# Eastern Kern Air Pollution Control District

# Rule 425.2
## BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN)

**STAFF REPORT**

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## I. INTRODUCTION

The Eastern Kern Air Pollution Control District (District) is proposing to adopt amendments to Rule 425.2, Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen). Rule 425.2 was originally adopted October 13, 1994 and amended April 6, 1995 and July 10, 1997. This proposed amendments is to reduce emissions of nitrogen oxides (NOx) by lowering the current NOx limits. NOx compounds are precursors in the formation of ground level ozone and particulate matter. The District has nonattainment status for the federal 8-hour ozone standard. This staff report presents an extensive revision of the Rule.

A majority of Rule 425.2 proposed amendments are modeled after California Air Resources Board (ARB)'s *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters*[1]. Similar rules can also be found in Bay Area, San Diego, and Santa Barbara Air Pollution Control Districts.

Appendix A is the clean version of proposed Rule 425.2, Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen).

Appendix B shows all changes made to proposed Rule 425.2, Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen) in strikeout underline form.

## II. PROPOSED RULE OVERVIEW

Proposed rule will lower the current NOx limits for boilers, steam generators and process heaters with rated heat input of 5 million Btu per hour or more and fired with gaseous and/or liquid fuels. For units with annual heat input of 90,000 therms or more during one or more of the three preceding years of operation, NOx emission levels shall not exceed 30 parts per million by volume (ppmv) when operated on gaseous fuel and 40 ppmv when operated on liquid fuel. For units with annual heat inputs of less than 90,000 therms, the requirements will be unchanged. Additionally, carbon monoxide (CO) emissions limits of 400 ppmv will be unchanged.

## III. EMISSIONS FROM BOILERS, STEAM GENERATORS, AND PROCESS HEATERS

Boilers, steam generators, and process heaters emit NOx from combustion of fuels. NOx is one of two precursors in the formation of ozone which is the primary component of smog. The second precursor is volatile organic compounds (VOCs). Because the District has nonattainment status for federal 8-hour ozone standard, the District is required to implement all feasible State and Federal measures to reduce emissions of ozone precursors, including NOx. NOx reacts photochemically with VOCs to form ozone. Ozone irritates human respiratory systems and damages plant life and

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[1] Complete Document can be found at: https://www.arb.ca.gov/ractbarc/boilers.pdf

property. Exposure to ozone can be associated with hospitalization for cardiopulmonary causes, asthma episodes, restrictions in physical activity, and premature death. NOx emissions from boilers, steam generators, and process heaters can also react with other pollutants to form airborne particles smaller than 2.5 micrometer (microns) in diameter called $PM_{2.5}$. When inhaled, $PM_{2.5}$ can travel deep into the lungs and reduce lung function.

## IV. NOx EMISSIONS REDUCTION (CONTROL TECHNOLOGIES)

Reducing NOx emissions from boilers, steam generators, and process heaters can be achieved by applying control technologies and they can be broken down into four methods. These are

A. Retrofitting of low-NOx-emitting burners;
B. Retrofitting of flue-gas-recirculation systems;
C. Installation of ammonia injection systems for selective noncatalytic reduction; and
D. Installation of ammonia injection systems along with catalytic reactors for selective catalytic reduction.

### A. Low-NOx Burner

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. Stage-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 1,600 to 2,200 degrees Fahrenheit, 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 of the DeNOx reaction down to 1,300°F.

NOx reductions of up to 90 percent have been demonstrated on 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 with greater than one percent excess $O_2$.

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.

Selective catalytic reduction 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 capacity, or possibly an additional fan, may be necessary. SCR has been extensively employed in Japan on gas-fired and oil-fired industrial and utility boilers.

## V. COST-EFFECTIVENESS

ARB's *Determination of Reasonably Available Control Technology (RACT) and Best Available Retrofit Control Technology (BARCT) for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, 1991*, listed cost effectiveness for control technologies mentioned above.

## VI. APPLICABILITY

Provisions of Rule 425.2 are applicable to any boiler, steam generator or process heater with rated heat input of 5 million Btu per hour or more with gaseous and/or liquid fuels.

## VII. CHANGES IN RULE 425.2

The following requirements and figures have been added to Rule 425.2:

- The purpose of this Rule is to limit oxides of nitrogen (NOx) emissions from boilers, steam generators, and process heaters.
- Section V.A.2 shall not apply to any unit while forced to burn liquid fuel during time of natural gas curtailment. NOx emission limit shall not exceed 150 ppmv or 0.215 pounds per million Btu of heat input when burning liquid fuel. This exemption shall not exceed 168 cumulative hours of operation per calendar year excluding equipment testing not to exceed 48 hours per calendar year.
- 30 parts per million by volume (ppmv) or 0.036 pound per million Btu of heat input when operated on gaseous fuel.
- 40 parts per million by volume (ppmv) or 0.052 pounds per million Btu of heat input when operated on liquid fuel.
- The heat-input weighted averaged of the limits specified in Section V.A.1 and V.A.2 above when operated on combination of gaseous and liquid fuel.

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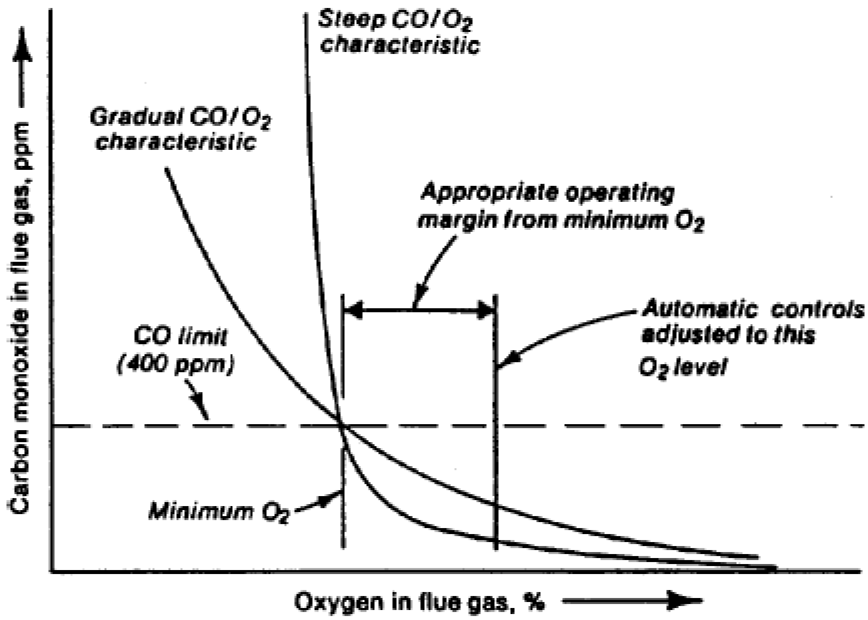


