# Section E

# EMISSIONS

CONTENTS



**ILLUSTRATIONS**

## INTRODUCTION

This section of the Boiler Book contains background information regarding boiler emissions.

This section does not include emission performance for individual Cleaver-Brooks boiler models. Emission information for each product is included in the specific section of the Boiler Book for the product or you can contact your local Cleaver-Brooks authorized representative for the necessary information.

## POLLUTANTS AND CONTROL TECHNIQUES

Combustion of standard fossil fuels (natural gas and ASTM Grade Oil) in commercial and industrial boilers results in the following nine emissions; carbon dioxide, nitrogen, oxygen, water, carbon monoxide, nitrogen oxide, sulfur oxides, volatile organic compounds, and particulate matter. The latter five products of combustion are considered pollutants and are known to, either directly or indirectly, cause harmful affects on humans and the environment.

The following section describes the formation and control of each of the pollutants in commercial and industrial boilers:

- Carbon Monoxide
- Nitrogen Oxides
- Sulfur Oxides
- Volatile Organic Compounds/Hydrocarbons
- Particulate Matter

## NITROGEN COMPOUNDS (NOx)

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 the other 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 NOx.

The contribution from different NOx sources to the total NOx levels 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** 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** 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 E-1). 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 (fuels containing less fuel-bound nitrogen), if available.

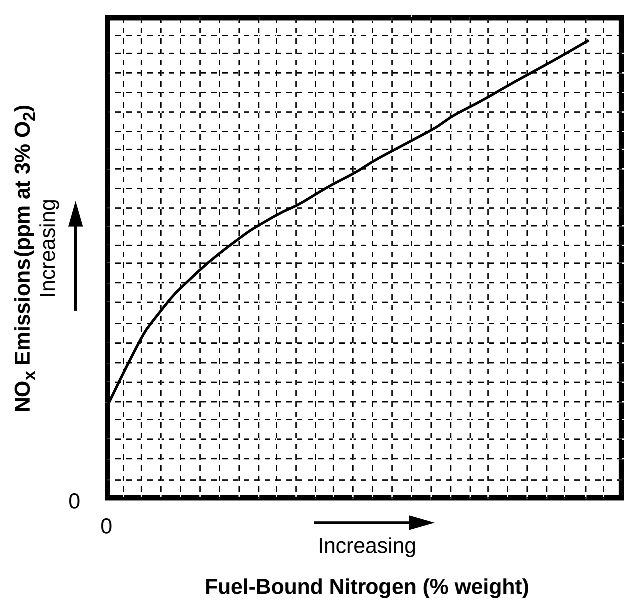



*Figure E-1. Effects of Fuel-Bound Nitrogen on NOx Emissions for Fuel Oils*

## 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 include:

- Selective Non-Catalytic Reduction
- Selective Catalytic Reduction

Combustion control techniques include:

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

Each method results in a different degree of NOx control. For example, when firing natural gas, low excess air firing typically reduces NOx 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 NOx reducing agent, such as ammonia or urea, into the boiler exhaust gases at a temperature of approximately 1400-1600 °F (see Figure E-2). The ammonia or urea breaks down the NOx in the exhaust gases into water and atmospheric nitrogen. Selective non-catalytic reduction reduces NOx up to 70%. However, the technology is extremely difficult to apply to industrial boilers that modulate or cycle 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 or cycle 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 or cycle 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 E-3). The catalyst allows the ammonia to reduce NOx 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 gasses are between 500 °F and 1200 °F, depending on the catalyst used. Selective catalytic reduction can result in NOx reductions up to 90%. However, it is costly to use and can rarely be cost justified on boilers with inputs less than 100 MMBtu/hr.

## COMBUSTION CONTROL TECHNIQUES

Combustion control techniques reduce the amount of NOx emission by limiting the amount of NOx 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 NOx 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 NOx formation in a boiler is the excess air levels. High excess air levels (>45%) may result in increased NOx formation because the excess nitrogen and oxygen in the combustion air entering the

