

File → AP-42
Fifth Edition
Supplement F
September 2000

SUPPLEMENT F

TO

COMPILATION

OF

AIR POLLUTANT

EMISSION FACTORS

VOLUME I:

STATIONARY POINT

AND AREA SOURCES

Office of Air Quality Planning and Standards
Office of Air and Radiation
U. S. Environmental Protection Agency
Research Triangle Park, NC 27711

September 2000

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AP-42
Fifth Edition
Volume I
Supplement F

**Instructions for Inserting
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Into AP-42**

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- 3.1 Stationary Gas Turbines
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3.1 Stationary Gas Turbines

3.1.1 General¹

Gas turbines, also called “combustion turbines”, are used in a broad scope of applications including electric power generation, cogeneration, natural gas transmission, and various process applications. Gas turbines are available with power outputs ranging in size from 300 horsepower (hp) to over 268,000 hp, with an average size of 40,200 hp.² The primary fuels used in gas turbines are natural gas and distillate (No. 2) fuel oil.³

3.1.2 Process Description^{1,2}

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo. An annular combustor is a doughnut-shaped, single, continuous chamber that encircles the turbine in a plane perpendicular to the air flow. Can-annular combustors are similar to the annular; however, they incorporate several can-shaped combustion chambers rather than a single continuous chamber. Annular and can-annular combustors are based on aircraft turbine technology and are typically used for smaller scale applications. A silo (frame-type) combustor has one or more combustion chambers mounted external to the gas turbine body. Silo combustors are typically larger than annular or can-annular combustors and are used for larger scale applications.

The combustion process in a gas turbine can be classified as diffusion flame combustion, or lean-premix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-premix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging, or both; however, the same staged, lean-premix principle is applied. Gas turbines using staged combustion are also referred to as Dry Low NO_x combustors. The majority of gas turbines currently manufactured are lean-premix staged combustion turbines.

Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at temperatures up to 2600°F. Energy from the hot exhaust gases, which expand in the power turbine section, are recovered in the form of shaft horsepower. More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive an external load.² Gas turbines may have one, two, or three shafts to transmit power between the inlet air compression turbine, the power turbine, and the exhaust turbine. The heat content of the exhaust gases exiting the turbine can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).

The simple cycle is the most basic operating cycle of gas turbines with a thermal efficiency ranging from 15 to 42 percent. The cycle thermal efficiency is defined as the ratio of useful shaft energy to fuel energy input. Simple cycle gas turbines are typically used for shaft horsepower applications without recovery of exhaust heat. For example, simple cycle gas turbines are used by electric utilities for generation of electricity during emergencies or during peak demand periods.

A regenerative cycle is a simple cycle gas turbine with an added heat exchanger. The heat exchanger uses the turbine exhaust gases to heat the combustion air which reduces the amount of fuel required to reach combustor temperatures. The thermal efficiency of a regenerative cycle is approximately 35 percent. However, the amount of fuel efficiency and saving may not be sufficient to justify the capital cost of the heat exchanger, rendering the process unattractive.

A cogeneration cycle consists of a simple cycle gas turbine with a heat recovery steam generator (HRSG). The cycle thermal efficiency can be as high as 84 percent. In a cogeneration cycle, the steam generated by the HRSG can be delivered at a variety of pressures and temperatures to other thermal processes at the site. For situations where additional steam is required, a supplementary burner, or duct burner, can be placed in the exhaust duct stream of the HRSG to meet the site's steam requirements.

A combined cycle gas turbine is a gas turbine with a HRSG applied at electric utility sites. The gas turbine drives an electric generator, and the steam from the HRSG drives a steam turbine which also drives an electric generator. A supplementary-fired boiler can be used to increase the steam production. The thermal efficiency of a combined cycle gas turbine is between 38 percent and 60 percent.

Gas turbine applications include gas and oil industry, emergency power generation facilities, independent electric power producers (IPP), electric utilities, and other industrial applications. The petroleum industry typically uses simple cycle gas turbines with a size range from 300 hp to 20,000 hp. The gas turbine is used to provide shaft horsepower for oil and gas production and transmission. Emergency power generation sites also utilize simple cycle gas turbines. Here the gas turbine is used to provide backup or emergency power to critical networks or equipment. Usually, gas turbines under 5,000 hp are used at emergency power generation sites.

Independent electrical power producers generate electricity for resale to larger electric utilities. Simple, regenerative, or combined cycle gas turbines are used at IPP; however, most installations use combined cycle gas turbines. The gas turbines used at IPP can range from 1,000 hp to over 100,000 hp. The larger electric utilities use gas turbines mostly as peaking units for meeting power demand peaks imposed by large commercial and industrial users on a daily or seasonal basis. Simple cycle gas turbines ranging from 20,000 hp to over 200,000 hp are used at these installations. Other industrial applications for gas turbines include pulp and paper, chemical, and food processing. Here, combined cycle gas turbines are used for cogeneration.

3.1.3 Emissions

The primary pollutants from gas turbine engines are nitrogen oxides (NO_x), carbon monoxide (CO), and to a lesser extent, volatile organic compounds (VOC). Particulate matter (PM) is also a primary pollutant for gas turbines using liquid fuels. Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Carbon monoxide, VOC, hazardous air pollutants (HAP), and PM are primarily the result of incomplete combustion. Trace to low amounts of HAP and sulfur dioxide (SO_2) are emitted from gas turbines. Ash and metallic additives in the fuel may also contribute to PM in the exhaust. Oxides of sulfur (SO_x) will only appear in a significant quantity if heavy oils are fired

in the turbine. Emissions of sulfur compounds, mainly SO_2 , are directly related to the sulfur content of the fuel.

Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. The emission factors for this sections are presented for gas turbines operating under high load conditions. Section 3.1 background information document and emissions database contain additional emissions data for gas turbines operating under various load conditions.

Gas turbines firing distillate oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel ash should be used for flue gas emission factors assuming all metals pass through the turbine.

If the HRSG is not supplementary fuel fired, the simple cycle input-specific emission factors (pounds per million British thermal units [lb/MMBtu]) will also apply to cogeneration/combined cycle systems. If the HRSG is supplementary fired, the emissions attributable to the supplementary firing must also be considered to estimate total stack emissions.

3.1.3.1 Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing gas or distillate fuel is thermal NO_x , which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface.

The second mechanism, called prompt NO_x , is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x forms within the flame and is usually negligible when compared to the amount of thermal NO_x formed. The third mechanism, fuel NO_x , stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen (although some molecular nitrogen is present). Essentially all NO_x formed from natural gas combustion is thermal NO_x . Distillate oils have low levels of fuel-bound nitrogen. Fuel NO_x from distillate oil-fired turbines may become significant in turbines equipped with a high degree of thermal NO_x controls. Otherwise, thermal NO_x is the predominant NO_x formation mechanism in distillate oil-fired turbines.

The maximum thermal NO_x formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_x . Thermal NO_x formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NO_x can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air, because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits. In older gas turbine models, where combustion is in the form of a diffusion flame, most of the dilution takes place downstream of the primary flame, which does not minimize peak temperature in the flame and suppress thermal NO_x formation.

Diffusion flames are characterized by regions of near-stoichiometric fuel/air mixtures where temperatures are very high and significant thermal NO_x is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame, and therefore to thermal NO_x emissions. Thermal NO_x can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature, and therefore thermal NO_x . Newer model gas turbines use lean, premixed combustion where the fuel is typically premixed with more than 50 percent theoretical air which results in lower flame temperatures, thus suppressing thermal NO_x formation.

Ambient conditions also affect emissions and power output from turbines more than from external combustion systems. The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure.⁴ Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam. As heat energy is used for water to steam conversion, the temperature in the flame zone will decrease resulting in a decrease of thermal NO_x formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NO_x significantly. Similarly, the gas turbine operating loads affect NO_x emissions. Higher NO_x emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NO_x .

3.1.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions both result from incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolyzed volatile organic emissions.

Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

3.1.3.3 Particulate Matter¹³ -

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content. PM emissions can be classified as "filterable" or "condensable" PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state and

can be measured on a EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half" of the sampling train. The collection, recovery, and analysis of the impingers is described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter.

3.1.3.4 Greenhouse Gases⁵⁻¹¹ -

Carbon dioxide (CO₂) and nitrous oxide (N₂O) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO₂ during the combustion process. This conversion is relatively independent of firing configuration. Methane (CH₄) is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas or a product of combustion in the case of distillate fuel oil.

Although the formation of CO acts to reduce CO₂ emissions, the amount of CO produced is insignificant compared to the amount of CO₂ produced. The majority of the fuel carbon not converted to CO₂ is due to incomplete combustion.

Formation of N₂O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. However, the formation of N₂O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent).

3.1.3.5 HAP Emissions -

Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emissions data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines, formaldehyde accounts for about two-thirds of the total HAP emissions. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. For No. 2 distillate oil-fired turbines, small amount of metallic HAP are present in the turbine's exhaust in addition to the gaseous HAP identified under gas fired turbines. These metallic HAP are carried over from the fuel constituents. The formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions increase with reduced operating loads. Typically, combustion turbines operate under full loads for greater fuel efficiency, thereby minimizing the amount of CO and HAP emissions.

3.1.4 Control Technologies¹²

There are three generic types of emission controls in use for gas turbines, wet controls using steam or water injection to reduce combustion temperatures for NO_x control, dry controls using advanced combustor design to suppress NO_x formation and/or promote CO burnout, and post-combustion catalytic control to selectively reduce NO_x and/or oxidize CO emission from the turbine. Other recently developed technologies promise significantly lower levels of NO_x and CO emissions from diffusion combustion type gas turbines. These technologies are currently being demonstrated in several installations.

Emission factors in this section have been determined from gas turbines with no add-on control devices (uncontrolled emissions). For NO_x and CO emission factors for combustion controls, such as water-steam injection, and lean pre-mix units are presented. Additional information for controlled

emissions with various add-on controls can be obtained using the section 3.1 database. Uncontrolled, lean-premix, and water injection emission factors were presented for NO_x and CO to show the effect of combustion modification on emissions.

3.1.4.1 Water Injection -

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_x emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NO_x levels, such rates of injection may reduce NO_x by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.

3.1.4.2 Dry Controls -

Since thermal NO_x is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_x emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_x formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NO_x emissions associated with the high temperature pilot flame are insignificant. Low NO_x emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H₂, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NO_x generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NO_x formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NO_x (DLN), Dry-Low Emissions (DLE), or SoLoNO_x.

3.1.4.3 Catalytic Reduction Systems -

Selective catalytic reduction (SCR) systems selectively reduce NO_x emissions by injecting ammonium (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3 , and O_2 react on the surface of the catalyst to form N_2 and H_2O . The exhaust gas must contain a minimum amount of O_2 and be within a particular temperature range (typically 450°F to 850°F) in order for the SCR system to operate properly.

