lower effective temperatures in the secondary, air-rich combustion zone. Unless the active burners can carry the fuel requirement for full load, use of off-stoichiometric firing and biased firing can bring about a load reduction. This is often true for coal fired boilers where pulverizer capacity may be a limiting factor. New unit designs are being built with overfire air ports so that all burners are active. This technique is applicable for all fuels especially for coal where the bulk of the NO results from fuel nitrogen conversion. Two potential problem areas with coal fired boilers (i.e., slagging and fireside corrosion) are being addressed in EPA-sponsored studies.

Reduced Air Preheat Temperature

Reduction of combustion air preheat temperature has the effect of lowering combustion zone peak temperatures with a subsequent reduction in thermal NO_x. It is not considered a practical control technique because of its adverse impact on thermal efficiency.

Load Reduction

Operating combustion processes under reduced load generally brings about reductions in thermal NO_x because of the decrease in combustion intensity and peak temperatures. Load reduction is not consistent with meeting today's energy needs especially for electric generation.

Burner Design

Experimental work being conducted under EPA contracts is showing good promise for low-NO_x burner designs applicable to all fuels and a variety of systems. Work performed for EPA by the International Flame Research Foundation[10] in IJmuiden, Holland has had primary emphasis on pulverized coal flames with a secondary emphasis on residual oil. In addition to input/output testing to evaluate promising low-NO_x conditions, the work also included detailed mapping of selected flames for definition of important aerodynamic effects and pollutant specie concentrations. Several promising low-NO_x (150-300 ppm) burner configurations for use in wall fired pulverized coal boilers have been identified. Future R&D will develop scale-up criteria for pulverized coal burners to a size of about 10^8 Btu/hr. to validate emission and combustion performance. Following this effort, a prototype burner will be installed in an industrial boiler. Later, the design will be tested in a multi-burner utility boiler.

EPA in-house studies of a number of commercially available distillate oil fired burners[12] concluded that an optimum burner design could control NO with smoke-free low excess air operation. An EPA-sponsored study with the Rocketdyne Division of Rockwell International[13] is developing an optimum distillate oil burner for residential and commercial applications. To date, the optimized design has produced NO levels from 50 to 65% of those from conventional burners and is capable of smoke-free operation at 10% excess air.

Burner design studies of gas fired industrial burners are being performed for EPA by the Institute of Gas Technology. The first phase of work consisted of input/output testing of five burner types with detailed flame probing of selected burners under low-NO_x conditions.[14] On-going work is evaluating three specific burner types (kiln, baffle and boiler burners) for input/output testing and detailed flame analysis. NO reductions of 40-50% have been achieved through burner/fuel injector changes and are showing the importance of aerodynamic effects on pollutant formation.

Corporate-sponsored burner design work is also being performed by such companies as TRW, Babcock & Wilcox, Exxon R&E, and Foster Wheeler.

In the long term, improved burner design may well replace the external combustion modifications now in use and achieve NO_x levels significantly below today's state-of-the-art.

NO_x COMBUSTION CONTROL TECHNIQUES FOR STATIONARY I.C. ENGINES

Most of the control technology for stationary I. C. engines has been developed by the automotive industry. Table 6 lists some of the techniques for pollutant control for stationary I. C. engines.

Table 6

POLLUTANT CONTROL TECHNIQUES FOR STATIONARY I. C. ENGINES[15]

Technique	Major Effect	Potential Problems
Speed vs stoichiometry	With speed, NO increases under fuel rich and decreases under fuel lean conditions	Retrofit difficulties; inability to meet load demand
Decreased torque load (at constant speed)	Peak temperature reduction	Retrofit difficulties; inability to meet load demand
Decreased air manifold temperature and exhaust back pressure increase	Peak temperature reduction	Efficiency reduction
Increased valve overlap	Peak temperature reduction	Fuel economy reduction. Applicable only to 4 cycle engines
Exhaust gas recirculation	Peak temperature reduction	Additional controls; intake manifold fouling; operating difficulties; efficiency reduction
Pre-combustion chamber	Two-stage combustion	Primarily for liquid fueled engines; higher first cost
Water injection	Peak temperature reduction	Decreased efficiency; higher operating and maintenance costs
Fuel injection/ignition timing	Peak temperature reduction	Could reduce power output and efficiency
Variable compression ratio	Peak temperature reduction	Higher first cost and maintenance
Exhaust thermal reactor and catalytic converter	Oxidation of CO and HC. Reduction of NO_x with NH_3 or natural gas	Higher first costs, maintenance and operating cost. Catalyst developmental problems

The optimum choice for any engine is dependent on the effectiveness of the control technique weighted against its effect on engine reliability, durability and life. A study by McGowin[16] recommends the following NO_x control techniques for stationary diesel and natural gas engines:

ENGINE	SHORT & IMMEDIATE TERM	LONG TERM
Diesel	Water Injection Precombustion Chamber	Catalytic NO_x Reduction
Natural Gas	Water Injection. Increased Valve Overlap for 4 cycle naturally aspirated engines	Catalytic NO_x Reduction

NO_x COMBUSTION CONTROL TECHNIQUES FOR STATIONARY GAS TURBINES

Most of the control techniques for stationary gas turbines are being developed by the engine manufacturers. Additionally, NO_x control for aircraft engines is under development by the manufacturers and NASA. Some of the technology for flight engines could be applicable to stationary engines. Table 7 lists some of the techniques for pollutant control for stationary gas turbine engines.

It appears that for the short term, water injection will be used to control NO_x from stationary gas turbines. For the long term, dry control technology based on combustor design concepts will replace water injection.

Table 7

POLLUTANT CONTROL TECHNIQUES FOR STATIONARY GAS TURBINES[15]

Technique	Major Effect	Potential Problems
Primary zone leaning by modified combustion chamber design	Peak temperature reduction. Reduced residence time of fuel at peak temperature	Less control over flame stabilization. Less control over lower lean extinction performance
Water injection	Peak temperature reduction	Reduced efficiency. Increased maintenance. Additional equipment for handling demineralized water. Higher operating costs
Exhaust gas recirculation	Peak temperature reduction	Reduced efficiency. Additional controls. Operational problems
Reduced turbine inlet temperature	Peak temperature reduction	Reduced efficiency. Requires larger turbine size for a given power output

NO_x COMBUSTION CONTROL TECHNIQUES FOR COMMERCIAL, RESIDENTIAL AND PROCESS HEATING

Some of the techniques described for boilers have application to commercial, residential and process heating. A prime consideration for these classes of equipment is cost since external combustion modifications (e.g., staged combustion or flue gas recirculation) could markedly increase the first cost of these systems. Presently, low excess air firing and improved burner designs appear to be the most viable techniques for this equipment class. EPA-sponsored studies of improved burner designs for process furnaces and residential heaters appear promising as a cost-effective method of substantially reducing NO_x emissions from these systems.

COMBUSTION MODIFICATION EXPERIENCE

Utility Boilers

Utility boilers encompass the size range of 250 million Btu/hr. and above. Uncontrolled NO_x emissions from these boilers cover a rather wide range. Table 8 gives typical levels of NO_x from utility boilers together with the levels of NO_x reduction achieved with combustion modifications. Uncontrolled values shown parenthetically are instances of high emissions but are not necessarily typical. The percent NO_x reductions shown for low excess air (LEA) firing, LEA + staging and flue gas recirculation (FGR) were attained under full load (90 to 105% of nameplate rating) conditions. The data shown under "25% load reduction" are presented to give an indication of the degree of NO_x reduction achieved with load reduction alone.

Low excess air firing and combinations of low excess air and some form of staged combustion are strong tools for NO_x reduction and are applicable to virtually all classes of utility boilers and fuel types. Flue gas recirculation has not been as widely practiced and its efficacy is most pronounced for natural gas where the NO_x is thermally produced. Data on combustion modifications to cyclone fired boilers is limited. This equipment class is the most difficult of all to control by conventional combustion modifications because of its comparatively limited flexibility.

