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Project Summary

Combustion Modification Controls for Stationary Gas Turbine

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The report gives results of an environmental assessment of combustion modification techniques for stationary gas turbines with respect to nitrogen oxides (NO_x) control effectiveness, operational impact, thermal efficiency impact, control costs, and effect on emissions of pollutants other than NO_x. Wet controls, which inject steam or water directly into the combustion chamber, are the only currently available methods sufficiently developed to reduce NO_x emissions below the recently promulgated New Source Performance Standard of 75 ppm at 15 percent O_2 for clean fuels (greater than 50 percent reduction). However, the effectiveness of wet controls decreases significantly as the percentage of fuel-bound nitrogen increases. Emissions of unburned hydrocarbons (UHC) and carbon monoxide (CO) can increase with wet controls. However, results from a detailed Level 1 Environmental Assessment test on a 60 MW utility gas turbine indicate that incremental emissions of pollutants other than NO_x (trace elements, organic compounds, sulfur species, CO, and particulate) remain relatively unchanged. Wet controls increase the cost of electricity by 2-5 percent, due in large part to the associated fuel penalty. Dry NO_x controls, being developed, involve combustor modifications, but not water or steam injection. They hold much promise because of their NO_x control effectiveness for both clean and dirty fuels, and their expected lower cost and operational impacts.

This Project Summary was developed by EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

With the increasing extent of NO_x control application in the field, and expanded NO_x control development anticipated for the future, there is currently a need to: (1) ensure that current and emerging control techniques are technically and environmentally sound and compatible with efficient and economical operations of systems to which they are applied, and (2) ensure that the scope and timing of new control development programs are adequate to allow stationary sources of NO_x to comply with potential air quality standards. With these needs as background, EPA's Industrial Environmental Research Laboratory, Research Triangle Park (IERL-RTP) initiated the Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies (NO_x EA) Program in 1976. This program has two main objectives: (1) to identify the multimedia environmental impact of stationary combustion sources and NO_x combustion modification controls applied to these sources, and (2) to identify the most cost-effective, environmentally sound NO_x combustion modification controls for attaining and maintaining current and projected NO_2 air quality standards to the year 2000.

The NO_x EA's assessment activities have placed primary emphasis on: major stationary fuel combustion NO_x sources (utility and industrial boilers, gas turbines, internal combustion (IC) engines, and commercial and residential warm air furnaces); conventional gaseous, liquid, and solid fuels burned in these sources; and combustion modification controls applicable to these sources with potential for implementation to the year 2000.

This report summarizes the environmental assessment of combustion modification controls for stationary gas turbines. It outlines the environmental, economic, and operational impacts of applying combustion modification controls to this source category. It also summarizes results of a field test program aimed at providing data to support the environmental and operational impact evaluation.

Conclusions

Source Characterization

Gas turbines are rotary IC engines commonly, although not universally, fired with natural gas or "clean" liquid fuels such as diesel or distillate oils. The basic gas turbine consists of a compressor, combustion chamber(s), and a turbine. Pressurized combustion air, supplied by the compressor, and fuel are burned in the combustion chamber(s). The hot combustion gases are rapidly quenched in the combustor by secondary dilution air and then expanded through turbines which drive the compressor and provide shaft power to, for example, a generator, compressor, or pump.

As shown in Figure 1, the gas turbines represented the fifth largest contributor of NO_x emissions from stationary sources in the U.S. in 1977—constituting 2.0 percent. However, a variety of factors, including fuel availability, electricity demand, and increasing thermal efficiencies, may tend to intensify the NO_x problem from stationary gas turbines. Thus, they represent a priority source category for control evaluation in the NO_x EA.

Three different thermodynamic cycles are typically used in stationary gas turbine engines—simple, regenerative, and combined.

