INSPECTOR’S GUIDANCE MANUAL

Stationary Gas Turbines

40 CFR Part 60

Subpart GG

Developed By:
Stationary Sources Branch
Air Pollution Control Division
4300 Cherry Creek Drive South
Denver, Colorado 80222
(303) 692-3150
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4 Stationary Gas Turbines - Subpart GG

4.1 Introduction

On September 10, 1979, under Section 111 of the Clean Air Act, as amended, the U.S. Environmental Protection Agency (“U.S. EPA”) promulgated standards of performance which limit emissions of nitrogen oxides and sulfur dioxide from new, modified and reconstructed stationary gas turbines. This guidance document presents procedures for inspection of stationary gas turbines in order to determine permit compliance and compliance with this New Source Performance Standard (NSPS). This document also provides background information that will aid the inspector in understanding stationary gas turbines.

4.2 Background Information

4.2.1 General

Stationary gas turbines are applied in electric power generators, in gas pipeline pump and compressor drives, and in various process industries. A gas turbine is an internal combustion engine that operates with rotary motion. Gas turbines are used in electric power generators, and various process industries. 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. Gas turbines greater than 4,021 hp that are used in electrical generation are used for continuous, peaking, or standby power. The primary fuels used are natural gas and distillate (No. 2) fuel oil.

4.2.2 Process Description

Gas turbines are made up of three major components: compressor, combustor, and power turbine. Multiple compressors, turbines and combustors can be used in various arrangements (Figure 4-1). In the simple cycle gas turbine, air enters the compressor and is compressed. Then enters the combustor and is ignited with fuel, and then the combustion products turn on the turbine. A second turbine can be added to extract more energy from the exhaust gases. In theory, another combustion chamber can be added to reheat the gases after the first turbine expansion. Additional compressors can be added to further compress the air, increasing the overall pressure ratio and efficiency.

In actual practice, it is common for gas turbines to have two compressors and two turbines with one combustor. The first compressor that the air enters is called the low pressure compressor. If there is a second compressor, it is called the high pressure compressor, since it raises the pressure of the air higher than the low pressure compressor. The low pressure compressor has a larger diameter than the high pressure compressor, and the compressor blades on the low pressure compressor are larger than those of the high pressure compressor. This type of design is called a “split compressor” or “twin spool” engine.
Figure 4-1. Various Open Cycle Gas Turbine Arrangements
If there are two turbines after the combustor, the first turbine after the combustor is called the high pressure turbine. The second turbine that the exhaust gases flow through is called the low pressure turbine. When the air enters the first turbine it is near its highest pressure, and by the time it exits the high pressure turbine and enters the low pressure turbine the pressure of the gases has decreased substantially. The diameter and blade size of the high and low pressure turbines is analogous to the size in the high and low pressure compressor. The low pressure turbine has a larger diameter and larger blades.

The low pressure compressor is driven by the low pressure turbine and the high pressure compressor is driven by the high pressure turbine. A coaxial shaft is often used in gas turbines with high and low pressure compressors and turbines. The shaft between the low pressure compressor and low pressure turbine rotates within the shaft for the high pressure compressor and the high pressure turbine.

On stationary gas turbines, the high pressure compressor and turbine can be run at the most optimum speed while the low pressure compressor and turbine are varied to meet load requirements. Stationary gas turbines may be called “heavy duty” or “industrial” engines or manufacturers may have specific names for their stationary engines; some are very large.

4.2.2.1 Compressors

Compressors increase the pressure of air before it enters the combustor for combustion. The compressor gets more air in the engine, and in general the more air that is put in the engine the more power will be produced. The energy released by the combustor is proportional to the mass of the air that enters the engine, so the compressor is an important part of the engine. The main kinds of compressors that have been used with gas turbines include centrifugal flow, and axial flow compressors (Figures 4-2 and 4-3).
Figure 4-2. Centrifugal Compressor

Figure 4-3. Edge View of Axial Compressor
4.2.2.1.1 Centrifugal Compressors

Centrifugal compressors use centrifugal force to displace and compress air. A rotating impeller is used to impart energy to air or a gas to compress it. After flowing through a fixed guide vanes at the compressor entrance, air enters the center of the compressor impeller hub and moves radially outward. At first the air flows axially, parallel to the shaft on which the impeller rotates, then it is channeled by the impeller with a 90° change in direction, and discharged into the diffuser. The mechanical energy of the rotating impeller is transferred to the air by increasing its velocity. The air flows radially outward along the vanes of the impeller and the air’s velocity and pressure increase as it moves outward. Some energy from the impeller increases the air’s temperature from friction between the air and the blades and due to the work done on the air. When the air leaves the impeller, it enters divergent nozzle vanes in the diffuser that convert the kinetic energy of the air into pressure energy. It is common to design the impeller so that half the pressure rise occurs in the impeller and half occurs in the diffuser.

4.2.2.1.2 Axial Compressors

The axial compressor is used in most modern gas turbines. It has a cylindrical hub with “rings” or stages of rotor blades. In between each set of rotor blades are the stator blades. The stator blades do not rotate and they are a part of the case that surrounds the compressor rotor. The case is often in two halves, so that the compressor can be opened and inspected or repaired. The number of stages is usually determined by the number of rows of blades on the rotating rotor. There is usually one more set of stator vanes than rotor blades since the stators are at the front and rear end of the compressor. At the ends of the larger sized stator blades toward the center of the rotor are shrouds that connect the ends of the stator blades together. The shrouds help prevent air from being lost in the inner part of the compressor or being lost between stages and it helps reduce vibrations. Small stators toward the rear of the compressor often do not have shrouds. Each stage of stator blades changes the direction of the air flow (angle of attack) as it leaves the rotor, so it will enter the next rotor stage at the correct angle.

4.2.2.1.3 Axial/Centrifugal Compressor Comparison

Centrifugal compressors are stronger than axial compressors. The impellers of centrifugal compressors are stronger that the thin blades of the axial compressor. The small stator and rotor blades at the back of the compressor are especially fragile and susceptible to damage from foreign objects. Centrifugal compressors are also simpler and less expensive to manufacture. An axial compressor may have over 1000 blades and stator vanes; furthermore, close fits between its parts are required for efficient operation. Axial compressors are more sensitive to changes in air flow rate and rotational speed and have a narrower range of operating conditions. Changes in air flow rate and rotational speed can lead to rapid drop in efficiency. This also has a negative effect on the part load performance of the compressor and gas turbine.

On the other hand, in practically all applications for gas turbines, axial compressors are used because of their advantages. Axial compressors are more efficient than centrifugal compressors. It is
cheaper to manufacture a centrifugal compressor, but the cost savings is lost from the decreased efficiency. Centrifugal compressors have a larger diameter, increasing space requirements and frontal area. Given a centrifugal compressor and an axial compressor with the same frontal area, the axial compressor will consume more air; therefore, a higher pressure ratio and more output power can be produced.

