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# *2025 Emissions Inventory Guidelines*

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Air Quality Division

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

# 2025 Emissions Inventory Guidelines

Prepared by
Air Quality Division

RG-360/25
January 2026

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY • PO BOX 13087 • AUSTIN, TX 78711-3087

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# Chapter 1. Emissions Inventory General Information

## Introduction to Emissions Inventory

As part of national and state efforts to protect human health and the environment, federal and state laws require the state of Texas to develop an annual emissions inventory (EI) of the air pollutants.

The Texas Commission on Environmental Quality (TCEQ) is authorized to request emissions inventories and supporting documentation under the provisions of:

- Federal Clean Air Act.
- Texas Clean Air Act, Texas Health and Safety Code Section 382.014.
- Title 30 of the Texas Administrative Code (30 TAC), Section 101.10—the Emissions Inventory Requirements.

To meet the reporting requirements of these regulations, the regulated community will be working with the Emissions Assessment Section (EAS) of TCEQ's Office of Air.

TCEQ uses the EI to plan pollution control programs, promote compliance with laws and regulations, conduct permit reviews, develop airshed modeling and rulemaking activities, and supply required data to the U.S. Environmental Protection Agency (EPA).

## What This Publication Contains

This chapter discusses 30 TAC Section 101.10 and what constitutes a complete EI submission. This information should help owners or operators of regulated entities determine whether an EI is required for a site and correctly prepare a complete EI submission by the due date. A brief discussion of the EAS's confidentiality policy is included in this chapter. The chapter concludes with a brief discussion of the two options available for submitting an EI through the Annual Emissions Inventory Report (AEIR) program area within the State of Texas Electronic Emissions Reporting System (STEERS) Web-EI System.

Chapter 2 explains the EI process and its key concepts to those unfamiliar with the EI.

Chapter 3 discusses correct EI structure (representing processes in the EI), gives examples for some common industrial processes, and supplies guidance for modifying existing representations.

Chapter 4 presents information about requested emissions data; using acceptable actual emissions determination methodologies; speciating emissions; and correctly reporting actual annual emissions, ozone season emissions, and emissions due to emissions events and scheduled maintenance, startup, and shutdown activities.

Chapter 5 offers an example of creating an initial EI.

Chapter 6 contains instructions for updating an EI.

Chapter 7 includes instructions on revising EI data, requesting EI data, and verifying site coordinate data.

The appendices contain:

- Technical supplements intended to help determine emissions from certain sources.
- Sample letters that may help address some common situations.
- EPA and TCEQ resources to assist in completing or updating an EI.

Also included in this publication are (1) a glossary, (2) a list of abbreviations, and (3) information on contacting the EAS. A checklist is available upon request to help determine if all necessary supporting documentation is included with the EI.

*Note:* Detailed EI reporting instructions and frequently asked questions are available for download at the EAS webpage Point Source Emissions Inventory.[a] Any EI tools referred to in this publication can be found on that webpage.

# About 30 Texas Administrative Code Section 101.10

This section includes a discussion of the EI process as a self-reporting process, the special inventory request, location of 30 TAC Section 101.10, and a table depicting the state's special inventory areas.

A map and summary table titled "Emissions Inventory Reporting Requirements" that identifies EI reporting thresholds, ozone nonattainment and ozone-precursor special inventory reporting requirements can be found on the EAS webpage. The map and associated table are intended to clarify reporting requirements and do not supersede or replace requirements of federal or state law, including 30 TAC Section 101.10. It is the responsibility of the owner or operator of a regulated entity to read and understand all federal and state laws and regulations applicable to the regulated entity, including 30 TAC Section 101.10, the Emissions Inventory Requirements. The requirements of 30 TAC Section 101.10 can be found at the Texas Administrative Code online.[b]

## A Self-Reporting Process

TCEQ requires sites that meet the reporting requirements of 30 TAC Section 101.10 to submit emissions inventories through the STEERS-AEIR Web-EI System. Please contact the EAS immediately if you have questions regarding the online reporting requirement.

The EI process requires self-reporting. The owner or operator of the regulated entity is responsible for determining if and when 30 TAC Section 101.10 applies to the site. If it applies, or if TCEQ requests a special inventory, the owner or operator must submit an

[a] www.tceq.texas.gov/goto/ieas
[b] www.tceq.texas.gov/goto/view-30tac

EI by March 31 of the calendar year immediately after the reporting year or as directed in writing by the agency. Failure to do so may result in the agency initiating an enforcement action against the owner or operator. Responsibility for submitting the EI resides with the owner or operator of the site at the time the inventory is due.

**Compliance with 30 TAC Section 101.10 is required even if you do not receive a courtesy reminder notification from TCEQ.**

Requirements for submitting an EI may vary based on the site location and on the type and quantity of emissions released. This publication will help in determining whether the owner or operator must submit an EI and, if so, how to determine emissions, and how to prepare and submit the required information.

TCEQ requires emissions inventories to be submitted online through its STEERS-AEIR Web-EI system, either by interactive web entry or text-file upload. For more information on how to submit online, please see the EAS webpage.

## Nonattainment Designations

For the official list and boundaries of nonattainment areas, see Title 40, Code of Federal Regulations (CFR), Section 81.344, and pertinent *Federal Register* notices.

Please note that EPA has not updated the CFR to reflect the D.C. Circuit Court of Appeals' June 30, 2023, decision regarding EPA's nonattainment designation for the 2015 ozone NAAQS for the El Paso-Las Cruces, Texas-New Mexico area. As a result of the Court's decision, El Paso County has reverted to its prior attainment designation for the 2015 ozone NAAQS. TCEQ is conducting a special emissions inventory request for El Paso County for the 2025 reporting year under the provisions explained below. The map titled "Emissions Inventory Reporting Requirements" identifies the EI reporting thresholds, ozone nonattainment areas, and ozone-precursor special inventory counties.

*Note:* For areas designated as nonattainment under more than one ozone National Ambient Air Quality Standard (NAAQS), the most stringent classification is used to determine reporting requirements for ozone-precursor potential emissions.

A link to this map can be found on the EAS webpage. The map and its associated table are intended as guidance and do not supersede or replace any state or federal law or regulation.

## Special Inventory Request

TCEQ, under the "special emissions inventory" provisions of 30 TAC Subsection 101.10(b)(3), has the authority to request emissions inventories to be completed and submitted. If a regulated entity meets the thresholds explained below and TCEQ has notified the regulated entity with a formal written request, the owner or operator must complete and submit an EI by the required date.

*Note:* Regulated entities that meet any of the other applicability requirements of 30 TAC Section 101.10 are required to submit an EI regardless of whether TCEQ has made a formal written request.

## *Requirements for Sources That Emit Ozone Precursors in Specified Counties*

TCEQ is conducting a special EI for sources that emit ozone precursors in specified counties under the authority of 30 TAC Subsection 101.10(b)(3). Regulated entities that are located in a specified county and emit a minimum of either 10 tons per year (tpy) of volatile organic compounds (VOC) or 25 tpy of nitrogen oxides ($NO_x$) during normal operations must submit a complete EI by the required due date, if TCEQ has notified the regulated entity with a formal written request.

### Ozone-Precursor Special Inventory Counties

Bastrop
Bell
Caldwell
Comal
El Paso
Gregg
Guadalupe
Hardin
Harrison
Hays
Henderson
Hood
Jefferson
McLennan
Nueces
Orange
Rusk
San Patricio
Smith
Travis
Upshur
Victoria
Williamson
Wilson

## Emissions Inventory Reporting Requirements Map

The map is located on the EAS webpage. The map and associated table are intended to clarify reporting requirements and do not supersede or replace requirements of federal or state law, including 30 TAC Section 101.10.

# Due Date

The EI is due on March 31 of the calendar year immediately after the reporting year unless otherwise specified in writing by TCEQ.

Emissions inventories that are submitted through the STEERS-AEIR Web-EI system will not be considered late as long as the file is validated by the due date. After submitting the EI, the user will receive two emails. The first email confirms that the data have been placed in the queue for validation processing. The second email will state whether the submission passed or failed validation. If validation succeeded, TCEQ will consider the EI "received" in accordance with 30 TAC Section 101.10. If validation failed, the user must correct the errors and submit the data again. The EI will not be assigned a received date until the EI passes validation.

Sample calculations and supporting documentation are part of a complete EI submission and must be submitted by the EI due date. Nonconfidential information should be attached to the STEERS-AEIR Web-EI system or emailed to psdocument@tceq.texas.gov. Confidential information can be submitted through the TCEQ secure File Transfer Protocol (FTPS) website. Check for an existing FTPS account, register for a new FTPS account, log into an existing FTPS account, and find FTPS help documents at the FTPS webpage.[a] Please contact the EAS for assistance on submitting confidential information through the secure FTPS website.

Inapplicability and Insignificant Emissions Change Notification letters can only be submitted on paper (consult the section titled "Hard Copy Signature Requirements") and must be postmarked by the EI due date. A courtesy copy may be emailed to psdocument@tceq.texas.gov.

The owner or operator on the date that the inventory is due is responsible for submitting the EI. To document compliance, TCEQ recommends that the owner or operator confirms receipt by the agency and keeps a record of the confirmation on file; for example, archiving the email from the STEERS-AEIR Web-EI system stating that the EI submission passed validation.

Compliance with 30 TAC Section 101.10 is required even if you do not receive a courtesy reminder notification from TCEQ.

*Note:* New owners or operators should ensure that they obtain all appropriate records necessary to accurately represent emissions for the full EI reporting period.

[a] ftps.tceq.texas.gov/

*Note:* If the due date falls on a weekend or legal holiday, the EI must be validated (for STEERS-AEIR Web-EI system submissions) or postmarked (for notification letters) by the following business day, per 30 TAC Section 1.7.

## What Constitutes a Complete Submission?

A complete EI submission includes a complete and updated EI; a signed certification statement; sample calculations representative of the current processes at the site; summary test results, if stack-test data are used to determine emissions; either summary Relative Accuracy Test Audit (RATA) sheets, or, if a RATA is not required by applicable permit conditions or regulations, documentation from a similar system audit (e.g., cylinder gas audit) for continuous emissions monitoring systems (CEMS) or predictive emissions-monitoring systems (PEMS) data that are used to determine emissions; and material throughput information.

TCEQ requires annual EI updates, initial emissions inventories, and special emissions inventories to be submitted online through the STEERS-AEIR Web-EI system, using either the interactive web entry or text-file upload. Submission through the STEERS-AEIR Web-EI system serves as the certification and constitutes a legally binding electronic signature by the legally responsible party. The STEERS-AEIR Web-EI submission process also includes an option for an electronic Emissions Events Certification signature (if applicable).

*Note:* Submission through the STEERS-AEIR Web-EI system must be certified and submitted by a legally responsible company official. For Title V sites, submit authority should only be given to the responsible official or their duly authorized representative. Under no circumstances should a consultant be given submit authority or certify an EI.

For additional requirements regarding EI submissions through STEERS-AEIR Web-EI system, refer to the sections later in this chapter and the information at the EAS webpage.

This section discusses various reporting situations in detail below. No matter what the reporting situation, compliance with 30 TAC Section 101.10 is required even if you do not receive a courtesy reminder notification from TCEQ.

## Requirements for Submitting a New or Updated EI

If a site has not previously submitted an EI and it meets the EI reporting requirements of 30 TAC Section 101.10 for a given calendar year (reporting year), then the owner or operator is required to submit an initial emissions inventory (IEI).

Any regulated entity that continues to meet the EI reporting requirements of 30 TAC Section 101.10 is required to submit an annual emissions inventory update (AEIU).

When submitting the IEI or AEIU through the STEERS-AEIR Web-EI system, the following information must also be submitted:

- A Core Data Form (TCEQ-10400). For an IEI, this form is necessary when the information is not yet in the Central Registry. For an AEIU, the form is necessary

when sites are updating ownership, name, or location. If this form has already been submitted to the Central Registry, please include a copy with the EI.

- Supporting documentation and sample calculations representative of the current processes at the site.

The Core Data Form, supporting documentation, and sample calculations may be submitted using the document-attachment function in the STEERS-AEIR Web-EI system. Supporting documentation and sample calculations that are considered confidential should not be submitted through STEERS. Consult the section entitled "Confidential Data and Other Information" below for instructions on submitting supporting documentation that is considered confidential.

When sending electronic files, ensure that the data are self-contained and not linked to external data sources unavailable to TCEQ. For electronic files, the preferred formats are Microsoft Word, Excel, Access, and Adobe PDF.

*Note:* All EIs must be submitted through the STEERS-AEIR Web-EI system. For more information on how to submit online, please see the EAS webpage or contact the EAS.

## Special Requirements for a Site That Experienced Insignificant Changes in Emissions

Submission of an updated EI is not required if the total actual annual emissions of VOCs, $NO_x$, carbon monoxide (CO), sulfur dioxide ($SO_2$), lead (Pb), particulate matter with an aerodynamic diameter less than or equal to 10 micrometers ($PM_{10}$), and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$) are each within 5% or five tons, whichever is greater, of the most recent total actual annual emissions reported in the State of Texas Air Reporting System (STARS) database. Instead, the owner or operator may request that the EAS roll over the most recent annual emissions to the current reporting year.

If the site experienced no emissions due to emissions events (EE) or scheduled maintenance, startup, or shutdown (SMSS) activities, then the owner or operator may formally request to have the EAS roll over the most recent annual and ozone season emissions to the current reporting year by submitting the following by the EI due date:

- Insignificant Emissions Change Notification letter in Appendix B or a similarly worded letter.
- Account Information and Emissions Inventory Contact Information, page 2 of the EIQ.
- Criteria Emissions Totals and Site Quantifiable Event Totals, page 3 of the EIQ with the current year's totals entered.
- Signed Emissions Events and Legally Responsible Party certification statements, page 4 of the EIQ.

If the site experienced emissions due to EE or SMSS activities, the owner or operator may still submit a formal request to have the EAS roll over the most recent annual and

ozone season emission rates to the current year. However, the emissions from EE or SMSS activities are required to be updated by submitting the following by the EI due date:

- Insignificant Emissions Change Notification letter in Appendix B or similarly worded letter.
- Account Information and Emissions Inventory Contact Information, page 2 of the EIQ.
- Criteria Emissions Totals and Site Quantifiable Event Totals, page 3 of the EIQ.
- For regulated entities reporting only SMSS emissions and not reporting emissions events, the signed Emissions Events certification statement, page 4 of the EIQ.
- Signed Legally Responsible Party certification statement, page 4 of the EIQ.
- All applicable pages relating to path emissions of the original EIQ updated to reflect emissions from EE or SMSS activities.

For a complete STEERS EI submission, an Insignificant Emissions Change Notification letter is required to be submitted when the site's actual annual emissions are being rolled over from the most recent emissions to the current reporting year. A hard copy of the insignificant change letter should be mailed or hand delivered to the EAS (consult the section entitled "Hard Copy Signature Requirements").

When submitting an Insignificant Emissions Change Notification letter, sample calculations and other supporting documentation may need to be supplied upon request.

*Note:* The Insignificant Change Notification letter and the certification statements must be signed by a legally responsible official of the company. These documents cannot be signed by a consultant.

## If a Site Does Not Meet the Requirements of 30 TAC Section 101.10 for the Current Emissions Inventory Year (But Wants to Remain on the Mailing List)

If the owner or operator has determined that a site does not meet the EI reporting requirements of 30 TAC Section 101.10 for the current inventory year, but may meet applicability requirements in future years, then the site may submit an Inapplicability Notification letter (Appendix B) or similarly worded letter by the EI due date. In this reporting scenario, choose "Option 1" on the Inapplicability Notification letter in Appendix B to keep the site on the mailing list. The hard copy letter must be mailed or hand delivered to the EAS (consult section entitled "Hard Copy Signature Requirements"); currently there is no option to submit an inapplicability notification through the STEERS-AEIR Web-EI system.

*Note:* By submitting this letter or a similarly worded letter, the owner or operator of the regulated entity will remain on future EAS mailing lists and continue to receive a courtesy notification letter. The owner or operator must submit a letter to the agency for each reporting year that the site does not meet the reporting requirements. The

letter must be signed by a legally responsible official of the company and may not be signed by a consultant.

For this reporting situation, sample calculations and other supporting documentation may need to be supplied upon request.

An Inapplicability Notification letter may not be submitted in lieu of an EI if the site meets any of the EI reporting requirements of 30 TAC Section 101.10 at any time during the calendar year. If those EI reporting requirements occur, owner or operator shall submit an annual emissions inventory for that calendar year.

If the site is a major source as defined in 30 TAC Section 116.12 or 30 TAC Section 122.10 at any time during the calendar year or has an active Title V permit due to either actual annual emissions or potential-to-emit (PTE) levels, the owner or operator must submit an EI by the applicable due date.

Sitewide permitted emissions-limits and actual emissions should be reviewed to determine if they exceed the EI reporting thresholds. For example, a site that is not a major source but is permitted by rule may still exceed the EI reporting thresholds.

## If a Site Does Not Expect to Meet the Applicability Requirements of 30 TAC Section 101.10 in Future Years (And Wants to Be Removed From the Mailing List)

If the owner or operator has determined that a site does not meet the applicability requirements of 30 TAC Section 101.10 for the current reporting year *and* does not expect to do so in future reporting years, then the owner or operator may formally request the site's removal from the EAS mailing list by submitting an Inapplicability Notification letter (Appendix B) or a similarly worded letter by the EI due date. In this reporting scenario, choose "Option 2" on the Inapplicability Notification letter in Appendix B to remove the site from the mailing list. The hard copy letter must be mailed or hand delivered to the EAS (consult the section titled "Hard Copy Signature Requirements"); currently there is no option to submit an Inapplicability Notification through STEERS-AEIR Web-EI system.

The letter must be signed by a legally responsible official of the company and may not be signed by a consultant. The EAS only accepts written requests for removal from the mailing list.

If the latest emissions reported in the STARS database exceed the rule applicability requirements, TCEQ cannot remove the regulated entity from the annual EI mailing list unless the owner or operator submits a current updated EI and sample calculations. After the EI data are updated in STARS, the site can then be removed from the mailing list.

If the site is a major source as defined in 30 TAC Section 116.12 or 30 TAC Section 122.10 at any time during the calendar year, the site cannot be removed from the mailing list for that year. The owner or operator must submit an EI by the applicable due date.

*Note:* If a site has an active Title V permit due to either actual annual emissions or PTE levels, the site will remain on the mailing list.

Sitewide permitted emissions limits and actual emissions should be reviewed to determine if they exceed the EI reporting thresholds. For example, a site that is not a major source but is permitted by rule may still exceed the EI reporting thresholds. If the site meets any of the EI reporting requirements of 30 TAC Section 101.10 at any time during the calendar year, the owner or operator must submit an annual emissions inventory for that calendar year.

For example, if the owner or operator of a site lowers the site's PTE levels below major-source thresholds by accepting federally enforceable limitations in a NSR permit issued in June of a calendar year, and actual annual emissions for that calendar year do not meet the reporting thresholds of 30 TAC Section 101.10, the owner or operator must submit an inventory for the entire calendar year since site PTE levels were at or above major-source levels for part of the year. For the subsequent calendar year, if the site did not meet reporting requirements of 30 TAC Section 101.10, the owner or operator can request to be removed from the mailing list.

**If a regulated entity that has been removed from the mailing list meets the EI reporting requirements of 30 TAC Section 101.10 at any time in the future, it is the responsibility of the owner or operator to submit an EI by the due date.**

## Hard Copy Signature Requirements

The Inapplicability and Insignificant Emissions Change Notification letters must contain a wet-ink signature of the appropriate responsible official (if Title V) or company representative to comply with the EPA's Cross-Media Electronic Reporting Rule.

## If a Site Is Permitted but Not Built

If a site is permitted but not built, the requirement to submit an EI may not apply. However, an owner or operator may submit an IEI to establish structure. All emissions should be entered as zero. However, due to database requirements, seasonal percentages must total 100. For more information on reporting structure for sites that are "planned" or "under construction," contact the EAS.

## Sample Calculations

Per 30 TAC Subsection 101.10(c), sample calculations representative of the processes at the site must be submitted with the inventory and updated each year. Submit sample calculations showing determinations of emissions for each different type of process present in the EI, including enough data so that the determination results may be reasonably reproduced. TCEQ cannot accept generic sample calculations, since they do not contain representative process data and do not demonstrate actual emissions determinations. For similar reasons, summary spreadsheets listing emissions quantities are not considered sample calculations. Sample calculation templates giving minimum requirements for common source types are available on the EAS webpage.

Refer to the following guidelines when sending representative sample calculations:

- When several sources of the same type are present and a **single** calculation methodology was used to determine emissions:
  - Include calculations for the source with the highest emissions.
  - Include the current reporting year's process data for each source for which sample calculations are not supplied.
- When several sources of the same type are present but **different** calculation methodologies were used to determine emissions:
  - Include calculations for the source with the highest emissions for each calculation methodology.
  - Include typical process data for each source that uses a different calculation methodology and for which sample calculations are not supplied.

Examples of the current reporting year's process data include heat inputs and fuel types for combustion sources and chemical types and throughputs for storage tanks and loading sources.

*Note:* All printed supporting documentation should be submitted in 10 point or larger type unless specifically approved by EAS.

## Confidential Data and Other Information

TCEQ holds data confidential as requested in accordance with agency policy and rules (see 30 TAC Section 1.5) unless the Texas Attorney General's Office rules or a court issues an opinion that the data are not protected by state law. If there are any special concerns about confidentiality, contact the EAS. Confidentiality claims do not justify withholding relevant information from TCEQ.

The following information will be kept confidential (when clearly marked as confidential) in accordance with agency policy and rules (see 30 TAC Section 1.5) unless the Texas Attorney General's Office rules or a court issues an opinion that the data are not protected by state law:

- material data (submitted in supporting documentation)
- process flow diagrams
- process rates
- trade secrets (information that reveals secret processes or methods of manufacture or production)

**Information *not* considered confidential includes**:

- the EI report and data contained therein
- emission rates
- heat-input data
- emission point data

- type of emissions control equipment
- type of emitting equipment

Please do not submit confidential information through the STEERS-AEIR Web-EI system or by email to the EAS. Confidentiality cannot be ensured across multiple email servers. The STEERS-AEIR Web-EI system does not have a process to designate information as confidential. Confidential information can be submitted through the TCEQ FTPS website. Check for an existing FTPS account, register for a new FTPS account, log into an existing FTPS account, and find FTPS help documents at the FTPS webpage. After logging into the FTPS account, upload the confidential files, and share with psdocument@tceq.texas.gov. Please contact the EAS for assistance on submitting confidential information through the secure FTPS website.

# Web Reporting

Two options are available for updating EI data: an interactive web entry system or text-file upload.

## Reporting an Initial EI or Submitting an Annual EI Update Through Interactive Web Entry

IEIs and AEIUs can be submitted through interactive web entry in STEERS, but please contact the EAS before submitting an IEI through STEERS. Interactive web entry allows updating of the EI data on the company, site, contacts, facility, control devices, emission points, and path emissions through graphical-user-interface windows. The user may save the data in the work area in one or more work sessions until the web entry for the entire updated EI is complete. Users who have historically submitted EI updates on paper may prefer this process. Built-in data checks help prevent errors such as missing required information, data in the wrong format, or limited data that fall outside preset constraints.

After all required EI data is entered, the EI is submitted through STEERS. The system will run validation routines—typically overnight—and inform the user of the status (usually the following business day) by email. If no errors were encountered, the email will state, “AEIR validation process successful,” and the electronic submission will be considered complete. If errors were encountered, the email will state, “AEIR validation process failed,” and an error log will be attached with instructions for viewing the log through STEERS. The STEERS user must correct the errors and attempt validation again. The system will also supply the user with a copy of record of the transacted data.

*Note:* All STEERS-AEIR status emails are sent to users with “edit and submit” authority.

A date of receipt will be assigned to the file on the day the validation is successful. TCEQ must receive a validated file by the EI due date. Otherwise, it will consider the AEIU submission delinquent. The sample calculations and supporting documentation must also be submitted by the EI due date.

The STEERS-AEIR Web-EI system features a document-attachment function that allows inclusion of nonconfidential sample calculations and supporting documentation with the Web-EI submission. The document-attachment function is the primary method for submitting sample calculations and supporting documentation. For electronic files submitted through STEERS, the preferred formats are Microsoft Word, Excel, Access, and PDF.

Additional information on reporting through the STEERS-AEIR, Web-EI system appears at the EAS webpage.

## Reporting an Initial EI or Submitting a Text File of the Annual EI Update Online Through STEERS

The IEI and AEIU can be updated and submitted through a text-file upload in STEERS. Please contact the EAS before submitting an IEI through STEERS. The text file must be in an approved electronic format, as outlined in the Electronic Emissions Inventory File Specification, available upon request.

Two steps are required to submit the AEIU text file:

- First, the text file must be loaded into the STEERS work area from the user's personal computer. After the AEIU text file is submitted to the STEERS work area, TCEQ will respond via email, detailing whether the system accepted the AEIU text file.
- Second, the user will submit the file from the STEERS work area to the EAS. The system will run validation routines, typically overnight, and inform the user of the status, usually the following business day, by email.

If no errors were encountered, the email will state "AEIR validation process successful" and the AEIU text-file submission is considered complete. If errors were encountered, the email will state "AEIR validation process failed." The system will also supply the user with a copy of record of the transacted data.

*Note:* All STEERS-AEIR status emails are sent to users with "edit and submit" authority.

If the AEIU text file does not pass the validation routine by the EI due date, TCEQ will consider the AEIU submission delinquent. The sample calculations and supporting documentation must also be submitted by the EI due date for the submission to be considered complete.

Additional information on reporting through the STEERS-AEIR Web-EI system appears on the EAS webpage.

# Chapter 2. Creating an Initial Emissions Inventory

This chapter explains the EI process, including how to prepare an EI for the first time, and defines key terms associated with this process. For any unfamiliar term or concept, please consult the Glossary, or contact the EAS for assistance.

## The Emissions Inventory Process

TCEQ annually collects statewide data on emissions from industries that meet the EI reporting requirements and stores the data in its STARS database. The emissions data is collected in a standard format to ensure consistency among types of data collected and to facilitate data upload into, and retrieval from, STARS. The data collected identify the company, site, point of contact, emission source, abatement device, emission point, and path emissions.

Every EI is currently identified with and indexed by a site-specific, air-regulated entity reference number (RN), a unique identification number assigned by TCEQ. A site's air RN will also uniquely identify its EI.

## Requirements for Submitting an Emissions Inventory

TCEQ requires emissions inventories from regulated entities that satisfy the applicability requirements (also called *reporting requirements*), as set forth in 30 TAC Section 101.10.

The reporting requirements for emissions inventories will vary depending on:

- site location
- the type and quantity of emissions

The *attainment status* of the county where the regulated entity is located will impact the EI reporting requirements that concern both emissions type and quantity. Specifically, the county's attainment status for a particular pollutant will affect both the **potential** and **actual annual** emissions level reporting requirements for this pollutant. Thus, a regulated entity located in a county designated as nonattainment for ozone will be subject to more stringent annual emissions level reporting requirements for ozone-precursor pollutants than a regulated entity located in a county designated as attainment for ozone.

The term *actual emission* is defined in 30 TAC Section 101.10 as the actual rate of emissions of a pollutant from an emissions unit as it enters the atmosphere. *Potential emissions* from a specific unit are referred to as its potential to emit—as defined by 30 TAC Section 116.12 (the definition is also available in the Glossary). Note that, while both actual and potential emissions are defined above in relation to an emissions-generating source or unit, the EI reporting requirements are based on site-wide actual annual (routine) and potential emissions.

The owner or operator of the regulated entity must determine the attainment status of the county where the site is located. The map located on the EAS webpage contains a table that provides the EI reporting requirements by listing the actual annual and potential emissions levels for all counties in Texas. For more information, consult 30 TAC Section 101.10.

*Note:* The map and associated table are intended to clarify reporting requirements and do not supersede or replace 30 TAC Section 101.10. To determine both the actual annual and potential emissions level reporting requirements for a specific county, consult 30 TAC Section 101.10. For major-source thresholds please consult 30 TAC Section 116.12.

The owner or operator of a regulated entity must identify every emission source present at the site. For additional information consult both this chapter and "Identifying Emission Sources" in Chapter 3. After identifying all emission sources at the site, the owner or operator must determine each source's actual annual and potential emissions. To determine the quantity and type of actual annual and potential emissions, consult Chapter 4. Finally, the total actual annual emissions, as well as the potential emissions, for the entire site must be calculated.

Based on the reporting requirements associated with the site's location and the actual annual and potential emissions, the owner or operator must determine whether submission of an EI is required. If so, the owner or operator must report the actual emissions. Representing sources within the EI is termed *emissions inventory structure* and it is explained in the following section.

# Understanding Emissions Inventory Structure

The EI is used to report the quantities of emissions at a site. This information on emissions, which is loaded into STARS, is not just associated with a site's air RN, but is specifically tied to individual sources. Associating emissions to a particular source in this manner assures the quality of data and enhances statewide emissions modeling.

The way the EI ties emissions data to particular emission sources is called *structure*. The key concepts associated with structure are discussed in the following sections.

## Facilities and Emission Points

In EI terminology, a source capable of generating emissions (for example, an engine or a sandblasting area) is called a *facility*. Thus, *facility* and *emission source*, or "source" for short, are synonymous.

The actual physical location where the emissions enter the atmosphere (for example, an engine stack or a sandblasting yard) is called an emission point. Emission points are currently classified into three different types:

1. *Stack*-type emission points, such as boiler stacks or building vents.
2. *Fugitive*-type emission points, such as sandblasting yards or marine loading areas.
3. *Flare*-type emission points that only include flares.

Thus, an emission point's type can range from a smaller, more precise location (such as a glycol still vent) to a larger, wider area (such as an outdoor lot where surface-coated metal pieces finish drying).

For EI purposes, a facility (emission source) must be linked to at least one emission point, and vice versa; this allows the inventory to capture the maximum amount of data about a source. For example, an internal combustion engine with one stack is represented as the facility and emission point, respectively.

The engine's burn type and design capacity will be captured in the facility data, and the stack height, diameter, exhaust exit velocity, and exhaust temperature will be captured in the emission point data.

## Emission Paths

As stated in the previous section, a facility must be linked to at least one emission point. This association of one facility to one emission point is termed a *path*. A path essentially traces an air pollutant's origination, from its creation by the facility to its entrance into the atmosphere via the emission point. If a control device is involved, the path traces an air pollutant's origination, from its creation by the facility, to its abatement by the control device, to its entrance into the atmosphere via the emission point.

It is important to note that a path represents **one** facility linked to **one** emission point; in other words, a path traces **only one** route in a facility's emissions travel to reach the atmosphere. If one facility is linked to **more than one** emission point, then multiple paths exist. For example, if a paint booth has three exhaust vents, then three different paths exist, since there are three different routes the facility's (source's) emissions can travel to enter the atmosphere.

Thus, when actual emissions data are reported in the EI, the data will be associated with a path—in other words, the emissions data will be associated with the facility (emission source) that created the emissions, and the point where they entered the atmosphere. If a control device is involved, it will also be associated with the path.

The site's EI will consist of a collection of paths that will allow for the submission of detailed emissions data, as well as detailed facility and emission point attributes. These collective paths, facilities, emission points, and any associated control devices will form the *EI structure*.

These key elements of EI structure are important because they allow emissions data to be tied to specific sources. Chapter 3 discusses in detail how to establish the EI structure.

# Chapter 3. Emissions Inventory Structure

Emissions inventory information must be stored in a manner that accurately represents a site's processes. This chapter begins with a section on identifying emission sources and a general discussion of how to represent these sources in the standardized EI format. The representation of sources in this standardized format is referred to as *EI structure*. Examples of common industrial processes and their appropriate structural representation are discussed. Finally, the chapter concludes with a section on modifying existing EI structure.

## Identifying Emission Sources

To develop an accurate EI, emission sources at the site must be identified. Using all available tools—including, but not limited to, plot plans, site maps, comprehensive process flow diagrams, and knowledge of the site's processes—list all equipment and operations that may result in air emissions, such as:

- Combustion sources.
- Storage tanks.
- Loading operations.
- A fugitive area representing grouped piping components in similar service.
- Wastewater collection and treatment systems.
- Process areas (for example, building vents, process vents, or reactors).
- Evaporative losses (for example, in surface coating, solvent degreasing, railcar or tank truck cleaning, or printing operations).
- Plant roads.

## Guidelines for Including Sources in Emissions Inventory Structure

Depending upon the type of emission source, the owner or operator of the regulated entity must add the emission source to the EI as an individual source, group the emission source with other similar sources, or may omit the source from the EI.

### Sources That Must Be Added and That May Be Grouped as Collective Sources

Each emission source at a site must be added with associated emissions to the EI if it meets any of the following criteria:

- It emits 1 ton or more of any regulated pollutant.
- It emits 0.1 ton or more of any toxic chemical or hazardous air pollutant (HAP).
- It emits 0.001 ton or more of any individual HAP or aggregate HAPs listed in any TCEQ-enforceable document such as a permit, regulation, or commission order.

- It emits 0.001 ton or more of mercury or lead.
- It is separately identified in any TCEQ-enforceable document such as a permit, regulation, or commission order.

*Note:* A registered permit by rule (PBR) that includes a certification of federally enforceable emission limits (e.g., using Form PI-7-CERT, designated Form TCEQ-20182) is a TCEQ-enforceable document.

If individual sources do not meet the requirements listed above, these sources are not required to be reported in the EI, provided that the collective emissions from all such unreported sources total less than 5 tons of any regulated pollutant and less than 1 ton of aggregate HAPs.

If individual sources do not meet the requirements listed above, but exceed the collective emissions totals outlined above, then these sources must either be:

- individually added with associated emissions to the EI, or
- grouped according to the "Collective Sources" section of this chapter and added with associated emissions to the EI as a collective source.

TCEQ encourages the grouping of similar small emission sources. When creating a new path for grouped sources (grouped facilities) refer to the guidelines in the "Collective Sources" section. If small sources or small facilities are grouped in a permit, group these sources in a similar manner when adding them to the EI.

Individual fugitive components are not considered individual facilities (sources) and must be reported as collective sources following the guidance in this section and Technical Supplement 3.

# Representing the Structure of a Regulated Entity in the Emissions Inventory

For EI purposes, the term facility refers to a source, unit, device, structure, or area capable of generating air contaminants. The point where air contaminants are emitted to the environment is called the *emission point*. Some contaminants are controlled by an abatement device prior to being emitted at the emission point. When representing emission points in the EI, ensure that the nomenclature aligns with nomenclature in the permit.

## Facilities and Facility Identification Numbers

Each facility at the site must be identified. Examples of a facility include:

- a reciprocating engine
- a spray booth
- a chemical storage tank
- a flare

Each facility at the site must be given a unique alphanumeric code called a facility identification number (FIN). The FIN cannot be longer than 10 characters. Examples of possible FINs for the facilities listed above are:

- COMP01
- SPRBTH
- TANK03
- FLR

Every FIN must be linked to at least one emission point.

## Emission Points and Emission Point Numbers

An emission point is the spatial location (point) where emissions enter the atmosphere. Every facility has at least one emission point. Examples of emission points include:

- an engine exhaust stack
- a spray-booth vent
- a process fugitive area
- a building vent

Each emission point must be given a unique alphanumeric code called an emission point number (EPN). The EPN cannot be longer than 10 characters. Examples of possible EPNs for the emission points listed above are:

- STK1A
- VENT
- FUG
- BLDGVENT

Every EPN must be linked to at least one facility.

## Abatement Devices and Control Identification Numbers

An abatement device, also called a control device, is a piece of equipment or a recognized operational procedure that limits, controls, or abates emissions. Each abatement device at the site must be identified. Examples of abatement devices include:

- a flare
- a scrubber
- a condenser
- a vapor recovery unit

Each abatement device must be given a unique alphanumeric code called a control identification number (CIN). The CIN cannot be longer than 10 characters. Examples of possible CINs for the abatement devices listed above are:

- FLR
- SCRUB4
- VAPORCOND
- VRU

Every CIN must be associated with at least one facility (identified by a FIN) that is linked to an emission point (identified by an EPN).

Some control devices, such as thermal oxidizers and flares, also create emissions and must be represented as both facilities and control devices. For more information on this subject, refer to "Representing Combustive Abatement Devices" later in this chapter.

## Emission Paths

An emission path is the route a contaminant must travel from the facility to the abatement device to the atmosphere via the emission point. Every emission path must include at least one facility and one emission point.

## Collective Sources (Collective Facilities)

Emission sources or facilities that emit small quantities of regulated pollutants have similar source classification codes (SCCs), and generate similar emissions may be grouped as one collective emission source (collective facility). To be grouped within a collective emission source, each small, individual emission source or small facility must meet **all** the following criteria:

- Emitted less than 1 ton of each regulated pollutant.
- Emitted less than 0.1 ton of any toxic chemical or HAP.
- Is not required to be included in the inventory's structure under any other TCEQ enforceable document, such as a permit or a commission order.

For example, 20 similar aggregate storage piles each emitted 0.5 tpy of $PM_{10}$. These emissions must be represented in the EI, since collectively the storage piles emitted 10 tpy of $PM_{10}$, which surpasses the reporting limit for collective sources (refer to "Sources that Must Be Added to the EI and that May Be Grouped as Collective Sources," above). If the storage piles are not individually represented in any permits, they could be grouped together as a collective emission source under a single facility.

If small sources or small facilities are grouped in the regulated entity's air permits, group these sources as collective FINs in a similar manner when adding them to the EI. Use the following guidelines when adding collective sources to the EI.

### *Facility Guidelines*

Group only those sources with similar SCCs and similar emissions as one collective facility. Create different collective FINs for each distinct type of process and equipment. Complete the appropriate facility information for each collective source and assign representative average or median values for required attributes. Examples of different source types that may be grouped in a collective FIN include:

- solvent cleaning areas and equipment
- painting areas and equipment
- piping components in similar service
- VOC loading operations
- tanks
- internal combustion sources (e.g., generators)
- external combustion sources
- other sources as appropriate

### *Emission Point Guidelines*

Unless all sources in a collective facility group vent to a common control device, a collective facility group must have a fugitive area emission point.

- Complete the emission point information—selecting the fugitive profile option for the fugitive area emission point. The length and width of the fugitive area is the overall length and width of the area spanning the locations of the collective sources, and the height of the fugitive area for collective sources is the average height of the point where the fugitive emissions from the collective sources enter the atmosphere. For a trench or impoundment, enter a default height of 3 feet.
- If the collective emission point is represented in any air permits for the site, TCEQ requires using the same naming convention as the air permit when assigning the EPN; otherwise, the EPN can begin with the character string “GRP,” such as EPN: GRPTANKS or EPN: GRPSOURCES.
- When supplying Universal Transverse Mercator (UTM) coordinates for the collective emission point, use the UTM coordinates for the site centroid.

