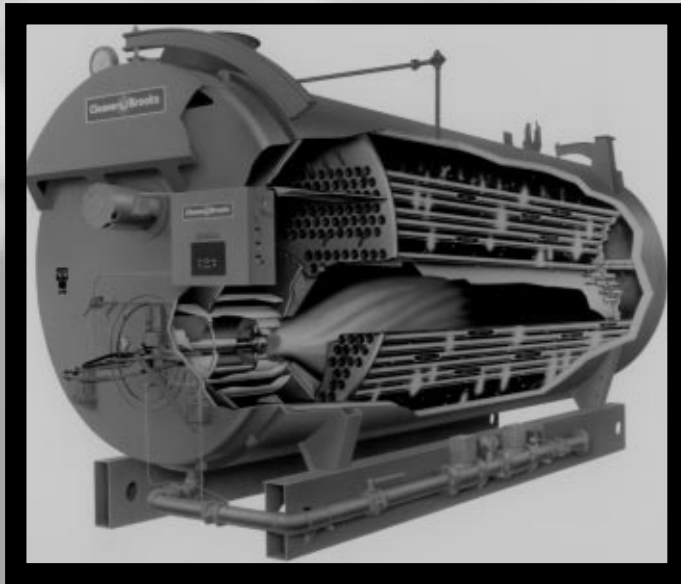


BOILER EMISSIONS

REFERENCE GUIDE



2nd Edition

Cleaver-Brooks[®]

Division of Aqua-Chem, Inc.

BOILER EMISSIONS REFERENCE GUIDE

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Introduction

Since the beginning of time, mankind, flora, and fauna have been sustained by sunlight, fresh water, and clean air. But fly over many regions of the country today, and one will see our cities and mountains shrouded in a dull haze of pollutants. Look upon the horizon and see the sun's rays reflect a kaleidoscope of colors — grey for lead, yellow for sulphur, brown for nitrogen oxides.

From the Appalachian Mountains, where brown tree tops are brittle and burnt from acid rain, to the Great Lakes, where shorelines all too often appear rimmed by murky mist, to the San Gabriel Mountains, where a natural inversion of the atmosphere presses a blanket of smog upon Southern California, we can't escape the damage.

Carbon Monoxide, lead, nitrogen oxides, ozone, particulate matter, and sulfur, are now cited as the most insidious of pollutants. They are proven to contribute to respiratory illnesses in humans, damage to the environment and buildings and, ultimately, lead to higher costs for health care and environmental cleanup.

Over the past several decades, the culprit pollutants spewed into our environment at increasing rates. Thus, in the 1980s, alarmed environmental activists and coalitions began to pressure Congress for stiffer air pollution control regulations. The result: in 1990, Congress passed its most comprehensive piece of environmental legislation, the Clean Air Act Amendments (CAAA).

The Boiler Emissions Reference Guide is a multi-purpose tool, which is intended to give you a clearer understanding of how industrial boilers fit into the clean air equation.

In the first part, the guide discusses how federal and state actions are driving the air cleanup. It discusses air quality standards and areas of attainment and nonattainment for the pollutants. It describes how the government has set up emission limits for industrial boilers and other equipment. And, it looks at permitting, emission limitations, and BACT, RACT, LAER — the alphabet of control techniques.

The second part of the guide examines the six major pollutants in detail and discusses various control techniques. Emphasis is placed on combustion control for industrial boilers and how to choose the best technology.

The guide concludes with special appendices, which provide fingertip information — a must when dealing with a problem as complex as air pollution.



REGULATIONS

Air pollution regulations are enacted at the federal level or at the state and local level. Federal regulations, which primarily establish outdoor, or ambient, air quality standards, are the primary drivers behind state and local air pollution regulations. However, with a few exceptions, the New Source Performance Standards (see page 5 for more information), federal regulations only set the ambient air quality standards. They do not detail how to accomplish them. The necessary actions to accomplish the federal standards must be developed and implemented by state and local air quality agencies. It is the state and local actions, along with the Federal New Source Performance Standards, that directly impact industrial boilers.

FEDERAL ACTIONS

The Clean Air Act

Nearly all air pollution regulations originate from the Clean Air Act, which was enacted in 1963. The act improved and strengthened pollution prevention programs and was the first major step toward more federal control of air pollution. The first major amendments to the Clean Air Act occurred in 1970. The 1970 amendments set national air quality standards and established performance standards for new sources of pollution. As a result of the 1970 amendments, standards were set for sulfur oxides and nitrogen oxides for several sources, including boilers.

The next significant amendment to the Clean Air Act occurred in 1977. The 1977 amendment enhanced many aspects of the Clean Air Act by implementing a more comprehensive permit program, establishing emission limitations on existing sources, and imposing stricter emission standards on new sources. But most importantly, the 1977 amendment extended compliance deadlines because many geographical areas had not achieved compliance with the ambient air quality standards. After regulating air pollution for almost 15 years, nationwide compliance still had not been achieved.

The most recent amendment to the Clean Air Act occurred in 1990. The 1990 Clean Air Act Amendment has been labelled the most complex, comprehensive, and far-reaching environmental law Congress has ever enacted. The 1990 amendments consist of 11 titles. Some of the titles are revisions of existing titles and others are new titles. As a result, the Clean Air Act now encompasses most aspects of air pollution.

The act:

- Controls air pollution from stationary and mobile sources
- Controls the release of air toxins
- Controls acid rain pollutants (NO_x and SO_x)
- Establishes a massive permit program
- Sets-up enforcement provisions
- Establishes many miscellaneous programs

The Clean Air Act Amendment of 1990

The Clean Air Act, its interpretations and associated implications, are very complex. It would be impractical to list the details of the amendment and the requirements for future activity that the federal government dictates for state governments. For this reason, this section provides basic insight into the implications the act poses for fossil-fuel fired packaged boilers.

As mentioned earlier, the 1990 Clean Air Act Amendment is comprised of 11 titles (see Figure 1). The provisions contained in the titles have the potential to affect nearly every source of air pollution. Although several titles affect industrial boilers, the title having the most impact is Title I, Attainment and Maintenance of the National Ambient Air Quality Standards.

Title I - National Ambient Air Quality Standards

The National Ambient Air Quality Standards (NAAQS) are pollution standards set by the federal Environmental Protection Agency (EPA) through the Clean Air Act. The NAAQS set ambient pollutant standards to address six 'criteria' pollutants (see Figure 2):

- Ozone (O₃)
- Carbon Monoxide (CO)
- Nitrogen Dioxide (NO₂)
- Sulfur Dioxide (SO₂)
- PM₁₀ (particulate matter with a diameter of less than 10 microns)
- Lead

The NAAQS are designed to protect humans and the environment from the adverse effects of air pollutants. Unlike emission limitations, which specify allowable pollutant releases from air pollution sources, ambient standards set forth maximum allowable concentrations of pollutants in the outdoor, or ambient, air. The Clean Air Act sets specific deadlines for every area in the country not in compliance with the NAAQS to enact regulations for achieving these standards.

■ 1990 CAAA Titles

Title I - Attainment and Maintenance of the National Ambient Air Quality Standards: Deals with attaining and maintaining the National Ambient Air Quality Standard (NAAQS) for six criteria pollutants.

Title II - Mobile Sources: Establishes stricter emission standards for motor vehicles.

Title III - Hazardous Air Pollutants: Identifies and calls for reductions in 189 toxic pollutants.

Title IV - Acid Deposition Control: Addresses NO_x and SO₂ reduction in large utility boilers (major sources). Regulations for industrial units will be developed shortly.

Title V - Permits: Establishes a comprehensive operating permit program for air emissions.

Title VI - Stratospheric Ozone Protection: Requires a complete phase-out of chlorofluorocarbons (CFCs) and halons.

Title VII - Enforcement: Gives the EPA more administrative enforcement penalties. It is now a felony to knowingly violate the Clean Air Act.

Title VIII - Miscellaneous: Addresses oil drilling and visibility provisions.

Title IX - Clean Air Research: Addresses air pollution research in the areas of monitoring and modeling, health effects, ecological effects, pollution prevention, emission control, and acid rain.

Title X - Disadvantaged Business Concerns: Requires that a portion of federal funds for air research go to disadvantaged firms.

Title XI - Clean Air Employment Transition Assistance: Provides additional unemployment benefits to workers for retraining who are laid off because of compliance with the Clean Air Act.

figure 1

■ National Ambient Air Quality Standards (NAAQS)

Pollutant	Averaging Time				
	1 hour	8 hour	24 hour	Annual	Calendar Quarter
Ozone	0.12 ppm				
Carbon Monoxide	35 ppm	9 ppm			
Nitrogen Dioxide				0.053 ppm	
Sulfur Dioxide			0.14 ppm	0.03 ppm	
PM ₁₀			0.000066 grains/ft ³		
Lead					0.00000066 grains/ft ³

The National Ambient Air Quality Standards are ambient emission standards set by the Federal EPA for six criteria pollutants. The ambient levels are measured on a time average basis by air pollution monitoring stations located throughout the country. For example, the ambient level of ozone must not exceed 0.12 ppm for any one hour period in order for the local area to be in compliance with the NAAQS for ozone.

figure 2

Attainment and Nonattainment

Through the NAAQS, areas of the United States are designated as attainment and nonattainment. Simply put, areas with ambient pollutant levels below the NAAQS are in attainment. Areas with pollutant levels above the NAAQS are in nonattainment.

Note: Attainment/Nonattainment designation is made on a pollutant-by-pollutant basis for all pollutants included in the NAAQS. Therefore, an area can be designated as attainment and nonattainment because it may be in compliance with the NAAQS for one pollutant but not another.

The most common pollutant for which the NAAQS are exceeded is ozone. Ozone is not emitted directly from smokestacks, tailpipes, or other pollution sources. Instead, it is formed by the reaction of volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of sunlight. NO_x and VOCs are released into the air by automobiles, factories, and several other sources, including industrial boilers. As of January, 1994, there are 101 cities and towns violating the NAAQS for ozone (see Figure 3). Ozone nonattainment areas are classified into one of five categories, based on the amount by

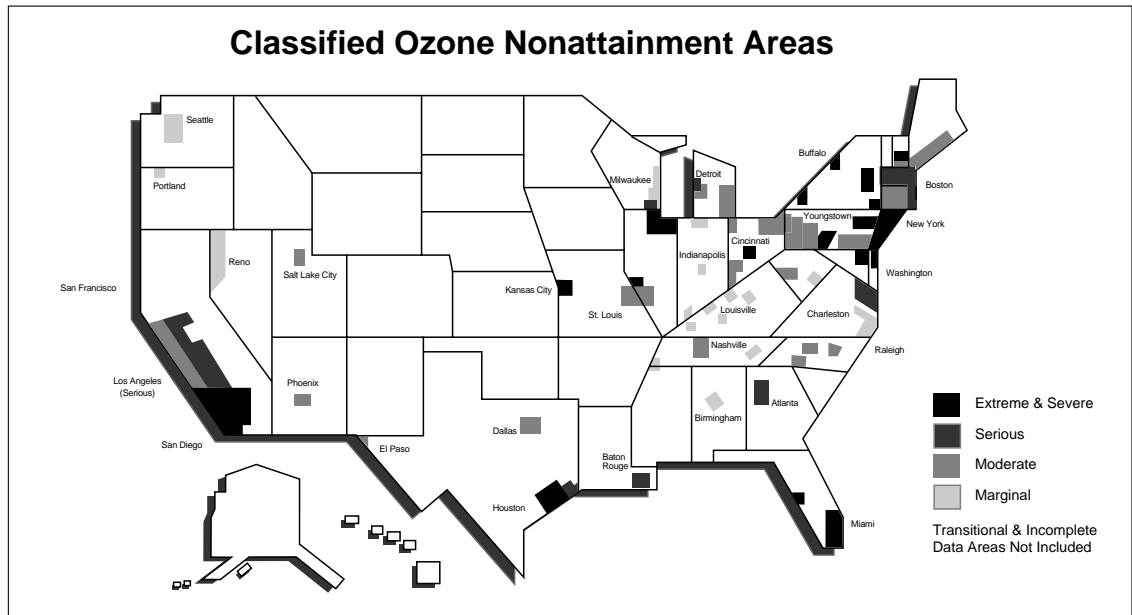


figure 3

which the local ozone levels exceed the NAAQS. From highest to lowest degree of nonattainment, the categories are: extreme; severe; serious; moderate; and marginal.

The second most common nonattainment pollutant is carbon monoxide. As of January, 1994, 52 metropolitan areas exceed the NAAQS for carbon monoxide (see Figure 4). Carbon monoxide nonattainment areas are classified as

serious and moderate, depending on the amount local CO levels exceed the NAAQS for CO.

Although the number of nonattainment areas are not as great as they are for ozone and carbon monoxide, there are several areas violating the NAAQS for PM₁₀, NO_x, SO_x, and lead. Areas violating the NAAQS for PM₁₀ are subclassified as serious or moderate. There are no subclassifications for NO_x, SO_x, and lead.

