# 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.

A word of caution...

The information conveyed in the appendix and figures 2, 3, 4 & 5 are dynamic and may change based on the latest requirements issued by the EPA. Visiting an EPA site such as <epa.gov> will assist you in keeping abreast of the latest requirements.
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 (NOx and SOx)
- 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.

1997 Changes to the Clean Air Act

EPA recently reviewed the current air quality standards for ground-level ozone (commonly known as smog) and particulate matter (or PM). Based on new scientific evidence, revisions have been made to both standards. At the same time, EPA is developing new programs to control regional haze, which is largely caused by particulate matter and mercury.

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 seven ‘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.

**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 (NOx) in the presence of sunlight. NOx 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 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 PM$_{10}$, NO$_x$, SO$_x$, and lead. Areas violating the NAAQS for PM$_{10}$ are subclassified as serious or moderate. There are no subclassifications for NO$_x$, SO$_x$, and lead.

A listing of the ozone, CO, PM$_{10}$, and SO$_2$ 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.

**Offsets**

If an owner or operator of a major source wants to release more of a criteria air pollutant, an offset (a reduction of the criteria air pollutant by an amount somewhat greater than the planned increase) must be obtained somewhere else, so that permit requirements are met and the nonattainment area keeps moving toward attainment. The company must also install tight pollution controls. An increase in a criteria air pollutant can be offset with a reduction of the pollutant from some other stack at the same plant or at another plant owned by the same or some other company in the nonattainment area. Since total pollution will continue to go down, trading offsets among companies is allowed. This is one of the market approaches to cleaning up air pollution in the Clean Air Act.

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. 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.

**State Implementation Plans**

**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\textsubscript{x}, SO\textsubscript{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\textsubscript{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 5.

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.

**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 appraised 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\textsubscript{x} emissions. If the total NO\textsubscript{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
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.
NO\textsubscript{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 6.

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\textsubscript{x} level of 57 tons per year (based on a NO\textsubscript{x} level of 0.13 lb/MMBtu). Referring to major source trigger levels specified in Figure 6, 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\textsubscript{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

An Emission Alphabet

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

- Maximum Achievable Control Technology (MACT)
- 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.

Maximum Achievable Control Technology

Maximum Achievable Control Technology (MACT) 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. MACT evaluates the optimum effectiveness of a control technology against the

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**Figure 6**

Ozone Nonattainment Areas

Major Source Levels

<table>
<thead>
<tr>
<th>Ozone Nonattainment Status</th>
<th>Annual NO\textsubscript{x} Emissions (tpy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Attainment</td>
<td>0</td>
</tr>
<tr>
<td>Marginal</td>
<td>50</td>
</tr>
<tr>
<td>Moderate</td>
<td>100</td>
</tr>
<tr>
<td>Serious</td>
<td>150</td>
</tr>
<tr>
<td>Severe</td>
<td>200</td>
</tr>
<tr>
<td>Extreme</td>
<td>250</td>
</tr>
</tbody>
</table>
extremity of the environmental condition. In establishing MACT for a source, cost is not the only the driving factor. When cost is a consideration, the equipment (cost) is compared to the annual emission reductions in order to determine a figure in dollars per ton of pollutant removed (see Figure 7). The comparison is called the cost effectiveness of the technology.

The regulations requiring MACT 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 MACT 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\textsubscript{x} control technologies that result in a cost effectiveness figure between $3,000-$10,000 per ton of NO\textsubscript{x} removed. In severe and extreme ozone nonattainment areas, the required cost effectiveness can be as high as $24,500 per ton of NO\textsubscript{x} controlled.

### 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 MACT is used on new or modified sources. The cost requirements for RACT are less and are 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\textsubscript{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

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**MACT/RACT Cost Effectiveness**

**Annualized Costs of Control Equipment**

<table>
<thead>
<tr>
<th>Uncontrolled Emission Rate</th>
<th>—</th>
<th>Controlled Emission Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Example:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Uncontrolled Emission Rate = 18 tons/year</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Controlled Emission Rate = 4 tons/year</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annualized Cost of Emission</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Control Method             = $70,000/year</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| \[
\frac{\$70,000}{18 \text{ tpy} - 4 \text{ tpy}} = \$5,000/\text{ton of NO}_x \text{ removed}
\] |   |                          |

* considering hardware, installation, operating and maintenance costs

*figure 7*
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 NOx in itself, is harmful to humans, the main reason NOx 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 NOx 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 (NO2), collectively referred to as NOx. The majority of NOx produced during combustion is NO (95%). Once emitted into the atmosphere, NO reacts to form NO2. It is NO2 that reacts with other pollutants to form ozone.

The contribution from different NOx sources to the total NOx level varies among metropolitan areas. In general, the contribution of mobile sources to the total NOx level ranges from 60 to 80 percent. For stationary sources, it ranges between 20 and 40 percent. A significant portion of the NOx from stationary sources can be attributed to residential, commercial, and industrial sources, including industrial boilers. In industrial boilers, NOx is primarily formed in two ways; thermal NOx and fuel NOx.

Thermal NOx

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

Fuel NOx

Fuel NOx 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 NOx can account for up to 50% of the total NOx emissions.

NOx 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 NOx formation are excess air level and combustion air temperature.