The temperature range is dictated by the catalyst material which is typically made from noble metals, including base metal oxides such as vanadium and titanium, or zeolite-based material. The removal efficiency of an SCR system in good working order is typically from 65 to 90 percent. Exhaust gas temperatures greater than the upper limit (850°F) cause NO_x and NH_3 to pass through the catalyst unreacted. Ammonia emissions, called NH_3 slip, may be a consideration when specifying an SCR system.

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site and injected into the exhaust stream upstream of the catalyst. Although an SCR system can operate alone, it is typically used in conjunction with water-steam injection systems or lean-premix system to reduce NO_x emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems). The SCR system for landfill or digester gas-fired turbines requires a substantial fuel gas pretreatment to remove trace contaminants that can poison the catalyst. Therefore, SCR and other catalytic treatments may be inappropriate control technologies for landfill or digester gas-fired turbines.

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NO_x , O_2 , and NH_3 , to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst. Some SCR installations incorporate CO catalytic oxidation modules along with the NO_x reduction catalyst for simultaneous CO/ NO_x control.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. CO catalysts are also being used to reduce VOC and organic HAPs emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are expected on other HAP pollutants.

3.1.4.4 Other Catalytic Systems^{14,15} -

New catalytic reduction technologies have been developed and are currently being commercially demonstrated for gas turbines. Such technologies include, but are not limited to, the SCONOX and the XONON systems, both of which are designed to reduce NO_x and CO emissions. The SCONOX system is applicable to natural gas fired gas turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO_2 and NO_2 . The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer guarantees CO emissions of 1 ppm and NO_x emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems. Only limited emissions data were available for a gas turbine equipped with a SCONOX system. This data reflected HAP emissions and was not sufficient to verify the manufacturer's claims.

The XONON system is applicable to diffusion and lean-premix combustors and is currently being demonstrated with the assistance of leading gas turbine manufacturers. The system utilizes a flameless combustion system where fuel and air reacts on a catalyst surface, preventing the formation of NO_x while achieving low CO and unburned hydrocarbon emission levels. The overall combustion process consists of the partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. The partial combustion within the catalyst produces no NO_x , and the combustion downstream of the catalyst occurs in a flameless homogeneous reaction that produces almost no NO_x . The system is totally contained within the combustor of the gas turbine and is not a process for clean-up of the turbine exhaust. Note that this technology has not been fully demonstrated as of the drafting of this section. The catalyst manufacturer claims that gas turbines equipped with the XONON Catalyst emit NO_x levels below 3 ppm and CO and unburned hydrocarbons levels below 10 ppm. Emissions data from gas turbines equipped with a XONON Catalyst were not available as of the drafting of this section.

3.1.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the new EFIG home page (<http://www.epa.gov/ttn/chief>).

Supplement A, February 1996

- For the PM factors, a footnote was added to clarify that condensables and all PM from oil- and gas-fired turbines are considered PM-10.
- In the table for large uncontrolled gas turbines, a sentence was added to footnote "e" to indicate that when sulfur content is not available, $0.6 \text{ lb}/10^6 \text{ ft}^3$ (0.0006 lb/MMBtu) can be used.

Supplement B, October 1996

- Text was revised and updated for the general section.
- Text was added regarding firing practices and process description.
- Text was revised and updated for emissions and controls.
- All factors for turbines with SCR-water injection control were corrected.
- The CO_2 factor was revised and a new set of N_2O factors were added.

Supplement F, April 2000

- Text was revised and updated for the general section.
- All emission factors were updated except for the SO_2 factor for natural gas and distillate oil turbines.

- Turbines using staged (lean-premix) combustors added to this section.
- Turbines used for natural gas transmission added to this section.
- Details for turbine operating configurations (operating cycles) added to this section.
- Information on new emissions control technologies added to this section (SCONOX and XONON).
- HAP emission factors added to this section based on over 400 data points taken from over 60 source tests.
- PM condensable and filterable emission factors for natural gas and distillate oil fired turbines were developed.
- NOx and CO emission factors for lean-premix turbines were added.
- Emission factors for landfill gas and digester gas were added.

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors ^a				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines ^b	(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02 ^d	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines ^e	(lb/MMBtu) ^f (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^f (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines ^g	(lb/MMBtu) ^h (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^h (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines ^j	(lb/MMBtu) ^k (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^k (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

^a Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^b Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 1020.

^d It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

^e SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

^f Emission factors based on an average distillate oil heating value of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

^g SCC for landfill gas-fired turbines is 2-03-008-01.

^h Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10⁶ scf) multiply by 400.

^j SCC for digester gas-fired turbine is 2-03-007-01.

^k Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf) multiply by 600.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors ^a - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines ^b		Distillate Oil-Fired Turbines ^d	
	(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^e (Fuel Input)	Emission Factor Rating
CO ₂ ^f	110	A	157	A
N ₂ O	0.003 ^g	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO ₂	0.94S ^h	B	1.01S ^h	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04 ^j	E
TOC ^k	1.1 E-02	B	4.0 E-03 ^l	C
PM (condensable)	4.7 E-03 ^l	C	7.2 E-03 ^l	C
PM (filterable)	1.9 E-03 ^l	C	4.3 E-03 ^l	C
PM (total)	6.6 E-03 ^l	C	1.2 E-02 ^l	C

^a Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

^b SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

^d SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

^e Emission factors based on an average distillate oil heating value of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

^f Based on 99.5% conversion of fuel carbon to CO₂ for natural gas and 99% conversion of fuel carbon to CO₂ for distillate oil. CO₂ (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO₂, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10⁶scf. For distillate oil, CO₂ (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

^g Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

^h All sulfur in the fuel is assumed to be converted to SO₂. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

^j VOC emissions are assumed equal to the sum of organic emissions.

^k Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

^l Emission factors are based on combustion turbines using water-steam injection.

Table 3.1-2b. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors ^a - Uncontrolled				
Pollutants	Landfill Gas-Fired Turbines ^b		Digester Gas-Fired Turbines ^d	
	(lb/MMBtu) ^c	Emission Factor Rating	(lb/MMBtu) ^c	Emission Factor Rating
CO ₂ ^f	50	D	27	C
Lead	ND	NA	< 3.4 E-06 ^g	D
PM-10	2.3 E-02	B	1.2 E-02	C
SO ₂	4.5 E-02	C	6.5 E-03	D
VOC ^h	1.3 E-02	B	5.8 E-03	D

^a Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

^b SCC for landfill gas-fired turbines is 2-03-008-01.

^c Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 400.

^d SCC for digester gas-fired turbine include 2-03-007-01.

^e Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 600.

^f For landfill gas and digester gas, CO₂ is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent).

^g Compound was not detected. The presented emission value is based on one-half of the detection limit.

^h Based on adding the formaldehyde emissions to the NMHC.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS
FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
1,3-Butadiene ^d	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene ^e	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde ^f	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide ^d	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

^a SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

^e Benzene with SCONOX catalyst is 9.1 E-07, rating of D.

^f Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.1-4. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS
FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
1,3-Butadiene ^d	< 1.6 E-05	D
Benzene	5.5 E-05	C
Formaldehyde	2.8 E-04	B
Naphthalene	3.5 E-05	C
PAH	4.0 E-05	C

^a SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-5. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
Arsenic ^d	< 1.1 E-05	D
Beryllium ^d	< 3.1 E-07	D
Cadmium	4.8 E-06	D
Chromium	1.1 E-05	D
Lead	1.4 E-05	D
Manganese	7.9 E-04	D
Mercury	1.2 E-06	D
Nickel ^d	< 4.6 E-06	D
Selenium ^d	< 2.5 E-05	D

^a SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-6. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS
FROM LANDFILL GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
Acetonitrile ^d	< 1.2E-05	D
Benzene	2.1E-05	B
Benzyl Chloride ^d	< 1.2 E-05	D
Carbon Tetrachloride ^d	< 1.8 E-06	D
Chlorobenzene ^d	< 2.9 E-06	D
Chloroform ^d	< 1.4 E-06	D
Methylene Chloride	2.3 E-06	D
Tetrachloroethylene ^d	< 2.5 E-06	D
Toluene	1.1 E-04	B
Trichloroethylene ^d	< 1.9 E-06	D
Vinyl Chloride ^d	< 1.6 E-06	D
Xylenes	3.1 E-05	B

^a SCC for landfill gas-fired turbines is 2-03-008-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 400.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-7. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS
FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Ratings
1,3-Butadiene ^d	< 9.8 E-06	D
1,4-Dichlorobenzene ^d	< 2.0 E-05	D
Acetaldehyde	5.3 E-05	D
Carbon Tetrachloride ^d	< 2.0 E-05	D
Chlorobenzene ^d	< 1.6 E-05	D
Chloroform ^d	< 1.7 E-05	D
Ethylene Dichloride ^d	< 1.5 E-05	D
Formaldehyde	1.9 E-04	D
Methylene Chloride ^d	< 1.3 E-05	D
Tetrachloroethylene ^d	< 2.1 E-05	D
Trichloroethylene ^d	< 1.8 E-05	D
Vinyl Chloride ^d	< 3.6 E-05	D
Vinylidene Chloride ^d	< 1.5 E-05	D

^a SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 600.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-8. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
Arsenic ^d	< 2.3 E-06	D
Cadmium ^d	< 5.8 E-07	D
Chromium ^d	< 1.2 E-06	D
Lead ^d	< 3.4 E-06	D
Nickel	2.0 E-06	D
Selenium	1.1 E-05	D

^a SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factor based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 600.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

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3.2 Natural Gas-fired Reciprocating Engines

3.2.1 General¹⁻³

Most natural gas-fired reciprocating engines are used in the natural gas industry at pipeline compressor and storage stations and at gas processing plants. These engines are used to provide mechanical shaft power for compressors and pumps. At pipeline compressor stations, engines are used to help move natural gas from station to station. At storage facilities, they are used to help inject the natural gas into high pressure natural gas storage fields. At processing plants, these engines are used to transmit fuel within a facility and for process compression needs (e.g., refrigeration cycles). The size of these engines ranges from 50 brake horsepower (bhp) to 11,000 bhp. In addition, some engines in service are 50 - 60 years old and consequently have significant differences in design compared to newer engines, resulting in differences in emissions and the ability to be retrofitted with new parts or controls.

At pipeline compressor stations, reciprocating engines are used to power reciprocating compressors that move compressed natural gas (500 - 2000 psig) in a pipeline. These stations are spaced approximately 50 to 100 miles apart along a pipeline that stretches from a gas supply area to the market area. The reciprocating compressors raise the discharge pressure of the gas in the pipeline to overcome the effect of frictional losses in the pipeline upstream of the station, in order to maintain the required suction pressure at the next station downstream or at various downstream delivery points. The volume of gas flowing and the amount of subsequent frictional losses in a pipeline are heavily dependent on the market conditions that vary with weather and industrial activity, causing wide pressure variations. The number of engines operating at a station, the speed of an individual engine, and the amount of individual engine horsepower (load) needed to compress the natural gas is dependent on the pressure of the compressed gas received by the station, the desired discharge pressure of the gas, and the amount of gas flowing in the pipeline. Reciprocating compressors have a wider operating bandwidth than centrifugal compressors, providing increased flexibility in varying flow conditions. Centrifugal compressors powered by natural gas turbines are also used in some stations and are discussed in another section of this document.

