Bay Area Air Quality Management District

Petroleum Refinery Emissions Inventory Guidelines

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Executive Summary

Petroleum refineries are complex facilities with hundreds of thousands of sources of air pollutants. The District currently estimates and tracks emissions from permitted and formally permit exempt sources.

To ensure a consistent approach to estimating emissions is used by the Bay Area petroleum refineries, guidance is required.

Petroleum refineries within the Bay Area should estimate and report emissions of criteria pollutants, toxic air contaminants, and greenhouse gases for:

(1) all continuous, intermittent, predictable, or accidental air releases resulting from petroleum refinery processes at stationary sources at a petroleum refinery, and

(2) all air releases from cargo carriers (e.g. ships and trains), excluding motor vehicles, that load or unload materials at a petroleum refinery including emissions from such carriers while operating within the District or within California Coastal Waters.

These guidelines describe the emission estimation methodologies that have been reviewed and approved by the District to be used when calculating emissions, outline quality assurance and quality control measures to follow to ensure quality data, and provide report formats to follow when submitting emission inventories for District and the public's review.

By following these guidelines, petroleum refinery emission inventories should be:

- comprehensive (include all emission activities and sources),
- comparable (follows same conventions and procedures used by all refineries),
- robust (data quality is high and follows proper quality assurance and quality controls procedures),
- verifiable (all documentation required to replicate estimates is maintained and available for review), and
- transparent (methodologies used and rationale are stipulated).

