

APPENDIX A—TECHNICAL SUPPLEMENTS

Disclaimer

The Emissions Assessment Section (EAS) has developed technical supplements for several common emission sources. The supplements are intended to help you accurately determine and correctly report emissions from specific types of sources, and may not cover every source in your account. You are responsible for reporting emissions from every source required to be included in your emissions inventory. See Chapter 1 for information on reporting requirements.

These supplements reflect our current understanding of how certain processes work and how they generate emissions. The supplements may change over time as we continue our scientific studies and as new information becomes available. We welcome any data, information, or feedback that may improve our understanding.

The methods discussed in this appendix are intended as an aid in calculating emissions. Certain process or operational conditions may make alternate calculation methods equally acceptable if they are based upon, and adequately demonstrate, sound engineering principles or data. You are responsible for using the best available method to determine and report the emissions that accurately reflect the conditions at your site. If you have a question regarding the acceptability of a given emissions determination method, contact the EAS at 512-239-1773.

Miscellaneous VOC Sources

One of the goals of the EAS is to identify sources that are failing to report or underreporting their VOC emissions. The TCEQ is not aware of any specific guidance that is readily available to estimate the emissions from these types of sources. However, these sources are present and the emissions should be represented in the emissions inventory using the best available emission estimation methodologies. These sources include, but are not limited to, casing head gas releases, coking units, confined entry ventilation, and Mercox units.

Casing Head Gas Releases

Casing head gas is unprocessed natural gas and other hydrocarbon vapors that emerge at the casing head fitting when crude oil is pumped to the surface in a well. During normal operating conditions, the casing head fitting is tight and no vapors leak into the atmosphere. When the casing head gas is vented, the emissions should be included in the emissions inventory.

Coking Units

Coking is a severe method of thermal cracking used to break heavy, long-chained hydrocarbons into lighter products. The residual product of the coking process is a solid carbon substance called *petroleum coke*.

Petroleum coke is removed from the walls of a coke drum by *decoking* or *coke cutting*. During the decoking or coke cutting process, VOC gases trapped in the coke will be released, creating hot spots and steam eruptions. Hydrocarbons may also be emitted during the associated cooling and venting of the coke drum prior to decoking.

Confined Entry Ventilation

Confined entry usually occurs during inspection, repair, or maintenance. Before entry, gas hazards are controlled by purging, inerting, flushing, or ventilating the space as necessary. Examples of confined spaces include, but are not limited to, tanks, manholes, boilers, furnaces, vaults, pipes, trenches, tunnels, ducts, and bins.

If the seal of a confined space is broken and uncontrolled, the contaminants within the confined space may be released into the atmosphere. These emissions should be included in the EI. Consult Chapter 3 for information on Collective Sources to determine if these ventilation emission sources can be grouped in your EI.

Merox Units

After mercaptan-rich hydrocarbon liquids are treated in a Merox unit, they are often placed in a storage tank. Inert gases may become trapped in this hydrocarbon liquid and can strip VOCs while escaping during storage. These additional emissions may not be included by the EPA TANKS program.

If the liquid streams are warmer than ambient temperature, see Technical Supplement 6 for information on hot-product storage to determine the tank's routine emissions. Additional emissions from inert gas stripping should be calculated using sound engineering principles and data.

Technical Supplements

The following technical supplements are included in this appendix.

Technical Supplement 1: Select Combustion Sources addresses common problems and concerns regarding internal combustion engines (turbines, reciprocating engines, and gasoline and diesel EAS engines); external combustion sources burning natural gas; and combined-cycle turbines with heat recovery steam generators.

Technical Supplement 2: Cooling Towers will help you to determine the nature of the emissions from your cooling tower system, to identify some of the methods that may be used to quantify those emissions, and to correctly report the emissions on the annual emissions inventory.

Technical Supplement 3: Equipment Leak Fugitives discusses emissions from piping components at industrial facilities resulting from leaking seals or connections.

Technical Supplement 4: Flares clarifies how elevated flare emissions should be estimated and reported.

Technical Supplement 5: Marine Facilities discusses stationary emissions from vessel cleaning, material transfer, and dockside sources such as particulate stockpiles, silos, VOC collection units, loading racks, and abatement devices. All of these emissions sources must be reported in the dock owner's emissions inventory.

Technical Supplement 6: Aboveground Liquid Storage Tanks explores stationary emissions from storage tank breathing and working losses, flashing losses, and landing losses. The supplement identifies some of the methods used to quantify those emissions.

TECHNICAL SUPPLEMENT 1: SELECTED COMBUSTION SOURCES

Technical Disclaimer

This technical supplement is intended to help you accurately determine and correctly report emissions from combustion sources. It does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how combustion sources work and how they generate emissions, how they are monitored or tested, and what data are available for emissions determination, may change over time as we continue our scientific studies and as new information becomes available. We welcome any data, information, or feedback that may improve our understanding of combustion emissions and thereby further improve emissions reported within the emissions inventory.

The calculation methods represented are intended as an aid; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. If you have a question regarding the acceptability of a given emissions determination method, contact the Emissions Assessment Section at 512-239-1773.

Introduction

This technical supplement addresses common problems and concerns with internal combustion engines (turbines, reciprocating engines, and gasoline and diesel industrial engines); external combustion sources burning natural gas; and combined-cycle turbines with heat recovery steam generators. For more information about these sources, or for information about combustion sources not covered in this supplement, consult the appropriate TCEQ new source review guides and the EPA's *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources* (publication number AP-42), continually updated.

Internal Combustion Engines

Expected Contaminants

Reported engine emissions should include all of the following:

- TSPs (contaminant code 10000)
- PM₁₀ (contaminant code 20000)
- PM_{2.5} (contaminant code 39999)
- VOCs (contaminant codes 50001 through 59998)
- HAPs, such as formaldehyde, ≥ 0.1 tpy

- NO_x (contaminant code 70400)
- SO₂ (contaminant code 70510)
- CO (contaminant code 90300)

Emissions Determination Methodologies

The appropriate emissions determination methodologies for internal combustion engines are accepted in the following order of preference:

- D (continuous emissions monitoring system or CEMs)
- F (predictive emissions monitoring system or PEMS)
- M (measured—stack test data)
- V (vendor-supplied emissions factors)
- A (AP-42 factors)
- S (scientifically calculated)
- E (estimated)

Testing conducted with a portable analyzer does not qualify as stack testing, and using this data would be considered an estimated (“E”) methodology. Using stack test results from an identical unit also falls under the estimated (“E”) methodology.

Note that material balance (“B”) is not explicitly mentioned in the list because of its limited applicability in determining emissions from combustion sources. If you feel that none of these methodologies will accurately represent a source’s emissions, contact the EAS for further assistance.

SO₂ Emissions

If any sulfur is present in a source’s inlet gas, then the source will emit sulfur dioxide as a product of combustion. When selecting a methodology for determining SO₂ emissions, CEMS, PEMS, and stack test data are, in that order, the preferred emissions determination methods. However, material balance emissions determinations based upon the combusted fuel’s sulfur content are preferred to both vendor and AP-42 determinations.

Particulate Emissions

Determining and reporting particulate emissions has caused some confusion in previous years. Please read the following information carefully.

Combustion sources emit particulate matter. Furthermore, particulate matter emitted from internal combustion engines has an aerodynamic diameter smaller than 2.5 microns. Thus, all particulate emissions from

these sources should be reported as PM_{2.5}, total suspended particulate (TSP) matter, and PM₁₀. See Chapter 4, “Particulate Emissions,” for more details.

In the past, some confusion has arisen from AP-42’s representation of three particulate emission factors: PM₁₀ (filterable), PM_{2.5} (filterable), and PM (condensable). Since the condensable and filterable fractions represent two different halves of cumulative particulate emissions, these factors must be used together to accurately represent cumulative particulate emissions.

However, the manner used to sum these emission factors is not straightforward. Since all particulate matter emitted from internal combustion engines is PM_{2.5} or smaller, the PM₁₀ (filterable) and PM_{2.5} (filterable) factors are equivalent; those two factors represent the same set of particulate emissions. In calculating emissions, then, you only need to use one of these factors when attempting to obtain the cumulative emissions factor.

To calculate particulate emissions, sum the condensable factor and one of the two filterable factors to obtain the cumulative emissions factor. Use this cumulative emissions factor to determine all particulate emissions. Report the emission rate thus obtained as follows:

- total suspended particulate (contaminant code 10000);
- PM₁₀ (contaminant code 20000); and
- PM_{2.5} (contaminant code 39999).

Example: Suppose that AP-42 shows the following emission factors for particulate matter from a certain type of engine:

PM₁₀ (filterable) = 0.0095 lb/MMBtu

PM_{2.5} (filterable) = 0.0095 lb/MMBtu

PM (condensable) = 0.00991 lb/MMBtu

Then the correct particulate emission factor for this engine type would be the sum of the PM_{2.5} (filterable) and the PM (condensable) factors, or 0.01941 lb/MMBtu. If the engine consumed 35,000 MMBtu of fuel during the year, then its particulate emissions would be:

$$\frac{0.0194 \text{ lb}}{\text{MMBtu}} \times \frac{35,000 \text{ MMBtu}}{\text{year}} \times \frac{1 \text{ ton}}{2000 \text{ lb}} = 0.3395 \text{ tons (for the year)}$$

The correct way to report these emissions is shown in the following table:

Table A-1. Reporting Particulate Emissions

Contaminant Code	Contaminant	Annual Emissions
10000	Part—unclassified	0.3395 tons
20000	PM ₁₀ —unclassified	0.3395 tons
39999	total PM _{2.5}	0.3395 tons

VOC Emissions

Determining, speciating, and reporting VOC emissions have caused some confusion in previous years. Please read the information in this section carefully. VOC emissions may be determined using a combination of stack test data, vendor data, and AP-42 factors. Each methodology is discussed separately in the following sections; each section contains methodology-specific speciation instructions.

Stack Test Data

When using stack test data to determine VOC emissions, verify that the test measured VOCs rather than total hydrocarbons. If it did measure VOCs, then use the test data to determine emissions; code the emissions with a determination methodology of “M.”

If the test instead measured total hydrocarbons, then you will need to adjust for this by multiplying the hydrocarbon factor by the following ratio: AP-42 VOC factor / AP-42 total organic carbon (TOC) factor. Code the emissions with a determination methodology of “S.”

Because complex oxidation reactions in the combustion chamber significantly alter the emissions composition, it is unacceptable to apply the inlet gas stream’s VOC percentage to the stack test TOC factor to obtain a VOC emission factor.

Vendor Data

When using vendor data to determine VOC emissions, verify that the factor refers to VOCs rather than total hydrocarbons. If it does, then use it to determine emissions; code the emissions with a determination methodology of “V.”

If the factor refers instead to total hydrocarbons, then you will need to adjust for this by multiplying the hydrocarbon factor by the following ratio: AP-42 VOC factor / AP-42 TOC factor. Code the emissions with a determination methodology of “S.”

Because complex oxidation reactions in the combustion chamber significantly alter the emissions composition, it is unacceptable to apply the inlet gas stream’s VOC percentage to the vendor’s TOC factor to obtain a VOC emission factor.

AP-42 Factors

AP-42 provides both VOC and TOC factors. Because complex oxidation reactions in the combustion chamber significantly alter the composition of emissions, it is unacceptable to apply the inlet gas stream's VOC percentage to the AP-42 TOC factor to obtain a VOC emission factor.

When using an AP-42 factor to determine emissions, use the most recent VOC factor. Code emissions with a determination methodology of "A."

Speciation

To determine whether or not you need to speciate VOC emissions from an internal combustion engine, see Chapter 4.

If you have any source-specific information about the VOC emissions composition for a source, then you should use it to speciate the emissions. Supply the data and related information with your emissions inventory.

If you do not have any source-specific information about the VOC emissions' composition, then you should speciate the emissions using those AP-42 "trace organic compounds" factors that are graded "C" or better. Divide each trace organic factor by AP-42's VOC factor to obtain the contaminant's speciation ratio. Multiply the source's total VOC emissions by each ratio to obtain that compound's emission rate. You need only report speciated emissions of at least 0.1 ton; smaller rates may be reported under VOC—u (contaminant code 50001).

If you used stack test data or vendor data to determine total VOC emissions, then code the speciated emissions with a determination methodology of "S" for "scientifically calculated"; the VOC-u emissions will be coded as "M" or "V." If you used an AP-42 factor to determine total VOC emissions, then code all VOC emissions with a determination methodology of "A."

Example: Using a vendor-supplied VOC factor, you have determined VOC emissions from a four-cycle lean burn compressor at 11.2 tons. You have no information about the composition of the exhaust VOCs. You do have an inlet gas analysis, but because complex oxidation reactions in the combustion chamber alter the emissions composition significantly, you know that you cannot use those data to speciate the VOC emissions. You therefore turn to AP-42.

In AP-42, you find that one of the Trace Organic Compounds factors graded C or better is for formaldehyde: 0.0528 lb/MMBtu. The total VOC emission factor in AP-42 is 0.118 lb/MMBtu. To obtain formaldehyde's speciation ratio, you divide the formaldehyde factor by the total VOC factor:

$$0.0528 \text{ lb/MMBtu} \div 0.118 \text{ lb/MMBtu} = 0.44746$$

Now you multiply the engine’s total VOC emissions by this ratio to determine the formaldehyde emissions:

$$11.2 \text{ tons VOC} \times 0.44746 = 5.0115 \text{ tons formaldehyde}$$

If you perform a similar calculation for each Trace Organic Compound with a factor graded C or better, you will obtain 27 speciated emission rates. However, only eight of these exceed the 0.1 ton threshold. You should report the speciated emissions for these eight compounds and report the balance of VOC emissions under “VOC—unclassified,” as shown in Table A-2.

Table A-2. Reporting Internal Combustion VOC Emissions

Contaminant Code	Contaminant	Annual Emissions	Determination Methodology
50001	VOC—unclassified	0.2240 ton	V
51620	acetaldehyde	0.7935 ton	S
51640	acrolein	0.4879 ton	S
51680	formaldehyde	5.0115 tons	S
51530	methanol	0.2373 ton	S
56150	methylcyclohexane	0.1167 ton	S
56600	<i>n</i> -hexane	0.1054 ton	S
56750	<i>n</i> -pentane	0.2468 ton	S
56775	propane	3.9769 ton	S

Ozone Season Emissions

Ozone season emissions should reflect an average daily emission rate. Do not report maximum daily emissions based on a design capacity and the assumption that the facility operated 24 hours each day. For sources that run regularly throughout the ozone season, divide the total emissions from June, July, and August by the number of days the facility is operated. For sources that run intermittently during the ozone season (e.g., emergency generators that operate a few hours every couple of weeks), use a straight conversion of the annual tons per year to pounds per day.