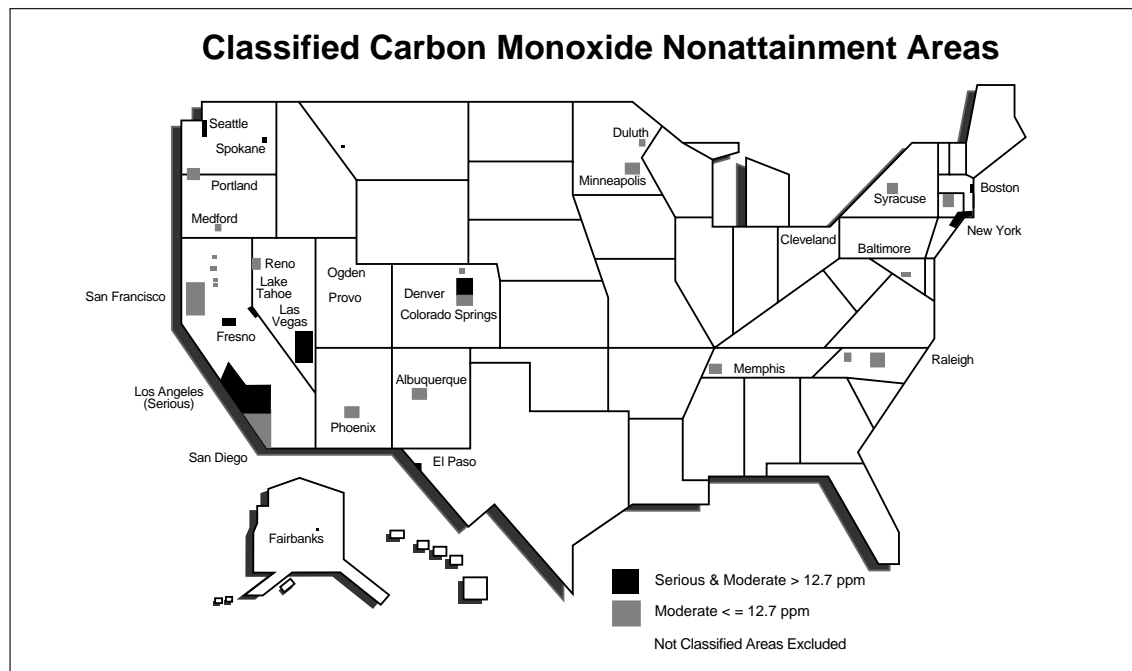


figure 4

A listing of the ozone, CO, PM₁₀, and SO₂ nonattainment areas as of January, 1994 is included in Appendix A. The classifications of areas are constantly changing as air pollution levels are continuously under review for attainment/nonattainment designation. For the most current attainment/nonattainment classification, contact your local air pollution control agency.

State Implementation Plans

Through the NAAQS, the EPA has established pollution standards for six criteria pollutants. However, the NAAQS are only an interim step in the regulation of these pollutants. The ambient standards do not tell an individual polluter what must be done to control their emissions. Rather, Title I of the 1990 Clean Air Act Amendments delegates the responsibility to the states by requiring local nonattainment areas to develop a plan to reduce ambient pollution levels below the NAAQS.

Nonattainment characteristics vary by area and pollutant. A nonattainment area can be affected by weather, geography, demographics, and other forces. Therefore, regulations established for one area may not be effective in another area. This is why the Federal EPA does not establish general, source-specific regulations for all nonattainment areas. The responsibility is assigned to the states. The states are required to develop State Implementation Plans, or SIPs. SIPs include regulations addressing individual pollution sources in order to achieve the pollutant reductions necessary to comply with the NAAQS.

SIPs must address several elements of air pollution control as required by the EPA. The elements include:

- Attainment of the NAAQS within specified deadlines
- Emission limitations for individual sources
- Monitoring provisions
- Permit programs
- Several miscellaneous provisions

A SIP is developed as follows. State regulation developers draft the SIP. Then it undergoes public comment. Next, it is submitted to the EPA for review. The EPA has established submittal dates for the SIPs, which vary depending on the nonattainment status of the local area. Many states have missed the deadlines and are still developing their SIPs. Figure 5 shows the EPA SIP submittal dates.

Once the EPA reviews the SIP, it is either approved or, if it fails to fulfill all requirements, the plan could be returned to the state for revision, or the EPA could draft a plan or portions of the plan for the state.

Note: You can obtain a copy of the sections of any SIP applying to industrial boilers by contacting your state air quality agency. It is important to become familiar with the SIP in your state, as the provisions within the SIP may directly impact industrial boilers.

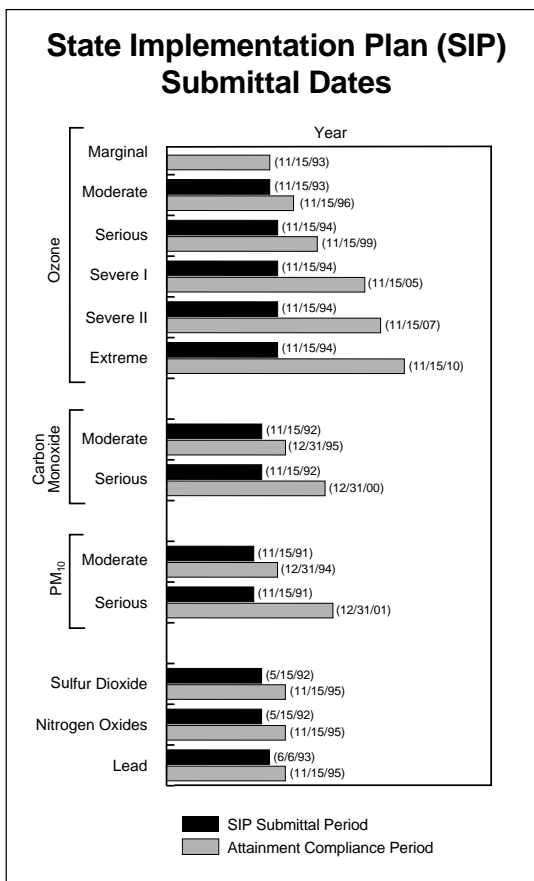


figure 5

New Source Performance Standards

One situation where the Federal EPA has established nationally uniform source-specific regulations is through the New Source Performance Standards, or NSPS. The standards, which set minimal requirements for individual sources, address approximately 65 categories of new or modified stationary sources, including industrial boilers. However, because the NSPS are not based on the nonattainment status of the local area, they may result in over control in some locations and under control in others.

The NSPS for industrial boilers regulate levels for NO_x , SO_x , and particulate matter. The regulated pollutants and requirements vary for different fuels and boiler sizes. There are currently three categories for the NSPS:

- Boilers with inputs greater than 250 MMBtu/hr
- Boilers with inputs between 100-250 MMBtu/hr
- Boilers with inputs between 10-100 MMBtu/hr

The current Small Boiler NSPS apply to all new, modified, or reconstructed boilers with inputs between 10-100 MMBTU/hr where construction, modification, or reconstruction commenced after June 9, 1989. They set emission standards for SO_x and particulate matter for boilers firing coal, distillate and residual oil, and wood. The NSPS also dictate record keeping requirements regarding fuel usage for all fuels, including natural gas. Record keeping requirements and compliance standards for the different emissions depends on the type of fuel fired and on the boiler size. For a summary of the Small Boiler NSPS, see Figure 6.

Expect to hear more about the NSPS. The 1990 Clean Air Act Amendments require the EPA to review the current NSPS and modify the requirements to incorporate new technologies for several source categories addressed through the NSPS.

STATE ACTIONS

Nonattainment Areas

Air quality monitoring stations operate throughout the United States to assess local air quality. Readings are continuously taken from the stations to monitor the six criteria pollutants regulated through the NAAQS. The levels of the pollutants are continuously evaluated. If levels exceed the NAAQS, the area is classified as nonattainment.

States must determine the boundaries of nonattainment areas through the use of the data collected. The boundaries of nonattainment and attainment areas can be difficult to define. For example, because of the high population in the northeastern United States and the close proximity of major cities, an ozone nonattainment area may enact regulations to bring the area into compliance. But because of the influence of the surrounding cities, attainment may not be achieved. Ozone nonattainment areas in the northeast are forming alliances to develop

regulations because of the influence of pollution from a broad area. For example, uniform regulations are being developed for eleven states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont) in what is designated by the Federal EPA as the Northeast Ozone Transport Region.

Emission Inventories

Once a nonattainment area is defined, the pollution sources are identified and the quantity of emissions from the sources are evaluated. To help states determine the types and levels of emissions for the various sources, the EPA has established the AP-42 Compilation of Air Pollutant Emission Factors. The document indicates average emission levels emitted by various equipment and industries. Once the individual sources in a nonattainment area have been identified, the AP-42 can be used to determine the type and level of emissions. The emission inventory is a valuable tool, which can be used to evaluate different regulatory actions and to calculate the reduction of emissions and the impact on the total emissions.

The average emission levels in AP-42 have sometimes been used as a standard for equipment performance by regulators who are unfamiliar with the equipment. Using the AP-42 levels as pollution standards is not the intent of the AP-42. The AP-42 was developed to provide a "rule-of-thumb" to estimate emissions for a broad category of equipment. Specific emission levels for sites need to be evaluated on a site-specific basis, as the AP-42 states. And because the AP-42 is based on averages, half of the sites reviewed and half of the applications exceed the pollutant levels in the AP-42. In fact, few applications are below all the pollutant averages listed in the AP-42.

Note: Because few applications are below all the pollutant levels listed the AP-42, the AP-42 emission levels should not be used to permit boilers. The boiler/burner manufacturer should be contacted to obtain the emissions levels that should be used to permit the boiler.

Appendix B shows the AP-42 emission levels for industrial boilers firing natural gas, distillate and residual oils, and propane.

Summary of Federal EPA Rules

NEW SOURCE PERFORMANCE STANDARDS For Boilers 10-100 MMBtu/hr, built or modified after 6-9-1989

RULES FOR SULFUR DIOXIDE (SO₂) EMISSIONS

1. Coal Firing

- 1.2 lb SO₂/MMBtu Limit all 10-100 MMBtu.
- 90% SO₂ reduction required if > 75 MMBtu and > 55% annual coal capacity.
- Initial performance testing required within 180 days of start-up.
- 30 day rolling average used in calculations.
- Continuous Emission Monitoring System (CEMS) required except:
 - Fuel analysis may be used (before cleanup equipment).
 - Units < 30 MMBtu may use supplier certificate for compliance.

2. Residual Oil Firing

- Limit of 0.5 lb SO₂/MMBtu or 0.5% sulfur in fuel.
- CEMS required to meet SO₂ limit except fuel analysis can be used as fired condition before cleanup equipment.
- Fuel sulfur limit compliance can be:
 - Daily as fired fuel analysis.
 - As delivered (before used) fuel analysis.
 - Fuel supplier certificate for units < 30 MMBtu.
- Initial performance testing and 30 day rolling average required except for supplier certificate.

3. Distillate Oil Firing (ASTM grades 1 and 2)

- Limit 0.5% sulfur in fuel (required in ASTM standard).
- Compliance by fuel supplier certificate.
- No monitoring or initial testing required.

RULES FOR PARTICULATE MATTER (PM) EMISSIONS

1. General

- Limits established only for units between 30-100 MMBtu.
- All coal, wood and residual oil fired units > 30 MMBtu must meet opacity limit of 20%, except one 6 minute/hour opacity of 27%. CEMS required to monitor opacity.

2. Coal Firing

- 0.05 lb/MMBtu limit if > 30 MMBtu and > 90% annual coal capacity.
- 0.10 lb/MMBtu limit if > 30 MMBtu and < 90% annual coal capacity.
- 20% opacity (CEMS) and initial performance tests on both PM limit and opacity.

3. Wood Firing

- 0.10 lb/MMBtu limit if > 30 MMBtu and > 30% annual wood capacity.
- 0.30 lb/MMBtu limit if > 30 MMBtu and < 30% annual wood capacity.
- Opacity limits and initial testing per above.

4. Oil Firing

- All units > 30 MMBtu subject to opacity limit, only residual oil firing must use CEMS.
- Initial performance testing required.

REPORTING REQUIREMENTS

- Owners or operators of all affected units must submit information to the administrator, even if they are not subject to any emission limits or testing. Required reports include:
 - Information on unit size, fuels, start-up dates and other equipment information.
 - Initial performance test results, CEMS performance evaluation.
 - Quarterly reports on SO₂ and/or PM emission results, including variations from limits and corrective action taken.
 - For fuel supplies certificate, information on supplies and details of sampling and testing for coal and residual oil.
 - Records must be maintained for two years.

figure 6

State Activities

All of the activities mentioned earlier eventually will result in some form of regulation for areas classified as nonattainment. While it is impossible to predict what any given state will do, it appears that many are following the lead of Southern California. Southern California has the worst air quality in the United States. Their efforts toward cleaner air are usually considered to be the basis for establishing regulations in other areas of the country in high degrees of ozone nonattainment.

Regulations will change as new technologies allow for lower emission levels. Also, adjustments will be made based on the improvements in air quality. It is necessary to stay involved with air quality regulations to keep apprised of any regulation changes.