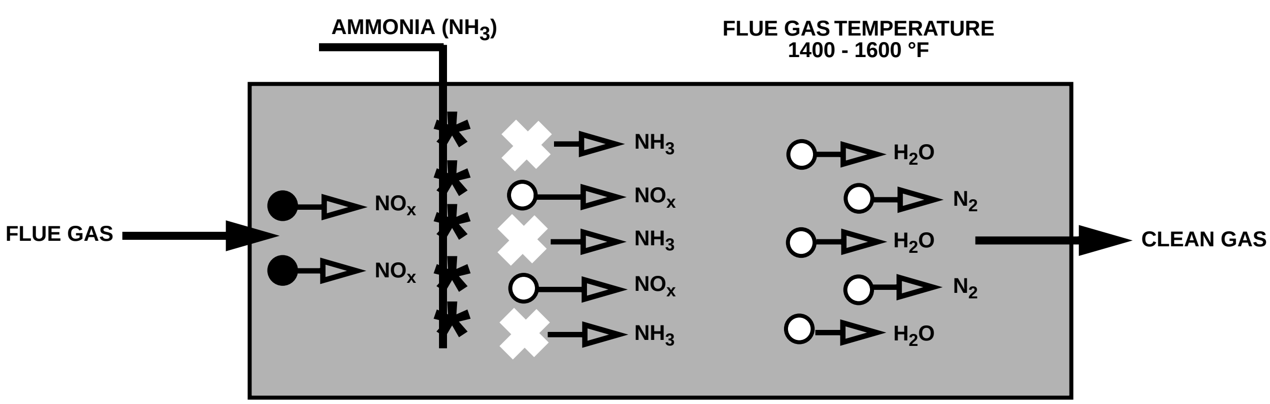



*Figure E-2. Selective Non-Catalytic Reduction (SNCR)*

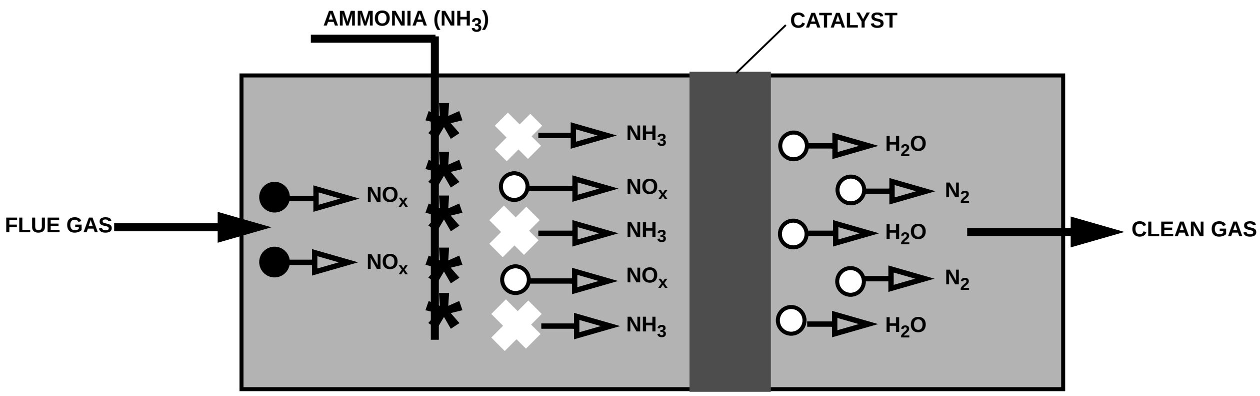



*Figure E-3. Selective Catalytic Reduction (SCR)*

flame will combine to form thermal NOx. 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 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 NOx reductions of 5-10% when firing natural gas.

## Low Nitrogen Fuel Oil

When firing fuel oils, NOx formed by fuel-bound nitrogen can account for 20-50% of the total NOx level. One method to reduce NOx 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 NOx oil is fired in firetube boilers utilizing flue gas recirculation, NOx reductions of 60%-70% over NOx emissions from standard No. 2 oils have been achieved. Low nitrogen oil is used most frequently in southern California.

## Burner Modifications

Burner modifications for NOx 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 NOx formation which, in turn, results in lower overall NOx 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 NOx reduction methods, such as flue gas recirculation. If burner modifications are utilized exclusively to achieve low NOx 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 boiler performance when selecting NOx control technologies.

## Water/Steam Injection

Water or steam injection can be utilized to reduce NOx levels. By injecting water or steam into the flame, flame temperatures are reduced, thereby lowering thermal NOx formation and overall NOx levels. Water or steam injection can reduce NOx 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% boiler efficiency loss. Many times water or steam injection is used in conjunction with other NOx 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 NOx emission from industrial boilers with inputs below 100 MMBtu/hr. FGR entails recirculating a portion of relatively cool exhaust gases back into the combustion process in order to lower the flame temperature and reduce NOx formation. It is currently the most effective and popular low NOx technology for firetube and watertube boilers. And, in many applications, it does not require any additional reduction equipment to comply with regulations.

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 flame. 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 flame. 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 NOx reduction with FGR; practically, there is a physical, feasible limit. The limit of NOx reduction varies for different fuels — 80% for natural gas and 20-25% for standard fuel oils.