### *Abatement Device Guidelines*

Add abatement devices to collective facilities. If the abatement device only abates certain sources in the grouped facilities, note this in the “Path Comments” portion of the EI.

For assistance with collective source structure, please contact the EAS helpline at 512-239-1773.

## Representing Combustive Abatement Devices

Most abatement devices do not generate their own emissions and therefore appear only as control devices within the EI structure. However, a combustive abatement device generates emissions while burning contaminants and must be represented in the EI structure as an emission source and as an abatement device.

Emergency-flare structure is similar to process flare structure, except that the emergency flare may not need to be linked to each individual facility, per guidance below. If an emergency flare controls emissions from a large number of sources, then associating it with each facility would greatly increase the inventory's size without substantially improving its quality. For emergency flares, the emissions path will be from the process to the abatement device to the flare. Therefore, the owner or operator would create the path FIN: PROCESS / CIN: FLARE / EPN: FLARE. All undestroyed waste gas emissions must be reported in this path. Another emissions path must be created to report the emissions generated by the combustion of the waste gas at the flare. The products of combustion must be reported at the path representing the flare as the source and flare as the emission point, FIN: FLARE / EPN: FLARE.

For assistance with establishing correct flare structure, please contact the EAS.

# Appropriate Structural Representation of Common Industrial Processes

This section discusses appropriate structural representation of some common emission sources. For assistance with establishing the correct structure for a process, please contact the EAS.

## Cooling Towers

To promote data consistency within the STARS database, represent each cooling tower as one facility with one associated stack emission point, regardless of whether it is a natural-draft or a mechanical-draft tower. A mechanical-draft tower with multiple cells must also be considered one facility with one stack emission point; the number of cells must be represented as one of the attributes under the FIN group type and profile on the EI.

Cooling towers are typically designed with drift eliminators. A drift eliminator is part of a cooling tower's basic design and is not considered an abatement device from a structural standpoint.

## Glycol Units and Amine Units

For the purposes of establishing EI structure, treat an amine unit as a glycol unit, using the following guidance.

Two paths are required to represent each glycol unit:

1. A still path for reporting emissions from gas stripping.
2. A heater path for reporting emissions from combustion.

An additional path for the flash tank is required if air emissions from the flash tank are authorized separately from the glycol still emissions.

The correct way to represent emissions for each path depends on how those emissions are vented or routed. If the flash tank is not explicitly listed in the examples below; please contact the EAS for further assistance.

### *Venting to Separate Stacks*

When still and heater emissions are vented through separate stacks represent each unit as a separate facility linked to its own emission point. Each unit must be represented as its own emission path, as shown in Figure 3-1. Report the stripping emissions at the glycol still FIN / glycol still vent EPN path. Report the combustion emissions from the heater at the heater FIN / heater stack EPN path.

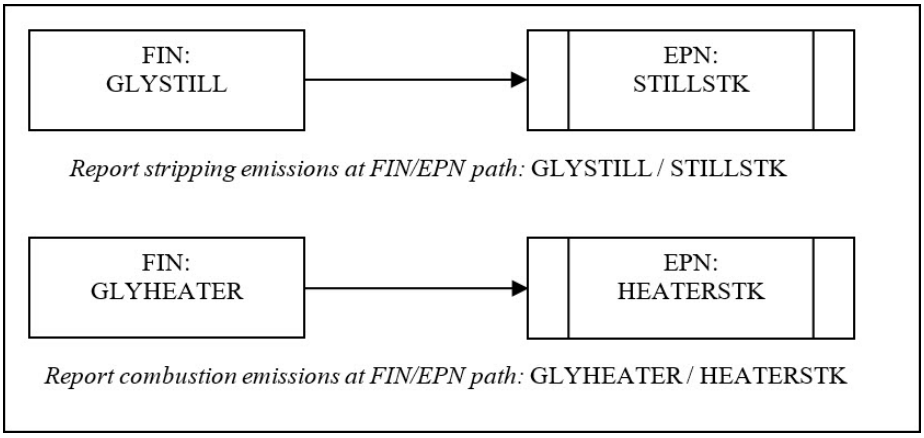


**Figure 3-1. Glycol Unit: Separate Still and Heater Vents**

### *Venting to a Common Stack*

If emissions from a glycol still and a heater both vent through a common stack, represent the glycol still and heater as two facilities that are linked to a single emission point. This structure is shown in Figure 3-2. Report the stripping emissions at the glycol still FIN / heater stack EPN path. Report the combustion emissions from the heater at the heater FIN / heater stack EPN path.

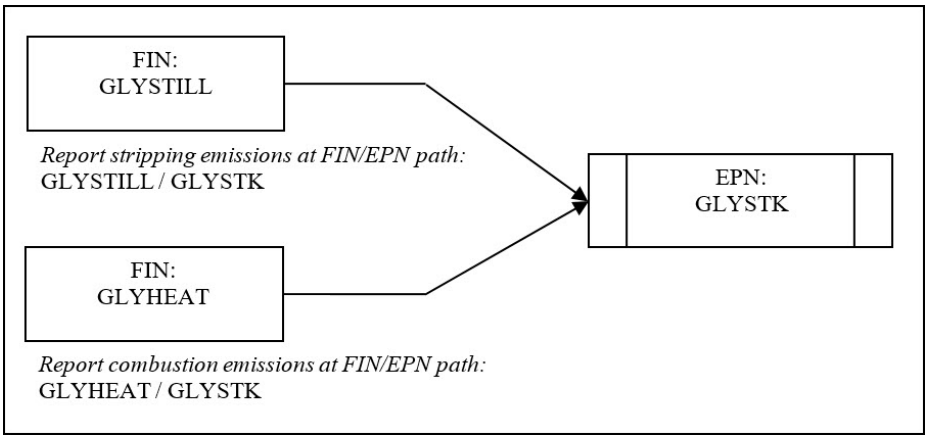


**Figure 3-2. Glycol Unit: Common Still and Vents**

## *Routing Still Emissions to a Flare*

If glycol-still emissions are routed to a flare, the glycol still and heater must be represented as shown in Figure 3-3. Represent the glycol heater as its own facility linked to its own emission point. Represent the glycol still and flare as separate facilities linked to a single emission point, with an abatement device added to the glycol still. Report glycol-heater combustion emissions at the heater FIN / heater stack EPN path. Report undestroyed stripping emissions at the glycol still FIN / flare CIN / flare EPN path. Finally, report the flare combustion emissions at the flare FIN / flare EPN path.

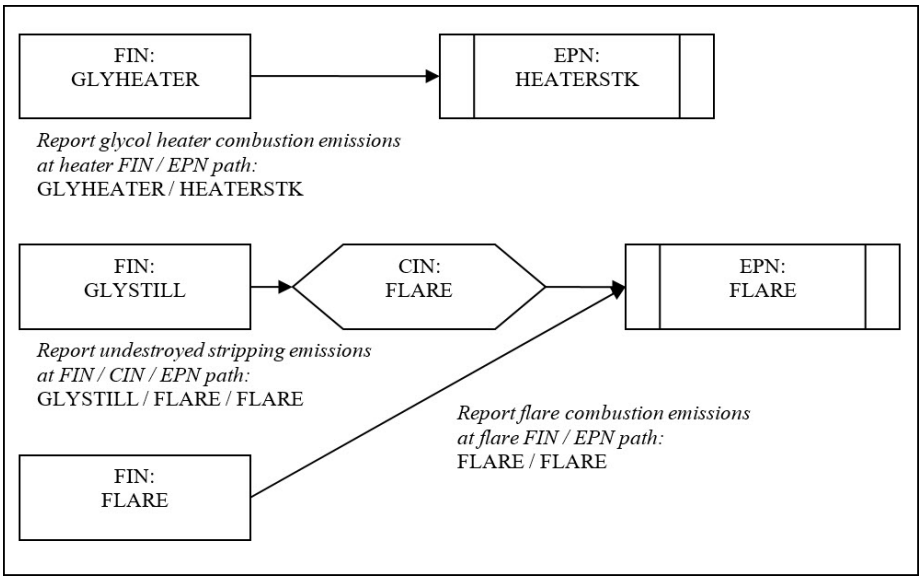


**Figure 3-3. Glycol Unit: Flared Still Emissions**

## *Routing Still Emissions Through the Heater*

If glycol-still emissions are routed through the heater and combusted, the still and heater must be represented as shown in Figure 3-4. Represent the glycol still and glycol heater as separate facilities linked to a single emission point, with an abatement device

added to the glycol still. Report undestroyed stripping emissions at the glycol still FIN / heater CIN / heater stack EPN path. Report combustion emissions at the heater FIN / heater stack EPN path.

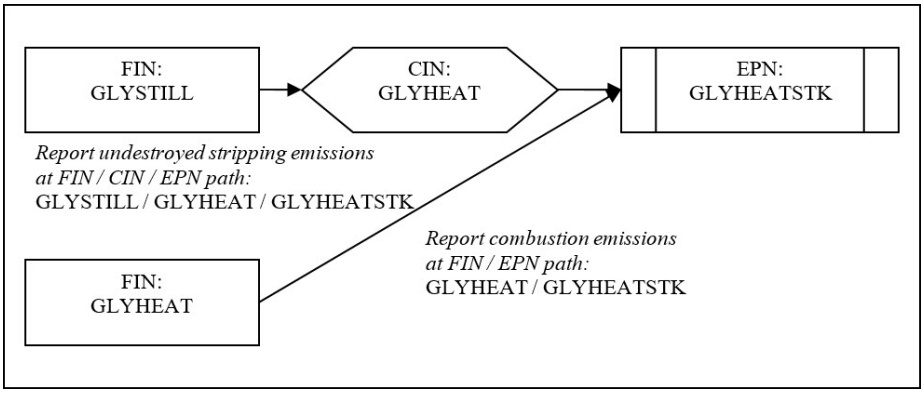


**Figure 3-4. Glycol Unit: Still Emissions Routed Through Heater**

## Sulfur Recovery Units

An SRU is not an abatement device, but rather a unit generating hydrogen sulfide ($H_2S$) emissions. Some common SRU structures are shown in Figures 3-5 through 3-8.

### *An Unabated Sulfur Recovery Unit (SRU)*

If the SRU emissions are not controlled by an abatement device, represent the SRU as a single facility linked to a single emission point, as shown in Figure 3-5. Report the $H_2S$ emissions at the SRU FIN / SRU EPN path.

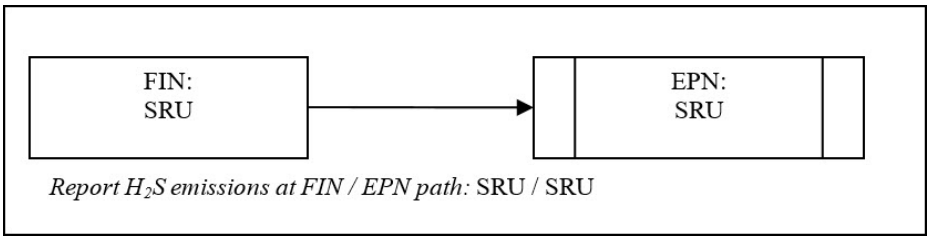


**Figure 3-5. Sulfur Recovery Unit, Unabated**

### *Controlled by a Scrubber*

If the SRU emissions are controlled by a scrubber, represent the SRU as a single facility linked to a single emission point, with an abatement device added to the SRU, as shown in Figure 3-6. Report unscrubbed $H_2S$ emissions at the SRU FIN / scrubber CIN / scrubber EPN path.

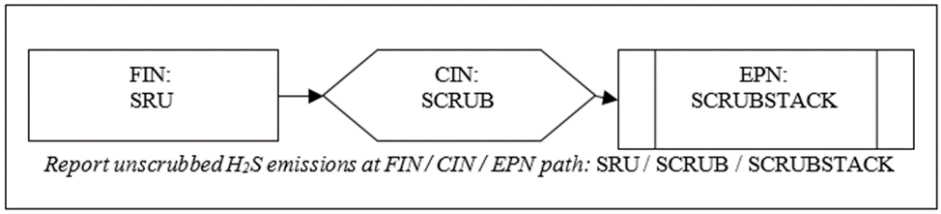


**Figure 3-6. Sulfur Recovery Unit With Scrubber**

## *Routing Sulfur Recovery Unit Emissions to an Incinerator*

If the SRU emissions are controlled by an incinerator, represent the SRU and incinerator as two separate facilities linked to a single emission point, with an abatement device added to the SRU, as shown in Figure 3-7. Report undestroyed $H_2S$ emissions at the SRU FIN / incinerator CIN / incinerator EPN path. Report combustion emissions at the incinerator FIN / incinerator EPN path.

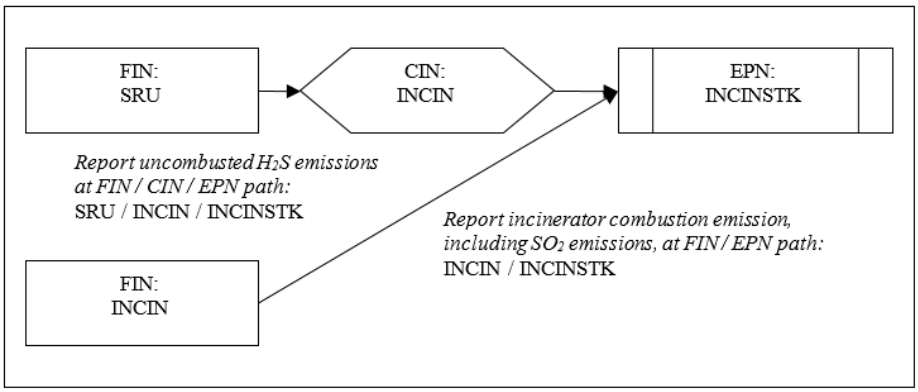


**Figure 3-7. Sulfur Recovery Unit With Incinerator**

## *Routing Sulfur Recovery Unit Emissions Through a Scrubber Prior to an Incinerator*

If the SRU emissions are first controlled by a scrubber and then routed to an incinerator, represent the SRU and incinerator as two separate facilities linked to a single emission point, with two different abatement devices added to the SRU, as shown in Figure 3-8. Report the uncombusted $H_2S$ emissions at the SRU FIN / scrubber CIN / incinerator CIN / incinerator stack EPN path. Report the incinerator combustion emissions at the incinerator FIN / incinerator stack EPN path.

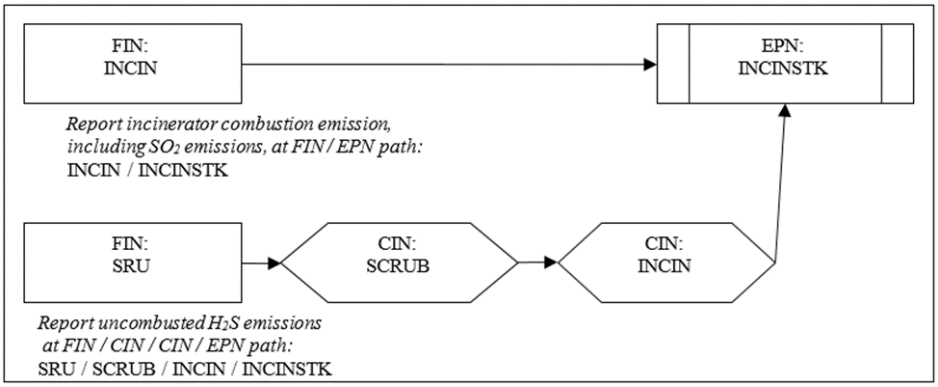


**Figure 3-8. Sulfur Recovery Unit With Scrubber Prior to Incinerator**

# Loading Operations

## *Unabated Loading Operation*

If loading emissions are not routed to an abatement device, represent the loading area by a single facility linked to a fugitive-type emission point, as shown in Figure 3-9. Report uncaptured emissions at the loading FIN / loading EPN path.

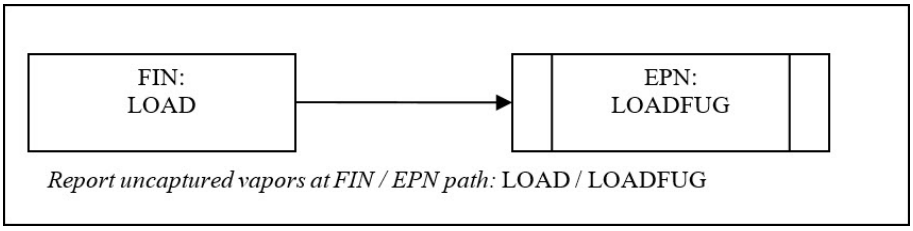


**Figure 3-9. Loading Area, Unabated**

## *Controlled by a Flare*

If loading emissions are controlled by a flare, the emissions paths will be the loading operation linked to the fugitive loading area and the flare emission points. Represent the loading operation and flare as two separate facilities linked to a single emission point, with an abatement device added to the loading operation. Report the emissions from the captured, undestroyed vapors at the abatement device. Then report the uncaptured vapors that are not routed to the flare at a separate fugitive loading area emission point linked to the loading-operation facility. Be sure to indicate the capture efficiency of the loading rack in the facility comment field. Figure 3-10 illustrates proper structure for a loading area controlled by a flare.

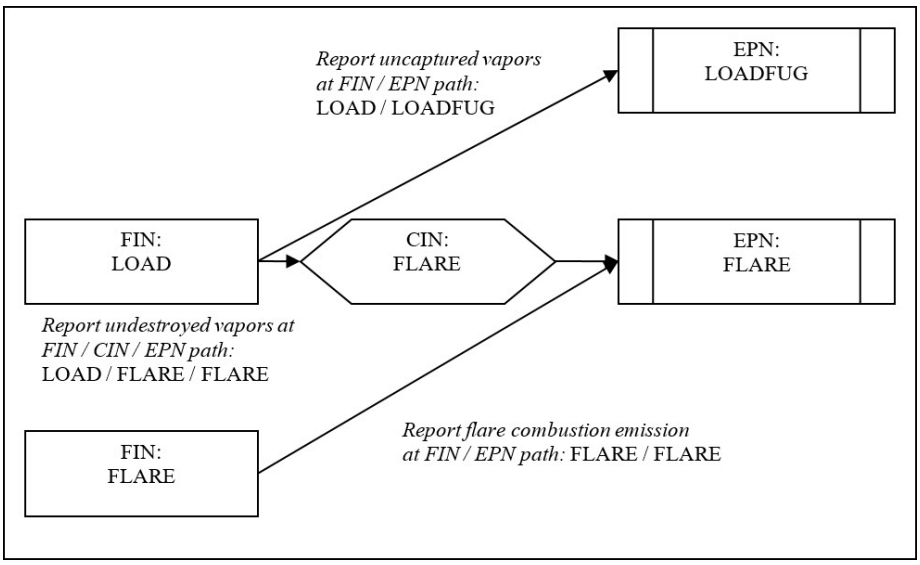


**Figure 3-10. Loading Area Controlled by a Flare**

## Blowdown Operations

Compressor engines and other process equipment are taken offline for periodic maintenance or emergency shutdown. Before maintenance can be performed, the gas in the lines is usually vented. These vented gases can result in significant emissions depending on the volume of gas released. The emissions can either be vented to the atmosphere or sent to a control device.

### *Venting Through Separate Stacks*

Blowdown emissions must be reported at a VOC Process facility path if combustion and blowdown emissions are vented through separate stacks, as shown in Figure 3-11. Represent the compressor engine and compressor blowdowns as two separate facilities linked to two different emission points. Combustion emissions are reported at the engine FIN / engine stack EPN path, and the blowdown emissions at the blowdown FIN / blowdown stack EPN path.

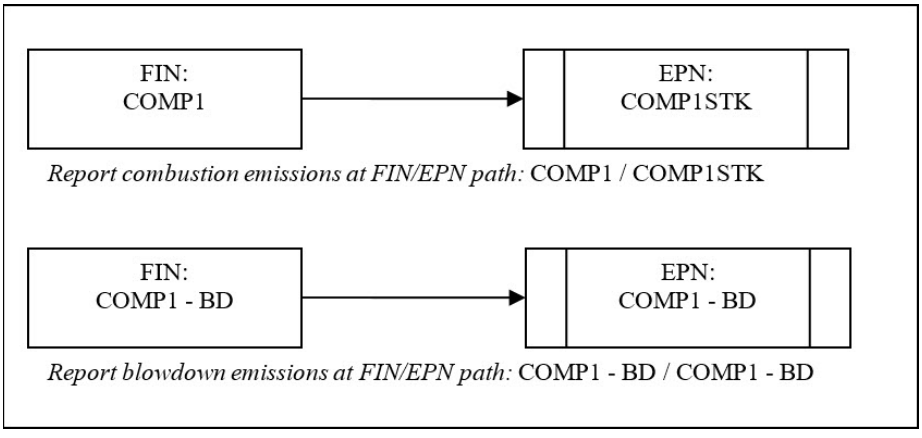


**Figure 3-11. Blowdown: Separate Compressor Engine and Blowdown Vents**

### *Venting to a Common Stack*

If combustion and blowdown emissions are vented through the same stack, represent the structure as shown in Figure 3-12. Represent the compressor engine and compressor blowdowns as two facilities linked to a single emission point. Report the combustion emissions at the engine FIN / engine stack EPN path and the blowdown emissions at the blowdown FIN / compressor stack EPN path.

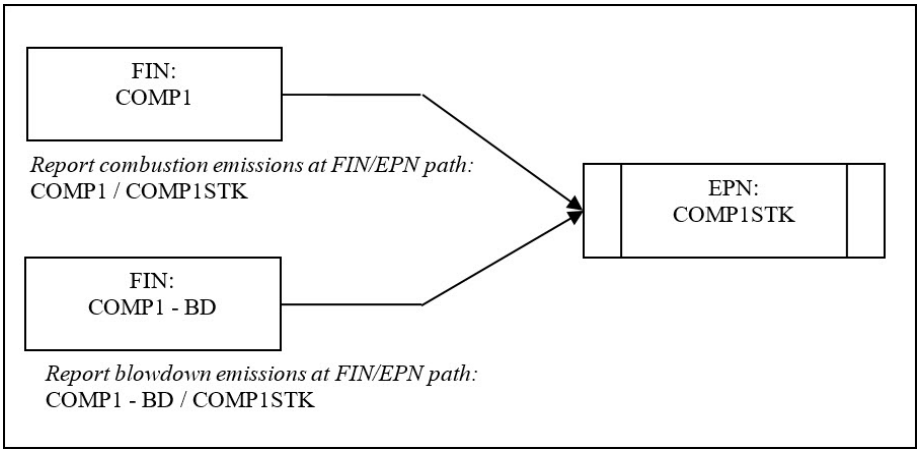


**Figure 3-12. Blowdown: Common Compressor Engine and Blowdown Vent**

### *Blowdown Emissions Routed to a Flare*

If blowdown operations are routed to a flare, represent the combustion and blowdown emissions as shown in Figure 3-13. Represent the compressor engine as a single facility linked to a single emission point. Represent the compressor blowdowns and flare as two facilities linked to a single emission point, with an abatement device added to the compressor blowdowns. Report the combustion emissions from the engine at the engine FIN / engine stack EPN path. Report the blowdown emissions at the blowdown FIN / flare CIN / flare EPN path and the combustion emissions from the flare at the flare FIN / flare EPN path.

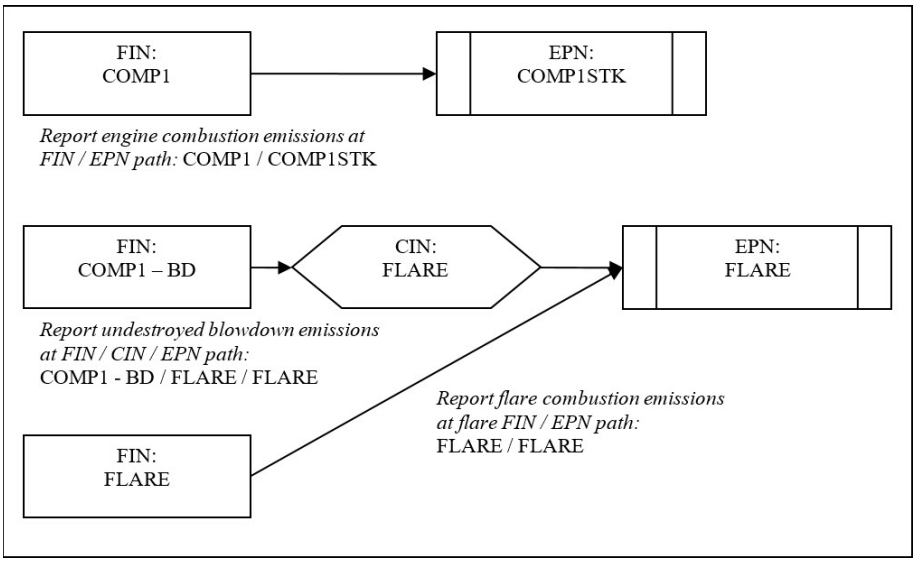


**Figure 3-13. Blowdown: Flared Blowdown Emissions**

## *Grouping as a Collective Emission Source*

If the blowdown operations do not meet the requirements for reporting as individual sources, the emissions can be grouped together as a collective emission source. One facility and one emission point can represent two or more collective blowdown-operations facilities, as shown in Figure 3-14. Represent each compressor engine as a single facility attached to a single emission point. Represent the grouped compressor blowdowns as a single facility attached to a single emission point. Report combustion emissions from the compressor engine at the engine FIN / engine stack EPN path and the grouped blowdown emissions at the blowdown FIN / engine stack EPN path.

See “Collective Emission Sources” in this chapter for details on reporting requirements and how to represent the emission point for such sources.

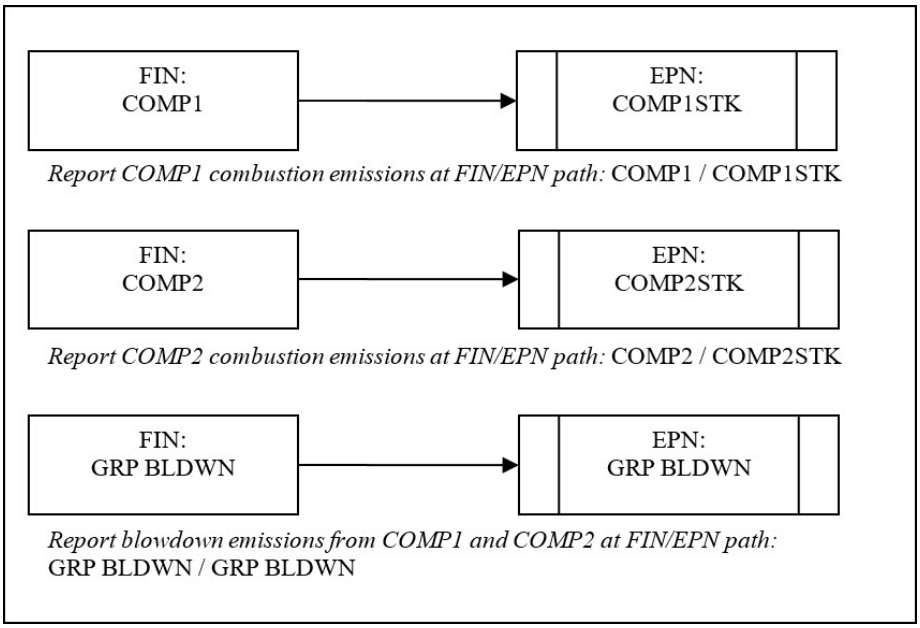


**Figure 3-14. Blowdown Operations: Grouped Compressor Blowdowns**

## Surface Coating Operations

### *Unabated Paint Booth*

If emissions from a paint booth are completely uncontrolled, represent the booth as a single facility linked to a single emission point path, as shown in Figure 3-15. Report VOC and particulate emissions at the paint booth FIN / paint booth vent EPN path.

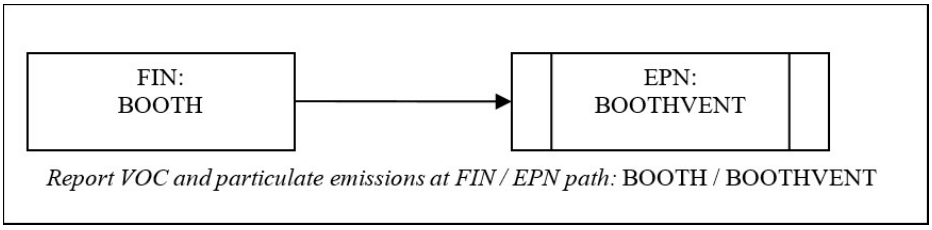


**Figure 3-15. Paint Booth: Unabated**

### *Controlling Particulate Emissions With a Filter*

If emissions are filtered to control particulate emissions, represent the paint booth as a single facility linked to a single emission point, with the filter added as an abatement device for the paint booth, as shown in Figure 3-16. Report VOC and particulate emissions at the paint booth FIN / filter CIN / paint booth vent EPN path.

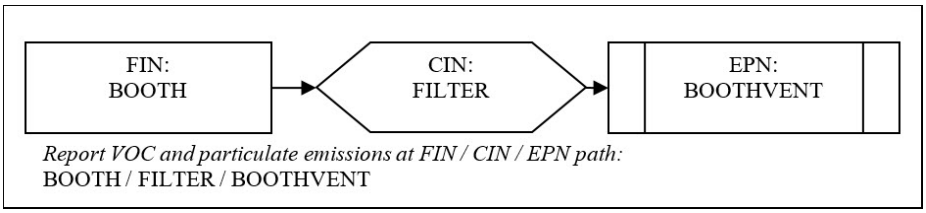


**Figure 3-16. Paint Booth: Particulate Emissions Abated by a Filter**

### *Routing VOC Emissions to an Incinerator*

If paint-booth emissions are routed to an incinerator to control VOC emissions, represent the booth and incinerator as two facilities linked to a single emission point, with an abatement device added to the booth. Then link a second emission point to the booth to report emissions not captured by the booth ventilation system, as shown in Figure 3-17. Report the uncaptured emissions at the paint booth FIN / paint booth stack EPN path. Report the captured but undestroyed VOC emissions at the paint booth FIN / incinerator CIN / incinerator stack EPN path. Report the combustion emissions from the incinerator at the incinerator FIN / incinerator stack EPN path.

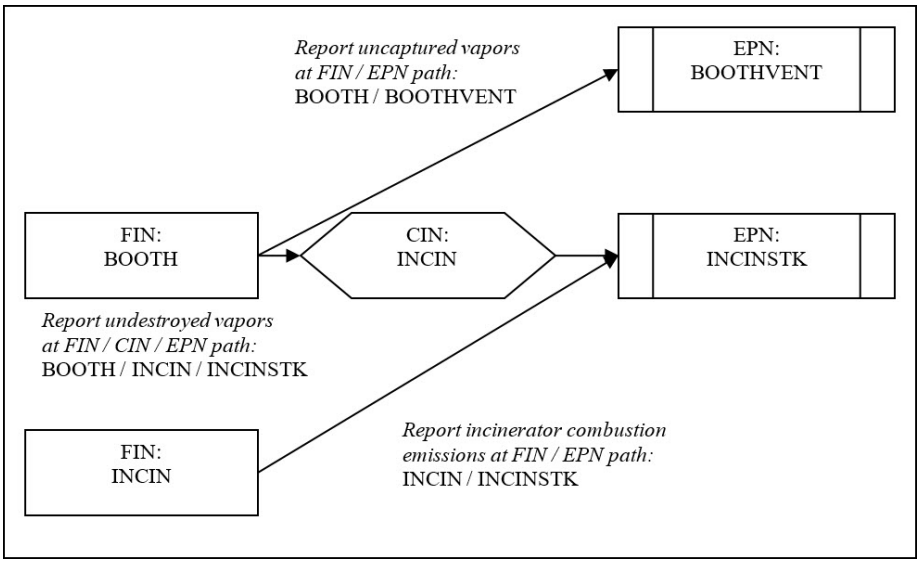


**Figure 3-17. Spray Booth Controlled by an Incinerator**

If coated surfaces are heat dried, be certain to include the dryer in the EI structure.

## Aggregate Operations

Emission sources from aggregate operations include storage piles and material transport and processing operations, such as crushing, grinding, milling, mixing, calcining, and kilning. Represent each step in material storage, transport, and processing with a separate path composed of a unique FIN and EPN.

### *Storage Piles*

Classify aggregate storage piles by material type and particle size—for example, represent a site using a water-spray system to control emissions from a fine-particle

pile and a coarse-particle pile composed of the same material as two facilities linked to two emission points, with a single abatement device added to each facility, as shown in Figure 3-18. For fine particulates, report emissions from the storage pile at the fine storage pile FIN / water spray CIN / fine storage pile EPN path. Report coarse emissions at the coarse pile FIN / coarse pile EPN path.

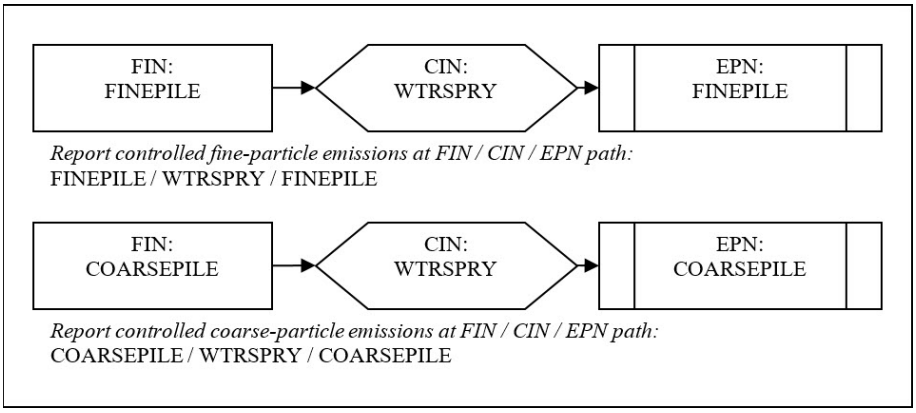


**Figure 3-18. Fine and Coarse Piles: Emissions Controlled by Water Supply**

## *Batch and Continuous Operations*

Separate batch from continuous material-transport operations. For example, an operation moves limestone in batches from a quarry to a storage pile and then the limestone is fed continuously into a process stream. Represent this process as two separate facilities linked to two separate emission points, as shown in Figure 3-19. Report emissions from the batch operations at the batch FIN / batch pile EPN path. Report emissions from the continuous operations at the continuous operations FIN / continuous operations EPN path.

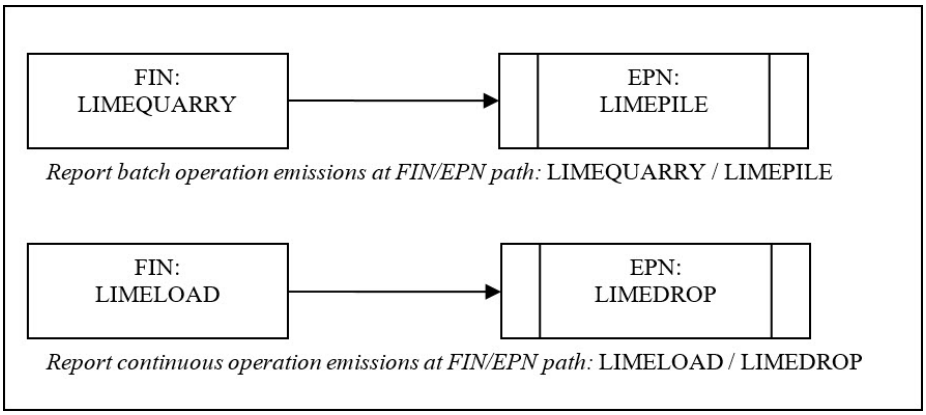


**Figure 3-19. Continuous and Batch Operations, Separated**

## *Conveyor Transport Operations*

Rather than grouping all conveyor transport operations under a single FIN / EPN path, represent each of the conveyor's interdependent operating systems separately. For example, represent a conveyor system that has both a fine- and a coarse-particle process line as two facilities linked to two emission points, shown in Figure 3-20. For

fine particulates, report emissions from the conveyor at the fine conveyor FIN / fine conveyor EPN path. Report coarse emissions at the coarse conveyor FIN / coarse conveyor EPN path.

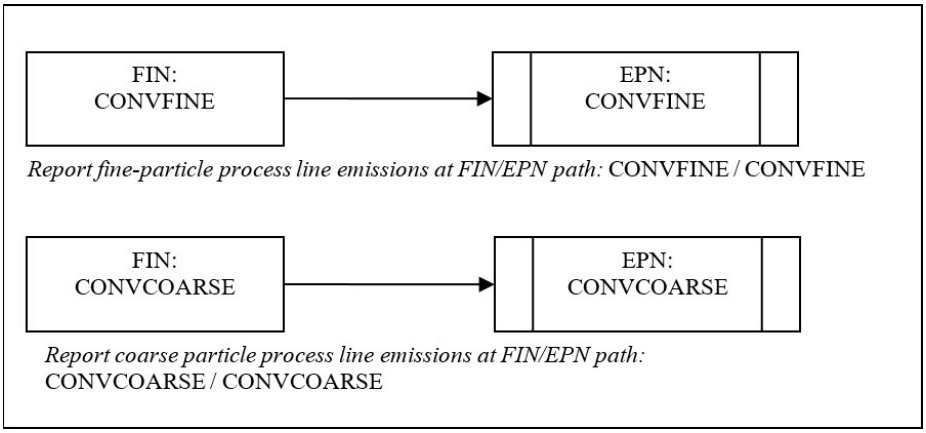


**Figure 3-20. Conveyor Transport: Interdependent Systems**

## Marine Operations

Rather than reporting all marine losses at a single FIN / EPN path, each individual equipment or process type must be uniquely identified in the EI. This section addresses correct structure for several common marine operations. Please contact the EAS for additional guidance on representing the structure of the marine facility.

### *Loading and Unloading Bulk Liquids*

#### Unabated Loading Operations

If loading operations are uncontrolled, represent the emissions path from one or more vessels as a single facility linked to a single emission point, as shown in Figure 3-21. Report the gas freeing or conditioning emissions at the loading FIN / loading EPN path.

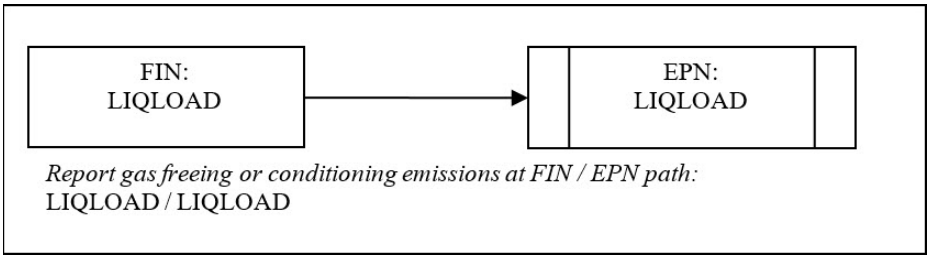


**Figure 3-21. Uncontrolled Bulk Liquid Material Emissions**

#### Using a Vapor Recovery System

If loading operations use a vacuum-assisted vapor recovery system, any uncollected emissions must be reported at the vessel, with the balance of emissions reported at the onshore equipment serving as a control device. For example, if the vapors captured by the vapor recovery system are routed to an incinerator, represent the loading operation and incinerator as two facilities linked to a single emission point, with both

abatement devices added to the loading operation. Then link the loading facility to a separate fugitive emission point to report emissions not captured by the vapor recovery system, as shown in Figure 3-22. Report the uncaptured emissions at the loading FIN/loading fugitive EPN path. Report the captured but undestroyed emissions at the loading FIN / VRU CIN / incinerator stack EPN path. Finally, report the combustion emissions from the incinerator at the incinerator FIN / incinerator stack EPN path.