The application of regulations can take several different forms and is often based on the degree of nonattainment. Required controls are based on the size of equipment, total emissions from a facility, type of fuels used, or a combination of factors. For example, in ozone nonattainment areas, the required measures depend on the nonattainment degree and total emissions from the facility. Levels set by the EPA help identify 'major' sources of VOCs and NO_x emissions. If the total NO_x or VOC emissions for a facility located in an ozone nonattainment area exceed the pre-established major source trigger

levels, extensive computer modeling and stringent regulations may be necessary. The major source trigger levels are indicated in tons per year and apply to the total NO_x or VOC emissions for all sources located at the facility. The major source trigger levels for the different ozone nonattainment classifications are shown in Figure 7.

To put this in perspective, a facility with three 800 horsepower boilers firing natural gas 24 hours per day, 365 days per year, would result in an uncontrolled NO_x level of 57 tons per year (based on a NO_x level of 0.13 lb/MMBtu). Referring to major source trigger levels specified in Figure 7, consider the following. If the facility is located in a moderate or marginal ozone nonattainment area, it is not a major source. But, if it is located in a serious, severe, or extreme ozone nonattainment area, it is a major source and would have specific air quality NO_x control requirements. These requirements may include:

- An extensive permit application
- Dispersion modeling
- Procurement of emission offsets
- Stringent emission limitations
- Continuous emission monitoring equipment
- Extensive emission controls
- Detailed fuel usage recording

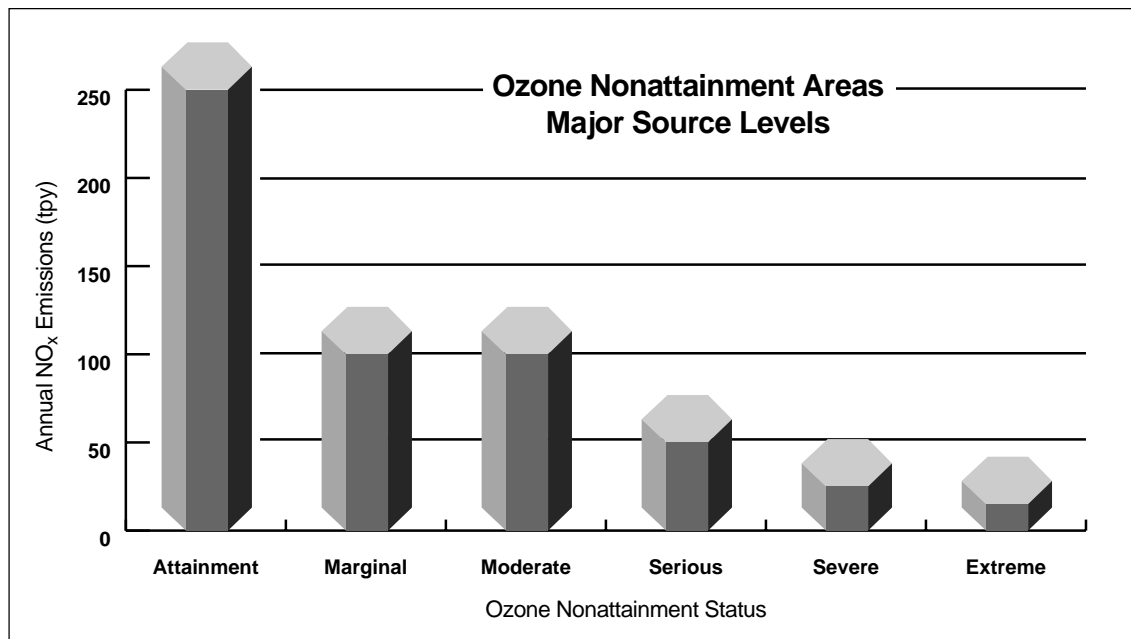


figure 7

An Emission Alphabet

If a facility is classified as a major source, regulations may require technology equivalent to:

- Best Available Control Technology (BACT)
- Lowest Achievable Emission Rate (LAER)
- Reasonably Available Control Technology (RACT)

All three regulations are based on technology and do not directly specify an emission level requirement. Instead, they require an evaluation of each affected facility in order to determine the applicable emission and technology requirements. As new technologies are developed, which may result in greater emission reductions than currently available, they must be included in the evaluation. Technology-based regulations have been utilized for years and proven effective.

Best Available Control Technology

Best Available Control Technology (BACT) is a regulation requiring an evaluation of all current technologies to determine the emission limitation for a new source. It is established on a case-by-case basis for sources and takes into account energy, environmental, and economic impacts. BACT evaluates the effectiveness of a control technology against the cost of the technology.

In establishing BACT for a source, cost is usually the driving factor. The cost of the equipment is compared to the annual emission reductions in order to determine a figure in dollars per ton of pollutant removed (see Figure 8). The comparison is called the cost effectiveness of the technology.

The regulations requiring BACT set a maximum cost figure that the polluter can spend in order to meet local emission requirements. If the cost effectiveness of the technology is above the figure, the technology is not required and the next lower cost technology is evaluated. The process of reviewing each technology in decreasing order of cost is called Top Down BACT. The Top Down BACT process assures that the source achieves the lowest emission level within the required cost effectiveness.

Typical regulations in areas of moderate and serious nonattainment for ozone require boiler owners to utilize NO_x control technologies that result in a cost effectiveness figure between \$3,000-\$10,000 per ton of NO_x removed. In severe and extreme ozone nonattainment areas, the required cost effectiveness can be as high as \$24,500 per ton of NO_x controlled.

BACT/RACT Cost Effectiveness

Annualized Costs of Control Equipment*

Uncontrolled Emission Rate — **Controlled Emission Rate**

Example:

Uncontrolled Emission Rate	=	18 tons/year
Controlled Emission Rate	=	4 tons/year
Annualized Cost of Emission Control Method	=	\$50,000/year
$\frac{\$50,000}{18 \text{ tpy} - 4 \text{ tpy}}$	=	\$3,571/ton of NO _x removed

* considering hardware, installation, operating and maintenance costs

figure 8

Reasonably Available Control Technology

Reasonably Available Control Technology (RACT) is similar to BACT in that cost effectiveness is associated with the boiler owners' emission requirements. The difference is that RACT is utilized on existing sources while BACT is used on new or modified sources. The cost requirements for RACT are less than BACT; RACT is intended to be available at a 'reasonable' cost.

Many states with ozone nonattainment areas have submitted proposed RACT regulations to the EPA for approval as part of the SIP requirements. Many of the regulations set emission limitations from industrial boilers that can be achieved through burning cleaner fuels (i.e., natural gas), utilizing low NO_x technologies, or a combination of both. Owners of industrial boilers located in ozone nonattainment areas should be familiar with the RACT requirements in their states.

Lowest Achievable Emission Rates

Some regulations require technology equivalent to the Lowest Achievable Emission Rate (LAER) be utilized in new major sources located in nonattainment areas. LAER is different from BACT in that it has no economic justification associated with its requirements. When required, technology equivalent to LAER must be installed regardless of costs impacts. It is the most stringent of all technology-based regulations.

Permits

The permit program established under Title V of the 1990 Clean Air Act Amendments will undoubtedly affect the way each state conducts its permitting process. Title V requires a review (and most likely a revision) of each state's permitting program in order to ensure that the state's permit program meets all Federal EPA requirements. Elements of state permit programs that could be affected include:

- The permit application process
- Monitoring and reporting requirements
- Permit renewal process
- Several other permitting issues

By November of 1993, states were required to submit proposed permitting programs to the EPA. By November of 1994, the EPA must approve or disapprove the proposed permit programs. The new permit programs will go into effect when approved by the EPA or the EPA

promulgates a program for states failing to submit a satisfactory program.

Currently, several states have implemented a two-stage permitting process. In the first stage, a permit to construct must be obtained. The permit usually requires a detailed description of the installation, including information such as the type and size of equipment and associated emissions. The second stage of the permit process consists of obtaining an operating permit. In some states, emission testing may be part of the requirement for obtaining an operating permit.

Although many states may have the same basic permitting structure, the details and requirements of the permitting process are different for each state. It is important to be aware of not only the state permitting requirements, but also any federal requirements (i.e., Small Boiler New Source Performance Standards) that may be applicable. It is particularly important to be familiar with the permitting process as the new federal and state programs are implemented. Nearly every source of air pollution will be affected. Any violators may face stiff penalties.

POLLUTANTS AND CONTROL TECHNIQUES

A pollutant can be defined as matter that contaminates air, soil, or water. Air pollutants are airborne contaminants that produce unwanted effects on humans and the environment. They occur as solids, liquid droplets, gases, or combinations of these forms. Generally, air pollutants are classified into two major categories:

- Primary Pollutants - pollutants emitted directly from identifiable sources
- Secondary Pollutants - pollutants formed by interaction between two or more primary pollutants

To protect humans and the environment from the adverse effects of air pollutants, the EPA has established the National Ambient Air Quality Standards (see Figure 2, page 3). The Clean Air Act Amendments of 1990 require areas in noncompliance for one or more of the NAAQS pollutants to implement regulations to reduce ambient levels. All six pollutants addressed in the National Ambient Air Quality Standards are directly or indirectly related to the combustion process. The following sections describe the formation and control of the pollutants in industrial boilers, discuss their impact on humans and the environment, and describe the current emission control technologies.

Nitrogen Compounds

Although there is evidence proving NO_x , in itself, is harmful to humans, the main reason NO_x is considered an environmental problem is because it initiates reactions that result in the production of ozone and acid rain. Ozone and acid rain can damage fabric, cause rubber to crack, reduce visibility, damage buildings, harm forests and lakes, and cause health problems. By controlling NO_x levels, along with other contributing primary pollutants, the levels of acid rain and ozone can be reduced.

The principal nitrogen pollutants generated by boilers are nitric oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as NO_x . The majority of NO_x produced during combustion is NO (95%). Once emitted into the atmosphere, NO reacts to form NO_2 . It is NO_2 that reacts with other pollutants to form ozone.

The contribution from different NO_x sources to the total NO_x levels varies among metropolitan areas. In general, the contribution of mobile

sources to the total NO_x level ranges from 60 to 80 percent: For stationary sources, it ranges between 20 and 40 percent. A significant portion of the NO_x from stationary sources can be attributed to residential, commercial, and industrial sources, including industrial boilers. In industrial boilers, NO_x is primarily formed in two ways; thermal NO_x and fuel NO_x .

Thermal NO_x

Thermal NO_x is formed when nitrogen and oxygen in the combustion air combine with one another at the high temperatures in a flame. Thermal NO_x makes up the majority of NO_x formed during the combustion of gases and light oils.

Fuel NO_x

Fuel NO_x is formed by the reaction of nitrogen in the fuel with oxygen in the combustion air. It is rarely a problem with gaseous fuels. But in oils containing significant amounts of fuel-bound nitrogen, fuel NO_x can account for up to 50% of the total NO_x emissions.

NO_x emissions from boilers are influenced by many factors. The most significant factors are flame temperature and the amount of nitrogen in the fuel. Other factors affecting NO_x formation are excess air level and combustion air temperature.

While flame temperature primarily affects thermal NO_x formation, the amount of nitrogen in the fuel determines the level of fuel NO_x emissions. Fuel containing more nitrogen results in higher levels of NO_x emissions (see Figure 9). Most NO_x control technologies for industrial boilers, with inputs less than 100 MMBtu/hr, reduce thermal NO_x and have little effect on fuel NO_x . Fuel NO_x is most economically reduced in commercial and industrial boilers by switching to cleaner fuels, if available.

NO_x Control Technologies

NO_x controls can be classified into two types; post combustion methods and combustion control techniques. Post combustion methods address NO_x emissions after formation while combustion control techniques prevent the formation of NO_x during the combustion process. Post combustion methods tend to be more expensive than combustion control techniques and generally are not used on boilers with inputs of less than 100 MMBtu/hr. Following is a list of different NO_x control methods.

