RG-360A/11
Revised February 2012

2011 Emissions Inventory Guidelines

Air Quality Division

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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2011
Emissions Inventory Guidelines

Prepared by
Emissions Assessment Section
Air Quality Division
Chief Engineer's Office

RG-360A/11
Revised February 2012

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CHAPTER 1—GENERAL INFORMATION

Introduction

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 emitted by companies at their sites.

- The Texas Commission on Environmental Quality (TCEQ) is authorized to request emissions inventories and supporting documentation under the provisions of:
- the federal Clean Air Act;
- the Texas Clean Air Act, Texas Health and Safety Code Chapter 382, Section 014; and
- Title 30 of the Texas Administrative Code (30 TAC), Section 101.10.

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

The TCEQ uses the emissions inventory 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. In order to meet its goal of protecting human and natural resources, the TCEQ needs the full and complete cooperation of the regulated community.

EAS Objectives

In order to improve the overall quality of the statewide emissions inventory and to meet the goals stated above, the EAS objectives are to:

- ensure that the data requested in the emission inventory meet the requirements of the federal Clean Air Act and various other federal and state mandates;
- collect data in a standard format using the EAS forms and the emissions inventory questionnaire (EIQ);
- ensure that companies consistently use the most current and accurate information available for determining their emissions;
- help industry accurately report emissions data, especially by offering assistance through the EAS Help Line (512-239-1773);
- maintain data in a standard format using the State of Texas Air Reporting System (STARS) database;

- supply data to other personnel in the TCEQ; and
- continually update EAS publications in order to improve communication with companies submitting emissions inventories.

What This Book Contains

This chapter discusses EAS objectives, 30 TAC 101.10, and what constitutes a complete EI submission. This information should clarify why the EAS requires emissions inventories, help determine whether an emissions inventory is required for a site, and help correctly prepare a complete emissions inventory submission. The chapter concludes with a brief discussion of the EAS's confidentiality policy.

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

Chapter 3 discusses correct EI structure (representing processes on EIQ forms), 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 EIQ.

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

Chapter 8 answers questions about site quantifiable event totals; reporting emissions from emission events and scheduled maintenance, startups, and shutdowns; excess opacity; and the emissions event certification.

The appendixes contain:

- technical supplements intended to help determine emissions from certain common sources;
- sample letters that may help address some common situations;
- EPA and TCEQ resources that are available to assist in completing or updating an EI;

- information about qualifying for small-business assistance;
- pollution prevention tips from the TCEQ Pollution Prevention and Education Section; and
- a checklist designed to assist in determining whether all of the necessary information has been included with the EI.

Also included are a glossary and a list of abbreviations, followed by information on contacting the EAS.

Note: Due to space considerations, the EI forms and instructions are available in **a separate companion document**, *2011 Emissions Inventory Forms and Instructions* (TCEQ publication number RG-360B/11). This document can be downloaded from the EAS Web page at <www.tceq.texas.gov/goto/ieas>, or obtain a hard copy by contacting the EAS. Any EI forms referred to in this chapter can be found in that document.

About 30 TAC 101.10

This section includes a discussion of the emissions inventory process as a self-reporting process, the special inventory request, a copy of 30 TAC 101.10, and maps and tables depicting the state's nonattainment and special inventory areas. The maps and tables are intended to clarify reporting requirements and do not supersede or replace requirements of federal or state law, including 30 TAC 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 the EI rule.

A Self-Reporting Process

The EI process requires self-reporting. The owner or operator of the regulated entity is responsible for determining whether 30 TAC 101.10 applies to the site. If a site meets the applicability requirements of 30 TAC 101.10 or the EAS requests a special inventory, the owner or operator must submit an EI by the due date. Failure to do so may result in the initiation of an enforcement action against the company.

Requirements for submitting an EI are 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 emissions inventory and, if so, how to determine emissions and how to prepare and submit the required forms.

Nonattainment Designations

To determine the attainment status of the county where a site is located, please consult the Glossary. For the official list and boundaries of nonattainment areas, see 40 CFR Part 81 and pertinent *Federal Register* notices.

Submission requirements for emissions inventories will apply to those regulated entities located in a county designated as a nonattainment county under the 1997 eight-hour ozone standard, as well as any regulated entity requested to submit a special inventory, regardless of location.

The map entitled "Eight-Hour Ozone Nonattainment Areas" on page 9 identifies the nonattainment counties. A link to this map also appears on the EAS Web page at <www.tceq.texas.gov/goto/ieas>. 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

The TCEQ, under the "special emissions inventory" provisions of 30 TAC 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 the TCEQ has initiated a formal written request, the owner or operator must complete and submit an EI by the required date. The TCEQ is conducting a special emissions inventory for entities that emit or have the potential to emit lead and for entities that emit ozone precursors.

Requirements for All Counties Concerning Lead

For the 2011 reporting year, the TCEQ is conducting a special inventory for lead sources under the authority of 30 TAC 101.10(b)(3). Any regulated entity that emits 0.5 ton(s) per year (tpy) of lead emissions during normal operations or has the potential to emit 5 tpy of lead emissions must submit a complete emissions inventory by the required due date.

Ozone Precursors in Specified Counties

The TCEQ is conducting a special emissions inventory for sources that emit ozone precursors in the specified counties listed in Table 1-1 under the authority of 30 TAC 101.10(b)(3). Regulated entities that are located in one of these counties and emitted 10 tpy of volatile organic compounds or 25 tpy of nitrogen oxides during normal operations must submit a complete emissions inventory by the required due date.

Note: Regulated entities that meet any of the other applicability requirements of 30 TAC 101.10 are required to submit an annual

emissions inventory regardless of whether the TCEQ has initiated a formal written request.

Table 1-1. Ozone-Precursor Special Inventory Counties

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

30 TAC §101.10. Emissions Inventory Requirements

(a) **Applicability.** The owner or operator of an account or source in the State of Texas or on waters that extend 25 miles from the shoreline meeting one or more of the following conditions shall submit emissions inventories and/or related data as required in subsection (b) of this section to the commission on forms or other media approved by the commission:

(1) an account which meets the definition of a major facility/stationary source, as defined in §116.12 of this title (relating to Nonattainment Review Definitions), or any account in an ozone nonattainment area emitting a minimum of ten tons per year (tpy) volatile organic compounds (VOC), 25 tpy nitrogen oxides (NO_x), or 100 tpy or more of any other contaminant subject to national ambient air quality standards (NAAQS);

(2) any account that emits or has the potential to emit 100 tpy or more of any contaminant;

(3) any account which emits or has the potential to emit 10 tons of any single or 25 tons of aggregate hazardous air pollutants as defined in FCAA, §112(a)(1); and

(4) any minor industrial source, area source, non-road mobile source, or mobile source of emissions subject to special inventories under subsection (b)(3) of this section. For purposes of this section, the term “area source” means a group of similar activities that, taken collectively, produce a significant amount of air pollution.

(b) **Types of inventories.**

(1) Initial emissions inventory. Accounts, as identified in subsection (a)(1), (2), or (3) of this section, shall submit an initial emissions inventory (IEI) for any criteria pollutant or hazardous air pollutant (HAP) that has not been identified in a previous inventory. The IEI shall consist of actual emissions of VOC, NO_x, carbon monoxide (CO), sulfur dioxide (SO_2), lead (Pb), particulate matter of less than 10 microns in diameter (PM_{10}), any other contaminant subject to NAAQS, emissions of all HAPs identified in FCAA §112(b), or any other contaminant requested by the commission from individual emission units within an account. For purposes of this section, the term “actual emission” is the actual rate of emissions of a pollutant from an emissions unit as it enters the atmosphere. The reporting year will be the calendar year or seasonal period as designated by the commission.

Reported emission activities must include annual routine emissions; excess emissions occurring during maintenance activities, including startups and shutdowns; and emissions resulting from upset conditions. For the ozone nonattainment areas, the inventory shall also include typical weekday emissions that occur during the summer months. For CO nonattainment areas, the inventory shall also include typical weekday emissions that occur during the winter months. Emission calculations must follow methodologies as identified in subsection (c) of this section.

(2) Statewide annual emissions inventory update (AEIU). Accounts meeting the applicability requirements during an inventory reporting period as identified in subsection (a)(1), (2), or (3) of this section shall submit an AEIU which consists of actual emissions as identified in subsection (b)(1) of this section if any of the following criteria are met. If none of the following criteria are met, a letter certifying such shall be submitted instead:

(A) any change in operating conditions, including start-ups, permanent shut-downs of individual units, or process changes at the account, that results in at least a 5.0% or 5 tpy, whichever is greater, increase or reduction in total annual emissions of VOC, NO_x, CO, SO_2, Pb, or PM_{10} from the most recently submitted emissions data of the account; or

(B) a cessation of all production processes and termination of operations at the account.

(3) Special inventories. Upon request by the executive director or a designated representative of the commission, any person owning or operating a source of air emissions which is or could be affected by any rule or regulation of the commission shall file emissions-related data with the commission as necessary to develop an inventory of emissions. Owners or operators submitting the requested data may make special procedural arrangements with the Industrial Emissions Assessment Section to submit data separate from routine emission inventory submissions or other arrangements as necessary to support claims of confidentiality.

(c) **Calculations.** Actual measurement with continuous emissions monitoring systems (CEMS) is the preferred method of calculating emissions from a source. If CEMS data is not available, other means for determining actual emissions may be utilized in accordance with detailed instructions of the commission. Sample calculations representative of the

processes in the account must be submitted with the inventory.

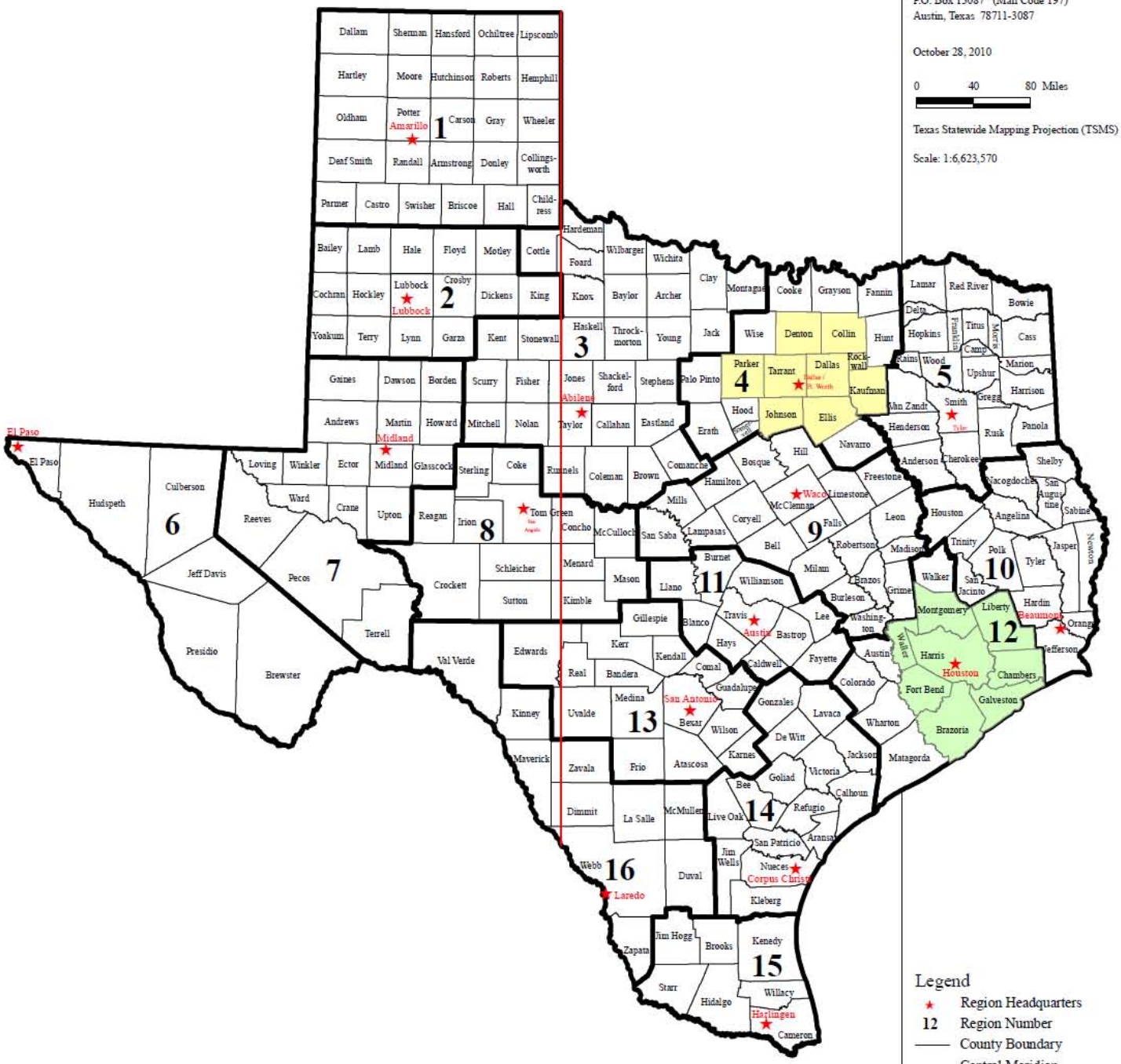
(d) **Certifying statement.** A certifying statement, required by the FCAA, §182(a)(3)(B), is to be signed by the owner(s) or operator(s) and shall accompany each emissions inventory to attest that the information contained in the inventory is true and accurate to the best knowledge of the certifying official.

(e) **Reporting requirements.** The IEI or subsequent AEIUs shall contain emissions data from the previous calendar year and shall be due on March 31 of each year or as directed by the commission. Owners or operators submitting emissions data may make special procedural arrangements with the Industrial Emissions Assessment Section to submit data separate from routine emission inventory submissions or other arrangements as necessary to support claims of confidentiality. Emissions-related data submitted under a special inventory request made under subsection (b)(3) of this section are due as detailed in the letter of request.

(f) **Enforcement.** Failure to submit emissions inventory data as required in this section shall result in formal enforcement action under the TCAA, §382.082 and §382.088. In addition, the TCAA, §361.2225, provides for criminal penalties for failure to comply with this section.

December 23, 1999

Eight-Hour Ozone Nonattainment Areas



Protecting Texas by Reducing and Preventing Pollution

TCEQ

Texas Commission on Environmental Quality
P.O. Box 13087 (Mail Code 197)
Austin, Texas 78711-3087

October 28, 2010

0 40 80 Miles

Texas Statewide Mapping Projection (TSMS)

Scale: 1:6,623,570

Legend

- ★ Region Headquarters
- 12 Region Number
- County Boundary
- Central Meridian

Source: The county boundaries and region headquarters are U S Census Bureau 1992 Tiger/Line data (1:100,000).

This map was generated by the Information Resources Division of the Texas Commission on Environmental Quality. This product is for informational purposes and may not have been prepared for or be suitable for legal, engineering, or surveying purposes. It does not represent an on-the-ground survey and represents only the approximate relative location of property boundaries. For more information concerning this map, contact the Information Resource Division at (512) 239-0800.

M McDonough CRF-336597

Table 1-2. Eight-hour ozone nonattainment areas

Summary of Reporting Requirements (tpy) for 30 TAC Section 101.10										
County	VOC		NOX		Other		Individual HAP		Aggregated HAP	
	Actual	Potential	Actual	Potential	Actual	Potential	Actual	Potential	Actual	Potential
Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, Waller SEVERE / OZONE	10	25	25	25	100	100	10	10	25	25
Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, Tarrant SERIOUS / OZONE	10	50	25	50	100	100	10	10	25	25
All Other Counties	100	100	100	100	100	100	10	10	25	25

Note: If an account's emissions meet or exceed the tons per year (tpy) thresholds listed in this table, an emissions inventory questionnaire must be submitted to the TCEQ. This table is not the actual rule. If a discrepancy exists between the table and rule 30 TAC Section 101.10 and 30 TAC Section 116.12 (Major Source Definition), then the rule will take precedence.

What Constitutes a Complete Submission?

A complete EI submission includes a complete and updated EI, sample calculations representative of the processes at the site, summary test results if stack test data are used to determine emissions, summary Relative Accuracy Test Audit sheets if CEMS or PEMS data are used to determine emissions, material throughput forms (for oil field storage tanks), Fugitive Data Forms if required by the Technical Supplement 3 in Appendix A, and any forms necessary to add or change EI structure. For paper and diskette submissions through the mail, a complete submission also includes the signed Emissions Events Certification (if applicable) and the EIQ page for account-information certification, including the signature of the legally responsible party. If you are supplying the supporting documentation electronically in PDF, be sure to separate confidential from nonconfidential information in different electronic files.

Sample Calculations

Per 30 TAC 101.10(c), sample calculations representative of the processes at the site must be submitted with the inventory. Submit sample calculations showing determinations of actual annual emissions for each different type of process present in the EIQ, including enough data so that the determination results may be reasonably reproduced. Generic sample calculations cannot be accepted since they do not contain representative process data and do not demonstrate actual annual emissions determinations. For similar reasons, summary spreadsheets listing emissions quantities are not considered sample calculations. Note that sample calculations are required to be submitted and updated each year.

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 level of emissions.
  - Include typical process data for all of the similar sources where sample calculations are not supplied. Typical process data would include heat inputs and fuel types for combustion sources and chemical types and throughputs for storage tanks and loading sources.
- When several sources of the same type are present but different calculation methodologies were used to determine their emissions:
  - Include calculations for the source with the highest emissions for each calculation methodology.
  - Include typical process data for all of the similar sources where

sample calculations are not supplied. Typical process data would include heat inputs and fuel types for combustion sources and chemical types and throughputs for storage tanks and loading sources.

Requirements for a New Emissions Inventory

If a site has not previously submitted an emissions inventory and it meets the EI reporting requirements of 30 TAC 101.10, then the owner or operator is required to submit an EI by March 31, 2012:

- A full set of properly completed forms (see *2011 Emissions Inventory Forms and Instructions*, TCEQ publication RG-360B/11, or the EAS Web page), including:
  - A completed Account Emissions form with required signatures—

    1. *Emissions Events Certification*. This statement **must** be signed if and only if there were no emissions events and no emissions from emissions events will be reported in the EI.

    2. *Signature of the Legally Responsible Party*. The signature of the individual legally responsible for certifying that the inventory is, to the best of her or his knowledge, accurate and complete. Note that the legally responsible party **may not be a consultant**. See the Account Emissions form instructions for further details.
  - An Account Information form.
  - A Contact Information form.
  - A Structural Overview form.
  - The appropriate Facility Information form for each facility listed on the Structural Overview form.
  - An Abatement Device Information form for each abatement device listed on the Structural Overview form.
  - The appropriate Emission Point Information form for each emission point listed on the Structural Overview form.
  - A Path Emissions form for each path listed on the Structural Overview form.
  - Sample calculations representative of the processes at the site.
  - Summary test results if stack test data is used to determine emissions; or summary Relative Accuracy Test Audit sheets if CEMS or PEMS data are used to determine emissions.

- Flare Data, Fugitive Data, and Material Throughput for oil field storage tanks forms, if required by the technical supplements in Appendix A.

Requirements for Updating an EI

Any regulated entity that continues to meet the EI reporting requirements of 30 TAC 101.10 is required to submit an EI by March 31, 2012, or as directed—

- **For a hard copy (paper) EI:** A properly and thoroughly updated paper EIQ; complete instructions can be found in Chapter 6. The preparer may not substitute a spreadsheet for the EIQ.
  - The required signatures on the EIQ—

    (1) *Emissions Events Certification:* This statement **must** be signed **if and only if** there were no emissions events and no emissions from emissions events will be reported in the EI.

    (2) *Signature of the Legally Responsible Party:* The signature of the individual legally responsible for certifying that the inventory is, to the best of her or his knowledge, accurate and complete. Note that the legally responsible party may not be a consultant. See the subheading "Signature of Legally Responsible Party" in Chapter 6, "Updating an Emissions Inventory Questionnaire," for further details.
  - Sample calculations representative of the processes at the site.
  - Summary test results if stack test data is used to determine emissions; or summary Relative Accuracy Test Audit sheets if CEMS or PEMS data are used to determine emissions.
  - Material Throughput forms (for oil field storage tanks) and Fugitive Data Forms, if required by the technical supplements in Appendix A.
  - Any forms necessary to add or change account structure (add forms).
- **For an EI submitted through online data entry:** Updated EI data via the STARS EI Web portal using the State of Texas Environmental Electronic Reporting System (STEERS) available at <https://www6.tceq.texas.gov/steers/>. The Emissions Events Certification (if applicable) and Signature of the Legally Responsible Party are part of the electronic system and do not need to be submitted separately. Additionally, submit the following:

- Site-wide emissions totals for the criteria pollutants. These will be used to compare the emissions submitted through STEERS to the STARS generated totals for the current reporting year.
- Sample calculations representative of the processes at the site.
- Summary test results if stack test data are used to determine the emissions or summary Relative Accuracy Test Audit sheets if CEMS or PEMS data are used to determine the emissions.
- Material Throughput forms (for oil field storage tanks) and Fugitive Data Forms, if required by the technical supplements in Appendix A.
- Any forms necessary to add or change EI structure.

Sample calculations and supporting documentation may be mailed to the EAS or sent by e-mail to <psdocument@tceq.texas.gov>. If sending electronic files, ensure that the data are self-contained and not linked to external data sources unavailable to the TCEQ. For electronic files, the preferred formats are Microsoft Word, Excel, and Access, and Adobe PDF. If e-mailing documentation, the site's RN and reporting year must be included in the subject line, and the company name, site name, and AEIU online submission date in the body. If you are supplying the supporting documentation electronically in PDF, be sure to separate confidential from nonconfidential information in different electronic files.

- **For an updated electronic EI text file submitted online through STEERS:** An updated EI via the STARS EI Web portal using the State of Texas Environmental Electronic Reporting System (STEERS) available at <https://www6.tceq.state.tx.us/steers/>. The Emissions Events Certification (if applicable) and the signature of the legally responsible party are part of the electronic system and do not need to be submitted separately. Additionally, submit the following:
  - Site-wide emissions totals for the criteria pollutants. These will be used to compare the emissions submitted through STEERS to the STARS-generated totals for the current reporting year.
  - Sample calculations representative of the processes at the site.
  - Summary test results if stack test data are used to determine the emissions or summary Relative Accuracy Test Audit sheets if CEMS or PEMS data are used to determine the emissions.
  - Material Throughput forms (for oil field storage tanks) and Fugitive Data Forms, if required by the technical supplements in Appendix A.
  - Any forms necessary to add or change account structure (add forms).

Sample calculations and supporting documentation may be mailed to the EAS or sent by e-mail to <psdocument@tceq.texas.gov>. If electronic files are provided, ensure that the data are self-contained and not linked to external data sources unavailable to the TCEQ. For electronic files, the preferred formats are Microsoft Word, Excel, and Access, and Adobe PDF. If the documentation is sent by e-mail, the site's RN and reporting year must be included in the subject line, and the company name, site name, and AEIU online submission date in the body. If you are supplying the supporting documentation electronically in PDF, be sure to separate confidential from nonconfidential information in different electronic files.

Note: The EAS will no longer accept an electronic EI submitted by mail on an external medium such as CD-ROM. All electronic EIs must be submitted through STEERS. For more information, consult the *Online Annual Emissions Inventory Report User's Guide* available on the EAS Web page at <www.tceq.texas.gov/goto/ieas> or contact the EAS.

If a Site Experienced Insignificant Changes in Emissions

Submission of an updated EI is not required if the total actual annual emissions of volatile organic compounds (VOCs), nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), lead (Pb), and particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) are all within 5 percent or five tons, whichever is greater, of the most recent total actual annual emissions reported in the STARS database. Instead, the owner or operator may request that the EAS copy the most recent annual emissions to the current reporting year.

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

- a letter similar to the Insignificant Change Notification letter in Appendix B;
- the Account Information and Emissions Inventory Contact Information, page 2 of the EIQ;
- the Criteria Emissions Totals and Site Quantifiable Event Totals, page 3 of the EIQ; and
- the signed Emissions Events and Legally Responsible Party certification statements, page 4 of the EIQ.

If the site did experience emissions due to EE and SMSS activities, the owner or operator may still submit a formal request to have the EAS copy the most recent annual and ozone season emission rates to the current year.

However, the emissions from emissions events and/or SMSS activities need to be updated by submitting:

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

Sample calculations and other supporting documentation may need to be supplied upon request.

Please note: The Insignificant Change Notification letter and the certification statements should be signed by a responsible official of the company. These documents should not be signed by a consultant.

If a Site Does Not Meet the Requirements of 30 TAC 101.10 for the Current Emissions Inventory Year

If the owner or operator has determined that a site does not meet the EI reporting requirements of 30 TAC 101.10 for the current inventory year, but may meet applicability requirements in future years, the preparer must submit by March 31, 2012, or as directed, a letter similar to the Inapplicability Notification letter in Appendix B.

Note: By signing this letter or a similar letter, the owner or operator of the regulated entity will remain on the EAS mailing list and continue to receive a request to submit annual emissions inventory questionnaires. A letter must be submitted to the agency for each reporting year that the site does not meet the reporting requirements. The letter must not be signed by a consultant.

Sample calculations and other supporting documentation may need to be supplied upon request.

If a Site Will Not Meet the Requirements of 30 TAC 101.10 in Future Years

If the owner or operator has determined that a site does not currently meet the applicability requirements of 30 TAC 101.10, and if the site will not meet those requirements in future years, then the owner or operator may formally request its removal from the EAS mailing list. Submit a letter similar to the Inapplicability Notification letter in Appendix B by March 31, 2012, or as directed.

As stated in 30 TAC 101.10, "actual emission" is the actual rate of emissions of a pollutant from an emissions unit as it enters the atmosphere. This would include routine annual emissions and emissions from emissions events and maintenance, startup, and shutdown activities.

Note: The owner or operator—not a consultant—must sign a letter requesting this action. Only written requests to be removed from the mailing list are accepted.

Annual Emissions Inventory Update (AEIU) requests are based primarily on the most recent EI as it appears in the STARS database. If the emissions reported in the STARS database or allowable rates exceed the rule applicability requirements, the regulated entity cannot be removed from the annual EI mailing list. For the site to be removed from the mailing list, submit a current updated EIQ and sample calculations. After the EI data are updated in STARS, the site can then be removed from the mailing list.

A site may have to void its Title V permit to demonstrate that PTE levels are below the EI reporting requirements as described in 30 TAC 101.10(a) before the site can be removed from the mailing list. If a regulated entity voids its Title V permit and has the action certified by the TCEQ by December 31, 2011, the permit will be considered void for the entirety of 2011, and the site can be removed from the mailing list. If the regulated entity voids its Title V permit after December 31, 2011, the PTE levels are still applicable for the 2011 EI.

If a regulated entity that has been removed from the mailing list meets the EI reporting requirements of 30 TAC 101.10 at any time in the future, it is the responsibility of the owner or operator to submit an EI by March 31 of the following year.

A Note about Confidentiality

The EAS will respect the confidentiality of certain data unless the Texas Attorney General's Office rules that the data are not protected by state law. If there are any special concerns about confidentiality, contact the EAS.

Such concerns do not justify withholding relevant information from the EAS.

The following information will be kept confidential if clearly marked:

- material data (as reported on Material Throughput forms)
- process flow diagrams
- process rates
- trade secrets (information that reveals secret processes or methods of manufacture or production)

Information **not** considered confidential includes:

- emission rates
- emission point data
- type of emissions control equipment
- type of emitting equipment

Under no circumstance should the preparer enter confidential information on the EIQ. Instead, submit confidential information separately, with each page clearly marked CONFIDENTIAL. If you are supplying the supporting documentation electronically in PDF, be sure to separate confidential from nonconfidential information in different electronic files. If both confidential and nonconfidential information is included in a single PDF, the TCEQ will treat all of the information as nonconfidential.

Electronic Reporting

Two options are available for updating EI data through the Web: an online data entry system or submission of a text file.

Updating an Electronic AEIU through Online Data Entry

The electronic AEIU can be updated and submitted through an online data-entry option in STEERS, and regulated entities are encouraged to use this online option. The Annual Emissions Inventory Report (AEIR) system is a Web-based application that allows regulated entities to update their AEIU data using an online data-entry interface.

The online data-entry option allows updating of the EI data on the company, site, contacts, facility, control devices, emission points, and path emissions through graphical-user-interface (GUI) windows. The user may save the data in the work area in one or more work sessions until online data 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 of the required EI data is entered, the AEIU 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 e-mail. If no errors were encountered, the e-mail will state, "AEIR validation process successful," and the electronic submission will be considered complete. If errors were encountered, the e-mail will state, "AEIR validation process failed," and an error log will be attached with instructions for viewing the log through STEERS. The STEERS user will need to 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 file-status e-mails are sent to each individual with "submit" authorization as identified by STEERS.

A date of receipt will be assigned to the file on the day the validation is successful. The TCEQ must receive the file by the EI due date, which is March 31, 2012, or as the agency has directed. Otherwise, it will consider the AEIU submission delinquent. The sample calculations and supporting documentation must also be submitted by the EI due date.