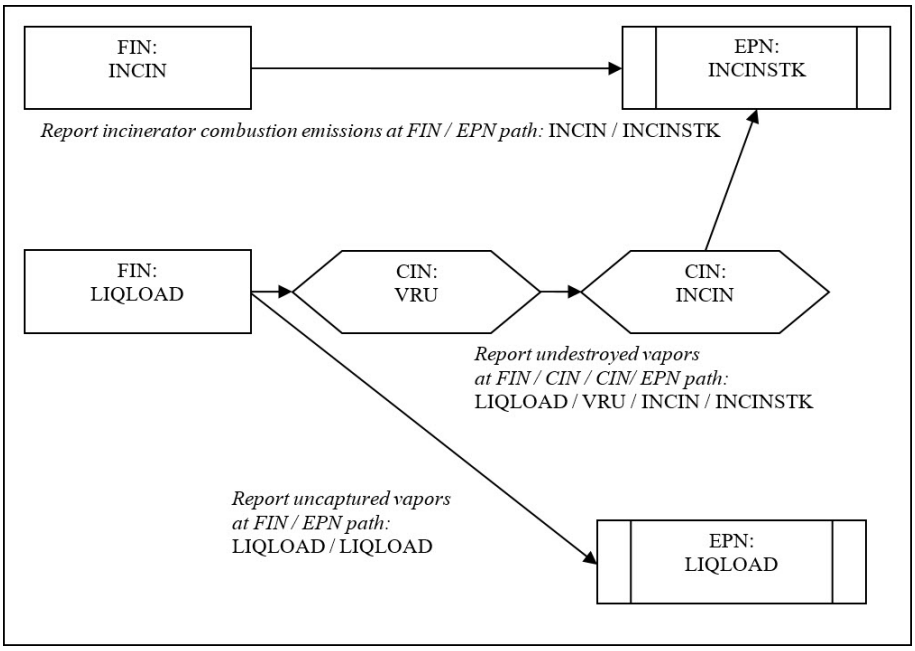


**Figure 3-22. Liquid Loading Controlled by a Vapor Recovery Unit and Incinerator**

## *Loading and Unloading Bulk Liquefied Gaseous Materials*

Pressurized marine vessel compartments do not normally emit to the atmosphere. However, loading and unloading bulk liquefied gaseous materials may generate fugitive emissions from piping components and related equipment leaks. These emissions must be reported at the appropriate equipment leak fugitive area on the dock.

If gas freeing or gas conditioning is performed, represent the path as a single facility linked to a single emission point, as shown in Figure 3-23. Report the emissions at the loading FIN / loading fugitive EPN path.

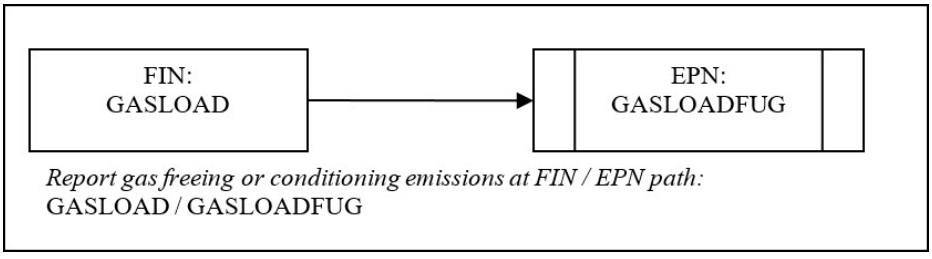


**Figure 3-23. Uncontrolled Degassing and Cleaning Emissions**

## *Loading and Unloading Solid Bulk Materials*

Although unloading operations are not limited to the use of hoppers or pneumatic systems, those are perhaps the most common methods. Pneumatic systems transfer material to silos or storage tanks, where air is separated from the material and vented to a baghouse or cyclone. Represent this loading operation as a single facility linked to a single emission point, with an abatement device added to the loading operation, as shown in Figure 3-24. Report the emissions at the loading FIN / baghouse CIN / baghouse stack EPN path.

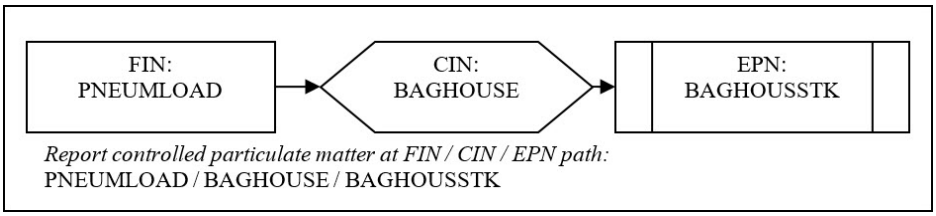


**Figure 3-24. Pneumatic Transfer of Solids Controlled by a Baghouse**

## *Degassing and Cleaning Liquid Vessel Compartments*

Emissions from liquid vessel cleaning and degassing will occur either from the vessel itself (if the vessel does not have a vapor recovery system) or from the shore-based control equipment.

### Unabated Vessel Cleaning and Degassing

If the vessel does not have a vapor recovery system, represent the vessel cleaning and degassing as a single facility linked to a single emission point, as shown in Figure 3-25. Report the emissions at the cleaning FIN / cleaning EPN path.

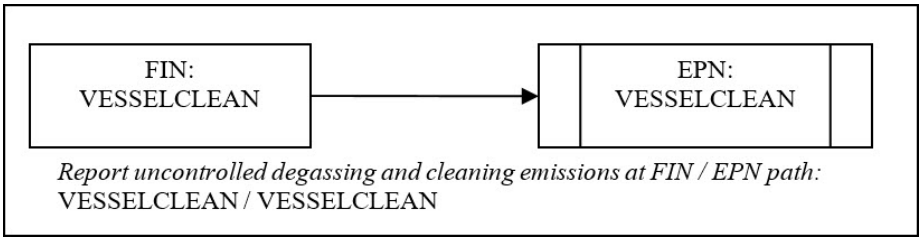


**Figure 3-25. Uncontrolled Degassing and Cleaning Emissions**

### Using a Vapor Recovery System

If the vessel has a vapor recovery system, the captured vapors are routed to shore-based control equipment. For example, if the vapors are routed to an incinerator, represent the vessel cleaning and degassing and the incinerator as two facilities linked to a single emission point, with two abatement devices added to the vessel cleaning and degassing facility. Then link a separate fugitive emission point to the vessel cleaning and degassing facility to report emissions not captured by the vapor recovery system, as shown in Figure 3-26. Report the uncaptured emissions at the vessel cleaning FIN / vessel cleaning EPN path. Report the captured but undestroyed emissions at the cleaning vessel FIN / VRU CIN / incinerator stack EPN path. Finally,

report the combustion emissions from the incinerator at the incinerator FIN / incinerator stack EPN path.

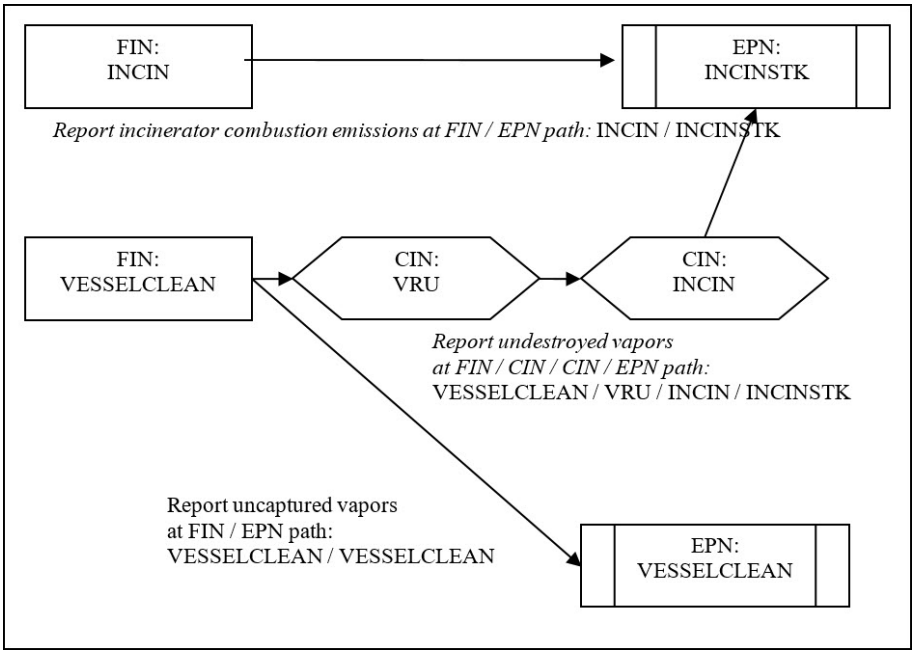


**Figure 3-26. Degassing and Cleaning Emissions Routed to VRU and Incinerator**

## Wastewater Collection and Treatment

Because wastewater collection and treatment involve several different processes, an entire wastewater collection and treatment system must not be represented by a single path. Instead, represent each of the system's processes, including collection, by a unique FIN / EPN path. For assistance with establishing or modifying the wastewater plant's structure, contact the EAS.

## Chemical Production

Do not represent an entire chemical plant by a single facility linked to multiple emission points. If the emission sources are to be grouped by plant, each group must be assigned a unique plant identification number. Each source within a plant must be assigned a unique FIN / EPN path.

Chemical plant structures vary widely. For assistance with establishing or modifying the plant's structure, contact the EAS.

# Modifying Existing Emissions Inventory Structure

Most structural changes can be made in STEERS, such as adding new FINs, EPNs, or CINs or creating a new path from sources that already exist in the EI. Path emissions and information on the facility, emission points, and abatement devices for the newly added equipment must be included, if not already present in the EI. Refer to the web-based EI reporting instructions available at the EAS webpage for more information.

*Note:* The same principles for modifying existing EI structure apply to all inventory types. If existing representation of EI structure is incorrect, please contact the EAS for assistance.

A Path Deactivation Request Form is also available on the EAS webpage. Use the Path Deactivation Request Form to request that the EAS unlink an active, existing FIN from an existing EPN. Please give a reason for each set of deactivation requests. Paths cannot be deactivated using the STEERS-AEIR Web-EI system.

*Example*: A (FIN) TANK previously vented to the atmosphere through (EPN) TANKSTK but now only vents to (EPN) FLARE. Use this form to communicate that path (FIN) TANK / (EPN) TANKSTK needs to be deactivated.

The new path (FIN) TANK / (EPN) FLARE can be added using the STEERS-AEIR Web-EI system. Refer to the Web-based EI reporting instructions for more information.

## Removing Structure

For historical reasons, TCEQ does not normally delete existing structure or emissions records. If a facility has been permanently shut down or removed from the site, simply change its status accordingly and zero all emission rates. If a facility operated at any time during the EI year, choose “active” for the operating status.

*Note:* If existing structure was inadvertently created and the source never existed at the site, please contact the EAS to have the source deleted. The EAS will approve these requests case by case.

## Changing Facility, Emission-Point, or Abatement-Device Nomenclature

TCEQ does not normally allow changes to facility, emission-point, or abatement-device nomenclature due to the historical nature of emissions data, except to correct errors or to align EI nomenclature with permit nomenclature. If revisions are necessary, submit a Revision Request form available at the EAS webpage and state the reason. TCEQ reserves the right to approve or disapprove all such revision requests. Nomenclature cannot be changed in the STEERS-AEIR Web-EI system.

# Chapter 4. Determining and Reporting Emissions

This chapter provides general information about required emissions data, acceptable emissions determination methodologies, speciating emissions (categorizing emissions by chemical species), and correctly reporting annual emissions, ozone season emissions, and emissions due to emissions events and scheduled maintenance, startup, and shutdown activities. For more detailed information about determining emissions from internal and external combustion sources, cooling towers, equipment leak fugitive components, flares, marine operations, and aboveground storage tanks, consult the appropriate technical supplement (Appendix A).

By completing the submission process in the STEERS-AEIR Web-EI system, the owner or operator certifies that all the information reported in the EI is true and accurate, and fully represents the emissions that occurred during the reporting year to the best of his or her knowledge. The STEERS-AEIR Web-EI submission constitutes a legally binding electronic signature by the legally responsible party.

## Required Emissions Data

If a site meets the reporting requirements of 30 TAC Section 101.10, actual emissions for each regulated pollutant must be reported in the EI. For the purposes of this document, the term regulated pollutant includes the following:

- Any VOC, as defined in 30 TAC Section 101.1.
- Any pollutant subject to federal Clean Air Act Section 111 or listed as a HAP under Section 112.
- Each pollutant that has a national primary ambient air quality standard.
- Any other air pollutant subject to requirements under TCEQ rules, regulations, permits, orders of the commission, or court orders.

*Note:* Greenhouse gases as listed in 30 TAC Section 101.1 are not required to be included in the EI.

## Acceptable Determination Methodologies

Many different methods exist to determine emissions. To ensure accuracy and consistency, TCEQ accepts only a limited number of determination methodologies, issues specific guidance on their use, and further requires that all emissions be determined using the best methodology available for EI purposes. Determination methodologies other than those listed below must not be employed without TCEQ's prior approval.

Depending on the type of emission source, the methodology preference will often vary. The acceptable methodologies are discussed in a general order from preferred to least preferred and are labeled with a relevant heading (for example, stack testing is discussed under "Measured Data"). Regulated entities must not use a less preferred

determination methodology to determine inventory emissions if valid data from a preferred determination methodology exist. If emissions data from multiple determination methodologies exist for a given emission source, and a regulated entity believes that data from a less preferred determination methodology more accurately represents the source's emissions than data from a more preferred methodology, the regulated entity must present its argument in writing to TCEQ and request that the agency review and approve the exception to the order of preference outlined in this document. TCEQ reserves the right to disapprove such requests and to determine which methodology more accurately and consistently represents a source's emissions for EI purposes.

*Note:* Emissions must be determined and reported from sources, even if the sources are not included in an EPA document such as AP-42. The best method available must be used to determine emissions in these cases.

For any of the methodologies, data from a current year must not be used to report or revise emissions for any previous year's EI. For example, if $NO_x$ emissions from an engine were stack tested in calendar year 2024, those test results can be used starting with the 2024 EI. The stack-test results should not be used to report $NO_x$ emissions in the 2023 EI or to revise any EI submitted for a year before 2024.

If valid site-specific data is available, it should be used to determine emissions instead of default values provided by AP-42, software program, process simulators, or other emissions determination method. If default values are used, provide documentation that the default data is representative of the site.

Preceding each heading in the section below is a single letter, such as "A" or "V," which is the code to be entered on the EI when using that emissions determination methodology. One of these codes must be selected for each reported contaminant. Each contaminant listed on the EI can only have one corresponding code selected and this code must represent how the emissions of that contaminant were determined.

## Source-Specific Determination Methodologies

For information about the preferred emissions determination methodology or methodologies for a specific source type, consult the appropriate technical supplement (Appendix A), or contact the EAS helpline.

If a preferred method does not apply to a given source, or its use would misrepresent the source's emissions, contact the EAS for approval of an alternate methodology.

When an emissions determination method uses certain laboratory analyses, assessment, or measurement to determine emissions, the analytical environmental data must be generated by a laboratory accredited under the National Environmental Laboratory Accreditation Program (NELAP) standard for the matrices, methods, or

parameters of analysis. See a list of currently accredited laboratories and current fields of accreditation (i.e., methods, analyses, matrices, parameters of analysis, etc.).[a]

The example below is provided for reference purposes only, as an illustration of the requirements detailed above. Your site's situation may differ.

*Example*: A site uses the material balance method to determine a source's VOC emissions. To assist in quantifying the VOC emissions, the site uses an EPA reference method, specifically EPA Compendium Method TO-15, Determination of VOC in Air Collected in Specially-Prepared Canisters and Analyzed by Gas Chromatography/Mass Spectrometry. To be able to use these test results for emissions determinations, the site must ensure that the laboratory performing this analysis is accredited by TCEQ's Laboratory Accreditation Program under the NELAP standard for EPA Compendium Method TO-15.

Certain exceptions or exemptions apply, including methods for which TCEQ does not offer accreditation. For specific requirements and details, see 30 TAC Chapter 25, Subchapter A.[b] For more general information on the TCEQ NELAP program, please visit a list of currently accredited laboratories and current fields of accreditation.

### *D: Continuous Emissions Monitoring Systems*

CEMS generate real-time emissions data 24 hours per day. Note that portable analyzers are not CEMS. If CEMS are properly calibrated and operated, they offer the best means of determining a source's emissions in most situations.

Please note that a continuous monitoring system (CMS) that measures the gas composition of a process stream and does not quantify emissions released to the atmosphere is not a CEMS. Therefore, the emissions determined from CMS would not be coded with a determination methodology of "D" for "CEMS." Instead, a determination methodology of "B" for "material balance" is correct.

Supply a representative set of summary sheets from RATAs performed during the EI calendar year. If a RATA is not required by applicable permit conditions or regulations, submit documentation from a similar system audit (e.g., cylinder gas audit). If $NO_X$ emissions are determined using CEMS, note the molecular weight used in the data logger. Since the calculation is based on $NO_2$ by convention, a molecular weight of 46.01 must be used to determine $NO_X$ emissions. If a CEMS is inoperative for any part of the EI calendar year, other data may be used to determine emissions during CEMS downtime, provided that the data substitution method is allowed by state or federal regulation and is well-documented in the EI and its supporting documentation. However, if valid CEMS data are available, they must be used to determine emissions.

[a] www.tceq.texas.gov/agency/qa/env_lab_accreditation.html
[b] www.tceq.texas.gov/goto/view-30tac

### *H: Highly Reactive Volatile Organic Compound Monitoring Systems*

HRVOC monitoring required by 30 TAC Sections 115.725–115.726 involves a CMS that measures the gas composition of a waste stream and does not directly quantify emissions released to the atmosphere. Emissions determined from the data generated by these systems are coded "H."

Emissions determined from HRVOC monitoring systems not required by Sections 115.725–115.726 must be coded "B" for "material balance" and not "H." Similarly, emissions determined from a CMS for compounds other than HRVOCs are coded "B." For example:

- Ethylene emissions determined from a TCEQ-required HRVOC monitor must be coded "H." Ethylene is a HRVOC monitored by a TCEQ-required monitor.
- Ethylene emissions determined from a monitoring system not required by Sections 115.725-115.726 must be coded "B." The monitoring of ethylene was not required under 30 TAC Chapter 115.
- Propane emissions must be coded as "B" regardless of the monitoring reason, because propane is not a HRVOC.

If a CMS is inoperative for any part of the EI calendar year, other data may be used to determine emissions during CMS downtime, provided that the data-substitution method is allowed by state regulation and is well documented in the EI and the supporting documentation.

For cooling towers, emissions data from a HRVOC monitoring system required by Section 115.764 must be coded "H." For more details, see Technical Supplement 2.

### *F: Predictive Emissions Monitoring Systems*

PEMS predict real-time emissions data continuously. Since correct calibration and operation are critical to system performance, PEMS may be used to determine emissions only if they have been certified according to EPA or TCEQ standards.

Supply a representative set of summary sheets from RATAs performed during the EI calendar year. If a RATA is not required by applicable permit conditions or regulations, submit documentation from a similar system audit (e.g., cylinder gas audit). If $NO_X$ emissions are determined using PEMS, provide the molecular weight used in the data logger. As with CEMS, a molecular weight of 46.01 must be used to determine $NO_X$ emissions.

If a PEMS is inoperative for any part of the EI calendar year, other data may be used to determine emissions during PEMS downtime, provided that the data substitution method is well documented in the EI and the supporting documentation.

### *M: Measured Data (Stack Sampling Data)*

Stack testing is a formal, structured event coordinated with the appropriate TCEQ regional office. Testing conducted using a Draeger tube, fuel gas analysis, or fuel flow

measurement does not qualify as stack testing because the data obtained from these types of tests produce emission rates that are considered engineering estimates.

While properly performed stack testing can provide valuable information about a source's operation, improperly performed testing may grossly misrepresent a source's emissions. For this reason, TCEQ requires that all stack-test data used to determine emissions be collected using methods approved by the EPA or TCEQ.

If a unit is modified, or its operating conditions or associated process parameters change significantly such that previous stack-test results no longer accurately reflect the unit's emissions, TCEQ requires that a more appropriate method be used to calculate emissions determinations.

Stack-test results must be based on process rate data. If the results are reported as a lb/hour rate, use the factor and the process rate at the time of testing to obtain a process-based emissions rate. For example, for combustion sources, divide the lb/hour emission rate by the MMBtu/hour fuel usage rate to obtain a factor with units of lb/MMBtu. Similarly, for cement kilns, divide the lb/hour emission rate by the tons of clinker/hour to obtain a factor with units of lb/ton of clinker.

If identical sources with similar emissions are located at the same site but stack-test data are available for only one of them, TCEQ may approve the use of the tested source's emission factors to determine emissions from the other identical facilities. In these cases, only the tested source's emissions are coded "M" for "measured." The other related sources' emissions are coded "E" for "estimated," because these facilities were not actually tested.

*Note:* Stack-test data from an identical source at the same site are typically the preferred data for determining emissions over vendor data, material balance, or industry factors when CEMS data, PEMS data, or source-specific stack-test data are not available.

TCEQ will also consider, case by case, the validity of using stack-test emission factors generated for one source at a site to determine emissions from identical facilities at another site. In these cases, only the tested source's emissions are coded "M." The other related facilities' emissions are coded "E," because these facilities were not actually tested.

TCEQ requires the most recent representative stack-test data for the applicable reporting year to be used to determine emissions. To be considered representative, stack-test data must reflect current operations and processes including control equipment. The use of historical stack-test data is acceptable, provided that the equipment is operating within the same parameters and under the same conditions that were in place at the time of the test. If a unit is tested every year for a criteria pollutant, use the most recent applicable reporting year's stack-test results to determine emissions. If the unit is tested multiple times within a calendar year, average the most recent calendar year's test results to determine emissions. Stack-test data from multiple calendar years must not be averaged to determine emissions unless the source operated under the same conditions (fuel type, control equipment, other process parameters, etc.). TCEQ will consider, case by case, the validity of averaging

stack-test data from multiple calendar years. Supporting documentation must be provided to verify that averaging stack tests from multiple calendar years is appropriate and representative of current reported emissions.

If $NO_X$ emissions are determined from stack sampling data, use a molecular weight for $NO_X$ of 46.01 when converting from parts per million to report the mass emission rate of $NO_X$.

## *Q: Portable-Analyzer Measurement Data*

TCEQ prefers properly performed, representative, periodic emissions measurements using a portable analyzer instead of vendor or AP-42 factors (see below).

While accurate portable-analyzer measurements can provide valuable information about a source's operation, improper measurements may grossly misrepresent a source's emissions. For that reason, TCEQ requires that all test data used to determine emissions be collected using methods approved by the EPA or TCEQ.

Portable-analyzer measurements must be taken during conditions that reflect the actual routine operation of the unit. If a unit is modified, or its operating conditions or associated process parameters change significantly, previous measurements will no longer accurately reflect the unit's emissions and TCEQ requires that a more appropriate method be used to recalculate emissions.

Measurement results must be based on process rate data. If the results are reported in lb/hr, use the factor and the process rate at the time of testing to obtain a process-based emissions rate. For example, for combustion sources, divide the emission rate in lb/hr by the fuel usage rate in MMBtu/hr to obtain a factor with units of lb/MMBtu.

If a source is tested more than once a year, account for this in the emissions determination. For example, if a source is tested quarterly, apply the emissions factors appropriately to determine emissions for each quarter. Averaging test results may or may not be appropriate, depending on source operation. If there are multiple test results for a calendar year, do not select one test result to determine emissions for the entire year.

When using portable-analyzer measurements to determine $NO_X$ emissions, use a molecular weight for $NO_X$ of 46.01 when converting from parts per million to report the mass emission rate of $NO_X$.

## *V: Vendor-Supplied Emissions Factors*

Many manufacturers of industrial equipment supply emissions information for their products. These data, based on testing, are developed for a particular piece of equipment and, if applicable, for a particular unit size. Vendor data may be used to determine emissions only if they are based on approved stack testing and if no significant modifications have been made to the equipment. A modification to a unit or its operation, including a significant change in fuel characteristics, may significantly affect the unit's emissions and therefore invalidate the manufacturer's emissions data.

Include a copy of the manufacturer's data with the supporting documentation.

### *A: AP-42 and Other EPA- or TCEQ-Approved Factors*

The EPA's Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources (AP-42)—with supplements (updated continually)—includes discussions of various industrial processes, descriptions of these processes' emissions, and emission factors useful for determining these emissions.[a] Equipment emission factors have generally been determined by testing a representative population varying in size and age.

The EPA is working to improve the quality and quantity of the AP-42 factors. When factors are revised, the new factors wholly replace the older factors for EI reporting. When using a published factor from the EPA or TCEQ, use the most recent factor as of the end of the calendar year for which the EI is being prepared. A factor published after the end of the EI calendar year may not be used to determine emissions from a source for that calendar year or previous calendar years.

Emissions determined using tools other than AP-42 factors may still be coded with a determination methodology of "A" if the determinations were based on EPA- or TCEQ-approved programs or factors. Examples include emissions determined using TCEQ flare guidance factors, WATER9 software program, and component fugitive emissions determined using factors published in the EPA's *Protocol for Equipment Leak Emissions Estimates* (EPA 453/R-95-017).

### *B: Material Balance*

Material balance can only be performed for specific types of sources whose processes are well understood and relatively simple (for example, surface coating or parts cleaning). Emissions determinations must be based on process rates and material quantity and composition. Guidance on determining emissions from several process types may be found in AP-42 or in various TCEQ guides to air permitting; see Appendix C for a list of helpful TCEQ and EPA resources.

Certain methodologies for determining emissions may be labeled "material balance" even if those methodologies incorporate analytical measurements. A TCEQ-approved program for monitoring cooling towers, an extended inlet-gas analysis from a glycol still for use in GRI-GLYCalc, or a CMS used to determine flow rate and composition of gas routed to a flare measure the physical properties of the process stream and do not measure the emissions released to the atmosphere. Therefore, emissions determination methodologies that use such measurements are labeled "B," since the results of the measurements are used in emissions equations.

### *S: Scientific Calculation*

For the EI, the use of first-order engineering principles (for example, thermodynamic equations or the ideal gas law) constitutes a scientific calculation. Process simulators, such as Promax, use engineering principles in the emission calculations and therefore the determination method should be coded as "S." Use of process rate data in conjunction with AP-42 or vendor-supplied emission factors, like simple use of a

[a] www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emission-factors

calculator to multiply or add values, does not constitute a “scientifically calculated” emissions determination.

### *E: Estimation*

If the EPA or TCEQ has not published guidance on determining emissions for a particular source, and if a more preferable emissions determination method (as discussed in this chapter) is not available, emissions should be determined using an engineering estimate. Any such estimate must be the best possible, given the available data, and must be accompanied by enough supporting documentation to allow TCEQ to logically understand how the estimation was made. If TCEQ determines that an estimation is unfounded, then TCEQ will require that emissions be recalculated.

### *O: Other*

If the EPA or TCEQ has not published emissions determination guidance for a particular source, and if a preferable emissions determination method (as discussed in this chapter) is not available, it may be acceptable to use factors developed by an industry group. When using such factors, code the associated emissions with a determination methodology of “other.”

Note that certain industry-published software programs, such as GRI-GLYCalc, use emissions determination methodologies that are more appropriately coded with methodologies besides “O.” For example, GRI-GLYCalc uses site-specific analytical measurements input into material balance equations to determine glycol still emissions. Therefore, GRI-GLYCalc emissions determinations are coded “B.”

E&P TANK is used to calculate working, breathing, and flash losses from storage tanks. E&P TANK uses the Peng-Robinson equation of state to determine flash emissions and can determine breathing and working loss emissions using AP-42 or similar equations and factors. However, E&P TANK emissions determinations are coded “O,” since flash losses typically account for the majority of tank emissions.

When using industry group guidance, carefully check emissions determination methodologies to ensure there is no code more appropriate than “O.” Additionally, if TCEQ determines that an emissions determination is unfounded, then TCEQ may require recalculation of emissions.

## Choosing a Determination Methodology When More Than One Is Used for a Contaminant

When more than one methodology is used to determine emissions for a contaminant, use the code that represents the majority of the emissions. When determining emissions from a storage tank with flash emissions for example, if the working and breathing losses are calculated using AP-42, Chapter 7 equations (determination methodology “A”) while the flash losses are calculated using the gas/oil ratio (GOR) method (determination methodology “B”), the total emissions reported in the EI are coded “B,” assuming the flash losses are greater than the working and breathing losses.

Also, emissions from permitted MSS activities are reported in the annual column. Therefore, if the majority of emissions reported for a source are from permitted MSS activities, use the method code that corresponds to the emissions determination method for those activities.

When a control efficiency is applied to an emissions factor, the methodology that corresponds to the emissions factor must be used. For example, if the VOC emissions for a compressor engine are determined using the AP-42 Section 3.2 factor (determination methodology "A") with a vendor control efficiency (determination methodology "V") applied, the total VOC emissions reported in the EI are coded "A."

When a ratio of AP-42 factors—or others, such as industry factors—is used to speciate total VOC emissions that are determined using stack-test data or vendor data, report the determination methodology as "S" for the speciated emissions; report the VOC-unclassified (VOC-u) emissions using the appropriate code for the determination method (e.g., "M" or "V").

### *Determining Methodologies for a Hypothetical Source*

A turbine has CEMS installed to measure $NO_X$ and CO. Additionally, stack testing, conducted in coordination with the appropriate TCEQ regional office, has measured $SO_2$ emission rates for this same turbine. CEMS data must be used to determine $NO_X$ and CO emissions, which are then coded on the EI with a determination methodology of "D." Since the turbine has no CEMS or PEMS in place to measure $SO_2$, the data from the stack test mentioned previously must be used to determine $SO_2$ emissions; those resulting emissions are coded "M." For all other expected contaminants—including, but not limited to, total PM, $PM_{10}$, $PM_{2.5}$, and VOC—the best available determination methodologies must be used, and these emissions coded appropriately. For more information on preferred determination methodologies for turbines, please consult "Technical Supplement 1: Select Combustion Sources" in Appendix A.

### *Minimum Detection Limits*

Certain source-specific methods listed in the preceding sections, such as measured data or material balance, use analytical measurements to determine emissions. Analytical test methods can indicate that measurements of a contaminant likely to be present in an emissions stream are below either the analytical method's minimum detection limit or its reporting limit. However, such a finding is not equivalent to a finding that the contaminant is absent from the emissions stream. Therefore, if measurements of a contaminant likely to be in an emissions stream are below the minimum detection limit or reporting limit (that is, non-detected), then half of the detection or reporting limit must be used to determine the emissions, unless otherwise specified by permit condition, TCEQ or federal rule, or commission order. When using half the detection limit or the reporting limit to determine emissions, use the appropriate method code. For example, if the unit was stack tested then use method code "M" to report the emissions resulting from half the detection limit.

## General Order of Preference

If a source-specific order of preference for determination methodologies is not provided for a given source (see technical supplements in Appendix A), then this general order of preference for emissions determination methodologies must be followed:

1. D (Continuous emissions monitoring system, or CEMS)
2. H (HRVOC monitoring system)
3. F (Predictive emissions monitoring system, or PEMS)
4. M (Measured: stack-test data)
5. Q (Portable-analyzer test data)
6. V (Vendor-supplied emissions factors)
7. A (AP-42 and other EPA-approved factors)
8. B (Material balance)
9. S (Scientifically calculated)
10. E (Estimated)
11. O (Other)

## Using Factors From a Permit

Do not list a permit as a factor's source. If the same factor is used to determine emissions for the EI as was used in a permit application, then disclose the origin of the factor (for example, vendor data or AP-42). The emission factor used to obtain a permit must not be used in estimating the emissions in the inventory if any of the following applies:

- If the permit factor came from a document such as AP-42 and the factor has been revised—instead, the most recent version of that factor must be used.
- If testing was conducted or continuous monitoring implemented at a site after TCEQ issued a permit for that site—instead, the resulting data must be used.
- If a source's permit no longer reflects the conditions of its actual operations.

Rates reported on the EI must represent actual emissions, rather than maximum potential emissions.

# Speciating Emissions

Once the emissions from each source at the site have been determined, the owner or operator must specifically identify and quantify individual chemical substances, or species, within each emission category. This process is known as *speciation*. This section offers only a brief overview of speciation requirements. For more information about emissions speciation for a particular source, consult the appropriate technical supplement (Appendix A), or contact the EAS.

## Speciating Volatile Organic Compounds

VOC speciation requirements depend on a site's geographic location. If the site is in El Paso County or east of the 100° longitude line (refer to map on EAS webpage), the VOCs must be speciated from each non-combustion source emitting at least 5 tons of VOCs annually. If the site is located west of the 100° longitude line (except for El Paso County), the VOCs must be speciated from each non-combustion source emitting at least 25 tons of VOCs annually. For each source that meets these requirements,

speciate VOC emissions to at least 90% of the total VOC emissions reported for each source. If any speciated contaminant was emitted at a level below 0.1 ton, the emissions may be reported for that contaminant under "VOC-unclassified" (contaminant code 50001). For combustion sources, it is often not possible to speciate VOC to 90%; however, all HAPs greater than or equal to 0.1 tpy must be reported. Special speciation requirements apply to lead compounds and HAPs listed in any TCEQ-enforceable document such as a permit, regulation, or commission order.

Each emitted substance (for example, CO or benzene) must be identified by a unique five-digit number known as the contaminant code. It is very important that each emission rate be reported under the most accurate contaminant code available. For example, benzene must be reported under the benzene-specific code (52420) rather than under the general VOC code (50001).

A complete list of contaminant codes can be found on the EAS webpage. TCEQ attempts to ensure that the list is complete and accurate. If there is no code listed for the contaminant in question, contact the EAS for assistance. If possible, be prepared to provide the compound's Chemical Abstracts Service (CAS) number to aid in identification.

To obtain a "VOC-unclassified" (contaminant code 50001) total, subtract all speciated VOCs from the total VOC number.

*Example:* A fugitive area located east of 100° longitude emitted 10 tons of VOCs. Based on the VOC weight percentages obtained using a site gas analysis, the released contaminants are determined to be:

- propane (60%)
- butane (8%)
- isobutane (7%)
- pentane (7%)
- isopentane (6%)
- hexane (4%)
- heptane (3%)
- individual VOCs occurring in such small amounts that they cannot reasonably be separated (5%)

**Table 4-1. Example of Speciated VOC Emissions**

| Contaminant Code | Contaminant | Actual Emissions (tpy) |
|---|---|---|
| 50001 | VOC-unclassified | 0.5 |
| 56775 | propane | 6.0 |
| 56725 | butane | 0.8 |

| Contaminant Code | Contaminant | Actual Emissions (tpy) |
|---|---|---|
| 56625 | isobutane | 0.7 |
| 56750 | pentane | 0.7 |
| 56700 | isopentane | 0.6 |
| 56600 | hexane | 0.4 |
| 56575 | heptane | 0.3 |

Notice that the total VOC emissions of 10 tons are not explicitly shown in the EI. The STARS database will automatically sum the reported VOCs for each source to obtain the total VOC number. Do not report the total 10 tons of VOC emissions under contaminant code 50001 and then report the speciated emissions shown in Table 4-1, because STARS will then arrive at a total VOC emission rate of 19.5 tons for this source, resulting in an over reporting of 9.5 tons of emissions.

## Speciating Hazardous Air Pollutants and Other Compounds of Interest

### *Hazardous Air Pollutants*

HAPs are air pollutants designated as hazardous by the EPA and are identified in the federal Clean Air Act, Subsection 112(b). Speciate all HAPs that are emitted from any source at or above 0.1 tpy. Additionally, for HAP emissions authorized by any TCEQ-enforceable document such as a permit, regulation, or commission order, speciate these emissions at or above 0.001 tpy. If aggregate HAPs are listed in any TCEQ-enforceable document such as a permit, regulation, or commission order, each individual HAP must be speciated.

### *Chemical Mixtures*

For certain chemical mixtures such as condensate or gasoline, quantify and speciate the HAPs, list each HAP under the appropriate contaminant code, and report the balance of the emissions under the chemical mixture's contaminant code, such as 59090 (for condensate) or 59003 (for gasoline). For speciation guidance on other complex contaminants, contact the EAS.

### *Toxic Compounds*

Toxic compounds are chemicals that are designated as toxic by the EPA. Toxic chemicals are identified in 40 CFR 372.65. Speciate all toxic compounds, particularly if they were emitted from any source at or above 0.1 ton per year.

Toxic compounds reported in the Toxics Release Inventory (TRI) must be reported in the EI. If there are discrepancies in reporting between the TRI and EI, please include an explanation in the supporting documentation.

### *Lead and Mercury*

Note the source reporting requirements when determining and reporting lead and mercury emissions. TCEQ requires that all regulated entities report lead and mercury emissions from any source that emits more than 0.001 ton of either lead or mercury per year.

### *Highly Reactive Volatile Organic Compounds and Compounds of Interest for Nonattainment Counties*

In an ozone nonattainment county, speciate each of the following chemicals, particularly if they were emitted from any source at or above 0.1 ton:

- ethylene
- propylene
- isoprene
- 1,3-butadiene
- all isomers of butene (all isomers of butylene)
- all isomers of pentene
- all isomers of trimethylbenzene
- all isomers of xylene
- all isomers of ethyltoluene

## Speciating Particulate Matter

### *PM, $PM_{10}$, and $PM_{2.5}$*

PM is a collective term used for any material, except uncombined water, that exists as a solid or liquid in the atmosphere or in a gas stream at standard conditions. While individual particles may not necessarily be seen with the naked eye, collectively they can appear as black soot, dust clouds, or gray hazes.

Since a particle's transport characteristics and its potential health effects may depend on its size, the EPA has promulgated national primary and secondary air quality standards concerning two subsets of fine (small) particulate matter: $PM_{10}$ and $PM_{2.5}$.

$PM_{10}$ is defined as the portion of PM that has an aerodynamic diameter less than or equal to 10 micrometers. Therefore, $PM_{10}$ is a subset of PM by definition. Most PM is composed of a certain percentage of $PM_{10}$; that is, a certain percentage of PM comprises particles less than or equal to 10 micrometers in diameter, while the remaining percentage comprises larger particles. Therefore, when reporting PM, also report $PM_{10}$, unless the owner or operator can document that all PM is greater than 10 micrometers in diameter.