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

NOx Control Technologies

NOx controls can be classified into two types; post combustion methods and combustion control techniques. Post combustion methods address NOx emissions after formation while combustion control techniques prevent the formation of NOx 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 NOx control methods.
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\textsubscript{x} control. For example, when firing natural gas, low excess air firing typically reduces NO\textsubscript{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\textsubscript{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\textsubscript{x} in the exhaust gases into water and atmospheric nitrogen. Selective non-catalytic reduction reduces NO\textsubscript{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\textsubscript{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\textsubscript{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\textsubscript{x} emission by limiting the amount of NO\textsubscript{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\textsubscript{x} controls.
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\textsubscript{x} formation in a boiler is the excess air levels. High excess air levels (>45%) may result in increased NO\textsubscript{x} formation because the excess nitrogen and oxygen in the combustion air entering the flame will combine to form thermal NO\textsubscript{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\textsubscript{x} reductions of 5-10% when firing natural gas.

Low Nitrogen Fuel Oil

When firing fuel oils, NO\textsubscript{x} formed by fuel-bound nitrogen can account for 20-50% of the total NO\textsubscript{x} level. Utilizing fuel oils with lower nitrogen contents results in lower NO\textsubscript{x} levels. One method to reduce NO\textsubscript{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\textsubscript{x} oil is fired in firetube boilers utilizing flue gas recirculation, NO\textsubscript{x} reductions of 60%-70% over NO\textsubscript{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\textsubscript{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\textsubscript{x} formation which, in turn, results in lower overall NO\textsubscript{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\textsubscript{x} reduction methods, such as flue gas recirculation. If burner modifications are utilized exclusively to achieve low NO\textsubscript{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\textsubscript{x} control when selecting NO\textsubscript{x} control technologies (see Side Bar, this page).

**Water/Steam Injection**

Water or steam injection can be utilized to reduce NO\textsubscript{x} levels. By introducing water or steam into the flame, flame temperatures are reduced, thereby lowering thermal NO\textsubscript{x} formation and overall NO\textsubscript{x} levels. Water or steam injection can reduce NO\textsubscript{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\textsubscript{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\textsubscript{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\textsubscript{x} formation. It is currently the most effective and popular low NO\textsubscript{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\textsubscript{x} reduction with FGR; practically, there is a physical, feasible limit. The limit of NO\textsubscript{x} reduction varies for different fuels - 90% for natural gas and 25-30% for standard fuel oils.

The current trends with low NO\textsubscript{x} technologies are to design the boiler and low NO\textsubscript{x} equipment as a package. Designing as a true package allows the NO\textsubscript{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\textsubscript{x} technology as a package with the boiler, the effects of the low NO\textsubscript{x} technology on boiler operating parameters (turndown, capacity, efficiency, and CO levels) can be addressed and minimized.

### Side Bar:

**CHOOSING THE BEST NO\textsubscript{x} TECHNOLOGY FOR THE JOB**

What effect does NO\textsubscript{x} control technology ultimately have on a boiler’s performance? Certain NO\textsubscript{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\textsubscript{x} control technology.
**TURODOWN**

Choosing a low NOx technology that sacrifices turndown can have many adverse effects on the boiler. When selecting NOx 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 NOx control, always consider the burner's turndown capability.

**CAPACITY**

When selecting the best NOx control, capacity and turndown should be considered together because some NOx control technologies require boiler derating in order to achieve guaranteed NOx reductions. For example, flame shaping (primarily enlarging the flame to produce a lower flame temperature - thus lower NOx 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 NOx control, capacity and turndown should be considered together for proper boiler selection and to meet overall system load requirements.

**EFFICIENCY**

Some low NOx 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 loss can be greatly reduced or eliminated by the boiler/burner 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 NOx control technology, remember, it is not necessary to sacrifice efficiency for NOx 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). NOx 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. NOx 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 NOx 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 NOx control technologies used on industrial and commercial boilers reduce NOx 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 NOx 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 NOx 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 NOx 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 NOx control technology that results in the greatest NOx 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 NOx technologies provide NOx reductions without affecting total boiler performance.

**Sulfur Compounds (SOx)**

The primary reason sulfur compounds, or SOx, 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 SOx (sulfur oxides). The level of SOx emitted depends directly on the sulfur content of the fuel (see Figure 11). The level of SOx 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 SOx emissions.

Historically, SOx 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 SOx emissions. Today, dispersion alone is not enough to meet more stringent SOx emission requirements; reduction methods must also be employed.

Methods of SOx 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 SOx 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. SOx emission reductions of 90-95% can be achieved through FGD. Fuel desulfurization and FGD are primarily used for reducing SOx 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 SOx reduction. Because SOx emissions primarily depend on the sulfur content of the fuel, burning fuels containing a minimal amount of sulfur (distillate oil) can achieve SOx reductions, without the need to install and maintain expensive equipment.