Sample calculations and supporting documentation may be mailed to the EAS or sent by e-mail to <psdocument@tceq.texas.gov>. For electronic files, the preferred formats are Microsoft Word, Excel, Access, and PDF. If the documentation is sent by e-mail, the site's RN and reporting year must be included in the subject line, and the company name, site name, and AEIU online submission date in the body. If you are supplying the supporting documentation electronically in PDF, be sure to separate confidential from nonconfidential information in different electronic files.

For more information, consult the *Online Annual Emissions Inventory Report User's Guide* available on the EAS Web page at <www.tceq.texas.gov/goto/ieas> or contact the EAS.

Submitting an Electronic Text File of the AEIU Online through STEERS

An electronic AEIU can be submitted online. The AEIR system is a Web-based application that allows regulated entities to submit their AEIU to the TCEQ using STEERS.

The AEIR text file can be loaded from the user's personal computer. This file is a complete update of their EI. Past users who have submitted updated emissions inventories on diskettes or compact discs may prefer to use this process. Historically, these files were submitted via diskettes or compact disks and loaded into STARS by TCEQ. Regulated entities can now submit the electronic AEIU through STEERS. The file must be in an approved electronic format, as outlined in the *Electronic Emissions*

Inventory File Specification. This document is available online at <www.tceq.texas.gov/goto/starsguide>.

Starting with the 2011 EI, **all** electronic EIs **must** be submitted through STEERS. Two steps are required to submit the AEIU text file. The text file must be loaded into the STEERS work area from the user's personal computer. After the electronic AEIU is submitted to the STEERS work area, regulated entities will receive an e-mail response detailing whether the system accepted the AEIU file. As a second step, 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 e-mail. If no errors were encountered, the e-mail will state "AEIR validation process successful" and the electronic submission is considered complete. If errors were encountered, the e-mail will state "AEIR validation process failed." The system will also supply the user with a copy of record of the transacted data. *Note:* All file-status e-mails are sent to each individual with "submit" authorization as identified by STEERS.

If the electronic AEIU does not pass the validation routine by the EI due date—which is March 31, 2012, or as directed by the agency—the AEIU submission will be considered delinquent. The sample calculations and supporting documentation must also be submitted by the EI due date.

Sample calculations and supporting documentation may be mailed to the EAS or sent by e-mail to <psdocument@tceq.texas.gov>. For electronic files, the preferred formats are Microsoft Word, Excel, Access, and PDF. If the documentation is sent by e-mail, the site's RN and reporting year must be included in the subject line, and the company name, site name, and AEIU online submission date in the body.

For more information about online electronic reporting, consult the *Online Annual Emissions Inventory Report User's Guide*, available on the EAS Web page at <www.tceq.texas.gov/goto/ieas>.

Contact the EAS for further assistance with electronic reporting.

A Note about the EI Due Date

The EI is due on March 31, 2012, or 90 days from the EI request date (as indicated on the EI cover letter sent by the TCEQ), whichever is later. The EI will not be considered late as long as it is postmarked by the due date.

To document compliance, the TCEQ recommends that the preparer use a delivery method that confirms receipt by the agency and keep a record of the confirmation on file.

Note: If the due date falls on a weekend, the EI must be postmarked by the preceding business day.

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

The EAS annually collects statewide data on emissions from industries that meet the EI reporting requirements and stores those data in its database, the State of Texas Air Reporting System (STARS). An EI is the result of a process the EAS uses to collect data on standardized forms to ensure consistency among types of data collected, and to facilitate data entry 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, a unique identification number assigned by the TCEQ. A site's air regulated entity reference number will thus also uniquely identify its EI.

Requirements for Submitting an Emissions Inventory

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

The reporting requirements for emissions inventories will vary, depending on both:

- site location and
- the type and quantity of emissions.

The *attainment status* of the county where the regulated entity is located will impact the emissions inventory 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** emissions level reporting requirements for this pollutant. Thus, a regulated entity located in a county designated in nonattainment for ozone will be subject to more stringent potential and actual emissions level reporting requirements for ozone-precursor pollutants than a regulated entity located in a county designated as in attainment for ozone.

The term *actual emission* is defined in 30 TAC 101.10 as the actual rate of emissions of a pollutant from an emissions generating source, or *unit*, as the pollutant enters the atmosphere. Potential emissions from a specific unit are referred to as its *potential to emit*. Potential to emit is defined in the Glossary as well as 30 TAC 122.10. Note that, while both actual and potential emissions are defined above in relation to an emissions generating source or unit, the emissions inventory reporting requirements concerning actual and potential emissions are **site-wide**.

The owner or operator of the regulated entity must determine the attainment status of the county where the site is located. The map in Chapter 1 contains a table that gives the EI reporting requirements by listing the actual and potential emissions levels for all counties in Texas. For more information, consult the text of 30 TAC 101.10 in Chapter 1.

Note the map and associated table are intended to clarify reporting requirements and do not supersede or replace 30 TAC 101.10. To determine both the actual and potential emissions level reporting requirements for a specific county, consult 30 TAC 101.10.

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

Based on the reporting requirements associated with the site's location and the actual and potential emissions, the owner or operator must determine whether submission of an EI is required. If so, the preparer must report the actual annual emissions on the standardized EI forms. Representing sources within the emissions inventory 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 entered into STARS, is not just associated with a site's regulated entity reference number, 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 emissions sources is called *structure*. In other words, structure aids in the translation of the emissions-

generating equipment and processes onto paper forms. The key concepts associated with structure are discussed in the following sections.

Facilities and Emission Points

In EI terminology, any source capable of generating emissions (for example, an engine or a sandblasting area) is called a *facility*. Thus, *facility* and *emissions 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:

- *stack-type* emission points, such as boiler stacks or building vents;
- *fugitive-type* emission points, such as sandblasting yards or marine loading areas;
- and *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, every facility (emissions 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 emissions 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.

Paths

As stated in the previous section, every 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 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 (emissions 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 characteristics. 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 standardized 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 emissions inventory 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, each emission source 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
- piping component fugitive areas
- 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 emissions source, the owner or operator of the regulated entity needs to add the emissions source to the EI as an individual source, group the emissions source with other similar sources, or possibly omit the source from the EI.

Sources that Must Be Added to the EI and that May Be Grouped as Collective Sources

Each emissions 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.
- It emits 0.001 ton or more of mercury, lead, or any individual HAP or aggregate HAP listed in any TCEQ-enforceable document such as a permit, regulation, or commission order.
- It is listed in any TCEQ-enforceable document such as a permit, regulation, or commission order.
- *Please 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 may be omitted from 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.

The EAS 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 EIQ.

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.

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 than10 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. 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 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
- a fugitive leak detection and repair program

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

- FLR
- SCRUB4
- VAPORCOND
- VRU
- LDAR2

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

Small emission sources or facilities that emit a small amount of emissions, have similar source classification codes (SCCs), and emit similar emissions may be grouped as one collective emission source. The collective emission source will be given a unique FIN and be added to the EI. A small emission source or a small facility must meet all of the following criteria:

- the source emitted less than 1 ton of each regulated pollutant;
- the source emitted less than 0.1 ton of any toxic chemical or hazardous air pollutant; and
- the source 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 need to be represented in the EIQ since collectively the storage piles emitted 10 tpy of PM_{10}. If the storage piles are not individually represented in any permits, they could be grouped together 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 EIQ. Use the following guidelines when adding collective sources to the EIQ.

Facility Guidelines

Group only those sources with similar SCC and similar emissions as one collective facility. Create different collective FINs for each distinct type of process and equipment. Examples of different source types that can be grouped in a collective FIN include:

- solvent cleaning areas and equipment
- painting areas and equipment
- piping component fugitive areas
- VOC loading operations
- tanks
- internal combustion sources
- external combustion sources
- other sources as appropriate

Emission Point Guidelines

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

- Complete the Emission Point Information—Fugitive form for the fugitive area emission point. The length and width of the fugitive area is the length and width of the entire site, and the height of the fugitive area is the estimated height reached by the fugitive emissions. 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, the TCEQ recommends 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 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 EIQ.

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

Representing Combustive Abatement Devices

Most abatement devices do not generate their own emissions and should 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. 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. Thus, the preparer would create the path FIN: PROCESS / CIN: FLARE / EPN: FLARE. All undestroyed waste gas emissions should be reported in this path. Another emissions path will have to be created to report the emissions generated by the combustion of the waste gas at the flare. The products of combustion should be reported at the path representing the flare as the source and flare as the emissions 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 emissions sources. For assistance with establishing the correct structure for a process, please contact the EAS.

Cooling Towers

In order 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 should also be considered one facility with one stack emission point; the number of cells should be represented as one of the parameters under the FIN group and profile characteristics on the EIQ.

Cooling towers are 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.

From the list that follows, at least paths 1 and 2 are needed to represent each glycol unit, and 3 is optional:

- a still path for reporting emissions from the gas-stripping process
- a reboiler path for reporting combustion emissions
- a path for the flash tank, 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. 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 reboiler emissions are vented through separate stacks, represent each unit as a separate facility linked to its own emission point. In other words, each unit should be represented as its own emission path, as shown in Figure 3-1.

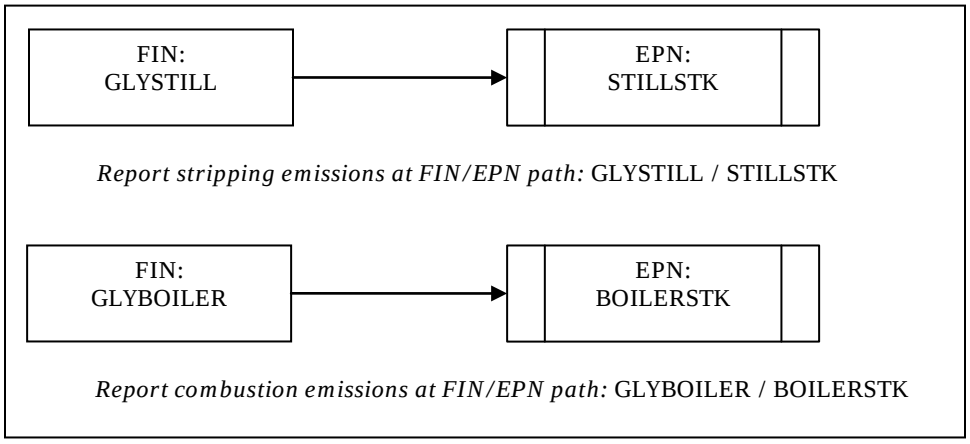


Figure 3-1. Glycol Unit—Separate Still and Reboiler Vents

Venting to a Common Stack

If glycol still emissions and reboiler emissions both vent through a common stack, represent the glycol still and reboiler as two facilities that are linked to a single emission point. This structure is shown in Figure 3-2.

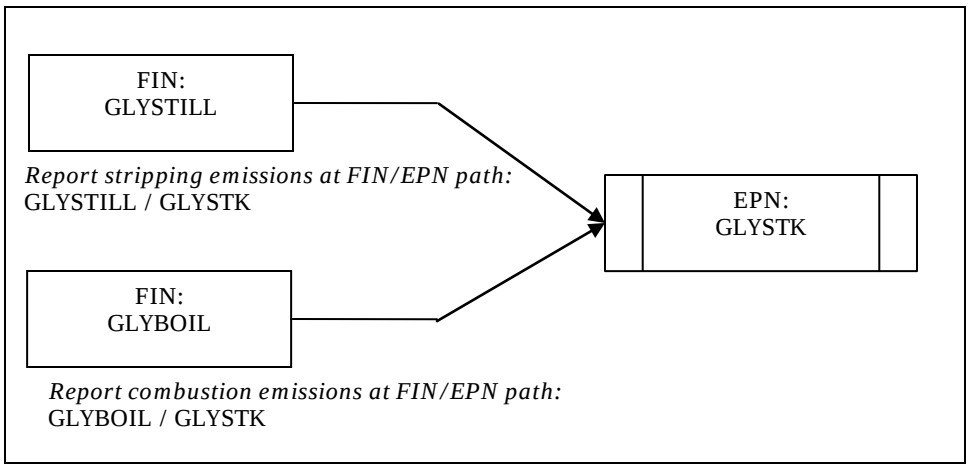


Figure 3-2. Glycol Unit—Common Still and Reboiler Vents

Routing Still Emissions to a Flare

If glycol still emissions are routed to a flare, the glycol still and reboiler should be represented as shown in Figure 3-3. Represent the glycol reboiler as its own facility linked to its own emission point. Represent the glycol still and flare as separate facilities linked to a single emissions point, with an abatement device added to the glycol still.

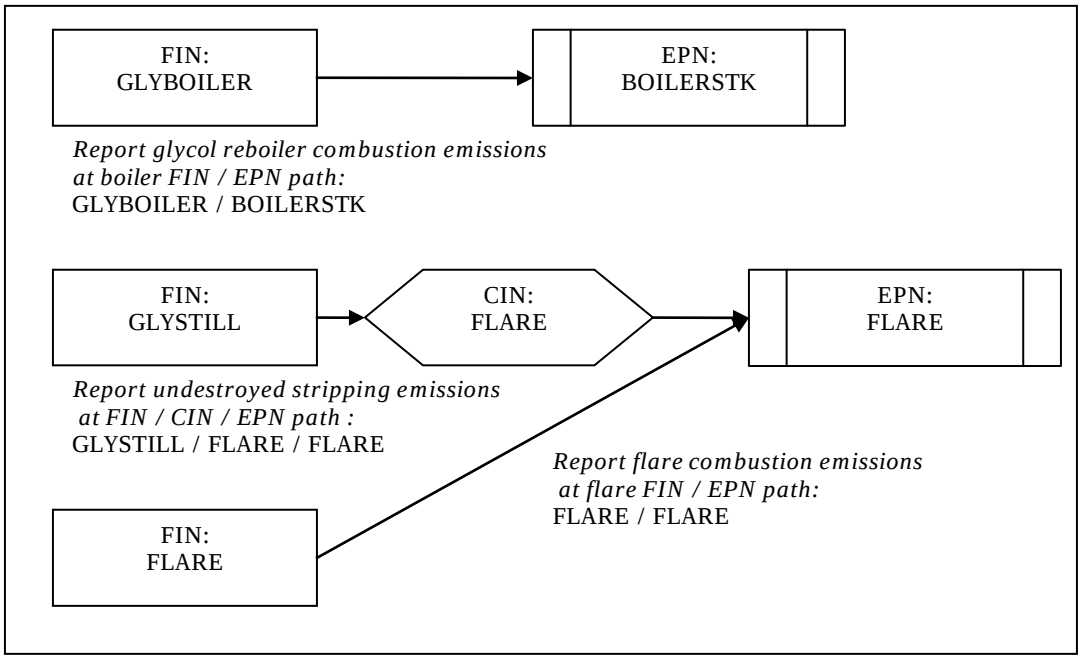


Figure 3-3. Glycol Unit—Flared Still Emissions

Routing Still Emissions through the Reboiler

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

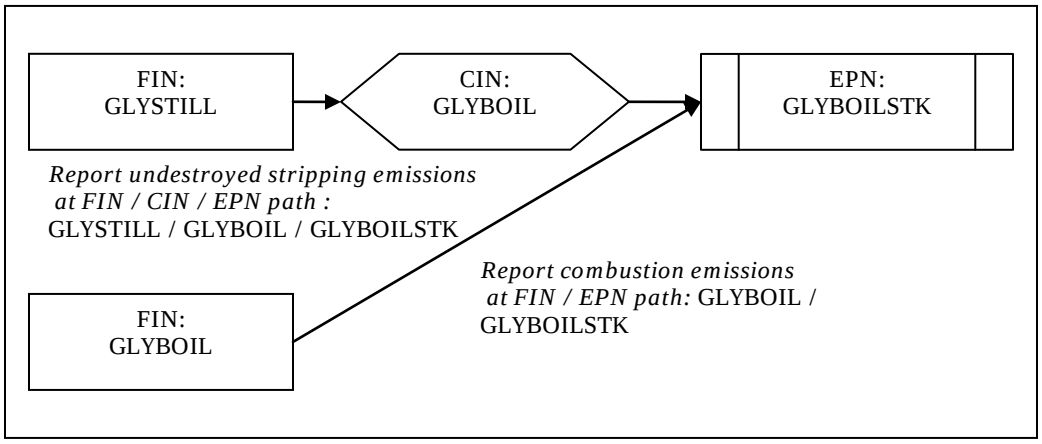


Figure 3-4. Glycol Unit—Still Emissions Routed Through Reboiler

Sulfur Recovery Units

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

An Unabated 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.

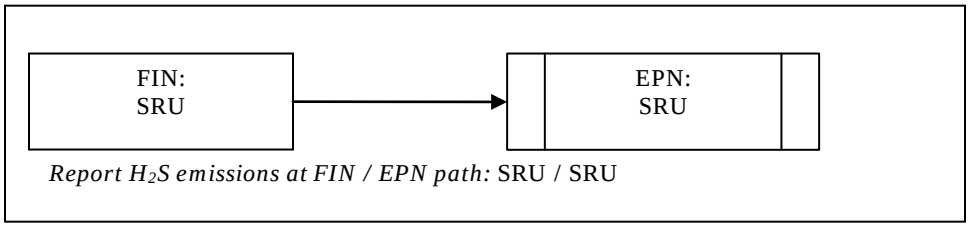


Figure 3-5. Sulfur Recovery Unit—Unabated

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.

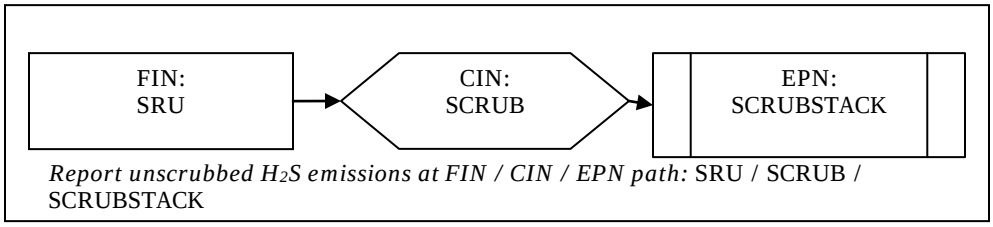


Figure 3-6. Sulfur Recovery Unit with Scrubber

Routing SRU 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.

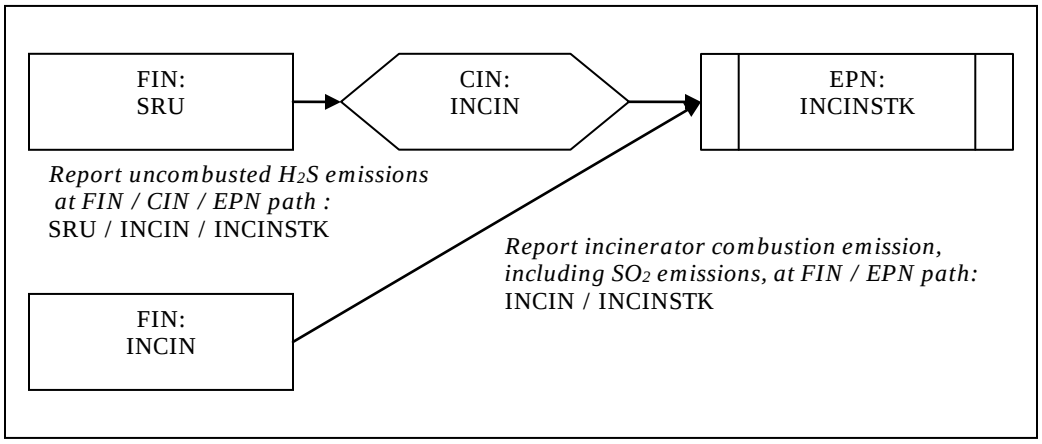


Figure 3-7. Sulfur Recovery Unit with Incinerator

Routing SRU 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.

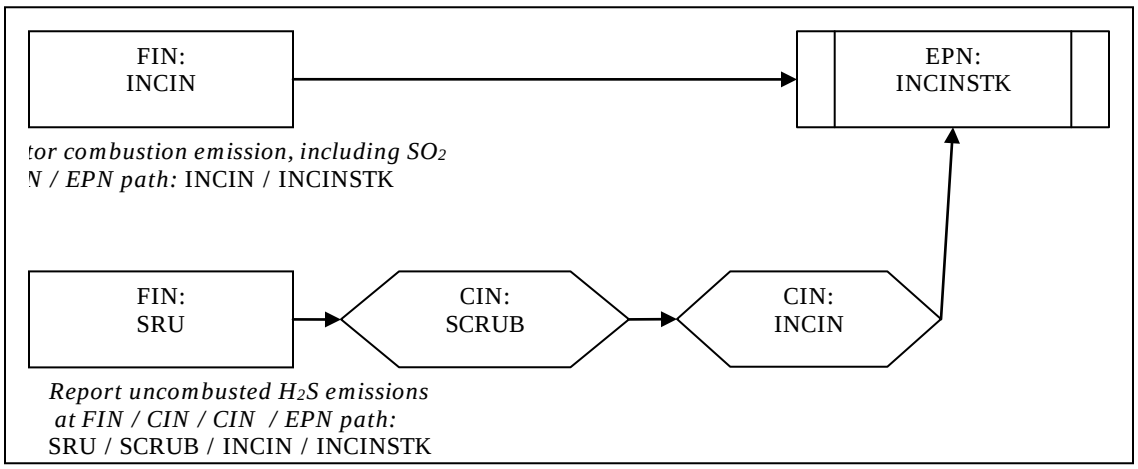


Figure 3-8. Sulfur Recovery Unit with Scrubber Prior to Incinerator

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.

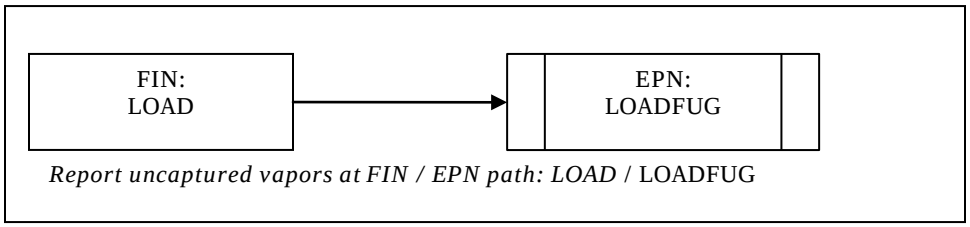


Figure 3-9. Loading Area—Unabated

Controlled by a Flare

If loading emissions are controlled by a flare, the emissions paths will be from the loading operation 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. 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. Report the emissions from the captured, undestroyed vapors at the abatement device. Be sure to indicate the capture efficiency in the facility comment field. Figure 3-10 illustrates proper structure for a loading area controlled by a flare.

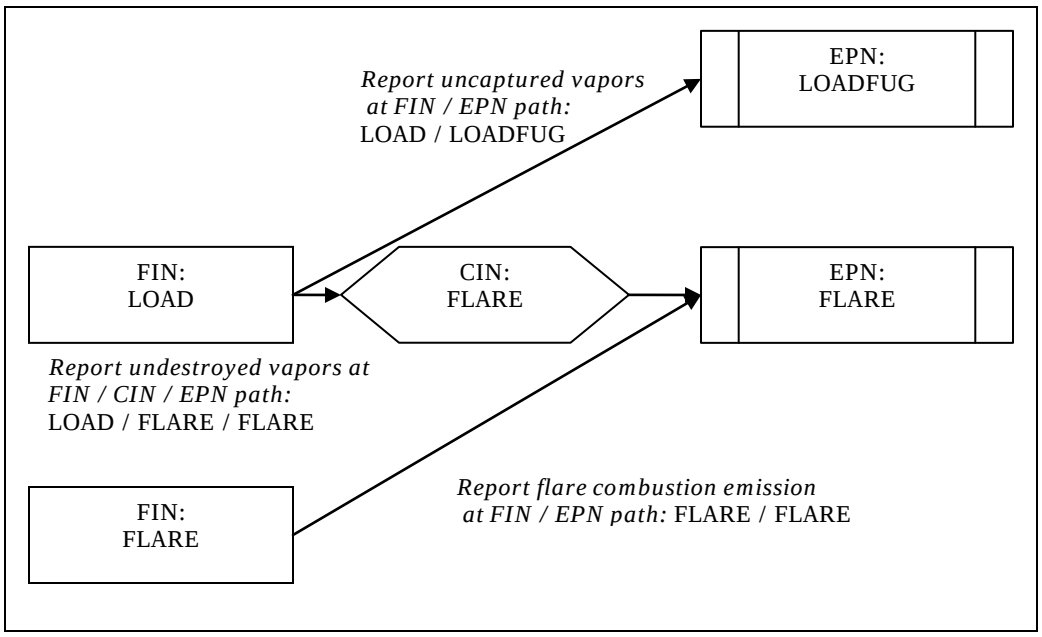


Figure 3-10. Loading Area Controlled by a Flare

Blowdown Operations

Compressor engines and other forms of process equipment are routinely 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 maintenance schedules, line pressures, and 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 should 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.

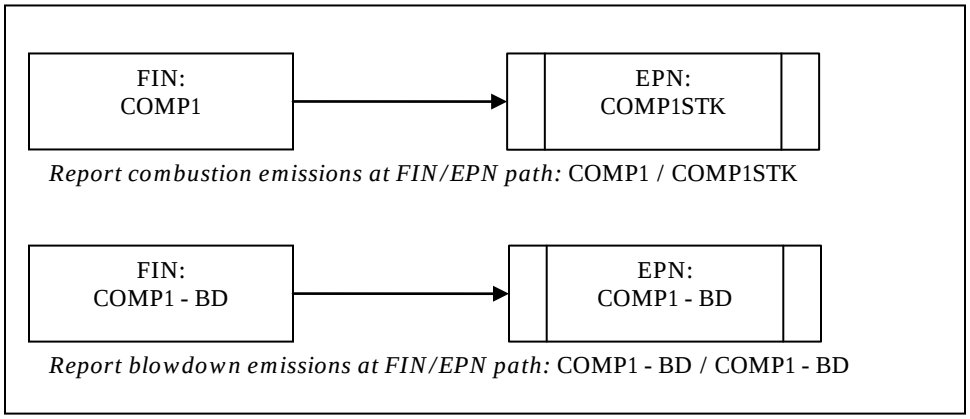


Figure 3-11. Blowdown Operations—Separate Compressor Engine and Blowdown Vents

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.

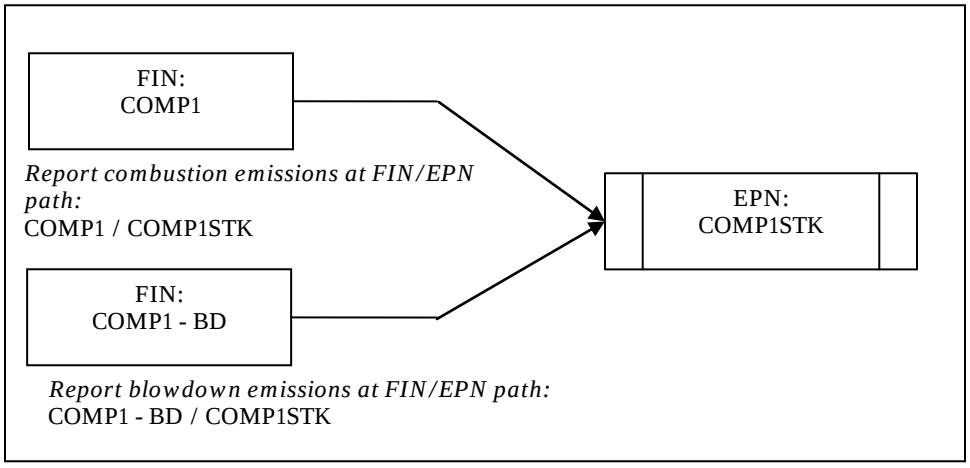


Figure 3-12. Blowdown Operations—Common Compressor Engine and Blowdown Vent

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.

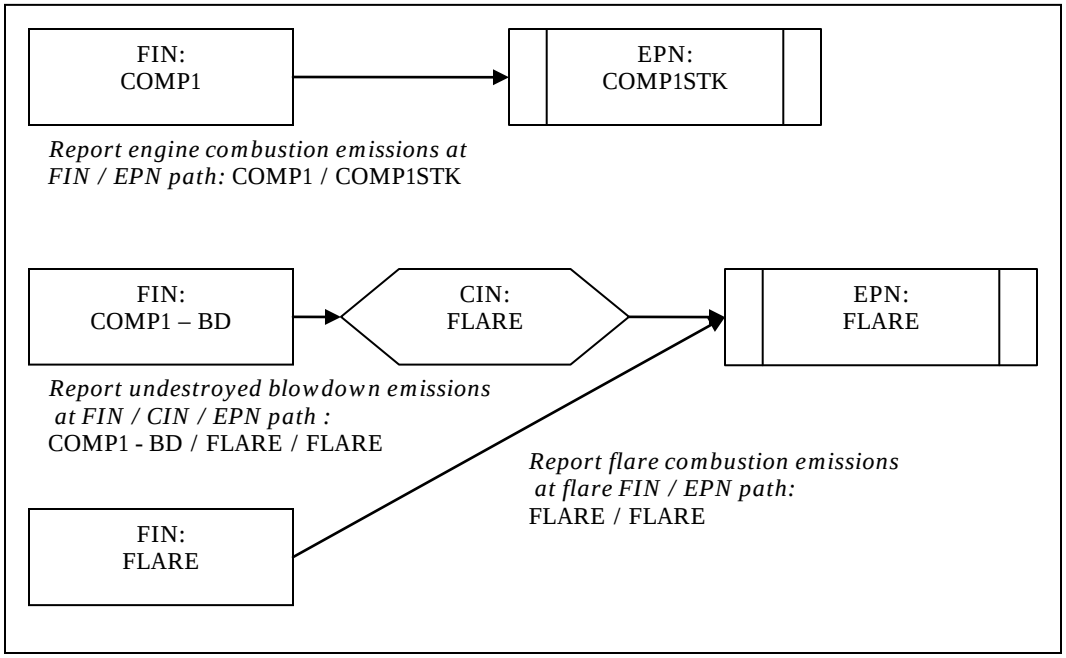


Figure 3-13. Blowdown Operations—Flared Blowdown Emissions

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.