External Combustion Sources Burning Natural Gas

Expected Contaminants

Reported boiler emissions should include all of the following:

- TSP (contaminant code 10000)
- PM₁₀ (contaminant code 20000)
- PM_{2.5} (contaminant code 39999)
- VOCs (contaminant codes 50001 through 59998)
- NO_x (contaminant code 70400)
- SO₂ (contaminant code 70510)
- CO (contaminant code 90300)

Emissions Determination Methodologies

The appropriate emission determination methodologies for boilers are, in order of preference:

- D (continuous monitoring system)
- F (predictive monitoring system)
- M (measured—stack test data)
- V (vendor-supplied emissions factors)
- A (AP-42 factors)
- S (scientifically calculated)
- E (estimated)

Testing conducted using these data would be considered an estimated (“E”) methodology. Using stack test results from an identical unit also falls under the estimated (“E”) methodology.

If you feel that none of these methodologies will accurately represent a source’s emissions, contact the EAS for further assistance.

SO₂ Emissions

Note that if any sulfur is present in a source’s inlet gas, then the source will emit sulfur dioxide as a product of combustion.

Particulate Emissions

Determining and reporting particulate emissions has caused some confusion in previous years. Please read the following information carefully.

Combustion sources emit particulate matter. Furthermore, all of the particulate matter emitted from boilers as a result of combustion has an aerodynamic diameter smaller than 2.5. Hence, all particulate emissions from these sources should be reported as TSP, PM₁₀, and PM_{2.5}.

Note that AP-42 provides three particulate emission factors: PM (total), PM (condensable), and PM (filterable). Use the PM (total) factor [which can also be obtained by summing the PM (condensable) and PM

(filterable) factors] to determine boiler particulate emissions. Report these emissions as TSP (contaminant code 10000), as PM₁₀ (contaminant code 20000), and as PM_{2.5} (contaminant code 39999).

VOC Emissions

The practice of determining, speciating and reporting VOC emissions has caused some confusion in previous years. Please read the information in this section carefully. Emissions may be determined using stack test data, AP-42 factors, or both. Each methodology is discussed separately in the following sections, and is followed by instructions on speciation.

Stack Test Data

When using stack test data to determine VOC emissions, verify that the test measured VOCs rather than total hydrocarbons. If it did measure VOCs, then use the test data to determine emissions; code the emissions with a determination methodology of “M.”

If the test instead measured total hydrocarbons, then you will need to adjust for this by multiplying the hydrocarbon factor by the following ratio: AP-42 VOC factor / AP-42 TOC factor. Code the emissions with a determination methodology of “S.” Because complex oxidation reactions in the combustion chamber significantly alter the composition of emissions, it is unacceptable to apply the inlet gas stream’s VOC percentage to the stack test TOC factor to obtain a VOC emission factor.

Vendor Data

When using vendor data to determine VOC emissions, verify that the factor refers to VOCs rather than total hydrocarbons. If it does, then use it to determine emissions; code the emissions with a determination methodology of “V.”

If the factor refers instead to total hydrocarbons, then you will need to adjust for this by multiplying the hydrocarbon factor by the ratio: AP-42 VOC factor / AP-42 TOC factor. Code the emissions with a determination methodology of “S.”

Because complex oxidation reactions in the combustion chamber significantly alter the emissions composition, it is unacceptable to apply the inlet gas stream’s VOC percentage to the vendor’s TOC factor to obtain a VOC emission factor.

AP-42 Factors

AP-42 provides both VOC and TOC factors. Because complex oxidation reactions in the combustion chamber significantly alter the emissions composition, it is unacceptable to apply the inlet gas stream’s VOC percentage to the AP-42 TOC factor to obtain a VOC emission factor.

When using an AP-42 factor to determine emissions, use the most recent factor. Code all emissions with a determination methodology of “A.”

Speciation

To determine whether or not you need to speciate VOC emissions from a source, consult Chapter 4.

If you have any source-specific information about the composition of VOC emissions for a source, then you should use it to speciate the emissions. Supply the data and related information with your emissions inventory.

If you do not have any source-specific information about the composition of VOC emissions, then you should speciate the emissions using the AP-42 speciated organic compounds factors for formaldehyde, toluene, and benzene. Divide each of these factors by the AP-42 VOC factor to obtain the contaminant’s speciation ratio. Then multiply the source’s total VOC emissions by each contaminant’s ratio to obtain that contaminant’s emission rate. Report the emissions balance as “VOC—unclassified” (contaminant code 50001).

If you used stack test data to determine total VOC emissions, then code the speciated emissions with a determination methodology of “S” for ‘scientifically calculated’; the VOC—u emissions will be coded as “M.” If you used an AP-42 factor to determine total VOC emissions, then code all VOC emissions with a determination methodology of “A.”

Example: Using stack test data, you have determined VOC emissions from a boiler at 43 tons. You have no information about the composition of the exhaust VOCs. You do have an inlet gas analysis, but because complex oxidation reactions in the combustion chamber alter the emissions composition significantly, you know that you cannot use these data to speciate the VOC emissions. You therefore turn to AP-42.

In AP-42, you find that one of the speciated organic compounds factors graded C or better is for formaldehyde: 0.075 lb/MMscf. The total VOC emission factor in AP-42 is 5.5 lb/MMscf. To obtain formaldehyde’s speciation ratio, you divide the formaldehyde factor by the total VOC factor:

$$0.075 \text{ lb/MMscf} \div 5.5 \text{ lb/MMscf} = 0.0136$$

Now you multiply the boiler’s total VOC emissions by this ratio to determine the formaldehyde emissions:

$$43 \text{ tons VOC} \times 0.0136 = 0.5864 \text{ ton formaldehyde}$$

Perform similar calculations for benzene and toluene. Report the boiler’s VOC emissions as shown in Table A-3.

Table A-3. Reporting External Combustion VOC Emissions

Contaminant Code	Contaminant	Annual Emissions	Determination Methodology
50001	VOC— unclassified	42.3706 tons	M
51680	formaldehyde	0.5864 ton	S
52420	benzene	0.0164 ton	S
52490	toluene	0.0266 ton	S

Combined-Cycle Turbines with Heat Recovery Steam Generators

Structure

Structural representation of cogeneration turbines with an associated duct burner, heat recovery steam generator (HRSG), or boiler will vary, depending upon the operation of the units in question.

If the unit associated with the cogeneration turbine cannot operate independently from the turbine, represent the units as one facility–emissions point path, noting in the path or facility comments that a duct burner or HRSG operates in conjunction with the turbine.

If the unit associated with the cogeneration turbine can operate independently from the turbine, as is the case for most boilers, then represent the turbine as one facility and the associated unit as a separate facility. If both the turbine and the associated unit vent to the same emission point, create a common emission point for both facilities.

If the turbine can vent to a separate emission point (that is **not** the emission point shared with the associated unit) when it operates independently, that emission point also needs to be represented in the EI. Create two paths for the turbine, using one facility and two emission points: one for the separate turbine stack, and one for the stack shared with the associated unit. Remember also to include the path for the associated unit that vents to the shared stack in the EI.

Expected Contaminants

These facilities' reported emissions should include all of the following:

- TSP (contaminant code 10000)
- PM₁₀ (contaminant code 20000)
- PM_{2.5} (contaminant code 39999)
- VOCs (contaminant codes 50001 through 59998)

- NO_x (contaminant code 70400)
- SO₂ (contaminant code 70510)
- CO (contaminant code 90300)
- NH₃ (contaminant code 70050)

Emissions Determination Methodologies

The appropriate emission determination methodologies for combined-cycle turbines are, in order of preference:

- D (continuous monitoring system)
- F (predictive monitoring system)
- M (measured—stack test data)
- V (vendor-supplied emissions factors)
- A (AP-42 factors)
- S (scientifically calculated)
- E (estimated)

Quarterly testing with a portable instrument falls under the scientifically calculated (“S”) methodology. Using stack test results from an identical unit falls under the estimated (“E”) methodology.

If you feel that none of these methodologies will accurately represent a source’s emissions, contact the EAS for further assistance.

NO_x and CO Emissions

NO_x and CO emissions from these sources are typically continuously monitored. In this case, emissions reporting is straightforward.

If, however, you use stack test data to determine emissions from a combined-cycle turbine equipped with a duct burner, you should use two data sets: one representing emissions with the duct burner on, the other representing emissions with the duct burner off. If you do not have two separate data sets, or if you are using another method to determine emissions, then contact the EAS for guidance.

Particulate, VOC, and SO₂ Emissions

For guidance on determining and speciating these emissions, see “Internal Combustion Engines” earlier in this supplement.

TECHNICAL SUPPLEMENT 2: COOLING TOWERS

Technical Disclaimer

This technical supplement is intended to help you accurately determine and correctly report cooling tower emissions. It does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how cooling towers work and how they generate emissions, how they are monitored or tested, and what data are available for emissions determination, may change over time as we continue our scientific studies and as new information becomes available. We welcome any data, information, or feedback that may improve our understanding of cooling tower emissions and thereby further improve determinations within the emissions inventory.

The calculation methods represented are intended as an emissions calculation aid; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. If you have a question about the acceptability of a given emissions determination method, contact the Emissions Assessment Section at 512-239-1773.

Introduction

This technical supplement offers guidance on identifying, quantifying, and correctly reporting cooling tower emissions on the annual emissions inventory. It does not address devices such as fin-fan coolers and the cooling towers used exclusively in HVAC systems.

Definitions

In this document, *cooling tower* refers to the equipment that, through the process of direct contact with atmospheric air, reduces the temperature of water used to cool either process equipment or process fluid streams. *Cooling tower heat exchange system* refers to the cooling tower and all associated heat exchangers, pumps, and ancillary equipment where water is used as a cooling medium to transfer heat from the process fluids to the water.

Cooling Tower Structure

Each cooling tower in VOC service must be represented as a facility in the EI. For a multicell tower, represent the entire tower as a single facility.

To add a cooling tower in VOC service to the EI, use the Facility Information for Cooling Tower form. For cooling towers already in the EI, ensure that the appropriate facilities have a “cooling tower” group and profile, and that all facility profile characteristics are complete. If a

cooling tower facility has the incorrect group type, strike through the incorrect group type on the EI and write “cooling tower,” and then update the facility by attaching a completed Facility Information for Cooling Tower form to the EI; be sure to write “UPDATE FACILITY” across the top of the form.

Each cooling tower facility must have a **stack** type emissions point. This stack type emissions point should have:

- a stack diameter equal to the diameter
 - of the tower top for natural draft towers; or
 - of the fan for mechanical draft towers; or
 - of an average fan for multicell towers;
- a stack velocity of 10–20 feet per second;
- a temperature ranging from ambient to 15 degrees Fahrenheit above ambient;
- a nonzero moisture content (generally between 5 to 10 percent); and
- no horizontal discharge, except for crossflow towers (possibly).

When a permit lists multiple fans in a multicell tower, use multiple stack type emissions points attached to a single cooling tower facility.

Cooling Tower Source Classification Codes

Use either SCC 38500101 (for mechanical-draft cooling towers) or SCC 38500102 (for natural-draft cooling towers).

Expected Emissions

Cooling towers operate in such a manner that they may emit particulate matter, dissolved solids, or chemicals entrained in the cooling water. Cooling tower emissions fall into three categories: particulate matter, inorganic compounds, and volatile organic compounds (VOCs). Any tower has the potential to emit all three of these emissions types in varying amounts, depending on its service.

Particulate Matter

Particulate emissions result from the presence of minerals or any dissolved or suspended solids in the cooling water. Air flowing through the tower can entrain water droplets and carry them out of the cooling tower in a process referred to as *drift*. Once these drift droplets leave the tower and evaporate, they deposit dissolved or suspended solids as fine particulate matter (PM₁₀ or smaller).

Cooling towers are generally designed with drift eliminators—typically mesh or a series of angled slates placed above the water inlet. Note that, despite its name, a drift eliminator will reduce, but not eliminate, drift.

Inorganic Compounds

Inorganic emissions may result from inorganic process fluids leaking into the cooling water or from water treatment chemicals or other additives used in the cooling water system. The air flowing through the tower may strip these inorganic compounds from the water, resulting in their emission. Typical inorganic emissions may consist of chlorinated compounds, brominated compounds, or any other inorganic substance present in the cooling water.

Volatile Organic Compounds

Although some VOC emissions may result from the stripping of organic water treatment chemicals, the primary sources of VOC emissions are hydrocarbon-containing process fluids leaked into the cooling water by components of the cooling tower heat exchange system. Once the hydrocarbon-contaminated cooling water reaches the tower, the VOCs either flash out of the water or are stripped out by the tower's air flow. This may result in many tons of VOC emissions.

Emissions Determination

The process serviced by the cooling tower will largely determine how emissions should be determined and reported. For each contaminant type, determination methods and special concerns are discussed in the following sections.

Particulate Matter

Some manufacturers provide drift factors that may help you to determine particulate emissions. If you use a vendor-supplied drift factor, code the associated emissions with a determination methodology of "V" for 'vendor data.'

If no drift data are available from the manufacturer, determine particulate emissions using the appropriate factor from AP-42, Chapter 13. Code the associated emissions with a determination methodology of "A."

Inorganic Compounds

Very little research has focused on inorganic compound emissions from cooling towers. Emissions resulting from water additives may be determined based on the additive's chemical characteristics, the amount of additive used, the volume of cooling water, and a scientifically based

assumption about the percentage of additive stripped from the cooling water at the tower. Code the associated emissions with at determination methodology of “E” for ‘estimated.’

Volatile Organic Compounds

Emissions Determination Methodologies: Order of Preference

The appropriate VOC emissions determination methodologies for cooling towers are, in order of preference:

- emissions data from a TCEQ-approved air-stripping method (code as “M”);
- emissions data from an approved monitoring and control program plan, other than an air-stripping method, on file with the TCEQ (code as “B”);
- emissions data from an unapproved monitoring and control program (code as “E”);
- the AP-42 **uncontrolled** factor.

The use of the AP-42 controlled factor is not allowed. Detailed explanations of these emissions determination methodologies appear in the following sections.

Emissions Determination Methodologies

If cooling water is used to cool VOC process streams, emissions will result from process fluid leaks into the cooling water, with one exception. If the cooling water is maintained at a pressure at least 5 psi greater than the process fluid pressure throughout the entire cooling tower heat exchange system, then any leak in the heat exchanger will result in water leaking into the process fluid. For such systems, heat exchanger leaks do not generate VOC emissions from the cooling tower. For all other cooling tower heat exchange systems, where the cooling water is not maintained at a pressure at least 5 psi greater than the process fluid pressure throughout the entire cooling tower heat exchange system, use the following guidelines to determine emissions.

If VOC emissions are determined using a factor from Section 5.1 of AP-42, the uncontrolled emission factor (6 lb/MMgal) must be used. According to AP-42, use of the controlled factor (0.7 lb/MMgal) is contingent upon the use of applicable control technology to minimize hydrocarbon leaks into the cooling water system and the monitoring of cooling water for hydrocarbons. If a monitoring system allows for such control, then the associated data should be sufficiently detailed to allow for the derivation of an emission rate, either through a measurement of total VOC or through testing for all VOC species present in the cooling water. If the monitoring system is insufficient in monitoring hydrocarbons, the “uncontrolled” VOC emission factor should be used. If you determine

emissions in this manner, code them with a determination methodology of “A.”