**Carbon Monoxide (CO)**

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 compromised furnace seal. 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 (PM)**

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 asphalts. 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 (O₃)**

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 (NOₓ) 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 NOₓ, methods of ozone reduction focus on the control of these two pollutants. Recent studies show that reducing NOₓ 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 NOx 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.
ALABAMA (Region IV)
  Birmingham, AL (Subpart 1)
    Jefferson Co [m*]
    Shelby Co [m*]

ARIZONA (Region IX)
  Phoenix-Mesa, AZ (Subpart 1)
    Maricopa Co (P) [n*]
    Pinal Co (P) [*]

ARKANSAS (Region VI)
  Memphis, TN-AR (Marginal)
    Crittenden Co

CALIFORNIA (Region IX)
  Amador and Calaveras Cos (Central Mtn), CA (Subpart 1)
    Amador Co
    Calaveras Co
  Chico, CA (Subpart 1)
    Butte Co [n*]
  Imperial Co, CA (Marginal)
    Imperial Co [n*]
  Kern Co (Eastern Kern), CA (Subpart 1)
    Kern Co (P) [m*]
  Los Angeles South Coast Air Basin, CA (Severe 17)
    Los Angeles Co (P) [n*]
    Orange Co [n*]
    Riverside Co (P) [n*]
    San Bernardino Co (P) [n*]
  Los Angeles-San Bernardino Cos (W Mojave), CA (Moderate)
    Los Angeles Co (P) [n*]
    San Bernardino Co (P) [n*]
  Mariposa and Tuolumne Cos (Southern Mtn), CA (Subpart 1)
    Mariposa Co
    Tuolumne Co
  Nevada Co. (Western Part), CA (Subpart 1)
    Nevada Co (P)
  Riverside Co, (Coachella Valley), CA (Serious)
    Riverside Co (P) [n*]
  Sacramento Metro, CA (Serious)
    El Dorado Co (P) [n*]
    Placer Co (P) [n*]
    Sacramento Co [n*]
    Solano Co (P) [n*]
    Sutter Co (P) [n*]
    Yolo Co [n*]
  San Diego, CA (Subpart 1)
    San Diego Co (P) [m*]

San Francisco Bay Area, CA (Marginal)
  Alameda Co [n*]
  Contra Costa Co [n*]
  Marin Co [n*]
  Napa Co [n*]
  San Francisco Co [n*]
  San Mateo Co [n*]
  Santa Clara Co [n*]
  Solano Co (P) [n*]
  Sonoma Co (P) [n*]

San Joaquin Valley, CA (Serious)
  Fresno Co [n*]
  Kern Co (P) [n*]
  Kings Co [n*]
  Madera Co [n*]
  Merced Co [n*]
  San Joaquin Co [n*]
  Stanislaus Co [n*]
  Tulare Co [n*]

Sutter Co (Sutter Buttes), CA (Subpart 1)
  Sutter Co (P) [n*]

Ventura Co, CA (Moderate)
  Ventura Co (P) [n*]

COLORADO (Region VIII)
  Denver-Boulder-Greeley-Ft Collins-Love., CO (Subpart 1 EAC)
    Adams Co [m*]
    Arapahoe Co [m*]
    Boulder Co [m*]
    Broomfield Co [m*]
    Denver Co [m*]
    Douglas Co [m*]
    Jefferson Co [m*]
    Larimer Co (P) [*]
    Weld Co (P) [*]

CONNECTICUT (Region I)
  Greater Connecticut, CT (Moderate)
    Hartford Co [n*]
    Litchfield Co [n*]
    New London Co [n*]
    Tolland Co [n*]
    Windham Co [n*]

New York-N. New Jersey-Long Island, NY-NJ-CT (Moderate)
    Fairfield Co [n*]
    Middlesex Co [n*]
    New Haven Co [n*]

DELAWARE (Region III)
  Philadelphia-Wilmington-Atlantic Ci, PA-NJ-MD-DE (Moderate)
    Kent Co [n*]
    New Castle Co [n*]
    Sussex Co [n*]
CLASSIFIED OZONE NONATTAINMENT AREAS (DATE ???)

DISTRICT OF COLUMBIA (Region III)

Washington, DC-MD-VA (Moderate)
Entire District [n*]

GEORGIA (Region IV)

Atlanta, GA (Marginal)
Barrow Co
Bartow Co
Carroll Co
Cherokee Co [n*]
Clayton Co [n*]
Cobb Co [n*]
Coweta Co [n*]
DeKalb Co [n*]
Douglas Co [n*]
Fayette Co [n*]
Forsyth Co [n*]
Fulton Co [n*]
Gwinnett Co [n*]
Hall Co
Henry Co [n*]
Newton Co
Paulding Co [n*]
Rockdale Co [n*]
Spalding Co
Walton Co

Chattanooga, TN-GA (Subpart 1 EAC)
Catawba Co

Macon, GA (Subpart 1)
Bibb Co
Monroe Co (P)

Murray Co (Chattahoochee Nat Forest), GA (Subpart 1)
Murray Co (P)

ILLINOIS (Region V)

Chicago-Gary-Lake County, IL-IN (Moderate)
Cook Co [n*]
DuPage Co [n*]
Grundy Co (P) [n*]
Aux Sable Township,
Goose Lake Township
Kane Co [n*]
Kendall Co (P) [n*]
Oswego Township
Lake Co [n*]
McHenry Co [n*]
Will Co [n*]

St Louis, MO-IL (Moderate)
Jersey Co [m*]
Madison Co [m*]
Monroe Co [m*]
St Clair Co [m*]

INDIANA (Region V)

Chicago-Gary-Lake County, IL-IN (Moderate)
Lake Co [n*]
Porter Co [n*]

KENTUCKY (Region IV)

Cincinnati-Hamilton, OH-KY-IN (Subpart 1)
Dearborn Co (P)

