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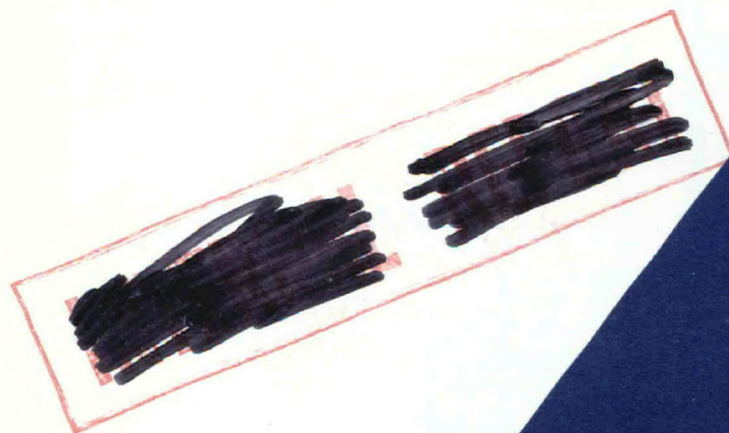
NO<sub>x</sub> AND SO<sub>2</sub> EMISSIONS  
WITH NO. 6 AND NO. 4 FUEL OILS  
AT CANADIAN FORCES BASE HALIFAX;

JANUARY 1992


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**NO<sub>x</sub> AND SO<sub>2</sub> EMISSIONS  
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**JANUARY 1992**

**F.D. Friedrich\*, V.V. Razbin\*\* and  
F.L. Wigglesworth\*\*\***

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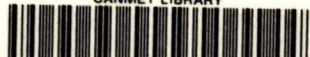
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## **NO<sub>x</sub> AND SO<sub>2</sub> EMISSIONS WITH NO. 6 AND NO. 4 FUEL OILS AT CANADIAN FORCES BASE HALIFAX; JANUARY 1992**

**F.D. Friedrich, V.V. Razbin and F.L. Wigglesworth**

### **ABSTRACT**

In 1990, as part of the Federal Industrial Boiler Emissions Control (FIBEC) Program, National Defence Canada undertook to demonstrate a low NO<sub>x</sub> burner at Canadian Forces Base Halifax. A state-of-the-art dual register burner employing both flue gas recirculation (FGR) and staged air supply was installed in Boiler 5; a 60 000 lb/h package boiler installed in 1986, which is normally fired with No. 6 fuel oil.

Tests conducted in January 1991 showed that NO<sub>x</sub> emissions with the new burner exceeded by about 50% the limits proposed for the FIBEC regulations. Furthermore, FGR had only a modest effect on reducing NO<sub>x</sub>.

National Defence then decided to conduct similar tests with No. 4 oil, which normally contains less nitrogen than No. 6 oil, and therefore could be expected to produce lower emissions. A series of 25 tests was conducted on Boiler 5 and two other boilers at CFB Halifax, to compare emissions from No. 6 fuel oil and No. 4 fuel oil. Boiler operating conditions were also adjusted to achieve lower NO<sub>x</sub>.

Compared with No. 6 oil, No. 4 oil offered only a modest decrease in NO<sub>x</sub> emissions ranging from 30% to zero. Lower excess air had a strong influence in minimizing NO<sub>x</sub> formation. Indeed, with careful control of excess air, the two older boilers not equipped with low NO<sub>x</sub> burners produced lower emissions than the boiler with the low NO<sub>x</sub> burner, and the effect of FGR was negligible. This shows that there are important factors besides burner design. Emissions of SO<sub>2</sub> were also measured, and always exceeded the proposed limit.

It is concluded that the technology of low NO<sub>x</sub> burners is not yet sufficiently advanced that they can be reliably employed to meet stringent emissions standards. Depending on furnace size, shape and construction, operation at low excess air may provide better results, but this can only be established by evaluating individual boilers, or at least boiler types. The proposed SO<sub>2</sub> emission regulation can only be met by utilizing a residual oil containing no more than 1% sulphur, which is not available from refineries in the Halifax area.

**ÉMISSIONS DE NO<sub>x</sub> ET SO<sub>2</sub> POUR LES MAZOUTS  
LOURDS N° 6 ET N°4 À LA BASE DES FORCES ARMÉES CANADIENNES,  
HALIFAX; JANVIER 1992**

**F.D. Friedrich, V.V. Razbin et F.L. Wigglesworth**

**RÉSUMÉ**

En 1990, dans le cadre du Programme de réduction des émissions des chaudières des installations fédérales (PRECIF), le ministère de la Défense nationale a entrepris une démonstration d'un brûleur à faible émissions de NO<sub>x</sub> à la base des Forces canadiennes Halifax. Un brûleur à deux registres hautement perfectionné qui utilise à la fois la recirculation des gaz de carneau et la combustion étagée, a été installé sur la chaudière 5, chaudière préfabriquée de 60 000 lb/h qui est habituellement alimentée au mazout lourd n° 6.

Les essais d'émission réalisés en janvier 1991 ont montré que les émissions de NO<sub>x</sub> provenant du nouveau brûleur dépassaient d'environ 50% les limites proposées en vertu des règlements du PRECIF. En outre, la recirculation des gaz de carneau n'a eu qu'un effet modeste.

On a alors décidé d'entreprendre des essais semblables en utilisant du mazout lourd n° 4, qui est normalement moins riche en azote que le mazout lourd n° 6 et qui devrait donc produire moins d'émissions. Le rapport décrit une série de 25 essais menés sur trois chaudières à la BFC Halifax en vue de comparer les émissions provenant du mazout lourd n° 6 et du mazout lourd n° 4.

L'utilisation du mazout lourd n° 4 a donné lieu à une réduction modeste (allant de 0% à 30%) des émissions de NO<sub>x</sub>, par rapport au mazout lourd n° 6. Le faible excès d'air a beaucoup contribué à minimiser la formation de NO<sub>x</sub>. En effet, en contrôlant soigneusement l'excès d'air, les émissions des deux chaudières non munies de brûleurs à faible émission de NO<sub>x</sub> ont été moins abondantes que celles de la chaudière équipée d'un brûleur à faible émission de NO<sub>x</sub> et l'effet de la recirculation des gaz de carneau a été négligeable. On a également mesuré les émissions de SO<sub>2</sub>, qui ont toujours dépassé les limites proposées.

Le rapport conclut que la technologie des brûleurs à faible émission de NO<sub>x</sub> n'est pas encore suffisamment perfectionnée et que ces brûleurs ne sont pas assez fiables pour se conformer à des normes d'émission rigoureuses. On pourrait avoir de meilleurs résultats avec un faible excès d'air mais, pour vérifier cette possibilité, il faudrait évaluer chaque chaudière ou, à tout le moins, chaque type de chaudière. Pour se conformer aux limites proposées en matières d'émissions de SO<sub>2</sub>, il faudrait utiliser un combustible dont la teneur en soufre ne dépasse pas 1%.

## CONTENTS

	Page
ABSTRACT .....	i
RÉSUMÉ .....	ii
INTRODUCTION .....	1
DESCRIPTION OF PLANT .....	2
TEST PROGRAM .....	2
Objectives .....	2
Procedure .....	2
RESULTS AND DISCUSSION .....	3
Fuel Analyses .....	3
NO <sub>x</sub> Emissions .....	3
Boiler 5 .....	3
Boiler 4 .....	4
Boiler 3 .....	4
SO <sub>2</sub> Emissions .....	5
CO Emissions .....	5
Boiler Efficiency .....	5
Boiler 5 .....	5
Boiler 4 .....	5
Boiler 3 .....	6
Summary of Boiler Efficiency .....	6
CONCLUSIONS .....	7
ACKNOWLEDGEMENTS .....	8
REFERENCES .....	9
APPENDIX A. DETAILS OF TESTS .....	A-1
Instrumentation .....	A-1
Test Conditions .....	A-1
General .....	A-1
Boiler 5 .....	A-3
Boiler 4 .....	A-5
Boiler 3 .....	A-6
APPENDIX B. MECHANISMS OF NO <sub>x</sub> FORMATION AND DESTRUCTION .....	B-1

## CONTENTS - continued

## TABLES

	Page
1. Summary of proposed FIBEC emission regulations . . . . .	10
2. Fuel analytical data . . . . .	11
A-1 Data for Boiler 5 with No. 6 oil . . . . .	A-9
A-2 Data for Boiler 5 with No. 4 oil . . . . .	A-11
A-3 Data for Boiler 4 with No. 4 oil and No. 6 oil . . . . .	A-13
A-4 Data for Boiler 3 with No. 4 oil . . . . .	A-15
A-5 Data for Boiler 3 with No. 6 oil . . . . .	A-16
B-1 Effect of temperature on formation and decomposition rate for nitric oxide . . . . .	B-2

## FIGURES

1. Boiler 5 - NO <sub>x</sub> versus boiler load . . . . .	12
2. Boiler 5 - NO <sub>x</sub> versus O <sub>2</sub> in flue gas . . . . .	13
3. Boiler 4 - NO <sub>x</sub> versus boiler load . . . . .	14
4. Boiler 3 - NO <sub>x</sub> versus boiler load . . . . .	15
5. Boiler 3 - NO <sub>x</sub> versus O <sub>2</sub> in flue gas . . . . .	16
6. Range of SO <sub>2</sub> measurements for Boilers 3, 4 and 5 . . . . .	17
7. Summary of boiler efficiency for all tests . . . . .	18
A-1 Radiation and convection loss for Boilers 4 and 5 . . . . .	A-17
A-2 Radiation and convection loss for Boiler 3 . . . . .	A-18
B-1 Equilibrium composition of NO for adiabatic combustion of methane with air at 1 atm . . . . .	B-7
B-2 Hypothetical equilibrium and probable NO concentration in a stoichiometric propane-air mixture . . . . .	B-8
B-3 Nitric oxide versus excess air as predicted by Brown's model for No. 2 fuel oil . . . . .	B-9

## INTRODUCTION

The work described in this report arises from a program initiated by the Department of National Defence (DND) in 1990 to prepare for new emissions standards expected to result from the Federal Industrial Boiler Emissions Control (FIBEC) Program. Table 1 summarizes the draft regulations, which were prepared by Environment Canada (EC) and which propose stringent new standards, especially for nitrogen oxides (NO<sub>x</sub>) and sulphur dioxide (SO<sub>2</sub>).

National Defence Canada, being a major boiler owner within the federal government, undertook to demonstrate low NO<sub>x</sub> combustion technologies in two of its heating plants; CFB St. Hubert, which normally burns natural gas, with No. 2 fuel oil as backup, and CFB Halifax Dockyard, which normally burns No. 6 (Bunker C) fuel oil, also with No. 2 fuel oil as backup. In each plant, one boiler was retrofitted with a state-of-the-art burner employing flue gas recirculation (FGR) to reduce NO<sub>x</sub> emissions. As part of Energy, Mines and Resources Canada's (EMR) contribution to the FIBEC program, the Combustion and Carbonization Research Laboratory (CCRL) of CANMET's Energy Research Laboratories conducted emissions and efficiency tests on the retrofitted boilers.

The tests at CFB St. Hubert, conducted in October 1990 showed that with natural gas, FGR reduced NO<sub>x</sub> emissions by about 50%, and brought them within the levels proposed in the draft regulations (1). When firing natural gas without FGR, NO<sub>x</sub> emissions exceeded the proposed limits. With No. 2 fuel oil the reduction achieved by FGR was less pronounced; about 15%, and at boiler loads above 40% maximum capacity rating (MCR), the allowable NO<sub>x</sub> levels were exceeded.

The retrofitted boiler at CFB Halifax Dockyard was tested in January 1991, using the Bunker C oil normally supplied to the plant. It was found that FGR reduced NO<sub>x</sub> emissions only modestly, and they typically exceeded the limits of the draft regulations by about 50% (2). Also, SO<sub>2</sub> emissions were almost double the allowable level. DND, EC and EMR then agreed to collaborate on a further series of tests to determine whether NO<sub>x</sub> emission levels could be achieved with No. 4 fuel oil, also known as bunker A. This grade normally contains lower levels of organic nitrogen and sulphur and in some other instances has yielded NO<sub>x</sub> and SO<sub>2</sub> emissions close to the allowable levels (3). The costs were shared by DND and EC, while the Efficiency and Alternative Division of EMR/CANMET provided project initiation and management.

This report describes a series of 25 tests conducted on three boilers at CFB Halifax Dockyard, to compare the emissions obtained using No. 6 (Bunker C) and No. 4 (Bunker A) fuel oils. These tests, like the previous ones, were conducted by CCRL.

## DESCRIPTION OF PLANT

The central heating plant at CFB Halifax Dockyard contains five watertube boilers, all fired with heavy oil. Boilers 1, 2 and 3 are Vickers field-erected boilers, rated at 30,000 lb/h of steam at about 135 psig (13,600 kg/h at 932 kPa). They were installed in 1942, equipped with coal stokers, but were later converted to oil firing by means of a single Todd steam-atomized dual-register burner per boiler. Boiler 4 is a Babcock and Wilcox package watertube unit rated at 60,000 lb/h (27,500 kg/h) of steam, installed in 1971. It is still equipped with a Todd single-register steam-atomized burner that was part of the original supply. Boiler 5, installed in 1986, is also a package watertube boiler rated at 60,000 lb/h (27,500 kg/h) of steam. It was manufactured by Versatile Vickers Inc. and was retrofitted in 1990 with a low NO<sub>x</sub> Faber burner marketed by Tampella Keeler. This is a dual register burner having a measure of air staging effected by secondary air nozzles which project into the furnace about 20 cm beyond the oil nozzle. Also, flue gas recirculation (FGR) is provided by a 15 hp blower which can draw from either upstream or downstream of the economizer, and delivers to the burner windbox.

## TEST PROGRAM

### OBJECTIVES

The primary objective was to determine the NO<sub>x</sub> emissions obtainable with the two types of fuel from each of three boiler/burner combinations existing in the plant. A secondary objective was to establish the effect of FGR on emissions when firing No. 4 oil. This could only be done with Boiler 5, which was retrofitted in 1990 with a burner having FGR capability. SO<sub>2</sub> and CO emissions were also measured.

### PROCEDURE

In total eleven tests were carried out on Boiler 5; five with No. 6 oil and six with No. 4 oil, covering the load range, with and without FGR. Six tests were



conducted on Boiler 4; three with each fuel, and eight tests were conducted on Boiler 3, three with No. 4 oil and five with No. 6 oil.

Detailed descriptions of the tests are presented in Appendix A, along with tables of the measured and calculated data for each test, and graphs showing radiation and convection losses for each boiler. To help understand the results, which sometimes appear to be anomalous, Appendix B presents a brief description of the mechanisms by which  $\text{NO}_x$  is formed and broken down.