Centrifugal compressors are not as adaptable to multi-staging. Most of the centrifugal gas turbines ever made used a maximum of two stages. A centrifugal compressor is the best option to use for small engines when the application requires strength and simplicity, but a lower pressure ratio and other disadvantages can be tolerated. Centrifugal compressors are often used for the small engines in auxiliary power units.

4.2.2.2 Combustors

The combustor is the combustion chamber for the gas turbine. The main type of turbine for stationary engines is the silo combustor (Figure 4-4); the silo combustor is mounted externally to the gas turbine. This type of combustor may also be called the “single can,” “sore thumb,” or “green thumb” combustor by various manufacturers. A single can design is usually a smaller sized external combustion chamber, and silo combustors are usually referred to as larger sized combustors with a length that is over two times the diameter of the gas turbine. More than one external combustor can be used in the silo design.

Silo combustors look like grain silos or cylinders and they are generally mounted perpendicular to the gas turbine. The inside of the silo combustor is fitted with a ceramic lining to protect the metal of the combustor from heat.

4.2.2.2.1 Combustor Performance

For a combustor to perform well, it must have a high combustion efficiency, it must have a low pressure loss, and it must have a stable flame. A high combustion efficiency is necessary for a high overall thermal efficiency. When the combustion efficiency is low, unburned fuel could be exiting the combustor and burning in the turbine and exhaust. Fuel burning in the turbine is detrimental to the turbine and exhaust. Flame stability means a steady constant flame. A flame that has poor stability will pulsate and could blow out. Pressure and the velocity of the gases in the combustor have a large effect on the range of a stable flame. The lower the pressure is, the narrower the range of stable flame operation. If the pressure is continually lowered the flame will become unstable and will not be able to burn. Higher exhaust gas velocities will also decrease the stable flame operating range. If the velocity is increased to its critical velocity, the flame will blow out. In addition, requirements for good combustion include: low amounts of deposits formed in the combustor, turbine and regenerator (if there is one); and the equipment must be serviceable and have a reasonable life.
Figure 4-4. Silo Combustor
4.2.2.3 Turbines

The turbine does the inverse of the compressor; the turbine extracts energy from the hot, high-velocity gases leaving the combustor. As stated earlier, the compressor adds energy to entering air by increasing its velocity, and the velocity of the air is then decreased, creating a corresponding increase in pressure. The energy extracted by the turbine is converted to shaft horsepower by the rotation of the turbine. In stationary gas turbine operations, over 90% of the energy of the combustion gases will be extracted by the turbine.

4.2.2.3.1 Types of Turbines

There are two basic types of turbines, which are analogous to the centrifugal and axial types of compressors. These two turbines include the radial-inflow turbine and the axial-flow turbine. The radial-inflow turbine is essentially a centrifugal compressor with a reversed flow. Less than 20% of gas turbines use the radial-inflow type of turbine and they are usually used for smaller loads and for smaller operating ranges than axial turbines. Radial turbines are shorter that axial turbines, which can be an advantage depending upon the application.

The two main parts that make up a turbine are the turbine blades and the disk. The disk is often made mostly of alloyed steel, chromium, nickel and cobalt. Blades are attached to the disk with a “fir tree” design fit. The blades are prevented from sliding out of the disk by rivets, locking tabs, or other devices. The turbine must also be carefully balanced. Turbine blades may be shrouded or open at the tips. A shroud helps prevent blade tip losses and excessive vibration, Shrouded blades also tend to resist distortion from high loads. The added rigidity of the shroud prevents the blades from twisting. On the other hand, a turbine with shrouding must be run at cooler temperatures or at reduced speeds. The turbine is designed to distribute the load evenly between all the turbine stages, so each successive stage has larger blades with a larger area.

4.2.2.3.2 Stationary Gas Turbine Cogeneration/Combined Cycle Power Plants

The main use for stationary gas turbines is to produce electrical power in a power plant. Before air enters the gas turbine it is filtered, to prevent material from getting into the compressor and collecting on the compressor blades or other equipment (Figure 4-5). Modern filtering systems are equipped with self-cleaning mechanisms. Pulses of compressed air may be used to provide cleaning of the filters. Many modern power plants with gas turbines cool the entering air with a chiller or air conditioner coil to maximize the efficiency. The cooling water used may come from chilled water from the cooling tower.

The air enters the compressor of the gas turbine and is compressed. Only about a quarter of the air is used for combustion and the rest is used to provide cooling to the gas turbine. Cooling air must be continually delivered to the liner in the combustor to prevent damage from excessive temperatures and to cool gases to the turbine inlet temperature.

Compressed air enters the combustor, fuel is added and the air/fuel mixture is ignited. Hot
gases then expand through the turbine of the engine, forcing the turbine to turn rapidly. The energy transferred to the turbine is mostly used to turn the compressor. The shafts of the turbine and compressor are directly connected. Some designs may have gearing between the generator and gas turbine to attain the desired revolutions per minute (rpm). The net output energy of the turbine turns the generator to convert the mechanical energy of the gas turbine into electricity. Cooling is also required for the generator. Air is drawn into the generator enclosure for cooling. Some generators are water cooled and oil is used to provide lubrication and cooling. The generator may be mounted on the turbine side of the gas turbine or on the compressor side, depending on the type of gas turbine.

Most stationary gas turbines use natural gas as a fuel. The natural gas is delivered to the plant by a pipeline. Compressors are used to increase the pressure of the natural gas to the pressure that is required for the fuel injectors in the combustor. An electric motor or engine may be used to run the natural gas compressor. Oil may also be used to run the gas turbine, but it is usually a backup fuel in case natural gas is temporarily unavailable.

Some gas turbines also have equipment to extract more energy from the hot gases leaving the turbine (Figure 4-5). Feed water pumps run water through heat exchangers in the exhaust portion of the gas turbine called the heat recovery steam generator (HRSG) or waste heat boiler. The heat exchangers are generally large bundles of tubes made of highly conductive materials such as steel. Hot gases exchange heat energy with the water through the boiler tubes before the exhaust exits the stack. A power plant is a cogeneration plant when it produces power and also makes steam that is sent elsewhere to run other equipment. This steam could be used to heat water, heat air for space heating, turn a turbine for mechanical energy, or to operate other industrial processes.
Figure 4-5. Stationary Gas Turbine Cogeneration/Dual Cycle Power Plant

Last Revised: June 22, 1998
The heat recovery sections in the heat recovery steam generator may include the economizer, low pressure, intermediate pressure, and the high pressure section. The economizer is generally the last heat exchanger in the system before flue gases are released to the stack. As its name implies, its function is to capture as much of the last amounts of heat energy available in the stack gas to save money. Feedwater pumps pump the water through the economizer and then into the low pressure boiler tubes and comes back to the low pressure boiler, increasing the temperature of the water. The low pressure section is also called the deaerator, because dissolved corrosive gases are usually removed from the water in this section. Oxygen is the primary gas that is removed. Steam is sent from the low pressure boiler to the intermediate boiler. Heated water from the economizer is also pumped to the intermediate section. As with the low pressure boiler, the intermediate boiler is a heat exchanger that absorbs heat from the flue gas. The intermediate steam produced from the intermediate boiler is at a higher pressure and temperature than the steam from the low pressure boiler. For simplicity, only one feedwater pump is shown and the intermediate boiler section has been left out of Figure 4-5.

