HEATING PLANT PERFORMANCE AND EMISSIONS NOVA SCOTIA HOSPITAL, DARTMOUTH, N.S.

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ABSTRACT

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The heating plant at Nova Scotia Hospital is fired with No. 4 residual fuel oil and has experienced a persistent problem of soot emissions. Early in 1991, the Combustion and Carbonization Laboratory (CCRL) of CANMET's Energy Research Laboratories was contracted to conduct an investigation of possible causes and corrective measures.

It was found that the automatic combustion controls on the boilers were inadequate to cope with the rapid fluctuations in steam demand. Frequently, on increasing load, the fuel controller would respond more rapidly than the air controller, resulting in substoichiometric combustion and heavy smoke emissions. Numerous measures were implemented to improve combustion control and burner performance, including installation and calibration of new electronic control systems with parallel demand systems for fuel and air.

Boiler efficiency was measured over the working load range, and is reported. In addition, gaseous emissions of CO, NO_x, and SO_2 were measured, and these are discussed in light of a proposed emission standard for industrial boilers, that is expected to take effect in 1994.

RÉSUMÉ

RENDEMENT DE L'INSTALLATION DE CHAUFFAGE ET ÉMISSIONS HÔPITAL NOVA SCOTIA, DARTMOUTH (N.-É.)

V.V. Razbin, F.D. Friedrich et S.W. Lee

L'installation de chauffage de l'hôpital Nova Scotia est alimentée au fuel-oil no. 4 et elle a présenté un problème persistant d'émission de suie. Au début de 1991, un contrat a été accordé au Laboratoire de recherche sur la combustion et la carbonisation (LRCC) des Laboratoires de recherche énergétique de CANMET en vue d'effectuer une étude sure les causes possibles du problème et de trouver des mesures correctives.

On a trouvé que les commandes automatiques de combustion des chaudières étaient incapables de répondre aux variations rapides de la demande de vapeur. Souvent, lors d'un accroissement de la charge, le régulateur de combustible répondait plus rapidement que le régulateur d'air, ce qui se traduisait par une combustion substoechiométrique et de fortes émissions de fumée. De nombreuses mesures on été prises en vue d'améliorer la régulation de la combustion et le rendement du brûleur, notamment l'installation et l'étalonnage de nouveaux systèmes de régulation électroniques avec des systèmes de demande parallèles pour le combustible et l'air.

Le rendement des chaudières a été mesuré sur la plage de charge d'utilisation et les résultats sont présentés. De plus, les émissions gazeuses de CO, NO_x et SO_2 ont été mesurées et elles sont étudiées à la lumière d'une norme d'émission proposée relative aux chaudières industrielles qui devrait entrer en vigueur en 1994.

CONTENTS

TABLES

FIGURES

INTRODUCTION

In December, 1990, B. Lavers, Chief Engineer of the central heating plant for the Nova Scotia Hospital, located in Dartmouth, N.S., contacted Dr. S.W. Lee of the Combustion and Carbonization Research Laboratory (CCRL) concerning soot emissions from the heating plant, which burns residual oil. Subsequently, V. Razbin, also of CCRL, visited the plant to assess the situation, and as a result CCRL submitted a proposal to carry out performance and emissions tests on all four boilers, over the full load range. It was expected that this would not only quantify the emissions, but identify the causes, and thus point the way to improved performance in terms of reduced emissions and increased efficiency. It would furthermore provide the plant with baseline data required under regulations expected in the next few years, governing emissions from industrial boilers.

The management of Nova Scotia hospital accepted the CCRL proposal and the testwork was carried out in two periods during early 1991; March 16 to 20, and May 29 and 30. A preliminary report was submitted to Nova Scotia Hospital on April 15, 1991. It addressed findings and recommendations concerning Boilers 1, 2, and 4 arising from the tests conducted in March, 1991. The present, final report provides more detailed information on the plant, on the testwork and results, and on recommendations for improved plant performance. It also addresses the work carried out in May 1991 on Boiler 3.

The data in this report are mostly in non-metric units. This reflects the age of the plant instrumentation and the authors' opinion that, if the report is to be of maximum use to the operating staff, the data it contains should be in the same units that are employed in the plant.

PLANT DESCRIPTION

EQUIPMENT

The initial heating plant was built in 1957, and was equipped with two "D" type watertube package boilers (Boilers 1 and 2) built by Dominion Bridge Co. Ltd. These were rated at 30 000 lb/h of steam each, with a maximum working pressure of 200 psig. The boilers were first fired by means of coal stokers, but in 1973 they were converted to Bunker C residual oil, each fired by means of two Peabody Model PE 730 steam-atomized single register burners, placed side by side in the front wall. Fuel/air ratio is controlled by parallel signals to pneumatic drivers which position the oil valve and inlet vanes on the forced draft fan. A slight positive pressure is maintained in the furnace, and flue gas is exhausted through a brick chimney,175 ft high.

In 1975, the capacity of the heating plant was substantially expanded by the addition of two Volcano boilers (Boilers 3 and 4) rated at 55,000 lb/h of steam each. These are also "D" type package boilers, initially equipped with Todd steam atomized single register burners, one per boiler. A pneumatic control system was installed, but with the fuel/air ratio dependent upon mechanical linkages. Boilers 3 and 4 were initially equipped with separate stub stacks.

For reasons explained in the next section, the burner in Boiler 4 was changed, and both Boilers 3 and 4 were connected to the same chimney which serves Boilers 1 and 2. The normal plant operating pressure is 120 psig. It is believed that the existing steam flow orifices are calibrated for a pressure of 100 psig. However, this could not be confirmed without physically removing them, which would have required shutdown of the plant. In the data presented later, measured steam flow has been corrected to account for an orifice calibration pressure of 100 psig. The effect of the assumption possibly being erroneous is also discussed.

OPERATION AND EMISSIONS

Soot emissions have been an ongoing problem at the plant, with complaints coming from the private sector as well as the Nova Scotia Department of the Environment. The plant is located in a residential neighbourhood which includes the Dartmouth General Hospital and a station of the Dartmouth Fire Department. In response to complaints, the Nova Scotia Hospital, about 1983, retrofitted Boiler 4 with a Faber steam-atomized dual register burner in the hope of eliminating soot by improving combustion. In 1985, Boilers 3 and 4 were connected to the 175 ft stack in order to reduce low level emissions into the immediate neighbourhood. In 1986, the plant switched from Bunker C residual oil (No. 6) to Bunker A residual oil (No. 4), at an additional annual operating cost of $100,000 per annum, in the hope that a higher grade of fuel would reduce soot formation. More recently, in 1990 and

1991, mud drum heaters were installed in Boilers 3 and 4 to reduce the number of burner starts required to maintain readiness to meet sudden load demands. Also, all burners were equipped with new atomizer tips and diffusors. Boilers 3 and 4 were equipped with microprocessor controls, and a new smoke opacity meter was installed. The plant was provided with a weather station which indicates wind speed, direction, and temperature. This information is used to ensure that soot blowing is carried out only when it will not affect sensitive locations.

Despite the foregoing measures, soot emissions persisted. They are described as light, flaky, black and oily; adjectives which suggest that some oil droplets are only partly devolatilized before leaving the furnace. There are several possible causes, such as poor atomization, insufficient combustion air, poor fuel/air mixing, flame shape incompatible with the furnace configuration and flame impingement on cold surfaces. Diagnosis is complicated by the fact that soot formation and emissions may not be concurrent. For example, soot may be formed at low boiler loads, accumulate in the convective passes, and then be carried through the boiler and out the chimney when gas velocities increase due to higher boiler load. An operating condition which exacerbates the situation is the drastic load swings resulting from the hot water requirements of the central laundry. This can impose almost instantaneous changes in steam demand of up to 20 000 lb/h.

FUEL SPECIFICATIONS

As noted earlier, for the past five years the plant has been burning Bunker A, also known as No. 4, residual fuel oil. Table 1 compares the National Standard of Canada specifications for this oil with those of Bunker C or No. 6, residual fuel oil. The main differences are in viscosity and in allowable water and sediment content. To quote the Standard (CAN/CGSB -3.2 -M89: Fuel Oil - Heating):

> "7.2.7 Type 4 is an industrial type of fuel intended primarily for burner installations not equipped with preheating facilities.
> 7.2.9 Type 6 is a high viscosity residual oil for use in burners equipped with preheating facilities adequate for handling oil of high viscosity."

Since the plant has preheating facilities, it continues to use them with the No. 4 oil, in order to obtain the best possible atomization.

Table 2 presents the results of three fuel analyses; one performed by Dearborn Chemical Company Ltd. in September 1990 and two performed by the Energy Research Laboratories, on samples obtained in December 1990, and January 1991. All are typical of Bunker A fuel oil but the December 1990 sample analyzed by ERL showed considerable contamination by water. Residual oils normally contain less than 1% water; indeed, the limit on water plus sediment is 0.5% for No. 4 oil. The presence of a larger amount suggests an unrepresentative sample. For purposes of calculating boiler efficiency, it seems most appropriate to use the ultimate analysis and higher heating value measured on the sample of January 1991. The total of the ultimate analysis indicates less than 0.1% water, and the higher heating value is close to that of the Dearborn sample.

WORK PLAN

The work plan which CCRL submitted to Nova Scotia Hospital proposed that continuous flue gas analyzers for CO_2, O_2, CO, NO_x, and SO_2, together with thermocouples to measure stack temperatures and combustion air temperatures, be connected to each boiler in turn. The boiler under test would then be operated at each of three load conditions; minimum fire, 40% load, and maximum achievable load. The load would be set by manual control, but the fuel/air ratio would be determined by the automatic controls. It was expected that the flue gas analyzers would identify conditions likely to cause soot formation and therefore suggest corrective action. Also, the resulting data could be used to adjust the automatic controls for optimum combustion performance over the full load range.

Following retuning of the controls, emission levels and efficiency were to be measured at maximum load, and emissions were to be measured under transient conditions, that is, while boiler load was being varied from minimum to maximum and back again, at rates normally experienced. It was estimated that two days of testing would be required for each boiler.

The instrument package employed by CCRL for work such as this is a well-proven system comprising, besides the analyzers, a stainless sinter stack probe with a heated line and a sample conditioning unit. The system extracts the sample from the stack, removes the moisture, which would otherwise contaminate the analyzer cells, and delivers dry flue gas at constant temperature, pressure, and flow rate to the analyzers. The principle of operation, make and model of the analyzers are as follows:

O_2	Paramagnetic	Beckman Model 755
CO_2	Infrared	Horiba Model PIR 2000
CO	Infrared	Horiba Model PIR 2000
SO_2	Ultraviolet	Western Research Model 721A
NO_x	Chemiluminescent	ThermoElectron Model 10

The instruments are calibrated on-site at regular intervals by means of bottled gases. Outputs from the analyzers and thermocouples are fed to a datalogger which records the data at 10 sec intervals and prints 5 min averages.

MEASUREMENT PROGRAM AND RESULTS

BOILER 4

The first period of on-site testwork began on March 16, 1991. The CCRL instrument package was connected to Boiler 4, which was then run through the load range on automatic control, to establish whether recalibration was necessary. The plant superintendent had arranged for a controls technologist to be on hand.

It was quickly determined that the forced draft fan is substantially oversized, resulting in poor control of combustion air. As the boiler load varied from minimum to maximum, the cam on the Bailey drive which controls the combustion air dampers moved through only a small portion of its travel. To provide more controller travel and therefore more accurate control of air flow, two of the four windbox dampers were disconnected from the controller and locked shut. Thus the entire air supply was required to flow through the two remaining dampers; this resulted in much better control: about 75% of cam travel. This work was done in the morning of March 17.