$PM_{2.5}$ is defined as the portion of PM that has an aerodynamic diameter less than or equal to 2.5 micrometers. Therefore, $PM_{2.5}$ is a subset of PM and $PM_{10}$ by definition. For many sources, $PM_{2.5}$ constitutes a certain percentage of PM. For example, sources that combust natural gas emit particulate matter less than 1 micrometer in diameter. Thus, all particulate matter emitted from natural gas combustion is not only $PM_{2.5}$ (since it is smaller than 2.5 micrometers in diameter), but also PM and $PM_{10}$, since $PM_{2.5}$ is a subset of PM and $PM_{10}$ by definition.

### *Particle Size Distribution*

The percentages of $PM_{10}$ and $PM_{2.5}$ that constitute a source's PM are often referred to as a particle size distribution. Source-specific, EPA-approved testing is the best method available to determine particle size distribution for a particular emission source. If test data are not available, process knowledge—including manufacturers' data—may help determine a source's particle size distribution. AP-42 also contains particle size distributions for certain sources.

### *Reporting and Speciating Particulate Matter*

All particulate matter as defined by 30 TAC Section 101.1 must be reported regardless of size as PM under the "1xxxx" series of contaminant codes. Since PM is defined as all particulate matter that exists in the atmosphere (that is, there are no size restrictions on PM), even the portion of PM that is $PM_{10}$ and $PM_{2.5}$ must be reported under the "1xxxx" contaminant code series. Similarly, all particles with an aerodynamic diameter less than or equal to 10 micrometers must be reported as $PM_{10}$ under the "2xxxx" contaminant code series, even if a portion of these particles can be considered $PM_{2.5}$. Note that, since $PM_{10}$ and $PM_{2.5}$ are subsets of PM, representing particulate matter as PM, $PM_{10}$, and $PM_{2.5}$ does not result in repeated counting of the emissions.

When determining PM emissions, both filterable and condensable emissions must be determined and reported in the EI. If a particular source has been stack tested for total particulates, reported particulate matter must adhere to the applicable definitions in 30 TAC Section 101.1. If only filterable particulate emissions have been measured from a source, please contact the EAS for assistance.

To speciate particulate matter, follow these guidelines:

- Report all speciated particulate emissions under the appropriate "1xxxx" contaminant code.
- List the remaining unspeciated particulate emissions under the contaminant code 10000.
- Report the portion of the particulate emissions with an aerodynamic diameter of 10 micrometers or less ($PM_{10}$) under a "2xxxx" contaminant code.
- List the remaining unspeciated $PM_{10}$ emissions under contaminant code 20000.
- Report the portion of the particulate emissions with an aerodynamic diameter of 2.5 micrometers or less ($PM_{2.5}$) under contaminant code 39999.

***Example:*** A source emitted 10 tons of particulate matter. The matter is determined to have been mostly phosphorus (75%) and zinc (16%), with the remaining 9% of unknown composition. The phosphorus and zinc particles are larger than 2.5 micrometers, but smaller than 10 micrometers, in aerodynamic diameter. The other 9% of particles are believed to be larger than 10 micrometers in aerodynamic diameter. The emissions in this example would be reported as shown in Table 4-2.

**Table 4-2. Example of Speciated Particulate Matter Emissions**

| Contaminant Code | Contaminant | Actual Emissions (tpy) |
|---|---|---|
| 10000 | Part-unclassified | 0.9 |
| 14460 | phosphorus | 7.5 |
| 14780 | zinc | 1.6 |
| 20000 | $PM_{10}$-unclassified | 0 |
| 24460 | $PM_{10}$ phosphorus | 7.5 |
| 24780 | $PM_{10}$ zinc | 1.6 |
| 39999 | total $PM_{2.5}$ | 0 |

Notice that the total particulate number (10 tons) and the total $PM_{10}$ number (9.1 tons) are not explicitly listed in this report. Once again, the STARS database will sum all appropriate individual contaminants to obtain these numbers. Verify that the sum of the emission rates reported in the entire "10000" series of contaminants represents the intended total particulate emission rate, and that the sum of the emission rates reported in the entire "20000" series of contaminants represents the intended total $PM_{10}$ emission rate.

## Speciation Criteria Summary

Speciation criteria may vary depending on the contaminant and the site's geographic location. For a summary of speciation requirements, see Table 4-3.

**Table 4-3. Summary of Speciation Criteria**

| Contaminant | Applicable Counties | If the emissions at the source satisfy the tpy limit listed below, speciate the actual emissions. |
|---|---|---|
| Lead (Pb) | All counties | ≥ 0.001 |
| Mercury (Hg) | All counties | ≥ 0.001 |
| HAPs[a] listed in any TCEQ-enforceable document[b] | All counties | Speciate HAPs ≥ 0.001 when the contaminant is listed in any TCEQ enforceable document such as a permit, regulation, or commission order. If aggregate HAPs are listed in any TCEQ enforceable document such as a permit, regulation, or commission order, then each individual HAP must be speciated. |
| All other HAPs[c] | All counties | ≥ 0.1 |
| Toxics[d] | All counties | ≥ 0.1 |
| HRVOCs[e] | Nonattainment counties | ≥ 0.1 |
| Compounds of Interest (COIs)[f] | Nonattainment counties | ≥ 0.1 |
| Total VOCs[g] | East of 100° longitude, El Paso | ≥ 5, 90% speciation required for non-combustion sources and undestroyed VOC from flares and other combustive abatement devices |
| Total VOCs[h] | West of 100° longitude, except El Paso | ≥ 25, 90% speciation required for non-combustion sources and undestroyed VOCs from flares and other combustive abatement devices |
| PM, $PM_{10}$, $PM_{2.5}$ | All counties | Speciate particulate classes. |
| Chemical Mixtures | All counties | When speciating chemical mixtures, speciate HAPs and other species first, then report the remainder under the chemical-mixture code. Use the most specific contaminant code possible for chemical mixtures such as condensate (59090), crude oil (59001), and gasoline (59003). |

a. HAPs—*Hazardous air pollutants* as identified at federal Clean Air Act 115(b).
b. A registered PBR that includes a certification of federally enforceable emission limits (e.g., using Form PI-7 CERT, designated form TCEQ-20182) is a TCEQ-enforceable document.
c. HAPs—*Hazardous air pollutants* as identified at federal Clean Air Act 115(b).
d. Toxics—*Toxic air pollutants* as identified at 40 CFR 372.65.
e. HRVOCs—*Highly reactive volatile organic compounds* are, for inventory purposes: 1,3-butadiene, ethylene, propylene, and all isomers of butene.
f. COIs—*Compounds of interest* are, for inventory purposes: isoprene, all isomers of pentene, all isomers of trimethylbenzene and all isomers of ethyltoluene.
g. VOCs—*Volatile organic compounds* as defined in 30 TAC Section 101.1.
h. VOCs—*Volatile organic compounds* as defined in 30 TAC Section 101.1.

## Reporting Emissions

Before entering emission rates in the EI, the annual emissions and the emissions resulting from emissions events or scheduled maintenance, startup, and shutdown activities must be determined. Depending on the site's location, the daily emission rates for the ozone season may need to be determined and reported in the EI. For definitions of terms used in this section, consult the Glossary.

## Annual Emissions

Annual emissions include a site's actual routine emissions, including emissions from authorized maintenance, startup, and shutdown activities. It also includes unauthorized emissions (1) from unauthorized facilities, or (2) that are excess emissions from authorized facilities, **other than** excess emissions that are defined in 30 TAC Section 101.1 as emissions events or scheduled maintenance, startup, and shutdown activities (see information regarding reporting of EE and SMSS activities in the following paragraphs).

Determine and speciate annual emissions according to the guidance in this chapter and the technical supplements. The reporting year is the calendar year for the EI.

## Ozone Season Emissions

If the regulated entity is located in El Paso County or east of the 100° longitude line (see subheading "Ozone Season Daily Rates Are Required from Sites in These Counties" for those counties), the average daily release rates during the ozone season—May 1 through Sept. 30—must be determined. The ozone season emissions must be reported in pounds per day (ppd) under the "Ozone" heading on the Path Emissions portion of the EI. The EAS database can no longer automatically calculate ozone rates.

For each FIN/EPN path, use actual process or emissions data (or both) gathered during the ozone season to determine total ozone season emission rates. For example, for a combustion source, determine total ozone season emissions contaminant by contaminant from the amount of fuel burned from May 1 through Sept. 30. For sources equipped with CEMS, determine total ozone season emissions from CEMS data gathered from May 1 through Sept. 30.

For each FIN/EPN path, quantify every contaminant's total ozone season emissions (in pounds). **Do not include emissions events or *unauthorized* scheduled maintenance, startup, and shutdown emissions in ozone season emissions calculations.**

*Note:* **Authorized** maintenance, startup, and shutdown emissions are considered annual (routine) emissions and are included when calculating ozone season emissions.

Use the following equation to determine the FIN/EPN path's average ozone season emission rates in ppd:

$$E_{Average\ ozone\ rate} = \frac{(E_{Ozone\ Season}) \times (lbs)}{153\ days}$$

Where:

$E_{Average\ ozone\ rate}$ = ozone rate (ppd) for one contaminant

$E_{Ozone\ Season}$= tons per year of **routine** emissions of each contaminant emitted only during the ozone season (May 1 through Sept.30)

Depending on the type of source, there may be many ways to determine $E_{average\ ozone\ rate}$ in the equation above. Use the method that gives the most accurate estimate of the actual emissions during the ozone season. Make sure to account for parameters that may cause emissions to vary in the ozone season such as fuel usage, chemical vapor pressures, storage temperature, operating schedule, and material usage.

For example, an emergency generator or fire pump is tested quarterly but otherwise remains idle. During the one-day July test, the unit emits 1,000 pounds of $NO_X$. However, those emissions must **not** be reported as 1000 ppd. Rather, they must be averaged over 153 days, resulting in ozone season emissions of 6.535 ppd.

## Ozone Season Daily Rates Are Required From Sites in These Counties

*Notes:* (1) The EAS database cannot calculate ozone rates. (2) When a county is split by the 100˚ longitude line, the entire county is treated as east of the 100˚ longitude line and required to report ozone season emissions.

**Counties Required to Report Ozone Season Emissions**

| | | | | |
|---|---|---|---|---|
| Anderson | Concho | Haskell | Madison | San Saba |
| Angelina | Cooke | Hays | Marion | Shackelford |
| Aransas | Coryell | Henderson | Mason | Shelby |
| Archer | Dallas | Hidalgo | Matagorda | Smith |
| Atascosa | DeWitt | Hill | McCulloch | Somervell |
| Austin | Delta | Hood | McLennan | Starr |
| Bandera | Denton | Hopkins | McMullen | Stephens |
| Bastrop | Dimmit | Houston | Medina | Tarrant |
| Baylor | Duval | Hunt | Menard | Taylor |
| Bee | Eastland | Jack | Milam | Throckmorton |
| Bell | Edwards | Jackson | Mills | Titus |
| Bexar | El Paso | Jasper | Montague | Travis |
| Blanco | Ellis | Jefferson | Montgomery | Trinity |
| Bosque | Erath | Jim Hogg | Morris | Tyler |
| Bowie | Falls | Jim Wells | Nacogdoches | Upshur |
| Brazoria | Fannin | Johnson | Navarro | Uvalde |
| Brazos | Fayette | Jones | Newton | Van Zandt |
| Brooks | Foard | Karnes | Nueces | Victoria |
| Brown | Fort Bend | Kaufman | Orange | Walker |
| Burleson | Franklin | Kendall | Palo Pinto | Waller |
| Burnet | Freestone | Kenedy | Panola | Washington |
| Caldwell | Frio | Kerr | Parker | Webb |
| Calhoun | Galveston | Kimble | Polk | Wharton |
| Callahan | Gillespie | Kleberg | Rains | Wichita |
| Cameron | Goliad | Knox | Real | Wilbarger |
| Camp | Gonzales | La Salle | Red River | Willacy |
| Cass | Grayson | Lamar | Refugio | Williamson |
| Chambers | Gregg | Lampasas | Robertson | Wilson |
| Cherokee | Grimes | Lavaca | Rockwall | Wise |
| Clay | Guadalupe | Lee | Runnels | Wood |
| Coleman | Hamilton | Leon | Rusk | Young |
| Collin | Hardeman | Liberty | Sabine | Zapata |
| Colorado | Hardin | Limestone | San Augustine | Zavala |
| Comal | Harris | Live Oak | San Jacinto | |
| Comanche | Harrison | Llano | San Patricio | |

## Emissions Events

Report emissions events separately under the “EE” category of the EI. Include the emissions in tpy from all releases due to emissions events, regardless of whether those releases represent reportable or non-reportable quantities and regardless of whether an affirmative defense is claimed for those emissions. The emissions thresholds specified in Chapter 3 of this document do not apply to emissions events. Emissions from any emissions event must be reported. For more information, consult 30 TAC Sections 101.1 and 101.201.

For sources controlled by an abatement device, such as a flare, the emissions may be reported at the flare facility. The emissions may also be reported at an associated

facility (such as a piping-component-fugitive area). Otherwise, these sources can be added to the EI as a collective source. Consult Chapter 3 for more guidance about collective sources.

For guidance on interpreting rules concerning emissions events, contact TCEQ's Section Manager for the region where the regulated entity is located. Additional guidance can also be found at the EAS webpage.

### *Excess Opacity Events*

The total number of excess opacity events must be reported in the EI. However, the excess opacity event itself cannot be reported in terms of opacity percentage in the EI. Rather, the emissions associated with the event must be calculated and reported under a specific path as a mass quantity (in terms of tons), using the best emissions determination method available, such as process knowledge, past engineering analysis, or testing.

### *Certification Statement*

Under Texas Health and Safety Code Subsection 382.0215(f), an owner or operator of a regulated entity that experienced no emissions events during the relevant calendar year must include, as part of the reported inventory, a signed statement certifying that the regulated entity experienced no emissions events during the reporting year.

The certification is also required for regulated entities that experienced one or more excess opacity events but did not experience any emissions events. This certification is included in the STEERS-AEIR Web-EI system.

## Scheduled Maintenance, Startup, and Shutdown

Report the emissions in tons from all releases due to scheduled maintenance, startup, and shutdown activities that are **not** authorized by a new source review permit or PBR in the "SMSS" category, regardless of whether those releases represent reportable or non-reportable quantities and regardless of whether an affirmative defense is claimed for those emissions. Emissions from any SMSS above zero tpy must be reported in the EI. For more information, consult 30 TAC Sections 101.1 and 101.211.

*Note:* Emissions from maintenance, startup, and shutdown activities that are authorized under a permit or PBR must be reported in the "Annual" category and not included in the "SMSS" category.

For guidance on interpreting rules concerning scheduled maintenance, startup, and shutdown activities, contact TCEQ's Section Manager in the region where the regulated entity is located.

Additional guidance can also be found at the EAS webpage.

# Chapter 5. Example of an Initial Emissions Inventory

This chapter presents an example of an initial EI for a hypothetical site producing and processing natural gas. Carefully consult the materials in Chapters 3 and 4 in conjunction with this example.

## Identifying Emission Sources

The following processes occur at an upstream gas field site (hypothetical):

- Natural gas production.
- Separation of natural gas and liquids.
- Natural gas sweetening.
- Natural gas dehydration.
- Natural gas compression and delivery to a pipeline.
- Storage of condensate and natural gas liquids.
- Loading of condensate on trucks.
- Blowdown operations.

The following equipment is involved in the above processes:

- Lift pump and associated electric motor.
- Gunbarrel separator (initial gas-liquids separation).
- Amine unit, associated heater, and diethylamine storage tank.
- Glycol dehydration still, associated heater, and ethylene glycol storage tank.
- Emergency flare to control glycol unit and amine unit emissions events, as well as blowdowns.
- Refrigerated absorption unit and fractionation columns (further gas-liquids separation).
- Compressor engines:
- One 2000 hp turbine with dual exhaust stacks.
- One 1200 hp lean-burn, 4-stroke engine,
- One 1000 hp rich-burn, 4-stroke engine with a 70%–efficient nonselective catalytic reduction (NSCR) system.
- Two 1500-gallon condensate fixed-roof storage tanks.
- One condensate truck loading rack (uncontrolled).
- Blowdown equipment.

Analyzing the two above lists, the following emission sources can be identified.

**Table 5-1. Identifying Emission Sources From Equipment and Processes for a Hypothetical Upstream Gas-Field Site**

| Equipment or Process | Emission Source |
|---|---|
| Lift pump and associated electric motor | Piping fugitive components (including pump) |
| Gunbarrel separator | Gunbarrel separator: flash emissions |
| Gunbarrel separator | Piping fugitive components |
| Natural gas sweetening | Amine unit: $H_2S$ emissions |
| Natural gas sweetening | Amine heater unit: combustion emissions |
| Natural gas sweetening | Diethylamine storage tank |
| Natural gas sweetening | Piping fugitive components |
| Natural gas dehydration | Glycol still: VOC and HAP emissions |
| Natural gas dehydration | Glycol heater unit: combustion emissions |
| Natural gas dehydration | Glycol-still flash tank: VOC and HAP emissions |
| Natural gas dehydration | Ethylene glycol storage tank |
| Natural gas dehydration | Piping fugitive components |
| Refrigerated absorption unit and fractionation columns | Piping fugitive components |
| Compressor engines | Turbine |
| Compressor engines | Lean-burn four-stroke engine |
| Compressor engines | Rich-burn four-stroke engine |
| Compressor engines | Piping fugitive components |
| Flaring of emissions events | Emergency flare: combustion emissions |
| Flaring of emissions events | Source that generated emissions events (amine unit, blowdown, etc.) |
| Flaring of emissions events | Piping fugitive components |
| Condensate storage | First 1500-gal condensate fixed-roof storage tank |
| Condensate storage | Second 1500-gal condensate fixed-roof storage tank |
| Condensate storage | Piping fugitive components |
| Condensate truck loading | Loading rack: loading emissions |
| Condensate truck loading | Piping fugitive components |
| Natural gas liquids storage | Piping fugitive components, especially relief valves |
| Gas delivery to pipeline | Piping fugitive components |
| Blowdown operations | Blowdown equipment |

# Representing Emission Sources in the Emissions Inventory

**Sources (Facilities).** After the emission sources have been identified, they must be added to the inventory in the STEERS-AEIR Web-EI system, using either the interactive Web entry or text-file upload. Review Chapter 3, "Emissions Inventory Structure," in conjunction with this chapter.

For an EI, a *facility* is defined as a unique unit, device, structure, or area capable of generating emissions. The sources listed in Table 5-1 are all emission sources at the site. Each source that will be reported in the EI must be assigned a unique FIN by the owner or operator. The EI naming conventions (for facilities as well as emission points) must follow the naming conventions of any associated permits. A list of FINs (and their corresponding emission sources) for the hypothetical site appears in Table 5-2.

**Table 5-2. Assigning FINs to Emission Sources for a Hypothetical Upstream Gas-Field Site**

| Emissions Source | FIN |
|---|---|
| All natural gas piping fugitive components | FUGAREA1 |
| All condensate piping fugitive components | CONDFUGS |
| Gunbarrel separator | GUNBARSEP |
| Amine unit | AMINEUNIT |
| Amine heater unit | AMHEATER |
| Diethylamine storage tank | DEA-TANK |
| Glycol still | GLYCOLSTIL |
| Glycol heater unit | GLHEATER |
| Ethylene glycol storage tank | EG-TANK |
| Turbine | TURBINE1 |
| Lean-burn four-stroke engine | COMP1 |
| Rich-burn four-stroke engine | COMP2 |
| Emergency flare | UPSETFLARE |
| First 1500-gal condensate fixed-roof storage tank | CONDTANK1 |
| Second 1500-gal condensate fixed-roof storage tank | CONDTANK2 |
| Loading rack: loading emissions | LOADRACK |
| Blowdown operations | BLOWDOWN |

Note that, in Table 5-2, piping fugitive components are grouped together into two facilities: one equipment leak fugitive facility for the natural gas streams, and one equipment leak fugitive facility for the condensate streams. If an emission source handles similar process streams, uses the same emissions determination methodology, and is monitored under the same monitoring program, all components will be grouped under one facility. See Technical Supplement 3 in Appendix A for more details on creating facilities for piping component fugitive areas.

**Emissions points.** Once all of the FINs have been assigned for the emission sources, their associated emission points must be identified. From Tables 5-1 and 5-2, most of the sources' emission points can be identified. However, **all possible** emission points for a facility have to be listed. Based on this information, Table 5-3 lists all possible emission points identified for the sources listed in Table 5-2.

**Table 5-3. Identifying Emissions Points for FINs for a Hypothetical Upstream Gas-Field Site**

| FIN | Emissions Point(s) |
|---|---|
| FUGAREA1 | Fugitive area encompassing piping component fugitives in natural gas service |
| CONDFUGS | Fugitive area encompassing piping component fugitives in condensate service |
| GUNBARSEP | Separator vent |
| AMINEUNIT | Amine unit vent |
| AMINEUNIT | Flare (during emissions events) |
| AMHEATER | Heater stack |
| DEA-TANK | Tank vent |
| GLYCOLSTIL | Glycol still vent |
| GLYCOLSTIL | Flare (during emissions events) |
| GLHEATER | Heater stack |
| EG-TANK | Tank vent |
| TURBINE1 | Stack one (dual exhaust stack) |
| TURBINE1 | Stack two (dual exhaust stack) |
| COMP1 | Compressor stack |
| COMP2 | Compressor stack |
| UPSETFLARE | Flare |
| CONDTANK1 | Tank vent |
| CONDTANK2 | Tank vent |
| LOADRACK | Area where fugitive loading emissions escape |
| BLOWDOWN | Emergency flare |

In Table 5-3, all facilities that are able to route their emissions from emissions events have the flare as an emission point. Each emission point must be assigned a unique EPN. The EI naming conventions for EPNs must follow the same naming conventions as their air permit. Table 5-4 lists the FINs and their corresponding EPNs.

**Table 5-4. Assigning EPNs to Emissions Points for a Hypothetical Upstream Gas-Field Site**

| FIN | Emissions Point(s) | EPN |
|---|---|---|
| FUGAREA1 | Fugitive area encompassing piping component fugitives | FUGAREA1 |
| CONDFUGS | Fugitive area encompassing piping component fugitives | CONDFUGS |
| GUNBARSEP | Separator vent | SEPVENT |
| AMINEUNIT | Amine unit vent | AMINEVENT |
| AMINEUNIT | Flare (during emissions events) | FLARE |
| AMHEATER | Heater stack | HEATERSTK1 |
| DEA-TANK | Tank vent | DEA-TANK |
| GLYCOLSTIL | Glycol still vent | GLYCOLVENT |
| GLYCOLSTIL | Flare (during emissions events) | FLARE |
| GLHEATER | Heater stack | HEATERSTK2 |
| EG-TANK | Tank vent | EG-TANK |
| TURBINE1 | Stack one (dual exhaust stack) | TURBSTK1 |
| GLYCOLSTIL | Stack two (dual exhaust stack) | TURBSTK2 |
| COMP1 | Compressor stack | COMP1STK |
| COMP2 | Compressor stack | COMP2STK |
| UPSETFLARE | Flare | FLARE |
| CONDTANK1 | Tank vent | CONDTANK1 |
| CONDRANK2 | Tank vent | CONDTANK2 |
| LOADRACK | Fugitive loading emissions area | LOADFUGS |
| BLOWDOWN | Emergency flare | FLARE |

**Control Devices.** Control devices must be added to the appropriate paths. From the information in Table 5-4, control devices must be added to the following FIN/EPN paths:

- AMINEUNIT / FLARE
- GLYCOLSTIL / FLARE
- COMP2 / COMP2 (remember, this engine has NSCR controls)
- BLOWDOWN / FLARE

Each control device must be assigned a unique CIN. Table 5-5 lists the FINs, the EPNs, and their associated CINs.

**Table 5-5. Assigning CINs to Paths for a Hypothetical Upstream Gas-Field Site**

| FIN | EPN | CIN (if applicable) |
|---|---|---|
| FUGAREA1 | FUGAREA1 | -- |
| CONDFUGS | CONDFUGS | -- |
| GUNBARSEP | SEPVENT | -- |
| AMINEUNIT | AMINEVENT | -- |
| AMINEUNIT | FLARE | FLARE |
| AMHEATER | HEATERSTK1 | -- |
| DEA-TANK | DEA-TANK | -- |
| GLYCOLSTIL | GLYCOLVENT | -- |
| GLYCOLSTIL | FLARE | FLARE |
| GLHEATER | HEATERSTK2 | -- |
| EG-TANK | EG-TANK | -- |
| TURBINE1 | TURBSTK1 | -- |
| TURBINE1 | TURBSTK2 | -- |
| COMP1 | COMP1STK | -- |
| COMP2 | COMP2STK | NSCR |
| UPSETFLARE | FLARE | -- |
| CONDTANK1 | CONDTANK1 | -- |
| CONDTANK2 | CONDTANK2 | -- |
| LOADRACK | LOADFUGS | -- |
| BLOWDOWN | FLARE | FLARE |

**Creating EI Structure.** Emission paths can be created using the STEERS-AEIR Web-EI system by linking together the appropriate FIN/EPN/CIN for each path. Additional information on submitting an IEI through the STEERS-AEIR Web-EI system is available at the EAS webpage. Facility information is required for different types of processes or units depending on the profile:

- cleaning
- coating or printing
- cooling tower
- flare (combustion unit—flare profile)
- leaking component fugitives
- loading
- non-flare combustion unit
- storage tank
- VOC process
- wastewater system
- wastewater system component
- other facility

The agency requires information on different types of emission points depending on the profile:

- flare
- fugitive
- stack

Abatement-device information is required for control devices.

For this hypothetical site, Table 5-6 lists the appropriate groups and profiles to select when adding structure for facilities and emission points to the EI. To supply the required information online, use the STEERS-AEIR Web-EI system.

If a facility has multiple emission points, the facility information is only completed **once** to add the facility. The facility can then be linked to its multiple emission points in the STEERS-AEIR Web-EI system. Add the **one** facility, add all its emission points, and then link the facility to each of its emission points to create each emissions path.

Similar procedures can also be used for emission points and abatement devices that have multiple paths.

**Completing Path Information.** Emissions data must be completed for each path shown in Table 5-6. Use the information in Table 5-6 to complete the structure in the account.

Material throughput supporting documentation necessary for supplying process rate data and sample calculations used in emissions determinations can be attached to the EI in the STEERS-AEIR Web-EI system.

Refer to Appendix A for information on determining emissions from common sources.

Additional information on submitting an IEI through the STEERS-AEIR Web-EI system is located at the EAS webpage.

**Table 5-6. Selecting Group Types and Profiles for a Hypothetical Upstream Gas-Field Site**

| Appropriate FIN and Group Type / Profile | Appropriate EPN Profile | CIN |
|---|---|---|
| FUGAREA1: Fugitives / Equipment Leak Fugitives | FUGAREA1: Fugitive-type EPN | -- |
| CONDFUGS: Fugitives / Equipment Leak Fugitives | CONDFUGS: Fugitive-type EPN | -- |
| GUNBARSEP: VOC Process / Other VOC Processes | SEPVENT: Stack-type EPN | -- |
| AMINEUNIT: Other / Other | AMINEVENT: Stack-type EPN | -- |
| AMINEUNIT: Other / Other | FLARE: Flare-type EPN | FLARE |
| AMHEATER: Combustion / Heater | HEATERSTK1: Stack-type EPN | -- |
| DEA-TANK: Tanks / (tank profile information as appropriate) | DEA-TANK: Stack-type EPN | -- |
| GLYCOLSTIL: VOC Process / Glycol Still | GLYCOLVENT: Stack-type EPN | -- |
| GLYCOLSTIL: VOC Process / Glycol Still | FLARE: Flare-type EPN | FLARE |
| GLHEATER: Combustion / Heater | HEATERSTK2: Stack-type EPN | -- |
| EG-TANK: Tanks / (tank profile information as appropriate) | EG-TANK: Stack-type EPN | -- |
| TURBINE1: Combustion / Turbine | TURBSTK1: Stack-type EPN | -- |
| TURBINE1: Combustion / Turbine | TURB2STK: Stack-type EPN | -- |
| COMP2: Combustion / I.C. Engine | COMP2STK: Stack-type EPN | NSCR |
| UPSETFLARE: Combustion / Flare | FLARE: Flare-type EPN | -- |
| CONDTANK1: Tanks / (tank profile information as appropriate) | CONDTANK1: Stack-type EPN | -- |
| CONDTANK2: Tanks / (tank profile information as appropriate) | CONDTANK2: Stack-type EPN | -- |
| LOADRACK: Loading / (loading profile information as appropriate) | LOADFUGS: Fugitive-type EPN | -- |
| BLOWDOWN: VOC Process / Blowdown Operations | FLARE: Flare-type EPN | FLARE |

# Chapter 6. Updating an Emissions Inventory

This chapter explains how to update an EI. Review all information in this publication before attempting to update an EI. The required method for submitting an EI is through the STEERS-AEIR Web-EI system, using either interactive Web entry or text-file upload. For information on updating an EI online through STEERS, refer to the EAS webpage. Be certain to review all data in the EI for accuracy and update EI items as necessary.

## Updating Data

### Special Notes

#### *Sample Calculations*

Under 30 TAC Subsection 101.10(c), regulated entities must submit sample calculations representative of the sources and pollutants from their site by the EI due date. Submit sample calculations showing emissions determinations for each different process type present in the EI, including enough information to reasonably reproduce the emissions reported. Please do not submit generic sample calculations since they do not contain representative process data and do not demonstrate actual emissions. Nonconfidential sample calculations and supporting documentation can be attached to the STEERS-AEIR Web-EI system, submitted by hard copy (see Appendix C, "EAS Contact Information and Other Resources" for address information), or e-mailed to psdocument@tceq.texas.gov, with the RN included in the subject line. Confidential sample calculations and supporting documentation can be submitted in hard copy with each page clearly marked as confidential, or through the TCEQ FTPS website. Please contact the EAS for assistance on submitting confidential information through the secure FTPS website.

Use the following guidelines when sending representative calculations:

- When several sources of the same type are present and a single calculation methodology was used to determine emissions, include:
  - calculations for the source with the highest emissions; and
  - actual process data for each source where sample calculations are not supplied.
- When several sources of the same type are present but different calculation methodologies were used to determine emissions, include:
  - calculations for the source with the highest emissions for each calculation methodology; and
  - actual process data for each source that uses a different calculation methodology for which sample calculations are not supplied.

Examples of actual process data include heat inputs and fuel types for combustion sources and chemical types and throughputs for storage tanks and loading sources.

## Account Information

For a detailed description of the items in this section, consult the Glossary. To make any significant changes to any of the other account information, such as RN, CN, or ownership change, complete a Core Data Form and send it to the EAS.[a]

## Contact Information

Contact information can be updated through the STEERS-AEIR Web-EI system. For more information, please refer to the EAS webpage.

## Criteria Emissions Totals

There are four categories of emissions: *Annual, Ozone, EE*, and *SMSS*.

After the EI has been updated using the STEERS-AEIR Web-EI system, the site level criteria emission totals are automatically summed from the emissions that were reported at each path. The VOC totals only include emissions from volatile organic compounds. Emissions from nonreactive hydrocarbons such as acetone are not included in the VOC totals. $NO_X$ emissions are reported under contaminant code 70400 (nitrogen oxides). For EI purposes, the total $NO_X$ emissions include emissions reported under contaminant codes 70400 (nitrogen oxides), 70401 (nitric oxide), and 70402 (nitrogen dioxide). Emissions reported under contaminant code 70403 (nitrous oxide) are not included in the $NO_X$ totals.

For a thorough discussion of the elements of this section, please consult Chapter 4.

## Site Quantifiable Event Totals

The total number of reportable and non-reportable emissions events; reportable and non-reportable scheduled maintenance, startup, and shutdown activities; and excess opacity events are required to be reported each year per 30 TAC Sections 101.201 and 101.211. An explanation of each type of event follows.

*Reportable Emissions Events* is the total number of emissions events that resulted in unauthorized emissions equal to or in excess of the reportable quantity (RQ) for any individual air contaminant. These events should have been reported previously to TCEQ as required by 30 TAC Section 101.201.

*Non-Reportable Emissions Events* is the total number of emissions events that did not result in unauthorized emissions equal to or in excess of the RQ for any individual air contaminant.

*Reportable Scheduled Maintenance, Startup, and Shutdown Activities* is the total number of SMSS activities that resulted in unauthorized emissions equal to or in excess of the RQ for any individual air contaminant. These activities should have been reported previously to TCEQ as required by 30 TAC Section 101.211.

[a] www.tceq.texas.gov/permitting/central_registry/guidance.html

*Non-Reportable Scheduled Maintenance, Startup, and Shutdown Activities* is the total number of SMSS activities that did not result in unauthorized emissions equal to or in excess of the RQ for any individual air contaminant.

*Excess Opacity Events* is the total number of excess opacity events where the opacity readings equaled or exceeded 15 percentage points above an applicable opacity limit, averaged over a six-minute period.

Enter the total number of each type of event. Enter zero if there were no events of a particular type. Do not include events from maintenance, startup, and shutdown activities that are authorized by a permit or PBR. When authorized, these activities are considered routine operations. However, DO enter all activities where the maintenance, startup, and shutdown activities resulted in emissions that exceeded the authorized amounts.

For definitions of terms used in this section, consult the Glossary. For guidance on interpreting rules concerning EE and SMSS activities, contact the TCEQ regional office where the regulated entity is located.

## Emissions Events Certifying Signature

Per 30 TAC Subsection 101.10(d)(2), an owner or operator of a regulated entity that experienced no emissions events during the relevant calendar year must include, as part of the reported inventory, a statement certifying that the regulated entity experienced no emissions events during the reporting year.

The certification is also required for regulated entities that experienced one or more excess opacity events but did not experience any emissions events.

The STEERS-AEIR Web-EI system has two radio buttons for the EE certifying signature, one that states the site did not experience any emissions events during the calendar year and one that states the site did experience emissions events during the calendar year. Selecting one of the radio-button options and submitting the EI to TCEQ constitutes a legally binding electronic signature. Additional information on the EE certifying signature is available at the EAS webpage.

## Signature of Legally Responsible Party

Per 30 TAC Subsection 101.10(d)(1), a complete inventory requires the signature of the individual responsible for certifying that the inventory is, to the best of his or her knowledge, accurate and complete.

The data in STEERS can only be submitted by a user with submitting authority. By completing the submit process, the user certifies the EI data. After reviewing the data and selecting the appropriate EE Certification statement, the user will be taken to a page showing the criteria emissions totals and several legal statements regarding the certification of the EI data. Submission through the STEERS-AEIR Web-EI system serves as the certification and constitutes a legally binding electronic signature and must be certified/submitted by a company legally responsible official. Company consultants must not be given submit authority. For Title V sites, submit access must be given only

to the Responsible Official or their Duly Authorized Representation. Additional information on signing and certifying an EI is located at the EAS webpage. For additional guidance regarding the definition of the legally responsible party, please consult 30 TAC Section 122.165.

Note that the legally responsible party **must not** be a consultant.

## Facility Information

Descriptions of most of the items in this section, along with information on accepted values, may be found in the Glossary. The following discussion focuses on updating facility data.

If corrections to any of the information in this section are necessary and cannot be updated through the STEERS-AEIR Web-EI system, please contact the EAS.

### *Source Classification Code*

A facility's SCC is an **eight-digit** EPA-developed code that associates emissions determinations with identifiable industrial processes. TCEQ uses a facility's SCC for modeling, rulemaking, and SIP-related activities; therefore, a facility's SCC must be as accurate as possible.

Point source SCCs can be found on EPA's webpage.[a] When using this data, only use the codes that have a value of "POINT" in the "Data Category" column, as only those codes are appropriate for the point source EI. Please do not enter SIC (Standard Industrial Classification) codes or AMS (area and mobile source) codes for SCCs on the EI.

SCCs cannot be updated through the STEERS-AEIR Web-EI system; please contact the EAS to update an SCC.

### *Status, Status Date*

If the facility's status has changed, enter the appropriate letter and the date when the status changed. Status options are:

- **A** (active): If the facility operated for any portion of the reporting year.
- **I** (idle): If the facility was idle or temporarily shut down for the entire reporting year.
- **S** (shut down): If the facility has been permanently shut down and will never operate again. **Note that a facility, once shut down, cannot be reactivated in the STARS database.**
- **D** (demolished): If the facility has been removed from the site.

Changing a facility's status code may require contacting the EAS. Users may not be able to make updates using the STEERS-AEIR Web-EI system for the following options:

[a] sor-scc-api.epa.gov/sccwebservices/sccsearch/

- **N** (permitted but never built): For more information on reporting structure for sites that are "planned" or "under construction," contact the EAS.
- **O** (ownership transferred to a new party): If the facility has been sold, or if responsibility for it has been transferred to another owner, during the reporting year. Supply the new owner's TCEQ air RN and the date of ownership transfer.

*Note:* The Path Deactivation Request Form should be used to unlink an active FIN from an EPN. Please provide a reason for each deactivation request. The EI form and instructions are available from the EAS webpage. Path deactivations cannot be completed through the STEERS-AEIR Web-EI system.

*Example:* (FIN) TANK previously vented to the atmosphere through (EPN) TANKSTK but now only vents to (EPN) FLARE. Use this form to communicate that path (FIN) TANK / (EPN) TANKSTK needs to be deactivated. The new path (FIN) TANK / (EPN) FLARE can be added using the STEERS-AEIR Web-EI system. Additional information on creating new paths is available at the EAS webpage.

### *Operating Schedule and Annual Operating Hours*

These fields must reflect a facility's **actual** annual operating schedule and operating hours, **not** maximum potential hours of operation. Update these fields every reporting year with actual data for the facility.

If a facility's operating schedule is inconsistent throughout the reporting year, provide the actual number of weeks that the facility operated in the "Weeks per Year," and provide average data for the fields "Days/Week" and "Hours/Day."

### *Seasonal Operating Percentages*

Seasonal operating percentages represent the percentage of actual facility operations that occurs during each season. These percentages are normally based upon process rate data. For EI purposes, "spring" includes March through May; "summer" includes June through August; "fall" includes September through November; and "winter" includes January, February, and December of the same calendar year. The percentages must be reported as whole numbers (no decimals) and must sum to 100. Note that the ozone season (May through September) no longer represents the same time period as "summer," but STARS treats them as such. Therefore, if a facility operated during the ozone season but not during the summer months, provide a nonzero summer percentage (e.g., *1%*) and report the ozone-season emissions.

### *FIN Group Type, Profile, and Attributes*

In STARS, every facility has a group type and profile associated with it; a list of current group types and profiles is available in Table 6-1.