Steam from the intermediate boiler and feedwater is sent to the high pressure boiler. Water flows from the high pressure drum into the tubes of the high pressure boiler, returning to the high pressure drum and creating high pressure steam. Steam from the high pressure drum or boiler then goes to the superheater. The superheater is located toward the hottest section of the HRSG. Only water that is in its gaseous state is sent to the superheater. The superheater increases the pressure and temperature of the steam to its highest value in the system. Superheated steam from the superheater is sent to a steam turbine to produce more energy. Intermediate steam and low pressure steam may be drawn off the intermediate and low pressure boilers to supplement the steam turbine, to run other processes or for steam injection into the gas turbine.

At the front side of the heat recovery steam generator near the exit of the gas turbine, the temperature of the gases is generally around 1000°F. By the time the flue gases exit the stack of the HRSG, the temperature is generally in the 200°F to 300°F range.

A duct burner can be installed at the front side of the HRSG. The purpose of the duct burner is to add additional heat to the flue gases exiting the turbine utilizing the available oxygen. Some duct burner designs can also allow the steam plant to operate when the gas turbine is not in operation, but this operation (fresh air firing) is not common practice since it is not very efficient. Fresh air may be added for the burner by a fan upstream of the duct burner. Additional fuel (usually natural gas) is added to the burner.

Equipment for air pollution control in the heat recovery steam generator includes the carbon monoxide catalyst, the ammonia injection grid and the selective catalytic reduction catalyst. The carbon monoxide catalyst is used to help remove carbon monoxide by oxidizing it to carbon dioxide. Ammonia is injected in the HRSG for NOx control. Ammonia and the selective catalytic reduction catalyst work to change NOx compounds into nitrogen.

Superheated steam from the HRSG is injected into a steam turbine. As the steam expands through the turbine its temperature and pressure decrease and energy is transferred to the turbine,
making it rotate. The turbine then turns a generator to produce electricity, in addition to the electricity produced by the generator connected to the gas turbine. This is why this type of power plant is called a “combined cycle” or “dual cycle.” The thermal efficiency of the overall combined cycle may be over 50%.

After the steam exits the steam turbine, it flows through the condenser. The condenser is essentially a heat exchanger where the steam is cooled and condensed back into water by cooling water from the cooling tower. The cooling water from the cooling tower flows through the tubes in the condenser while the steam flows over the tubes. Condensed water from the condenser is then pumped from the condenser by the condensate pump to the feedwater pumps and back into the boiler.

The cooling tower is often used to cool the water that was used to condense steam in the condenser. Cooling towers are generally rectangular structures that may be divided into a few independent cells. Within the stack or body of a cooling tower is a large fan that draws air up through the cooling tower from the sides of the device. As air is being pulled up through the device, the warmed water from the condenser is sprayed down from the top of the tower. The water trickles down by gravity through the tower over baffles or packaging, which help maximize the surface area of the water and the contact between the air and water. The air and water also move in a counter-flow arrangement which helps improve contact between the two flows. Heat is primarily removed from the water through evaporation of water in the cooling tower. This process is also called evaporative cooling. Cooled water falls to the bottom of the cooling tower in a basin, where it can be pumped to the condenser to continue condensing steam. Since water is continually lost to the atmosphere from the stack of the cooling tower, make-up water is added to the system.

Not all gas turbines are equipped with steam turbines. Some of them simply use the heat recovery steam generator to produce steam for steam injection. Some plants may be equipped with simple cycle peaking turbines to produce power during high energy demand.

4.2.2.3.2.1 Duct Burner Operation

As mentioned earlier, many cogeneration or combined cycle gas turbine power plants use a duct burner to increase the steam capacity of the HRSG and power output. Duct burners usually burn natural gas, but they may also burn oil. Duct burners can almost double the temperatures of exhaust gases in the HRSG to 200°F, but most duct burners are run to increase temperatures in the neighborhood of 1400°F.

Different designs of duct burners exist, but Figure 4-6 illustrates a cross-sectional view of a low NO$_x$ duct burner that burns natural gas. Exhaust gases from the gas turbine flow around the fuel manifold and mix with the natural gas flowing from orifices in the manifold. The zone around the fuel manifold (zone A) is a fuel rich zone since only a small amount of the exhaust gases can pass through the small slot between the manifold and the stabilizer casing of the duct burner. A “diffusion flame” burns in zone “A” forming a recirculation pattern. When exhaust gases flow into zone “B” they mix with combustion products from the turbine, more eddies are formed behind the stabilizer casing and combustion is completed.

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The effect of duct burners on the total NO\textsubscript{x} produced from a power plant varies with different systems, but duct burners produce relatively small amounts of NO\textsubscript{x} emissions. In some systems, a duct burner can even reduce NO\textsubscript{x} emissions.

Figure 4-6. Top, Cross-sectional View of Duct Burner
4.2.3 Emission Control

4.2.3.1 Gas Turbine Emissions

Air pollution emissions from gas turbines are almost exclusively from combustion, but there is a potential for emissions from the storage of the fuel for a gas turbine. Combustion emissions from a gas turbine include nitrogen oxides (NO\textsubscript{x}), sulfur dioxides (SO\textsubscript{x}), carbon monoxide (CO), un-burned hydrocarbons, and particulate matter. The storage of fuels can be potential sources of emissions because volatile hydrocarbons or volatile organic compounds (VOCs) can escape from storage and enter the atmosphere. Overall, NO\textsubscript{x} and CO are the most significant emissions from gas turbines.

Natural gas is the fuel often used for a stationary gas turbine, and it is usually delivered to a plant via a pipeline and generally is not stored at a plant in large quantities. Methane (CH\textsubscript{4}) is the main gas component in natural gas, as well as various amounts of ethane (C\textsubscript{2}H\textsubscript{6}), and other hydrocarbons. Methane is a greenhouse gas but it is not considered to be a VOC; ethane is not a VOC.

A variety of petroleum distillates from heavier fuels to light gases can be used to run a gas turbine. These fuels include diesel, kerosene, jet fuel, gasoline, propane, butane, methane and others. The storage of gasoline is a source of VOC emissions. Diesel fuel is sometimes used as a backup or emergency fuel for a gas turbine, but its vapor pressure at ambient conditions is low enough to prevent problems with VOC emissions.