## RESULTS AND DISCUSSION

### FUEL ANALYSES

Six fuel samples were taken during the test program; one represented each delivery of No. 4 oil, and one represented each main test period using No. 6 oil from the main storage. The results are reported in Table 2. The two grades of oil are very similar in terms of carbon content. The somewhat higher hydrogen content of No. 4 oil reflects a reduction of about 25% in both nitrogen and sulphur. Nitrogen content was determined according to ASTM Method 0-4629, which gives total nitrogen content.

As explained in Appendix A, the No. 6 oil in the main storage tank was progressively diluted by No. 4 oil recirculated from the burners. The effect is apparent in the last sample; A0545-92. Prorating the reduction in either specific gravity or sulphur content indicates that it contained about 25% No. 4 oil.

### $\text{NO}_x$ EMISSIONS

#### Boiler 5

$\text{NO}_x$  emissions for Boiler 5 are summarized in Fig. 1 and 2. No. 4 oil seems to offer only modest advantages compared with No. 6 oil. The only tests which met the requirement of the proposed regulation were those with No. 4 oil at 50% MCR. Flue gas recirculation shows no advantage with either fuel. Comparing the results obtained for No. 6 oil with those obtained in January 1991(2),  $\text{NO}_x$  levels at full load are now lower by about 30 ng/J, i.e., by about 17%, but in the mid-load range they are about the same. The January 1992 results do not show the slight advantage of FGR that was apparent in the January 1991 results. The 1992 program did not include any tests at 30% MCR, and therefore cannot confirm the increase in  $\text{NO}_x$  emissions at low load

which was observed in 1991. Figure 2 shows that NO<sub>x</sub> emissions tend to increase as excess air level increases, and the relationship is much the same as found in the 1991 tests.

#### **Boiler 4**

Figure 3 shows NO<sub>x</sub> emissions over the load range for Boiler 4. It is noteworthy that it offers lower NO<sub>x</sub> emissions than Boiler 5, despite the low-NO<sub>x</sub> burner with which the latter is equipped. For No. 6 oil, emissions are about the same at full load; 134 ng/J for Boiler 4 versus 144 ng/J for Boiler 5, but at 35% and 60% MCR Boiler 4 very nearly achieves the allowable limit of 110 ng/J. NO<sub>x</sub> levels on this boiler, measured in January 1991 without boiler tuning by CCRL staff, were about the same at 40% MCR, but rose to about 145 ng/J at 75% MCR and about 160 ng/J at 90% MCR.

Also, for this boiler the use of No. 4 oil offers a more clear-cut advantage in NO<sub>x</sub> reduction. In the draft regulation the rate of contaminant discharge is defined as the arithmetic mean of the results from two tests, one conducted between 30% and 40% of MCR, and the other between 60 and 70% of MCR. When tested according to this criterion Boiler 4 can readily meet the proposed NO<sub>x</sub> limit when firing No. 4 oil, provided the present burner adjustments and excess air levels are maintained.

#### **Boiler 3**

As Fig. 4 shows, when Boiler 3 is operated at low levels of excess air (close to the threshold of visible smoke) it meets the proposed NO<sub>x</sub> regulation at all loads with either fuel. Furthermore, it has a good safety margin in the load range of 30 to 70% MCR in which testing for NO<sub>x</sub> emissions would normally take place. With low excess air, No. 4 oil shows a modest advantage of about 10 ng/J in the mid-load range, but no advantage at full load. It should be noted that the levels of excess air which produced the low NO<sub>x</sub> emissions also produced unusual flame shape and furnace conditions, as described in Appendix A. Most operators, with no instrumentation to assure them that these conditions were both safe and clean, would have increased the excess air level.

With this boiler, the effect of increased excess air is quite dramatic, as shown in Fig. 5. As O<sub>2</sub> in the flue gas increases from the 2 to 3.5% range to about 8%, NO<sub>x</sub> emissions approximately double to about 60% above the allowable limit.

## SO<sub>2</sub> EMISSIONS

Emissions of SO<sub>2</sub> are reported in Appendix A, Tables A-1 to A-5, in both nanograms per Joule and volumetric parts per million, corrected to 3% O<sub>2</sub> in the flue gas. On either basis they should be dependent only on the sulphur content of the fuel. The range of measurements is shown in Fig. 6. The range for No. 6 oil is somewhat biased because the No. 6 oil fired in Boiler 3 was in fact diluted with about 25% No. 4 oil, as previously explained. In summary, SO<sub>2</sub> emissions are about 30% lower for No. 4 oil than for No. 6 oil, a number consistent with the relative sulphur contents reported in Table 2. However, the SO<sub>2</sub> emissions for No. 4 oil still exceed the proposed allowable limit by 30%.

## CO EMISSIONS

Carbon monoxide emissions are also reported in Tables A-1 to A-5 of Appendix A. For the most part, they are well below the allowable limit of 125 ng/J. The only exception is Test 4 on Boiler 5, a full-load test with No. 6 oil, employing FGR. In that test the average CO level was 135 ng/J. In general, it was found that CO emissions close to the allowable limit were associated with unacceptable levels of smoke.

## BOILER EFFICIENCY

### Boiler 5

With No. 6 oil, boiler efficiency is lower by 1 to 2% compared with results of January 1991, although excess air levels are about the same. Some fouling of the heat exchange surfaces is one possible explanation and increased leakage at the economizer bypass damper is another. There is no clear pattern between efficiency and type of oil. Although the No. 4 oil has a slightly higher loss due to moisture from the combustion of hydrogen, this is offset, in some tests, at least, by the ability to operate with lower excess air.

### Boiler 4

Table A-3 shows that under the test conditions, with excess air held between 9 and 12%, the efficiency of Boiler 4 ranges from about 84.8% at 35% MCR to 80.5% at 100% MCR, and is not much affected by oil type. Under normal operating conditions on automatic control, when higher excess air levels

prevail, boiler efficiency is doubtless somewhat lower.

### **Boiler 3**

Efficiency data for Boiler 3 are shown in Tables A-4 and A-5. Like Boiler 4, when excess air is kept to a minimum the highest efficiency is obtained at low load. For Boiler 3 it ranges from about 83% at 40% MCR to 78% at 90% MCR. However, under automatic control the excess air in the mid-load range is 50% to 60%, and this reduces boiler efficiency by 6 to 7%. Unless the annual service factor is low, it would probably be cost-effective to upgrade the control system for Boiler 3 to maintain the substantially lower levels of excess air at which it can operate satisfactorily.

### **Summary of Boiler Efficiency**

Efficiency data for all the tests are plotted in Fig. 7, which clearly shows how all the boilers tend to perform at higher efficiency in the mid-load range. Since this is also the range in which NO<sub>x</sub> emissions are generally minimized, it appears that the present plant practice of operating several boilers as much as possible in the mid-load range is a good one. Figure 7 also shows the substantial potential for improving the efficiency of Boiler 3, and presumably Boilers 4 and 5 as well, through closer control of excess air.

## CONCLUSIONS

1. The proposed emissions limit of 125 ng/J for NO<sub>x</sub> was met under the following conditions:

Boiler 5: only at 50% MCR (and perhaps lower), and then only with No. 4 oil and low excess air.

Boiler 4: At loads up to about 80% MCR with No. 4 oil and low excess air.

Boiler 3: At all loads, with both oils, at low levels of excess air.

2. Concerning NO<sub>x</sub> emissions, the following additional observations are made:

- While NO<sub>x</sub> emissions with No. 4 oil were always lower than with No. 6 oil, the difference ranged from about 30% reduction (Boiler 5, 40% MCR) to very little reduction (Boiler 5, 100% MCR and Boiler 3, 90% MCR).

- Excess air level has a strong, dominant effect on NO<sub>x</sub> emissions. For example, with Boiler 5, reducing excess air from 5% O<sub>2</sub> in the flue gas to 2% reduces NO<sub>x</sub> by about 30 ng/J. With Boiler 3 the effect is more extreme.

- The effect of flue gas recirculation in Boiler 5 was negligible. In fact, the low NO<sub>x</sub> burner in Boiler 5 produced higher NO<sub>x</sub> emissions than the other two boilers, except when Boiler 3 was operated with high levels of excess air. This is not easily explained, but Appendix B shows that the mechanisms governing NO<sub>x</sub> formation and decomposition are very complex, and one would need to know much about conditions in the furnace to make reliable predictions of NO<sub>x</sub> emissions. The low NO<sub>x</sub> burner in Boiler 5 employs flue gas recirculation and combustion air staging to reduce flame temperature and maintain low excess air levels at the core of the flame. This is a good approach theoretically, but it may be offset by decomposition reactions being inhibited by the highly cooled furnace. By comparison, the more moderately cooled furnace of Boiler 3 seems to permit complete combustion at low levels of excess air, even though inefficient mixing by the burner results in a furnace full of flame.

- In summary, upgrading the burner controls to maintain low excess air seems to offer more potential for reducing  $\text{NO}_x$  emissions than the installation of low  $\text{NO}_x$  burners. Routine operation at low excess air is within the capability of the present operating staff if they are properly equipped and trained. Equipment requirements are a flue gas sampling and analysis system like the one used by CCRL, which would cost between \$60,000 and \$100,000, depending on the amount of backup and datalogging capability. Training would have to cover both maintenance of the instrumentation and application of the analytical results to boiler operation. It could probably be accomplished by two instructors in three weeks.

3. The proposed emissions limit of 500 ng/J for  $\text{SO}_2$  was not met with either No. 4 oil or No. 6 oil. The former exceeded the limit by about 35%, the latter by about 85%. A fuel sulphur content of about 1% would be required to meet the emissions limit.
4. The proposed emissions limit for CO was easily met.
5. At low levels of excess air, boiler efficiency was highest in the low to mid-load range for all boilers. With Boiler 3, there was a 6 to 7% difference in efficiency between low and normal excess air. At 50% MCR, this represents a potential saving of 50 L/h fuel oil.
6. A good strategy for minimizing emissions from this plant would be to upgrade the controls to maintain low excess air, and operate the boilers, particularly the older units 1, 2 and 3, in the mid-load range as much as possible. These conditions minimize  $\text{NO}_x$  formation per unit of fuel consumed. Furthermore, because of increased efficiency fuel consumption is reduced, thereby reducing emissions of both  $\text{NO}_x$  and  $\text{SO}_2$  under the bubble option of emissions control. However, the  $\text{SO}_2$  emissions would likely still exceed the proposed limits.

#### **ACKNOWLEDGEMENTS**

Boiler tests of this type, where equipment is being tuned and operated close to the threshold of objectionable smoke emissions, require the constant attention of the operating staff. Hook-up and operation of the plant from the temporary tanker truck required special attention and the authors wish to thank both the shift operators and the plant superintendent for their consistent, capable and cheerful cooperation.

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Table 1 - Summary of regulations proposed by the Federal Industrial Boiler Emissions Control program <sup>1</sup>

Fuel type	CO ng/J	NO <sub>x</sub> ng/J	SO <sub>2</sub> ng/J	Particulates mg/m <sup>3</sup>
Natural gas	125	22	--	--
No.1 and No.2 oil	125	43	25	--
No.4, No.5 and No.6 oil	125	110	500	--
Solid fuel	125	150	500	160

<sup>1</sup> Applicable to existing boilers having a heat input capacity between 5.9 MJ/s and 50 MJ/s ( 20 x 10<sup>6</sup> and 170 x 10<sup>6</sup> Btu/h )



Table 2 - Fuel analytical data

Sample No.	A049-92	A050-92	A051-92	A052-92	A053-92	A054-92
Date - 1992	Jan.21	Jan.23	Jan.23	Jan.24	Jan.24	Jan.25
Oil type	No. 6	No. 6	No. 4	No. 4	No. 4	No.6 <sup>1</sup>
Boiler test	1 to 5	6 to 8	9 to 10	11to16	17to20	21to25

Ultimate analysis, wt %

Carbon (C)	86.20	86.30	86.30	86.20	86.40	86.40
Hydrogen (H <sub>2</sub> )	10.90	10.90	11.60	11.60	11.30	10.80
Nitrogen (N <sub>2</sub> )	0.46	0.46	0.33	0.33	0.35	0.41
Sulphur (S)	1.97	1.95	1.46	1.41	1.45	1.82
Total	99.53	99.61	99.69	99.54	99.50	99.43

Higher heating value

MJ/kg	42.69	42.66	43.41	43.45	43.55	42.71
Btu/lb	18360	18350	18670	18690	18730	18370

Specific gravity (relative to water )

	0.990	0.988	0.952	0.951	0.952	0.980
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<sup>1</sup> This oil was somewhat diluted with No.4 oil because burner return lines were piped into the main storage tank as explained in the report. Prorating of either specific gravity or sulphur content indicates that this sample contains about 25% No. 4 oil.