Evansville, IN (Subpart 1)
Vanderburgh Co [m*]
Warrick Co

Fort Wayne, IN (Subpart 1)
Allen Co

Greene Co, IN (Subpart 1)
Greene Co

Indianapolis, IN (Subpart 1)
Boone Co
Hancock Co
Hendricks Co
Johnson Co
Madison Co
Marion Co [m*]
Morgan Co
Shelby Co

Jackson Co, IN (Subpart 1)
Jackson Co

La Porte, IN (Marginal)
La Porte Co

Louisville, KY-IN (Subpart 1)
Clark Co [m*]
Floyd Co [m*]

Muncie, IN (Subpart 1)
Delaware Co

South Bend-Elkhart, IN (Subpart 1)
Elkhart Co [m*]
St Joseph Co [m*]

Terre Haute, IN (Subpart 1)
Vigo Co

LOUISIANA (Region VI)

Baton Rouge, LA (Marginal)
Ascension Par [n*]
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</tr>
<tr>
<td>Baltimore Co</td>
<td>Ottawa Co</td>
</tr>
<tr>
<td>Carroll Co</td>
<td>Huron Co</td>
</tr>
<tr>
<td>Harford Co</td>
<td>Huron Co (Hagerstown), MD (Subpart 1 EAC)</td>
</tr>
<tr>
<td>Howard Co</td>
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<tr>
<td></td>
<td><strong>Kalamazoo-Battle Creek, MI (Subpart 1)</strong></td>
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<tr>
<td></td>
<td>Calhoun Co</td>
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<td>Van Buren Co</td>
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<tr>
<td><strong>Washington Co (Hagerstown), MD (Subpart 1 EAC)</strong></td>
<td><strong>Lansing-East Lansing, MI (Subpart 1)</strong></td>
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<td>Mason Co, MI (Subpart 1)</td>
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<tr>
<td><strong>Washington, DC-MD-VA (Moderate)</strong></td>
<td><strong>Muskegon, MI (Marginal)</strong></td>
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<tr>
<td>Calvert Co</td>
<td>Muskegon Co</td>
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<tr>
<td>Charles Co</td>
<td>[m]</td>
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<tr>
<td>Frederick Co</td>
<td>[m]</td>
</tr>
<tr>
<td>Montgomery Co</td>
<td>[m]</td>
</tr>
<tr>
<td>Prince George’s Co</td>
<td>[m]</td>
</tr>
<tr>
<td></td>
<td><strong>MISSOURI (Region VII)</strong></td>
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<tr>
<td></td>
<td>St Louis, MO-IL (Moderate)</td>
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<tr>
<td></td>
<td>Franklin Co</td>
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<td></td>
<td>Jefferson Co</td>
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<td></td>
<td>St Charles Co</td>
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<tr>
<td></td>
<td>St Louis</td>
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<td></td>
<td>St Louis Co</td>
</tr>
</tbody>
</table>
## Nevada (Region IX)

- **Las Vegas, NV (Subpart 1)**
  - Clark Co (P) [*]

## New Hampshire (Region I)

- **Boston-Manchester-Portland(SE), NH (Moderate)**
  - Hillsborough Co (P) [*]
  - Merrimack Co (P) [*]
  - Rockingham Co (P) [*]
  - Strafford Co (P) [*]

## New Jersey (Region II)

- **New York-N. New Jersey-Long Island, NY-NJ-CT (Moderate)**
  - Bergen Co [*]
  - Essex Co [*]
  - Hudson Co [*]
  - Hunterdon Co [*]
  - Middlesex Co [*]
  - Monmouth Co [*]
  - Morris Co [*]
  - Passaic Co [*]
  - Somerset Co [*]
  - Sussex Co [*]
  - Union Co [*]
  - Warren Co [*]

- **Philadelphia-Wilmington-Atlantic Ci, PA-NJ-MD-DE (Moderate)**
  - Atlantic Co [*]
  - Burlington Co [*]
  - Camden Co [*]
  - Cape May Co [*]
  - Cumberland Co [*]
  - Gloucester Co [*]
  - Mercer Co [*]
  - Ocean Co [*]
  - Salem Co [*]

## New York (Region II)

- **Albany-Schenectady-Troy, NY (Subpart 1)**
  - Albany Co [*]
  - Greene Co [*]
  - Montgomery Co [*]
  - Rensselaer Co [*]
  - Saratoga Co [*]
  - Schenectady Co [*]
  - Schoharie Co

- **Buffalo-Niagara Falls, NY (Subpart 1)**
  - Erie Co [*]
  - Niagara Co [*]

## New York-N. New Jersey-Long Island, NY-NJ-CT (Moderate)

- Bronx Co [*]
- Kings Co [*]
- Nassau Co [*]
- New York Co [*]
- Queens Co [*]
- Richmond Co [*]
- Rockland Co [*]
- Suffolk Co [*]
- Westchester Co [*]

## Poughkeepsie, NY (Moderate)

- Dutchess Co [*]
- Orange Co [*]
- Putnam Co [*]

## North Carolina (Region IV)

- **Charlotte-Gastonia-Rock Hill, NC-SC (Moderate)**
  - Cabarrus Co [*]
  - Gaston Co [*]
  - Iredell Co (P)
  - Davidson Township Coddle Creek Township
  - Mecklenburg Co [*]
  - Lincoln Co
  - Rowan Co
  - Union Co