Figure 1: Oxygen/CO Characteristic Curve

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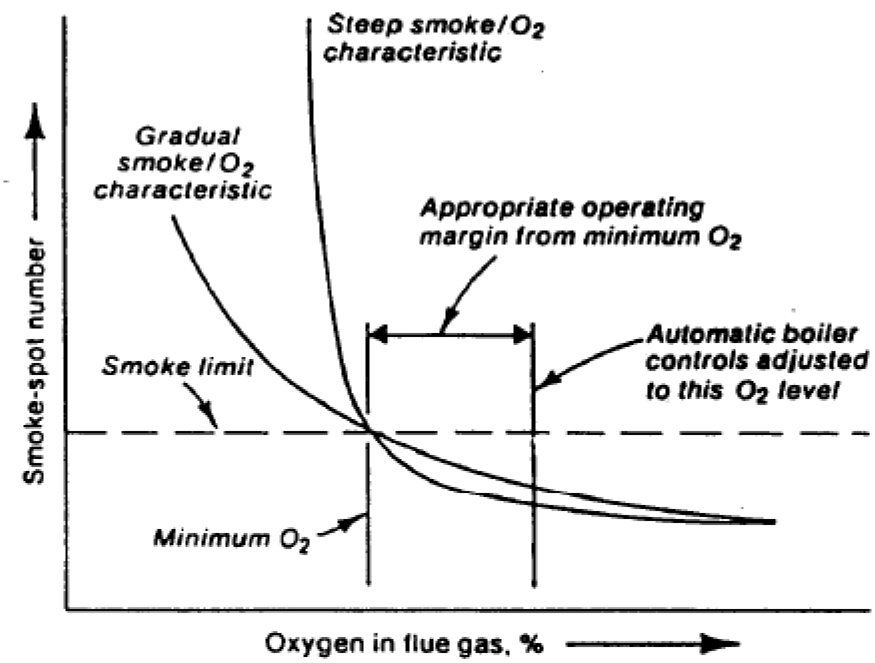


Figure 2: Oxygen/Smoke Characteristic Curve

The following requirements of Rule 425.2 have been revised:

- Definition of Natural gas curtailment has been revised from: ~~*loss of natural gas supply due to action of PUC-regulated supplier. For Section V curtailment limit to apply, curtailment must not exceed 168 cumulative hours of operation per calendar year, excluding equipment testing not to exceed 48 hours per calendar year.*~~ To: <u>A shortage in the supply of natural gas, due solely to limitations or restrictions in distribution pipelines by the utility supplying natural gas, and not due to the cost of natural gas.</u>

- Definition of Standard Conditions has been revised from: ~~*as defined in Rule 102, Subsection DD*~~. To: <u>As defined in Rule 102, Subsection RR.</u>

- Recordkeeping and reporting requirement (Section VI.A.4) has been revised from:

  ~~*Records shall be maintained for at least two calendar years on site and shall be made readily available to District personnel.*~~

  To:

  Records shall be maintained for a period of five (5) years and made available for District inspection at any time.

- Compliance testing requirement (Section VI.C.3) has been revised from:

  ~~*3. Test results from an individual unit may be used for other units at the same location provided manufacturer, model number, rated capacity, fuel type, and emission control provisions are identical and key operating parameters such as stack gas oxygen, fuel consumption, etc. are monitored and established to correlate with NOx emissions from unit tested.*~~

  To:

  3. Test results from an individual unit may be used for other units when the following criteria are met:

     a. Units are located at the same facility,
     b. Units are produced by the same manufacturer, have the same model number, and have the same rated capacity and operating specifications,
     c. Units are operated and maintained in a similar manner, and
     d. District, based on documentation submitted by the facility, determines that the variability of emissions for identical tested units is low enough for confidence that the untested unit will be in compliance.

4. An owner/operator utilizing Section VI.C.3 shall ensure that all units be tested within a certain number of years. For example, testing one third of a fleet every year shall result in every unit being tested after three years, and not the same units being tested every year.

The following requirements of Rule 425.2 have been deleted:

- ~~*The purpose of this Rule is to limit oxides of nitrogen (NOx) emissions from boilers, steam generators, and process heaters to levels consistent with Reasonably Available Control Technology (RACT) to satisfy California Health and Safety Code Section 40918(b) and 1990 Federal Clean Air Act Amendments, Section 182(f). Carbon monoxide emissions are also limited to insure efficient combustion at reduced NOx levels.*~~

- ~~*Reasonably Available Control Technology (RACT) - lowest emission limitation a particular source is capable of meeting by application of control technology reasonably available considering technological and economic feasibility.*~~

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| | ~~*Gaseous Fuel*~~ | ~~*Liquid Fuel*~~ |
|---|---|---|
| ~~*During Normal Operation*~~ | ~~*70 ppmv, or 0.09 lb/MMBtu*~~ | ~~*115 ppmv, or 0.15 lb/MMBtu*~~ |
| ~~*During Natural Gas Curtailment*~~ | ~~----~~ | ~~*150 ppmv, or 0.19 lb/MMBtu*~~ |

## VIII. 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 $PM_{10}$ 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 $PM_{10}$ 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. There 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.

## IX. SOCIOECONOMIC IMPACTS

CHSC Section 40728.5 exempts districts with a population of less than 500,000 persons from the requirement to assess the socioeconomic impacts of proposed rules. Eastern Kern County population is below 500,000 persons.

## X. RULE APPROVAL PROCESS

The District will be accepting written comments and concerns from persons interested in Rule 425.2 for a period of 30 days following the November 2, 2017 workshop. District anticipates that Rule 425.2 will be considered for adoption by the Board at the January 2018 Board Hearing.

# APPENDIX A:

## AMENDED RULE 425.2

## BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN)

## CLEAN VERSION

**RULE 425.2** **Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen) –** Adopted 10/13/94, Amended 4/6/95, 7/10/97, XX/XX/XX

## I. Purpose

The purpose of this Rule is to limit oxides of nitrogen (NOx) emissions from boilers, steam generators, and process heaters.

## II. Applicability

This Rule shall apply, as specified, to any boiler, steam generator or process heater operating in the Eastern Kern Air Pollution Control District (District) with rated heat input of 5 million Btu per hour or more and fired with gaseous and/or liquid fuels.

## III. Definitions

A. Annual Heat Input: total heat released (therms) by fuel(s) burned in a unit during a calendar year as determined from higher heating value and cumulative annual fuel(s) usage.

B. Boiler or Steam Generator: any external combustion unit fired with liquid and/or gaseous fuel used to produce hot water or steam, but not including gas turbine engine exhaust gas heat recovery systems.

C. British Thermal Unit (Btu): amount of heat required to raise the temperature of one pound of water from 59°F to 60°F at one atmosphere.