The current trends with low NOx technologies are to design the boiler and low NOx equipment as a package. Designing as a true package allows the NOx 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 NOx technology as a package with the boiler, the adverse effects of the low NOx technology on boiler operating parameters (turndown, capacity, efficiency, and CO levels) can be addressed and minimized.

## CHOOSING THE BEST NOx TECHNOLOGY FOR THE JOB

What effect does NOx control technology ultimately have on a boiler's performance? Certain NOx 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 are related to NOx control technologies.

### Turndown

Choosing a low NOx technology that sacrifices turndown can have many adverse effects on the boiler. When selecting NOx controls, 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 even at low firing rates.

Every time the boiler cycles off, before it comes back on, it must go through a specific start-up sequence for safety assurance. It takes between 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. The need for maintenance increases, the chance of component failure increases, and boiler downtime increases. So, when selecting NOx control, always consider the burners 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 that may occur. 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 radiant 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 offset technique can be inherent in the NOx design.

One technology that offsets the efficiency loss due to lower flame temperatures in a firetube boiler is flue gas recirculation. Although the loss of 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 radiant 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% $O_2$). 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.

## Carbon Monoxide (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 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. 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 forms of $SO_2$ (sulfur dioxide) and $SO_3$ (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 E-4). 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 $SO_2$, 1-5% as $SO_3$, 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 non-regenerable or regenerable. Non-regenerable FGD systems, the most common type, result in a waste product that requires proper disposal. Regenerable FGD converts the waste by-product 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

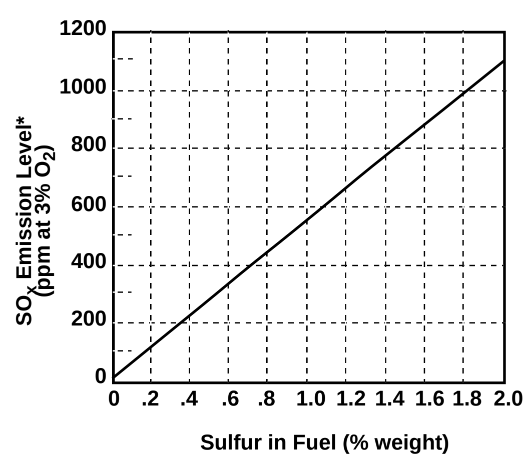



*Figure E-4. Effects of Fuel Sulfur Content on SOx Emissions for Fuel Oils* most cost effective method of SOx reduction. Because SOx emissions primarily depend on the sulfur content of the fuel, burning fuels containing a minimal amount of sulfur (distillate oil) can achieve SOx reductions, without the 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. Even short-term over exposure to carbon monoxide can be critical, or fatal, to people with heart and lung diseases. It may also cause headaches and dizziness in healthy people.

During combustion, carbon in the fuel oxidizes through a series of reactions to form carbon dioxide ($CO_2$). However, 100 percent conversion of carbon to $CO_2$ 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 (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 $PM_{10}$. $PM_{10}$ 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 $PM_{10}$, because of its ability to bypass the body's natural filtering system.

PM emissions are primarily dependent 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 asphalenes. These constituents exist in fuel oils, particularly residual oils, and have a major effect on particulate emissions. By knowing the fuel constituent levels, 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.

## VOLATILE ORGANIC COMPOUNDS (VOCs)/HYDROCARBONS (HC)

Volatile organic compounds, or VOCs, are compounds containing combinations of carbon, hydrogen, and sometimes oxygen. VOCs vaporize easily once emitted into the air and are of concern because of their role in ground level ozone formation. In reference to boiler performance, they are often referred to as hydrocarbons and generally are divided into two categories — methane and non-methane.

Formation of VOCs in commercial and industrial boilers primarily result from poor or incomplete combustion due to improper burner set-up and adjustment. To control VOC emissions from commercial and industrial boilers, no auxiliary equipment is needed; properly maintaining the burner/boiler package will keep VOC emissions at a minimum. Proper maintenance includes keeping the air/fuel ratio at the manufacturer's specified setting, having the proper air and fuel pressures at the burner, and maintaining the atomizing air pressure on oil burners at the correct levels. An improperly maintained boiler/burner package can result in VOC levels over 100 times the normal levels.

## EMISSION LEVEL UNITS

This section describes the different units for emission levels. Emission levels can be provided in many different units depending on whether the measurement is volume or mass based.