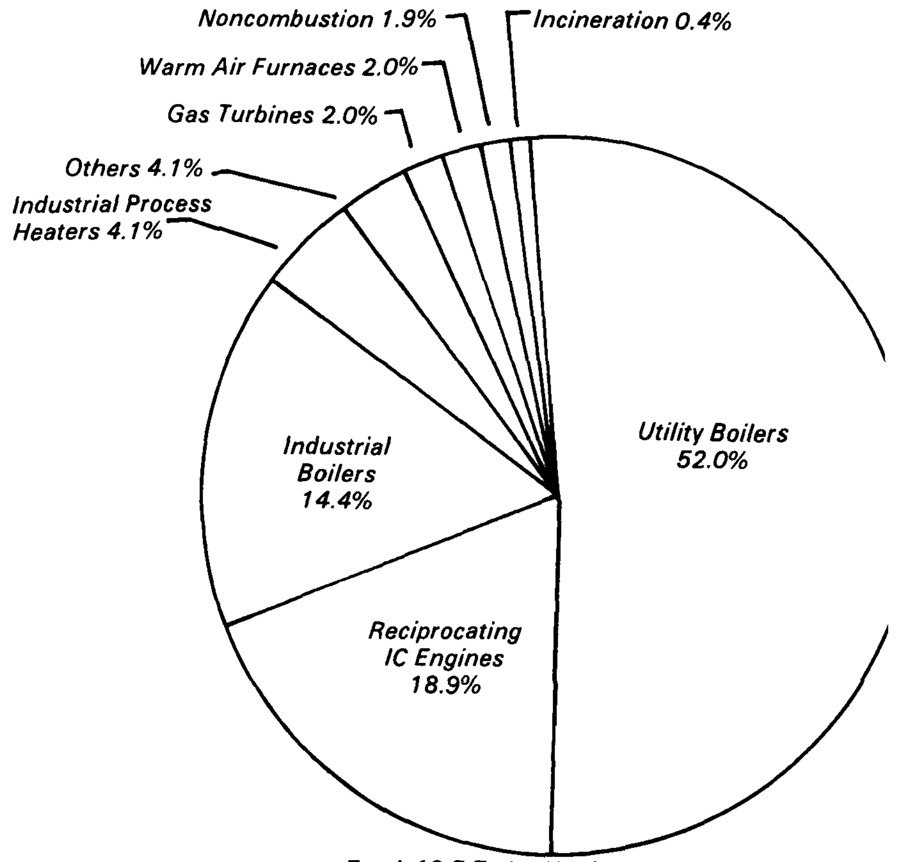


Figure 1. Distribution of stationary anthropogenic NO_x emissions for the y 1977 (controlled NO_x levels).

The simple cycle is the basic gas turbine engine; the regenerative and combined cycles employ exhaust waste heat recovery.

Gas turbines range in size from 30 kW to over 75 MW (40 to over 100,000 hp) power output. For evaluation, though, the source category can be divided into three capacity ranges: large capacity, including combined cycle—greater than 15 MW (20,000 hp); medium capacity—4-15 MW (5,000-20,000 hp); and small capacity less than 4 MW (5,000 hp). Each of these capacity ranges finds distinct use applications. Large capacity turbines are primarily used for base, midrange, and peaking utility electricity generation. Medium capacity turbines find primary uses in standby electricity generation, pipeline compression and pumping, industrial electricity generation, and various industrial shaft power applications. Small capacity turbines are primarily used for gas compression and standby electricity generation in the oil and gas industry.

Gas turbines experienced spectacu sales growth through 1970 due p marily to their inherent low cost a operational and maintenance adva tages over other prime movers and ele trical generators. A growing econor combined with delays in nuclear pla licensing also contributed to their pop larity. However, with the 1970's car decreased oil availability along with i creased cost, and a growing uncertain among users concerning the reliability gas turbines. These caused a subseque steady decline in sales. Thus, forecas of new generating requirements by tl National Electrical Manufacturers Ass ciation (NEMA) have shown substant reductions over previous forecasts gas turbine equipment. Figure 2 shov results from the Sixth Biennial Survey Power Equipment Requirements (SPER) The gas turbine generating additio predicted in 1978 decreased 78 perce from NEMA's 1973 predictions. Ho ever, the survey predicts a relative level rate of additions in the near futu

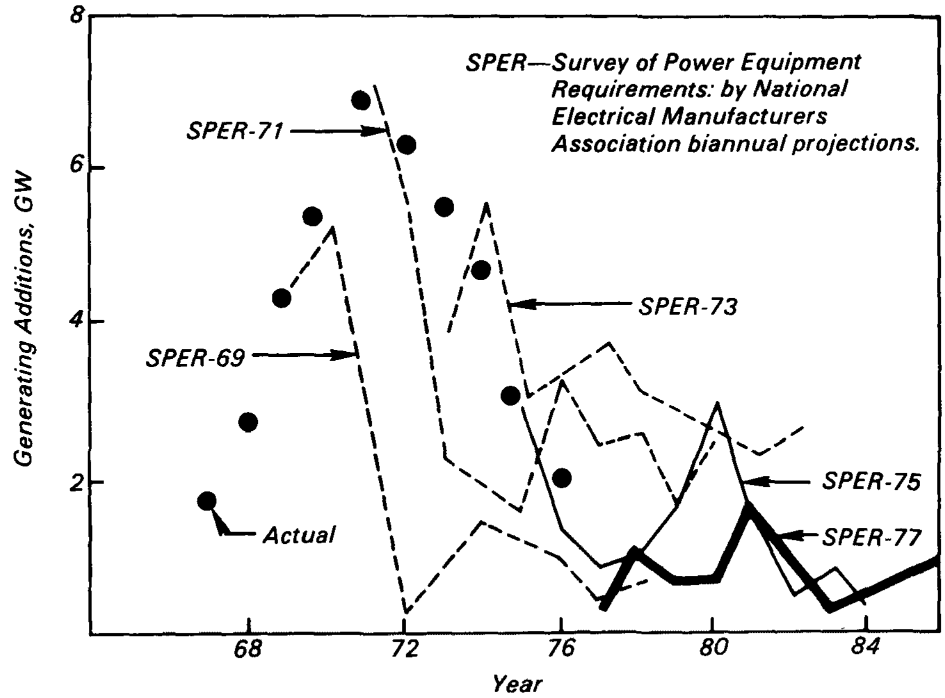


Figure 2. Projected gas turbine generating additions.[1]

and manufacturers are optimistic about an upswing in the market, particularly for combined cycle plants.

Fuels and Emissions

Natural gas and distillate oils are preferred for gas turbines because they are relatively clean burning and serve as the primary experience base for manufacturers and users. Those oils containing significant ash and high levels of sulfur and certain trace elements (particularly vanadium, lead, sodium, potassium, and calcium), such as crude oil, residual oil, and synthetic fuels, may require some treatment before they can be used. However, several utilities are currently firing residual oils in spite of high pretreatment costs.