D. Gaseous Fuel: any fuel existing as gas at standard conditions.

E. Heat Input: total heat released (Btu's) by fuel(s) burned in a unit as determined from higher heating value, not including sensible heat of incoming combustion air and fuel(s).

F. Higher Heating Value (HHV): total heat released per mass of fuel burned (Btu's per pound), when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to standard conditions.

G. Liquid Fuel: any fuel, including distillate and residual oil, existing as liquid at standard conditions.

H. Natural Gas Curtailment: a shortage in the supply of natural gas, due solely to limitations or restrictions in distribution pipelines by the utility supplying natural gas, and not due to the cost of natural gas.

I. Oxides of Nitrogen (NOx): total nitrogen oxides (expressed as $NO_2$).

J. Process Heater: any external combustion unit fired with liquid and/or gaseous fuel used to transfer heat from combustion gases to liquid process streams.

K. Rated Heat Input: heat input capacity (Btu's/hr) specified on nameplate of unit or by manufacturer for that model number, or as limited by District permit.

L. Standard Conditions: as defined in Rule 102, Subsection RR.

M. Therm: 100,000 British thermal units (Btu's).

N. Unit: any boiler, steam generator or process heater as defined in this Rule.

## IV. Exemption

1. This Rule shall not apply to any unit with rated heat input less than 5 million Btu per hour.

2. Section V.A.2 shall not apply to any unit while forced to burn liquid fuel during time of natural gas curtailment. NOx emission limit shall not exceed 150 ppmv or 0.215 pounds per million Btu of heat input when burning liquid fuel. This exemption shall not exceed 168 cumulative hours of operation per calendar year excluding equipment testing not to exceed 48 hours per calendar year.

## V. Requirements

A. An owner/operator of any unit subject to this Rule with annual heat input of 90,000 therms or more during one or more of the three preceding years of operation shall comply with following applicable NOx emission limit(s):

1. 30 parts per million by volume (ppmv) or 0.036 pound per million Btu of heat input when operated on gaseous fuel.

2. 40 parts per million by volume (ppmv) or 0.052 pound per million Btu of heat input when operated on liquid fuel.

3. The heat-input weighted averaged of the limits specified in Section V.A.1 and V.A.2 above when operated on combination of gaseous and liquid fuel.

For units subject to this Section, carbon monoxide (CO) emissions shall not exceed 400 parts per million by volume (ppmv).

NOx emission limit for any unit fired simultaneously with gaseous and liquid fuels shall be heat input-weighted average of applicable limits. Calculations shall be performed as prescribed in Section VIII.C.

NOx and CO emission limits in ppmv are referenced at dry stack gas conditions, adjusted to 3.00 percent by volume stack gas oxygen in accordance with Section VIII, and averaged over 15 consecutive minutes from no less than 5 data sets, recorded from sampling of no more than 3 minutes.

B. An owner/operator of any unit subject to this Rule with annual heat input rate of 90,000 therms or more shall comply, until November 10, 2020, and any unit with annual heat input rate of less than 90,000 therms shall comply with one of the following NOx minimization procedures:

1. Tune each unit at least once per year in accordance with Section IX.;

2. Operate each unit in a manner maintaining stack gas oxygen at no more than 3.00 percent by volume on dry basis; or

3. Operate each unit with an automatic stack gas oxygen trim system set at 3.00 (±0.15) percent by volume on dry basis.

C. Monitoring Requirements

1. An owner/operator of any unit simultaneously firing a combination of different fuels shall install and maintain a totalizing mass or volumetric flow rate meter in each fuel line.

2. An owner/operator of any unit utilizing equipment intended to reduce or control NOx shall install and maintain appropriate provisions to monitor operational parameters of unit and/or NOx control system that correlate to NOx emissions.

D. Compliance Demonstration

1. An owner/operator of any unit subject to Section V.A shall have the option of complying with either concentration (ppmv) emission limits or heat input basis (lb/MMBtu) emission limits as specified in Section V.A. All compliance demonstrations shall be performed using applicable test method(s) specified in Section VI.B and methods selected to demonstrate compliance shall be specified in Emission Control Plan required by Section VI.D.

2. All emission measurements shall be made with unit operating at conditions as close as physically possible to maximum firing rate allowed by the District Permit to Operate.

## VI. Administrative Requirements

A. Recordkeeping and Reporting

1. An owner/operator of any unit subject to this Rule or limited by permit condition to firing less than 5 million Btu's/hr shall monitor and record HHV and cumulative annual use of each fuel.

2. An owner/operator of any unit operated under natural gas curtailment limit of Section V.A shall monitor and record cumulative annual hours of operation on liquid fuel during curtailment and during testing.

3. An owner/operator of any identical units wishing to limit emissions testing to one unit per group of units pursuant to Section VI.C shall establish correlation of NOx emissions and key operating parameters and keep records of these data for each affected unit.

4. Records shall be maintained for a period of five (5) years and made available for District inspection at any time.

5. Compliance test data and results collected to satisfy Section VI.C shall be submitted to District within 60 days of collection.

B. <u>Test Methods</u>

1. Fuel HHV shall be certified by third party fuel supplier or determined by:

   a. ASTM D 240-87 or D 2382-88 for liquid fuels; and

   b. ASTM D 1826-88 or D 1945-81 in conjunction with ASTM D 3588-89 for gaseous fuels.

2. Oxides of nitrogen (ppmv) - EPA Method 7E, or CARB Method 100.

3. Carbon monoxide (ppmv) - EPA Method 10, or CARB Method 100.

4. Stack gas oxygen - EPA Method 3 or 3A, or CARB Method 100.

5. NOx emission rate (heat input basis) - EPA Method 19, or CARB Method 100 and data from fuel flow meter.

6. Stack gas velocity - EPA Method 2.

7. Stack gas moisture content - EPA Method 4.

C. <u>Compliance Testing</u>

1. Any unit subject to requirements of Section V.A shall be tested to determine compliance with applicable requirements not less than once every 12 months. An owner/operator of gaseous fuel-fired units demonstrating compliance for two consecutive years can, if desired, demonstrate compliance once every thirty-six months.

2. An owner/operator of any unit subject to Section V.B.2 shall sample and record stack gas oxygen content at least monthly.

3. Test results from an individual unit may be used for other units when the following criteria are met:

a. Units are located at the same facility,
b. Units are produced by the same manufacturer, have the same model number, and have the same rated capacity and operating specifications,
c. Units are operated and maintained in a similar manner, and
d. District, based on documentation submitted by the facility, determines that the variability of emissions for identical tested units is low enough for confidence that the untested unit will be in compliance.

4. An owner/operator utilizing Section VI.C.3 shall ensure that all units be tested within a certain number of years. For example, testing one third of a fleet every year shall result in every unit being tested after three years, and not the same units being tested every year.

