

GE Energy

# Air Emissions Terms, Definitions and General Information

Authored by:

**Stephanie Wien**

Environmental Engineer  
Environmental and Acoustic Engineering  
GE Energy

**Jeanne Beres**

Manager  
Environmental and Acoustic Engineering  
GE Energy

**Brahim Richani**

Master Black Belt  
GE Energy





## CONTENTS

---

Introduction .....	1
PM-10 and PM Emissions .....	1
VOC Emissions .....	2
NO <sub>x</sub> Emissions .....	3
CO Emissions .....	3
Sulfur Oxide (SO <sub>x</sub> ) Emissions .....	4
HAP Emissions .....	4
Ammonia Emissions .....	5
Start-up/Shut-down (SU/SD) Emissions .....	5
GE Emissions Estimates and Guarantees.....	6
Additional References.....	8



## Introduction

The main objective of this summary is to provide a clear definition of common terms regarding emissions, and also to provide background information on some of the frequently asked questions regarding GE emissions guarantees.

The document has been divided into sections that comprise the various air emissions that may be covered in GE emissions estimates or guarantees. Information is provided on the definition of various pollutants, recommended test methods for measurement and explanation of GE emissions estimates and guarantee requirements, along with any references for additional background information.

## PM-10 and PM Emissions

### 1. Definition

- a. For gas turbines, particulate matter (PM) emissions are assumed equal to PM-10 emissions.
- b. PM-10 emissions are defined as particulate matter emissions that are less than ten (10) microns in diameter.
- c. PM-10 emissions, as defined by US EPA, include filterable (front half) and condensable (back half) emissions.
- d. GE believes that PM-10 emissions from natural gas combustion are essentially zero (no emissions from the combustion process itself). GE believes that the reported levels in the gathered data are due to non-combustion factors, which include test sampling and construction debris.
- e. PM-10 emissions from oil-fired turbines are dependent on the amount of ash, sulfur and impurities in the fuel.
- f. On oil-fired turbines, PM-10 emissions increase with increasing exhaust flow rate.
- g. PM-10 emissions from NG combustion are difficult to demonstrate; emissions test take at least three (3) hours of sampling per test run.
  - i) Filterable Emissions:**
    - (a) Filterable emissions are emissions that exit the stack in either solid or liquid state, and omits any condensable.
    - (b) Filterable emissions are referred to as front half emissions or non-condensable emissions (the solid portion captured in the front half of the sampling train and on the filter).
    - (c) Front half emissions are quantified using US EPA Method 5 or 5B.
    - (d) Reported front-half PM results from combustion turbines using US EPA Method 5/5B generally include:
      - (i) Airborne PM that passes through the gas turbine inlet air filters.
      - (ii) Particulate matter (inert solids) in the fuel gas supply.
      - (iii) Airborne construction debris.
      - (iv) Metallic rust or oxidation products.
      - (v) Measurement (Method 5 or 5B) artifacts.
  - ii) Condensable Emissions:**
    - (a) Condensable PM is the portion of PM emissions that exit the stack in gaseous form and condense in the cooler ambient air to form particulate matter. These emissions are most likely from liquid hydrocarbons, sulfates that are unaccounted for in the fuel analysis, and/or fluids used in the manufacture of the turbine.
    - (b) Condensable emissions are referred to as back half emissions (the portion that is captured in the back half of the sampling train).

- (c) Condensable emissions include organic and inorganic emissions.
- (d) Condensable emissions are measured using US EPA Method 202.
- (e) Reported back-half condensable matter results using US EPA Method 202 may contain:
  - (i) Sulfates even without an SCR system.
  - (ii) Unburned fuel hydrocarbons, which agglomerate to form particles.
  - (iii) Possible other undefined condensables.
  - (iv) Formation of ammonium sulfates from the SCR system, which in a combined cycle application will accelerate the corrosion of the heat recovery steam generator (HRSG) tubes downstream from the catalyst.