Some of the most promising new clean fuels are low- and high-Btu gases and process gases such as coke oven and blast furnace gases. Improved thermodynamic cycle efficiencies and low NO_x emissions make these clean fuels attractive alternatives in broadening basic energy sources. There are, however, a number of redesign considerations with the use of certain low Btu fuels in conventional engines. Modifications to the combustion and fuel systems are all that are required with some fuels. But with others, significant problems arise from a compressor-turbine mismatch due to high pressure ratios caused by excessive turbine mass flow.

Synthetic liquid fuels, such as the middle and heavy distillates obtained from coal liquefication products, are also becoming potential gas turbine fuels. Indeed, synthetic fuels may be the future fuels for gas turbines due to the changing market for more conventional fuels, Federal fuel use regulations, and other considerations.

Air emissions in the form of exhaust gases are essentially the only effluent stream from stationary gas turbines. Stream composition depends on the fuel burned, combustor geometry, and combustion and operating characteristics. NO_x emissions are highest and CO and UHC are lowest when the engine operates at design conditions (i.e., rated power output). Off-design firing, while limiting NO_x, enhances the production of unburned species through incomplete oxidation. Virtually all fuel sulfur is converted to sulfur dioxide (SO_2) in a turbine engine. Thus, SO_2 emissions are a function solely of fuel sulfur content. Particulate emissions depend on the ash content of the fuel and the levels of unburned carbon and condensible hydrocarbons resulting from incomplete combustion.

The only liquid and solid wastes from gas turbines are from the water treatment facilities associated with water injection for NO_x control. These effluent streams are relatively small, generally not hazardous, and easily disposed of in landfill areas or to rivers or municipal sewers.

Of the pollutants emitted from gas turbines for which the emission level can be affected by combustion conditions (i.e., not exclusively fuel composition dependent), NO_x is considered the primary pollutant of concern. NO_x in gas turbines, as in all combustion sources, is formed primarily by two mechanisms—thermal fixation and fuel NO_x formation. Thermal NO_x results from the thermal fixation of molecular nitrogen and oxygen in the combustion air, and the rate of formation increases exponentially with local flame temperature. Fuel NO_x results from the oxidation of organically bound nitrogen in such fuels as residual oil, and primarily depends on the nitrogen content of the fuel and oxygen availability in the primary combustion zone. Since gas turbines generally fire clean fuels, with correspondingly low nitrogen contents, thermal NO_x predominates. However, with increasing use of residual oils and synthetic liquid fuels, both of which contain higher levels of fuel nitrogen, the contribution of fuel NO_x will become more important.

In general, liquid fuels yield higher NO_x emissions than gaseous fuels. This is due primarily to higher localized flame temperatures resulting from droplet burning and, to some extent, to the higher fuel nitrogen content of liquid fuels. Still, for a given fuel, time, temperature, and mixing, as it affects oxygen availability, will govern the amount of NO_x formed. High temperature, long residence time at high temperature, and ready oxygen availability promote high levels of NO_x.

The effect of local flame temperature on NO_x formation is shown in Figure 3, which shows the exponential increase in NO_x emissions with combustor inlet temperature.

Figure 4 shows the effect of both combustor residence time and fuel equivalence ratio (defined as the rate of fuel introduced into the combustor divided by the stoichiometric rate of fuel additives required to just consume all the oxygen in the air added to the combustor) for a lean primary zone combustor typical of today's turbines. Figure 4 shows decreased NO_x as the mixture is made more lean, in essence emphasizing the temperature dependence of NO_x for-