Table of Contents

Executive Summary ii

Section 1: Introduction 1

Section 2: Overriding Principles 1

Section 3: Source-Specific Emission Calculation Procedures 4

Section 3.1: Fugitive Emission Leaks 5

Section 3.2: Storage Tanks 8

Section 3.3: Stationary Combustion 10

Section 3.4: Process Vents 14

Section 3.4.1 – Catalytic Cracking Units 14

Section 3.4.2 – Fluid Coking Units 16

Section 3.4.3 – Delayed Coking Units 18

Section 3.4.4 – Catalytic Reforming Units 20

Section 3.4.5 – Sulfur Recovery Plants 21

Section 3.4.6 – Other Miscellaneous Process Vents 23

Section 3.4.6.1 – Hydrogen Plant Vents 23

Section 3.4.6.2 – Asphalt Plant Vents 24

Section 3.4.6.3 – Coke Calcining 25

Section 3.4.6.4 – Blowdown Systems 27

Section 3.4.6.5 – Vacuum Producing Systems 28

Section 3.5: Flares 30

Section 3.6: Wastewater 34

Section 3.7: Cooling Towers 36

Section 3.8: Loading Operations 39

Section 3.9: Fugitive Dust 42

Section 3.10: Startup and Shutdown 45

Section 3-11: Malfunctions/Upsets 47

Section 3.12: Miscellaneous Sources 52

Section 3.12.1: Non-Retail Gasoline and Diesel Dispensing Facility 52

Section 3.12.2: Architectural or Equipment Painting 53

Section 3.12.3: Abrasive Blasting 54

Section 3.12.4: Solvent Degreaser 55

Section 3.12.5: Soil Remediation 56

Section 3.12.6: Groundwater Remediation (Air Stripping) 57

Section 3.12.7: Contractor Operations 58

Section 3.13: Cargo Carriers 59
Section 3.13.1 – Marine 59
Section 3.13.2 – Rail 68
Section 3.13.3 – Shared Emissions 73
Section 3.14: Greenhouse Gas Emissions 75
Section 3.15: Emission Calculation Spreadsheets 77
Section 4: Procedure for Revising Emission Factor, Methodology, or Ranking 78
Section 4.1: Emission Factor Revision 78
Section 4.2: Emission Estimation Methodology Revision 78
Section 4.3: Ranking Revision 78
Section 5: Data Usage and Calculations 79
Section 5.1: Limit of Detection or Accuracy 79
Section 5.1.1 – Limit of Detection 79
Section 5.1.2 – Instrumentation Accuracy 80
Section 5.2: Calculations Involving Averages 81
Section 5.3: Data Substitution 82
Section 5.3.1 –Continuous Emission Monitor (CEM) 82
Section 5.3.2 – Parametric Monitor 83
Section 5.3.3 –Non-CEM, Non-Parametric Monitor 84
Section 5.4: Conventions 85
Section 5.4.1 – Significant Figures 85
Section 5.4.2 – Rounding 85
Section 5.4.3 –Standard Conditions 86
Section 5.3.4 –Conversion Factors 87
Section 6: Quality Assurance and Quality Control 88
Section 6.1: Quality Assurance 88
Section 6.1.1 – Quality Assurance Program 88
Section 6.1.2 –Accuracy 89
Section 6.1.3 –Error Prevention 89
Section 6.2: Quality Control 90
Section 6.2.1 – Methods 90
Section 6.2.2 – Error Detection and Correction 90
Section 6.3: Uncertainty Analysis 91
Section 6.4: Documentation 92
Section 6.5: Quality Assurance Plan 93

Section 7: Inventory Usage for Regulatory Compliance........95
Section 7.1: Regulatory Basis........95
Section 7.2: Regulatory Comparisons........95
Section 8: Report Formats........96
Section 8.1: Public Version and Confidential Version........96
Section 8.2: Physical and Digital Copies........96
Section 8.3: Emissions Summaries........96
Section 8.4: Emission Comparisons........98
Section 8.4.1 – Comparison to First Inventory........98
Section 8.4.2 – Comparison to Previous Inventory and Historical Trend Lines........99
Section 9: Timeline for Emission Estimation Methodology or Data Revision........100
Section 10: Guidelines Revision Procedure........101
Section 10.1: Revision Requirement........101
Section 10.2: Revision Procedure........101
Section 10.2.1 – Identification of Need for Revision........101
Section 10.2.2 – Notification of Interested Stakeholders........102
Section 10.2.3 – Comment Review........102
Section 10.2.4 – Publication of Revised Guidelines........102
Section 10.2.5 – Adoption of Revised Guidelines........102
Section 11: Emission Inventory Review Criteria........103
Section 11.1: Completeness........103
Section 11.2: Methodology........103
Section 11.3: Data Quality........103
Section 11.4: Documentation........103
Section 11.5: Timing........103
Section 12: Bibliography........104

Appendix A: Default Emission Factors
Appendix B: Emission Calculation Templates
Appendix C: Quality Assurance Program (Example Outline)
Appendix D: Emission Inventory Report Format (Approved Format)

Acronyms, Definitions, and Terms

Accuracy	The maximum deviation of a value from its true value.
AP-42	U.S. EPA AP 42, *Compilation of Air Pollutant Emission Factors*
ARB (or CARB)	California Air Resources Board
BAAQMD	Bay Area Air Quality Management District
Bias	The systematic or persistent distortion of a measurement process which causes error in one direction (either positive or negative)
BTU	British thermal unit
CAPCOA	California Air Pollution Control Officers Association
CATEF	California Air Toxics Emission Factors
CEM	continuous emission monitor
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents, usually expressed in metric tons
DSCF	dry, standard cubic foot
EEPPR	U.S. EPA *Emission Estimation Protocol for Petroleum Refineries*
EPA	United States Environmental Protection Agency
GHG	greenhouse gas
HAP	hazardous air pollutant
Heavy liquid	liquids with an ASTM D86 10 percent distillation temperature greater than or equal to 150 degrees Celsius (302 degrees Fahrenheit)
lb	pounds
LDAR	leak detection and repair
LOD	limit of detection
NO_X	oxides of nitrogen
Parametric monitor	any monitoring device or system required by District permit condition or regulation to monitor the operational parameters of either a source or an abatement device. Parametric monitors may record temperature, gauge pressure, flowrate, pH, hydrocarbon breakthrough, or other factors
PFD	process flow diagram
P&ID	piping and instrumentation diagram
PM	particulate matter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
PM_{10}	particulate matter less than 10 microns in diameter
ppm	parts per million
ppmv	parts per million, by volume
ppmw	parts per million, by weight
Precision	A measure of mutual agreement among individual measurements of the same property usually under prescribed similar conditions.
Representativeness	The degree in which data accurately and precisely represents a characteristic of a population, parameter variation at a sampling point, a process condition, or an environmental condition
QA	quality assurance
QC	quality control
SCF	standard cubic foot
SO_2	sulfur dioxide
TAC	toxic air contaminant
TDS	total dissolved solids
VOC	volatile organic compounds