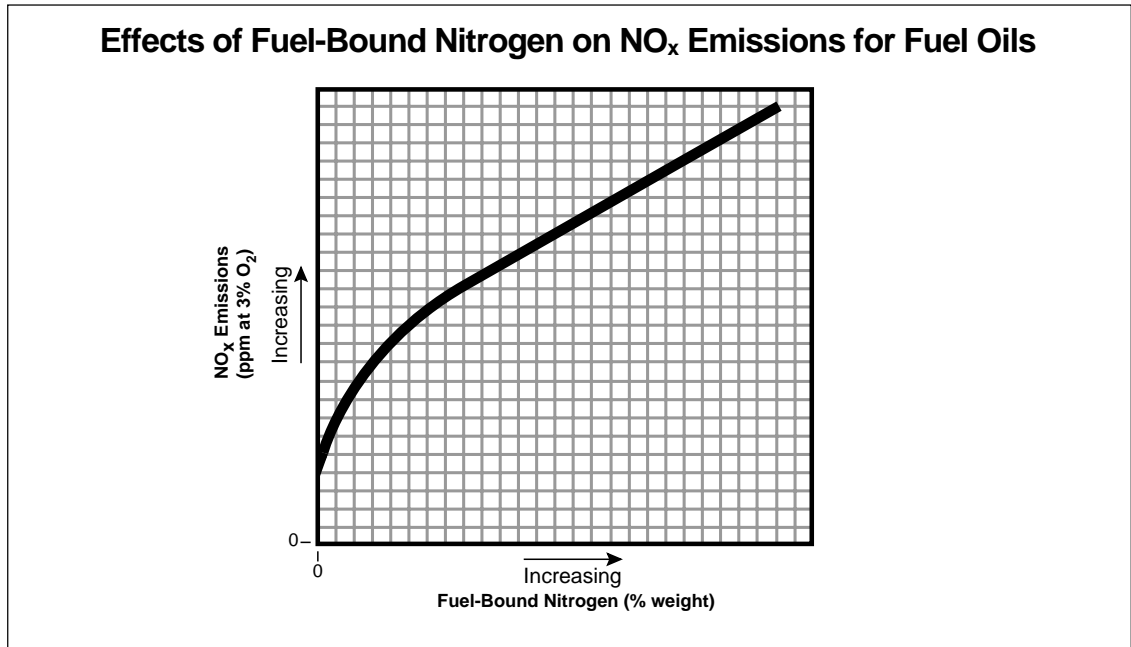


figure 9

Post Combustion Control Methods

- Selective Non-Catalytic Reduction
- Selective Catalytic Reduction

Combustion Control Techniques

- Low Excess Air Firing
- Low Nitrogen Fuel Oil
- Burner Modifications
- Water/Steam Injection
- Flue Gas Recirculation

Each method results in a different degree of NO_x control. For example, when firing natural gas, low excess air firing typically reduces NO_x by 10%, flue gas recirculation by 75%, and selective catalytic reduction by 90%.

Post Combustion Control Methods

Selective Non-catalytic Reduction

Selective non-catalytic reduction involves the injection of a NO_x reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400-1600°F (see Figure 10). The ammonia or urea breaks down the NO_x in the exhaust gases into water and atmospheric nitrogen. Selective non-catalytic reduction reduces NO_x up to 50%. However, the technology is extremely difficult to apply to industrial boilers that modulate frequently. This is because the ammonia (or urea) must be injected in the flue gases at a specific flue gas temperature. And in industrial boilers that

modulate frequently, the location of the exhaust gases at the specified temperature is constantly changing. Thus, it is not feasible to apply selective non-catalytic reduction to industrial boilers that have high turndown capabilities and modulate frequently.

Selective Catalytic Reduction

Selective catalytic reduction involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst (see Figure 11). The catalyst allows the ammonia to reduce NO_x levels at lower exhaust temperatures than selective non-catalytic reduction. Unlike selective non-catalytic reduction, where the exhaust gases must be approximately 1400-1600°F, selective catalytic reduction can be utilized where exhaust gases are between 500° and 1200°F, depending on the catalyst used. Selective catalytic reduction can result in NO_x reductions up to 90%. However, it is costly to use and rarely can be cost justified on boilers with inputs less than 100 MMBtu/hr.

Combustion Control Techniques

Combustion control techniques reduce the amount of NO_x emission by limiting the amount of NO_x formation during the combustion process. This is typically accomplished by lowering flame temperatures. Combustion control techniques are more economical than post combustion methods and are frequently utilized on industrial boilers requiring NO_x controls.

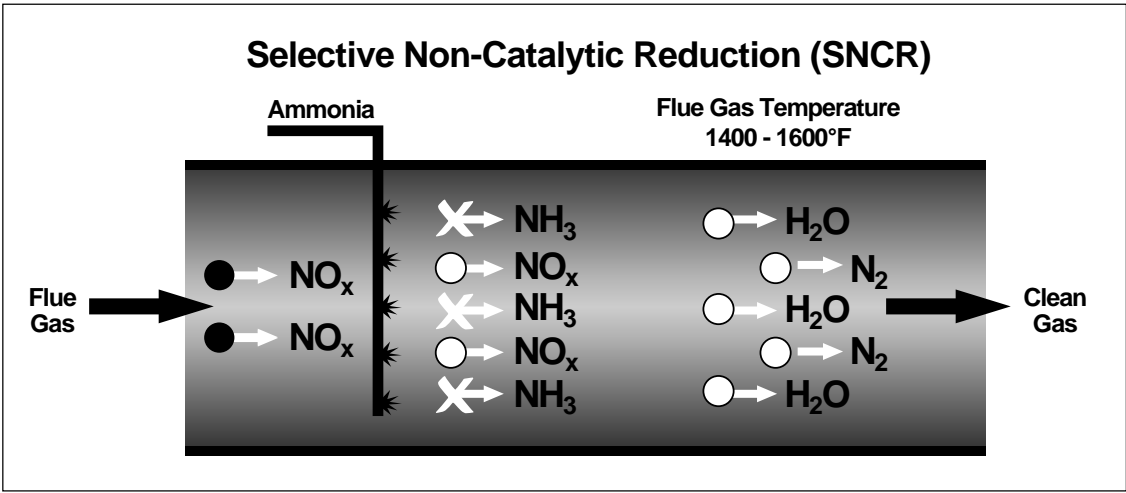


figure 10

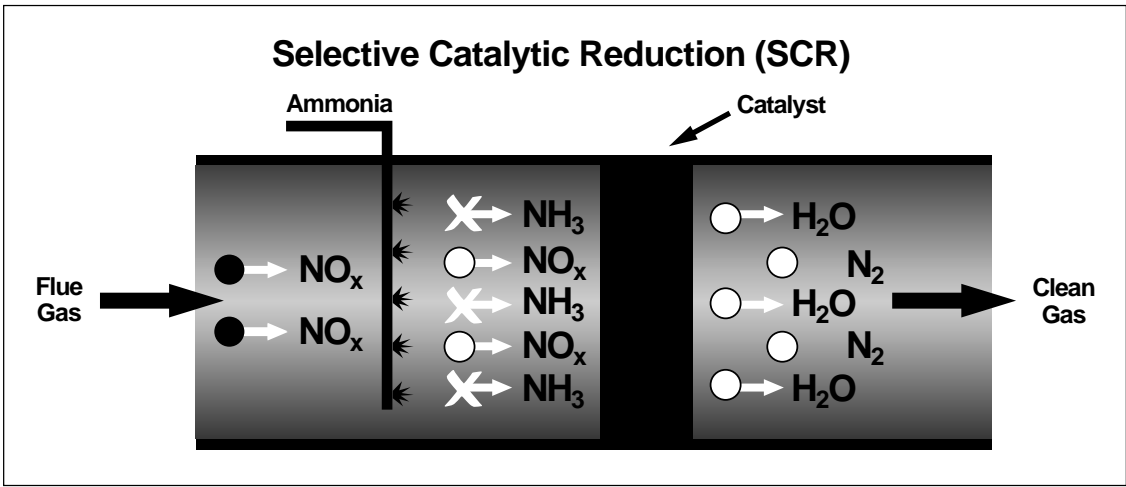


figure 11

Low Excess Air (LEA) Firing

As a safety factor to assure complete combustion, boilers are fired with excess air. One of the factors influencing NO_x formation in a boiler is the excess air levels. High excess air levels (>45%) may result in increased NO_x formation because the excess nitrogen and oxygen in the combustion air entering the flame will combine to form thermal NO_x. Low excess air firing involves limiting the amount of excess air that is entering the combustion process in order to limit the amount of extra nitrogen and oxygen that enters the flame. Limiting the amount of excess air entering a flame is usually accomplished through burner design and can be optimized through the use of oxygen trim controls. Low excess air firing can be used on most boilers and generally results in overall NO_x reductions of 5-10% when firing natural gas.

Low Nitrogen Fuel Oil

When firing fuel oils, NO_x formed by fuel-bound nitrogen can account for 20-50% of the total NO_x level. Utilizing fuel oils with lower nitrogen contents results in lower NO_x levels. One method to reduce NO_x levels from boilers firing distillate oils is through the use of low nitrogen fuel oil. Low nitrogen oils can contain up to 15-20 times less fuel-bound nitrogen than standard No. 2 oil (less than 0.001% fuel-bound nitrogen). When low NO_x oil is fired in firetube boilers utilizing flue gas recirculation, NO_x reductions of 60%-70% over NO_x emissions from standard No. 2 oils have been achieved. Low nitrogen oil is currently used most frequently in Southern California.

Burner Modifications

Burner modifications for NO_x control involve changing the design of a standard burner in order



to create a larger flame. Enlarging the flame results in lower flame temperatures and lower thermal NO_x formation which, in turn, results in lower overall NO_x emissions. The technology can be applied to most boiler types and sizes. It is most effective when firing natural gas and distillate fuel oil and has little affect on boilers firing heavy oil. To comply with the more stringent regulations, burner modifications must be used in conjunction with other NO_x reduction methods, such as flue gas recirculation. If burner modifications are utilized exclusively to achieve low NO_x levels (30 ppm), adverse affects on boiler operating parameters such as turndown, capacity, CO levels, and efficiency may result. It is important to address all aspects of NO_x control when selecting NO_x control technologies (see Side Bar, this page).

Water/Steam Injection

Water or steam injection can be utilized to reduce NO_x levels. By introducing water or steam into the flame, flame temperatures are reduced, thereby lowering thermal NO_x formation and overall NO_x levels. Water or steam injection can reduce NO_x up to 80% (when firing natural gas) and can result in lower reductions when firing oils. There is a practical limit to the amount of water or steam that can be injected into the flame before condensation problems are experienced. Additionally, under normal operating conditions, water/steam injection can result in a 3-10% efficiency loss. Many times water or steam injection is used in conjunction with other NO_x control methods such as burner modifications or flue gas recirculation.

Flue Gas Recirculation

Flue gas recirculation, or FGR, is the most effective method of reducing NO_x emission from industrial boilers with inputs below 100 MMBtu/hr. FGR entails recirculating a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NO_x formation. It is currently the most effective and popular low NO_x technology for firetube and watertube boilers. And, in many applications, it does not require any additional reduction equipment to comply with the most stringent regulations in the United States.

Flue gas recirculation technology can be classified into two types; external or induced.

External flue gas recirculation utilizes an external fan to recirculate the flue gases back into the combustion zone. External piping routes the exhaust gases from the stack to

the burner. A valve controls the recirculation rate, based on boiler input.

Induced flue gas recirculation utilizes the combustion air fan to recirculate the flue gases back into the combustion zone. A portion of the flue gases are routed by duct work or internally to the combustion air fan, where they are premixed with the combustion air and introduced into the flame through the burner. New designs of induced FGR that utilize an integral FGR design are becoming popular among boiler owners and operators because of their uncomplicated design and reliability.

Theoretically, there is no limit to the amount of NO_x reduction with FGR; practically, there is a physical, feasible limit. The limit of NO_x reduction varies for different fuels - 80% for natural gas and 20-25% for standard fuel oils. When firing natural gas, typical NO_x reductions are 45% with 10% recirculation and 75% with 20% recirculation.

The current trends with low NO_x technologies are to design the boiler and low NO_x equipment as a package. Designing as a true package allows the NO_x control technology to be specifically tailored to match the boiler's furnace design features, such as shape, volume, and heat release. By designing the low NO_x technology as a package with the boiler, the effects of the low NO_x technology on boiler operating parameters (turndown, capacity, efficiency, and CO levels) can be addressed and minimized.

SIDE BAR:

CHOOSING THE BEST NO_x TECHNOLOGY FOR THE JOB

What effect does NO_x control technology ultimately have on a boiler's performance? Certain NO_x controls can worsen boiler performance while other controls can appreciably improve performance. Aspects of the boiler performance that could be affected include turndown, capacity, efficiency, excess air, and CO emissions.

Failure to take into account all of the boiler operating parameters can lead to increased operating and maintenance costs, loss of efficiency, elevated CO levels, and shortening of the boiler's life.

The following section discusses each of the operating parameters of a boiler and how they relate to NO_x control technology.

TURNDOWN

Choosing a low NO_x technology that sacrifices turndown can have many adverse effects on the boiler. When selecting NO_x control, the boiler should have a turndown capability of at least 4:1 or more, in order to reduce operating costs and the number of on/off cycles. A boiler utilizing a standard burner with a 4:1 turndown can cycle as frequently as 12 times per hour or 288 times a day because the boiler must begin to cycle at inputs below 25% capacity.

With each cycle, pre- and post-purge air flow removes heat from the boiler and sends it out the stack. The energy loss can be reduced by using a high turndown burner (10:1), which keeps the boiler on at low firing rates.

Every time the boiler cycles off, it must go through a specific start-up sequence for safety assurance. It takes about one to two minutes to get the boiler back on line. If there is a sudden load demand, the response cannot be accelerated. Keeping the boiler on line assures a quick response to load changes.

Frequent cycling also deteriorates the boiler components. Maintenance increases, the chance of component failure increases, and boiler downtime increases. So, when selecting NO_x control, always consider the burner's turndown capability.