## CORRECTING EMISSIONS TO 3% OXYGEN (15% EXCESS AIR)

The following equation shows how to correct emission readings to 3% oxygen (15% excess air). Because boilers don't

| | |
|---|---|
| ppm | **Parts per Million** — Indicates emission levels on a volume basis. Sometimes may be shown as $ppm_v$. Part per million must be referenced to some oxygen level (excess air level) which, for industrial boilers, is typically 3% oxygen (15% excess air). Actual measurements recorded during boiler testing are usually in ppm. |
| lb/MMBtu | **Pounds per Million Btu** — Indicates emission levels on a mass basis. Emission levels are shown in pounds of pollutant per million Btu input to the boiler. This level is useful when hourly or annual emission levels must be determined. |
| lb/hr | **Pounds per Hour** — Indicates emission levels on a mass basis. This unit represents the amount of pollutant emitted on an hourly basis. |
| tpy | **Tons per Year** — Indicates emission levels on a mass basis. This unit corresponds to the annual pollutant levels. |
| $lb/10^6$ cu-ft | **Pounds per Million Cubic Feet** — Indicates emission levels on a mass basis. This unit is used for gaseous fuels and indicates the emission level in pounds per million cubic feet of fuel (gaseous fuel) input to the boiler. This is useful when the actual gas usage of the boiler is known. |
| $lb/10^3$ gal | **Pounds per Thousand Gallons** — Indicates emission levels on a mass basis. This unit is used for liquid (oil) fuels and indicates the emission level in pounds per thousand gallons of oil fired. This is useful when the actual oil usage of the boiler is known |

always operate at 3% oxygen, it is necessary to convert ppm values measured at various excess air levels to 3% oxygen for comparison and regulation compliance purposes. To correct emission levels to 3% oxygen that are referenced to excess air levels other than 3%, use the following equation.

## CONVERTING EMISSIONS BETWEEN PPM AND LB/MMBTU

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

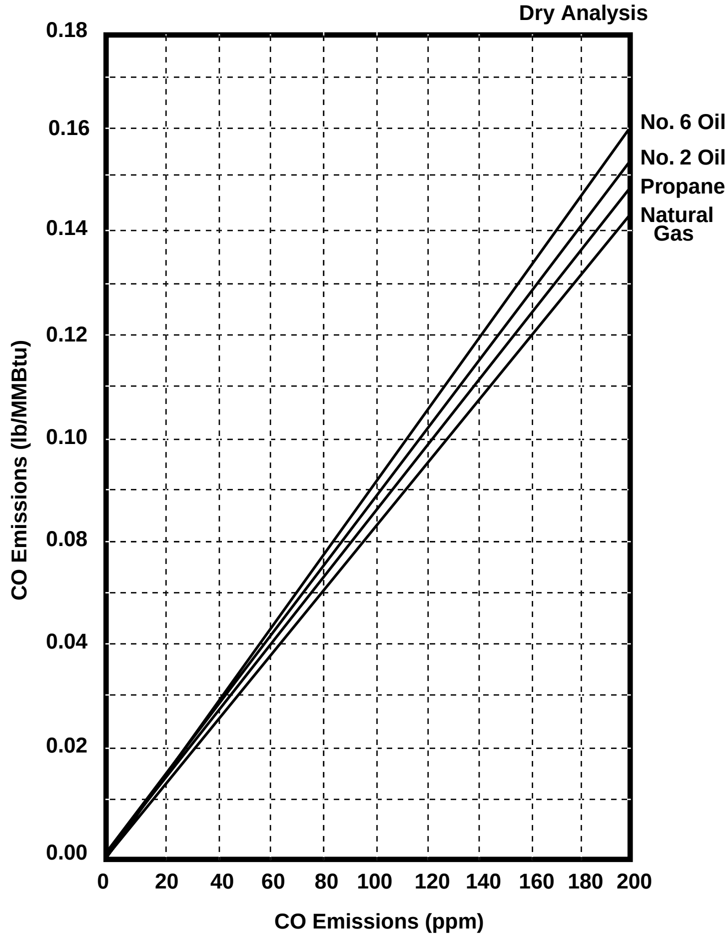
Example: What is the NOx level corrected to 3% oxygen for a measured level of 27 ppm at 7.1% oxygen?

$$\text{ppm (@3\%)} = \frac{21 - 3}{21 - 7.1} \times 27 = 35 \text{ ppm NOx}$$

Although emission levels can be given in many different units, the most common are ppm (corrected to 3% oxygen) and lb/MMBtu. Conversion between these two types of units is very simple, however, it does depend on the fuel type and excess air level.

The following graphs and equations show the relationships and conversions between ppm (corrected to 3% oxygen) and lb/MMBtu. If the conversion involves a ppm level referenced to an oxygen level other than 3%, the ppm level must be corrected to 3% oxygen (see previous section) before using the following graphs and equations (Figure E-5 through E-8).