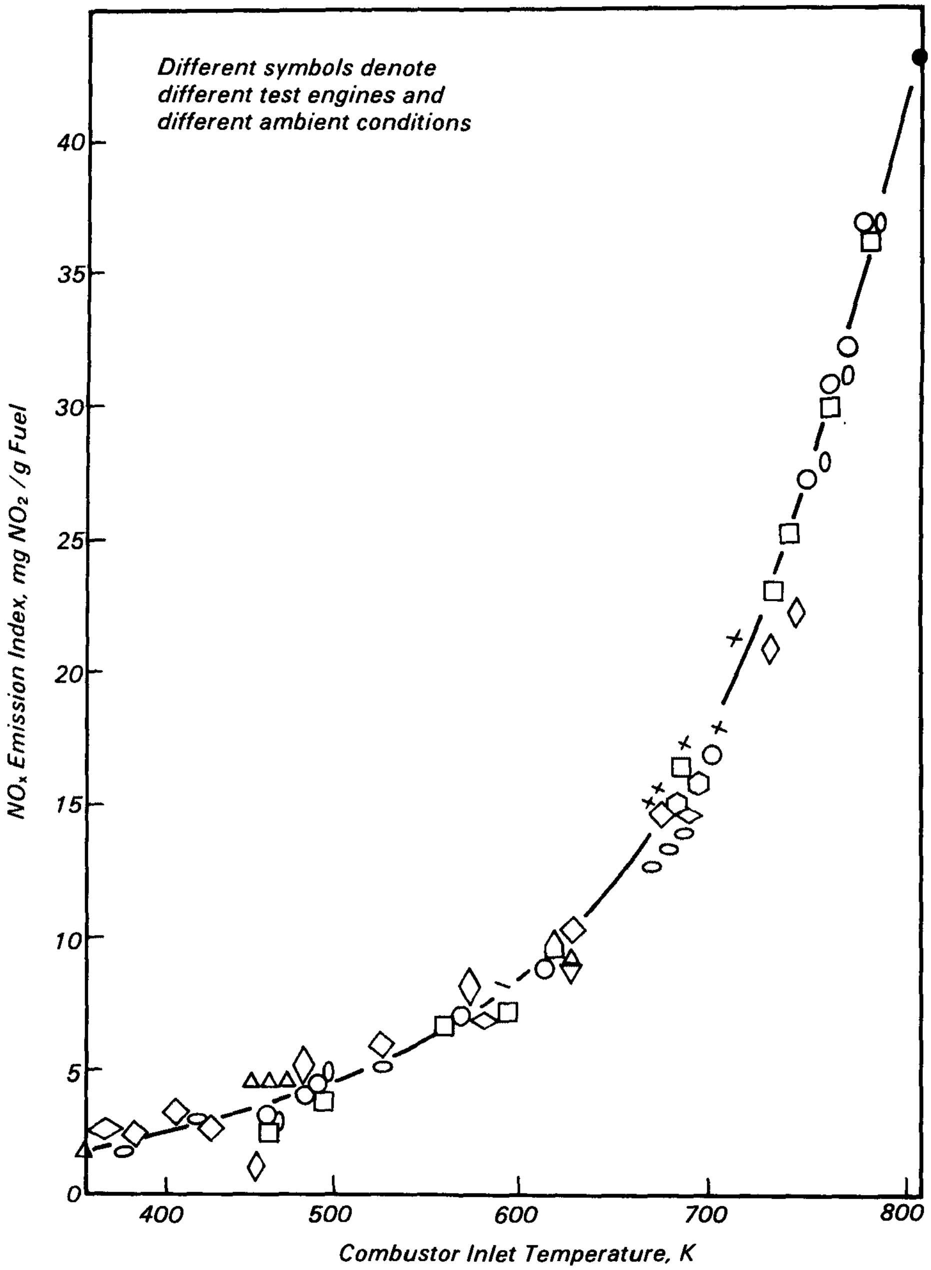


Figure 3. *NO_x emissions as a function of combustor inlet temperature.*[2]

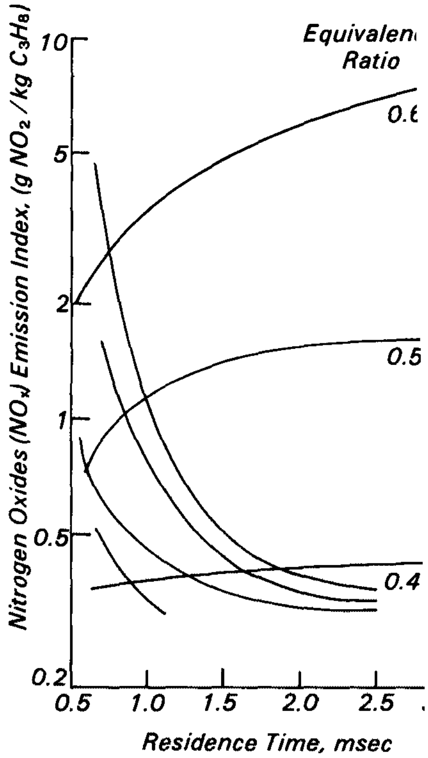


Figure 4. *Effect of residence tin on NO_x emissions for lean primary combust Propane fuel inlet mi ture temperature, 8C K; inlet pressure, 5 atm; reference velocit 25 and 30 m/s.*[3]

mation; leaner mixtures in this range of equivalence ratios produce lower temperature flames due to the dilution and cooling effects of the added air. Figure 4 also shows the increase in NO_x with increasing residence time. HC and CO emissions are functions of the combustion efficiency of the unit. Since most units are designed for high efficiency at maximum load, reduced load tends to increase CO and HC emissions. CO reacts slowest of all components formed during combustion; therefore, it is emitted in the largest concentrations.

Emissions of CO and HC are also a function of the method of fuel injection, including atomization method and pressure, degree of fuel/air mixing, and residence time at combustion temperature. Note that improved atomization and rapid fuel/air mixing can reduce thermal NO_x as CO and CH are reduced. However, increased residence time and combustion temperature for more complete combustion may increase NO_x, at lea for the fuel-lean primary zone cor bustors typical of today's design.

Table 1 summarizes uncontrollı emission factors (ng/J heat input) fro stationary gas turbines. For pollutan which depend on fuel composition, typical fuel composition was used.

Control Alternatives

Since NO_x is the major pollutant ı concern from gas turbines, control tecl niques discussed here focus on reducir NO_x emissions. NO_x controls for gas tu bines are usually classified either as wı techniques which inject water or steaı into the combustion zone, or dry tecl niques which involve some process mod fication other than adding water. Th typically takes the form of combustı redesign.

The formation of thermal NO_x is highl dependent on flame temperature. I fact, virtually all thermal NO_x is forme in the region of highest flame temperaı

Table 1. Gas Turbine Criteria Pollutant Emissions Factors (ng/J)

Size (Power Output)	*NO_x (as NO_2)*	*SO_2*	*Particulate*	*CO*	*HC*
>15 MW					
Natural gas	*195*	*2.2*	*6.0*	*49.0*	*8.6*
Diesel oil	*365*	*10.7*	*16.0*	*47.0*	*8.6*
4-15 MW					
Natural gas	*194*	*2.2*	*6.0*	*49.4*	*8.2*
Diesel oil	*365*	*10.7*	*15.5*	*47.3*	*9.9*
<4 MW					
Natural gas	*194*	*2.2*	*6.0*	*49.4*	*8.2*
Diesel oil	*365*	*10.7*	*15.5*	*47.3*	*9.9*

ture, and amounts formed increase exponentially with increasing temperature, as noted in Figure 3. With the injection of atomized water or steam directly into the primary combustion zone, peak flame temperatures are lowered since the sensible heat of the water or steam as well as vaporization of water effectively removes some of the heat from the primary combustion zone. NO_x emissions have been reduced as much as 80 percent with water injection in gas turbines, as shown in Figure 5. The figure also shows that the effectiveness of water injection in reducing NO_x varies strongly with injected water/fuel ratio and that virtually any NO_x reduction below 80 percent can be attained by varying the water/fuel ratio.