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

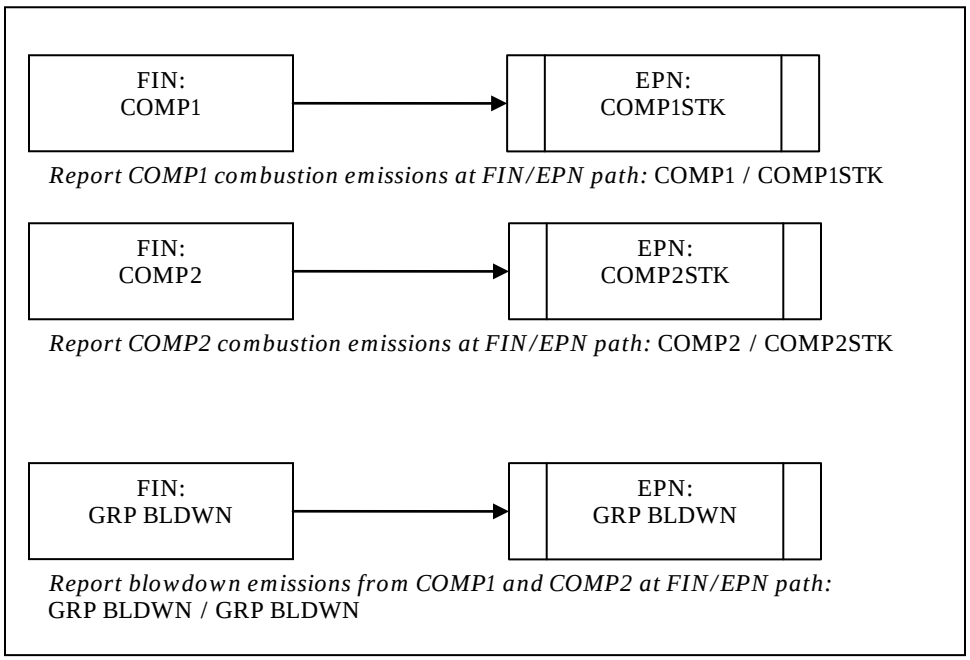


Figure 3-14. Blowdown Operations—Grouped Compressor Blowdowns

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.

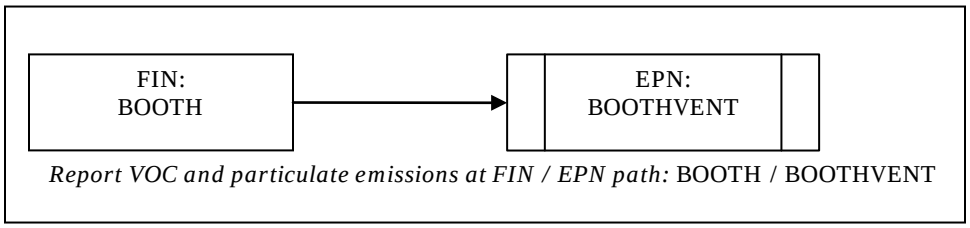


Figure 3-15. Paint Booth—Unabated

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.

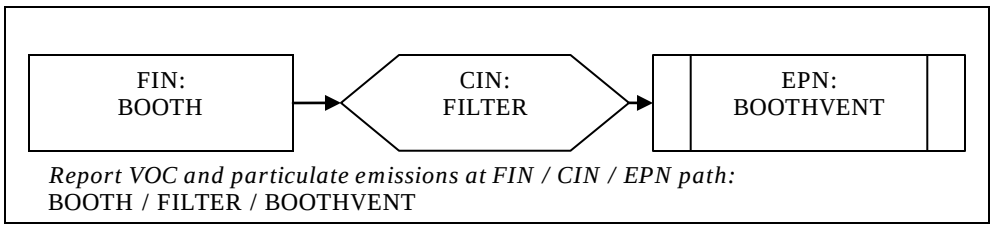


Figure 3-16. Paint Booth—Particulate Emissions Abated by a Filter

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 emissions point, with an abatement device added to the booth. Then link a second emission point to the booth, as shown in Figure 3-17.

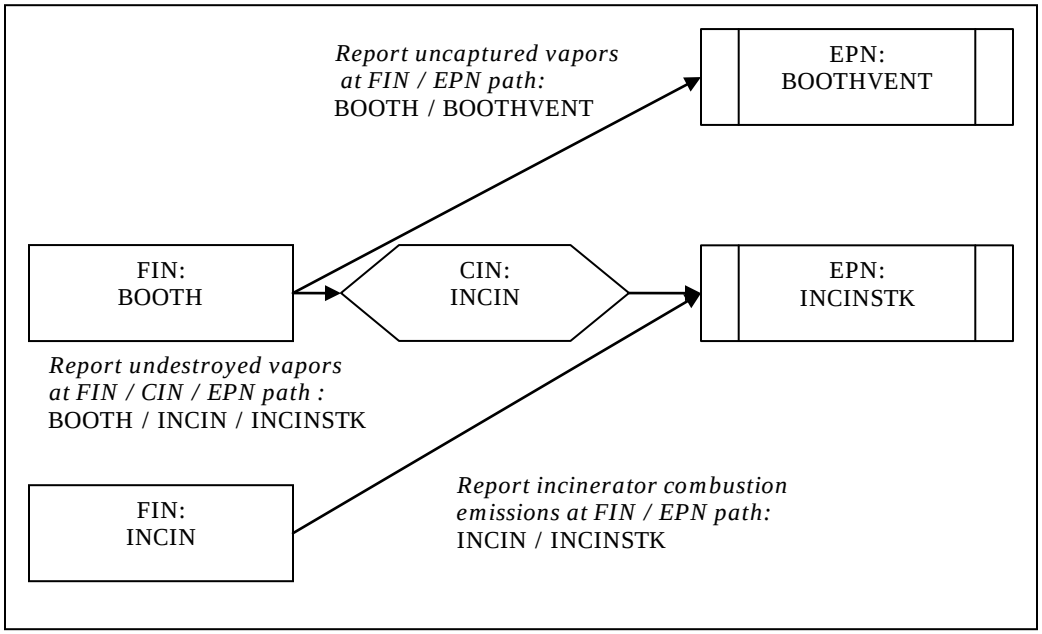


Figure 3-17. Spray Booth Controlled by an Incinerator

If coated surfaces are heat dried, be certain to include the drier 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, calcinating, and kilning. Represent each step in material storage, transport, and processing with a separate path made up 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.

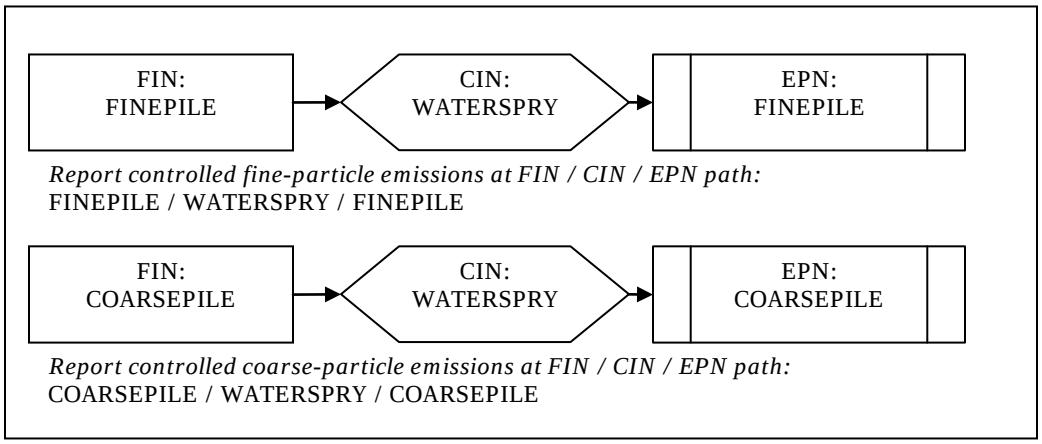


Figure 3-18. Fine and Coarse Piles—Emissions Controlled by Water Spray

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.

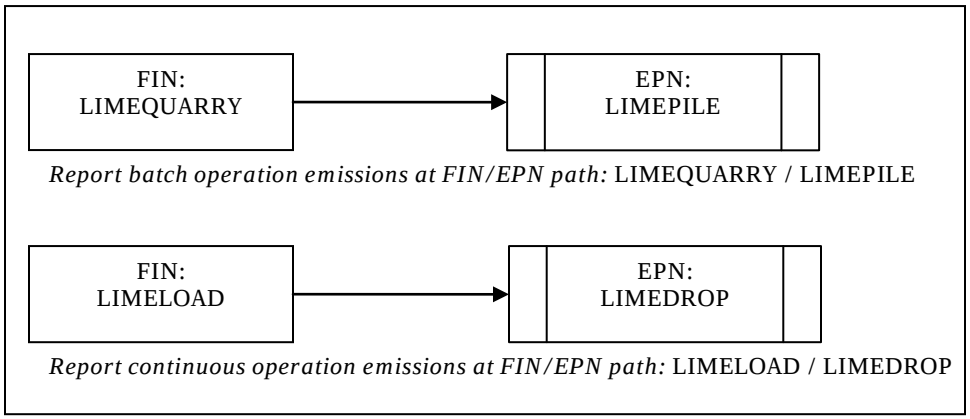


Figure 3-19. Continuous and Batch Operations Separated

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.

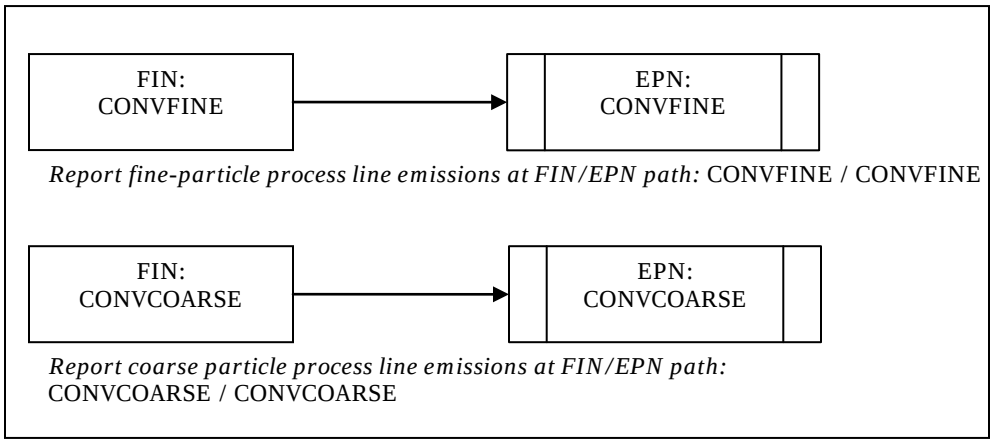


Figure 3-20. Conveyor Transport—Interdependent Systems

Marine Operations

Rather than reporting all marine losses at a single FIN / EPN path, each individual equipment or process type should 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.

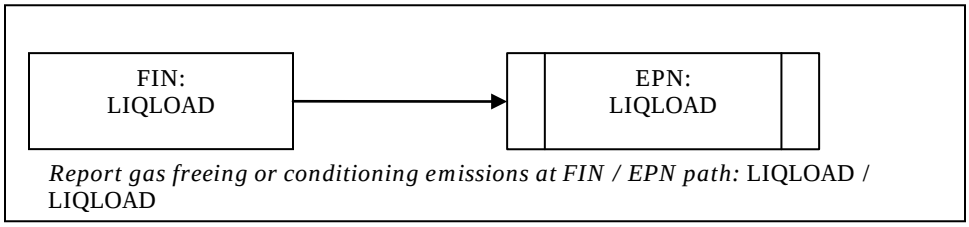


Figure 3-21. Uncontrolled Bulk Material Liquid Emissions

Using a Vapor Recovery System

If loading operations use a vacuum-assisted vapor recovery system, any uncollected emissions should 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 emission point, as shown in Figure 3-22.

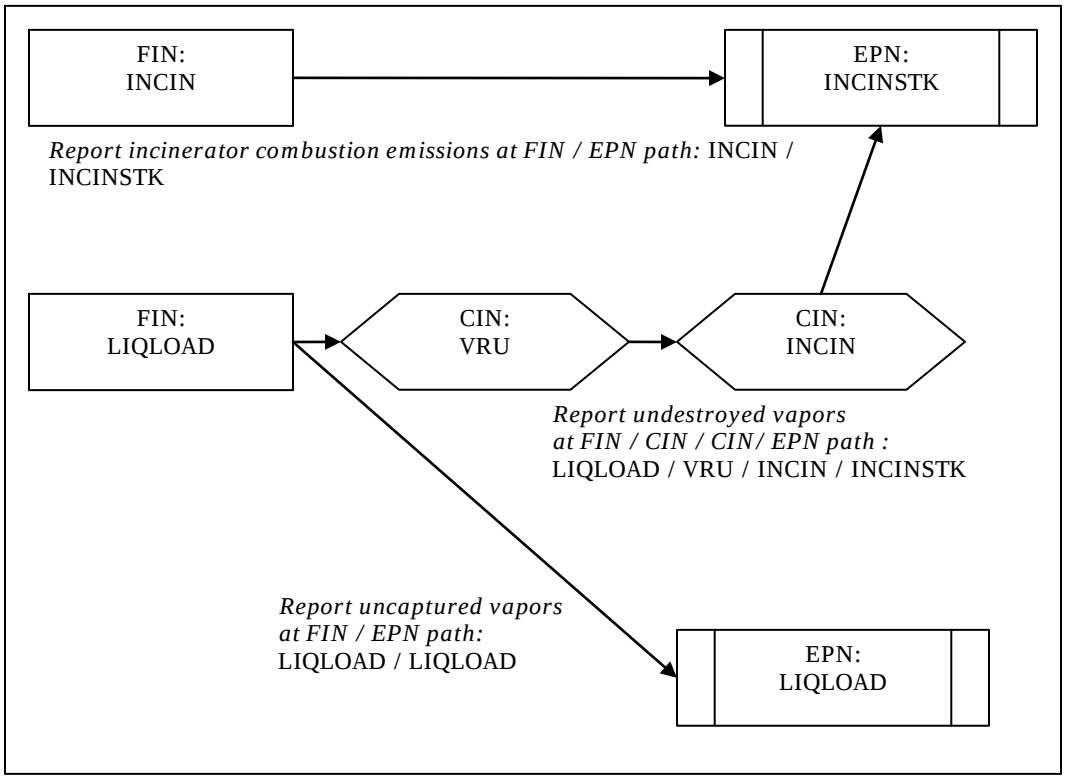


Figure 3-22. Liquid Loading Controlled by a Vapor Recovery Unit and Routed to an Incinerator

Loading and Unloading Bulk Liquefied Gaseous Materials

Since pressurized marine vessel compartments do not normally release to the atmosphere, loading and unloading bulk liquefied gaseous materials may generate fugitive emissions from equipment leaks. These should 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.

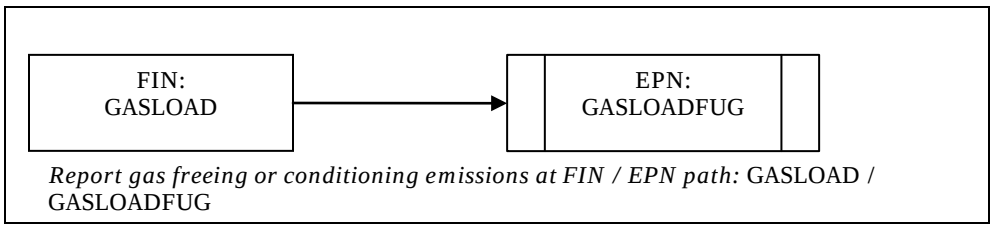


Figure 3-23. Uncontrolled Degassing and Cleaning Emissions

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.

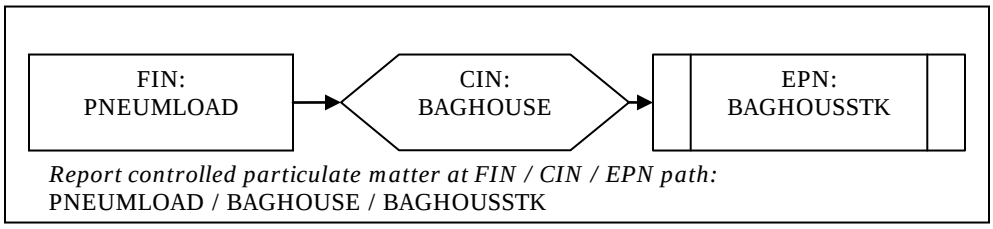


Figure 3-24. Pneumatic Transfer of Solids Controlled by a Baghouse

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.

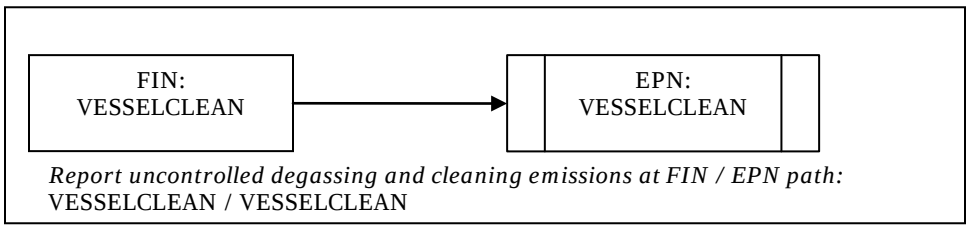


Figure 3-25. Uncontrolled Degassing and Cleaning Emissions

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 emission point to the vessel cleaning and degassing facility, as shown in Figure 3-26.

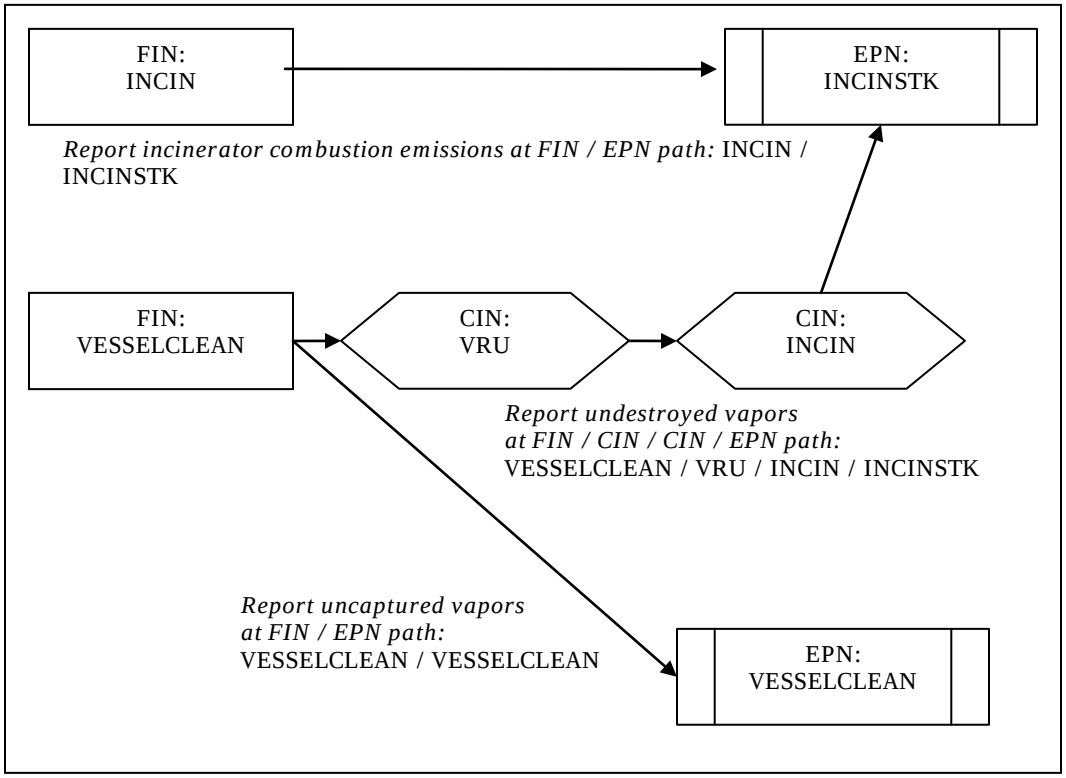


Figure 3-26. Degassing and Cleaning Emissions Captured by a VRU and Routed to an Incinerator

Wastewater Collection and Treatment

Because wastewater collection and treatment involve several different processes, an entire wastewater collection and treatment system should 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 should be assigned a unique plant identification number. Each source within a plant should 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

If the EI structure is incorrect, or if it has changed because new equipment has been added or existing equipment has been newly linked, the structure should be modified by submitting the appropriate forms available in *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11) or at the EAS Web page, <www.tceq.texas.gov/goto/ieas>. The remainder of this chapter tells how to make common structural modifications.

Removing Structure

For historical reasons, the EAS does not normally delete 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 emissions inventory year, the operating status should be marked as "active."

Changing Facility and Emission Point Designations

The EAS does not normally allow changes to facility or emission point 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. If revisions to facility or emission point designations are necessary, submit a Revision Request form available in the *2011 Emissions Inventory Forms and Instructions* (RG-360B/11) or at the EAS Web page, <www.tceq.texas.gov/goto/ieas>. Be sure to give a reason for the requested revisions. The EAS reserves the right to approve or disapprove all such revision requests.

Adding a New Emission Point to an Existing Facility

To add a new emission point to an existing facility:

- list the new path on one line of the Structural Overview form;
- complete an Emission Point Information form; and
- complete a Path Emissions form, noting that the facility "Already exists in STARS database."

Example: If a new flare, EPN: FL, needs to be linked to an existing tank, FIN: TK:

- enter the new FIN: TK / CIN: FL / EPN: FL path on the Structural Overview form, since the flare will also act as a control device to control the tank's emissions;
- complete an Abatement Device Information form for the flare;
- complete an Emission Point Information form for the flare, including the form's Flare Information section;
- complete a Path Emissions form for the FIN: TK / CIN: FL / EPN: FL path, noting that the FIN: FL "Already exists in STARS database";
- enter the new FIN: FL / EPN: FL path on the Structural Overview form because the flare is also an emissions source (a facility) in this case;
- complete the Facility Information for a Flare Combustion Unit form for the flare;
- complete a Path Emissions form for the FIN: FL / EPN: FL path; and
- complete a Material Throughput for Combustion Units form for the flare.

Adding a New Facility to an Existing Emission Point

To add a new facility to an existing emission point:

- list the new path on one line of the Structural Overview form;
- complete the appropriate Facility Information form as determined by the nature of the facility (combustion unit, storage tank, wastewater facility or other);
- complete a Path Emissions form, noting that the EPN: FL "Already exists in STARS database"; and
- complete the appropriate Material Throughput form.

Example: If a new tank, FIN: TK, needs to be added and the emissions are routed to an existing flare, EPN: FL:

- enter the new FIN: TK / CIN: FL / EPN: FL path on the Structural Overview form;
- complete the Facility Information for Storage Tanks form for the tank;

- complete a Path Emissions form for the FIN: TK / CIN: FL / EPN: FL path, noting that the EPN: FL "Already exists in STARS database"; and
- complete a Material Throughput for Storage Tanks form for the tank.

Linking an Existing Facility to an Existing Emission Point

To connect an existing facility to an existing emission point:

- list the new path on one line of the Structural Overview form and
- complete a Path Emissions form, noting that the FIN and EPN each "Already exists in STARS database."

Example: If an existing tank, FIN: TK, is being connected to an existing flare, EPN: FL:

- enter the new FIN: TK / CIN: FL / EPN: FL path on the Structural Overview form and
- complete a Path Emissions form for the FIN: TK / CIN: FL / EPN: FL path, noting that the FIN:TK and EPN:FL each "Already exists in STARS database."

Adding a New Abatement Device to an Existing FIN / EPN Path without Changing the Emission Point

To add a new abatement device to an existing FIN / EPN path, leaving the emission point unchanged:

- list the new path on one line of the Structural Overview form;
- complete an Abatement Device Information form; and
- complete a Path Emissions form for the new path, noting that the facility and emission point each "Already exists in STARS database."

Example: To add a catalytic converter, CIN: CC, to an existing engine path FIN: COMP / EPN: STK:

- enter the new FIN: COMP / CIN: CC / EPN: STK path on the Structural Overview form;
- complete an Abatement Device Information form for CIN: CC;
- and complete a Path Emissions form for the new path, noting that the FIN: COMP and EPN: STK each "Already exists in STARS database."

Adding a New CIN / EPN Path to an Existing Facility, Unlinking the Old Emission Point, and Linking the New CIN / EPN Path

To add a new abatement device to an existing FIN path, deactivate the old abatement device, and activate the new CIN / EPN path:

- list the new path on one line of the Structural Overview form;
- complete an Abatement Device Information form;
- complete an Emission Point Information form for the new emission point;
- complete a Path Emissions form for the new path, noting that the facility "Already exists in STARS database"; and
- mark the status of the old path on the EIQ (where the facility is linked to the old emission point) as "DEACTIVATED."

Example: Suppose that all emissions from an existing tank, FIN: TK, are now sent to a new flare, EPN: FL:

- enter the new FIN: TK / CIN: FL / EPN: FL path on the Structural Overview form;
- complete an Abatement Device Information form for the flare;
- complete an Emission Point Information Flare form for the flare;
- complete a Path Emissions form for the FIN: TK / CIN: FL / EPN: FL path, noting that the FIN:TK "Already exists in STARS database";
- mark the status of the FIN / old EPN path as appropriate on the EIQ;
- enter the new FIN: FL / EPN: FL path on the Structural Overview form, because, in this case, the flare is also an emissions source (a facility);
- complete the Facility Information for Flare Combustion Units form for the flare;
- complete a Path Emissions form for the FIN: FL / EPN: FL path; and
- complete a Material Throughput for Combustion Units form for the flare.

Adding an Existing Abatement Device to an Existing FIN / EPN Path without Changing the Emission Point

To add an existing abatement device to an existing FIN / EPN path, leaving the emission point unchanged:

- list the new path on one line of the Structural Overview form and
- complete a Path Emissions form for the new path, noting that the facility, emission point, and abatement device "Already exists in STARS database."

Adding an Existing Abatement Device to an Existing Facility, Unlinking the Old Emission Point, and Linking the New CIN / EPN Path

To add an existing abatement device to an existing facility, deactivate the old emission point, and activate the new CIN / EPN path:

- list the new path on one line of the Structural Overview form;
- complete an Emission Point Information form if the abatement device is not already an emission point elsewhere in the EIQ;
- complete a Path Emissions form for the new path, noting that the facility, emission point, and abatement device each "Already exists in STARS database"; and
- mark the status of the old path on the EIQ (where the old facility is linked to the old emission point) as "DEACTIVATED."

CHAPTER 4—DETERMINING AND REPORTING EMISSIONS

This chapter gives general information about required actual emissions data, acceptable emissions determination methodologies, speciating emissions (categorizing emissions by chemical species), and correctly reporting actual 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 fugitives, flares, and marine operations, and aboveground storage tanks, consult the appropriate technical supplement (Appendix A).

Required Actual Emissions Data

If a site meets the reporting requirements of 30 TAC 101.10(b)(1) and 40 CFR Part 51, all actual emissions for each regulated pollutant must be reported in the emissions inventory. For the purposes of this document, the term *regulated pollutant* shall include the following:

- any VOC, as defined in 30 TAC 101.1;
- any pollutant subject to federal Clean Air Act (FCAA) Section 111;
- any pollutant listed as a hazardous air pollutant under FCAA Section 112;
- each pollutant that has a national primary ambient air quality standard; and
- any other air pollutant subject to requirements under TCEQ rules, regulations, permits, orders of the commission, or court orders.

Non-criteria, regulated pollutants include—but are not limited to—ammonia, and H_2S.

Acceptable Determination Methodologies

Many different methods exist to determine emissions. In order to promote accuracy and consistency among emissions inventories, the EAS accepts only a limited number of determination methodologies, and further requires that all emissions be determined using the best methodology available. Determination methodologies other than those listed as follows may not be employed without the EAS's prior approval. Depending on the type of emission source, the methodology preference will often vary. The acceptable methodologies are discussed in alphabetical order and are labeled with a relevant heading (for example, stack testing is discussed under "Measured Data").