Section 1: Introduction

This guidance document describes methodologies for calculating and reporting petroleum refinery emission inventories that have been reviewed and approved by District staff. While alternative methodologies may be proposed to the District for acceptance, the methodologies set forth in this guidance are presumptively the most accurate and valid, and so should be used until this guidance is revised to reflect a different methodology.

These guidelines include District staff recommendations made in the District report entitled *Refinery Emissions Inventory Guidelines: An Assessment of EPA Document Emission Estimation Protocol for Petroleum Refineries* (dated September 2013).

The District staff report reviewed the document entitled *Emission Estimation Protocol for Petroleum Refineries* (version 2.1.1, May 2011) by the staff of the District. The *Emission Estimation Protocol for Petroleum Refineries* (EEPPR) was prepared by RTI International for U.S. EPA to provide guidance to petroleum refineries on how to calculate emission inventories, for the purpose of satisfying EPA's 2011 information collection request. The EEPPR was revised in April 2015.

The EEPPR is divided into several chapters covering common emission categories at refineries. Each chapter contains several options for calculating emissions, and ranks those options in order of preference. Staff reviewed the chapters to see how the various calculation methods compare to the way the District typically calculates emissions. For each chapter, staff prepared a summary report and provided recommendations on which method(s) in the EEPPR, if any, should be used by the District.

These guidelines incorporate staff recommendations as well input from the regulated entities and the public.

Section 2: Overriding Principles

An emission inventory is a compilation of estimates of emission estimates from individual and aggregated activities and sources. When estimating emissions, not all methodologies are equal nor result in the same quality or reliability of estimate. Often, there are multiple methodologies that may be employed. However, using a methodology that has a greater degree of reliability (certainty) of an estimate typically costs more (in time, money, and resources) and may not be cost-effective if resulting emission estimates are low or a greater degree of certainty is not needed. Typical methods for estimating emissions compared to their relative costs are shown in Figure 2.1.