CAPACITY

When selecting the best NO_x control, capacity and turndown should be considered together because some NO_x control technologies require boiler derating in order to achieve guaranteed NO_x reductions. For example, flame shaping (primarily enlarging the flame to produce a lower flame temperature - thus lower NO_x levels) can require boiler derating, because the shaped flame could impinge on the furnace walls at higher firing rates.

However, the boiler's capacity requirement is typically determined by the maximum load in the steam/hot water system. Therefore, the boiler may be oversized for the typical load conditions occurring.

If the boiler is oversized, its ability to handle minimum loads without cycling is limited. Therefore, when selecting the most appropriate NO_x control, capacity and turndown should be considered together for proper boiler selection and to meet overall system load requirements.

EFFICIENCY

Some low NO_x controls reduce emissions by lowering flame temperature, particularly in boilers with inputs less than 100 MMBtu/hr. Reducing the flame temperature decreases the radiative heat transfer from the flame and could lower boiler efficiency. The efficiency loss due to the lower flame temperatures can be partially offset by utilizing external components, such as an economizer. Or, the technique can be inherent in the NO_x design.

One technology that offsets the efficiency loss due to lower flame temperatures in a firetube boiler is flue gas recirculation. Although the radiant heat transfer could result in an efficiency loss, the recirculated flue gases increase the mass flow through the boiler - thus the convective heat transfer in the tube passes increases. The increase in convective heat transfer compensates for losses in radiative heat transfer, with no net efficiency loss. When considering NO_x control technology, remember, it is not necessary to sacrifice efficiency for NO_x reductions.

EXCESS AIR

A boiler's excess air supply provides for safe operation above stoichiometric conditions. A typical burner is usually set up with 10-20% excess air (2-4% O₂). NO_x controls that require higher excess air levels can result in fuel being used to heat the air rather than transferring it to usable energy. Thus, increased stack losses and reduced boiler efficiency occur. NO_x controls that require reduced excess air levels can result in an oxygen deficient flame and increased levels of carbon monoxide or unburned hydrocarbons. It is best to select a NO_x control technology that has little effect on excess air.

CO EMISSIONS

High flame temperatures and intimate air/fuel mixing are essential for low CO emissions. Some NO_x control technologies used on industrial and commercial boilers reduce NO_x levels by lowering flame temperatures by modifying air/fuel mixing patterns. The lower flame temperature and decreased mixing intensity can result in higher CO levels.

An induced flue gas recirculation package can lower NO_x levels by reducing flame temperature without increasing CO levels. CO levels remain constant or are lowered because the flue gas is introduced into the flame in the early stages of



combustion and the air fuel mixing is intensified. Intensified mixing offsets the decrease in flame temperature and results in CO levels that are lower than achieved without FGR. Induced FGR lowers CO levels as well as NO_x levels. But, the level of CO depends on the burner design. Not all flue gas recirculation applications result in lower CO levels.

TOTAL PERFORMANCE

Selecting the best low NO_x control package should be made with total boiler performance in mind. Consider the application. Investigate all of the characteristics of the control technology and the effects of the technology on the boiler's performance. A NO_x control technology that results in the greatest NO_x reduction is not necessarily the best for the application or the best for high turndown, adequate capacity, high efficiency, sufficient excess air, or lower CO. The newer low NO_x technologies provide NO_x reductions without affecting total boiler performance.

Sulfur Compounds (SO_x)

The primary reason sulfur compounds, or SO_x, are classified as a pollutant is because they react with water vapor (in the flue gas and atmosphere) to form sulfuric acid mist. Airborne sulfuric acid has been found in fog, smog, acid rain, and snow. Sulfuric acid has also been found in lakes, rivers, and soil. The acid is extremely corrosive and harmful to the environment.

The combustion of fuels containing sulfur (primarily oils and coals) results in pollutants occurring in the form of SO₂ (sulfur dioxide) and SO₃ (sulfur trioxide), together referred to as SO_x (sulfur oxides). The level of SO_x emitted depends directly on the sulfur content of the fuel (see Figure 12). The level of SO_x emissions is not dependent on boiler size or burner design. Typically, about 95% of the sulfur in the fuel will be emitted as SO₂, 1-5% as SO₃, and 1-3% as sulfate particulate. Sulfate particulate is not considered part of the total SO_x emissions.

Historically, SO_x pollution has been controlled by either dispersion or reduction. Dispersion involves the utilization of a tall stack, which enables the release of pollutants high above the ground and over any surrounding buildings, mountains, or hills, in order to limit ground level SO_x emissions. Today, dispersion alone is not enough to meet more stringent SO_x

emission requirements; reduction methods must also be employed.

Methods of SO_x reduction include switching to low sulfur fuel, desulfurizing the fuel, and utilizing a flue gas desulfurization (FGD) system. Fuel desulfurization, which primarily applies to coal, involves removing sulfur from the fuel prior to burning. Flue gas desulfurization involves the utilization of scrubbers to remove SO_x emissions from the flue gases.

Flue gas desulfurization systems are classified as either nonregenerable or regenerable. Non-regenerable FGD systems, the most common type, result in a waste product that requires proper disposal. Regenerable FGD converts the waste byproduct into a marketable product, such as sulfur or sulfuric acid. SO_x emission reductions of 90-95% can be achieved through FGD. Fuel desulfurization and FGD are primarily used for reducing SO_x emissions for large utility boilers. Generally the technology cannot be cost justified on industrial boilers.

For users of industrial boilers, utilizing low sulfur fuels is the most cost effective method of SO_x reduction. Because SO_x emissions primarily

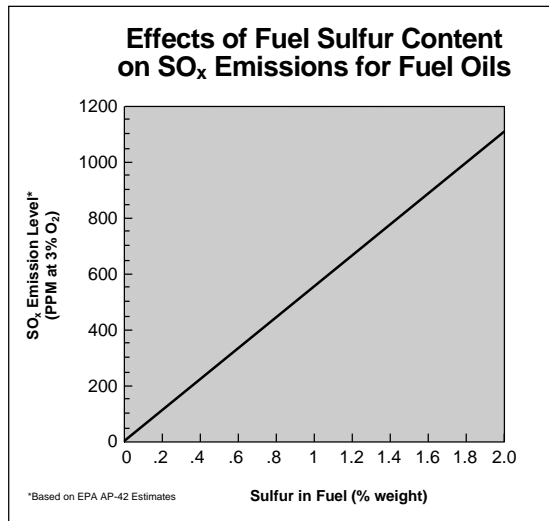


figure 12

depend on the sulfur content of the fuel, burning fuels containing a minimal amount of sulfur (distillate oil) can achieve SO_x reductions, without the need to install and maintain expensive equipment.

Carbon Monoxide

Carbon monoxide is a pollutant that is readily absorbed in the body and can impair the oxygen-carrying capacity of the hemoglobin. Impairment of the body's hemoglobin results in less oxygen

to the brain, heart, and tissues. Short-term over exposure to carbon monoxide can be critical, even fatal, to people with heart and lung diseases. It also may cause headaches and dizziness in healthy people.

During combustion, carbon in the fuel oxidizes through a series of reactions to form carbon dioxide (CO₂). However, 100 percent conversion of carbon to CO₂ is rarely achieved in practice and some carbon only oxidizes to the intermediate step, carbon monoxide.

Older boilers generally have higher levels of CO than new equipment because CO has only recently become a concern and older burners were not designed to achieve low CO levels. In today's equipment, high levels of carbon monoxide emissions primarily result from incomplete combustion due to poor burner design or firing conditions (for example, an improper air-to-fuel ratio) or possibly a leaky furnace. Through proper burner maintenance, inspections, operation, or by upgrading equipment or utilizing an oxygen control package, the formation of carbon monoxide can be controlled at an acceptable level.

Particulate Matter

Emissions of particulate matter (PM) from combustion sources consist of many different types of compounds, including nitrates, sulfates, carbons, oxides, and any uncombusted elements in the fuel. Particulate pollutants can be corrosive, toxic to plants and animals, and harmful to humans.

Particulate matter emissions generally are classified into two categories, PM and PM₁₀. PM₁₀ is a particulate matter with a diameter less than 10 microns. All particulate matter can pose a health problem. However, the greatest concern is with PM₁₀, because of its ability to bypass the body's natural filtering system.

PM emissions primarily depend on the grade of fuel fired in the boiler. Generally, PM levels from natural gas are significantly lower than those of oils. Distillate oils result in much lower particulate emissions than residual oils.

When burning heavy oils, particulate levels mainly depend on four fuel constituents: sulfur, ash, carbon residue, and asphaltines. The constituents exist in fuel oils, particularly residual oils, and have a major effect on particulate emissions. By knowing the content of the components, the particulate emissions for the oil

can be estimated.

Methods of particulate control vary for different types and sizes of boilers. For utility boilers, electrostatic precipitators, scrubbers, and baghouses are commonly utilized. For industrial and commercial boilers, the most effective method is to utilize clean fuels. The emission levels of particulate matter can be lowered by switching from a residual to a distillate oil or by switching from a distillate oil to a natural gas. Additionally, through proper burner set-up, adjustment and maintenance, particulate emissions can be minimized, but not to the extent accomplished by switching fuels.

Ozone

Ozone is a highly reactive form of oxygen. Ground level ozone is a secondary pollutant formed by the reaction of volatile organic compounds (VOCs) with nitrogen oxides (NO_x) in the presence of sunlight. Ozone formed at the ground level is the main component of smog. It is known to irritate the eyes, nose, throat, and lungs, and also cause damage to crops. Ground level ozone should not be confused with ozone in the upper atmosphere.

Since ozone is formed by the reaction of VOCs and NO_x, methods of ozone reduction focus on the control of these two pollutants. Recent studies show that reducing NO_x emissions in several ozone nonattainment areas would be beneficial in meeting federal ozone standards.

Sources of VOCs are automobiles, solvents, paints, domestic products and, in nature, decomposition of organic materials such as wood and grass. Although a major source of VOCs is automobiles, the ozone standards also address stationary sources; including boilers. Regulations limiting VOC emissions from stationary combustion sources are relatively new. The regulations originally applied only to large utility boilers, but now are beginning to address industrial boilers. These regulations are primarily at the state level and vary among states.

VOCs are compounds containing combinations of carbon, hydrogen and sometimes oxygen. They can be vaporized easily at low temperatures. They often are referred to as hydrocarbons and generally are divided into two categories — methane and non-methane hydrocarbons.

VOCs can result from poor combustion but, more commonly, result from vaporization of fuels



and paints. Leaks in oil or gas piping, and even the few drops of gasoline spilled when filling an automobile, are sources of VOCs.

Control of VOC emissions is best accomplished by maintaining proper combustion conditions. The use of controls to maintain proper air-to-fuel ratios and periodic burner maintenance checks should result in reducing VOC emissions below imposed limits.

Note: If a boiler is operated improperly or is poorly maintained (incorrect air/fuel ratio, inadequate atomizing pressure for oil burners, and improper air and fuel pressures), the concentration of VOCs may increase by several orders of magnitude.

Lead

Lead poisoning can lead to diminished physical fitness, fatigue, sleep disturbance, headache, aching bones and muscles, and digestive upset, including anorexia. Lead poisoning primarily involves the gastrointestinal tract and the peripheral and central nervous systems.

Lead emissions are primarily a result of gasoline combustion in automobile engines and depend highly on the lead content of the fuel. Efforts to reduce lead emissions have focused on the use of lead-free fuels, particularly in automobiles. New blends of gasoline containing lower levels of lead additives continue to be introduced.

The impact of lead emission regulations in industrial boilers that burn standard fuels has been minimal because the fuels generally contain little or no lead. Boilers that fire alternate fuels containing lead are subject to stringent federal, state, and local regulations. For example, under the Federal Resource Conservation Recovery Act (RCRA), waste oil to be burned as fuel in an industrial boiler must contain less than 50 ppm lead. As a result of such strict regulations, the use of fuel containing lead in industrial boilers is limited.

CONCLUSION

We hope you have a better grasp of how federal, state, and local governments are regulating air pollution. We also hope you have a better understanding of NO_x and CO emissions and industrial boiler control technologies.

When you need to specify or purchase an industrial boiler with emission control technology, your local Cleaver-Brooks authorized representative is available to discuss control technology options and how you can achieve the lowest possible emissions.

If at any time you need more information, please don't hesitate to contact your local Cleaver-Brooks representative.