A compressor in storage service pumps gas from a low-pressure storage field (500 - 800 psig) to a higher pressure transmission pipeline (700 - 1000 psig) and/or pumps gas from a low-pressure transmission line (500 - 800 psig) to a higher pressure storage field (800 - 2000 psig).

Storage reciprocating compressors must be flexible enough to allow operation across a wide band of suction and discharge pressures and volume variations. The compressor must be able to compress at high compression ratios with low volumes and compress at low compression ratios with high volumes. These conditions require varying speeds and load (horsepower) conditions for the reciprocating engine powering the reciprocating compressor.

Reciprocating compressors are used at processing plants for process compression needs (e.g. refrigeration cycles). The volume of gas compressed varies, but the pressure needed for the process is more constant than the other two cases mentioned above.

3.2.2 Process Description¹⁻³

Natural gas-fired reciprocating engines are separated into three design classes: 2-cycle (stroke) lean-burn, 4-stroke lean-burn, and 4-stroke rich-burn. Two-stroke engines complete the power cycle in a

single crankshaft revolution as compared to the two crankshaft revolutions required for 4-stroke engines. All engines in these categories are spark-ignited.

In a 2-stroke engine, the air-to-fuel charge is injected with the piston near the bottom of the power stroke. The intake ports are then covered or closed, and the piston moves to the top of the cylinder, compressing the charge. Following ignition and combustion, the power stroke starts with the downward movement of the piston. As the piston reaches the bottom of the power stroke, exhaust ports or valves are opened to exhaust, or scavenge, the combustion products, and a new air-to-fuel charge is injected. Two-stroke engines may be turbocharged using an exhaust-powered turbine to pressurize the charge for injection into the cylinder and to increase cylinder scavenging. Non-turbocharged engines may be either blower scavenged or piston scavenged to improve removal of combustion products. Historically, 2-stroke designs have been widely used in pipeline applications. However, current industry practices reflect a decline in the usage of new 2-stroke engines for stationary applications.

Four-stroke engines use a separate engine revolution for the intake/compression cycle and the power/exhaust cycle. These engines may be either naturally aspirated, using the suction from the piston to entrain the air charge, or turbocharged, using an exhaust-driven turbine to pressurize the charge. Turbocharged units produce a higher power output for a given engine displacement, whereas naturally aspirated units have lower initial costs and require less maintenance.

Rich-burn engines operate near the stoichiometric air-to-fuel ratio (16:1) with exhaust excess oxygen levels less than 4 percent (typically closer to 1 percent). Additionally, it is likely that the emissions profile will be considerably different for a rich-burn engine at 4 percent oxygen than when operated closer to stoichiometric conditions. Considerations such as these can impact the quantitative value of the emission factor presented. It is also important to note that while rich-burn engines may operate, by definition, with exhaust oxygen levels as high as 4 percent, in reality, most will operate within plus or minus 1 air-to-fuel ratio of stoichiometry. Even across this narrow range, emissions will vary considerably, sometimes by more than an order of magnitude. Air-to-fuel ratios were not provided in the gathered emissions data used to develop the presented factors.

Lean-burn engines may operate up to the lean flame extinction limit, with exhaust oxygen levels of 12 percent or greater. The air to fuel ratios of lean-burn engines range from 20:1 to 50:1 and are typically higher than 24:1. The exhaust excess oxygen levels of lean-burn engines are typically around 8 percent, ranging from 4 to 17 percent. Some lean-burn engines are characterized as clean-burn engines. The term "clean-burn" technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NO_x by operating at high air-to-fuel ratios. Engines operating at high air-to-fuel ratios (greater than 30:1) may require combustion modification to promote stable combustion with the high excess air. These modifications may include a turbo charger or a precombustion chamber (PCC). A turbo charger is used to force more air into the combustion chamber, and a PCC is used to ignite a fuel-rich mixture that propagates into the main cylinder and ignites the very lean combustion charge. Lean-burn engines typically have lower oxides of nitrogen (NO_x) emissions than rich-burn engines.

3.2.3 Emissions

The primary criteria pollutants from natural gas-fired reciprocating engines are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC). The formation of nitrogen oxides is exponentially related to combustion temperature in the engine cylinder. The other pollutants, CO and VOC species, are primarily the result of incomplete combustion. Particulate matter (PM) emissions include trace amounts of metals, non-combustible inorganic material, and condensable,

semi-volatile organics which result from volatilized lubricating oil, engine wear, or from products of incomplete combustion. Sulfur oxides are very low since sulfur compounds are removed from natural gas at processing plants. However, trace amounts of sulfur containing odorant are added to natural gas at city gates prior to distribution for the purpose of leak detection.

It should be emphasized that the actual emissions may vary considerably from the published emission factors due to variations in the engine operating conditions. This variation is due to engines operating at different conditions, including air-to-fuel ratio, ignition timing, torque, speed, ambient temperature, humidity, and other factors. It is not unusual to test emissions from two identical engines in the same plant, operated by the same personnel, using the same fuel, and have the test results show significantly different emissions. This variability in the test data is evidenced in the high relative standard deviation reported in the data set.

3.2.3.1 Nitrogen Oxides -

Nitrogen oxides are formed through three fundamentally different mechanisms. The principal mechanism of NO_x formation with gas-fired engines is thermal NO_x . The thermal NO_x mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_x formed through the thermal NO_x mechanism occurs in high-temperature regions in the cylinder where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface. The second mechanism, called prompt NO_x , occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible compared to the level of NO_x formed through the thermal NO_x mechanism. The third mechanism, fuel NO_x , stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically bound fuel nitrogen (although some molecular nitrogen is present).

Essentially all NO_x formed in natural gas-fired reciprocating engines occurs through the thermal NO_x mechanism. The formation of NO_x through the prompt NO_x mechanism may be significant only under highly controlled situations in rich-burn engines when the thermal NO_x mechanism is suppressed. The rate of NO_x formation through the thermal NO_x mechanism is highly dependent upon the stoichiometric ratio, combustion temperature, and residence time at the combustion temperature. Maximum NO_x formation occurs through the thermal NO_x mechanism near the stoichiometric air-to-fuel mixture ratio since combustion temperatures are greatest at this air-to-fuel ratio.

3.2.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions are both products of incomplete combustion. CO results when there is insufficient residence time at high temperature to complete the final step in hydrocarbon oxidation. In reciprocating engines, CO emissions may indicate early quenching of combustion gases on cylinder walls or valve surfaces. The oxidation of CO to carbon dioxide (CO_2) is a slow reaction compared to most hydrocarbon oxidation reactions.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds that are photoreactive in the atmosphere. VOC occur when some of the gas remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carryover, unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. Partially burned hydrocarbons result from poor air-to-fuel mixing prior to, or during, combustion, or incorrect air-to-fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system. Also, low cylinder temperature may yield partially burned hydrocarbons due to excessive cooling through the walls, or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed.

3.2.3.3 Particulate Matter⁴ -

PM emissions result from carryover of noncombustible trace constituents in the fuel and lubricating oil and from products of incomplete combustion. Emission of PM from natural gas-fired reciprocating engines are generally minimal and comprise fine filterable and condensible PM. Increased PM emissions may result from poor air-to-fuel mixing or maintenance problems.

3.2.3.4 Carbon Dioxide, Methane, and Nitrous Oxide⁵ -

Carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O) are referred to as greenhouse gases. Such gases are largely transparent to incoming solar radiation; however, they absorb infrared radiation re-emitted by the Earth. Where available, emission factors for these pollutants are presented in the emission factors tables of this section.

3.2.4 Control Technologies

Three generic control techniques have been developed for reciprocating engines: parametric controls (timing and operating at a leaner air-to-fuel ratio); combustion modifications such as advanced engine design for new sources or major modification to existing sources (clean-burn cylinder head designs and prestratified charge combustion for rich-burn engines); and postcombustion catalytic controls installed on the engine exhaust system. Post-combustion catalytic technologies include selective catalytic reduction (SCR) for lean-burn engines, nonselective catalytic reduction (NSCR) for rich-burn engines, and CO oxidation catalysts for lean-burn engines.

3.2.4.1 Control Techniques for 4-Cycle Rich-burn Engines^{4,6} -

Nonselective Catalytic Reduction (NSCR) -

This technique uses the residual hydrocarbons and CO in the rich-burn engine exhaust as a reducing agent for NO_x. In an NSCR, hydrocarbons and CO are oxidized by O₂ and NO_x. The excess hydrocarbons, CO, and NO_x pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H₂O and CO₂, while reducing NO_x to N₂. NO_x reduction efficiencies are usually greater than 90 percent, while CO reduction efficiencies are approximately 90 percent.

The NSCR technique is effectively limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke rich-burn turbocharged engines. Engines operating with NSCR require tight air-to-fuel control to maintain high reduction effectiveness without high hydrocarbon emissions. To achieve effective NO_x reduction performance, the engine may need to be run with a richer fuel adjustment than normal. This exhaust excess oxygen level would probably be closer to 1 percent. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.

Prestratified Charge -

Prestratified charge combustion is a retrofit system that is limited to 4-stroke carbureted natural gas engines. In this system, controlled amounts of air are introduced into the intake manifold in a specified sequence and quantity to create a fuel-rich and fuel-lean zone. This stratification provides both a fuel-rich ignition zone and rapid flame cooling in the fuel-lean zone, resulting in reduced formation of NO_x. A prestratified charge kit generally contains new intake manifolds, air hoses, filters, control valves, and a control system.

3.2.4.2 Control Techniques for Lean-burn Reciprocating Engines^{4,6} -

Selective Catalytic Reduction^{4,6} -

Selective catalytic reduction is a postcombustion technology that has been shown to be effective in reducing NO_x in exhaust from lean-burn engines. An SCR system consists of an ammonia storage, feed, and injection system, and a catalyst and catalyst housing. Selective catalytic reduction systems selectively reduce NO_x emissions by injecting ammonia (either in the form of liquid anhydrous ammonia or aqueous ammonium hydroxide) into the exhaust gas stream upstream of the catalyst. Nitrogen oxides, NH₃, and O₂ react on the surface of the catalyst to form N₂ and H₂O. For the SCR system to operate properly, the exhaust gas must be within a particular temperature range (typically between 450 and 850°F). The temperature range is dictated by the catalyst (typically made from noble metals, base metal oxides such as vanadium and titanium, and zeolite-based material). Exhaust gas temperatures greater than the upper limit (850°F) will pass the NO_x and ammonia unreacted through the catalyst. Ammonia emissions, called NH₃ slip, are a key consideration when specifying a SCR system. SCR is most suitable for lean-burn engines operated at constant loads, and can achieve efficiencies as high as 90 percent. For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.