Emissions determined based on measurements from an air-stripping method as outlined in the *TCEQ Sampling Procedures Manual*, Appendix P, are preferred. This document is available at www.tceq.state.tx.us/assets/public/implementation/air/sip/miscdocs/mgf/115/AppP.pdf. When using such data to determine emissions, assume that VOCs were present at the measured concentration for the entire period between samples. If analytical test methods indicate that VOC measurements are below the minimum detection limit, half of the detection limit must be used to calculate VOC emissions unless otherwise specified by a permit condition, TCEQ or federal rule, or commission order. This method applies to monitoring that determines a total VOC emission rate, either from a measurement of total VOCs or by a summation of measurements of all of the VOC species in the cooling water. Where only a select few of the possible VOCs present in the cooling water are measured, the AP-42 uncontrolled factor should be used to determine the total VOC emission rate from the cooling tower, and the measurements of the select VOC species (such as HRVOCs) should be speciated in the emissions reporting and subtracted from the total VOC emission rate derived from AP-42. Since this method measures the amount of air-strippable VOCs present in the cooling water, emissions should be coded as “M” (for ‘measured’).

Emissions determinations based on actual measured cooling water VOC concentrations and flow rate data may also be used. When using such data to determine emissions, assume that VOCs were present at the measured concentration for the entire period between samples. If analytical test methods indicate that VOC measurements are below the minimum detection limit, half of the detection limit must be used to calculate VOC emissions unless otherwise specified by a permit condition, TCEQ or federal rule, or commission order. This method applies to situations where monitoring is done such that a total VOC emission rate can be determined, either from a total VOC measurement or a summation of measurements of all of the VOC species in the cooling water. For cases where only a select few of the possible VOCs present in the cooling water are measured, the AP-42 uncontrolled factor should be used to determine the total VOC emission rate from the cooling tower, and the measurements of the select VOC species (such as HRVOCs) should be speciated in the emissions reporting and subtracted from the AP-42 derived total VOC emission rate. Because these methods measure the composition of chemicals in the cooling water rather than the amount of emissions, the emissions are not to be coded with a determination methodology of “M” (for ‘measured.’) The appropriate determination methodology will depend upon whether data are gathered following an approved monitoring and control program plan on file with the TCEQ. If so, code the associated emissions with a

determination methodology of “B” for ‘material balance.’ If not, code them with a determination methodology of “E,” for ‘estimated.’ Please note that, in the case of cooling towers, such estimates are still preferred to AP-42 factors.

If the air-strippable VOC concentration or cooling water VOC concentration is measured, but a large leak occurs between times of sampling events and no monitoring data are available for the period of the leak, then use the AP-42 uncontrolled emission factor to determine emissions for the leak period. If you do not know when the leak began, assume that it began immediately after the previous sample was taken. If the majority of annual emissions are determined using the measured data, then code them as described in the preceding paragraph.

Note that the information from devices such as lower explosive limit detectors, chlorine residual measurements, and total organic carbon measurements do not qualify as adequate monitoring or control technology and therefore do not allow use of the controlled VOC emission factor from AP-42.

Annual and Ozone Season Rates

If measured data are available for a cooling tower, then calculate the reported emissions should be calculated using actual, rather than average, test data. Use test data from each sampling event to determine emissions released since the prior sampling. Sum the different sampling periods’ emissions to obtain the annual total. If analytical test methods indicate that VOC measurements are below the minimum detection limit (that is, undetected), then half of the detection limit must be used to calculate VOC emissions, unless otherwise specified by permit condition, TCEQ or federal rule, or commission order.

For example, suppose that tests are performed weekly to determine a cooling tower’s VOC emission rate. Using the test results from each week and the associated water flow for the seven days preceding the sample time, one would calculate the total emissions for each seven-day period during the year, then sum those weekly emissions to arrive at the annual total.

To obtain ozone season emission rates, average over 92 days the total emissions during the months of June, July, and August.

Speciation

If samples were tested for VOCs, then use the measured data to speciate emissions. For more information on speciation requirements, see Chapter 4. For guidance regarding method detection limits and speciated

compounds, follow the general guidance outlined in “Minimum Detection Limits,” Chapter 4.

Supporting Documentation

Include documentation with your emissions inventory that supports and validates the emissions reported in the inventory. The relevant supporting documentation for cooling towers includes, but may not be limited to, representative samples of the following types of data:

- VOC test results, especially from times when leaks were discovered;
- cooling water and process fluid pressure readings for systems that maintain cooling water at a pressure at least 5 psi greater than the process fluid pressure throughout the entire cooling tower heat exchange system;
- annual water treatment chemical usage data for all chlorinated or brominated chemicals;
- annual and daily flow rate for cooling water; and
- emission rates calculated from measured data.

Issues of Special Concern

What if I share a cooling tower with another company?

Emissions should be reported by the regulated entity who owns the cooling tower. Please call the EAS for additional guidance if you have questions about your particular situation.

Are there any circumstances when I may use the AP-42 controlled VOC factor?

No. According to AP-42, use of the “controlled” factor (0.7 lb/MMgal) is contingent upon the use of applicable control technology to minimize hydrocarbon leaks into the cooling water system and the monitoring of cooling water for hydrocarbons. If a monitoring system is sufficient to provide such “control,” then the associated data should be sufficiently detailed to allow for the derivation of an emission rate. If the monitoring system is insufficient to provide data for determining emissions, then the system is insufficient to provide reliable “control” and so the “uncontrolled” VOC emission factor is appropriate.

Must I report particulate matter emissions?

Yes. While drift eliminators greatly reduce cooling tower drift, the drift droplets that do escape are so small and of such little mass that they can remain airborne for some time and travel a significant distance.

My cooling tower’s emission point is currently shown as a fugitive area. Must I change this?

Yes. Your cooling tower’s emission point should be shown as a stack. For

more information, see “Cooling Tower Structure” earlier in this supplement, as well as instructions for completing the Emission Point Information: Stack Profile form in *2008 Emissions Inventory Forms and Instructions* (TCEQ publication RG-360B).

What does the cooling tower characteristic “HRVOC Service?” mean?

Regardless of the county location of the regulated entity, if the cooling water cools any process equipment or process fluid stream containing over 5 percent by weight of aggregate highly reactive volatile organic compounds (HRVOCs—ethylene, propylene, all isomers of butene, and 1,3-butadiene), then the cooling tower is considered to be in HRVOC service for emissions inventory purposes.

If my cooling tower is used exclusively for comfort cooling and does not cool process fluids in a heat exchange system, how do I represent that on the EIQ?

This information may be included in the comments field under the Facility Information portion of the EIQ for the cooling tower in question.

References

- Compilation of Air Pollutant Emission Factors. 1995. Vol. I: Stationary Point and Area Sources. 5th ed. AP-42. Research Triangle Park, NC: U.S. Environmental Protection Agency. Available online at: <www.epa.gov/ttn/chief/ap42/index.html>. Accessed November 14, 2008.
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TECHNICAL SUPPLEMENT 3: EQUIPMENT LEAK FUGITIVES

Technical Disclaimer

This technical supplement is intended to help you accurately determine and correctly report equipment leak fugitive emissions. It does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how piping components work and how they generate emissions, how they are monitored or tested, and what data are available for emissions determination, may change over time as we continue our scientific studies and as new information becomes available. We welcome any data, information, or feedback that may improve our understanding of equipment leak fugitive emissions and thereby further improve determinations within the emissions inventory.

The calculation methods represented are intended as an emissions calculation aid; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. If you have a question regarding the acceptability of a given emissions determination method, contact the Emissions Assessment Section at 512-239-1773.

Introduction

This technical supplement offers guidance for identifying, determining, and correctly reporting equipment leak fugitive emissions from piping components and associated equipment at industrial facilities. It does not address emissions from cooling towers, oil-water separators, material stockpiles, loading operations, or other sources not related to piping components.

Please note that structural representation of equipment leak fugitive areas in the emissions inventory is specifically addressed under “Issues of Special Concern” later in this supplement. For general guidance on this topic, consult Chapter 3, “Emissions Inventory Structure.”

Definitions

In this document, *traditional component types* refers to those component types traditionally considered and reported as sources of equipment leak fugitive emissions: valves, connectors, pumps, compressor seals, relief valves, sampling connections, process drains, and open-ended lines. *Nontraditional component types* refers to component types traditionally not treated as sources of equipment leak fugitive emissions, but identified as such by recent scientific studies. Examples include screwed fittings, liquid relief valves, agitators, heat exchanger heads, site glasses, bolted

manways and hatches, blind flanges, caps and plugs, connectors, compression fittings, and metal-to-metal seals.

Expected Emissions

Equipment leak fugitive emissions may include organic or inorganic compounds in gaseous or liquid state, depending upon the composition of streams flowing through the associated piping components.

Quantifying Equipment Leak Fugitive Emissions

Introduction

Equipment leak fugitive emissions are determined using emission factors or equations statistically developed from component- and industry-specific sampling data. Methodologies will differ, depending upon whether a source is monitored using a VOC instrument detector or is not monitored. For monitored sources, base determinations on correlation equations and the individual screening values obtained with the instrument. For unmonitored sources, base determinations on average emission factors.

For detailed information on available emission factors and determination methods, see the EPA documents *Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017) and “Preferred and Alternative Methods for Estimating Fugitive Emissions from Equipment Leaks” (Emissions Inventory Improvement Program Document Series, Volume II, Chapter 4, November 1996), as well as the TCEQ Air Permits technical guide for equipment leak fugitives available at <www.tceq.state.tx.us/goto/nsr_elf> and the guidance available at the EAS Web page, <www.tceq.state.tx.us/goto/ieas>.

Requirements for Determining Equipment Leak Fugitive Emissions

Emissions from monitored equipment leak fugitive components must be determined using the actual monitoring data gathered at a site. Most LDAR program permit conditions require the retention of screening value data for all monitored components. Therefore, most sites with a monitoring program will have the necessary data to use correlation equations to determine equipment leak fugitive emissions.

Specifically, if a regulated entity is required by permit condition, TCEQ rule, or commission order to retain screening value data for its monitored components, correlation equations must be used to determine emissions.

The EAS has previously allowed the use of LDAR reduction credits applied to the EPA’s average factors for annual emissions determinations.

However, using actual leaking component data, reflecting a site's actual leak fraction and LDAR program effectiveness, will allow for more accurate emission determinations than using average emission factors with LDAR reduction credits.

Since all monitored equipment leak fugitive sources should have individual screening values for monitored components, the use of average emission factors with LDAR reduction credits to determine emissions from monitored components will no longer be allowed. One exception is detailed under "Quantifying Emissions from Components Monitored by an Audio/Visual/Olfactory Inspection" later in this supplement.

Emissions Determination Methodologies: Order of Preference

The appropriate methodologies for determining VOC emissions for equipment leak fugitive components are, in order of preference:

- Unit-specific correlation equations developed in accordance with EPA guidelines (code as "M")
- EPA correlation equations (code as "A")
- EPA industry-appropriate average factors (code as "A")

The use of reduction credits (from a LDAR program) applied to the EPA's average factors for emissions inventory purposes is no longer allowed, with few exceptions. One exception is detailed under "Quantifying Emissions from Components Monitored by an Audio/Visual/Olfactory Inspection" later in this supplement.

Emissions Factors

All emissions factors discussed in this supplement are available in the PDF document titled *Emissions Factors for Equipment Leak Fugitive Components* on the EAS's Web page at <www.tceq.state.tx.us/goto/ieas>.

Determining Emissions from Monitored Components

Quantifying Emissions Using Correlation Equations

Emissions determinations for monitored equipment leak fugitive emissions sources must be determined using site-specific monitoring data. Specifically, correlation equations must be used to determine emissions when a permit condition, TCEQ rule, or commission order requires the retention of screening value data.

Correlation equations use an instrument-measured VOC concentration screening value to determine a component-specific emission rate.

Screening value data are collected using a portable monitoring instrument to sample air from potential leak interfaces on individual pieces of equipment. Screening data must be collected in accordance with EPA Reference Method 21, as detailed in 40 CFR 60, Appendix A and *Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017), available at the EPA's Web site at <www.epa.gov/ttnchie1/publications.html>.

To determine emissions, the screening value data are used either in industry-specific correlation equations developed by the EPA or in correlation equations developed by a company for a specific process unit. The EPA correlation equations are available in *Protocol for Equipment Leak Emission Estimates* and in the PDF document *Emissions Factors for Equipment Leak Fugitive Components* on the EAS's Web page at <www.tceq.state.tx.us/goto/ieas>. The EPA has approved separate correlation-equation sets for synthetic organic chemical manufacturing industry (SOCMI) components and petroleum industry components (including refineries, marketing terminals, and oil and gas production facilities).

The TCEQ accepts the use of correlation equations for screening values between zero and 100,000 parts per million. To determine emissions using correlation equations, you must consider each component's screening value (adjusted for the background concentration) as follows:

- Before using the screening value in the appropriate correlation equation, determine the screened stream's response factor and, if necessary, adjust the screening value according to the guidance in *Protocol for Equipment Leak Emission Estimates*.
- For each component with a nonzero and nonpegged screening value, enter the screening value into the applicable correlation equation to determine a mass emission rate. Sum the individual mass emission rates for each component to determine a total leak rate. Note that each individual screening value must be entered into the correlation equation to predict a component's leak rate. Averaged screening values should not be used to determine emissions.
- For each component with a screening value of zero, note that, although the correlations predict a leak rate of zero for screening values of zero, the EPA data suggest that this prediction is incorrect. The EPA has established a default zero leak rate factor that should be applied to each component whose screening value was zero.
- For each component with a pegged screening value, use the EPA-developed default 100,000 ppm pegged leak rate factor. Note that if a pegged value of 10,000 ppm is indicated (i.e., the instrument will not quantify the screening value between 10,000 ppm and 100,000 ppm), then use the default 100,000 ppm pegged leak rate factor—**not** the default 10,000 ppm rate factor.

This information is summarized in Table A-4.

Table A-4. Determining Emissions Using Correlation Equations

Screening value	Determine emissions using ...
Zero	The default zero leak rate factor
Nonzero and nonpegged	The screening value in the applicable correlation equation
Pegged	The default 100,000 ppm pegged leak rate factor

Since a component’s screening concentration may vary from one monitoring period to another, emissions for each period should be based upon each component’s screening concentration for that period. These period-specific emission rates should then be summed to obtain an annual emissions rate. For example, if components are monitored quarterly, each component’s quarterly screening value should be used to determine quarterly emissions, and then the quarterly emission rates summed to obtain the component’s total annual emissions.

When determining a component’s leak duration, it would be most conservative to assume that the component was leaking at the measured concentration for the entire period since last monitored. An acceptable engineering estimate would be that the component was leaking at the measured concentration for half the monitoring period, plus the time needed to repair the component. The EAS must approve any other method of determining leak durations before you use it.

When using the correlation equations to calculate emissions, the components must be monitored at least once during the year. Using monitoring data from a previous year to estimate future emissions is a difficult process. If this is done, sound engineering assumptions to support the calculations must be provided with the emissions inventory.

Detailed information about correlation equations can be found in *Protocol for Equipment Leak Emission Estimates*.