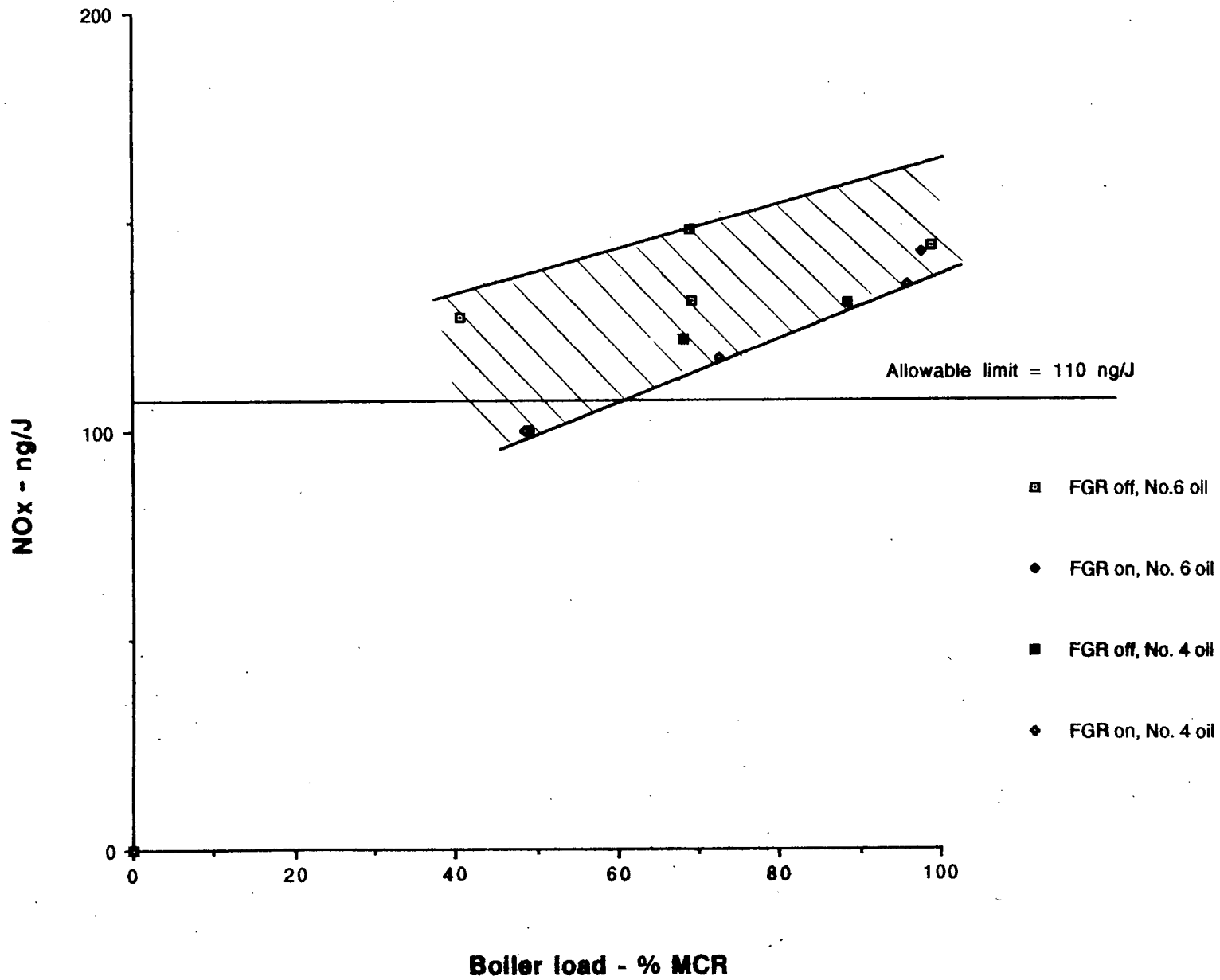


Fig. 1 - Boiler 5; NOx versus boiler load

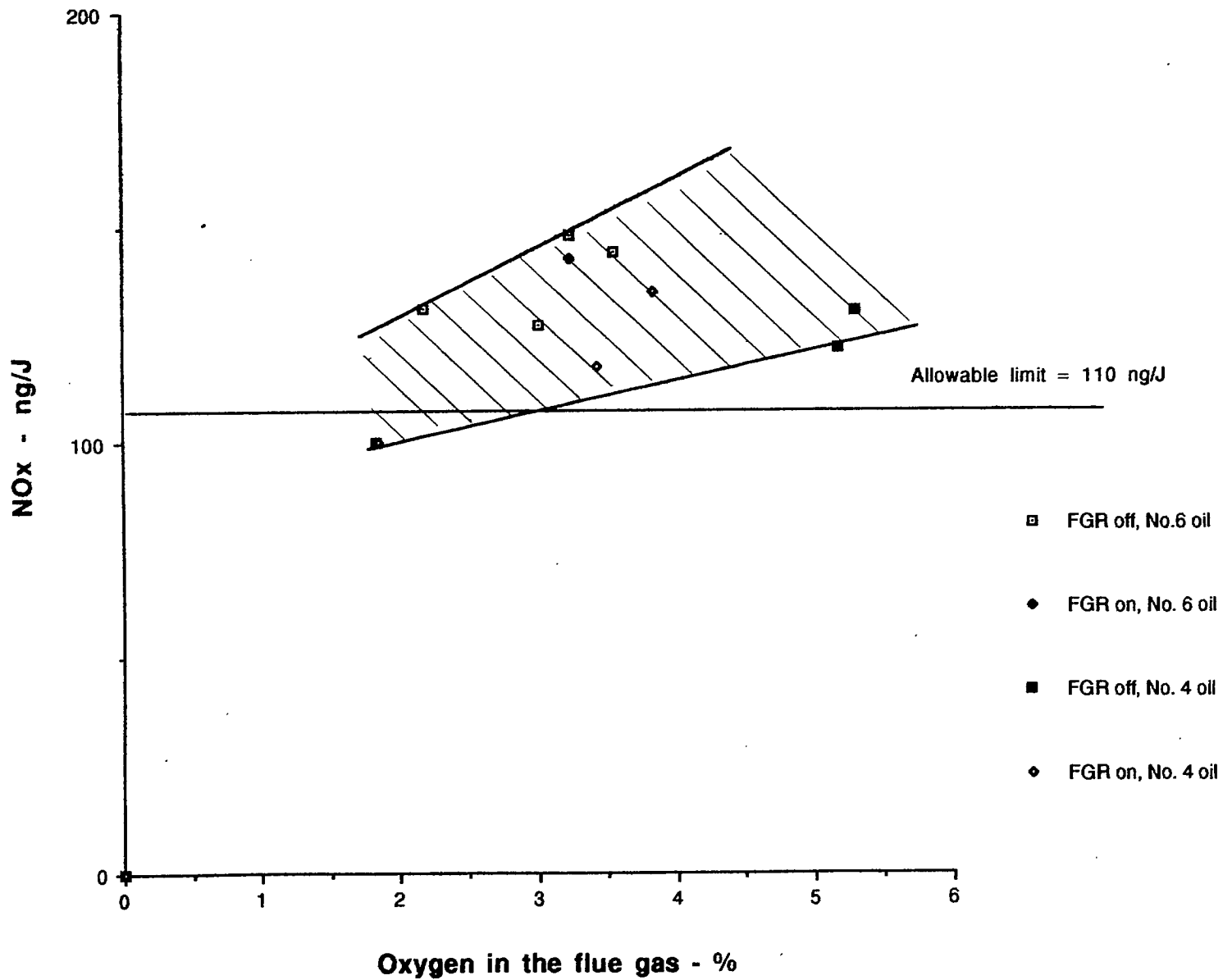


Fig. 2 - Boiler 5; NOx versus oxygen in flue gas

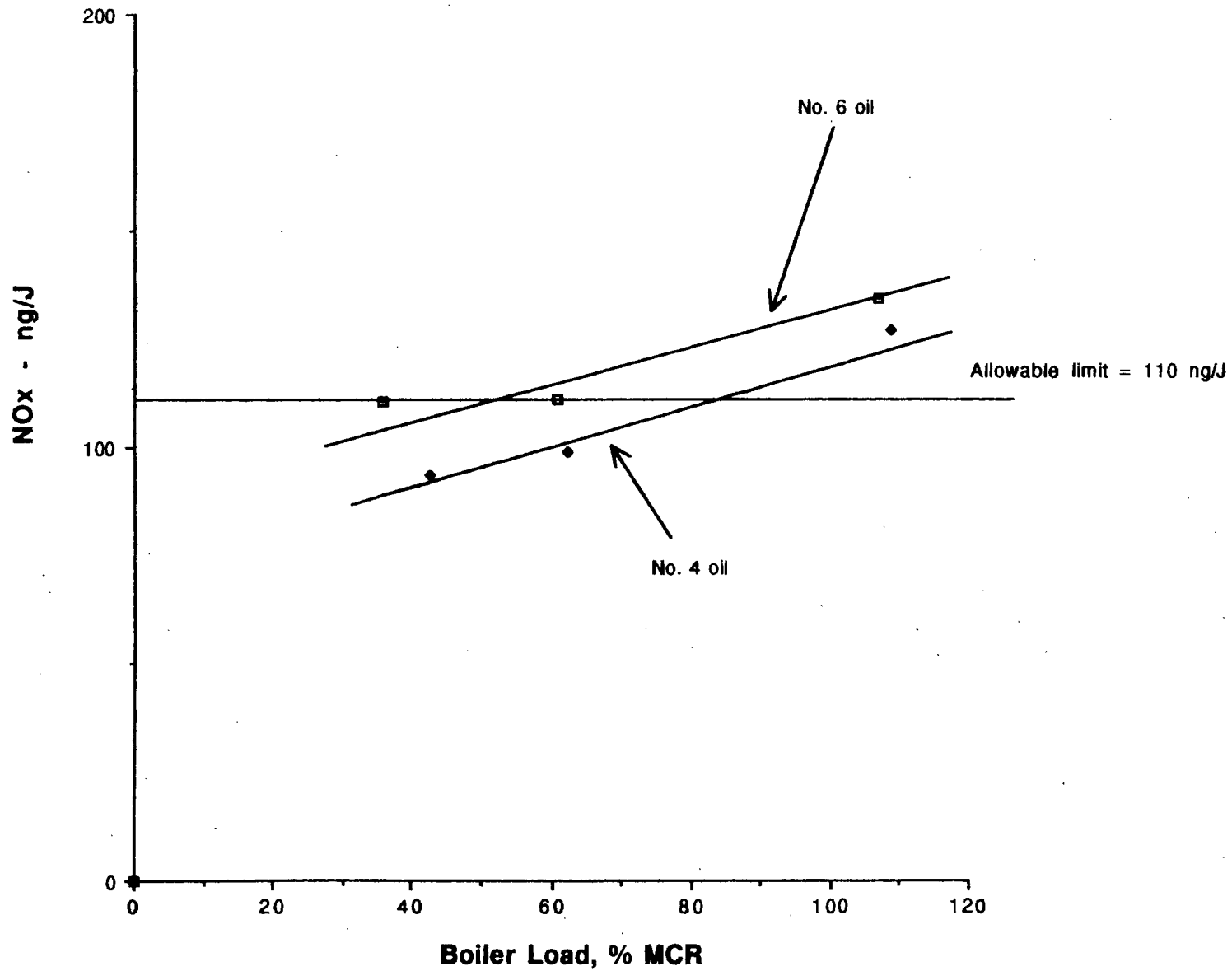


Fig. 3 - Boiler 4; NOx versus boiler load

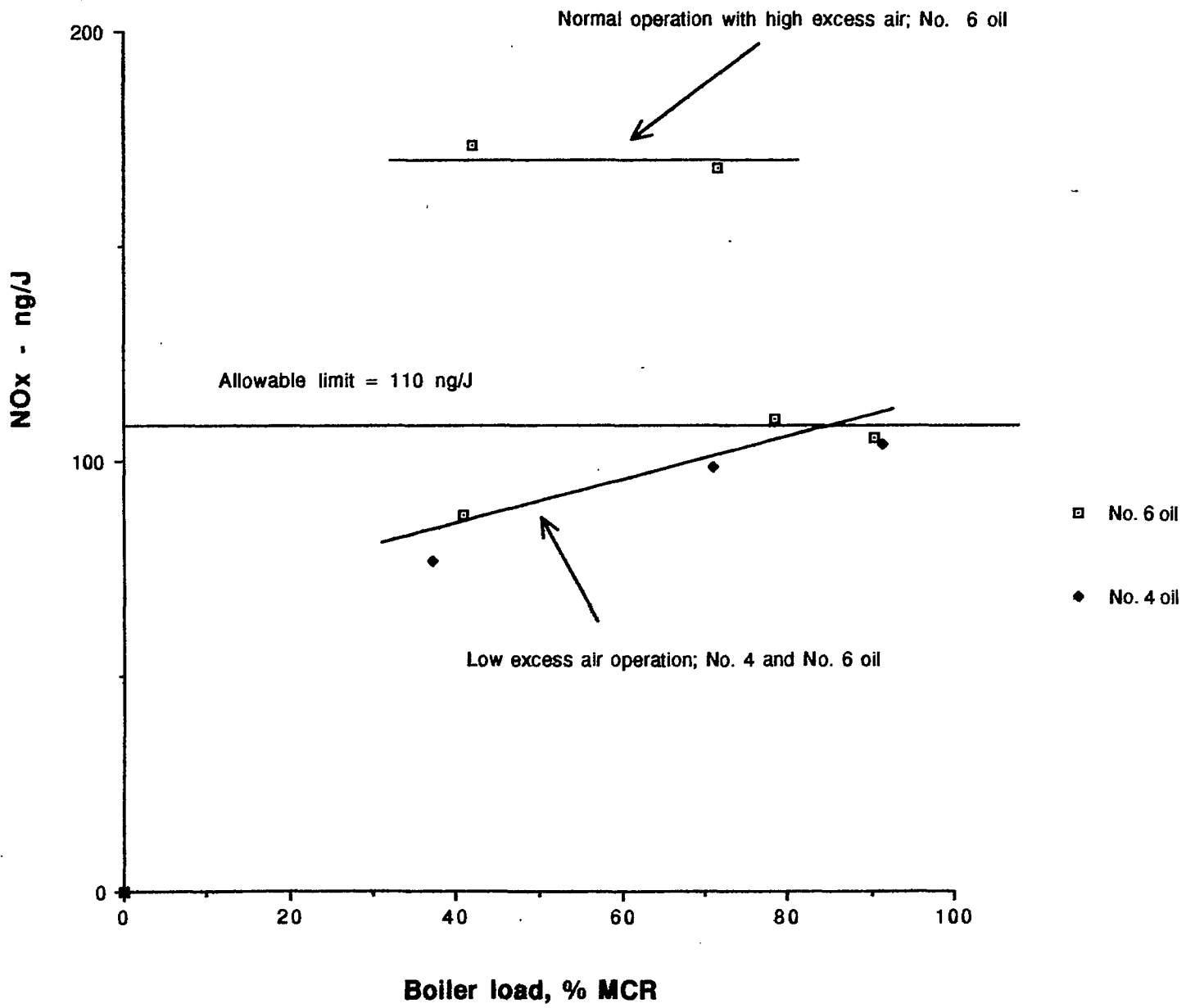


Fig. 4 - Boiler 3; NOx versus boiler load

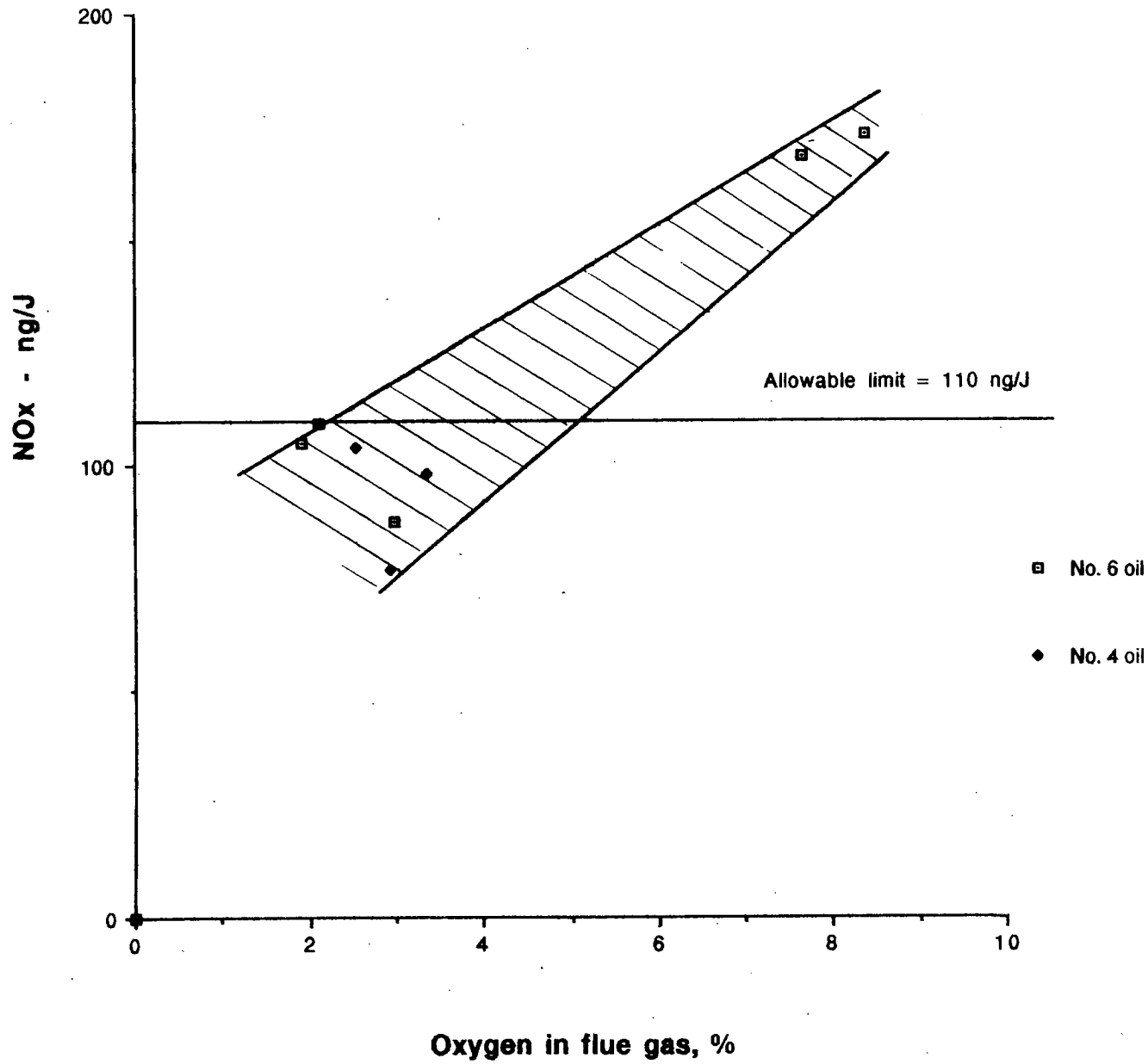
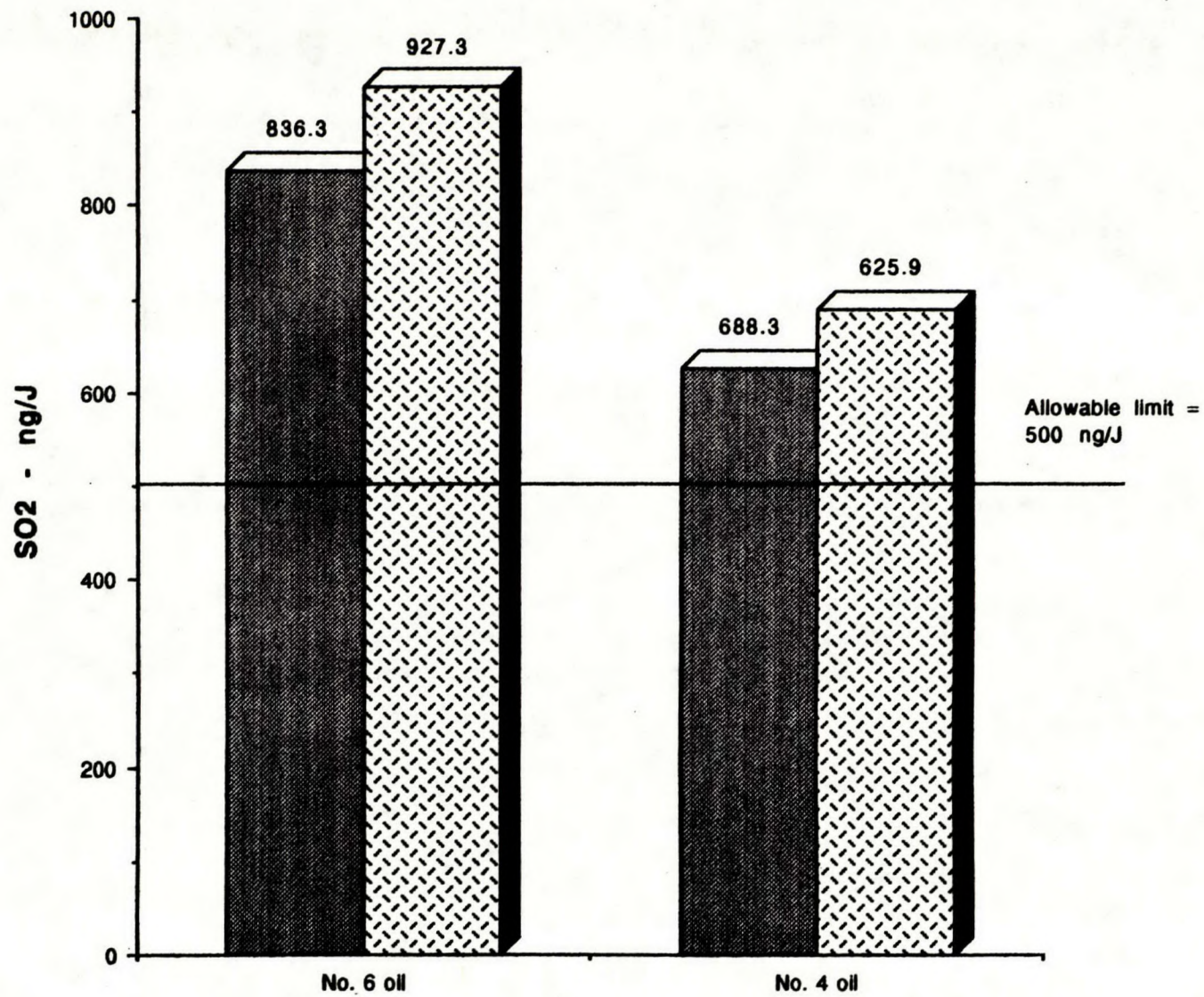


Fig. 5 - Boiler 3; NOx versus oxygen in flue gas



**Fig. 6; Range of SO2 measurements for Boilers 3, 4 and 5**

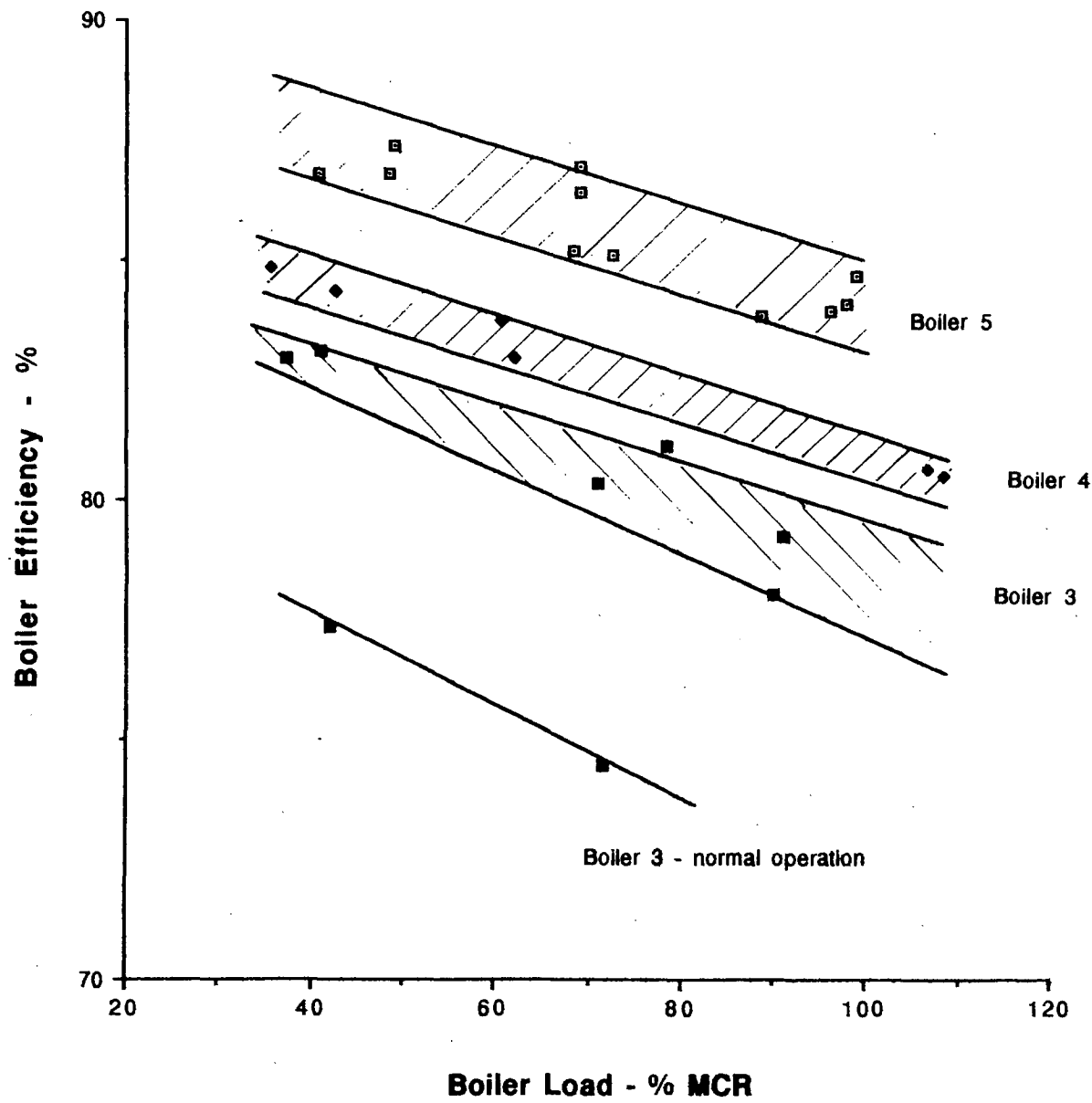


Fig. 7; Summary of boiler efficiency for all tests



## APPENDIX A. DETAILS OF TESTS

### INSTRUMENTATION

For flue gas analysis CCRL brought its mobile emissions monitoring laboratory to the plant. This consists of a well-proven, trailer-mounted package of analyzers for O<sub>2</sub>, CO<sub>2</sub>, CO, NO<sub>x</sub> and SO<sub>2</sub>, together with the necessary sample extraction system, in-duct filter, heated sample line, sample conditioning unit, and bottled calibration gases. Chromel-alumel thermocouples were installed to measure stack temperature and combustion air temperature. An automatic datalogging system records flue gas analyses and temperatures, normally every ten seconds, from which one minute average values are computed and stored. The computer continuously displays emissions both as measured and normalized to 3% O<sub>2</sub> in the flue gas. It also performs combustion and efficiency calculations based on an assumed fuel analysis.

Boilers 1, 2 and 3 are connected to the chimney by a common breeching. To facilitate access to the flue gas for analysis and temperature measurement, new pipe ports were welded into the breeching directly above each boiler flue. Unfortunately, the location permits the sample for Boiler 3 to be diluted by any air which infiltrates through Boilers 1 and 2. Flue gas analysis through the new port for Boiler 3 indicated the unreasonably high level of 13% O<sub>2</sub>, compared to a level of 9.5% for a sample taken from the connector between Boiler 3 and the breeching. Therefore all tests on Boiler 3 were conducted while sampling from the connector, rather than from the breeching.

### TEST CONDITIONS

#### General

Since the plant's only fuel oil tank is required for No. 6 oil, plans were made to supply No. 4 oil directly from a tanker truck, by means of a heated connection into the supply line from the storage tank to the plant. This meant that all operating boilers were firing the same fuel, even though only one was being tested at any given time. It also meant that when No. 4 oil was being supplied from the tanker truck, some portion of it was reaching the storage tank by means of the burner recirculation lines. This is because, in heavy-oil systems, it is desirable for a number of reasons to maintain a flow of heated oil through the burner piping, and indeed through the entire storage and delivery system. The burners draw from this the amount required to meet steam demand and the remainder is returned either to the pumpset inlet, or as