Catalytic Oxidation -

Catalytic oxidation is a postcombustion technology that has been applied, in limited cases, to oxidize CO in engine exhaust, typically from lean-burn engines. As previously mentioned, lean-burn technologies may cause increased CO emissions. The application of catalytic oxidation has been shown to be effective in reducing CO emissions from lean-burn engines. In a catalytic oxidation system, CO passes over a catalyst, usually a noble metal, which oxidizes the CO to CO₂ at efficiencies of approximately 70 percent for 2SLB engines and 90 percent for 4SLB engines.

3.2.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the Clearinghouse for Inventories/Emission Factors (CHIEF) electronic bulletin board (919-541-5742), or on the new Emission Factor and Inventory Group (EFIG) home page (<http://www.epa.gov/ttn/chief>).

Supplement A, February 1996

- In the table for uncontrolled natural gas prime movers, the Source Classification Code (SCC) for 4-cycle lean-burn was changed from 2-01-002-53 to 2-02-002-54. The SCC for 4-cycle rich-burn was changed from 2-02-002-54 to 2-02-02-002-53.
- An SCC (2-02-002-53) was provided for 4-cycle rich-burn engines, and the "less than" symbol (<) was restored to the appropriate factors.

Supplement B, October 1996

- The introduction section was revised.
- Text was added concerning process description of turbines.

- Text concerning emissions and controls was revised.
- References in various tables were editorially corrected.
- The inconsistency between a CO₂ factor in the table and an equation in the footnote was corrected.

Supplement F, July 2000

- Turbines used for natural gas compression were removed from this section and combined with utility turbines in Section 3.1. Section 3.2 now only contains information on natural gas-fired reciprocating engines.
- All emission factors were updated based on emissions data points taken from 70 emission reports containing over 400 source tests. Many new emission factors have been incorporated in this section for speciated organic compounds, including hazardous air pollutants.

TABLE 3.2-1 UNCONTROLLED EMISSION FACTORS FOR 2-STROKE LEAN-BURN ENGINES^a
(SCC 2-02-002-52)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO _x ^c 90 - 105% Load	3.17 E+00	A
NO _x ^c <90% Load	1.94 E+00	A
CO ^c 90 - 105% Load	3.86 E-01	A
CO ^c <90% Load	3.53 E-01	A
CO ₂ ^d	1.10 E+02	A
SO ₂ ^e	5.88 E-04	A
TOC ^f	1.64 E+00	A
Methane ^g	1.45 E+00	C
VOC ^h	1.20 E-01	C
PM10 (filterable) ⁱ	3.84 E-02	C
PM2.5 (filterable) ⁱ	3.84 E-02	C
PM Condensable ^j	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane ^k	6.63 E-05	C
1,1,2-Trichloroethane ^k	5.27 E-05	C
1,1-Dichloroethane	3.91 E-05	C
1,2,3-Trimethylbenzene	3.54 E-05	D
1,2,4-Trimethylbenzene	1.11 E-04	C
1,2-Dichloroethane	4.22 E-05	D
1,2-Dichloropropane	4.46 E-05	C
1,3,5-Trimethylbenzene	1.80 E-05	D
1,3-Butadiene ^k	8.20 E-04	D
1,3-Dichloropropene ^k	4.38 E-05	C
2,2,4-Trimethylpentane ^k	8.46 E-04	B
2-Methylnaphthalene ^k	2.14 E-05	C
Acenaphthene ^k	1.33 E-06	C

Table 3.2-1. UNCONTROLLED EMISSION FACTORS FOR 2-STROKE LEAN-BURN ENGINES

(Continued)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Acenaphthylene ^k	3.17 E-06	C
Acetaldehyde ^{k,l}	7.76 E-03	A
Acrolein ^{k,l}	7.78 E-03	A
Anthracene ^k	7.18 E-07	C
Benz(a)anthracene ^k	3.36 E-07	C
Benzene ^k	1.94 E-03	A
Benzo(a)pyrene ^k	5.68 E-09	D
Benzo(b)fluoranthene ^k	8.51 E-09	D
Benzo(e)pyrene ^k	2.34 E-08	D
Benzo(g,h,i)perylene ^k	2.48 E-08	D
Benzo(k)fluoranthene ^k	4.26 E-09	D
Biphenyl ^k	3.95 E-06	C
Butane	4.75 E-03	C
Butyr/Isobutyraldehyde	4.37 E-04	C
Carbon Tetrachloride ^k	6.07 E-05	C
Chlorobenzene ^k	4.44 E-05	C
Chloroform ^k	4.71 E-05	C
Chrysene ^k	6.72 E-07	C
Cyclohexane	3.08 E-04	C
Cyclopentane	9.47 E-05	C
Ethane	7.09 E-02	A
Ethylbenzene ^k	1.08 E-04	B
Ethylene Dibromide ^k	7.34 E-05	C
Fluoranthene ^k	3.61 E-07	C
Fluorene ^k	1.69 E-06	C
Formaldehyde ^{k,l}	5.52 E-02	A

Table 3.2-1. UNCONTROLLED EMISSION FACTORS FOR 2-STROKE LEAN-BURN ENGINES
(Concluded)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Indeno(1,2,3-c,d)pyrene ^k	9.93 E-09	D
Isobutane	3.75 E-03	C
Methanol ^k	2.48 E-03	A
Methylcyclohexane	3.38 E-04	C
Methylene Chloride ^k	1.47 E-04	C
n-Hexane ^k	4.45 E-04	C
n-Nonane	3.08 E-05	C
n-Octane	7.44 E-05	C
n-Pentane	1.53 E-03	C
Naphthalene ^k	9.63 E-05	C
PAH ^k	1.34 E-04	D
Perylene ^k	4.97 E-09	D
Phenanthrene ^k	3.53 E-06	C
Phenol ^k	4.21 E-05	C
Propane	2.87 E-02	C
Pyrene ^k	5.84 E-07	C
Styrene ^k	5.48 E-05	A
Toluene ^k	9.63 E-04	A
Vinyl Chloride ^k	2.47 E-05	C
Xylene ^k	2.68 E-04	A

^a Reference 7. Factors represent uncontrolled levels. For NO_x, CO, and PM₁₀, "uncontrolled" means no combustion or add-on controls; however, the factor may include turbocharged units. For all other pollutants, "uncontrolled" means no oxidation control; the data set may include units with control techniques used for NO_x control, such as PCC and SCR for lean burn engines, and PSC for rich burn engines. Factors are based on large population of engines. Factors are for engines at all loads, except as indicated. SCC = Source Classification Code. TOC = Total Organic Compounds. PM₁₀ = Particulate Matter ≤ 10 microns (μm) aerodynamic diameter. A "<" sign in front of a factor means that the corresponding emission factor is based on one-half of the method detection limit.

^b Emission factors were calculated in units of (lb/MMBtu) based on procedures in EPA

Method 19. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by the heat content of the fuel. If the heat content is not available, use 1020 Btu/scf. To convert from (lb/MMBtu) to (lb/hp-hr) use the following equation:

$$\text{lb/hp-hr} = (\text{lb/MMBtu}) (\text{heat input, MMBtu/hr}) (1/\text{operating HP, 1/hp})$$

- ^c Emission tests with unreported load conditions were not included in the data set.
- ^d Based on 99.5% conversion of the fuel carbon to CO₂. CO₂ [lb/MMBtu] = (3.67)(%CON)(C)(D)(1/h), where %CON = percent conversion of fuel carbon to CO₂, C = carbon content of fuel by weight (0.75), D = density of fuel, 4.1 E+04 lb/10⁶ scf, and h = heating value of natural gas (assume 1020 Btu/scf at 60°F).
- ^e Based on 100% conversion of fuel sulfur to SO₂. Assumes sulfur content in natural gas of 2,000 gr/10⁶ scf.
- ^f Emission factor for TOC is based on measured emission levels of 43 tests.
- ^g Emission factor for methane is determined by subtracting the VOC and ethane emission factors from the TOC emission factor. Measured emission factor for methane compares well with the calculated emission factor, 1.48 lb/MMBtu vs. 1.45 lb/MMBtu, respectively.
- ^h VOC emission factor is based on the sum of the emission factors for all speciated organic compounds less ethane and methane.
- ⁱ Considered ≤ 1 μm in aerodynamic diameter. Therefore, for filterable PM emissions, PM10(filterable) = PM2.5(filterable).
- ^j No data were available for condensable PM emissions. The presented emission factor reflects emissions from 4SLB engines.
- ^k Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.
- ^l For lean burn engines, aldehyde emissions quantification using CARB 430 may reflect interference with the sampling compounds due to the nitrogen concentration in the stack. The presented emission factor is based on FTIR measurements. Emissions data based on CARB 430 are available in the background report.

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES^a
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO _x ^c 90 - 105% Load	4.08 E+00	B
NO _x ^c <90% Load	8.47 E-01	B
CO ^c 90 - 105% Load	3.17 E-01	C
CO ^c <90% Load	5.57 E-01	B
CO ₂ ^d	1.10 E+02	A
SO ₂ ^e	5.88 E-04	A
TOC ^f	1.47 E+00	A
Methane ^g	1.25 E+00	C
VOC ^h	1.18 E-01	C
PM10 (filterable) ⁱ	7.71 E-05	D
PM2.5 (filterable) ⁱ	7.71 E-05	D
PM Condensable ^j	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane ^k	<4.00 E-05	E
1,1,2-Trichloroethane ^k	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene ^k	2.67E-04	D
1,3-Dichloropropene ^k	<2.64 E-05	E
2-Methylnaphthalene ^k	3.32 E-05	C
2,2,4-Trimethylpentane ^k	2.50 E-04	C
Acenaphthene ^k	1.25 E-06	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES
(Continued)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Acenaphthylene ^k	5.53 E-06	C
Acetaldehyde ^{k,l}	8.36 E-03	A
Acrolein ^{k,l}	5.14 E-03	A
Benzene ^k	4.40 E-04	A
Benzo(b)fluoranthene ^k	1.66 E-07	D
Benzo(e)pyrene ^k	4.15 E-07	D
Benzo(g,h,i)perylene ^k	4.14 E-07	D
Biphenyl ^k	2.12 E-04	D
Butane	5.41 E-04	D
Butyr/Isobutyraldehyde	1.01 E-04	C
Carbon Tetrachloride ^k	<3.67 E-05	E
Chlorobenzene ^k	<3.04 E-05	E
Chloroethane	1.87 E-06	D
Chloroform ^k	<2.85 E-05	E
Chrysene ^k	6.93 E-07	C
Cyclopentane	2.27 E-04	C
Ethane	1.05 E-01	C
Ethylbenzene ^k	3.97 E-05	B
Ethylene Dibromide ^k	<4.43 E-05	E
Fluoranthene ^k	1.11 E-06	C
Fluorene ^k	5.67 E-06	C
Formaldehyde ^{k,l}	5.28 E-02	A
Methanol ^k	2.50 E-03	B
Methylcyclohexane	1.23 E-03	C
Methylene Chloride ^k	2.00 E-05	C
n-Hexane ^k	1.11 E-03	C
n-Nonane	1.10 E-04	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES
(Continued)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
n-Octane	3.51 E-04	C
n-Pentane	2.60 E-03	C
Naphthalene ^k	7.44 E-05	C
PAH ^k	2.69 E-05	D
Phenanthrene ^k	1.04 E-05	D
Phenol ^k	2.40 E-05	D
Propane	4.19 E-02	C
Pyrene ^k	1.36 E-06	C
Styrene ^k	<2.36 E-05	E
Tetrachloroethane ^k	2.48 E-06	D
Toluene ^k	4.08 E-04	B
Vinyl Chloride ^k	1.49 E-05	C
Xylene ^k	1.84 E-04	B

