State of California
AIR RESOURCES BOARD

DETERMINATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY AND BEST AVAILABLE RETROFIT CONTROL TECHNOLOGY FOR INDUSTRIAL, INSTITUTIONAL, AND COMMERCIAL BOILERS, STEAM GENERATORS, AND PROCESS HEATERS

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Approved by

the Technical Review Group
of the
California Air Pollution Control Officers' Association

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INTRODUCTION

This report presents the proposed determinations of reasonably available control technology (RACT) and best available retrofit control technology (BARCT) for industrial, institutional, and commercial boilers, steam generators, and process heaters. The RACT/BARCT Determination is presented in Appendix A of this document. The determinations follow the "California Clean Air Act Guidance for the Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology," approved by the California Air Resources Board (ARB) on April 13, 1990. The determinations have been reviewed and approved by the Technical Review Group (TRG) of the California Air Pollution Control Officers' Association (CAPCOA).

In developing the proposed RACT and BARCT determinations, the staff reviewed a statewide suggested control measure (SCM) and several district rules. Tables 1 and 2 present summaries of the SCM and the district rules that the staff reviewed. The Technical Support Document (TSD) for the SCM is available upon request. The complete texts of the applicable district rules are contained in Appendices B-E.

I. RACT/BARCT RECOMMENDATION

A. RACT Discussion

On April 29, 1987, the TRG approved a suggested control measure for the control of emissions of oxides of nitrogen (NOx) from industrial, institutional, and commercial boilers, steam generators and process heaters. This SCM was subsequently approved by the ARB on September 10, 1987. The SCM applies to units with rated heat inputs of 10 million British thermal units per hour (MMBtu/hr) and up, except units with rated heat inputs of greater than 40 MMBtu/hr that are based in petroleum refineries.

The lowest emission limits contained in the SCM apply to units with rated heat inputs of greater than or equal to 20 million Btu per hour and less than or equal to 150 million Btu per hour, operating with annual capacity factors of greater than 10 percent. The limits for these units are 70 parts per million by volume (ppmv) NOx for gaseous fuel operations and 115 ppmv NOx for number 1 or number 2 grade fuel oil.

For the RACT determination, we have extended the application of these limits to all units with rated heat inputs of greater than or equal to 5 million Btu per hour, operating with annual heat inputs of greater than or equal to 90,000 therms. We have also applied the limit for operating on number 1 or number 2 grade fuel oil to operation with all types of nongaseous fuels. Units which normally burn only gas are allowed a 150 ppmv NOx emission limit for burning nongaseous fuel for not more than 168 hours per year, if gas is unavailable for purchase.

Table 1

Emission Limits Contained in the Suggested Control Measure Approved by the Air Resources Board on September 10, 1987

Rated[a/] Heat Input	Annual Capacity Factor	Fuel Type	NO_x[b/] Emission Limits
≥20 and ≤150 MMBtu/hr	>10.0%	Gas	70 ppmv NO_x or 0.08 lbs NO_2/MMBtu
		Fuel Oil #1 or #2	115 ppm NO_x or 0.15 lbs NO_2/MMBtu
		Other Fuel Oil	150 ppmv NO_x or 0.20 lbs NO_2/MMBtu
>150 MMBtu/hr	>5.0%	Gas	85 ppmv NO_x or 0.10 lbs NO_2/MMBtu
		Fuel Oil #1 or #2	135 ppmv NO_x or 0.18 lbs NO_2/MMBtu
		Other Fuel Oil	165 ppmv NO_x or 0.22 lbs NO_2/MMBtu

a/ Units with rated heat inputs of greater than or equal to 10 MMBtu/hr, and less than 20 MMBtu/hr, and with annual capacity factors of greater than 10.0%, are subject to other requirements.

b/ Corrected to 3.00 percent by volume O_2, dry, and averaged over 15 consecutive minutes.

Table 2

Summary District Rules Reviewed for NOx Emissions from Non-Utility Boilers and Process Heaters

Rated Heat Input	Annual Heat Input or Capacity Factor	NOx[c] Emission Limits	CO[c] Emission Limits
-------SCAQMD's Rule 1146.1, Boilers and Process Heaters (10/5/90)----------			
≥2 and <5 MMBtu/hr	>18,000 therms[a]	30 ppmv or 0.037 lbs NO_2/MMBtu	400 ppmv
-------SCAQMD's Rule 1146, Boilers and Process Heaters (9/9/88, 1/6/89)-----			
≥5 MMBtu/hr	≤90,000 therms[b]	40 ppmv or 0.05 lbs NO_2/MMBtu	400 ppmv
≥40 MMBtu/hr	>25%	30 ppmv	400 ppmv
-------SCAQMD's Rule 1109, Boilers and Process Heaters - Petroleum----------- Refineries, (11/1/85, 8/5/88)			
>40 MMBtu/hr	≥10%	0.03 lbs NO_2/MMBtu @ maximum rated capacity	
-------VCAPCD's Rule 74.15, Boilers and Process Heaters, (3/28/89)----------			
≥5 MMBtu/hr	≥90,000 therms[b]	40 ppmv	400 ppmv

a/ Units with annual heat inputs of less than 18,000 therms are subject to other requirements.

b/ Units with annual heat inputs of less than 90,000 therms are subject to other requirements.

c/ Corrected to 3.00 percent by volume O_2, dry, and averaged over 15 consecutive minutes.

A summary of the RACT determination is presented in Table 3.

B. BARCT Discussion

As shown in Table 2, both the South Coast Air Quality Management District (SCAQMD) and the Ventura County Air Pollution Control District (VCAPCD) have adopted source specific rules for NOx emission control on non-electric-generating boilers, steam generators, and process heaters. SCAQMD Rule 1109, adopted November 1, 1985, and amended August 5, 1988, applies to units with rated heat inputs of greater than 40 MMBtu/hr located at petroleum refineries. SCAQMD Rule 1146, adopted September 9, 1988, and amended January 6, 1989, applies to units with rated heat inputs of 5 MMBtu/hr and up not located at petroleum refineries. SCAQMD Rule 1146.1, adopted October 5, 1990, applies to units with rated heat inputs from 2 MMBtu/hr to less than 5 MMBtu/hr. VCAPCD Rule 74.15, adopted March 28, 1989, applies to units with rated heat inputs of 5 MMBtu/hr and up, except water heaters.

The emission limits contained in district rules are 30 ppmv NOx for units with rated heat inputs of greater than or equal to 2 million Btu per hour and less than 5 million Btu per hour, having annual heat inputs of greater than 18,000 therms; 40 ppmv NOx for units with rated heat inputs of greater than or equal to 5 million Btu per hour, having annual heat inputs of greater than 90,000 therms; 30 ppmv NOx for units with rated heat inputs of greater than or equal to 40 million Btu per hour, operating at annual capacity factors of greater than 25 percent; and 0.03 pounds NO_2 per million Btu of heat input for units operating at maximum rated capacity with rated heat inputs of greater than 40 million Btu per hour, sited at petroleum refineries and operating at annual capacity factors of greater than or equal to 10 percent.

For the BARCT determination, we have applied the 30 ppmv NOx emission limit to all units burning gas, having rated heat inputs of greater than or equal to 5 million Btu per hour and operating with annual heat inputs of greater than or equal to 90,000 therms. For units burning nongaseous fuels, we have applied the 40 ppmv NOx emission limit to all units having rated heat inputs of greater than or equal to 5 million Btu per hour, operating with annual heat inputs of greater than or equal to 90,000 therms. Units which normally burn only gas are allowed a 150 ppmv NOx emission limit for burning nongaseous fuel for not more than 168 hours per year, if gas is unavailable for purchase.

Table 3

RACT/BARCT Summary for Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters

Standards

---------- RACT -----------

Rated Heat Input	Annual[a/] Heat Input	Fuel Type	NOx[b/] Emission Limits	CO[b/] Emission Limits
$\geq$ 5 MMBtu/hr	$\geq$ 90,000 therms	Gas	70 ppmv[c/]	400 ppmv
		Other	115 ppmv[d/]	400 ppmv
		Exemption[g/]	150 ppmv[h/]	400 ppmv

---------- BARCT ----------

Rated Heat Input	Annual[a/] Heat Input	Fuel Type	NOx[b/] Emission Limits	CO[b/] Emission Limits
$\geq$ 5 MMBtu/hr	$\geq$ 90,000 therms	Gas	30 ppmv[e/]	400 ppmv
		Other	40 ppmv[f/]	400 ppmv
		Exemption[g/]	150 ppmv[h/]	400 ppmv

a/ Units with annual heat inputs of less than 90,000 therms are subject to other requirements.

b/ Corrected to 3.00 percent by volume O_2, dry, and averaged over 15 consecutive minutes.

c/ 0.084 pounds NO_2 per MMBtu of heat input.

d/ 0.150 pounds NO_2 per MMBtu of heat input.

e/ 0.036 pounds NO_2 per MMBtu of heat input.

f/ 0.052 pounds NO_2 per MMBtu of heat input.

g/ For not more than 168 hours per calendar year, only when gas is not available for purchase.

h/ 0.215 pounds NOx per MMBtu of heat input.

We chose 30 ppmv as the uniform BARCT NOx emission limit for gas firing of all industrial, institutional, and commercial boilers, steam generators, and process heaters. This uniform emission limit reflects improvements in technology which have occurred in the last few years. We believe that most units can meet this limit by installing new burners with flue gas recirculation. Some units may need to add selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems. We believe that 30 ppmv is the appropriate BARCT NOx emission limit due to the many units currently operating within this limit without the use of flue gas emission controls. New units of the near future may achieve emission limits below 15 ppmv NOx without the use of flue gas emission controls. However, for districts which have recently adopted rules which allow higher emissions, the incremental cost-effectiveness of requiring 30 ppmv may be high for some affected units. Therefore, districts which have adopted rules covering the applicability of this determination, within three years prior to the date of approval of this determination, are deemed to comply with this determination.

In the SCAQMD, specially blended low-NOx fuel oil, which has low sulfur, nitrogen, and aromatic hydrocarbon contents, is being used to meet the 40 ppmv limit of Rule 1146. Since the low-NOx fuel oil is blended in small quantities, it is much more expensive than number 2 fuel oil. Therefore, this low-NOx fuel oil is being used primarily for dual fuel firing capability at this time. Methanol is also being used in the SCAQMD to meet the 40 ppmv limit with dual fuel firing capability. We believe that, in the future, liquid fuel firing at 40 ppmv NOx may be economically competitive with gas firing at 30 ppmv NOx.

A summary of the BARCT determination is also presented in Table 3.

II. CONTROL TECHNOLOGY

Nitric oxide (NO) forms in process equipment such as boilers and heaters, which operate on the combustion of fuel and air. The NO may then be emitted to the atmosphere along with other products of combustion in the flue gas. Smaller amounts of nitrogen dioxide (NO_2) form in the combustion process, and some NO oxidizes to NO_2 in the stack.

We refer to NO and NO_2 cumulatively as oxides of nitrogen (NO_x), and we quantify NO_x emissions as parts per million (ppm) by volume, relative to dry stack gases at 3 percent O_2. Alternately, we may quantify NO_x emissions as pounds of NO_2 per million British thermal unit (MMBtu) of fuel input to the process, based on the higher heating value (HHV) and flow rate of the fuel.

The formation of NO by combustion processes is governed primarily by (1) the chemically-bound nitrogen content of the fuel, (2) the oxygen concentration of the flame, (3) the temperature of the flame, and (4) the length of time for which the combustion gases are held at the flame temperature.

Chemically-bound nitrogen of 1000 ppm by weight in fuel oil could result in NO formation of up to 83 ppm by volume, relative to dry stack gases at 3 percent O_2. This estimate is based on 65 percent conversion of fuel-nitrogen to NO. For higher fuel-nitrogen contents the percent conversion is lower. For lower fuel-nitrogen contents, the percent conversion is higher. Residual fuel oils may have nitrogen contents of between 1000 ppm and 8000 ppm by weight. In California, distillate fuel oils with nitrogen contents between 200 and 600 ppm by weight are typically available. By 1994, distillate fuel oils with nitrogen contents below 10 ppm by weight may be available as a result of statewide regulations limiting the sulfur content of motor vehicle diesel fuel. Chemically-bound nitrogen of 10 ppm in fuel oil could not convert to more than 1 ppm of NO. Due partly to chemically-bound nitrogen in fuel oils, the combustion of fuel oils produces more NO than the combustion of natural gas at the same conditions.

Generally, premixed flames, such as in natural gas combustion, will produce less NO than diffusion flames, such as in oil droplet combustion, with the same amount of excess air. This is because the peak temperatures in diffusion flames occur at surfaces of theoretically correct air-to-fuel ratios, while the peak temperatures for premixed flames are lower due to excess-air dilution.

For most applications reducing NOx emissions from industrial, institutional, and commercial boilers, steam generators, and process heaters can be broken down into four methods. These are (1) retrofitting of low-NOx-emitting burners, (2) retrofitting of flue-gas-recirculation systems (3) installation of ammonia injection systems for selective noncatalytic reduction, and (4) installation of ammonia injection systems along with catalytic reactors for selective catalytic reduction. These methods are discussed below.

A. <u>Low-NOx Burners</u>

Low-NOx burners employ low excess air combustion, air staging, fuel staging, or combustion product recirculation to lower NOx formation in the flame. Low excess air combustion and combustion product recirculation decrease the oxygen available for NOx formation. Combustion product recirculation also lowers the bulk flame temperature, and consequently lowers the NOx formation rate and equilibrium concentration. Staged-air burners lower available oxygen at points in the combustion chamber where the temperature is high. Staged-fuel burners lower the temperature at points in the combustion chamber where available oxygen is high. Retrofitting of low-NOx burners may require derating of equipment, because flame lengths may be significantly increased.

Low-NOx burners are applicable to most gas-fired and oil-fired units. For gas-fired units, the control effectiveness ranges from 10 to 55 percent. For units fired with low-nitrogen oil, the control effectiveness is expected to be within the same range.

B. Flue Gas Recirculation

Flue gas recirculation (FGR) for NOx control consists of extracting a portion of the flue gas from the economizer outlet and returning it to the furnace, admitting the flue gas through the furnace windbox. Flue gas recirculation lowers the bulk furnace gas temperature and reduces oxygen concentration in the combustion zone.

A retrofit installation of FGR consists of adding a fan, ductwork, dampers, and controls as well as possibly having to increase existing fan horsepower due to increased draft loss.

FGR is an effective control technique for both gas-fired and distillate oil-fired units. FGR is not effective at reducing NOx formation originating from fuel-bound nitrogen. The control effectiveness of flue gas recirculation ranges from 60 to 70 percent for gas-fired units. The control effectiveness of FGR for units firing low-nitrogen oil is expected to be within the same range.

C. Selective Noncatalytic Reduction

Exxon Research and Engineering Company has developed, patented, and is offering for license, a noncatalytic process called Thermal DeNOx for removing oxides of nitrogen from flue gas in stationary combustion sources. Thermal DeNOx is based on the gas phase homogeneous reaction between NOx in flue gas and ammonia (NH_3), which produces nitrogen and water.

In general, NH_3 is injected into the hot flue gas by means of either air or steam carrier gas at a point in the flue specifically selected to provide optimum reaction temperature and residence time. In the temperature range of 1600°F to 2200°F, the reaction occurs through the injection of NH_3 alone. Hydrogen (H_2) can also be injected along with NH_3 to extend the effectiveness range of the deNOx reaction down to 1300°F.

NOx reductions of up to 90 percent have been demonstrated on an oil field steam generators where favorable process conditions exist. DeNOx performance using earlier technology ranges from 50 to 70 percent reduction for most oil-fired and gas-fired process heaters and steam boilers.