at the Dockyard plant, to the storage tank. The first few tests with No. 4 oil showed the rate of return to the storage tank to be at least twice the rate of use by the burners. It was subsequently reduced by throttling the valves on the burner return lines but could not be completely eliminated. This affected the quality of No. 6 oil used in subsequent tests, and analytical results showed that the No. 6 oil used in the tests on Boiler 3 actually contained about 25% No. 4 oil.

The test program proceeded as follows:

The morning of January 21 the CCRL mobile gas sampling laboratory was provided with an electric power connection, enabling the analytical equipment to be warmed up and calibrated. That afternoon and evening baseline tests with No. 6 fuel oil were conducted on Boiler 5.

The morning of January 22, while a tanker truck of No. 4 oil was being connected to the plant supply line, CCRL's NO<sub>x</sub> analyzer began to perform erratically and then failed altogether. Since NO<sub>x</sub> levels are a primary parameter, test work could not proceed. However, the weather was too cold to allow the oil to remain in the tanker, therefore it was pumped into the storage tank for No. 6 oil. A replacement analyzer arrived from Ottawa that evening and was installed.

The morning of January 23, while awaiting another delivery of No. 4 oil, baseline tests were run with No. 6 oil on Boiler 4. At noon the fuel supply was switched to No. 4 oil, whereupon full and 70% load tests were conducted on Boiler 4. This depleted the supply of No. 4 oil, and brought to light the recirculation situation already described. Another delivery of No. 4 oil was not possible that day.

On January 24, with a fresh supply of No. 4 oil, a low load test on Boiler 4 was completed. Instrumentation was then moved to Boiler 5 and it was tested over the load range with No. 4 oil, both with and without FGR. That evening the instrumentation was moved to Boiler 3 and it was tested at three loads with No. 4 oil, of which another tanker load had been delivered during the afternoon.

On the morning of January 25, baseline tests were conducted on Boiler 3 using No. 6 oil from the storage tank, which by this time contained substantial quantities of No. 4 oil. Tests were conducted both under manual control, with excess air adjusted to minimize NO<sub>x</sub>, and under automatic control, in which case the excess air was much higher and NO<sub>x</sub> emissions approximately doubled. This completed the test program.

The following sections describe the conditions for each test, grouped by boiler and fuel. Since the major objective of the test program was to establish emission levels, a given set of conditions was only maintained long enough for emissions to stabilize. A typical steady state test was 30 to 60 min. Experiments showed that the lag time through the gas sampling train was less than one minute.

### **Boiler 5**

Except where noted, tests were conducted with the boiler under manual control, and the excess air reduced to the threshold of high CO or visible smoke. Inadequate sight ports limited the observation of furnace conditions. From the front of the boiler only the flame front at the burner throat can be seen. Viewed from the rear of the boiler, only parts of the rear wall and right sidewall of the furnace were visible. Data from the tests on Boiler 5 are given in Tables A-1 and A-2.