Note: Emissions must be determined from all sources including those that are not included in an EPA document such as AP-42. The best method available should be used to determine emissions in these cases.

Preceding each heading is a single letter, such as "A" or "V," the code to be entered on the EIQ when using that emissions determination methodology. These codes should be entered on the "Path Emissions" portion of the EIQ under the heading "Method" for each reported contaminant. Each contaminant listed on the EIQ can only have one corresponding code entered under "Method," and this code should 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 call the EAS help line.

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

D: Continuous Emissions Monitoring Systems

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. CEMS may be used to determine emissions only if they have been certified according to EPA or TCEQ standards.

Please note that a continuous monitoring system (CMS) that measures the gas composition contained in a process stream (and not the amount of 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 'continuous emissions monitoring system.' Instead, a determination methodology of "B" for 'material balance' would be chosen.

Supply a representative set of summary sheets from Relative Accuracy Test Audits performed during the EI calendar year. 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, the logger should use a molecular weight of 46.01 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 well documented in the EI and its supporting documentation.

H: Highly Reactive Volatile Organic Compound (HRVOC) Monitoring Systems

HRVOC monitoring required by 30 TAC 115.725–26 involves a continuous monitoring system (CMS) that measures the gas composition contained in a process stream (and not the amount of emissions released to the atmosphere).

HRVOC monitoring systems not required by 30 TAC 115.725–26 should not be coded as "H" but as "B" for 'material balance.' Similarly, a CMS for compounds other than HRVOCs should also be coded as "B."

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 well documented in the EI and the supporting documentation.

F: Predictive Emissions Monitoring Systems

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 relative accuracy test audits performed during the EI calendar year. If NO_x emissions are determined using PEMS, provide the molecular weight used in the data logger. As with CEMS, the logger should use a molecular weight of 46.01 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 its 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 facility's operation, improperly performed testing may grossly misrepresent a facility's emissions. For this reason, the EAS requires that all stack-test data used to determine emissions be collected using methods approved by the EPA or the TCEQ.

Test stacks 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 stack test results may no longer accurately reflect the unit's emissions and the EAS may require that a more appropriate method be used to recalculate emissions determinations.

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

The EAS will also consider, case by case, the validity of using stack-test emission factors generated for one site to determine emissions from identical facilities in another site. In these cases, only the tested facility's emissions may be coded as "M". The other related facilities' emissions must be coded as "E," because these facilities were not actually tested.

The EAS prefers that stacks be tested during the EI calendar year. However, 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. Stack-test data from a current year should not be used to determine emissions for previous years.

By signing the front page of the Emissions Inventory Questionnaire and submitting the document to the EAS, the owner or operator certifies that all test data used are certified as accurately representing the facility's emissions.

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

If the TCEQ Emissions Banking and Trading program requires an individual emissions unit to use stack test emissions data to generate credits or allowances, or to comply with other program requirements, then the same stack test data should be used to calculate emissions for the EI.

Q: Portable Analyzer Measurement Data

The 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 facility's operation, improper measurements may grossly misrepresent a facility's emissions. For that reason, the EAS requires that all test data used to determine emissions be collected using methods approved by the EPA or the TCEQ.

Portable analyzer measurements should 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 may no longer accurately reflect the unit's emissions and the EAS may require 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 (for example if it is tested quarterly), make sure to account for this in the emission determination. Do not apply one test result to the entire year.

By signing the front page of the Emissions Inventory Questionnaire and submitting the document to the EAS, the owner or operator certifies that all measurements included accurately represent the facility's emissions.

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 a mass emission rate.

If the TCEQ Emissions Banking and Trading program requires an individual emissions unit to use stack test emissions data to generate credits or allowances, or to comply with other program requirements, then the same stack test data should be used to calculate emissions for the EI.

V: Vendor-Supplied Emissions Factors

Many industrial equipment manufacturers supply emissions information for their products. These data, based on equipment 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 changes have been made to the equipment. A change to a facility or its operation, including a significant change in fuel characteristics, may significantly affect the

facility's emissions and therefore invalidate the manufacturer's emissions data.

Include a copy of the manufacturer's data with the supporting documentation. In signing the front page of the EIQ and submitting the document to the EAS, the owner or operator certifies that the facility was operated in the same manner in which it was tested.

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

One method used to determine emissions is the EPA's *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources* (AP-42), with supplements (updated continually)—available at <www.epa.gov/ttn/chief/ap42/index.html>. AP-42 includes brief discussions of various industrial processes, descriptions of these processes' emissions, and emission factors useful for determining these emissions. Equipment emission factors have generally been determined by testing a representative population varying in size and age. Since this limits the accuracy of determining emissions of these factors, specific equipment factors are preferable to AP-42 factors.

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

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 the TANKS and WATER9 software programs and fugitive emissions determined using factors taken from EPA-453/R-95-017.

B: Material Balance

Material balance can only be performed for specific types of facilities 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 D for a list of helpful EPA and TCEQ 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 continuous monitoring system used to determine flow rate and composition of gas routed to a flare measures the physical properties of the process stream and does 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 emissions inventory, the use of first-order engineering principles (for example, thermodynamic equations or the ideal gas law) constitutes a scientific calculation. Use of process rate data in conjunction with AP-42 or vendor-supplied emission factors, like simple use of a calculator to multiply or add values, does not constitute a “scientifically calculated” emissions determination.

E: Estimation

If the EPA or the TCEQ has not published guidance on determining emissions for a particular process, and if a preferable emissions determination method 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 the EAS to logically understand how the estimation was made. If the EAS determines that an estimation is unfounded, then the EAS will require that emissions determinations be recalculated.

O: Other

If the EPA or TCEQ has not published emissions determination guidance for a particular process, and if a preferable emissions determination method 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 should be 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 should be 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 the EAS determines that an emissions determination is unfounded, then the EAS 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 the TANKS 4.09D software (determination methodology "A") while the flash losses are calculated using the gas/oil ratio method (determination methodology "B"), the total emissions reported in the EI should be coded as "B," assuming the flash losses are greater than the working and breathing losses.

When a control efficiency is applied to an emissions factor, the methodology that corresponds to the emissions factor should 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 should be 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—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, formal 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 actual annual emissions, and these resulting emissions should be coded on the EIQ 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 actual annual emissions; those resulting emissions should be 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 should 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 the analytical method's minimum detection 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 (that is, non-detected), then half of the detection limit must be used to determine the emissions of the contaminant, unless otherwise specified by permit condition, TCEQ or federal rule, or commission order.

General Order of Preference

If a source-specific order of preference for determination methodologies does not exist for a given facility (see technical supplements in Appendix A), the general order of preference listed in Table 4-1 should be followed.

Table 4-1. General Order of Preference for Emissions Determination Methodologies (to Be Used Only in the Absence of Source-Specific Guidance)

D (Continuous emissions monitoring system or CEMS)
H (HRVOC monitoring system)
F (Predictive emissions monitoring system or PEMS)
M (Measured—stack test data)
Q (Portable analyzer test data)
V (Vendor-supplied emissions factors)
A (AP-42 and other EPA-approved factors)
B (Material balance)
S (Scientifically calculated)
E (Estimated)
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 demonstrated in a permit application, then the EI must 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 should be used.

- If testing was conducted or continuous monitoring implemented at a site after the TCEQ issued a permit for that site—instead, the resulting data must be used.
- If a facility's permit no longer reflects the conditions of its actual operations.

Rates reported on the EIQ should represent actual emissions, rather than maximum potential emissions.

Speciating Emissions

Once the emissions from each facility at the site have been determined, the preparer may need to specifically identify and quantify individual chemical substances, or species, within each emission category. This process, known as *speciation*, is particularly important when reporting emissions of volatile organic compounds (VOCs). 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 VOCs

VOC speciation requirements depend on a site's geographic location. If the site is in El Paso County or east of the 100º longitude line (see map on page 9), the VOCs should be speciated from each source emitting at least 5 tons of VOCs annually. If the site is located west of the 100º longitude line (except for El Paso County), the VOCs should be speciated from each source emitting at least 25 tons of VOCs annually. For each source that meets these requirements, speciate VOC emissions to at least 90 percent of the total VOC emissions reported for each facility. If any speciated contaminant was emitted at a level below 0.1 ton, the emissions should be reported for that contaminant *under VOC—unclassified* (contaminant code *50001*). Special speciation requirements apply to lead compounds and HAPs listed in any TCEQ-enforceable document such as a permit, regulation, or commission order. *Please note:* a registered permit by rule that includes a certification of federally enforceable emission limits (e.g., using FormPI-7-CERT, designated form TCEQ-20182) is a TCEQ-enforceable document.

Each emitted substance (for example, carbon monoxide 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 should be reported under the benzene-specific code (*52420*) rather than under the general VOC code (*50001*).

For a complete list of contaminant codes, consult *2011 Emissions Inventory Forms and Instructions* (TCEQ publication number RG-360B/11). This document can be found on the EAS Web page at <www.tceq.texas.gov/goto/ieas>. The EAS 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. Note that the contaminant code *50000*, unspeciated hydrocarbons, is no longer in use.

To obtain a *VOC—unclassified* (contaminant code *50001*) total, subtract all speciated VOCs from the total VOC number. Note that the EAS no longer requires explicit reporting of total VOC emissions under contaminant code *59999*. The following example should clarify VOC reporting requirements.

Example: A fugitive area located east of 100º 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 4-2 shows how to report these emissions.

Table 4-2. Example of Speciated VOC Emissions

Contaminant Code	Contaminant	Actual Emissions (tpy)
50001	VOC—unclassified	0.5
56775	propane	6.0
56725	butane	0.8
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 EIQ. The STARS database will automatically sum the reported VOCs for each source to obtain the total VOC number (previously reported under contaminant code *59999*). Do not report the total 10 tons of VOC emissions under contaminant code *50001* and then report the speciated emissions shown in Table 4-2, because STARS will then arrive

at a total VOC emission rate of 19.5 tons for this facility, resulting in an overreporting of 9.5 tons of emissions.

Speciating Hazardous Air Pollutants and Other Compounds of Interest

Hazardous Air Pollutants (HAPs)

HAPs are air pollutants designated as hazardous by the EPA and are identified at federal Clean Air Act 115(b). Speciate all HAPs that are emitted from any facility (source) at or above 0.1 ton per year. 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 ton per year. If aggregate HAPs are listed in any TCEQ-enforceable document such as a permit, regulation, or commission order, each individual HAP must be speciated. *Please note:* a registered permit by rule that includes a certification of federally enforceable emission limits (e.g., using TCEQ form PI-7-CERT) is a TCEQ-enforceable document.

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 facility (source) at or above 0.1 ton per year.

Toxic compounds reported in the Toxics Release Inventory (TRI) should 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

Give special consideration to determining and reporting lead and mercury emissions. The TCEQ is requiring that all regulated entities report lead and mercury emissions from any facility (or source), especially those whose emissions exceed 0.001 ton of either lead or mercury per year.

Highly Reactive Volatile Organic Compounds (HRVOCs) and Compounds of Interest (COIs) for Nonattainment Counties

In a nonattainment county, speciate each of the following chemicals, particularly if they were emitted from any facility 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 $PM_{2.5}$

Particulate matter 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 cannot 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 microns. 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 microns in diameter, while the remaining percentage comprises larger particles. Therefore, when reporting PM, also report PM_{10} , unless the facility can document that all PM is greater than 10 microns in diameter.

$PM_{2.5}$ is defined as the portion of PM that has an aerodynamic diameter less than or equal to 2.5 microns. 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 micron in diameter. Thus, all particulate matter emitted from natural gas combustion is not only $PM_{2.5}$ (since it is smaller than 2.5 microns 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 emissions source (facility). 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 emissions must be reported regardless of size as PM under the *1xxxx* series of contaminant codes. Since PM is defined as all particulate matter (that is, there are no size restrictions on PM), even the portion of PM that is PM_{10} and $PM_{2.5}$ should be reported under the *1xxxx* contaminant code series. Similarly, all particles with an aerodynamic diameter less than or equal to 10 microns should 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.

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 microns or less (PM_{10}) under a *2xxxx* contaminant code,
- list the remaining unspeciated PM_{10} emissions under contaminant code *20000*, and
- report the portion of the particulate emissions with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$) under contaminant code *39999*.

Example: A facility emitted 10 tons of particulate matter. The matter is determined to have been mostly phosphorus (75 percent) and zinc (16 percent), with the remaining 9 percent of unknown composition. The phosphorus and zinc particles are larger than 2.5 microns, but smaller than 10 microns, in aerodynamic diameter. The other 9 percent of particles are believed to be larger than 10 microns in aerodynamic diameter. The emissions in this example should be reported as shown in Table 4-3.

Table 4-3. 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 of the 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

Table 4-4 summarizes the criteria for speciating emissions.

Reporting Emissions

Before entering emission rates on the EIQ, 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 summer months may need to be determined. Then the emissions are reported in the EI.

Annual Emissions

These include all of a facility's emissions, including authorized emissions from maintenance, startup, and shutdown activities. It does not include emissions that are defined in 30 TAC 101.1 as emissions events or scheduled maintenance, startup, and shutdown activities. Determine and speciate annual emissions according to the guidance in this chapter and the technical supplements.

Ozone Season Emissions

If the regulated entity is located in El Paso County or east of the 100º longitude line (see Table 4-5 for those counties), the average daily release rates during the ozone season—May 1 through September 30—must be determined. The ozone season emissions should be reported in pounds per

day (ppd) under the "Ozone" heading on the Path Emissions portion of the EIQ. The EAS database can no longer automatically calculate ozone rates.

Table 4-4. Summary of Speciation Criteria

Contaminant	Applicable Counties	If the emissions at the FIN/EPN path satisfy the tpy limit listed below, report or speciate the actual emissions.
Lead (Pb)	All counties	≥ 0.001
Mercury (Hg)	All counties	≥ 0.001
HAPs[a] listed in any TCEQ-enforceable document	All counties	Speciate HAPs ≥ 0.001when the contaminant is listed in any TCEQ enforceable document such as a permit, regulation, or commission order.[b] 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[a]	All counties	≥ 0.1
Toxics[c]	All counties	≥ 0.1
HRVOCs[d]	Nonattainment counties	≥ 0.1
COIs[e]	Nonattainment counties	≥ 0.1
Total VOCs[f]	East of 100º longitude, El Paso	≥ 5, 90% speciation required
	West of 100º longitude, except El Paso	≥ 25, 90% speciation required
PM, PM_{10}, $PM_{2.5}$	All counties	Speciate particulate classes.
Chemical Mixtures	All counties	Use the most specific contaminant code possible for chemical mixtures such as condensate (*59090*), crude oil (*59001*) and gasoline (*59003*). When using chemical mixtures, speciate HAPs and other species first, then report the unspeciated remainder under the applicable code.
IC Engines	All counties	Report all HAPs ≥ 0.1 tpy *Note:* formaldehyde is typically ≥ 0.1 tpy when the total VOCs are ≥ 2 tpy.

[a] HAPs—*Hazardous air pollutants* as identified at federal Clean Air Act 115(b).
[b] A registered permit by rule 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] Toxic—*Toxic air pollutants* as identified at 40 CFR 372.65.
[d] HRVOC—*Highly reactive volatile organic compounds* are, for inventory purposes, 1,3-butadiene, ethylene, propylene, and all isomers of butene.
[e] COI—Compounds of interest are, for inventory purposes: isoprene, all isomers of pentene, all isomers of trimethylbenzene, and all isomers of ethyltoluene.
[f] VOCs—*Volatile organic compounds* as defined in 30 TAC 101.1.

Table 4-5. Ozone Season Daily Rates Are Required from Sites in These Counties

Note: The EAS database is no longer capable of automatically calculating ozone rates.

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

For each FIN/EPN path, use actual process and/or emissions data 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 September 30. For sources (facilities) equipped with CEMS, determine total ozone season emissions from CEMS data gathered from May 1 through September 30.

For each FIN/EPN path, quantify every contaminant's total ozone season emissions (in pounds). Do not include emissions events or scheduled maintenance, startup, and shutdown emissions in total ozone season emissions. However, authorized maintenance, startup, and shutdown emissions that are included in the annual emissions rate should be accounted in the total ozone season emissions. Next, for each FIN/EPN path, determine how many days the facility emitted through this emission point during the ozone season. Then use the following equation to determine the FIN/EPN path's ppd emissions rates:

$$E_{ozone\ rate} = \frac{E_{ozone\ total}\ \text{(lbs)}}{Operation\ Days_{ozone}}$$

Where:

$E_{ozone\ rate}$ = ppd (pounds per day) ozone rate for one contaminant

$E_{ozone\ total}$ = total ozone season emissions for one contaminant, in lbs

$Operation\ Days_{ozone}$ = number of days FIN/EPN path operated during ozone season; not to exceed 153

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

$Operation\ Days_{ozone}$ in the above formula will vary, depending upon a facility's operating schedule. If the associated facility has a consistent weekly operating schedule, then ozone emissions can be calculated using the actual number of days operated during the ozone season. Ensure that the facility's operating schedule on the EIQ has been updated with data for the current year.

Please note: Use caution when using a pound-per-hour rate to determine ozone season emissions. The pound-per-hour rate should not be multiplied by 24 hours a day unless the source actually operated each day for 24 hours. That would be equivalent to reporting the maximum ozone season rate versus an actual average ozone season emission rate.

If a facility does not operate consistently during the summer months, then ozone season emissions data should be averaged over 153 days (that is, enter "153" for $Operation\ Days_{ozone}$ in the above formula) to avoid unusually large ozone emissions.

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 should **not** be reported as

1000 pounds per day. Rather, they should be averaged over 153 days, resulting in ozone season emissions of 10.87 pounds per day.

If a facility's inconsistent operating schedule produces unusually large ozone season emissions, or if an EIQ source operated during the summer months, but specific ozone season emissions data are not available to determine ppd rates, please contact the EAS for assistance.

Emissions Events (EE)

Report emissions events separately under the "EE" column on the "Path Emissions" portion of the EIQ. Include the yearly emissions in tons from all releases due to emissions events, regardless of whether those releases represent reportable or nonreportable quantities and regardless of whether an affirmative defense is claimed for those emissions. The emissions thresholds specified in Chapter 3 do not apply to emissions events. Emissions from any emissions event above 0 tons per year must be reported. For more information, consult 30 TAC 101.1 and 101.201.

EE emissions from sources that do not meet the requirements to be included individually in an EI are still required to be reported to the TCEQ (see Chapter 3 for more information). 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 the TCEQ's Air Section manager for the region where the regulated entity is located.

Excess Opacity Events

Emissions that occur during excess opacity events need to be quantified and reported in the EI. However, the excess opacity event itself cannot be reported in terms of percent opacity in the EI. Rather, the emissions associated with the event must be calculated and reported in the "Emissions Event" column 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 382.015(f), an owner or operator of a regulated entity that experienced no emissions events during the relevant calendar year and that is required to submit an annual EI must include as part of the inventory a signed statement that the regulated entity experienced no emissions events during the reporting year.

However, if the owner or operator notified the TCEQ in accordance with 30 TAC 101.201 about only an excess opacity event which had no emissions associated with it, he or she must sign the EE certification.

Scheduled Maintenance, Startup, and Shutdown (SMSS) Activities

Report emissions from scheduled maintenance, startup, and shutdown activities separately under the "SMSS" column on the "Path Emissions" portion of the EIQ. Report the annual 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 permit by rule in the "SMSS" column, regardless of whether those releases represent reportable or nonreportable quantities and regardless of whether an affirmative defense is claimed for those emissions. The emissions thresholds specified in Chapter 3 do not apply to emissions events. Emissions from any emissions event above 0 tons per year must be reported. For more information, consult 30 TAC 101.1 and 101.211.

Note: Emissions from maintenance, startup, and shutdown activities that are authorized under a permit or permit by rule should be reported in the "Annual" column and not included in the "SMSS" column.

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

Special Note: "EE/SMSS" Column

As outlined in the previous section, emissions from emissions events and SMSS activities must be reported in either the "EE" or the "SMSS" column, as appropriate. A regulated entity that reports emissions in the "EE/SMSS" (totals) column must also report emissions in the "EE" or "SMSS" column (or both), as appropriate.

CHAPTER 5—EXAMPLE 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 reboiler, and diethylamine storage tank
- glycol dehydration still, associated reboiler, and ethylene glycol storage tank
- emergency flare to control glycol unit and amine unit emission events, as well as blowdowns
- refrigerated absorption unit and fractionation columns (further natural 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 percent–efficient nonselective catalytic reduction (NSCR) system
- two 1500 gal condensate fixed-roof storage tanks
- one condensate truck loading rack (uncontrolled)
- high-pressure storage tanks

Analyzing the two above lists, the following emission sources can be identified. Characteristic source emissions are listed, as appropriate.

Table 5-1. Identifying Emission Sources from Equipment and Processes

Equipment or Process	Emission Source
Lift pump and associated electric motor	Piping fugitive components (including pump)
Gunbarrel separator	Gunbarrel separator: flash emissions
	Piping fugitive components
Natural gas sweetening	Amine unit: hydrogen sulfide emissions
	Amine reboiler unit: combustion emissions
	Diethylamine storage tank
	Piping fugitive components
Natural gas dehydration	Glycol still: source of VOC and HAP emissions
	Glycol reboiler unit: combustion emissions
	Glycol-still flash tank: source of VOC and HAP emissions
	Ethylene glycol storage tank
	Piping fugitive components
Refrigerated absorption unit and fractionation columns	Piping fugitive components
Compressor engines	Turbine
	Lean-burn four-stroke engine
	Rich-burn four-stroke engine
	Piping fugitive components
Flaring of emissions events	Emergency flare: combustion emissions
	Source that generated emissions events (amine unit, blowdown, etc.)
	Piping fugitive components

Table 5-1. Identifying Emission Sources, continued

Equipment or Process	Emission Source
Condensate storage	First 1500 gal condensate fixed-roof storage tank
	Second 1500 gal condensate fixed-roof storage tank
	Piping fugitive components
Condensate truck loading	Loading rack: loading emissions
	Piping fugitive components
Natural gas liquids storage	Piping fugitive components, especially relief valves
Gas delivery to pipeline	Piping fugitive components
Blowdown operations	Blowdown process

Translating Emission Sources to the Emissions Inventory

Facilities. After the emission sources have been identified, they need to be transferred to the standardized EI forms. Review the material in Chapter 3, "Emissions Inventory Structure," in conjunction with the guidance in this chapter.

A *facility* is defined as a unique unit, device, structure, or area capable of generating emissions. The facilities listed in Table 5-1 are all of the emission sources at the site. Each facility in the EI needs to be assigned a unique facility identification number (FIN) by the preparer. The EI naming conventions (for facilities as well as emission points) should 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

Emission source	FIN
All natural gas piping fugitive components	FUGAREA1
All condensate piping fugitive components	CONDFUGS
Gunbarrel separator	GUNBARSEP
Amine unit	AMINEUNIT
Amine reboiler unit	AMREBOILER
Diethylamine storage tank	DEA-TANK
Glycol still	GLYCOLSTIL
Glycol reboiler unit	GLREBOILER
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 of the components can be grouped under one facility. See Technical Supplement 3 in Appendix A for more details on creating facilities for piping component fugitive areas.

Emission points. Once all of the FINs have been assigned for the emission sources, their associated emission points need to 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 of the possible emission points identified for the sources listed in Table 5-2.

Table 5-3. Identifying Emission Points for FINs

FIN	Emission 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
	Flare (during emissions events)
AMREBOILER	Reboiler stack
DEA-TANK	Tank vent
GLYCOLSTIL	Glycol still vent
	Flare (during emissions events)
GLREBOILER	Reboiler stack
EG-TANK	Tank vent
TURBINE1	Stack one (dual exhaust stack)
	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 emission point number. The EI naming conventions for EPNs should 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 Emission Points

FIN	Emission point	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
AMREBOILER	Reboiler stack	REBOILSTK1
DEA-TANK	Tank vent	DEA-TANK
GLYCOLSTIL	Glycol still vent	GLYCOLVENT
	Flare (during emissions events)	FLARE
GLREBOILER	Reboiler stack	REBOILSTK2
EG-TANK	Tank vent	EG-TANK
TURBINE1	Stack one (dual exhaust stack)	TURBSTK1
	Stack two (dual exhaust stack)	TURBSTK2
COMP1	Compressor stack	COMP1STK
COMP2	Compressor stack	COMP2STK
UPSETFLARE	Flare	FLARE
CONDTANK1	Tank vent	CONDTANK1
CONDTANK2	Tank vent	CONDTANK2
LOADRACK	Fugitive loading emissions area	LOADFUGS
BLOWDOWN	Emergency flare	FLARE

Control Devices. Before adding the emissions paths to the EI, the control devices need to be added to the appropriate paths. From the information in Table 5-4, control devices need to be added to the following FIN/EPN paths:

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

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

Table 5-5. Assigning CINs to Paths

FIN	EPN	CIN (if applicable)
FUGAREA1	FUGAREA1	
CONDFUGS	CONDFUGS	
GUNBARSEP	SEPVENT	
AMINEUNIT	AMINEVENT	
AMINEUNIT	FLARE	FLARE
AMREBOILER	REBOILSTK1	
DEA-TANK	DEA-TANK	
GLYCOLSTIL	GLYCOLVENT	
GLYCOLSTIL	FLARE	FLARE
GLREBOILER	REBOILSTK2	
EG-TANK	EG-TANK	
TURBINE1	TURBSTK1	
TURBINE1	TURBSTK2	
COMP1	COMP1STK	
COMP2	COMP2STK	NSCR
UPSETFLARE	FLARE	
CONDTANK1	CONDTANK1	
CONDTANK2	CONDTANK2	
LOADRACK	LOADFUGS	
BLOWDOWN	FLARE	FLARE

EI Forms. The emission paths can now be transferred to the appropriate Facility Information, Emission Point Information, and Abatement Device Information forms. These forms are available on the EAS Web page or in *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11).

Different types of Facility Information and Emission Point Information forms exist to represent different types of processes or units. A Facility Information form exists for each type of process or unit:

- 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

There are three different types of Emission Point Information forms:

- flare
- fugitive
- stack

There is only one Abatement Device Information form for control devices.

For this hypothetical site, Table 5-6 lists the forms required to add the structure to the EI.

Table 5-6. Appropriate Forms for Adding Structure to the EI

FIN and Appropriate Facility Form	EPN and Appropriate Emission Point Form	CIN
FUGAREA1: Facility Information form for Leaking Component Fugitives	FUGAREA1: Emission point form for a Fugitive-type EPN	
CONDFUGS: Facility Information form for Leaking Component Fugitives	CONDFUGS: Emission point form for a Fugitive-type EPN	
GUNBARSEP: Facility Information form for a VOC Process (under the "Profile" section of the form, check "other").	SEPVENT: Emission point form for a Stack-type EPN	
AMINEUNIT: Facility Information form for Other Facility	AMINEVENT: Emission point form for a Stack-type EPN	
AMINEUNIT: Facility Information form for Other Facility	FLARE: Emission point form for a Flare-type EPN	FLARE*
AMREBOILER: Facility Information form for a Combustion Unit	REBOILSTK1: Emission point form for a Stack-type EPN	
DEA-TANK: Facility Information form for a Storage Tank	DEA-TANK: Emission point form for a Stack-type EPN	
GLYCOLSTIL: Facility Information form for a VOC Process (under the "Profile" section of the form, check "glycol still")	GLYCOLVENT: Emission point form for a Stack-type EPN	
GLYCOLSTIL: Facility Information form for a VOC Process (under the "Profile" section of the form, check "glycol still")	FLARE: Emission point form for a Flare-type EPN	FLARE*
GLREBOILER: Facility Information form for a Combustion Unit	REBOILSTK2: Emission point form for a Stack-type EPN	
EG-TANK: Facility Information form for a Storage Tank	EG-TANK: Emission point form for a Stack-type EPN	

* Since only one abatement device form exists for control devices, complete the Abatement Device Information form for these two CINs.

(continued)

Table 5-6. Appropriate Forms for Adding Structure to the EI, continued

FIN and Appropriate Facility Form	EPN and Appropriate Emission Point Form	CIN
TURBINE1: Facility Information form for a Combustion Unit (under the "Profile" section of the form, check "turbine")	TURBSTK1: Emission point form for a Stack-type EPN	
TURBINE1: Facility Information form for a Combustion Unit (under the "Profile" section of the form, check "turbine")	TURBSTK2: Emission point form for a Stack-type EPN	
COMP1: Facility Information form for a Combustion Unit (under the "Profile" section of the form, check "IC Engine," and complete the remaining blanks "4-cycle, lean-burn")	COMP1STK: Emission point form for a Stack-type EPN	
COMP2: Facility Information form for a Combustion Unit (under the "Profile" section of the form, check "IC Engine," and complete the remaining blanks "4-cycle, rich-burn")	COMP2STK: Emission point form for a Stack-type EPN	NSCR*
UPSETFLARE: Facility Information form for a Flare (Combustion Unit—Flare Profile)	FLARE: Emission point form for a Flare-type EPN	
CONDTANK1: Facility Information form for a Storage Tank	CONDTANK1: Emission point form for a Stack-type EPN	
CONDTANK2: Facility Information form for a Storage Tank	CONDTANK2: Emission point form for a Stack-type EPN	
LOADRACK: Facility Information form for a Loading facility	LOADFUGS: Emission point form for a Fugitive-type EPN	
BLOWDOWN: Facility Information form for a VOC Process (under the "Profile" section of the form, check "blowdown operations")	FLARE: Emission point form for a Flare-type EPN	FLARE*

* Since only one abatement device form exists for control devices, complete the Abatement Device Information form for these two CINs.