D. Selective Catalytic Reduction

Selective catalytic reduction (SCR) refers to a process that chemically reduces NOx with NH_3 over a heterogeneous catalyst in the presence of oxygen (O_2). The process is termed selective because the reducing agent NH_3 preferentially attacks NOx rather than O_2. However, the O_2 enhances the reaction and is a necessary part of the reaction scheme. Thus, SCR is potentially applicable to flue gas under oxidizing conditions, greater than one percent O_2.

In theory a 1:1 stoichiometric molar ratio of NH_3 to NO is sufficient to reduce NOx to molecular nitrogen (N_2) and water vapor (H_2O). In practice a NH_3:NO ratio of 1:1 has typically reduced NOx emissions by 80 to 90 percent with a residual NH_3 concentration of less than 20 ppmv. The optimum temperature range for the catalytic reaction is 570°F to 845°F.

SCR retrofitting requires a reactor, which contains the catalytic material, and an ammonia storage and injection system. Due to the increased pressure drop across the reactor, some increase in boiler fan horsepower, or possibly a new fan, may be necessary.

SCR has been extensively employed in Japan on gas-fired and oil-fired industrial and utility boilers.

III. COST-EFFECTIVENESS

Flue-gas recirculation and ammonia injection are probably the most universally applicable methods for reducing NOx emissions from industrial, institutional, and commercial boilers, and process heaters. The unit cost of NOx emission reduction with FGR ranges from $1600 to $7800 per ton at 50 percent capacity factors. The unit cost of NOx emission reduction with ammonia injection ranges from $1500 to $6000 per ton at 50 percent capacity factors. Low-NOx burners are generally less expensive, and SCR is generally more expensive, than these methods. The ranges are reflective that unit costs generally increase with decreasing equipment size. Furthermore, unit costs increase rapidly with decreasing capacity factors below 25 percent. Table 4 presents a summary of cost-effectiveness ranges for the different technologies.

Table 4

Cost-Effectiveness of Selected NOx Emission Control Technologies

	Annual Capacity Factor	Unit Size Range (MMBtu/hr)	NOx Emission Reduction Cost-Effectiveness Range (1986$ thousand/ton NOx)
Low-NOx Burners	10%		2.3 to 27
	50%	3.5 to 150	0.5 to 6.4
	90%		0.3 to 4.0
Flue Gas Recirculation	10%		6.8 to 29
	50%	3.5 to 350	1.6 to 6.8
	90%		1.0 to 3.7
Selective Noncatalytic Reduction	10%		2.3 to 20
	50%	50 to 375	1.5 to 6.0
	90%		1.3 to 3.8
Selective Catalytic Reduction	10%		24 to 66
	50%	50 to 350	6.0 to 14
	90%		4.0 to 9.0

Reasonably available control technology (RACT) requirements can be met with either FGR or ammonia injection. However, for oil-firing, switching to a lower nitrogen-content fuel may be required. FGR is ineffective at reducing NOx formation originating from fuel nitrogen, and the absolute amount of NOx passing through ammonia injection systems increases directly with the amount entering. Where applicable, low-NOx burners may be more effective at reducing emissions when firing with high-nitrogen fuel.

Best available retrofit control technology (BARCT) requirements for gas-firing may be met by installing new burners with either FGR or ammonia injection. However, both methods, or SCR, may be necessary for up to twice the cost.

IV. IMPACTS

A. Economic

The potential economic impacts of this determination are the capital cost of emission control equipment and the increased operating cost associated with emission control equipment. If combustion equipment is operated with lower excess air after, or instead of, retrofitting control equipment; there will be a cost benefit due to increased thermal efficiency.

B. Air Quality

The most significant impact of this determination is the decrease in NOx emissions and resultant decrease in atmospheric ozone and PM10 formation. Other potential impacts include ammonia slip from SNCR and SCR systems and ammonia leakage from storage and handling systems, which will result in emissions of ammonia to the atmosphere. Ammonia emissions will increase the formation of PM10 in the atmosphere.

C. Hazards

Ammonia is a toxic, highly reactive compound and its use, storage, and transport can be hazardous, especially in the case of worker exposure to highly concentrated ammonia vapor or contact with liquid ammonia. Occupational Safety and Health Administration (OSHA) regulations specify the methods for the use, storage, and transport of ammonia. These regulations were developed to reduce the hazards that could occur when handling ammonia.

The spent catalyst materials from the use of SCR commonly contain small amounts of hazardous materials, including vanadium pentoxide. This compound is toxic if inhaled. A majority of catalysts used in California are now reclaimed and recycled by the manufacturer, so that their disposal should pose no significant environmental impacts. For those facilities that do not recycle their catalysts, the spent material would have to be deposited in a Class I landfill. The only operational Class I disposal site in California is located in Kings County.

D. Energy

Additional fan energy will be required to operate FGR, SNCR, and SCR systems. All of the systems require additional mass flows and gas velocities, which will increase flow losses through the furnaces and downstream passages. The FGR ducting and SCR reactor are additional flow impedances.

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APPENDIX A

RACT/BARCT Determination

DETERMINATION OF REASONABLY AVAILABLE CONTROL TECHNOLOGY AND BEST AVAILABLE RETROFIT CONTROL TECHNOLOGY FOR INDUSTRIAL, INSTITUTIONAL, AND COMMERCIAL BOILERS, STEAM GENERATORS, AND PROCESS HEATERS

I. Applicability

This determination applies to boilers, steam generators, and process heaters with rated heat inputs of greater than or equal to 5 million Btu per hour, used in all industrial, institutional, and commercial operations. This determination does not apply to boilers used by electric utilities to generate electricity, waste heat recovery boilers that are used to recover sensible heat from the exhaust of combustion turbines, dryers in which the material being dried is in direct contact with the products of combustion, cement and lime kilns, glass melting furnaces, and smelters.

II. Definitions

A. **ANNUAL HEAT INPUT** means the total heat input of fuels burned by a unit in a calendar year, as determined from the HHV and cumulative annual usage of each fuel.

B. **BARCT** means "best available retrofit control technology," defined in section 40406 of the California Health and Safety Code as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

C. **BOILER OR STEAM GENERATOR** means any combustion equipment fired with any fuel and used to produce steam that is not used exclusively to produce electricity for sale. BOILER or STEAM GENERATOR does not include any waste heat recovery boiler that is used to recover sensible heat from the exhaust of a combustion turbine.

D. **BRITISH THERMAL UNIT (Btu)** means the amount of heat required to raise the temperature of one pound of water from $59^{o}F$ to $60^{o}F$ at one atmosphere.

E. **HEAT INPUT** means the chemical heat released due to fuel combustion in a unit, using the higher heating value of the fuel. This does not include the sensible heat of incoming combustion air.

F. **GAS** means any fuel which is a gas at standard conditions.

G. **HIGHER HEATING VALUE (HHV)** means the total heat liberated per mass of fuel burned (Btu per pound), when fuel and dry air at standard conditions undergo complete combustion and all resultant products are brought to their standard states at standard conditions. HHV shall be determined by one of the following test methods: (1) ASTM D 2015-85 for solid fuels; (2) ASTM D 240-87 or

ASTM D 2382-88 for liquid hydrocarbon fuels; or (3) ASTM D 1826-88, or ASTM D 1945-81 in conjunction with ASTM D 3588-89 for gaseous fuels.

H. **NOx EMISSIONS (NOx)** means the sum of nitric oxides and nitrogen dioxide in the flue gas.

I. **NONGASEOUS FUEL** means any fuel which is not a gas at standard conditions.

J. **PARTS PER MILLION (BY VOLUME) (ppmv)** means the ratio of the number of gas molecules of a given species, or group, to the number of millions of total gas molecules.

K. **PROCESS HEATER** means any combustion equipment fired with any fuel, and which transfers heat from combustion gases to water or process streams. PROCESS HEATER does not include any dryers in which the material being dried is in direct contact with the products of combustion, cement or lime kilns, glass melting furnaces, or smelters.

L. **RACT** means "reasonably available control technology."

M. **RATED HEAT INPUT** (million Btu per hour) means the heat input capacity specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified such that its maximum heat input is different than the heat input capacity specified on the nameplate, the maximum heat input shall be considered as the rated heat input.

N. **STANDARD CONDITIONS** means $68^{o}F$ and one atmosphere.

O. **THERM** means one hundred thousand (100,000) Btu.

P. **THREE PREVIOUS CALENDAR YEARS** means the three consecutive years immediately preceding the year in which final compliance is required by this determination, or the three consecutive years immediately preceding each calendar year of compliance thereafter.

Q. **UNIT** means any boiler, steam generator or process heater as defined in Sections C and K, above.

III. Standards

(FOR RACT)

A. For units with rated heat inputs of greater than or equal to 5 million Btu per hour and annual heat inputs of greater than or equal to 90,000 therms for any of the three previous calendar years, NOx emissions shall not exceed the following levels:

1) 70 parts per million by volume, or 0.084 pound per million Btu of heat input, when operated on gas, or

2) 115 parts per million by volume, or 0.150 pound per million Btu of heat input, when operated on nongaseous fuel, or

3) the heat-input weighted average of the limits specified in 1) and 2), above, when operated on combinations of gas and nongaseous fuel.

Emissions from units subject to this subsection shall not exceed a carbon monoxide concentration of 400 parts per million by volume.

B. Units with rated heat inputs of greater than or equal to 5 million Btu per hour and annual heat inputs of less than 90,000 therms for each of the three previous calendar years shall:

1) be operated in a manner that maintains stack-gas oxygen (O_2) concentrations at less than or equal to 3.00 percent by volume on a dry basis; or

2) be operated with a stack-gas oxygen trim system set at 3.00 percent by volume oxygen (O_2). The tolerance of the setting shall be plus or minus five (± 5.0) percent; or

3) be tuned at least once per year by a technician that is qualified, to the satisfaction of the Executive Officer/Air Pollution Control Officer, to perform a tune-up in accordance with the procedure described in Attachment 1; or

4) be operated in compliance with the applicable emission levels specified in Subsection III A.

(FOR BARCT)

A. For units with rated heat inputs of greater than or equal to 5 million Btu per hour and annual heat inputs of greater than or equal to 90,000 therms for any of the three previous calendar years, NOx emissions shall not exceed the following levels:

1) 30 parts per million by volume, or 0.036 pound per million Btu of heat input, when operated on gas, or

2) 40 parts per million by volume, or 0.052 pound per million Btu of heat input, when operated on nongaseous fuel, or

3) the heat-input weighted average of the limits specified in 1) and 2), above, when operated on combinations of gas and nongaseous fuel.

Emissions from units subject to this subsection shall not exceed a carbon monoxide concentration of 400 parts per million by volume.

B. Units with rated heat inputs of greater than or equal to 5 million Btu per hour and annual heat inputs of less than 90,000 therms for each of the three previous calendar years shall:

1) be operated in a manner that maintains stack-gas oxygen concentrations at less than or equal to 3.00 percent by volume on a dry basis; or

2) be operated with a stack-gas oxygen trim system set at 3.00 percent by volume oxygen. The tolerance of the setting shall be plus or minus five (± 5.0) percent; or

3) be tuned at least once per year by a technician that is qualified, to the satisfaction of the Executive Officer/Air Pollution Control Officer, to perform a tune-up in accordance with the procedure described in Attachment 1; or

4) be operated in compliance with the applicable emission levels specified in Subsection III A.

IV. Exemptions

A. Units subject to the requirements of Subsection III A which normally burn only gas shall comply with a 150 ppmv, or 0.215 pound per million Btu of heat input, NOx emission limit when burning nongaseous fuel, if gas is unavailable for purchase. This exemption is good for not more than 168 hours of operation per calendar year, excluding equipment and emission testing time not exceeding 48 hours per calendar year.

V. Compliance Requirements

A. Compliance Schedule

The owner or operator of units subject to this determination shall fulfill the following increments of progress:

1) Submit, within two years from the date of adoption of this determination, a plan containing the following:

(a) A list of all units with their rated heat inputs and anticipated annual heat inputs.

(b) For owners or operators of units subject to Subsection III A, for each unit listed, the selected method of achieving the applicable standard or standards of Subsection III A.

(c) For owners or operators of units to Subsection III B, for each unit listed, a selection of one of the four options specified in Subsection III B to achieve compliance with this determination.

2) Within four years from the date of adoption of this determination, demonstrate final compliance with all applicable standards and requirements of the determination.

B. Compliance Determination

1) An owner or operator of any unit(s) shall have the option of complying with either the pounds-per-million-Btu emission rates or parts-per-million-by-volume emission limits specified in Subsection III A.

2) All emission determinations shall be made in the as-found operating condition, except that emission determinations shall include at a minimum one source test conducted at the maximum firing rate allowed by the district permit, and no compliance determination shall be established within two hours after a continuous period in which fuel flow to the unit is zero, or shut off, for 30 minutes or longer.

3) All ppmv emission limits specified in Subsections III A and IV A are referenced at dry stack-gas conditions and 3.00 percent by volume stack-gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen as follows:

$$[\text{ppm NOx}]_{\text{corrected}} = \frac{20.95\% - 3.00\%}{20.95\% - [\%\ O_2]_{\text{measured}}} * [\text{ppm NOx}]_{\text{measured}}$$

$$[\text{ppm CO}]_{\text{corrected}} = \frac{20.95\% - 3.00\%}{20.95\% - [\%\ O_2]_{\text{measured}}} * [\text{ppm CO}]_{\text{measured}}$$

4) All pounds-per-million-Btu emission rates shall be calculated as pounds of nitrogen dioxide per million Btu of heat input.

5) All emission concentrations and emission rates shall be based on 15-consecutive-minute averages. The averages shall be calculated from no less than five data sets, recorded from samplings on intervals of no greater than three minutes.

6) Compliance with the NOx emission requirements and the stack-gas carbon monoxide and oxygen requirements of Section III shall be determined using the following test methods.

   (a) Oxides of Nitrogen - ARB Method 100

   (b) Carbon Monoxide - ARB Method 100

   (c) Stack Gas Oxygen - ARB Method 100

   (d) NOx Emission Rate (Heat Input Basis) - EPA Method 19

(7) Integrated sampling methods for oxides of nitrogen, stack-gas oxygen, and stack-gas carbon dioxide, as approved by the Executive Officer/Air Pollution Control Officer, may be acceptable for determination of compliance with NOx emission concentration or rate limits.

(8) All units covered under Subsections III A and III B shall be tested for compliance not less than once every 12 months, except that units complying with Subsection III B (3) shall be tuned not less than once every 12 months.

(9) A violation of the plan required under Subsection V A (1) shall constitute a violation of this determination.

(10) The cumulative annual usage of each fuel shall be monitored from utility service meters, purchase or tank fill records, or by any other acceptable methods, as approved by the Executive Officer/Air Pollution Control Officer.

C. <u>Administrative Requirements</u>

1) The owners or operators of units subject to Section III of this determination shall monitor and record for each unit the HHV and cumulative annual usage of each fuel. The owners and operators of units exempt from Subsection III A in accordance with Subsection IV A shall monitor and record for each unit the cumulative annual hours of operation on each nongaseous fuel. This data shall be updated weekly and made available to district or state auditors upon their request. Historical annual data for the three previous calendar years shall be kept and made available by the owners and operators.

2) The owners or operators of units subject to Section III of this determination shall submit compliance test reports on each unit for each fuel burned, including any fuels which may

be burned in accordance with Subsection IV A, not less than once every 12 months; except that tune-up verification reports shall be submitted not less than once every 12 months for each unit complying with Subsection III B (3) for each fuel burned. Test reports shall include the operational characteristics of all flue-gas NOx reduction equipment. The first test or tune-up report, for each unit subject to Section III of this determination, shall be submitted within four years from the date of adoption of this determination.