- **Fayetteville, NC (Subpart 1 EAC)**
  - Cumberland Co

- **Greensboro-Winston Salem-High Point, NC (Marginal EAC)**
  - Alamance Co
  - Caswell Co
  - Davidson Co [*]
  - Davie Co [*]
  - Forsyth Co [*]
  - Guilford Co [*]
  - Randolph Co
  - Rockingham Co

- **Haywood and Swain Cos (Great Smoky NP), NC (Subpart 1)**
  - Haywood Co (P)
  - Swain Co (P)
Hickory-Morganton-Lenoir, NC  
(Subpart 1 EAC)

- Alexander Co
- Burke Co (P)
- Unifour Metropolitan Planning Organization Boundary
- Caldwell Co (P)
- Unifour Metropolitan Planning Organization Boundary
- Catawba Co

Raleigh-Durham-Chapel Hill, NC  
(Subpart 1)

- Chatham Co (P)
  - Baldwin Township, Center Township, New Hope Township, Williams Township
- Durham Co
- Franklin Co
- Granville Co
- Johnston Co
- Orange Co
- Person Co
- Wake Co

Rocky Mount, NC (Subpart 1)

- Edgecombe Co
- Nash Co

OHIO (Region V)

Canton-Massillon, OH (Subpart 1)

- Stark Co

Cincinnati-Hamilton, OH-KY-IN  
(Subpart 1)

- Butler Co
- Clermont Co
- Clinton Co
- Hamilton Co
- Warren Co

Cleveland-Akron-Lorain, OH (Moderate)

- Ashtabula Co
- Cuyahoga Co
- Geauga Co
- Lake Co
- Lorain Co
- Medina Co
- Portage Co
- Summit Co

Columbus, OH (Subpart 1)

- Delaware Co
- Fairfield Co
- Franklin Co
- Knox Co
- Licking Co
- Madison Co

Dayton-Springfield, OH (Subpart 1)

- Clark Co
- Greene Co
- Miami Co
- Montgomery Co

Lima, OH (Subpart 1)

- Allen Co

Parkerburg-Marietta, WV-OH  
(Subpart 1)

- Washington Co

Steubenville-Weirton, OH-WV  
(Subpart 1)

- Jefferson Co

Toledo, OH (Subpart 1)

- Lucas Co
- Wood Co

Wheeling, WV-OH (Subpart 1)

- Belmont Co

Youngstown-Warren-Sharon, OH-PA  
(Subpart 1)

- Columbiana Co
- Mahoning Co
- Trumbull Co

PENNSYLVANIA (Region III)

Allentown-Bethlehem-Easton, PA (Subpart 1)

- Carbon Co
- Lehigh Co
- Northampton Co

Altoona, PA (Subpart 1)

- Blair Co

Clearfield and Indiana Cos, PA  
(Subpart 1)

- Clearfield Co
- Indiana Co

Erie, PA (Subpart 1)

- Erie Co

Franklin Co, PA (Subpart 1)

- Franklin Co

Greene Co, PA (Subpart 1)

- Greene Co

Harrisburg-Lebanon-Carlisle, PA  
(Subpart 1)

- Cumberland Co
- Dauphin Co
- Lebanon Co
- Perry Co

Johnstown, PA (Subpart 1)

- Cambria Co

Lancaster, PA  
(Marginal)

- Lancaster Co
# Classified Ozone Nonattainment Areas (Date ???)

## Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE (Moderate)
- Bucks Co
- Chester Co
- Delaware Co
- Montgomery Co
- Philadelphia Co

## Pittsburgh-Beaver Valley, PA (Subpart 1)
- Allegheny Co
- Armstrong Co
- Beaver Co
- Butler Co
- Fayette Co
- Washington Co
- Westmoreland Co

## Reading, PA (Subpart 1)
- Berks Co

## Scranton-Wilkes-Barre, PA (Subpart 1)
- Lackawanna Co
- Luzerne Co
- Monroe Co
- Wyoming Co

## State College, PA (Subpart 1)
- Centre Co

## Tioga Co, PA (Subpart 1)
- Tioga Co

## York, PA (Subpart 1)
- Adams Co
- York Co

## Youngstown-Warren-Sharon, OH-PA (Subpart 1)
- Mercer Co

## Rhode Island (Region I)

### Providence (All RI), RI (Moderate)
- Bristol Co
- Kent Co
- Newport Co
- Providence Co
- Washington Co

## Tennessee (Region IV)

### Chattanooga, TN-GA (Subpart 1 EAC)
- Hamilton Co
- Meigs Co

### Clarksville-Hopkinsville, TN-KY (Subpart 1)
- Montgomery Co

### Johnson City-Kingsport-Bristol, TN (Subpart 1 EAC)
- Hawkins Co
- Sullivan Co

### Knoxville, TN (Subpart 1)
- Anderson Co
- Blount Co
- Cocke Co (P)
- (Great Smoky Mtn Park)
- Jefferson Co
- Knox Co
- Loudon Co
- Sevier Co

### Memphis, TN-AR (Marginal)
- Shelby Co

## Nashville, TN (Subpart 1 EAC)
- Davidson Co
- Rutherford Co
- Sumner Co
- Williamson Co
- Wilson Co

## Texas (Region VI)

### Beaumont-Port Arthur, TX (Marginal)
- Hardin Co
- Jefferson Co
- Orange Co

### Dallas-Fort Worth, TX (Moderate)
- Collin Co
- Dallas Co
- Denton Co
- Ellis Co
- Johnson Co
- Parker Co
- Rockwall Co
- Tarrant Co