That afternoon, more precise adjustments of fuel/air ratio were conducted at medium and minimum loads, under manual control. First, at about 25 000 lb/h of steam, the boiler was operated at about 3.2% O_2 in the flue gas. When this was found to produce very low levels of CO, typically 25 ppm, the excess air level was further reduced, to about 2.5% O_2 in the flue gas, in order to increase boiler efficiency. Typical results from this final adjustment are reported in Table 3 under Test 4-1.

Similarly, at a load of about 19 000 lb/h of steam, it was possible to achieve very low levels of excess air with quite modest emissions of CO. Test 4-2 was run with O_2 levels in the flue gas at about 1.7%. Typical results for this test are also reported in Table 3. Subsequently, however, the excess air level for this load condition was adjusted upward to about 3.2% O_2 in the flue gas, to provide a little more control range for lower loads.

On the morning of March 18, the maximum load test on manual control was undertaken. Because steam demand was moderate at the time, it was necessary to vent steam to atmosphere. This put constraints on both steam output and duration of the test because the feedwater preparation system could not keep up with the increased demand. Typical results are reported in Table 3 as Test 4-3.

Boiler load was then reduced to meet plant demand, and the installation of new controllers for fuel, air and furnace pressure was completed. This was part of a contract, mentioned previously, to equip Boilers 3 and 4 with up-to-date microprocessor controls. The new system is electronic, and provides parallel demand signals to individual cams controlling fuel and air flow. This eliminates the mechanical push-rods which previously linked the oil valve to the air damper, and provided only limited accuracy of control. The new system also permits control-room bias on either fuel or air flow.

In the afternoon and early evening of March 18, three further tests were run at minimum, intermediate and full loads. In each case, load was determined by adjusting the boiler master controller, so that Boiler 4 was responding fully on automatic control. The average results are reported in Table 3 as Tests 4-4, 4-5, and 4-6.

<u>BOILER 2</u>

Work on this boiler was carried out on March 19, 1991. On manual control, with the left burner operating at minimum fire, air flow was progressively reduced while monitoring CO concentrations. However, the boiler tripped out due to excessive pressure differential between fuel oil and atomizing steam. Operation was resumed with the right hand burner which was found to give somewhat more stable performance.

Single burner operation was observed to produce an asymmetric flame; when the left hand burner was operated alone, the flame pulled to the left, tending to impinge on the left wall of the furnace. Similarly, when the right hand burner was operated alone, the flame tended to pull to the right. This is probably caused by the air entering the furnace through whichever burner is out of service, since the register is usually left open. It was also observed that the diffusors were at different axial positions and were not centred in the burner throats. The diffusors were cleaned and adjusted; then two tests were run; one at minimum fire and one at maximum fire, with only the right hand burner in operation. The second condition produced about 50% of boiler capacity. The results are reported in Table 4 as Tests 2-1 and 2-2 respectively.

Similar tests were then carried out with both burners in operation, again under manual control. With both burners at minimum fire (Test 2-3), steam output was 30% of maximum capacity rating (MCR), whereas both burners at maximum output produced about 80% of MCR (Test 2-4). Burner output was limited by lack of pressure differential between fuel oil and atomizing steam. With two burners in operation, both flames were straight and well shaped. However, as with Boiler 4, the forced draft fan was found to be oversized. Combustion air flow is determined by adjusting the inlet louvres on the forced draft fan, and very little movement is required between low load and full load conditions, resulting in poor control.

Overall the control system was found to be in serious need of overhaul; a number of gauges and indicators were inoperative, and fuel oil flow swung widely for no apparent reason, resulting in load fluctuations of about 6 000 lb/h of steam. Also, air flow was found to respond to changes in demand much more slowly than fuel flow, resulting in spikes of high CO concentrations and visible smoke emissions. The plant superintendent explained that a contract had already been let to upgrade the control systems for Boilers 1 and 2. In light of this information, no attempt was made to recalibrate the existing system and run tests on automatic control.

<u>BOILER 1</u>

Preliminary operation on the morning of March 20, 1991 identified the same problems that had been experienced with Boiler 2; that is, the burners were not co-axial with the burner throat and the forced draft fan is oversized, resulting in poor control of combustion air flow rate. Optimum flame conditions were established by adjusting the burners and diffusors, and by setting the register vanes for maximum swirl, clockwise on the left burner, counterclockwise on the right burner. On the forced draft fan, three of the six inlet louvres were disconnected from the control drive and tack-welded shut, in order to provide the drive with more travel over the load range, and therefore more accurate control of air flow. It was also found that there was an air blockage in the air line conveying the signal to the air flow meter on the control room panel, and this was corrected.

In all, five tests were run, average results for which are recorded in Table 5. The boiler was on manual control throughout. The first two tests, 1-1 and 1-2, were run with only the left hand burner in operation, at minimum fire and at close to maximum fire, which produced about 45% of boiler MCR. At both load conditions, the flame pulled to the left and impinged on the left wall of the furnace. At the higher load, there was some impingement on the rear wall as well.

When the second burner was brought into service, both flames were straight, with no impingement on the side walls and, only at full load , slight impingement on the rear wall of the furnace. Three tests were run, 1-3, 1-4, and 1-5, representing 35%, 50%, and 80% of MCR. It has been plant practice to limit the output of Boilers 1 and 2 to 75% of MCR because of their age. Furthermore, on automatic control, a similar limit is imposed by the lack of pressure differential between the fuel oil and atomizing steam.

BOILER 3

Boiler 3 was down for repairs in March 1991; therefore its calibration and testing had to be deferred to May 29 and 30, 1991. To improve combustion air control, one of the four windbox dampers was locked shut, as had been found desirable on Boiler 4. Fuel and air flow controls were then calibrated over the very limited load range offered by the mild weather. Tests 3-1 and 3-2 were then carried out, respectively, at minimum fire and about 50% of MCR. The boiler master was on manual control; fuel flow and air flow were on automatic. Average results for these tests are reported in Table 6. Some steam had to be vented to achieve the 50% load condition.

Following Tests 3-1 and 3-2, steam output was manipulated up and down by means of the boiler master to observe the response of the controls to transient conditions. It was found that the fuel control responded well, but the air control responded slowly to load variations. This resulted in high levels of CO as illustrated in Fig. 1.

To improve combustion air control, a second windbox damper was disconnected from the controller and locked shut. Fuel and air then tracked well as load was increased to 90% of MCR, the condition at which Test 3-3 was carried out. This was the maximum load which could be achieved at the time because the high rate at which steam was being vented to atmosphere strained the capabilities of the feedwater supply system. Also, at this load, fuel oil and atomizing steam were at the same pressure, whereas to ensure good atomization it is desirable to have about a 20 psi differential in favour of the steam.

Finally, while the gas analyzers monitored emissions, the boiler was allowed to track load completely on automatic control, from 1950 h on May 29 to 0900 h on May 30. This covered the period from the lowest demand of the day through the period when, due to operation of the laundry, the load increases sharply and fluctuates widely. The results are summarized in Fig. 2.

OBSERVATIONS AND CONCLUSIONS

BOILERS 1 AND 2

Soot Emissions

A number of potential causes of soot formation were identified. The chief one has undoubtedly been an inadequate combustion control system which, under fluctuating load conditions, allowed fuel supply to increase more rapidly than air supply, resulting in unacceptably low excess air levels. This has been partially corrected by permanently closing half of the intake louvres on the forced draft fan, which gives the air controller cam a greater range of travel, and therefore more precise control. At the time these boilers were tested, a contract had already been let to upgrade the control system. It is important, once the new controls are installed, that they be properly calibrated and maintained.

Secondary causes of sooting and appropriate corrective actions are as follows:

- With only one burner in operation, the flame tends to impinge on a sidewall and, when the burner is close to maximum capacity, on the rear wall of the furnace. This may result in soot formation by quenching oil droplets before combustion is complete. The boilers should only be operated with both burners in service, since flame impingement on the walls does not occur under this condition.

- Burner adjustment was not optimal. The oil guns were not co-axial with the burner throat and location of the diffusors and settings of the registers were not consistent. Appropriate adjustments were made at the time of the tests, but the settings should be re-examined after the new controls have been installed. Normally boilers with two burners should have the registers set to opposite swirl, to avoid excessive shear and turbulence in the inter-burner zone.

- At high loads, fuel oil pressure and atomizing steam pressure were about the same, whereas the steam pressure should always be about 20 psi higher, to ensure good atomizing. The oil-to-steam pressure regulator should be adjusted or replaced.

Under fixed load and manual control the present burners proved capable of clean, efficient combustion: that is, low excess air levels, low emissions of CO and no visible stack emissions. The existing automatic controls were tuned up and recalibrated to the best extent possible, but since their replacement is imminent, no attempt was made to evaluate performance on automatic control under varying load conditions.

<u>Boiler Efficiency</u>

For a given boiler firing a given fuel, the main variable affecting boiler efficiency is excess air level, which in turn is a parameter of burner performance. The existing burners, under manual control, proved quite satisfactory in this respect. Good combustion was achieved with 20 to 25% excess air at low loads and about 10% excess air at high loads. A good burner management system should be able to achieve these conditions on automatic control.

Boiler efficiency was calculated using the indirect method specified in the "ASME Test Form for Abbreviated Efficiency Test, PTC 4.1-a (1964)." The major losses for all tests with two burners are given in Table 7. Loss due to the formation of water by the combustion of hydrogen is determined primarily by the hydrogen content of the fuel, but varies slightly with stack temperature. The loss due to radiation and convection from the boiler casing is constant in terms of heat quantity, and therefore variable as a percentage of boiler heat output. It was determined by means of the "Radiation and Convection Heat Loss Chart", prepared by the American Boiler Manufacturers Association and published in the ASME Power Test Code. From it was prepared Fig. 3, which is specific to boilers of the same type and capacity as Boilers 1 and 2. Unmeasured losses, such as those due to unburned fuel and moisture in the combustion air, are covered by an assumed loss of 0.25%.

An important advantage of the indirect method for determining boiler efficiency is that it does not require metering of the fuel, and only an approximate measure of steam flow. It does require determinations of stack temperature and flue gas analysis, but these need not be highly accurate. For example, to change the calculated efficiency by 1%, the stack temperature would have to be in error by about 30°C, or the measurement of O_2 in the flue gas would have to be in error by about two percentage points (e.g., reading 2% when its actually 4%). In fact, it is fairly easy to determine stack temperature within 5°C, and O_2 in the flue gas within 0.1 percentage point (e.g., 2.5 % $\pm$ 0.1). By comparison, conventional oil flow meters may easily be in error by 5 to 10%; this would result in an equal error in the efficiency determination if the direct method were used.

The indirect method does require an approximate measure of steam flow, in terms of per cent of boiler MCR, in order to determine the radiation and convection loss. It was stated earlier, in the section "Plant Description", that there was some uncertainty about the pressure for which the steam flow orifices had been calibrated. A value of 100 psig has been assumed. The effect of an error in this assumption is modest. If, for example, the correct calibration pressure were 120 psig, then the steam outputs reported in Table 7 would be high by about 2% at low load and 6% at full load. The reported radiation and convection loss, in turn, would be low by about 0.15% at low load and 0.10% at full load. Thus, the effect on calculated efficiency is minimal.

In summary, the boilers, with their existing burners, are capable of efficiencies of 80 to 83%. As Fig. 4 shows, efficiency varies little over the load range.