All utility boiler manufacturers are now guaranteeing that NO_x emissions on new units will not exceed the NSPS limits for the particular

Table 8

NO_x LEVELS AND TYPICAL NO_x REDUCTIONS WITH COMBUSTION MODIFICATION TO UTILITY BOILERS [17,18,19,20]

			% NO_x REDUCTION WITH COMBUSTION MODIFICATION			
Boiler Type	Fuel	Uncontrolled NO_x, ppm*	LEA	LEA + Staging**	FGR	25% Load Reduction
Tangential	Gas	100-350	37	24-72	67	Typical NO_x reductions for boilers with a 25% load reduction are: Gas: 30% Oil: 10% Coal: 18%
Tangential	Oil	100-350 (600)	28	20-55	10-40	
Tangential	Coal	300-600	27-49	24-59	-	
Front Wall	Gas	130-700 (1500)	15-23	23-72	-	
Front Wall	Oil	250-550 (650)	19-35	26-45	31-46	
Front Wall	Coal	425-850	11-29	34-53	-	
Horizontally Opposed	Gas	400-950 (1500)	15-21	34-71	-	
Horizontally Opposed	Oil	200-500	3-9	19-40	-	
Horizontally Opposed	Coal	400-900	21-28	34-48	-	
Cyclone	Oil	300-500	10-16	-	-	
Cyclone	Coal	500-1200	-	-	-	

*ppm @ 3% O_2, dry basis
**Variations of staged combustion. Includes two-stage, off-stoichiometric firing and/or biased firing.

fuel being burned. Their approach is to use one or more of the combustion modification techniques available in their new unit designs.

Although Source Performance Standards have not yet been promulgated for existing utility boilers, it is significant that the data developed thus far has been obtained from existing units. Consequently, these techniques could be applied to a large portion of the existing utility boiler population.

Industrial Boilers

Industrial boilers include the size range of 10×10^6 to 500×10^6 Btu/hr. Field testing of industrial boilers is being conducted under EPA contract by KVB Engineering, Inc. The first phase of work has been completed. During this phase, 47 boilers were tested. Since some of these boilers were tested with more than one fuel and/or burner, a total of 75 sets of test data on different boiler/burner/fuel combinations were obtained.

Typically, existing industrial boilers in the range from 10×10^6 to 250×10^6 Btu/hr. have limited flexibility to permit combustion modifications. This is due primarily to the relatively small size and simple construction of these boilers especially those with single burners, fixed air swirl, and unsophisticated control systems. However, in most cases, NO_x reductions could be achieved by off-stoichiometric combustion for multiple burner units or by changes in excess air level, burner adjustments or other operational parameters. Industrial boilers greater than 250×10^6 Btu/hr. generally have the same flexibility

as utility boilers, and thus are more adaptable to combustion modification. Pertinent results of the Phase I work are summarized below.[21] NO_x emissions are corrected to 3% O_2, dry basis.

Coal Fired Boilers

Base load NO_x emissions for these boilers varied from 224 to 800 ppm for a variety of underfed and spreader stokers, pulverized coal units and one cyclone unit. Excess air was found to be a strong factor affecting NO_x emissions, decreasing with decreasing excess air. For the watertube boilers, NO_x decreased on the average by 50 ppm for each one percent decrease in O_2. Boilers with lower volumetric heat release rates (Btu/hr.-ft.^{3}) had lower NO_x emissions. Similarly a strong dependence on burner heat release rates was shown. Burners in the 8 to 30 MBtu/hr. size range had NO_x emissions between 200 and 400 ppm. Burners in the 30 to 100 MBtu/hr. range had NO_x emissions between 370 and 600 ppm. The highest NO_x emissions of 800 ppm occurred with a 255 MBtu/hr. cyclone coal combustor.

One of the most successful tests on coal fired units was conducted on a spreader stoker traveling grate boiler. Staged combustion was simulated by utilizing auxiliary oil burner ports as air injection ports. Diverting some of the air from the grates to these burner ports resulted in lower NO_x emissions and higher grate temperatures, so a compromise between NO_x reduction and grate temperature was required. The resulting NO_x emissions were reduced by 20-25% over the boilers operating load range.

Oil Fired Boilers

Base load NO_x emissions for these boilers varied from 50 to 200 ppm with No. 2 oil and 150 to 619 ppm for No. 5 and No. 6 oils. The influence of fuel nitrogen content was clearly shown. Base load NO_x emissions ranged from about 105 ppm for 0.01% nitrogen fuel oils to about 400 ppm for 0.5% nitrogen fuel oils. This corresponds to an average fuel nitrogen to NO conversion of about 46%.

The oil fired firetube boilers tested during the program with No. 2 and No. 5 oils showed little dependence of NO_x emissions on excess air and load. All the firetube boilers used ambient temperature combustion air. The oil fired watertube boilers with and without preheated combustion air showed decreasing NO_x with decreasing excess air. The No. 2 oil tests were not as sensitive to excess air levels as were the No. 5 and No. 6 oil tests. Boilers with lower volumetric heat release rates (Btu/hr.-ft.^{3}) had lower NO_x emissions. Similarly, burners with lower heat release rates had lower NO_x emissions.

Multiburner oil fired units were successfully operated under off-stoichiometric conditions by terminating fuel flow to individual burners and using that burner port as an air injection port. NO_x reductions of 17 to 49% were achieved by this technique. Generally, removing a top burner from fuel service gave a higher NO_x reduction than removing a lower burner.

For properly atomized oils, the type of atomizer (air, steam or mechanical) did not significantly affect NO_x emissions for a particular fuel oil.

Gas Fired Boilers

Base load NO_x emissions for these boilers ranged from 50 to 375 ppm. Combustion air temperature strongly affected NO_x emissions as expected since the NO_x from gas firing is thermally produced. To further illustrate, base load NO_x emissions for boilers using ambient temperature combustion air varied from 55 to 116 ppm (70 to 116 ppm for watertube boilers and 55 to 107 for firetube boilers). Base load NO_x emissions for watertube boilers with preheated combustion air ranged from 90 to 374 ppm. The firetube boilers were not equipped with air heaters.

NO_x emissions decreased with decreasing burner heat release rates. This relationship was closely coupled to combustion air temperature as was the effect of excess air. For example, the decrease in NO_x with decreasing excess air was more pronounced when preheated combustion air was being employed.

Multiburner natural gas fired boilers were successfully operated under off-stoichiometric conditions by terminating fuel flow to individual burners and using that burner port as an air injection port. NO_x reductions of 12 to 40% were achieved by this technique. In one instance, a 24% NO_x reduction was obtained by only adjusting the fuel/air mixture ratio at the burners. No burners were taken out of service for this test.

The ability to reduce NO_x emissions from industrial boilers is dependent on the design of the boiler and the fuel being fired. The

importance of this field testing work is to illustrate that NO_x emissions from this equipment class can be significantly reduced. New unit designs could incorporate features for staged combustion and controlled air/fuel mixing at nominal cost.

Future field testing of industrial boilers will serve to refine the data obtained thus far and explore in greater detail the effectiveness of combustion modifications.

Stationary I. C. Engines

Stationary I. C. engines are built in a wide range of sizes depending on their application. Generally, spark-ignition engines range from fractional horsepower single cylinder units to large multi-cylinder units of over 1000 horsepower. Diesel engines range in size from under 100 horsepower to over 1000 horsepower.

NO_x emissions from this equipment category cover a wide range of about 100 to 3000 ppm depending on engine type, size, design, fuel, load, fuel/air stoichiometry, etc. In fact, NO_x emissions from stationary I.C. engines are subject to as many, if not more, variables as other combustion systems. The bibliography on this subject is quite extensive and it is beyond the scope of this overview paper to delve into this broad area in great detail. The subject has been treated in depth most recently in EPA-sponsored studies conducted by Shell[16] and Aerospace.[22] Consequently, only a brief summary of emission control techniques for stationary I.C. engines is presented.

Derating of stationary engines, although effective for NO_x control, is economically unattractive because of the increase in the cost of

the engine per unit horsepower output. However, NO_x reductions of 40% have been obtained with 30% derating of diesel engines.