Water injection is now commonly accepted as a valid way to control NO_x emissions from current combustor design. One turbine manufacturer has more than 61 large gas turbines equipped with water injection equipment. Some of these are used to meet local air pollution regulations; others are used to increase power output by increasing mass flowrates through the turbine. Another manufacturer guarantees its gas turbine NO_x emissions to 75 ppm at 15 percent oxygen in the flue gas; yet another supplies wet controls on an "as needed" basis.

It must be emphasized, though, that experience, described above, has largely been limited to turbines burning clean fuels. In contrast, recent studies have shown that the effectiveness of wet controls decreases significantly as the percentage of fuel-bound nitrogen in a fuel increases. For example, one study showed (in tests in a subscale combustor version of a commercial Westinghouse unit) that the performance of water injection decreases significantly with high nitrogen fuels such as solvent refined coal fuels.[5] Indeed, Figure 6 shows that, with a high water/fuel mass ratio and a high-nitrogen fuel, water injection actually hinders NO_x reduction.

Dry NO_x controls involve combustor modifications, but not water or steam injection. A number of general concepts have been investigated. However, two concepts are currently thought to be most promising: the use of super-lean primary zone combustors and the rich-burn/quick-quench (RBQQ) concept. Both rely in part on prevaporization and premixing of fuel and air, but there the similarities end.

Super-lean primary zone combustors rely primarily on carrying out combustion under very lean conditions to limit flame temperature, thereby limiting thermal NO_x formation. Various combustor designs have been tested to extend flammability limits for stable super-lean combustion. These include the General Electric radial/axial staged combustor with premix and lean primary combustion, the Pratt and Whitney Swirl Vorbix, and the solar vortex air blast (VAB) and jet-induced circulation (JIC) concepts. The General Electric and Swirl Vorbix concepts have achieved 60 percent NO_x reduction in test rigs with very low CO and HC emissions; the VAB concept, over 90 percent NO_x reduction; and the JIC concept, about 90 percent reduction in test rigs, also at very low CO and hydrocarbon emissions.

However, all these super-lean primary zone concepts control only thermal NO_x and would thus be less effective in reducing NO_x from the burning of higher nitrogen content fuels. In fact, their super-lean primary combustion would promote fuel nitrogen oxidation so that the concepts might be counterproductive in the combustion of higher nitrogen fuels.

In contrast, the second promising concept, the RBQQ concept being developed by Pratt and Whitney, can be used in burning high nitrogen fuels. The RBQQ concept essentially is a means of promoting staged combustion in a gas turbine. Premixed fuel and air is burned under rich conditions in the primary zone. Secondary dilution air is then added through quick-quench slots to complete combustion at lower temperature. Thermal and fuel NO_x are limited by the low oxygen availability in the primary zone; thermal NO_x is further limited by the lowered primary zone temperatures.

Laboratory testing showed the concept capable of NO_x emissions as low as 20 ppm (15 percent O_2) for diesel fuel; full scale turbine emissions of 40-45 ppm have been obtained. Tests on a 0.5 percent nitrogen fuel have given 50 ppm NO_x. All tests have had acceptably low CO levels.

In summary, wet controls are currently the only available way to meet the recently promulgated NSPS for stationary gas turbines of 75 ppm (15 percent O_2). However, rapidly developing dry controls should be available by the mid 1980's.

Costs of Control

Implementing wet NO_x controls can significantly impact the total operating cost of a stationary gas turbine. Actual cost estimates vary, however. Various utilities have reported capital costs ranging from $4/kW in 1975 dollars to almost $23/kW in 1978 dollars. By comparison, a typical utility gas turbine will cost about $150/kW in 1978 dollars. Actual costs are site specific and depend to a great extent on required water purification equipment and to a lesser extent on required turbine modifications. The approximately 2 percent fuel penalty resulting from an increased heat rate with water injection is another significant cost impact. Using a nominal $10/kW (1978 dollars) capital cost for applying water injection to large turbines, and increased operating and maintenance costs (including fuel penalty) of about 3 percent of installed cost per year, the annualized cost of wet controls, including capital and operating costs, raises the cost of electricity by 2-5 percent.