Gaseous Emissions

Environment Canada, at the request of the Canadian Council of Ministers of the Environment, is in the process of developing emission standards for industrial boilers. These are expected to become law in 1994. The proposed allowable emissions for existing boilers having a heat input capacity between 5.9 MJ/s and 50 MJ/s (20×10^6 and 170×10^6 Btu/h) are:

Fuel Type	CO ng/J	NO_x ng/J	SO_2 ng/J	Particulates mg/m^3
Natural gas	125	22	--	--
No. 1 and 2 oil	125	43	25	--
No. 4, 5 and 6 oil	125	110	500	--
Solid fuel	125	150	500	160

The existing burners, firing No. 4 fuel, are quite capable of meeting the proposed CO and NO_x standards, at least under manual control. As Fig. 5 and 6 show, CO emissions are typically about 10% of the allowable limit, while NO_x emissions are close to, but below, the limit.

SO_2 emissions are more problematic. The allowable limit of 500 ng/J for residual oils can only be met by burning a fuel which consistently contains about 1% S or less. The alternative of SO_2 capture by limestone injection or flue gas scrubbing is generally not economically viable for small plants. Figure 7 shows SO_2 emissions from Boilers 1 and 2. It appears that the sulphur content of the fuel fluctuates substantially from the value of 1.6% which was found in the sample taken in January 1991, but mostly to a lower level.

BOILERS 3 AND 4

Soot Emissions

The main cause of soot formation in Boilers 3 and 4 has been the same as in Boilers 1 and 2; namely, inadequate combustion controls which, under fluctuating load conditions, did not maintain a sufficient margin of excess air. This can be seen from Fig. 1 and 2, that present, for Boiler 3, correlations of CO concentration to other parameters such as steam flow, oil flow and air flow, respectively. The CO and O_2 data were obtained from the CCRL datalogger, whereas the steam, oil and air flow data were obtained from the Bailey 24 h circular charts in the plant. Precise time correlation is difficult because, to avoid physical interference of the pens on the circular chart, time offsets may be as great as 30 min. However, careful study of the data, presented in Fig. 1 and 2, indicates the following analysis:

Figure 1 addresses a period during the afternoon of May 29 in which boiler load was manipulated by means of the master controller in order to determine the response of the automatic controls. It became clear that air flow response is slow. While the mean value of O_2 in the flue gas for the test period was 4.6%, 5 min averages were as low as 1.6% and as high as 13.8%. Shorter-term variations were undoubtedly more severe. A reliable correlation of CO concentrations to steam flow, air flow and oil flow could not be achieved. Instead, Fig. 1 plots CO and O_2 against time. It appears that CO forms not only when O_2 drops to 2% or less, but also when O_2 rises sharply to levels in excess of 10%. This suggests that such high excess air levels have a negative effect on burner aerodynamics.

As a result of this information, further adjustments were made to the controls. After the full-load test (Test 3-3) was completed, the boiler was put on automatic control overnight, while emissions were monitored. During the quiet hours steam flow, oil flow and air flow were very stable; O_2 varied only between 3.8 and 5.0%. Emissions of CO were also low; 15 to 25 ppmv. However, at 0600 h, presumably when the laundry plant came on stream, steam load increased sharply and fluctuated rapidly.

Figure 2 shows data for the subsequent 3 h. It appears that oil flow follows steam demand closely, but air flow lags somewhat, particularly on sharp increases in steam demand. This results in periods of inadequate excess air, and peaks in CO emissions, which may also be accompanied by soot formation. One possibility for maintaining a better margin of excess air is to attenuate the signal to the oil valve, so the air controller has more time to keep up.

Flame impingement does not appear to be a problem with Boilers 3 and 4, and the adjustment of burner components, such as swirl vanes and diffusor, was satisfactory at the time of the tests. However, as with Boilers 1 and 2, the oil-to-steam pressure regulator fails to maintain sufficient differential at full load, and should be adjusted or replaced.

Boiler Efficiency

Under automatic control, excess air levels are satisfactory with both boilers, although some further fine-tuning seems possible. At full load, excess air level on Boiler 3 could probably be reduced to the 10 to 15% range, while at low load on Boiler 4 it might be brought down to about 25 or 30%.

The range of efficiencies for Boilers 3 and 4, as shown in Table 8 and Fig. 9, is about 2% higher than for Boilers 1 and 2. Some of the gain is due to lower radiation and convection losses, an inherent benefit of a larger boiler, but most of it is due to lower stack temperatures, indicating more or cleaner heat exchange surface.

Figure 8 shows radiation and convection loss for boilers similar in type and size to Boilers 3 and 4, derived in the same manner as Fig. 3. As with Boilers 1 and 2, possible errors in steam flow make only modest changes in this loss. If the correct calibration pressure of the steam flow orifices were 120 psig instead of 100 psig, calculated boiler efficiency would be reduced by about 0.2% at 25% MCR and only about 0.05% at full load.

Gaseous Emissions

As with Boilers 1 and 2, the burners in Boilers 3 and 4 achieve low CO emissions. As shown in Fig. 10, these are typically 10 to 13 ng/J, compared to an allowable limit of 125 ng/J.

Unlike Boilers 1 and 2, Boilers 3 and 4 exceed the allowable limit for NOx. As Fig. 11 shows, emissions vary from nearly 200 ng/J at low loads to about 120 ng/J at full load. The most likely explanation for this trend is the lower excess air level which prevails at high loads. That is, higher levels of excess air tend to produce higher peak flame temperatures, which in turn create more NO_x. Emission levels of NO_x at low load could doubtless be lowered by reducing the excess air level, but this would increase the likelihood of soot emissions. It may be possible to adjust the existing burners to obtain some improvement, for example, by adjusting the axial position of the oil gun. Burner replacement is not recommended at this time. Burners designed to minimize NO_x emissions usually employ some means such as fuel staging, air staging or flue gas recirculation to reduce peak flame temperatures, but low-NO_x burners which can be retrofitted to a variety of small industrial boilers with reliable results have not yet been demonstrated, at least for residual fuel oils.

Figure 12 shows SO_2 emissions for Boilers 3 and 4. These data reinforce the conclusion that sulphur content of the fuel fluctuates from the value of 1.6% measured in January 1991. The tests on Boiler 4, which were conducted in March 1991, indicate a sulphur level of about 0.9%, and are below the allowable limit, whereas the tests on Boiler 3, conducted in May 1991, indicate a sulphur level of about 1.2%.

RECOMMENDATIONS

ALL BOILERS

1. The primary recommendation would be that the automatic control of fuel/air ratio be upgraded to ensure an adequate level of excess air at all times. However, this was already being done at the time the boilers were being tested. As a result of the tests, combustion air entry was restricted by closing forced draft fan inlet louvres or windbox dampers, in order to improve control of combustion air flow. In the case of Boilers 3 and 4, the installation of new hardware was sufficiently advanced that CCRL data were used to calibrate the new automatic controls. The new controls on the other boilers likewise need to be calibrated carefully over the load range.

2. Each boiler should be equipped with continuously-recording monitors for O_2. CO analyzers would also be desirable. Installation of the analyzers needs to be supplemented with adequate maintenance and the operators need

to be trained to use the information to run the boilers at optimal efficiency. This can be expected to save money in the long run.

3. It seems likely that with a good automatic control system, properly calibrated, the plant could return to the use of Bunker C oil. This would require refurbishing the heating system for the fuel storage tanks and the pipes between the tanks and the pumpset. However, this would have a negative effect on gaseous emissions. Levels of NO_x would probably rise somewhat, and SO_2 levels would more than double due to the higher levels of sulphur in Bunker C oil.

4. If, as expected, the plant is required to comply with an industrial boiler emission standard having the emission limits presently proposed, the following three strategies may be considered:

a) Attempt to adjust the burners on Boilers 3 and 4 to meet the NO_x emission standard (it has already been demonstrated that this is possible with Boilers 1 and 2) and, to meet the SO_2 emission standards, buy fuel which has been blended to ensure that sulphur content does not exceed 1%.

b) Retrofit the boilers with low-NO_x burners, assuming that proven burners are available, and buy low-sulphur fuel as in a).

c) Opt for the "total emissions reduction" offered as an alternative in the proposed standard, use emissions with No. 4 fuel oil as the base case, and then switch some or all of the boilers to No. 2 fuel oil.

If and when the proposed standards become a law, the foregoing alternatives will need to be studied in detail to determine which is most cost-effective.

5. The oil-to-steam pressure regulators do not provide sufficient pressure differential between atomizing steam and fuel oil over the load range. The steam pressure should always be at least 20 psi higher. The regulators should be adjusted or replaced.

Boilers 1 and 2

1. These boilers should always be operated with both burners in service, otherwise flame impingement occurs. This sets a minimum load of about 8 000 lb/h of steam.

2. On each boiler the secondary air swirl vanes should be set opposite one another as was done during the CANMET tests. That is, if the vanes on the left burner are set clockwise, the vanes on the right burner should be counter-clockwise.

3. Unit output should be limited to about 25 000 lb/h of steam to avoid flame impingement, excessive furnace heat release rates, and potential tube corrosion problems.

4. Location of the burners relative to the burner throat and the swirl vane settings should be maintained as adjusted during the tests in March, 1991.

Boilers 3 and 4

1. These boilers, being larger, newer and more efficient, should be used to supply as much as possible of the steam demand, within the constraint of a minimum load of about 12 000 lb/h of steam each.

2. The new automatic controls should be checked and recalibrated annually.

3. The present burners, particularly the dual-register burner in Boiler 4, may be capable of reducing NO_x emissions to the level of 110 ng/J specified in the proposed standard for industrial boilers. It is likely to require a few days of trial-and-error testing to establish this, but when compliance with the standard becomes necessary, such testing should be undertaken as a first step, since if it is successful, it will provide a solution with little or no capital cost.

ACKNOWLEDGEMENTS

Special thanks are due to F.L. Wigglesworth, CCRL's electronics technologist, for his assistance in setting up and calibrating the CCRL instrument package, and for replacing a defective analyzer on short notice. The assistance and cooperation of Chief Engineer, Brian Lavers and the plant operating staff are also very much appreciated.

Table I - Residual fuel oil specifications [1]

Property	Type of fuel oil 4	6
Flash point, °C, min	54	60
Sulfur, % by mass, max	(Par 5.2)	(Par. 5.2)
Pour point, °C, max	(Par. 5.3)	-
Cloud point, °C, max	(Par. 5.4)	-
Water and sediment, max % by vol. or mass	0.50 (Par. 5.5.1)	2.00 (Par. 5.5.2)
Ash, % wt. or mass, max	0.10	-
Kinematic viscosity, min	5.5	-
at 40 °C, cST, max	24.0	-
Kinematic viscosity, min	-	92
at 50 °C, cSt, max	-	638

Par 5.2: **Sulfur** - Sulfur content may be established by government regulations where the fuel is to be used, or shall be as required by contractual agreement.

Par. 5.3: **Pour Point** - Pour points except for Type 00, shall be specified by the user as required by the conditions of storage or use or as agreed by contract. Flow improved fuel designed to provide satisfactory performance under the conditions of storage and use may also be used.

Par. 5.4: **Cloud Point** - Cloud points except for Type 00 shall be specified as described in Par. 5.3.

Par. 5.5 **Water and Sediments**

Par. 5.5.1 For Type 4, this can be a distillate or a cut back residual requiring a higher limit than distillate.

Par. 5.5.2 For Type 6, the amount of water by distillation plus the sediment by extraction shall not exceed 2.00% mass. The amount of sediment by extraction shall not exceed 0.50% mass. A deduction in quantity shall be made for all water and sediment in excess of 1.00% mass.