For a facility that has multiple emission points, only **one** Facility Information form needs to be submitted to add the facility. To link the facility to other emission points, enter the FIN in the appropriate blank on the Path Emissions form. These procedures can also be used for emission points and abatement devices that have multiple paths.

Completing Path Information. Emissions data need to be completed for each path shown in Table 5-6. A separate Path Emissions form should be completed for each path. Submit Material Throughput forms as necessary to supply process rate data used in emissions determinations.

Completing Account Information. An Account Information form must be completed, as well as the Contact Information forms.

Use the information in Table 5-6 to complete the Structural Overview form, which documents emission path data.

The sum of all criteria pollutants reported at all emission paths must be entered on the Account Emissions form. The legally responsible party must fill out and sign the section headed "Signature of Legally Responsible Party." If no emissions from emissions events are being reported within the EIQ, the legally responsible party must sign the Emissions Events certification.

Detailed instructions on how to complete each EI form are available in the companion volume, *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11), and on the EAS Web page.

CHAPTER 6—UPDATING AN EMISSIONS INVENTORY QUESTIONNAIRE

This chapter tells how to update an EIQ. Review all of the information in this book before attempting to update these forms.

Be certain to review all data on the EIQ for accuracy. Update EIQ items as necessary, using the blank space provided (usually below or to the right of the item) and draw a line through the outdated information. If the EIQ has no blank space for a specific item on the EIQ, write the updated data next to the item, circling or highlighting it if possible. **Important:** The TCEQ will assume that any items left unchanged, including emission rates, are correct for 2011 and will enter them into the STARS database as part of the 2011 inventory.

Note: When printing the EIQ using the Central Registry's Integrated Web Report, the EE and SMSS emissions from the previous EI are shown. Please update these emissions as well.

The emissions inventory forms and instructions are available in a **separate document**, *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11). This document appears online at <www.tceq.texas.gov/goto/ieas>, and a hard copy is available by contacting the EAS. Any EI forms referred to in this chapter appear in that companion document.

Updating EIQ Data

Special Notes

Sample Calculations

30 TAC 101.10(c) requires all regulated entities to submit sample calculations representative of the sources and pollutants from their site. Submit sample calculations showing actual annual emissions determination for each different process type present in the EI, including enough data so that the determination results may be reasonably reproduced. Generic sample calculations cannot be accepted, since they do not contain representative process data and do not demonstrate actual annual emissions determinations.

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 level of emissions.
- Include typical process data for all of the similar sources where sample calculations are not supplied. Typical process data would include heat inputs and fuel types for combustion sources and chemical types and throughputs for storage tanks and loading sources.
- When several sources of the same type are present but different calculation methodologies were used to determine their emissions:
- Include calculations for the source with the highest emissions for each calculation methodology.
- Include typical process data for all of the similar sources where sample calculations are not supplied. Typical process data would include heat inputs and fuel types for combustion sources and chemical types and throughputs for storage tanks and loading sources.

Use Permanent Ink

Please use permanent ink instead of pencil when updating the EIQ. Pencil tends to smudge and can be difficult to read, increasing the chance of data-entry errors or omissions. Permanent ink, especially ink in colors other than black, is clearer and more legible. There are no restrictions on ink color, but colors other than black make EIQ updates more noticeable.

Printing the EIQ

Starting in 2012, the EAS will no longer mail hard copies of the EIQ. A printable version of the EIQ is available through the Integrated Web Reporting System at the Central Registry website <www12.tceq.texas.gov/crpub/>. Instructions for navigating the Central Registry's website and downloading an EIQ formatted for printing are available on in this EAS document: <www.tceq.texas.gov/goto/eiqprint>. If the preparer makes a copy of the completed EIQ for submission, make sure it is printed on only **one** side of each page (do not duplex).

1A *Account Information*

General information on the regulated entity is printed at the top of the EIQ's second page, as shown in the example on page 86, section 1A. For a detailed description of the items in this section, consult *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11) on completing an Account Information form.

To make changes to the company name, site name, or site centroid coordinates, draw a line through the incorrect information, and provide the

updated information in the corresponding blank. To make any significant changes to any of the other account information, notify Central Registry of the changes and send the EAS a copy of the notification.

1B

Emissions Inventory Contact Information

EI contact information is printed at the bottom of the EIQ's second page, as shown on page 86, section 1B. For a detailed description of the requirements concerning EI contact information, please consult *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11). To correct any of the information in this section, draw a line through the incorrect information and enter the updated information in the blank, or complete and submit the Contact Information form.

TCEQ Emissions Inventory Questionnaire Page: 2

1A

ACCOUNT INFORMATION EIQ Year: 2011
RN:RN123456789 _____ Account:HG6789X _____
Company: JOHNSON GAS COMPANY _____ Last EI Date:12/31/2010
Company is Owner/Operator: BOTH__ Site Independently Owned (Y/N): Y _ No. of Employees: __
Site Name: CREEK COMPRESSOR STATION _____
Primary SIC: 1311- CRUDE PETROLEUM AND NATURAL GAS _____
Secondary SIC: _____
Location: TWO MILES SOUTHWEST OF CORBIN ON FM2345 _____
Near City: HOUSTON _____ County: HARRIS _____ Region:12 ____
UTM Zone: 15 ____ Latitude: 155258 _____
UTM North Meters: ~~1756498~~ **3225729** Longitude: 942521 _____
UTM East Meters: ~~347693~~ **208957** _____
Site Status:O _____ Oper Schedule:24___hr/day, 7___da/wk, 52__wk/yr Tot Oper Hrs: 8760__
Seasonal Operating Percentages(NOTE: Spring%+Summer%+Fall%+Winter% must be equal to 100%)
Spring: 25%_____ Summer: 25%_____ Fall: 25%_____ Winter: 25%_____

1B

EMISSIONS INVENTORY CONTACT INFORMATION
Name: CODY MCLAIN _____ Title: ENVIRONMENTAL COORDINATOR _____
Mailing Address: ~~11783 CANYON BLUFF DRIVE~~ **P.O. BOX 13087**

City: AUSTIN _____ State:TX _____ Zip Code:78753-0001 **78711-3087**
Bus Phone:(512)555-1144_____ Fax:(512) 555-1515_____ Email: CMCLAIN@JGC.COM_____

PLANT CONTACT INFORMATION
Name: ~~MATOAKA JOHNSON~~ **I.M. BOSS** Title: ~~PRESIDENT~~ **PLANT MANAGER**
Mailing Address: ~~PO BOX 2575~~ **P.O. BOX 13087**

City: AUSTIN _____ State:TX _____ Zip Code: ~~78753-2575~~ **78711-3087**
Bus Phone: ~~(512)555-1144~~ **(512) 239-1773** Fax:(512)555-1515_____ Email: ~~M@JGC.COM~~ **BOSS@JGC.COM**

Figure 6-1. Sample EIQ Page for Account Information and Emissions Inventory Contact Information

2A Criteria Emissions Totals

This section contains five columns for emissions reporting: *Annual*, *Ozone*, *EE* (Emissions Events), *SMSS* (scheduled maintenance, startup, and shutdown activities), and *EE/SMSS* (totals from EE and SMSS emissions). An example appears on page 89, section 2A. There are seven rows, each representing a criteria pollutant. Each column contains two subcolumns: one with a printed number and one with a blank. The printed number is the site-wide emissions total reported on the most recently submitted EI. In the blank to the right of that number, enter the site-wide emissions total for the current EI and **do not** draw a line through the printed emissions totals.

The VOC totals only include emissions from volatile organic compounds. Emissions from non-reactive hydrocarbons such as acetone should not be 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) should not be included in the NO_x totals.

Note that these reported emissions totals are not entered into STARS. The reported totals are used for comparison to ensure that STARS correctly sums the emissions reported within the EIQ itself. Emissions reported in "Criteria Emissions Totals" section must also be reported at the appropriate paths within the EIQ.

For a thorough discussion of the elements of this section, please consult Chapter 4, "Determining and Reporting Emissions," and *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11) for instructions on completing an Account Emissions form.

2B Site Quantifiable Event Totals

Site quantifiable event totals are reported in this section, as shown in the example on page 89, section 2B. The total number of reportable and non-reportable emission 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 101.201 and 101.211. An explanation of each type of event follows.

Total Number of Reportable Emission Events is the total number of emission 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 the TCEQ as required by 30 TAC 101.201.

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

Total Number of 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 the TCEQ as required by 30 TAC 101.211.

Total Number of 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.

Total Number of 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 in the blanks provided. If there were no events of a particular type, enter zero in the space provided. For additional information on completing this section, consult the Account Emissions form instructions in *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11). For guidance on interpreting rules concerning EE and SMSS activities, contact the TCEQ regional office where the regulated entity is located.

TCEQ Emissions Inventory Questionnaire Page: 3

ACCOUNT INFORMATION EIQ Year: 2011
RN: RN123456789 Account: HG6789X
Company: JOHNSON GAS COMPANY Last EI Date:12/31/2010

2A

CRITERIA EMISSIONS TOTALS

Class	Annual(TPY)/Current	Ozone(PPD)/Current	SMSS(TPY)/Current	EE(TPY)/Current	EE/SMSS(TPY)
PM10	0.0000/ 4.0700	0.0000/ 22.1196	0.0000/_____	0.0000/_____	0.0000
PB	0.0000/_____	0.0000/_____	0.0000/_____	0.0000/_____	0.0000
SO2	0.0000/143.6177	0.0000/780.5310	0.0000/_____	0.0000/_____	0.0000
NOX	0.0000/ 138.49	0.0000/752.6630	0.0000/ 1.2050	0.0000/_____	0.0000
CO	0.0000/220.909	0.0000/1200.5924	0.0000/ 2.3498	0.0000/_____	0.0000
VOC	0.0000/44.2613	0.0000/ 240.5505	0.0000/_____	0.0000/_____	0.0000
PM2.5	0.0000/ 4.0700	0.0000/ 22.1196	0.0000/_____	0.0000/_____	0.0000

2B

SITE QUANTIFIABLE EVENT TOTALS

Note:
Report TOTAL NUMBER of each event type for the reported EIQ Year per 30 TAC Sections 101.201 and 101.211.

Reportable Emission Events: 3
Non-Reportable Emission Events: 5
Reportable Scheduled Maintenance, Startup, and Shutdown Activities: 0
Non-Reportable Scheduled Maintenance, Startup, and Shutdown Activities: 2
Excess Opacity Events: 0

Figure 6-2. Sample Account Emissions EIQ Page

3A Emissions Events Certifying Signature

Page four of the EIQ contains two signature sections. The first is an Emissions Events Certification, as shown in the example on page 91, section 3A. This must be signed if and **only** if the regulated entity did not experience any emissions events.

If the owner or operator notified the TCEQ, in accordance with 30 TAC 101.201, about only an excess opacity event where there were no emissions, he or she must sign the EE certification.

3B Signature of Legally Responsible Party

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. Fill in all of the blanks on this portion of the EIQ, as shown on page 91, section 3B.

For additional guidance regarding the definition of the legally responsible party, please consult 30 TAC 122.165, Certification by a Responsible Official.

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

TCEQ Emissions Inventory Questionnaire Page: 4

ACCOUNT INFORMATION EIQ Year: 2011
RN: RN123456789 Account: HG6789X
Company: JOHNSON GAS COMPANY Last EI Date:12/31/2010

3A

Emissions Events Certification

Pursuant to Texas Health and Safety Code 382.0215(f). I do hereby certify that 'NO Emissions Events' were experienced at this account during the Emissions Inventory Reporting Calendar year.
(Sign here if and only if you reported no emissions from emission events.)

Signature _____

3B

Signature of Legally Responsible Party

I do hereby certify that information reported in this inventory is true, accurate, and fully represents the emissions that occurred during the Emissions Inventory Reporting Calendar year to the best of my knowledge.

I.M. Boss	PLANT MANAGER	(512) 239-1773
Signature	Title	Phone
I.M. BOSS	2/28/2011	(512) 555-1515
Printed Name	Date	Fax

Figure 6-3. Sample Account Information Certification EIQ Page

Facility Information

Descriptions of most of the items in this section, along with information on accepted values, may be found in *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11) for each relevant Facility Information form. The following discussion focuses on updating facility data.

If corrections to any of the information in this section are necessary, draw a line through the incorrect information and supply the updated information in the corresponding blank, as shown on page 98, sections 4A through 4G. A discussion of each section follows.

4A Source Classification Code (SCC)

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

The EPA maintains a current list of SCCs under the link "EIS Code Tables (including SCCs)" at <www.epa.gov/ttn/chief/eiinformation.html>. When using this file, 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 EIQ.

4B Status, Status Date

If the facility's status has changed, enter the appropriate letter and enter 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.**
- **D** (demolished): If the facility has been removed from the site.
- **N** (permitted but never built).
- **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 regulated entity reference number.

4C 4D

Operating Schedule and Annual Operating Hours

These fields should 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 annual data for the facility.

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

4E

Seasonal Operating Percentages

Seasonal operating percentages represent the percentage of actual annual 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. Note that the percentages must be reported as whole numbers (no decimals) and must sum to 100.

4F 4G

FIN Group Type, Profile, and Characteristics

In STARS, every facility has a group type associated with it; a list of current group types is available in Table 6-1. These group types also appear on the Facility Information forms. Associating each facility with a group type allows the EAS to collect data on sources of interest, and also facilitates data retrieval.

If the facility's group type or profile appears incorrect, consult Table 6-1. Most of the group types are self-explanatory; for examples of facility types that belong to each group, refer to the associated profiles.

If the facility has an incorrect group type or profile (for example, a flare has a group type of "equipment leak fugitive"), correct the group type and profile on the EIQ itself. Next, complete the appropriate Facility Information form to update the facility information; in our example, a Facility Information for Combustion Unit—Flare Profile Facility Information form will be necessary. To avoid any confusion, the word "update" must appear at the top of the form.

For more information about the characteristics associated with each profile, please identify the facility appropriate group type, and then consult

the instructions for completing the relevant facility form in *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11). For example, if additional information is needed for a cooling tower's characteristics, consult the instructions for completing a Facility Information for Cooling Towers form.

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

Group	Profile	Characteristics
Cleaning	Dip degreasing Vapor degreasing Barge cleaning Railcar cleaning Tank truck cleaning Other	Not applicable
Combustion	Flare	Design capacity in MMBtu per hour Assist type (steam, air, or none) Service type (process, emergency, or both) HRVOC Service? (yes or no)
	I.C. engine	Number of cycles (two or four) Burn type (rich or lean) Design capacity in MMBtu per hour Engine rating in horsepower
	Boiler, dryer, furnace, heater, incinerator, kiln, oven, turbine, thermal oxidizer, other	Design capacity in MMBtu per hour Firing type
	Fluid catalytic cracking unit (FCCU)	Not applicable
	Boiler—Electric Generation I.C. Engine—Electric Generation Turbine—Electric Generation	Design capacity in MMBtu per hour Firing Type Power Generation Capacity in MW

Group	Profile	Characteristics
Coating or printing	Coating or printing	Not applicable
Cooling tower	Cooling tower	Design flow rate in MMgal per day Draft design type (natural or mechanical) Number of cells Sampling schedule Sample tested for VOCs? Sampling data used to calculate emissions? HRVOC Service? (yes or no)
Equipment leak fugitives (Leaking component fugitives)	Equipment leak fugitives	Emissions determination methodology* Leak detection and repair program* % VOC in Stream* Monitoring equipment data* ** refer to the Facility Information for Leaking Component Fugitives form*
Loading	Railcar Tanker truck Railcar / tanker truck Marine Other	Not applicable
Other	Other	Not applicable

(continued)

Table 6-1. STARS Facility Types, Profiles, and Characteristics, continued

Group	Profile	Characteristics
Tanks	Horizontal fixed roof Vertical fixed roof Internal floating roof Pressure tank Underground tank External floating roof: double deck, single seal External floating roof: double deck, double seal External floating roof: pontoon, single seal External floating roof: pontoon, double seal Domed external floating roof: double deck Domed external floating roof: pontoon Other	Refer to the Facility Information for Storage Tanks form.
VOC process	Analyzer Blowdown operations Delayed Coker Unit Flexi Coker Unit Glycol still Polyethylene unit Polypropylene unit Mixing vessel Reactor Other	Not applicable

Group	Profile	Characteristics
Wastewater	Wastewater system	Flow model (flowthrough or disposal) Aeration (diffused air, mechanical or none) Biodegradation mechanism (biodegradation, activated sludge, or none) Design type (surface, subsurface, or other) Depth Surface area Flow rate in MMgal per day
Wastewater	Basin Clarifier Closed sump Lift station Open sump Reactor Stripper Separator Other wastewater component	Not applicable

FIN: ENGINE1 EPN: VENT
Comment: ~~STANDBY UNIT FOR 2005~~

FACILITY INFORMATION

FIN: ENGINE1 Facility Name: ~~COMPRESSOR ENGINE NUMBER 1~~ Plant ID:
_____ **Internal Combustion Engine 212** **PROCESS 1**

Comment
_**OPERATED AT 1650 HP in 2011**_____

4A — SCC: ~~20200254~~ **20200253** Description: INDUSTRIAL NATURAL GAS 4-CYCLE LEAN BURN

4B — Status: ~~I~~ **A** Status Date: ~~1/1/2006~~ **1/1/2011**

4C — Operating Schedule: 20__hrs/day, 7 __days/wk, 52__wks/yr

4D — Annual Operating Hours: ~~0~~ **7280** Percentage Max Capacity: ~~0~~ __**88**__ Start Time: 0600 _____

4E — Seasonal Operating Percentages(NOTE: Spring % + Summer % + Fall % + Winter % must be equal to 100%)
Spring: 30%_____ Summer: 29%_____ Fall: 31%_____ Winter: 10%_____

4F — Group Type: COMBUSTN
Profile: I.C. ENGINE

4G

Characteristic	Value	Unit	Characteristic	Value	Unit
BURN TYPE	RICH	----	CYCLE	4	----
DESIGN CAPACITY	~~5.44~~ **160**	MMBTU/HR	ENGINE RATING	**2085**	
FIRING TYPE	OT				

Figure 6-4. Sample Facility Information EIQ Page

Control Device Information

Descriptions of the items in this section, along with information on accepted values, appear in the instructions for completing the Abatement Device Information form. If corrections need to be made to any of the information in this section, draw a line through the incorrect information and provide the updated information in the corresponding blank, as shown in the example on page 100, sections 5A through 5E.

For each abatement device, verify that:

5A 5B
- the abatement code and number of units are correct,

5C
- the percentage of time offline is reflected in annual emissions determinations,

5D
- the inspection and maintenance (I/M) schedule is accurate, and

5E
- the stated abatement efficiencies 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.

```
RN: RN123456789      Account: HG6789X
Company: JOHNSON GAS COMPANY                                        EIQ Year: 2011


FIN: ENGINE1       EPN:  VENT
Comment: STANDBY UNIT FOR 2005
-------------------------------------------------------------------------------------------
CONTROL DEVICE INFORMATION
-------------------------------------------------------------------------------------------
*CIN: CAT       Name:  CAT 001
     ______            ____________________________________________________________________

5A   Abatement Code:631 ____  Desc: CATALYTIC REDUCTION                      5C
5B   No. Of Units:1 ___ Annual Operating Hrs: 7280 ___ % Time Off Line: 0 ___ IM Schedule: Q ___  5D
5E   Control Efficiencies:
        VOC: 50.00%_____        NOX: 92.00%_____        CO: 90.00%_____       IOC:  0.00%_____
        TSP:  0.00%_____       PM10:  0.00%_____       SO2:  0.00%_____     C1-C3:  0.00%_____
        C4+:  0.00%_____        H2S:  0.00%_____       NH3:  0.00%_____
```

Figure 6-5. Sample Control Device Information EIQ Page

Parameters for Emission Points

Descriptions of most of the items in this section, along with information on accepted values, may be found in the instructions for completing the relevant Emission Point Information form. If corrections need to be made to any of the information in this section, draw a line through the incorrect information and update the information in the corresponding blank, as shown in the example on page 102, sections 6A through 6C.

6A Emission Point Coordinates

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

Verify that each emission point has accurate coordinates; for most nonfugitive emission points, these coordinates should be unique. Also, verify that the site centroid, printed on page 2 of the EIQ, is correct.

6B 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 the EAS to collect data on sources of interest and facilitates data retrieval.

If the emission point profile is incorrect, draw a line through the printed profile on the EIQ and write in the correct profile.

6C EPN Parameters

Accurate emission point parameters are essential to urban airshed modeling activities. Emission point parameters should represent **actual** stack, fugitive, or flare parameter values, not values for permit modeling purposes. Verify that all emission points have accurate, actual parameter values.

If the EPN profile was corrected, fill out the appropriate Emission Point Information form. Write “updated” at the top of the form. The parameter data may also be corrected by writing the information directly on the EIQ.

FIN: ENGINE1 EPN: VENT
Comment: STANDBY UNIT FOR 2005.

EMISSION POINT INFORMATION

EPN:VENT _____ Point Name: ENGINE 1 VENT_____

6A

UTM Zone: 15 _____ Latitude: 155258 _____
UTM North Meters: ~~1756493~~ **3225729** Longitude: 942521 _____
UTM East Meters: ~~347693~~ **208957**

6B

Profile: ~~FUGITIVE~~ **STACK**

6C

Characteristic	Value	Unit			
DEGREES	~~36~~	~~DEGREES~~	**DIAMETER**	**2.5**	**FEET**
HEIGHT	~~1~~	~~FEET~~	**HEIGHT**	**40**	**FEET**
LENGTH	~~55~~	~~FEET~~	**HORDSCHG**	**N**	
OFNORTH	~~E~~	~~----~~	**MOISTURE**		
WIDTH	~~89~~	~~FEET~~	**TEMP**	**813**	**DEG F**
			VELOCITY	**8.3**	**FT/SEC**

Figure 6-6. Sample Emission Point Information EIQ Page

7A Total Aggregate Annual Heat Input

For combustion units, enter the total heat value (in MMBtu) of all fuels that the facility combusted during the year, as shown on page 108, section 7A. 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 aggregate heat input for the facility.

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).

7B Emissions Factors

In the spaces provided, supply the emissions factors that were used to determine the emissions for each individual FIN/EPN path. In the far right column, enter the source of the emissions factor. This is shown on page 108, section 7B.

In particular, the EAS uses the reported NO_x emission factors on the EIQ to improve the TCEQ's airshed modeling and rulemaking. To promote consistency among similar emissions sources, the EAS 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 @ 0% O_2 (FCCUs)

If an 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 an 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 EIQ. *Note:* The factors should account for any controls. The reported NO_x emission factor should 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

Detailed discussion of the items in this section may be found in *2011 Emissions Inventory Forms and Instructions* (RG-360B/11) in the section on completing the Path Emissions form. The following discussion focuses primarily on updating emissions data for each path.

Updated emissions must be reported on the appropriate EIQ forms. **The EAS does not allow the submission of spreadsheets in lieu of completed EIQ forms.** If the emissions information in this section needs to be updated, supply the updated information in the corresponding blank, as shown in the example on page 108, sections 7C through 7H.

7C 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 under the "Method" heading (on the Path Emissions portion of the EIQ). To obtain the code for a particular EIQ determination methodology, consult the appropriate heading in Chapter 4.

7D Annual Emissions

For annual emissions, report total annual emissions for the year during routine operations for all contaminants emitted, quantified in tons. Annual emissions should not include emissions from emissions events or schedule maintenance, startup, and shutdown activities that are not authorized by a

new source review permit or permit by rule. However, annual emissions should include authorized emissions from maintenance, startup, and shutdown activities. Ensure that all criteria emissions totals (as updated on page 3 of the EIQ) are included as path emissions within the body of the EIQ.

Update annual emissions under the "Path Emissions" portion of the EIQ. The printed numbers in this section reflect the emissions rates submitted on the most recent inventory. Enter the new rates in the space provided; only **one** rate may be entered per blank. If no update is made in the blank provided, the TCEQ will not enter the rate as zero but instead will apply the printed rate for the current EI year. If the rate needs to be updated to zero, the preparer must enter a zero in the blank. Crossing out the previous rate or putting a line in the blank will not cause the emissions to be entered as zero.

7E Ozone Season Emissions

For ozone season emissions, report actual emissions during the ozone season, measured in pounds per day. Recall that the ozone season is defined as the 153 days from May 1 through September 30, inclusive; see Chapter 4, "Determining and Reporting Emissions," for more details. 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 Table 4-5. The EAS database can no longer automatically calculate ozone season rates.

The printed numbers in this section reflect the emissions rates submitted for the most recent inventory. Enter the new rates in the space provided; only one rate may be entered per blank. If no update is made in the blank provided, the rate will not be entered as zero; instead, the TCEQ will apply the printed rate for the current EI year. If the rate needs to be updated to zero, the preparer must enter a zero in the blank. Crossing out the previous rate or putting a line in the blank will not cause the emissions to be entered as zero.

7F Scheduled Maintenance, Startup, and Shutdown (SMSS) Activities

Report emissions from scheduled maintenance, startup, and shutdown activities that are not authorized by a new source review permit or permit by rule in the "SMSS" column, using the blanks provided. Emissions from maintenance, startup, and shutdown activities that are authorized under a permit or permit by rule should not be included in the "SMSS" column. Instead, these emissions should be reported in the "Annual" column. For more information on SMSS emissions, see Chapter 4.

7G

Emissions Events (EE)

Report emissions from emissions events in the EE column, using the blanks provided. For more information on emissions events, see Chapter 4, "Determining and Reporting Emissions."

7H

EE/SMSS Column: Reporting Guidelines

As outlined in the previous section, emissions from emissions events and/or SMSS activities must be reported in either the EE or SMSS column, as appropriate. **If a regulated entity reports emissions in the "EE/SMSS totals" column, emissions must also be reported in the "EE" or "SMSS" columns, or both, as appropriate.**

7I

Adding Emissions Rates

To add an emissions rate to the EIQ, the preparer will need to identify a contaminant code. Contaminant codes are unique five-digit codes associated with individual contaminants. An updated list of contaminant codes is available in *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11).

To report emissions of a contaminant not printed on the form, simply add the following below the last printed entry:

- the contaminant code;
- the determination methodology; and
- the associated annual, ozone, EE, and SMSS emissions rates (as applicable).

If numerous contaminants need to be added that will not fit on the EIQ page itself, an additional Path Emissions form should be submitted with the appropriate information. On the form, write "Additional contaminants being added to an existing path."

If a contaminant does not appear to have a contaminant code, try electronically searching for the contaminant's Chemical Abstracts Service (CAS) number in *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11). If a search by CAS number fails, contact the EAS for assistance; be sure to have the chemical's name and CAS number readily available.

Emissions Rates: Numeric Format

STARS cannot accept emissions rates beyond four decimal places. Emissions rates that extend beyond four decimal places should be rounded

as appropriate. Under no circumstances may scientific notation be used when reporting emissions rates, as data in this numeric format cannot be entered into STARS.

Only one emissions rate can be entered per blank. STARS does not support the routine reporting of emissions rates for periods of less than one year, such as quarterly emissions rates.

Changing FIN and EPN Designations

The EAS 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. If revisions to FIN or EPN designations are necessary, please submit a Revision Request form and give 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 the EAS reserves the right to approve or disapprove all such revision requests. Additional information about the Revision Request form is available in *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11).

FIN: ENGINE1 EPN: VENT
Comment: STANDBY UNIT FOR 2005

EMISSIONS FACTORS

7A Total Annual Aggregate Heat Input: 1,164,800 MMBTU (Combustion Units Only)

7B

Criteria Pollutant	Emissions Factor	Emissions Factor Units	Reference/Source
VOC	0.0296	lb/MMBtu	AP-42
NOX	2.21	lb/MMBtu	AP-42
CO	3.72	lb/MMBtu	AP-42
SO2	0.000588	lb/MMBtu	AP-42
TSP	0.01941	lb/MMBtu	AP-42

EMISSIONS INFORMATION

Code	Cas #	Contaminant	Method (7C)	Annual(TPY) (7D)	Ozone(PPD) (7E)	SMSS(TPY) (7F)	EE(TPY) (7G)	EE/SMSS (7H)
10000	0	PART-U	A	0.0000	0.0000	0.0000	0.0000	0.0000
				11.3044	71.2668			
20000	0	PM10 PART-U	A	0.0000	0.0000	0.0000	0.0000	0.0000
				11.3044	71.2668			
50001	0	VOC-UNCLASSIFIED	A	0.0000	0.0000	0.0000	0.0000	0.0000
				3.6749	23.168			
70400	0	NITROGEN OXIDES	A	0.0000	0.0000	0.0000	0.0000	0.0000
				1287.1040	8114.3513			
70510	0	SULFUR DIOXIDE	A	0.0000	0.0000	0.0000	0.0000	0.0000
				0.3425	2.1589			
90300	0	CARBON MONOXIDE	A	0.0000	0.0000	0.0000	0.0000	0.0000
				2166.5280	13658.5461			
39999		$PM_{2.5}$	A	11.3044	71.2668	0.0000	0.0000	0.0000
51680		Formaldehyde	A	11.9392	75.2689	0.0000	0.0000	0.0000

7I

Figure 6-7. Sample Path Emissions EIQ Page

CHAPTER 7—EI REVISIONS, DATA REQUESTS, SITE COORDINATE DATA

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

A revision request is made to correct erroneous EI data 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 the TCEQ. Whether retrieving electronic data from STARS or viewing an EI file on paper, there are procedures in place to request such information. This chapter discusses what data EAS can provide and when an "open records" request may be more appropriate.