At this stage of development, it is difficult to accurately predict associated

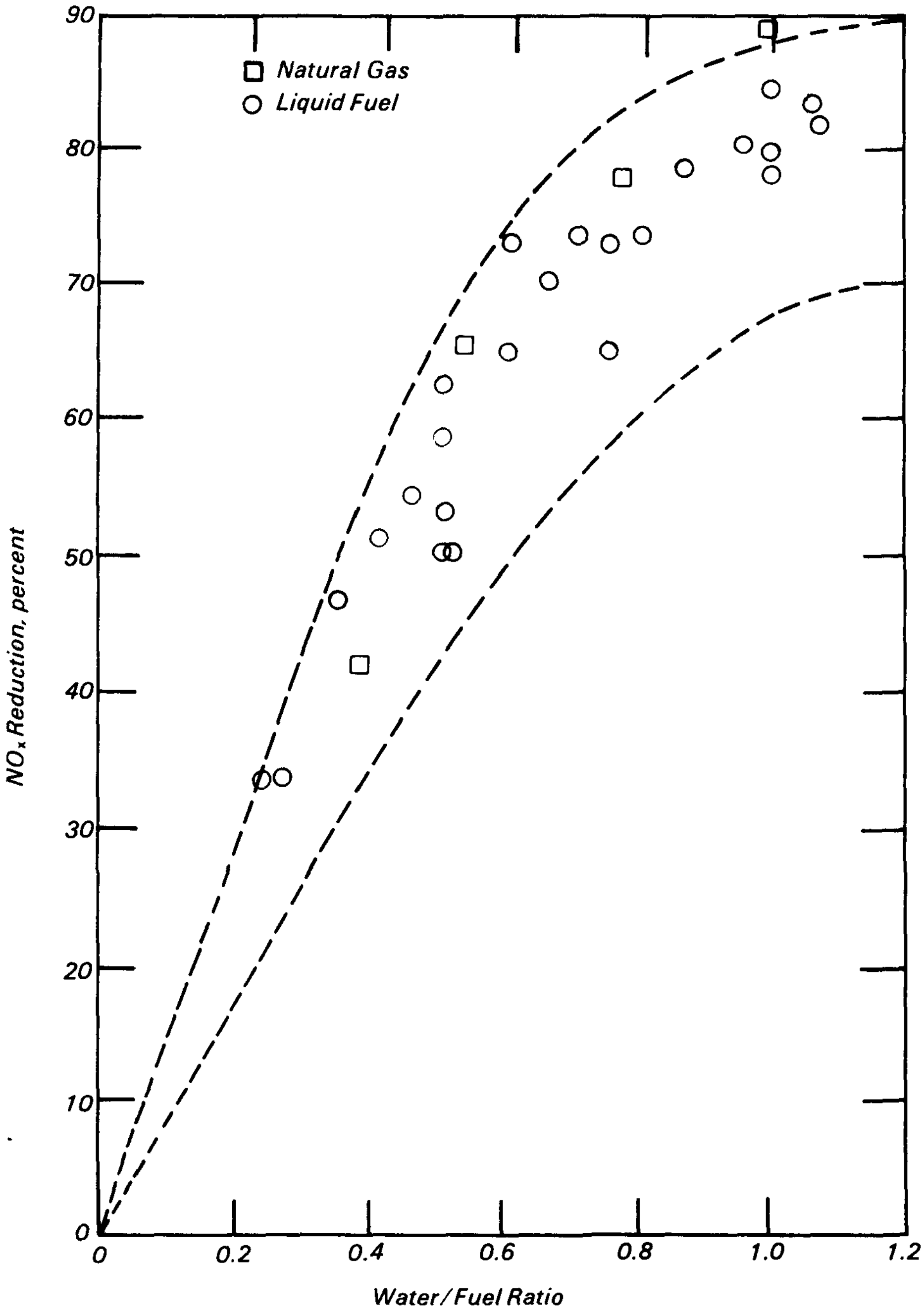


Figure 5. *Effectiveness of water injection in reducing NO_x emissions.*[4]

costs of dry controls. A major factor in dry control economics is passing development costs on to the user. Dry NO_x controls including development expenditures in their total cost appear to cost somewhat less than wet NO_x controls for a comparably sized unit. If development costs are not passed on, dry control combustors are expected to be only nominally more costly than existing combustor models.

Operational Impacts of Controls

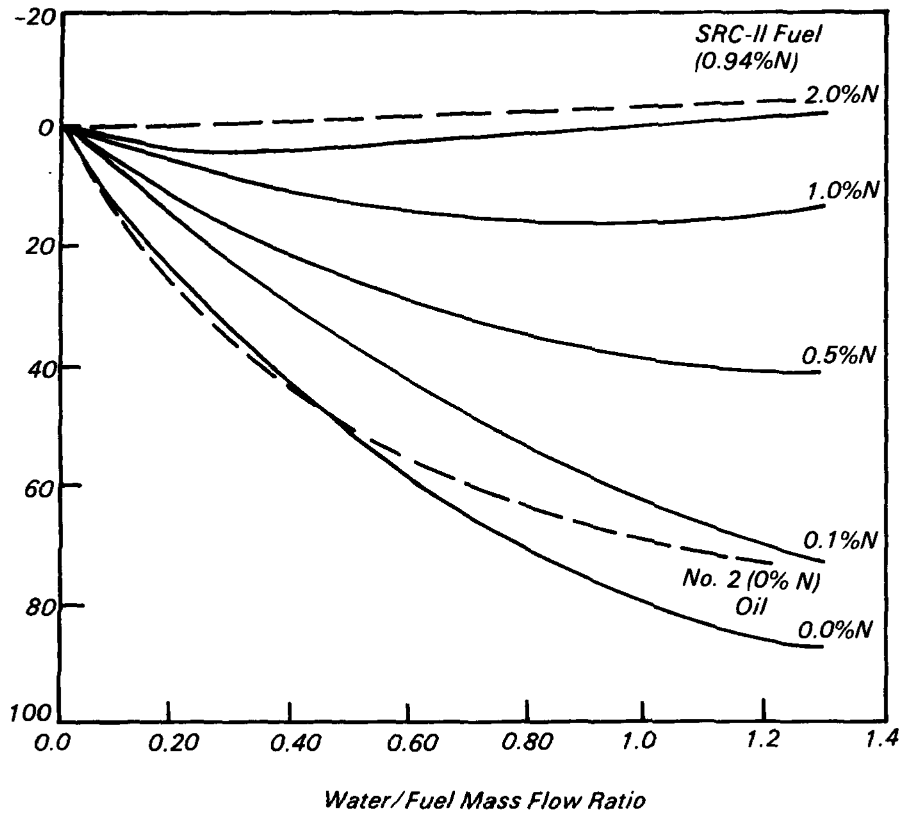
There is considerable disagreement about the impact that wet controls have on the daily operation and maintenance of gas turbines. An increase in engine heat rate, manifested as a maximum of 5 percent (nominal 2 percent) increase in fuel usage, is the most significant impact on operations. This may be offset somewhat by increased power output caused by the increase in mass through Periodic recharging of the water pı cation system will most certainly required. Indeed, a full-time operı maintenance person may even be ı ranted for some installations. S users have reported significant mai nance problems with the water tı ment system itself and internal tur problems due to water use. The lı problems generally involve either part embrittlement or particle deposi and contamination. These problems affected not only by water qua water/fuel ratio, and equipment tı but also by day-to-day operation maintenance procedures. At least utilities have accumulated over 50,(hours of wet NO_x control experience have experienced no significant probl or outages directly attributable to control technique.