4.2.3.1.1 Nitrogen Oxides Control Systems

Nitrogen oxide (NO\textsubscript{x}) emissions are the main pollutant from gas turbines. Nitrogen oxides include nitrogen dioxide (NO\textsubscript{2}) and nitrogen oxide (NO). 90% to 95% of the nitrogen oxides that form from a combustion process are in the form of NO\textsubscript{2}, but nitrogen oxide will, later photochemically react to form NO\textsubscript{2}. Nitrous oxide (N\textsubscript{2}O) can also form from NO\textsubscript{x} control processes and is sometimes a concern. Nitrogen oxide, nitrogen dioxide and sometimes nitrous oxide are produced in high enough concentrations to be considered pollutants.

The combustor is the source of NO\textsubscript{x} emissions for gas turbines, but cogeneration and dual cycle power plants usually have a duct burner which is an extra source of NO\textsubscript{x} emissions in the heat recovery steam generator (HRSG). The quantity of NO\textsubscript{x} emissions from the duct burner is independent of the combustor operation.

The main method for the control of NO\textsubscript{x} emissions from gas turbines include diluent injection, selective catalytic reduction, and low NO\textsubscript{x} burners. NO\textsubscript{x} control systems can be categorized by being a “front end” control or a “back end” control. A front end control is an attempt to control NO\textsubscript{x} emissions by preventing them from forming during combustion. A back end NO\textsubscript{x} control is an attempt to convert NO\textsubscript{x} emissions back to N\textsubscript{2}, the natural form of nitrogen in the atmosphere. The amount of NO\textsubscript{x} emissions produced is highly dependent on the fuel, the ambient conditions, the design of the combustor, and the percentage of the rated full power output that the engine is operating.
Diluent injection, also known as wet controls, water injection, or steam injection, is a popular method used to decrease NO\textsubscript{x} emissions. It involves injecting water or steam into the combustor of a gas turbine in order to quench the flame. This lowers the combustion zone temperature inside the combustor. As stated earlier, the formation of NO\textsubscript{x} compounds is a function of the temperature inside the combustion chamber and lower combustion temperatures will produce less NO\textsubscript{x}. The temperature of combustion is the main factor affecting NO\textsubscript{x} formation.

Older gas turbines primarily made use of water injection, but today’s modern gas turbines mostly use steam injection. Other factors such as the availability and cost of steam, impacts on maintenance and performance, and the availability of water or steam injection nozzles help determine the type of injection.

Catalytic combustion involves using a catalyst bed to oxidize a lean air/fuel mixture within a combustor instead of burning with a flame as a blow torch in a conventional combustor. In a catalytic combustor, the air/fuel mixture oxidizes at lower temperatures, producing less NO\textsubscript{x}.

One manufacturer currently has available a catalytic combustion system known as Xonon\textsuperscript{TM} flameless combustor that is currently demonstratable with NO\textsubscript{x} emissions below 3ppm and carbon monoxide and unburned hydrocarbon emissions below 10 ppm with no other emission controls. This system will start undergoing official testing in a Kawasaki gas turbine in July of 1996 and will be commercially available for Kawasaki engines in 1997. This new combustor employs a “chemical thermostat” that prevents the catalyst from getting too hot.

4.2.3.1.2 Carbon Monoxide Control Systems

Carbon monoxide (CO) is emitted from gas turbines and other combustion devices from incomplete combustion. Incomplete combustion can occur when there is too much fuel or not enough air in the combustion process. Incomplete combustion can also occur from insufficient fuel and air mixing, and excessively low combustion temperatures. Smoke is a sign of incomplete combustion. Carbon monoxide (CO) forms instead of carbon dioxide (CO\textsubscript{2}) in incomplete combustion.

The CO catalyst is similar to the catalyst used for selective catalytic reduction and is often made with a honeycomb structure or parallel plates. The active element that oxidizes the carbon monoxide is a precious metal such as platinum. The catalyst is often applied as a coating over the catalyst structure. In order to withstand the high temperatures downstream of the turbine the catalyst structure is made with a ceramic material. In some ways, the CO catalyst is very similar to a catalytic converter on a car.

4.2.3.1.3 Sulfur Oxides Emissions

Sulfur oxides (SO\textsubscript{x}) are primarily sulfur dioxide (SO\textsubscript{2}). Sulfur dioxide comes from the combustion of fuels with sulfur in them. Sulfur compounds occur naturally in crude oils and most fuels are derived from petroleum. Unless the sulfur is removed, the sulfur in the fuel will also burn, forming sulfur dioxide and other sulfur compounds. Sulfur burning in a fuel contributes to its energy
output, but sulfur in a fuel is undesirable because it can cause corrosion of combustion equipment and because of the SO$_x$ emissions. Sulfur compounds can also be found in natural gas in the form of hydrogen sulfide (H$_2$S). Natural gas can be processed to remove sulfur compounds after it is recovered from a well.

4.2.3.1.4 Hydrocarbon Emissions

Hydrocarbons are compounds made of carbon and hydrogen atoms, and fuels are mostly made up of different hydrocarbons. Many hydrocarbons are also volatile organic compounds (VOCs). Hydrocarbon emissions from gas turbines are a concern because volatile hydrocarbons can contribute to the formation of ozone (O$_3$).

The potential sources of hydrocarbons from gas turbines are from the storage of fuel for a gas turbine and unburned hydrocarbons from the exhaust. Emissions of unburned hydrocarbons from gas turbines are very low and most of the hydrocarbons that make up natural gas are not considered to be ozone precursors.

4.2.3.1.5 Particulate Matter Emissions

Particulate matter (PM) is small, liquid or solid particles of material that can easily become airborne. Besides being directly emitted into the atmosphere, PM can be created in the atmosphere by chemical reactions. Sulfur dioxide emissions and nitrogen oxide emissions released into the atmosphere can later develop into sulfate and nitrate particles respectively through chemical reactions. Any fuel used in a gas turbine containing sulfur compounds will emit sulfur oxides.

4.2.3.2 Continuous Emissions Monitoring

Gas turbines frequently have automatic sampling systems or continuous emissions monitors (CEMs), although Subpart GG does not require CEMs. Figure 4-7 illustrates the major components of an automatic sampling system for a gas turbine. Emissions are initially drawn into the system through the probe which is mounted into the stack so it is exposed to the exhaust. A pump is used to acquire a sample from the stack. The sample is conditioned to protect the analyzers. After the stack gas passes through the analyzer, it goes into an exhaust manifold and out to the atmosphere. The system also uses calibration gases to confirm the accuracy of the analyzers. When calibrations are performed, the valve to the desired calibration gas is opened, while no exhaust is allowed to flow from the stack. Since the concentration of the pollutant in the calibration gas is known, the operation of the analyzers can be checked.
Figure 4-7. Stack Sampling System
4.3 New Source Performance Standard for Stationary Gas Turbines

The Federal Clean Air Act requires the U.S. Environmental Protection Agency (EPA) to establish new source performance standards (NSPS) for categories of sources which significantly contribute to air pollution. The NSPS apply to both new sources and to modifications of existing sources of air pollution. The Clean Air Act directly prohibits operation of sources in violation of the NSPS.