Changes to fuel injection timing or ignition timing retard are applicable to diesel and spark ignition engines and require no hardware changes or additions. Injection/ignition retard is not particularly cost effective because the technique can result in high specific fuel consumption and higher exhaust gas temperatures. For example, at 12 degrees ignition retard, NO_x reductions of 50% have occurred but fuel consumption increased 12%. A limited amount of injection retard combined with intake air cooling could be used on diesel engines with virtually no loss in fuel economy and achieve NO_x reduction of about 25%.

Exhaust gas recirculation and water injection can be employed on stationary engines. NO_x reductions of about 60% have been realized with a slight increase in specific fuel consumption.

Turbocharging of naturally aspirated diesel engines combined with retarded injection timing and intercooling can give NO_x reductions of up to 35%. Specific fuel consumption did not seem to be affected.

Thermal reactors and catalytic converters for exhaust gas treatment have been developed for automotive application. Their effectiveness has not been adequately demonstrated for stationary engines. These techniques could control HC and CO but would not effect NO_x unless injection of a reducing species like NH_3, H_2 or natural gas were used for catalytic reduction of NO_x.

Gas Turbines

Gas turbines for stationary application range in size from 40 to 87,000 horsepower (about 65 MW) although larger machines are being designed. Base load NO_x emissions vary widely and are a function of turbine size and fuel type. Under base load conditions NO_x emissions increase with increasing turbine size primarily due to the higher combustor pressures and turbine inlet temperatures employed for increased efficiency, and increased residence time at high temperature. NO_x emissions from oil fired turbines are higher than those from gas fired turbines due in part to fuel nitrogen conversion. NO_x emissions are referenced to 15% O_2 because this is generally the O_2 level in a gas turbine exhaust. Typical base load NO_x levels from uncontrolled gas and oil fired turbines are shown in Figure 2.

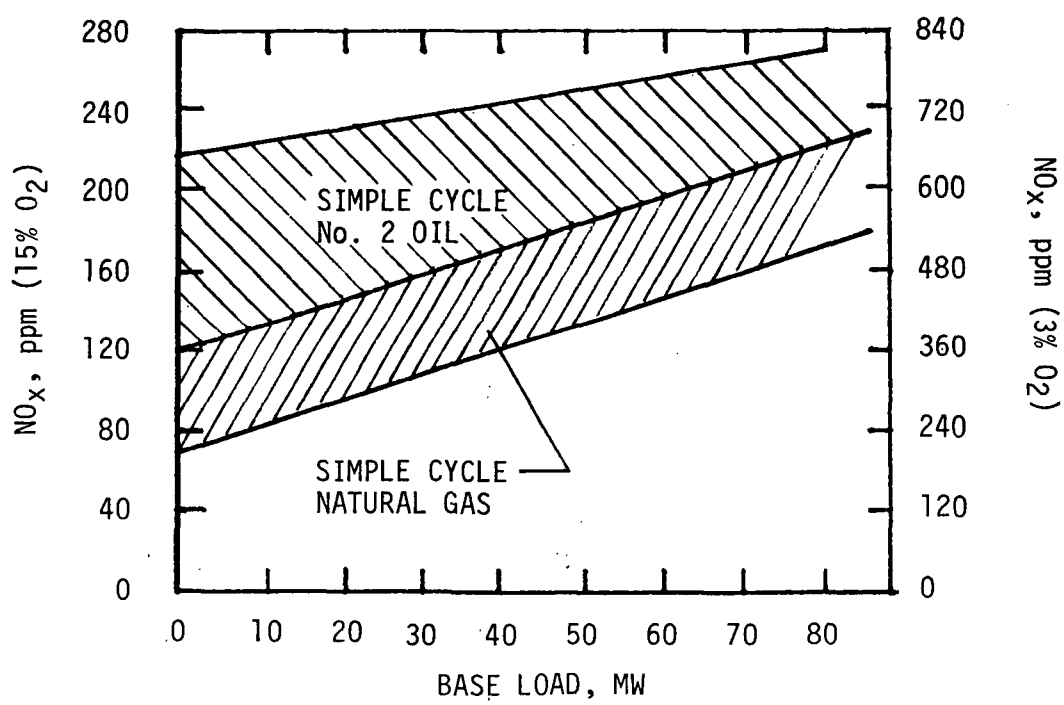


Fig. 2. Typical gas turbine base load NO_x emissions.[22]

The levels are also shown corrected to 3% O_2 so that they may be compared to other conventional combustion equipment. It can be seen that NO_x emissions from gas turbines are comparable to those from utility boilers. The variance in NO_x levels between turbines of equal size is due in part to design differences and/or fuel characteristics.

Combustion modification experience for gas turbines has centered chiefly around schemes for peak temperature reduction. This is a generally viable approach since the principal fuels used in these machines are natural gas and distillate oils and the bulk of the NO_x produced is thermal. However, gas turbines are being built to fire residual oils. In these instances, conversion of fuel nitrogen to NO could be significant.

Tests conducted with water and steam injection have shown significant reductions in NO_x although turbine efficiency is affected. Since the heat of vaporization is about one-third of the total heat absorbed by water, steam injection requires greater flow rates than water to achieve the same flame temperature reduction. However, the better mixing achievable with steam can tend to reduce the difference in the flow rates. Since the heat required to vaporize water is not recovered in the turbine cycle, the useful heat input to the turbine is reduced and turbine efficiency drops. However, with steam injection, the mass flow through the turbine is increased without additional compressor work and the thermal efficiency can improve. Typically one to three percent decreases in thermal efficiency occur when water is injected at a rate equal to one percent of the turbine air mass

flow rate (one percent of the air mass flow rate is equivalent to about 60 percent of the fuel flow rate or a water/fuel ratio of 0.6).

The actual degree of NO_x reduction is strongly influenced by the water or steam to fuel ratio. Equally important is the injection technique. A properly injected engine can achieve higher NO_x reductions at equivalent or lower water/fuel ratios than can an improperly injected engine.

Figure 3 shows a broad data band indicating the effectiveness of water or steam injection. The data band includes a variety of turbine sizes firing natural gas and oils. Generally, for water or steam injection ratios in the range of 0.6 to 1.0 NO_x reductions of about 50-75% have been achieved with oil firing and about 60-90% reductions have been achieved with gas firing. The proposed gas turbine New Source Performance Standards of 55 ppm (gas) and 75 ppm (oil) at 15% O_2 should be achievable on an individual basis by adjustments in injection ratios. Experience to date does not indicate any adverse effects of injection techniques on turbines, provided the dissolved solids in the water are below 5 ppm or that steam is kept superheated prior to injection.

Turbine manufacturers are continuing development work on low NO_x combustors since it is felt that "dry" controls will be more economical and attractive to users. Techniques being evaluated include primary zone leaning, and exhaust gas recirculation both of which serve to suppress peak temperature. Advanced concepts being studied

include premixed, prevaporized, and well stirred external combustors. These combustors could offer more flexibility toward reducing emissions since, being external, they would not have to be designed to fit between the compressor and turbine as are typical combustors. Additionally, advanced combustors could incorporate variable geometry features to optimize air/fuel stoichiometry over the turbine's load range.

Table 9 summarizes various combustion modifications applicable to gas turbines and gives an indication of the degree of pollutant control achievable with these techniques.

Commercial and Residential Heating

Boilers for commercial heating cover a capacity range of 10 to 300 boiler horsepower (about 0.30 to 10 million Btu/hr.). Residential heating units generally include a size range of 75,000 to 300,000 Btu/hr. The most recent and comprehensive studies of emissions from these classes of equipment have been performed by Battelle[24,25] and EPA.[12] Typical baseline emission levels of pollutants from commercial boilers and residential heating systems are presented in Table 10.