Since dry controls are essenti modified conventional combust although more complex, there probı will not be any additional impact operation and maintenance. Still, problems experienced by manufactu in the developmental stage must be sol before the concepts are used comn cially on full scale engines. Moreo new problems will no doubt surface ı ing the scale-up process. Currently, controls are not expected to significa affect heat rate. However, combu liners may need more frequent replı ment than with conventional combust

Incremental Emissions Due tc Controls

Combustion modifications used control NO_x emissions from gas turbi might also be expected to affect level of emissions of other pollutant s cies discharged. If other pollutant er sions increase significantly, the environmental effect of controlling N through combustion modification n be detrimental. For stationary comb tion sources, the pollutants of conc are the criteria pollutants CO, UHC, ı particulate (both mass emission ra and emitted size distribution), along w sulfates, organic compounds, and tr metals.

CO, UHC, and (to some extent) par ulate (soot) are products of incompl combustion which can result from dr ping temperatures too rapidly. An eng at idle and low power produces high and UHC because combustion efficiei is low. Full load produces high comb tion efficiency and therefore low CO ı



gure 6. *Predicted decrease in NO_x emissions through water injection with increasing amounts of bound nitrogen in fuel oil.*[5]

igh UHC. While data demonstrating the fect of NO_x controls on CO, UHC, and articulate emissions are limited, trends eem to indicate that water and steam ıjection increase these emissions. Dry ontrols, such as the super-lean and the BQQ concepts, appear to be capable of ıinimizing CO and UHC, but each type ıf combustor has limitations that need o be corrected before it becomes comnercially available.

Data on the effects of combustion nodifications on emissions of the other ıollutants of concern are virtually nonıxistent. For this reason, a field test proȝram was initiated on a large utility gas :urbine equipped with water injection for NO_x control.

The unit tested was a 60 MW (electri- ;al) simple-cycle, single-shaft, heavy duty utility turbine firing No. 2 distillate ɔil. Tests were performed under two ɔperating conditions: a baseline test, with the unit under normal full-load operaion; and a low NO_x test, with water inection at a water/fuel weight ratio of).42, also at full load. The water/fuel ratio selected was that required to lower NO_x emissions below the gas turbine NSPS of 75 ppm (dry at 15 percent O_2).

Slightly modified Environmental Assessment Level 1 sampling and analysis procedures were followed.[6] Flue gas NO_x, O_2, CO_2, CO, and UHC were measured using continuous gas monitors. The flue gas UHC was speciated by boiling range (C_1 to C_6), using an on-site gas chromatograph. Particulate emissions were determined using EPA Method 5. Flue gas sulfur species (SO_2, SO_3, condensed sulfate) were measured using EPA Method 8. The flue gas was sampled with a Level 1 Source Assessment Sampling System (SASS) train. In addition, grab samples were taken of the fuel and water from the water injection purification system.

Sample analyses essentially followed Level 1 protocol. SASS train samples were analyzed for trace element and organic content. The organic analyses included separation by boiling range (373 to 573 K—TCO, and greater than 573 K—GRAV), and gas chromatography/mass spectrometry analysis for selected polycyclic organic matter (POM) constituents. Level 1 bioassay tests were also performed on SASS train sorbent extract from the water injection test.[7]

Summary results from the field test program are shown in Table 2. The table shows that, with water injection, NO_x emissions were reduced 58 percent from baseline levels. CO and UHC (listed as methane in Table 2 since all UHC detected in the tests chromatographed as methane) levels may have increased slightly with water injection. Higher molecular weight organic species (greater than C_7) emissions appeared unchanged with water injection. Most of these detected for both tests were in the TCO boiling range. POM species were detected at low levels for both tests and may have increased with water injection. Water injection had no detectable effect on emissions of all other species analyzed in the program.

The microbial mutagenesis bioassay of the SASS train sorbent extract gave negative mutagenicity results. The cytotoxicity assay using human lung fibroblasts showed low toxicity.