#### **Test 1. No. 6 Oil, 70% MCR, FGR Off**

January 21, 1992; 1430-1530 h. The boiler had been switched from automatic to manual control without further adjustment, so the excess air level was that normally provided by automatic control. The inner register was 80% open to the right; the outer register was 50% open to the right. The flame front was clean and soft yellow. The diffusor was clean. The flame was licking the right side of the boiler (as viewed from the rear).

#### **Test 2. No. 6 Oil, 70% MCR, FGR Off**

January 21, 1992; 1550-1620 h. Conditions were the same as for Test 1; except that excess O<sub>2</sub> was reduced from about 3.2% to about 2.2%, the threshold of high CO levels. The flame front was somewhat darker but other conditions were unchanged.

#### **Test 3. No. 6 Oil, 100% MCR, FGR Off**

January 21, 1992; 1750-1820 h. As load was increased from the conditions of Test 2, difficulty was experienced with smoke and high CO. The level of excess air was increased to about 3.5%. Experimentation with the burner register led to the following settings, which increased swirl: inner register was 50% open to the right; outer register was 40% open to the right. This produced a soft, clean orange-yellow flame front, strongly swirled, with some flame behind the diffusor. Impingement on the right sidewall was minor, and

the stack showed a faint haze. The CO level was about 200 ppm.

**Test 4. No. 6 Oil, 100% MCR, FGR On**

January 21, 1992; 1835-1905 h. Compared with Test 3, FGR reduced O<sub>2</sub> slightly, to about 3.2%, but doubled the average CO to about 400 ppm. The flame front appeared about the same except that there was no flame behind the diffusor. In the furnace, there was still some impingement on the right wall and more sparklers were observed than in Test 3.

**Test 5. No. 6 Oil, 40% MCR, FGR Off**

January 21, 1992; 1940-2020 h. Burner register settings were unchanged from Tests 3 and 4. It was possible to reduce excess air to 3% O<sub>2</sub>, and CO levels were low, about 30 ppm. The flame front was bright, clean and soft yellow. Viewed from the rear, the flame was clean but impinged substantially on the right sidewall.

**Test 12. No. 4 Oil, 70% MCR, FGR Off**

January 24, 1992; 1155-1225 h. Burner register settings were unchanged from Test 3. A high excess air level, about 5% O<sub>2</sub>, was required to avoid excessive CO. Viewed from the rear, the flame seemed clean but was washing along the right wall. Smoke density at the stack was estimated at about 5%.

**Test 13. No. 4 Oil, 70% MCR, FGR On**

January 24, 1992; 1305-1320 h. The more intense mixing provided by the FGR system made it possible to reduce excess air to 3% O<sub>2</sub> while maintaining a clear stack and avoiding excessive CO. Viewed from the rear of the furnace, the flame seemed cleaner than in Test 12, but was still washing along the right wall.

**Test 14. No. 4 Oil, 50% MCR, FGR On**

January 24, 1992; 1400-1440 h. At this load it was possible to reduce excess air to less than 2% O<sub>2</sub>. The flame was clean and shorter than before; just brushing the right wall.

**Test 15. No. 4 Oil, 50% MCR, FGR Off**

January 24, 1992; 1515-155- h. Without the FGR it was possible to achieve the same low excess air level as in Test 14, with about the same level of CO. Furnace conditions were also about the same.

**Test 16. No. 4 Oil, 95% MCR, FGR On**

January 24, 1992; 1710-1740 h. To reduce visible smoke to about 5 to 10% opacity, it was necessary to increase excess air to nearly 4% O<sub>2</sub>. The flame front was clean and soft orange-yellow but the furnace was full of flame. Oil was impinging on, and burning from the right wall of the furnace, which doubtless was the main source of the smoke.

**Test 17. No. 4 Oil, 95% MCR, FGR Off**

January 24, 1992; 1800-1830 h. When the FGR was turned off, excess air had to be further increased, to about 5.3% O<sub>2</sub>, to avoid smoke and excessive CO. The flame front was clean, with some flame behind the diffusor. Viewed from the rear the flame was shorter and only occasionally reached the furnace wall, but oil was still impinging on the right wall of the furnace and burning there.

**Boiler 4**

As with Boiler 5, tests were conducted under manual control, reducing excess air to the threshold of smoke and CO, the condition which usually minimized NO<sub>x</sub> formation. The location of sight ports made it possible to observe the flame front at the burner and both sidewalls of the furnace. In the subsequent descriptions the left and right furnace walls are described as viewed from the rear of the boiler, where the sight ports are located. For all tests, the burner register was set at one notch toward open from the midpoint. The data from these tests are recorded in Table A-3.

**Test 6. No. 6 Oil, 35% MCR**

January 23, 1992; 0915-0945 h. At 2.3% O<sub>2</sub> in the flue gas the flame was still short and clean, although there were large quantities of sparklers. Some impingement of oil on the left wall of the furnace resulted in an area of coke deposit.

**Test 7. No. 6 Oil, 60% MCR**

January 23, 1992; 1030-1100 h. As load was increased, unsuccessful attempts were made to reduce  $\text{NO}_x$  emissions by adjusting burner position. It was possible to reduce excess air slightly, while maintaining a clean stack. The flame was washing along both sidewalls of the furnace and there was a substantial deposit of coke, about 3 to 5 cm thick, on the left wall.

**Test 8. No. 6 Oil, 105% MCR**

January 23, 1992; 1135-1205 h. Surprisingly, flame impingement was reduced compared with the lower load condition of Test 7. The tubes on the right sidewall were visible and clean; those on the left were intermittently visible with perhaps a 1 m<sup>2</sup> area of coke deposits. Excess air and CO levels were about the same as in Test 7.

**Test 9. No. 4 Oil, 110% MCR**

January 23, 1992; 1330-1400 h. At a somewhat reduced excess air level (1.9%  $\text{O}_2$  compared with 2.0% for Test 8) the flame was bright and short. It occasionally licked the left wall but was clear of the right wall by 60 cm. The stack was clean but CO levels were high, more than 300 ppm.

**Test 10. No. 4 Oil, 60% MCR**

January 23, 1992; 1500-1530 h. Excess air was increased slightly to 2.3%  $\text{O}_2$  and CO dropped to modest levels.  $\text{NO}_x$  levels were substantially lower than in Test 9. The flame was bright and clear of the furnace walls. The coke deposit evident in earlier tests had burned or fallen off.

**Test 11. No. 4 Oil, 40% MCR**

January 24, 1992; 1030-1105 h. At about 2.1%  $\text{O}_2$  in the flue gas, the flame was large, washing both sidewalls in the front half of the furnace. The flame tips were somewhat smoky, although the stack was clear and CO levels were modest.

**Boiler 3**

Under manual control, with excess air reduced to the threshold of smoke, tests were run at three different loads on each fuel. Then, while firing No. 6 oil, tests 24 and 25 were carried out at the excess level provided by the

automatic controls. This demonstrated that for this boiler  $\text{NO}_x$  emissions are very sensitive to burner adjustment and excess air levels. This boiler has four large inspection ports which provide excellent views of the flame and furnace. The measured and calculated data pertaining to tests on Boiler 3 are given in Tables A-4 and A-5.

**Test 18. No. 4 Oil, 35% MCR**

January 24, 1992; 2025-2110 h. At about 3%  $\text{O}_2$  in the flue gas, the flame was an intensely bright yellow at the throat but long orange tails just brushed the rear wall. It held somewhat to the right of the furnace, as viewed from the front of the boiler. CO levels were moderate.

**Test 19. No. 4 Oil, 70% MCR**

January 24, 1992; 2140-2220 h. Although excess air had been increased somewhat, the rear of the furnace was full of loose, unshapen flame that appeared orange and smoky. CO levels were nonetheless low, about 50 ppm.

**Test 20. No. 4 Oil, 90% MCR**

January 24, 1992; 2235-2305 h. It was possible to reduce excess air to 2.5%  $\text{O}_2$  compared with about 3.4% for Test 19. Flame conditions were about the same; very bright and well-shaped at the throat, darker and shapeless in the rear of the furnace. From the front wall ports the rear furnace wall was not visible on the left side, and only occasionally on the right.

**Test 21. No. 6 Oil, 90% MCR**

January 25, 1992; 0920-0950 h. Excess air was reduced to 1.9%  $\text{O}_2$  while maintaining a clear stack and low CO emissions. The flame at the burner throat was sharply defined and intensely bright, while the furnace was full of transparent orange gas that bounced off the rear wall and licked forward along the sidewalls.

**Test 22. No. 6 Oil, 75% MCR**

January 25, 1992; 1025-1055 h. Excess air level was slightly higher than in Test 21; other conditions were essentially unchanged. The flame seemed clearer than the equivalent condition with No. 4 oil. The normalized  $\text{NO}_x$  level was about 200 ppm.

**Test 23. No. 6 Oil, 40% MCR**

January 25, 1992; 1115-1155 h. To reduce CO to the 200 ppm range, it was necessary to increase excess air to about 3% O<sub>2</sub> in the flue gas. The flame was well defined, very bright and much smaller than in the earlier tests, with the tails barely visible from the ports in the front wall. There were, however, clouds of burning gas swirling to the sides of the furnace at the rear. The plume from the stack had an opacity estimated at 5 to 10%. The normalized NO<sub>x</sub> level was about 160 ppm.

**Test 24. No. 6 Oil, 40% MCR, Automatic Control**

January 25, 1992; 1205-1215 h. Under automatic control O<sub>2</sub> in the flue gas was about 8.4%, while CO was about 30 ppm. The flame was very short and bright with some sparklers. The normalized NO<sub>x</sub> level was about 313 ppm, nearly double that of Test 23.

**Test 25. No. 6 Oil, 70% MCR, Automatic Control**

January 25, 1992; 1225-1235 h. As load was increased O<sub>2</sub> in the flue gas dropped only slightly to 7.6%. Levels of CO remained about the same. The flame was yellow to white at the burner throat, with long, clear tips having some sparklers striking the rear corners of the furnace. The normalized NO<sub>x</sub> level was 303 ppm, about 50% higher than in Test 22.



Table A-1. - Measured and calculated data for Boiler 5 with No. 6 oil

Test	1	2	3	4	5
<u>Output data</u>					
Load, % MCR	69.1	69.3	98.9	97.8	40.8
Steam output, lb/h <sup>1</sup>	41440	41600	59350	58660	24500
Steam pressure, psig	137	137	141	141	133
<u>Burner data</u>					
Fuel oil pressure, psig	43	43	63	63	30
Fuel oil temperature, °C	97	97	97	97	95
Atom. steam press., psig	50	50	66	66	40
<u>Boiler gas-side data</u>					
Flue gas recirculation fan	off	off	off	on	off
Windbox pressure, mm H <sub>2</sub> O	60	50	160	180	15
Furnace pressure, mm H <sub>2</sub> O	30	25	90	105	5
Economizer outlet press. mm H <sub>2</sub> O	- 5	- 5	- 4	- 5	- 7
Stack temperature, °C	185.2	182.3	227.5	244.3	161.9
Combustion air temp., °C	25.2	25.9	23.8	23.5	22.4
<u>Economizer data</u>					
Feedwater temp. in, °C	112	112	113	113	113
Feedwater pressure in, psig	135	135	146	142	129
Feedwater temp out, °C	140	138	153	156	128
Feedwater pressure out, psig	132	131	142	139	127
Flue gas temp. in, °C	352	348	400+	400+	264
Flue gas temp. out, °C	164	164	204	216	148

A-9

<sup>1</sup> Corrected to orifice calibration pressure of 145 psig

cont'd

Table A-1 (cont'd) - Measured and calculated data for Boiler 5 with No. 6 oil

Test	1	2	3	4	5
Load, % MCR	69.1	69.3	98.9	97.8	40.8
<u>Flue gas analysis</u>					
Oxygen, %	3.23	2.18	3.54	3.23	3.01
Carbon dioxide, %	13.48	14.24	13.19	13.44	13.67
C O , ppmv at 3% O <sub>2</sub>	31	109	218	402	27
C O , ng/J	10.4	36.7	73.4	135.4	9.1
N O <sub>x</sub> , ppmv at 3% O <sub>2</sub>	268	237	261	258	230
N O <sub>x</sub> , ng/J	148.2	131.1	144.4	142.7	127.2
S O <sub>2</sub> , ppmv at 3% O <sub>2</sub>	1200	1200	1201	1193	1171
S O <sub>2</sub> , ng/J	925.0	925.0	925.8	919.6	902.7
<u>Boiler efficiency</u>					
Excess air, % <sup>2</sup>	16.92	10.79	18.95	16.81	15.60
Dry flue gas, lb/lb fuel burned <sup>3</sup>	16.26	15.42	16.57	16.25	16.04
Dry flue gas loss, % <sup>3</sup>	6.12	5.63	7.94	8.44	5.26
Hydrogen loss, % <sup>3</sup>	6.31	6.29	6.51	6.59	6.23
Radiation and convection loss, % <sup>4</sup>	0.92	0.91	0.63	0.64	1.48
Unmeasured losses, % <sup>5</sup>	0.25	0.25	0.25	0.25	0.25
Total losses, %	13.60	13.08	15.33	15.92	13.22
Efficiency, %	86.40	86.92	84.67	84.08	86.78

<sup>2</sup> Calculated from O<sub>2</sub> analysis

<sup>3</sup> Calculated according to ASME test code PTC 4.1

<sup>4</sup> From Fig. A-1

<sup>5</sup> An assumed value to cover minor losses

Table A-2 - Measured and calculated data for Boiler 5 with No. 4 oil

Test	12	13	14	15	16	17
<u>Output data</u>						
Load, % MCR	68.3	72.6	48.6	49.1	98.1	88.7
Steam output, lb/h <sup>1</sup>	40980	43580	29170	29470	57670	53220
Steam pressure, psig	140	140	136	136	127	138
<u>Burner data</u>						
Fuel oil pressure, psig	32	32	26	26	43	41
Fuel oil temperature, °C	66	64	70	72	71	70
Atom. steam press., psig	43	42	38	38	49	49
<u>Boiler controllers and gas-side data</u>						
Flue gas recirculation fan	off	on	on	off	on	off
Windbox pressure, mm H <sub>2</sub> O	90	110	35	25	190	170
Furnace pressure, mm H <sub>2</sub> O	45	60	20	10	110	90
Economizer outlet pressure, mm H <sub>2</sub> O	- 5	- 5	- 5	- 5	- 3	- 3
Stack temperature, °C	198.1	215.3	177.1	164.8	242.4	229.9
Combustion air temp., °C	31.9	32.9	32.7	33.1	33.0	32.5
<u>Economizer data</u>						
Feedwater temp. in, °C	110	110	110	110	110	110
Feedwater pressure in, psig	137	139	132	133	130	140
Feedwater temp. out, °C	143	147	135	128	154	152
Feedwater pressure out, psig	134	136	130	131	128	137
Flue gas temp. in, °C	368	388	304	280	400+	400+
Flue gas temp. out, °C	180	188	158	145	216	209