1 Abstracted from National Standard of Canada CAN/CGSB -3.2-M89 "Fuel Oil, Heating".

Table 2 - Fuel analytical data

Dearborn, Sept. 1990		ERL, December 1990		ERL, January 1990	
API gravity at 60°F:	18.0	API gravity at 15°C:	16.1		
Relative density at 60°F:	0.9465				
Density at 15°C:	0.9459	Density at 15°C, kg/m^3:	958.4		
Flash point, °C:	105	Flash point, °C:	NA[1]		
Pour point, °C:	-24				
Viscosity, SSF at 122°F:	33.1	Viscosity, cst at 50°C:	135.4		
Higher heating value, Btu/lb:	18,820	HHV, Btu/lb:	17,781	HHV, BTU/lb:	18,737
Higher heating value, Btu/gal:	178,137				
Sediment, vol. %:	0.60				
Water, vol. %:	0.08	Ultimate analysis [2]		Ultimate analysis	
Sulphur, wt%:	1.42	Carbon wt%:	83.80	Carbon, wt%:	86.7
Sodium as Na, ppm:	6	Hydrogen wt%:	11.70	Hydrogen, wt%:	11.3
Vanadium as P_2O_5, ppm:	156	Sulphur wt%:	1.20	Sulphur , wt%:	1.60
Ash, wt%:	0.053	Nitrogen wt%:	0.28	Nitrogen, wt%:	0.31

1 The presence of water in the sample precluded a successful flash point determination.

2 The total of the ultimate analysis, at 96.98%, is outside the limits of error for the analytical techniques which were employed. This suggests that the sample contained as much as 3% water which, in turn, suggests that the sample was not representative.

Table 3 - Measured data for Boiler 4

Test number	4-1	4-2	4-3	4-4	4-5	4-6
Controls	manual	manual	manual	auto	auto	auto
Steam output, 1000 lb/h[1]	25.5	18.8	51.8	12.8	26.7	54.6
Steam pressure, psig	122	123	125	128	112	130
Fuel oil flow, Igph.	160	125	303	109	168	304
Air flow, rel.	167	142	276	110	174	302
Fuel oil pressure, psig	42	34	70	30	44	72
Fuel oil temp., °F	195	192	192	192	196	202
Atomizing steam pressure, psig	67	58	94	55	70	95
Windbox pressure, in. H_2O	3.0	2.9	3.8	1.3	1.0	4.6
Furnace pressure, in. H_2O	1. 5	0.7	1.0	2.2	0.7	1.5
Boiler outlet pressure, in. H_2O	-0.25	-0.30	-0.25	-0.25	-0.25	-1.5
Combustion air temp., °C [2]	33.2	33.0	35.2	36.4	35.5	33.2
Stack temp., °C [2]	211.9	189.5	304.4	193.9	213.7	309.6
<u>Flue gas analysis</u>						
Oxygen, %	2.43	1.65	2.60	6.53	3.53	2.28
Carbon dioxide, %	14.0	14.5	13.8	10.9	13.2	14.2
Carbon monoxide, ppmv,	27	30	18	30	34	48
Nitrogen oxides, ppmv,	262	280	211	258	244	219
Sulphur dioxide, ppmv,	607	659	584	486	558	585

1 Corrected to orifice calibration pressure of 100 psig.
2 Thermocouples installed by CCRL

Table 4 - Measured data for Boiler 2

Test number	2-1	2-2	2-3	2-4
Controls	manual	manual	manual	manual
No. of Burners	1	1	2	2
Steam output, 1000 lb/h[1]	7.2	15.4	10.0	26.5
Steam pressure, psig	126	129	128	132
Fuel oil flow, % of range	16	40	20	61
Air flow (relative)	5.2	13.4	7.9	19.9
Fuel oil pressure, psig	38	72	20	70
Fuel oil temp., °F	187	203	194	214
Atomizing steam pressure, psig	67	96	42	96
Windbox air temp., in. H_2O	inop.	0.38	inop.	1.15
Furnace pressure, in. H_2O	-0.05	-0.05	-0.05	+0.05
Combustion air temp., °C [2]	28.2	27.4	28.5	24.2
Stock temp., °C [2]	190.6	265.7	213.0	330.8
<u>Flue gas analysis</u>				
Oxygen, %	5.40	6.63	4.34	1.99
Carbon dioxide, %	11.4	10.2	11.9	13.7
Carbon monoxide, ppmv, measured	38	31	29	50
Nitrogen oxides, ppmv, measured	131	160	150	172
Sulphur dioxide, ppmv, measured	505	480	513	844

1 Corrected to orifice calibration pressure of 100 psig
2 Thermocouples installed by CCRL

Table 5 - Measured data for Boiler 1

Test number	1-1	1-2	1-3	1-4	1-5
Controls	manual	manual	manual	manual	manual
No. of burners	1	1	2	2	2
Steam output, 1000 lb/h [1]	7.8	13.2	10.7	14.8	24.8
Steam pressure, psig	128	130	133	136	130
Fuel oil flow, % of range	11	25	18	40	75
Air flow, rel.	-	-	-	-	-
Fuel oil pressure, psig	32	50	22	36	64
Fuel oil temp., ^oF	195	202	202	210	216
Atomizing steam pressure, psig	57	75	46	64	86
Windbox pressure, in. H_2O	0.01	0.02	0.01	0.04	1.2
Furnace pressure, in. H_2O	-0.04	-0.04	-0.04	-0.04	-0.02
Combustion air temp., ^oC	28.8	26.5	25.2	23.9	23.7
Stack temp., ^oC	194.3	219.9	211.3	296.4	297.3
Flue gas analysis					
Oxygen, %	6.44	5.58	3.68	4.23	2.14
Carbon dioxide, %	10.8	11.4	12.9	12.5	14.2
Carbon monixide, ppmv, measured	31	28	27	25	43
Nitrogen oxides, ppmv, measured	120	147	137	179	176
Sulphur dioxide, ppmv, measured	500	535	569	669	1046

1 Corrected to orifice calibration pressure of 100 psig.
2 Thermocouples installed by CCRL

Table 6 - Measured data for Boiler 3

	3-1	3-2	3-3
Test number	3-1	3-2	3-3
Controls	auto	auto	auto
Steam output, 1000 lb/h [1]	15.8	28.6	48.9
Steam pressure, psig	125	120	125
Fuel oil flow, % of range	23	38	75
Air flow, rel.	16	37	78
Fuel oil pressure, psig	31	53	90
Fuel oil temp., ^{o}F	190	198	200
Atomizing steam pressure, psig	46	65	90
Furnace pressure, in H_2O	0.2	0.6	2.1
Combustion air temp., ^{o}C [2]	41.2	41.4	35.6
Stack temp. ^{o}F	354	390	490
<u>Flue gas analysis</u>			
Oxygen, %	5.23	2.12	4.32
Carbon dioxide, %	11.7	14.2	12.4
Carbon monoxide, ppmv, measured	31	34	30
Nitrogen oxides, ppmv, measured	311	323	208
Sulphur dioxide, ppmv, measured	640	762	751

1 Corrected to orifice calibration pressure of 100 psig
2 Thermocouple installed by CCRL
3 Boiler flue temperature recorder.

Table 7 - Efficiency and emissions; Boilers 1 and 2

Test number	1-3	1-4	1-5	2-3	2-4
Controls	manual	manual	manual	manual	manual
No. of burners	2	2	2	2	2
Steam output, % MCR	35.7	49.3	82.7	33.3	88.3
Excess air, % [1]	19.69	23.37	10.54	23.95	9.65
Dry flue gas, lb/lb of fuel fired [2]	17.04	17.56	15.55	18.39	16.08
<u>Boiler efficiency - indirect method</u>					
Dry flue gas loss, % [2]	7.31	11.03	9.81	7.82	11.37
Hydrogen loss, % [2]	6.52	6.93	6.93	6.50	7.08
Radiation and convection loss, % [3]	2.35	1.73	1.08	2.50	0.97
Unmeasured losses, % [4]	0.25	0.25	0.25	0.25	0.25
Total losses, %	16.43	19.94	18.07	17.07	19.67
Efficiency, %	83.57	80.06	81.93	82.93	80.33
<u>Flue gas emissions - calculated</u>					
Carbon monoxide, ppmv at 3% O_2	28	27	41	32	50
Carbon monoxide, ng/J	9.4	9.1	13.8	10.8	16.8
Nitrogen oxides, ppmv at 3% O_2	143	192	168	164	172
Nitrogen oxides, ng/J	79.1	106.2	92.9	90.7	95.1
Sulphur dioxide, ppmv at 3% O_2	596	720	1000	560	844
Sulphur dioxide, ng/J	459.4	555.0	770.8	431.7	650.6

1 Calculated from O_2 analysis
2 Calculated according to ASME test procedure
3 From Fig. 3
4 An assumed value to cover minor losses

Table 8 - Efficiency and emissions; Boilers 3 and 4

Test number	3-1	3-2	3-3	4-4	4-5	4-6
Controls	auto	auto	auto	auto	auto	auto
Steam output, % MCR	28.7	52.0	88.9	23.3	48.5	99.3
Excess Air, % [1]	30.68	10.43	23.98	41.82	18.77	11.33
Dry flue gas, lb/lb of fuel fired [2]	18.70	15.55	17.69	20.03	16.67	15.56
<u>Boiler efficiency - indirect method</u>						
Dry flue gas loss, % [2]	5.94	5.65	8.92	7.27	6.85	9.92
Hydrogen loss, % [2]	6.22	6.31	6.62	6.34	6.44	6.90
Radiation and correction loss, % [3]	2.10	1.22	0.73	2.65	1.30	0.65
Unmeasured losses, % [4]	0.25	0.25	0.25	0.25	0.25	0.25
Total losses, %	14.51	13.43	16.52	16.51	14.84	17.72
Efficiency, %	85.49	86.57	83.48	83.49	85.16	82.28
<u>Flue gas emissions - calculated</u>						
Carbon monoxide, ppmv at 3% O_2	36	33	32	38	35	46
Carbon monoxide, ng/J	12.1	11.1	10.8	12.8	11.8	15.5
Nitrogen oxides, ppmv at 3% O_2	356	309	225	321	251	211
Nitrogen oxides, ng/J	197.0	170.9	124.5	177.6	138.8	116.7
Sulphur dioxide, ppmv at 3% O_2	733	729	766	603	575	564
Sulphur dioxide, ng/J	565.0	562.0	590.5	464.8	443.2	434.8