Unit-Specific Correlation Equations

If a regulated entity has developed its own set of unit-specific correlation equations for its equipment leak fugitive components, those equations may be used to determine emissions only if the equations, sampling procedures, and all related procedures and data comply with EPA Reference Method 21 and the guidance in *Protocol for Equipment Leak Emission Estimates*.

When using company-developed correlation equations, supply supporting documentation indicating the basis for these equations. Also, if the site-specific equations do not take into consideration components with screening values of zero, the EAS may require the use of the EPA’s default zero leak rates. Likewise, if the site-specific equations do not

include components with pegged screening values, the EAS may require the use of the EPA's pegged leak rates.

Quantifying Emissions from Components Monitored by an Audio/Visual/Olfactory Inspection

For odorous or toxic inorganic compounds, an AVO inspection may be required by TCEQ rule, commission order, or permit condition. Generally, an AVO inspection program may only be applied to inorganic compounds that cannot be monitored by instrument. In limited instances, the AVO inspection program may be applied to extremely odorous organic compounds such as mercaptans. *Note:* the trace amounts of mercaptans present in natural gas are not sufficient to allow for an AVO inspection. However, a plant that manufactures mercaptans would be eligible, since the process streams contain a sufficient concentration of these compounds.

If no monitoring or screening data exist for AVO-monitored components, then average emissions factors with AVO reduction credits applied can be used to determine emissions. To claim credit for this program, you must be able to produce, upon request, documentation that all elements of the program are in place and were followed.

AVO factors can be found in the PDF document titled Emissions Factors for Equipment Leak Fugitive Components on the EAS's Web page at <www.tceq.state.tx.us/goto/ieas>.

Please note that an AVO inspection is different than a weekly physical inspection (a weekly walkthrough inspection). An AVO inspection is typically performed once per shift (every four to eight hours) versus once per week, and earns a reduction credit of up to 97 percent. A weekly walkthrough inspection earns only a 30 percent reduction credit.

Determining Emissions from Unmonitored Components

Emissions Determination Requirements

Emissions for monitored equipment leak fugitive emissions sources must be determined using actual monitoring data. However, for unmonitored components, average emissions factors may still be used to quantify emissions.

Quantifying Emissions Using Average Factors

Average emission factors are divided into four categories:

- SOCFI factors,
- oil and gas production factors,

- refinery factors, and
- factors for petroleum marketing terminals.

Within each category, factors vary depending upon specific component type (connectors, valves, pumps, etc.) and material in service (light liquid, heavy liquid, gas-vapor, or water–light liquid). For components in liquid service, you may need to choose between a “heavy liquid” factor and a “light liquid” factor. Use the “heavy liquid” factor if the stream’s vapor pressure is less than or equal to 0.044 psia at 68°F. If the stream’s vapor pressure is greater than 0.044 psia at 68°F, use the appropriate “light liquid” factor.

Note that the average factors generally determine total hydrocarbon emissions. Therefore, you may need to multiply the calculated emission rates by the stream’s weight percentage of VOC compounds to determine total VOC emissions.

The EPA average emissions factors for the industry types described in the following sections can be found in *Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017), available at the EPA Web site at <www.epa.gov/ttnchie1/publications.html>.

SOCMI Factors

Use the SOCMI factors to determine equipment leak emissions from chemical plants or chemical processes within refineries. SOCMI factors are divided into three categories: SOCMI average factors, “SOCMI with ethylene” factors, and “SOCMI without ethylene” factors.

Use the SOCMI average factors, which were developed to represent fugitive emission rates from all chemical plants, for streams containing between 11 percent and 85 percent ethylene. For streams containing more than 85 percent ethylene, use the “SOCMI with ethylene” factors. For streams containing less than 11 percent ethylene, use the “SOCMI without ethylene” factors.

Oil and Gas Production Factors

The oil and gas production factors are based on oil and gas production equipment leak emissions data gathered by the American Petroleum Institute and evaluated by the EPA. The oil and gas production factors include four different equipment service categories: gas, heavy oil (less than 20° API gravity), light oil (greater than 20° API gravity), and water/light oil (water streams in light oil service with a water content between 50 percent and 99 percent).

Refinery Factors

Use refinery factors to determine equipment leak fugitive emissions from a refinery process. For a chemical process located within a refinery that is

not specifically considered a refinery process (for example, an MTBE production unit), use the SOCMIs factors rather than the refinery factors to calculate emissions.

Petroleum Marketing Terminal Factors

Use the factors for petroleum marketing terminals to determine equipment leak fugitive emissions at gasoline-distribution facilities that are one step removed from local gasoline stations and other end users. Do not use these factors to determine equipment leak fugitive emissions from loading racks at chemical plants and refineries; instead, use the appropriate SOCMIs or refinery factors.

The use of these factors must be accompanied by an AVO program performed monthly. To claim credit for this program, you must be able to produce, upon request, documentation that all elements of the program are in place and were followed. Because the petroleum marketing terminal factors include the appropriate reduction credit for the AVO inspection, no additional reductions may be taken.

If a monthly AVO inspection was not performed, use the refinery factors to determine emissions.

Quantifying Emissions from Components Exempt from Monitoring

Some components may be exempt from monitoring requirements based on size, physical location at a facility, or low vapor pressure. Exempt components' emissions, like those from unmonitored components, **must** be calculated and reported. Since these components are not monitored, calculate their associated emissions based on average factors with no reduction credit applied. When calculating emission rates, inaccessible components and other unmonitored components must be clearly identified and separated from monitored components.

Quantifying Emissions Using Average Factors with Emissions Reduction Credits

Quantifying emissions using average factors with emissions reduction credits applied implies the use of a monitoring (LDAR) program. Most instrument-based LDAR program permit conditions will require the retention of screening value data. Since the use of such data in correlation equations provides more accurate emissions determinations, the use of average factors with applied emissions reduction credits to determine actual annual emissions rates is no longer allowed.

Reduction Credit for Connector Monitoring

Because connector monitoring is not usually required, emission reductions are not typically claimed for these components. However, if a weekly physical inspection program is in place, a 30 percent emissions reduction credit applied to average factors is allowed. To claim credit for any such program, you must be able to produce, upon request, documentation that all elements of the program are in place and were followed. If connectors are instrument monitored, then you should use correlation equations to determine emissions according to the guidance in this supplement. In these cases, no additional reduction credit for connector monitoring may be applied to the correlation equation.

Quantifying Emissions of Odorous or Toxic Inorganic Compounds

The best method to determine equipment leak emissions of odorous or toxic inorganic compounds like chlorine (Cl_2), ammonia (NH_3), hydrogen sulfide (H_2S), hydrogen fluoride (HF), and hydrogen cyanide (HCN) would be to develop unit-specific correlation equations, as described in Section 2.3.4 of *Protocol for Equipment Leak Emission Estimates*. To develop these equations, it is necessary to use a monitoring instrument that could detect the inorganic compounds in question.

Note that it also would be necessary to use a monitoring instrument that could detect the inorganic compounds in question to apply either EPA-developed correlation equations or screening range emissions factors. If monitoring data are not available, calculate uncontrolled equipment leak fugitive emissions using the industry-specific factors discussed previously. Although these VOC emission factors were not developed specifically for use with inorganic compounds, they are presently the best data available for determining inorganic equipment leak fugitive emissions.

Quantifying Emissions for Nontraditional Components

Emissions from nontraditional piping sources should be calculated and included in all emissions inventories. While these sources have not historically been included, recent scientific studies and equipment monitoring have indicated that these components are a source of emissions.

Although component-specific factors do not exist for most nontraditional components, the TCEQ has identified appropriate substitute factors based on component, leak potential, and leak mechanism similarity. These factors are listed in Table A-5.

The component-specific emission factors for pressurized railcar loading operations threaded connections and quick-connect couplers are listed in Table A-5 and should be applied when a pressurized railcar is connected

to the loading system using a loading arm. The loading arm may consist of a combination of threaded and quick-connect components and each component should be included in the inventory.

Special Considerations when Quantifying Emissions

When determining fugitive emissions, note the following special considerations.

Hours of Operation

Equipment leak fugitive emission factors are independent of process unit throughput. Because emissions occur whenever material is in the line, regardless of process activity or downtime, all streams should be in service for 8,760 hours annually. Any exception to this service time would require that the lines be purged during process downtime.

Equipment Design Specifications

Certain facility design specifications may eliminate or minimize equipment leak fugitive emissions. If components are designed as described in the following sections, you may apply the stated emissions reduction credit.

Table A-5. Appropriate Substitute Factors for Nontraditional Components

To determine this nontraditional component's emissions use this factor.
Agitator	Light liquid pump
Blind flange	Flange
Bolted manway or hatch	Flange
Cap or plug	Flange
Compression fitting	Flange
Connector	Flange
Heat exchanger head: unmonitored monitored	Open-ended line Flange correlation equation
Liquid relief valve	Light liquid valve
Metal-to-metal seal	Flange
Screwed fitting	Flange
Site glass	Flange times two
Pressurized railcar loading arm: threaded connection quick-connect coupler	0.0214 lb/hr/component 0.0055 lb/hr/component

Relief Valves: 100 percent control may be assumed if either of the following conditions is met:

- relief valve vents are routed to a properly operating control device; or
- relief valves are equipped with a rupture disc and pressure sensing device (between the valve and disc) to monitor for disc integrity.

It is important to verify proper relief valve operation if one of these design specifications is not used. If a relief valve does not reseal properly, the resulting emissions must be determined and reported. Possible sources of emissions include storage tanks, pressure tanks, loading operations, reactors, and mixing vessels controlled by relief valves.

Pumps: The following pump types are designed to be “leakless” and are eligible for a 100 percent control credit:

- canned pumps
- magnetic drive pumps
- diaphragm-type pumps
- pumps with double mechanical seals that use a barrier fluid at a higher pressure than the process fluid pressure
- pumps with double mechanical seals that vent the barrier fluid seal pot to a control device

Valves: You may take a 100 percent control credit for the following:

- bellows valves with bellows welded to both the bonnet and stem
- diaphragm-type valves
- seal-welded, magnetically actuated, packless, hermetically sealed control valves

Connectors: You may take a 100 percent control credit if the connections are welded together around their circumference so that the flanges cannot be unbolted.

Compressors: You may take a 100 percent control credit if a compressor is designed with enclosed distance pieces and if the crankcase vents to a control device.

Double Mechanical Seals: You may take a 75 percent control credit for any component employing double mechanical seals.

Speciation

Use current gas or liquid process stream analysis (or both) to speciate equipment leak fugitive emissions. Remember to speciate HAP emissions greater than 0.1 tpy for all sources. In nonattainment counties, supply

HRVOC speciation to 0.1 tpy. For more information about speciation requirements for the emissions inventory, see Chapter 4.

Supporting Documentation

Include representative sample calculations for each equipment leak fugitive area, including a list of the components where a 100 percent control credit has been applied with a footnote describing the specific control method. If screening range emissions factors are used, the EAS may require the submission of supporting documentation to verify that a permitted monitoring program is not required to retain screening value data.

In addition, if an equipment leak fugitive area emitted more than 5 tons during the year, complete and submit the Fugitive Data Form found at the end of this supplement.

Issues of Special Concern

May I put the whole plant's equipment leak fugitives under one facility and emissions point?

In a relatively small plant, such as a natural gas compressor station or a petroleum marketing terminal, the entire plant's equipment leak fugitive emissions may be represented by one facility–emissions point path. For larger plants, however, it is generally more appropriate to report fugitive emissions under more than one facility.

There are two main items to consider when breaking fugitive areas into multiple facilities. First, if different process areas within a plant follow different leak detection and repair programs, each area should be represented by a separate path to avoid confusion. Second, since stream composition may differ greatly between processes and may necessitate the use of different calculation methodologies, fugitive emissions from separate processes should be reported under separate facilities. Consider, for instance, a refinery with a process area for MTBE production. Emissions determinations for the MTBE process area should use correlation equations or the SOCFI average emission factors, as they are more appropriate than the refinery factors. Separate facility–emissions point paths should represent the MTBE process area fugitives and the refinery fugitives.

Do I have to report emissions from components that are exempt from monitoring (such as components less than 2 inches in diameter)?

Yes. All components' emissions must be determined and reported, regardless of monitoring exemptions based on size, physical location, or low vapor pressure. Since these components are exempt from monitoring,

an approach based on determining average factors will typically be used and no reduction credits from monitoring may be applied.

I have a unit that was shut down part of the year. Must I determine equipment leak fugitives for the entire year or just for the part of the year when the unit was operating?

Equipment leak fugitive emissions should be determined for the entire year (8,760 hours) unless the unit's lines were purged during the downtime.

I want to use correlation equations to determine equipment leak fugitive emissions. May I get screening values for a certain percentage of components and use the average value to represent all other components?

No. Correlation equations may only be used to determine emissions for those components with individual screening values. If screening values are not determined for certain components, you must use a different calculation methodology for these unmonitored components.

I have a crude oil storage and loading facility. May I use the emission factors for bulk terminals?

No. If you have monitoring data for the fugitive components, then monitoring data must be used to determine emissions in accordance with the guidance in this supplement.

In the absence of monitoring data, use the oil and gas production average factors to determine component emissions. The bulk terminal average factors were developed specifically for gasoline and gasoline product loading operations. For crude oil storage and loading, the Oil and Gas Production factors would be more appropriate.

I have an LDAR program. Is there any way to represent this on my emissions inventory?

You may represent an LDAR program as part of the emissions inventory structure. For fugitive facilities with an LDAR program, add a CIN with abatement code 800. Since the LDAR reduction credits can no longer be applied to average factors for emissions determinations, you do not need to give a control efficiency for this type of CIN.

How do I find out if any new equipment leak fugitive factors have been developed or approved by the TCEQ?

To find out if new factors have been approved by the TCEQ, review the PDF document *Emissions Factors for Equipment Leak Fugitive Components*, available on the EAS's Web page at <www.tceq.state.tx.us/goto/ieas>.

Do I have to report emissions of nonreactive compounds?

Nonreactive compounds like methylene chloride and acetone are still considered air contaminants and should be reported. This is particularly

important if a nonreactive compound has an associated allowable emission rate. Nonreactive equipment leak fugitive emissions should be calculated in the same way as VOC fugitive emissions.

For my permit, I used the EPA’s average emissions factors with LDAR reduction credits to determine my equipment leak fugitive emissions. Can I use this approach to report these emissions in the emissions inventory?

No. All monitored equipment leak fugitive components should either have limited data for leaking components or, preferably, have individual screening values. Since using this monitoring data with correlation equations or screening range emissions factors will provide a more accurate determination of a site’s emissions, the use of LDAR reduction credits applied to average emission factors for emissions determinations will not be allowed.

I monitor my connectors only once every four years based on “skip period” provisions in my permit. For years where the connectors are not monitored, should I use the average factors with no reductions applied to estimate my emissions? Or can I apply the correlation equations using the data from the last monitoring period?

Normally, the EAS would require components to be monitored at least once during the current inventory year to use the correlation equations. Using monitoring data from previous years to predict future emissions requires the assumption that component leaks will not grow in the future—a questionable engineering assumption that will likely result in underestimation of emissions.