<sup>1</sup>Corrected to orifice calibration pressure of 145 psig

cont'd

Table A-2 (cont'd) - Measured and calculated data for Boiler 5 with No. 4 oil

Test	12	13	14	15	16	17
Load, % MCR	68.3	72.6	48.6	49.1	98.1	88.7
<u>Flue gas analysis</u>						
Oxygen, %	5.16	3.43	1.85	1.83	3.83	5.29
Carbon dioxide, %	11.56	12.92	14.15	14.19	12.57	11.38
C O , ppmv at 3% O <sub>2</sub>	77	59	90	109	99	135
C O , ng/J	25.9	19.9	30.3	36.7	33.3	45.5
N O <sub>x</sub> , ppmv at 3% O <sub>2</sub>	220	212	181	181	244	236
N O <sub>x</sub> , ng/J	121.7	117.3	100.1	100.1	134.9	130.5
S O <sub>2</sub> , ppmv at 3% O <sub>2</sub>	833	827	824	850	854	856
S O <sub>2</sub> , ng/J	642.1	637.5	635.2	655.2	658.3	659.8
<u>Boiler efficiency</u>						
Excess air, % <sup>2</sup>	30.10	18.10	8.95	8.86	20.60	31.00
Dry flue gas, lb/lb fuel burned <sup>3</sup>	18.77	16.88	15.47	15.43	17.33	19.08
Dry flue gas loss, % <sup>3</sup>	7.21	7.11	5.16	4.70	8.37	8.67
Hydrogen loss, % <sup>3</sup>	6.59	6.66	6.48	6.42	6.78	6.54
Radiation and convection loss, % <sup>4</sup>	0.93	0.87	1.29	1.27	0.68	0.71
Unmeasured losses % <sup>5</sup>	0.25	0.25	0.25	0.25	0.25	0.25
Total loss, %	14.98	14.89	13.18	12.64	16.08	16.17
Efficiency, %	85.02	85.11	86.82	87.36	83.92	83.83

<sup>2</sup> Calculated from O<sub>2</sub> analysis

<sup>3</sup> Calculated according to ASME test code PTC 4.1

<sup>4</sup> From Fig. A-1

<sup>5</sup> An assumed value to cover minor losses

Table A-3 - Measured and calculated data for Boiler 4 with No. 4 oil and No. 6 oil

Test	6	7	8	9	10	11
Fuel type	No.6	No. 6	No. 6	No. 4	No. 4	No. 4
<u>Output data</u>						
Load, % MCR	35.7	60.8	106.8	108.6	62.3	42.5
Steam output, lb/h <sup>1</sup>	21430	36480	64090	65150	37380	25510
Steam pressure, psig	134	139	139	146	138	137
Feedwater temp., °C	107	107	107	107	107	107
<u>Burner data</u>						
Fuel oil pressure, psig	16	32	81	84	30	15
Fuel oil temperature, °C	114	117	116	68	69	68
Atom. steam press., psig	26	40	83	86	40	22
<u>Boiler controllers and gas-side data</u>						
Fuel controller, %	13	23	40	40	23	16
Air controller, %	25	46	84	84	47	32
Windbox pressure, in. H <sub>2</sub> O	0.7	3.0	8.5	8.1	2.5	1.0
Furnace pressure, in. H <sub>2</sub> O	0.1	0.8	3.5	3.4	1.0	0.2
Stack temperature, °C	210.6	260.2	343.4	346.6	269.9	232.0
Combustion air temp., °C	24.9	29.7	26.9	27.8	28.6	32.5

<sup>1</sup>Corrected to orifice calibration pressure of 145 psig

cont'd

Table A-3 (cont'd) - Measured and calculated data for Boiler 4 with No. 4 oil and No. 6 oil

Test	6	7	8	9	10	11
Fuel type	No. 6	No. 6	No. 6	No. 4	No. 4	No. 4
Load, % MCR	35.7	60.8	106.8	108.6	62.3	42.5
<u>Flue gas analysis</u>						
Oxygen, %	2.34	2.11	2.04	1.87	2.29	2.14
Carbon dioxide, %	14.12	14.27	14.26	14.29	13.91	14.01
C O , ppmv at 3% O <sub>2</sub>	43	60	102	307	51	47
C O , ng/J	14.5	20.2	34.3	103.4	17.2	15.8
N O <sub>x</sub> , ppmv at 3% O <sub>2</sub>	200	201	243	230	179	169
N O <sub>x</sub> , ng/J	110.6	111.2	134.4	127.2	99.0	93.5
S O <sub>2</sub> , ppmv at 3% O <sub>2</sub>	1177	1198	1203	839	812	848
S O <sub>2</sub> , ng/J	907.2	923.5	927.3	646.7	625.9	653.7
<u>Boiler efficiency</u>						
Excess air, % <sup>2</sup>	11.69	10.41	10.00	9.07	11.34	10.56
Dry flue gas, lb/lb fuel burned <sup>3</sup>	15.58	15.40	15.41	15.38	15.75	15.62
Dry flue gas loss, % <sup>3</sup>	6.81	8.36	11.50	11.35	8.79	7.20
Hydrogen loss, % <sup>3</sup>	6.43	6.61	7.02	7.35	6.96	6.74
Radiation and convection loss, % <sup>4</sup>	1.67	1.05	0.59	0.58	1.02	1.44
Unmeasured losses, % <sup>5</sup>	0.25	0.25	0.25	0.25	0.25	0.25
Total losses, %	15.16	16.27	19.36	19.53	17.02	15.63
Efficiency, %	84.84	83.73	80.64	80.47	82.98	84.37

<sup>2</sup> Calculated from O<sub>2</sub> analysis

<sup>3</sup> Calculated according to ASME test code PTC 4.1

<sup>4</sup> From Fig. A-1

<sup>5</sup> An assumed value to cover minor losses

Table A-4 - Measured and calculated data for Boiler 3 with No. 4 oil

Test	18	19	20
<u>Output data</u>			
Load, % MCR	37.3	71.0	91.2
Steam output, lb/h <sup>1</sup>	11200	21300	27350
Steam pressure, psig	136	139	141
<u>Burner data</u>			
Fuel oil press., psig	25	56	77
Fuel oil temp., °C	75	77	77
Atomizing steam press., psig	45	70	89
<u>Boiler controllers and gas-side data</u>			
Flue flow controller, lb/h	800	1630	2140
Air controller, %	25	55	74
Windbox press., in. H <sub>2</sub> O	0.0	0.7	1.6
Furnace press., in. H <sub>2</sub> O	-0.4	-0.4	-0.3
Stack temperature, °C	226.7	312.7	359.3
Combustion air temp., °C	24.1	26.7	27.9
<u>Flue gas analysis</u>			
Oxygen, %	2.94	3.36	2.53
Carbon dioxide, %	13.33	13.01	13.64
C O, ppmv at 3% O <sub>2</sub>	74	49	57
C O, ng/J	24.9	16.5	19.2
N O <sub>x</sub> , ppmv at 3% O <sub>2</sub>	139	178	188
N O <sub>x</sub> , ng/J	76.9	98.5	104.0
S O <sub>2</sub> , ppmv at 3% O <sub>2</sub>	865	882	893
S O <sub>2</sub> , ng/J	666.7	679.8	688.3
<u>Boiler efficiency</u>			
Excess air, % <sup>2</sup>	15.12	17.62	12.69
Dry flue gas, lb/lb fuel burned <sup>3</sup>	16.42	16.80	16.07
Dry flue gas loss, % <sup>3</sup>	7.66	11.06	12.26
Hydrogen loss, % <sup>3</sup>	6.61	6.99	7.20
Radiation and convection, % <sup>4</sup>	2.50	1.35	1.05
Unmeasured losses, % <sup>5</sup>	0.25	0.25	0.25
Total losses, %	17.02	19.65	20.76
Efficiency, %	82.98	80.35	79.24

1 Corrected to orifice calibration pressure of 145 psig

2 Calculated from O<sub>2</sub> analysis

3 Calculated according to ASME test procedure PTC 4.1

4 From Fig. A-2

5 An assumed value to cover minor losses

Table A-5 - Measured and calculated data for Boiler 3 with No. 6 oil

Test	21	22	23	24	25
<u>Output data</u>					
Load, % MCR	90.3	78.5	41.0	42.0	71.5
Steam output, lb/h <sup>1</sup>	27080	23550	12300	12600	21450
Steam pressure, psig	137	137	135	135	139
<u>Burner data</u>					
Fuel oil pressure, psig	110	66	29	32	65
Fuel oil temperature, °C	102	102	103	102	102
Atom. steam press., psig	110	82	51	52	80
<u>Boiler panel and gas-side data</u>					
Control mode, manual/auto	manual	manual	manual	auto	auto
Fuel flow controller, lb/h	2200 +	1630	780	870	1635
Air controller, %	88	54	23	42	78
Windbox pressure, in. H <sub>2</sub> O	2.5	0.6	0	0.2	1.8
Furnace pressure, in. H <sub>2</sub> O	-0.3	-0.4	-0.4	-0.4	-0.4
Stack temperature, °C	396.9	311.0	223.2	260.1	346.7
Combustion air temp., °C	23.5	19.6	16.5	13.6	18.7
<u>Flue gas analysis</u>					
Oxygen, %	1.90	2.10	2.99	8.37	7.64
Carbon dioxide, %	14.40	14.26	13.58	9.28	9.88
C O , ppmv at 3% O <sub>2</sub>	42	45	216	45	45
C O , ng/J	14.1	15.2	72.7	15.2	15.2
N O <sub>x</sub> , ppmv at 3% O <sub>2</sub>	190	198	158	313	304
N O <sub>x</sub> , ng/J	105.1	109.5	87.4	173.2	168.2
S O <sub>2</sub> , ppmv at 3% O <sub>2</sub>	1142	1103	1085	1087	1106
S O <sub>2</sub> , ng/J	880.2	850.2	836.3	837.9	852.5
<u>Boiler efficiency</u>					
Excess air, % <sup>2</sup>	9.28	10.37	15.44	61.25	52.80
Dry flue gas, lb/lb fuel burned <sup>3</sup>	15.30	15.42	16.15	23.30	21.93
Dry flue gas loss, % <sup>3</sup>	13.43	10.56	7.85	13.50	16.92
Hydrogen loss, % <sup>3</sup>	7.23	6.86	6.50	6.69	7.04
Radiation and convection loss, % <sup>4</sup>	1.07	1.20	2.28	2.22	1.32
Unmeasured loss, % <sup>5</sup>	0.25	0.25	0.25	0.25	0.25
Total losses, %	21.98	18.87	16.88	22.66	25.53
Efficiency, %	78.02	81.13	83.12	77.34	74.47

<sup>1</sup> Corrected to orifice calibration pressure of 145 psig

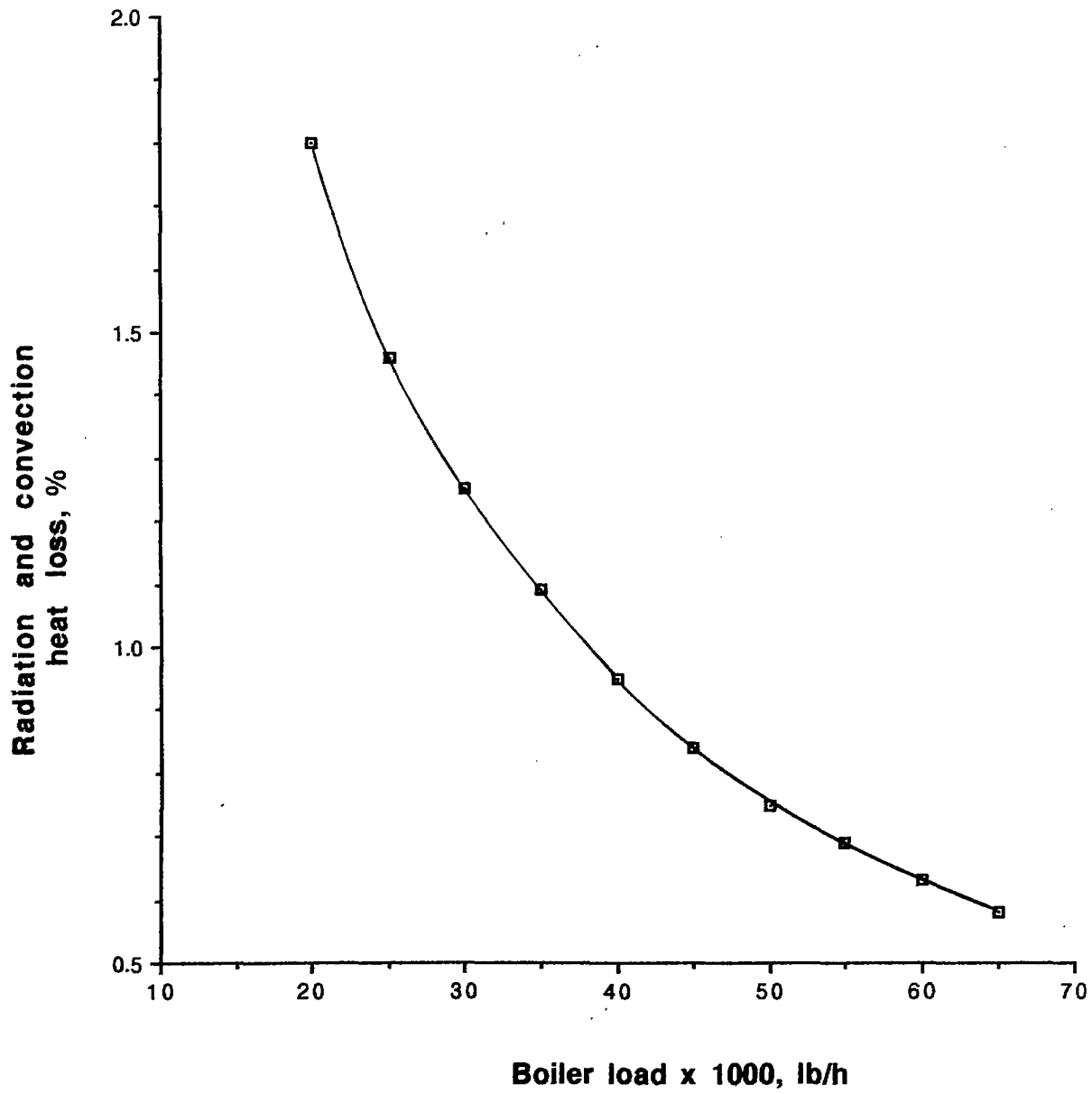
<sup>2</sup> Calculated from O<sub>2</sub> analysis