CLASSIFIED OZONE NONATTAINMENT AREAS (January 1994)

Alabama			Kansas	
Birmingham	Marginal		Kansas City	Sub Marginal
Arizona			Kentucky	
Phoenix	Moderate		Cincinnati – Hamilton	Moderate
California			Boone, Campbell, and	
Los Angeles – South Coast	Extreme		Kenton Counties	
Air Basin			Edmonson County	Marginal
Monterey Bay	Moderate		Ashland – Huntington	Moderate
Sacramento Metro	Serious		Lexington – Fayette	Marginal
San Diego	Severe-15		Louisville	Moderate
San Francisco – Bay Area	Moderate		Owensboro	Marginal
San Joaquin Valley	Serious		Pudacah	Marginal
Santa Barbara – Santa Maria -			Louisiana	
Lompoc	Moderate		Baton Rouge	Serious
Southeast Desert			Lake Charles	Marginal
Modified AQMA	Severe-17		Maine	
Ventura County	Severe-15		Hancock and Waldo Counties	Marginal
Connecticut			Knox and Lincoln Counties	Moderate
Greater Connecticut	Serious		Lewiston – Auburn	Moderate
Fairfield, Hartford, Litchfield,			Portland	Moderate
Middlesex, New Haven,			Maryland	
New London, Tolland, and			Baltimore	Severe-15
Windham Counties			Kent and Queen Anne's	
New York – N. New Jersey -			Counties	Marginal
Long Island	Severe-17		Philadelphia – Wilmington -	
Parts of Fairfield and			Trenton	Severe-15
Litchfield Counties			Cecil County	
Delaware			Washington D.C.	Serious
Wilmington – Philadelphia -			Calvert, Charles, Frederick,	
Trenton	Severe-15		Montgomery, and	
Sussex County	Marginal		Prince George's Counties	
District of Columbia			Massachusetts	
Entire District	Serious		Boston – Lawrence –	
Florida			Worcester	Serious
Miami – Fort Lauderdale –			Springfield	Serious
W. Palm Beach	Moderate		Michigan	
Tampa – St. Petersburg –			Detroit – Ann Arbor	Moderate
Clearwater	Marginal		Grand Rapids	Moderate
Georgia			Muskegon	Serious
Atlanta	Serious		Missouri	
Illinois			Kansas City	Sub-Marginal
Chicago – Gary – Lake County	Severe-17		St. Louis	Moderate
Jersey County	Marginal		Nevada	
St. Louis	Moderate		Reno	Marginal
Madison, Monroe, and			New Hampshire	
St. Clair Counties			Boston – Lawrence –	
Indiana			Worcester	Serious
Gary – Chicago – Lake County	Severe-17		Parts of Hillsborough and	
Evansville	Marginal		Rockingham Counties	
Indianapolis	Marginal		Manchester	Marginal
Louisville	Moderate		Portsmouth - Dover -	
Clark and Floyd Counties			Rochester	Serious
South Bend – Elkhart	Marginal			

New Jersey			
Allentown – Bethlehem -			Serious
Easton – Warren County	Marginal		Moderate
Atlantic City	Moderate		Serious
N. New Jersey – New York -			Severe-17
Long Island	Severe-17		
Trenton – Philadelphia -			
Wilmington	Severe-15		
New York			
Albany – Schenectady – Troy	Marginal		
Buffalo – Niagara Falls	Marginal		
Essex County	Marginal		
Jefferson County	Marginal		
New York – N. New Jersey –			
Long Island	Severe-17		
Poughkeepsie	Marginal		
North Carolina			
Charlotte – Gastonia	Moderate		
Greensboro – Winston – Salem –			
High Point	Moderate		
Raleigh – Durham	Moderate		
Ohio			
Canton	Marginal		
Cincinnati – Hamilton	Moderate		
Cleveland – Akron – Lorain	Moderate		
Columbus	Marginal		
Dayton – Springfield	Moderate		
Toledo	Moderate		
Youngstown – Warren – Sharon	Marginal		
Oregon			
Portland – Vancouver AQMA	Marginal		
Pennsylvania			
Allentown – Bethlehem – Easton	Marginal		
Altoona	Marginal		
Erie	Marginal		
Harrisburg – Lebanon – Carlisle	Marginal		
Johnstown	Marginal		
Lancaster	Marginal		
Philadelphia – Wilmington –			
Trenton	Severe-15		
Pittsburgh – Beaver Valley	Moderate		
Reading	Moderate		
Scranton – Wilkes – Barre	Marginal		
York	Marginal		
Sharon – Youngstown – Warren	Marginal		
Rhode Island			
Entire State	Serious		
South Carolina			
Cherokee County	Marginal		
Tennessee			
Knoxville	Marginal		
Memphis	Marginal		
Nashville	Moderate		
Texas			
Beaumont – Port Arthur			Serious
Dallas – Ft. Worth			Moderate
El Paso			Serious
Houston – Galveston – Brazoria			Severe-17
Utah			
Salt Lake City			Moderate
Virginia			
Norfolk – Virginia Beach -			
Newport News			Marginal
Richmond – Petersburg			Moderate
Smyth County			Marginal
Washington D.C.			Serious
Arlington, Fairfax, Loudoun,			
Prince William, and Stafford			
Counties; Alexandria, Fairfax,			
Falls Church, Manassas, and			
Manassas Park			
Washington			
Vancouver AQMA – Portland			Marginal
Seattle – Tacoma			Marginal
West Virginia			
Charleston			Moderate
Greenbrier County			Marginal
Huntington – Ashland			Moderate
Parkersburgh			Moderate
Wisconsin			
Door County			Marginal
Kewaunee County			Moderate
Manitowoc County			Moderate
Milwaukee – Racine			Severe-17
Sheboygan			Serious
Walworth County			Marginal

NOTE: If there is no listing for a state, there are no classified ozone nonattainment areas located in the state.



CLASSIFIED CARBON MONOXIDE NONATTAINMENT AREAS (January 1994)

Alaska			New Jersey	
Anchorage	Moderate	>12.7 ppm	N. New Jersey –	
Fairbanks	Moderate	≤12.7 ppm	New York – Long Island	Moderate >12.7 ppm
Arizona			Camden County –	
Phoenix	Moderate	≤12.7 ppm	Philadelphia	Moderate ≤12.7 ppm
California			New Mexico	
Chico	Moderate	≤12.7 ppm	Albuquerque	Moderate ≤12.7 ppm
Fresno	Moderate	>12.7 ppm	New York	
Lake Tahoe South Shore	Moderate	≤12.7 ppm	New York –	
Los Angeles South Coast Air Basin	Serious		N. New Jersey –	
Modesto	Moderate	≤12.7 ppm	Long Island	Moderate >12.7 ppm
Sacramento	Moderate	≤12.7 ppm	Syracuse	Moderate ≤12.7 ppm
San Diego	Moderate	≤12.7 ppm	North Carolina	
San Francisco – Oakland – San Jose	Moderate	≤12.7 ppm	Raleigh – Durham	Moderate ≤12.7 ppm
Stockton	Moderate	≤12.7 ppm	Winston – Salem	Moderate ≤12.7 ppm
Colorado			Ohio	
Colorado Springs	Moderate	≤12.7 ppm	Cleveland	Moderate ≤12.7 ppm
Denver – Boulder	Moderate	>12.7 ppm	Oregon	
Fort Collins	Moderate	≤12.7 ppm	Grants Pass	Moderate ≤12.7 ppm
Longmont	Moderate	≤12.7 ppm	Klamath Falls	Moderate ≤12.7 ppm
Connecticut			Medford	Moderate ≤12.7 ppm
Hartford – New Britain – Middletown	Moderate	≤12.7 ppm	Portland – Vancouver	Moderate ≤12.7 ppm
New York – N. New Jersey – Long Island	Moderate	>12.7 ppm	Pennsylvania	
Parts of Fairfield and Litchfield Counties			Philadelphia – Camden County	Moderate ≤12.7 ppm
District of Columbia			Tennessee	
Entire District	Moderate	≤12.7 ppm	Memphis	Moderate ≤12.7 ppm
Maryland			Texas	
Baltimore	Moderate	≤12.7 ppm	El Paso	Moderate ≤12.7 ppm
Washington D.C. Montgomery and Prince George's Counties	Moderate	≤12.7 ppm	Utah	
Massachusetts			Ogden	Moderate ≤12.7 ppm
Boston	Moderate	≤12.7 ppm	Provo	Moderate >12.7 ppm
Minnesota			Virginia	
Duluth	Moderate	≤12.7 ppm	Washington D.C.	
Minneapolis – St. Paul	Moderate	≤12.7 ppm	Alexandria City, Arlington County	Moderate ≤12.7 ppm
Montana			Washington	
Missoula	Moderate	≤12.7 ppm	Vancouver – Portland	Moderate ≤12.7 ppm
Nevada			Seattle – Tacoma	Moderate >12.7 ppm
Las Vegas	Moderate	>12.7 ppm	Spokane	Moderate >12.7 ppm
Reno	Moderate	≤12.7 ppm	NOTE: If there is no listing for a state, there are no classified carbon monoxide nonattainment areas located in the state.	

**CLASSIFIED PM₁₀
NONATTAINMENT AREAS (January 1994)**

Arizona

Ajo
Douglas
Hayden/Miami
Nogalas
Paul Spur
Phoenix
Rillito
Yuma

Arkansas

Eagle River
Juneau

California

Coachella Valley
Imperial Valley
Mammoth Lake
Owens Valley
San Joaquin Valley
Searles Valley
South Coast Basin

Colorado

Aspen
Canon City
Denver Metro
Lamar
Pagosa Springs
Telluride

Connecticut

New Haven

Idaho

Boise
Bonner County
Pinehurst
Pocatello

Illinois

Granite City
Lyons Township, McCook
Oglesby
Southeast Chicago

Indiana

Lake County
Vermillion County

Maine

Presque Isle

Michigan

Detroit

Minnesota

Rochester
St. Paul

Montana

Butte
Columbia

Kalispell
Lame Deer
Libby
Missoula
Polson
Ronan

Nevada

Las Vegas
Reno

New Mexico

Anthony

Ohio

Cuyahoga County
Mingo Junction

Oregon

Grant Pass
Klamath Falls
La Grand
Medford
Springfield/Eugene

Pennsylvania

Clairton

Texas

El Paso

Utah

Salt Lake County
Utah County

Washington

Kent
Olympia/Tumwater/Lacey
Seattle Spokane
Tacoma
Wallula
Yakima

West Virginia

Follansbee

Wyoming

Sheridan

NOTE: If there is no listing for a state, there are no classified PM-10 nonattainment areas located in the state.



CLASSIFIED SULFUR DIOXIDE NONATTAINMENT AREAS (January 1994)

Alabama

Colbert Co.
Lauderdale Co.

Arizona

Cochise Co. (Douglas)
Gila Co. (Miami/Globe)
Greenlee Co. (Morenci)
Pima Co. (Ajo)
Pinal Co. (Hayden)
Pinal Co. (San Manuel)

Illinois

Peoria Co.
Tazwell Co.

Indiana

Lake Co.
Laporte Co.
Marion Co.
Vigo Co.
Wayne Co.

Kentucky

Boyd Co.
Muhlenberg Co.

Maine

Penobscot Co.
Millinocket

Minnesota

Minneapolis-St. Paul.
Olmsted Co. (Rochester)

Montana

Lewis and Clark Co.
Yellowstone Co. (Laurel)

New Jersey

Warren Co.

New Mexico

Grant Co.

Nevada

White Pine Co.

Ohio

Coshocton Co.
Cuyahoga Co. (part)
Gallia Co. (Addison Twnshp.)
Jefferson Co. (part)
Lake Co. (part)
Lorain Co. (part)
Lucas Co. (part)
Morgan Co. (Center Twnshp.)
Washington Co.

Pennsylvania

Allegheny Co.
Armstrong Co.
Warren Co.

Tennessee

Benton Co.
Humphreys Co.
Polk Co.

Utah

Salt Lake Co.
Tooele Co. (part)

Wisconsin

Brown Co. (Green Bay)
Dane Co. (Madison)
Marathon Co. (Rothschild)
Milwaukee Co. (Milwaukee)
Oneida Co. (Rhineland)

West Virginia

Hancock Co. (part)

NOTE: If there is no listing for a state, there are no classified SO₂ nonattainment areas located in the state.