## 2. Test Methods

- a. Use all the test methods and procedures recommended in GEK-28172 with particular attention to the following:
  - i) For front-half PM use US EPA Methods 5 (hot box temperature > dew point of H<sub>2</sub>SO<sub>4</sub>), 5B (for non-sulfuric acid PM-10), or 201A (for PM-10).
  - ii) Use US EPA Method 19 for exhaust flow determination, which in turn is used to determine lb/hr PM, as indicated in GEK-28172.
  - iii) For back half/condensable PM use US EPA Method 202, including the post-test nitrogen purge to eliminate possible SO<sub>2</sub>.
  - iv) Sample a minimum exhaust-gas volume of 125 dry standard cubic feet (dscf) (3.5 standard cubic meters (scm)) per test run.
  - v) Use of an emissions test firm agreed to by GE and the customer.
- b. No continuous emissions monitoring systems (CEMS) have been approved by the US EPA for measurement that can reliably measure particulate matter mass on a mass per unit time (i.e., lbs/hr) or concentration basis. Continuous opacity monitoring systems (COMS) measure percent opacity only.
- vi) A gas turbine (GT) compressor wash is highly recommended prior to PM-10 testing.
- vii) It is recommended that ambient air particulates be minimized during testing. That includes minimizing site dust if construction is not complete, and delaying testing if crop burning is taking place.

## VOC Emissions

### 1. Definition

- a. VOC (volatile organic compounds) emissions are total hydrocarbon emissions (THC), or unburned hydrocarbons (UHC), excluding methane and ethane.
- b. For natural gas fuel combustion, GE estimates VOC emissions are at 20% of UHC emissions; for distillate oil fuel combustion, the VOC emissions are 50% of UHC emissions.
- c. Since VOC emissions include non-ethane, non-methane hydrocarbons, they include hazardous air pollutants (HAPs).

### 2. Test Methods

- a. Follow test procedures per GEK-28172.
- b. VOC emissions are measured using a combination of US EPA Method 25A and US EPA Method 18.7.2 (on-line flame ionization detector [FID] working in tandem with a gas chromatography [GC]). The methane and ethane emissions per Method 18.7.2 are subtracted from the Method 25A results.

- c. GE does not suggest US EPA Method 18.7.1, which is an integrated bag sample. This method can introduce considerable error.
- d. Equivalent molecular weight of methane is used in the calculations (use methane as the calibration gas for Method 25A to enhance analyzer response. Both total UHC and non-methane/non-ethane VOC guarantees are expressed as methane).
- e. GE does not recommend CEMS for measurement of VOCs.

### NO<sub>x</sub> Emissions

#### 1. Definition

- a. Nitrogen oxides (NO<sub>x</sub>) emissions include NO and NO<sub>2</sub>. From gas turbines NO<sub>x</sub> is predominately NO (for purpose of reporting, NO<sub>2</sub> is used as the mass reference for NO<sub>x</sub>).
- b. NO<sub>x</sub> emissions are due to thermal NO<sub>x</sub> from combustion and fuel bound nitrogen (FBN). In the case of natural gas, fuel bound nitrogen is assumed to be negligible, and all NO<sub>x</sub> emissions are assumed to be thermal NO<sub>x</sub>.
- c. The FBN (organic NO<sub>x</sub>) is the amount of nitrogen present in the fuel that is oxidized via the combustion process to NO<sub>x</sub>. Typically, a credit is allowed up to the maximum limit of the FBN in the fuel (in the US per US EPA standard).
- d. CEMS are available for monitoring NO<sub>x</sub> emissions on a continuous, on-line basis.

#### 2. Test Methods

- a. Follow test procedures per GEK-28172.
- b. Emissions testing for NO<sub>x</sub> is determined using US EPA Method 20, with a chemiluminescent-type NO<sub>x</sub> analyzer per Method 7E.

- c. Oxygen should be sampled simultaneously with all NO<sub>x</sub> measurements per Method 3A, for correction of NO<sub>x</sub> to 15% O<sub>2</sub>.
- d. FBN in distillate oil is quantified by ASTM D4629, which is based on a combustion/chemiluminescence method.

### CO Emissions

#### 1. Definition

- a. Carbon monoxide (CO) emissions are a measure of combustion completion as higher values of CO indicate more incomplete combustion (less oxidation) of CO to CO<sub>2</sub>.
- b. CO is typically low due to the high combustion temperatures and the thermal efficiency of the unit.
- c. An oxidation catalyst in the exhaust duct can be used to reduce CO emissions by converting CO in the exhaust gas to CO<sub>2</sub> through reaction with O<sub>2</sub> ( $2\text{CO} + \text{O}_2 \rightarrow 2\text{CO}_2$ ). They operate best with gas temperatures of 850°F to 1100°F (the operating range of a CO oxidation catalyst is 600°F to 1400°F). Most of GE's newer, advanced-combustion gas turbines should not require a CO oxidation catalyst.
- d. Material for oxidation catalysts can be sensitive to the sulfur in the fuel. Typically platinum catalysts are used for fuels with sulfur, and a combination of platinum and palladium is used for non-sulfur fuel applications.