D. Emission Control Plan

An owner/operator of any unit subject to this Rule shall submit to Control Officer an Emission Control Plan including:

1. List of units subject to Rule, including rated heat inputs, anticipated annual heat input, applicable Section V requirements, and control option chosen, if applicable;

2. Description of actions to be taken to satisfy requirements of Section V. Such plan shall identify actions to be taken to comply, including any type of emissions control to be applied to each unit and construction schedule, or shall include test results to demonstrate unit already complies with applicable requirements; and

3. Specification of proposed test methods.

## VII. Compliance Schedule

A. An owner/operator of any unit subject to Section V shall comply with following schedule:

1. By May 1, 2018, submit to Control Officer an Emission Control Plan pursuant to Section VI.D, and a complete application for Authority to Construct emission control equipment, if necessary;

2. By July 31, 2018 demonstrate compliance with Section V.B; and

3. By November 10, 2020 demonstrate full compliance with all additional and applicable provisions of this Rule.

B. An owner/operator of any unit becoming subject to requirements of Section V.A by exceeding the annual heat input exemption threshold shall comply with following increments of progress:

1. On or before December 31st of calendar year immediately following year annual heat input threshold was exceeded, submit an Emission Control Plan containing information prescribed in Section VI.D; and

2. No later than three calendar years following submission of Emission Control Plan, demonstrate final compliance with all applicable standards and requirements of this Rule.

## VIII. Calculations

A. All ppmv emission limits specified in Section V.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:

$$[\text{ppmv NOx}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O_2]_{\text{measured}}} \times [\text{ppmv NOx}]_{\text{measured}}$$

$$[\text{ppmv CO}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O_2]_{\text{measured}}} \times [\text{ppmv CO}]_{\text{measured}}$$

B. All lb/MMBtu NOx emission rates shall be calculated as pounds of nitrogen dioxide per million Btu's of heat input (HHV).

C. Heat input-weighted average NOx emission limit for combination of gaseous and liquid fuel shall be calculated as follows:

$$\text{NOx Emission Limit} = \frac{(30\ \text{ppmv} \times X) + (40\ \text{ppmv} \times Y)}{X + Y}$$

Where X = heat input from gaseous fuel and Y = heat input from liquid fuel.

## IX. NOx Minimization Tuning Procedures

A. Purpose

The purpose of these procedures is to provide a reasonable, cost-effective method to minimize NOx emissions from smaller, or low-fire/low use-rate combustion units subject to this Rule. These procedures not only minimize NOx emissions, but also result in reduced operating costs.

B. Equipment Tuning Procedure[1] for Mechanical Draft Boilers, Steam Generators, and Process Heaters

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 Insurers, National Fire Prevention Association, California Department of Industrial Relations (Occupational Safety and Health Division), Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate unit at firing rate most typical of normal operation. If unit experiences significant load variations during normal operation, operate 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 firing rate selected. If excess oxygen in the stack gas is at lower end of range of typical minimum values[3]; and if CO emissions are low and there is no smoke, unit is probably operating at near optimum efficiency - at this particular firing rate. However, complete remaining portion of this procedure to determine whether still lower oxygen levels are practical.

3. Increase combustion air flow to unit until stack gas oxygen levels increase by one to two percent over level measured in Step 2. As in Step 2, record 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 unit operation stabilizes.

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

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

[2] The smoke-spot number can be determined with ASTM Test Method D-2156 or with the Bacharach method.

[3] Typical minimum oxygen levels for boilers at high firing rates are:
For natural gas: 0.5% to 3% and For liquid fuels: 2% to 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 ppmv,

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

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

| Fuel | Measurement | Value |
|---|---|---|
| Gaseous | CO Emissions | 400 ppmv |
| #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 |

   Above conditions are referred to as CO or smoke thresholds, or as minimum excess oxygen levels.

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

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

9. If load of unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent upper and lower limits of 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 optimum excess oxygen level at all firing rates. If this is the case, choose burner control settings that give best performance over range of firing rates. If one firing rate predominates, setting should optimize conditions at that rate.