In the case of “skip period” provisions in a permit, it is permissible to use data from the last monitoring period in the correlation equations. For future leaking components, you should use leaking component screening values **before** any repairs are done. Since there is a history of monitoring and monitoring will occur in the future, the snapshot (as it were) taken before repairs should reasonably mirror any future monitoring.

Because there is no way to estimate the amount of time a component will leak in the future, the most conservative estimate would be to assume any leaking component will do so for an entire year. If you elect to use a different method to estimate your emissions, you must provide valid engineering assumptions to support your calculations.

In the past, I used screening range (leak/no-leak) emissions factors to determine emissions from my fugitive area. May I continue to use this method?

The correlation equations should be used to determine emissions from your fugitive area if you have screening value data from a monitoring program.

If your monitoring program does not retain screening value data, emissions must be determined using the best available method. If you elect to use the screening range emissions factors to estimate your emissions, you must supply valid engineering assumptions to support your calculations.

The TCEQ accepts the use of the correlation equations for screening values between zero and 100,000 ppm. If my instrument indicates nonpegged screening values above 100,000 ppm, can I use the correlation equations for those readings?

For emissions inventory purposes, the TCEQ currently accepts correlation equations as an acceptable method to determine emissions where the screening value is above 100,000 ppm.

My site does not fit specifically into one of the four categories of EPA average emission factors. What emission factors should I use?

The most representative emission factors. For example, a chemical storage and loading facility would select the SOCFI emission factors instead of the “petroleum marketing terminal” or “oil and gas” factors. Both the type of product and the type of process should be considered when selecting the most appropriate factor.

References

Texas Commission on Environmental Quality. 2005. Emissions Factors for Equipment Leak Fugitive Components. TCEQ Industrial Emissions Assessment Section draft document. Available online at: <www.tceq.state.tx.us/goto/ieas>. Accessed November 14, 2008.

U.S. Environmental Protection Agency. 1996. Preferred and Alternative Methods for Estimating Fugitive Emissions from Equipment Leaks. Vol. 2, Emissions Inventory Improvement Program Document Series, chapter 4. Available online at: <www.epa.gov/ttn/chief/eiip/techreport/volume02/index.html>. Accessed November 14, 2008.

U.S. Environmental Protection Agency. 1995. Protocol for Equipment Leak Emission Estimates. EPA-453/R-95-017. Available online at: <www.epa.gov/ttnchie1/publications.html>. Accessed November 14, 2008.

Fugitive Data Form

TCEQ Emissions Inventory Year _____

TCEQ Air Account Number: _____

FIN: _____

COMPONENT COUNTS

	Service	Unmonitored	Monitored			
		Number of components	Number of components	Leak definition (ppm)	Number of leakers	Number pegged
Valves	Gas/Vapor					
	Light liquid					
	Heavy liquid					
	H ₂ O/Light oil					
Pumps	Gas/Vapor					
	Light liquid					
	Heavy liquid					
	H ₂ O/Light oil					
Flanges	Gas/Vapor					
	Light liquid					
	Heavy liquid					
	H ₂ O/Light oil					
Open-Ended Lines	Gas/Vapor					
	Light liquid					
	Heavy liquid					
	H ₂ O/Light oil					
Connectors	Gas/Vapor					
	Light liquid					
	Heavy liquid					
	H ₂ O/Light oil					
Relief Valves	Gas/Vapor					
	Light liquid					
	Heavy liquid					
	H ₂ O/Light oil					
Compressor Seals	Gas/Vapor					
	Light liquid					
	Heavy liquid					
	H ₂ O/Light oil					
Other	Gas/Vapor					
	Light liquid					
	Heavy liquid					
	H ₂ O/Light oil					

VOC PERCENTAGES

MONITORING EQUIPMENT DATA

Gas/vapor stream: _____ %
 Light liquid stream: _____ %

Pegged Component Screening Value: _____ ppm
 Calibration Range: _____ min _____ max

EMISSIONS DETERMINATION METHODOLOGY OR LDAR PROGRAM USED

- | | | |
|---|--|---|
| <input type="checkbox"/> Oil and Gas Factors | <input type="checkbox"/> SOCM1 Average Factors | <input type="checkbox"/> SOCM1 without Ethylene Factors |
| <input type="checkbox"/> Refinery Factors | <input type="checkbox"/> SOCM1 with Ethylene Factors | <input type="checkbox"/> Correlation Equations |
| <input type="checkbox"/> Petroleum Marketing Terminal Factors | <input type="checkbox"/> Other (explain): _____ | |

LDAR PROGRAM: None 28M 28RCT 28VHP 28MID 28LAER
 AVO 28CNTA 28CNTQ HRVOC Other: _____

Instructions for Completing the Fugitive Data Form

Component Counts

Enter the number of each component type (valves, flanges, etc.) in each service (gas/vapor, light liquid, etc.). Note that water/light liquid service applies only to the oil and gas industry. Be certain to fill in all columns.

Unmonitored: Number of Components

For each component type, enter the number of unmonitored components in the fugitive area. If an LDAR program is in place, include components exempt from monitoring in this column.

Monitored: Number of Components

For each component type, enter the number of instrument-monitored components in the fugitive area.

Leak Definition

For each monitored component type, enter the leak definition level measured in parts per million.

Number of Leakers

For each monitored component type, enter the number of components that leaked at or above the leak definition threshold. Count each component once for each period that it leaked. For example, if a valve monitored quarterly was found to be leaking each quarter in a year, it should be counted as four leakers.

Number Pegged

For each monitored component type, enter the number of components that leaked at or above the “pegged” screening value. Count each component once for each period that it leaked at or above the pegged rate. For example, if a valve monitored quarterly was found to be leaking above the pegged rate each time, it should be counted as four pegged valves.

Monitoring Frequency

For each monitored component type, enter how frequently the components are monitored (annually, semiannually, quarterly, monthly, biweekly, etc.).

VOC Percentages

Enter the average VOC percentages for the gas/vapor stream and the light liquid stream. Heavy liquid streams are assumed to be 100 percent VOC.

Monitoring Equipment Data

Enter the equipment's calibration value range and the "pegged" components' screening value.

Emissions Determination Methodology

Select the industry type and methodology that you use to determine fugitive emissions. Please note that if more than one method is used for a single facility, you should create separate facilities for each factor group used.

LDAR Program Used

Select the leak detection and repair program implemented at the facility. Please note that if more than one LDAR program is implemented for a single facility, you should create separate facilities for each such program.

TECHNICAL SUPPLEMENT 4: FLARES

Technical Disclaimer

This technical supplement is intended to help you accurately determine and correctly report flare emissions. It does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how flares work and how they generate emissions, how they are monitored or tested, and what data are available for emissions determination, may change over time as we continue our scientific studies and as new information becomes available. We welcome any data, information, or feedback that may improve our understanding of flare emissions and thereby further improve determinations within the emissions inventory.

The calculation methods represented are intended as an aid; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. If you have a question regarding the acceptability of a given emissions determination method, contact the Emissions Assessment Section at 512-239-1773.

Introduction

This technical supplement offers guidance on identifying, quantifying, and correctly reporting elevated flare emissions on the annual emissions inventory.

This document does not address flare structural representation in the inventory. For guidance on this topic, consult Chapter 3.

Definitions

In this supplement, *waste gas* refers to gas streams produced in the process unit and routed to the flare for destruction.

Supplemental fuel refers to the gas that mixes with waste gas prior to its arrival at the flare tip, ensuring the combustibility of the total gas stream.

Flared gas refers to the combination of waste gas and supplemental fuel.

Pilot gas refers to the gas routed to the flare tip to ensure flared gas ignition.

Expected Emissions

Flare emissions will include, at a minimum, nitrogen oxides (NO_x), carbon monoxide (CO), and uncombusted flared gas compounds. In addition, if the flared gas contains sulfur-bearing compounds, emissions will also include hydrogen sulfide (H₂S) and sulfur dioxide (SO₂).

Products of Combustion

Products of combustion include NO_x, CO, and SO₂. Flared and pilot gas heat outputs impact emission rates of NO_x and CO. The sulfur content of both flared and pilot gases determines SO₂ emissions.

Compounds from Uncombusted Flared Gas

The flare's destruction efficiency determines what fraction of the flared gas remains uncombusted. The uncombusted flared gas compounds are generally volatile organic compounds, but may also include H₂S, CO, ammonia, and other organic and inorganic compounds present in the flared gas.

Emissions Determination

Generally, flare emissions determinations should be consistent with the TCEQ Air Permits technical guide for flares and vapor oxidizers, available at <www.tceq.state.tx.us/goto/nsr_flares>. However, if actual flare operation deviates from the specific operating conditions assumed in permit guidance, then it may not be appropriate to use this guidance to determine emissions. Exceptions for actual operation are identified in the following sections.

All flare emissions determinations depend upon the flared gas flow rate and composition. Therefore, before specific emission calculations are discussed, the preferred methods for obtaining the actual flared gas flow rate and composition data will be addressed.

Flared Gas Flow Rate and Composition

To obtain the most accurate emissions determination, base your calculations on the actual flow rate and the specific composition of the gas routed to the flare. The generally preferred methods of obtaining data on flared gas flow rate and composition are, in order of preference:

1. continuous monitoring with quality assured instruments
2. continuous monitoring with instruments that may not meet all quality-assurance tests
3. periodic testing with instruments and laboratory analytical methods

- 4a. engineering determinations based on detailed process evaluation
- 4b. a one-time performance test conducted during the inventory year

For flares subject to Chapter 115, Subchapter H, relating to highly reactive volatile organic compounds, flow rate and composition data required by 30 TAC 115.725–726 should be used to determine emissions for any portions of 2008 that HRVOC monitors were installed and operational.

In the absence of monitoring data, selection of the most accurate method may sometimes require exercising scientific judgment. For example, when using the results of a one-time performance test, the test conditions should be compared to the flare's actual operating conditions during the inventory year to determine whether the test accurately represents the flare's performance. If test conditions do not accurately model flare operation, then engineering determinations based on detailed process evaluation may provide the best data.

NO_x and CO Emissions

To calculate NO_x and CO emissions, you must first know the net heating value of the flared gas. Using the actual short-term flared gas composition and flow rate data for the inventory year, calculate the net heating value of the flared gas and the total heat release for each short time period. Use these total heat release data, in conjunction with the appropriate emission factors from TCEQ Air Permits guidance, to determine NO_x and CO emissions for each time segment. Since the calculated net heating value of the gas and the assist gas type will determine the appropriate emission factors you must carefully select the correct factors for each flare from Table A-6.

Table A-6. TCEQ Air Permits Flare Emission Factors

Contaminant	Assist Type	Waste Gas Stream Net Heating Value^{a,b}	Emission Factor
NO _x	Steam	High Btu	0.0485 lb/MMBtu
		Low Btu	0.068 lb/MMBtu
	Air or Unassisted	High Btu	0.138 lb/MMBtu
		Low Btu	0.0641 lb/MMBtu
CO	Steam	High Btu	0.3503 lb/MMBtu
		Low Btu	0.3465 lb/MMBtu
	Air or Unassisted	High Btu	0.2755 lb/MMBtu
		Low Btu	0.5496 lb/MMBtu

^a High Btu: > 1000 Btu/scf

^b Low Btu: 192–1000 Btu/scf

Calculate emissions using the most accurate data on gas flow rate and composition available. (See “Flared Gas Flow Rate and Composition” earlier in this supplement for more information on preferred data.) Regardless of the data's source, code NO_x and CO emissions with a determination methodology of “A” for ‘TCEQ-approved factor.’

For flares subject to the HRVOC regulations in Chapter 115, Subchapter H, use the net heating value data required by 30 TAC 115.725 and 115.726 to determine NO_x and CO emissions for any portions of 2008 that HRVOC monitors were installed and operational.

Uncombusted Flared Gas Emissions

Uncombusted flared gas emissions usually include VOCs, H₂S, or both. Emissions calculations for these contaminants are based on the flared gas flow rate and composition and the appropriate destruction efficiency, which depends upon the actual flare operation. Flare destruction efficiency varies with flame stability, operating conditions, flare tip size and design, the specific compounds being combusted, and gas composition. The EPA has determined operating limits (see 40 CFR 60.18), that result in stable operation of flare flames. Therefore, emission determinations may vary depending on whether the criteria of 40 CFR 60.18 are satisfied.

Chapter 115 HRVOC regulations address flare operational requirements in regard to 40 CFR 60.18. For flares subject to HRVOC regulations, use the appropriate destruction efficiencies specified in 30 TAC 115.725. Additionally, for flares subject to Chapter 115 HRVOC regulations, use the required HRVOC monitoring data to determine emissions of uncombusted flared gases for any portions of 2008 that HRVOC monitors were installed and operational.

Otherwise, if the flare’s operation is consistent with 40 CFR 60.18, then use the appropriate destruction efficiencies from TCEQ Air Permits guidance shown in Table A-7.

Table A-7. TCEQ Air Permits Flare Destruction or Removal Efficiencies for 40 CFR 60.18–Compliant Flares

Waste Stream Composition	Destruction or Removal Efficiency
VOC, Number of Carbons	
C1–C3 ^a	99%
> C3	98%
H ₂ S	98%

^a 99% reduction should only be applied for compounds containing no more than three carbons that contain no elements other than carbon and hydrogen in addition to the following compounds: methanol, ethanol, propanol, ethylene oxide, and propylene oxide.

Note that, for flare operation to be considered consistent with 40 CFR 60.18, it should:

- meet the flared gas heating value and flare exit tip velocity limitations;
- be equipped with proper liquid knockout and ignition systems; and
- operate smokelessly.

If the flare's operation is not consistent with 40 CFR 60.18, then the flare is likely to be operating at or near unstable flame mode. If specific data on destruction efficiency are available for the flare tip and design, compounds being combusted, gas composition, and operating conditions of the flare in question, these may be used to determine emissions in such cases. Otherwise, it will be necessary to use the destruction efficiency described in the following paragraph.

Although only limited test data are available for flares operating with an unstable flame, EPA test data indicate that destruction efficiencies generally range from 85 to 97 percent in such cases. The median destruction efficiency for the EPA data set appears to be approximately 93 percent. Although other data suggest that efficiencies may be even lower during unstable flame operations, you may assume a 93 percent destruction efficiency for flare operating conditions that do not satisfy 40 CFR 60.18.

On steam-assisted flares, there is the potential for over-steaming of the gas stream and the destruction efficiency may be lower than the appropriate destruction efficiencies given in Table A-7. You may assume a 93 percent destruction efficiency for flare operating conditions that do not satisfy 40 CFR 60.18.

Of course, if the flare flame is ever extinguished, one should assume no destruction for the period when the flame was out.

Code uncombusted flared gas emissions with a determination methodology of "B" (for 'material balance') when the actual flow rate and composition of the gas routed to the flare are obtained through continuous monitoring. Since these methods measure the gas composition before destruction by the flare rather than the amount of emissions released to the atmosphere, the emissions should not be coded with a determination methodology of "M" (for 'measured data') or "D" (for 'continuous emissions monitoring systems'). If the flow rate and composition of the gas routed to the flare are determined using process knowledge and engineering calculations, code the uncombusted flared gas emissions with a determination methodology of "S" (for 'scientific calculation').