Federal air pollution regulations for gas turbines are located in the New Source Performance Standards in the Code of Federal Regulations, Title 40 Part 60 (40 CFR 60); the Federal regulations for gas turbines are in Subpart GG - Standards of Performance for Stationary Gas Turbines.

The sections within this regulation include: 60.330 (Applicability and designation of affected facility), 60.331 (Definitions), 60.332 (Standard for nitrogen oxides), 60.333 (Standard for Sulfur dioxide), 60.334 (Monitoring of operations), and 60.335 (Test methods and procedures).

4.3.1 Rule Applicability

The first section, 60.330, describes what gas turbines are subject to the rule. The rule basically states that any stationary gas turbine with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour), based on the lower heating value of the fuel, must meet the requirements in the rule. The word “stationary” is included in the rule so that aviation gas turbines (i.e. jet engines) will not be affected by the rule.

The rule also mentions the “lower heating value (LHV)” of the fuel. The gross heat that can be acquired from burning a fuel is called the “higher heating value (HHV).” The units of heating value are usually in Btu/lbm (Btu per pound-mass of fuel). The higher heating value includes the heat of vaporization of water, but the lower heating value does not. The higher heating value is therefore larger than the lower heating value. When a fuel is burned, the main exhaust products are carbon dioxide and water. In the LHV, the energy that was used to vaporize the water in the gas is not included. The heating value of the fuel affects the calculations that are made to determine the energy output of a gas turbine.

Section 60.330 (b) states that gas turbines built or modified after October 3, 1977 are subject to the requirements of the rule. However, Section 60.330 (b) refers to two exemptions to this statement listed in Section 60.332 (e) and (j). If construction of a gas turbine commenced before October 3, 1982 and the heat input at peak load is greater than 10 million Btu/hr (10.7 gigajoules/hr) but less than 100 million Btu/hr (107.2 gigajoules per hour), based on the lower heating value of the fuel, the gas turbine is exempt from the NO\textsubscript{x} requirements of the rule. This exemption is found in Section 60.332(e) of the rule.

Last Revised: June 22, 1998
The other exemption is for gas turbines that were required by the September 10, 1979 Federal Register (44 FR 52792) to comply with NO\textsubscript{x} standards. These exempt turbines must have a heat input at peak load greater than 100 million Btu/hr (107.2 gigajoules/hr) and commenced construction or had a modification between October 3, 1977 and January 27, 1982. The exemption does not apply to electric utility stationary gas turbines. Few gas turbines are able to meet the requirements of this exemption, since most gas turbines are used to produce electricity. This exemption is found in Section 60.332(j) of the rule.

4.3.2 Definitions

The next section, 60.331, contains definitions. They are briefly summarized below, for a complete text, see the regulation.

Stationary gas turbine - any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self-propelled. It may be mounted on a vehicle for portability.

Simple cycle gas turbine - any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

Regenerative cycle gas turbine - any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

Combined cycle gas turbine - any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

Emergency gas turbine - any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source has been rendered inoperable by an emergency.

Ice fog - an atmospheric suspension of highly reflective ice crystals.

ISO (International Standards Organization) standard day conditions - 288° K temperature, 60% relative humidity, and 101.3 kilopascals pressure.

Efficiency - gas turbine manufacturer’s rated heat rate at peak load, in terms of heat input per unit of power output, based on the lower heating value of the fuel.

Peak load - 100% of the manufacturer’s design capacity of a gas turbine at ISO standard day conditions.

Base load - the load at which a gas turbine is normally operated.
Electric utility stationary gas turbine - any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system.

Emergency fuel - a fuel fired by a gas turbine only during a breakdown or other occurrence.

4.3.3 Standards of Nitrogen Oxides

Nitrogen oxides (NO\textsubscript{x}) are the main emissions of concern from gas turbines. Section 60.332 contains a limitation of NO\textsubscript{x} emissions from gas turbines. The limit of NO\textsubscript{x} emissions from stationary gas turbines is determined by one of the following equations:

A. If an electric utility stationary gas turbine has a heat input at peak load that is greater than 100 million Btu/hr (107.2 gigajoules/hr) based on the lower heating value of the fuel, the allowable NO\textsubscript{x} emissions are computed with equation #1. (Section 60.332(b) of the rule). \[
STD = 0.0075 \left( \frac{14.4}{Y} \right) + F
\]

B. If the stationary gas turbine has a heat input at peak load equal to or greater than 10 million Btu/hr (10.7 gigajoules/hr) but less than or equal to 100 million Btu/hr (107.2 gigajoules/hr) based on the lower heating value of the fuel, the allowable NO\textsubscript{x} emissions are computed with equation #2. (Section 60.332(c) of the rule). \[
STD = 0.015 \left( \frac{14.4}{Y} \right) + F
\]

Where:

STD = the allowable NO\textsubscript{x} emission (percent by volume at 15% oxygen on a dry basis)

Y = manufacturer’s rated heat rate at the manufacturer’s rated load, or the actual measured heat rate based on the lower heating value of the fuel as measured at actual peak load for the facility. “Y” cannot exceed 14.4 kilojoules/watt hour.

F = the percent NO\textsubscript{x} by volume from fuel bound nitrogen. Nitrogen is found in fossil fuels and when the fuel is burned, nitrogen oxides can form. Table 4-1 illustrates how to determine “F.”

<table>
<thead>
<tr>
<th>Fuel-bound nitrogen (% by weight)</th>
<th>F (NO\textsubscript{x} % by volume)</th>
</tr>
</thead>
<tbody>
<tr>
<td>N\leq0.015</td>
<td>0</td>
</tr>
<tr>
<td>0.015&lt;N\leq0.1</td>
<td>0.04(N)</td>
</tr>
<tr>
<td>0.1&lt;N\leq0.25</td>
<td>0.004+0.0067(N-0.1)</td>
</tr>
<tr>
<td>N&gt;0.25</td>
<td>0.005</td>
</tr>
</tbody>
</table>

Note: N = the nitrogen content of the fuel (% by weight)
C. Stationary gas turbines with a manufacturer’s rated base load at ISO conditions of 30 megawatts (30 million watts, which is equivalent to 107.2 gigajoules/hr) or less must meet the NO$_x$ limits calculated from equation B except as provided in Section 60.332(b) of the rule (this is summarized above in “A”). (Section 60.332(d) of the rule).

**Note:** the first condition above is for “electric utility stationary gas turbines”, but the other two conditions are for “stationary gas turbines.”

4.3.3.1 Exemptions for NO$_x$ Limitations

Stationary gas turbines that use water injection for the control of NO$_x$ emissions are exempt from NO$_x$ limits when ice fog becomes a traffic hazard, according to the owner or operator of the gas turbine (see Section 60.332(f) of the rule).

Gas turbines that are used for emergencies, by the military for use other than a garrison facility, for military training, and for fire fighting are exempt from the NO$_x$ limits of the rule (see Section 60.332(g) of the rule).

Stationary gas turbines that are used by manufacturer’s to perform research and development for gas turbine emission control and efficiency improvements are exempt from NO$_x$ limits on a case-by-case basis as determined by the EPA Administrator (see Section 60.332(h) of the rule).