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

Revising an EI

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; it is not necessary to submit the entire EIQ (STEERS printouts are not an acceptable format for submitting revisions; see "Printing the EIQ" in Chapter 6 for information on obtaining EIQ pages)
- updated criteria emissions totals for the site (found on page 3 of an 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.

To obtain an electronic copy of the most current data for the EI revision year, contact the EAS. The EAS help line number is 512-239-1773.

Use Permanent Ink

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.

How to Submit

The revised EIQ pages submitted to the TCEQ should 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.

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.

Previous Reporting Year

The emissions for the previous EI reporting year can also be revised, following the same procedure as for the current EI reporting year. In the cover letter, indicate which year the revision applies to.

Note: If the request is for revisions to any EI reporting year earlier than the 2009 EI, the agency will not update the emissions data currently in STARS. Instead, the EAS staff will document the revision request and file the information in the EI folder.

Revising STARS Data

Revisions are processed according to current EAS procedures. The EAS will review each revision request to determine if the data currently in STARS should be updated. This review takes into account the justification for the updates and the magnitude of the change in emissions, if applicable.

After the review, the EAS will determine whether to record the emission revisions in STARS or, alternatively, to file them in the EI folder. Since each revision is unique, the EAS recommends the preparer contact a current EI-review staff member to address any questions about the submitted revisions.

Please note: Revision requests are processed as time permits. Generally processing takes place after the EAS has reviewed all emissions inventories for the current reporting year.

EI Data Requests

Historical EI data are available in several formats. General emissions data are available through the TCEQ Data Clearinghouse. Site-specific EI data and reports are available through the Central Registry Integrated Web

Reports (IWR) system at <www12.tceq.state.tx.us/crpub/>. Site-level EI information also appears online at the EAS Web page, while more detailed data can be obtained by completing an Emissions Data Request form. EI files can also be viewed in person at the TCEQ central office in Austin.

TCEQ Data Clearinghouse

A wide collection of regulatory and environmental information is available through the TCEQ Data Clearinghouse, including historical EIQs and site-wide contaminant summary reports. The clearinghouse is at 512-239-DATA (3282) or online at <www.tceq.texas.gov/goto/data>.

TCEQ Central Registry Integrated Web Reports

Site-specific data and reports are available through the TCEQ Central Registry IWR system, including path-level and site-level emissions, path-list reports, and the EIQ. The IWR Web page is at <www12.tceq.state.tx.us/crpub/>.

Data Available at the EAS Web Site

The EAS Web page titled Point Source Emissions Inventory <www.tceq.texas.gov/goto/ieas> links to easily accessible EI data. Before contacting the TCEQ for EI data, please refer to that Web page to make sure the information is not already available. Information available there includes emissions inventory trends, total criteria emissions for each site that reported an EI for the previous year, tools for completing an EI, this document, and the companion document, *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11).

Emissions Data Requests

To request emissions data, please complete the form at the end of this chapter and fax it to the EAS at the number on the form. The EAS will determine if the requested data are available electronically or if paper EI files are available for review. Please allow at least eight business days for the EAS to produce the data.

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

Paper EI Data Requests

EI Files Available at the TCEQ Central Office

The EAS maintains files for the current EI reporting year and the two most recent years. To request them, contact the EAS help line 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' prior notice to view a file. This allows the EAS time to retrieve it and allows the agency 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 two 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 e-mail to <openrecs@tceq.texas.gov> or in writing to the Public Information Officer. Please allow a few days for the state library to forward the files. For more information, visit <www.tceq.texas.gov/goto/openrecords>.

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

The TCEQ has recently made available an online viewer that uses Google Maps to help determine accurate coordinate data. See <www.tceq.texas.gov/goto/sqmaview>.

TCEQ Point Source Emissions Inventory Data Request

Requester

Name: _____ Company:_____
Phone: _____ E-mail: _____
Mailing Address: _____
City: _____ State: _____ Zip: _____

Contaminants Requested

☐ All Criteria Pollutants ☐ NO_x ☐ VOC (☐ Speciated ☐ Total)
☐ Lead ☐ CO ☐ PM (☐ Speciated ☐ Total)
☐ SO_2 ☐ $PM_{2.5}$ ☐ PM_{10} (☐ Speciated ☐ Total)

☐ Specific Contaminant(s) (list):	Contaminant Code

Emission Type

☐ Annual (tpy)
☐ Ozone Season (ppd)
☐ SMSS (tpy)
☐ EE (tpy)

Inventory Years

☐ All ☐ Most Recent
Specify Year(s):
_____
_____

Retrieve Data For

☐ Regulated Entity Reference Number: RN_____ ☐ Air Account Number:_____
☐ Company Name:_____ ☐ County:_____
☐ Statewide ☐ All Nonattainment ☐ All Attainment ☐ BPA ☐ DFW ☐ El Paso
☐ HGB: ☐ 11-county area or ☐ 8-county area ☐ Other:_____

Source Type

☐ All types of Processes ☐ Top Emitters (top how many? _____)
☐ Specific Process Types:_____
☐ Specific SIC types:_____

Sum Data By

☐ Site ☐ Emission Point (EPN) ☐ Generator (FIN) ☐ County
☐ Statewide ☐ Attainment Area ☐ Nonattainment Area ☐ Contaminant

Show Other Data

☐ Account Number ☐ Company & Site Name ☐ Principal Business (SIC) ☐ FIN ☐ EPN ☐ County

Other Requirements (specify)

Final Report Format

Report Data as:	☐ Printed Table(s) (paper) ☐ Excel Spreadsheet (electronic)		
Report Delivery:	☐ Email ☐ Fax ☐ Mail	**Date Needed:***	

Fax completed request to: EAS at 512-239-1515 or 512-239-1555 Attention: EAS Manager TCEQ-20473 (11-21-11)
*Allow at least eight business days minimum for processing.

CHAPTER 8—QUESTIONS ANSWERED: EMISSION EVENTS, EXCESS OPACITY EVENTS, SMSS ACTIVITIES

Site Quantifiable Event Totals

By what authority are the site quantifiable event totals required to be reported in the EI?
The total number of reportable and nonreportable EE and SMSS events are required to be reported per 30 TAC 101.201 and 101.211 respectively.

Where must I report the total number of reportable and nonreportable EE and SMSS activities?
Report these activities on page 3 of the EIQ or the Account Emissions page for an initial EI submission.

Where must I report the total number of excess opacity events?
Report these events on page 3 of the EIQ or the Account Emissions page for an initial EI submission.

What is the difference between a reportable and a nonreportable EE or SMSS release?
Reportability depends on whether emissions exceed a reportable quantity, which in turn depends on the contaminant released and the discharge location. Refer to 30 TAC 101.1(88) for chemical specific reportable quantities. A reportable release is an emissions release equal to or greater than the reportable quantity for a contaminant. For additional assistance with determining if a release is reportable, please contact the office for the region where the site is located.

I know I have to report my permitted emissions from SMSS activities as annual tons per year in the EI. Do I include the number of permitted SMSS activities in the total reportable or nonreportable SMSS activities on page 3 of the EIQ?
No, permitted SMSS activities should not be included in the total reportable or nonreportable SMSS activities on page 3 of the EIQ.

Reporting EE and SMSS Emissions

I reported my EE and SMSS tons per year on page 3 of the EIQ. Do I have to include the EE and SMSS amounts in tons per year at a specific path or paths in the EI?
Yes, in order for the emissions from EE and SMSS activities to be updated in the STARS database, the emissions must be reported at the specific path

in the EI. The emissions on page 3 of the EIQ are sitewide totals and are not data-entered.

Do I include EE and SMSS releases when determining ozone season emissions in pounds per day (ppd)?
Ozone season emissions should be based on the emissions reported in the "Annual" tpy column. If the SMSS releases are permitted, these emissions should be reported in the "Annual" tpy column and should also be included when calculating the data for the "Ozone" ppd column.

Can I add a separate path to my EI to report all EE and SMSS activities, instead of specifying the EE and SMSS activities on specific paths?
The EAS would prefer that the preparer not add a separate path solely for EE and SMSS emissions in the EI. Instead, report these emissions at the paths where they occurred. If the EE and SMSS activities are permitted under a single site-wide cap, it may be appropriate to add a separate path. For specific questions, please contact the EAS.

The emissions from SMSS releases at my site are permitted. Where should these permitted SMSS releases be reported in the EI?
Emissions from SMSS activities authorized by a New Source Review permit or by a permit by rule should be reported as annual emissions and should not be included in the "SMSS" column (which is only for emissions from SMSS activities that are not authorized by a permit).

Do I have to report the emissions from nonreportable EE or SMSS releases in the EI?
Yes, report the total emissions in tons per year from all EE releases or SMSS activities at each FIN/EPN path, regardless of whether those releases represent reportable or nonreportable quantities.

I have several pieces of equipment that start and stop for maintenance several times a day. Over the course of a year, this can result in thousands of SMSS activities with minimal emissions (for example, last year there were 1,506 activities). These emissions are nonreportable and are not permitted. Do I have to report the emissions from the SMSS activities as a tpy emission quantity in the EI? Do I have to include these activities in the number of nonreportable SMSS activities on page 3 of the EIQ?
Yes, all emissions from SMSS activities must be reported in the EI, regardless of whether they are reportable or nonreportable. The emissions are to be reported in the SMSS column at the FIN/EPN path in the EI because the emissions are not permitted. Include the 1,506 activities in the total number of the nonreportable SMSS activities on page 3 of the EIQ.

How do I estimate emissions during maintenance, startup, and shutdown activities?
Please use the best emissions determination methods available, such as good engineering practices, process knowledge, or test data.

Where would emissions from maintenance activities that were not scheduled be reported? What exactly does "scheduled" mean?
Report the emissions from any MSS activity that was not scheduled in the "EE" column at the FIN/EPN path in the EI. Scheduled MSS activities as defined in 30 TAC 101.1(90) are those for which the region is required to be notified in advance, per 30 TAC 101.211.

Excess Opacity

Excess opacity is permitted as a percentage. Can I report my excess opacity events in the EI as a percentage?
No. However, if emissions from an emissions event were associated with the excess opacity event, those emissions must be calculated and reported in the "EE" column in tons per year at the applicable FIN/EPN path.

I had an excess opacity event with associated emissions. How do I determine those emissions?
Use the best emissions determination method available, such as process knowledge, past engineering analysis, or testing to calculate and report the emissions at the specific path in the EI.

Emissions Event Certification

When is a signed Emissions Event Certification required?
When no emissions events occurred at the site, the signature certifies that no emissions from emissions events occurred during the EI reporting year, per Texas Health and Safety Code 382.0215(f).

My excess opacity event was not associated with the release of emissions and no emissions from EE occurred at my site during the reporting year. I reported the number of excess opacity events on page 3 in the EIQ. Do I have to submit a signed Emissions Event Certification?
Yes, submit and sign the Emissions Event Certification, since the site experienced no emissions events.

APPENDIX A—TECHNICAL SUPPLEMENTS

Disclaimer

The Emissions Assessment Section (EAS) has developed technical supplements for several common emission sources. The supplements are intended to provide guidance for determining and correctly 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 they generate emissions. The supplements may change over time as a result of findings of scientific studies and as new information becomes available. The EAS greatly appreciates any data, information, or feedback that may improve these supplements.

The methods discussed in this appendix are intended as an aid in calculating emissions. Certain process or operational conditions may make alternate calculation methods equally acceptable if they are based upon, and adequately demonstrate, sound engineering principles or data. 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 his or her site. Additional guidance regarding the acceptability of a given emissions determination method is available from the EAS at 512-239-1773.

Miscellaneous VOC Sources

One of the goals of the EAS is to identify sources that are failing to report or underreporting their VOC emissions. The sources that fall into this category include, but are not limited to, casing head gas releases, coking units, confined entry ventilation, and Merox units. The EPA has released a draft document titled *Emission Estimation Protocol for Petroleum Refineries* that is currently under review. Once finalized, this document may provide guidance on determining emissions from coking units and Merox units. The TCEQ is not aware of any additional specific guidance that is readily available to determine the emissions from these types of sources. If these sources 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 emission determination methodologies.

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

Petroleum coke is removed from the walls of a coke drum by *decoking* or *coke cutting*. During the decoking or coke cutting process, VOC gases trapped in the coke will be released 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 Merox unit, they are often placed in a storage tank. Inert gases may become trapped in this hydrocarbon liquid and can strip VOCs while escaping during storage. The EPA TANKS program may not account for these additional emissions in the calculated emissions report.

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 BTEX and other HAPs) 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 gas analysis must be speciated 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. Controls for the regenerator and flash tank vents can be accounted for in the GRI-GLYCalc program. When the GRI-GLYCalc program is used to determine the emissions, include the "Aggregate Summary Emission Report" in the sample calculations. Flash tanks must be represented as individual sources in the emissions inventory if they are permitted separately from the glycol still or dehydrator unit. Use the Facility Information—VOC Process form to add the glycol flash tank structure to the inventory. For assistance, contact the EAS.

Amine Units in Carbon Dioxide 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 is often vented to the atmosphere. Amine solutions can absorb VOCs (including BTEX and other HAPs) and release them to the atmosphere during the regeneration cycle. Current and accurate simulation techniques to determine emissions or stack sampling must be used to ensure that speciated VOCs are reported from amine units in CO_2 service.

Technical Supplements

The following technical supplements are included in this appendix.

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

Technical Supplement 2: Cooling Towers will help you in determining the nature of the emissions from a cooling tower system, in identifying some of the methods that may be used to quantify those emissions, and in correctly reporting 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 discusses stationary emissions from vessel cleaning, material transfer, and dockside sources such as particulate stockpiles, silos, VOC collection units, loading racks, and abatement devices. All of these emissions sources must be reported in the dock owner's EI.

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

TECHNICAL SUPPLEMENT 1: SELECTED COMBUSTION SOURCES

Technical Disclaimer

This technical supplement is intended to help the preparer determine and correctly 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. The EAS greatly appreciates any data, information, or feedback that may improve the supplement.

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

Introduction

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

Internal Combustion Engines

Expected Contaminants

Reported engine emissions should include all of the following:

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

- VOCs (contaminant codes *50001* through *59998*)
- HAPs, such as formaldehyde, ≥ 0.1 tpy
- NOx (contaminant code *70400*)
- SO_2 (contaminant code *70510*)
- CO (contaminant code *90300*)

Emissions Determination Methodologies

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

- D (continuous emissions monitoring system or CEMS)
- F (predictive emissions monitoring system or PEMS)
- M (measured—stack test data)
- Q (portable analyzer test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- 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 reported as measured ("M"). If the stack test results from an identical unit are used to determine the emissions, the emissions determination methodology must be reported as 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. 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 sulfur dioxide as a product of combustion. CEMS, PEMS, and stack test data are the preferred order when identifying the determination methodology for determining the SO_2 emissions. In lieu of using a vendor or AP-42 SO_2

emission factor, the SO_2 emissions must be determined using material balance based upon the combusted fuel's sulfur content.

Particulate Emissions

Combustion sources emit particulate matter. Furthermore, particulate matter emitted from internal combustion engines has an aerodynamic diameter smaller than 2.5 microns. Thus, all particulate emissions from these sources must be reported as $PM_{2.5}$, PM_{10}, and PM (total). See Chapter 4, "Speciating Particulate Matter," for more details.

In the past, 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 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.

However, summing these emission factors is not straightforward. Since all particulate matter emitted from internal 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. In calculating the PM emissions, use one of the filterable emission factors when attempting to obtain the cumulative emission factor.

To calculate particulate emissions, add the condensable emission factor and one of the two filterable emission factors to obtain the cumulative PM emission factor, and use that factor to determine all particulate emissions. Report the emission rate as follows:

- PM (contaminant code *10000*);
- PM_{10} (contaminant code *20000*); and
- $PM_{2.5}$ (contaminant code *39999*).

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

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 $PM_{2.5}$ (filterable) and the PM (condensable) factors, or

0.01941 lb/MMBtu. If the engine consumed 35,000 MMBtu of fuel during the year, then its particulate emissions would be:

$$PM = 0.0194 \ \frac{lb}{MMBtu} \times 35{,}000 \ \frac{MMBtu}{year} \times \frac{1 \ ton}{2000 \ lb} = 0.3395 \ tons/year$$

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

Table A-1. Reporting Particulate Emissions

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

VOC Emissions

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

Stack Test Data

When using stack test data to determine VOC emissions, 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 total organic carbon (TOC) emission factor*. The determination methodology must be reported as “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 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 must be calculated and the determination methodology must be reported as “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 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 reported as “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 composition of emissions, 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, the most recent VOC emission factor must be used and the determination methodology must be reported as “A.”

Speciation

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

Any source-specific information about the VOC emissions composition must be used to speciate the emissions. Submit the data and related information with the EI.

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. 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—u* (contaminant code 50001).

Note: Some vendor-provided VOC emission factors exclude formaldehyde. In those cases, the exclusion 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.

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

Where:

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

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

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

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

$E_{total\ VOC}$ = the tpy total VOC determined using stack test data or vendor data

If stack test data or vendor data are used to determine total VOC emissions, the determination methodology must be reported as “S” for “scientifically calculated”; the *VOC—u* emissions must be reported as “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 reported as “A.”

Example: Using a vendor-supplied VOC emission factor, the 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 emissions composition significantly. Therefore, the emission factors in AP-42 must be used to speciate the VOC emissions.

In AP-42, formaldehyde is one of the “Trace Organic Compounds” that has 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:

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

The engine's total VOC emissions should be multiplied by this ratio to determine the formaldehyde emissions:

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

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 Internal Combustion VOC Emissions

Contaminant Code	Contaminant	Annual Emissions	Determination Methodology
50001	VOC—unclassified	0.2240 ton	V
51620	acetaldehyde	0.7935 ton	S
51640	acrolein	0.4879 ton	S
51680	formaldehyde	5.0115 tons	S
51530	methanol	0.2373 ton	S
56150	methylcyclohexane	0.1167 ton	S
56600	*n*-hexane	0.1054 ton	S
56750	*n*-pentane	0.2468 ton	S
56775	propane	3.9769 ton	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 facility operated 24 hours each day. For sources that run regularly throughout the ozone season, divide the total emissions from May, June, July, August, and September by the number of days the facility is operated. For sources that run intermittently during the ozone season (e.g., emergency generators that operate a few hours every couple of weeks), use a straight conversion of the annual tons per year to pounds per day.

External Combustion Sources Burning Natural Gas

Expected Contaminants

Reported boiler emissions should include all of the following:

- PM (contaminant code *10000*)
- PM_{10} (contaminant code *20000*)
- $PM_{2.5}$ (contaminant code *39999*)
- VOCs (contaminant codes *50001* through *59998*)
- NO_x (contaminant code *70400*)
- SO_2 (contaminant code *70510*)
- CO (contaminant code *90300*)

Emissions Determination Methodologies

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

- D (continuous monitoring system)
- F (predictive monitoring system)
- M (measured—stack test data)
- Q (portable analyzer test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- 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 reported as measured (“M”). If the stack test results from an identical unit are used to determine the emissions, the emissions determination methodology must be reported as 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 sulfur dioxide as a product of combustion. CEMS, PEMS, and stack test data is the preferred order when identifying the determination methodology for SO_2 emissions. In lieu of using a vendor or AP-42 SO_2 emission factor, the SO_2 emissions must be determined using a material balance based upon the combusted fuel's sulfur content.

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. 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*).

VOC Emissions

VOC emissions may be determined using stack test data, AP-42 emission factors, or both. Each methodology is discussed separately in the following sections, and is followed by instructions on speciation.

Stack Test Data

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

If the stack test measured total hydrocarbons, the VOC emissions will need to 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 reported as "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 reported as "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 reported as "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 or not the VOC emissions from a source need to be speciated, consult Chapter 4.

Any source-specific information about the composition of VOC emissions for a source must be used to speciate the emissions. Submit the data and related information with the EI.

If source-specific information about the composition of the VOCs does not exist, the VOC emissions must be speciated using the AP-42 factors for the speciated organic compounds formaldehyde, toluene, and benzene. 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 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 reported as "S" for 'scientifically calculated'; the *VOC—u* emissions must be reported as "M." If AP-42 emission factors are used to determine total VOC emissions, the determination methodology must be reported as "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 VOCs exists. Inlet gas analysis was performed, but because complex oxidation reactions occur in the combustion chamber that alter the emissions composition 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 that is 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:

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

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

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

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

Table A-3. Reporting External Combustion VOC Emissions

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

Combined-Cycle Turbines with Heat Recovery Steam Generators

Structure

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

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

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

If the turbine can vent to a separate emission point (that is **not** the emission point shared with the associated unit) when it operates independently, 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 should include all of the following:

- PM (contaminant code *10000*)
- PM_{10} (contaminant code *20000*)
- $PM_{2.5}$ (contaminant code *39999*)
- VOCs (contaminant codes *50001* through *59998*)
- NO_x (contaminant code *70400*)
- SO_2 (contaminant code *70510*)
- CO (contaminant code *90300*)
- NH_3 (contaminant code *70050*)

Emissions Determination Methodologies

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

- D (continuous monitoring system)
- F (predictive monitoring system)
- M (measured—stack test data)
- Q (portable analyzer test data)
- V (vendor-supplied emission factors)
- A (AP-42 factors)
- 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 reported as measured ("M"). If the stack test results from an identical unit are used to determine the emissions, the determination methodology must be reported as 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 is used to determine emissions from a combined-cycle turbine equipped with a duct burner, two data sets should 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.

Air-Curtain Incinerators

Structure

Air-curtain incinerators forcefully project a curtain of air across a pit where open burning occurs. The air curtain is intended to increase combustion efficiency and reduce smoke and PM emissions. Under-fire air is also used to increase combustion efficiency. Air-curtain incinerators can be built either above or below ground. Some units have mesh screens to contain larger particles of fly ash, but other add-on pollution controls are normally not present. The primary use of air-curtain incinerators is in the disposal of wood wastes, yard wastes, and clean lumber; however, some of these incinerators are used to burn municipal solid waste or construction debris.

An air-curtain incinerator must be reported in the EI by representing the pit or refractory-wall chamber as the facility and as the fugitive emission point. If a diesel blower is used to generate the air, the diesel blower needs to be represented in the EI if it emitted 1 ton or more of any regulated pollutant as discussed in Chapter 3.

Expected Contaminants

The reported emissions should include all of the following:

- PM (contaminant code *10000*)
- PM_{10} (contaminant code *20000*)
- $PM_{2.5}$ (contaminant code *39999*)
- VOCs (contaminant codes *50001* through *59998*)
- NO_x (contaminant code *70400*)
- SO_2 (contaminant code *70510*)
- CO (contaminant code *90300*)

Emissions Determination Methodologies

The appropriate emission determination methodologies for air-curtain incinerators are, in order of preference:

- V (vendor-supplied emission factors)
- A (AP-42 factors)
- S (scientifically calculated)

- E (estimated)

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

TECHNICAL SUPPLEMENT 2: COOLING TOWERS

Technical Disclaimer

This technical supplement is intended to help determine and correctly report cooling tower emissions. 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 they generate emissions, how they 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. The EAS greatly appreciates any data, information, or feedback that may improve this supplement.

The methods represented are intended as an aid in calculating emissions; alternate methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data. Additional guidance regarding the acceptability of a given emissions determination method is available from the EAS at 512-239-1773.

Introduction

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.

Definitions

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

Cooling Tower Structure

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

To add a cooling tower in VOC service to the EI, use the Facility Information for Cooling Tower form. For cooling towers already in the EI, ensure that the appropriate facilities have a “cooling tower” group

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

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

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

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

Cooling Tower Source Classification Codes

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

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

Particulate Matter

Particulate emissions result from the presence of minerals or any dissolved or suspended solids in the cooling water. Air flowing through the tower can entrain water droplets and carry them out of the cooling tower in a

process referred to as *drift*. Once these drift droplets leave the tower and evaporate, they deposit dissolved or suspended solids as fine particulate matter (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.

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 to 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. This may result in many tons of 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 reported as “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 reported as “A.”

Inorganic Compounds

Very little research has focused on inorganic compound emissions from cooling towers. Emissions resulting from water additives may be determined based on the additive’s chemical characteristics, the amount of additive used, the volume of cooling water, and a scientifically based assumption about the percentage of additive stripped from the cooling water at the tower. The determination methodology must be reported as “E” for ‘estimated.’

Volatile Organic Compounds

Emissions Determination Methodologies: Order of Preference

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

- emissions data from a HRVOC monitoring system required by 30 TAC 115.764 (code as “H”);
- emissions data from a TCEQ-approved air-stripping method (code as “M”);
- emissions data from an approved monitoring and control program plan, other than an air-stripping method, on file with the TCEQ (code as “B”);
- emissions data from an unapproved monitoring and control program (code as “E”);
- the AP-42 **uncontrolled** factor.

Emissions based on HRVOC monitoring systems required by 30 TAC 115.764 must be coded as “H.” However, emissions determined using monitoring systems not required by 30 TAC 115.764 must be reported as “B.”

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

Emissions Determination Methodologies

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

If VOC emissions are determined using an emission factor from Section 5.1 of AP-42, the uncontrolled emission factor (6 lb/MMgal) must be used. According to AP-42, use of the controlled 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 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 in monitoring hydrocarbons, the “uncontrolled” VOC emission factor must be used. If the emissions are determined in this manner, the determination methodology must be reported as “A.”

Emissions determined based on measurements from an air-stripping method as outlined in the *TCEQ Sampling Procedures Manual*, Appendix P, are preferred. This document is available at <www.tceq.texas.gov/assets/public/implementation/air/sip/miscdocs/mgf/115/AppP.pdf >. When using such data to determine emissions, assume that VOCs were present at the measured concentration for the entire period between samples. If analytical test methods indicate that VOC measurements are below the minimum detection limit, 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. 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 reported as "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 and must not be used. 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 the TCEQ. If so, the determination methodology must be reported as "B" for 'material balance.' If not, the determination methodology must be reported as "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 should be reported as described in the preceding paragraph.

Note that the information from devices such as lower explosive limit detectors, chlorine residual measurements, and total organic carbon measurements do not qualify as adequate monitoring or control technology; 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, determine the emission rates in pounds per day during May, June, July, August, and September.

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; and
- emission rates calculated from measured data.

Issues of Special Concern

What if I share a cooling tower with another company?

Emissions must be reported by the regulated entity who owns 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.

Must I report particulate matter emissions?

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

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

Yes. The cooling tower's emission point must be shown as a stack. For more information, see "Cooling Tower Structure" earlier in this supplement, as well as instructions for completing the Emission Point Information: Stack Profile form in *2011 Emissions Inventory Forms and Instructions* (TCEQ publication number RG-360B/11).

What does the cooling tower characteristic "HRVOC Service?" mean?

Regardless of the county location of the regulated entity, if the cooling water cools any process equipment or process fluid stream containing over 5 percent by weight of aggregate highly reactive volatile organic compounds (HRVOCs—ethylene, propylene, all isomers of butene, and 1,3-butadiene), 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 EIQ?

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

References

Compilation of Air Pollutant Emission Factors. 1995. Vol. I: *Stationary Point and Area Sources.* 5th ed. AP-42. Research Triangle Park, NC: U.S. Environmental Protection Agency. Available online at: <www.epa.gov/ttn/chief/ap42/index.html>. Accessed September 28, 2011.

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

Technical Disclaimer

This technical supplement is intended to help determine and correctly report fugitive 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 they generate emissions, how they 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. The EAS greatly appreciates any data, information, or feedback that may improve this supplement.

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

Introduction

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

Please note that structural representation of 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."

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

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.

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

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.

The EAS 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 emission determinations than using average emission factors with LDAR reduction credits.

Since all monitored sources should 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 Inspection" later in this supplement.

Emissions Determination Methodologies: Order of Preference

The appropriate methodologies for determining 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 Inspection" later in this supplement.

Emission Factors

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

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, TCEQ rule, or commission order requires the retention of screening value data.

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

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

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

- Before using the screening value in the appropriate correlation equation, determine the screened stream's response factor and, if necessary, adjust the screening value according to the guidance in *Protocol for Equipment Leak Emission Estimates*.
- For each component with a nonzero and nonpegged screening value, enter the screening value into the applicable correlation equation to determine a mass emission rate. Sum the individual mass emission rates for each component to determine a total leak rate. Note that each individual screening value must be entered into the correlation

equation to predict a component's leak rate. Averaged screening values 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 indicated (i.e., the instrument will not quantify the screening value between 10,000 ppm and 100,000 ppm), then use the default 100,000 ppm pegged leak rate factor—**not** the default 10,000 ppm rate factor.