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

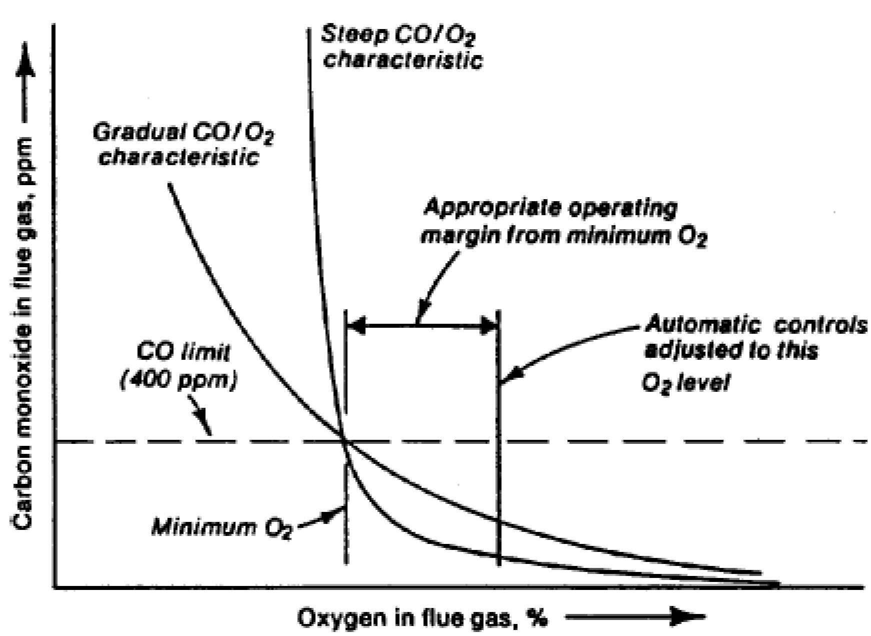


Figure 1: Oxygen/CO Characteristic Curve

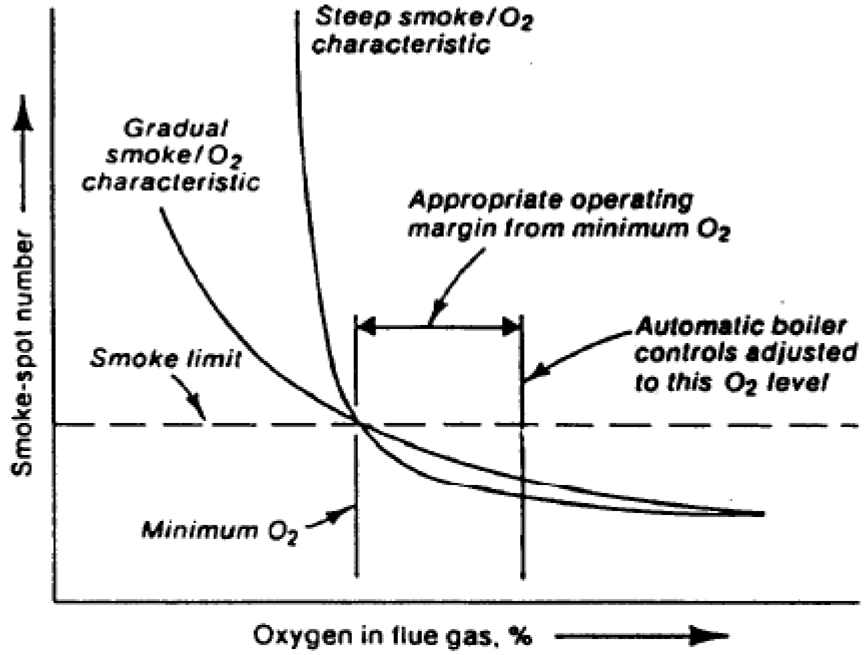


Figure 2: Oxygen/Smoke Characteristic Curve

C. Equipment Tuning Procedure[4] for Natural and Induced-Draft Boilers, Steam Generators, and Process Heaters

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 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. Preliminary analysis

   a. Check operating pressure or temperature. Operate unit at lowest acceptable pressure or temperature that will satisfy load demand. Determine pressure or temperature that will be used as basis for comparative combustion analysis before and after tune-up.

   b. Check operating hours. Plan workload so that unit operates only the minimum hours and days necessary to perform work required.

   c. Check air supply. Area of air supply openings must be in compliance with applicable codes and regulations. Air openings must be kept wide open when burner is firing and clean from restriction to flow.

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[4] This tuning procedure is based on a tune-up procedure developed by Parker Boiler for South Coast AQMD.

d. Check vent. Check to be sure vent is in good condition, sized properly and with no obstructions.

e. Perform combustion analysis. Perform an "as is" flue gas analysis ($O_2$, CO, $CO_2$, etc.) at high and low fire, if possible. In addition to data obtained from combustion analysis, also record following:

1) Inlet fuel pressure at burner (at high and low fire),
2) Draft at inlet of draft hood or barometric damper at high, medium, and low settings, if applicable,
3) Steam pressure, water temperature, or process fluid pressure or temperature entering and leaving unit, and
4) Unit rate, if meter is available.

With above conditions recorded, make following checks and corrective actions as necessary.

2. Checks and Corrections

a. Check burner condition. Clean burners and burner orifices thoroughly. To clean burners effectively all burners must be removed, blown out with high pressure air and checked for obstructions. All accumulated sediment, dirt, and carbon must be removed. Check for smooth lighting and even flame. Also, ensure that fuel filters and moisture traps are in place, clean, and operating properly, to prevent plugging of gas orifices. Confirm proper location and orientation of burner diffuser spuds, gas canes, etc. Look for any burned-off or missing burner parts, and replace as needed.

b. Check for clean boiler, steam generator, or process heater tubes and heat transfer surfaces. Clean tube surfaces, remove scale and soot, assure proper fluid flow, and flue gas flow.

c. Check water treatment and blowdown program. Employ timely flushing and periodic blowdown to eliminate sediment and scale build-up in heat exchange tubes.

d. Check for steam hot water or process fluid leaks. Repair all leaks immediately. Be sure there are no leaks through the blow-off drains, safety valve, by-pass lines or at the feed pump, if used.

3. Safety Checks

    a. Test primary and secondary low water level controls.

    b. Check operating and limit pressure and temperature controls.

    c. Check safety valve pressure and capacity to meet boiler, steam generator, or process heater requirements.

    d. Check limit safety control and spill switch.

4. Adjustments

    While taking combustion readings with unit at operating temperature and at high fire perform checks and adjustments as follows:

    a. Adjust unit to fire at rated capacity. Record fuel manifold pressure.

    b. Adjust draft and/or fuel pressure to obtain efficient, clean combustion at both high, medium and low fire. Carbon monoxide value should always be below 400 ppm at 3% $O_2$. If CO is high make necessary adjustment such as increasing draft. Check to ensure burner light offs are smooth and safe. A reduced fuel pressure test at both high and low fire should be conducted in accordance with manufacturer's instructions and maintenance manuals.

    c. Check and adjust operation of modulation controller. Insure proper, efficient and clean combustion through range of firing rates. When above adjustments and corrections have been made, record all data.

5. Final Test

    Perform final combustion analysis with unit at operating temperature and at high, medium, and low fire, whenever possible. In addition to data from combustion analysis, also check and record:

    a. Fuel pressure at burner (high, medium, and low settings, if applicable).

    b. Draft at inlet or above draft hood or barometric damper (high, medium, and low settings, if applicable).

    c. Steam pressure or water temperature entering and leaving unit.

    d. Unit rate, if fuel meter is available.

When above checks and adjustments have been made, record data and attach combustion analysis data to boiler, steam generator, or process heater records indicating name and signature of person, title, company name, company address and date tune-up was performed.

# APPENDIX B:

## AMENDED RULE 425.2

## BOILERS, STEAM GENERATORS, AND PROCESS HEATERS (OXIDES OF NITROGEN)

## STRIKEOUT UNDERLINE VERSION

**RULE 425.2 Boilers, Steam Generators, and Process Heaters (Oxides of Nitrogen)** – Adopted 10/13/94, Amended 4/6/95, 7/10/97, XX/XX/XX

## I. Purpose

The purpose of this Rule is to limit oxides of nitrogen (NOx) emissions from boilers, steam generators, and process heaters. ~~to levels consistent with Reasonably Available Control Technology (RACT) to satisfy California Health and Safety Code Section 40918(b) and 1990 Federal Clean Air Act Amendments, Section 182(f). Carbon monoxide emissions are also limited to insure efficient combustion at reduced NOx levels.~~

## II. Applicability

This Rule shall apply, as specified, to any boiler, steam generator or process heater operating in the Eastern Kern Air Pollution Control District (District) with rated heat input of 5 million Btu per hour or more and fired with gaseous and/or liquid fuels.

## III. Definitions

A. Annual Heat Input: ~~-~~ total heat released (therms) by fuel(s) burned in a unit during a calendar year as determined from higher heating value and cumulative annual fuel(s) usage.

B. Boiler or Steam Generator: ~~-~~ any external combustion unit fired with liquid and/or gaseous fuel used to produce hot water or steam, but not including gas turbine engine exhaust gas heat recovery systems.

C. British Thermal Unit (Btu): ~~-~~ amount of heat required to raise the temperature of one pound of water from 59°F to 60°F at one atmosphere.

D. Gaseous Fuel: ~~-~~ any fuel existing as gas at standard conditions.

E. Heat Input: ~~-~~ total heat released (Btu's) by fuel(s) burned in a unit as determined from higher heating value, not including sensible heat of incoming combustion air and fuel(s).