^a Reference 7. Factors represent uncontrolled levels. For NO_x, CO, and PM₁₀, “uncontrolled” means no combustion or add-on controls; however, the factor may include turbocharged units. For all other pollutants, “uncontrolled” means no oxidation control; the data set may include units with control techniques used for NO_x control, such as PCC and SCR for lean burn engines, and PSC for rich burn engines. Factors are based on large population of engines. Factors are for engines at all loads, except as indicated. SCC = Source Classification Code. TOC = Total Organic Compounds. PM-10 = Particulate Matter ≤ 10 microns (μm) aerodynamic diameter. A “<” sign in front of a factor means that the corresponding emission factor is based on one-half of the method detection limit.

^b Emission factors were calculated in units of (lb/MMBtu) based on procedures in EPA Method 19. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by the heat content of the fuel. If the heat content is not available, use 1020 Btu/scf. To convert from (lb/MMBtu) to (lb/hp-hr) use the following equation:

$$\text{lb/hp-hr} = (\text{lb/MMBtu}) (\text{heat input, MMBtu/hr}) (1/\text{operating HP, 1/hp})$$

^c Emission tests with unreported load conditions were not included in the data set.

^d Based on 99.5% conversion of the fuel carbon to CO₂. CO₂ [lb/MMBtu] = (3.67)(%CON)(C)(D)(1/h), where %CON = percent conversion of fuel carbon to CO₂, C = carbon content of fuel by weight (0.75), D = density of fuel, 4.1 E+04 lb/10⁶ scf, and

- h = heating value of natural gas (assume 1020 Btu/scf at 60°F).
- ^e Based on 100% conversion of fuel sulfur to SO₂. Assumes sulfur content in natural gas of 2,000 gr/10⁶ scf.
- ^f Emission factor for TOC is based on measured emission levels from 22 source tests.
- ^g Emission factor for methane is determined by subtracting the VOC and ethane emission factors from the TOC emission factor. Measured emission factor for methane compares well with the calculated emission factor, 1.31 lb/MMBtu vs. 1.25 lb/MMBtu, respectively.
- ^h VOC emission factor is based on the sum of the emission factors for all speciated organic compounds less ethane and methane.
- ⁱ Considered $\leq 1 \mu\text{m}$ in aerodynamic diameter. Therefore, for filterable PM emissions, PM₁₀(filterable) = PM_{2.5}(filterable).
- ^j PM Condensable = PM Condensable Inorganic + PM-Condensable Organic
- ^k Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.
- ^l For lean burn engines, aldehyde emissions quantification using CARB 430 may reflect interference with the sampling compounds due to the nitrogen concentration in the stack. The presented emission factor is based on FTIR measurements. Emissions data based on CARB 430 are available in the background report.

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN
ENGINES^a
(SCC 2-02-002-53)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO _x ^c 90 - 105% Load	2.21 E+00	A
NO _x ^c <90% Load	2.27 E+00	C
CO ^c 90 - 105% Load	3.72 E+00	A
CO ^c <90% Load	3.51 E+00	C
CO ₂ ^d	1.10 E+02	A
SO ₂ ^e	5.88 E-04	A
TOC ^f	3.58 E-01	C
Methane ^g	2.30 E-01	C
VOC ^h	2.96 E-02	C
PM10 (filterable) ^{i,j}	9.50 E-03	E
PM2.5 (filterable) ^j	9.50 E-03	E
PM Condensable ^k	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane ^l	2.53 E-05	C
1,1,2-Trichloroethane ^l	<1.53 E-05	E
1,1-Dichloroethane	<1.13 E-05	E
1,2-Dichloroethane	<1.13 E-05	E
1,2-Dichloropropane	<1.30 E-05	E
1,3-Butadiene ^l	6.63 E-04	D
1,3-Dichloropropene ^l	<1.27 E-05	E
Acetaldehyde ^{l,m}	2.79 E-03	C
Acrolein ^{l,m}	2.63 E-03	C
Benzene ^l	1.58 E-03	B
Butyr/isobutyraldehyde	4.86 E-05	D
Carbon Tetrachloride ^l	<1.77 E-05	E

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES
(Concluded)

Pollutant	Emission Factor (lb/MMBtu) ^b (fuel input)	Emission Factor Rating
Chlorobenzene ¹	<1.29 E-05	E
Chloroform ¹	<1.37 E-05	E
Ethane ⁿ	7.04 E-02	C
Ethylbenzene ¹	<2.48 E-05	E
Ethylene Dibromide ¹	<2.13 E-05	E
Formaldehyde ^{1,m}	2.05 E-02	A
Methanol ¹	3.06 E-03	D
Methylene Chloride ¹	4.12 E-05	C
Naphthalene ¹	<9.71 E-05	E
PAH ¹	1.41 E-04	D
Styrene ¹	<1.19 E-05	E
Toluene ¹	5.58 E-04	A
Vinyl Chloride ¹	<7.18 E-06	E
Xylene ¹	1.95 E-04	A

^a Reference 7. Factors represent uncontrolled levels. For NO_x, CO, and PM-10, “uncontrolled” means no combustion or add-on controls; however, the factor may include turbocharged units. For all other pollutants, “uncontrolled” means no oxidation control; the data set may include units with control techniques used for NO_x control, such as PCC and SCR for lean burn engines, and PSC for rich burn engines. Factors are based on large population of engines. Factors are for engines at all loads, except as indicated. SCC = Source Classification Code. TOC = Total Organic Compounds. PM10 = Particulate Matter ≤ 10 microns (μm) aerodynamic diameter. A “<” sign in front of a factor means that the corresponding emission factor is based on one-half of the method detection limit.

^b Emission factors were calculated in units of (lb/MMBtu) based on procedures in EPA Method 19. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by the heat content of the fuel. If the heat content is not available, use 1020 Btu/scf. To convert from (lb/MMBtu) to (lb/hp-hr) use the following equation:

$$\text{lb/hp-hr} = (\text{lb/MMBtu}) (\text{heat input, MMBtu/hr}) (1/\text{operating HP, 1/hp})$$

^c Emission tests with unreported load conditions were not included in the data set.

^d Based on 99.5% conversion of the fuel carbon to CO₂. CO₂ [lb/MMBtu] = (3.67)(%CON)(C)(D)(1/h), where %CON = percent conversion of fuel carbon to CO₂,

- C = carbon content of fuel by weight (0.75), D = density of fuel, 4.1 E+04 lb/10⁶ scf, and h = heating value of natural gas (assume 1020 Btu/scf at 60°F).
- ^e Based on 100% conversion of fuel sulfur to SO₂. Assumes sulfur content in natural gas of 2,000 gr/10⁶ scf.
 - ^f Emission factor for TOC is based on measured emission levels from 6 source tests.
 - ^g Emission factor for methane is determined by subtracting the VOC and ethane emission factors from the TOC emission factor.
 - ^h VOC emission factor is based on the sum of the emission factors for all speciated organic compounds. Methane and ethane emissions were not measured for this engine category.
 - ⁱ No data were available for uncontrolled engines. PM10 emissions are for engines equipped with a PCC.
 - ^j Considered $\leq 1 \mu\text{m}$ in aerodynamic diameter. Therefore, for filterable PM emissions, PM10(filterable) = PM2.5(filterable).
 - ^k No data were available for condensable emissions. The presented emission factor reflects emissions from 4SLB engines.
 - ^l Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.
 - ^m For rich-burn engines, no interference is suspected in quantifying aldehyde emissions. The presented emission factors are based on FTIR and CARB 430 emissions data measurements.
 - ⁿ Ethane emission factor is determined by subtracting the VOC emission factor from the NMHC emission factor.

References For Section 3.2

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2. *Standards Support And Environmental Impact Statement, Volume I: Stationary Internal Combustion Engines*, EPA-450/2-78-125a, U. S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, July 1979.
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12.2 Coke Production

12.2.1 General

Metallurgical coke is produced by destructive distillation of coal in coke ovens. Prepared coal is "coked", or heated in an oxygen-free atmosphere until all volatile components in the coal evaporate. The material remaining is called coke.

Most metallurgical coke is used in iron and steel industry processes such as blast furnaces, sinter plants, and foundries to reduce iron ore to iron. Over 90 percent of the total metallurgical coke production is dedicated to blast furnace operations.

Most coke plants are co-located with iron and steel production facilities. Coke demand is dependent on the iron and steel industry. This represents a continuing decline from the about 40 plants that were operating in 1987.

12.2.2 Process Description^{1,2}

All metallurgical coke is produced using the "byproduct" method. Destructive distillation ("coking") of coal occurs in coke ovens without contact with air. Most U. S. coke plants use the Kopper-Becker byproduct oven. These ovens must remain airtight under the cyclic stress of expansion and contraction. Each oven has 3 main parts: coking chambers, heating chambers, and regenerative chambers. All of the chambers are lined with refractory (silica) brick. The coking chamber has ports in the top for charging of the coal.

A coke oven battery is a series of 10 to 100 coke ovens operated together. Figure 12.2-1 illustrates a byproduct coke oven battery. Each oven holds between 9 to 32 megagrams (Mg) (10 to 35 tons) of coal. Offtake flues on either end remove gases produced. Process heat comes from the combustion of gases between the coke chambers. Individual coke ovens operate intermittently, with run times of each oven coordinated to ensure a consistent flow of collectible gas. Approximately 40 percent of cleaned oven gas (after the removal of its byproducts) is used to heat the coke ovens. The rest is either used in other production processes related to steel production or sold. Coke oven gas is the most common fuel for underfiring coke ovens.

A typical coke manufacturing process is shown schematically in Figure 12.2-2. Coke manufacturing includes preparing, charging, and heating the coal; removing and cooling the coke product; and cooling, cleaning, and recycling the oven gas.