SO₂ Emissions

Calculations of SO₂ emissions are based on the amount of sulfur-bearing compounds in the flared gas and on the appropriate destruction efficiency, as discussed previously.

For example, assume that 100 pounds per hour of flared gas, composed of 80 percent butane and 20 percent H₂S, is burned in a flare that satisfies 40 CFR 60.18. The hourly uncombusted flared gas emissions would be 1.6 pounds of butane and 0.4 pounds of H₂S. In addition, the flare creates SO₂ from the H₂S. Determine the SO₂ emissions as follows:

$$\frac{20 \text{ lb H}_2\text{S}}{\text{hour}} \times 0.98 \times \frac{\text{lb-mole}}{34 \text{ lb H}_2\text{S}} \times \frac{64 \text{ lb SO}_2}{\text{lb-mole}} = 36.9 \text{ lb/hr SO}_2$$

Note that, as the criteria of 40 CFR 60.18 were met, a 98 percent destruction efficiency was assumed.

Code SO₂ emissions with a determination methodology of “B” for ‘material balance.’

Annual and Ozone Season Rates

Typically, flared gas flow rate and composition are highly variable; therefore, calculations of flare emissions need to take this variability into consideration. In general, emission determinations should not be based on annual average conditions. Instead, calculate emissions for short time segments when flare flow rate and composition are relatively constant, and then sum those short-term emissions to obtain the actual annual total. For example, if hourly flow rates and composition data are available, then calculate hourly emissions (lb/hr) and sum all hourly rates to obtain the annual total. If only weekly data are available, then calculate weekly average emissions and sum those to obtain the annual total.

These principles are especially important for ozone season emission calculations. The actual short-term emissions calculated for the months of June, July, and August should be used to develop the daily average ozone season emissions.

If no flow rate or composition data are available, engineering estimates should take into consideration annual process variations that might affect flared gas.

Speciation of Uncombusted Flared Gas Compounds

Depending on the flare service, emissions of uncombusted flared gas could include carbon, nitrogen, and sulfur compounds.

At this time, the composition of the uncombusted flared gas is assumed to remain unchanged. Although complex oxidation reactions in the flare flame may alter the emissions composition, no definitive method exists to identify those new compounds. Thus, emission determinations should assume no change in the composition of the uncombusted gas.

For example, consider a flared gas flow rate of 100 pounds per hour of VOC with a composition by weight of:

- 20 percent toluene,
- 60 percent xylene,
- and 20 percent butane.

If the flare satisfies 40 CFR 60.18 performance criteria with this flow rate and composition, then a 98 percent destruction efficiency may be used. Based on the flow rate, composition, and destruction efficiency, **total** VOC emissions would be 2 pounds per hour.

Since these emissions are assumed to be 20 percent toluene, 60 percent xylene and 20 percent butane by weight, speciated VOCs would be reported as:

- 0.4 pound per hour toluene,
- 1.2 pounds per hour xylene, and
- 0.4 pound per hour butane.

For flares subject to HRVOC regulations, determine speciated uncombusted flare gas emissions according to the requirements (including destruction efficiencies) outlined in 30 TAC 115.725.

Supporting Documentation

Flare emissions depend heavily on a flare's destruction efficiency. Supply detailed sample calculations showing the basis of flare destruction efficiencies and emissions.

For each flare in HRVOC service, indicate "Yes" on the "HRVOC Service?" characteristic. Regardless of the county location of the regulated entity, if any individual gas stream routed to the flare contains more than 5 percent by weight of aggregate highly reactive volatile organic compounds (HRVOCs—ethylene, propylene, all isomers of butene, and 1,3-butadiene), then the flare is considered to be in HRVOC service for emissions inventory purposes.

In addition, the EAS may request data for those times when the flare did not satisfy 40 CFR 60.18 criteria. These data include, but are not limited to:

- the date and time of the period;
- the flare emissions point;

- waste gas and supplemental fuel flow rate in scfm;
- waste gas and supplemental fuel composition in volumetric percentages
- the Btu/scf value for each component of the waste gas and supplemental fuel
- the flare tip diameter; and
- the steam/air assist gas rate.

Reporting Emissions from a Shared Flare

In some cases, process streams are sent off-site to a flare owned by a different regulated entity. The applicable structure, including the flare emission point, should be included in the emissions inventory where the process equipment is located and the emissions are generated; however, the path emissions will be zero because the combustion emissions generated by the flare and the non-combusted contaminants are required to be reported by the owner of the flare. A path comment should be included on the path emissions page identifying the shared flare's EPN and its regulated entity reference number. Please call the EAS for additional guidance if you have questions about your particular situation.

References

Engineering Science, preparer. 1983. A Report on Flare Efficiency Study. Vol. 1. Chemical Manufacturers' Association.

Energy and Environmental Research Corporation, preparer. 1984. Evaluation of the Efficiency of Industrial Flares: Test Results. EPA report 600/2-84-095. Industrial and Environmental Research Lab.

U.S. Environmental Protection Agency. 1985. Evaluation of the Efficiency of Industrial Flares: Flare Head Design and Gas Composition. EPA report 600/2-85-106. Washington.

TECHNICAL SUPPLEMENT 5: MARINE FACILITIES

Technical Disclaimer

This technical supplement is intended to help you accurately determine and correctly report equipment leak fugitive emissions. It does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how piping components work and how they generate emissions, how they are monitored or tested, and what data are available for emissions determination, may change over time as we continue our scientific studies and as new information becomes available. We welcome any data, information, or feedback that may improve our understanding of equipment leak fugitive emissions and thereby further improve determinations within the emissions inventory.

The calculation methods represented are intended as an emissions calculation aid; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. If you have a question regarding the acceptability of a given emissions determination method, contact the Emissions Assessment Section at 512-239-1773.

Introduction

This technical supplement offers guidance on identifying, quantifying, and correctly reporting marine facility emissions on the annual emissions inventory. Marine facility emissions must be reported as part of the annual routine emissions inventory. The onshore facilities' owner or operator does not own or operate the marine vessel itself, but does operate most of the activities resulting in vessel emissions while the vessel is docked. Therefore, the onshore facilities' owner or operator is responsible for reporting dock and dockside marine vessel emissions in the annual emission inventory. This is consistent with the longstanding approach of reporting truck loading and cleaning emissions in the truck terminal or cleaning facility owner's inventory.

Several categories of facilities are associated with marine operations, including:

- onshore process units or equipment performing a function associated with dockside marine vessels (e.g., solid-material stockpiles, silos, tanks, and abatement devices)
- the dock and all of its associated equipment (e.g., conveying lines, piping, valves, pumps, hoses, and blowers); and

- dockside marine vessel loading and unloading, cleaning and degassing, and abrasive blasting and painting. A marine vessel is considered dockside if it is in any way connected to the shore. This includes vessels connected to the dock, connected to a vessel that is connected to the dock, or connected directly to the land.

Because onshore process units and equipment are addressed elsewhere in *2008 Emissions Inventory Guidelines*, this technical supplement addresses only dock and dockside marine vessel emissions.

This supplement does not address the structural representation of marine operations in the inventory. For guidance, consult Chapter 3.

Multiple Air Permits draft guidance documents are referred to in this supplement. The documents are available by contacting TCEQ Air Permits personnel at 512-239-1250.

Expected Emissions

Emissions associated with the dock and the dockside marine vessels, except for emissions from marine vessel engines, should be determined and reported in the annual emission inventory. This includes any emissions from marine vessel-to-marine vessel transfers (i.e., lightering or barging).

A marine facility's emissions depend on the activity performed and the materials handled or used.

Dock emissions may include:

- fugitive particulate matter from conveying lines; and
- fugitive VOCs from equipment leak fugitives.

Dockside marine vessel emissions may include:

- VOCs from loading or unloading liquid bulk materials,
- VOCs from loading or unloading liquified gaseous materials,
- particulate matter from loading or unloading solid bulk materials (including lightering or barging at the dock),
- VOCs from degassing and cleaning liquid vessel compartments, and
- particulate matter and VOCs from abrasive blasting and surface coating.

Determining Emissions

For primary guidance on determining marine emissions, consult the Air Permits draft guidance document *Dockside Vessel Emissions*. In particular, Section 2 of that document addresses each dockside activity

discussed in the following section, giving background information, specific guidance on calculations, and references to other specific documents relating to air permits that may also be helpful. The following sections address the key points related to the emissions inventory.

Loading and Unloading Bulk Liquid Materials

Loading and unloading bulk liquid materials may result in emissions at the dock and at the vessel. Dock emissions result from equipment leak fugitives, while vessel emissions result from vapor displacement during liquid loading.

Determine dock emissions from equipment leak fugitives following the guidance in Technical Supplement 3: Equipment Leak Fugitive Emissions. Code the emissions with a determination methodology of “A.” Equipment leak fugitives should be determined for the entire period when VOCs are present in the dock piping.

Determine vessel emissions from liquid material loading and unloading using the techniques in the TCEQ air permits draft guide Loading Operations. Code the associated emissions with a determination methodology of “A.”

If loading emissions are collected and abated, some emissions will escape collection and, additionally, some collected emissions will escape destruction. The Air Permits document *Loading Operations* gives guidance on determining uncollected emissions that should be coded with a determination methodology of “A.” The collected emissions that escape destruction at the abatement device should be determined using an appropriate destruction efficiency. Code these emissions with a determination methodology of “B.”

During unloading operations, vapor in the receiving storage tank’s vapor space is displaced, resulting in emissions that should be reported at the storage tank using storage tank emission calculations and following the general guidance.

After unloading operations, the liquid left in sumps can evaporate over time, resulting in emissions. Those emissions should be reported with the equipment leak fugitives using a material balance approach.

Loading and Unloading Bulk Liquefied Gaseous Materials

Loading and unloading liquefied gases will result in VOC emissions from dock equipment leak fugitives, and may also result in vessel emissions from gas freeing and vessel conditioning.

When liquefied gaseous materials are transferred to or from a pressurized marine vessel compartment, emissions usually come only from dock piping components. For guidance on determining these emissions,

consult Technical Supplement 3. Code the associated emissions with a determination methodology of “A.” Equipment leak fugitive emissions should be determined for the entire period when VOCs are present in the dock piping.

Emissions from a pressurized marine vessel compartment may result from two processes used to ensure safety and product quality: gas freeing and gas conditioning. Gas freeing is the evacuation of residual liquid (“heel”) and vapor after unloading and prior to loading a new material. Gas conditioning displaces the residual nitrogen pad from the marine vessel compartment and saturates the vapor space with product vapor prior to loading. Calculate gas freeing or gas conditioning emissions using the ideal gas law and the actual pressure, concentration and vessel volume data. Since the ideal gas law is a first-order scientific principle, code the associated emissions with a determination methodology of “S” for ‘scientifically calculated.’

Loading and Unloading Bulk Solid Materials

Emissions from bulk solid material loading and unloading result from dock fugitives and from entrainment of solids during displacement of the vessel compartment air space during loading.

Material transfer methods determine where and how particulate matter is emitted. Emissions from such transfer methods as pneumatic systems, clamshell buckets, drag chains, belt conveyors, manual operations, or a combination of these methods should be determined following the detailed guidance in the Air Permits document *Dockside Vessel Emissions*.

If a material type is explicitly addressed in air permits guidance, then code the associated emissions with a determination methodology of “A.” If the material type is not explicitly addressed, use the method for the most closely related material and code the emissions with a determination methodology of “E” for ‘estimated.’

Degassing and Cleaning Vessel Compartments

Cleaning operations remove residual material from vessel compartments prior to change of service, maintenance, or repair. Depending on the vessel compartment’s condition, as many as three steps in the process may result in emissions: degassing, deheeling, and cleaning. *Dockside Vessel Emissions* explains the emission calculation method for degassing, deheeling, and cleaning. It also references the Air Permits document for determining uncontrolled vessel degassing and cleaning emissions, *Tank Truck and Rail Car Cleaning*. Since these techniques use the ideal gas law, code the associated emissions with a determination methodology of “S” for ‘scientifically calculated.’

If saturation test results are used to calculate degassing, deheeling, and cleaning emissions, then the ambient temperature during the test should correspond to or be greater than the average ambient temperature for that year's ozone season. Similarly, the chemical vapor pressure(s) used to calculate emissions should be the vapor pressure(s) of the chemical(s) at the average ozone season temperature. Additionally, the test results can only be applied to chemicals that have an equivalent or lower vapor pressure than the tested chemical's vapor pressure.

If emissions are determined using saturation test results, code the associated emissions with a determination methodology of "B" for 'material balance.' Submit summary test results with each year's EIQ, and include information such as the ambient temperature during testing and vapor pressures of the tested chemicals.

Abrasive Blasting and Surface Coating

Building or repairing marine vessels and offshore platforms may involve abrasive blasting and painting operations. Abrasive blasting results in particulate matter emissions of the abrasive material and the old paint. Painting results in emissions of the VOCs that volatilize from the paint as it cures and particulate matter resulting from paint overspray. Determine these emissions using the Air Permits draft documents *Abrasive Blast Cleaning* and *Surface Coating Operations*.

Since particulate emissions from abrasive blasting are calculated based on the abrasive material usage and the emission factors in the abrasive blast cleaning guidance, code the emissions with a determination methodology of "A."

Since VOC and particulate emissions from coatings are determined based on the coating composition and the application equipment's transfer efficiency, code the emissions with a determination methodology of "B" for 'material balance.'

Annual and Ozone Season Emission Rates

Determine actual annual emissions following the guidance in this supplement. If the same material is handled throughout the year, then use annual material throughput and the guidance in this supplement to determine emissions. If materials vary, determine emissions from each individual operation using the guidance in this supplement and the following information:

- the amount and type of material processed;
- speciation of any VOC or particulate emissions;
- temperature, vapor pressure, molecular weight, and any other data necessary to determine emissions.

Report the resulting emission rates at the appropriate facility–emissions point paths as the annual emissions rates. Do not use average or typical operations data to determine actual annual emissions.

To obtain ozone season emission rates for each facility/emissions point path, first determine emissions (in pounds) that the facility generated and emitted during the months of June, July, and August. Next, divide the resulting emissions rates by the number of days that the facility operated during the months of June, July, and August. Report the resulting rates as the ozone season pound per day emissions rates for that facility/emissions point path. Note that the number of days that a facility can operate during the ozone season cannot exceed 92. For more information, consult “Reported Emissions”: “Ozone Season Emissions” in Chapter 4.

VOC and Particulate Speciation

Speciation should follow the *2008 Emissions Inventory Guidelines*.

In general:

- Emissions from bulk liquids and liquefied gaseous materials loading and unloading will be VOCs, with a composition corresponding to that of the material loaded or unloaded.
- Vessel gas freeing and conditioning emissions will be VOCs, with a composition corresponding to that of the previously loaded material or the material now being loaded.
- Emissions from loading solid bulk material will be particles of the material loaded.
- Degassing and cleaning emissions will be VOCs, with a composition corresponding to that of the material previously held in the vessel compartment.
- Abrasive blasting results in particulate matter emissions of the abrasive material and the old paint. Painting results in emissions of the VOCs that volatilize from the paint as it cures and particulate matter resulting from paint overspray.