D. Equipment Requirements

1) Owners or operators of units which simultaneously fire combinations of different fuels, and are subject to the requirements of Subsection III A, shall install mass flow rate meters in each fuel line. Alternatively, volumetric flow rate meters may be installed in conjunction with temperature and pressure probes in each fuel line.

2) Owners or operators of units which employ flue-gas NOx reduction technology, and are subject to the requirements of Subsection III A, shall install meters as applicable to allow instantaneous monitoring of the operational characteristics of the NOx reduction equipment.

Attachment 1

Tuning Procedure [1/]

Nothing in this Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurors, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate the unit at the firing rate most typical of normal operation. If the unit experiences significant load variations during normal operation, operate it at its average firing rate.

2. At this firing rate, record stack gas temperature, oxygen concentration, and CO concentration (for gaseous fuels) or smoke-spot number[2/] (for liquid fuels), and observe flame conditions after unit operation stabilizes at the firing rate selected. If the excess oxygen in the stack gas is at the lower end of the range of typical minimum values[3/], and if CO emissions are low and there is no smoke, the unit is probably operating at near optimum efficiency - at this particular firing rate. However, complete the remaining portion of this procedure to determine whether still lower oxygen levels are practical.

3. Increase combustion air flow to the furnace until stack gas oxygen levels increase by one to two percent over the level measured in Step 2. As in Step 2, record the stack gas temperature, CO concentration (for gaseous fuels) or smoke-spot number (for liquid fuels), and observe flame conditions for these higher oxygen levels after boiler operation stabilizes.

4. Decrease combustion air flow until the stack gas oxygen concentration is at the level measured in Step 2. From this level gradually reduce the combustion air flow, in small increments. After each increment, record the stack gas temperature, oxygen concentration, CO concentration (for gaseous fuels) and smoke-spot number (for liquid fuels). Also, observe the flame and record any changes in its condition.

1/ This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for the EPA. This procedure is included as Attachment 2 to this determination.

2/ The smoke-spot number can be determined with ASTM test method D-2156 or with the Bacharach method. ASTM test method D-2156 is included as Attachment 3 to this determination. The Bacharach method is included in a tune-up kit that can be purchased from the Bacharach Company.

3/ Typical minimum oxygen levels for boilers at high firing rates are:
1. For natural gas: 0.5 - 3%
2. For liquid fuels: 2 - 4%

5. Continue to reduce combustion air flow stepwise, until one of these limits is reached:

   a. Unacceptable flame conditions - such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability.

   b. Stack gas CO concentrations greater than 400 ppm.

   c. Smoking at the stack.

   d. Equipment-related limitations - such as low windbox/furnace pressure differential, built in air-flow limits, etc.

6. Develop an O_2/CO curve (for gaseous fuels) or O_2/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2 using the excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.

7. From the curves prepared in Step 6, find the stack gas oxygen levels where the CO emissions or smoke-spot number equal the following values:

Fuel	Measurement	Value
Gaseous	CO Emissions	400 ppm
#1 and #2 oils	smoke-spot number	number 1
#4 Oil	smoke-spot number	number 2
#5 Oil	smoke-spot number	number 3
Other oils	smoke-spot number	number 4

The above conditions are referred to as the CO or smoke thresholds, or as the minimum excess oxygen levels.

Compare this minimum value of excess oxygen to the expected value provided by the combustion unit manufacturer. If the minimum level found is substantially higher than the value provided by the combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mix, thereby allowing operations with less air.

Figure 1

Oxygen/CO Characteristic Curve

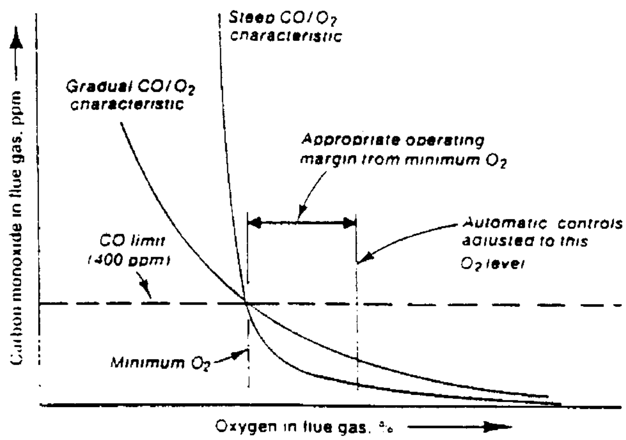
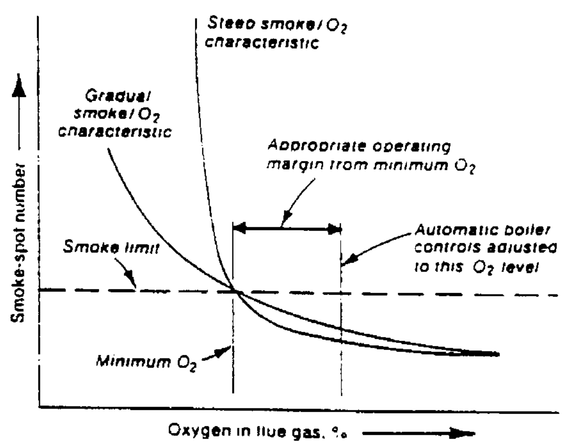


Figure 2

Oxygen/Smoke Characteristic Curve



APPENDIX F

Significant Comments and Responses

Kern Oil & Refining Company (5/31/91)

Comment 1.

"The proposed BAR[CT] limits of 30 ppm NOx on gas fuel and 40 ppm NOx on liquid fuel are substantially lower than the limits contained in ARB's 1987 Suggested Control Measure ('SCM')..."

Response:

We agree with this statement. The SCM was approved by the California Air Pollution Control Officer's Association's (CAPCOA's) Technical Review Group (TRG) on April 20, 1987, and approved by the Air Resources Board (ARB) on September 10, 1987. The SCM was developed to guide the air pollution control and air quality management districts in their consideration and development of rules and regulations. The SCM is based on reducing oxides of nitrogen (NOx) emissions from industrial, institutional, and commercial boilers, steam generators, and process heaters by approximately 40 to 45 percent with an average cost-effectiveness of about $1.00 to $3.00 per pound of NOx removed. Since the approval of the SCM, four district rules have been adopted or amended, which have more stringent standards than the SCM. These rules have taken advantage of improvements in NOx emission control technology in the last few years. The proposed RACT/BARCT determination also reflects these improvements.

Furthermore, on September 30, 1988, the California Legislature enacted the California Clean Air Act (CCAA), which requires each district with serious or severe air pollution to include in its attainment plan a requirement for the application of best available retrofit control technology (BARCT) to existing stationary sources. "Best Available Retrofit Control Technology" means an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source.

Comment 2.

"The proposed BARCT limits go beyond the technology that is available for retrofitting existing equipment... We estimate that a 94 percent reduction would be required to meet the proposed 40 ppm limit... In any event, the cost of providing SCR on our existing heaters and boilers would probably exceed the cost of new heaters and boilers... We suggest that the BARCT for NOx emissions from boilers and process heaters either exempt devices that are permitted to burn residual fuel oil, or include a NOx limit for those devices that is achievable by combustion modifications such as low NOx burners and flue gas recirculation."

Response:

We know of no technological reason why selective catalytic reduction (SCR) cannot achieve 94 percent reduction to meet 40 ppm NOx; however, we believe that the commentor should also consider the cost of retrofitting low-NOx emitting burners plus a lesser degree of SCR. A NOx reduction of 0.78 pounds per million Btu is likely to be relatively cost-effective. The cost-effectiveness estimates contained in the technical support document (TSD) for the SCM are based on NOx reductions of 0.05 to 0.35 pounds per million Btu. The difference between the cost of retrofitting an existing unit to meet the BARCT standard and the cost of installing a new unit with best available control technology (BACT) is dependent on the size of the unit, the type of emission control equipment required to meet standards, and other site-specific factors.

For a large unit burning residual fuel oil, retrofitting to meet BARCT is probably much less expensive than installing a new unit with BACT. This is due to the facts that the cost of a unit increases with its size, and that flue gas emission controls would be required in either case. On the other hand, if a small gas-fired unit requires flue gas emission controls to meet the BARCT standard, and a new unit without flue gas emission controls complies with BACT, then the cost difference between the two choices may be negligible, or the new unit may cost less than the retrofit. In deciding whether to retrofit or replace a unit, the age of the unit at the final compliance date should also be considered. An exemption for units burning residual fuel oil does not encompass the scope of the CCAA requirement of BARCT for existing stationary sources, nor does a standard based solely on combustion modifications. Flue gas recirculation is not effective at reducing NOx emissions originating from fuel-bound nitrogen.

<u>Comment 3.</u>

"South Coast Air Quality Management District ('SCAQMD') Rule 1109, Section (b)(1)(A)(ii) requires devices operated or liquid fuel to meet a NOx limit of 0.308 pounds per million [B]tu."

<u>Response:</u>

SCAQMD Rule 1109 was amended on August 5, 1988. For 36 percent of the refinery-wide heat input to applicable units by December 31, 1992, and for 100 percent of the refinery-wide heat input to applicable units by December 31, 1995, the rule will require that NOx emissions from each applicable unit not exceed 0.03 pound per million Btu of heat input when firing at the maximum rated capacity. This limit is approximately equal to 21 parts per million by volume (ppmv), corrected to 3 percent oxygen (O_2), relative to dry stack gases, when firing residual fuel oil.

California Manufacturers Association (7/11/91)

Comment 4.

The proposed limits contained in the determination would make the use of residual fuel oil unaffordable and thus adversely impact the ability to obtain competitive natural gas rates, and operate during periods of natural gas curtailment.

Response:

In our drafting of the proposed determination, we included a provision which allows the use of residual fuel oil for up to 168 hours during a calendar year in the event that natural gas is curtailed, subject to an oxides of nitrogen emission limit of 115 ppm. Based on this comment and our subsequent review of emission limits, we have increased the oxides of nitrogen emission limit to 150 ppm. We believe that the use of low-NOx burners designed to meet the emission limit for natural gas can readily achieve the 150 ppm limit when using residual oil.

Ventura County Air Pollution Control District (7/10/91)

Comment 5.

"ARB states on Page 3 [of the 7/5/91 revision] of the determination report (report) that 'most units can meet [the 30 ppm] limit by installing new burners with flue gas recirculation.' No evidence in support of this belief is presented in the report. The paragraph goes on to say that '30 ppm is the appropriate BARCT NOx emission limit due to the many units currently operating within this limit without the use of flue gas emission controls.' Again, not one case is sited to support this claim. If these units exist, we need to know the circumstances under which they operate. It is also unclear how any unit, new or retrofitted, can meet a 30 ppm NOx limit 'without the use of flue gas emission controls.'"

Response:

We do not have a list of units which are meeting the 30 ppm limit. We believe the most convincing evidence for the appropriateness of a 30 ppm BARCT limit is the SCAQMD's recent adoption of Rule 1146.1 for units 2 to 5 million BTU per hour in size. The 30 ppm standard for these small units is based solely on combustion modifications. The same or similar control technologies as which are the bases of the standard for the small units have been, and will be, applied to larger units. Burner manufacturers have not challenged the technical feasibility of the 30 ppm standard for larger units, though they have indicated to us that not all units can be economically retrofitted to meet the standard solely with combustion modifications. For some units selective noncatalytic reduction or selective catalytic reduction may be the preferred method of NOx emission control. Economic and other considerations have caused, and will cause, operators of units less than 50 million Btu per hour in size to favor combustion modifications over flue-gas emission controls in their selection of retrofit emission control equipment.

Comment 6.

"Even though the report states that 'consideration should be given to the incremental cost-effectiveness of achieving the lower 30 ppm,' both [the SCAQMD and Ventura County] districts will be forced to spend a substantial amount of time proving that the incremental cost-effectiveness of achieving the lower 30 ppm limit is too high."

Response:

The determination has been modified to state that districts which have adopted rules between July 18, 1988 and July 18, 1991, covering the applicability of this determination, are considered to be in compliance with this determination.

Comment 7.

"This lack of factual support [for the 30 ppm limit] is made worse by ARB's position that BARCT should be 'technology forcing' when Health and Safety Code Section 40406 states that BARCT means 'the maximum degree of reduction achievable.' This means that any technology that cannot yet be achieved goes beyond the definition of BARCT. Any technology that has not been proven successful is inappropriate."

Response:

This RACT/BARCT determination is not "technology forcing." All of the technologies described in the report, and which may be necessary for compliance with the BARCT determination, are proven, available, and in-use in California.

Comment 8.

"Selective Non-catalytic Reduction (SNCR) is discussed on Page 7. Table 2 implies that the applicable range for this technology is 50 MMBTU/hr or more. It is not clear if units in this size range have flue gas temperatures in the 1600 to 2200 degree F range. Stack gas temperatures for the two large units in our report are 591 degrees F (Arcturus) and 760 degree[s] F (Rocketdyne). SNCR is offered as a viable possibility on Page 3, but, in fact, it may work on only a small percentage of units. On what units will SNCR work?

Response:

SNCR injection is not normally retrofitted to the stack or flue gas ducting. A flue gas temperature of 1600 to 2200 degrees F indicates an extremely low combustion efficiency. Normally an SNCR injection grid is retrofitted within a unit at the downstream end of the furnace. SNCR will work on all units which will allow adequate residence time within the reaction temperature window.

Comment 9.

"There is no basis for the 40 ppm limit for units burning non-gaseous fuel (Page 3). No information is provided on the source of this limit or how it will be met. Under what circumstances is this limit applicable?"

Response:

Information has been added to the report regarding the use of methanol and specially blended oil to meet a 40 ppm limit for units burning non-gaseous fuel.

Comment 10.

"Limiting total use of non-gaseous back-up fuel to 168 hours per year is unreasonable. Back-up fuel is typically used during natural gas curtailments; we cannot assume (without vast statistical support) that ... curtailments will always last less than 168 hours (seven days) per year. Back-up fuel equipment must be tested periodically; a 168 to 200 hour per year limit on testing would be reasonable."

Response:

A 168-hour allowance for burning back-up fuel will enable unit operators to qualify for a noncore (lower) rate for purchasing gas. If the higher NOx emission concentration of 150 ppm were not subject to a time limitation, it could not be allowed under the RACT/BARCT determination. Operators must be prepared to either (1) pay a higher rate for gas, (2) have a back-up gas supply, (3) meet RACT/BARCT standards for nongaseous fuel firing, or (4) shut down, when gas is unavailable for purchase for more than 168 hours per year. We have added an allowance of 48 hours per year for equipment and emission testing with back-up fuel burning.

Comment 11.

"Selective Catalytic Reduction (SCR) needs additional discussion (Page 8). As noted above for SNCR, stack gas temperatures in the 570 to 845 degree F range occur only in very large units (over 100 MMBTU/hr). Does this mean that flue gas preheaters will be required? On Page 9, the cost effectiveness of SCR is all but ignored. This technology is extremely expensive, which is exactly why it was not considered to be a reasonable emission control technology for industrial boilers in Ventura."

Response:

Low-pressure heating boilers operate at saturated steam temperatures not exceeding 250 degrees F. They may have flue gas temperatures as low as 400 degrees F. For most units, a flue-gas temperature below 570 degrees F is difficult to achieve without an economizer and an air preheater. An SCR reactor should be appropriately located in the flue gas ducting to optimize the catalytic reaction. It is unlikely that SCR technology will be necessary to control NOx emissions from low-pressure heating boilers. However, if it is necessary, a boiler may have to be modified to operate at a higher flue gas temperature and lower combustion efficiency. The cost-effectiveness of SCR technology will be high for small boilers firing gas. However, there are other technologies available for use in complying with the BARCT standard.