<sup>3</sup> Calibrated according to ASME test code PTC 4.1

<sup>4</sup> From Fig. A-2

<sup>5</sup> Assumed value to cover minor losses





**Fig. A-1; Radiation and convection heat loss for Boilers 4 and 5**

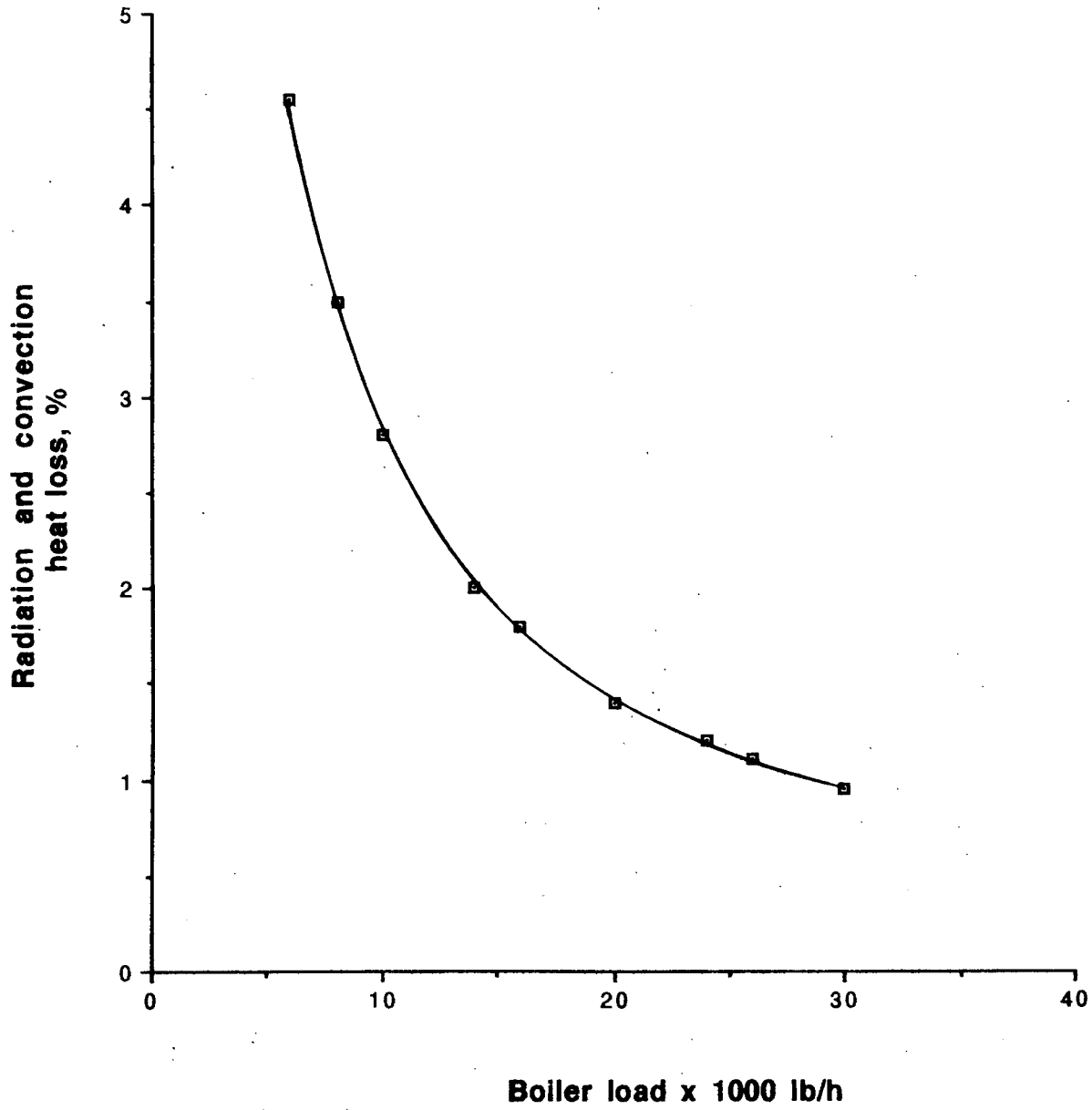
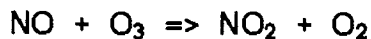


Fig. A-2; Radiation and convection heat loss for Boiler 3

## APPENDIX B. MECHANISMS OF NO<sub>x</sub> FORMATION AND DECOMPOSITION

### FUEL NO<sub>x</sub> AND THERMAL NO<sub>x</sub>

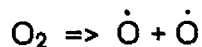
NO<sub>x</sub> in the products of combustion is primarily in the form of nitric oxide (NO). In the atmosphere it oxidizes fairly rapidly to nitrogen dioxide (NO<sub>2</sub>), probably by reaction with ozone, according to the equation:



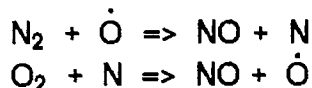
The source of nitrogen for NO may be either nitrogen-containing organic compounds in the fuel or nitrogen in the combustion air. In the former case, the product is called fuel NO<sub>x</sub>; in the latter case it is called thermal NO<sub>x</sub>.

It is difficult to prevent the formation of fuel NO<sub>x</sub>, for although the fuel may contain only small concentrations of the parent compounds, their breakdown during combustion commonly results in free atoms of nitrogen, which are very reactive and readily combine with oxygen to form NO. Methods for controlling fuel NO<sub>x</sub> consist of employing fuels that have a low organic nitrogen content (natural gas has virtually none), modifying the combustion process to encourage the NO<sub>x</sub> decomposition reactions which are discussed below, or flue gas scrubbing.

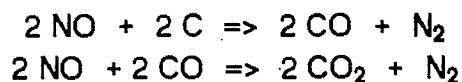
Thermal NO<sub>x</sub> forms by the reaction of nitrogen in the combustion air with atomic oxygen, produced by dissociation at high temperature in flames, as follows:



This nascent oxygen is very reactive and may combine according to the equations:



On the other hand, NO may be decomposed by reaction with CO or hot char according to the equations:



The major factors affecting these reactions are temperature, time and the relative concentrations of oxygen, carbon and carbon monoxide.

### EQUILIBRIUM CONCENTRATIONS OF THERMAL NO<sub>x</sub>

The strong effect of temperature on O<sub>2</sub> dissociation and NO formation is shown by the following equilibrium data for heated air.

<u>Temp. °C</u>	<u>NO, ppmv</u>	<u>O<sub>2</sub>, ppmv</u>
840	100	0
1170	1000	0
1560	5000	80

That is, given sufficient time at 840 °C, enough O<sub>2</sub> will dissociate into nascent oxygen and recombine with nitrogen to form 100 ppmv of NO. At 1560°C dissociation would be sufficient to form 5000 ppmv of NO plus a surplus of about 80 ppmv of nascent oxygen.

The effect of oxygen concentration on NO<sub>x</sub> formation is shown in Fig. B-1. Since methane contains no organic nitrogen, all the NO must be formed by the thermal mechanisms, and one would expect, under adiabatic conditions, that the highest NO concentration would correspond to stoichiometric combustion, which produces the highest flame temperature. However, NO concentration peaks in the range of 10 to 25 % excess air, and continues to exceed the stoichiometric level up to about 55% excess air.

The time required to reach equilibrium is temperature-dependent and substantial for both the formation and decomposition reactions, as shown in Table B-1.

Table B-1. Effect of temperature on formation and decomposition rate for nitric oxide.

<u>Temperature K*</u>	<u>Time for formation of half of equilibrium NO</u>	<u>Time for decomposition of half of pure NO</u>
1000	81 y	-
1500	30 h	3 m
1700	1 h	15 s
1900	2 m	1 s
2000	5 s	0.07 s
2300	0.2 s	0.005 s
2500	0.01 s	-
2900	0.0003 s	-

\* K = °C + 273

Equilibrium concentrations are seldom achieved in a boiler. The residence time from fuel and air entering the burner to the flue gas leaving the stack is typically a few seconds. During this time the mean temperature of the components rises from near ambient to flame temperature and drops back to stack temperature. From published data for a stoichiometric mixture of propane and air one can construct the hypothetical case shown in Fig. B-2. Assume that it takes 0.1 s from time of ignition for the mixture to reach the maximum temperature of 1950 °C, and that in the following 2 s the gases then cool at a uniform rate to 840°C. Then at time = 0.1 s, when temperature is 1950°C, the equilibrium concentration of NO is about 2000 ppmv, but at that temperature about 1 s is required to form half that amount, so perhaps only about 20 ppmv form before the temperature starts to drop. The equilibrium concentration then declines with the temperature. NO continues to form because the actual concentration is still below the equilibrium concentration, but the rate decreases rapidly. As temperature continues to decline a crossover point is reached, perhaps at 0.7 s, when equilibrium is momentarily achieved because the equilibrium concentration drops to the actual concentration, which by then is perhaps 340 ppmv. Subsequently no additional NO forms. In fact, as the equilibrium concentration drops below the actual concentration, NO begins to decompose, but not rapidly enough to maintain equilibrium. Thus, at time = 1.1 s the equilibrium concentration is about 80 ppmv but the actual concentration may be 225 ppmv. As gas temperature continues to drop the equilibrium concentration approaches zero but the rate of decomposition becomes very slow, and the flue gas leaves the system with NO concentration essentially frozen at a level well above equilibrium for the stack temperature.

### MATHEMATICAL MODELS FOR PREDICTING NO FORMATION

There now exists a very large body of fundamental studies and actual NO measurements on pilot-scale and industrial combustion equipment. This has been used as the basis for developing a number of mathematical models which attempt to predict NO emissions and how they can be affected by varying combustion conditions. On the whole, the models are quite reliable for small combustion systems, but less so for large industrial and utility systems.

A simple model which provides some useful insights was postulated by T.D. Brown in 1973. The fuel is No. 2 furnace oil, expressions for reaction rate are taken from the literature, and a simple time-temperature profile is assumed in which the gas temperature rises linearly from an air preheat temperature of 200°C to the adiabatic flame temperature in 0.02 s, then falls linearly to

1425°C in an additional 0.48 s. Figure B-3 shows this model's predictions of NO formation for a nitrogen-free fuel fired at different levels of excess air, under two scenarios of gas cooling. The slow cooling scenario is the time-temperature profile given above. In the fast cooling scenario, the gas cools from the adiabatic flame temperature to 1425°C in 0.24 s.

Figure B-3 shows two important predictions of Brown's model. First, excess air level has a strong effect. At excess air levels of 5 to 7 %, NO concentrations should peak and be about twice as high as when excess air levels are about 15%. Second, NO emissions can be substantially reduced by rapid cooling of the combustion gases. Additional predictions of the model are:

- virtually no thermal NO is formed if maximum flame temperature does not exceed 1625°C,
- yield of NO increases sharply as maximum flame temperature increases above 1825°C,
- below 1725°C, reducing maximum flame temperature is not an effective method of reducing fuel NO.

### **TECHNIQUES FOR NO REDUCTION**

Models such as Brown's, reinforced by practical experience, identify two main ways to reduce thermal NO. One is to manipulate the excess air level; the other is to implement measures which reduce flame temperature and increase the rate of gas cooling.

Figure B-3 predicts that NO concentrations peak at excess air levels of 5 to 7 %, at least when No. 2 furnace oil is the fuel. This is supported by experimental data from small combustion systems such as residential furnaces or laboratory burners. However, for industrial-scale equipment the results are somewhat different, for reasons which will be discussed later. In heating plant boilers, for example, the peak in NO formation is likely to occur in the range of 20 to 50 % excess air and is likely to be less pronounced than shown in Fig. B-3. NO may be substantially reduced by operating in the range of 5 to 10 % excess air, provided that this can be accomplished without excessive emissions of smoke and CO.

Several techniques are available for reducing flame temperature. A popular, straightforward approach is flue gas recirculation (FGR), in which relatively cool flue gas from the boiler exit is injected into the burner at the rate of

about 15 % of combustion air requirements. This not only reduces the peak flame temperature by dilution, but slows down the mixing of fuel and oxygen, so the flame envelope is larger and loses more heat to its surroundings. Another technique is to employ a small furnace with watercooled walls, thus providing a high level of heat absorption, which quickly cools the gases to temperatures which do not favour NO formation. An alternative approach yielding the same effect is to adjust the atomization and aerodynamics of the burner to provide relatively slow mixing and therefore a long flame.

Air staging and fuel staging are additional techniques for reducing flame temperature which are most commonly employed in the furnaces of large utility boilers. Air staging involves the provision of something less than stoichiometric air through the burner so that much of the combustion occurs in reducing conditions which are unfavourable to NO formation. Air to complete combustion is added further downstream, when sufficient heat absorption has occurred to reduce the flame temperature. In fuel staging, the burner is operated with a moderately high level of excess air, but additional fuel is injected near the tip of the flame. This creates a localized reducing zone conducive to NO decomposition, and combustion is completed slowly, again at relatively low temperatures. Both air staging and fuel staging are helpful in controlling fuel NO as well as thermal NO, but require a substantial furnace volume to provide the necessary residence time, which is why they are most successfully applied in large boilers.