If a facility's group type or profile is incorrect in the EI, please contact the EAS to have it updated. Group type and profiles cannot be updated through the STEERS-AEIR Web-EI system. If the information is incorrect (for example, a flare has a group type of "equipment leak fugitive"), provide updates with the supporting documentation, noting that you are correcting the facility's profile.

For more information about the attributes (formerly characteristics) associated with each profile, identify the appropriate group type for the facility, and then consult the Glossary.

**Table 6-1. STARS Facility Group Types, Profiles, and Attributes**

| Group Type | Profile | Attributes |
|---|---|---|
| Cleaning | • Dip degreasing<br>• Vapor degreasing<br>• Barge cleaning<br>• Railcar cleaning<br>• Tank truck cleaning<br>• Other | Not applicable |
| Combustion | Flare | • Design capacity in MMBtu per hour<br>• Assist type (steam, air, or none)<br>• Service type (process, emergency, or both)<br>• HRVOC Service? (yes or no) |
| Combustion | I.C. engine | • Number of cycles (two or four)<br>• Burn type (rich or lean)<br>• Design capacity in MMBtu per hour<br>• Engine rating in horsepower |
| Combustion | Boiler, dryer, furnaces, heater, incinerator, kiln, oven, turbine, thermal oxidizer, other | • Design capacity in MMBtu per hour<br>• Firing type |
| Combustion | Fluid catalytic cracking unit (FCCU) | Not applicable |
| Combustion | • Boiler-Electric Generation<br>• I.C. Engine-Electric Generation<br>• Turbine-Electric Generation | • Design capacity in MMBtu per hour<br>• Firing Type<br>• Generation Capacity in MW |
| Coating or printing | Coating or printing | Not applicable |
| Cooling tower | Cooling tower | • Design flow rate in MM gallons per day<br>• Draft design type (natural or mechanical)<br>• Number of cells<br>• Sampling schedule<br>• Sample tested for VOCs? (yes or no)<br>• Sampling data used to calculate emissions? (yes or no)<br>• HRVOC Service? (yes or no) |

| Group Type | Profile | Attributes |
|---|---|---|
| Equipment leak fugitives (Leaking component fugitives) | Equipment leak fugitives | • Emissions determination methodology<br>• Leak detection and repair (LDAR) program<br>• % VOC in Stream<br>• Monitoring equipment data<br>• *Note:* For all these attributes refer to the Facility Information for Component Fugitives form. |
| Loading | • Railcar<br>• Tanker truck<br>• Railcar and tanker truck<br>• Marine<br>• Other | Not applicable |
| Other | Other | Not applicable |
| Tanks[b] | • Horizontal fixed roof<br>• Vertical fixed roof<br>• Internal floating roof<br>• Pressure tank<br>• Underground tank<br>• External floating roof: double deck, single seal<br>• External floating roof: pontoon, single seal<br>• External floating roof: pontoon, double seal<br>• Domed external floating roof: double deck<br>• Domed external floating roof: pontoon<br>• Other | Attributes vary depending on the tank profile. |

b. Do not use the Tank profile for silos storing dry, solid materials. A more appropriate group type and profile is Other/Other.

| Group Type | Profile | Attributes |
|---|---|---|
| VOC process | • Analyzer<br>• Blowdown operations<br>• Delayed coker unit<br>• Flexi coker unit<br>• Glycol still<br>• Polyethylene unit<br>• Polypropylene unit<br>• Mixing vessel<br>• Reactor<br>• Other | Not applicable |
| Wastewater | Wastewater system | • Flow model (flowthrough or disposal)<br>• Aeration (diffused air, mechanical, or none)<br>• Biodegradation mechanism (biodegradation, activated sludge, or none)<br>• Design type (surface, subsurface, or other)<br>• Depth<br>• Surface area<br>• Flow rate in MM gallons per day |
| Wastewater | • Basin<br>• Clarifier closed sump<br>• Lift station<br>• Open sump<br>• Reactor<br>• Stripper<br>• Separator<br>• Other wastewater component | Not applicable |

## Control Device Information

Descriptions of the items in this section, along with information on accepted values, appear in the glossary.

For each abatement device, verify that the:

- Abatement code and number of units are correct.
- Percentage of time offline is reflected in annual emissions determinations.
- Inspection and maintenance schedule is accurate.
- Stated control efficiencies of each pollutant are accurate.

For abatement devices that can also be considered facilities, such as combustive abatement devices, ensure that these devices are not abating their own emissions. Abatement devices cannot abate themselves.

If an abatement device's abatement code appears incorrect in the EI, and the information cannot be updated in the STEERS-AEIR Web-EI system, provide updates in the supporting documentation noting that the control device's abatement code has been corrected.

## Emission Point Information

Descriptions of most of the items in this section, along with information on accepted values, may be found in the glossary.

### *Emission Point Coordinates*

Accurate coordinates for each emission point are essential to modeling and other air quality planning activities. All UTM and latitude-longitude coordinates must be expressed in the North American Datum of 1983 (NAD83) coordinate system and all latitudes and longitudes must be expressed as degrees, minutes, and seconds (in the format DDMMSS).

Verify that each emission point has accurate coordinates; for most non-fugitive emission points, these coordinates must be unique. Also, verify that the site centroid is correct.

### *EPN Profiles*

In STARS, every emission point has a profile associated with it: currently, *stack, flare*, or *fugitive*. Associating each emission point with a profile allows TCEQ to collect data on sources of interest and facilitates data retrieval.

If the emission point profile is incorrect in the EI, please contact the EAS to have it updated. Profiles cannot be updated through the STEERS-AEIR Web-EI system.

### *EPN Attributes*

Accurate emission point attributes are essential to modeling and other air quality planning activities. Emission point attributes must represent **actual** stack, fugitive, or flare attributes values, not values for permit modeling purposes. Verify that all emission points have accurate values.

## Total Aggregate Annual Heat Input

For combustion units, enter the total heat value (in MMBtu) of all fuels (including waste gases, liquids, and solids) that the facility combusted during the year. **This value must be entered every year. It is not carried over from the previous year.** When the facility has multiple emission points, do not divide the heat input between paths. Instead, sum the individual heat inputs and report the total annual aggregate heat input for the unit.

To determine the total aggregate annual heat input, first determine the heat input for **each** fuel that the facility combusted during the year by multiplying the fuel's gross heating (calorific) value (in Btu/lb) by the fuel's annual feed rate (in lb/year). Next, sum these individual annual heat inputs for all fuels combusted during the year, and convert from Btu to MMBtu to obtain the total aggregate annual heat input (in MMBtu/year).

## Emissions Factors

TCEQ requires that users enter $NO_X$ emissions factors in the EI.

To promote consistency among similar emission sources, TCEQ requests that the $NO_X$ emissions factors be based upon the following process-rate data. Examples of the preferred process-rate-based $NO_X$ factors include:

- lb/MMBtu (boilers, furnaces, heater, and turbines)
- g/hp-hr or lb/MMBtu (all engines)
- lb of $NO_X$/ton of clinker (cement kilns)
- lb of $NO_X$/ton of calcium oxide (lime kilns)
- lb of $NO_X$/ton of product (lightweight aggregate)
- lb/Mgal (liquid-fired boilers)
- ppmv @ zero percent $O_2$ (FCCUs)

If a $NO_X$ factor is reported as a lb/hour (or similar) rate, use the factor and the process rate at the time of testing to obtain a process-based emissions rate. For example, for combustion sources, divide the lb/hour emission rate by the MMBtu/hour fuel-usage rate to obtain a factor with units of lb/MMBtu. Similarly, for cement kilns, divide the lb/hour emission rate by the tons of clinker/hour to obtain a factor with units of lb/ton of clinker.

If the process-rate-based $NO_X$ factor from a CEMS or PEMS cannot be obtained, calculate one by converting the reported tons/year of $NO_X$ to lb/year, and then divide the result by the MMBtu/year heat input to obtain a $NO_X$ factor in units of lb/MMBtu.

Ensure that a $NO_X$ emissions factor has been entered for every $NO_X$ source on the "Emissions Factor" portion of the EI. **This value must be entered every year. It is not carried over from the previous year.**

*Note:* The factors must account for any controls. If controls exist, the reported $NO_X$ emission factor must not be an uncontrolled factor.

In cases where multiple $NO_X$ emissions factors exist (e.g., when the facility burns multiple types of fuel), either report a single weighted average $NO_X$ factor or report separate factors for each type of fuel.

## Updating Reported Emissions

The following discussion focuses primarily on updating emissions data for each path.

### *Determination Methodology*

The determination methodology represents the method used to determine the reported emissions. Acceptable methods are described in Chapter 4.

Verify an emissions rate's determination methodology every year, updating the methodology as needed with the correct code. To obtain the code for a particular determination methodology, consult the appropriate heading in Chapter 4.

### *Annual Emissions*

For annual emissions, report total annual emissions for the year during routine operations for all contaminants emitted, quantified in tons. Annual emissions must not include emissions from emissions events or scheduled maintenance, startup, and shutdown activities that are **not** authorized by a new source review permit or PBR. However, annual emissions must include **authorized** emissions from maintenance, startup, and shutdown activities.

### *Ozone Season Emissions*

For ozone season emissions, report emissions during the ozone season, measured in ppd. Recall that the ozone season is defined in Chapter 4, "Determining and Reporting Emissions." Ozone season emissions are mandatory for all regulated entities in El Paso County and for all regulated entities in any county east of the Central Meridian. These counties are listed in subheading "Ozone Season Daily Rates are Required from Sites in These Counties" in Chapter 4.

### *Scheduled Maintenance, Startup, and Shutdown*

Report emissions from scheduled maintenance, startup, and shutdown activities that are **not** authorized by a new source review permit or PBR in the "SMSS" category. Emissions from maintenance, startup, and shutdown activities that are **authorized** under a permit or PBR must not be included in the "SMSS" category. Instead, these

emissions must be summed into the “Annual” category. For more information on SMSS emissions, see Chapter 4.

### *Emissions Events*

Report emissions from emissions events in the “EE” category. For more information on emissions events, see Chapter 4.

### *Changing FIN and EPN Designations*

TCEQ does not normally change FIN or EPN designations, due to the historical nature of emissions data. Exceptions to this policy will be made to correct errors or to align EI nomenclature with permit nomenclature. FIN and EPN designations cannot be updated through the STEERS-AEIR Web-EI system. If revisions to FIN or EPN designations are necessary, submit a Revision Request form (TCEQ-20041f) and state a reason for the requested revisions. Include any applicable supporting information, such as a copy of the Maximum Allowable Emissions Rate Table (MAERT). Note that TCEQ reserves the right to approve or disapprove all such revision requests. Additional information about the Revision Request form is available in the instructions at the EAS webpage.

# Chapter 7. EI Revisions and Data, and Site Coordinate Data

This chapter covers submitting EI revisions, requesting EI data, and reviewing site coordinate data.

A regulated entity can make a revision request to correct erroneous EI data it previously reported. A discussion on how to submit a revised EI for the current and previous reporting years is included in this chapter.

Regulated entities may request historical EI data from TCEQ. Whether the request is for retrieving electronic data from STARS or for viewing a historic EI file, procedures are in place to request such information. This chapter discusses what data TCEQ can supply and when an "open records" request may be more appropriate.

Because EPN and site centroid coordinate data are used for modeling, TCEQ may request updates to those data. This chapter discusses coordinate data and can assist in locating a site's coordinates.

## Revising an EI

### Current and Previous Reporting Year

All revision requests are subject to TCEQ review and approval. In the cover letter, indicate the years being revised.

For any of the methodologies, data from a current year must not be used to report or revise emissions for any previous year's EI. For example, if $NO_X$ emissions from an engine were stack tested in calendar year 2024, those test results can be used starting with the 2024 EI. The stack-test results cannot be used to report $NO_X$ emissions in the 2023 EI, or to revise any EI submitted for a year prior to 2024.

*Note:* Revision requests are generally processed after TCEQ has reviewed and loaded the emissions inventories for the current reporting year.

#### *What Is Required*

A revision must address errors in the self-reported EI. Submit the following to revise EI data:

- A signed cover letter describing the revisions being made and the reason for the revisions.
- Revised EIQ pages only.
  - It is not necessary to submit the entire EIQ (STEERS printouts are not an acceptable format for submitting revisions).

  - A printable version of the EIQ is available through the IWR system at the Central Registry webpage.[a]
  - Instructions for navigating the Central Registry website and downloading an EIQ formatted for printing are available in pdf.[b]
- Updated criteria emissions totals for the site (found on page 3 of the EIQ) to help identify any errors in entering or submitting data.
- Detailed sample calculations and supporting documentation for the revised emissions—see Chapter 1 for additional instructions.

*Note:* When printing the EIQ using the Central Registry's IWR system, the previous reporting year will appear on the EIQ pages. The EIQ referenced is a historical report containing the latest data as entered in STARS. To update, cross out the previous year on page 2 of the EIQ and write the current reporting year. It is not necessary to update the year for subsequent EIQ pages.

*Note:* Please use permanent ink instead of pencil when revising the EIQ. Pencil tends to smudge and can be difficult to read, increasing the chance of data entry errors or omissions. For each revision, use a different ink color to distinguish the most recently corrected EI information. There are no restrictions on ink color, but colors other than black make EIQ updates more noticeable.

To obtain an electronic copy of the most current data for the EI revision year, contact the EAS helpline at 512-239-1773.

### *How to Submit*

The revised EIQ pages submitted to TCEQ must be printed on only one side of the page and not copied on both sides of the page (do not duplex). Do not submit pages printed from STEERS. STEERS printouts are not an acceptable format for submitting revisions.

Contact the EAS to identify the staff member assigned to review the EI for the current year. When submitting revisions, address them to the applicable EAS staff member at MC 164.

*Note:* Provide notice to other program areas that may be impacted by the revisions. For example, if a company submits EI revisions and is also subject to the annual emissions fee per 30 TAC Section 101.27, contact the air fees program at airfees@tceq.texas.gov.

## Other Reporting Years

All revision requests are subject to TCEQ review and approval. If the revision request is for a year two to four years prior to the current reporting year, TCEQ may or may not update the emissions data in STARS. TCEQ will review revision requests to determine if the data currently in STARS should be updated. This review considers the justification for the revisions, the EI year in question, and the magnitude of the change in

[a] www.tceq.texas.gov/goto/cr-query
[b] www.tceq.texas.gov/downloads/air-quality/point-source/forms/eiq-print-copy.pdf

emissions, if applicable. For any of the methodologies, data from a current year must not be used to report or revise emissions for any previous year's EI. For example, $NO_X$ from an engine was stack tested in calendar year 2024; those test results can be used starting with the 2024 EI. The stack-test results cannot be used to report $NO_X$ emissions in the 2023 EI or revise any previous year's EI. After the review, TCEQ will determine whether to update the emission revisions in STARS or, alternatively, to file them in the EI folder. Since each revision is unique, TCEQ recommends that the owner or operator contact the EAS to address any questions about the submitted revisions.

Requests for revisions to EI reporting years five or more years prior to the current reporting year will be filed with the appropriate EIQ and will be noted in the STARS tracking system.

*Example:* The current reporting year is 2024. Revision requests may be processed and updated in STARS for 2024 and 2023. The EAS will review revision requests for 2022, 2021, and 2020 case by case. The EAS will determine whether the emissions will be updated in STARS or filed in the EIQ folder. Revision requests for 2019 and earlier will be filed with the appropriate EIQ and noted in the STARS tracking system.

# EI Data

Historical EI data are available and can be obtained through the processes described below. Please choose the appropriate process based on the type of data requested.

## View and Download Data From the Emissions Assessment Section Webpage

The EAS webpage links to site-specific summary EI data. Before contacting TCEQ for EI data, please refer to this webpage for more information on available EI data and other related useful resources. Information available on the webpage includes EI trends, total criteria emissions for each site that reported an EI for the previous year, tools for completing an EI, this document, and EI forms.

## Run TCEQ Central Registry Integrated Web Reports

Site-specific EI reports are available through the TCEQ Central Registry IWR system including path-level and site-level emissions, path-list reports, and the EIQ.[a] For instructions on navigating the Central Registry online and obtaining EI reports, please refer to the EAS webpage.

## Request Detailed Emissions Data From the Emissions Assessment Section

To request customized data extracts or detailed emissions data that are not available on our EAS webpage, please complete the Emissions Data Request form and email psinvent@tceq.texas.gov the form to TCEQ. The form can be downloaded at the EAS

[a] www.tceq.texas.gov/goto/cr-query

webpage. TCEQ will determine if the requested data are available electronically or if paper EI files are available for review. Data requests may require a fee. Please allow 10 business days for TCEQ to contact you about your request.

For additional guidance on how to complete the form or on what EI data are available, please contact the EAS helpline at 512-239-1773.

## File a TCEQ Open Records Request

A data request may be referred to TCEQ's open records request team when it involves other program areas, media, EI contact information, or EI files that have been sent to the Texas State Library. These types of requests can be made by email to openrecs@tceq.texas.gov or in writing to the public information officer.

## View Paper EI Data

### *EI Files Available at the TCEQ Central Office*

EI files can also be viewed in person at the TCEQ central office in Austin. TCEQ maintains files for the current EI reporting year and the three most recent years. To request them, contact the EAS helpline at 512-239-1773. The account number or RN, company and site names, and EI years desired are required so the files can be identified and located.

Please allow at least 48 hours' notice to view a file for TCEQ to retrieve it and to ensure it contains no confidential information. It will then be available in the Central File Room for review. Copying and various other services are also available.

After three years, EI files are transferred to the state archives at the Texas State Library.

### *Archived Files*

If an EI file has already been sent to the Texas State Library, an "open records" request is necessary to obtain the file. This request can be made by email to openrecs@tceq.texas.gov or in writing to the public information officer. Please allow at least a few days for the state library to forward the files. For more information, visit online to learn how to make a public information request.[a]

# Coordinate Data

## Spatial Queries and Mapping Application Viewer

Advancements in GIS software and its wide availability have drawn increased attention to obtaining accurate coordinate data for the site centroid and EPNs. Because site

[a] www.tceq.texas.gov/agency/data/records-services/reqinfo.html

coordinates can potentially have an impact on emissions modeling, TCEQ may request updates to them.

TCEQ has recently made available an online viewer that uses Google Maps to help determine accurate coordinate data. [a]

[a] www.tceq.texas.gov/gis/hb-610-viewer

# Appendix A. Technical Supplements

**Disclaimer**

TCEQ developed the technical supplements in Appendix A for several common emission sources. These supplements are intended to provide guidance for determining and reporting emissions from specific types of sources and may not cover every source at the site. It is the responsibility of the owner or operator of a regulated entity to report the emissions from every source required to be included in its EI. See Chapter 1 for information on reporting requirements.

These supplements reflect how certain processes work and how emissions are generated. The supplements may change over time as a result of findings of scientific studies and as new information becomes available. TCEQ greatly appreciates any data, information, or feedback that may improve these supplements.

The methods discussed in this appendix are intended to assist with 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. It is the responsibility of the owner or operator of a regulated entity to use the best available method to determine and report the emissions that accurately reflect the conditions at their site. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS helpline at 512-239-1773.

## Miscellaneous VOC Sources

One of the goals of TCEQ is to identify sources that are failing to report, or are underreporting, their VOC emissions. The sources that fall into this category include, but are not limited to, casing head gas releases, coking units, confined entry ventilation, and Merox units. If any of the sources listed below are present at the site, the sources must be represented in the EI and the emissions must be determined and reported in the EI using the best available emissions determination methodologies. All sources of VOC emissions must be accounted for in the EI according to the guidance in Chapter 3.

### 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 of 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, any emissions meeting EI reporting requirements must be reported in the EI.

### Coking Units

*Coking* is a method of severe 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 decoking (or coke cutting), VOC gases trapped in the coke will be released while 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 must be included in the EI. Consult Chapter 3 for information on collective sources to determine if these ventilation emission sources can be grouped in the EI.

## Merox Units

After mercaptan-rich hydrocarbon liquids are treated in a mercaptan oxidation (Merox) unit, they are often placed in a storage tank. Inert gases may become trapped in this hydrocarbon liquid and can strip VOCs while vaporizing during storage, resulting in VOC emissions.

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 must be calculated using sound engineering principles and data.

## Glycol Dehydration Operations

Glycol dehydration units are used to remove water from natural gas streams to prevent the formation of hydrates and corrosion in the pipeline. Once the glycol is saturated with water, the rich glycol is pumped to a glycol reboiler heater to be regenerated and reused. When the glycol is heated, the VOCs (including benzene, toluene, ethylbenzene, xylene [BTEX], and other hazardous air pollutants [HAP]) and water are boiled off and may be released to the atmosphere through the glycol still vent.

Whether the GRI-GLYCalc program or a material balance based on a rich-lean analysis is used to determine emissions, an extended gas analysis is necessary for an accurate determination. The wet gas must be sampled at a point in the process ahead of the glycol contactor. The extended gas analysis must be speciated beyond C6+ for each chemical including, but not limited to, BTEX and HAPs. For the rich-lean analysis, the rich glycol stream must be sampled at an appropriate location in the process to accurately assess the VOC content (e.g., after the glycol contactor but before the regenerator or reboiler). The lean glycol stream must be sampled at a point in the process after the regenerator or reboiler.

If the process operations include a flash tank, the flash tank emissions must be included in the EI. When properly used, data from either GRI-GLYCalc or sampling can account for VOC emissions from the flash tank. Controls for the flash tank vents, as well as the regenerator, can be accounted for in the GRI-GLYCalc program. If emissions are routed to the reboiler firebox for control, reduce the control efficiency to account for the heating cycle of the firebox, unless there is a modification to ensure continuous combustion. Include the Aggregate Summary Emission Report in the sample calculations, which provides the information needed for review.

Flash tanks must be represented as individual sources in the EI if they are permitted separately from the glycol still or dehydrator unit. If missing, add the glycol flash tank structure to the inventory.

Glycol units at a site should be represented in the inventory, even if the emissions are routed back into the process. For assistance, please contact the EAS.

## Amine Units in Carbon Dioxide ($CO_2$) Service

Amine units in $CO_2$ service that are vented to the atmosphere can be a significant source of VOC emissions (including BTEX and other HAPs). Amine units are used to remove acidic gases including $CO_2$ from natural gas streams. Once the amine is saturated with acid gas, the rich amine is pumped to the amine regenerator to be recycled and the $CO_2$ may be vented to the atmosphere. Amine solutions can absorb VOCs (including BTEX and other HAPs) and release them into the atmosphere during the regeneration cycle.

VOC emissions from amine units should be determined using measured emissions data (preferred) or software models that accurately determine the VOC emissions. Current and accurate simulation methods, such as the PROSIM, ProMax, etc., to determine emissions or stack sampling must be used to ensure that speciated VOC emissions are reported from amine units in $CO_2$ service that are vented to the atmosphere.

## Limitations of AMINECalc

The use of AMINECalc software to determine emissions is limited to processes that use one of five amine solvents that are single components. AMINECalc cannot be used to determine emissions for amine processes using blends and other solvents (such as piperazine). AMINECalc is also limited to the standard amine unit process configuration, which contains an absorber, rich amine flash, and regenerator. For sites with processes outside this configuration, AMINECalc cannot be used to determine emissions. Due to these limitations with AMINECalc, VOC emissions from amine units should be determined using measured emissions data (preferred) or current and accurate simulation methods, such as the PROSIM, ProMax, etc.

## Pigging Units

Pigging refers to a process for clearing condensate and other accumulated liquids out of natural gas pipelines. A cylindrical device called a “pig” is inserted into a pig

launcher upstream of the pipeline segment where the condensates have accumulated. The gas flowing through the pipeline pushes the pig through the line, allowing the pig to sweep along the accumulated liquid. The pig is then caught in the pig receiver and removed from the pipeline.

When the launcher and receiver are depressurized and opened to insert and remove the pig, the gases released contain VOCs and HAPs. Additionally, any gases entrained in the liquid will flash out, adding to the VOC and HAP emissions. If no liquid accumulation occurs at the pig launcher barrel, emissions can be estimated using the Real Gas Law. If there is liquid accumulation at the pig receiver barrel, emissions estimates should account for both the impact of any liquid accumulation in the pig receiver barrels and gas entrained in that liquid (flash) and depressurization emissions estimated based on the Real Gas Law. See the September 2019 EPA Enforcement Alert (Publication no. EPA 325-F-19-001) for more information.

## Pneumatic Devices

Pneumatic pumps are devices that use gas pressure to drive a fluid by raising or reducing its pressure through positive displacement of a piston or set of rotating impellers. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved to discharge the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas. Gas-powered pneumatic pumps are generally used at oil and natural gas production sites where electricity is not available and can be a significant source of VOC emissions. Emissions should be determined from the flow of gas to the pumps, if measured, and the VOC content of the gas stream. Otherwise, vendor data or EPA factors should be used.

Pneumatic controllers are used for maintaining a process condition. Natural gas-driven controllers are powered by pressurized natural gas. These are characterized by the amount of natural gas emitted by the controller, also known as the bleed rate. Continuous bleed controllers use natural gas to modulate flow, liquid level, or pressure and gas is vented continuously at a rate that may vary over time. Continuous bleed controllers can be high or low bleed rates. High bleed rates are above six cubic feet per hour and low bleed rates are equal to or below six cubic feet per hour. Intermittent controllers vent non-continuously and are actuated using pressurized natural gas. Zero bleed controllers do not vent to the atmosphere; the released gas is routed to a downstream pipeline. Emissions should be determined from the flow of gas to the controllers, if monitored. Otherwise, vendor or EPA factors should be used to determine emissions in conjunction with the VOC content of the gas stream.

## Level Control Valves

Level control valves maintain liquid levels in separators and compressor scrubbers. The valves open and close when the level controllers are actuated, releasing the liquid to storage tanks. Occasionally the valves malfunction and are stuck open, resulting in the release of gas as well as liquid to the tank. Emissions from these incidents should

be reported as emissions events at the receiving tank facility identification number (FIN) in the emissions inventory and determined using known flow rates or engineering estimates.

## Thief Hatches

Thief hatches are access points on top of upstream oil and gas tanks to enable visual inspection and sampling. For tanks with emissions controlled by vapor recovery or vapor routing systems, an open or malfunctioning thief hatch compromises the control system and results in uncontrolled emissions during the period the hatch is open or malfunctioning. If the hatch is not properly seated or the seal has been worn, the hatch should be treated as malfunctioning and the tank would be considered uncontrolled during that period.

The emissions should be reported at the tank FIN. For tanks where the hatch is permitted to be open during maintenance intervals, the emissions should be treated as routine. For periods where the hatch is open outside of the permitted interval, or when the hatch seal is malfunctioning, the tank should be treated as uncontrolled and emissions reported in the maintenance or emissions events field.

## VOCs and HAPs From Metal Shredding

Metal recycling sites with metal shredders collect automobiles, large appliances, and other items containing recyclable metal. These items are broken into a size suitable for further processing. The process of shredding and grinding generates heat, which can volatilize organic materials from fluids, plastic, paint, and similar materials in the scrap. Additionally, shredding operations can create particulate matter emissions and emissions of heavy metals (HAPs) present in the scrap.

Regulatory emissions tests have found significant VOC emissions at metal shredding operations. Determine and report all VOC and HAP emissions from the metal recycling process. See the July 2021 EPA Enforcement Alert (Publication no. EPA 310-F-21-003) for more information.

## Municipal Solid Waste Landfills

A municipal solid waste (MSW) landfill unit is a discrete area of land or an excavation that receives household waste, and that is not a land application unit, surface impoundment, injection well, or waste pile. An MSW landfill unit may also receive other types of wastes, such as commercial solid waste, nonhazardous sludge, and industrial solid waste.

Methane and $CO_2$ are the primary constituents of landfill gas (LFG) along with a small amount of non-methane organic compounds (NMOC) and are produced by microorganisms within the landfill under anaerobic conditions. Other emissions associated with MSW landfills include combustion products from LFG control and utilization equipment (i.e., flares, engines, turbines, and boilers). EPA recently updated AP-42 emissions determination factors and guidance for landfills, emphasizing that site-specific measurements should be used to determine emissions instead of AP-42

default data. See the August 2024 update to AP-42 Chapter 2, Section 4—*Municipal Solid Waste Landfills* for more information.

## References

U.S. Environmental Protection Agency. 2021. *Violations at Metal Recycling Facilities Cause Excess Emissions in Nearby Communities* EPA 310-F-21-003. Available online at: www.epa.gov/system/files/documents/2021-07/metalshredder-enfalert.pdf. Accessed Sept. 30, 2021.

U.S. Environmental Protection Agency. 2019. *EPA Observes Air Emissions from Natural Gas Gathering Operations in Violation of the Clean Air Act* EPA EPA 325-F-19-001. Available online at: www.epa.gov/sites/default/files/2019-09/documents/naturalgasgatheringoperationinviolationcaa-enforcementalert0919.pdf. Accessed Sept. 30, 2021.

U.S. Environmental Protection Agency. 2024. *Final Emissions Factors for AP-42 Chapter 2, Section 4—Municipal Solid Waste Landfills* Available online at: www.epa.gov/air-emissions-factors-and-quantification/final-emissions-factors-ap-42-chapter-2-section-4 Accessed Sept. 30, 2024.

# Technical Supplements

The following technical supplements are included in this appendix.

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

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

**Technical Supplement 3: Equipment Leak Fugitives** contains guidance for determining and reporting emissions from piping components at industrial facilities resulting from leaking seals or connections.

**Technical Supplement 4: Flares** contains guidance for determining and reporting emissions from elevated flares.

**Technical Supplement 5: Marine Facilities** contains guidance for determining and reporting emissions from vessel cleaning, material transfer, and dockside sources such as stockpiles of solid materials, silos, VOC collection units, loading racks, and abatement devices.

**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

This technical supplement addresses common problems and concerns with internal combustion engines (turbines, reciprocating engines, gasoline and diesel industrial engines, and portable engines); external combustion sources burning natural gas; combined-cycle turbines with heat-recovery steam generators; and coal-fired boilers. 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.

**Disclaimer for Technical Supplement 1**

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

This guidance reflects the current understanding of how combustion sources work, how emissions are generated, how combustion sources are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. TCEQ greatly appreciates any data, information, or feedback that may improve the supplement.

The methods represented are intended to assist with calculating emissions; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS helpline at 512-239-1773.

## Internal Combustion Engines

### *Expected Contaminants*

Reported engine emissions must include all of the following:

- PM (contaminant code 10000)
- $PM_{10}$ (contaminant code 20000)
- $PM_{2.5}$ (contaminant code 39999)
- VOCs (contaminant codes within the range of 50001 through 59998)
- HAPs (≥ 0.1 tpy)
- $NO_x$ (contaminant code 70400)
- $SO_2$ (contaminant code 70510)
- CO (contaminant code 90300)

*Note:* Formaldehyde is typically ≥ 0.1 tpy when total VOCs are ≥ 1 tpy.

### *Emissions Determination Methodologies*

Emissions determination methodologies for all regulated pollutant emissions from 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)
- Q (portable-analyzer-test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- B (material balance)
- S (scientifically calculated)
- E (estimated)

Portable analyzers have their own determination methodology and must be coded "Q." Testing conducted with a portable analyzer does not qualify as stack testing; therefore, the emissions determination methodology must not be coded "measured" ("M"). If the stack-test results from an identical unit are used to determine the emissions, the emissions determination methodology must be coded "estimated" ("E").

Note that material balance ("B") is not explicitly mentioned in the list because of its limited applicability in determining emissions from combustion sources, except $SO_2$. If these methodologies will not accurately represent a source's emissions, contact the EAS for further assistance.

### *$SO_2$ Emissions*

If any sulfur is present in a source's inlet gas, the source will emit $SO_2$ as a product of combustion. CEMS, PEMS, and stack-test data are the preferred methods, in descending order, for determining the $SO_2$ emissions. If data from direct measurements are not available, then $SO_2$ emissions must be determined using material balance based upon the combusted fuel's sulfur content. If the unit only burns pipeline-grade sweet natural gas, AP-42 factors or vendor data can be used to estimate the $SO_2$ emissions.

### *Particulate Emissions*

Combustion sources emit particulate matter. Furthermore, particulate matter emitted from internal combustion engines has an aerodynamic diameter smaller than 2.5 micrometers. Thus, all particulate emissions from these sources must be reported under three different contaminant codes as $PM_{2.5}$, contaminant code 39999; $PM_{10}$, contaminant code 20000; and PM (total of all sizes, hereafter referred to as total), contaminant code 10000. See "Speciating Particulate Matter," in Chapter 4, for more details.

Use AP-42 to determine internal combustion engine particulate matter emissions only if preferable data does not exist. Use of EPA factors other than AP-42 is acceptable only if the Air Permits Division has approved the emissions factors to determine

permitted emission rates and more preferred data (such as vendor or stack test data) are not available.

*Note:* Some confusion has arisen from AP-42's representation of three particulate emission factors: $PM_{10}$ (filterable), $PM_{2.5}$ (filterable), and PM (condensable). PM consists of both condensable particulate matter and filterable particulate matter; therefore, the emissions from condensable particulates and from filterable particulates must be determined to calculate the cumulative particulate emissions for each size of particulate matter: $PM_{2.5}$, $PM_{10}$, and PM (total).

However, summing these emission factors is not straightforward. Since all particulate matter emitted from internal and external combustion engines is $PM_{2.5}$ or smaller, the $PM_{10}$ (filterable) and $PM_{2.5}$ (filterable) emission factors are equivalent; those two factors represent the same set of particulate emissions. Therefore—for internal and external combustion engines only—obtain the cumulative PM emission factor by summing the AP-42 condensable emission factor and the AP-42 $PM_{10}$ filterable emission factor. Use this cumulative emission factor in conjunction with the appropriate annual activity rate to determine cumulative PM emissions. Report the total emissions obtained by this method under each of the following contaminant codes:

- PM (contaminant code 10000)
- $PM_{10}$ (contaminant code 20000)
- $PM_{2.5}$ (contaminant code 39999)

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

$PM_{10}$ (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 $PM_{10}$ (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:

$$PM = 0.0194 \frac{lb}{MMBtu} \times 35{,}000 \frac{MMBtu}{year} \times \frac{1\ ton}{2{,}000\ lb} = 0.3395\ tons/year$$

The correct way to report these emissions appears in Table A-1.

**Table A-1. Reporting Particulate Emissions**

| Contaminant Code | Contaminant | Annual Emissions (tons) |
|---|---|---|
| **10000** | Part-unclassified | 0.3395 |
| **20000** | $PM_{10}$-unclassified | 0.3395 |

| Contaminant Code | Contaminant | Annual Emissions (tons) |
|---|---|---|
| **39999** | total $PM_{2.5}$ | 0.3395 |

## *VOC Emissions*

Determining, speciating, and reporting VOC emissions are not always straightforward. Please read the information in this section carefully. Although source-specific VOC data as detailed in the Emissions Determination Methodologies section above must be used to determine VOC emissions if available, in practice, it is possible to determine VOC emissions using a combination of stack-test data, vendor data, and AP-42 emission factors. Each methodology is discussed separately in the following sections; each section contains methodology-specific speciation instructions.

Because complex oxidation reactions occur in the combustion chamber that significantly alter the composition of emissions, it is unacceptable to apply the inlet-gas stream's VOC percentage to a total organic carbon (TOC) emission factor from a stack test, vendor data, or AP-42 to obtain a VOC emission factor.

### Stack-Test Data

When using valid stack-test data to determine VOC emissions, the results of the stack test must be verified to ensure that the test measured VOCs rather than total hydrocarbons. If it did measure VOCs, then the test data must be used to determine emissions; code the emissions with a determination methodology of "M."

If the stack test measured total hydrocarbons, the VOC emissions must be determined by multiplying the hydrocarbon emission factor by the following ratio: *AP-42 VOC emission factor / AP-42 TOC emission factor*. The determination methodology must be coded "S."

### Vendor Data

When using vendor data to determine VOC emissions, verify that the vendor's emission factor refers to VOCs rather than total hydrocarbons. If it does, the VOC emissions must be calculated and the determination methodology must be coded "V." **Also, verify whether the vendor's emission factor accounts for formaldehyde and other aldehyde compounds.** If the factor excludes only formaldehyde, see the "Speciation" section that follows. If the factor excludes all aldehyde compounds, please contact the EAS.

If the emission factor determines the amount of total hydrocarbons, the VOC emissions must be determined by multiplying the hydrocarbon emission factor by the following ratio: *AP-42 VOC emission factor / AP-42 TOC emission factor*. The determination methodology must be coded "S."

## AP-42 Factors

AP-42 provides both VOC and TOC emission factors. When using an AP-42 emission factor to determine emissions, the most recent VOC emission factor must be used and the determination methodology must be coded "A."

## Speciation

To determine whether to speciate VOC emissions from an internal combustion engine, see Chapter 4.

If speciation is required for the emissions source, source-specific information, if available, must be used when calculating the speciated VOC emissions.

If no source-specific information about the VOC composition exists, the VOC emissions must be speciated using the AP-42 "trace organic compounds" emission factors that are graded "C" or better.

Note that the total VOC factor in AP-42 is simply the sum of the speciated emission factors. If a method for determining VOC emissions preferred over AP-42 is used to determine total VOC emissions, the ratio of the AP-42 speciated emission factor to the total AP-42 VOC emission factor must be applied to determine each individual species' emissions rate. This ensures that the total of the speciated emissions does not exceed the total VOC factor.

To determine the speciated emissions, divide each trace organic factor by AP-42's VOC emission 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. The speciated VOC emissions that are at least 0.1 ton must be reported; smaller rates may be included under "VOC-unclassified" (contaminant code 50001).

If stack-test data or vendor data are used to determine total VOC emissions, the determination methodology must be coded "S" for "scientifically calculated"; the VOC-u emissions must be coded "M" or "V." If an AP-42 emission factor is used to determine the total VOC emissions, the determination methodology for all of the VOC pollutants must be coded "A."

***Example: Speciating VOCs using a vendor-supplied VOC emission factor that includes formaldehyde***

The total VOC emissions from a four-cycle lean-burn compressor have been determined to be 11.2 tons. Assuming the composition of the exhaust VOCs is not known, the inlet-gas analysis cannot be used to speciate the VOC emissions, because complex oxidation reactions occur in the combustion chamber that alter the composition of emissions significantly. Therefore, the factors in AP-42 must be used to speciate the VOC emissions.

In AP-42, formaldehyde is one of the "trace organic compounds" that have an emission factor (0.0528 lb/MMBtu) with a grade C or better. The total VOC emission factor in AP-42 is 0.118 lb/MMBtu. To obtain formaldehyde's speciation ratio, divide the formaldehyde emission factor by the total VOC emission factor:

$$0.0528\,\frac{lb}{MMBtu} \div 0.118\,\frac{lb}{MMBtu} = 0.44746$$

Multiply the engine's total VOC emissions by this ratio to determine the formaldehyde emissions:

$$11.2\ tons\ VOC \times 0.44746 = 5.0115\ tons\ formaldehyde$$

If this calculation is performed for each trace organic compound with a factor graded C or better, there are 27 speciated emission rates that must be determined. However, only eight of those exceed the 0.1-ton threshold. The speciated emissions for these eight compounds must be reported in the EI and the remaining balance of the total VOC emissions must be reported under "VOC-unclassified," as shown in Table A-2.