## CALCULATION OF ANNUAL EMISSIONS FOR INDUSTRIAL




**Conversion Equations**

| No. 2 Oil: | Natural Gas: |
|---|---|
| ppm = (lb/MMBtu)*1290 | ppm = (lb/MMBtu)*1370 |
| lb/MMBtu = (ppm)/1290 | lb/MMBtu = (ppm)/1370 |
| **No. 6 Oil:** | **Propane:** |
| ppm = (lb/MMBtu)*1260 | ppm = (lb/MMBtu)*1340 |
| lb/MMBtu = (ppm)/1260 | lb/MMBtu = (ppm)/1340 |

*Figure E-5. CO Emissions Conversion Curves, 3% Oxygen, (15% Excess Air)*

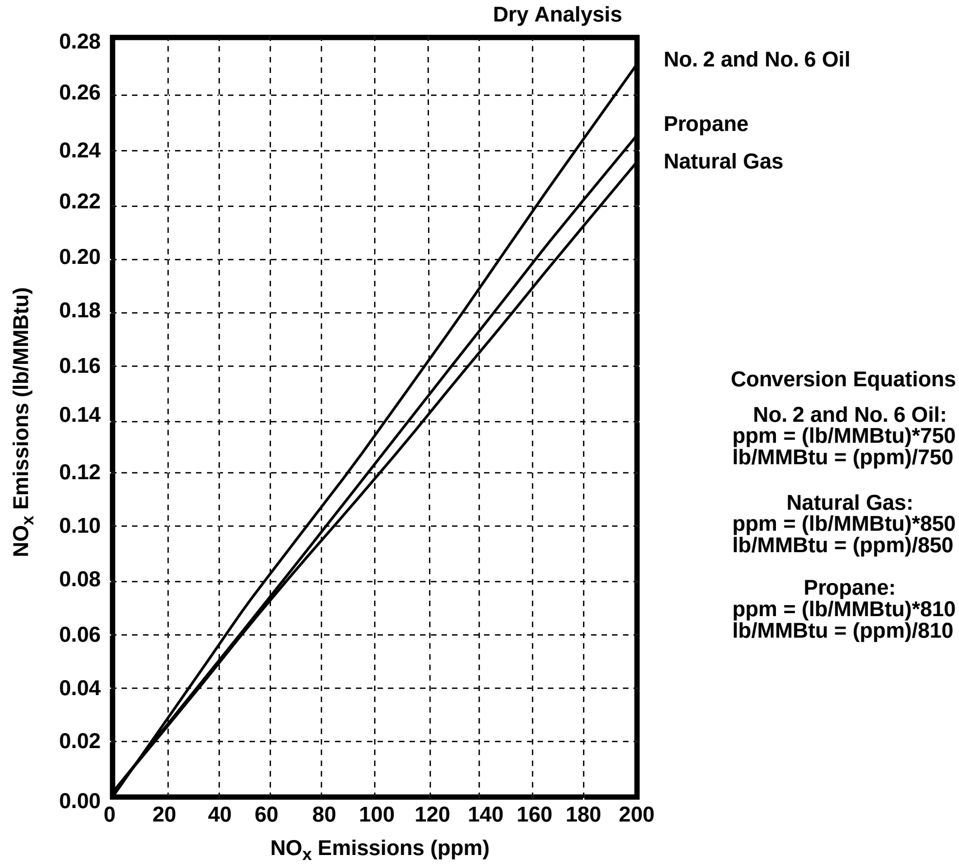



*Figure E-6. NOx Emissions Conversion Curves, 3% Oxygen, (15% Excess Air)*

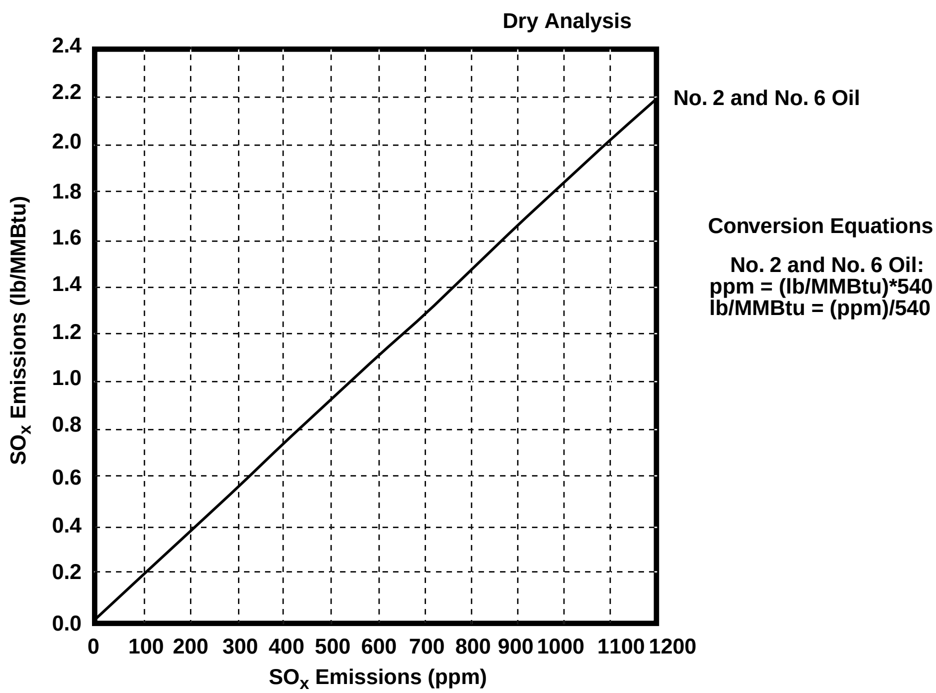



*Figure E-7. SOx Emissions Conversion Curves, 3% Oxygen, (15% Excess Air)*

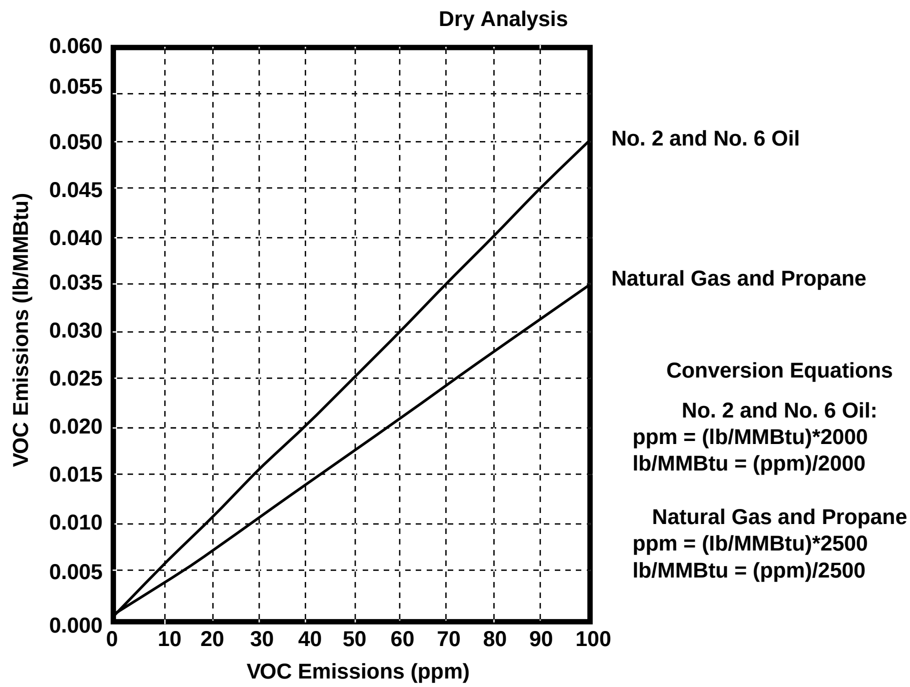



*Figure E-8. Volatile Organic Compound Conversion Curves, 3% Oxygen, (15% Excess Air)*

## 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 NOx are of concern and frequently must be calculated. Following is an example of how to calculate the potential annual NOx emissions for industrial boilers.

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

1. The NOx 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.

Emission Factor x Boiler Input x Annual Hours of Operation = Total Annual Emissions

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

Emission Factor = 0.13 lb/MMBtu (110 ppm = 0.13 lb/MMBtu)

Boiler Input = 33.5 MMBtu/hr (Based on 80% Efficiency)

Annual Hours of Operation = 8760 hours/year (24 hours/day x 365 days/year)

Substituting this data into the previous equation yields the annual NOx emissions for this specific boiler, which is 19.1 tpy.