This emission data is derived from field tests performed by Battelle. Thirty-five residential systems (33 on oil and two on gas) and 13 commercial boilers firing oil and/or gas (33 boiler/fuel combinations) were tested. Obviously variations occurred for all pollutants due to boiler size, design, age, burner type, fuel, operating

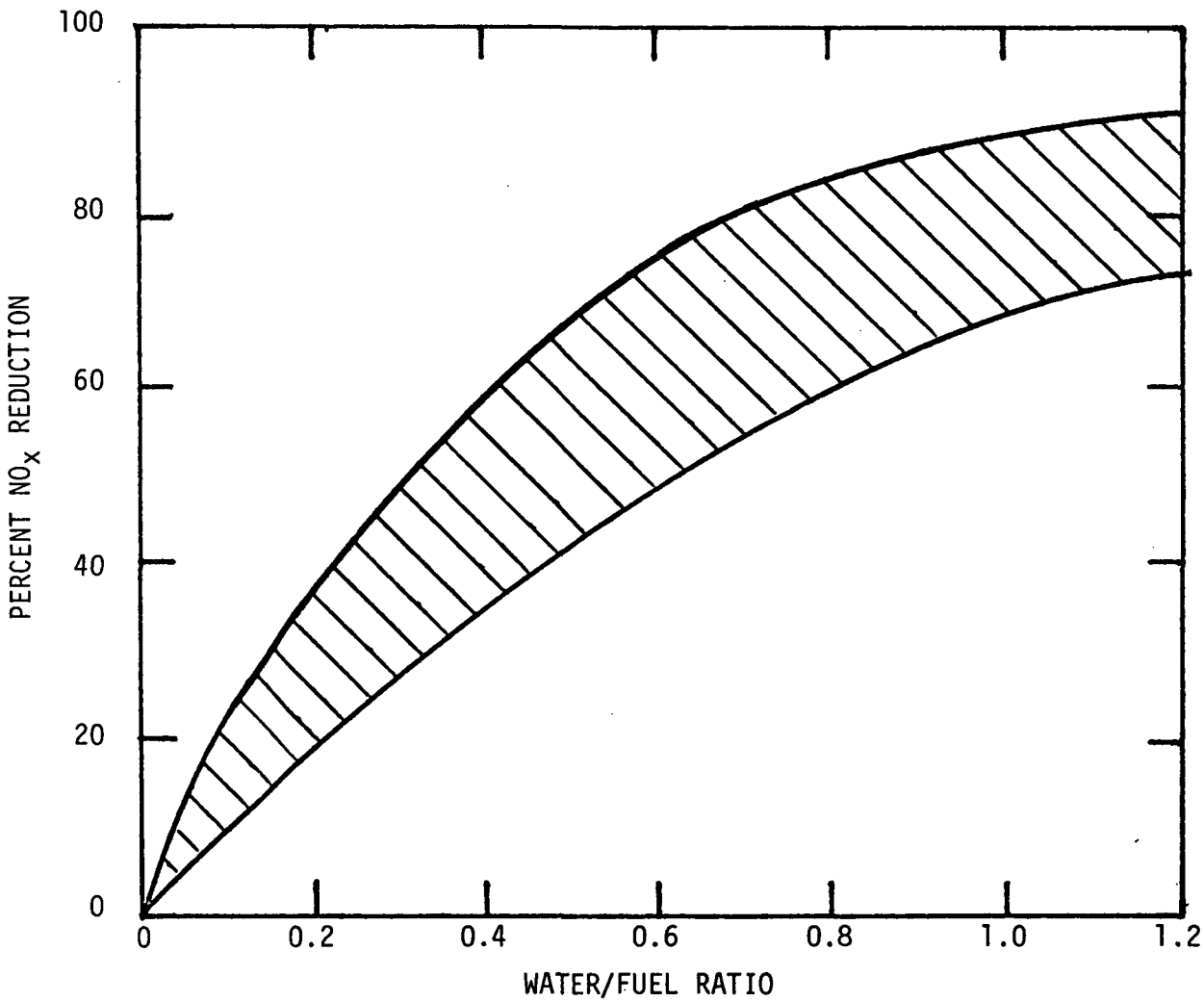


Fig. 3. Effectiveness of water or steam injection in reducing NO_x formation.[23]

conditions, etc. The data presented is only meant to give a general indication of emission levels for a broad range of equipment. The effect of fuel type on NO_x emissions is most pronounced. Conversion of 40 to 60% of the fuel nitrogen to NO_x was indicated in these studies.

Table 10

TYPICAL BASELINE EMISSION LEVELS FROM COMMERCIAL AND RESIDENTIAL HEATING

		Emission Concentration, ppm 3% O_2, dry basis			
Unit	Fuel	NO_x as NO_2	CO	HC	Bacharach Smoke
Residential	Gas	70	15	3	0
Residential	No. 2 Oil	115	65	13	3
Commercial	Gas	80	20	9	0.2
Commercial	No. 2 Oil	100	4	3	0.9
Commercial	No. 4 Oil	390	7	3	2.6
Commercial	LSR*	260	3	5	2.9
Commercial	No. 5 Oil	290	16	4	3.0
Commercial	No. 6 Oil	415	10	5	3.9

*Low Sulfur Residual Oil (~1% S)

Combustion modification of this class of equipment is quite limited. Equipment in this size range is all of the single burner type, and is of relatively simple design. Operating variables are generally limited to excess air variations, load, atomization method and/or pressure. Generally, the range within which operating variables can be operated

Table 9

EFFECTIVENESS OF COMBUSTION MODIFICATION ON GAS TURBINES[22]

Combustion Modification	Emissions			
	NO_x	CO	HC	Smoke
Interim				
Primary Zone Leaning	10 - 30% reduction	Small reduction	Small reduction	Reduction
Exhaust Gas Recirculation	∿30% reduction	Negligible effect	Negligible effect	Negligible effect
Water/Steam Injection	50 - 75% reduction (oil). 60 - 90% reduction (gas)	Some reduction or increase	Small reduction or small increase	Small increase possible
Advanced Combustors				
Premixed, prevaporized, well stirred, variable geometry, external combustors	20 ppm achievable	40 ppm achievable	5 ppm achievable	Invisible

is quite narrow and adjustments of burners for these systems is often based on acceptable smoke and CO_2 performance.

Commercial Boilers

Emissions from commercial boilers can be reduced by controlling excess air levels to optimize all gaseous emissions. Reduced excess air could reduce NO_x emissions by about 10% for the higher nitrogen fuel oils; i.e., No. 4 and above.

An obvious method of reducing NO_x and smoke is to select a fuel oil having a lower nitrogen content. Economics and supply factors will dictate the extent to which this technique can be practiced.

Improved burner design can ultimately provide significantly lower levels of NO_x without adversely affecting CO, HC, and smoke. By providing aerodynamic staging and internal recirculation of flue gases, both fuel and thermal NO_x can be suppressed. EPA-sponsored R&D in this area is showing promising results. Low emission burner designs will probably be the most cost effective method for reducing combustion related pollutants from commercial boilers.

Residential Systems

Emissions from residential systems can be reduced by proper tuning and maintenance. This is effective in reducing smoke, particulate, CO and HC emissions although NO_x is unaffected. Tuning can improve efficiency by about 2% and subsequently result in lower emissions as a result of fuel savings.

Identification and replacement of units in poor condition would reduce area-wide emissions. Newer burners typically have lower emissions and higher fuel efficiency than older burners.

Methods for reducing mean pollutant emissions and estimates of the degree of reduction suggested in the Battelle study are shown in Table 11.

Table 11

EFFECT ON MEAN EMISSIONS OF IDENTIFYING AND "REPLACING" RESIDENTIAL UNITS IN "POOR" CONDITION AND TUNING[25]

	Reduction in Emissions, percent	
Pollutant	Step 1 Identifying and Replacing of Poor Units	Step 2 "Replacement" Plus Tuning
Smoke	-	59
CO	>65	>81
HC	87	90
NO_x	No change	No change
Filterable Particulate	17	24

Again, improved burner design will ultimately provide for low emission residential heating systems. Since these units are fired almost exclusively with gas and No. 2 oil the NO_x to be controlled is thermally formed. Burners having internal flue gas recirculation,

controlled mixing of air and fuel, and ability to operate at low excess air levels should reduce thermal NO_x by 60% or more.

Process Heating

A comprehensive study of emissions from process heating together with an estimate of potential NO_x control techniques has recently been initiated as an EPA contract. It is expected that this study will provide definitive guidance for future R&D in combustion control of NO_x from process furnaces together with cost estimates for implementing such control.