Comment 12.

"On Page 11 [of the 7/15/91 version], under Hazards, it is misleading to say that 'a majority of catalysts used in California are now reclaimed and recycled by the manufacturer.' We believe that most of the catalyst material in the state is in Ventura County (by virtue of the IC engine rule) and, while some manufacturers may provide this service, we know of no organized recycling system. We are optimistic that increased use of catalyst material will lead to such a system."

Response:
We do not believe that the report is misleading.

Comment 13.

"The RACT limit for 'other' fuels (III.A.2) should be increased to 150 ppm, similar to the 'exemption' limit in the BARCT section (IV.A). For RACT, 'other' fuels means fuel oil, and fuel oil is what the 150 ppm limit in the BARCT section is intended to regulate."

Response:
We disagree; the "exemption" limit is for units which normally burn only gas and applies only when gas is unavailable for purchase. Units with emission control equipment designed for gas-firing are allowed a 150 ppm limit for burning "back-up" fuel. We have extended the applicability of this exemption to the RACT standard, also.

Kings County Air Pollution Control District (7/30/91)

Comment 14.

"Section IV. of the draft determination BARCT rule (Appendix A) provides that boilers shall meet 150 ppmv or 0.215 lb NOx/MMBtu for no more than a total of 216 hours per year, including testing time, when natural gas is unavailable for purchase. Our experience with dual fired boilers indicates, that for at least boilers operating 24 hours per day, such a limited firing period is highly unrealistic. Pursuant to the above requirement, will the District require the temporary shutdown of a boiler if beyond the control of the owner operator gaseous fuel cannot be burned?"

Response:
The boiler operator may either (1) comply with the BARCT standard for nongaseous fuel firing, (2) obtain a back-up gas supply, (3) pay a higher (core-customer) rate for natural gas, or (4) shutdown the boiler.

Comment 15.

"Gas supply curtailments are more likely to occur during the winter months due to increased public demand. In areas that are not likely to exceed ozone standards during the winter, restrictions on the use of fuel oil during these months may have little effect on ozone levels, yet may be difficult to comply with because of the increased likelihood of curtailment."

Response:
A precedent has been set by Ventura County APCD's Rule 59, "Electrical Power Generating Equipment - Oxides of Nitrogen Emissions," to allow winter-month flexibility for fuel oil burning on days for which ambient ozone is predicted to not exceed 0.07 ppm. Districts should be careful in considering this approach. Emissions from fuel oil burning contribute directly and indirectly to ambient PM10. In Ventura County there is a strong daily correlation between not exceeding the 0.07 ppm 1-hour ambient ozone and not exceeding 50 $\mu g/m^3$ 24-hour PM10.

Comment 16.

"Is the intent of 150 ppmv for firing on nongaseous fuel not to allow the burning of No. 6 oil with standard nitrogen content? For No. 6 fuel, compliance with this limit would require controls beyond flue gas recirculation and burner replacement."

Response:
The intent of the exemption of 150 ppmv NOx for firing a nongaseous back-up fuel is to allow the use of residual fuel oil for back-up situations without necessitating additional emission control equipment beyond that required for gas firing. There is no standard for nitrogen

content of residual fuel oil; however, the range is 1000 to 8000 ppm by weight. 0.150 lbs/MMBtu (104 ppmv) NOx with Kern County residual fuel firing has been met with staged combustion without flue gas recirculation.

Comment 17.

"If a significant amount of boilers in California are fired primarily on fuel oil, is the present supply of "specially blended" low nitrogen fuel oil sufficient to meet state wide needs? If not, than do the retrofit cost figures include installation of natural gas supply equipment?"

Response:

The BARCT standard for oil firing is cost-effective with flue gas emission controls. Some boiler operators may determine that switching to gas firing with combustion modifications to meet a lower limit is less costly and therefore more cost-effective. The cost-effectiveness of using methanol or "specially blended" oil with combustion modifications to meet the BARCT standard will depend on the future demands and prices of methanol or "specially blended" oil.

Comment 18.

"Buyers have the option of lower gas costs if the supplier does not guarantee supply at all or most times. Do these cost figures include natural gas cost increases from the supplier which would result because the buyer (source) would not have the option of random curtailments."

Response:

The exemption for back-up fuel burning when gas is unavailable for purchase will enable the buyer to qualify for a noncore gas rate.

Comment 19.

"The use of natural gas will increase with the various clean fuels programs for both stationary and mobile sources. Has the availability of future natural gas supplies been studied adequately to warrant the virtual elimination of fuel oil?"

Response:

The economical choice of fuel and emission control equipment is left to the market interaction between the fuel suppliers, the control equipment suppliers, and the unit operators. Oil firing with flue-gas emission controls is considered to be available and cost-effective. The fuel supply and cost-effectiveness resulting from market interaction can only be better.

Comment 20.

"The NOx retrofit of a boiler may cause an increase in CO emissions. In some circumstances an increase to 400 ppm could cause an emissions change greater than 550 lbs/day. Although many low NOx burner manufacturers are reluctant to guarantee less than 400 ppm CO, in Fresno County 100 ppm has been both required and achieved after FGR and burner replacement (135 MMBtu/hr boiler)."

Response:

In most districts, any CO increase from permitted levels will activate the new source review process. By necessity, operators will have to maintain CO emissions at levels which will not activate the new source review process. Therefore, operators should consider CO emissions as a factor in their selection of NOx emission control equipment.

Figure 1

Oxygen/CO Characteristic Curve

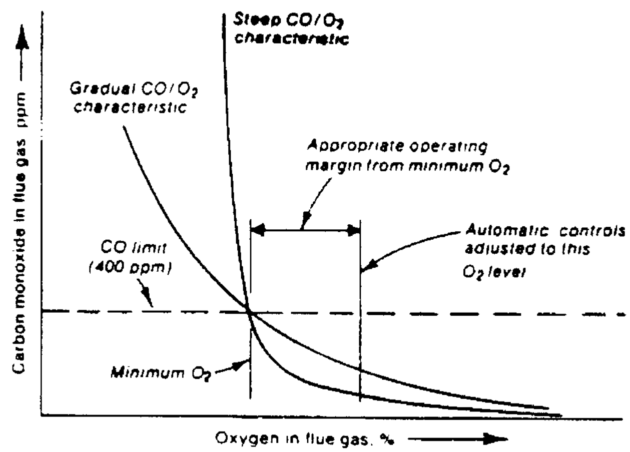
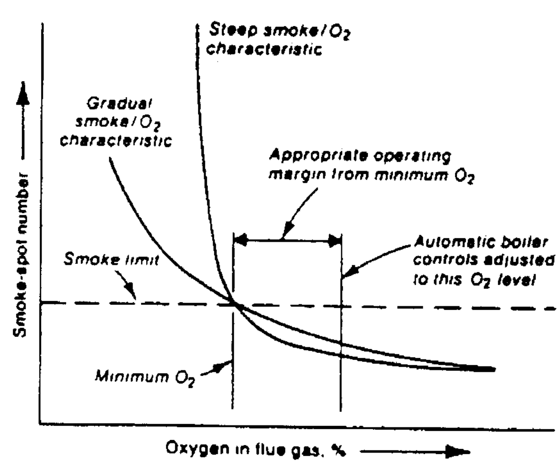


Figure 2

Oxygen/Smoke Characteristic Curve



Source: KVB Inc.

8. Add 0.5 to 2.0 percent to the minimum excess oxygen level found in Step 7 and reset burner controls to operate automatically at this higher stack gas oxygen level. This margin above the minimum oxygen level accounts for fuel variations, variations in atmospheric conditions, load changes, and nonrepeatability or play in automatic controls.

9. If the load of the combustion unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent the upper and lower limits of the range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish the optimum excess oxygen level at all firing rates. If this is the case, choose the burner control settings that give best performance over the range of firing rates. If one firing rate predominates, setting should optimize conditions at the rate.

10. Verify that the new settings can accommodate the sudden load changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing the flame and stack. If any of the conditions in Step 5 result, reset the combustion controls to provide a slightly higher level of excess oxygen at the affected firing rates. Next, verify these new settings in a similar fashion. Then make sure that the final control settings are recorded at steady-state operating conditions for future reference.

TUNING INDUSTRIAL BOILERS—II

Attachment 2

Establish excess-air levels

Use the test program outlined below to identify the minimum amount of excess oxygen required for combustion of gaseous, liquid, and solid fuels in industrial boilers

By D E Shore and **M W McElroy,** KVB Inc

Once your boiler is in good working order (see Part I of this series, April 1977), the next major step in improving efficiency, and in reducing emissions, is to establish the lowest level of excess oxygen at which the unit can operate safely and still meet the clean-air laws. Since most industrial boilers operate over a reasonably broad load range, tests must be run at several firing rates to determine the minimum excess-oxygen level for each. Only then can the combustion-control system be tuned for optimum fuel economy.

At each firing rate investigated, excess oxygen in the flue gas should be varied from 1-2% above the normal operating point, down to where the boiler just starts to smoke (Fig 4), or to where CO emissions exceed 400 ppm. This latter condition is referred to as the smoke or CO threshold, or simply as the *minimum-oxygen point*. The smoke threshold generally applies to coal and oil firing, because smoking usually occurs before CO emissions reach significant levels. The CO threshold pertains to gaseous fuels.

The smoke threshold for solid and liquid fuels represents the lowest possible excess-oxygen level at which acceptable stack conditions still can be maintained. In terms of the Bacharach smoke-spot number (SSN) scale, the maximum desirable smoke number for coal is 4 (measured downstream of the dust collector). For No. 6 (residual) oil, it also is 4: No. 5 and low-sulfur resid, a SSN of 3; No. 4, a SSN of 2; and No. 2, a SSN of less than 1.

A proven method for determining the minimum amount of excess oxygen required for combustion involves developing so-called oxygen/CO and oxygen/smoke characteristic curves, like those shown in Figs 5 and 6. Based on test measurements, these curves show how boiler smoke and CO levels change as excess oxygen is varied.

Each of the figures depicts two distinct curves, illustrating the extremes in smoke and CO behavior that may be encountered. One curve exhibits a very gradual increase in CO or smoke as the minimum excess-oxygen condition is reached. The other has a gradual slope at relatively high oxygen levels, and a steep slope near the minimum-oxygen point. For cases represented by this second curve, unpredictably high levels of smoke or CO, or potentially unstable conditions, can occur with small changes in air flow.

Thus, caution is required on your part when reducing air flow near the smoke or CO threshold—that is, carefully monitor instruments and controls, flame appearance, and stack conditions simultaneously. Decrease the level of excess oxygen in very small increments until there are enough data to show whether the boiler exhibits a gradual or steep characteristic curve. Note, too, that your boiler may exhibit a gradual characteristic at one firing rate and a steep one at another.

Adjusting boiler controls for low-excess oxygen—a step-by-step procedure

1. **Establish the desired firing rate** and switch combustion controls from automatic to manual operation. *Make sure all safety interlocks are still functioning.*

2. **Record boiler and stack data** (pressures, temperatures, etc), and observe flame conditions after boiler operation stabilizes at the particular firing rate selected. If you find that the amount of excess oxygen in the flue gas is at the lower end of the range of typical minimum values (see text), and if CO and smoke are at acceptable levels, the boiler probably is already operating at near optimum efficiency—*at this particular firing rate*. It may still be desirable, however, to complete the remaining portion of this procedure, to determine whether still lower levels are practical. A word of caution: Do not assume that excess-oxygen settings at other firing rates also are close to the optimum.

3. **Increase air flow to the furnace** until readings of excess oxygen at the stack increase by 1-2%. Again, be sure to take readings after boiler operation stabilizes, and note any changes in flame conditions.

4. **Return air flow to the normal level** and begin *slowly* to reduce it further, in *small* increments. Watch the stack for any signs of smoke, and constantly observe the flame. Record stack excess-oxygen reading, smoke-spot number, the concentration of CO in flue gas, and stack temperature following each change.

Remember not to reduce air flow by throttling the burner air registers, because this alters the fuel and air mixing characteristics and complicates the tests. Also, if you run tests at low firing rates, which is not generally recommended (see step 9), keep a close watch on the windbox/furnace pressure differential. If it drops too low, a fuel trip will be initiated by the burner safeguards system.

5. **Continue to reduce air flow stepwise** until you reach one of these limits:

- Unacceptable flame conditions—such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability.
- High level of CO in the flue gas.
- Smoking at the stack. Do not confuse smoke with water vapor, sulfur, or dust plumes, which usually are white or gray in appearance, and remember to observe local air-pollution ordinances.
- Incomplete burning of solid fuels. Recognize this by high carbon carryover to dust collectors or increased quantities of combustibles in the ash.
- Equipment-related limitations—such as low windbox/furnace pressure differential, built-in air-flow limits, etc.

6. **Develop O_2/smoke or O_2/CO characteristic curves,** similar to those shown in Figs 4 and 5, using the excess oxygen and CO or smoke-spot number data obtained at each air-flow setting.

A high minimum-oxygen reading may indicate a burner malfunction or other fuel- or equipment-related problems. But realize that different burner designs and fuels generally have different minimum-oxygen requirements. In addition, many burners exhibit a higher minimum-oxygen level at low firing rates than they do at high firing rates. For these reasons, it is difficult to specify a range of minimum levels that would be considered normal for all boilers.

Results of tests at many industrial power plants are provided, however, to help you judge whether the minimum-oxygen levels you measure are typical values. The data: For natural gas, the typical range of minimum excess oxygen at high firing rates is 0.5-3%; for liquid fuels, 2-4%; for pulverized coal, 3-6%; and for stoker-fired coal, 4-8%.

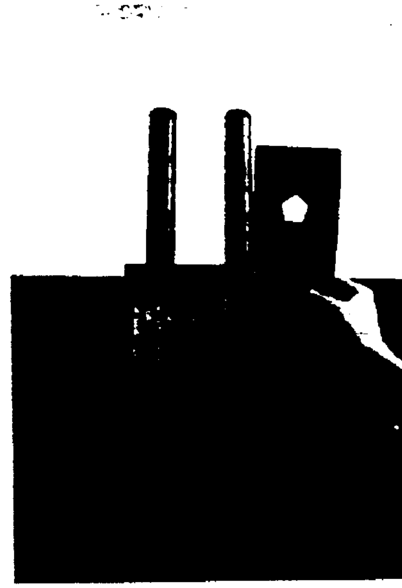
Boiler startup records showing initial excess-oxygen conditions provide a valuable reference point for your tuneup program. If current minimum-oxygen levels are higher than expected, any necessary maintenance or repairs should be completed before making final adjustments to the combustion-control system.

Once the minimum-oxygen setting is established, the next step is to determine the appropriate operating margin above minimum oxygen where the boiler can be operated routinely. This lowest practical oxygen level for the boiler offers the optimum setting for high efficiency and, in most cases, the lowest NO_x emissions. The excess-oxygen margin above the minimum-oxygen point accommodates:

- Rapid boiler modulation, which could cause smoking or a high concentration of combustibles in the flue gas.
- Nonrepeatability or play in automatic controls (Excessive play should be corrected.)
- Normal variations in atmospheric conditions, which also can change the level of excess oxygen on units not equipped with temperature- and pressure-compensated combustion-air systems. This is an important factor, which often is neglected. Extreme variations in ambient conditions can easily produce changes in excess oxygen of 1% or more.
- Changes in fuel properties, which may require varying amounts of excess air at the burner.