This information is summarized in Table A-4.

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 last monitored. An acceptable engineering estimate would be that the component was leaking at the measured concentration for half the monitoring period, plus the time needed to repair the component. The EAS must approve any other method of determining leak durations.

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

Table A-4. Determining Emissions Using Correlation Equations

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

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

Unit-Specific Correlation Equations

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

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

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

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

If no monitoring or screening data exist for AVO-monitored components, then average 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.

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

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

Determining Emissions from Unmonitored Components

Emissions Determination Requirements

Emissions from monitored components must be determined using actual monitoring data. However, for unmonitored components, average emission factors may still be used to quantify emissions.

Quantifying Emissions Using Average Factors

Average emission factors are divided into four categories:

- SOCMI,
- oil and gas production,
- refinery, and
- petroleum marketing terminals.

Within each category, factors vary depending upon specific component type (connectors, valves, pumps, etc.) and material in service (light liquid, heavy liquid, gas-vapor, or water–light liquid). For components in liquid service, 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. Therefore 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 Web site at <www.epa.gov/ttnchie1/publications.html>.

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 percent and 85 percent ethylene. For streams containing more than 85 percent ethylene, use the "SOCMI with ethylene" emission factors. For streams containing less than 11 percent 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 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 percent and 99 percent).

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. Do not use these emission factors to determine the fugitive emissions 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, emission reductions are not typically claimed for these components. However, if a weekly physical inspection program is in place, a 30 percent emissions reduction credit applied to average 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 chlorine (Cl_2), ammonia (NH_3), hydrogen sulfide (H_2S), hydrogen fluoride (HF), and hydrogen cyanide (HCN) would be to develop unit-specific correlation equations, as described in Section 2.3.4 of *Protocol for Equipment Leak Emission Estimates*. To develop these equations, it is necessary to use a monitoring instrument that could detect the inorganic compounds in question.

Note that it also would be necessary to use a monitoring instrument that could detect the inorganic compounds in question to apply either EPA-developed correlation equations or screening range 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 presently the best data 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, the TCEQ has identified appropriate substitute emission factors based on component, leak potential, and leak mechanism similarity. These emission factors are listed in Table A-5.

The component-specific emission factors for pressurized railcar loading operations threaded connections and quick-connect couplers are listed in Table A-5 and 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.

Table A-5. Appropriate Substitute Factors for Nontraditional Components

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

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 percent control may be assumed if either of the following conditions is met.

- relief-valve vents are routed to a properly operating control device, or
- relief valves are equipped with a rupture disc and pressure-sensing device (between the valve and 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 percent control credit:

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

***Valves*:** Take a 100 percent control credit for the following:

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

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

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

***Double Mechanical Seals*:** Take a 75 percent control credit for any component employing double mechanical seals.

Speciation

Use current gas or liquid process stream analysis (or both) to speciate 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 emissions inventory, see Chapter 4.

Supporting Documentation

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

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

Issues of Special Concern

May I put the whole plant's fugitive emissions from piping components under one facility and emissions point?

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

There are two main items to consider when breaking fugitive areas into multiple facilities. First, if different process areas within a plant follow different leak detection and repair programs, each area 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. Consider, for instance, 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)?

Yes. The emissions from all 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 typically be used and no reduction credits from monitoring may be applied.

I have a unit that was shut down part of the year. Must I determine 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 should be determined for the entire year (8,760 hours) unless the unit's lines were purged during the downtime.

I want to use correlation equations to determine 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 a crude oil storage and loading facility. 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. The bulk terminal average emission factors were developed specifically for gasoline and gasoline product loading operations. For crude oil storage and loading, the oil and gas production emission factors would be more appropriate.

I have an 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 the TCEQ?

Review the PDF document *Emissions Factors for Equipment Leak Fugitive Components*, available on the EAS's Web page at <www.tceq.texas.gov/goto/ieas>.

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

In the case of "skip period" provisions in a permit, it is permissible to use data from the last monitoring period in the correlation equations. For future leaking components, 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 most conservative estimate would be to assume any leaking component will do so for an entire year. If a different method to determine the emissions is used, document valid engineering assumptions to support the calculations.

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 a monitoring program are available.

If a monitoring program does not retain screening value data, emissions must be determined using the best available method. If the screening range emission factors are used to determine the emissions, supply valid engineering assumptions to support the calculations.

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

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

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

The most representative emission factors 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.

References

Texas Commission on Environmental Quality. 2005. *Emissions Factors for Equipment Leak Fugitive Components.* TCEQ Industrial Emissions Assessment Section draft document. Available online at: <www.tceq.texas.gov/goto/ieas> . Accessed September 28, 2011.

U.S. Environmental Protection Agency. 1995. *Protocol for Equipment Leak Emission Estimates.* EPA-453/R-95-017. Available online at: <www.epa.gov/ttnchie1/publications.html>. Accessed September 28, 2011.

———. 1996. *Preferred and Alternative Methods for Estimating Air Emissions from Equipment Leaks.* Vol. 2, Emissions Inventory Improvement Program Document Series, chapter 4. Available online at: <www.epa.gov/ttn/chief/eiip/techreport/volume02/index.html>. Accessed September 28, 2011.

Fugitive Data Form

TCEQ Emissions Inventory Year_____

TCEQ Air Account Number:	**FIN:**

COMPONENT COUNTS

	Service	Unmonitored	Monitored				
		Number of components	Number of components	Leak definition (ppm)	Number of leakers	Number pegged	Monitoring frequency
Valves	Gas/Vapor						
	Light liquid						
	Heavy liquid						
	H_2O/Light oil						
Pumps	Gas/Vapor						
	Light liquid						
	Heavy liquid						
	H_2O/Light oil						
Flanges	Gas/Vapor						
	Light liquid						
	Heavy liquid						
	H_2O/Light oil						
Open-Ended Lines	Gas/Vapor						
	Light liquid						
	Heavy liquid						
	H_2O/Light oil						
Connectors	Gas/Vapor						
	Light liquid						
	Heavy liquid						
	H_2O/Light oil						
Relief Valves	Gas/Vapor						
	Light liquid						
	Heavy liquid						
	H_2O/Light oil						
Compressor Seals	Gas/Vapor						
	Light liquid						
	Heavy liquid						
	H_2O/Light oil						
Other	Gas/Vapor						
	Light liquid						
	Heavy liquid						
	H_2O/Light oil						

VOC PERCENTAGES	**MONITORING EQUIPMENT DATA**
Gas/vapor stream: _____ %	Pegged Component Screening Value: _____ppm
Light liquid stream: _____ %	Calibration Range: _____min _____max

EMISSIONS DETERMINATION METHODOLOGY OR LDAR PROGRAM USED

☐ Oil and Gas Factors ☐ SOCMI Average Factors ☐ SOCMI without Ethylene Factors
☐ Refinery Factors ☐ SOCMI with Ethylene Factors ☐ Correlation Equations
☐ Petroleum Marketing Terminal Factors ☐ Other (explain): _____

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

Instructions for Completing the Fugitive Data Form

Component Counts

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

Unmonitored: Number of Components

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

Monitored: Number of Components

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

Leak Definition

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

Number of Leakers

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

Number Pegged

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

Monitoring Frequency

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

VOC Percentages

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

Monitoring Equipment Data

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

Emissions Determination Methodology

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

LDAR Program Used

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

TECHNICAL SUPPLEMENT 4: FLARES

Technical Disclaimer

This technical supplement is intended to help determine and correctly report flare emissions. 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 they generate emissions, how they 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. The EAS greatly appreciates any data, information, or feedback that may improve this supplement.

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

Introduction

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.

Definitions

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

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

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

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

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 with a very limited range of assist rates to achieve the assumed DRE of 98 percent or greater. This project also demonstrated that operating a flare in compliance with 40 CFR 60.18 does not ensure that the flare will achieve 98 percent DRE. Flare assist rates and other operating information should be reviewed and assessed to determine whether a flare may be operating at assist ranges that do not achieve the 98 percent DRE, in which case the flare DRE must be reduced accordingly when determining and reporting flare emissions in the EI. The final report and additional project information are at <www.tceq.texas.gov/goto/2010-flare-study>.

Expected Emissions

Flare emissions will include, at a minimum, nitrogen oxides (NO_x), carbon monoxide (CO), and uncombusted flared gas compounds. In addition, if the flared gas contains sulfur-bearing compounds, emissions will also include hydrogen sulfide (H_2S) and sulfur dioxide (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.

Compounds from Uncombusted Flared Gas

The flare's destruction efficiency determines what fraction of the flared gas remains uncombusted. The uncombusted flared gas compounds are generally volatile organic compounds, but may also include H_2S, CO, ammonia, and other organic and inorganic compounds present in the flared gas.

Emissions Determination

Generally, flare emissions determinations must be consistent with the TCEQ Air Permits technical guide for flares and vapor oxidizers, available at <www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/emiss_calc_flares.pdf>. However, if actual flare operation deviates from the specific operating conditions assumed in permit guidance, then it may not be appropriate to use this guidance to determine emissions. Exceptions for actual operation are identified in the following sections.

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

Flared Gas Flow Rate and Composition

To 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 highly reactive volatile organic compounds, flow rate and composition data required by 30 TAC 115.725–26 must be used to determine emissions for any portions of 2011 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 should be compared to the flare's actual operating conditions during the inventory year to determine whether the test accurately represents the flare's performance. If test conditions do not accurately model flare operation, then engineering determinations based on detailed process evaluation may provide the best data.

NO_x and CO Emissions

To calculate NO_x and CO emissions, 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 from TCEQ Air Permits guidance, to determine NO_x and CO emissions for each time segment. Since the calculated net heating value of the gas and the assist gas type will determine the appropriate emission factors, carefully select the correct factors for each flare from Table A-6.

Table A-6. TCEQ Air Permits Flare Emission Factors

Contaminant	Assist Type	Waste Gas Stream Net Heating Value[a,b]	Emission Factor
NO_x	Steam	High Btu	0.0485 lb/MMBtu
		Low Btu	0.068 lb/MMBtu
	Air or Unassisted	High Btu	0.138 lb/MMBtu
		Low Btu	0.0641 lb/MMBtu
CO	Steam	High Btu	0.3503 lb/MMBtu
		Low Btu	0.3465 lb/MMBtu
	Air or Unassisted	High Btu	0.2755 lb/MMBtu
		Low Btu	0.5496 lb/MMBtu

[a] High Btu: > 1000 Btu/scf

[b] Low Btu: 192–1000 Btu/scf

Calculate emissions using the most accurate data 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 data's source, the determination methodology for NO_x and CO emissions must be reported as "A" for 'TCEQ-approved factor.'

For flares subject to the HRVOC regulations in Chapter 115, Subchapter H, use the net heating value data required by 30 TAC 115.725 and 115.726 to determine NO_x and CO emissions for any portions of 2011 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 flame stability, operating conditions, flare tip size and design, the specific compounds being combusted, and gas composition. The EPA has determined operating limits (see 40 CFR 60.18), that result in stable operation of flare flames. Therefore, emission determinations may vary depending on whether the criteria of 40 CFR 60.18 are satisfied. Chapter 115 HRVOC regulations address flare operational requirements in regard to 40 CFR 60.18. For

flares subject to HRVOC regulations, use the appropriate destruction efficiencies specified in 30 TAC 115.725.

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

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

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

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

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

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

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

Determining Emissions

When flow rate and composition data are available from continuous monitoring systems, they should be used to determine the uncombusted emissions. Otherwise process knowledge and engineering calculations should be used to determine emissions.

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

Waste Stream Composition	Destruction or Removal Efficiency
VOC, C_1–C_3[a]	99%
VOC, > C_3	98%
H_2S	98%

[a] 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.

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 reported as "M" (for 'measured data') or "D" (for 'continuous emissions monitoring systems'). The determination methodology for uncombusted flared gas emissions must be reported as "H" (for 'HRVOC monitoring') when the actual flow rate and composition of the gas routed to the flare are obtained through a continuous monitoring system required by 30 TAC 115.725–26. When the actual flow rate and composition of the gas routed to the flare are obtained through a continuous monitoring system not required by 30 TAC 115.725–26, the determination methodology must be reported as "B" (for 'material balance') instead of "H." 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 reported as "S" (for 'scientific calculation').

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 percent butane and 20 percent H_2S, is burned in a flare that satisfies 40 CFR 60.18. The hourly uncombusted flared gas emissions would be 1.6 pounds of butane and 0.4 pounds of H_2S. In addition, the flare creates SO_2 from the H_2S. Determine the SO_2 emissions as follows:

$$20\frac{\text{lb } H_2S}{\text{hour}} \times 0.98 \times \frac{\text{lb-mole}}{34 \text{ lb } H_2S} \times 64\frac{\text{lb } SO_2}{\text{lb-mole}} = 36.9\frac{\text{lb } SO_2}{\text{hr}}$$

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

The determination methodology for SO_2 emissions must be reported as "B" for 'material balance.'

Annual and Ozone Season Rates

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

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

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

Speciation of Uncombusted Flared Gas Compounds

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

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

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

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

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

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

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

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

Supporting Documentation

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

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

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

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

Reporting Emissions from a Shared Flare

In some cases, process streams are sent off-site to a flare owned by a different regulated entity. The applicable structure, including the flare emission point and abatement device, must be included in the emissions inventory where the process equipment is located and the emissions are generated. However, the path emissions will be zero because the owner of the flare is required to report the combustion emissions generated by the flare and the non-combusted contaminants. A path comment should be included on the path emissions page identifying the shared flare's EPN and its air account number. Please call the EAS for additional guidance.

References

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

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

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

TECHNICAL SUPPLEMENT 5: MARINE FACILITIES

Technical Disclaimer

This technical supplement is intended to help determine and correctly 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 they generate emissions, how they 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. The EAS greatly appreciates any data, information, or feedback that may improve this supplement.

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

Introduction

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 annual routine EI. The owner or operator of the onshore facilities does not own or operate the marine vessel itself, but does operate most of the activities resulting in vessel emissions while the vessel is docked. Therefore, the owner or operator of the onshore facilities is responsible for reporting dock and dockside marine vessel emissions in the annual EI. 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 of its associated equipment (e.g., conveying lines, piping, valves, pumps, hoses, and blowers); and
- dockside marine vessel loading and unloading, cleaning and degassing, and abrasive blasting and painting. A marine vessel is considered

dockside if it is in any way connected to the shore. This includes vessels connected to the dock, connected to a vessel that is connected to the dock, or connected directly to the land.

Because onshore process units and equipment are addressed elsewhere in *2011 Emissions Inventory Guidelines*, this technical supplement addresses only dock and dockside marine vessel emissions.

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

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

Expected Emissions

Emissions associated with the dock and the dockside marine vessels, except for emissions from marine vessel engines, 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; and
- fugitive VOCs from equipment leak fugitives.

Dockside marine vessel emissions may include:

- VOCs from loading or unloading liquid bulk materials,
- VOCs from loading or unloading 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, and
- particulate matter and VOCs from abrasive blasting and surface coating.

Determining Emissions

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

discussed in the following section, giving background information, specific guidance on calculations, and references to other specific documents relating to air permits that may also be helpful. The following sections address the key points related to the 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 reported as "A." The fugitive emissions must be determined for the entire period when VOCs were present in the dock piping.

Determine vessel emissions from liquid material loading and unloading using the techniques in the TCEQ air permits draft guide *Loading Operations*. The determination methodology must be reported as "A."

If loading emissions are collected and abated, some emissions will escape collection and, additionally, some collected emissions will escape destruction. The Air Permits document *Loading Operations* gives guidance on determining uncollected emissions and the determination methodology must be reported as "A." The collected emissions that escape destruction at the abatement device must be determined using an appropriate destruction efficiency. The determination methodology must be reported as "B."

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

After unloading operations, the liquid left in sumps can evaporate over time, resulting in emissions. Those emissions must be reported with the fugitive emissions from piping components using a material balance approach.

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 reported as "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 reported as "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 the Air Permits document *Dockside Vessel Emissions*.

If a material type is explicitly addressed in air permits guidance, the determination methodology must be reported as "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. *Dockside Vessel Emissions* explains the emission calculation method for degassing,

deheeling, and cleaning. It also references the Air Permits document for determining uncontrolled vessel degassing and cleaning emissions, *Tank Truck and Rail Car Cleaning*. Since these techniques use the ideal gas law, the determination methodology must be reported as "S" for 'scientifically calculated.'

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

If emissions are determined using saturation test results, the determination methodology must be reported as "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. Painting results in emissions of the VOCs that volatilize from the paint as it cures and particulate matter resulting from paint overspray. Determine these emissions using the Air Permits draft documents *Abrasive Blast Cleaning* and *Surface Coating Operations*.

Since particulate emissions from abrasive blasting are calculated based on the abrasive material usage and the emission factors in the abrasive blast cleaning guidance, the determination methodology must be reported as "A."

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 reported as "B" for 'material balance.'

Annual and Ozone Season Emission Rates

Determine actual annual emissions following the guidance in this supplement. If the same material is handled throughout the year, then

use annual material throughput and the guidance in this supplement to determine emissions. If materials vary, determine emissions from each individual operation using the guidance in this supplement and the following information:

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

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

To obtain ozone season emission rates for each facility/emissions point path, first determine emissions (in pounds) that the facility generated and emitted during the months of May, June, July, August, and September. Next, divide the resulting emissions rates by the number of days that the facility operated during the months of May, June, July, August, and September. Report the resulting rates as the ozone season pound per day emissions rates for that facility/emissions point path. Note that the number of days that a facility can operate during the ozone season cannot exceed 153. For more information, consult “Reported Emissions”: “Ozone Season Emissions” in Chapter 4.

VOC and Particulate Speciation

Speciation should follow the *2011 Emissions Inventory Guidelines*. In general:

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

that volatilize from the paint as it cures and particulate matter resulting from paint overspray.

Supporting Documentation

To allow for the verification of reported emissions, include representative sample calculations with 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 emission determinations;
- material composition data, if the associated emissions (total or speciated) depend upon them; and
- all other information necessary to determine emissions.

Issues of Special Concern

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

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

Since I don't own the marine vessel, 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 should be reported by the regulated entity that owns the marine loading facility. Please call 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 should be reported by the dock owner or operator.

References

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

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TECHNICAL SUPPLEMENT 6: ABOVEGROUND LIQUID STORAGE TANKS

Technical Disclaimer

This technical supplement is intended to help determine and correctly 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 they generate emissions, how they 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. The EAS greatly appreciates any data, information, or feedback that may improve this supplement.

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

Introduction

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 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.

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; and
- special considerations in determining emissions for certain situations involving storage tanks.

Definitions

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

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

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

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

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

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

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

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

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

Expected Emissions

Storage tank emissions can include VOC, HAP, toxic, and inorganic emissions from flashing, landing, breathing, and working losses. Storage

tank emissions may also include emissions from degassing, cleaning, and defective tank seals and fittings. All storage tank emissions, whether routine or not, must be quantified and reported in the EI.

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 current edition of AP-42, Chapter 7.

The current version of the TANKS program, the EPA’s free software that calculates emissions from fixed-roof and floating-roof storage tanks, can be used to determine emissions for certain types of storage tanks in accordance with this document. The current version is available at <www.epa.gov/ttn/chief/software/tanks/index.html>.

Annual and Ozone Season Emissions

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

For tanks with roofs that store products at ambient temperatures, the current TANKS program can be used to determine annual emissions following the detailed guidance below. The EAS requests the "summary" or "detail" report types from the TANKS program to be included with the sample calculations. These reports include sufficient information to verify the emissions.

For floating- and fixed-roof storage tanks that store products at ambient temperature, annual emissions must be determined by generating a TANKS report and choosing the "monthly" time basis and selecting all 12 months of the year. This is more representative than choosing the "annual" time basis because it takes into account the monthly variations in meteorological data.

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 with roofs that store products at ambient temperature will need to be determined using the data for increased vapor pressure in the appropriate AP-42, Chapter 7, equations. Using those equations, or a software program that uses the equations accurately, is the preferred method for determining ozone season emissions. The EAS is investigating the accuracy of ozone season emissions calculated using the current version of TANKS. See "Key Considerations when Using TANKS 4.09D" below.

For heated storage tanks or tanks storing warmer-than-ambient stock (hot product), the current version of TANKS cannot determine annual or ozone season emissions accurately and cannot be used. Instead, annual and ozone season emissions for these tanks 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 "Special Considerations when Quantifying Emissions" below.

Obtaining Accurate Emissions Determinations from TANKS

Accurate data input is essential to obtaining valid emissions determinations when using the TANKS program. The program has default settings for many input variables, including floating-roof tank fittings, and speciation profiles for chemical mixtures. The default settings can result in inaccurate or invalid emissions determinations and the EAS will no longer accept their use. Therefore, the user must use site-specific data 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 the TANKS program's chemical database; use these new chemical data to generate emissions reports. Default chemicals available in TANKS must not be used unless the default vapor pressure and composition of the product are representative of the stored liquid's vapor pressure and composition. For example, the crude oil default in TANKS (RVP 5) does not typically represent the range of crude oils stored in tanks.

Similarly, detailed information on the number and physical characteristics of the tank fittings must be used in the "detailed" fittings selection in the "Physical Characteristics" portion of TANKS. The "typical" fittings selection will no longer be accepted for emission determinations.

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

Key Considerations when Using TANKS 4.09D

In 2010, the EPA released version 2.0 of its *Emission Estimation Protocol for Petroleum Refineries*. Section 3 of that EPA document contains the following guidance for obtaining accurate emissions determinations using TANKS 4.09D:

- 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 characteristics of each tank. Default settings must not be used.

- Tanks must be modeled, and emissions determined, using monthly parameters, including average monthly measured tank-liquid temperatures. In spite of selecting the monthly calculation option, the **annual** average liquid temperature is used for the calculations; therefore, TANKS will not sufficiently account for monthly emissions

variations. TANKS 4.09D is not an acceptable method for calculating annual emissions for tanks with seasonal throughputs that vary significantly. For more information, see “Special Considerations When Quantifying Emissions” below.

- Emissions from floating-roof tanks containing liquids that are warmer than ambient temperature are underestimated using TANKS. In this case, AP-42, Chapter 7, equations must be used directly. See “Heated Tanks” and “Tanks Storing Hot Products” under “Special Considerations When Quantifying Emissions” below.

- TANKS does not determine emissions from tank roof landings. See “Determining Emissions from Landing Losses” below.

Obtaining Accurate Emissions Determinations from the E&P TANK Program

Accurate data input is essential to obtaining valid emissions determinations when using the E&P TANK program. The program has default settings for many input variables, including a geographic-database option for crude oil. Using the default settings can result in inaccurate or invalid emissions determinations. Therefore, the user must use site-specific data to obtain the greatest accuracy. Because the E&P TANK program gives only an annual emissions amount, use caution when determining ozone season emissions. One option for determining ozone season emissions is to enter the monthly throughputs for only the ozone season (May, June, July, August, and September), while zeroing out the throughputs for the other months. The resulting emissions will then be distributed throughout the 153-day ozone season.

Determining Emissions from Flashing Losses

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

From a process perspective, flash emissions from storage tanks generally occur when pressurized liquids are sent to storage at a lower pressure. Specifically, flash emissions from storage tanks can occur at wellhead sites, tank batteries, compressor stations, gas plants, and "pigged" gas lines when pressurized gas and liquids are sent to atmospheric storage vessels. These flash emissions are vented to the atmosphere through a tank's pressure relief valve, hatch, or other openings, or alternatively may be routed to a control device. 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 more preferred method may not necessarily be applicable to a process based upon its specific parameters. Specific constraints for each method are explained in detail in the following sections. If the EAS determines that a determination method for a site-specific process is unfounded, then the EAS may require that the emissions determinations be recalculated using a more appropriate method.

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

Black Oil Systems

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

- direct measurement of emissions (code as "M");
- process simulator models (code as "S");

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

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

Gas Condensate Systems

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

- direct measurement of emissions (code as “M”)
- process simulator models (code as “S”)
- the E&P TANK program (code as “O”)
- the gas/oil ratio (GOR) method (code as “B”)

Note: For EI purposes, the Environmental Consultants and Research (EC/R) equation is no longer an acceptable method to determine flash emissions for gas condensate systems.

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, HYSIS, WINSIM, PROSIM, etc.), each employing similar basic principles. While process simulators are primarily used in process design, these

models can also determine and speciate flash emissions using the Peng-Robinson equation of state option. Although other equations of state are available in the model, the Peng-Robinson equation best suits flash emissions determinations.

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

E&P Tank Program

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

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 Reid vapor pressure (RVP),
- sales oil production rate, and
- 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 gas/oil ratio (GOR);
- laboratory analysis of hydrocarbon liquid produced (to obtain API gravity, RVP, and C_7–C_{10+} characteristics); and
- 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. GOR and measurement data from similar sites will not be accepted. Additionally, the Geographical Database does not contain site-specific compositions and will not be accepted for Known Separator Stream Information. When the AP-42 model 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 produce more precise emissions determinations. 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.

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

Vasquez-Beggs Correlation Equation

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

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

The method requires eight input variables:

- stock-tank API gravity;
- separator pressure;

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

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

These equations to determine flash emissions are available in a Microsoft Excel spreadsheet originally developed by the Oklahoma Department of Environmental Quality, and can be downloaded at <www.deq.state.ok.us/AQDnew/resources/Calculations11.xls>. Please note that while this spreadsheet indicates an API gravity between 16 and 58 may be used, the 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.

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, making it inapplicable for determining flash emissions.

Gas/Oil Ratio (GOR) Method

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

The flash emissions are then determined by multiplying the GOR by the throughput of the tank. An extended hydrocarbon analysis of the flash gas

from the sample should also be conducted to identify the concentrations of the individual components of the tank's flash emissions. When such sampling is conducted, the GOR method is appropriate for either black oil or gas condensate systems.

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 Landing Losses

Introduction

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

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

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

Neither the EPA's TANKS program nor any other storage-tank emissions software currently determines landing loss emissions as part of routine program operation. However, landing loss emissions may be determined using the guidance outlined in American Petroleum Institute Technical Report 2567, "Evaporative Loss from Storage Tank Floating Roof Landings" (API TR 2567). EPA has also incorporated this API guidance

into a 2009 version of Chapter 7, "Liquid Storage Tanks," available at <www.epa.gov/ttn/chief/ap42/>.

The emissions determination method detailed in AP-42, Chapter 7, 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 categories for emissions determination purposes:

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

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

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

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

Required Data for Determining Landing Loss Emissions

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

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

Reporting Landing Loss Emissions within the Inventory

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, revise annual and ozone season emissions accordingly. For specific procedural guidance on reporting emissions in the EI, please consult Chapter 4.

Determining Emissions from Degassing and Cleaning

Emissions from tank degassing and cleaning operations must be determined using site-specific knowledge and material balance equations. The liquid-heel method described in Section 11, "Startup and Shutdown," of the EPA's *Emission Estimation Protocol for Petroleum Refineries* <www.epa.gov/ttn/chief/efpac/protocol/index.html> is also acceptable.

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

Degassing (Emptying) a Storage Tank

For a drain-dry fixed-roof tank, degassing emissions can be determined in accordance with API Technical Report 2568, *Evaporative Loss from the Cleaning of Storage Tanks.*

For a drain-dry floating-roof tank, degassing emissions can be determined in accordance with API Technical Report 2567, *Evaporative Loss from Storage Tank Floating Roof Landings*.

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

Cleaning (Sludge Handling)

Emissions from the cleaning of tanks can be determined in accordance with API Technical Report 2568, *Evaporative Loss from the Cleaning of Storage Tanks*.

Special Considerations when Quantifying Emissions

When determining storage tank emissions, the following should be considered.

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 non-routine emissions, must be reported in the EI.

Low-pressure tanks can experience breathing and working losses. While these emissions are usually 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.

Since the TANKS program uses equations developed under atmospheric conditions, it does not accurately model emissions from low-pressure tanks. Instead, use AP-42, Chapter 7, equations directly to determine breathing and working losses from low-pressure tanks.

Nitrogen-Blanketed Tanks

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

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

Heated Tanks

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

The current TANKS program, version 4.09D, contains several default routines that prevent it from properly applying the equations of AP-42 to heated fixed-roof tanks. For example, TANKS automatically sets the vapor-space temperature range for a heated tank equal to the liquid-surface temperature range. This assumption introduces a significant error for tanks that are designated as heated but which are not both well-insulated and equipped with high vent settings. Therefore, TANKS is no longer an acceptable option to determine emissions from heated tanks. Acceptable

methods are the AP-42, Chapter 7, equations or a software program that uses those equations accurately.

Tanks Storing Hot Products

If hot products (materials with a temperature above the ambient temperature) are put into an unheated tank, ambient meteorological data cannot be used to properly determine the tank's emissions. TANKS 4.09D cannot determine emissions from tanks that receive warmer-than-ambient stock, but which are not heated, because it does not allow the user to enter key parameters such as the liquid bulk temperature. Therefore, TANKS 4.09D is no longer an acceptable option for calculating emissions from tanks storing hot products. Instead, AP-42, Chapter 7, equations or software that uses those equations accurately must be used to determine emissions. When using the AP-42, Chapter 7, equations to determine emissions, the elevated stock temperature must be used as the liquid bulk temperature.