Coal is prepared for coking by pulverizing so that 80 to 90 percent passes through a 3.2 millimeter (1/8 inch) screen. Several types of coal may be blended to produce the desired properties, or to control the expansion of the coal mixture in the oven. Water or oil may be added to adjust the density of the coal to control expansion and prevent damage to the oven.

Coal may be added to the ovens in either a dry or wet state. Prepared wet coal is finely crushed before charging to the oven. Flash-dried coal may be transported directly to the ovens by the hot gases used for moisture removal. Wall temperatures should stay above 1100°C (2000°F) during loading operations and actual coking. The ports are closed after charging and sealed with luting ("mud") material.

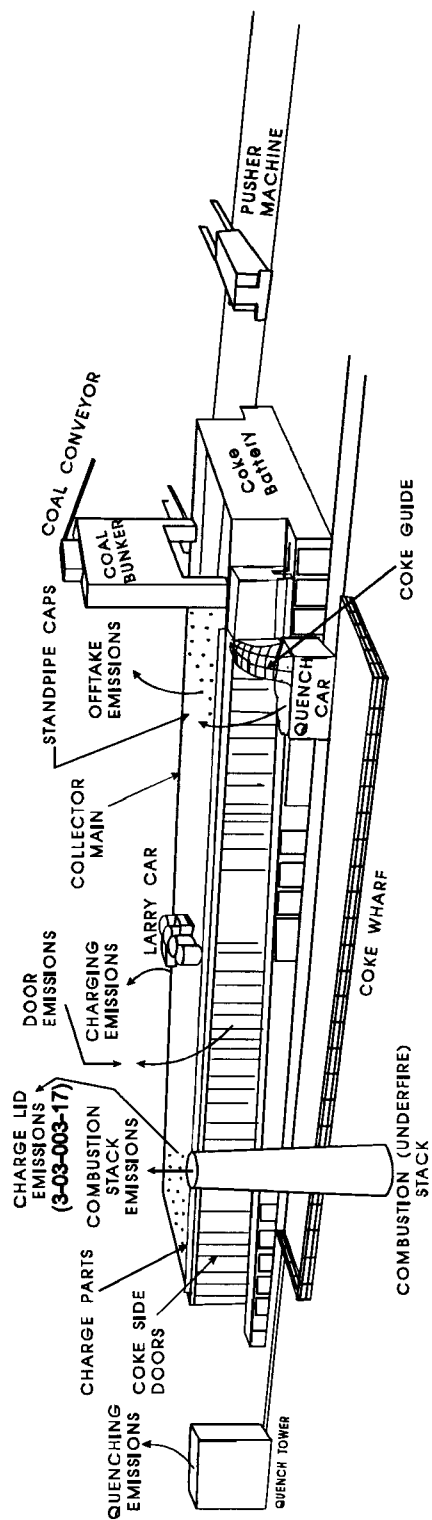


Figure 12.2-1. Byproduct coke oven battery showing major emission points. (Source Classification Codes in parentheses.)

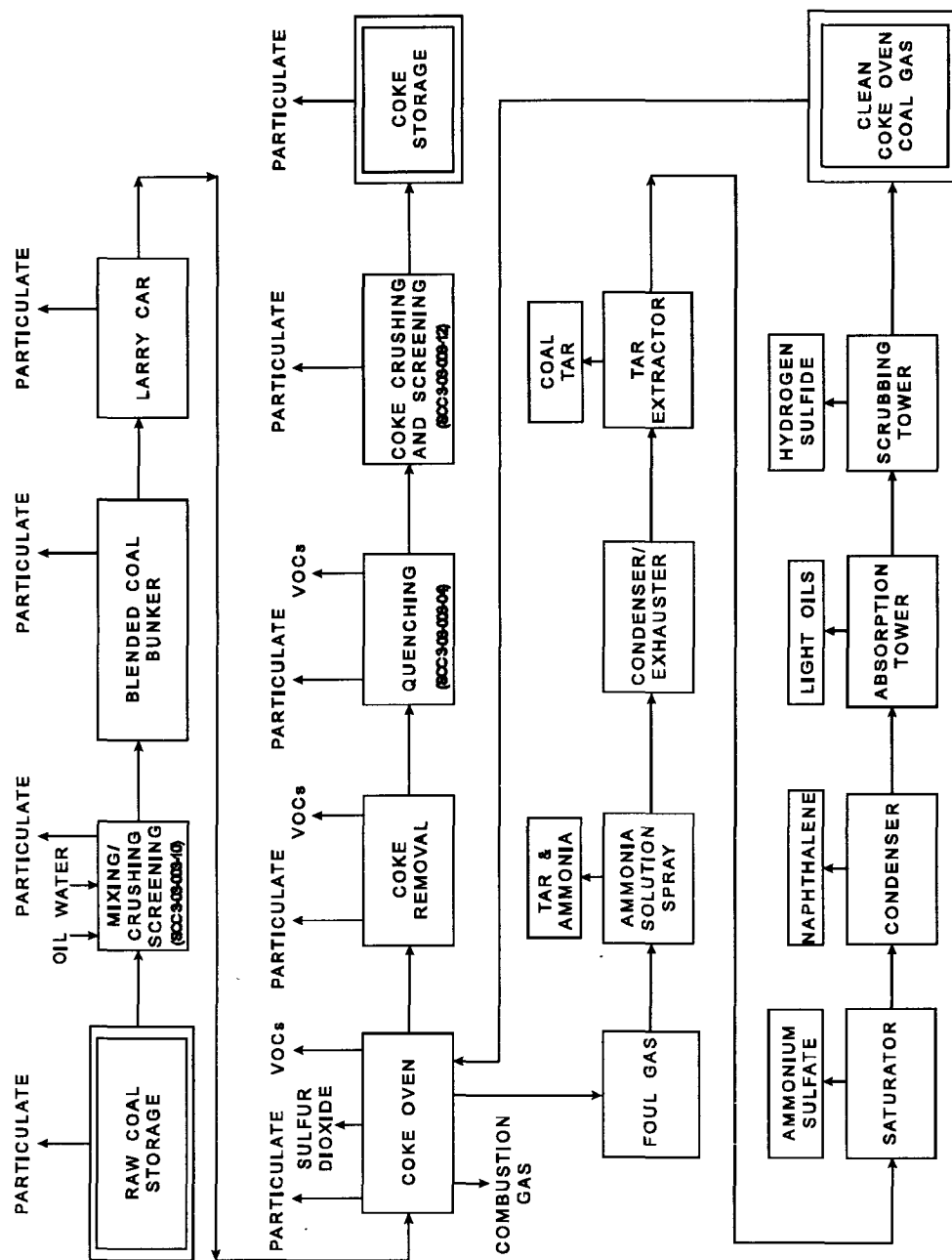


Figure 12.2-2. Flow diagram of coke manufacturing. VOC = volatile organic compound. (Source Classification Codes in parentheses.)

The blended coal mass is heated for 12 to 20 hours for metallurgical coke. Thermal energy from the walls of the coke chamber heats the coal mass by conduction from the sides to the middle of the coke chamber. During the coking process, the charge is in direct contact with the heated wall surfaces and develops into an aggregate "plastic zone". As additional thermal energy is absorbed, the plastic zone thickens and merges toward the middle of the charge. Volatile gases escape in front of the developing zone due to heat progression from the side walls. The maximum temperature attained at the center of the coke mass is usually 1100 to 1150°C (2000 to 2100°F). This distills all volatile matter from the coal mass and forms a high-quality metallurgical coke.

After coking is completed (no volatiles remain), the coke in the chamber is ready to be removed. Doors on both sides of the chamber are opened and a ram is inserted into the chamber. The coke is pushed out of the oven in less than 1 minute, through the coke guide and into a quench car. After the coke is pushed from the oven, the doors are cleaned and repositioned. The oven is then ready to receive another charge of coal.

The quench car carrying the hot coke moves along the battery tracks to a quench tower where approximately 1130 liters (L) of water per Mg of coke (270 gallons of water per ton) are sprayed onto the coke mass to cool it from about 1100 to 80°C (2000 to 180°F) and to prevent it from igniting. The quench car may rely on a movable hood to collect particulate emissions, or it may have a scrubber car attached. The car then discharges the coke onto a wharf to drain and continue cooling. Gates on the wharf are opened to allow the coke to fall onto a conveyor that carries it to the crushing and screening station. After sizing, coke is sent to the blast furnace or to storage.

The primary purpose of modern coke ovens is the production of quality coke for the iron and steel industry. The recovery of coal chemicals is an economical necessity, as they equal approximately 35 percent of the value of the coal.

To produce quality metallurgical coke, a high-temperature carbonization process is used. High-temperature carbonization, which takes place above 900°C (1650°F), involves chemical conversion of coal into a mostly gaseous product. Gaseous products from high-temperature carbonization consist of hydrogen, methane, ethylene, carbon monoxide, carbon dioxide, hydrogen sulfide, ammonia, and nitrogen. Liquid products include water, tar, and crude light oil. The coking process produces approximately 338,000 L of coke oven gas (COG) per megagram of coal charged (10,800 standard cubic feet of COG per ton).

During the coking cycle, volatile matter driven from the coal mass passes upward through cast iron "goosenecks" into a common horizontal steel pipe (called the collecting main), which connects all the ovens in series. This unpurified "foul" gas contains water vapor, tar, light oils, solid particulate of coal dust, heavy hydrocarbons, and complex carbon compounds. The condensable materials are removed from the exhaust gas to obtain purified coke oven gas.

As it leaves the coke chamber, coke oven coal gas is initially cleaned with a weak ammonia spray, which condenses some tar and ammonia from the gas. This liquid condensate flows down the collecting main until it reaches a settling tank. Collected ammonia is used in the weak ammonia spray, while the rest is pumped to an ammonia still. Collected coal tar is pumped to a storage tank and sold to tar distillers, or used as fuel.

The remaining gas is cooled as it passes through a condenser and then compressed by an exhaustor. Any remaining coal tar is removed by a tar extractor, either by impingement against a metal surface or collection by an electrostatic precipitator (ESP). The gas still contains 75 percent of original ammonia and 95 percent of the original light oils. Ammonia is removed by passing the gas through a saturator containing

a 5 to 10 percent solution of sulfuric acid. In the saturator, ammonia reacts with sulfuric acid to form ammonium sulfate. Ammonium sulfate is then crystallized and removed. The gas is further cooled, resulting in the condensation of naphthalene. The light oils are removed in an absorption tower containing water mixed with "straw oil" (a heavy fraction of petroleum). Straw oil acts as an absorbent for the light oils, and is later heated to release the light oils for recovery and refinement. The last cleaning step is the removal of hydrogen sulfide from the gas. This is normally done in a scrubbing tower containing a solution of ethanolamine (Girbotol), although several other methods have been used in the past. The clean coke oven coal gas is used as fuel for the coke ovens, other plant combustion processes, or sold.