**Table A-2. Reporting VOC Emissions From Internal Combustion—Vendor Factor Includes Formaldehyde**

| Contaminant Code | Contaminant | Annual Emissions (tons) | Determination Methodology |
|---|---|---|---|
| **50001** | VOC-unclassified | 0.2240 | V |
| **51620** | acetaldehyde | 0.7935 | S |
| **51640** | acrolein | 0.4879 | S |
| **51680** | formaldehyde | 5.0115 | S |
| **51530** | methanol | 0.2373 | S |
| **56150** | methylcyclohexane | 0.1167 | S |
| **56600** | n-hexane | 0.1054 | S |
| **56750** | n-pentane | 0.2468 | S |
| **56775** | propane | 3.9769 | S |

***Example: Using a vendor-supplied VOC emission factor that excludes formaldehyde***

Formaldehyde emissions are difficult to quantify using existing EPA reference methods. Typically, a separate test for formaldehyde is needed to quantify these emissions. Therefore, some vendor-provided, as well as stack-test, VOC emission factors exclude formaldehyde. In those cases, the formaldehyde must be accounted for in the VOC speciation calculations. Subtract the AP-42 formaldehyde factor from the AP-42 VOC emission factor and then divide each trace organic factor by the resulting amount according to the formula below:

$$E_{speciated\ VOC} = \frac{EF_{AP-42\ speciated\ VOC}}{EF_{AP-42\ total\ VOC} - EF_{AP-42\ formaldehyde}} \times E_{total\ VOC}$$

Where:

$E_{speciated\ VOC}$ = the tpy rate for a speciated VOC contaminant

$EF_{AP\text{-}42\ speciated\ VOC}$ = the specific trace organic factor for the compound in AP-42

$EF_{AP\text{-}42\ total\ VOC}$ = the AP-42 VOC emission factor

$EF_{AP\text{-}42\ formaldehyde}$ = the AP-42 formaldehyde factor

$E_{total\ VOC}$ = the tpy total VOC (formaldehyde excluded) determined using stack-test data or vendor data

In the following example, a vendor supplied the total VOC factor and the formaldehyde factor. Total VOC emissions were determined to be 11.2 tons; formaldehyde emissions, 3.8 tons. Assuming the composition of the exhaust VOCs is not known, the inlet-gas analysis cannot be used to speciate the VOC emissions because complex oxidation reactions occur in the combustion chamber that alter the emissions composition significantly. Therefore, the emission factors in AP-42 must be used to speciate the remaining VOC emissions. To obtain the speciation ratio, first subtract the AP-42 formaldehyde factor from the AP-42 total VOC factor:

$$0.118\frac{lb}{MMBtu} - 0.0528\frac{lb}{MMBtu} = 0.0652$$

Then divide each trace organic compound's emission factor by the adjusted VOC emission factor. The AP-42 emission factor for acetaldehyde is 0.00836 lb/MMBtu:

$$0.00836\frac{lb}{MMBtu} \div 0.0652\frac{lb}{MMBtu} = 0.1282$$

Multiply the engine's total VOC emissions by this ratio to determine the acetaldehyde emissions:

$$11.2\ tons\ VOC \times 0.1282 = 1.4358\ tons\ acetaldehyde$$

Only the trace organic compounds exceeding the 0.1-ton threshold must be reported in the EI, and the remaining balance of the total VOC emissions must be reported under "VOC-unclassified," as shown in Table A-3.

**Table A-3. Reporting VOC Emissions From Internal Combustion—Vendor Factor Excludes Formaldehyde**

| Contaminant Code | Contaminant | Annual Emissions (tons) | Determination Methodology |
|---|---|---|---|
| **50001** | VOC-unclassified | 0.4055 | V |

| Contaminant Code | Contaminant | Annual Emissions (tons) | Determination Methodology |
|---|---|---|---|
| **51620** | acetaldehyde | 1.4358 | S |
| **51640** | acrolein | 0.8829 | S |
| **51680** | formaldehyde | 3.8 | V |
| **51530** | methanol | 0.4294 | S |
| **56150** | methylcyclohexane | 0.2113 | S |
| **56600** | n-hexane | 0.1907 | S |
| **56750** | n-pentane | 0.4466 | S |
| **56775** | propane | 7.1975 | S |

### *Ozone Season Emissions*

Ozone season emissions must reflect an average daily emission rate. Do not report maximum daily emissions based on a design capacity and the assumption that the source operated 24 hours each day. For sources that run regularly throughout the ozone season, divide the total emissions during the ozone season (as designated in Chapter 4) by 153.

## External Combustion Sources Burning Gaseous Fuel

### *Expected Contaminants*

Reported boiler emissions must include all of the following:

- PM (contaminant code 10000)
- $PM_{10}$ (contaminant code 20000)
- $PM_{2.5}$ (contaminant code 39999)
- VOCs (contaminant codes within the range of 50001 through 59998)
- HAPs, such as formaldehyde
- $NO_X$ (contaminant code 70400)
- $SO_2$ (contaminant code 70510)
- CO (contaminant code 90300)

### *Emissions Determination Methodologies*

The appropriate emissions determination methodologies for regulated pollutant emissions from boilers are, in order of preference:

- D (CEMS)

- F (PEMS)
- M (measured: stack-test data)
- Q (portable-analyzer-test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- B (material balance)
- S (scientifically calculated)
- E (estimated)

Portable analyzers have their own determination methodology and must be designated as "Q." Testing conducted with a portable analyzer does not qualify as stack testing; therefore, the emissions determination methodology must not be coded measured ("M"). If the stack-test results from an identical unit are used to determine the emissions, the emissions determination methodology must be coded "estimated" ("E").

If none of these methodologies accurately represent a source's emissions, contact the EAS for further assistance.

### *$SO_2$ Emissions*

If any sulfur is present in a source's inlet gas, the source will emit $SO_2$ as a product of combustion. CEMS, PEMS, and stack-test data are the preferred methods, in descending order, for determining the $SO_2$ emissions. If data from direct measurements are not available, then $SO_2$ emissions must be determined using material balance based upon the combusted fuel's sulfur content. If the unit only burns pipeline-grade sweet natural gas, AP-42 factors or vendor data can be used to estimate the $SO_2$ emissions.

### *Particulate Emissions*

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 microns. Hence, all particulate emissions from these sources must be reported as PM, $PM_{10}$, 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 PM (contaminant code 10000), as $PM_{10}$ (contaminant code 20000), and as $PM_{2.5}$ (contaminant code 39999).

Use of EPA factors other than AP-42 is acceptable only if the Air Permits Division has approved the emissions factors to determine permitted emissions rates and if more preferred data, such as vendor or stack test data, are not available.

## VOC Emissions

Source-specific data for total VOC emissions as detailed in "Emissions Determination Methodologies" (above), if available, must be used to determine VOC emissions. Speciated VOC emissions may be determined using multiple methods, including stack-test data, vendor data, or AP-42 emission factors, or a combination. Each methodology is discussed separately in the following sections and is followed by instructions on speciation.

## CEMS Data

If available, CEMS data must be used to determine a source's total VOC emissions. Please see the guidance in Chapter 4 for more information.

If a CEMS measures total hydrocarbon emissions instead of VOC emissions, special attention is necessary to determine VOC emissions accurately. Please contact the EAS for assistance.

## Stack-Test Data

When using stack-test data to determine VOC emissions, verify that the test measured total VOCs rather than total hydrocarbons. If the test measured VOCs, the results must be used to determine the VOC emissions and the determination methodology coded "M."

If the stack test measured total hydrocarbons, the VOC emissions will need to be determined by multiplying the hydrocarbon emission factor by the following ratio: *AP-42 VOC emission factor / AP-42 TOC emission factor*. The determination methodology must be coded "S." Because complex oxidation reactions occur in the combustion chamber that significantly alter the composition of emissions, it is unacceptable to apply the inlet-gas stream's VOC percentage to the stack-test TOC emission factor to obtain a VOC emission factor.

## Vendor Data

When using vendor data to determine VOC emissions, verify that the vendor's emission factor refers to VOCs rather than total hydrocarbons. If it does, the VOC emissions can be calculated, and the determination methodology must be coded "V."

If the vendor's emission factor refers to total hydrocarbons, the VOC emissions must be determined by multiplying the hydrocarbon emission factor by the ratio: *AP-42 VOC emission factor / AP-42 TOC emission factor*. The determination methodology must be coded "S."

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

## AP-42 Factors

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

When using an AP-42 emission factor to determine emissions, use the most recent emission factor and report the determination methodology as "A."

## Speciation

To determine whether to speciate VOC emissions from a natural gas-fired external combustion source, consult Chapter 4.

If speciation is required for the emissions source, source-specific information, if available, must be used when calculating the speciated VOC emissions.

If no source-specific information about the VOC composition exists, the VOC emissions must be speciated using the AP-42 "speciated organic compounds" emission factors that are graded "C" or better. Divide each of these factors by the AP-42 VOC emission factor to obtain the contaminant's speciation ratio. Then multiply the source's total VOC emissions by each contaminant's speciation ratio to obtain that contaminant's emission rate. The remaining balance of the VOC emissions must be included in the "VOC-unclassified" emissions (contaminant code 50001).

If stack-test data are used to determine total VOC emissions, the determination methodology for the speciated emissions must be coded "S" for "scientifically calculated"; the VOC-u emissions must be coded "M." If AP-42 emission factors are used to determine total VOC emissions, the determination methodology must be coded "A."

*Example*: Using stack-test data, the VOC emissions from a boiler have been determined to be 43 tons. No information about the composition of the exhaust VOC emissions exists. Inlet gases were analyzed but, because complex oxidation reactions occur in the combustion chamber that alter the composition of emissions significantly, the results of the inlet-gas analysis cannot be used to speciate the VOC emissions. The VOC emission factors in AP-42 must be used to speciate the VOC.

In AP-42, formaldehyde is one of the compounds graded C or better and the emission factor is 0.075 lb/MMscf. The total VOC emission factor in AP-42 is 5.5 lb/MMscf. To obtain formaldehyde's speciation ratio, divide the formaldehyde emission factor by the total VOC emission factor:

$$0.075\frac{lb}{MMscf} \div 5.5\frac{lb}{MMscf} = 0.0136$$

Multiply the boiler's total VOC emissions by this ratio to determine the formaldehyde emissions:

$$43\ tons\ VOC \times 0.0136 = 0.5864\ ton\ formaldehyde$$

Perform similar calculations for benzene and toluene. Report the boiler's VOC emissions as shown in Table A-4.

**Table A-4. Reporting VOC Emissions From External Combustion**

| Contaminant Code | Contaminant | Annual Emissions (tons) | Determination Methodology |
|---|---|---|---|
| **50001** | VOC-unclassified | 42.3706 | M |
| **51680** | formaldehyde | 0.5864 | S |
| **52420** | benzene | 0.0164 | S |
| **52490** | toluene | 0.0266 | 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, 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 vents to a separate emission point (that is not the emission point shared with the associated unit) when it operates independently, the emission point 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. The path for the associated unit that vents to the shared stack must be represented in the EI.

### *Expected Contaminants*

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

- PM (contaminant code 10000)

- $PM_{10}$ (contaminant code 20000)
- $PM_{2.5}$ (contaminant code 39999)
- VOCs (contaminant codes within the range of 50001 through 59998)
- HAPs, such as formaldehyde
- $NO_X$ (contaminant code 70400)
- $SO_2$ (contaminant code 70510)
- CO (contaminant code 90300)

Additionally, ammonia ($NH_3$), contaminant code 70050, may be emitted from units that use certain control technologies.

### *Emissions Determination Methodologies*

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

- D (continuous emissions monitoring system, or CEMS)
- F (predictive emissions monitoring system, or PEMS)
- M (measured: stack-test data)
- Q (portable-analyzer-test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- B (material balance)
- S (scientifically calculated)
- E (estimated)

Portable analyzers have their own determination methodology and must be designated as “Q.” Testing conducted with a portable analyzer does not qualify as stack testing; therefore, the emissions determination methodology must not be coded “measured” (“M”). If the stack-test results from an identical unit are used to determine the emissions, the determination methodology must be coded “estimated” (“E”).

If none of these methodologies 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.

If stack-test data are used to determine emissions from a combined-cycle turbine equipped with a duct burner, two data sets must be used to determine the emissions: one representing emissions with the duct burner on, and the other with the duct burner off. If two separate data sets do not exist or if another method is used to determine emissions, contact the EAS for guidance.

### *Particulate, VOC, and $SO_2$ Emissions*

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

## Portable Engines

### *Structure*

A portable engine is an engine that is designed to be—and can be—moved. It is considered a stationary source only if it remains at a single location for 12 or more consecutive months. Therefore, it may be subject to reporting requirements. Even if the portable engine itself may not be subject to the reporting requirements, emissions from any maintenance performed on the engine may need to be reported.

An engine that replaces another engine at a location and that is intended to perform the same or similar function is included in calculating the consecutive time period. A portable engine is represented in the EI the same way as an internal combustion engine and emissions are calculated in the same manner. Please refer to "Internal Combustion Engines," earlier in this supplement.

## Coal-Fired Boilers

Coal is a combustible sedimentary rock composed of a complex combination of organic matter and inorganic mineral matter. Coal is classified by rank (type) as lignite, bituminous, sub-bituminous, or anthracite. Emissions from coal combustion depend on the type and composition of the coal, the type and size of the boiler, boiler firing operations, boiler load, type of control technologies abating the emissions, and the level of equipment maintenance. The following sections discuss expected contaminants and emissions from coal-fired boilers in general and are not specific to boiler configuration or coal type.

### *Expected Contaminants*

Reported boiler emissions must include all of the following:

- PM (contaminant code 10000)
- $PM_{10}$ (contaminant code 20000)
- $PM_{2.5}$ (contaminant code 39999)
- Lead compounds (various contaminant codes)
- Mercury compounds (various contaminant codes)
- VOCs (contaminant codes within the range of 50001 through 59998)
- HAPs, including PM and VOC
- Air toxics
- $NO_X$ (contaminant code 70400)
- $SO_2$ (contaminant code 70510)

- Acid gases such as hydrochloric acid, hydrofluoric acid, sulfuric acid, etc. (various contaminant codes)
- CO (contaminant code 90300)

Additionally, $NH_3$, contaminant code 70050, may be emitted from units that use certain control technologies.

### *Emissions Determination Methodologies*

In general, the appropriate emissions determination methodologies for coal-fired boilers are, in order of preference:

- D (continuous emissions monitoring system, or CEMS)
- F (predictive emissions monitoring system, or PEMS)
- M (measured: stack-test data)
- Q (portable-analyzer-test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- S (scientifically calculated)
- E (estimated)

If the stack-test results from an identical unit at the same site are used to determine the emissions, the emissions determination methodology must be coded "estimated" ("E"). TCEQ will also consider, case by case, the validity of using stack-test emission factors generated for one source at a site to determine emissions from identical facilities at another site.

Portable analyzers have their own determination methodology and must be coded "Q." Testing conducted with a portable analyzer does not qualify as stack testing; therefore, the emissions determination methodology must not be coded "measured" ("M").

### *$NO_X$, $SO_2$, and CO Emissions*

$NO_X$ and $SO_2$ emissions from these sources are typically continuously monitored.

CO emissions from these sources are typically either continuously monitored or determined using stack-test results.

If the methodologies discussed in this section do not accurately represent a source's emissions, contact the EAS for further assistance.

### *Particulate Matter Emissions*

If available, source-specific data must be used to determine particulate matter emissions as detailed in "Emissions Determination Methodologies" (above). Note that the method (or methods) used to calculate particulate matter emissions must account for the entire filterable and condensable portions of particulate matter emissions in accordance with 30 TAC Section 101.1(77), which defines particulate matter emissions.

Therefore, both filterable and condensable particulate matter must be quantified and reported within the EI.

It is anticipated that most coal-fired boilers will have stack-test data or monitoring data to determine filterable particulate matter emissions. However, depending on the source-specific data available, a combination of different determination methods may have to be used to quantify the filterable and condensable portions of particulate matter.

For example, a source has stack-test results for particulate matter. However, the testing equipment was not modified to collect condensable particulate matter. Therefore, the stack-test results may be used to determine the filterable portion of particulate matter emissions, but a different method (such as AP-42) will have to be used to quantify the condensable portion of the particulate matter emissions. The filterable and condensable emissions will have to be summed and reported as particulate matter emissions in the EI. Code the resulting total particulate matter emissions with the determination method that represents the largest portion of the emissions.

### Particle Size Distribution

The percentages of $PM_{10}$ and $PM_{2.5}$ that constitute a boiler's particulate matter emissions are often referred to as a particle size distribution. Source-specific, EPA-approved testing is the best method available to determine particle size distribution. If test data are not available, process knowledge—including industry data or test data from a similar unit—may help determine a source's particle size distribution. AP-42 also contains particle size distribution information for coal-fired boilers.

### Speciation

General guidance concerning speciating particulate matter emissions is available in Chapter 4.

Speciated particulate matter emissions may be determined using multiple methods, including stack-test data, vendor or industry data, AP-42 emission factors, or a combination of these.

Evaluate and use the best available method to determine emissions for individual particulate matter species on a contaminant-by-contaminant basis. Different particulate matter species may be determined by using different methods as long as the best available method is used for each contaminant. Contact the EAS directly if you have questions.

Report total acid gas emissions in the EI. If sufficient source-specific information exists to partition acid gas emissions between the particulate matter (i.e., condensed) and vapor phases, report the different phases of the emissions under the appropriate contaminant codes. Document the partitioning in the supporting documentation, including method used. Ensure that particulate matter and vapor phase acid gas emissions accurately sum to the total acid gas emissions from the source.

Do not exclude sulfate emissions from particulate matter emissions, especially from emissions determined using stack-test results. Naturally occurring sulfate salts—such as sodium sulfate, potassium sulfate, ammonium sulfate, etc.—are typically present in coal-fired boiler particulate matter emissions and must be reported in the EI. If concerns exist about stack-test results being representative of a coal-fired boiler's particulate matter emissions, contact the EAS directly for assistance.

Specific guidance regarding speciating particulate matter emissions that are classified as HAPs or air toxics is available in the section below.

### *HAP and Air Toxic Emissions*

General guidance concerning speciating HAP and toxic emissions, including applicable reporting thresholds, is available in Chapter 4.

If available, source-specific data must be used to determine HAP and air toxic emissions as detailed below.

#### HAP- and Air Toxic-Specific Emissions Determination Methodologies

The appropriate emissions determination methodologies for coal-fired boilers are, in order of preference:

- D (continuous emissions monitoring system, or CEMS)
- D (sorbent trap monitoring system)
- F (predictive emissions monitoring system, or PEMS)
- M (measured: stack-test data)
- Q (portable-analyzer-test data)
- E (estimated) only for stack-test results from an identical unit
- B (material balance)
- A (AP-42 emissions factors) *or* O (industry-supplied emissions factors)
- S (scientifically calculated)
- E (estimated) for all other methods except for stack-test results from an identical unit

For HAPs and air toxics from coal-fired boilers, stack-test results from an identical unit are preferred to emissions factors that are based on units of varying ages that potentially fired different types of coal. If the stack-test results from an identical unit at the same site are used to determine the emissions, the emissions determination methodology must be coded "estimated" ("E"). TCEQ will also consider, case by case, the validity of using stack-test emission factors generated for one source at a site to determine emissions from identical facilities at another site.

Portable analyzers have their own determination methodology and must be coded "Q." Testing conducted with a portable analyzer does not qualify as stack testing; therefore, the emissions determination methodology must not be coded "measured" ("M").

Evaluate and use the best available method to determine emissions for individual HAPs or air toxic species on a contaminant-by-contaminant basis. Different HAPs or air toxics may be determined using different methods, as long as the best available method is used for each contaminant. Contact the EAS directly if you have questions.

### Mercury Emissions

It is anticipated that most sources will have either CEMS or sorbent-trap monitoring data to determine mercury emissions.

If neither of these methodologies accurately represent a source's emissions, contact the EAS for further assistance.

### Other Metal Emissions

It is anticipated that most sources will use stack-test results from the unit itself or from an identical unit to determine emissions.

If neither of these methods are available, material balance or emissions factors methods may be used to determine emissions. Ensure that reported metal emissions account for both filterable and condensable particulate matter emissions in accordance with 30 TAC Section 101.1(77).

# Technical Supplement 2: Cooling Towers

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

**Disclaimer for Technical Supplement 2**

This technical supplement is intended to help determine and report emissions from cooling towers. This supplement does not supersede or replace any state or federal law, rule, or regulation. This guidance reflects the current understanding of how cooling towers work, how emissions are generated, how cooling towers are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies conducted and as new information becomes available. TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The methods represented are intended to assist with calculating emissions; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS helpline at 512-239-1773.

## 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.

For cooling towers already in the EI, ensure that the appropriate facilities have a "cooling tower" group and profile and that all facility profile attributes are complete. Each cooling tower facility must have a stack-type emissions point. This **stack** type emissions point must have all of the following five features:

1. A stack diameter equal to the diameter of one of the following:
   a. the tower top (for natural draft towers)
   b. the fan (for mechanical draft towers)
   c. an average fan (for multicell towers)
2. A stack velocity of 10–20 feet per second.
3. A temperature ranging from ambient to 15 degrees Fahrenheit above ambient.
4. A nonzero moisture content (generally between 5% to 10%).
5. A horizontal discharge, except for crossflow towers (possibly).

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

## Cooling Tower Source Classification Codes

The cooling tower must be represented on the EI with an SCC of either *38500101* (for mechanical-draft cooling towers) or *38500102* (for natural-draft cooling towers).

## Expected Emissions

Depending on their service, cooling towers have the potential to emit particulate matter, inorganic compounds, or VOCs.

### *Particulate Matter*

All cooling towers have the potential to emit 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 ($PM_{10}$ 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.

Please represent drift eliminators (whether aftermarket installed or as a design of the cooling tower) as an abatement device with the PM control percentage calculated as the difference between the AP-42 default drift of 0.02% and the vendor drift factor. For example, if the vendor drift factor is 0.001%, the PM control percentage would be 95%.

### *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 into the atmosphere. 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, resulting in VOC emissions.

## Emissions Determination

The process serviced by the cooling tower will largely determine how emissions must 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 determine particulate emissions. If a vendor-supplied drift factor is used, the determination methodology must be coded "V" for "vendor data."

If no drift data are available from the manufacturer, determine particulate emissions using the appropriate factor from AP-42, Section 13.4. The determination methodology must be coded "A."

*Note:* AP-42 does not include factors for $PM_{2.5}$ emissions. Use the best available site-specific data and process knowledge to determine $PM_{2.5}$ emissions from cooling towers. If using a size fraction algorithm to determine $PM_{10}$ and $PM_{2.5}$ emissions, the determination methodology must be coded "S" for scientific.

### *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. The determination methodology must be coded "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 an HRVOC monitoring system required by 30 TAC Section 115.764 (coded "H").
- Emissions data from a TCEQ-approved air-stripping method (coded "M").
- Emissions data from an approved monitoring and control program plan, other than an air-stripping method, on file with TCEQ (coded "B").
- Emissions data from an unapproved monitoring and control program (coded "E").
- The AP-42 **uncontrolled** VOC factor (coded "A").

Emissions determined from HRVOC monitoring systems not required by 30 TAC Section 115.764 must be coded "B" for "material balance" and not "H." Similarly, emissions determined from a CMS for compounds other than HRVOCs are coded "B."

For example:

- Ethylene emissions determined from a TCEQ-required HRVOC monitor must be coded "H." Ethylene is a HRVOC monitored by a TCEQ-required monitor.
- Ethylene emissions determined from a monitoring system not required by Section 115.764 must be coded "B." The monitoring of ethylene was not required under 30 TAC Chapter 115.
- Propane emissions must be coded as "B" regardless of the monitoring reason because propane is not a HRVOC.

The use of the AP-42 **controlled** VOC emission factor is **not** allowed. Detailed explanations of methods used to determine emissions 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. 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 an emission factor from Section 5.1 of AP-42, the uncontrolled emission factor (6 lb/MMgal) must be used. According to AP-42, the control indicated by the controlled emission factor (0.7 lb/MMgal) is technology that minimizes hydrocarbon leaks into the cooling water system and monitors the cooling water for hydrocarbons. If a monitoring system allows for such control, then the associated data must be sufficiently detailed to allow for the derivation of an emission rate, either through a measurement of total VOCs or through testing for all VOC species present in the cooling water. If the monitoring system is insufficient to monitor and quantify hydrocarbons, the "uncontrolled" VOC emission factor must be used. If the emissions are determined in this manner, the determination methodology must be coded "A."

Emissions determined based on measurements from an air-stripping method as outlined in the TCEQ Sampling Procedures Manual, Appendix P, are preferred.[a] 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, the value equating to 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.

[a] www.tceq.texas.gov/downloads/compliance/investigations/assistance/samplingappp.pdf

This method applies to monitoring that determines the 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 emission factor must be used to determine the total VOC emission rate from the cooling tower, and the measurements of the select VOC species (such as HRVOCs) must 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, the determination methodology must be coded "M" (for "measured").

Measured cooling water VOC concentrations and flow rate data may be used to determine the VOC 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 situations where 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. **Please note that the application of TOC or VOC concentration to water drift does not properly account for the VOC emissions stripping or flashing out of the water. Therefore, this method must not be used to determine emissions.** Concentrations must be applied to the flow (circulation) rate data to determine emissions.

For cases where only a select few of the possible VOCs present in the cooling water are measured, the AP-42 uncontrolled emission factor must be used to determine the total VOC emission rate from the cooling tower, and the measurements of the select VOC species (such as HRVOCs) must be speciated in the emissions reporting and subtracted from the total VOC emission rate derived from AP-42. Since these methods measure the composition of chemicals in the cooling water rather than the amount of emissions, the emissions are not determined by using measured data. The appropriate determination methodology will depend upon whether data are gathered by following an approved monitoring and control program plan on file with TCEQ. If so, the determination methodology must be coded "B" for "material balance." If not, the determination methodology must be coded "E" for "estimated." Please note that, in the case of cooling towers, such estimates are preferred instead of the AP-42 emission 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 the beginning date and time when the leak began are not known, assume that the leak began immediately after the previous sample was taken. If the majority of annual emissions are determined using the measured data, the determination methodology must be reported as described in the preceding paragraph.

Note that the information from devices such as lower explosive limit detectors, chlorine ($Cl_2$) residual measurements, and total organic carbon measurements do not

qualify as adequate monitoring or control technology; therefore, the AP-42 controlled VOC emission factor must not be used.

## Annual and Ozone Season Rates

If measured data are available for a cooling tower, calculate the reported emissions using actual, rather than average, test data. Use test data from each sampling event to determine emissions released since the prior sampling event. Sum the emissions obtained from the different sampling periods 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, 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, use the same methodology but only sum the emissions from sampling periods that occurred during the ozone season months.

## 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 the EI 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.
- Emission rates calculated from measured data.
- Drift rate.

## Issues of Special Concern

### *What if I share a cooling tower with another company?*

Emissions must be reported by the owner or operator of the cooling tower. Please call the EAS for additional guidance about an individual situation.

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

No. According to AP-42, use of the "controlled" emission 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 must 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 for EI purposes.

### *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. Please represent drift eliminators (whether aftermarket installed or as a design of the cooling tower) as an abatement device with the PM control percentage calculated as the difference between the AP-42 default drift of 0.02% and the vendor drift factor. For example, if the vendor drift factor is 0.001%, the PM control percentage would be 95%.

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

Yes. The cooling tower's emission point must be shown as a stack. For more information, see "Cooling Tower Structure" earlier in this supplement.

### *What does the cooling tower attribute "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% by weight of aggregate HRVOCs (ethylene, propylene, all isomers of butene, and 1,3-butadiene), the cooling tower is considered to be in HRVOC service for EI 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 EI?*

This information may be included in the comments field under the Facility Information portion of the EI 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/air-emissions-factors-and-quantification/ap-42-compilation-air-emission-factors. Accessed Sept. 1, 2020.

Perry, Robert H., et al. 1997. *Perry's Chemical Engineers' Handbook*. 7th ed. New York: McGraw-Hill.

# Technical Supplement 3: Fugitive Emissions From Piping Components

This technical supplement offers guidance for identifying, determining, and correctly reporting fugitive emissions from piping components and associated equipment. 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 piping components as a fugitive area in the EI is specifically addressed under "Issues of Special Concern" later in this supplement. For general guidance on this topic, consult Chapter 3, "Emissions Inventory Structure."

### Disclaimer for Technical Supplement 3

This technical supplement is intended to help determine and report emissions from piping components. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how piping components work, how emissions are generated, how piping components are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The methods represented are intended to assist with calculating emissions; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS helpline at 512-239-1773.

## Definitions

In this document, *traditional component types* refers to those component types traditionally considered and reported as sources of fugitive emissions from piping components: 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 fugitive emissions from piping components but identified as such by recent scientific studies. Examples include screwed fittings, liquid relief valves, agitators, heat exchanger heads, sight glasses, bolted manways and hatches, blind flanges, caps and plugs, compression fittings, and metal-to-metal seals.

## Fugitive Component Structure

The EI structure of fugitive piping components will depend on the site. For sites that process or handle a single hydrocarbon or inorganic stream, such as a natural gas compressor station or a petroleum marketing terminal, the fugitive emissions from the entire plant's piping components must be represented by one facility-emissions point path. For sites that process or handle multiple hydrocarbon or inorganic streams with varying compositions, however, fugitive emissions must be reported by process area as detailed below. Please note that individual fugitive components must be grouped and reported as collective sources according to the guidance below as well as the section "Guidelines for Including Sources in Emissions Inventory Structure" in Chapter 3. Individual fugitive components are not considered individual facilities.

When separating fugitive areas into multiple facilities, if different process areas within a plant follow different LDAR programs, each area must be represented by a separate path to avoid confusion. Also, since stream composition may differ greatly between processes and may necessitate the use of different calculation methodologies, fugitive emissions from separate processes must be reported under separate facilities. Consistent with these criteria, fugitive components—including valves, piping, flanges, and other components—must continue to be grouped together and reported under one FIN and not under individual FINs. For example, for a refinery with a process area for methyl tert-butyl ether (MTBE) production, emissions determinations for the MTBE process area must use correlation equations or the Synthetic Organic Chemical Manufacturing Industry (SOCMI) average emission factors, as they more accurately determine emissions than the refinery factors. Separate facility-emissions point paths must represent the MTBE process area fugitives and the refinery fugitives.

## Expected Emissions

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

## Quantifying Fugitive Emissions From Piping Components

### *Introduction*

The fugitive emissions from piping components 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.

### *Emission Factors*

All emission factors discussed in this supplement are available in the PDF document titled *Emission Factors for Equipment Leak Fugitive Components* on the EAS webpage. 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.[a]

### *Requirements for Determining Fugitive Emissions From Piping Components*

Emissions from instrument-monitored 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 the 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.

TCEQ has previously allowed the use of LDAR reduction credits applied to the EPA's average emission 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 emissions determinations than using average emission factors with LDAR reduction credits.

Since all monitored sources have individual screening values, the use of average emission factors with LDAR reduction credits to determine emissions from monitored components is not allowed. One exception is detailed under "Quantifying Emissions from Components Monitored by an Audio/Visual/Olfactory (AVO) Inspection" later in this supplement.

### *Emissions Determination Methodologies: Order of Preference*

The appropriate methodologies for determining total or speciated VOC emissions from piping components are, in order of preference:

- Unit-specific correlation equations developed using bagging data in accordance with EPA guidelines (code as "M").
- EPA correlation equations using screening values from an LDAR program (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 EI purposes is no longer allowed, with few exceptions. One exception is detailed under "Quantifying Emissions from Components Monitored by an Audio/Visual/Olfactory (AVO) Inspection" later in this supplement.

[a] www.tceq.texas.gov/goto/nsr_elf

# Determining Emissions From Monitored Components

## *Quantifying Emissions Using Correlation Equations*

Emissions from monitored components must be determined using site specific monitoring data. Specifically, correlation equations must be used to determine emissions when a permit condition, EPA or 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 website.[a]

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 webpage. The EPA has approved separate correlation-equation sets for SOCMI components and petroleum industry components (including refineries, marketing terminals, and oil and gas production facilities).

TCEQ accepts the use of correlation equations for screening values between zero and 100,000 parts per million. To determine emissions using correlation equations, 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 non-pegged 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 must 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 must 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

[a] www.epa.gov/chief

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-5.

Since a component's screening concentration may vary from one monitoring period to another, emissions for each period must be based upon each component's screening concentration for that period. These period-specific emission rates must then be summed to obtain an annual emissions rate. For example, if components are monitored quarterly, each component's quarterly screening value must 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 it was 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. TCEQ must approve any other method of determining leak durations.

**Table A-5. 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 |

When using the correlation equations to calculate emissions, the components must be monitored at least once during the year. Monitoring data from a previous year may only be used to determine future emissions if approved by the EAS. Please see the "Issues of Special Concern" section below for specific guidance.

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, TCEQ 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, TCEQ may require the use of the EPA's pegged leak rates.

## *Quantifying Emissions From Components Monitored under Alternative Work Practices Using an Optical Gas Imaging System*

Since the publication of the EPA's regulatory guidance document on fugitive emission estimation methods, new approaches to fugitive monitoring have been developed. One of these approaches, optical gas imaging (OGI), uses a camera with a filter in the infrared spectrum to allow an operator to qualitatively "see" hydrocarbon leaks.

TCEQ authorizes OGI monitoring of fugitive components under the alternative work practices (AWP) specified in 30 TAC Section 115.358 and 40 CFR parts 60, 63, and 65. Under these programs, components are monitored for leaks using OGI at a rule-specified frequency and may be monitored annually using EPA Reference Method 21.

The following guidance applies to determining emissions from components monitored under an authorized AWP using OGI, including difficult-to-monitor components.

### Quantifying Emissions Using Correlation Equations

Emissions from components monitored using EPA Reference Method 21 must be determined using site-specific monitoring (screening) data. Specifically, correlation equations must be used to determine emissions when a permit condition, EPA or TCEQ rule, or commission order requires the retention of screening value data.

For non-leaking components, use annual EPA Reference Method 21 data and correlation equations to determine emissions.

For leaking components where EPA Reference Method 21 data is used to both quantify leaks found using OGI and to confirm leak repair, use correlation equations to determine emissions. Account for the leak's duration when determining emissions. An acceptable engineering estimate would be that the component was leaking at the measured concentration for half of the monitoring period, plus the time needed to repair the component. TCEQ must approve any other method of determining leak durations.

### Quantifying Emissions Using Other Methods

For non-leaking components that do not have EPA Reference Method 21 data (such as component repairs verified using OGI), use the appropriate no-leak (<10,000 ppmv) screening range emission factors from Tables 2-5 through 2-8 of the EPA's *Protocol for Equipment Leak Emission Estimates* for the period that the component is not leaking.

For a leaking component that does not have EPA Reference Method 21 data, use the appropriate leaking (≥10,000 ppmv) screening range emission factors from Tables 2-5 through 2-8 of the Protocol for Equipment Leak Emission Estimates to determine

emissions; account for the period the component is leaking. An acceptable engineering estimate would be that the component was leaking at the measured concentration for half of the monitoring period, plus the time needed to repair the component. TCEQ must approve any other method of determining leak durations.

For components where leaks were repaired and confirmed using OGI only (not EPA Reference Method 21), use the appropriate no-leak (<10,000 ppmv) screening range emission factors from Tables 2-5 through 2-8 of EPA's *Protocol for Equipment Leak Emission Estimates* to determine emissions from the time of the repair. If the repair occurs before the annual EPA Reference Method 21 reading during a calendar year, then the annual EPA Reference Method 21 result should be used to quantify the emissions from the time of the repair unless re-monitoring of the repaired component indicates a leak. In that case, use the leaking (≥10,000 ppmv) screening range emission factors as described within this section.

As an example, a compressor seal under semi-annual OGI monitoring was monitored on Dec. 1, 2023 and had no visible leaks. The same component was monitored on May 1, 2024 and was found to be leaking. It was repaired and also rechecked on May 30 and had no visible leaks. During the semi-annual OGI monitoring on Nov. 30, 2024. The total annual emissions would be calculated as the sum of the leaking and non-leaking emissions as follows:

$$Total\ annual\ emissions = Leaking\ emissions + Non - leaking\ emissions$$

Where:

*Leaking emissions* = ≥10,000 ppmv screening range factor for "other" component * [(half the Dec. 1 through May 1 interval) + (May 2 through May 30 interval)]

*Non-leaking emissions* = <10,000 ppmv screening range factor for "other" component * (hours for the remainder of the year)

### Other Considerations

Components outside the AWP monitoring workplan are considered unmonitored. To determine emissions, see Determining Emissions from Unmonitored Components.

## *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 emission factors with AVO reduction credits applied can be used to determine emissions. To claim credit for this program, the documentation must demonstrate that all elements of the program are in place and were followed.

Factors for equipment leak fugitives appear in *Emission Factors for Equipment Leak Fugitive Components* (PDF) on the EAS webpage.

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%. A weekly walk-through inspection earns only a 30% reduction credit. An AVO inspection should be coded as "**A**" in the EI.

## Determining Emissions From Unmonitored Components

### *Emissions Determination Requirements*

Emissions from monitored components must be determined using actual monitoring data. However, for unmonitored components, average emission factors should be used to quantify emissions.

### *Quantifying Emissions Using Average Factors*

Average emission factors are divided into four categories:

- SOCMI
- oil and gas production
- refinery
- petroleum-marketing terminal

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, choose between a "heavy liquid" emission factor and a "light liquid" emission factor. Use the "heavy liquid" emission 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" emission factor.

Note that the average emission factors generally determine total hydrocarbon emissions. Determine the total VOC emissions by multiplying the calculated emission rates by the stream's percentage by weight of VOC compounds.

The EPA average emission 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 website.

## SOCMI Emission Factors

Use the SOCMI emission factors to determine the fugitive emissions from piping components at chemical plants or chemical processes within refineries. SOCMI emission factors are divided into three categories: SOCMI average emission factors, "SOCMI with ethylene" emission factors, and "SOCMI without ethylene" emission factors.

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

## Oil and Gas Production Emission Factors

The oil and gas production emission factors are based on data from piping component leaks from oil and gas production sites gathered by the American Petroleum Institute (API) and evaluated by the EPA. These 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% and 99%).

## Refinery Emission Factors

Use refinery emission factors to determine the fugitive emissions from piping components for 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 SOCMI factors, rather than the refinery factors, to calculate emissions.