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 more accurately 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 the TANKS program 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 the TANKS program were developed to determine evaporative losses from storage of organic liquids, they currently present the best available method for determining inorganic emissions from storage tanks.

Tanks with a Liquid Heel

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

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

Oil Field Wellhead Tank Batteries

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

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

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

Produced Water Tanks

Produced water is generated during oil and gas exploration, production, transmission, and treatment, and typically stored on-site. It may contain various contaminants, including hydrocarbons that generate VOC emissions. Currently, specialized methods for determining emissions from produced water storage tanks do not exist. However, these tanks are a potential source of VOC emissions that must be represented in the EI.

If VOCs are present in produced water, the VOCs may vaporize in the tank's headspace causing working and breathing losses. To determine working and breathing losses, it is possible to add a custom mixture in the TANKS program similar to the composition of the produced water stored in the tanks (e.g., a mixture of 99 percent water and 1 percent condensate) to determine the emissions.

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. To determine flash losses, direct measurement of emissions and measurement of the amount of flash gas from a pressurized

sample of produced water (similar to the GOR method) are the preferred methods for determining emissions. If neither of those methods is available, a process simulator may be able to determine emissions, provided an accurate sample composition and site-specific inputs are available.

Winter Gas Blending

Some sites blend butane into gasoline during the fall and winter to increase the Reid Vapor Pressure (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.

Determining Emissions using Chemical Mixtures

For compounds whose physical properties can vary widely, such as condensate, or for site-specific or proprietary compounds or chemical mixtures, enter specific chemical or mixture data into the TANKS program's chemical database; use these new chemical data to generate emissions reports.

Additionally, data on chemical mixtures must be used to determine emissions from tanks where chemicals are combined. For example, when cutter stock is added to a heavy hydrocarbon storage tank, the cutter stock's composition must also be represented in the tank emission calculations by creating a mixture of both components.

Default Chemical Properties in the TANKS program

Care is needed when choosing default chemical properties in the TANKS program. For chemicals whose properties can vary widely, specific site data must be used. For example, crude oil storage tanks must account for the actual vapor pressure instead of using the program's default "crude oil (RVP 5)" option. If the actual vapor pressure is not known, "gasoline (RVP 10)" must be selected to determine the emissions.

Additionally, for gasoline storage tanks, variations in product must be accounted for by using actual vapor pressure information for each month of the year. An average gasoline profile must not be used to determine the emissions.

Speciation

If any source-specific information about storage tank VOC composition is available, use it to speciate the emissions. The TANKS program has several options for adding source-specific composition information in order to speciate emissions. 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 therein—including, but possibly not limited to, representative samples of:

- calculations detailing the tank parameters (diameter, height, shell color, roof color, paint condition, shell construction, capacity, primary and secondary seals, fittings, and throughput rate);
- if the TANKS program is used, a report generated using the “detailed” report option;
- physical properties of each product, including liquid density, liquid molecular weight, vapor molecular weight, and vapor pressure;
- sampling analysis;
- all supporting data used to calculate the flash losses, including identification of the determination method, sample analysis, API gravity, density of liquid petroleum, gas/oil ratio, gas gravity, molecular weight of stock, and VOC percentage by weight of both the stored liquid and flash gas; and
- all other information necessary to determine emissions.

For More Information

Additional guidance for storage tanks is available at the EPA’s Web site: <www.epa.gov/ttn/chief/faq/tanksfaq.html>.

While those questions are not reproduced here due to space considerations, they address such topics as underground storage tanks, vapor-balanced

tanks, tanks with roof geometries other than a cone or a dome, indoor storage tanks, and tanks storing a two-phase liquid.

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APPENDIX B—SAMPLE LETTERS

The following sample letters demonstrate the information required for prompt handling of EIs that:

- do not meet the applicability requirements of 30 TAC 101.10 for the current inventory year, but that wish to remain on the EAS mailing list to continue to receive future inventories;
- have experienced an insignificant emissions change; or
- are not expected to meet the applicability requirements of 30 TAC 101.10 in future years and therefore wish to be removed from the mailing list.

Inapplicability Notification

Mr. Kevin Cauble, 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.: _____

Dear Mr. Cauble:

Pursuant to Texas Clean Air Act Section 382.014 and Title 30, Texas Administrative Code (30 TAC), Section 101.10, the Texas Commission on Environmental Quality (TCEQ) has requested that an emissions inventory be submitted for calendar year _____ for the above referenced site. Upon reviewing the applicability requirements as presented in 30 TAC 101.10, I certify the referenced account does not meet the 30 TAC 101.10 applicability requirements for the current inventory year.

Choose one of the following:

☐ **Please keep this site on the annual emissions inventory update mailing list.** I understand that:

- the TCEQ will continue to request an emissions inventory update each calendar year;
- I (or my representative) must submit an updated emission 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, the 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; and
- annual reporting of the number of emissions events and of any maintenance, startup, and shutdown activities may still be required in accordance with 30 TAC 101.201 and 101.211. Additional information can be found on the EAS Web page at <www.tceq.texas.gov/goto/ieas>.

☐ **Please remove this site from the annual emissions inventory update mailing list.** I understand that all of the following apply:

- The 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 emissions for the current inventory year are below the required levels for emissions inventory reporting as described in 30 TAC 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 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, the 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.
- Annual reporting of the number of emissions events and/or maintenance, startup, and shutdown activities may still be required in accordance with 30 TAC 101.201 and 101.211. Additional information can be found on the EAS Web page at <www.tceq.texas.gov/goto/ieas>.

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 emission 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 potential to emit.

If you have any questions concerning the determination of the status of this site or the calculation methodologies used, please contact _____ at _____ or via e-mail at _____.

Sincerely,

Responsible Official (print) _____ Title (print) _____

Signature_____ Date Signed _____

Insignificant Emissions Change Notification

Mr. Kevin Cauble, 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.: _____

Dear Mr. Cauble:

Pursuant to Texas Clean Air Act Section 382.014 and 30 Texas Administrative Code (TAC) Section 101.10, the Texas Commission on Environmental Quality (TCEQ) has requested that an emissions inventory be submitted for calendar year (CY) _____ for the above referenced site.

Per 30 TAC 101.10(b)(2)(A), this letter is to inform the TCEQ that this site has not undergone any operational or process changes to produce a significant change in the actual emission rates for any of the criteria pollutants. The annual emission totals for volatile organic compounds, nitrogen oxides, carbon monoxide, sulfur dioxide, lead, and particulate matter with an aerodynamic diameter of 10 microns or less are each within 5 percent or 5 tons of the most recently reported total annual emissions.

Please note that (check one):

☐ No emissions events or maintenance, startup, or shutdown activities occurred at the above referenced site during the entire calendar year. By submitting this letter, I understand the 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, Emissions Inventory Contact Information, Criteria Emissions Totals, and Site Quantifiable Event Totals. The signed Emissions Events Certification and Legally Responsible Party for the CY _____ emissions inventory questionnaire are also enclosed.

☐ Emissions events or maintenance, startup, or shutdown activities occurred at the site during the calendar year. By submitting this letter, I understand the 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 the TCEQ can update the emissions from any emissions events and maintenance, startup, or shutdown activities, I am enclosing:

- the completed pages of the CY _____ emissions inventory questionnaire: Account Information, Emissions Inventory Contact Information, Criteria Emissions Totals, and Site Quantifiable Event Totals,
- the signed Emissions Events Certification and Legally Responsible Party for the CY _____ emissions inventory questionnaire, and
- the Path Emissions page(s) of the CY _____ emissions inventory questionnaire to report the emissions from each emission event and maintenance, startup, or shutdown 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 emission 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 e-mail at _____.

Sincerely,

Responsible Official (print) _____ Title (print) _____

Signature_____ Date Signed _____

APPENDIX C—EPA AND TCEQ RESOURCES

Helpful resources from the EPA and the TCEQ are listed here.

EPA Resources

Air CHIEF

The EPA's Clearing House 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/ttn/chief/>. A CD-ROM (Version 10) is available by calling the Info CHIEF Help Desk at 919-541-1000, or by e-mail 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 (5th Ed., Vol. 1, January 1995, Supplements A–F)

AP-42 is discussed in Chapter 4 ("Determining and Reporting Emissions") of this document. It is included in Air CHIEF.

FIRE (Factor Information Retrieval Data System, Version 6.25)

FIRE is a database containing the EPA's recommended emission estimation factors for criteria and hazardous air pollutants. FIRE is available online at <www.epa.gov/ttn/chief/software/fire/index.html>.

TANKS 4.09D

TANKS is a Windows-based computer software program that can be used to determine emissions of volatile organic compounds and hazardous air pollutants from certain types of storage tanks. The current version of TANKS is based on the emission estimation procedures from Chapter 7 of AP-42, and is available online at <www.epa.gov/ttn/chief/software/tanks/>.

Green Book

The EPA's "Green Book" (*Nonattainment Areas for Criteria Pollutants*) provides up-to-date information on nonattainment status. The Green Book is available online at <www.epa.gov/oar/oaqps/greenbk/>.

Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)

Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017) may be downloaded from the EPA Web site at <www.epa.gov/ttn/chief/efdocs/equiplks.pdf>.

If you cannot navigate directly to the PDF, navigate to <www.epa.gov/ttn/chief/publications.html#factor>, 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

2011 Emissions Inventory Forms and Instructions
<www.tceq.texas.gov/goto/ei2011> (follows this document, *2011 Emissions Inventory Guidelines*)

Tools for Completing the EI

<www.tceq.texas.gov/goto/ieas>

Information about Electronic Reporting

<www.tceq.texas.gov/goto/ieas>

Central Registry Integrated Web Reports

<www12.tceq.texas.gov/crpub/>

EI Account Mailing Status

<www.tceq.texas.gov/goto/ieas>

Air Permits Guidance Documents (may be helpful for determining emissions)

<www.tceq.texas.gov/goto/air_perm_guide>

Contacting the Emissions Assessment Section

EAS Web page: <www.tceq.texas.gov/goto/ieas>

EAS e-mail address: <psdocument@tceq.texas.gov>

EAS Help Line: 512-239-1773

APPENDIX D—SMALL-BUSINESS INFORMATION

Small businesses may qualify for assistance in completing an emissions inventory. This appendix includes a form that small businesses may use to request help in understanding how 30 TAC 101.10 applies to their site and how to estimate emissions. To determine if your business qualifies for assistance, see the top of the request form.

Application for Small-Business Emissions Inventory Assistance
Please print or type

If your business:

- has 100 or fewer full-time employees,
- is independently owned and operated,
- is a first-time reporter of emissions inventory or has completed past inventories in good faith, and
- owns or operates the site for which the EI is due,

then you may request help with your emissions inventory by completing this form.

Company name: _____

TCEQ air account number: _____

Business type: _____

Site location: _____

Contact person and title: _____

Telephone Number: (____) ____-_____ Number of Employees at site: _____

An independently owned and operated company is self-operated, managed and owned, and is not a subsidiary or controlled by a corporation with multiple holdings. Is this business independently owned and operated? yes no

Please describe, as accurately as possible, the type of assistance that you require.

Notes: If emissions at your site meet or exceed the reporting thresholds described in Chapter 1 of this book, you must submit an emissions inventory. You will be required to supply emission rates and other required data in the approved format. You must meet all applicable deadlines for emissions reporting.

If you do not have the data necessary to determine whether emissions at your site meet or exceed the reporting thresholds, or if you need clarification of the requirements or information about the reporting format, contact the EAS at 512-239-1773.

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Return this form to: Emissions Inventory Data, MC 166
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, TX 78711-3087

APPENDIX E—POLLUTION PREVENTION INFORMATION

Introduction

The TCEQ encourages businesses to implement policies that are beneficial while complying with state and federal rules. This appendix contains Best Management Practices (BMPs) for pollution prevention, devised by the TCEQ's Pollution Prevention and Education Section in order to help businesses improve performance and reduce air pollution from various sources. The purpose of these BMPs is to encourage businesses to move above and beyond regulatory requirements.

Marine Terminals

Steps that can improve marine terminals:

- Institute a hose–connector management system to ensure consistent transfer of liquid that results in fewer leaks. Ensure that responsibilities are documented in operational procedures.
- Improve corporate policy on docked barges and make sure they meet terminal emission and operating standards. Ensure that vessel operators conform to maintenance standards for terminal relief valves and terminal closed-dome loading and unloading procedures.
- Improve VOC containment where vapor balance is less than completely effective when loading barges, tankers, railcars, and trucks. Use a VOC detector to ensure tight connections.
- Use combined heat and power (CHP) technology for energy recovery.
- Use CHP chillers to deliver refrigeration for tanks requiring condensers to reduce product loss. CHP technology can supply electricity, steam, and refrigeration from any fuel source with 80–90 percent efficiency.

Storage Tanks

Breathing Losses

Breathing losses are the escape of vapor from a tank vapor space that has expanded due to daily variation in temperature and pressure. Reduce breathing losses by reducing vapor space in the tank. In fixed-roof tanks, breathing losses can account for 10 to 95 percent of total annual emissions. Much of the breathing losses result from thermal expansion of

the VOC-saturated vapor in the tank head space. To prevent these losses, reduce the tank head space by operating at a full level and constant rate (fill rate = withdrawal rate). Keep the tank at a more constant temperature by painting it white to reflect more sunlight and by insulating it to reduce heat transfer between the tank liquids and the surrounding air. Supplemental cooling or heating from a CHP system can be used to keep the tank at constant temperature. Raise the vent temperature and consider raising the pressure at which the conservation vent opens to reduce emissions caused by thermal expansion of the tank vapor space. However, do not exceed the tank design pressure. Tanks that operate conservation vents at 2.5 psig or higher will often have low breathing losses, or none.

Working Losses

Working losses result from filling and emptying tanks and can be reduced significantly by implementing BMPs. Install vapor-return lines to send the displaced vapor from the tank being filled back to the liquid source (tank truck, railcar, or barge). Equalize vapor space between tanks in a tank farm using a common vent header. This would apply to tanks containing the same solvent or where cross-contamination is acceptable. The displaced vapor space of a tank being filled will fill the resulting vapor space of a tank being emptied. Equalize the fill rate and withdrawal rate to eliminate working losses.

Reducing the number of tank turnovers per year will reduce working loss emissions. Vapors displaced during filling and thermal outbreathing can be contained by installing a vapor holder (giving the tank a variable vapor space). The vapors from the holder can then be returned to the liquid storage tank during emptying and inbreathing.

Floating-Roof Landing Losses

In a floating-roof tank, the roof floats on the surface of the liquid inside the tank to reduce evaporative losses during normal operation. However, when the tank is drained to a level where its roof lands on its deck legs or other support mechanism, a vacuum breaker opens to prevent collapse of the roof and a vapor space underneath the roof is created. Liquid remaining in the bottom of the tank continuously emits 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. Significant air emissions and loss of product can occur during landing of floating roofs. Floating-roof tanks should be operated in a manner that minimizes the amount and length of time of roof landings.

Other Tank Options

Other options to consider:

- using insulating paint on the roofs of floating-roof tanks
- installing vapor-recovery systems
- using tank emissions for energy recovery in a CHP system

Cooling Towers

Ways to improve performance of cooling towers:

- Get as many passes as possible.
- Find creative ways to capture and collect water to be used as makeup water for the system.
- Replace old, leaking heat exchangers.
- Install backup heat exchangers to avoid plant shutdowns.
- Monitor cooling tower exhausts to provide real-time notification of heat-exchanger leaks.
- Reduce drift losses by using baffles or drift eliminators to conserve water, retain water-treatment chemicals in the system, and improve operating efficiency.
- Control blowdown manually or automatically by valves actuated by timers or by conductivity meters.

Glycol Units

Things to consider when dealing with glycol units:

- Replace gas pneumatics with air-system instruments.
- Install flash tank separators on glycol dehydrators.
- Implement directed inspection and maintenance at gas plants and booster stations.
- Join the EPA's Natural Gas STAR Program.
- Install vapor recovery units on natural gas liquid transfer lines from storage tanks to rail and truck transportation vehicles.

General BMPs for VOC Emissions Control

Tips on controlling miscellaneous VOC sources:

- Process waste products for resource recovery, or as salable by-products. Recover VOCs via nondestructive methods (e.g., membrane recovery, biofilter, or cryogenic recovery) at or near the point of generation.

- Implement product substitution, product conservation, and changes in product composition. Use alternative products that would do the same job but with less harmful environmental impact (e.g., low-VOC or water-based products).
- Modify process chemistry or equipment design, improve operational procedures, increased automation, and improve process controls.
- Recover potential emissions for use as feed to the original process or in another process within the facility.
- Practice good housekeeping, implement an effective preventive maintenance or leak detection and repair program (or both), institute training and awareness programs, have effective supervision, encourage employee participation, review production scheduling and planning, and implement accounting and allocation practices that reflect the true cost of wasted products.
- Recycle wash solvents elsewhere in the process, use a less-volatile cleaning agent, and design equipment and procedures to minimize the need for cleaning.
- Employ parts washers that use steam instead of conventional ones that use solvents.
- Prevent the losses of volatile materials to wastewater streams where they may reappear as VOCs and evaporate.
- Keep paint and paint thinner away from high-traffic areas to avoid spills. Recycle paint, paint thinner, and solvents.
- Train employees on proper painting and spraying techniques, and use effective spray equipment that delivers more paint to the target and less overspray (high volume, low pressure spray guns).
- Replace existing atmospheric blowdown stacks with vapor recovery systems for energy recovery.
- Estimate the cost to install a marine vapor loss control system. Consider both vapor recovery and a CHP configuration.
- Reduce refinery odor from sour water.
- Replace solvent-based paints with low-VOC or water-based paints.
- Improve material handling, storage, and management practices. Such improvements may result in substantial reductions in spills, fugitive emissions, and leaks.
- Mix paints and solvents in designated areas, preferably indoors with appropriate ventilation.
- Have absorbent and other cleanup items readily available for immediate cleanup of spills.
- Keep VOC saturated pads, rags, and gloves in closed and vapor tight containers.

- Do not transfer or convert pollution from one medium to another.
- Modify the underground drainage system and process water treatment system to improve water treatment and reduce air emissions.
- Burn recovered hydrocarbons for energy recovery in a CHP system.
- Enclose, cover, or contain painting and related activities to the maximum extent practical.

Sandblasting

Enclose, cover, or contain blasting and sanding areas completely. Use shrouded or vacuum-assisted tools that can prevent abrasives, dust, and paint chips from leaving the area being worked on (e.g., dustless sanders and vacuum blasting robots).

Boilers and Process Heaters

Ways to improve boiler and heater operations:

- Develop, document and implement a maintenance procedure.
- Measure the gas temperature of stacks. If it is too high, install heat-recovery equipment such as an economizer or absorption chiller to chill water.
- Measure flue gas hydrocarbon concentration to ensure complete combustion.
- Clean the water and fire sides of the boiler to enhance heat transfer.
- Reduce excess air. It can lower boiler temperature.
- Install automatic combustion controls.
- Implement an environmental management system (EMS) that calls for continuous improvement of energy efficiency. Involve every employee in source reduction and minimizing waste.
- Improve water quality in the boiler tubes to decrease blowdowns.
- Harvest rainwater and use it in your boiler. Rainwater contains very few impurities and needs less demineralization and dealkalization.
- Reduce radiation and convection losses (*shell losses*) by improving insulation. Periodically measure shell temperatures.
- Steam leaks are very expensive, so repair steam leaks as soon as possible.
- Recover condensate and feed it back to the boiler.

If you have questions about these pollution prevention practices, or for additional technical assistance, please contact the TCEQ's Pollution Prevention and Education Section at 512-239-3143.

APPENDIX F—CHECKLIST

This list is intended to assist you in ensuring that you have supplied the information required for the EAS to adequately review your emissions inventory.

You are not required to submit this form to the EAS.

2011 Emissions Inventory Checklist

- ☐ 1. If the EI or plant contact information changed, did you update that information on page 2 of the EIQ?
- ☐ 2. Did you include criteria emissions totals on page 3 of the EIQ?
- ☐ 3. Have you completed the "Site Quantifiable Event Totals" section on page 3 of the EIQ? Please indicate zero if no events or activities occurred.
- ☐ 4. If applicable, did you sign the "Emissions Events Certification" on page 4 of the EIQ? Remember, a signature is required if you did not report any emissions from emission events.
- ☐ 5. Did you sign and complete the "Signature of Legally Responsible Party" section on page 4 of the EIQ?
- ☐ 6. Did you experience a large increase or decrease in emissions from the previous EI? If so, explain the reason for the change in your cover letter.
- ☐ 7. If you are adding structure, did you submit the appropriate forms, including facility, emission point, abatement device, and path forms?
- ☐ 8. Did you review all facility, emission point and abatement device parameters and complete any blank fields?
- ☐ 9. Are the seasonal operating percentages for each facility reported in whole numbers that add up to 100?
- ☐ 10. Did you indicate the status date for each facility status change?
- ☐ 11. For large sources, were VOC emissions speciated to 90 percent? A large source is defined as 5 tpy or greater for sites east of 100° longitude or in El Paso County or 25 tpy or greater for other sites west of 100° longitude.
- ☐ 12. Were HAPs and toxics speciated at or above 0.1 tpy for all sources?
- ☐ 13. Were lead and mercury emissions reported at 0.001 tpy or greater for all sources?
- ☐ 14. *Cooling Towers:* If you have monitoring data, did you use this data to determine your VOC emissions? Otherwise, did you use the uncontrolled AP-42 factor (since the controlled AP-42 factor is not accepted)?
- ☐ 15. *Cooling Towers:* Have you indicated whether the cooling towers are in HRVOC service?
- ☐ 16. *Equipment Leak Fugitive Areas:* Are you submitting a Fugitive Data Form for each fugitive area emitting more than five tons of VOC emissions?
- ☐ 17. *Equipment Leak Fugitive Areas:* Are you using correlation equations to determine emissions from monitored components? Applying reduction credits to average factors is not acceptable for monitored components.
- ☐ 18. *Flares:* Have you indicated whether the flare is in HRVOC service?
- ☐ 19. *Flares:* When reporting your average flow rate, did you use the correct units (Mscf/minute)?
- ☐ 20. *Storage tanks:* Did you complete the "Hot product (Y/N)" and "Heated tank (Y/N)" characteristics? Make sure to account for tanks that store hot products or are heated in your emission calculations.
- ☐ 21. *Storage tanks:* Was the actual vapor pressure used to calculate emissions, rather than TANKS defaults?
- ☐ 22. *Storage tanks:* Were flash losses accounted for in the emission calculations for fixed-roof tanks? Consult Technical Supplement 6 for updated guidance on approved methodologies.
- ☐ 23. *Storage tanks:* Were landing losses accounted for in the emission calculations for floating-roof tanks?
- ☐ 24. *Combustion sources:* Were the NO_x factors and annual aggregate heat inputs reported on the EIQ?
- ☐ 25. For VOC sources controlled by a combustion device, did you report the combustion emissions (NO_x, CO, SO_2 and PM) at the combustion source path and the undestroyed VOC emissions at the VOC source path?
- ☐ 26. Have you included thorough supporting documentation for all sources? (See Chapter 1 for more details.)
- ☐ 27. Have you included vendor data and stack test results where applicable?
- ☐ 28. Have you included plot plans and/or process flow diagrams?

ABBREVIATIONS

AEIR	annual emissions inventory report
AEIU	annual emissions inventory update
AMS	area and mobile source
API	American Petroleum Institute
AVO	aural/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
CEO	Chief Engineer's Office
CHP	combined heat and power
CO	carbon monoxide
COI	compound(s) of interest
CFR	Code of Federal Regulations
DRE	destruction and removal efficiency
EAS	Emissions Assessment Section
EE	emissions events
EGU	electric generating 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
GOR	gas/oil ratio
H_2S	hydrogen sulfide
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
lb	pound(s)

LDAR	leak detection and repair
MAERT	Maximum Allowable Emissions Rate Table
MM	million
MSS	maintenance, startup, and shutdown
NAAQS	national ambient air quality standards
NAD83	North American Datum of 1983
NH_3	ammonia
NSCR	nonselective catalytic reduction
NO_x	oxides of nitrogen
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 microns in diameter
PM_{10}	particulate matter no larger than 10 microns 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
RATA	relative accuracy test audit
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 (30 TAC *xx* = Title 30, Texas Administrative Code, Section *xx*)
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 emissions inventory. **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 vs. 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 in *2011 Emissions Inventory Forms and Instructions* (publication no. RG-360B/11).

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, Texas Administrative Code (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.

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 national ambient air quality standards 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*.

Chemical Abstract Service number—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 emissions inventory. This additional information will be used for quality assurance.

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 in *2011 Emissions Inventory Forms and Instructions* (TCEQ publication RG-360B/11).

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 emissions inventory may share the same CIN.

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 generating unit (EGU)—For emissions inventory purposes, an EGU is defined as 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.

emissions—Air contaminants generated by a facility. See also *contaminant*.

Emissions Assessment Section (EAS)—The section of the TCEQ's Chief Engineer's Office responsible for the emissions inventory process.

emissions event—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 forms—The forms used to add new structural information to an EI or to supply material usage data. Blank forms are available in *2011 Emissions Inventory Forms and Instructions* (TCEQ publication RG-360B/11) as well as the instructions for completing the forms.

emissions inventory questionnaire (EIQ) —A computer printout that shows an 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 emissions inventory. 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 emissions inventory is uniquely identified by an **emission point number**.

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—An event where an opacity reading meets or exceeds 15 additional percentage points above an applicable opacity limit, averaged over a six-minute period.

expected maximum capacity—The projected greatest capacity of a facility based on its physical and operational design or configuration and planned operation.

facility—A unit, device, structure or area capable of generating air contaminants. Each facility in the emission inventory is uniquely named by a facility identification number

(FIN). For purposes of Texas' emissions inventory, "facility" does not refer to the entire site, but rather to an individual process unit at the site.

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.

gas/oil ratio (GOR)—The relation of gas in cubic feet to the production of oil in barrels.

hazardous air pollutant (HAP)—An air pollutant designated as hazardous by the EPA. All HAPs should be listed individually (speciated) in your emissions inventory. 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 Web site.

highly reactive volatile organic compounds (HRVOCs)—For emissions inventory 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 115.

Maximum Allowable Emissions Rate Table (MAERT)—As defined in 30 TAC 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.

micron—One-millionth of a meter. Also called *micrometer*.

nonattainment county—A defined region within the state designated by the EPA as failing to meet the national ambient air quality standard 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 in excess of the reportable quantity as defined in 30 TAC 101.1.

non-reportable scheduled maintenance, startup, shutdown activity—An SMSS activity that is recorded as required by 30 TAC 101.211.

ozone season—The period from May 1 through September 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.

$$PTO = \frac{Hours\ Offline}{Annual\ Operating\ Hours} \times 100$$

permit by rule—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 microns. $PM_{2.5}$ is a subset of PM and PM_{10}.

PM_{10}—Portion of particulate matter with an aerodynamic diameter less than or equal to 10 microns. 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 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—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 hazardous air pollutant under FCAA Section 112; each pollutant for which a national primary ambient air quality standard has been promulgated (including carbon monoxide); 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 101.1.

reportable scheduled maintenance, startup, shutdown activity—An SMSS activity as defined in 30 TAC 101.1, where prior notice and a final report is submitted as required by 30 TAC 101.211.

scheduled maintenance, startup, shutdown (SMSS) activity—An activity as defined in 30 TAC 101.1 that is used in reporting required by Section 101.211.

site—As stated in 30 TAC 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 Standard Industrial Classification (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 classification code—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 emissions inventory data are stored.

structure—The representation, in the TCEQ database, of the paths (formerly "links") in an EI. EI structure should 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 book.

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 November 29, 2004 (69 *Federal Register* 69290)

CONTACTING THE EAS

Emissions Inventory Mailing Addresses

It is essential that you send your emissions inventory to the correct address. Failure to do so may delay or prevent delivery of your letter or package.

USPS

Send correspondence via the United States Postal Service (e.g., overnight mail, priority mail, certified mail) to:

Emissions Inventory Data, MC 166
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, Texas 78711-3087

Overnight Service

Send correspondence via special overnight carrier (for example, Airborne, FedEx, United Parcel Service) to:

Emissions Inventory Data, MC 166
Texas Commission on Environmental Quality
12100 Park 35 Circle, Bldg. E., Third Floor
Austin, Texas 78753

EAS Staff Mailing Addresses

To send mail to a particular EAS staff member, please use the appropriate address from above, replacing *Emissions Inventory Data, MC 166* with [staff member's name], *MC 164*.

EAS Help Line

For general questions concerning forms or emissions calculation methodology, call the EAS Help Line at 512-239-1773.

EAS Web Page

Information on emissions inventory trends, total criteria emissions for each site that reported an EI for the previous year, tools for completing an EI, this manual, and *2011 Emissions Inventory Forms and Instructions* (publication number RG-360B/11) are available on the EAS Web page at <www.tceq.texas.gov/goto/ieas>.