F. Higher Heating Value (HHV): ~~-~~ total heat released per mass of fuel burned (Btu's per pound), when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to standard conditions.

G. Liquid Fuel: ~~-~~ any fuel, including distillate and residual oil, existing as liquid at standard conditions.

H. Natural G~~g~~as C~~c~~urtailment: a shortage in the supply of natural gas, due solely to limitations or restrictions in distribution pipelines by the utility supplying natural gas, and not due to the cost of natural gas. ~~- loss of natural gas supply due to action of PUC-regulated supplier. For Section V curtailment limit to apply, curtailment must not exceed 168 cumulative hours of operation per calendar year, excluding equipment testing not to exceed 48 hours per calendar year.~~

I. Oxides of Nitrogen (NOx): - total nitrogen oxides (expressed as $NO_2$).

J. Process Heater: - any external combustion unit fired with liquid and/or gaseous fuel used to transfer heat from combustion gases to liquid process streams.

~~K. Reasonably Available Control Technology (RACT) - lowest emission limitation a particular source is capable of meeting by application of control technology reasonably available considering technological and economic feasibility.~~

~~L.~~K. Rated Heat Input: - heat input capacity (Btu's/hr) specified on nameplate of unit or by manufacturer for that model number, or as limited by District permit.

~~M.~~L. Standard Conditions: - as defined in Rule 102, Subsection RR~~DD~~.

~~N.~~M. Therm: - 100,000 British thermal units (Btu's).

~~O.~~N. Unit: - any boiler, steam generator or process heater as defined in this Rule.

## IV. Exemption

1. This Rule shall not apply to any unit with rated heat input less than 5 million Btu'~~s~~ per hour.

2. Section V.A.2 shall not apply to any unit while forced to burn liquid fuel during time of natural gas curtailment. NOx emission limit shall not exceed 150 ppmv or 0.215 pounds per million Btu of heat input when burning liquid fuel. This exemption shall not exceed 168 cumulative hours of operation per calendar year excluding equipment testing not to exceed 48 hours per calendar year.

## V. Requirements

A. An owner/operator of any unit subject to this Rule with annual heat input of 90,000 therms or more during one or more of the three preceding years of operation shall comply with following applicable NOx emission limit(s):

1. 30 parts per million by volume (ppmv) or 0.036 pound per million Btu of heat input when operated on gaseous fuel.

2. 40 parts per million by volume (ppmv) or 0.052 pound per million Btu of heat input when operated on liquid fuel.

3. The heat-input weighted averaged of the limits specified in Section V.A.1 and V.A.2 above when operated on combination of gaseous and liquid fuel.

| | ~~Gaseous Fuel~~ | ~~Liquid Fuel~~ |
|---|---|---|
| ~~During Normal Operation~~ | ~~70 ppmv, or 0.09 lb/MMBtu~~ | ~~115 ppmv, or 0.15 lb/MMBtu~~ |
| ~~During Natural Gas Curtailment~~ | ~~----~~ | ~~150 ppmv, or 0.19 lb/MMBtu~~ |

For units subject to this Section, carbon monoxide (CO) emissions shall not exceed 400 parts per million by volume (ppmv).

NOx emission limit for any unit fired simultaneously with gaseous and liquid fuels shall be heat input-weighted average of applicable limits. Calculations shall be performed as prescribed in Section VIII.C.

NOx and CO emission limits in ppmv are referenced at dry stack gas conditions, adjusted to 3.00 percent by volume stack gas oxygen in accordance with Section VIII, and averaged over 15 consecutive minutes from no less than 5 data sets, recorded from sampling of no more than 3 minutes.

B. An owner/operator of any unit subject to this Rule with annual heat input rate of 90,000 therms or more shall comply, until November 1~~3~~0, 2020~~1997~~, and any unit with annual heat input rate of less than 90,000 therms shall comply with one of the following NOx minimization procedures:

1. Tune each unit at least once per year in accordance with Section IX.;

2. Operate each unit in a manner maintaining stack gas oxygen at no more than 3.00 percent by volume on dry basis; or

3. Operate each unit with an automatic stack gas oxygen trim system set at 3.00 (±0.15) percent by volume on dry basis.

C. Monitoring Requirements

1. An owner/operator of any unit simultaneously firing a combination of different fuels shall install and maintain a totalizing mass or volumetric flow rate meter in each fuel line.

2. An owner/operator of any unit utilizing equipment intended to reduce or control NOx shall install and maintain appropriate provisions to monitor operational parameters of unit and/or NOx control system that correlate to NOx emissions.

D. Compliance Demonstration

1. An owner/operator of any unit subject to Section V.A shall have the option of complying with either concentration (ppmv) emission limits or heat input basis

(lb/MMBtu) emission limits as specified in Section V.A. All compliance demonstrations shall be performed using applicable test method(s) specified in Section VI.B and methods selected to demonstrate compliance shall be specified in Emission Control Plan required by Section VI.D.

2. All emission measurements shall be made with unit operating at conditions as close as physically possible to maximum firing rate allowed by the District~~KCAPCD~~ Permit to Operate.

## VI. Administrative Requirements

### A. Recordkeeping and Reporting

1. An owner/operator of any unit subject to this Rule or limited by permit condition to firing less than 5 million Btu's/hr shall monitor and record HHV and cumulative annual use of each fuel.

2. An owner/operator of any unit operated under natural gas curtailment limit of Section V.A shall monitor and record cumulative annual hours of operation on liquid fuel during curtailment and during testing.

3. An owner/operator of any identical units wishing to limit emissions testing to one unit per group of units pursuant to Section VI.C shall establish correlation of NOx emissions and key operating parameters and keep records of these data for each affected unit.

4. Records shall be maintained for a period of five (5) years and made available for District inspection at any time~~for at least two calendar years on site and shall be made readily available to District personnel~~.

5. Compliance test data and results collected to satisfy Section VI.C shall be submitted to District within 60 days of collection.

### B. Test Methods

1. Fuel HHV shall be certified by third party fuel supplier or determined by:

   a. ASTM D 240-87 or D 2382-88 for liquid fuels; and

   b. ASTM D 1826-88 or D 1945-81 in conjunction with ASTM D 3588-89 for gaseous fuels.

2. Oxides of nitrogen (ppmv) - EPA Method 7E, or CARB Method 100.

3. Carbon monoxide (ppmv) - EPA Method 10, or CARB Method 100.

4. Stack gas oxygen - EPA Method 3 or 3A, or CARB Method 100.

5. NOx emission rate (heat input basis) - EPA Method 19, or CARB Method 100 and data from fuel flow meter.

6. Stack gas velocity - EPA Method 2.

7. Stack gas moisture content - EPA Method 4.

C. Compliance Testing

1. Any unit subject to requirements of Section V.A shall be tested to determine compliance with applicable requirements not less than once every 12 months. An owner/operator of gaseous fuel-fired units demonstrating compliance for two consecutive years can, if desired, demonstrate compliance once every thirty-six months.