Typical margins above minimum oxygen may range from 0.5% to 2%, depending on the characteristics of the particular boiler-control system and the fuel being burned. If you think it necessary, the boiler manufacturer or a combustion consultant probably can establish a narrower range for your unit. Another point: If the boiler is to be operated at a constant firing rate for extended periods, the smallest possible margin should be selected.

Recognizing excessive play. A simple test can help you determine if there is excessive play (poor repeatability) in your combustion-control system. All you have to do is to repeat a firing-rate condition, allowing fuel and air controls to function in a normal manner. Approach the selected firing rate from both higher and lower firing rates, and compare stack excess-oxygen levels recorded after each run. Make sure boiler operation stabilizes before taking readings. Excess-oxygen data should repeat to within a few tenths of a percent; a greater difference indicates excessive wear or tolerance problems in air dampers, control shafts, valve cams, controllers, etc (Fig 7).



4. Ringelmann chart offers a quick way to determine if boiler emissions meet codes. Bacharach scale, more accurate, is better for burner adjustments

Atmospheric variations. Changes in air density at the forced-draft-fan inlet cannot be corrected like control-system play. Recognize that, while the f-d fan delivers a certain volume of air to the burner, as the air density changes, the number of pounds of air supplied to the

7. Find the minimum excess-oxygen level for your boiler from the curves prepared in step 6, but do not adjust the burner controls to this value. Though this may be the point of maximum efficiency, as well as minimal NO_x emissions, it usually is impractical to operate the boiler at this setting, because of the tendency to smoke, or to increase CO to dangerously high levels, as load changes.

Compare this minimum value of excess oxygen to the expected value provided by the boiler manufacturer. If the minimum level you found is substantially higher than the vendor's, burner adjustments probably can improve fuel and air mixing, thereby allowing operation with less air.

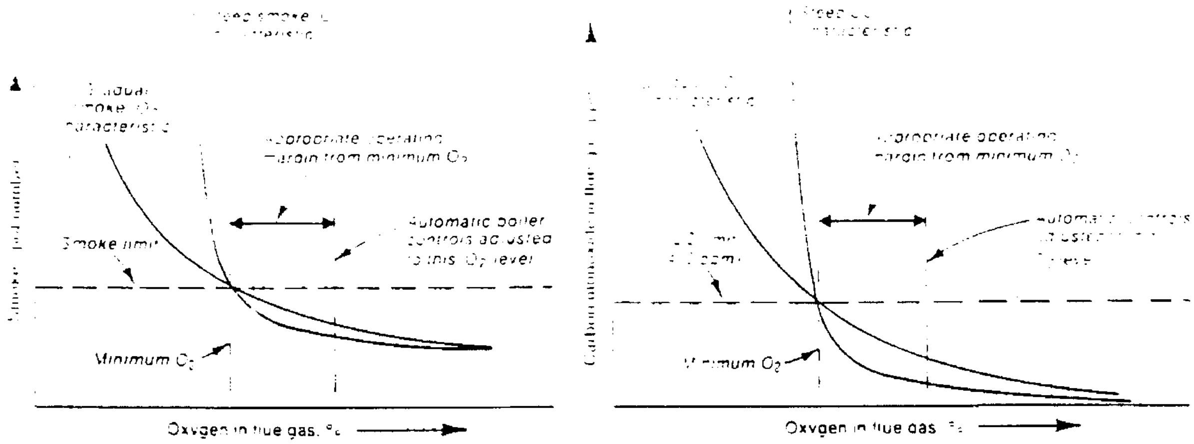
8. Establish the margin, in excess oxygen above the minimum value, required for fuel variations, load changes, and atmospheric conditions. Add this to the minimum value and reset burner controls to operate automatically at the higher level—the lowest practical setting at the particular firing rate. For most boilers, NO_x emissions typically will be lower at the new setting than they were originally. If they are higher, however, try to reduce them by adjusting the burner.

9. Repeat steps 1-8 for each firing rate to be tested. Bear in mind that, for some control systems, it is not possible to establish the optimum excess-oxygen level at each firing rate. Reason: Control adjustments at one firing rate also may affect conditions at other firing rates. In such cases, choose the settings that give best performance over a range of firing rates. A trial-and-error approach, one involving repeated tests, may be necessary. But if one firing rate predominates, settings should optimize conditions at that rate.

Many experts agree that it generally is best not to make any adjustments to your control system while the boiler is operating at low loads. Air-flow requirements at low-fire conditions usually are dictated by flame ignition characteristics and stability (and they can be critical and difficult to evaluate) rather than by efficiency. If process requirements force your boiler to operate at low loads much of the time, check with the boiler manufacturer's service group or a qualified combustion consultant before establishing excess-oxygen levels.

10. Verify that your new settings can accommodate the sudden load changes that may occur in daily operation without adverse affects. Do this by increasing and decreasing load rapidly while observing the flame and stack. If you detect undesirable conditions, reset the combustion controls to provide a slightly higher level of excess oxygen at the affected firing rates. Next, verify these new settings in a similar fashion. Then make sure that the final control settings are recorded at steady-state operating conditions for future reference.

One final note: When an alternative fuel is burned, perform these same tests and adjustments for the second fuel. Since it is not always possible to achieve optimum excess-oxygen levels for both fuels at all firing rates, you must establish the best conditions at normal firing rates.



5,6. Oxygen/CO and oxygen/smoke characteristic curves identify the minimum amount of excess oxygen required for combustion

burner varies, influencing the amount of excess oxygen. When combustion air is supplied from the boiler room, maintaining a constant boiler-room temperature minimizes the problem, but atmospheric-pressure effects are unavoidable.

Evaluating new settings

After the boiler has been tuned and returned to normal automatic firing, pay close attention to the unit for a few weeks, until confidence is gained in the new operating mode. Watch for any signs of unusual tube fouling or flame patterns, which might be corrected by further burner adjustments. Also, look for any equipment or operating changes that may alter the minimum-oxygen level—such as variations in fuel properties, inadvertent changes in burner settings, new boiler-control setpoints, air-control-damper deterioration, and air-preheater pluggage. Assure continuous high efficiency and low NO_x emissions on a continuous basis by plotting periodic stack measurements (excess oxygen, CO, smoke, temperature) on graph paper, and comparing these trends to the baseline data obtained during the boiler-test program.

Burner adjustments

As noted earlier, adjustments to the control system alone sometimes cannot improve efficiency and/or reduce pollutant emissions to desirable levels. In such cases, you should carefully inspect combustion equipment for proper operation. Often, you can achieve your operating goals by making changes in:

- Burner air-register settings (on swirl- or circular-type burners).
- Oil-burner tip position with respect to the burner throat.
- Oil-gun diffuser position with respect to the burner tip and burner throat.
- Fuel-oil temperature.
- Fuel-oil atomizing pressure.
- Coal-spreader position.
- Coal size.

The effects of such adjustments on NO_x formation and on minimum excess-oxygen levels vary from unit to unit, and are difficult to predict. Therefore, you should use a trial-and-error procedure when making changes. But be sure your program is sufficiently organized to assure adequate stack and flame monitoring. Observe the general precautions given for the excess-oxygen adjustments (see box). Such modifications to the firing system are best factored into the excess-oxygen adjustment tests (step 7 in box). This insures that changes are completed before the final control-system adjustments are made.

Also, after adjusting the burner, make a complete set of stack measurements to determine whether the change is producing the desired effects. Finally, make all burner adjustments slowly, to allow adequate time to evaluate each move. Look for any other changes in burner settings or fuel properties that might also affect the flow of air or fuel to the boiler and produce uncontrolled shifts in the excess-oxygen level.

The range of adjustment possible for the parameters listed above depends on the design of the burner or stoker and its particular operating characteristics. Example: It may be possible to vary the air-register settings on one boiler from 50% to 80% of full open, while on another unit little or no adjustment is practical. For the latter, further opening of the air register (reducing air swirl) may cause flame instability, while by closing off the air register (more swirl) you may widen the flame, causing flame impingement on the burner throat or furnace sidewalls. Read the boiler operating manual for information on your firing equipment.

An important factor in obtaining complete combustion of fuel oil at low excess-oxygen levels is to maintain the proper atomizing temperature. This is dictated by the fuel viscosity recommended by the burner manufacturer. Typical viscosity ranges for various liquid fuels and burner types are given in Fig 8. For stoker firing, coal size (Fig 9) is important. **RGS**

7. Excessive play in positioning combustion controls can be identified by marking linkage position for a particular firing rate and then approaching that rate from both higher and lower firing rates. Linkage position for the two test runs should match the original setting

Designation: D 2156 – 80

Standard Test Method for
SMOKE DENSITY IN FLUE GASES FROM BURNING DISTILLATE FUELS[1]

This standard is issued under the fixed designation D 2156; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ε) indicates an editorial change since the last revision or reapproval.

1. Scope

1.1 This method covers the evaluation of smoke density in the flue gases from burning distillate fuels. It is intended primarily for use with home heating equipment burning kerosine or heating oils. It may be used in the laboratory or in the field to compare fuels for clean burning or to compare heating equipment.

2. Applicable Document

2.1 *ASTM Standard:*

E 97 Test Method for 45-°, 0-° Directional Reflectance Factor of Opaque Specimens by Broad Band Filter Reflectometry[2]

3. Summary of Method

3.1 A test smoke spot is obtained by pulling a fixed volume of flue gas through a fixed area of standard filter paper. The color (or shade) of the spot thus produced is visually matched with a standard scale, and the smoke density is expressed as a "Smoke Spot Number."

4. Significance

4.1 This method provides a means of controlling smoke production in home heating equipment to an acceptable level. Excessive smoke density adversely affects efficiency by heat-exchanger fouling.

4.2 The range of smoke densities covered by this method is that which has been found particularly pertinent to home-heating application. It is more sensitive to small amounts of smoke than several other smoke tests as indicated in the following comparison:

Smoke Spot Number	Bacharach percent Transmission	Ringelman Smoke Number
0	100	0
2	95	0
4	80	0
6	54	0
8	18	0
9	3	0
9	0	0 to 5

5. Description of Terms

5.1 The test result is reported as the "Smoke Spot Number," which is the number of the spot on the standard scale most closely matching the color (or shade) of the test spot.

6. Apparatus

6.1 *Sampling Device*—A suitable device providing a total flue gas sample volume of 36 900 ± 1650 cm³ at 16°C, 1 atm (2250 ± 100 in.³ at 60°F, 1 atm) for each 6.45 cm² (1 in.²) effective surface area of filter paper shall be employed. The sampling device and connections shall be of such construction that the total travel of flue gas sample from flue to filter paper shall not exceed 410 mm (16 in.). The device shall provide for cooling the sample below the charring temperature for the filter paper but not below the dew point of the sample. Suitable laboratory and portable field service equipment is illustrated in Figs. 1 and 2.

6.2 *Smoke Scale*—The smoke scale required

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[1] This method is under the jurisdiction of ASTM Committee D-2 on Petroleum Products and Lubricants.

Current edition approved Aug. 29, 1980. Published October 1980. Originally published as D 2156 – [illegible]. Last previous edition D 2156 – [illegible].

[2] *Annual Book of ASTM Standards*, Vol 14.02.

consists of ten spots numbered consecutively from 0 to 9, ranging in equal photometric steps from white through neutral shades of gray to black, imprinted or otherwise processed on white paper or plastic stock having a surface reflectance of between 82.5 and 87.5 % 45°, 0° daylight luminous directional reflectance in accordance with Method E 97. The smoke scale spot number is defined as the reduction (due to smoke) in reflected incident light divided by 10. Thus, the first spot, which is the color of the unimprinted scale, will be No. 0, since in the case of this spot there will be no reduction in reflected incident light directed thereon. The last spot, however, is very dark, reflecting only 10 % of the incident light directed thereon; thus in this case the reduction in reflected incident light is 90 %, which gives to this darkest spot the No. 9. Intermediate spot numbers are similarly established. Limits of permissible reflectance variation of any smoke scale spot shall not exceed ±3 % relative reflectance (Notes 1 and 2).

NOTE 1—Such smoke scales are sufficiently accurate for field use and for many laboratory smoke testing applications. However, specially calibrated scales (known as certified smoke scales) will sometimes be required. A certified smoke scale is obtained by individually calibrating each smoke spot of a normal smoke scale.

NOTE 2—Where the smoke scale is protected with a plastic or transparent cover the construction employed shall be such that when the smoke spot on the filter paper is viewed for matching with the number spots on the smoke scale, both shall be visible through the same thickness and number of sheets of transparent protective cover.

7. Materials

7.1 *Test Filter Paper*, made from white filter paper stock having a surface reflectance of 82.5 to 87.5 % 45°, 0° daylight luminous directional reflectance, in accordance with the Method E 97. When clean air at standard conditions is drawn through clean filter paper at a rate of 47.6 cm³/s·cm² (1125 in.³/min·in.²) effective surface area of filter paper, the pressure drop across the filter paper should fall between limits of 13 and 64 mm (0.5 and 2.5 in.) Hg.

8. Procedure

8.1 The sampling procedure used is critical. Therefore, the procedure recommended by the equipment manufacturer shall be rigidly followed.

8.2 Use a clean, dry sampling device. If a hand sampler is used, warm it above room temperature to prevent condensation on the filter paper. (This may usually be done conveniently by placing the sampler on the boiler or furnace to be tested.)

8.3 Insert filter paper in the sampler and tighten the filter paper holder. Connect the sampling device to the flue gas probe. When taking smoke measurements in the flue pipe, position the end of the sampling probe at the center line of the flue pipe.

8.4 Draw the required sample. If a hand sampler is used, permit the pressures in the flue gas stream and the sampler to equalize after each stroke.

8.5 Remove the filter paper. Compare the test spot backed with a piece of white paper or plastic having 45°, 0° daylight luminous directional reflectance of not less than 75 %, with the standard scale.

9. Report

9.1 Report the smoke density as the Smoke Spot Number on the standard scale most closely corresponding to the test spot. Interpolate differences between two standard Smoke Spot Numbers to the nearest half number. Report Smoke Spot Numbers higher than 9 as "Greater than No. 9."

NOTE 3—Where more accurate results are desired, the human factor involved in visually comparing filter paper test spots with smoke scale spots can be eliminated by resort to direct use of a suitable photometer for evaluating test spots. This procedure is described in the Annex.

10. Precision

10.1 This test is reproducible to within ±½ of a Smoke Spot Number under normal conditions.

NOTE 4—Normal conditions are defined as those where no oily stain is deposited on the disk.