### Houston-Galveston-Brazoria, TX (Moderate)
- Brazoria Co
- Chambers Co
- Fort Bend Co
- Galveston Co
- Harris Co
- Liberty Co
- Montgomery Co
- Waller Co

## South Carolina (Region IV)

### Charlotte-Gastonia-Rock Hill, NC-SC (Moderate)
- York Co (P)
- Portion along MPO lines

### Columbia, SC (Subpart 1 EAC)
- Lexington Co (P)
- Richland Co (P)

### Greenville-Spartanburg-Anderson, SC (Subpart 1 EAC)
- Anderson Co
- Greenville Co
- Spartanburg Co

### San Antonio, TX (Subpart 1 EAC)
- Bexar Co
- Comal Co
- Guadalupe Co
**VIRGINIA (Region III)**

**Frederick Co, VA (Subpart 1 EAC)**
- Frederick Co
- Winchester

**Fredericksburg, VA (Moderate)**
- Fredericksburg
- Spotsylvania Co
- Stafford

**Madison and Page Cos (Shenandoah NP), VA (Subpart 1)**
- Madison Co (P)
- Page Co (P)

**Norfolk-Virginia Beach-Newport News (HR), VA (Marginal)**
- Chesapeake
- Gloucester Co
- Hampton
- Isle Of Wight Co
- James City Co
- Newport News
- Norfolk
- Poquoson
- Portsmouth
- Suffolk
- Virginia Beach
- Williamsburg
- York Co

**Richmond-Petersburg, VA (Marginal)**
- Charles City Co
- Chesterfield Co
- Colonial Heights
- Hanover Co
- Henrico Co
- Hopewell
- Petersburg
- Prince George Co
- Richmond

**Roanoke, VA (Subpart 1 EAC)**
- Botetourt Co
- Roanoke
- Roanoke Co
- Salem

**Washington, DC-MD-VA (Moderate)**
- Alexandria
- Arlington Co
- Fairfax
- Fairfax Co
- Falls Church
- Loudoun Co
- Manassas
- Manassas Park
- Prince William Co

**Charleston, WV (Subpart 1)**
- Kanawha Co
- Putnam Co

**Huntington-Ashland, WV-KY (Subpart 1)**
- Cabell Co
- Wayne Co

**Parkersburg-Marietta, WV-OH (Subpart 1)**
- Wood Co

**Steubenville-Weirton, OH-WV (Subpart 1)**
- Brooke Co
- Hancock Co

**Wheeling, WV-OH (Subpart 1)**
- Marshall Co
- Ohio Co

**WISCONSIN (Region V)**

**Door Co, WI (Subpart 1)**
- Door Co

**Kewaunee Co, WI (Subpart 1)**
- Kewaunee Co

**Manitowoc Co, WI (Subpart 1)**
- Manitowoc Co

**Milwaukee-Racine, WI (Moderate)**
- Kenosha Co
- Milwaukee Co
- Ozaukee Co
- Racine Co
- Washington Co
- Waukesha Co

**Sheboygan, WI (Moderate)**
- Sheboygan Co

**Key**

- \( n \) = county in current 1-hr Ozone Non-attainment area
- \( m \) = county in current 1-hr Ozone Maintenance area
- \( P \) = a portion of the county is located within the area
- * = county in 1-Hr Ozone, CO or PM-10 non-attainment or maintenance area

**WEST VIRGINIA (Region III)**

**Berkeley and Jefferson Counties, WV (Subpart 1 EAC)**
- Berkeley Co
- Jefferson Co
### Classified Carbon Monoxide Nonattainment Areas (January 1994)

<table>
<thead>
<tr>
<th>State</th>
<th>City or Region</th>
<th>Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alaska</td>
<td>Anchorage</td>
<td>Moderate &gt; 12.7 ppm</td>
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<tr>
<td></td>
<td>Fairbanks</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Arizona</td>
<td>Phoenix</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>California</td>
<td>Chico</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Fresno</td>
<td>Moderate &gt; 12.7 ppm</td>
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<tr>
<td></td>
<td>Lake Tahoe South Shore</td>
<td>Moderate ≤ 12.7 ppm</td>
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<td></td>
<td>Los Angeles South Coast Air Basin</td>
<td>Serious</td>
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<tr>
<td></td>
<td>Modesto</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Sacramento</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>San Diego</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>San Francisco – Oakland – San Jose</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Colorado</td>
<td>Colorado Springs</td>
<td>Moderate ≤ 12.7 ppm</td>
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<tr>
<td></td>
<td>Denver – Boulder</td>
<td>Moderate &gt; 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Fort Collins</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Longmont</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Connecticut</td>
<td>Hartford – New Britain - Middletown</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>New York – N. New Jersey – Long Island</td>
<td>Moderate &gt; 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Parts of Fairfield and Litchfield Counties</td>
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</tr>
<tr>
<td>District of Columbia</td>
<td>Entire District</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Maryland</td>
<td>Baltimore</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Washington D.C.</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Montgomery and Prince George’s Counties</td>
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</tr>
<tr>
<td>Massachusetts</td>
<td>Boston</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Minnesota</td>
<td>Duluth</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
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<td>Minneapolis – St. Paul</td>
<td>Moderate ≤ 12.7 ppm</td>
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<tr>
<td>Montana</td>
<td>Missoula</td>
<td>Moderate ≤ 12.7 ppm</td>
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<tr>
<td>Nevada</td>
<td>Las Vegas</td>
<td>Moderate &gt; 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Reno</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>New Jersey</td>
<td>N. New Jersey – New York – Long Island</td>
<td>Moderate &gt; 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Philadelphia</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Albuquerque</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Syracuse</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>North Carolina</td>
<td>Raleigh – Durham</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Winston – Salem</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Ohio</td>
<td>Cleveland</td>
<td>Moderate ≤ 12.7 ppm</td>
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<tr>
<td>Oregon</td>
<td>Grants Pass</td>
<td>Moderate ≤ 12.7 ppm</td>
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<td>Klamath Falls</td>
<td>Moderate ≤ 12.7 ppm</td>
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<td></td>
<td>Medford</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Portland – Vancouver</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>Philadelphia – Camden County</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Tennessee</td>
<td>Memphis</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Texas</td>
<td>El Paso</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td>Utah</td>
<td>Ogden</td>
<td>Moderate ≤ 12.7 ppm</td>
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<tr>
<td></td>
<td>Provo</td>
<td>Moderate &gt; 12.7 ppm</td>
</tr>
<tr>
<td>Virginia</td>
<td>Washington D.C.</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Alexandria City, Arlington County</td>
<td></td>
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<tr>
<td>Washington</td>
<td>Vancouver – Portland</td>
<td>Moderate ≤ 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Seattle – Tacoma</td>
<td>Moderate &gt; 12.7 ppm</td>
</tr>
<tr>
<td></td>
<td>Spokane</td>
<td>Moderate &gt; 12.7 ppm</td>
</tr>
</tbody>
</table>