1 Calculated from O_2 analysis

2 Calculated according to ASME test procedure

3 From Fig. 8

4 An assumed value to cover minor losses

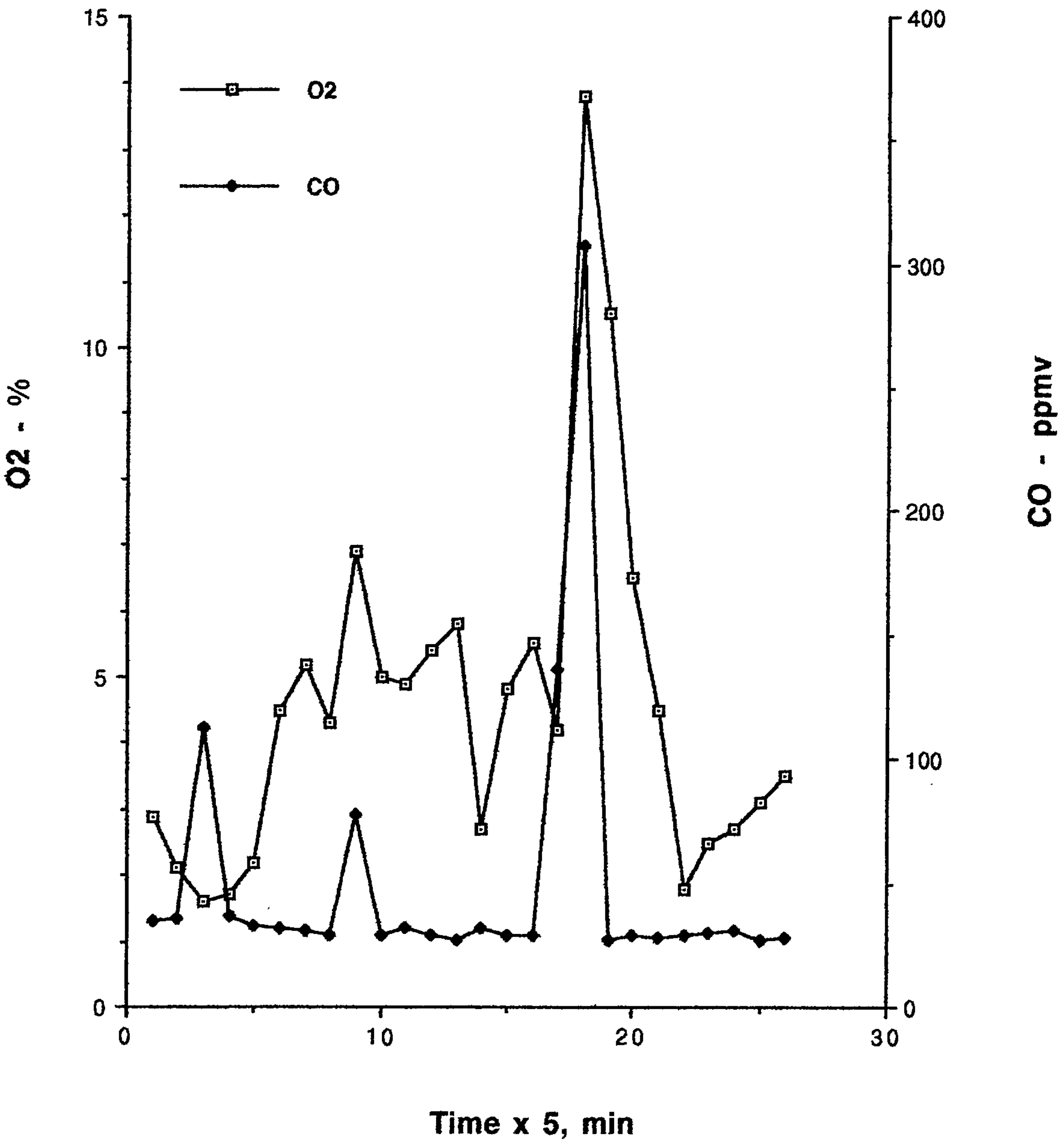

Fig. 1 Correlation of CO and O2 emissions in the flue gas for Boiler 3, May 29, 1991, 15:50h to 17:55h

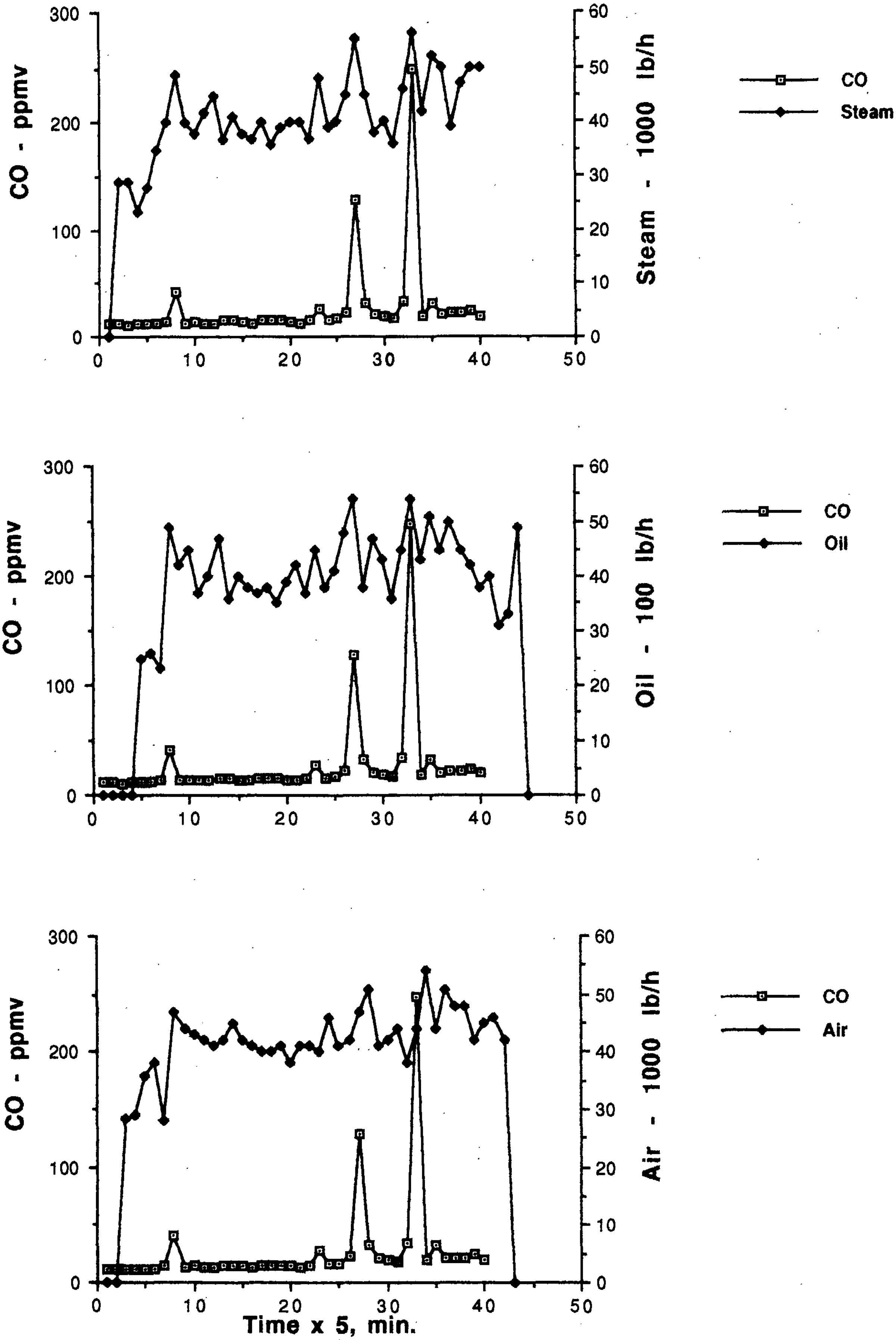

Fig. 2 Correlation of CO emissions to steam, oil and air flow for Boiler 3, May 30, 1991, 06:00 to 09:00 h

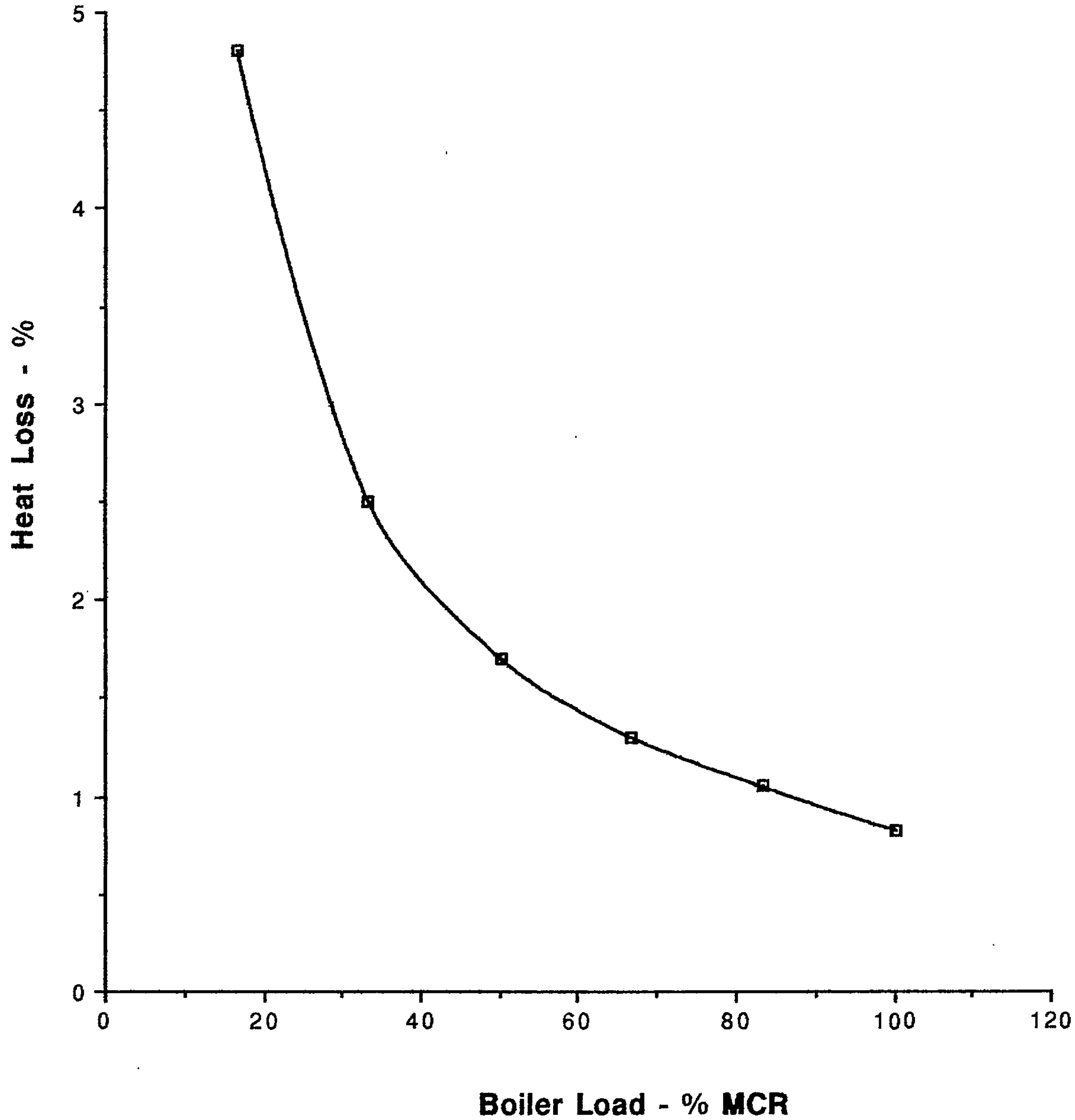

Fig. 3 Radiation and convection loss for Boilers 1 and 2 (100% MCR = 30 000 lb/h)