12.2.3 Emissions And Controls

Particulate, VOCs, carbon monoxide and other emissions originate from several byproduct coking operations: (1) coal preparation, (2) coal preheating (if used), (3) coal charging, (4) oven leakage during the coking period, (5) coke removal, (6) hot coke quenching and (7) underfire combustion stacks. Gaseous emissions collected from the ovens during the coking process are subjected to various operations for separating ammonia, coke oven gas, tar, phenol, light oils (benzene, toluene, xylene), and pyridine. These unit operations are potential sources of VOC emissions. Small emissions may occur when transferring coal between conveyors or from conveyors to bunkers. Figure 12.2-2 portrays major emission points from a typical coke oven battery.

The emission factors available for coking operations for filterable particulate, sulfur dioxide, carbon monoxide, VOCs, nitrogen oxides, and ammonia are given in Tables 12.2-1 and 12.2-2. Tables 12.2-3 and 12.2-4 give size-specific emission factors for coking operations.

A few domestic plants preheat the coal to about 260°C (500°F) before charging, using a flash drying column heated by the combustion of coke oven gas or by natural gas. The air stream that conveys coal through the drying column usually passes through conventional wet scrubbers for particulate removal before discharging to the atmosphere. Leaks occasionally occur from charge lids and oven doors during pipeline charging due to the positive pressure. Emissions from the other methods are similar to conventional wet charging.

Oven charging can produce significant emissions of particulate matter and VOCs from coal decomposition if not properly controlled. Charging techniques can draw most charging emissions into the battery collecting main. Effective control requires that goosenecks and the collecting main passages be cleaned frequently to prevent obstructions.

During the coking cycle, VOC emissions from the thermal distillation process can occur through poorly sealed doors, charge lids, offtake caps, collecting main, and cracks that may develop in oven brickwork. Door leaks may be controlled by diligent door cleaning and maintenance, rebuilding doors, and, in some plants, by manual application of lute (seal) material. Charge lid and offtake leaks may be controlled by an effective patching and luting program. Pushing coke into the quench car is another major source of particulate emissions. If the coke mass is not fully coked, VOCs and combustion products will be emitted. Most facilities control pushing emissions by using mobile scrubber cars with hoods, shed enclosures evacuated to a gas cleaning device, or traveling hoods with a fixed duct leading to a stationary gas cleaner.

Coke quenching entrains particulate from the coke mass. In addition, dissolved solids from the quench water may become entrained in the steam plume rising from the tower. Trace organic compounds may also be present.

12.2.4 Updates Since the Fifth Edition

Revisions to this section since the Fifth Edition release in January 1995 are summarized below.

Supplement F, April 2000

- Units for the emission factors provided in Tables 12.2-1 and 12.2-3 have been changed from kg of pollutant/Mg of coke produced to kg of pollutant/Mg of coal charged. None of the numerical values were changed.
- Units for the emission factors provided in Tables 12.2-2 and 12.2-4 have been changed from lb of pollutant/ton of coke produced to lb of pollutant/ton of coal charged. None of the numerical values were changed.

The October 1986 version of this section reported the emission factor units as lb of pollutant/ton of coal charged (kg of pollutant/Mg of coal charged). The January 1995 revision of this section did not change the numerical value for any of the emission factors but, due to a formatting error, the units were mistakenly reported as lb of pollutant/ton of coke produced (kg of pollutant/Mg of coke produced). Thus the revisions noted above correct errors to the January 1995 revision of this section.

September, 2000

- In Table 12.2-4, the PM factors in Metric units were incorrectly transcribed into the English unit table. This has been corrected. The PM factors in Table 12.2-4 now accurately reflect the English unit factors from the Fourth Edition. Some additional SCC codes were also added for the combustion stack and for oven charging.
- More errors were found and corrected in Table 12.2-1. The PM factor for uncontrolled combustion stack with an ESP (BFG) was corrected to "ND", and the PM factor for the same unit with ESP (COG) was corrected to 0.055 kg/MG of coal charged.
- The PM factors in all of the tables were labeled "filterable" to make the terminology consistent with the present day convention.

Table 12.2-1 (Metric Units). EMISSION FACTORS FOR COKE MANUFACTURING ^a

Type Of Operation	Filterable Particulate ^b	EMISSION FACTOR RATING	SO ₂	EMISSION FACTOR RATING	CO ^c	EMISSION FACTOR RATING	VOC ^{c,d}	EMISSION FACTOR RATING	NO _x ^e	EMISSION FACTOR RATING	Ammonia ^c	EMISSION FACTOR RATING
Coal crushing (SCC 3-03-003-10) With cyclone	0.055	D	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Coal preheating (SCC 3-03-003-13) Uncontrolled ^e	1.75	C	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
With scrubber	0.125	C	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
With wet ESP	0.006	C	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
Oven charging ^f (larry car) (SCC 3-03-003-02)												
Uncontrolled	0.24	E	0.01	D	0.3	D	1.25	D	0.015	D	0.01	D
With sequential charging	0.008	E	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
With scrubber	0.007	E	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
Oven door leaks (SCC 3-03-003-08) Uncontrolled	0.27	D		D	0.3	D	0.75	D	0.005	D	0.03	D
Oven pushing (SCC 3-03-003-03) Uncontrolled	0.58	B	ND	NA	0.035	D	0.1	D	ND	NA	0.05	D
With ESP ^g	0.225	C	ND	NA	0.035	D	0.1	D	ND	NA	ND	NA
With venturi scrubber ^h	0.09	D	ND	NA	0.035	D	0.1	D	ND	NA	ND	NA
With baghouse ^h	0.045	D	ND	NA	0.035	D	0.1	D	ND	NA	ND	NA
With mobile scrubber car ⁱ	0.036	C	ND	NA	0.035	D	0.1	D	ND	NA	ND	NA
Quenching (SCC 3-03-003-04) Uncontrolled												
Dirty water ^k	2.62	D	NA	NA	ND	NA	ND	NA	NA	NA	ND	NA
Clean water ^m	0.57	D	NA	NA	ND	NA	ND	NA	NA	NA	ND	NA
With baffles												
Dirty water ^k	0.65	B	NA	NA	ND	NA	ND	NA	NA	NA	ND	NA
Clean water ^m	0.27	B	NA	NA	ND	NA	ND	NA	NA	NA	ND	NA

Table 12.2-1 (cont.).

Type Of Operation	Filterable Particulate ^b	EMISSION FACTOR RATING	SO ₂	EMISSION FACTOR RATING	CO ^e	EMISSION FACTOR RATING	VOC ^{c,d}	EMISSION FACTOR RATING	NO _x ^e	EMISSION FACTOR RATING	Ammonia ^e	EMISSION FACTOR RATING
Combustion stack (SCC 3-03-003-17, for COG)												
(SCC 3-03-003-16, for BFG)												
Uncontrolled (raw COG)	0.234	A	2.0 ⁿ	D	ND	NA	ND	NA	ND	NA	ND	NA
Uncontrolled (desulfurized COG)	0.234	A	0.14 ^p	C	ND	NA	ND	NA	ND	NA	ND	NA
Uncontrolled (BFG)	0.085	A	0.54 ^q	D	ND	NA	ND	NA	ND	NA	ND	NA
With ESP (BFG)	ND	NA	0.32 ^r	C	ND	NA	ND	NA	ND	NA	ND	NA
With ESP (COG)	0.046	D	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
With baghouse (COG)	0.055	D	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
Coke handling (SCC 3-03-003-12)												
With cyclone ^s	0.003	D	ND	NA	ND	NA	NA	NA	NA	NA	NA	NA

^a Emission Factors are expressed in kg of pollutant/Mg of coal charged. SCC = Source Classification Code. NA = not applicable. ND = no data. BFG = blast furnace gas.

^b Reference 1. Filterable particulate is defined as the particulate that is measured in an EPA Method 5 train (or equivalent).

^c Reference 23.

^d Expressed as methane.

^e Exhaust gas discharged from series of primary and secondary cyclones used to separate flash-dried coal from hot gas.

^f Charged coal has not been dried.

^g Emissions captured by coke side shed.

^h Emissions captured by travelling hood.

ⁱ Emissions captured by quench car enclosure.

^j Dirty water ≥ 5000 Mg/L total dissolved solids.

^k Clean water ≤ 1500 Mg/L total dissolved solids.

ⁿ Reference 4. Factor for SO₂ is based on these representative conditions: (1) sulfur content of coal charged to oven is 0.8 weight %; (2) about 33 weight % of total sulfur in coal charged to oven is transferred to coke oven gas; (3) about 40% of coke oven gas is burned during underfiring operation, and about 60% is used in other operations where the rest of the SO₂ (3 kilograms/megagrams [6 lb/ton] of coal charged) is discharged; (4) gas used in underfiring has not been desulfurized.

^p Reference 21, desulfurized COG.

^q Reference 22.

^r Reference 23.

^s Defined as crushing and screening.

Table 12.2-2 (English Units). EMISSION FACTORS FOR COKE MANUFACTURING^a

Type Of Operation	Filterable Particulate ^b	EMISSION FACTOR RATING	SO ₂	EMISSION FACTOR RATING	CO ^c	EMISSION FACTOR RATING	VOC ^{c,d}	EMISSION FACTOR RATING	NO _x ^e	EMISSION FACTOR RATING	Ammonia ^e	EMISSION FACTOR RATING
Coal crushing (SCC 3-03-003-10) With cyclone	0.11	D	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Coal preheating (SCC 3-03-003-13) Uncontrolled ^e	3.50	C	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
With scrubber	0.25	C	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
With wet ESP	0.012	C	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
Oven charging ^f (larry car) (SCC 3-03-003-02) Uncontrolled	0.48	E	0.02	D	0.6	D	2.5	D	0.03	D	0.02	D
With sequential charging	0.016	E	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
With scrubber	0.014	E	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
Oven door leaks (SCC 3-03-003-08) Uncontrolled	0.54	D	ND	D	0.6	D	1.50	D	0.01	D	0.06	D
Oven pushing (SCC 3-03-003-03) Uncontrolled	1.15	B	ND	NA	0.07	D	0.2	D	ND	NA	0.1	D
With ESP ^g	0.45	C	ND	NA	0.07	D	0.2	D	ND	NA	ND	NA
With venturi scrubber ^h	0.18	D	ND	NA	0.07	D	0.2	D	ND	NA	ND	NA
With baghouse ^h	0.09	D	ND	NA	0.07	D	0.2	D	ND	NA	ND	NA
With mobile scrubber car	0.072	C	ND	NA	0.07	D	0.2	D	ND	NA	ND	NA
Quenching ⁱ (SCC 3-03-003-04) Uncontrolled												
Dirty water ^k	5.24	D	NA	NA	ND	NA	ND	NA	NA	NA	ND	NA
Clean water ^m	1.13	D	NA	NA	ND	NA	ND	NA	NA	NA	ND	NA
With baffles												
Dirty water ^k	1.30	B	NA	NA	ND	NA	ND	NA	NA	NA	ND	NA
Clean water ^m	0.54	B	NA	NA	ND	NA	ND	NA	NA	NA	ND	NA

Table 12.2-2 (cont.).