AP-42 Uncontrolled Emission Factors for Propane Combustion

lb/MMBtu						
Boiler Type	Particulate Matter (lb/MMBtu)	Sulfur Dioxide (lb/MMBtu)	Carbon Monoxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Volatile Organic Compounds	
					Nonmethane (lb/MMBtu)	Methane (lb/MMBtu)
Industrial	0.00098-0.0048	0.812 (%S)	0.034	0.136	0.0027	0.003
Commercial	0.00098-0.0048	0.812 (%S)	0.02	0.096	0.005	0.0026

ppm						
Boiler Type	Particulate Matter (ppm)	Sulfur Dioxide (ppm)	Carbon Monoxide (ppm)	Nitrogen Oxides (ppm)	Volatile Organic Compounds	
					Nonmethane (ppm)	Methane (ppm)
Industrial	N/A	475 (%S)	45	111	6.8	7.5
Commercial	N/A	475 (%S)	27	78	12.5	6.5

Notes: Estimated HHV of Propane: 91,500 Btu/gal

Industrial Boilers: 10-100 MMBtu/hr
Commercial Boilers: 0.5-10 MMBtu/hr

AP-42 Uncontrolled Emission Factors for Natural Gas Combustion

lb/MMBtu						
Boiler Type	Particulate Matter (lb/MMBtu)	Sulfur Dioxide (lb/MMBtu)	Carbon Monoxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Volatile Organic Compounds	
					Nonmethane (lb/MMBtu)	Methane (lb/MMBtu)
Industrial	0.00095-0.0048	0.00057	0.033	0.133	0.0027	0.0029
Commercial	0.00095-0.0048	0.00057	0.019	0.095	0.005	0.0023

ppm						
Boiler Type	Particulate Matter (ppm)	Sulfur Dioxide (ppm)	Carbon Monoxide (ppm)	Nitrogen Oxides (ppm)	Volatile Organic Compounds	
					Nonmethane (ppm)	Methane (ppm)
Industrial	N/A	0.34	46	112	6.8	7.3
Commercial	N/A	0.34	26	80	13	5.8

Notes: Estimated HHV of Natural Gas: 1050 Btu/FT³

Industrial Boilers: 10-100 MMBtu/hr
Commercial Boilers: 0.5-10 MMBtu/hr

AP-42 Uncontrolled Emission Factors for Fuel Oil Combustion

lb/MMBtu							Volatile Organic Compounds	
Boiler Type	Particulate Matter (lb/MMBtu)	Sulfur Dioxide (lb/MMBtu)	Sulfur Trioxide (lb/MMBtu)	Carbon Monoxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Nonmethane (lb/MMBtu)	Methane (lb/MMBtu)	
Industrial:								
Residual	0.0649(%S) + 0.0195	1.02(%S)	0.013(%S)	0.0325	0.357*	0.0018	0.0065	
Distillate	0.0143	1.01(%S)	0.013(%S)	0.0325	0.143	0.0014	0.0004	
Commercial:								
Residual	0.0649(%S) + 0.0195	1.02(%S)	0.013(%S)	0.0325	0.357*	0.0073	0.0031	
Distillate	0.0143	1.01(%S)	0.013(%S)	0.0325	0.143	0.00124	0.0015	

*Nitrogen oxide emissions from residual oil combustion in industrial and commercial boilers are strongly related to fuel nitrogen content.
 The emissions can be more accurately predicted by the empirical relationship:
 $2.6(\%N) \wedge 2 + 0.143 \text{ lb/MMBtu } (\%N \text{ in fuel } < 0.5\%)$
 For residual oils having nitrogen content (>0.5%) use 0.779 lb/MMBtu as an emission factor.

Notes:
 Estimated HHV of #2 Oil: 140,000 Btu/gal
 Estimated HHV of #6 Oil: 154,000 Btu/gal
 Industrial Boilers: 10 - 100 MMBtu/hr
 Commercial Boilers: 0.5 - 10 MMBtu/hr

AP-42 Uncontrolled Emission Factors for Fuel Oil Combustion

ppm						Volatile Organic Compounds	
Boiler Type	Particulate Matter (ppm)	Sulfur Dioxide (ppm)	Sulfur Trioxide (ppm)	Carbon Monoxide (ppm)	Nitrogen Oxide (ppm)	Nonmethane (ppm)	Methane (ppm)
Industrial:							
Residual	N/A	549(%S)	7(%S)	42	273*	3.6	13
Distillate	N/A	544(%S)	7(%S)	42	107	2.8	0.8
Commercial:							
Residual	N/A	549(%S)	7(%S)	42	273*	14.6	6.2
Distillate	N/A	544(%S)	7(%S)	42	107	4.8	3

*Nitrogen oxide emissions from residual oil combustion in industrial and commercial boilers are strongly related to fuel nitrogen content.
 The emissions can be more accurately predicted by the empirical relationship:
 $1,940(\%N) \wedge 2 + 107 \text{ ppm } (\%N \text{ in fuel } < 0.5\%)$
 For residual oils having nitrogen content (>0.5%) use 595 ppm as an emission factor.

Notes:
 Estimated HHV of #2 Oil: 140,000 Btu/gal
 Estimated HHV of #6 Oil: 154,000 Btu/gal
 Industrial Boilers: 10 - 100 MMBtu/hr
 Commercial Boilers: 0.5 - 10 MMBtu/hr

EPA REGIONAL AIR QUALITY DIVISIONS

Region 1

Boston, MA 617/565-3800
Maine, Vermont, New Hampshire,
Connecticut, Massachusetts, Rhode Island

Region 2

New York, NY 212/264-2301
New York, New Jersey, Puerto Rico, U.S.
Virgin Islands

Region 3

Philadelphia, PA 215/597-9390
Pennsylvania, Delaware, Virginia, West
Virginia, Maryland, District of Columbia

Region 4

Atlanta, GA 404/347-3043
Georgia, Florida, Alabama, North Carolina,
South Carolina, Kentucky Tennessee,
Mississippi

Region 5

Chicago, IL 312/353-2212
Illinois, Indiana, Michigan, Minnesota, Ohio,
Wisconsin

Region 6

Dallas, TX 214/655-7200
Texas, Arkansas, Oklahoma, Louisiana, New
Mexico

Region 7

Kansas City, MO 913/551-7020
Nebraska, Iowa, Kansas, Missouri

Region 8

Denver, CO 303/293-1438
Colorado, Utah, Wyoming, Montana, North
Dakota, South Dakota

Region 9

San Francisco, CA 414/744-1219
California, Arizona, Nevada, Hawaii,
American Samoa, Guam, Trust Territories of
the Pacific

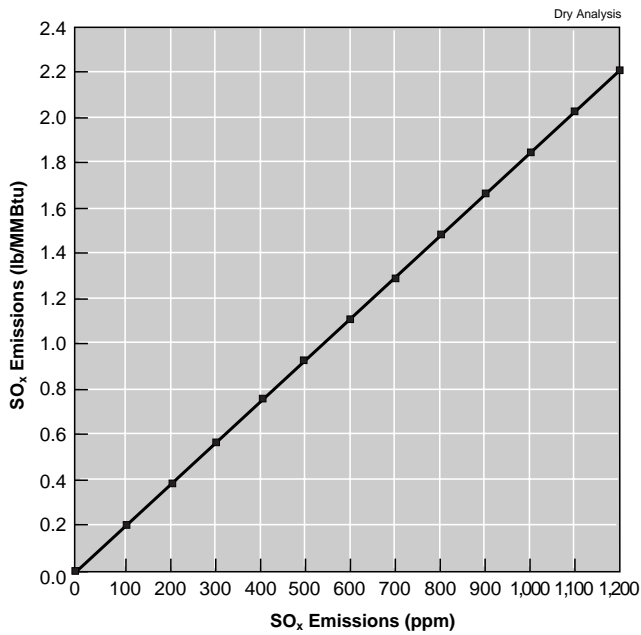
Region 10

Seattle, WA 206/422-4152
Washington, Oregon, Idaho, Alaska

ACRONYMS/DEFINITIONS

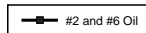
- ABMA** American Boiler Manufacturer's Association
A group of manufacturer's representing the boiler industry of which Cleaver-Brooks is a member
- APCD** Air Pollution Control District
Usually refers to a local air quality agency controlling pollution in a given district
- AQCR** Air Quality Control Region
Generally refers to one of the ten EPA regional offices throughout the U.S.
- AQMD** Air Quality Management District
Refers to an area or region where air quality is regulated by a local agency
- ARAC** Acid Rain Advisory Committee
A committee established by the EPA to focus efforts on the various aspects of Title IV (Acid Deposition Control) of the Clean Air Act
- ARB** Air Resource Board
An air quality agency usually responsible for pollution control at the state level
- BACT** Best Available Control Technology
An emission limitation based on the maximum degree of reduction, which the permitting authority has determined is achievable and cost effective
- BARCT** Best Available Retrofit Control Technology
A retrofit equipment emission limitation based on the BACT principles - but developed for retrofitting existing equipment
- CEM** Continuous Emission Monitoring
An emission monitoring system used for measuring emission levels without interruption - required in many local districts and NSPS for certain applications
- CFR** Code of Federal Regulations
A codification of the rules published in the *Federal Register* by the departments and agencies of the Federal Government
- EPA** Environmental Protection Agency
A federal agency responsible for pollution control at the national level
- ESP** Electrostatic Precipitators
Emission control equipment used to control particulate matter on large utility boilers
- FGD** Flue Gas Desulfurization
Emission control method used to control sulfur dioxide emissions
- FGR** Flue Gas Recirculation
NO_x emission control technique - involves returning a portion of the flue gases to the combustion zone
- LAER** Lowest Achievable Emission Rate
The most stringent emission limitation contained in any SIP or achieved in practice for a given class of equipment
- MACT** Maximum Available Control Technology
Emission standard requiring the maximum degree of emission reduction that has been demonstrated achievable
- NAAQS** National Ambient Air Quality Standards
EPA established air quality standards for ambient outdoor emission levels
- NESHAP** National Emission Standards for Hazardous Air Pollutants
Standards established by the EPA for regulation of air toxins
- NSPS** New Source Performance Standards
Regulations established by the EPA for emissions from equipment, including boilers. Many state regulations are more stringent than the NSPS
- NSR** New Source Review
A review performed during the permitting process for a new major installation in a nonattainment area
- PSD** Prevention of Significant Deterioration
A review performed during the permitting process for a new major installation in an attainment area
- RACT** Reasonably Available Control Technology
A set of recommended levels of emission controls applicable to specific sources or categories located in nonattainment areas
- SCAQMD** South Coast Air Quality Management District
The air pollution control agency for the Los Angeles, CA area - emission regulations enacted in this district generally set the trends for other local regulations throughout the U.S.
- SCR** Selective Catalytic Reduction
A NO_x control method in which ammonia or urea is injected into the exhaust gases in the presence of a catalyst
- SIP** State Implementation Plan
An EPA approved emission control plan to attain or maintain NAAQS
- SNCR** Selective Non-Catalytic Reduction
A NO_x control method where ammonia or urea is injected into the stack and where the exhaust gases are approximately 1600 degrees Fahrenheit

SO_x Emissions Conversion Curves 15% Excess Air

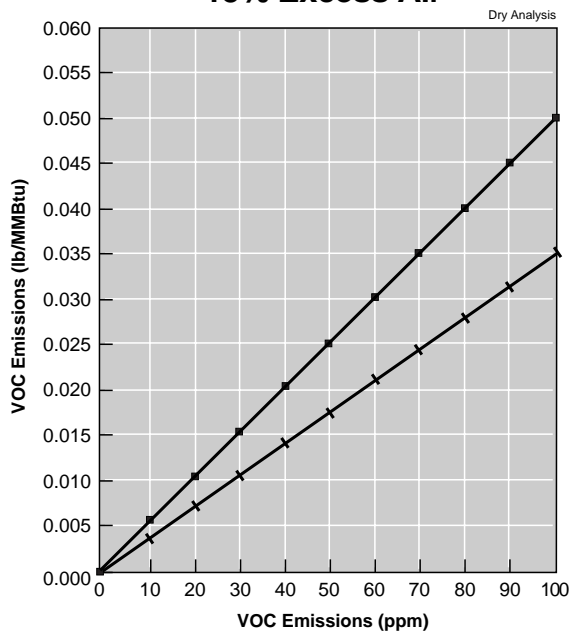


Conversion Equations

#2 and #6 Oil:
 $\text{ppm} = (\text{lb/MMBtu}) * 540$
 $\text{lb/MMBtu} = (\text{ppm}) / 540$



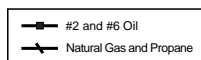
Volatile Organic Compound Conversion Curves 15% Excess Air



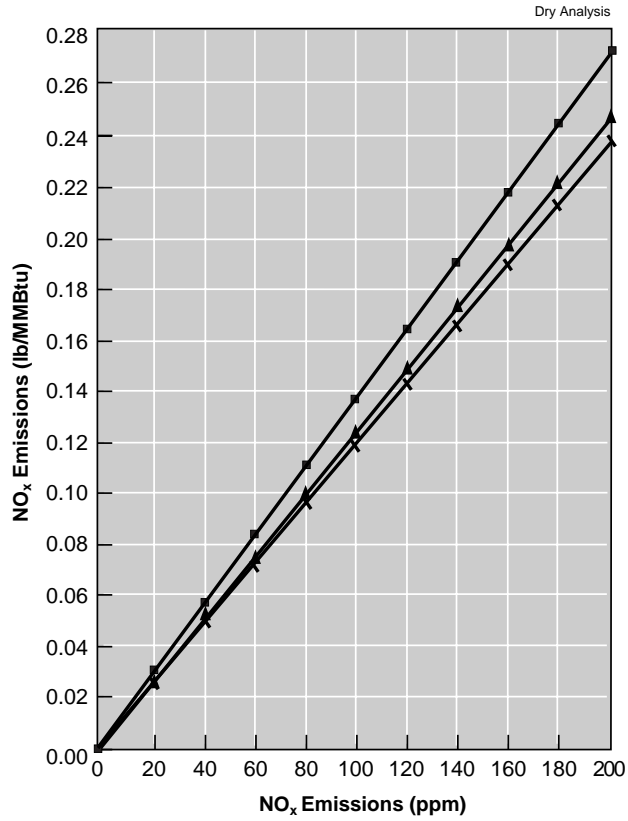
Conversion Equations

#2 and #6 Oil:
 $\text{ppm} = (\text{lb/MMBtu}) * 2000$
 $\text{lb/MMBtu} = (\text{ppm}) / 2000$

Natural Gas and Propane:
 $\text{ppm} = (\text{lb/MMBtu}) * 2500$
 $\text{lb/MMBtu} = (\text{ppm}) / 2500$