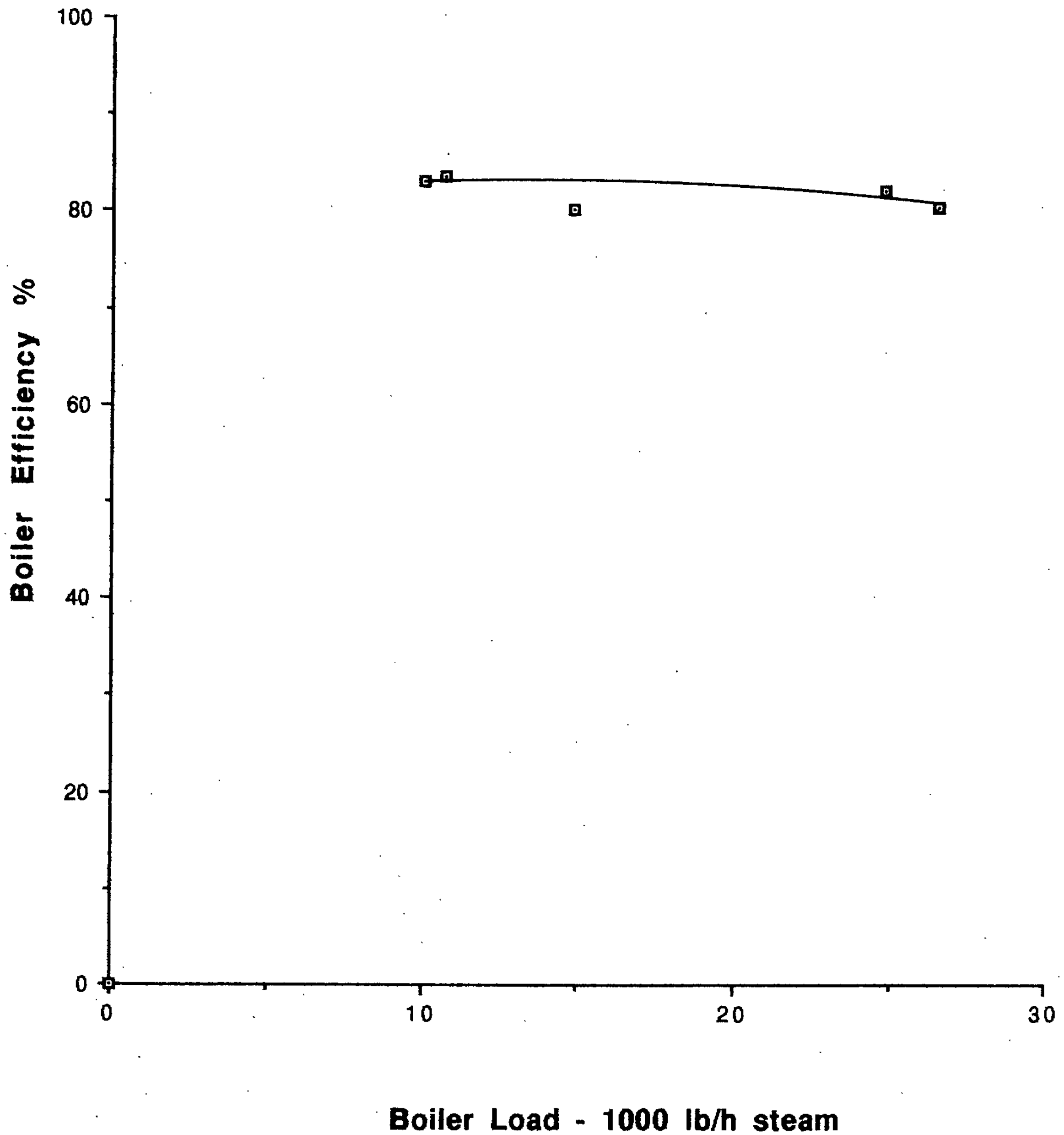

Fig. 4 Boiler efficiency versus load for Boilers 1 and 2

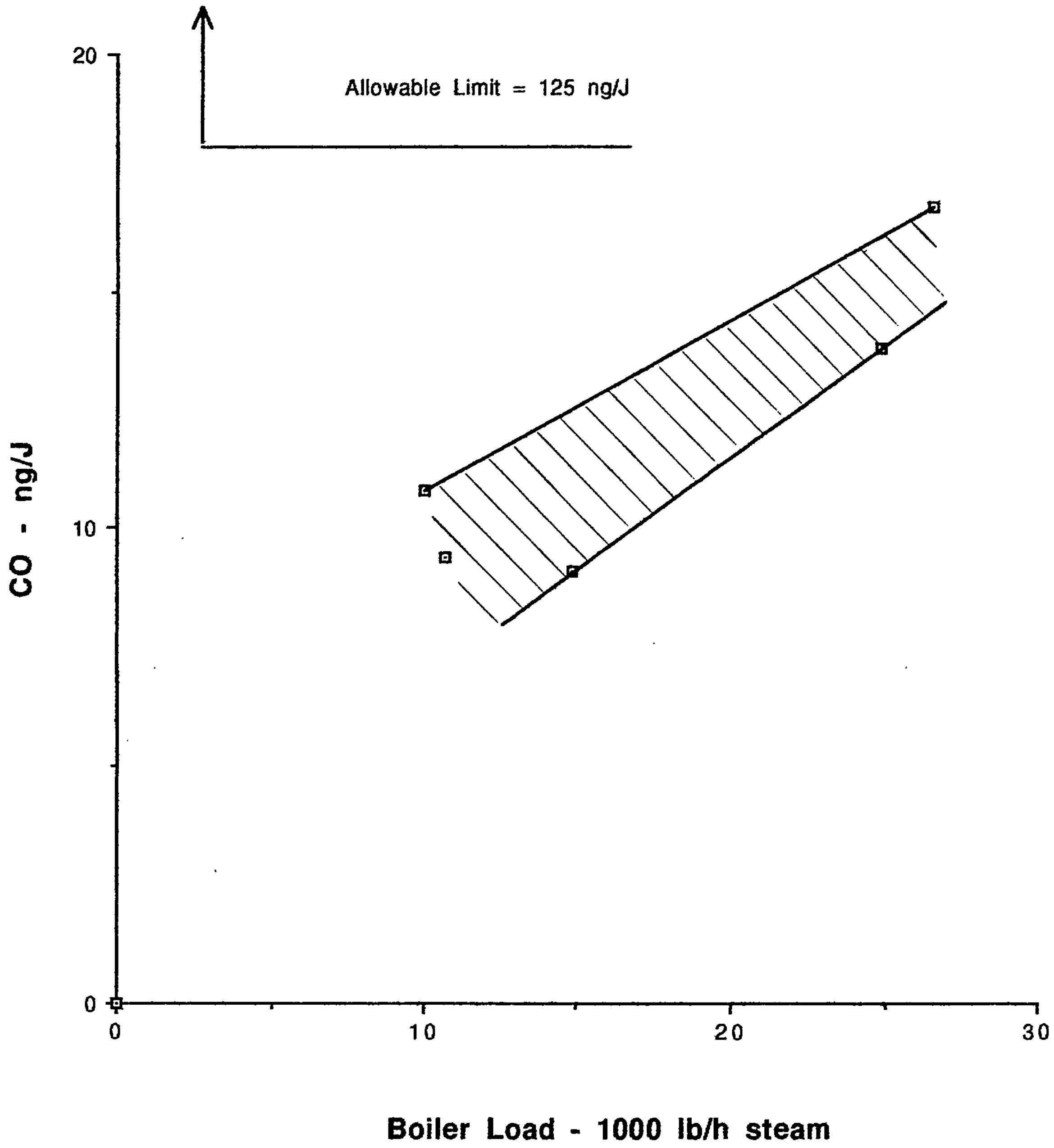

Fig. 5: CO emissions versus load for Boilers 1 and 2

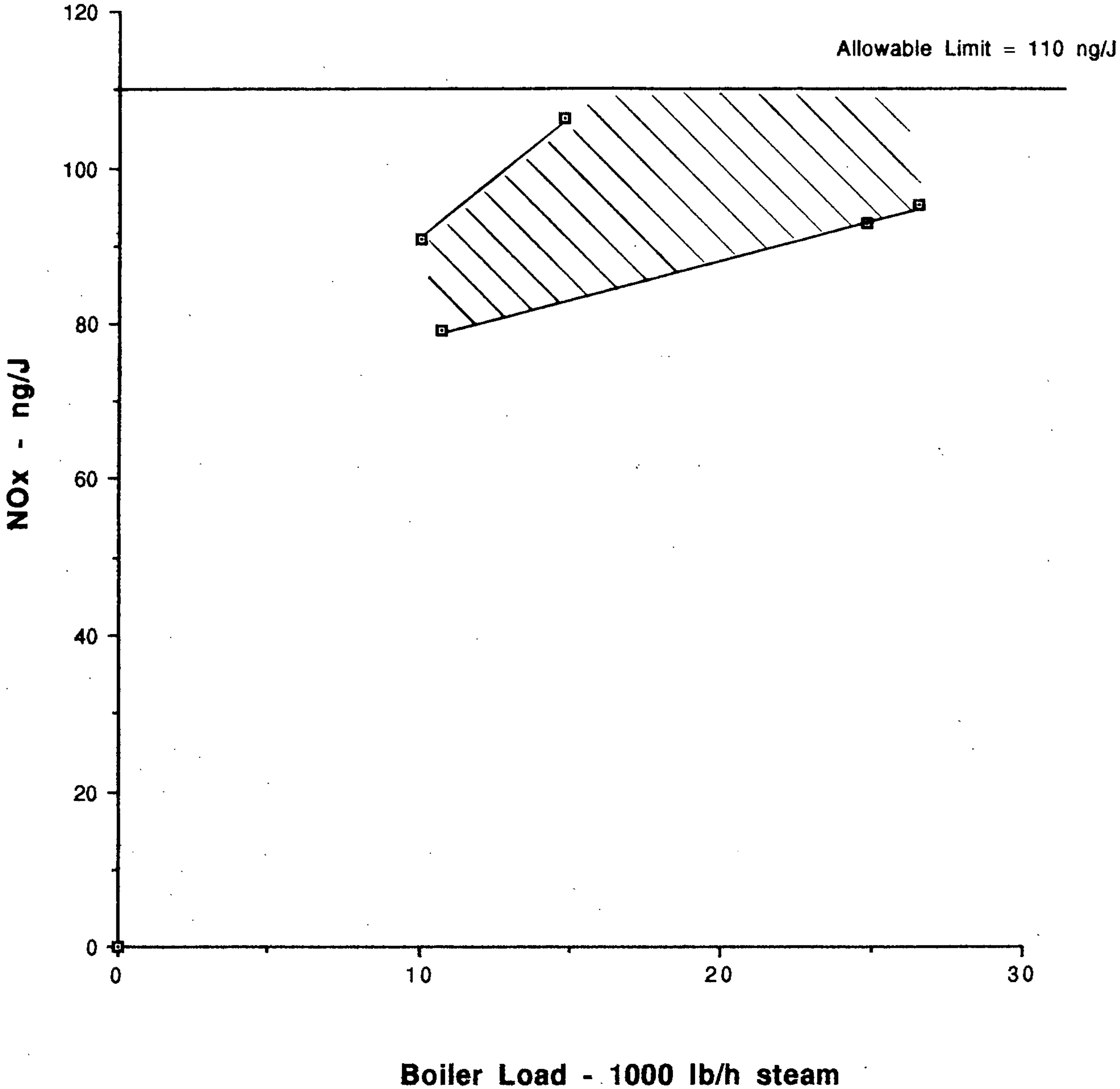