EFFLUENT TREATMENT NO_x CONTROL TECHNOLOGY

The Esso System Study(5) identified a number of candidate NO_x control processes based on treatment of process effluent gases. Alkaline scrubbing, molecular sieve absorption, and catalytic reduction were considered as possible NO_x control techniques. Based on this evaluation, effluent treatment appeared to hold some promise primarily for specialized cases where high NO_x concentrations are present or very low levels of NO_x emissions are required.

An EPA in-house study examined the feasibility of aqueous alkaline scrubbing in some detail. The variables consider included NO concentration, NO to NO_2 ratio, and scrubbing agent. It was concluded that alkaline scrubbing was not feasible for the removal of NO alone or equimolar concentrations of NO and NO_2. However, it was confirmed that NO_2 itself could be absorbed by several scrubbing solutions.(31) However, oxidation of NO to NO_2 appeared to be quite expensive.

Molecular sieve absorption is applicable to nitric acid plants where the NO_x emissions are a result of process conditions and can not be appreciabley changed by process modification. Demonstration

of this technology is underway on 2 nitric acid plant tail gases. This technology does not appear to be applicable to combustion flue gases because of preferential sorption of the moisture in the flue gas.

EPA activity in effluent treatment has been proceeding at a fairly low level but may be accelerated in view of delayed automobile compliance schedules and the need to meet NAAQS.

Current Research and Development

In a contract with Environics, Inc., selective noble metal reduction of NO_x with ammonia is being explored on a pilot scale. The experimental system utilizes a side stream equivalent to 2 MW from a gas fired utility boiler as a flue gas source. The flue gas, which contains around 225 ppm of NO, is mixed with ammonia and then contacted with a catalyst bed at elevated temperature. NO_x reductions of 90% have been achieved; however, equal or greater amounts of NH_3 (e.g., 25-30 ppm) are also present in the exhaust. The pilot scale unit has accumulated about 2000 hours of testing with natural gas firing with essentially no performance degradation of the catalyst. Current plans, necessitated by the recent natural gas curtailment for utility use in the L.A. area, are to test with sulfur-containing flue gas produced by combustion of oil, starting in the winter of 1974. In preparation for testing with flue gas from oil combustion, and electrical preheater has been installed to raise the flue gas temperature prior to entering the catalyst bed. A report on the pilot plant results with gas firing and oil firing is expected to be available in the spring of 1975.

TRW Systems has conducted a technical and economic assessment of various catalytic schemes for NO_x control for stationary power plants. The study purpose was to review catalyst technology for NO_x abatement, assess technical and economic feasibility of various schemes, evaluate the applicability to power plants, and recommend the most promising schemes. A comprehensive data bank was developed containing approximately 250 articles and patents on pertinent NO_x catalysts and catalytic processes. On a lab scale with simulated flue gas (without flyash), catalytic reduction of NO was investigated over a range of space velocities from 5,000 to 20,000 $hr.^{-1}$ (standard temperature and pressure) and temperatures from 200 to 450°C. Approximately 45 catalysts were screened to determine: nonselective NO_x reduction with H_2 and CO; and selective reduction with NH_3, H_2, and CO. Identified as being most promising (because of their activity) for selective reduction with NH_3 are: iron-chromium, vanadium, copper-lead, molybdenum, and platinum catalysts. Screening of Fe-Cr and vanadia indicated that the presence of SO_2 did not affect the catalyst.

Parametric investigations of best catalyst systems, with major emphasis on selective NO_x-NH_3 non-noble systems have been completed. These parametric studies indicated NO conversions of about 60-95% with NH_3 stoichiometry about 1.0, temperature of 400°C, space velocities of 5000 to 20,000 $hr.^{-1}$ and inlet NO concentrations of 250-1000 ppm.

A draft report covering the TRW program is undergoing review and is expected to be available in the very near future.

Under a research grant, Montana State University is conducting a detailed thermodynamic study on the use of metal sulfides for reducing NO via the following reaction: $MeS + 4NO \rightarrow MeSO_4 + 2N_2$. The reduction proceeds with all 17 of the different sulfides tested to date, but over a wide temperature range: from 650°C for CdS to about 100°C for K_2S. Operation in a typical flue gas temperature regime of about 150-175°C is desired. Certain compounds appear to promote or catalyze the reduction reaction. Tests with 10 different dry sulfides and promoter compounds such as $CoCl_2$, $NiCl_2$, $FeCl_2$, K_3CrF_6, and K_3FeF_6 showed significantly lower temperatures at which the reduction proceeded compared with reaction temperature requirements without the promoter. For example, using NaCl as a promoter, the reaction proceeded at 300°C versus 400°C for the unpromoted reaction. The alkaline earth sulfides (CaS, BaS, and SrS) and FeS currently appear most promising, with calcium sulfide one of the best for stability and economy. Furthermore, it has shown that precipitation of CaS onto a high surface area support greatly enhances the reaction rate. Research is currently underway to study some of the important kinetic parameters of the reaction of NO and CaS and other promising metal sulfides absorbed on various high surface area supports. A technical and economic system analysis will be performed based on the most promising materials and will consider possible regeneration of the metal sulfide from the metal sulfate.

NO_X COMBUSTION CONTROL COSTS

Effluent treatment technology is not sufficiently advanced to estimate costs at this time. This section will include costs for combustion modification only and will be presented by source.

Utility Boilers

The most recent and comprehensive study of NO_x control costs for utility boilers was performed by Combustion Engineering, Inc. under EPA contract.[26] The five combustion modification techniques investigated were:

1. Introducing 20 percent of the total combustion air over the fuel firing zone as overfire air.
2. Introducing 30 percent flue gas recirculation through the secondary air ducts and windbox compartment.
3. Combining the 20 percent overfire air and 30 percent flue gas recirculation of 1 and 2.
4. Introducing 17 percent flue gas recirculation through the transport air (primary air) of the coal pulverizer (mills) system.
5. Introducing water injection into the fuel firing zone at a rate of 5 percent of total evaporation (equivalent to about 50 pounds of water per million Btu's fired).

Two levels of cost were established; the first being for new unit designs with heating surfaces adjusted to compensate for changes in heat transfer distribution and rates resulting from the use of these techniques. The second level of cost applied to existing units with no changes to heating surface. For both cases, the costs shown are in 1973 dollars, and except where noted otherwise are estimated on a $\pm$ 10 percent basis.

Figures 4 and 5 show the cost ranges for the techniques considered. It can be seen that the cost ranges for existing units vary more widely than for new units. This is mainly due to variations in unit design and construction which can either hinder or aid the installation of a given NO_x control system. As an example, an overfire air system could be designed as a windbox extension unless existing structural requirements and/or obstructions necessitated installation of a more costly system including extensive ductwork and individual air injection ports. Similarly, water injection could require changes in unit ducting to maintain unit capacity. The cost range for the combined overfire air and windbox gas recirculation is the sum of the cost ranges for the individual systems. The cost ranges for existing units do not include any changes to heating surfaces since these changes must be made on an individual unit basis. Heating surfaces could increase, decrease or remain the same because of variations in existing designs.

At about 600 MW, single cell furnaces reach a practical size limit and divided furnace designs are employed. Since a divided tangentially fired furnace has twice the firing corners of a single cell furnace, the costs increase significantly.