#### 2. Test Methods

- a. Follow test procedures per GEK-28172.
- b. Sampling for CO is the same as for NO<sub>x</sub>, normally with the same line feeding the different instruments.
- c. CEMS are available for continuous monitoring of CO emissions.

## Sulfur Oxide (SO<sub>x</sub>) Emissions

### 1. Definition

- a. All sulfur emissions in a gas turbine are caused by the combustion of sulfur introduced into the turbine by the fuel (most common source), air, or injected steam or water.
- b. SO<sub>x</sub> emissions include SO<sub>2</sub> and SO<sub>3</sub> emissions.
- c. SO<sub>x</sub> emissions are typically quantified as SO<sub>2</sub> emissions (vast majority of SO<sub>x</sub> emissions).
- d. SO<sub>3</sub> combines with water vapor in the exhaust to form sulfuric acid mist.
- e. SO<sub>2</sub> to SO<sub>3</sub> emissions conversion as a result of the gas turbine combustion process is estimated at 5% to 10%, which is based on gathered emissions data; additional emissions conversions added for SCR (2%) and catalytic oxidizer controls (10% to 35%).
- f. Control of SO<sub>x</sub> emissions typically requires limiting the sulfur content of the fuel.

### 2. Test Methods

- a. SO<sub>x</sub> emissions should be determined based on the fuel flow rate and the fuel sulfur content. Refer to GEK-28172 for more information.
- b. CEMS are available for measurement of SO<sub>2</sub> emissions.

## HAP Emissions

### 1. Definition

- a. HAPs are hazardous air pollutants identified by the US EPA in 40 CFR 61.
- b. HAPs include both organic and inorganic compounds in gaseous and solid form.
- c. Organic HAPs are mostly categorized with VOCs.
- d. HAPs are different from toxic pollutants identified by state and local agencies. Typically, toxic emissions include additional

compounds/pollutants than what are defined as HAPs by the US EPA. HAPs are typically a subset of the toxic pollutants identified by the state and local organizations.

- e. Each state typically has its own toxic air pollutant (TAP) list and regulations.
- f. Emissions data indicate that formaldehyde (CH<sub>2</sub>O) is the primary HAP from gas turbines (both natural gas-fired and distillate oil-fired applications).
- g. HAP emissions reduction is required by the proposed Maximum Achievable Control Technology (MACT) rule which applies to ALL stationary equipment located at major sources (40 CFR Part 63).

#### i) Applicability:

- (a) US EPA has issued a stay for lean premix gas-fired turbines and diffusion flame gas-fired turbines (Federal Register Vol. 60, No. 159, August 18, 2004).
- (b) For gas turbines, HAP emissions are very low and formaldehyde is the primary HAP.
- (c) Formaldehyde is considered as a “surrogate” for other HAPs for stationary gas turbines, which means it is an indication to the level and presence of HAPs.

#### ii) MACT Requirements:

- (a) The MACT formaldehyde limit is 91 pbbvd at 15% O<sub>2</sub>.
- (b) “Pending the outcome of US EPA’s proposal to delete these subcategories from the source category list (68 FR 18338, April 7, 2004), US EPA is staying the effectiveness of the emissions and operating limitations in the stationary combustion turbines NESHAP for new sources in the lean premix gas-fired turbines and diffusion flame gas-fired turbines subcategories.”



- (c) The MACT limit applies to stationary lean-premix and diffusion-flame combustion turbines where all turbines at the site fire oil more than 1,000 hours per year.
- (d) The Gas Turbine Association and GE continue to work with the US EPA regarding the stay and delisting petition, including the applicability to oil-fired units, as noted in (c).

### 2. Test Methods

- a. Modified CARB (California Air Resource Board) Method 430 should be used for formaldehyde testing, with modifications as outlined in GEK-28172.
- b. US EPA Method 321: This method has not been demonstrated reliably for emission levels less than 50 ppb.