**NOTE:** If there is no listing for a state, there are no classified carbon monoxide nonattainment areas located in the state.
CLASSIFIED PM$_{10}$ NONATTAINMENT AREAS (JANUARY 1994)

**Arizona**
- Ajo
- Douglas
- Hayden/Miami
- Nogales
- 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 Township)
   Jefferson Co. (part)
   Lake Co. (part)
   Lorrain Co. (part)
   Lucas Co. (part)
   Morgan Co. (Center Township)
   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.
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

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>ABMA</td>
<td>American Boiler Manufacturer's Association - A group of manufacturer's representing the boiler industry of which Cleaver-Brooks is a member</td>
</tr>
<tr>
<td>APCD</td>
<td>Air Pollution Control District - Usually refers to a local air quality agency controlling pollution in a given district</td>
</tr>
<tr>
<td>AQCR</td>
<td>Air Quality Control Region - Generally refers to one of the ten EPA regional offices throughout the U.S.</td>
</tr>
<tr>
<td>AQMD</td>
<td>Air Quality Management District - Refers to an area or region where air quality is regulated by a local agency</td>
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<tr>
<td>ARAC</td>
<td>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</td>
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<tr>
<td>ARB</td>
<td>Air Resource Board - An air quality agency usually responsible for pollution control at the state level</td>
</tr>
<tr>
<td>BACT</td>
<td>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</td>
</tr>
<tr>
<td>BARCT</td>
<td>Best Available Retrofit Control Technology - A retrofit equipment emission limitation based on the BACT principles - but developed for retrofitting existing equipment</td>
</tr>
<tr>
<td>CEM</td>
<td>Continuous Emission Monitoring - An emission monitoring system used for measuring emission levels without interruption - required in many local districts and NSPS for certain applications</td>
</tr>
<tr>
<td>EPA</td>
<td>Environmental Protection Agency - A federal agency responsible for pollution control at the national level</td>
</tr>
<tr>
<td>ESP</td>
<td>Electrostatic Precipitators - Emission control equipment used to control particulate matter on large utility boilers</td>
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<tr>
<td>FGD</td>
<td>Flue Gas Desulfurization - Emission control method used to control sulfur dioxide emissions</td>
</tr>
<tr>
<td>FGR</td>
<td>Flue Gas Recirculation - NOx emission control technique - involves returning a portion of the flue gases to the combustion zone</td>
</tr>
<tr>
<td>LAER</td>
<td>Lowest Achievable Emission Rate - The most stringent emission limitation contained in any SIP or achieved in practice for a given class of equipment</td>
</tr>
<tr>
<td>MACT</td>
<td>Maximum Available Control Technology - Emission standard requiring the maximum degree of emission reduction that has been demonstrated achievable</td>
</tr>
<tr>
<td>NAAQS</td>
<td>National Ambient Air Quality Standards - EPA established air quality standards for ambient outdoor emission levels</td>
</tr>
<tr>
<td>NESHAP</td>
<td>National Emission Standards for Hazardous Air Pollutants - Standards established by the EPA for regulation of air toxins</td>
</tr>
<tr>
<td>NSPS</td>
<td>New Source Performance Standards - Regulations established by the EPA for emissions from equipment, including boilers. Many state regulations are more stringent than the NSPS</td>
</tr>
<tr>
<td>NSR</td>
<td>New Source Review - A review performed during the permitting process for a new major installation in a nonattainment area</td>
</tr>
<tr>
<td>PSD</td>
<td>Prevention of Significant Deterioration - A review performed during the permitting process for a new major installation in an attainment area</td>
</tr>
<tr>
<td>RACT</td>
<td>Reasonably Available Control Technology - A set of recommended levels of emission controls applicable to specific sources or categories located in nonattainment areas</td>
</tr>
<tr>
<td>SCAQMD</td>
<td>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.</td>
</tr>
<tr>
<td>SCR</td>
<td>Selective Catalytic Reduction - A NOx control method in which ammonia or urea is injected into the exhaust gases in the presence of a catalyst</td>
</tr>
<tr>
<td>SIP</td>
<td>State Implementation Plan - An EPA approved emission control plan to attain or maintain NAAQS</td>
</tr>
<tr>
<td>SNCR</td>
<td>Selective Non-Catalytic Reduction - A NOx control method where ammonia or urea is injected into the stack and where the exhaust gases are approximately 1600 degrees Fahrenheit</td>
</tr>
</tbody>
</table>
SO\textsubscript{x} Emissions Conversion Curves
15\% Excess Air (3\% O\textsubscript{2})