2. An owner/operator of any unit subject to Section V.B.2 shall sample and record stack gas oxygen content at least monthly.

3. Test results from an individual unit may be used for other units when the following criteria are met:~~at the same location provided manufacturer, model number, rated capacity, fuel type, and emission control provisions are identical and key operating parameters such as stack gas oxygen, fuel consumption, etc. are monitored and established to correlate with NOx emissions from unit tested.~~

   a. Units are located at the same facility,
   b. Units are produced by the same manufacturer, have the same model number, and have the same rated capacity and operating specifications,
   c. Units are operated and maintained in a similar manner, and
   d. District, based on documentation submitted by the facility, determines that the variability of emissions for identical tested units is low enough for confidence that the untested unit will be in compliance.

4. An owner/operator utilizing Section VI.C.3 shall ensure that all units be tested within a certain number of years. For example, testing one third of a fleet every year shall result in every unit being tested after three years, and not the same units being tested every year.

D. Emission Control Plan

An owner/operator of any unit subject to this Rule shall submit to Control Officer an Emission Control Plan including:

1. List of units subject to Rule, including rated heat inputs, anticipated annual heat input, applicable Section V requirements, and control option chosen, if applicable;

2. Description of actions to be taken to satisfy requirements of Section V. Such plan shall identify actions to be taken to comply, including any type of emissions

control to be applied to each unit and construction schedule, or shall include test results to demonstrate unit already complies with applicable requirements; and

3. Specification of proposed test methods.

## VII. Compliance Schedule

A. An owner/operator of any unit subject to Section V shall comply with following schedule:

1. By May~~rch~~ 1, 2018~~1995~~, submit to Control Officer an Emission Control Plan pursuant to Section VI.D, and a complete application for Authority to Construct emission control equipment, if necessary;

2. By July~~May~~ 31, 2018~~1995~~ demonstrate compliance with Section V.B; and

3. By November 1~~3~~0, 2020~~1997~~ demonstrate full compliance with all additional and applicable provisions of this Rule.

B. An owner/operator of any unit becoming subject to requirements of Section V.A by exceeding the annual heat input exemption threshold shall comply with following increments of progress:

1. On or before December 31st of calendar year immediately following year annual heat input threshold was exceeded, submit an Emission Control Plan containing information prescribed in Section VI.D; and

2. No later than three calendar years following submission of Emission Control Plan, demonstrate final compliance with all applicable standards and requirements of this Rule.

## VIII. Calculations

A. All ppmv emission limits specified in Section V.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:

$$[\text{ppmv NOx}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O_2]_{\text{measured}}} \times [\text{ppmv NOx}]_{\text{measured}}$$

$$[\text{ppmv CO}]_{\text{corrected}} = \frac{17.95\%}{20.95\% - [\%O_2]_{\text{measured}}} \times [\text{ppmv CO}]_{\text{measured}}$$

B. All lb/MMBtu NOx emission rates shall be calculated as pounds of nitrogen dioxide per million Btu's of heat input (HHV).

C. Heat input-weighted average NOx emission limit for combination of ~~natural~~ gaseous and liquid fuel shall be calculated as follows:

$$\text{NOx Emission Limit} = \frac{(30\ \text{ppmv} \times X) + (40\ \text{ppmv} \times Y)}{X + Y}$$

Where X = heat input from gaseous fuel and Y = heat input from liquid fuel.

## IX. NOx Minimization Tuning Procedures

A. Purpose

The purpose of these procedures is to provide a reasonable, cost-effective method to minimize NOx emissions from smaller, or low-fire/low use-rate combustion units subject to this Rule. These procedures not only minimize NOx emissions, but also result in reduced operating costs.

B. Equipment Tuning Procedure[1] for Mechanical Draft Boilers, Steam Generators, and Process Heaters

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 Insurers, National Fire Prevention Association, California Department of Industrial Relations (Occupational Safety and Health Division), Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate unit at firing rate most typical of normal operation. If unit experiences significant load variations during normal operation, operate 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 firing rate selected. If excess oxygen in the stack gas is at lower end of range of typical minimum values[3]; and if CO emissions are low and there is no smoke, unit is probably operating at near optimum efficiency - at this particular firing rate. However, complete remaining portion of this procedure to determine whether still lower oxygen levels are practical.

3. Increase combustion air flow to unit until stack gas oxygen levels increase by one to two percent over level measured in Step 2. As in Step 2, record 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 unit operation stabilizes.

4. Decrease combustion air flow until stack gas oxygen concentration is at level measured in Step 2. From this level gradually reduce combustion air flow, in

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[1] This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for U.S. EPA.
[2] The smoke-spot number can be determined with ASTM Test Method D-2156 or with the Bacharach method.
[3] Typical minimum oxygen levels for boilers at high firing rates are:
For natural gas: 0.5% to 3% and For liquid fuels: 2% to 4%.

small increments. After each increment, record stack gas temperature, oxygen concentration, CO concentration (for gaseous fuels) and smoke-spot number (for liquid fuels). Also, observe 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 ppmv,

   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 $O_2$/CO curve (for gaseous fuels) or $O_2$/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2 ~~on Page 425-13~~ using excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.

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

| Fuel | Measurement | Value |
|---|---|---|
| Gaseous | CO Emissions | 400 ppmv |
| #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 |

   Above conditions are referred to as CO or smoke thresholds, or as minimum excess oxygen levels.

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

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

9. If load of unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent upper and lower limits of 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 optimum excess oxygen level at all firing rates. If this is the case, choose burner control settings that give best performance over range of firing rates. If one firing rate predominates, setting should optimize conditions at that rate.