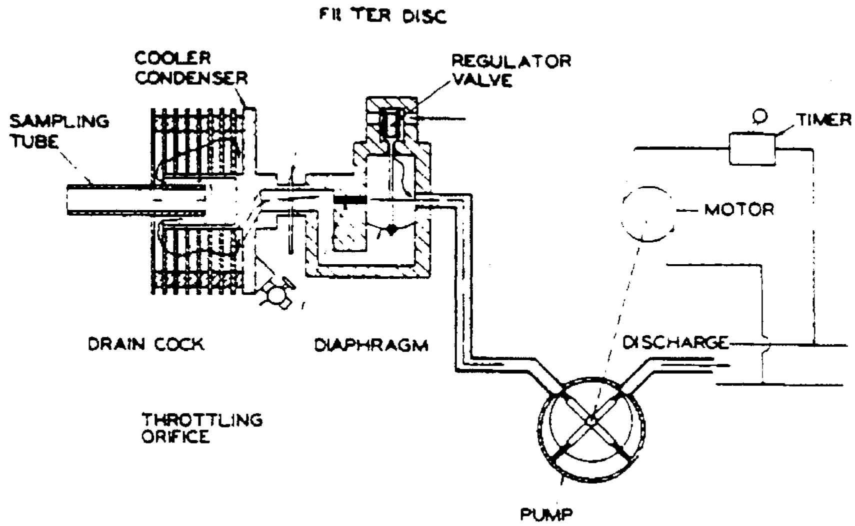

FIG. 1 Laboratory Type Smoke Meter

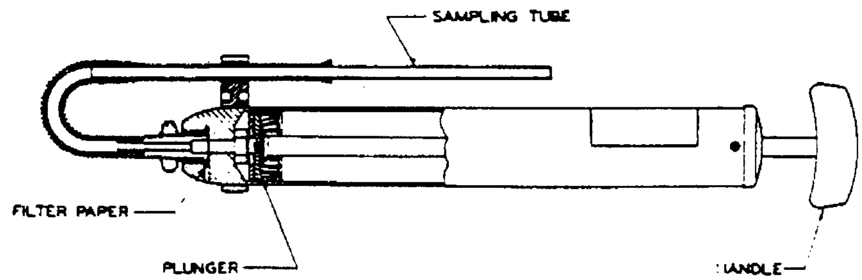

FIG. 2 Field Service Type Smoke Tester

ANNEX

A1. ALTERNATIVE PHOTOMETRIC METHOD

A1.1 Direct Photometric Evaluation

A1.1.1 The human factor involved in visually comparing filter paper test spots with smoke scale spots can be eliminated by resort to direct use of a suitable photometer for evaluating test spots. To make this direct photometric test spot evaluation, the following procedure shall be employed:

A1.1.1.1 Mount a clean, unused filter paper, backed by a plaque painted with MgO or material having a 45°, 0° daylight luminous directional reflectance of not less than 75 %, in the light beam of a suitable type reflectance photometer. Adjust the photometer to read 100 % reflectance in terms of the light reflected from this clean surface. Expose test smoke spot on filter paper to the photometer light beam and measure the percentage reduction in reflected light due to the presence of smoke particles on the filter paper. Gross Smoke Spot Number shall be defined as equal to the percentage reduction in reflected light divided by ten.

A1.2 Photometer Specifications

A1.2.1 The photometer to be employed for direct test spot number evaluation shall be of the electrically operated reflectance type employing a photoelectric cell, fitted with a special holder(s) to accommodate filter paper test specimens. It is to be capable of measuring the 45°, 0° daylight luminous directional reflectance. It is to be furnished complete with a green tristimulus filter and with reflectance standards of approximately 20, 40, 60, and 80 % 45°, 0° daylight luminous directional reflectance, to permit photometer readings between 10 and 90 % (relative to clean filter paper) to be made within ±2 % accuracy.

APPENDIX B

SCAQMD Rule 1146.1

Emissions of Oxides of Nitrogen From
Small Industrial, Institutional, and Commercial Boilers,
Steam Generators, and Process Heaters

(Adopted October 5, 1990)

RULE 1146.1. EMISSIONS OF OXIDES OF NITROGEN FROM SMALL INDUSTRIAL, INSTITUTIONAL, AND COMMERCIAL BOILERS, STEAM GENERATORS, AND PROCESS HEATERS

(a) Definitions

(1) ANNUAL HEAT INPUT means the actual amount of heat released by fuels burned in a unit during a calendar year, based on the fuel's higher heating value.

(2) BOILER OR STEAM GENERATOR means any combustion equipment fired with liquid and/or gaseous fuel, used to produce steam or to heat water, and that is not used exclusively to produce electricity for sale. Boiler or Steam Generator does not include any waste heat recovery boiler that is used to recover sensible heat from the exhaust of a combustion turbine or any unfired waste heat recovery boiler that is used to recover sensible heat from the exhaust of any combustion equipment.

(3) BTU means British thermal unit or units.

(4) NO_x EMISSIONS means the sum of nitric oxide and nitrogen dioxide in the flue gas, collectively expressed as nitrogen dioxide.

(5) PROCESS HEATER means any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to water or process streams. Process Heater does not include any kiln or oven used for drying, baking, cooking, calcining, or vitrifying; or any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment.

(6) RATED HEAT INPUT CAPACITY means the heat input capacity specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified such that its maximum heat input is different than the heat input capacity specified on the nameplate, the new maximum heat input shall be considered as the rated heat input capacity.

(7) THERM means 100,000 Btu.

(8) UNIT means any boiler, steam generator, or process heater as defined in subparagraph (a)(2) or (a)(5).

(b) Applicability

This rule applies to boilers, steam generators, and process heaters that are equal or greater than 2 million Btu per hour and less than 5 million Btu per hour rated heat input capacity used in any industrial, institutional, or commercial operation.

(c) Requirements

(1) The owner and/or operator of any unit subject to paragraph (b) shall operate such unit so that it discharges into the atmosphere no more than 30 ppm of NO_x emissions (0.037 pound NO_x per million Btu of heat input) and no more than 400 ppm of carbon monoxide. For each unit, a selection must be indicated in the application for permit to construct and operate between the ppm NO_x or pounds of NO_x per million BTU heat input compliance option.

(2) The owner or operator of any unit(s) subject to paragraph (b), and with an annual heat input of less than or equal to 18,000 therms per calendar year, shall:

(A) be operated in a manner that maintains stack-gas oxygen concentrations at less than or equal to 3 percent on a dry basis for any 15-consecutive-minute averaging period; or

(B) be tuned at least twice per year, (at intervals from 4 to 8 months apart) in accordance with the procedure described in Attachment 1, or other method as approved by the Executive Officer. If the unit does not operate during a six-month period, an annual tuneup is acceptable. The owner or operator of any unit(s) who specifies the semi-annual tuneup option shall maintain a record for a period of two years verifying that the tuneup has been performed. The record shall contain any other information or documentation that the Executive Officer determines to be necessary and made accessible upon request from an authorized District representative; or

(C) meet the emission limits specified in subparagraph (c)(1).

(3) The owner or operator of any unit(s) subject to subparagraph (c)(2) shall submit, for the approval of the Executive Officer, a plan that

demonstrates compliance with subparagraph (c)(2). Such plan shall contain:

(A) A list of all units with the rated heat input capacity, anticipated annual heat input, and permit number; and

(B) For each unit listed, a selection of one of the three options specified in subparagraph (c)(2) to achieve compliance with this rule; and

(C) Non-resettable, totalizing fuel meter(s) specifications; date of installation; and recorded fuel usage since installation.

(4) Any owner or operator who chooses the pound per million Btu of heat input compliance option shall install a non-resettable, totalizing fuel meter for each fuel used on an individual unit basis, as approved by the Executive Officer.

(d) Compliance Determination

(1) All units shall have the option of complying with either the pound per million Btu of heat input or parts per million emission limits specified in subparagraphs (c)(1) and (c)(2)(C).

(2) All emission determinations shall be made in the as-found operating condition, except no compliance determination shall be established during unit start up, shutdown, or under breakdown conditions. Start up or shutdown intervals may not last longer than is necessary to reach stable temperatures. In no case may the start up or shutdown interval last longer than specified in the permit to operate. In the event that permit conditions do not specify a time limit, the start up or shutdown may not exceed six hours for units subject to paragraph (b).

(3) All parts per million emission limits specified in subparagraph (c)(1) are referenced at 3 percent volume stack-gas oxygen on a dry basis averaged over a period of 15 consecutive minutes.

(4) Compliance with the NO_x and CO emission requirements of subparagraph (c)(1) and the stack-gas oxygen concentration requirement of subparagraph (c)(2)(A) shall be determined according to procedures in the District Source Test Manual or any other test method determined to be equivalent and approved by the Executive Officer. Emissions

determined to exceed any limits established by this rule through the use of any of the above-referenced test methods shall constitute a violation of this rule.

(e) Compliance Schedule

The owner or operator of units subject to this rule shall meet the following increments of progress:

(1) For owners and/or operators of units subject to subparagraph (c)(1):

(A) By January 1, 1993, submit required applications for permits to construct and operate, and

(B) By July 1, 1994, demonstrate compliance with subparagraph (c)(1).

(2) For owners and/or operators of units subject to subparagraph (c)(2):

(A) By January 1, 1993, submit a plan pursuant to paragraph (c)(3), and

(B) By December 31, 1993, demonstrate compliance with paragraph (c)(2).

(f) Exemption

The provisions of subparagraph (c)(1) shall not apply provided the owner and/or operator:

(1) Installs by January 1, 1992, or at the time the unit is constructed, a non-resettable, totalizing fuel meter for each fuel that demonstrates that the unit(s) operated with an annual heat input at or below 18,000 therms per calendar year; and

(2) Has available for inspection by the Executive Officer by February 1, 1993, and February 1 of each year thereafter, annual fuel-use data for the preceding calendar year. Records shall be maintained and made accessible to the Executive Officer or authorized District representative for a period of two years; and

(3) Demonstrates by February 1, 1993, that the annual heat input is less than or equal to 18,000 therms.

(g) Loss of Exemption

If any unit subject to a control plan submitted pursuant to subparagraph (c)(3) exceeds 18,000 therms of annual heat input after 1992, the owners or operators shall:

(1) Within 4 months from the end of the preceding calendar year, submit required applications for permits to construct and operate, and

(2) Within 18 months from the end of the preceding calendar year, demonstrate compliance with subparagraph (c)(1).

ATTACHMENT 1

Equipment Tuning Procedure[1]

Nothing in this Equipment Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate the unit at the firing rate most typical of normal operation. If the unit experiences significant load variations during normal operation, operate it at its average firing rate.
2. At this firing rate, record stack-gas temperature, oxygen concentration, and CO concentration (for gaseous fuels) or smoke-spot number[2] (for liquid fuels), and observe flame conditions after unit operation stabilizes at the firing rate selected. If the excess oxygen in the stack gas is at the lower end of the range of typical minimum values[3], and if CO emissions are low and there is not smoke, the unit is probably operating at near optimum efficiency at this particular firing rate.

[1]This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for the EPA.

[2]The smoke-spot number can be determined with ASTM Test Method D-2156 or with the Bacharach method. ASTM Test Method D-2156 is included in a tuneup kit that can be purchased from the Bacharach Company.

[3]Typical minimum oxygen levels for boilers at high firing rates are:

1. For natural gas: 0.5 percent - 3 percent.
2. For liquid fuels: 2 percent - 4 percent.

However, complete the remaining portion of this procedure to determine whether still lower oxygen levels are practical.

3. Increase combustion air flow to the furnace until stack-gas oxygen levels increase by one to two percent over the level measured in Step 2. As in Step 2, record the stack-gas temperature, CO concentration (for gaseous fuels) or smoke-spot number (for liquid fuels), and observe flame conditions for these higher oxygen levels after boiler operation stabilizes.
4. Decrease combustion air flow until the stack gas oxygen concentration is at the level measured in Step 2. From this level, gradually reduce the combustion air flow in small increments. After each increment, record the stack-gas temperature, oxygen concentration, CO concentration (for gaseous fuels), and smoke-spot number (for liquid fuels). Also observe the flame and record any changes in its condition.
5. Continue to reduce combustion air flow stepwise, until one of these limits is reached:
   a. Unacceptable flame conditions, such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability; or
   b. Stack gas CO concentrations greater than 400 ppm; or
   c. Smoking at the stack; or
   d. Equipment-related limitations, such as low windbox/furnace pressure differential, built in air-flow limits, etc.
6. Develop an O_2/CO curve (for gaseous fuels) or O_2/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2, using the excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.
7. From the curves prepared in Step 6, find the stack-gas oxygen levels where the CO emissions or smoke-spot number equal the following values:

Fuel	Measurement	Value
Gaseous	CO emissions	400 ppm
#1 and #2 oils	smoke-spot number	number 1
#4 oil	smoke-spot number	number 2
#5 oil	smoke-spot number	number 3
Other oils	smoke-spot number	number 4

The above conditions are referred to as the CO or smoke thresholds, or as the minimum excess oxygen level.

Compare this minimum value of excess oxygen to the expected value provided by the combustion unit manufacturer. If the minimum level found is substantially higher than the value provided by the combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mixing, thereby allowing operation with less air.

8. Add 0.5 to 2.0 percent of the minimum excess oxygen level found in Step 7 and reset burner controls to operate automatically at this higher stack-gas oxygen level. This margin above the minimum oxygen level accounts for fuel variations, variations in atmospheric conditions, load changes, and nonrepeatability or play in automatic controls.

9. If the load of the combustion unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent the upper and lower limits of the range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish the optimum excess oxygen level at all firing rates. If this is the case, choose the burner control settings that give best performance over the range of firing rates. If one firing rate predominates, settings should optimize conditions at that rate.

10. Verify that the new settings can accommodate the sudden load changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing the flame and stack. If any of the conditions in Step 5 result, reset the combustion controls to provide a slightly higher level of excess oxygen at the affected firing rates. Next, verify these new settings in a similar fashion. Then make sure that the final control settings are recorded at steady-state operating conditions for future reference.

APPENDIX C

SCAQMD Rule 1146

Emissions of Oxides of Nitrogen From
Industrial, Institutional, and Commercial Boilers,
Steam Generators, and Process Heaters

(Adopted September 9, 1988)(Amended January 6, 1989)

RULE 1146. EMISSIONS OF OXIDES OF NITROGEN FROM INDUSTRIAL, INSTITUTIONAL, AND COMMERCIAL BOILERS, STEAM GENERATORS, AND PROCESS HEATERS

(a) Definitions

(1) Annual Capacity Factor means the ratio of the amount of fuel burned by a unit in a calendar year to the amount of fuel it could have burned if it had operated at the rated heat input capacity for 100 percent of the time during the calendar year.

(2) Annual Heat Input means the actual amount of heat released by fuels burned in a unit during a calendar year.

(3) Boiler or Steam Generator means any combustion equipment fired with liquid and/or gaseous fuel and used to produce steam or to heat water and that is not used exclusively to produce electricity for sale. Boiler or Steam Generator does not include any waste heat recovery boiler that is used to recover sensible heat from the exhaust of a combustion turbine or any unfired waste heat recovery boiler that is used to recover sensible heat from the exhaust of any combustion equipment.

(4) BTU means British thermal unit.

(5) Heat Input means the chemical heat released due to fuel combustion in a unit, using the higher heating value of the fuel. This does not include the sensible heat of incoming combustion air.

(6) NOx Emissions means the sum of nitric oxides and nitrogen dioxide in the flue gas, collectively expressed as nitrogen dioxide.

(7) Process Heater means any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to water or process streams. Process Heater does not include any kiln or oven used for drying, baking, cooking, calcining, or vitrifying; or any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment.

(8) Rated Heat Input Capacity means the heat input capacity specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified such that its maximum heat input is different than the

heat input capacity specified on the nameplate, the new maximum heat input shall be considered as the rated heat input capacity.

(9) Therm means 100,000 Btu's.

(10) Unit means any boiler, steam generator, or process heater as defined in subparagraph (3) or (7) of this paragraph.

(b) Applicability

This rule applies to boilers, steam generators, and process heaters of equal to or greater than 5 million Btu's per hour rated heat input capacity used in all industrial, institutional, and commercial operations with the exception of:

(1) boilers used by electric utilities to generate electricity; and

(2) boilers and process heaters with a rated heat input capacity greater than 40 million Btu per hour that are used in petroleum refineries; and

(3) sulfur plant reaction boilers.

(c) Requirements

(1) The owner or operator of any unit(s) shall not discharge into the atmosphere oxides of nitrogen, expressed as nitrogen dioxide (NO_2), in excess of the concentrations shown in the following table.