In geographical areas where mandatory water restrictions are required by government agencies because of drought conditions, exemptions from NO$_x$ limits may be granted on a case-by-case basis. Exemptions will only be granted while mandatory water restrictions are in effect (see Section 60.332(i) of the rule).

Stationary gas turbines that burn natural gas and have a heat input equal to or greater than 10 million Btu/hr (10.7 gigajoules/hr) are exempt from NO$_x$ limits of the rule when being fired with an emergency fuel (see Section 60.332(k) of the rule).

Regenerative cycle gas turbines with a heat input less than or equal to 100 million Btu/hr (107.2 gigajoules/hr) are exempt from the NO$_x$ requirements of the rule (see Section 60.332(l) of the rule).

As discussed previously in Section 4.3.1 Rule Applicability, Section 60.332 (e) and (j) of the rule contains exemptions dealing with date of construction or modification of the gas turbine. If construction of a gas turbine commenced before October 3, 1982 and the heat input at peak load is greater than 10 million Btu/hr (10.7 gigajoules/hr) but less than 100 million Btu/hr (107.2 gigajoules per hour), based on the lower heating value of the fuel, the gas turbine is exempt from the NO$_x$ requirements of the rule. This exemption is found in Section 60.332(e) of the rule.

The other exemption is for gas turbines that were required by the September 10, 1979 Federal Register (44 FR 52792) to comply with NO$_x$ standards. These exempt turbines must have a heat input
at peak load greater than 100 million Btu/hr (107.2 gigajoules/hr) and commenced construction or
had a modification between October 3, 1977 and January 27, 1982. The exemption does not apply to
electric utility stationary gas turbines. Few gas turbines are able to meet the requirements of this
exemption, since most gas turbines are used to produce electricity. This exemption is found in Section
60.332(j) of the rule.

4.3.4 Standards of Sulfur Dioxide

Gas turbines can emit sulfur oxide emissions (SO2). Emission of sulfur oxides are dependent
on the sulfur content of the fuel. Table 4-2 illustrates the sulfur dioxide emission limits. Owners or
operators must comply with one or the other of the conditions shown in Table 4-2.

<table>
<thead>
<tr>
<th>Regulation</th>
<th>Limit</th>
</tr>
</thead>
</table>
| 60.333(a)  | discharge any gas that contains SO2 in excess of:
            | 0.015% by volume at 15% oxygen on a dry basis |
| 60.333(b)  | No burning any fuel which contains more than
            | 0.8% by weight sulfur |

4.3.5 Monitoring of Operations

Monitoring requirements are found in Section 60.334 and address the following areas.

4.3.5.1 Continuous Emissions Monitoring Requirements

Owners and operators of gas turbines, subject to the rule and using water injection to control
NOx, must install and operate a system that continuously monitors and records the fuel consumption
and the ratio of water injected to fuel burned. The system must have an accuracy between +/- 5% (see
Section 60.334(a)).

4.3.5.2 Monitoring NOx and SOx

Must monitor NOx and SOx content (60.334(b)) with the following frequency:

A) If a gas turbine subject to the rule is supplied by fuel from a storage tank, the sulfur and
nitrogen content of the fuel must be determined whenever fuel is transferred to the tank from another
source.

B) If a gas turbine subject to the rule is supplied fuel without intermediate storage, the sulfur
and nitrogen content of the fuel must be determined and recorded daily. Custom schedules for the
determination of sulfur and nitrogen content can be developed, but they must be approved by the EPA
Administrator.

4.3.5.3 Periods of Excess Emissions

This section of the rule describes how long a duration of violation in emissions requires the
reporting of those emissions. It also has requirements regarding ice fog and emergency fuel. (Table

4.3.6 Test Methods and Procedures

This section of the rule contains procedures for calculating NO\textsubscript{x} emissions to determine
compliance. It also tells the test methods that should be used to calculate the nitrogen and sulfur
content of fuels.

In order to compute nitrogen oxide emissions, the owner or operator of the gas turbine must
use methods that are accurate to within 5%. The methods used to determine NO\textsubscript{x} emissions and the
nitrogen content of the fuel must be approved by the EPA Administrator (Section 60.335 (a)).

Compliance with nitrogen oxide standards is computed by using the following equation:
(Section 60.335(c)(1)):
\[ \text{NO}_x = \text{NO}_{x0} \left( \frac{\text{Pr}}{\text{Po}} \right)^{0.5e19 \left( \text{Ho} \cdot 0.00633 \right)} \left( \frac{288^\circ \text{K}}{\text{Ta}} \right)^{1.53} \]

Where:

- \( \text{NO}_x \) = emission rate of \( \text{NO}_x \) at 15% \( \text{O}_2 \) and ISO conditions, volume percent
- \( \text{NO}_{x0} \) = observed \( \text{NO}_x \) concentration (ppm by volume (standard ambient))
- \( \text{Pr} \) = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure (mmHg (mercury))
- \( \text{Po} \) = observed combustor inlet absolute pressure at test (mm Hg)
- \( \text{Ho} \) = observed humidity of ambient air (g/H\(_2\)O/g air)
- \( e \) = transcendental constant (2.718)
- \( \text{Ta} \) = ambient temperature (\( ^\circ \text{K} \))

Monitoring devices used to record the fuel consumption and the ratio of water to fuel being fired in the turbine must be used at 30, 50, 75, and 100% of peak load or at four points in the normal operating range and the peak load must be included and all loads must be corrected to ISO conditions. (Sections 60.334(a), 60.332 and 60.335(c)(2)).

Method 20 (40 CFR 60, Appendix A - Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines) must be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. \( \text{NO}_x \) emissions must be determined at each of the required load conditions (30, 50, 75, and 100% or four different points including the maximum and minimum). (Section 60.335(c)(3)).

In order to determine compliance for the sulfur content of the fuel. ASTM D 2880-71 must be used for liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 must be used for gaseous fuels. Another method approved by the EPA Administrator that is accurate to within 5% can also be used to determine compliance. (Section 60.335(d)).

The owner or operator may use reference methods other than the ones in the rule as long as they are approved by the EPA Administrator. (Section 60.335(f) and 60.335(f)(1)). In particular, Section 60.335(f)(1) identifies specific ambient condition correction factors.

### 4.4 Inspection

Sources are inspected in order to verify that a company’s equipment is designed, installed, and operating in accordance with air pollution regulations and permits.

There are four ways that the compliance status of a source can be evaluated:

1. Engineering evaluations
2. Inspections
3. Source testing
4. Continuous emission monitoring (CEM)
Of these, only the third and fourth provide actual emission data measurements from a facility. Inspections will primarily be the focus of this section, but source testing and CEM shall be briefly discussed.