## Petroleum Marketing Terminal Emission Factors

Use the emission factors for petroleum marketing terminals to determine the fugitive emissions from piping components at gasoline-distribution facilities that are one step removed from local gasoline stations and other end users. Pipeline breakout stations that are in crude-oil, gasoline, diesel, and jet-fuel service can also use petroleum marketing terminal emission factors to determine the fugitive emissions from piping components. Do not use these emission factors to determine the fugitive emissions from other types of terminals or breakout stations or from loading racks at chemical plants and refineries; instead, use the appropriate SOCMI or refinery emission factors.

The use of these emission factors must be accompanied by an AVO program performed monthly. To claim credit for this program, the documentation must demonstrate that all elements of the program are in place and were followed. Because the petroleum marketing terminal emission 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 emission 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. Emissions from exempt components, like those from unmonitored components, must be calculated and reported. Since these components are not monitored, calculate their associated emissions based on average emission 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 Emission Factors With Emissions Reduction Credits*

Quantifying emissions using average emission 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 emission 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, emissions reductions are not typically claimed for these components. However, if a weekly physical inspection program is in place, a 30% emissions reduction credit applied to average emission factors is allowed. To claim credit for any such program, the documentation must demonstrate that all elements of the program are in place and were followed. If connectors are instrument monitored, the correlation equations must be used 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 the emissions of odorous or toxic inorganic compounds like $Cl_2$, $NH_3$, $H_2S$, 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 emission factors.

If monitoring data are not available, calculate uncontrolled fugitive emissions using the industry-specific emission factors discussed previously. Although these VOC emission factors were not developed specifically for use with inorganic compounds, they are the best data currently available for determining inorganic fugitive emissions from piping components.

### *Quantifying Emissions for Nontraditional Components*

Emissions from nontraditional piping sources must 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 emission factors do not exist for most nontraditional components, TCEQ has identified appropriate substitute emission factors based on component, leak potential, and leak mechanism similarity. These emission factors are listed in Table A-6.

**Table A-6. 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 |
| Heat exchanger head: unmonitored | Open-ended line |
| Heat exchanger head: monitored | Flange correlation equation |
| Liquid relief valve | Light liquid valve |
| Metal-to-metal seal | Flange |
| Screwed fitting | Flange |
| Sight glass | Flange times two |
| Pressurized railcar loading arm: threaded connection | 0.0214 lb/hr/component |
| Pressurized railcar loading arm: quick-connect coupler | 0.0055 lb/hr/component |

The component-specific emission factors for pressurized railcar loading operations threaded connections and quick-connect couplers are listed in Table A-6 and must 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 must be included in the EI.

## *Special Considerations When Quantifying Emissions*

When determining fugitive emissions, the hours of operation and equipment design specifications need to be considered.

### Hours of Operation

Fugitive emission factors for piping components are independent of process unit throughput. Because emissions occur whenever material is in the line, regardless of process activity or downtime, all streams must 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 the fugitive emissions from piping components. If components are designed as described in the following sections, apply the stated emissions reduction credit.

***Relief Valves***: 100% control credit 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 the 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 reseat 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% 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***: Take a 100% 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***: Take a 100% control credit if the connections are welded together around their circumference so that the flanges cannot be unbolted.

***Compressors***: Take a 100% control credit if a compressor is designed with enclosed distance pieces and if the crankcase vents to a control device.

***Double Mechanical Seals***: Take a 75% control credit for any component employing double mechanical seals.

## Speciation

Use current gas or liquid process stream analysis (or both) to speciate the fugitive emissions from piping components. 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 EI, see Chapter 4.

## Supporting Documentation

Include representative sample calculations for each fugitive area, including a list of the components where a 100% control credit has been applied with a footnote describing the specific control method. If screening range emission factors are used, TCEQ 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 more than 5 tons was emitted at a fugitive area during the year, complete and submit the Fugitive Data Form or submit the requested information in a similar format with the emissions inventory supporting documentation. The Fugitive Data Form and instructions are available upon request.

## Issues of Special Concern

### *May I put the whole plant's fugitive emissions from piping components under one facility and emissions point?*

In a relatively small plant that handles one hydrocarbon stream, such as a natural gas compressor station or a petroleum-marketing terminal, the fugitive emissions from the entire plant's piping components will typically 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 LDAR programs, each area must 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 must be reported under separate facilities.

As an example, for a larger site, consider a refinery with a process area for MTBE production. Emissions determinations for the MTBE process area must use correlation

equations or the SOCMI average emission factors, as they are more appropriate than the refinery factors. Separate facility-emissions point paths must 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)?*

In general, the emissions from components 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 be used and no reduction credits from instrument monitoring may be applied. Certain non-monitored components can be excluded from emissions determinations. Please consult the *Air Permit Technical Guidance for Chemical Sources Fugitive Guidance* document APDG 6422 for details.

### *I have a unit that was shut down part of the year. Must I determine fugitive emissions from piping components for the entire year or just for the part of the year when the unit was operating?*

The fugitive emissions from piping components must 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 the fugitive emissions from piping components. 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, a different calculation methodology must be used for these unmonitored components.

### *I have an oilfield tank battery that stores crude oil and has associated loading operations. For the fugitive components, may I use the emission factors for bulk terminals?*

No. If monitoring data for the fugitive components exist, then the 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 emission factors to determine the emissions. For crude oil storage and loading at an oilfield tank battery, the oil and gas production emission factors would be more appropriate.

### *I have a leak detection and repair (LDAR) program. Is there any way to represent this on my emissions inventory?*

An LDAR program can be represented in the EI by adding a CIN with an abatement code of *800*. Since the LDAR reduction credits can no longer be applied to average

factors for emissions determinations, a control efficiency for this type of CIN is not required.

### *How do I find out if any new fugitive emission factors for piping components have been developed or approved by TCEQ?*

Review the PDF document *Emissions Factors for Equipment Leak Fugitive Components*, available on the EAS webpage.

### *Do I have to report emissions of nonreactive compounds?*

Nonreactive compounds like methylene chloride and acetone are still considered air contaminants and must be reported. This is particularly important if a nonreactive compound has an associated allowable emission rate. Nonreactive fugitive emissions from piping components must be calculated in the same way as VOC fugitive emissions.

### *For my permit, I used the EPA's average emission factors with leak detection and repair reduction credits to determine my fugitive emissions from piping components. Can I use this approach to report these emissions in the emissions inventory?*

No. All monitored components must either have limited data for leaking components or, preferably, have individual screening values. Since using this monitoring data with correlation equations or screening range emission 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 emission factors with no reductions applied to determine my emissions? Or can I apply the correlation equations using the data from the last monitoring period?*

Normally, TCEQ 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, use data from the most recent (last) monitoring period in the correlation equations. For future leaking components, 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 determine the amount of time a component will leak in the future, the emissions must be determined conservatively by assuming any leaking component will do so for an entire year.

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

The correlation equations must be used to determine emissions from the fugitive area if screening value data from an authorized EPA Reference Method 21 monitoring program are available.

If a monitoring program does not retain screening value data, emissions must be determined using the best available method. For authorized OGI monitoring programs, use the approaches specified in the section "Quantifying Emissions from Components Monitored under Alternative Work Practices Using an Optical Gas Imaging System." For other programs, if the screening-range emission factors are used to determine the emissions, supply valid engineering assumptions to support the calculations.

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

For EI purposes, 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 must be used. For example, a chemical storage and loading facility would select the SOCMI emission factors instead of the "petroleum marketing terminal" or "oil and gas" emission factors. Both the type of product and the type of process must be considered when selecting the most appropriate factor.

### *Do I need to report emissions from insulated components?*

Emissions from insulated components will eventually escape to the atmosphere and should be reported. If the components are under weekly physical inspection, a 30% credit can be applied for emissions from insulated components that cannot be monitored with an instrument as long as a visual indication of a leak can be pin-pointed to the appropriate component and the insulation can be removed to repair the leak.

For insulated components under OGI monitoring where an indication of a leak on the camera can be pinpointed to the appropriate component and the insulation can be removed to repair the leak, see the section "Quantifying Emissions from Components Monitored under Alternative Work Practices Using an Optical Gas Imaging System" for information on quantifying emissions.

### *I have some components in an area under a monitoring component program that are not instrument monitored. Can I use average factors with the monitoring credit for these?*

No, components that are not under instrument or OGI monitoring should use the average factors with no additional credit applied. If a weekly physical inspection program is in place, a 30% emissions reduction credit can be applied to average emission factors.

### *I am completing the fugitive data sheet. Under which column do I put components that are under weekly physical inspection?*

Components under weekly physical inspection should be reported in the non-monitored column.

## References

Texas Commission on Environmental Quality. 2008. *Emission Factors for Equipment Leak Fugitive Components*. TCEQ Industrial Emissions Assessment Section. Available online at: www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/ef_elfc.pdf. Accessed Sept. 1, 2020.

———. 2018. Air Permit Technical Guidance for Chemical Sources Fugitive Guidance. APDG 6422. TCEQ Air New Source Review Permitting. Available online at: www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/fugitive-guidance.pdf. Accessed Sept. 1, 2020

U.S. Environmental Protection Agency. 1995. *Protocol for Equipment Leak Emission Estimates*. EPA-453/R-95-017. Available online at:www.epa.gov/sites/default/files/2020-09/documents/protocol_for_equipment_leak_emission_estimates.pdf. Accessed Nov 19. 2025.

———. 1996. *Preferred and Alternative Methods for Estimating Air Emissions from Equipment Leaks*. Vol. 2, chapter 4. Emissions Inventory Improvement Program Document Series. Available online at: www.epa.gov/sites/production/files/2015-08/documents/ii04.pdf. Accessed Sept. 1, 2020.

# Technical Supplement 4: Flares

This technical supplement offers guidance on identifying, quantifying, and correctly reporting emissions from elevated flares in the annual EI.

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

**Disclaimer for Technical Supplement 4**

This technical supplement is intended to help determine and report emissions from flares. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how flares work, how emissions are generated, how flares are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The methods represented are intended to assist with calculating emissions; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS helpline at 512 239 1773.

## Definitions

*Acid gas flare* refers to a flare used exclusively for the incineration of $H_2S$ and other acidic gases derived from natural gas sweetening processes.

*Flare* (as defined in 30 TAC 101.1) refers to an open combustion unit (i.e., lacking an enclosed combustion chamber) whose combustion air is provided by uncontrolled ambient air around the flame, and that is used as a control device. A flare may be equipped with a radiant heat shield (with or without refractory lining) but is not equipped with a flame air control damping system to control the air/fuel mixture. In addition, a flare may also use auxiliary fuel. The combustion flame may be elevated or at ground level. A vapor combustor, as defined in 30 TAC Section 101.1 is not considered a flare.

*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.

*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.

*Vapor combustor* refers to a partially enclosed combustion device used to destroy VOC by smokeless combustion, without extracting energy in the form of process heat or steam. The combustion flame may be partially visible, but at no time does the device operate with an uncontrolled flame. Auxiliary fuel and/or a flame air control damping system that can operate at all times to control the air/fuel mixture to the combustor's flame zone, may be required to ensure smokeless combustion during operation.

*Waste gas* refers to gas streams produced in the process unit and routed to the flare for destruction (for purposes of this supplement).

## TCEQ 2010 Flare Study

In the fall of 2010, TCEQ funded a research project on flare destruction and removal efficiency (DRE) at a flare-test facility. The results demonstrated that air-assisted and steam-assisted flares must operate within a very limited range of assist rates to achieve the assumed DRE of 98% or greater. This project also demonstrated that operating an assisted flare in compliance with 40 CFR 60.18 does not ensure that the flare will achieve 98% DRE. Flare assist rates and other operating information must be reviewed and assessed to determine whether a flare may be operating at assist ranges that do not achieve the 98% DRE. When operating in a low-flow routine condition, a dual-service flare can easily be over-assisted, resulting in a DRE below the assumed 98%. The final report and additional project information are available at this TCEQ webpage[a].

## Expected Emissions

Flare emissions will include, at a minimum, $NO_X$, CO, and uncombusted flared gas compounds. In addition, if the flared gas contains sulfur-bearing compounds, emissions will also include $SO_2$.

### *Products of Combustion*

Products of combustion include $NO_X$, CO, and $SO_2$. Flared and pilot gas heat outputs impact emission rates of $NO_X$ and CO. The sulfur content of both flared and pilot gases determines $SO_2$ emissions. Report the products of combustion (from pilot and flared gas) at the flare FIN/flare EPN path.

### *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 VOC, but may also include $H_2S$, CO, $NH_3$, and other organic and inorganic compounds present in the flared gas. Report the compounds from uncombusted flared gas at the source FIN / flare EPN path.

## Emissions Determination

All determinations of flare emissions 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.

[a] www.tceq.texas.gov/goto/2010-flare-study

## *Flared Gas Flow Rate and Composition*

To determine the emissions from flares, the actual flow rate and the specific composition of the gas routed to the flare must be known. The generally preferred methods of obtaining data on flared gas flow rate and composition are, in order of preference:

- Continuous monitoring with quality-assured instruments.
- Continuous monitoring with instruments that may not meet all quality-assurance tests.
- Periodic testing with instruments and laboratory analytical methods.
- Engineering determinations based on detailed process evaluation.
- A one-time performance test conducted during the inventory year.

For flares subject to Chapter 115, Subchapter H, relating to HRVOCs, valid flow rate and composition data required by 30 TAC Sections 115.725–115.726 must be used to determine emissions for any portions of the current reporting year during which 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 must 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, the net heating value of the flared gas must be known. 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 listed below, 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, carefully select the correct factors for each flare from Table A-7.

Calculate emissions using the most accurate data for the 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 source of the data on gas flow and composition, the determination methodology for $NO_X$ and CO emissions must be coded "A" for "TCEQ-approved factor" when using the factors below (Table A-7). The factors from Table A-7 are the factors for determining $NO_X$ and CO emissions for EI reporting, since they are based on flare type.

**Table A-7. Flare Emissions Factors**

| Contaminant | Assist Type | Waste Gas Stream Net Heating Value[a,b] | Emission Factor |
|---|---|---|---|
| **$NO_X$** | Steam | High Btu | 0.0485 lb/MMBtu |
| **$NO_X$** | Steam | Low Btu | 0.068 lb/MMBtu |
| **$NO_X$** | Air or Unassisted | High Btu | 0.138 lb/MMBtu |
| **$NO_X$** | Air or Unassisted | Low Btu | 0.0641 lb/MMBtu |
| **CO** | Steam | High Btu | 0.3503 lb/MMBtu |
| **CO** | Steam | Low Btu | 0.3465 lb/MMBtu |
| **CO** | Air or Unassisted | High Btu | 0.2755 lb/MMBtu |
| **CO** | Air or Unassisted | Low Btu | 0.5496 lb/MMBtu |

For flares subject to the HRVOC regulations in Chapter 115, Subchapter H, use the net heating value data required by 30 TAC Sections 115.725 and 115.726 to determine $NO_X$ and CO emissions for any portions of the current reporting year during which HRVOC monitors were installed and operational.

## *Uncombusted Flared Gas Emissions*

Uncombusted flared gas emissions usually include VOCs, $H_2S$, 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.

### Destruction Efficiencies

Flare destruction efficiency varies with assist gas flow rate, flame stability, operating conditions, flare tip size and design, the specific compounds being combusted, and gas composition. HRVOC regulations in 30 TAC Section 115 address flare operational requirements. If flare operations are consistent with Chapter 115, the destruction efficiencies specified in Section 115.725 may be used to determine VOC emissions.

a. High Btu: > 1000 Btu/scf
b. Low Btu: 192-1000 Btu/scf

Otherwise, if the flare met all applicable regulations, the appropriate destruction efficiencies from either an applicable permit or the destruction efficiencies in Table A-8—the maximum destruction efficiencies for EI purposes—may be used to determine flare emissions. For assisted flares, there is the potential for over-assisting the waste gas stream, and the destruction efficiency may be lower than either the permitted efficiency or the appropriate efficiencies contained in the Chapter 115 HRVOC regulations or Table A-8. Emissions determinations must be adjusted accordingly.

**Table A-8. Maximum Destruction or Removal Efficiencies for Emissions Inventory Determinations**

| Waste Stream Composition | Destruction or Removal Efficiency |
|---|---|
| **VOC, C1-C3**[a] | 99% |
| **VOC, > C3** | 98% |
| **$H_2S$** | 98% |

If the flare flame (not the flare pilot) is ever extinguished, the destruction efficiency for the period when the flame was out will be zero. The pilot combustion zone is separate from the flame combustion zone. Therefore, the flare flame can be extinguished while the flare pilots are still lit.

## Determining Emissions

When flow rate and composition data are available from a CMS, they must be used to determine the uncombusted emissions. Otherwise, process knowledge and engineering calculations must be used to determine emissions.

- Since continuous monitoring methods measure the gas composition before destruction by the flare rather than the amount of emissions released to the atmosphere, the determination methodology must not be coded “M” (for “measured data”) or “D” (for “CEMS”).
- The determination methodology for uncombusted flared gas emissions must be coded “H” (for “HRVOC monitoring”) when the actual flow rate and composition of the gas routed to the flare are obtained through a CMS required by 30 TAC Sections 115.725–115.726.
- When the actual flow rate and composition of the gas routed to the flare are obtained through a CMS not required by Sections 115.725–115.726, the determination methodology must be coded “B” (for “material balance”) instead of “H.”

a. The 99% reduction must 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.

- If the flow rate and composition of the gas routed to the flare are determined using process knowledge and engineering calculations, the determination methodology for uncombusted flared gas emissions must be coded “S” (for “scientific calculation”).

Emission factors cannot be used to determine uncombusted flared gas emissions. Do not use the total hydrocarbon or VOC emission factors from AP-42, Section 13.5, to estimate emissions. Uncombusted gas streams should be calculated using the flared gas flow rate, composition, and permitted DRE.

### *$SO_2$ Emissions*

$SO_2$ emissions are calculated 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% butane and 20% $H_2S$, is burned in an unassisted flare. The hourly uncombusted flared gas emissions would be 1.6 pounds of butane and 0.4 pounds of $H_2S$. In addition, the flare creates $SO_2$ from the $H_2S$. Determine the $SO_2$ emissions as follows:

$$20\ \frac{lb\ H_2S}{hour} \times 0.98 \times \frac{lb\text{-}mole}{34\ lb\ H_2S}\ \times 64 \frac{lb\ SO_2}{lb\text{-}mole}\ = 36.9 \frac{lb\ SO_2}{hour}$$

Note that a 98% destruction efficiency was assumed, since the flare does not have the potential for over-assisting and the flare complied with all applicable regulations.

The determination methodology for $SO_2$ emissions must be coded “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, emissions determinations must 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 ozone season months must be used to develop the daily average ozone season emissions.

If no flow rate or composition data are available, engineering estimates must 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, emissions determinations must 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% toluene
- 60% xylene
- 20% butane

If the flare is not over-assisted and sufficient waste gas heating value, volume, and concentration are present to support combustion, then a 98% 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% toluene, 60% xylene and 20% butane by weight, speciated VOCs would be reported as:

- 0.4 pound per hour toluene
- 1.2 pounds per hour xylene
- 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 Section 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?" attribute. Regardless of the county location of the regulated entity, if any individual gas stream routed to the flare contains more than 5% by weight of aggregate HRVOCs (ethylene, propylene, all isomers of butene, and 1,3-butadiene), the flare is considered to be in HRVOC service for EI purposes.

## 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 and abatement device, must be included in the EI where the process equipment is located and the emissions are generated. However, the path emissions will be zero because the owner of the flare is required to report the combustion emissions generated by the flare and the non-combusted contaminants. Include a comment identifying the shared flare's EPN and its air account number. Please contact the EAS for additional guidance.

## References

Allen, David T., and Vincent M. Torres. 2011. *2010 TCEQ Flare Study Project: Final Report*. Draft. Austin: Center for Energy and Environmental Resources, University of Texas.

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

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. Research Triangle Park, NC.

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

This technical supplement offers guidance on identifying, quantifying, and correctly reporting marine facility emissions on the annual EI. Marine facility emissions must be reported as part of the EI. The owner or operator of the onshore facilities is responsible for reporting dock and dockside marine vessel emissions in the annual EI, except for emissions from marine vessel engines. This is consistent with the long-standing 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 associated equipment (e.g., conveying lines, piping, valves, pumps, hoses, and blowers).
- 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 the *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.

**Disclaimer for Technical Supplement 5**

This technical supplement is intended to help determine and report emissions from marine facilities. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how marine facilities work, how emissions are generated, how marine facilities are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The methods represented are intended to assist with calculating emissions; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS helpline at 512-239-1773.

## Expected Emissions

Emissions associated with the dock and the dockside marine vessels, except for emissions from marine vessel engines, must be determined and reported in the annual EI. 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.
- 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 liquefied 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.
- Particulate matter and VOCs from abrasive blasting and surface coating.

## Determining Emissions

The following sections address the key points related to the EI.

### *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 fugitive emissions from piping components following the guidance in Technical Supplement 3: Fugitive Emissions from Piping Components. The determination methodology must be coded "A." The fugitive emissions must be determined for the entire period when VOCs were present in the dock piping.

Determine vessel loading emissions from liquid material loading and unloading using the method in AP-42, Chapter 5, or a material-balance method that accounts for the potential variables noted in that chapter. The determination methodology must be coded either "A" or "B," accordingly.

If loading emissions are controlled, some pollutants will escape collection, and some pollutants will be collected but not destroyed.

Uncollected emissions should be determined using one of the methods referenced above.

If loading emissions are collected for abatement, first determine the collection efficiency. After the collection efficiency is determined, use the appropriate destruction efficiency to determine emissions from the abatement device.

Other related emissions to consider are storage tanks and sumps.

### *Loading and Unloading Bulk Liquefied Gaseous Materials*

Loading and unloading liquefied gases will result in fugitive VOC emissions from dock piping components 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. The determination methodology must be coded "A." Fugitive emissions from piping components must 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 emissions from gas freeing or gas conditioning 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, the determination methodology must be coded "S" for "scientifically calculated."

### *Loading and Unloading Bulk Solid Materials*

Fugitive dock emissions occur at the loading and unloading operations for bulk solid materials. During loading, emissions also occur from the entrainment of solids during displacement of the vessel-compartment air space.

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 must be determined following the detailed guidance in AP-42.

If a material type is explicitly addressed in AP-42, the determination methodology must be coded "A." If the material type is not explicitly addressed, use the method for the most closely related material and report the determination methodology as "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. Determine emissions from degassing, deheeling, or cleaning

using either saturation-test data or the ideal-gas law and the actual pressure, concentration, and vessel-volume data. If the ideal-gas law is used to determine emissions, the determination methodology must be coded "S" for "scientifically calculated."

If saturation test results are used to calculate degassing, deheeling, and cleaning emissions, the ambient temperature during the test must correspond to or be greater than the average ambient temperature for that year's ozone season. Similarly, all chemical vapor pressures used to calculate emissions must be the vapor pressures of the chemicals 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, the determination methodology must be coded "B" for "material balance." Submit summary test results with each year's EI 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. Determine these emissions according to AP-42. The determination methodology must be coded "A."

Painting results in emissions of the VOCs that volatilize from the paint as it cures and particulate matter emissions resulting from paint overspray. Since VOC and particulate emissions from coatings are determined based on the coating composition and the application equipment's transfer efficiency, the determination methodology must be coded "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

ozone season months, May through September. Next, divide the resulting emissions rates by 153 days. Report the resulting rates as the ozone season pound per day emissions rates for that facility-emissions point path. For more information, consult "Reported Emissions: Ozone Season Emissions" in Chapter 4.

## VOC and Particulate Speciation

Speciation must follow the guidelines in "Speciating Emissions" in Chapter 4. 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 the EI 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 emissions determinations.
- Material composition data, if the associated emissions (total or speciated) depend upon them.
- Collection efficiency of vapor recovery units.
- Destruction efficiency of combustive abatement devices.
- 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 must be reported in the point source inventory.

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

Yes. The marine vessel is at the site supporting the business.

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

Emissions must be reported by the owner or operator of the marine loading facility. Please contact the EAS for additional guidance about a 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 must be reported by the dock owner or operator.

### *I have a vacuum loading system at my marine facility. Can I claim a 100% collection efficiency?*

A 100% collection efficiency should only be claimed for inland marine vessel vacuum loading. Federal Coast Guard Regulations typically require ocean-going ships to be inerted. Ocean-going ships subject to this requirement cannot use vacuum loading and the associated collection efficiency.

# Technical Supplement 6: Aboveground Liquid Storage Tanks

This technical supplement offers guidance on identifying, quantifying, and correctly reporting aboveground storage tank emissions in the annual EI. This document does not address underground storage tanks, open-top 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 EI. For guidance on this topic, consult Chapter 3.

**Disclaimer for Technical Supplement 6**

This technical supplement is intended to help determine and report emissions from aboveground liquid storage tanks. This supplement does not supersede or replace any state or federal law, rule, or regulation.

This guidance reflects the current understanding of how aboveground liquid storage tanks work, how emissions are generated, how storage tanks are monitored or tested, and what data are available for emissions determination. This supplement may change over time as a result of findings of scientific studies and as new information becomes available. TCEQ greatly appreciates any data, information, or feedback that may improve this supplement.

The methods represented are intended to assist with calculating emissions; alternate calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. For additional guidance regarding the acceptability of a given emissions determination method, contact the EAS helpline at 512-239-1773.

## Guidance Available in This Supplement

This supplement offers guidance on appropriate methodologies for determining emissions from storage tanks, EI 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.
- 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 volume of gas produced per volume of crude oil, condensate, or other hydrocarbon-containing liquid, such as produced water.

*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.

*Vapor pressure* is the pressure exerted by a gas vapor in equilibrium with its condensed phase(s) at a given temperature. For chemical mixtures, vapor pressure is the sum of the equilibrium partial pressures exerted by the individual liquid components.

*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 and Determination Methods

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, must be quantified and reported in the EI at the appropriate storage tank FIN / EPN path.

If more than one of the emissions modes listed above occurs at a storage tank path, use the emissions determination method associated with the mode that represents the majority of the emissions. Each mode is discussed separately below and assigned a determination method.

### *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 fugitive emissions from piping components at the same facility-emissions point path where storage tank breathing and working loss emissions are reported. The fugitive emissions from piping components must be reported at a separate path according to the guidance in Technical Supplement 3. To determine fugitive emissions from piping 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 the emissions are reported from storage tank breathing and working losses. The emissions from the loading rack and its related emissions must be reported 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 must be consistent with the guidance in this document.

#### Annual and Ozone Season Emissions

Annual and ozone season breathing and working loss emissions can be determined by using the guidance outlined in AP-42, Chapter 7. If only breathing and working emissions occur at the storage tank path, and equations from AP-42, Chapter 7 (or a software program that uses those equations correctly) are used to determine emissions, then code the emissions as "A" for "EPA- and TCEQ-approved emissions factors." If multiple modes of emissions occur at the storage tank path, report the determination method code that represents the majority of the emissions.

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 for tanks that store products at ambient temperature must be determined using the data for increased vapor pressure in the appropriate equations from AP-42, Chapter 7, or a software program that uses the equations accurately.

For heated storage tanks or tanks storing warmer-than-ambient stock (hot product), annual and ozone season emissions must be determined using the guidance and equations contained in AP-42, Chapter 7, or a software program that uses those equations accurately. For more details, see "Determining Emissions from Heated, Hot-Product, or Insulated Storage Tanks" later in this chapter.

## *Obtaining Accurate Emissions Determinations From TANKS 5.1*

On Oct. 9, 2024, the EPA released TANKS Version 5.1 (TANKS 5.1), which is a web-based application that estimates VOC and HAP emissions from fixed-roof and floating-roof tanks. Detailed instructions for using TANKS 5.1 can be found in the *TANKS 5.1 User Guide*. Regulated entities must input accurate, site-specific data to obtain valid emissions determinations when using the TANKS 5.1 program.

### Key Considerations When Using TANKS 5.1

When determining emissions with TANKS 5.1, use the following guidance:

- Site-specific conditions and material composition must be used to model and determine emissions from each tank. Default settings must not be used to determine emissions.
- The vapor pressure and composition of the stored material must be used to model and determine emissions from each tank. Unless the default parameters have been evaluated and are representative of the stored liquid, the defaults must not be used.
- The tank fittings selected for internal and external floating-roof tanks, including domed external floating-roof tanks, must be representative of the particular attributes of each tank.
- The monthly report option must be chosen to obtain accurate ozone season daily emissions. Due to higher temperatures during the ozone season, the May through September emissions in pounds should be summed and divided by 153 days to obtain the ozone season daily emissions; a daily average of the annual emissions cannot be used.
- For tanks with significant monthly throughput variations (greater than 10% difference in throughput from month to month), the throughput data must be entered monthly.

### TANKS 5.1 Liquid Composition Data

The user must enter site-specific data into TANKS 5.1 to obtain the greatest accuracy. Specifically, for compounds whose physical properties can vary widely—such as condensate, mid-refined products, etc.—or for site-specific or proprietary compounds or chemical mixtures, enter specific chemical or mixture data into TANKS 5.1 by clicking on the “Customize” tab in the application. Default refined product and crude oil characteristics available in TANKS 5.1 must not be used unless the default vapor pressure and composition of the product accurately represent the stored liquid’s vapor pressure and composition. For example, the crude oil default in TANKS 5.1 (RVP 5) does not typically represent the range of crude oils stored in tanks. For petroleum liquids (crude oil or refined products), use the “Customize” tab and the “Petroleum Liquids” tab within that to enter the specific characteristics of the crude oil or refined product.

### Determining Emissions Using Chemical Mixtures

Data on chemical mixtures must be used to determine emissions from tanks where chemicals are combined. For example, when transmix is formed in pipelines and stored

in tanks prior to reprocessing, the transmix's composition must be modeled as a mixture in the tank emissions calculations.

Additionally, for gasoline storage tanks, variations in product must be accounted for by using actual vapor-pressure information for each month of the year. A gasoline profile that averages characteristics such as RVP over the course of a year must not be used to determine the emissions.

### Tank Fittings

Similarly, detailed information on the number and physical attributes of the tank fittings must be used in the "New Tank Details" heading in TANKS 5.1.

The program user's manual, available in the TANKS 5.1 User Guide, contains detailed instructions for adding or modifying chemicals, chemical mixtures, and tank fittings, as well as general information on how to use the software.[a]

## *Determining Emissions From Flashing Losses*

### Introduction

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 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 as the gases vaporize. Flashing loss emissions (*flash emissions*) increase 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.

### Wellhead and Other Oil and Gas Storage Tanks

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.

Companies that own or operate sites in the upstream oil and gas industry must determine VOC emissions from all storage tanks to determine if these sites meet the requirements for submitting an EI. Each storage tank has the potential to generate working, breathing, and flashing emissions. Submit the throughput, and the stored liquid information for each tank in the supporting documentation.

[a] www.epa.gov/system/files/documents/2024-02/tanks_users_guide.pdf

### Tanks in Series

Oil or gas field tank batteries may have multiple tanks in series. The first tank in the battery typically receives liquid at high pressure directly from a separator, resulting in flashing losses. (*Note:* Some operators may refer to the first storage tank in a series as a "gunbarrel tank" or "gunbarrel separator.") The remaining tanks receive liquid at atmospheric pressure. Determine flashing, working, and breathing losses for the first tank in the series receiving the pressurized liquid. For subsequent tanks in the series that receive liquid at atmospheric pressure, determine working and breathing losses for each tank.

### Other Processes

Flash emissions can also be associated with high-, intermediate-, and low-pressure separators, heater treaters, surge tanks, and accumulator operations; however, this supplement does not address emissions determinations for those sources.

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 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 TCEQ determines that a determination method for a site-specific process is unfounded, then TCEQ will require that the emissions determinations be recalculated using a more appropriate method.

As a reminder, if the majority of tank emissions are flash emissions, use the appropriate determination-method code listed below when reporting emissions for the storage tank path.

### Black Oil Systems

"Black oil" is defined for EI purposes as heavy, low-volatility oil approximated by a GOR less than 1,750 cubic feet per barrel and an API gravity less than 40° per 40 CFR 63.761. 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").
- 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").
- GOR method (code as "B").

*Note:* Crude oil with an API gravity greater than 40° must be treated as gas condensate when determining flash emissions.

*Note:* E&P TANK 2.0 and Vasquez-Beggs or software that uses this correlation equation (such as GRI-HAPCalc) are no longer accepted as a flash emissions determination method for air permitting purposes and will no longer be accepted for emissions inventory purposes starting with the calendar year 2026 inventory.

### Gas Condensate Systems

"Gas condensate" is defined for EI purposes as a liquid hydrocarbon with an API gravity greater than or equal to 40° (and a specific gravity less than 0.8252) per the Feb. 6, 1998, *Federal Register* notice. 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").
- E&P TANK program (code as "O").
- GOR method (code as "B").

*Note:* For the EI, the Environmental Consultants and Research (EC/R) equation is not an acceptable method to determine flash emissions for gas condensate systems.

*Note:* E&P TANK 2.0 is no longer accepted as a flash emissions determination method for air permitting purposes and will no longer be accepted for emissions inventory purposes starting with the calendar year 2026 inventory.

### Produced-Water Systems

Produced water is generated during oil and gas exploration, production, transmission, and treatment, and is typically stored on-site. It may contain various contaminants, including hydrocarbons that generate VOC emissions. These tanks are a potential source of VOC emissions that must be represented in the EI.

Any VOCs in produced water will vaporize in the tank's headspace, causing working, breathing, and flash losses. To determine working and breathing losses, it is possible to use a custom mixture similar to the composition of the produced water stored in the tanks (e.g., a mixture of 99% water and 1% condensate) to determine the emissions.

Any VOCs entrained in water produced during oil and gas exploration and production could flash when transferred to atmospheric-pressure tanks due to pressure differentials. The preferred methods for determining flash emissions are, in general order of preference:

- Direct measurement of emissions (code as "M").

- GOR method (code as “B”).
- Process simulator models (code as “S”).
- E&P TANK program (code as “O”).

*Note:* Accurate sample composition and site-specific inputs are necessary to determine emissions from process simulators.

*Note:* E&P TANK 2.0 is no longer accepted as a flash emissions determination method for air permitting purposes and will no longer be accepted for emissions inventory purposes starting with the calendar year 2026 inventory.

### 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 the other emissions determination methodologies 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 determining 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, HYSYS, 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 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°).

*Note:* E&P TANK 2.0 is no longer accepted as a flash emissions determination method for air permitting purposes and will no longer be accepted for emissions inventory purposes starting with the calendar year 2026 inventory.

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 or gas composition.
- Separator temperature and pressure.
- Sales oil API gravity and RVP.
- Sales oil production rate.
- Ambient temperature and pressure.

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

When "Low Pressure Oil" or "High Pressure Oil" is chosen, a default analysis is already entered. However, the company must input a site-specific extended analysis to achieve accurate emissions and emissions speciation.

The "Low Pressure Gas" option can be used to determine emissions if the following site-specific measurements and related data are available:

- Laboratory analysis of a gas sample from the low-pressure separator.
- Laboratory analysis of the GOR.
- Laboratory analysis of hydrocarbon liquid produced (to obtain API gravity, RVP, and C7–C10+ characteristics).
- Tank specifications and location.

Documentation to support the GOR and other measurements must be included in the EI submission. A vapor sample of the sales gas is not acceptable for determining either a GOR or the compositional analysis of either the separator liquid or separator gas stream.

The E&P TANK model contains two methods to determine working and standing (breathing) losses: the AP-42 option or the RVP Distillation Column option. When the AP-42 option is selected for working and standing losses, E&P TANK allows users to input detailed information about tank size, shape, liquid bulk temperature, and ambient temperatures; therefore, the software can more precisely determine emissions. This flexibility in model design allows use of the model to match site-specific information. However, the RVP Distillation Column model does not allow these specifications.

## Obtaining Accurate Emissions Determinations From the E&P TANK Program

Accurate data input is essential to obtaining valid emissions determinations when using E&P TANK Version 2 or Version 3. The program has default settings for many input variables, including a Geographical-Database option for crude oil. The Geographical Database does not contain site-specific compositions and will not be accepted for known separator stream information.

Using any of the default settings in E&P TANK can result in inaccurate or invalid emissions determinations. Therefore, the user must use site-specific data to obtain the greatest accuracy. However, the use of site-specific measurement or analysis data for a current year cannot be used to revise emissions for previous years.

If site-specific data are not available, then representative data that meet all the following criteria must be used, the:

- Sample must have come from the same geological formation or reservoir.
- API gravity of the sample must be within 3° of the actual material.
- Process and treatment of the material must be the same.

Because the E&P TANK 2.0 program determines **annual** emissions, use caution when determining **ozone season** emissions. Ozone season emissions can be determined by adjusting the annual inputs as shown in Table A-9.

**Table A-9. Inputs for Calculating Ozone Season Emissions Using E&P TANK 2.0**

| Flowsheet Selection | Data Input | Parameters |
|---|---|---|
| **Tank with Separator** | Separator | Separator Temperature (˚F): Average separator temperature during the ozone season |
| **Tank with Separator** | Flash Valve | Ambient Temperature (˚F)[a]: Average maximum ambient temperature during the ozone season |
| **Tank with Separator** | Sales Oil | Production Rate (bbl/day): Average daily production during the ozone season |
| **Tank with Separator** | Sales Oil | 365 days[b] |
| **Stable Oil Tank** | Stable Oil | NA |
| **Stable Oil Tank** | Oil Tank | Meteorological Info: Choose the appropriate city from the drop-down menu |
| **Stable Oil Tank** | Sales Oil | Production Rate (bbl/day): Average production during the ozone season |
| **Stable Oil Tank** | Sales Oil | 365 days[c] |
| **Stable Oil Tank** | Sales Oil | Bulk Temperature (˚F): Average bulk temperature of the stock during the ozone season |

Run the report and multiply the hourly rates by 24 to calculate the ozone season daily rates. Do not use the tons per year rates to determine ozone season emissions.

## 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.

a. If not known, refer to Weatherbase, www.weatherbase.com.
b. At the time of publication, the E&P TANK 2.0 program contained an error that overestimates ozone season emissions when less than 365 operating days are entered. The EAS recommends using the following method to compensate for the error: Input the average production rate during the ozone season, keeping the days of operation as 365. Then calculate ozone season emissions by multiplying the lb/hr result by 24 hr/day to obtain ozone season daily emissions in lb/day.
c. At the time of publication, the E&P TANK 2.0 program contained an error that overestimates ozone season emissions when less than 365 operating days are entered. The EAS recommends using the following method to compensate for the error: Input the average production rate during the ozone season, keeping the days of operation as 365. Then calculate ozone season emissions by multiplying the lb/hr result by 24 hr/day to obtain ozone season daily emissions in lb/day.

The Vasquez-Beggs correlation equation determines the GOR of a hydrocarbon solution from variables input by the user; 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 that handle 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 all eight input variables:

1. stock-tank API gravity
2. separator pressure
3. separator temperature
4. gas specific gravity
5. volume of produced hydrocarbons
6. molecular weight of the stock-tank gas
7. the VOC fraction of the tank emissions
8. 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.