Fig. 6 NOx emissions versus load for Boilers 1 and 2

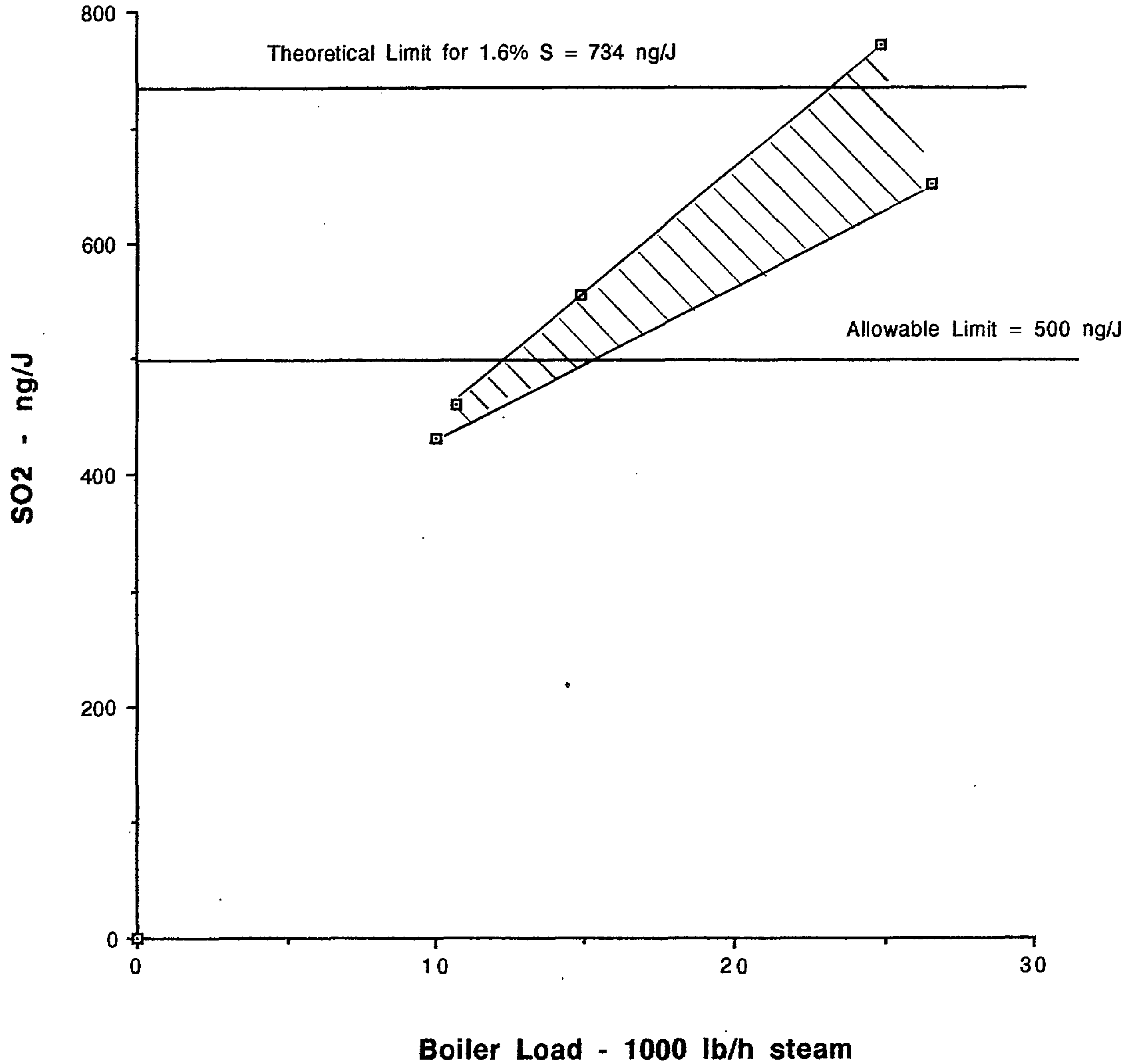

Fig. 7 SO2 emissions versus load for Boilers 1 and 2

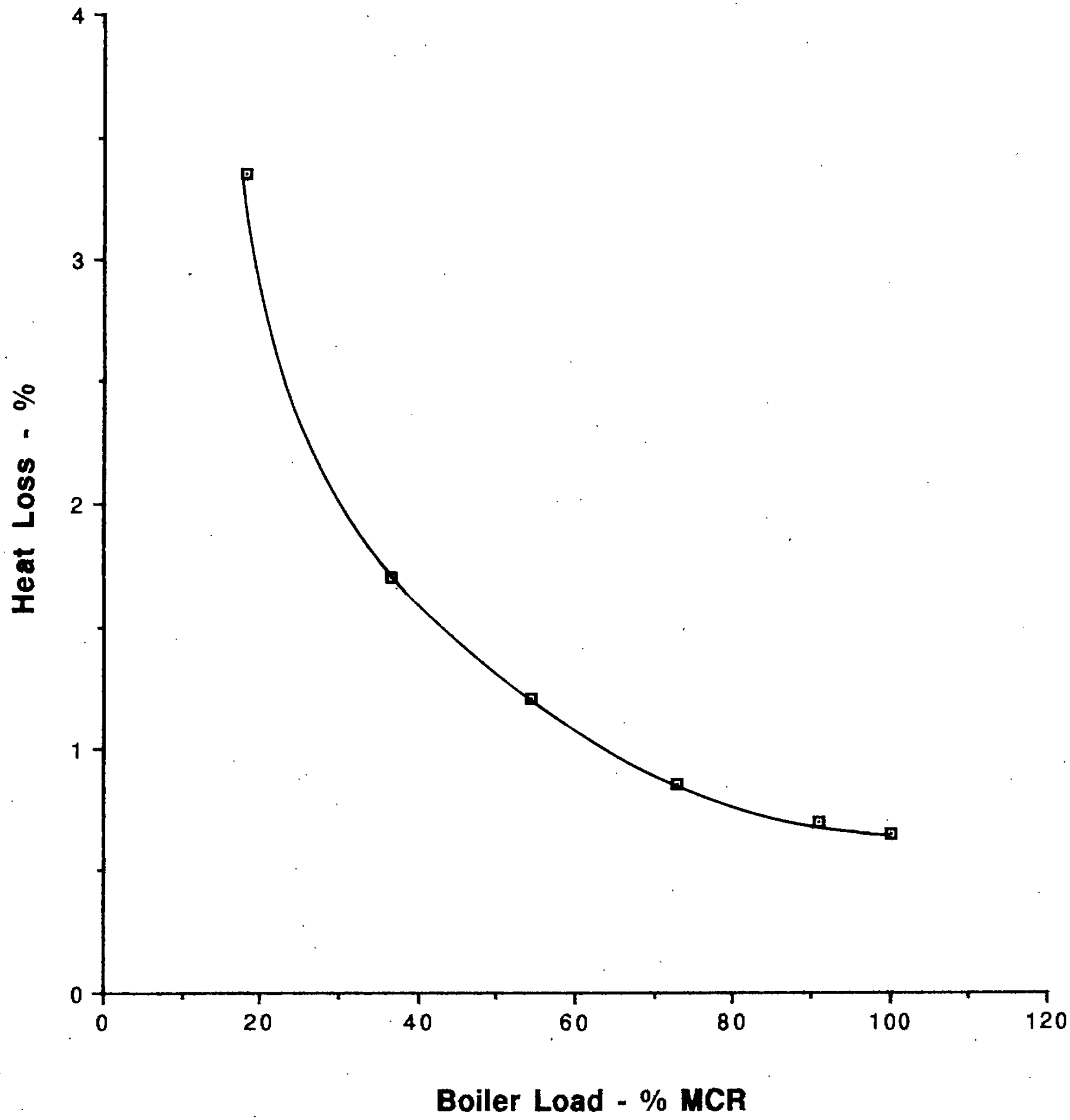

Fig. 8 Radiation and convection loss for Boilers 3 and 4 (100% MCR = 55,000 lb/h) steam