Conversion Equations

\#2 and \#6 Oil:
ppm = (lb/MMBtu) \times 540
lb/MMBtu = (ppm)/540

Volatile Organic Compound
Conversion Curves
15\% Excess Air (3\% O\textsubscript{2})

Conversion Equations

\#2 and \#6 Oil:
ppm = (lb/MMBtu) \times 2000
lb/MMBtu = (ppm)/2000
Natural Gas and Propane:
ppm = (lb/MMBtu) \times 2500
lb/MMBtu = (ppm)/2500
**NO\textsubscript{x} Emissions Conversion Curves**

15\% Excess Air (3\% O\textsubscript{2})

**Conversion Equations**

- **#2 and #6 Oil:**
  \[ \text{ppm} = \left( \frac{\text{lb}}{\text{MMBtu}} \right) \times 750 \]
  \[ \text{lb/MMBtu} = \left( \frac{\text{ppm}}{750} \right) \]

- **Natural Gas:**
  \[ \text{ppm} = \left( \frac{\text{lb}}{\text{MMBtu}} \right) \times 850 \]
  \[ \text{lb/MMBtu} = \left( \frac{\text{ppm}}{850} \right) \]

- **Propane:**
  \[ \text{ppm} = \left( \frac{\text{lb}}{\text{MMBtu}} \right) \times 810 \]
  \[ \text{lb/MMBtu} = \left( \frac{\text{ppm}}{810} \right) \]
**CO Emissions Conversion Curves**

15% Excess Air (3% O₂)

**Conversion Equations**

- **#2 Oil:**
  - ppm = (lb/MMBtu) × 1290
  - lb/MMBtu = (ppm) / 1290

- **#6 Oil:**
  - ppm = (lb/MMBtu) × 1260
  - lb/MMBtu = (ppm) / 1260

- **Natural Gas:**
  - ppm = (lb/MMBtu) × 1370
  - lb/MMBtu = (ppm) / 1370

- **Propane:**
  - ppm = (lb/MMBtu) × 1340
  - lb/MMBtu = (ppm) / 1340

**Correcting Emission Readings to 3% Oxygen**

\[ ppm\ (@3\%) = \frac{21 - 3}{21 - O_2\ (actual)} \times ppm\ (actual) \]

**Example:** What is the NO level corrected to 3% oxygen for a measured level of 12 ppm at 7.1% oxygen?

\[ ppm\ (@3\%) = \frac{21 - 3}{21 - 7.1} \times 12 = 15.5 \text{ ppm NO}_x \]
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\textsubscript{x} are of concern and frequently must be calculated. Following is an example of how to calculate the potential annual NO\textsubscript{x} emissions for industrial boilers.

To determine the annual NO\textsubscript{x} emissions for an industrial boiler, three items must be known:

1. The NO\textsubscript{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.

\[
\text{Boiler Emission Annual Hours Total Annual} \\
\text{Input Factor of Operation Emissions}
\]

For example, the calculation of the total annual NO\textsubscript{x} emissions for an 800 hp boiler operating 24 hours/day, 365 days/year and having a NO\textsubscript{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\textsubscript{x} emissions for this specific boiler is 19.1 tpy.

The following graphs indicate the annual NO\textsubscript{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\textsubscript{x} emission levels of 110, 60, 30, 25, and 20 ppm.
Annual NO\textsubscript{X} Emissions for 250-800 Horsepower Boilers

\[ \text{NO}_\text{X} = 20 \text{ ppm}^* \]

Annual NO\textsubscript{X} Emissions (tpy)

Annual Hours of Operation

Efficiency = 80%

*ppm corrected to 3% oxygen

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Annual NO\textsubscript{X} Emissions for 250-800 Horsepower Boilers

\[ \text{NO}_\text{X} = 25 \text{ ppm}^* \]

Annual NO\textsubscript{X} Emissions (tpy)

Annual Hours of Operation

Efficiency = 80%

*ppm corrected to 3% oxygen
Annual NO\textsubscript{x} Emissions for 250-800 Horsepower Boilers
NO\textsubscript{x} = 30 ppm\textsuperscript{*}

Annual NO\textsubscript{x} Emissions (tpy)

Annual Hours of Operation

Efficiency = 80%  
\textsuperscript{*}ppm corrected to 3% oxygen

Annual NO\textsubscript{x} Emissions for 250-800 Horsepower Boilers
NO\textsubscript{x} = 60 ppm\textsuperscript{*}

Annual NO\textsubscript{x} Emissions (tpy)

Annual Hours of Operation

Efficiency = 80%  
\textsuperscript{*}ppm corrected to 3% oxygen