*Note:* TCEQ only allows the Vasquez-Beggs correlations to be used for black oil systems (where the API gravity is less than 40˚).

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

*Note:* The Vasquez Beggs equation or software that uses this correlation equation (such as GRI-HAPCalc) is no longer accepted as a flash emissions determination method for air permitting purposes and will no longer be accepted for emissions inventory purposes starting with the calendar year 2026 inventory.

### EC/R Equation

The EC/R equation was designed to determine paraffin VOC emissions in higher proportion than in the default composition. The composition of stored condensate liquids deviates substantially from the composition used to derive the equation, and therefore the EC/R equation is not accepted for determining flash emissions.

### Gas/Oil Ratio Method

The GOR of a liquid that contains hydrocarbons 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 must 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.

### Griswold and Ambler GOR Chart Method

Please note that obtaining a GOR from sources such as the Griswold and Ambler GOR Chart is not an acceptable method for determining flash emissions for EI purposes. The Griswold-Ambler method cannot determine VOC emissions and cannot be used to determine the composition of flash emissions. In particular, it cannot distinguish between VOC and HAP emissions.

## *Determining Emissions From Heated, Hot-Product, or Insulated Storage Tanks*

TANKS 5.1 can be used to determine losses from heated tanks and tanks storing hot products. When calculating emissions from fully insulated tanks storing hot product, account for temperature variations for tanks occasionally receiving hot stock which cools over time prior to the next receipt of hot stock. See Section 7.1.3.8.4 of AP-42, Chapter 7 for further guidance on heating cycles in fully insulated tanks.

### Heated Tanks

For the EI, a *heated tank* is defined as a storage tank that is designed to store, and does store, product (including hot product) at a temperature above ambient temperature.

Acceptable calculation methods are the equations from AP-42, Chapter 7, or a software program that uses those equations accurately.

### Tanks Receiving Hot Products

For the EI, *hot products* are materials with a temperature above the ambient temperature, and hot-product tanks are defined as unheated storage tanks that receive product above ambient temperature. When hot products are put into an unheated tank, ambient meteorological data cannot be used to properly determine the tank's emissions. Equations from AP-42, Chapter 7, TANKS 5.1, or software that uses those equations accurately must be used. When using the AP-42, Chapter 7, equations to determine emissions, the elevated stock temperature must be used as the liquid bulk temperature.

### Breathing Losses From Heated, Insulated Tanks

Tanks that store heated products are often insulated to prevent heat loss. Historically, breathing losses from heated, insulated tanks have been assumed to be insignificant. Since heated tanks were assumed to maintain a constant temperature, both the daily ambient temperature changes due to radiation and daily heat losses due to convection were assumed to have insignificant impact on the bulk liquid temperature. However, the vapor space in heated storage tanks will cycle through a temperature range if the liquid is heated periodically and/or the tank receives hot product stock. This process can generate breathing loss emissions from the heated storage tank. Equations from

AP-42, Chapter 7, TANKS 5.1, or software that uses those equations accurately must be used to determine emissions.

Although heated storage tanks often have insulated side walls (shells), insulating the roofs of these storage tanks is not as common due to the complexities involved (e.g., fittings). Breathing emissions occur from tanks with an insulated shell and an uninsulated roof due to significant heat transfer through the roof. The preferred method to determine emissions from these tanks is to determine breathing-loss emissions as if the tank were uninsulated, using the actual bulk liquid temperature of the stored liquid and the daily ambient temperature range to calculate emissions. Equations from AP-42, Chapter 7, TANKS 5.1, or software that uses those equations accurately must be used to determine emissions.

Finally, fully insulated tanks (tanks that have both an insulated shell and insulated roof) can also experience breathing losses due to tank heating cycles resulting in temperature fluctuations in the product. Equations from AP-42, Chapter 7, TANKS 5.1, or software that uses those equations accurately must be used to determine emissions.

### Tanks Storing Heavy Fuel Oils

Products such as heavy fuel oils are often blended with stocks of lighter density to thin the heavy products to the desired viscosity. After the products are blended, they are often stored in tanks that are heated or insulated to maintain their viscosity.

Since heavy fuel oils and related products are often thinned with the available cutter stock at a particular site, site-specific information on cutter-stock percentage in heavy fuel oil, physical properties, and chemical composition should be used to determine emissions.

Vapor-pressure data for heavy fuel oils is available in the API's *Manual of Petroleum Measurement Standards*, Chapter 19.4, "Evaporative Loss Reference Information and Speciation Methodology," Fourth Edition, Addendum 1, Annex G. These data should only be used to determine emissions when site-specific data are not available.

### Sparging

In heated storage tanks, the stored liquid may be mixed using air injection (sparging). If constant air flows through the liquid, this air will exit the storage tank through the tank vents, generating VOC emissions. Currently, no commercial software or programs determine sparging emissions. Engineering calculations that account for air flow and volatility of the stored liquid and any cutter stock should be used to determine emissions.

## *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.

An overview of landing loss emissions is provided in American Petroleum Institute Technical Report 2567, *Evaporative Loss from Storage Tank Floating Roof Landings* (API TR 2567). The EPA has incorporated this API guidance into AP-42, Chapter 7, "Liquid Storage Tanks."

The emissions determination method detailed in AP-42, Chapter 7, TANKS 5.1, or a software program that uses these AP-42 equations accurately, 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 design categories for emissions determination purposes:

1. Internal floating-roof tanks (IFRTs) with a full or partial liquid heel.
2. External floating-roof tanks (EFRTs) with a full or partial liquid heel.
3. 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, classify the storage tank into one of the above categories. Use caution 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.
- 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 category of tank design 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 correctly determining the tank type, 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, 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 or AP-42, Chapter 7, take care to avoid using certain default parameters that may not accurately reflect a given storage tank. For example, the daily vapor temperature range must 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 required temperature and pressure units. In certain cases, the $K_E$ term may have to be calculated using the original equations or equations as presented in AP-42, Chapter 7.

### Reporting Landing Loss Emissions Within the Inventory

Landing losses for each storage tank must be reported on the appropriate path within the EI. If it is determined that landing loss emissions occurred due to normal, routine operation, report annual and ozone season emissions accordingly. For specific procedural guidance on reporting emissions in the EI, please consult Chapter 4.

### Tanks With a Liquid Heel

Use caution when classifying a tank as “drain dry.” If the tank drains to a sump that retains a liquid heel, resulting emissions cannot be assumed to be negligible. The API and EPA publish saturation factors to use in the landing-loss equations to determine the emissions. To consider a tank to be drain dry, ensure that the evaporation of the entire heel has been accounted for in the standing idle loss emissions. Otherwise, tanks with a liquid heel may generate emissions during degassing operations, tank cleaning, steam cleaning, and the use of vacuum trucks that may not be currently accounted for by using conventional software programs.

## *Determining Emissions From Degassing and Cleaning*

Emissions from tank degassing and cleaning operations must be determined using site-specific process and product knowledge.

For fixed-roof and floating-roof tanks, emptying (withdrawing liquid from) the tank will be accounted for in the working loss equations. When emptying a tank prior to cleaning, be sure to account for the turnover resulting from tank emptying and the change in average tank liquid height in the working loss equation.

Once a floating roof has landed on its legs or supports, use the landing loss equations in AP-42, Chapter 7, or TANK5.1, to estimate emissions for the period prior to degassing or cleaning.

Degassing emissions and cleaning emissions can be determined in accordance with AP-42, Chapter 7 or API Technical Report 2568, *Evaporative Loss from the Cleaning of Storage Tanks*. EPA’s TANKS 5.1 can also be used to estimate cleaning emissions; currently, there is no functionality in TANKS 5.1 to estimate degassing emissions.

For either fixed- or floating-roof tanks where liquid remains in the tank (liquid heel), the heel may be a continuing source of vapors that can generate emissions. Therefore, liquid-heel emissions must be accounted for when determining degassing emissions, including the initial vapor space purge and continued forced ventilation.

When sludge is removed from the bottom of the tank, the tank may be flooded with a light distillate liquid to assist with cleaning. Ensure any new material introduced into the tank during cleaning is properly accounted for in the liquid and vapor properties of the tank heel.

## *Special Considerations When Quantifying Emissions*

The following sections list common, site-specific equipment, operations, or processes that may affect determinations of emissions from storage tanks.

### 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 fugitive emissions from piping components associated with high-pressure tanks, as well as any nonroutine emissions, must be reported in the EI.

Low-pressure tanks can experience breathing and working losses. These losses are a function of the vent set pressure and are accounted for in the emissions equations for vertical fixed-roof breathing and working losses. While these emissions may be less than a similar atmospheric tank would experience, these emissions must be quantified and reported within the EI according to the guidance outlined in Chapters 3 and 4.

Use equations from AP-42, Chapter 7, 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% 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.

### Tanks with Significant Monthly Throughput Variations

For storage tanks with throughputs that vary significantly with the seasons, the equations in AP-42, Chapter 7 or a software program that uses these equations accurately must be used to determine annual emissions.

### 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 AP-42, Chapter 7 equations 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 program's chemical database.

Although the equations used in AP-42, Chapter 7 were developed to determine evaporative losses from storage of organic liquids, they currently are the best available method for determining inorganic emissions from storage tanks.

### Winter Gas Blending

Some sites blend butane into gasoline during the fall and winter to increase the RVP of the gasoline in a process called *winter gas blending* or gas butanizing. Butane emissions from this process must be determined and reported in the EI.

First, the normal working and breathing losses must be adjusted to account for the additional butane present in the gasoline. The RVP must be adjusted to match the actual RVP of the gasoline stored in the tank, and the gas mixture must reflect an increased butane component.

Next, if winter gas blending is carried out at the storage tank, additional butane emissions from the blending itself (separate from the working and breathing losses from the tank) must be determined and reported in the EI. The blending emissions can be determined using a material balance or from engineering knowledge of the blending process.

### Internal Floating Roof Tanks With Closed Vent Systems

The equations in AP-42, Chapter 7, for internal floating roof tank breathing and working loss emissions assume the tank has open vents around the perimeter of the fixed roof. If the tank has closed pressure/vacuum vents in the fixed roof the API Technical Report 2569, *Evaporative Loss from Closed-vent Internal Floating-roof Storage Tanks*, can be used to determine breathing and working loss emissions.

In general, the method presented in API Technical Report 2569 results in significant emissions determination differences only for small diameter tanks storing high volatility liquids that have infrequent turnovers. For other situations, the difference generally results in an adjustment of less than 10%. A default reduction of 5% can be applied to working and breathing loss emissions to account for the use of closed vents when present and operating properly.

### Variable Vapor Space Tanks

Variable vapor space tanks use an expandable vapor space to control losses. Loss of vapor occurs when the tank's vapor storage capacity is exceeded. Working losses can be determined using the method presented in AP-42, Chapter 7. Note that this equation may not accurately determine emissions for all variable vapor space tank operating situations, such as vapor balancing.

Variable vapor space tanks that rely on either a flexible diaphragm or a flexible coated fabric seal will have additional losses to the extent that vapors leak through or past the membrane used for the diaphragm or seal.

## Speciation

If any source-specific information about storage tank vapor VOC composition is available, use it to speciate the emissions. The weight fraction of a given component will vary with temperature. If vapor VOC composition is not available, it can be determined from the liquid mass fraction using the appropriate approach detailed in AP-42, Chapter 7. Supply the composition data and any related information (such as test results, etc.) with the EI. For more information on speciation requirements, see Chapter 4.

## Supporting Documentation

Include documentation with the EI that supports and validates the emissions reported including, but 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).
- 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, GOR, gas gravity, molecular weight of stock, and VOC percentage by weight of both the stored liquid and flash gas.
- Collection efficiency of any vapor recovery systems.
- Destruction efficiency of combustive abatement devices.
- All other information necessary to determine emissions.

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# Appendix B. Sample Letters

## Letters That May Be Submitted Instead of an EI

The sample letters in this appendix demonstrate the information required for prompt handling of EIs for situations when sites:

- Do not meet the applicability requirements of 30 TAC Section 101.10 for the current inventory year but wish to remain on the EAS mailing list to continue to receive future inventory notices.
- Do not meet the applicability requirements of 30 TAC Section 101.10 for the current inventory year and are not expected to meet those applicability requirements in future years, and therefore wish to be removed from the mailing list.
- Have experienced an insignificant change in emissions.

The EAS may require that other information be submitted with these letters. Please consult Chapter 1 for more information.

## Printing and Updating Required EI Questionnaire Pages

Pages with updated information from the latest EI may be submitted with a letter when a detailed annual EI update is not required. Instructions on how to print a copy of the EI can be found at the EAS webpage.

*Note:* When running the EIQ report using the Central Registry's IWR system, the previous reporting year will appear on the EIQ pages. The EIQ referenced is a historical report containing the latest data as entered in STARS. To update, cross out the previous year on page 2 of the EIQ and replace it with the current reporting year. It is not necessary to update the year for subsequent EIQ pages.

*Also note:* For each revision, use a different color font to distinguish the most recently corrected EI information. There are no restrictions on font color, but colors other than black make EIQ updates more noticeable.

# Inapplicability Notification

Manager
Emissions Assessment Section, MC 164
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, TX 78711-3087

Re: Calendar Year _____ Emissions Inventory

Company Name: _____

Site Name: _____

TCEQ RN: _____, TCEQ Air Account No.: _____

Upon reviewing the applicability requirements of 30 Texas Administrative Code (TAC) Section 101.10, I certify the referenced account does not meet the applicability requirements of 30 TAC Section 101.10 for the current inventory year.

Please check one:

☐ **Please keep this site on the annual emissions inventory mailing list.**

I understand that:

- TCEQ will continue to mail an emissions inventory notice each calendar year.
- I (or my representative) must submit an updated emissions inventory or an Inapplicability Notification letter each calendar year until I (or my representative) submit a written request to be removed from the mailing list.
- If emissions fees apply to the site, TCEQ will base the amount of the fee it assesses on the site's potential to emit (PTE) levels unless I (or my representative) submit updated emissions for this site.

☐ **Please remove this site from the annual emissions inventory mailing list.**

I understand that all of the following apply:

- TCEQ can only remove this site from the mailing list if its latest annual emissions totals, as shown in the State of Texas Air Reporting System (STARS) database, and the PTE levels and the actual annual emissions for the current inventory year are below the required levels for emissions inventory reporting as described in 30 TAC Subsection 101.10(a). Otherwise, I (or my representative) will have to submit an updated emissions inventory demonstrating that the emissions are below those required levels, along with representative sample calculations, before this site is removed from the mailing list.

- If the site meets the reporting requirements of 30 TAC Section 101.10 in the future, it is my (or my representative's) responsibility to submit an annual emissions inventory update by March 31 following the most recent full calendar year in which the site falls under those requirements.
- If emissions fees apply to the site, TCEQ will base the amount of the fee it assesses on the site's PTE levels unless I (or my representative) submit updated emissions for this site.

Upon request, I am prepared to submit supporting documentation. This may include, but may not be limited to, representative sample calculations, stack-test results, copies of continuous emissions monitoring system reports, and copies of applicable permit maximum allowable emission rate tables (MAERTs) or, for sources not listed on any MAERT, the calculations used in determining their PTE.

If you have any questions concerning the determination of the status of this site or the calculation methodologies used, please contact _____ at _____ or via email at _____.

Sincerely,

Responsible Official (print) _____ Title (print) _____

Signature _____ Date Signed _____

# Insignificant Emissions Change Notification

Manager
Emissions Assessment Section, MC 164
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, TX 78711-3087

Re: Calendar Year _____ Emissions Inventory

Company Name: _____

Site Name: _____

TCEQ RN: _____, TCEQ Air Account No.: _____

Per 30 Texas Administrative Code (TAC) Subsection 101.10(b)(2)(A), this letter is to inform TCEQ that this site has not undergone any operational or process changes to produce a significant change in the actual annual emission rates for any of the criteria pollutants. The actual annual emission totals for volatile organic compounds, nitrogen oxides, carbon monoxide, sulfur dioxide, lead, and particulate matter with an aerodynamic diameter less than or equal to 10 micrometers and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers are each within 5% or 5 tons of the most recently reported total annual emissions.

Please check one:

☐ No emissions events (EE) as described under 30 Texas Administrative Code (TAC) Section 101.201 or scheduled maintenance, startup, or shutdown (SMSS) activities as described under 30 Texas Administrative Code (TAC) Section 101.211 occurred at the above-referenced site during the entire calendar year. By submitting this letter, I understand TCEQ will copy the most recent annual and ozone season emissions as shown in the State of Texas Air Reporting System (STARS) database to the current reporting year. Therefore, I am enclosing the following completed pages of the CY _____ emissions inventory questionnaire:

- Account Information and Emissions Inventory Contact Information.
- Criteria Emissions Totals and Site Quantifiable Event Totals.
- Signed Emissions Events Certification certifying that no emissions events occurred at the site during the calendar year.
- Signature of Legally Responsible Party certifying that the information contained in the emissions inventory is true and accurate.

☐ EE and/or SMSS activities occurred at the site during the calendar year. By submitting this letter, I understand TCEQ will copy the most recent annual and ozone

season emissions as shown in the STARS database to the current reporting year. In addition, so that TCEQ can update the emissions from any EE and/or SMSS activities, I am enclosing the following completed pages of the CY_____ emissions inventory questionnaire:

- Account Information and Emissions Inventory Contact Information.
- Criteria Emissions Totals and Site Quantifiable Event Totals.
- If applicable, signed Emissions Events Certification certifying that no emissions events occurred. (Do not sign if there were emissions events.)
- Signature of Legally Responsible Party certifying that the information contained in the emissions inventory is true and accurate.
- Path Emissions page(s) to report the emissions from each EE and/or SMSS activity that occurred at each emission source.

Upon request, I am prepared to submit supporting documentation that includes, but is not limited to, representative sample calculations, stack-test results, and copies of continuous emissions monitoring system reports.

If you have any questions concerning the determination of the status of this site or the calculation methodologies used, please contact me via telephone at _____ or via email at _____.

Sincerely,

Responsible Official (print) _____ Title (print) _____

Signature _____ Date Signed _____

# Appendix C. Contact Information and Other Resources

## Contacting the Emissions Assessment Section

### Emissions Inventory Mailing Addresses

It is essential that you send your EI correspondence to the correct address. Failure to do so may delay or prevent delivery of your letter or package.

#### *United States Postal Service*

Send correspondence via the USPS (e.g., overnight mail, priority mail, certified mail) to:

Emissions Inventory Data, MC 166
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, TX 78711-3087

#### *Overnight Service*

Send correspondence via special overnight carrier (e.g., FedEx, UPS) to:

Emissions Inventory Data, MC 166
Texas Commission on Environmental Quality
12100 Park 35 Circle, Bldg. E., 3rd Floor
Austin, TX 78753

To send **nonconfidential** supporting documents and sample calculations to the EAS, use the e-mail address psdocument@tceq.texas.gov and include the RN in the subject line. *Reminder:* Nonconfidential documents can be submitted as attachments using the STEERS-AEIR Web-EI system.

### Staff Mailing Addresses

To send mail to a particular EAS staff member, use the appropriate address from above, replacing Emissions Inventory Data, MC 166 with [staff member's name], MC 164.

### Assistance

For general questions concerning EI reporting or emissions calculation methodology, contact the EAS helpline at 512-239-1773, or send an email to psinvent@tceq.texas.gov.

### EI Webpage

Information on EI trends, total criteria emissions for each site that reported an EI for the previous year, tools for completing an EI, FAQ document, and this manual are available on the EAS webpage, www.tceq.texas.gov/goto/ieas.

### Air Fees Webpage

Information on contacting the fee program, the air emissions fee, and obtaining/completing the fee basis form are available on the Fees webpage www.tceq.texas.gov/airquality/point-source-ei/air-fees.html.

## EPA Resources

### Air CHIEF

The EPA's Clearinghouse for Inventories and Emission Factors contains the most up-to-date emissions information and factors, including most of the tools listed below. CHIEF is accessible online at www.epa.gov/chief. A CD-ROM (Version 10) is available by calling the Info CHIEF Help Desk at 919-541-1000, or by email to info.chief@epa.gov.

To learn more about CHIEF, you can also write to:

Info CHIEF
Emission Factor and Inventory Group (MD-14)
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

### AP-42

AP-42 (5th Ed., Vol. 1, January 1995, Supplements A–F) is discussed in Chapter 4 of this document ("Determining and Reporting Emissions"). It is included in Air CHIEF.

### WebFIRE

The EPA's Web-based Factor Information Retrieval data system is a database containing the EPA's recommended emission estimation factors for criteria and HAPs. WebFIRE is available online at cfpub.epa.gov/webfire. *Note:* Custom factors designed using WebFIRE data can only be used when no other data is available and are subject to TCEQ approval. Document all assumptions and the design of the emissions factor in the site's supporting documentation. The method code that applies to the use of such factors would be "E."

### Green Book

The EPA's *Green Book (Nonattainment Areas for Criteria Pollutants)* contains up-to-date information on nonattainment status. The *Green Book* is available online at www.epa.gov/green-book.

### Protocol for Equipment Leak Emission Estimates

*Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017) may be downloaded from the EPA website at www.epa.gov/sites/default/files/2020-09/documents/protocol_for_equipment_leak_emission_estimates.pdf

If you cannot navigate directly to the PDF, navigate to www.epa.gov/chief, right-click (Windows) or CTRL-click (Mac) on the link "Protocol for Equipment Leak Emission Estimates," and then select the appropriate option from the pop-up menu to save the PDF file to your desktop.

# TCEQ Resources

## Tools for Completing the EI

www.tceq.texas.gov/goto/ieas

## Information About Online Reporting

www.tceq.texas.gov/goto/ieas

## Central Registry Integrated Web Reports

www.tceq.texas.gov/goto/cr-query

## EI Account Mailing Status

www.tceq.texas.gov/goto/ieas

## Air Permits Guidance Documents

(*may be helpful for determining emissions*)
www.tceq.texas.gov/permitting/air/guidance

## Small Business and Local Government Assistance

The SBLGA program provides technical assistance specifically tailored to help small businesses and local governments comply with environmental regulations.

SBLGA webpage: www.tceq.texas.gov/assistance
SBLGA helpline: 1-800-447-2827

## Public Education and Pollution Prevention

TCEQ encourages businesses to implement policies that are beneficial while complying with state and federal rules. Please contact TCEQ's Public Education Section for assistance with improving performance and reducing air pollution from various sources.

www.tceq.texas.gov/p2/

# Abbreviations

| Abbrev. | Term |
|---|---|
| AEIR | annual emissions inventory report |
| AEIU | annual emissions inventory update |
| AMS | area and mobile source |
| API | American Petroleum Institute |
| AVO | audio/visual/olfactory |
| BTEX | benzene, toluene, ethylbenzene, and xylenes |
| Btu | British thermal unit(s) |
| CAS | Chemical Abstracts Service |
| CEMS | continuous emissions monitoring system(s) |
| CFR | Code of Federal Regulations (40 CFR xx = Title 40, Code of Federal Regulations, section xx) |
| CIN | control identification number |
| $Cl_2$ | chlorine |
| CHP | combined heat and power |
| CMS | continuous monitoring system |
| CO | carbon monoxide |
| COI | compound(s) of interest |
| CFR | Code of Federal Regulations |
| DRE | destruction and removal efficiency |
| EAS | Emissions Assessment Section |
| EC/R | Environmental Consultants and Research |
| EE | emissions events |
| EGU | electric generation unit |
| EI | emissions inventory |
| EIQ | emissions inventory questionnaire |
| EPA | United States Environmental Protection Agency |
| EPN | emission point number |
| FCAA | Federal Clean Air Act |
| FCCU | fluid catalytic cracking unit |
| FIN | facility identification number |
| FTPS | Secure TCEQ File Transfer Protocol |
| GHG | greenhouse gas |
| GOR | gas/oil ratio |
| $H_2S$ | hydrogen sulfide |

| Abbrev. | Term |
|---|---|
| HAP | hazardous air pollutant |
| HCN | hydrogen cyanide |
| HF | hydrogen fluoride |
| HRSG | heat recovery steam generator |
| HRVOC | highly reactive volatile organic compound |
| HVAC | heating, ventilation, and air conditioning |
| IEI | initial emissions inventory |
| IWR | Central Registry Integrated Web Reports |
| lb | pound(s) |
| LDAR | leak detection and repair |
| MAERT | Maximum Allowable Emissions Rate Table |
| MEROX | mercaptan oxidation |
| MM | million |
| MSS | maintenance, startup, and shutdown |
| MTBE | methyl tert-butyl ether |
| NAAQS | national ambient air quality standards |
| NAD83 | North American Datum of 1983 |
| NELAP | National Environmental Laboratory Accreditation Program |
| $NH_3$ | ammonia |
| NSCR | nonselective catalytic reduction |
| $NO_X$ | oxides of nitrogen |
| OA | Office of Air |
| Pb | Lead |
| PBR | permit by rule |
| PEMS | predictive emissions monitoring system(s) |
| PM | particulate matter |
| $PM_{2.5}$ | particulate matter no larger than 2.5 micrometers in diameter |
| $PM_{10}$ | particulate matter no larger than 10 micrometers in diameter |
| ppd | pounds per day |
| ppm | parts per million |
| psi | pounds per square inch |
| psia | pounds per square inch, absolute |
| psig | pounds per square inch, gauge |
| PTE | potential-to-emit |
| RATA | relative accuracy test audit |

| Abbrev. | Term |
|---|---|
| RN | regulated entity reference number |
| RVP | Reid Vapor Pressure |
| SIC | Standard Industrial Classification |
| SCC | source classification code |
| $SO_2$ | sulfur dioxide |
| SOCMI | synthetic organic chemical manufacturing industry |
| SMSS | scheduled maintenance, startup, and shutdown |
| SRU | sulfur recovery unit |
| STARS | State of Texas Air Reporting System |
| STEERS | State of Texas Environmental Electronic Reporting System |
| TAC | Texas Administrative Code |
| TCAA | Texas Clean Air Act |
| TCEQ | Texas Commission on Environmental Quality |
| THSC | Texas Health and Safety Code |
| TOC | total organic carbon |
| TRI | Toxics Release Inventory |
| tpy | tons per year |
| -u | -unclassified |
| UTM | Universal Transverse Mercator |
| VOC | volatile organic compound |
| VRU | vapor recovery unit |

# Glossary

The definitions in this glossary are intended to assist you in understanding matters related to the annual EI. **Nothing in this glossary supersedes any information in any state or federal law, rule, or regulation. In the case of any discrepancy between information herein and information in a state or federal law, rule, or regulation, the law, rule, or regulation takes precedence.**

**abatement code.** A numeric code that identifies an abatement device. A list of abatement codes is available at the EAS webpage: www.tceq.texas.gov/goto/ieas. Refer to the Electronic Emissions Inventory File Specifications Reference Tables.

**abatement device.** A piece of equipment or recognized operation that limits, controls, or abates emissions of certain contaminants associated with certain processes. Examples include baghouses, flares, scrubbers, condensers, vapor recovery units, and component fugitive Inspection and Maintenance programs. Synonymous with control device.

**account.** See Title 30 TAC Section 101.1. For sources *where a permit is required under 30 TAC Chapter 122* (*Federal Operating Permits*), all sources aggregated as a site. For all other sources, any combination of sources under common ownership or control and located on one or more properties that are contiguous, or contiguous except for intervening roads, railroads, rights-of-way, waterways, or similar divisions.

**annual emissions.** These comprise a site's actual routine emissions, including emissions from authorized maintenance, startup, and shutdown activities. They also include unauthorized emissions (1) from unauthorized facilities, or (2) that are excess emissions from authorized facilities, other than excess emissions that are defined in 30 TAC Section 101.1 as emissions events or scheduled maintenance, startup, and shutdown activities.

**API gravity.** The weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute:

$$API\ gravity = \frac{141.5}{Specific\ gravity} \times 131.5$$

**attainment county.** A county where levels of criteria air pollutants meet the NAAQS for the pollutants. Attainment areas are defined using federal pollutant limits set by the EPA. Refer to FCAA 107(d) for further explanations of "nonattainment" and "attainment" designations. Compare *nonattainment county*.

**average flow to flare (flared gas flow rate).** The average volumetric flow rate of flared gas, in thousand standard cubic feet per minute, while routine process flow is sent to the flare. It does not include upset or emergency flow to the flare.

**Chemical Abstracts Service number (CAS).** A unique number assigned to a substance. Although the EAS identifies each substance with a *contaminant code* rather than with its CAS number, you should include the CAS number when adding a new contaminant to your EI. This additional information will be used for quality assurance.

**component.** A piece of equipment, including pumps, valves, compressors, connectors, and pressure relief valves, which has the potential to leak VOC. Components are not

considered individual facilities and must be grouped and represented as collective sources in the EI according to the guidance in Chapter 3 and Technical Supplement 3.

**condensate.** A liquid hydrocarbon with an API gravity greater than 40º API at 60º F (and a specific gravity less than 0.8251).

**contaminant.** A substance emitted into the air.

**contaminant code.** A contaminant's five-digit identifying code. A list is available at the EAS webpage: www.tceq.texas.gov/goto/ieas.

**control device.** See *abatement device*.

**control identification number (CIN).** A label that uniquely identifies an abatement device; limited to 10 alphanumeric characters. Please note that no two separate abatement devices within an EI may share the same CIN.

**design capacity.** A combustion unit's maximum heat input rating, in million Btu per hour.

**design flow rate.** The maximum flow rate that a cooling tower is designed to accommodate in million gallons per day.

**destruction and removal efficiency (DRE).** A percentage that represents the number of molecules of a compound removed or destroyed relative to the number of molecules entering the system.

**electric generation unit (EGU).** For the EI, a boiler (including an auxiliary steam boiler), internal combustion engine, or stationary gas turbine (including a duct burner used in a turbine exhaust duct) that generates electric energy for compensation and is owned or operated by a person doing business in Texas, including a municipal corporation, an electric cooperative, or a river authority.

**emissions.** Air contaminants generated by a facility. See also *contaminant*.

**Emissions Assessment Section (EAS).** The section of TCEQ's Office of Air responsible for the EI process.

**emissions event (EE).** Any upset event or unscheduled maintenance, startup, or shutdown activity from a common cause that results in unauthorized emissions of air contaminants from one or more points at a regulated entity.

**emissions inventory questionnaire (EIQ).** A computer printout, historically a paper report, that shows a site's self-reported data, including, but not limited to, account information, contact information, process structural data, facility identification data, control device data, emission point data, and path emissions for a given calendar year.

**emissions inventory structure.** The way that a site's facilities, abatement devices, and emission points are represented in the EI. Formerly *account structure*.

**emission point.** The geographical location (point) where emissions enter the air. An emission point is described by its group, profile, and characteristics. Each emission point in the EI is uniquely identified by an *EPN*.

**emission point number (EPN).** A label that uniquely identifies a given emission point; limited to 10 characters. Please note that no two distinct emission points in an EI may share the same EPN. The EPNs on your EIQ must match those on your permit.

**excess opacity event.** When an opacity reading is equal to or exceeds 15 additional percentage points above an applicable opacity limit, averaged over 6 minutes as defined in 30 TAC Section 101.1.

**expected maximum capacity.** The projected greatest capacity of a facility based on its physical and operational design or configuration and planned operation.

**facility.** A discrete or identifiable structure, device, item, equipment, or enclosure that constitutes or contains a stationary source, including appurtenances other than emission-control equipment. A mine, quarry, well test, or road is not a facility. An individual fugitive component is not a facility.

**facility identification number (FIN).** A label that uniquely identifies a given facility; limited to 10 alphanumeric characters. Please note that no two distinct facilities may share the same FIN. The FINs on your EIQ must match those on your permit.

**flare temperature.** The temperature of the flame tip of a flare in degrees Fahrenheit.

**generation capacity.** The maximum electrical generating output in megawatts for electric generation units. The capacity is based on a continuous steady-state operation.

**greenhouse gases (GHGs).** Carbon dioxide ($CO_2$), nitrous oxide ($N_2O$), methane ($CH_4$), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride ($SF_6$).

**gas/oil ratio (GOR).** The volume of gas produced per volume of crude oil, condensate, or other hydrocarbon-containing liquid, such as produced water.

**hazardous air pollutant (HAP).** An air pollutant designated as hazardous by the EPA. HAPs are identified in federal Clean Air Act 112(b); the 1990 Act allows the EPA to modify the list as necessary. A current list can be found on the EPA's website. All HAPs that meet the reporting requirements must be listed individually (speciated) in the EI.

**highly reactive volatile organic compounds (HRVOCs).** For EI purposes, the compounds ethylene, propylene, all isomers of butene, and 1,3-butadiene. This definition applies to all areas of the state, not just those counties subject to the HRVOC rules found in 30 TAC Section 115.

**Maximum Allowable Emissions Rate Table (MAERT).** As defined in 30 TAC Section 116.10, a table included with a preconstruction permit issued under Chapter 116 that contains the allowable emission rates established by the permit for a facility.

**micrometer.** One-millionth of a meter.

**nonattainment county.** A defined region within the state designated by the EPA as failing to meet the NAAQS for a pollutant for which a standard exists. The EPA will designate the area as nonattainment under the provisions of FCAA 107(d). For the official list and boundaries of nonattainment areas, see 40 CFR Part 81 and pertinent *Federal Register* notices.

**nonreactive organic compounds.** A group of organic compounds that do not significantly contribute to ozone formation.

**non-reportable emissions event.** Any emissions event that in any 24-hour period does not result in an unauthorized emission from any emissions point equal to or more than the reportable quantity as defined in 30 TAC Section 101.1.

**non-reportable scheduled maintenance, startup, shutdown activity.** An SMSS activity that is recorded as required by 30 TAC Section 101.211.

**ozone season.** The period from May 1 through Sept. 30 of a year as defined in Title 40, Code of Federal Regulations (40 CFR), Part 51.

**path.** A path consists of a facility (tracked by its FIN) that generates emissions; an associated emission point (tracked by its EPN) where emissions enter the atmosphere; and any abatement devices (tracked by CINs) that control emissions. All paths must consist of at least a FIN and an EPN. If emissions produced at a FIN are not abated before entering the atmosphere at the associated EPN, then the path consists only of a FIN and an EPN. If, however, an abatement device controls emissions between the FIN and the EPN, then the associated path consists of a FIN, a CIN, and an EPN.

**percent max capacity.** The ratio of a facility's annual operating capacity to the facility's maximum capacity:

$$Percent\ Max\ Capacity\ = \frac{Capacity_{actual}}{Capacity_{maximum}} \times 100$$

For a definition of *Capacity maximum*, see expected maximum capacity.

**percent time offline (PTO).** The ratio of the device's downtime to the annual operating time. If a control device requires a minimum temperature to be fully functional, it is considered offline for the time period(s) when the minimum temperature is not met.

$$PTO\ = \frac{Hours\ Offline}{Annual\ Operating\ Hours} \times 100$$

*Example:* FLARE1 operated on an emergency basis for a total of 1200 hours during the year. The flare was offline for 288 hours and malfunctioned for an additional 83 hours. The PTO for FLARE1 is:

$$PTO\ = \left(\frac{288 + 83}{1200}\right) \times 100\ = 30.92$$

**permit by rule (PBR).** State air authorization for activities that produce more than a *de minimis* level of emissions but less than other New Source Review permitting options.

**particulate matter.** Any material, except uncombined water, that exists as a solid or liquid in the atmosphere or in a gas stream at standard conditions.

**$PM_{2.5}$.** Portion of particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers. $PM_{2.5}$ is a subset of PM and $PM_{10}$.

**$PM_{10}$.** Portion of particulate matter with an aerodynamic diameter less than or equal to 10 micrometers. $PM_{10}$ is a subset of PM.

**potential-to-emit (PTE).** The maximum capacity of a facility or stationary source to emit a pollutant under its physical and operational design. Any physical or enforceable operational limitation on the capacity of the facility or stationary source to emit a pollutant, including the use of air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, should be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions, as defined in 40 CFR 51.165(a)(1)(viii), do not count in determining a stationary source's potential to emit.

**regulated entity.** As defined at 30 TAC Section 101.1, all regulated units, facilities, equipment, structures, or sources at one street address or location that are owned or operated by the same person. The term includes any property under common ownership or control identified in a permit or used in conjunction with the regulated activity at the same street address or location. Owners or operators of pipelines, gathering lines, and flowlines under common ownership or control in a particular county may be treated as a single regulated entity for purposes of assessment and regulation of emissions events.

**regulated entity reference number (RN).** A number that the Central Registry assigns to a location where a TCEQ-regulated activity occurs.

**regulated pollutant.** Includes any VOC; any pollutant subject to the federal Clean Air Act, Section 111; any pollutant listed as a HAP under FCAA Section 112; each pollutant for which a national primary ambient air quality standard has been promulgated (including CO); and any other air pollutant subject to requirements under TCEQ rules, regulations, permits, orders of the Commission, or court orders.

**reportable emissions event.** Any emissions event that, in any 24-hour period, results in an unauthorized emission from any emissions point equal to or in excess of the reportable quantity as defined in 30 TAC Section 101.1.

**reportable scheduled maintenance, startup, shutdown activity.** An SMSS activity as defined in 30 TAC Section 101.1, where prior notice and a final report is submitted as required by Section 101.211.

**scheduled maintenance, startup, shutdown (SMSS) activity.** An activity as defined in 30 TAC Section 101.1 that is used in reporting required by Section 101.211.

**site.** As defined in 30 TAC Section 122.10, the total of all stationary sources located on one or more contiguous or adjacent properties, which are under common control of the same person (or persons under common control). A research-and-development operation and a collocated manufacturing facility are considered a single site if they each have the same two-digit Major Group SIC code (as described in the Standard Industrial Classification Manual, 1987) or if the research-and-development operation is a support facility for the manufacturing facility.

**site centroid.** The physical center of a site, represented in coordinate form (latitude and longitude or UTM). Formerly *account centroid*.

**source.** A point of origin of air contaminants, whether privately or publicly owned or operated.

**source classification code (SCC).** An eight-digit, EPA-developed code that identifies a specific industrial process.

**special inventory county.** A county under special provisions related to emissions reporting. A list of these counties can be found in Chapter 1 in the Special Inventory Request section.

**speciation.** Categorization of the individual chemical substances, or species, within an emission.

**State of Texas Air Reporting System (STARS).** The database where EI data are stored.

**structure.** The representation, in the TCEQ database, of the paths (formerly “links”) in an EI. EI structure must reflect the processes as shown on the site’s process flow diagram. For more information on proper EI structure, consult the appropriate sections of this document.

**Title V permit.** An operating permit required by Title V of the federal Clean Air Act as amended in 1990.

**toxic.** A chemical so designated by the EPA. Toxic chemicals are identified in 40 CFR 372.65.

**volatile organic compounds (VOCs).** A group of compounds that photochemically react in the atmosphere to form ozone. The official definition is found in 40 CFR 51.100(s), except 51.100(s)(2–4), as amended on Aug. 1, 2016 (81 *Federal Register* 50330).