Supporting Documentation

To allow for the verification of reported emissions, include representative sample calculations with your emissions inventory submission. Supply the data used in these sample calculations, including:

- the amount and type of material processed during each operation, including the type and amount of material transferred between vessels at the docks;
- the date and time of the activity;
- temperature, vapor pressure, molecular weight, and other factors that affect emission determinations;

- material composition data, if the associated emissions (total or speciated) depend upon them; and
- all other information necessary to determine emissions.

Issues of Special Concern

May I omit my marine emissions from the annual inventory? Aren't these emissions included in the area source inventory?

No. The area source inventory only includes emissions from ships in transit. Once a ship is docked, it is considered a stationary source. All non-engine emissions from a docked vessel should be reported in the point source inventory.

Since I don't own the marine vessel, why am I required to report its emissions in my inventory?

Because the marine vessel is at your site supporting your business, the associated emissions should be reported in your inventory.

What if I share a marine loading facility with another company?

Emissions should be reported by the regulated entity that owns the marine loading facility. Please call the EAS for additional guidance if you have questions about your particular situation.

Should I report emissions generated when materials are transferred from one marine vessel to another while docked? (This is sometimes also called lightering or barging.)

Yes. All emissions from vessels at the dock should be reported by the dock owner or operator.

References

Texas Commission on Environmental Quality. 2000. Air Permit Technical Guidance for Chemical Sources: Loading Operations. TCEQ Air Permits Division draft document.

Texas Commission on Environmental Quality. 2001. Technical Guidance Package for Agricultural Sources: Grain Elevators. TCEQ Air Permits Division draft document.

Texas Commission on Environmental Quality. 2001. Dockside Vessel Emissions. TCEQ Air Permits Division draft document.

Texas Commission on Environmental Quality. 2001. Technical Guidance Package for Chemical Sources: Tank Truck and Rail Car Cleaning. TCEQ Air Permits Division draft document.

Texas Commission on Environmental Quality. 2001. Abrasive Blast Cleaning. TCEQ Air Permits Division draft document.

Texas Commission on Environmental Quality. 2001. Air Permit
Technical Guidance for Coating Sources: Surface Coating Operations.
TCEQ Air Permits Division draft document.

TECHNICAL SUPPLEMENT 6: ABOVEGROUND LIQUID STORAGE TANKS

Technical Disclaimer

This technical supplement is intended to help you accurately determine and correctly report equipment leak fugitive emissions. It does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how piping components work and how they generate emissions, how they are monitored or tested, and what data are available for emissions determination, may change over time as we continue our scientific studies and as new information becomes available. We welcome any data, information, or feedback that may improve our understanding of equipment leak fugitive emissions and thereby further improve determinations within the emissions inventory.

The calculation methods represented are intended as an emissions calculation aid; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. If you have a question regarding the acceptability of a given emissions determination method, contact the Emissions Assessment Section at 512-239-1773.

Introduction

This technical supplement offers guidance on identifying, quantifying, and correctly reporting aboveground storage tank emissions in the annual emissions inventory. This document does not address underground storage tanks or devices such as separators, reactors, mixing vessels, or blend tanks. For more information on the common tank designs covered in this technical supplement, consult the current edition of Chapter 7 of *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* (AP-42).

This document does not discuss tank structural representation in the emissions inventory. For guidance on this topic, consult Chapter 3.

Guidance Available in This Supplement

This supplement offers guidance on appropriate methodologies for determining emissions from storage tanks, emissions inventory reporting, and special considerations to be made when determining emissions. Specifically, it addresses:

- expected emissions from aboveground liquid storage tanks;
- quantifying emissions for breathing, working, flash, degassing, cleaning, and landing losses; and
- special considerations in determining emissions for certain situations involving storage tanks.

Definitions

In this document, *breathing losses* will refer to the emissions that occur when vapors are expelled from the tank due to changes in temperature, barometric pressure, or both. Breathing losses are also known as *standing losses*.

Cleaning refers to the process of removing vapor, sludge, or rinsing liquid from a storage tank.

Degassing is the process of removing organic gases or vapors from a storage tank.

Equation of state refers to an equation relating the temperature, pressure, and volume of a system in thermodynamic equilibrium.

Flash gas refers to the gas or vapor that is generated when a gas or liquid stream experiences a decrease in pressure or an increase in temperature.

Gas/oil ratio (GOR) means the number of standard cubic meters of gas produced per liter of crude oil or other hydrocarbon liquid.

Landing losses refers to emissions that occur from floating-roof tanks whenever the tank is drained to a level where its roof rests on its deck legs (or other supports).

Pigging (and its variants) refers to deploying a mobile plug (known as a *pig*) through a pipeline to perform various activities such as pipeline cleaning, inspection, or product removal.

Working losses are emissions related to the movement of the liquid level in the tank. Working losses from fixed-roof tanks occur as vapors are displaced from the tank during tank filling and emptying. Working losses from floating-roof tanks occur as the liquid level (and therefore the floating roof) is lowered, causing the liquid on the exposed tank walls and fittings to evaporate.

Expected Emissions

Storage tank emissions can include VOC, HAP, toxic, and inorganic emissions from flashing, landing, breathing, and working losses. Storage tank emissions may also include emissions from degassing, cleaning, and defective tank seals and fittings. All storage tank emissions, whether

routine or not, should be quantified and reported in the emissions inventory.

Associated Emissions

Equipment leaks and loading losses from trucks, railcars, tank cars, etc., are two other emissions sources generally associated with liquid storage operations.

Do not report equipment leak fugitive emissions at the same facility–emissions point path where storage tank breathing and working loss emissions are reported. Instead, report equipment leak fugitive emissions at a separate path according to the guidance in Technical Supplement 3. To determine emissions from equipment leak fugitive components, consult Technical Supplement 3.

Similarly, do not report truck, railcar, tank car, etc., loading operations associated with storage tanks at the same facility–emissions point path where you report emissions from storage tank breathing and working losses. Instead, report the loading rack and its related emissions at a unique facility–emissions point path. For further guidance on structural representation, consult “Loading Operations” in Chapter 3. For guidance on determining emissions from loading operations, consult the current version of AP-42, Chapter 5.2.

Quantifying Storage Tank Emissions

Determining Emissions from Breathing and Working Losses

Emissions from storage tanks occur because of evaporative losses of the liquid during storage (breathing losses) and as a result of changes in liquid level (working losses). Determining breathing and working loss emissions from liquid storage tanks should be consistent with the current edition of AP-42, Chapter 7.

Using the current version of TANKS, the EPA’s free software program that calculates fixed-roof and floating-roof storage tank emissions, will help to ensure that emissions determinations are consistent with the current edition of AP-42. The current version of TANKS is available at www.epa.gov/ttn/chief/software/tanks/index.html.

Annual and Ozone Season Emissions

Annual and ozone season breathing and working loss emissions can be determined by using the current TANKS program or by following the guidance outlined in AP-42, Chapter 7.

Due to higher average ambient temperatures during the ozone season, the vapor pressure of an organic liquid will increase; therefore, storage tank emissions rates will be greater in the summer than in the winter. Ozone

season emissions will need to be determined using the increased vapor pressure data in the appropriate equations. Ozone season emissions should be determined by generating a TANKS report for the months of June, July, and August. To obtain the ozone season emissions rate in pounds per day, divide the total emissions (in pounds) for the three-month summer period by 92 days (the total number of days during the ozone season).

Obtaining Accurate Emissions Determinations from TANKS

Accurate data input is essential to obtaining valid emissions determinations from the TANKS program. TANKS has programmed default settings for many input variables, including floating-roof tank fittings, and speciation profiles for chemical mixtures. If the TANKS default settings are used, it can result in inaccurate or invalid emissions determinations. Therefore, the user should use site-specific data to obtain the most accurate emissions determinations. Specifically, for compounds whose physical properties can vary widely, such as condensate, or for site-specific or proprietary compounds or chemical mixtures, enter specific chemical or mixture data into the TANKS chemical database; use these new chemical data to generate emissions reports.

Similarly, detailed information on the number and physical characteristics of the tank fittings should be used in the “detailed” fittings selection should be used in the “Physical Characteristics” portion of TANKS.

The TANKS user’s manual, available at <www.epa.gov/ttn/chief/software/tanks/index.html>, contains detailed instructions for adding or modifying chemicals, chemical mixtures, and tank fittings, as well as general information on how to use the software.

Determining Emissions from Flashing Losses

Flashing losses occur when a liquid with entrained gases experiences a pressure drop or a temperature increase. As the liquid equalizes to a new steady state, some of the lighter compounds dissolved in the liquid are released or “flashed” from the liquid. Additionally, some of the compounds that are liquids at the initial pressure and temperature transform into a gas or vapor and are also released or “flashed” from the liquid. As these gases are released, some of the other non-flashing compounds in the liquids may become entrained in these gases and will be emitted with them. Flashing loss emissions (*flash emissions*) are greater as the pressure drop increases and as the amount of lighter hydrocarbons in the liquid increases. The temperature of both the liquids and the storage tank will also influence the amount of flash emissions.

From a process perspective, flash emissions from storage tanks generally occur when pressurized liquids are sent to storage at a lower pressure. Specifically, flash emissions from storage tanks can occur at wellhead

sites, tank batteries, compressor stations, gas plants, and “pigged” gas lines when pressurized gas and liquids are sent to atmospheric storage vessels. These flash emissions are vented to the atmosphere through a tank’s pressure relief valve, hatch, or other openings, or alternatively may be routed to a control device. Additionally, flash emissions can also be associated with high-, intermediate-, and low-pressure separators, heater treaters, surge tanks, and accumulator operations, although emissions determinations for these sources are not addressed in this supplement.

While the composition of flash emissions varies, flash gas emissions include VOCs, HAPs, and toxics.

Emissions Determination Methodologies: Order of Preference

Several different methods of determining flash emissions exist; however, there are specific constraints associated with each method. The most appropriate method for determining flash emissions will depend upon the site-specific process. Acceptable determination methods for a given process should be evaluated upon whether the process parameters are consistent with the method’s development and underlying assumptions.

General orders of preference for black oil and gas condensate systems are listed below. However, for a given system, a more preferred method may not necessarily be applicable to a process based upon its specific parameters. Specific constraints for each method are explained in detail in the following sections. If the EAS determines that a determination method for a site-specific process is unfounded, then the EAS may require that the emissions determinations be recalculated using a more appropriate method.

Note that TANKS does **not** determine flash loss emissions, and cannot be used to determine losses from unstable or boiling stocks, or from mixtures of hydrocarbons or petrochemicals where the vapor pressure is not known or cannot be readily predicted.

Black Oil Systems

“Black oil” is defined as a heavy, low-volatility oil approximated by a GOR less than 1,750 cubic feet per barrel and an API gravity less than 40°. The appropriate methodologies for determining flash emissions for black oil systems are, in general order of preference:

- direct measurement of emissions (code as “M”);
- process simulator models (code as “S”);
- the E&P TANK program (code as “O”);
- Vasquez-Beggs or Rollins, McCain, and Creeger correlations, or software that uses these correlation equations (such as GRI-HAPCalc) (code as “O”);
- the gas/oil ratio (GOR) method (code as “B”).

Please note that crude oil with an API gravity greater than 40° should be treated as gas condensate when determining flash emissions.

Gas Condensate Systems

“Gas condensate” is defined as a liquid hydrocarbon with an API gravity greater than 40° at 60°F (and a specific gravity less than 0.8252). The appropriate methodologies for determining flash emissions for gas condensate systems are, in general order of preference:

- direct measurement of emissions (code as “M”);
- process simulator models (code as “S”);
- the E&P TANK program (code as “O”);
- the Environmental Consultants and Research, Inc. (EC/R) Equation (code as “O”); the gas/oil ratio method (code as “B”).

Direct Measurement of Emissions

Direct measurement provides the most accurate results for evaluating flash gas flow rates and the composition of flash emissions; however, this method can be more costly than others discussed below.

Process Simulator Models

Process simulators are computer models that use equations of state in conjunction with mass and energy balances to simulate petroleum processes for a variety of engineering purposes. Process simulator determinations generally are consistent with laboratory values, and therefore are expected to be more accurate when estimating flash emissions than most other determination methods (except measurements). However, process simulators are costly, and can be complicated to use.

There are several different process simulators (HYSIM, HYSIS, WINSIM, PROSIM, etc.), each employing similar basic principles. While process simulators are primarily used in process design, these models can also determine and speciate flash emissions using the Peng-Robinson equation of state option. Although other equations of state are available in the model, the Peng-Robinson equation best suits flash emissions determinations.

Required inputs may include an extended pressurized condensate analysis as well as other parameters (for example, temperature, pressure, and flow) for the process being simulated. Unlike other flash determination methods, process simulators are not constrained by American Petroleum Institute (API) gravity. Process simulators are appropriate for either black oil or gas condensate systems if detailed, accurate input data are available.

E&P TANK Program

API and the Gas Research Institute developed the E&P TANK model. It predicts VOC and HAP emissions (flashing, working, and standing losses) from petroleum production field storage tanks. The E&P TANK program bases flash emissions determinations on the Peng-Robinson equation of state, and requires site-specific information to determine emissions rates. E&P TANK is best suited for upstream operations, such as stock tanks at wellheads and tank batteries common to several wellheads, although it will handle a broad range of API gravities (15°–68°).

The E&P TANK model allows the user to input compositional analyses from pressurized oil and gas samples to simulate flash generation in storage tanks. Specifically, the minimum inputs needed for the model are:

- separator oil composition;
- separator temperature and pressure;
- sales oil API gravity and Reid Vapor Pressure (RVP);
- sales oil production rate; and
- ambient temperature and pressure.

Since separator oil composition is a key input in the model, E&P TANK includes a detailed sampling-and-analysis protocol for separator oil.

E&P TANK also allows users to input detailed information about tank size, shape, internal temperatures, and ambient temperatures, and therefore the software can produce more precise emissions determinations. This flexibility in model design allows users to employ the model to match site-specific information.

The E&P TANK software is available at <www.global.ihs.com>.

Vasquez-Beggs Correlation Equation

The Vasquez-Beggs correlation equation was developed in 1980 as part of a University of Tulsa research project. More than 6,000 samples from oil fields worldwide were used in developing correlations to predict oil properties.

The Vasquez-Beggs correlation equation determines the gas/oil ratio of a hydrocarbon solution from user-inputted variables; this GOR can then be used in conjunction with product and process parameters to determine flash emissions. This method was designed for gases dissolved in crude oils, and is most appropriate for use on upstream operations, such as stock tanks at wellheads, oil- and gas-production batteries, and for black oil. This method is not valid for gas condensate systems; see Emissions Determination Methodologies: Order of Preference above for the appropriate methodologies to determine flash emissions from those sources.

The method requires eight input variables:

- stock-tank API gravity,
- separator pressure,
- separator temperature,
- gas specific gravity,
- volume of produced hydrocarbons,
- molecular weight of the stock-tank gas,
- the VOC fraction of the tank emissions, and
- atmospheric pressure.