For new units, flue gas recirculation has the highest investment cost and overfire air has the lowest investment cost. For existing units, flue gas recirculation is again the most expensive control technique. Although water injection on existing units is

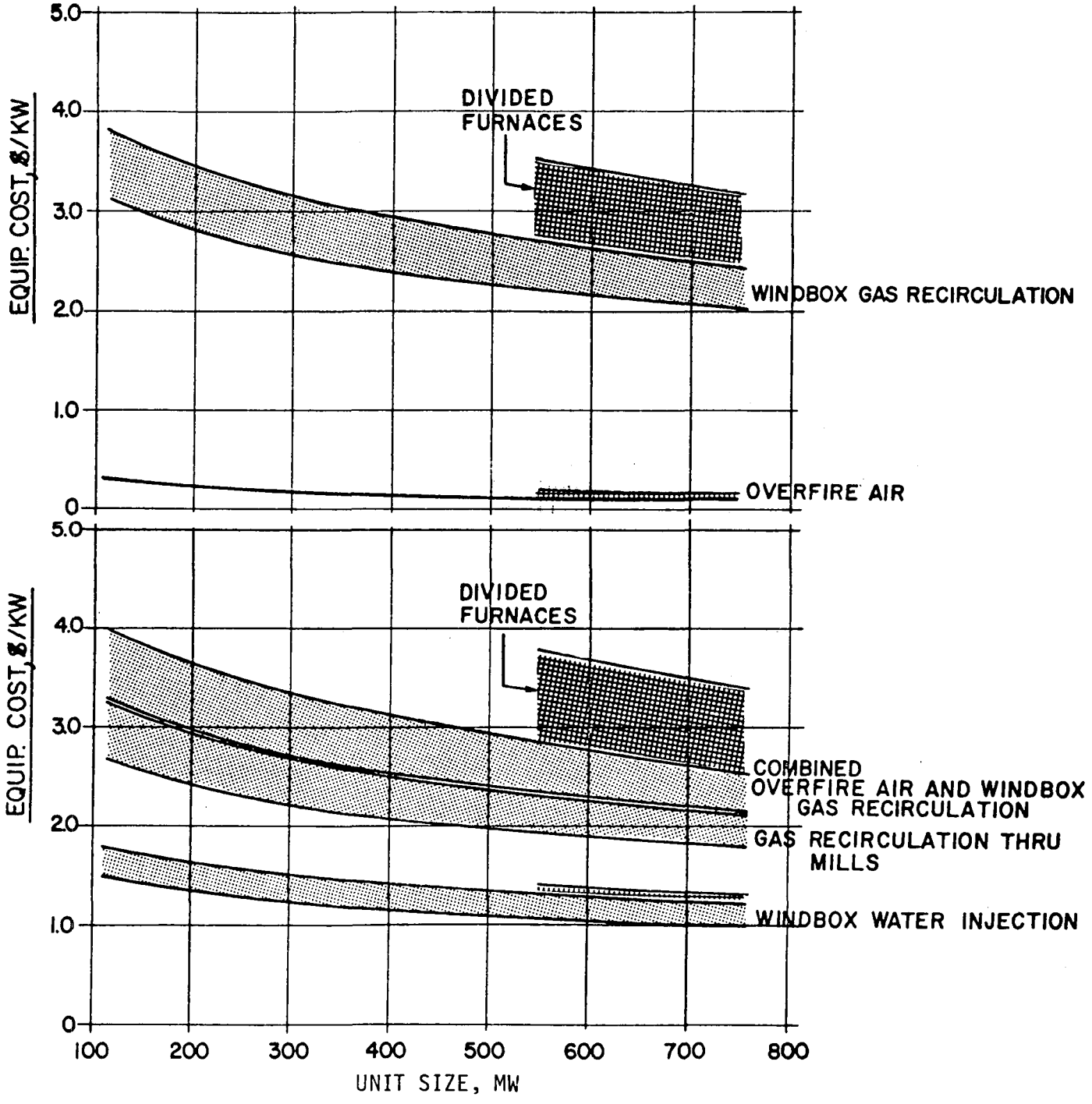


Fig. 4. Costs of NO_x control methods for new coal fired units (included in initial design).[26]

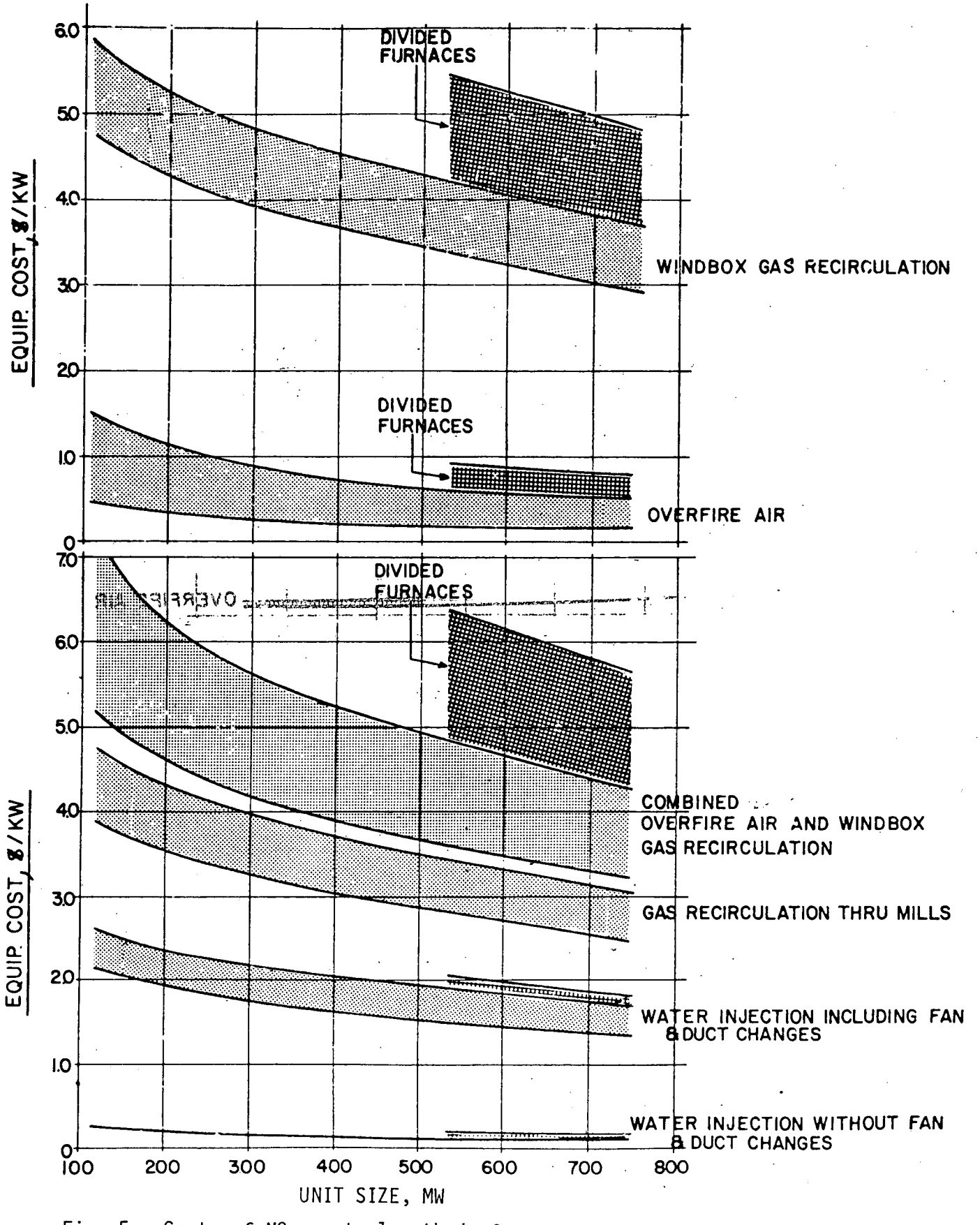


Fig. 5. Costs of NO_x control methods for existing coal fired units (heating surface changes not included).[26]

slightly cheaper than overfire air, its initially low cost is ultimately overshadowed by its high operating cost as will be later shown.

The cost of low excess air firing was not investigated since there is generally no significant additional cost for modern units or units in good condition. However, some older units could require modifications such as modified windboxes by addition of division plates, separate dampers and operators, air register operators, fuel valving, instrumentation for fuel and air flow and automatic combustion controls.

Table 12 shows estimated investment costs for low excess air firing on utility boilers requiring modifications.

Table 12

ESTIMATED INVESTMENT COSTS FOR LOW EXCESS AIR FIRING ON EXISTING UTILITY BOILERS NEEDING MODIFICATIONS

Unit Size MW	Investment Costs, $/KW Gas & Oil	Coal
1000	0.12	0.48
750	0.16	0.51
500	0.21	0.55
250	0.33	0.64
120	0.53	0.73

These costs can vary to some degree depending on the actual extent of modification required and are only provided as guidelines. Conversion of coal units is more expensive because of the added complexity and controls needed for proper air and fuel mixing. As unit size increases, the cost per KW decreases since the larger units typically have inherently greater flexibility and may require less extensive modification.