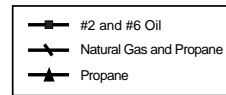


NO_x Emissions Conversion Curves 15% Excess Air

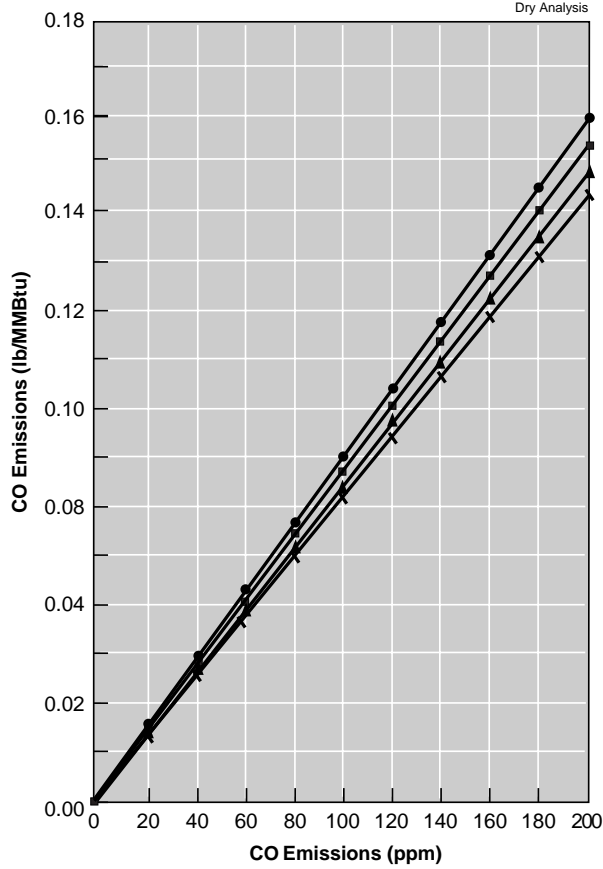


Conversion Equations

#2 and #6 Oil:	Natural Gas:
ppm = (lb/MMBtu)*750	ppm = (lb/MMBtu)*850
lb/MMBtu = (ppm)/750	lb/MMBtu = (ppm)/850
Propane:	
ppm = (lb/MMBtu)*810	
lb/MMBtu = (ppm)/810	

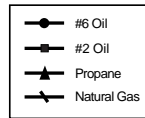


CO Emissions Conversion Curves 15% Excess Air



Conversion Equations

#2 Oil:	Natural Gas:
ppm = (lb/MMBtu)*1290	ppm = (lb/MMBtu)*1370
lb/MMBtu = (ppm)/1290	lb/MMBtu = (ppm)/1370
#6 Oil:	Propane:
ppm = (lb/MMBtu)*1260	ppm = (lb/MMBtu)*1340
lb/MMBtu = (ppm)/1260	lb/MMBtu = (ppm)/1340



Correcting Emission Readings to 3% Oxygen

$$\text{ppm (@3\%)} = \frac{21 - 3}{21 - \text{O}_2 \text{ (actual)}} \times \text{ppm (actual)}$$

Example: What is the NO_x level corrected to 3% oxygen for a measured level of 12 ppm at 7.1% oxygen?

$$\text{ppm (@3\%)} = \frac{21 - 3}{21 - 7.1} \times 12 = 15.5 \text{ ppm NO}_x$$



CALCULATION OF ANNUAL EMISSIONS FOR INDUSTRIAL BOILERS

Many provisions of the 1990 Clean Air Act Amendments assess the impact of pollution sources based on the potential annual emissions (usually expressed as tons per year, or tpy). When addressing industrial boilers, the potential annual emissions of NO_x are of concern and frequently must be calculated. Following is an example of how to calculate the potential annual NO_x emissions for industrial boilers.

To determine the annual NO_x emissions for an industrial boiler, three items must be known:

1. The NO_x emission factor for the boiler.
2. The maximum rated input for the boiler.
3. The maximum allowable hours of operation for the boiler.

Once the information above is obtained, the following equation can be used to determine annual emissions.

$$\begin{matrix} \text{Boiler} \\ \text{Input} \end{matrix} \times \begin{matrix} \text{Emission} \\ \text{Factor} \end{matrix} \times \begin{matrix} \text{Annual Hours} \\ \text{of Operation} \end{matrix} = \begin{matrix} \text{Total Annual} \\ \text{Emissions} \end{matrix}$$

For example, the calculation of the total annual NO_x emissions for an 800 hp boiler operating 24 hours/day, 365 days/year and having a NO_x level of 110 ppm would be as follows.

- Boiler Input = 33.5 MMBtu/hr (Based on 80% Efficiency)
- Emission Factor = 0.13 lb/MMBtu (110 ppm = 0.13 lb/MMBtu)
- Annual Hours of Operation = 8760 hours/year (24 hours/day x 365 days/year)

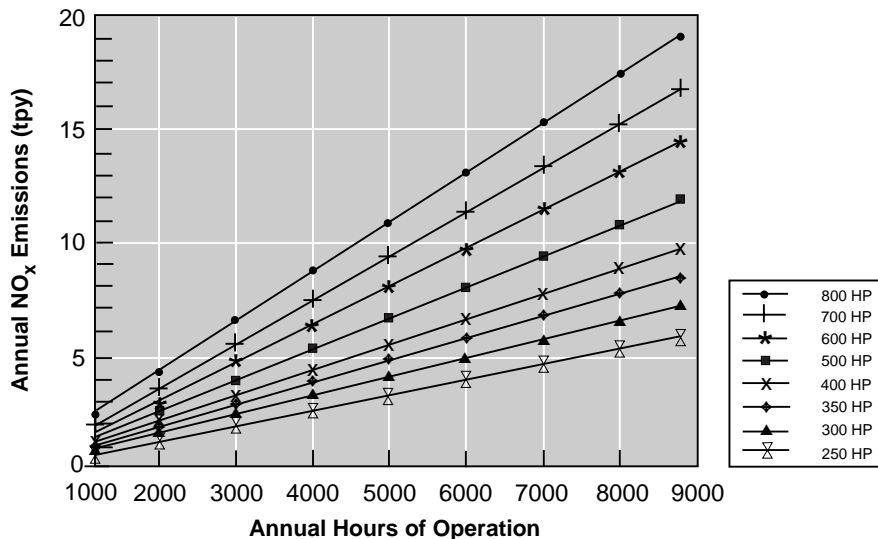
Substituting this data into the equation above yields:

$$\frac{0.13 \text{ lb NO}_x}{\text{MMBtu}} \times \frac{33.5 \text{ MMBtu}}{\text{hr}} \times \frac{8760 \text{ hrs}}{\text{year}} \times \frac{1 \text{ ton}}{2000\text{lb}} = 19.1 \text{ tpy NO}_x$$

The annual NO_x emissions for this specific boiler is 19.1 tpy.

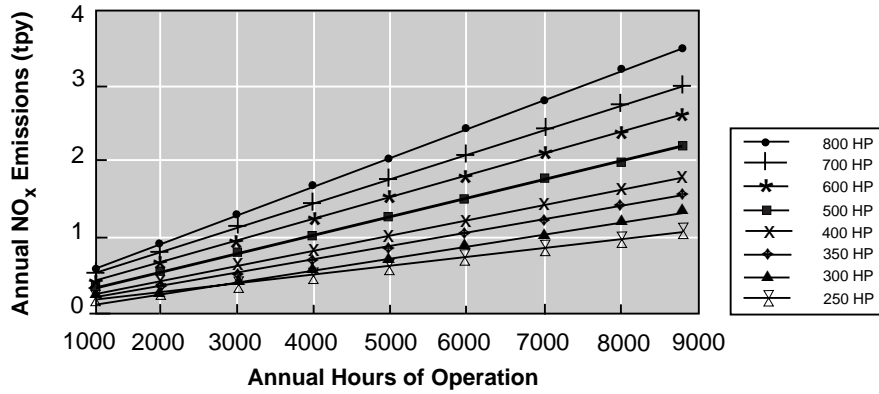
The following graphs indicate the annual NO_x emissions for boiler sizes 250-800 horsepower firing natural gas at maximum input operating 24 hours/day, 365 days/year. There are for NO_x emission levels of 110, 60, 30, 25, and 20 ppm.

**Annual NO_x Emissions for
250-800 Horsepower Boilers
NO_x = 110 ppm***



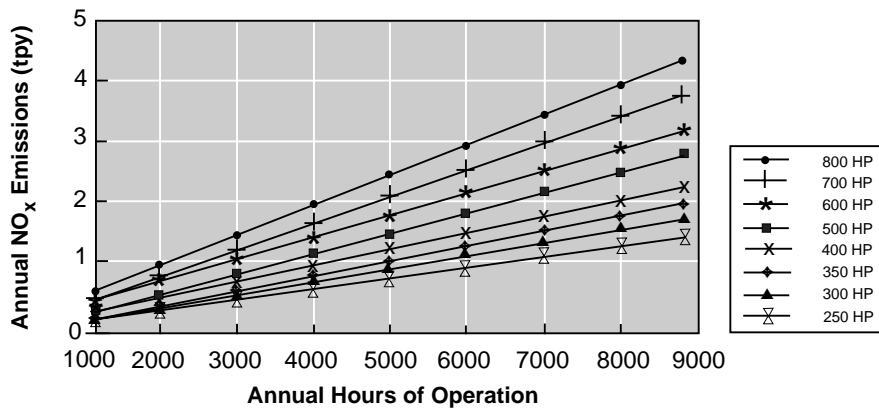
Efficiency = 80%
*ppm corrected to 3% oxygen

Annual NO_x Emissions for 250-800 Horsepower Boilers NO_x = 20 ppm*



Efficiency = 80%
*ppm corrected to 3% oxygen

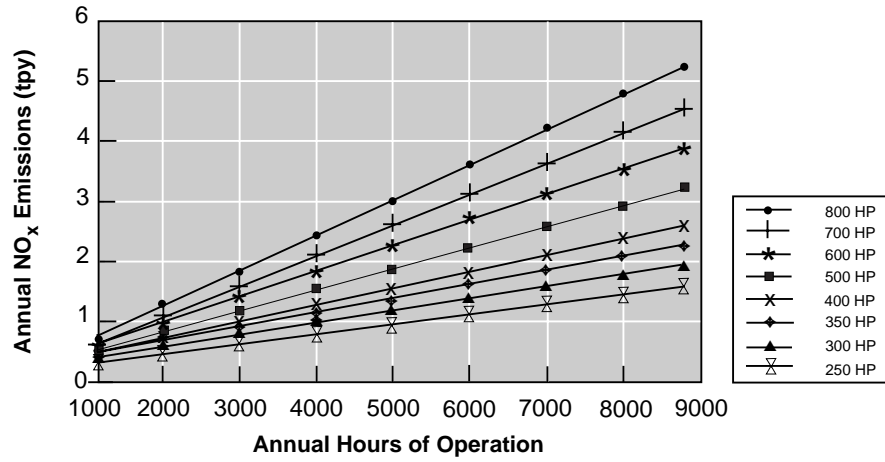
Annual NO_x Emissions for 250-800 Horsepower Boilers NO_x = 25 ppm*



Efficiency = 80%
*ppm corrected to 3% oxygen

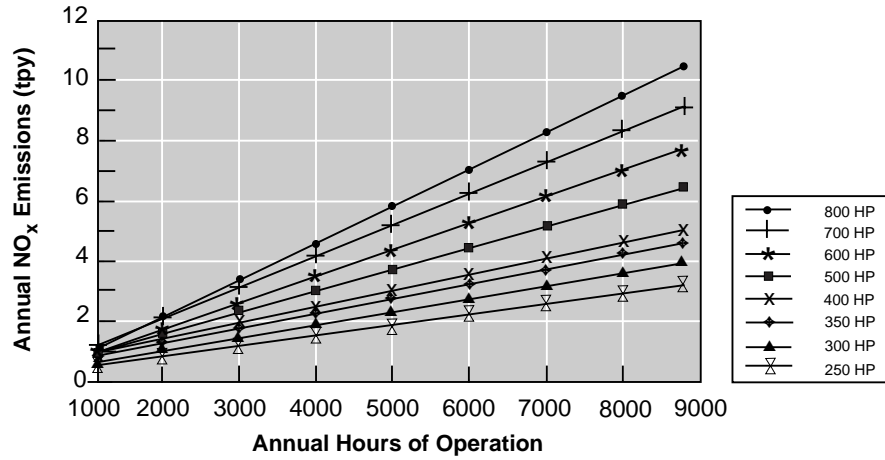


Annual NO_x Emissions for 250-800 Horsepower Boilers NO_x = 30 ppm*



Efficiency = 80%
*ppm corrected to 3% oxygen

Annual NO_x Emissions for 250-800 Horsepower Boilers NO_x = 60 ppm*



Efficiency = 80%
*ppm corrected to 3% oxygen

NOTES



**Cleaver-Brooks is pleased to present the Boiler Emissions Reference Guide.
Cleaner air and cleaner fuels must be a goal for all of us.
For more information on emissions,
please contact your local Cleaver-Brooks authorized Representative.**



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