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

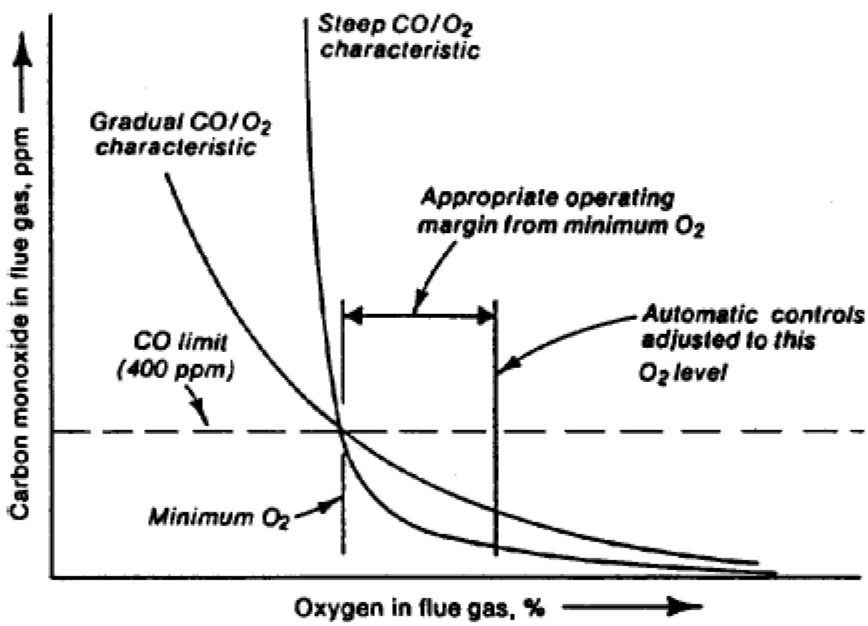


Figure 1: Oxygen/CO Characteristic Curve

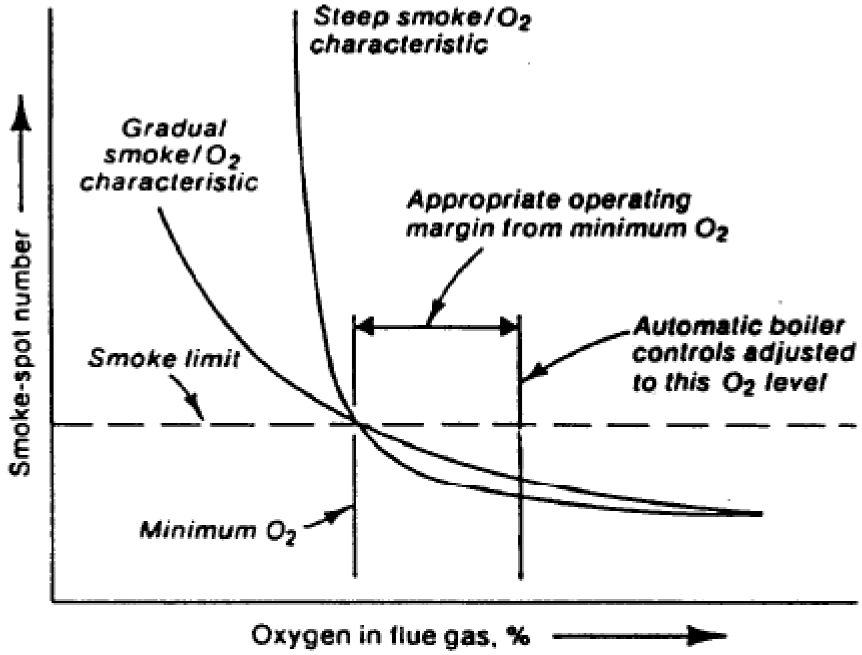


Figure 2: Oxygen/Smoke Characteristic Curve

C. Equipment Tuning Procedure[4] for Natural and Induced-Draft Boilers, Steam Generators, and Process Heaters

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 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. Preliminary analysis

   a. Check operating pressure or temperature. Operate unit at lowest acceptable pressure or temperature that will satisfy load demand. Determine pressure or temperature that will be used as basis for comparative combustion analysis before and after tune-up.

   b. Check operating hours. Plan workload so that unit operates only the minimum hours and days necessary to perform work required.

   c. Check air supply. Area of air supply openings must be in compliance with applicable codes and regulations. Air openings must be kept wide open when burner is firing and clean from restriction to flow.

[4] This tuning procedure is based on a tune-up procedure developed by Parker Boiler for South Coast AQMD.

d. Check vent. Check to be sure vent is in good condition, sized properly and with no obstructions.

e. Perform combustion analysis. Perform an "as is" flue gas analysis ($O_2$, CO, $CO_2$, etc.) at high and low fire, if possible. In addition to data obtained from combustion analysis, also record following:

1) Inlet fuel pressure at burner (at high and low fire),
2) Draft at inlet of draft hood or barometric damper at high, medium, and low settings, if applicable,
3) Steam pressure, water temperature, or process fluid pressure or temperature entering and leaving unit, and
4) Unit rate, if meter is available.

With above conditions recorded, make following checks and corrective actions as necessary.

2. Checks and Corrections

a. Check burner condition. Clean burners and burner orifices thoroughly. To clean burners effectively all burners must be removed, blown out with high pressure air and checked for obstructions. All accumulated sediment, dirt, and carbon must be removed. Check for smooth lighting and even flame. Also, ensure that fuel filters and moisture traps are in place, clean, and operating properly, to prevent plugging of gas orifices. Confirm proper location and orientation of burner diffuser spuds, gas canes, etc. Look for any burned-off or missing burner parts, and replace as needed.

b. Check for clean boiler, steam generator, or process heater tubes and heat transfer surfaces. Clean tube surfaces, remove scale and soot, assure proper fluid flow, and flue gas flow.

c. Check water treatment and blowdown program. Employ timely flushing and periodic blowdown to eliminate sediment and scale build-up in heat exchange tubes.

d. Check for steam hot water or process fluid leaks. Repair all leaks immediately. Be sure there are no leaks through the blow-off drains, safety valve, by-pass lines or at the feed pump, if used.

3. Safety Checks

    a. Test primary and secondary low water level controls.

    b. Check operating and limit pressure and temperature controls.

    c. Check safety valve pressure and capacity to meet boiler, steam generator, or process heater requirements.

    d. Check limit safety control and spill switch.

4. Adjustments

    While taking combustion readings with unit at operating temperature and at high fire perform checks and adjustments as follows:

    a. Adjust unit to fire at rated capacity. Record fuel manifold pressure.

    b. Adjust draft and/or fuel pressure to obtain efficient, clean combustion at both high, medium and low fire. Carbon monoxide value should always be below 400 ppm at 3% $O_2$. If CO is high make necessary adjustment such as increasing draft. Check to ensure burner light offs are smooth and safe. A reduced fuel pressure test at both high and low fire should be conducted in accordance with manufacturer's instructions and maintenance manuals.

    c. Check and adjust operation of modulation controller. Insure proper, efficient and clean combustion through range of firing rates. When above adjustments and corrections have been made, record all data.

5. Final Test

    Perform final combustion analysis with unit at operating temperature and at high, medium, and low fire, whenever possible. In addition to data from combustion analysis, also check and record:

    a. Fuel pressure at burner (high, medium, and low settings, if applicable).

    b. Draft at inlet or above draft hood or barometric damper (high, medium, and low settings, if applicable).

    c. Steam pressure or water temperature entering and leaving unit.

    d. Unit rate, if fuel meter is available.

When above checks and adjustments have been made, record data and attach combustion analysis data to boiler, steam generator, or process heater records indicating name and signature of person, title, company name, company address and date tune-up was performed.