One of the best ways a source can stay in complaince with air pollution regulations is through preventative maintenance inspections. Companies that have efficient inspection and maintenance (I&M) programs tend to have fewer breakdowns, require fewer variances, have less down time and can save money. With an efficient I&M program, problems with equipment can be anticipated and surprising catastrophic failures can be reduced. A good I&M program also requires that neat, orderly consistent records of self-inspections be kept by the company.

Inspections of facilities may be performed for any one of the following reasons:

1. Compliance determination
2. Complaint investigation as a result of excess emissions or equipment malfunction
3. Source plan approval
4. Review or renewal of Permits

Compliance-type inspections only provide preliminary emissions assessments. Source testing is the method of determining compliance with an emission standard. Compliance inspections are usually unannounced so that a facility can be evaluated under normal operating conditions.

For other inspections pertaining to source construction, plan approval, permits, or “baseline type” inspections, the plant should be given sufficient advance notice so that qualified plant personnel can be present to provide the drawings, manuals and process information that may be required. Pertinent supportive evidence should be obtained prior to, during and following the source evaluation.

4.4.1 Sequence of Inspection

The sequence of an inspection is a question of what order to inspect the equipment in a system. The two main logical sequences to follow are a co-current flow and a counter-flow approach, but regardless of the type of sequence chosen, it is usually best to initially inspect the outside of a facility. By inspecting the perimeter of a plant, an inspector can see if there are any illegal emissions or odors.

4.4.1.1 Co-current Approach

The inspection of a facility using a co-current approach is conducting the inspection in the same general direction as the flow of the gas stream. The general sequence would be the process, the capture system, the control device, and the stack.

An inspector may want to use this type of approach when he is unfamiliar with some process details.
4.4.1.2 Counter-flow Approach

An inspection with a counter-flow sequence is conducted against the direction of gas flow. An inspection of this type would generally begin at the stack and continue to the control device, capture system and then the process.

The advantage to this approach is that an inspector may be able to more quickly identify where an emission problem originates.

4.4.1.3 Other Approaches

In some instances, an inspector may not start with the stack of the process or the beginning or end of a system. If odors are detected outside of the facility, an inspector may want to head directly to the source of the odor. If an inspector suspects illegal tampering with the control device equipment, he may head there directly. If an inspection is a strict, unannounced compliance-type, or if an inspector is very familiar with the process and only has a particular item to deal with, the inspection could start and finish in a different manner.

4.4.2 Pre-inspection Procedures

It is important to prepare for the inspection prior to your visit to the facility.

Rules and permits can be very complicated and preparations must be made for a successful inspection. This section is a discussion of some general guidelines on what steps to follow prior to the inspection.

4.4.2.1 File Review

Prior to the site inspection, the inspector should review all information available in the source files including: approved permits, equipment lists, conditions for each permit, previous inspection reports, notices of violation, breakdown reports, enforcement actions taken, monitoring requirements (Title V Operating Permits), odor complaints, variance histories, alternative emissions control plans, abatement orders, source tests, and the design of the plant.

Verify that all applicable permits (including Title V Operating Permits) for the facility are current and valid. Bring a current copy of the PERMIT(s) and bring extra copies in case the facility has misplaced or lost their copy

4.4.2.2 Regulation Review

You should review any references to the specific rules which are noted in the source files. In particular, be familiar with each standard and exemption in the rules.
4.4.2.3 Equipment Check

Make sure you have the following equipment available for use during the inspection: vision protection, hearing protection, safety shoes, hard hat, gloves, identification, business cards, pens, inspection forms, chain of custody forms, sampling cans, can case, labels, and thermometer.

4.4.3 Pre-entry and Entry

When you arrive at the plant, notice if there are any visible emissions. If there are any visible emissions, make sure you document them and plan on finding the sources a soon as possible after entering the facility.

* Make sure you do not confuse steam or water vapor with a pollutant emission *

Request to see the previous contact mentioned in the files. Depending on the facility, it may be the environmental coordinator, supervisor, president, maintenance worker or operator.

* Always present your business credentials immediately to avoid confusion *

4.4.4 Pre-inspection Meeting

Before the inspection begins, the inspector should meet with the source representative to obtain operating information. The inspector should state the purpose of the inspection and identify the equipment which will be inspected. Facility information can be verified during this meeting, including: the facility name and ownership, address complete with city and zip code, contact name, contact title, phone number and area code. Discuss safety procedures and whether or not there have been any problems in the past. Request a copy of the applicable material safety data sheets (MSDS). A facility may have over a thousand of them since MSDSs exist for materials ranging from dishwashing soap to ammonia. If necessary, discuss sampling procedures with the source representative.

The applicable permit you bring with you should be compared to the facility’s copy of the permit to ensure that they contain the same conditions; if the permits do not contain the same conditions, you should verify which permit is the current permit. Also check existing permit conditions and ask if any other changes have been made to the operation which are not reflected in the permit; if the permit (unless the source is in the process of applying for a permit modification) does not contain changes made, there could be a potential violation.

4.4.5 Gas Turbine Inspections

Inspectors can determine whether a gas turbine complies with air pollution regulations and permits. CEMs or source tests must be used to determine the gas turbine emissions, but items in this section discuss how an inspector can determine compliance. If the facility has a Title V (T5)
Operating Permit, the T5 permit should state how the source is to determine compliance; you should confirm that the facility is complying with the T5 permit.

4.4.5.1 Gas Turbine Visible Emissions

EPA Method 9 (Visual Determination of the Opacity of Emissions from Stationary Sources) is found in 40 CFR Ch. I, Part 60. The method requires the recording of certain specific information in the field documentation of a visible emission observation. If possible, the visible emissions from the gas turbine stack should be observed before entering the facility. There should be little or no visible emissions coming from the stack. Only occasional faint wisps of smoke should be visible.

Another potential source of visible emissions violations is smoke from burning lubricating oil. The oil in the lubrication system, which is primarily for the bearings in the gas turbine, can get so hot that it may smoke. Some systems may be equipped with filters to help prevent violations from the smoke.

4.4.5.2 Gas Turbine General Physical Conditions

As with most inspections, it is good to walk around the equipment at the plant, familiarize yourself with it, and look at the general condition of the equipment. On the other hand, much of the equipment at gas turbine power plants cannot be physically inspected, especially if it is running. Check for any signs of excessive corrosion or erosion. Look for cracked or worn ductwork expansion joints. It is unlikely that a gas turbine would have these types of problems, since they could be dangerous and inefficient, however these are still good procedures to follow.

4.4.5.3 Gas Turbine Fuels

Gas turbines can burn a variety of fuels ranging from natural gas to distillate oil. Limits stated on the Permit may restrict what fuels can be used in the gas turbine. Permits may also require facilities to measure and record their fuel usage. Acquire a copy of the company’s records showing the fuels used and the fuel usage since the last inspection. If any fuel was used that is not on the Permit, it is a possible violation.

The inspector may either review the facility’s fuel sampling records, review shipment information from the vendor, or acquire a sample of the fuel to verify that it complies with the Permit. A major reason for sampling the fuel is to check the sulfur content. Permits may state the maximum allowable sulfur content of the fuel especially if it is distillate oil. The permit, compliance plan, or Title V permit will explain how compliance with the Sulfur limits is determined. Inspectors should determine this methodology and obtain the appropriate records to determine compliance.