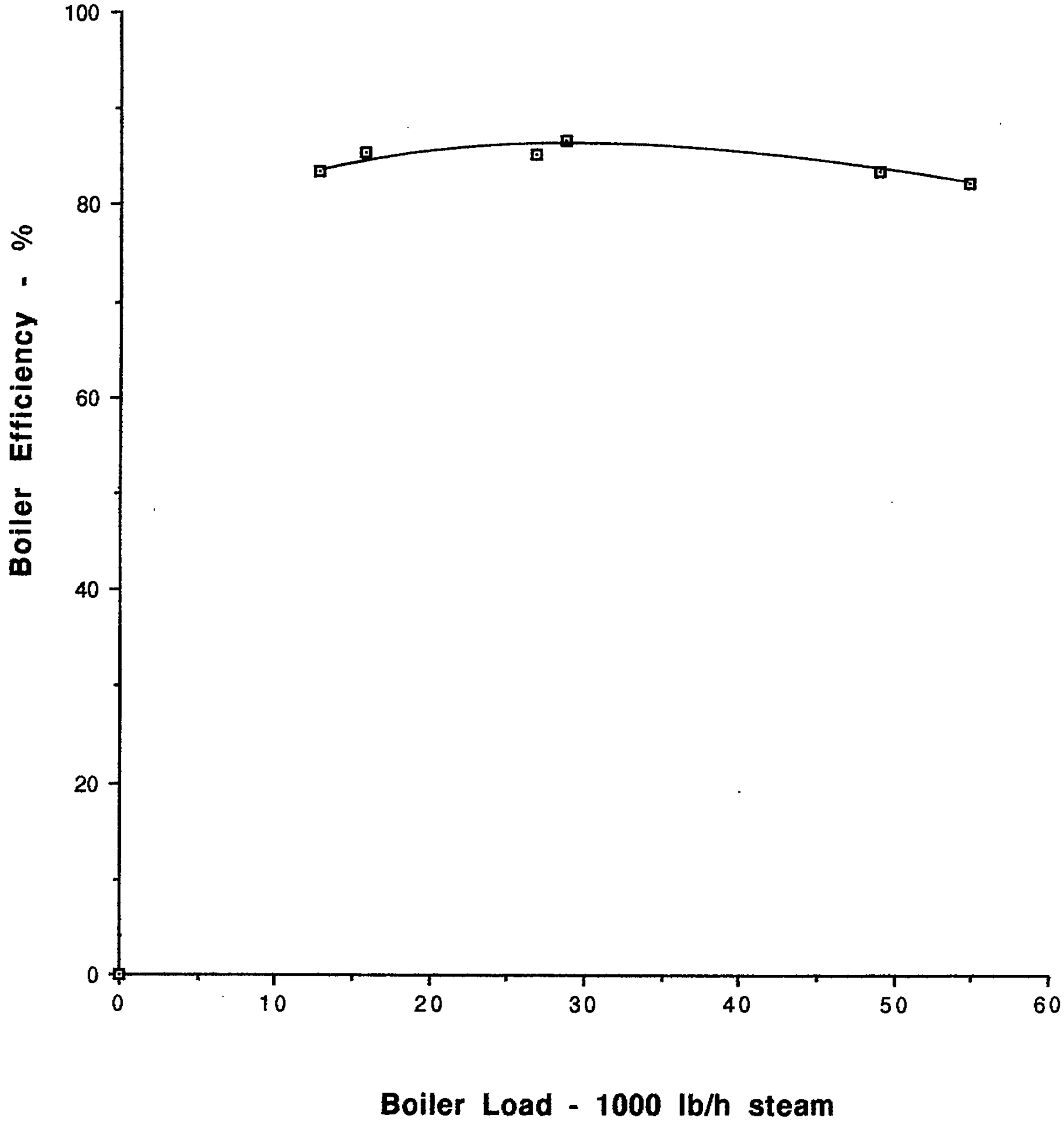

Fig. 9 Boiler efficiency versus load for Boilers 3 and 4

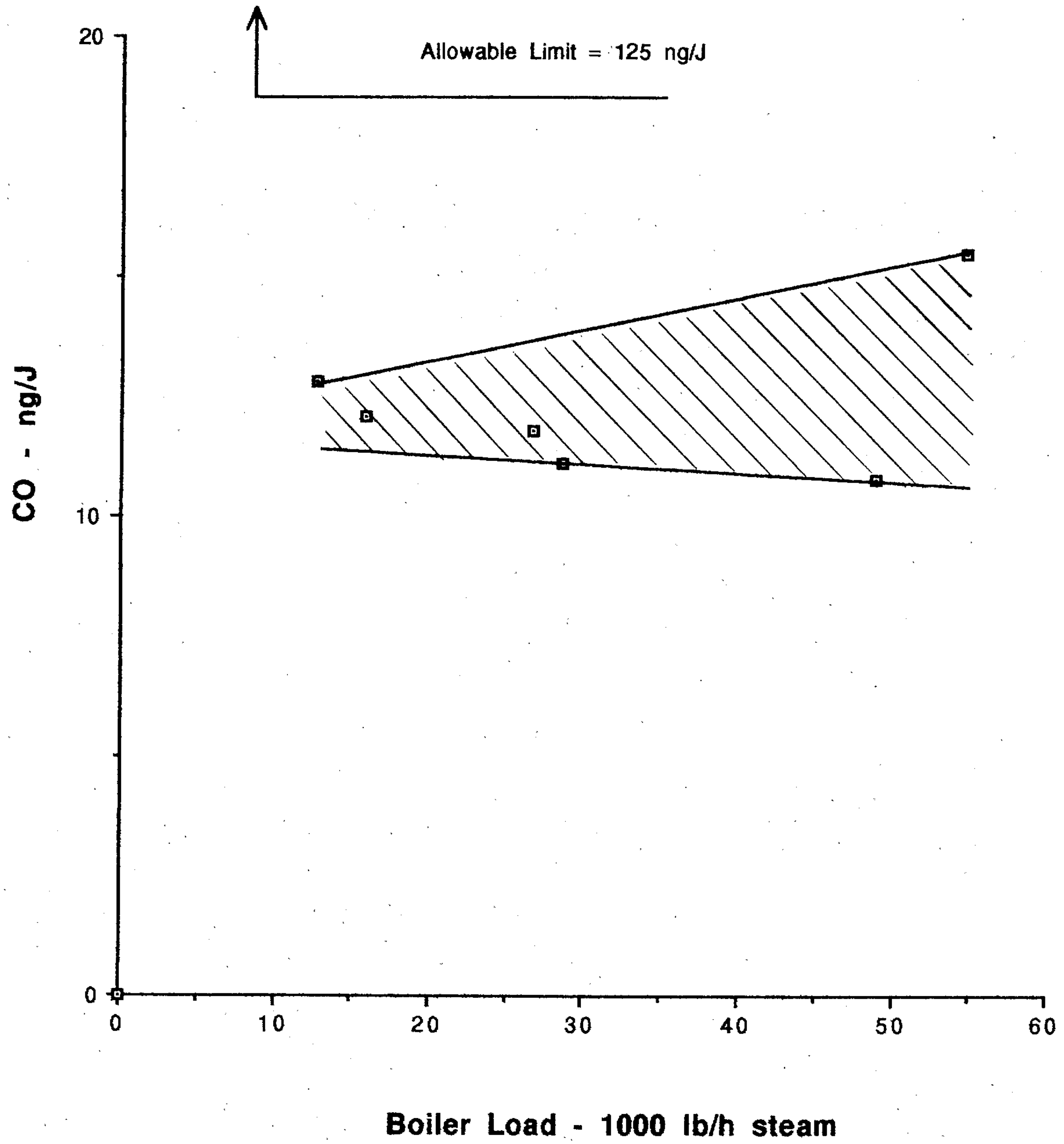

Fig. 10 CO emissions versus load for Boilers 3 and 4

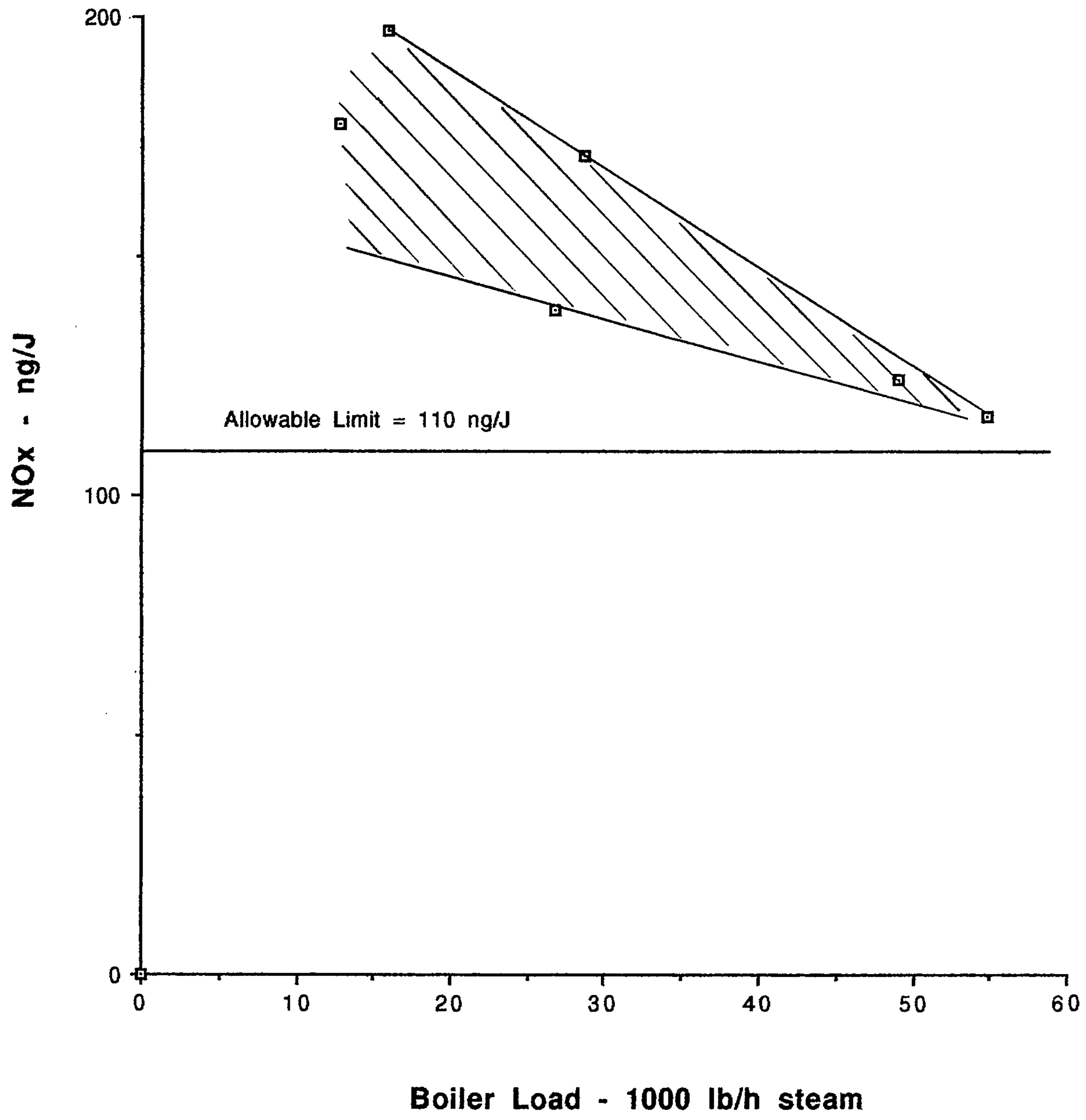

Fig. 11 NOx emissions versus load for Boilers 3 and 4

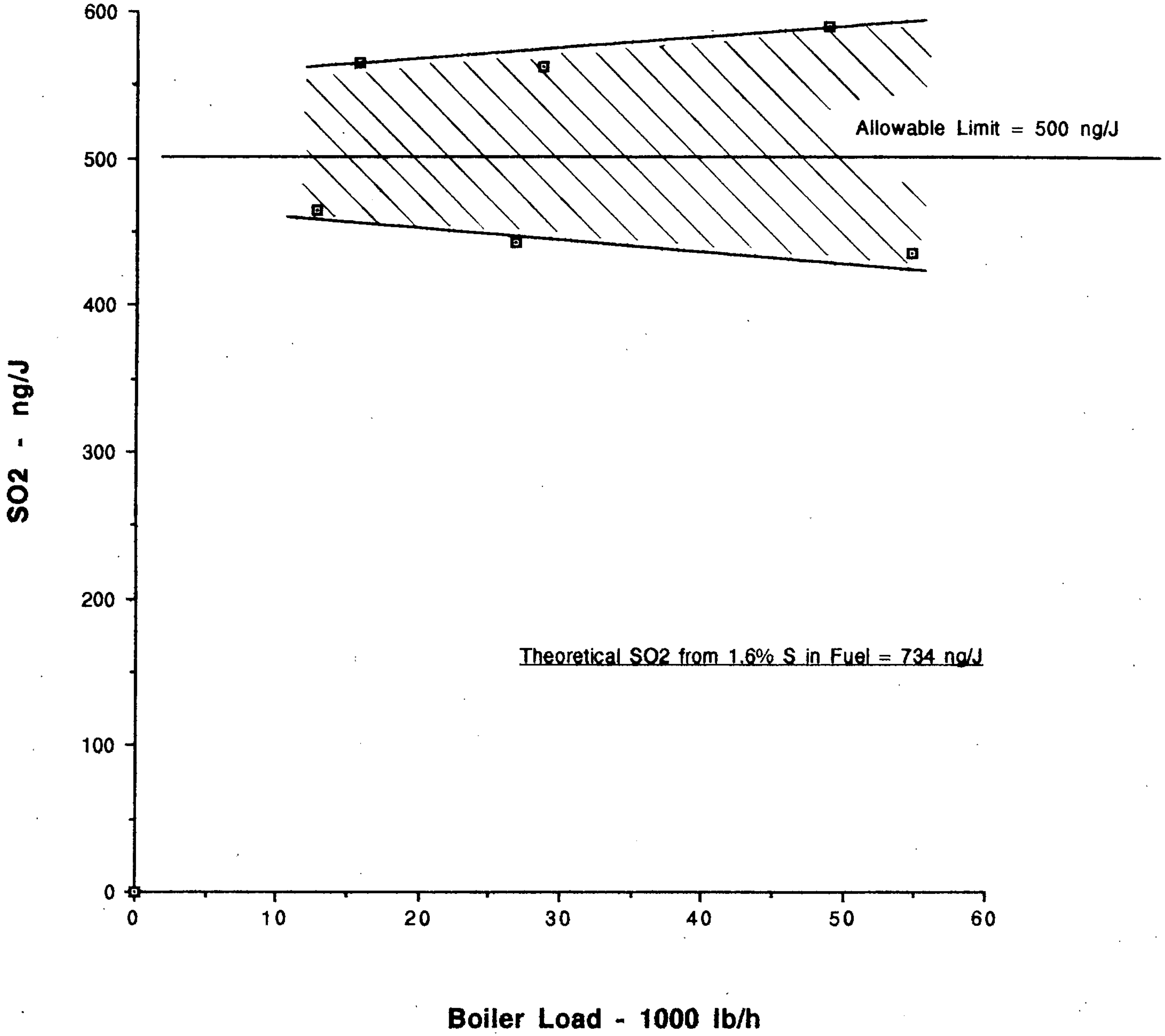

Fig. 12 SO2 emissions versus load for Boilers 3 and 4