Rated Heat Input Capacity		Annual Heat Input	Gaseous or Liquid Fuels
Equal to or greater than 5 million Btu's per hour	And	Greater than 9 x 10^9 Btu's per yr (90,000 Therms)	40 ppm (0.05 lb per 10^6 Btu's of heat input)
Equal to or greater than 40 million Btu's per hour	And	Greater than 25% annual capacity factor	30 ppm

Carbon monoxide (CO) emissions from unit(s) subject to this subparagraph shall not exceed 400 ppm.

(2) Any unit(s) with a rated heat input capacity greater than or equal to 5 million Btu per hour and an annual heat input less than or equal to 9.0 x 10^9 Btu per year, shall:

(A) be operated in a manner that maintains stack gas oxygen concentrations at less than or equal to 3 percent on a dry basis for any 15-consecutive-minute averaging period; or

(B) be tuned at least twice per year, once between March 15 and June 15, and once between September 15 and December 15 in accordance with the procedure described in Attachment 1. The owner or operator of any unit(s) who specifies the semi-annual tune-up option shall maintain a record made accessible to the Executive Officer for a period of two years verifying that the tune-up has been performed. The record shall contain any other information or documentation that the Executive Officer determines to be necessary; or

(C) be operated in compliance with a 40 ppm (0.05 lbs per 10^6 Btu of heat input) NOx emission level and a 400 ppm CO emission level.

(3) The owner or operator of any unit(s) subject to subparagraph (c)(2) shall submit for the approval of the Executive Officer a plan that demonstrates compliance with subparagraph (c)(2). Such plan shall contain:

(A) A list of all units with the rated heat input capacity and anticipated annual heat input.

(B) For each unit listed, a selection of one of the three options specified in subparagraph (c)(2) to achieve compliance with this rule.

(4) Any unit(s) with a rated heat input capacity greater than or equal to 40 million Btu per hour and an annual heat input greater than 200 x 10^9 Btu per year, or any units that are part of an Alternative Emission Control Plan, shall have a continuous in-stack nitrogen oxides monitor or equivalent verification system as approved by the Executive Officer. Records shall be maintained and made accessible for a period of two years in a form and manner as specified by the Executive Officer.

(5) Any owner or operator who chooses the pound per million Btu compliance option shall install totalizing fuel meters on an individual unit basis, as approved by the Executive Officer.

(6) Any owner or operator claiming an exemption from any of the provisions of subparagraphs (c)(1) and/or (c)(4) based on annual heat input, shall:

(A) install by February 1, 1989 for units with a rated heat input capacity equal to or greater than 5 but less than 40 million Btu per hour, or by May 1, 1989 for units with a rated heat input capacity equal to or greater than 40 million Btu per hour, or at the time the unit is constructed, a totalizing meter for each fuel that demonstrates that the unit(s) operated at or below the applicable heat input levels; and

(B) have available for inspection by the Executive Officer by March 1, 1989, and March 1, of each year thereafter, annual fuel use data for the preceding calendar year. Records shall be maintained and made accessible to the Executive Officer for a period of two years; and

(C) demonstrate that the annual heat input is less than or equal to the applicable amount listed in subparagraph (c)(1) and/or (c)(4).

(d) Alternative Emission Control Plan

(1) An owner or operator may achieve compliance with paragraph (c) by achieving equivalent nitrogen oxides emissions reductions obtained by alternative control methods provided the applicant submits an Alternative Emission Control Plan that is enforceable by the District and receives approval of the Plan in writing from the Executive Officer prior to implementation. The Alternative Emission Control Plan shall:

(A) Contain, as a minimum, all data, records, and other information necessary to determine eligibility for alternative emission control, including but not limited to:

(i) A list of equipment subject to alternative emission control;

(ii) Daily hours of utilization for applicable equipment;

(iii) Estimated emission of nitrogen oxides for each operation;

(iv) Rated capacity; and

(v) Historical and projected fuel use.

(B) Present the methodology for estimation of equivalency of emission reductions under the proposed Alternative Emission Control Plan as compared to either the emission reductions otherwise required by the rule or to actual emissions, whichever is less.

(C) Demonstrate that the permit units subject to the specified rule emission limitations are in compliance with or on an approved schedule for compliance with all applicable District rules.

(2) Revision of Control Plan

A revised control plan may be submitted by the owner or operator, along with any required permit applications. Such a plan shall adhere to the emissions limits and the final compliance dates of this rule. New units, including functionally identical replacement units, shall not be incorporated into the plan.

(e) Compliance Determination

(1) An owner or operator of any unit(s) shall have the option of complying with either the pound per million Btu or parts per million emission limits specified in subparagraph (c)(1).

(2) All emission determinations shall be made in the as-found operating condition, except no compliance determination shall be established during start-up, shutdown, or under breakdown conditions.

(3) All parts per million emission limits specified in paragraph (c) are referenced at 3 percent volume stack gas oxygen on a dry basis averaged over a period of 15 consecutive minutes.

(4) Compliance with the NOx emission requirements and the stack gas oxygen concentration requirement of paragraph (c) shall be determined according to procedures in the District Source Test Manual or in any other manner approved by the Executive Officer.

(f) Compliance Schedule

The owner or operator of units subject to this rule shall meet the following increments of progress:

(1) For owners or operators of units subject to subparagraph (c)(2), submit, by September 1, 1989, a plan pursuant to subparagraph (c)(3) and by March 1, 1990, demonstrate final compliance with subparagraph (c)(2).

(2) For owners or operators utilizing the Alternative Emission Control Plan, pursuant to paragraph (d), by September 1, 1989, submit a control plan.

(3) For owners or operators of units with a rated heat input capacity equal to or greater than 10 million Btu per hour that are subject to the 40 ppm emission limit specified in subparagraph (c)(1), including those with an approved Alternative Emission Control Plan;

(A) By March 1, 1990, submit required applications for permits to construct and operate.

(B) By September 1, 1991 demonstrate compliance with subparagraph (c)(1) and, if applicable, subparagraph (c)(4).

(4) For owners or operators of units with a rated heat input capacity equal to or greater than 5 million Btu per hour, but less than 10 million Btu per hour, that are subject to the 40 ppm emission limit specified in subparagraph (c)(1):

(A) By March 1, 1991, submit required applications for permits to construct and operate.

(B) By March 1, 1992, demonstrate compliance with subparagraph (c)(1).

(5) For owners or operators of units with a rated heat input capacity equal to or greater than 40 million Btu's per hour and an annual capacity factor of 25% that are subject to the 30 ppm emission limit specified in subparagraph (c)(1):

(A) By July 1, 1991, submit required applications for permits to construct and operate.

(B) By July 1, 1993, demonstrate compliance with subparagraph (c)(1).

(6) The provisions of subparagraph (c)(1) and/or (c)(4) shall become applicable for the life of the unit on March 1, of any calendar year if that unit operated for the previous calendar year at an annual heat input greater than the annual applicable heat input levels.

ATTACHMENT 1

Equipment Tuning Procedure[1]

Nothing in this Equipment Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurors, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate the unit at the firing rate most typical of normal operation. If the unit experiences significant load variations during normal operation, operate it at its average firing rate.
2. At this firing rate, record stack gas temperature, oxygen concentration, and CO concentration (for gaseous fuels) or smoke-spot number[2] (for liquid fuels), and observe flame conditions after unit operation stabilizes at the firing rate selected. If the excess oxygen in the stack gas is at the lower end of the range of typical minimum values[3], and if CO emissions are low and there is not smoke, the unit is probably operating at near optimum efficiency - at this particular firing rate.

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1. This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for the EPA.

2. The smoke-spot number can be determined with ASTM Test Method D-2156 or with the Bacharach method. ASTM Test Method D-2156 is included in a tuneup kit that can be purchased from the Bacharach Company.

3. Typical minimum oxygen levels for boilers at high firing rates are:
   1. For natural gas: 0.5% - 3%
   2. For liquid fuels: 2% - 4%

However, complete the remaining portion of this procedure to determine whether still lower oxygen levels are practical.

3. Increase combustion air flow to the furnace until stack gas oxygen levels increase by one to two percent over the level measured in Step 2. As in Step 2, record the stack gas temperature, CO concentration (for gaseous fuels) or smoke-spot number (for liquid fuels), and observe flame conditions for these higher oxygen levels after boiler operation stabilizes.
4. Decrease combustion air flow until the stack gas oxygen concentration is at the level measured in Step 2. From this level gradually reduce the combustion air flow, in small increments. After each increment, record the stack gas temperature, oxygen concentration, CO concentration (for gaseous fuels) and smoke-spot number (for liquid fuels). Also observe the flame and record any changes in its condition.
5. Continue to reduce combustion air flow stepwise, until one of these limits is reached:
   a. Unacceptable flame conditions - such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability.
   b. Stack gas CO concentrations greater than 400 ppm.
   c. Smoking at the stack.
   d. Equipment-related limitations - such as low windbox/furnace pressure differential, built in air-flow limits, etc.
6. Develop an O_2/CO curve (for gaseous fuels) or O_2/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2 using the excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.
7. From the curves prepared in Step 6, find the stack gas oxygen levels where the CO emissions or smoke-spot number equal the following values:

Fuel	Measurement	Value
Gaseous	CO Emissions	400 ppm
#1 and #2 oils	smoke-spot number	number 1
#4 oil	smoke-spot number	number 2
#5 oil	smoke-spot number	number 3
Other oils	smoke-spot number	number 4

The above conditions are referred to as the CO or smoke thresholds, or as the minimum excess oxygen level.

Compare this minimum value of excess oxygen to the expected value provided by the combustion unit manufacturer. If the minimum level found is substantially higher than the value provided by the combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mixing, thereby allowing operation with less air.

8. Add 0.5 to 2.0 percent of the minimum excess oxygen level found in Step 7 and reset burner controls to operate automatically at this higher stack gas oxygen level. This margin above the minimum oxygen level accounts for fuel variations, variations in atmospheric conditions, load changes, and nonrepeatability or play in automatic controls.

9. If the load of the combustion unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent the upper and lower limits of the range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish the optimum excess oxygen level at all firing rates. If this is the case, choose the burner control settings that give best performance over the range of firing rates. If one firing rate predominates, settings should optimize conditions at that rate.

10. Verify that the new settings can accommodate the sudden load changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing the flame and stack. If any of the conditions in Step 5 result, reset the combustion controls to provide a slightly higher level of excess oxygen at the affected firing rates. Next, verify these new settings in a similar fashion. Then make sure that the final control settings are recorded at steady-state operating conditions for future reference.

APPENDIX D

SCAQMD Rule 1109

Emissions of Oxides of Nitrogen From Boilers and Process Heaters in Petroleum Refineries

(Adopted November 1, 1985)(Amended August 5, 1988)

RULE 1109. EMISSIONS OF OXIDES OF NITROGEN FROM BOILERS AND PROCESS HEATERS IN PETROLEUM REFINERIES

(a) Definitions

(1) BOILER means any combustion equipment fired with liquid and/or gaseous fuel and used to produce steam, including a carbon monoxide boiler.

(2) PROCESS HEATER means any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to process streams.

(3) REFINERY-WIDE RATE OF NITROGEN OXIDES EMISSIONS means the ratio of the total mass rate of discharge into the atmosphere of nitrogen oxides from units (subject to the rule) when firing at their maximum rated capacity to the sum of the maximum rated capacities for those units.

(4) UNIT means any petroleum refinery boiler or process heater, as defined in subsections (1) and (2) of this section, with a permit to construct or a permit to operate prior to March 2, 1984.

(5) NITROGEN OXIDES means the sum of nitric oxide and nitrogen dioxide in the flue gas, collectively expressed as nitrogen dioxide and averaged over a period of 15 consecutive minutes.

(6) COMBUSTION MODIFICATION means any modification of the burner, combustion air flow, or fuel flow system that reduces nitrogen oxides emissions.

(7) MAXIMUM RATED CAPACITY means maximum design heat input at the higher heating value of the fuel unless:

(A) the boiler/process heater is limited by permit condition to a lesser heat input, in which case the limiting condition shall be used as the maximum rated capacity; or

(B) the boiler/process heater is operated above the maximum design heat input, in which case the maximum operated rate shall be used at the maximum rated capacity.

(8) EMISSIONS RATE means the ratio of the mass rate of discharge into

the atmosphere of nitrogen oxides from a unit to the actual heat input for that unit.

(9) HEAT INPUT means the heat of combustion released by fuel oxidation in a unit, using the higher heating value of the fuel. This does not include the enthalpy of incoming combustion air. In the case of carbon monoxide boilers, the heat input includes the enthalpy of all regenerator off gases and the heat of combustion of the incoming carbon monoxide and of the auxiliary fuel. The enthalpy of the fluid catalytic cracking unit regenerator off-gases refers to the total heat content of the gas at the temperature it enters the carbon monoxide boiler, referred to the heat content at 60^{O}F, as being zero.

(b) Requirements

(1) (A) From July 1, 1988 until December 31, 1992, the owner operator of any petroleum refinery shall reduce emissions of nitrogen oxides from units subject to this rule so that if all such units were operated at their maximum rated capacity the refinery-wide rate of nitrogen oxides emissions from these units would not exceed:

(i) 0.14 pound (0.064 kilogram) of nitrogen oxides per million BTU of heat input when operated on gaseous fuel;

(ii) 0.308 pound (0.14 kilogram) of nitrogen oxides per million BTU of heat input when operated on liquid fuel;

(iii) the weighted average of the limits of subsections (b)(1)(A)(i) and (b)(1)A(ii), when operated concurrently on both liquid and gaseous fuel. For purpose of this rule, the nitrogen oxides formed in the fluid catalytic cracking unit regenerator shall be assumed to be from the burning of gaseous fuel.

(B) On December 31, 1992 and subsequent dates, the owner or operator of any petroleum refinery shall reduce emissions of nitrogen oxides from each unit subject to this rule so that:

(i) From December 31, 1992 until December 31, 1995, emissions from units which represent at least 36 percent of the total heat input are less than or equal to 0.03 pound per million BTU of heat input when firing at the maximum rated capacity, or as specified in the Alternative Emission Control Plan (AECP). Any unit not meeting the 0.03 pound per million limit shall not exceed its pound per million BTU limit specified in the Approved Control Plan for compliance with (b)(1)(A);

(ii) From December 31, 1995, emissions are less than or equal to 0.03 pound per million BTU of heat input when firing at the maximum rated capacity, or as specified in the Alternative Emission Control Plan (AECP).

(iii) For each unit firing at less than the maximum rated capacity, mass emissions of nitrogen oxides shall be less than or equal to the quantity that would occur at the applicable limit specified in (b)(1)(B)(i) and (b)(1)(B)(ii) at maximum rated capacity, or as specified in the AECP.

(iv) Alternative Emission Control Plan (AECP)

An owner/operator may achieve compliance with paragraphs (b)(1)(B)(i) and (b)(1)(B)(ii) by achieving equivalent nitrogen oxides emissions reductions obtained by alternative control methods provided the applicant submits an Alternative Emission Control Plan that is enforceable by the District and receives approval of the Plan in writing from the Executive Officer prior to implementation. The Alternative Emission Control Plan shall:

(I) Contain, as a minimum, all data, records, and other information necessary to determine eligibility for alternative emission control, including but not limited to:

a) A list of equipment subject to alternative emission control;

b) Daily hours of utilization for applicable equipment;

c) Estimated emission of nitrogen oxides for each operation;

d) Rated capacity; and

e) Historical and projected fuel use.