The storage of fuels for a gas turbine can be a potential source of emissions. Liquid petroleum fuels are kept in storage tanks and may be a potential source of emissions, but may be exempt from Air Pollutant Emissions Notice (APEN) or permit requirements, and therefore, have no specific requirements. In general, depending on the vapor pressure of the product in the tank, the tank and its
pressure relief valves cannot leak hydrocarbon emissions. Floating roof tanks must also meet gap limits. Most gas turbines that run on liquid petroleum fuels use fuels with a low vapor pressure, such as diesel, which does not require vapor recovery or a gas tight tank. On the other hand, gas turbines can run on high vapor pressure fuels such as gasoline.

4.4.5.4 Time of Operation

A Permit may have conditions for a gas turbine that limit the hours of operation per year. Some facilities have peaking turbines that only run during heat waves in the summer months when energy demand is high. Gas turbines can also be used for emergency back-up power and these gas turbines often have limits on the hours of operation. Acquire a copy of the facility’s records showing the hours of operation since the last inspection. Compare the data to the requirements on the Permit and make sure the gas turbine operated for a period of time that is less than maximum time allowed.

A Permit may describe the length of time for a startup and a shutdown period. A startup period may be a few hours and a shutdown period is typically shorter in duration.

4.4.5.5 Water and Steam Injection

If the water or steam injection rate is too low, NO\textsubscript{x} emissions will be too high. If the water or steam injection rate is too high, carbon monoxide and unburned hydrocarbon emissions will be higher. The injection rate is usually computed as the ratio of the mass of water or steam to mass of fuel. Permits may require facilities to measure and record the water or steam to fuel ratio.

*Acquire a copy of the plant’s logs to verify water or steam injection rate requirements*

4.4.5.6 Ammonia Injection and SCR

The amount of ammonia injected for selective catalytic reduction is an important parameter. If enough ammonia is not injected, there will be a lower amount of NO\textsubscript{x} removed, but if the ammonia injection is excessive, there will be an excessive ammonia slip. In extreme cases, a large ammonia slip will cause a yellowish or brown plume. A bluish-white plume can also form under cold or humid conditions, due to the particle size distribution of ammonia. Permit conditions will also usually state the maximum concentration of ammonia allowed in the stack gas and require the facility to keep track of ammonia usage.

If a gas turbine power plant has SCR, the Permit will typically require that it operates. Except during startup and shutdown, when the flue gases in the HRSG are above a specific temperature. This temperature is usually relatively low so that during normal operation it will easily be exceeded. Continuous monitoring and recording of the temperature at the catalyst or other locations in the HRSG will probably be required.

*Acquire copies of the company’s ammonia usage records. Obtain copies of chart recorder printouts and other necessary data.*
4.4.5.7 CO Catalyst

Permits will often state that the carbon monoxide or oxidation catalyst must be installed and operating properly whenever the gas turbine is in operation. The facility may be exempt from this requirement during startup and shutdown.

4.4.5.8 Continuous Emissions Monitor Calibration

Permits may often state hourly or daily emission limits (i.e. lbm/day) and/or concentrations (i.e. ppmv) of NO\textsubscript{x}, CO, SO\textsubscript{x}, particulate matter, and hydrocarbons (usually non-methane hydrocarbons). Some stationary gas turbines may be equipped with advanced continuous emissions monitors (CEMs) that can measure NO\textsubscript{x}, CO, SO\textsubscript{x}, O\textsubscript{2} and make logs of the data. Permits will require specific pollutants that a facility must monitor. Typically, sources that have CEMs also maintain a report, as well as archived monitor data kept on site. The report is an Excess Emission Report (EER) and is sent to the Air Pollution Control Division. The report contains hours where the turbine exceeded emission limits as well as monitor downtime. Inspectors should obtain copies of the EER for the most recent quarter.

Inspectors should review the archived monitor data from the same quarter as the EER. The inspector should ensure that exceedances of the permit limits and monitor downtime in this archived data can be found in the EER. It is not necessary to check every day of the quarter, but a cursory check is necessary to verify that the source is meeting monitoring and reporting requirements.

For sources that do not have reporting requirements, inspectors should look through archived data on site to verify if permit exceedances or monitor downtimes are excessive. Generally, excessive monitor downtime is greater than 10% and excessive emissions are greater than 5% for any one quarter.

Most gas turbine facilities will not continuously monitor pollutants such as particulates and unburned hydrocarbons, especially if the engine will never burn distillate oil. Source tests are usually conducted to determine these emissions and these requirements may be stated on the Permit.

4.4.6 Post-inspection Procedures

Prior to leaving the facility, the inspector should evaluate the compliance status of the plant and should have obtained all of the information necessary to complete the inspection form.

The facility should be informed of the results of the inspection, or advised of areas of concern where additional information or investigation is needed. Be prepared to make your compliance determinations, calculate excess emissions, and issue all necessary violation notices. Be able to document future NOVs which may be pending due to sample results or additional information requests.
All possible violations should be followed up
### Appendix A. Inspection Checklist for Gas Turbines

<table>
<thead>
<tr>
<th>Pre-Inspection:</th>
<th>Field Inspection:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facility name:</td>
<td>Date/time:</td>
</tr>
<tr>
<td>Unit I.D. number:</td>
<td></td>
</tr>
<tr>
<td>Permit number:</td>
<td>Inspector:</td>
</tr>
<tr>
<td>Permit expiration date:</td>
<td>Agency:</td>
</tr>
<tr>
<td>Facility address:</td>
<td>Facility contact person(s)/title(s):</td>
</tr>
<tr>
<td>Date unit was built or last modified:</td>
<td></td>
</tr>
</tbody>
</table>

### Type of Emission Control System

- Water injection
- Steam injection
- Water in oil emulsion
- SCR
- CO catalyst
- Low NOx combustors
  - Type: Are the systems operating properly?

### Visible Emissions

- Any past problems with visible emissions?
- Are there any visible emissions?
- Result of visible emissions evaluation:

### General Physical Conditions

- Any past problems with air pollution related equipment?
- Any excessively corroded, or poorly maintained equipment?

### Fuels

- What fuel(s) is the gas turbine permitted to burn?
- What kind of fuel is the gas turbine burning?

### Time of Operation

- How many hours per year are the turbines allowed to operate?
- Hours of operation since last inspection:
- Hours of operation this year:

### Emission Data from CEMs

<table>
<thead>
<tr>
<th>Emission limits:</th>
<th>Emissions according to CEM:</th>
</tr>
</thead>
<tbody>
<tr>
<td>NOx: CO: SOx:</td>
<td>NOx: CO: SOx:</td>
</tr>
<tr>
<td>Ammonia slip: O2:</td>
<td>Ammonia slip: O2:</td>
</tr>
</tbody>
</table>