## Ammonia Emissions

### 1. Definition

- a. Ammonia (NH<sub>3</sub>) emissions are a result of the use of SCR catalysts for NO<sub>x</sub> control.
- b. With an SCR, ammonia is injected into the gas turbine exhaust gas stream to promote a chemical reaction with NO<sub>x</sub> in the presence of a catalyst.
- c. The ammonia that does not react with NO<sub>x</sub> is referred to as “ammonia slip” which represents ammonia emissions.
- d. Ammonia slip is expected to increase for low NO<sub>x</sub> exhaust streams (7FA DLN units), because the NO<sub>x</sub> molecules available to react with the ammonia molecules are much fewer.
- e. Ammonia slip is also expected to increase as the catalyst bed ages.
- f. With sulfur-bearing fuels, ammonia injection causes the formation of ammonium sulfate ((NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub>) and ammonium bisulfate (NH<sub>4</sub>HSO<sub>4</sub>).

- g. The ammonium sulfates and ammonium bisulfates are referred to as “ammonium salts” or “ammonium sulfates.”
- h. The ammonium bisulfate causes rapid corrosion of the HRSG heat transfer surfaces and downstream metal surfaces.
- i. Both of the ammonium compounds (ammonium salts) cause plugging and fouling of the catalyst surface, inhibiting the rate of NO<sub>x</sub> reduction even with low-sulfur distillate oil (0.05%S) and aviation fuel. This plugging increases pressure drop, reduces heat transfer, and increases PM-10 emissions.
- j. The rate of deposition of ammonium salts on the HRSG and downstream metal surfaces is dependent on the concentrations of ammonia and SO<sub>3</sub> in the exhaust and the duration of operation with sulfur-bearing fuels.

### 2. Test Methods

- a. GE has established a preference for the use of on-site sampling and analysis plus calculations in accordance with the industry procedure of indophenol absorptiometrics to determine ammonia slip emissions, as outlined in GEK-28172.
- b. There is currently no approved US EPA protocol for direct, continuous sensing of ammonia. Continuous emissions monitoring of NH<sub>3</sub> is accomplished using NO<sub>x</sub> analyzers as an indicator of NH<sub>3</sub> levels.

## Start-up/Shut-down (SU/SD) Emissions

### 1. Definition

- a. Historically startup, shutdown (SU/SD) and malfunction emissions have been exempt from regulation.
- b. SU/SD emissions are becoming more of an issue in permitting – largely driven by the US EPA Guideline Document to States to Include SU/SD in their SIP (State Implementation Plans).

- c. Basic startup definition is not standardized. As an Original Equipment Manufacturer (OEM), GE recommends “ignition to emissions compliance” as a standard startup definition. Startup times will vary depending on a cold, warm or hot start.
- d. Focus has incorrectly been on volumetric (ppm) measurements, which reach very high levels; however, the duration of these excursions is very brief and the airflows are transiently well below steady state values. This is why volumetric measurements are not representative of the total emissions for SU/SD. Measurements, reporting and permits for SU/SD emissions are recommended in mass (i.e., pounds) per event (lbs/event).
- e. SU/SD emissions levels vary depending on hot, warm, and cold starts.
- f. SU/SD emissions are impacted by plant operating conditions (loading limits, hold points etc.).
- g. For combined cycle applications, use GE recommended startup sequence (including recommended hold points) to optimize emissions.
- h. As NO<sub>x</sub> and other emissions are driven lower with new technologies, SU/SD become a larger percent of a smaller total number.
- i. Lack of standardized regulatory guidelines and methodology for reasonable, reliable measurements and reporting hinders the entire permitting process.
- j. GE is currently developing a model for optimizing SU/SD emissions and is conducting emissions testing to better estimate SU/SD emissions.

### 2. Test Methods

- a. No formal or approved test protocol currently exist for SU/SD quantification.
- b. Gaseous SU/SD emissions (NO<sub>x</sub> and CO) may be estimated with conventional methods as long as proper analyzers capable of measuring the

anticipated emission levels are used. In particular:

- i) Integrate measured ppm with exhaust flow rate to determine lbs/event values.
- ii) Volumetric (ppm) data may vary widely (typically two orders of magnitude or more) and will require the use of multiple analyzers and ranges.
- iii) Transient airflows, exhaust composition (O<sub>2</sub>) and temperature also complicate measurements.
- iv) Response time (especially via CEMS) and/or test methodology may limit the ability to accurately represent the transient nature of SU/SD emissions.