The use of low excess air firing reportedly increases boiler efficiency by 0.5 to 2%, in addition to savings resulting from decreased maintenance and operating costs especially for gas and oil fired units. Consequently, the investment costs, when required, can be offset in fuel and operating expenses. Thus, minimum or low excess firing can be the cheapest combustion control method available.

Table 13 gives the impact on major system components, efficiency and capacity when employing the NO_x control techniques considered. The relative changes in unit design or efficiency are shown to increase (or require addition) by a plus (+) or decrease by a minus (-). If the item is unchanged or changes to a negligible extent it is indicated as a zero (0). It must be remembered that for this comparison, heating surfaces are unchanged on existing units.

Thus, new unit designs can be built with full consideration of the impact of combustion modifications on heat transfer and operational aspects of the boiler. Capacity and boiler efficiency would not suffer except in the case of water injection where latent heat losses are not recoverable.

Table 13

IMPACT OF NO_x CONTROL TECHNIQUES ON MAJOR UTILITY BOILER COMPONENTS

System Component	NEW UNIT DESIGN					EXISTING UNITS				
	O.A.[a]	Sec. FGR[b]	a+b	Prim. FGR[c]	Water Inj.[d]	O.A.[a]	Sec. FGR[b]	a+b	Prim. FGR[c]	Water Inj.[d]
Forced Draft Fan Size	+	0	+	+	0 or +	0 or +	0	0 or +	+	0
Secondary Air Ducts	0	+	+	0	0	0	+	+	0	0
Windbox Size	0	+	+	+	0	0 or +	+	+	+	0
FGR Fan	N/A[e]	+	+	+	N/A	N/A	+	+	+	N/A
FGR Ducts	N/A	+	+	+	N/A	N/A	+	+	+	N/A
Dust Collectors	0	+	+	+	0	0	+	+	+	0
Coal Pulverizers	0	0	0	0	0	0 or +	0	0 or +	0	0
Convective Surface	0	+	+	+	+	N/A	N/A	N/A	N/A	N/A
Superheat Surface	0	-	-	-	-	N/A	N/A	N/A	N/A	N/A
Reheat Surface	-	-	-	-	-	N/A	N/A	N/A	N/A	N/A
Economizer Surface	0	+	+	+	+	N/A	N/A	N/A	N/A	N/A
Boiler Efficiency[f]	0	0	0	0	-	0	0	0	0	-
Capacity	0	0	0	0	0	0	-	-	-	-

a. Overfire air system
b. Flue gas recirculation through the secondary air duct and windbox compartments
c. Flue gas recirculation to the transport air (primary air) of the coal pulverizers (mills)
d. Water injection to the firing zone
e. Not applicable
f. Average heat rate, Btu/KWH

For existing units, boiler efficiency is essentially unchanged (except for water injection) although unit capacity will drop for all cases except overfire air operation unless compensation is made to heating surfaces.

Table 14 summarizes the operating costs for new units using the NO_x control techniques considered (in 1973 dollars). Divided furnaces were not considered in these estimates. Water injection is the most expensive system to operate due primarily to increased fuel costs resulting from losses in unit efficiency. The least expensive to operate is overfire air.

To put these operating costs in perspective, they can be compared to the "average" generating costs shown at the bottom of Table 14. Except for the case of water injection, the differential in operating cost is below 1% even with flue gas recirculation. The differential operating cost for overfire air is even lower, ranging from about 0.02 to 0.05%.

It is encouraging that the control techniques having the widest applicability for NO_x control from utility boilers (low excess air firing and staged combustion) also have the lowest investment and operating costs.

Although the cost data for utility boilers were developed for tangentially coal fired utility boilers, it is felt that the range of costs presented should be generally applicable to wall fired boilers burning coal. The cost of combustion modification to wall fired

Table 14

1973 OPERATING COSTS OF NO_x CONTROL METHODS FOR NEW COAL FIRED UNITS[26]

(Single Furnace)

Control Method		1. Overfire Air (20%)			2. Windbox Flue Gas Recirc. (30%)			3. Combination of 1 and 2			4. Coal Mill Flue Gas Recirc. (17%)			5. Water Injection		
MW Rating		100	450	750	100	450	750	100	450	750	100	450	750	100	450	750
Equipment Costs,	10^3\$	31	63	90	350	1185	1650	375	1248	1800	300	1015	1425	160	560	825
Annual Fixed Charge,	10^3\$	5	10	14	56	190	264	60	200	288	48	162	228	26	90	132
Additional Annual Fuel Cost,	10^3\$	---	---	---	---	---	---	---	---	---	---	---	---	147	660	1099
Additional Annual Fan Power Cost,	10^3\$	---	---	---	21	95	158	21	95	158	22	100	166	13	58	97
Total Annual Cost,	10^3\$	5	10	14	77	285	422	81	295	446	70	262	394	186	808	1328
Operating Cost,	mills/KWHR	0.009	0.004	0.003	0.143	0.117	0.104	0.150	0.121	0.110	0.130	0.108	0.097	0.344	0.332	0.327[g]

Based on:
a. Delivered and erected equipment costs (± 10% accuracy). Excluding contingency and interest during construction.
b. 5400 hr/yr at rated MW and net plant heat rate of 9400 Btu/KWHR.
c. 50¢/10^6 Btu coal cost.
d. \$250/hp fan power cost, or \$40/hp per year.
e. Annual fixed charge rate of 16%.
f. Operating costs are ± 10%.
g. Does not include cost of water piping in plant or cost of makeup water.

Base unit operating costs* for coal fired power plants excluding SO_2 removal systems.

Unit Size,	MW	100	450	750
Operating Cost,	mills/KWHR	16.2	13.5	12.6

*Includes 1973 capital costs, labor, maintenance, fuel costs, 20% contingency, 17% interest during construction.

boilers is being addressed as part of an EPA study being conducted by the Tennessee Valley Authority. Additionally, it is intuitively felt that the cost for similar combustion modification on gas and oil fired utility boilers should be no higher than for the coal fired units.

Industrial Boilers

Cost data for combustion modification of industrial boilers is virtually non-existent. Research and development, including field testing and application of NO_x control to this equipment category is in its early stages. Low excess air firing and some form of staged combustion appear to be widely applicable. It is expected that significant modifications are required; they will represent a higher fraction of the base unit cost than utility boilers. Cost estimates for NO_x control of industrial boilers will be developed as part of on-going and planned EPA studies.

Diesel Engines

Because of the relatively limited emission control work performed to date, it is difficult to make accurate estimates of cost and maintenance requirements for the various control options. Generally, most engine manufacturers feel that the basic engine cost would be increased by 10 to 50% and operating cost would increase by about 15% depending on the degree of NO_x reduction, control method and increase in specific fuel consumption.

Spark Ignition Engines

Many of the emission control systems utilized in automobile engines have application to stationary spark-ignition engines. The cost of these devices for automotive engines are known but it is difficult to estimate the cost per unit horsepower when applied to stationary engines. It is quite possible that similar devices could be several times more costly for stationary engines. Since these engines generally operate at constant speed, leaner air/fuel mixtures can be tolerated. Consequently, the fuel penalty could be lower than in the case of automotive engines.

Gas Turbines

Costs for NO_x control based on "wet" methods have most recently been estimated in Aerospace and EPA studies. Input to these studies have come from several gas turbine manufacturers and from utilities employing water or steam injection as a NO_x control technique.

Investment costs for water injection as provided by San Diego Gas and Electric are shown in Table 15.

For this example, the investment cost for water injection was about ten percent of baseline cost for 20 MW plants and about six percent for 29 and 81 MW plants.