Environmental Impact Evaluation

The data obtained in the field test program discussed above were evaluated by a Source Analysis Model (SAM), specifically SAM/IA,[8] to give a quantified measure of the seriousness of the potential hazard posed by emissions from a gas turbine. SAM/IA was developed by IERL-RTP for use in Environmental Assessment projects to estimate the potential hazard associated with some discharge streams. The basic index of potential hazard defined by SAM/IA is Discharge Severity (DS). The DS for a given species is defined as the ratio of its concentration to its multimedia environmental goal. Discharge Multimedia Environmental Goals (DMEGs), defined in the IERL-RTP Environmental Assessment program for a large number of species, represent the maximum pollutant concentration desirable in a discharge stream to preclude adverse effects on human health or ecological systems.

Table 3 presents DS (human-health-based) values, calculated from the data in Table 2, for species where DS exceeded unity for either the baseline or water injection test. Table 3 suggests that NO_x presents the greatest potential hazard in the flue gas from the gas turbine, followed by chromium, CO_2, SO_3 (vapor phase), arsenic, SO_2, and cadmium. The high measured levels of chromium

Table 2. *Flue Gas Composition (μg/dscm): 60 MW Utility Gas Turbine*

	Baseline	*Water Injection*
NO_x	3.5×10^5	1.5×10^5
SO_2	3.1×10^4	3.4×10^4
SO_3	8.1×10^3	6.0×10^3
CO	7.0×10^3	1.0×10^4
CO_2	8.0×10^7	8.4×10^7
Particulate	570	510
Antimony	< 4.6	< 4.7
Arsenic	<14	<14
Barium	< 3.5	< 3.6
Beryllium	< 0.92	< 0.14
Bismuth	< 1.8	< 2.3
Boron	$< 2.2 \times 10^3$	$< 2.0 \times 10^3$
Cadmium	<13	0.55
Chromium	<17	< 7.5
Cobalt	< 0.55	< 0.13
Copper	42	60
Iron	71	89
Lead	82	23
Manganese	< 0.48	< 0.050
Mercury	< 2.8	<21
Molybdenum	< 5.8	< 4.8
Nickel	< 0.24	< 0.61
Selenium	<11	<10
Tellurium	< 3.6	< 3.4
Thallium	<11	<10
Tin	<16	<44
Titanium	<29	<33
Vanadium	<22	<49
Zinc	<760	800
Organics ($>C_7$)	$< 1.3 \times 10^3$	$< 1.1 \times 10^3$
Methane	$< 1.6 \times 10^3$	$< 2.4 \times 10^3$
Dilphenyl ether	0.50	-
Diphenylcyclohexane	-	10
Fluoranthene	-	0.50
Naphthalene	-	1
Phenanthrene	0.50	1
Phenol	1.0	1
Pyrene	-	0.50
Terphenyl	-	5

(which cause the high DS values for this species) are probably an artifact of the gas sampling system which contains stainless steel parts. The high DS for CO_2 should not be of concern: its DMEG is based on its asphyxiant properties, not its toxicity. Note the absence from Table 3 of the POM species detected and listed in Table 2: although POMs were detected, SAM/IA suggests that they are emitted at levels too low to be of concern.

Table 3 suggests that using water injection to control NO_x from gas turbines results in a net environmental benefit. The DS for the compound presenting the greatest potential hazard, NO_x, is roughly halved, while the DS values for other potentially hazardous

Table 3. *Flue Gas Discharge Seve ity: 60 MW Utility G Turbine*

Component	*Discharge Severity* *Baseline*	*Low NO*
NO_x	39	17
Cr	17	8
CO_2	8.9	9.3
SO_3 (vapor)	8.1	6.0
As	7.0	7.0
SO_2	2.4	2.6
Cd	1.3	0.055
Total Stream	87.0	52.2

species remains generally unchange Total stream DS (sum over species an lyzed) decreases accordingly.

Recommendations

Performing the environmental asses ment of combustion modification contro for stationary gas turbines has often bee frustrated by the lack of good quali data in several areas. Thus, recomme dations from the study focus on extendir the data base necessary for evaluating th effects of these controls on turbine ope ation, costs of operation, and emission

For wet controls, there are specif areas where there appears to be a gener lack of consensus regarding their impact These include: (1) water injection co data for capital equipment, operating and maintenance expense, (2) the cos benefit ratio of wet controls for small ga turbines (less than 4 MW electrical ou put), (3) quantification of the fuel penalt due to increased heat rate as tempere by additional power output resultin from more mass throughout, and (4 quantification of the effect of NO_x cor trols on incremental emissions of pollu tant species other than NO_x.

Data needs for the dry control cor cepts, though, are perhaps more press ing, in addition to being more extensive Dry controls are an emerging technology and there are many unanswered ques tions regarding their incremental effect and associated costs. Manufacturer appear to be focusing on the most effec tive dry control concepts in reducing NO_x while minimizing incremental emis sions and maintaining acceptable systen efficiencies. The next critical step i scaling up to full size engines, assessing the various environmental impacts and de veloping long term operating experience

At present, dry NO_x controls appear to be the preferred option for new gas turbines within 5 years. Due to their present state of development, though, essentially no data regarding emission levels, control costs, and operation and maintenance impacts exist for the application of dry controls to full scale engines. All of these data are required to perform a meaningful environmental assessment of dry NO_x control. As the direction of dry controls research becomes evident, additional testing programs can be designed to provide the proper data base. Then, as dry controls become commercially feasible and users gain operating experience, additional data gaps can be filled. The types of data needed will primarily relate to additional operating and maintenance costs. These can be predicted accurately only through long-term accounting of such expenditures. Only by such careful front-end tracking of dry control developments can a comprehensive environmental assessment be performed.

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