Type Of Operation	Filterable Particulate ^b	EMISSION FACTOR RATING	SO ₂	EMISSION FACTOR RATING	CO ^c	EMISSION FACTOR RATING	VOC ^{c,d}	EMISSION FACTOR RATING	NO _x ^e	EMISSION FACTOR RATING	Ammonia ^e	EMISSION FACTOR RATING
Combustion stack (SCC 3-03-003-17, for COG) (SCC 3-03-003-18, for BFG)												
Uncontrolled (raw COG)	0.47	A	4.0 ⁿ	D	ND	NA	ND	NA	ND	NA	ND	NA
Uncontrolled (desulfurized COG)	0.47	A	0.28 ^g	C	ND	NA	ND	NA	ND	NA	ND	NA
Uncontrolled (BFG)	0.17	A	1.08 ^s	C	ND	NA	ND	NA	ND	NA	ND	NA
With ESP (BFG)	ND	B	0.64 ^t	C	ND	NA	ND	NA	ND	NA	ND	NA
With ESP (COG)	0.091	D	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
With baghouse (COG)	0.11	D	ND	NA	ND	NA	ND	NA	ND	NA	ND	NA
Coke handling (SCC 3-03-003-12) With cyclone ^e	0.006	D	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

^a Emission Factors are expressed in lb/ton of coal charged. SCC = Source Classification Code. NA = not applicable. ND = no data. BFG = blast furnace gas.

^b Reference 1. Filterable particulate is defined as the particulate that is measured in an EPA Method 5 train (or equivalent).

^c References 23.

^d Expressed as methane.

^e Exhaust gas discharged from series of primary and secondary cyclones used to separate flash dried coal from hot gas.

^f Charged coal has not been dried.

^g Emissions captured by coke side shed.

^h Emissions captured by travelling hood.

ⁱ Emissions captured by quench car enclosure.

^k Dirty water ≥ 5000 mg/L total dissolved solids.

^m Clean water ≤ 1500 mg/L total dissolved solids.

ⁿ Reference 4. Factor for SO₂ is based on these representative conditions: (1) sulfur content of coal charged to oven is 0.8 weight %; (2) about 33 weight % of total sulfur in coal charged to oven is transferred to coke oven gas; (3) about 40% of coke oven gas is burned during underfiring operation, and about 60% is used in other operations where the rest of the SO₂ (3 kilogram/megagram [6 pounds/ton] of coal charged) is discharged; (4) gas used in underfiring has not been desulfurized.

^p Reference 21, desulfurized COG.

^q Reference 22.

^r Reference 23.

^s Defined as crushing and screening.

Table 12.2-3. (Metric Units). SIZE-SPECIFIC EMISSION FACTORS
FOR COKE MANUFACTURING^a

EMISSION FACTOR RATING: D (except as noted)

Process	Particle Size (μm) ^b	Cumulative Mass % ≤ Stated Size	Cumulative Mass Emission Factors	Reference Source Number
Coal preheating (SCC 3-03-003-13) Uncontrolled	0.5	44	0.8	8
	1.0	48.5	0.8	
	2.0	55	1.0	
	2.5	59.5	1.0	
	5.0	79.5	1.4	
	10.0	97.5	1.7	
	15.0	99.9	1.7	
		100	1.7	
Controlled with venturi scrubber	0.5	78	0.10	8
	1.0	80	0.10	
	2.0	83	0.10	
	2.5	84	0.11	
	5.0	88	0.11	
	10.0	94	0.12	
	15.0	96.5	0.12	
		100	0.12	
Oven charging sequential or stage ^c (SCC 3-03-003-02)	0.5	13.5	0.001	9
	1.0	25.2	0.002	
	2.0	33.6	0.003	
	2.5	39.1	0.003	
	5.0	45.8	0.004	
	10.0	48.9	0.004	
	15.0	49.0	0.004	
		100	0.008	
Coke pushing (SCC 3-03-003-03) Uncontrolled	0.5	3.1	0.02	10 - 15
	1.0	7.7	0.04	
	2.0	14.8	0.09	
	2.5	16.7	0.10	
	5.0	26.6	0.15	
	10.0	43.3	0.25	
	15.0	50.0	0.29	
		100	0.58	

Table 12.2-3 (cont.).

Process	Particle Size (µm) ^b	Cumulative Mass % ≤ Stated Size	Cumulative Mass Emission Factors	Reference Source Number
Controlled with venturi scrubber	0.5	24	0.02	10, 12
	1.0	47	0.04	
	2.0	66.5	0.06	
	2.5	73.5	0.07	
	5.0	75	0.07	
	10.0	87	0.08	
	15.0	92	0.08	
		100	0.09	
Mobile scrubber car	1.0	28.0	0.010	16
	2.0	29.5	0.011	
	2.5	30.0	0.011	
	5.0	30.0	0.011	
	10.0	32.0	0.012	
	15.0	35.0	0.013	
		100	0.036	
Quenching (SCC 3-03-003-04)				17
Uncontrolled (dirty water)	1.0	13.8	0.36	
	2.5	19.3	0.51	
	5.0	21.4	0.56	
	10.0	22.8	0.60	
	15.0	26.4	0.69	
		100	2.62	
Uncontrolled (clean water)	1.0	4.0	0.02	17
	2.5	11.1	0.06	
	5.0	19.1	0.11	
	10.0	30.1	0.17	
	15.0	37.4	0.21	
		100	0.57	
With baffles (dirty water)	1.0	8.5	0.06	17
	2.5	20.4	0.13	
	5.0	24.8	0.16	
	10.0	32.3	0.21	
	15.0	49.8	0.32	
		100	0.65	

Table 12.2-3 (cont.).

Process	Particle Size (μm) ^b	Cumulative Mass % \leq Stated Size	Cumulative Mass Emission Factors	Reference Source Number
With baffles (clean water)	1.0	1.2	0.003	17
	2.5	6.0	0.02	
	5.0	7.0	0.02	
	10.0	9.8	0.03	
	15.0	15.1	0.04	
		100	0.27	
Combustion stack (SCC 3-03-003-17 for COG) Uncontrolled	1.0	77.4	0.18	18 - 20
	2.0	85.7	0.20	
	2.5	93.5	0.22	
	5.0	95.8	0.22	
	10.0	95.9	0.22	
	15.0	96	0.22	
		100	0.23	

^a Emission factors are filterable PM and are expressed in kg of pollutant/Mg of coal charged.

^b μm = micrometers

^c EMISSION FACTOR RATING: E

Table 12.2-4. (English Units). SIZE-SPECIFIC EMISSION FACTORS
FOR COKE MANUFACTURING^a

EMISSION FACTOR RATING: D (except as noted)

Process	Particle Size (μm) ^b	Cumulative Mass % ≤ Stated Size	Cumulative Mass Emission Factors	Reference Source Number
Coal preheating (SCC 3-03-003-13) Uncontrolled	0.5	44	1.5	8
	1.0	48.5	1.7	
	2.0	55	1.9	
	2.5	59.5	2.1	
	5.0	79.5	2.8	
	10.0	97.5	3.4	
	15.0	99.9	3.5	
		100	3.5	
	Controlled with venturi scrubber	0.5	0.20	8
		1.0	0.20	
		2.0	0.21	
		2.5	0.21	
		5.0	0.22	
		10.0	0.24	
		15.0	0.24	
		100	0.25	
Oven charging sequential or stage ^c (SCC 3-03-003-02)	0.5	13.5	0.002	9
	1.0	25.2	0.004	
	2.0	33.6	0.005	
	2.5	39.1	0.006	
	5.0	45.8	0.007	
	10.0	48.9	0.008	
	15.0	49.0	0.008	
		100	0.016	
Coke pushing (SCC 3-03-003-03) Uncontrolled	0.5	3.1	0.04	10 - 15
	1.0	7.7	0.09	
	2.0	14.8	0.17	
	2.5	16.7	0.19	
	5.0	26.6	0.30	
	10.0	43.3	0.50	
	15.0	50.0	0.58	
		100	1.15	

Table 12.2-4 (cont.).

Process	Particle Size (µm) ^b	Cumulative Mass % ≤ Stated Size	Cumulative Mass Emission Factors	Reference Source Number
Controlled with venturi scrubber	0.5	24	0.04	10, 12
	1.0	47	0.08	
	2.0	66.5	0.12	
	2.5	73.5	0.13	
	5.0	75	0.13	
	10.0	87	0.16	
	15.0	92	0.17	
		100	0.18	
Mobile scrubber car	1.0	28.0	0.020	16
	2.0	29.5	0.021	
	2.5	30.0	0.022	
	5.0	30.0	0.022	
	10.0	32.0	0.024	
	15.0	35.0	0.023	
		100	0.072	
Quenching (SCC 3-03-003-04)				17
Uncontrolled (dirty water)	1.0	13.8	0.72	
	2.5	19.3	1.01	
	5.0	21.4	1.12	
	10.0	22.8	1.19	
	15.0	26.4	1.38	
		100	5.24	
Uncontrolled (clean water)	1.0	4.0	0.05	17
	2.5	11.1	0.13	
	5.0	19.1	0.22	
	10.0	30.1	0.34	
	15.0	37.4	0.42	
		100	1.13	
With baffles (dirty water)	1.0	8.5	0.11	17
	2.5	20.4	0.27	
	5.0	24.8	0.32	
	10.0	32.3	0.42	
	15.0	49.8	0.65	
		100	1.30	

Table 12.2-4 (cont.).

Process	Particle Size (μm) ^b	Cumulative Mass % \leq Stated Size	Cumulative Mass Emission Factors	Reference Source Number
With baffles (clean water)	1.0	1.2	0.006	17
	2.5	6.0	0.03	
	5.0	7.0	0.04	
	10.0	9.8	0.05	
	15.0	15.1	0.08	
		100	0.54	
Combustion stack (SCC 3-03-003-17 for COG) Uncontrolled	1.0	77.4	0.36	18 - 20
	2.0	85.7	0.40	
	2.5	93.5	0.44	
	5.0	95.8	0.45	
	10.0	95.9	0.45	
	15.0	96	0.45	
		100	0.47	

^a Emission factors are filterable PM and are expressed in lb of pollutant/ton of coal charged.

^b μm = micrometers.

^c EMISSION FACTOR RATING: E

Combustion of gas in the battery flues produces emissions from the underfire or combustion stack. Sulfur dioxide emissions may also occur if the coke oven gas is not desulfurized. Coal fines may leak into the waste combustion gases if the oven wall brickwork is damaged. Conventional gas cleaning equipment, including electrostatic precipitators and fabric filters, have been installed on battery combustion stacks.

Fugitive particulate emissions are associated with material handling operations. These operations consist of unloading, storing, grinding and sizing of coal, screening, crushing, storing, and unloading of coke.

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