### GE Emissions Estimates and Guarantees

1. GE emissions guarantees are based on statistical representation of prior data.
2. Emissions estimates and guarantees are offered in units of mass per event (i.e., lbs/hr) or concentration (mg/Nm<sup>3</sup>), depending on customer needs.
3. As applicable, emissions estimates and guarantees must include any contribution of fired HRSG/duct burner emissions when this equipment is present.
4. PM emissions guarantees are offered at base load operations only, reflecting a worst-case scenario.
5. For fuels containing sulfur, the PM emissions estimates must account for the contribution of sulfuric acid mist emissions and/or sulfates or the estimate must specifically exclude them, as is GE's preference.
6. For cases including oxidation catalysts and SCR, the contribution of the CO catalyst to SO<sub>3</sub> formation, which leads to additional ammonium salts formation, will be accounted for in the PM and PM-10 emissions estimates or specifically excluded, as is preferable to GE.

7. Additional requirements for sites with a PM guarantee:
  - a. Inspect and clean exhaust of any and all loose debris. Wipe exhaust down to prevent metal weepage from stainless steel being airborne.
  - b. Inspect the HRSG and check for any tube spacers left in the HRSG. Thoroughly clean out the HSRG.
  - c. Operate the gas turbine for at least 300 fired hours prior to particulate testing.
  - d. Run the gas turbine for 3 to 4 hours at base load (or until all wheelspace temperatures have stabilized) prior to particulate testing.
  - e. Visually inspect and clean the inlet filter house prior to a test.
8. Subpart GG ISO correction for NO<sub>x</sub> is NOT applicable to DLN units (Note: DLN is only applicable to gas-fired units) or to GE's diffusion flame units with the Mark V or Mark VI controller.
9. Special requirements for CO emissions may be necessary in regions designated as "non-attainment" for CO.
10. GE does not offer guarantees for SO<sub>x</sub>/SO<sub>2</sub> emissions. SO<sub>x</sub> emissions are considered "pass through" and estimated as SO<sub>2</sub> emissions based on the sulfur content of the fuel and air pass through.
11. When combined with ammonia, sulfur bearing fuels cause the formation of ammonium sulfate and ammonium bisulfate salts, even with low sulfur distillate oil (0.05%S) and aviation fuel.
12. In combined cycle applications, ammonium sulfur salts cause:
  - a. Rapid corrosion of boiler tube material, resulting in an increased pressure drop and reduced heat transfer.
  - b. Increased pressure drop and reduced heat transfer.
  - c. Increased PM emissions (also in the case of simple cycle applications).
13. When ammonia injection is used in the HRSG:
  - a. Limit sulfur content in the fuel to very low levels (< 0.05% by wt.).
  - b. Limit the amount of excess ammonia available to react with sulfur oxides.
  - c. Paint critical internal stack sections.
  - d. Increase HRSG feedwater temperature to reduce condensation (keep temperature greater than the dewpoint of sulfuric acid mist).
  - e. Allow provisions for cleaning, draining, and drying of the HRSG tubes.
14. Do not use SCR on GTs with sulfur-bearing fuels as their primary fuel.
15. If a sulfur-bearing fuel is used as a backup fuel, the first recommendation is to turn the SCR and ammonia injection off, or if the SCR is needed to reduce NO<sub>x</sub>, limit the operation on the sulfur-bearing fuel to 240 hrs/yr.
16. Proper catalyst materials must be used for high sulfur content fuels, otherwise catalyst poisoning will occur reducing catalyst effectiveness and increasing emissions.
17. It is GE's experience that formaldehyde is the only HAP that requires permitting.
18. Currently, no guarantees are extended for formaldehyde or other HAPs emissions.
19. Currently GE does not guarantee SU/SD emissions for any pollutants.

### **Additional References**

---

1. "Support for Elimination of Oxidation Catalyst Requirement for GE PG7241FA DLN Combustion Turbines." GER-4213
2. "Gas Turbine NO<sub>x</sub> Emissions Approaching Zero – Is it Worth the Price?" GER-4172
3. "SCR Experience With Sulfur-Bearing Fuels," under Tab 8 – Environmental Engineering of GE's Combined Cycle Plant Design Guideline.