Table 15

WATER INJECTION INVESTMENT COST
(SAN DIEGO GAS AND ELECTRIC)[22]

Control System	Gas Turbine Size, MW		
	20	49	81
Combustor modifications including water injection nozzles	$1.00/KW	$0.86/KW	$1.04/KW
Water injection pumps and water regulation system	$3.54/KW	$2.88/KW	$3.10/KW
Associated piping and water storage facilities	$1.72/KW	$1.05/KW	$0.87/KW
Water treatment equipment	$0.90/KW	$0.47/KW	$0.47/KW
General expenses including engineering, administration, testing, taxes	$1.15/KW	$0.82/KW	$0.57/KW
Total	$8.31/KW	$6.07/KW	$6.05/KW

Table 16 illustrates how the investment for water injection and increased operating cost is prohibitive for the small gas turbines.

Table 16

WATER/STEAM INJECTION COST AS A FUNCTION OF POWER PLANT SIZE[22]

MW Output	Investment Cost, Percent Baseline		*Operational Cost, Percent Baseline	
	Water	Steam	Water	Steam
0.26 (350 hp)	100.0	150.0	55.0	165
2.90 (3900 hp)	18.0	24.0	6.5	32
20.00	10.0	12.0	6.0	--
33.00	7.3	10.6	5.7	--
65.00	7.3	10.6	5.7	--

*For peaking gas turbine, 1000 hr./yr.

However, since NO_x emissions for the smaller turbines are somewhat lower, they may not require water injection for NO_x control. Instead, they may be able to meet emission levels through combustion modifications.

Since the operating cost for water injection decreases with increasing turbine usage, the operating cost could drop to about 2.5% of basic operating costs for turbines operating 6000 to 8000 hours per year. Thus, NO_x control by water injection becomes more cost effective with increasing load factors.

Similar estimates for NO_x control of gas turbines have been prepared by EPA to support proposed emission standards. Table 17 shows the cost of NO_x control for small gas turbines using dry and wet techniques. It serves to illustrate the higher cost for control on small engines and the reduction in control cost when engines are run at higher load factors.

Table 18 provides cost estimates for water injection on large gas turbines. The costs for various load factors and water injection rates compare quite well to other reported data.

The long term effect of water or steam injection on long term engine life is still unknown. However, no major problems have been reported to date when the systems are properly operated. One of the major disadvantages of water injection is that siting flexibility is limited for simple cycle and regenerative gas turbines which would

Table 17

COST OF NO_x CONTROLS FOR SMALL GAS TURBINES[23]

Size, hp	350		3,500		3,500	
Purchase cost (PC), uncontrolled, $	8,800[a]		110,000[a]		110,000[a]	
Total installed cost (TIC),1.3xPC	11,440		143,000		143,000	
Total capital investment (TCI) 1.25 TIC, $	14,300		178,800		178,800	
Control increment, percent	Dry 20[b]		Dry 12[a]		Wet 25[c]	
TCI, controlled, $	17,200		200,000		224,000	
Unit investment, controlled, $/hp	49		57		64	
Heat rate, Btu/hph	12,000		11,000		11,000	
Equivalent hours duty per year	100[d]	8,000[e]	100	8,000	100	8,000
Fuel @ $0.91/MBtu[f], $	380	30,600	3,500	280,300	3,500	280,300
Fixed charges, uncontrolled[g], $	2,600	2,600	32,200	32,200	32,200	32,200
Total annual cost, uncontrolled, $	3,000	33,200	35,700	312,500	35,700	312,500
Utilities[h], $	--	--	--	--	12	1,000
Incremental fixed charges[g], $	520	520	3,900	3,900	8,000	8,000
Total annual cost, controlled, $	3,500	33,700	39,600	316,400	43,700	321,500
Control cost, percent	17	1.6	11	1.3	22	2.9

a Per vendor[27]
b Assumed
c Combustor modifications per vendor,[27] water treatment system per Crits [28]
d As in emergency service, including readiness tests
e As in pipeline service
f In the pipeline application, fuel from the line would be much less expensive
g Carrying charges 17%; maintenance 1%
h Raw water, regeneration chemicals, and power together assumed $1/1000 gallon

Table 18

COST OF WET NO_x CONTROLS FOR LARGE GAS TURBINES[23]

Size, MW		25			4x65	
Capital Costs, 10^3 $						
Total Capital Investment (TCI)[a], Uncontrolled		2800			26000	
Equivalent Hours Duty per Year	8000	1000	1000	4000	1000	1000
Water/Fuel Ratio	0.5	0.5	0.8	0.5	0.5	0.8
Control Increment[b], percent	10.0	8.5	9.5	3.9	3.5	3.9
TCI, Controlled	3120	3040	3070	27000	26900	27000
Unit Investment, Controlled, $/KW	125	121	123	104	103	104
Annualized Costs, $10^3$$						
Heat Rate, Btu/KWH		12400			11700	
Fuel @ $0.91/MBtu	2260	282	282	11070	2770	2770
Fixed Charges, Uncontrolled[d]	504	504	504	4670	4670	4670
Total Annual Cost, Uncontrolled	2764	786	786	15740	7440	7440
Utilities[e]	9	1	2	40	10	16
Incremental Fixed Charges	57	43	49	180	160	180
Total Annual Cost, Controlled	2830	830	837	15960	7610	7640
Incremental Annual Cost, percent	2.3	5.6	6.5	1.4	2.3	2.6

a Applying to the 25 MW case, the 1970 Federal Power Survey datum of $85/KW, escalating from 1968 to 1974 at 5% compounded, and assuming a weak economy of scale for the larger case.

b Wet controls include an injection system sized for peak injection rate, based on owner's data[29] and a treatment and storage system sized conservatively for peak daily usage, based on Crits.[28]

c In the 8000-hour case representing a pipeline compressor, fuel from the line would be much less expensive.

d Carrying charges 17%, maintenance 1%.

e Raw water, regeneration chemicals, power and sewerage together at $1/1000 gallons.

normally require no supply of water. This becomes an important consideration in areas of limited water supply or subfreezing ambient temperatures. The decrease in engine efficiency also becomes of prime importance with todays rising fuel costs.

It is expected that by the period 1979-1985, advanced combustor designs having very low emissions could be fully developed. These would ultimately replace "wet" control technology. Development costs would be in the range of 4 to 10 million dollars including the demonstration stage.

SUMMARY

New Stationary Source Performance Standards for NO_x that have been promulgated or are scheduled for very near term promulgation are based on current state-of-the-art combustion control technology. Because of the expected growth in stationary sources, delays in achieving automotive standards and the need to maintain or improve ambient air quality, it is expected that more stringent NO_x standards and/or regulations of additional stationary sources may be required. The need therefore exists for continued R&D to develop the technology that will be needed in future years. Control Systems Laboratory's R&D posture will be to achieve future NO_x goals without adverse impact on other combustion related pollutants, i.e., particulate, CO and UHC. Concurrently, future R&D will strive to maintain or improve process efficiency to the greatest extent possible.

Projected short and long term R&D goals for NO_x control are shown in Table 19. The 1980 goals are based on extension of existing technology coupled with new burner designs. It is felt that these goals can generally be attained with present combustor/furnace configurations. The 1985 goals could possibly entail the redesign of some equipment types or require the use of novel combustion and/or effluent treatment schemes.

Obviously, the achievement of these goals is heavily dependent on the level of funding that is ultimately provided.

Table 19

PROJECTED SHORT AND LONG TERM GOALS FOR NO_x CONTROL

(ppm @ 3% O^2)

Source	1980 Goal	1985 Goal
Utility Boilers		
Gas	100	50
Residual oil	150	90
Coal	200	100
Industrial Boilers		
Gas	80	50
Residual oil	125	90
Coal	150	100
Commercial Boilers		
Gas	50	30
Distillate oil	70	50
Residual oil	150	90
Spark Ignition Engines		
Gas	1200	400
Compression Ignition Engines		
Diesel Oil	1200	800
Gas Turbines		
Gas	90	90
Distillate Oil	165	165

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Conversion Table

To convert from	To	Multiply by
Btu	Calories, gram	251.98
Btu	Kilocalories, gram	0.25
Btu/ft^3	Calories, kg/m^3	8.899
Cubic feet	Cubic meters	0.0283
Horsepower	Horsepower (metric)	1.0139
$Lbs/10^6$ Btu	$Grams/10^6$ calories	1.80
Mile	Kilometers	1.6094
Pounds	Grams	453.5924
Tons (short)	Kilograms	907.19