The Vasquez-Beggs correlation equation determines the dissolved GOR of a hydrocarbon solution as a function of the separator temperature, pressure, gas specific gravity, and liquid API gravity. Flash emissions from the VOC storage tank are then determined by multiplying the GOR by the tank throughput, the molecular weight of the stock-tank gas, and the weight fraction of VOC in the gases.

These equations to determine flash emissions are available in a Microsoft Excel spreadsheet originally developed by the Oklahoma Department of Environmental Quality, and can be downloaded at www.deq.state.ok.us/AQDnew/resources/Calculations11.xls.

Programs such as GRI's HAPCalc model use the Vasquez-Beggs correlation equation to determine flash emissions; emissions determinations methods using such programs should be coded accordingly.

EC/R Equation

The EC/R equation calculates flash emissions based on the pressure drop of the process stream from the previous process vessel, the tank throughput, the density of the hydrocarbon liquids, and the mass fraction of each component in the liquid.

This method assumes that the liquid and vapor streams reach equilibrium at standard temperature and pressure and that the storage tank is at standard temperature and pressure. The EC/R algorithm is valid for vapor pressure of liquid streams entering the storage tank between 1.6 atmospheres and 5.1 atm. At vapor pressures less than 1.6 atm or greater than 5.1 atm, another method should be selected.

The EC/R equation is best suited to gas condensate systems operating in the pressure ranges described above. This equation is available in the Oklahoma DEQ's spreadsheet mentioned in the previous subsection.

Gas/Oil Ratio (GOR) Method

The hydrocarbon liquid GOR can be determined by laboratory analysis of

a pressurized sample collected upstream of the storage tank from the separator dump line (or from a similar apparatus). For more information, refer to Gas Processors Association Standard 2174-93. It gives details on sampling procedures for collecting a pressurized oil sample.

The flash emissions are then determined by multiplying the GOR by the throughput of the tank. An extended hydrocarbon analysis of the flash gas from the sample should also be conducted to identify the concentrations of the individual components of the tank's flash emissions. When such sampling is conducted, the GOR method is appropriate for either black oil or gas condensate systems.

Determining Emissions from Landing Losses

Introduction

Landing losses occur from floating-roof tanks whenever a tank is drained to a level where its roof lands on its deck legs or other supports (including roof suspension cables). When a floating roof lands on its supports or legs, it creates a vapor space underneath the roof. Liquid remaining in the bottom of the tank provides a continuous source of vapors to replace those expelled by breathing (in the case of internal floating-roof tanks) or wind action (in the case of external floating-roof tanks). These emissions, referred to as standing idle losses, occur daily as long as the tank roof remains landed.

Additional emissions occur when incoming stock liquid fills a tank with a landed roof; the incoming liquid not only displaces those vapors remaining under the floating roof, but also generates its own set of vapors that are displaced during the filling process. These two types of emissions are collectively referred to as filling losses.

For a given roof landing event, total landing loss emissions are therefore the sum of the filling losses and the daily standing idle losses over the entire period that the roof remained landed. Landing losses are inherently episodic in nature, and must be determined each time a tank's floating roof is landed.

Neither the EPA's TANKS program nor any other storage-tank emissions software currently determines landing loss emissions as part of routine program operation. However, landing loss emissions may be determined using the guidance outlined in American Petroleum Institute Technical Report 2567, "Evaporative Loss from Storage Tank Floating Roof Landings" (API TR 2567). EPA has also incorporated this API guidance into a new version of Chapter 7, "Organic Liquid Storage Tanks," available at: <www.epa.gov/ttn/chief/ap42/index.html>.

The emissions determination method detailed in AP-42, Chapter 7 is the preferred method for determining landing loss emissions.

Floating-Roof Tank Designs

Tank design considerations will impact both standing idle and filling loss emissions. Therefore, AP-42, Chapter 7 separates floating-roof tanks into the following three categories for emissions determination purposes:

- internal floating-roof tanks (IFRTs) with a full or partial liquid heel,
- external floating-roof tanks (EFRTs) with a full or partial liquid heel, and
- IFRTs and EFRTs that drain dry.

AP-42, Chapter 7, contains standing idle and filling loss equations for each different tank category listed above. To accurately use these equations, you must first classify the storage tank in question into one of the above categories. Care must be taken when classifying a tank as drain-dry. Both AP-42, Chapter 7 and API TR 2567 state that a tank is only a drain-dry tank if all of its free-standing liquid has been removed. The following tank configurations qualify as tanks with a partial liquid heel, according to API TR 2567:

- tanks that drain to a sump that retains a liquid heel,
- tanks whose sumps have baffles or similar fittings that retain liquid, or
- flat-bottom tanks whose contents have been removed by a vacuum truck, since liquid typically will still remain in irregular surfaces along the tank bottom.

For each tank category listed above, AP-42, Chapter 7, publishes different saturation factors that have been validated through API field studies to use in the landing loss equations. These saturation factors represent the stratification of vapors in the vapor space underneath the floating roof; therefore, no modification to these saturation factors based upon tank shell height is necessary.

Required Data for Determining Landing Loss Emissions

After you have correctly determined your tank type, you must collect the following information about the tank and its contents for each episode when the roof is landed:

- tank diameter
- tank color
- height of the vapor space under the floating roof
- height of the stock liquid
- atmospheric pressure at the tank's location
- average temperature of the vapor and liquid below the floating roof

- physical and chemical properties of the stored liquid (such as density, molecular weight, and vapor pressure)
- physical and chemical properties of the liquid that the tank is refilled with, if different from the previously stored liquid
- number of days that the tank stands idle while its floating roof is landed

For a given tank, you can then use this information in conjunction with the appropriate standing idle and filling loss equations to determine the emissions for each roof landing episode. The annual landing loss emissions can then be determined by summing the emissions from each episode occurring within a given calendar year. Emissions from each roof landing episode must be individually determined using accurate temperature data and stored liquid properties for the time of year when the roof landing occurred.

When using API TR 2567, care must be taken to avoid using certain default parameters that may not accurately reflect a given storage tank. For example, the daily vapor temperature range should be calculated from the appropriate equation presented within the document, instead of the default range being used.

Similarly, care must be taken using the “B” coefficient from Antoine's equation to calculate the K_E term for certain chemical species. The form of Antoine's equation used within API TR 2567 and AP-42, Chapter 7 closely resembles the Clausius-Clapeyron equation, and “B” values for many chemical species are not readily available in the prescribed units of temperature and pressure. In certain cases, the K_E term may have to be calculated using the original equation(s) as presented in AP-42, Chapter 7.

Reporting Landing Loss Emissions within the Inventory

Report landing losses for each storage tank on the appropriate path within the emissions inventory questionnaire (EIQ). If your site determines that landing loss emissions occurred due to normal, routine operation, revise annual and ozone season emissions accordingly. For specific procedural guidance on reporting emissions on the EIQ, please consult Chapter 4 of *2008 Emissions Inventory Guidelines*.

Determining Emissions from Degassing and Cleaning

Emissions from tank degassing and cleaning operations should be determined using site-specific knowledge and material balance equations.

Alternatively, the following methods developed by the EPA can be used to determine emissions.

Degassing (Emptying) a Storage Tank

For a drain-dry fixed-roof tank, degassing emissions can be determined by a two-part process. First, use TANKS to determine emissions from one turnover to identify the vapors displaced during filling. Next, determine the clingage emissions from one turnover by calculating the emissions as if the tank had an internal floating roof. Sum these two emission rates to determine degassing emissions.

For a drain-dry floating-roof tank, degassing emissions can be determined by a two-part process. First, use TANKS to determine emissions for one turnover. Next, to approximate the vapor displaced from the space under the floating roof, determine the emissions from the tank modeled as a fixed roof tank with a tank height equal to the height of the deck legs. Sum these two emission rates to determine degassing emissions.

For either fixed- or floating-roof tanks with a liquid heel, the heel may be a continuing source of vapors that can generate emissions. Therefore, liquid heel emissions should be accounted for when determining degassing emissions.

Cleaning (Sludge Handling)

Most aqueous sludges are about 80 percent to 90 percent water by weight. A conservative approach for determining emissions from sludge cleaning is to assume the sludge is 80 percent water; the remainder is assumed to be VOCs and emitted. As an alternative, the actual sludge moisture content can be determined.

Special Considerations when Quantifying Emissions

When determining storage tank emissions, note the following special considerations.

Pressure Tanks

Pressure tanks are designed to handle pressures significantly higher than atmospheric pressure. Two classifications of pressure tanks exist: low-pressure and high-pressure tanks. The API defines *low-pressure tanks* as those operating in the range of just above atmospheric pressure to 15 psig; *high-pressure tanks* are those operating at pressures above 15 psig.

High-pressure tanks are considered to be closed systems that prevent routine breathing and working loss emissions. However, routine emissions from equipment leak fugitive components associated with high-pressure tanks, as well as any non-routine emissions, should be reported in the EI.

Low-pressure tanks can experience breathing and working losses. While these emissions are usually less than those a similar atmospheric tank

would experience, these emissions should be quantified and reported within the EI according to the guidance outlined in Chapters 3 and 4.

Since the TANKS model uses equations developed under atmospheric conditions, it does not accurately model emissions from low-pressure tanks. Instead, you may use API Bulletin 2516, *Evaporation Loss From Low-Pressure Tanks*, to determine breathing and working losses from low-pressure tanks.

Nitrogen-Blanketed Tanks

Typically, storage tanks are blanketed with nitrogen (or other inert materials) to reduce the risk of fire, to reduce water acquisition by hygroscopic materials, or to prevent corrosion. However, nitrogen blanketing of an atmospheric storage tank does not reduce the tank's breathing or working loss emissions (note: air is approximately 78 percent nitrogen by volume).

Therefore, when determining emissions from nitrogen-blanketed atmospheric storage tanks (whether the tank is of fixed roof or internal floating-roof design), no modifications to the AP-42 equations (or software programs using these equations) are required. The gas blanket will not affect emissions if the tank is operated near atmospheric pressure.

Heated Tanks

If a tank is heated, the vapor space can be assumed to be at a constant temperature and no breathing losses will occur. The tank must be heated to a uniform temperature and well-insulated, thus isolating it from heat gains and losses due to insolation and variations in ambient temperature. Changes in atmospheric pressure are assumed to have only negligible contributions to breathing losses and are not considered.

When using the TANKS program, answer "yes" to the menu selection "Is Tank Heated?" on the Physical Characteristics screen to determine emissions from vertical and horizontal fixed-roof tanks. This will allow you to enter the temperature data directly on the Tank Contents screen. Temperature data input fields exist for Average, Minimum and Maximum Liquid Surface Temperature and for Bulk Liquid Temperature (degrees Fahrenheit). The temperature that the tank is heated to should be entered in all four data fields. If the tank is not well insulated, daily variations in liquid surface temperatures may be observed. The Minimum and Maximum Liquid Surface Temperatures, if available, should be input to estimate breathing losses.

You should also ensure that TANKS has the appropriate information for estimating vapor pressure at the desired temperature in its chemical database. For example, if TANKS uses Option 1 in the chemical database for estimating vapor pressure (for temperatures from 40° to 100°F) and the

desired temperature is over 100°F, the program will **not** extrapolate the vapor pressure to the higher temperature, but will instead calculate a vapor pressure at 100°F. Options 2, 3, or 4 in the chemical database should be used for estimating vapor pressures at temperatures greater than 100°F.

Tanks Storing Hot Products

If hot products (materials with a temperature above the ambient temperature) are stored in a tank, using ambient meteorological data will not properly model the tank's true emissions. If the TANKS program is used, the tank should be treated as a heated tank, as detailed in the section above. For material cooling, the Minimum and Maximum Liquid Surface Temperatures should be entered to estimate breathing losses.

Tanks Storing Inorganic Liquids

Currently, methods developed exclusively for determining inorganic compound emissions from storage tanks do not exist. However, it is possible to use the TANKS model to determine storage tank emissions from inorganic liquids if the inorganic liquid has a measurable vapor pressure and if data are available for one of the vapor pressure options in the TANKS chemical database.

Although the equations used in TANKS were developed to estimate evaporative losses from storage of organic liquids, they currently present the best available method for determining inorganic emissions from storage tanks.

Tanks with a Liquid Heel

Care must be taken when classifying a tank as "drain dry." If the tank drains to a sump that retains a liquid heel, the API publishes saturation factors to use in the landing loss equations in order to determine the resulting emissions, which cannot be assumed to be negligible.

Operations where potential emissions are generated and released include: degassing operations, tank cleaning, steam cleaning, and the use of vacuum trucks.

Oil Field Wellhead Tank Battery Emissions

A recent Houston Advanced Research Center study (HARC 51C), *Evaluation of VOC Emissions from Flash and Condensate Tanks*, has shown significant emissions from wellhead crude and condensate storage tanks in the upstream oil and gas industry. According to this study, many wellhead storage tank batteries meet or exceed emission inventory reporting thresholds. The study is available online at <www.harc.edu/Projects/AirQuality/Projects/Projects/H051C>.

This study has identified these storage tank batteries as potentially under-reported VOC emissions sources. Companies that own or operate sites in the upstream oil and gas industry should determine VOC emissions from all wellhead tank batteries to determine if these sites meet emissions inventory reporting requirements. Each storage tank in the wellhead battery will generate working, breathing, and flashing emissions. Please see Technical Supplement 6: Aboveground Storage Tanks, for guidance on determining storage tank emissions.

The EAS has developed a Material Throughput form specifically for oil field storage tanks and the form should be completed and include the production information for each tank.

Produced Water Tank Emissions

Currently, specialized methods for determining emissions from produced water storage tanks do not exist. However, these tanks are a potential source of VOC emissions that should be represented in the EI. It is possible to create a mixture in the TANKS program similar to the composition of the produced water stored in the tanks (e.g., a mixture of 99 percent water and 1 percent condensate) to determine the emissions.

Speciation

If you have any source-specific information about storage tank VOC composition, you should use it to speciate the emissions. Supply the composition data and any related information (such as test results, etc.) with your emissions inventory. If you do not have any source-specific information about speciation of storage tank VOCs, then use the default speciation profiles in the current TANKS program.

For more information on speciation requirements, see Chapter 4.

Supporting Documentation

Include documentation with your emissions inventory that supports and validates the emissions reported therein—including, but possibly not limited to, representative samples of:

- calculations detailing the tank parameters (diameter, height, shell color, roof color, paint condition, shell construction, capacity, primary and secondary seals, fittings, and throughput rate);
- if the TANKS program is used, a report generated using the “detailed” report option;
- physical properties of each product, including liquid density, liquid molecular weight, vapor molecular weight, and vapor pressure;

- sampling analysis;
- all supporting data used to calculate the flash losses, including identification of the determination method, sample analysis, API gravity, density of liquid petroleum, gas/oil ratio, gas gravity, molecular weight of stock, and VOC percentage by weight of both the stored liquid and flash gas; and
- all other information necessary to determine emissions.

For More Information

Answers to questions about storage tanks are available at the EPA's Web site: <www.epa.gov/ttn/chief/faq/tanksfaq.html>.

While those questions are not reproduced here due to space considerations, they address such topics as underground storage tanks, vapor-balanced tanks, tanks with roof geometries other than a cone or a dome, indoor storage tanks, and tanks storing a two-phase liquid.

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