(II) Present the methodology for estimation of equivalency of emission reductions under the proposed Alternative Emission Control Plan as compared to either the emission reductions otherwise required by the rule or to actual emissions, whichever is less.

(III) Demonstrate that the permit units subject to the specified rule emission limitations are in compliance with or on an approved schedule for compliance with all applicable District rules.

(2) The owner or operator shall operate each unit subject to this rule such that the assigned maximum nitrogen oxides emissions rate for each unit (pounds or kilograms per million BTU heat input, expressed as nitrogen dioxide) is in accordance with the list approved by the Executive Officer pursuant to subsection (b)(6)(B), and any specified permit conditions.

(3) The owner or operator of any petroleum refinery which has units subject to this rule shall submit to the Executive Officer a control plan for installation of nitrogen oxides emissions control equipment to meet the requirements of subsection (b)(1);

Such plan shall contain as a minimum:

(A) A list of all units with the maximum rated capacity for each unit,

(B) A list of units to be controlled and the type of control to be applied for all such units, including a construction schedule,

(C) The method of calculation of the mass rate of nitrogen oxides emissions for each unit to achieve the refinery-wide emissions rates specified in subsection (b)(1), and

(D) On-site nitrogen oxide offsets from co-generation facilities may be incorporated in the plan.

(4) All units which are identified in the control plan required by subsection (b)(3) shall be tested, in a manner approved by the Executive Officer, for nitrogen oxides emissions while firing gaseous fuel and liquid fuel, if

applicable, at the maximum rated capacity, or as near thereto as practicable. Such tests shall be performed:

(A) Within 180 days after completion of modifications, but no later than 1 month before any applicable compliance date for units which are to be modified with nitrogen oxides control equipment, and

(B) By December 1, 1986, for units which do not require modification.

(5) Total nitrogen oxides emissions (pounds or kilograms per hour) and total heat input rates (million BTU's per hour) during the tests required by subsection (b)(4), while firing gaseous fuel and while firing liquid fuel, shall be used for determination of initial compliance with the refinery-wide rate of emissions limits of subsection (b)(1).

(6) After verification of initial compliance with the limits of subsection (b)(1))(A):

(A) The owner or operator shall assign to each unit subject to this rule the maximum nitrogen oxides emissions rates (pounds or kilograms per million BTU heat input, expressed as nitrogen dioxide), while firing gaseous fuel or liquid fuel, which are allowable for that unit under the requirements of subsection (b)(1)(A).

(B) The owner or operator shall submit to the Executive Officer for approval a list, by the applicable compliance date, of the maximum allowable nitrogen oxides emissions rates identified in subsection (b)(6)(A) and a copy of the approved list shall be maintained for verification of continued compliance with the requirements of subsection (b)(2).

(C) Compliance with subsection (b)(1)(A) shall be determined by source testing any one unit subject to this rule, or additional units if required by the Executive Officer. No unit subject to this rule shall be operated at an emissions rate (pounds or kilograms per million BTU heat input, expressed as nitrogen dioxide) higher than that approved by the Executive Officer pursuant to subsection (b)(6)(B).

(7) Each unit subject to this rule shall have a continuous in-stack nitrogen

oxides monitor, or equivalent verification system, as approved by the Executive Officer at the time of compliance with the 0.03 pound per million BTU limit specified in subsections (b)(1)(B)(i) and (b)(1)(B)(ii).

(A) Records shall be maintained and made accessible for a period of two years to the Executive Officer in a form and manner as specified by the Executive Officer.

(B) Compliance with subsection (b)(1)(B) shall be determined by source testing and/or in-stack nitrogen oxides monitor data or other data as specified for the equivalent verification system.

(c) Revision of Control Plan

A revised control plan may be submitted by the owner operator, along with any required permit applications. Such a plan shall adhere to the emissions limits and the final compliance dates of this rule. New units, including functionally identical replacement units, shall not be incorporated into the plan.

(d) Exemptions

The requirements of Section (b) shall not apply to:

(1) Boilers or process heaters with maximum rated capacities equal to or less than 40 million BTU per hour heat input.

(2) Sulfur plant reaction boilers.

(3) Upon approval by the Executive Officer, units which are operated with a total heat input in a 12 month period of less than 10 percent of the maximum rated capacity for that period.

(e) Compliance Schedule

The owner or operator of a petroleum refinery having units subject to this rule shall fulfill the following increments of progress:

(1) For subsection (b)(1)(A), by July 1, 1988, demonstrate to the satisfaction of the Executive Officer final compliance with the rule.

(2) For subsection (b)(1)(B)(i):

(A) By April 1, 1989, submit a revised control plan, pursuant to subsection (b)(3) of the rule.

(B) By September 1, 1989, submit required applications for permits to construct and operate.

(C) By December 31, 1992 demonstrate to the satisfaction of the Executive Officer compliance with (b)(1)(B)(i).

(3) For subsection (b)(1)(B)(ii):

(A) By September 1, 1992, submit a revised control plan, pursuant to subsection (b)(3) of the rule.

(B) By February 1, 1993, submit required applications for permits to construct and operate.

(C) By December 31, 1995, demonstrate to the satisfaction of the Executive Officer compliance with (b)(1)(B)(ii).

APPENDIX E

VCAPCD Rule 74.15

Boilers, Steam Generators and Process Heaters

Rule 74.15. Boilers, Steam Generators and Process Heaters (Adopted 3/28/89)

A. Applicability

1. The provisions of this rule shall apply to boilers, steam generators and process heaters used in all industrial, institutional and commercial operations, except as follows:

   a. Utility electric power generating units and any auxiliary boiler used with a utility electric power generating unit.

   b. Water heaters.

B. Requirements

1. No person shall allow the discharge into the atmosphere from any boiler, steam generator or process heater with a rated heat input capacity of equal to, or greater than, five (5) million BTU's per hour, and an annual heat input rate of equal to, or greater than, 9×10^9 BTU's per calendar year, oxides of nitrogen emissions in excess of 40 parts per million volume. Carbon monoxide emissions from units subject to this rule shall not exceed 400 ppmv.

   Units subject to the above provisions shall test for compliance not less than once every 24 months.

2. Any boiler, steam generator or process heater with a rated heat input capacity of equal to, or greater than, five (5) million BTU's per hour, and having an annual heat input rate of <u>less</u> than 9×10^9 BTU's per calendar year, shall comply with one of the following requirements:

   a. The unit shall be operated in a manner that maintains stack gas oxygen concentrations at less than or equal to three (3) percent on a dry basis for any 15-consecutive-minute averaging period. Units subject to this provision shall test for compliance every six (6) months; or

   b. The unit shall be operated using a stack gas oxygen trim system set at three (3) percent oxygen. The tolerance of the setting shall be ± five (5) percent. Units subject to this provision shall test for compliance every twelve (12) months; or

   c. The unit shall be tuned at least twice per calendar year, once between March 15 and June 15 and once between September 15 and December 15, in accordance with the procedure described in Attachment 1; or

   d. The unit shall comply with the emission and testing requirements of Subsection B.1.

C. Exemptions

1. The provisions of this rule shall not apply to any boiler, steam generator or process heater with a rated heat input capacity of less than five (5) million BTU's per hour.

2. The provisions of Subsection B.1 of this rule shall not apply to any boiler, steam generator or process heater operated on alternate fuel under the following conditions:

   a. Alternate fuel use is required due to the curtailment of natural gas service to the individual unit by the natural gas supplier. Alternate fuel use in this case shall not exceed the period of natural gas curtailment.

   b. Alternate fuel use is required to maintain the alternate fuel system. Alternate fuel use in this case shall not exceed 50 hours per year.

3. The provisions of Subsection B.1 of this rule shall not apply to the use of an emergency standby unit when a breakdown occurs to the primary unit, and the breakdown is reported pursuant to the breakdown reporting requirements of Rule 32. Emissions resulting from the operation of the standby unit shall not exceed the total annual or hourly permitted emission rate of the primary unit. Operation of the standby unit shall not occur beyond the period of the primary unit's emergency breakdown.

D. Recordkeeping Requirements

1. Any person subject to the provisions of Subsection B.2 of this rule shall install by September 28, 1989, or at the time the unit is constructed, a totalizing fuel meter for each applicable unit and for each fuel. The meter shall be used to demonstrate that each unit operates at or below the applicable heat input level.

   Meters shall be accurate to ± one (1) percent, as certified by the manufacturer in writing. After December 28, 1989, totalizing fuel meter readings shall be recorded at the end of each operating day in units of either cubic feet per day or gallons per day. At the end of each month, daily records shall be compiled into a monthly report. Both monthly reports and daily records shall be maintained for a period of four (4) years and shall be made available for inspection by the Air Pollution Control Officer upon request.

2. Any person subject to the provisions of Subsection B.2.c of this rule shall submit a report to the District twelve (12) months after achieving compliance with Subsection B.2.c. Reports shall continue to be submitted every twelve (12) months. This report shall verify that each tune-up has been performed and that the results were satisfactory. The report shall contain all information or documentation that the Air Pollution Control Officer may determine, in writing, to be necessary.

3. Any person utilizing alternate fuel, pursuant to the provisions of Subsection C.2 of this rule, shall maintain permanent daily records of each occurrence. Each record shall include the type of fuel, the quantity of fuel, and the duration of the occurrence. Records shall be maintained for a period of four (4) years and shall be available for inspection by the Air Pollution Control Officer upon request.

E. Test Methods

1. Compliance with the emission requirements in Section B shall be determined using the following test methods:

   a. Oxides of Nitrogen - EPA Method 7E or ARB Method 100
   b. Carbon Monoxide - EPA Method 10 or ARB Method 100
   c. Stack Gas Oxygen - EPA Method 3A or ARB Method 100

2. Emission tests resulting in compliance determinations for the requirements of Subsection B.1 shall be conducted on units in "as-found" operating condition. However, no emission test for this rule shall be conducted during start-up, shutdown or under breakdown conditions.

3. The NOx parts per million emission limitation specified in Subsection B.1 is expressed as nitrogen dioxide. The limitations for both NOx and CO are referenced at three (3) percent volume stack gas oxygen on a dry basis averaged over 15 consecutive minutes.

F. Violations

1. Failure to comply with any provision of this rule shall constitute a violation of this rule.

2. Any unit subject to the provisions of Subsection B.2 shall comply with the provisions of Subsection B.1 if the unit operates during any twelve (12) month period at a total annual heat input rate greater than the applicable annual heat input rate specified in Subsection B.2.

G. Definitions

1. "Boiler, Steam Generator": Any combustion equipment fired with liquid and/or gaseous fuel and used to produce steam. These terms do not include any unfired waste heat recovery boiler that is used to recover sensible heat from the exhaust of any combustion equipment.

2. "Process Heater": Any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to water or process streams. Process Heater does not include any kiln or oven used for drying, baking, cooking, calcinating or vitrifying or any fuel-fired degreasing or metal finishing equipment.

3. "Rated Heat Input Capacity": The heat input capacity specified on the nameplate of the unit's burner. If the burner has been permanently altered or modified such that the maximum heat input is different than the input capacity specified on the nameplate, and this alteration or modification has been approved in writing by the Air Pollution Control Officer, then the new maximum heat input shall be considered as the rated heat input capacity.

4. "Unit": Any boiler, steam generator or process heater as defined in Subsections G.1 and G.2 of this rule.

5. "Water Heater": A device that heats water to a thermostatically-controlled temperature for delivery on demand.

H. Increments of Progress

1. For units subject to Subsection B.1 and with a rated heat input capacity of equal to or greater than ten (10) million BTU's per hour, complete Authority to Construct applications shall be submitted to the APCD before March 1, 1990, and final compliance shall be demonstrated before September 1, 1991.

2. For units subject to Subsection B.1 and with a rated heat input capacity of equal to or greater than five (5) million BTU's per hour, but less than ten (10) million BTU's per hour, complete Authority to Construct applications shall be submitted to the APCD before March 1, 1991, and final compliance shall be demonstrated before March 1, 1992.

3. For units subject to Subsections B.2, final compliance shall be demonstrated by March 1, 1990.

ATTACHMENT 1

Equipment Tuning Procedure[1]

Nothing in this Equipment Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurors, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division). the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate the unit at the firing rate most typical of normal operation. If the unit experiences significant load variations during normal operation, operate it at its average firing rate.

2. At this firing rate, record stack gas temperature, oxygen concentration, and CO concentration (for gaseous fuels) or smoke-spot number[2] (for liquid fuels), and observe flame conditions after unit operation stabilizes at the firing rate selected. If the excess oxygen in the stack gas is at the lower end of the range of typical minimum values[3], and if the CO emissions are low and there is not smoke, the unit is probably operating at near optimum efficiency - at this particular firing rate. However, complete the remaining portion of this procedure to determine whether still lower oxygen levels are practical.

3. Increase combustion air flow to the furnace until stack gas oxygen levels increase by one to two percent over the level measured in Step 2. As in Step 2, record the stack gas temperature, CO concentration (for gaseous fuels) or smoke-spot number (for liquid fuels), and observe flame conditions for these higher oxygen levels after boiler operation stabilizes.

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1. This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for the EPA.

2. The smoke-spot number can be determined with ASTM Test Method D-2156 or with the Bacharach method. ASTM Test Method D-2156 is included in a tuneup kit that can be purchased from the Bacharach Company.

3. Typical minimum oxygen levels for boilers at high firing rates are:

   1. For natural gas: 0.5% - 3%
   2. For liquid fuels: 2% - 4%

4. Decrease combustion air flow until the stack gas oxygen concentration is at the level measured in Step 2. From this level gradually reduce the combustion air flow, in small increments. After each increment, record the stack gas temperature, oxygen concentration, CO concentration (for gaseous fuels) and smoke-spot number (for liquid fuels). Also observe the flame and record any changes in its condition.

5. Continue to reduce combustion air flow stepwise, until one of these limits in reached:

   a. Unacceptable flame conditions - such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability.

   b. Stack gas CO concentrations greater than 400 ppm.

   c. Smoking at the stack.

   d. Equipment-related limitations - such as low windbox/furnace pressure differential, built in air-flow limits, etc.

6. Develop an O_2/CO curve (for gaseous fuels) or O_2/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2 using the excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.

7. From the curves prepared in Step 6, find the stack gas oxygen levels where the CO emissions or smoke-spot number equal the following values:

Fuel	Measurement	Value
Gaseous	CO Emissions	400 ppm
#1 & #2 oils	smoke-spot number	number 1
#4 oil	smoke-spot number	number 2
#5 oil	smoke-spot number	number 3
Other oils	smoke-spot number	number 4

The above conditions are referred to as CO or smoke threshold, or as the minimum excess oxygen level.

Compare this minimum value of excess oxygen to the expected value provided by the combustion unit manufacturer. If the minimum level found is substantially higher than the value provided by the combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mixing, thereby allowing operation with less air.

8. Add 0.5 to 2.0 percent to the minimum excess oxygen level found in Step 7 and reset burner controls to operate automatically at this higher stack gas oxygen level. This margin above the minimum oxygen level accounts for fuel variations, variations in atmospheric conditions, load changes, and nonrepeatability or play in automatic controls.

9. If the load of the combustion unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent the upper and lower limits of the range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish the optimum excess oxygen level at all firing rates. If this is the case, choose the burner control settings that give best performance over the range of firing rates. If one firing rate predominates, settings should optimize conditions at that rate.

10. Verify that the new settings can accommodate the sudden changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing the flame and stack. If any of the conditions in Step 5 result, reset the combustion controls to provide a slightly higher level of excess oxygen at the affect firing rates. Next, verify these new settings in a similar fashion. Then make sure that the final control settings are recorded at steady-state operating conditions for future reference.