The following graphs (Figure E- 9 through E-13) indicate the annual NOx emissions for boiler sizes 250-800 horsepower firing natural gas at maximum input operating 24 hours/day, 365 days/year. They are for NOx emission levels of 110, 60, 30, 25, and 20 ppm.

$$\frac{0.13 \text{ lb NOx}}{\text{MMBtu}} \times \frac{33.5 \text{ MMBtu}}{\text{hr}} \times \frac{8760 \text{ hrs}}{\text{year}} \times \frac{1 \text{ ton}}{2000 \text{ lb}} = 19.1 \text{ tpy NOx}$$

# Emissions

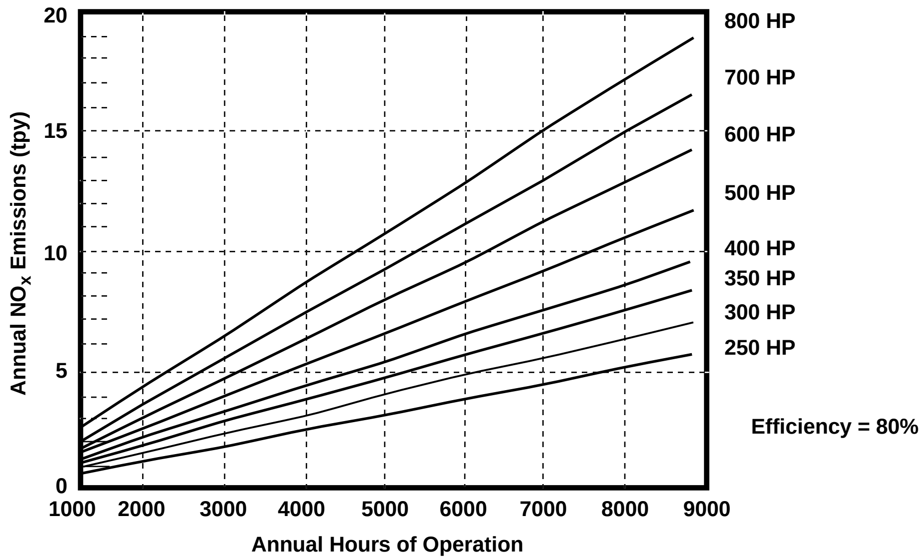



*Figure E-9. Annual NOx Emissions for 250-800 Horsepower Boilers, NOx = 110 ppm (Corrected to 3% $O_2$)*

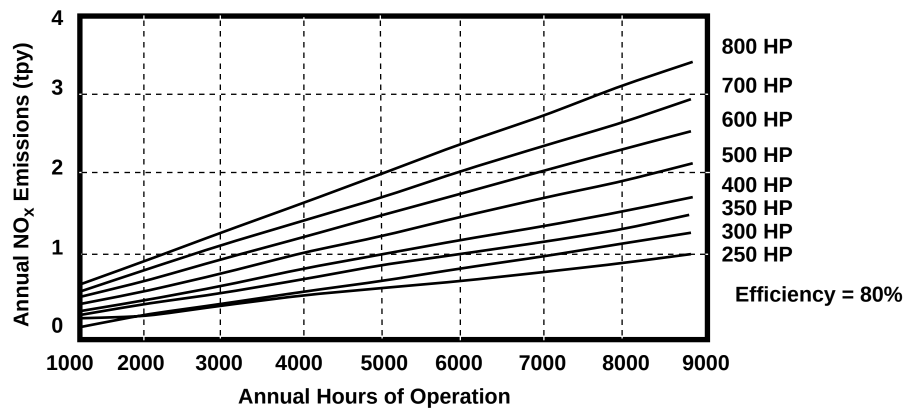



*Figure E-10. Annual NOx Emissions for 250-800 Horsepower Boilers, NOx = 20 ppm (Corrected to 3% $O_2$)*

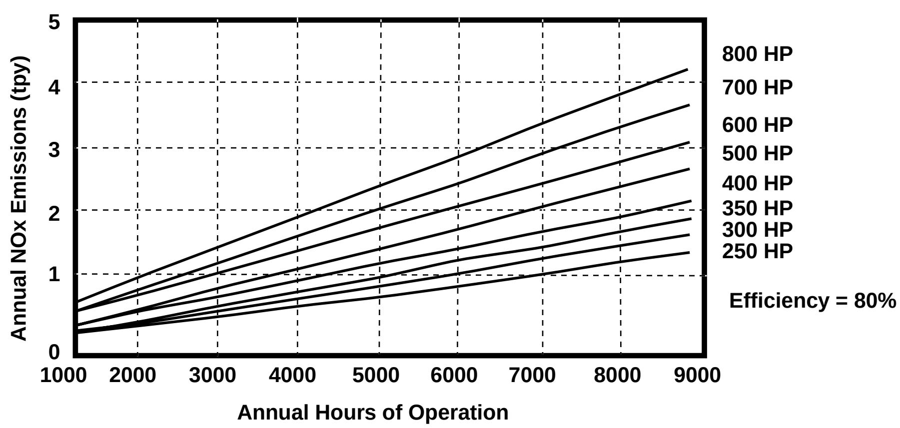



*Figure E-11. Annual NOx Emissions for 250-800 Horsepower Boilers, NOx = 25 ppm (Corrected to 3% $O_2$)*