### **BURNER AND FURNACE EFFECTS ON NO FORMATION**

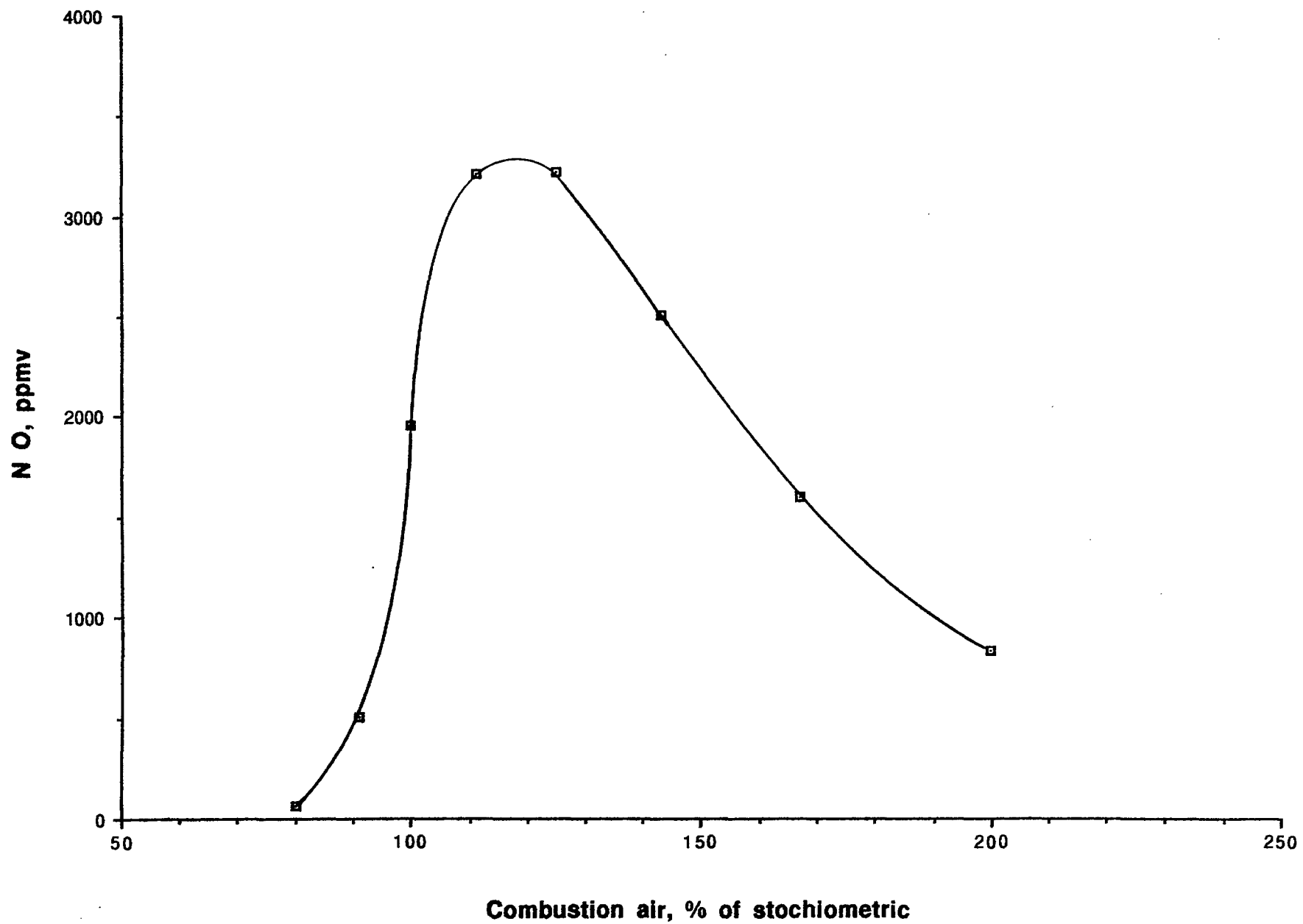
As stated earlier, mathematical models have been fairly successful in predicting NO emissions from small combustion systems, but less so with respect to industrial-scale systems. This is primarily because uniformity of mixing deteriorates rapidly as burner size increases. It is fairly easy to achieve good mixing of the fuel and air issuing from the 50 mm blast tube of a residential burner, but more difficult if the burner throat is 1 m in diameter and the oil nozzle still represents a point source. Thus, while a boiler may be operating at an average excess air level of 20 %, probably much of the flame envelope is fuel lean, and at too low a temperature to generate much NO, a portion of it is sub-stoichiometric, also not generating much NO but pockets of the flame are at conditions ideal for generation of NO. As average excess air level is increased, the substoichiometric volume is reduced and presumably the zones of high NO production are enlarged. This explains why, for large burners, the peak in NO emissions shifts to higher levels of excess air.

Because of mixing effects, measures to reduce flame temperature may be counter-productive. For example, the additional mixing energy imparted by an FGR blower may reduce or eliminate the advantages of reducing excess air. Alternatively, adjusting the burner to retard mixing may cause flame impingement on the furnace walls, resulting in smoke, soot formation and high levels of CO.

Furnace design also has important effects not easily predicted. The small, watercooled furnace which is expected to reduce NO formation by rapidly chilling the flame may, because of flame impingement problems, constrain excess air to high levels which maximize NO. Conversely, an old field-erected boiler with a large furnace having substantial amounts of refractory would be expected to facilitate high flame temperatures and therefore high NO levels. In fact, its modest rate of heat absorption may permit complete combustion at low excess air levels, resulting in low NO emissions.

In summary, NO emissions from industrial boilers are difficult to predict with accuracy. Theoretically sound measures for NO reduction may not work out in practice if fuel/air mixing effects are not well understood, and the influences of furnace design add further degrees of uncertainty. Each boiler or at least each combination of furnace and burner, has unique characteristics which should be examined before any NO reduction measures are implemented.





**Fig. B-1. Equilibrium composition of NO for adiabatic combustion of methane with air at 1 atm.**

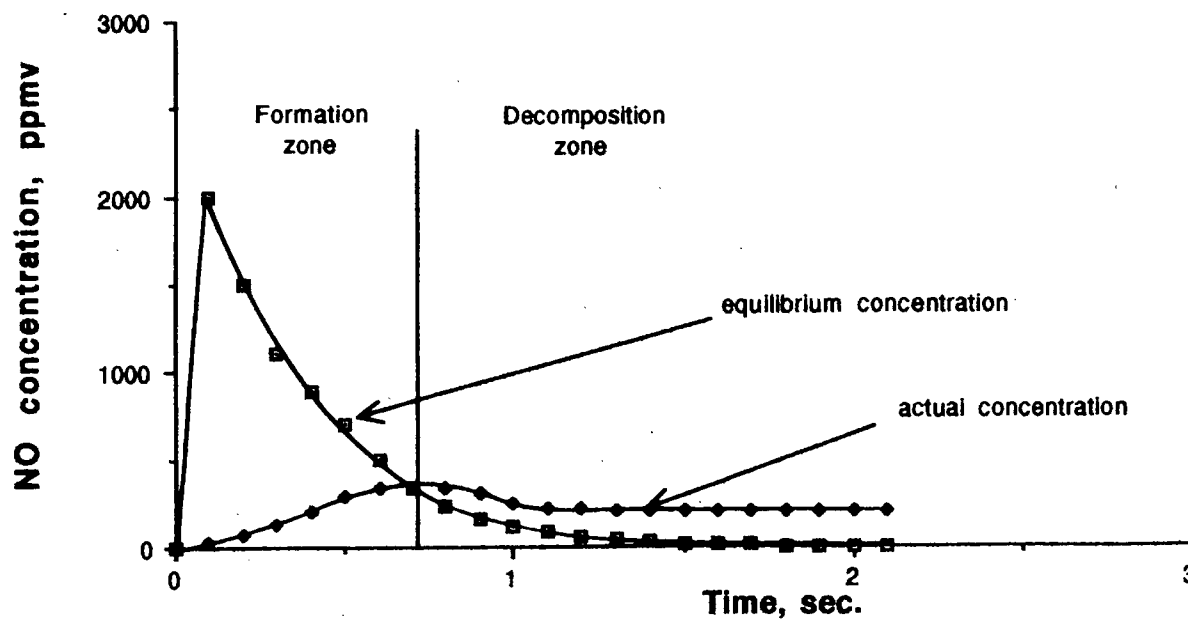
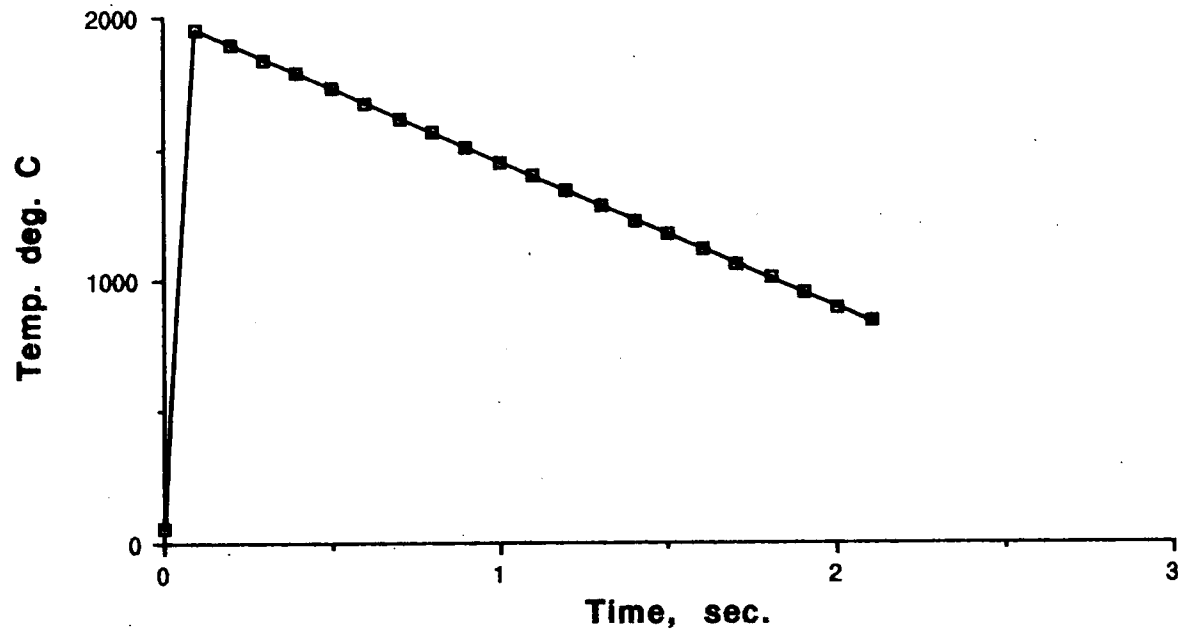


Fig. B-2 Hypothetical equilibrium and probable NO concentration in a stoichiometric propane-air mixture

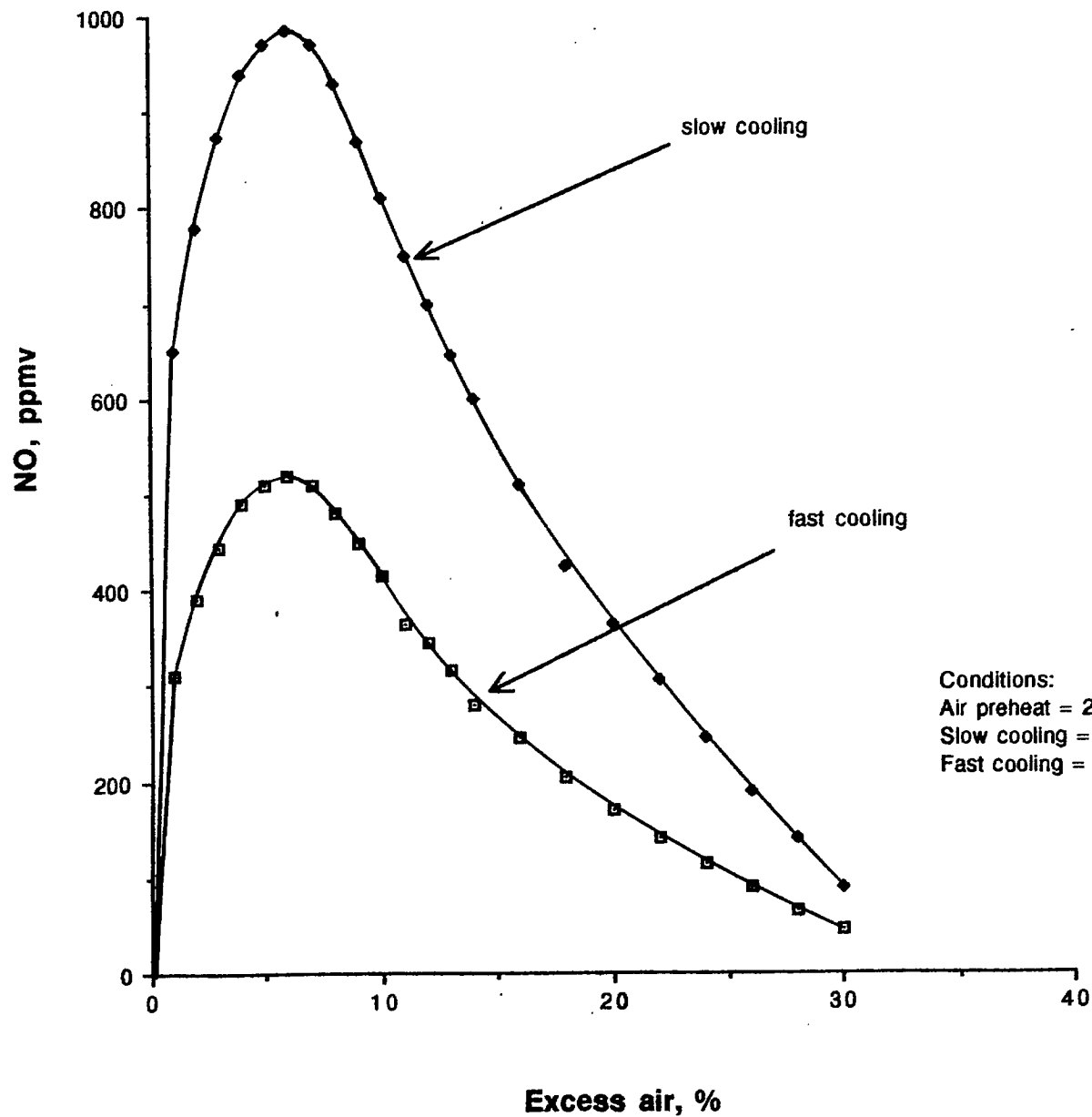


Fig. B-3. Nitric oxide versus excess air as predicted by Brown's model for No. 2 fuel oil

Table 1 - Summary of regulations proposed by the Federal Industrial Boiler Emissions Control program <sup>1</sup>

Fuel type	CO ng/J	NO <sub>x</sub> ng/J	SO <sub>2</sub> ng/J	Particulates mg/m <sup>3</sup>
Natural gas	125	22	--	--
No.1 and No.2 oil	125	43	25	--
No.4, No.5 and No.6 oil	125	110	500	--
Solid fuel	125	150	500	160

<sup>1</sup> Applicable to existing boilers having a heat input capacity between 5.9 MJ/s and 50 MJ/s ( 20 x 10<sup>6</sup> and 170 x 10<sup>6</sup> Btu/h )

Table 2 - Fuel analytical data

Sample No.	A049-92	A050-92	A051-92	A052-92	A053-92	A054-92
Date - 1992	Jan.21	Jan.23	Jan.23	Jan.24	Jan.24	Jan.25
Oil type	No. 6	No. 6	No. 4	No. 4	No. 4	No.6 <sup>1</sup>
Boiler test	1 to 5	6 to 8	9 to 10	11to16	17to20	21to25

Ultimate analysis, wt %

Carbon (C)	86.20	86.30	86.30	86.20	86.40	86.40
Hydrogen (H <sub>2</sub> )	10.90	10.90	11.60	11.60	11.30	10.80
Nitrogen (N <sub>2</sub> )	0.46	0.46	0.33	0.33	0.35	0.41
Sulphur (S)	1.97	1.95	1.46	1.41	1.45	1.82
Total	99.53	99.61	99.69	99.54	99.50	99.43

Higher heating value

MJ/kg	42.69	42.66	43.41	43.45	43.55	42.71
Btu/lb	18360	18350	18670	18690	18730	18370

Specific gravity (relative to water )

	0.990	0.988	0.952	0.951	0.952	0.980
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<sup>1</sup> This oil was somewhat diluted with No.4 oil because burner return lines were piped into the main storage tank as explained in the report. Prorating of either specific gravity or sulphur content indicates that this sample contains about 25% No. 4 oil.