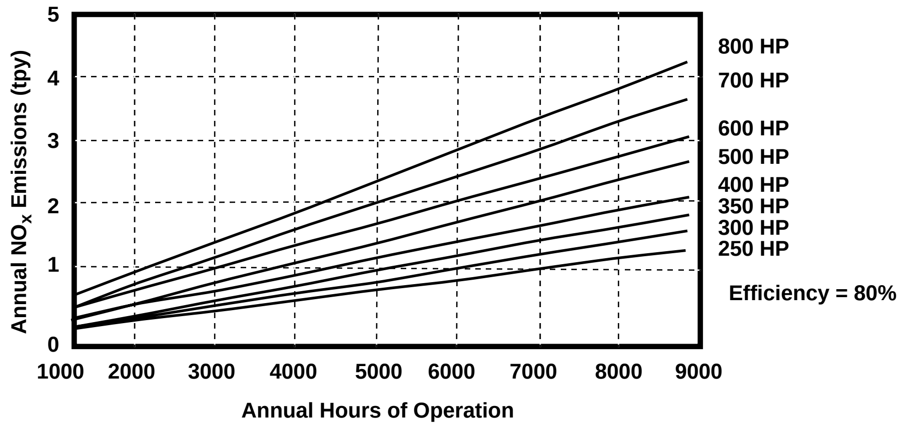



*Figure E-12. Annual NOx Emissions for 250-800 Horsepower Boilers, NOx = 30 ppm (Corrected to 3% $O_2$)*

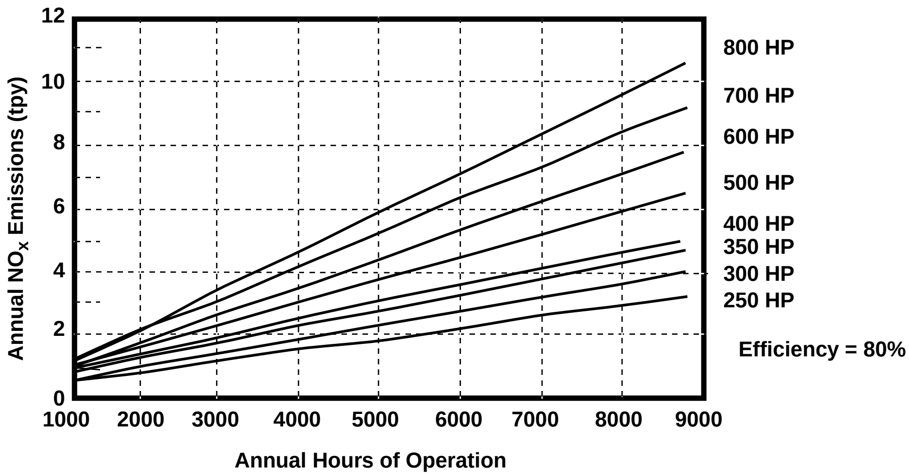



*Figure E-13. Annual NOx Emissions for 250-800 Horsepower Boilers, NOx = 60 ppm (Corrected to 3% $O_2$)*

## NEW SOURCE PERFORMANCE STANDARDS

The Federal EPA has established nationally uniform source-specific regulations through the New Source Performance Standards, or NSPS, for which all applicable sources must comply. The standards, which set minimal requirements for individual sources, address approximately 65 categories of new or modified stationary sources, including industrial boilers.

The NSPS for industrial boilers regulate levels for NOx, SOx, 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 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. The Small Boiler NSPS set emission standards for SOx and particulate matter for boilers firing coal, distillate and residual oil, and wood. The Small Boiler 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 E-14.

Be sure your boiler complies with the New Source Performance Standards as non-compliance may result in fines and/or forced boiler shutdown.

Contact your local Cleaver-Brooks authorized representative if you have questions regarding the New Source Performance Standards.

## New Source Performance Standards for Boilers 10–100 MMBtu/hr Built or Modified After 6/9/1989

**RULES FOR SULFUR DIOXIDE ($SO_2$) EMISSIONS**

**1. Coal Firing**

1.2 lb $SO_2$/MMBtu Limit all 10-100 MMBtu.
90% $SO_2$ 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 $SO_2$/MMBtu or 0.5% sulfur in fuel.
CEMS required to meet $SO_2$ 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 $SO_2$ 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 E-14. Summary of Federal EPA Rules*