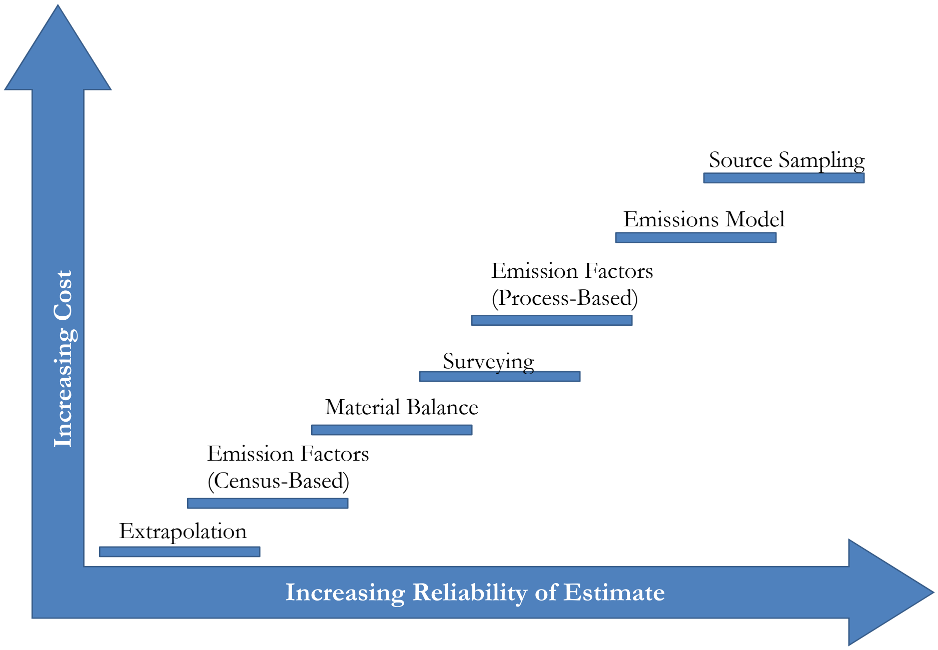

Figure 2.1 Emission estimation methodologies
(Source: Solomon, *Emission Inventories,* EPA)

As Figure 2.1 shows, source sampling (e.g. source tests, continuous emission monitor, etc.) has the greatest degree of reliability but also costs the most while extrapolation has the least degree of reliability but costs the least. From their inherent nature, the least reliable methods typically overestimate emissions due to the conservative assumptions made in their development.

As the purpose of emission inventories is for accurate emissions rather than a conservative maximum as often used in permit evaluations, these guidelines require using the most reliable method available and rank methods (shown in Figure 2.2) accordingly.

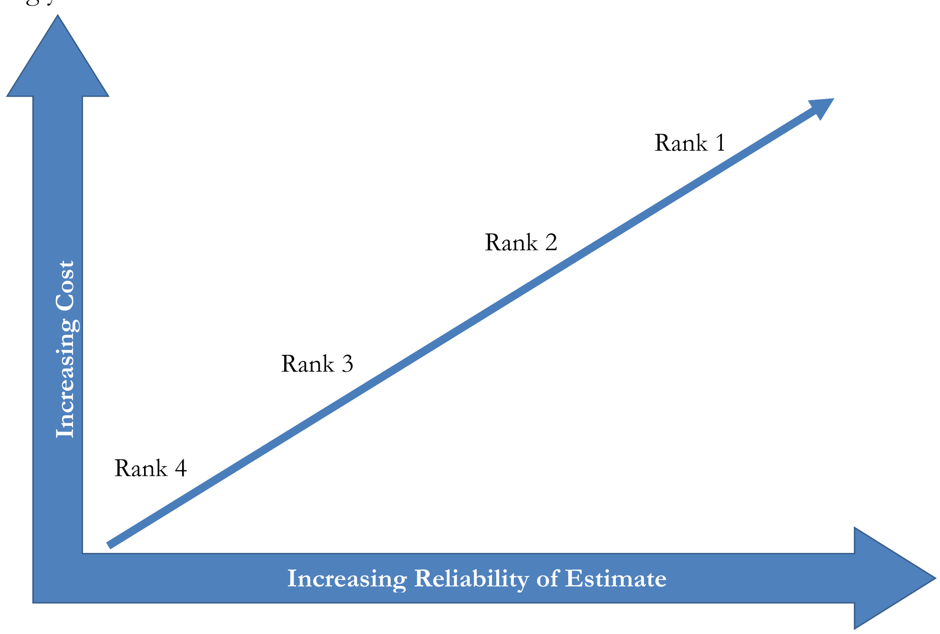

Figure 2.2 Emission estimation methodology rankings

When using the higher ranking emission estimation method, the following overriding principles should be considered when doing any type of emission calculation:

- Direct measurement is preferable to calculated emissions.
- Continuous measurement is preferable to periodic testing.
- Periodic source testing should be representative of typical source operation (unless intentionally testing for atypical conditions). If multiple source tests are available for the same source, source tests covering the inventory period should be used whenever available unless the source test represents atypical operation.
- Emission factors that are based on source testing should be updated as processes change.
- Use default emission factors only when other data is not available. While it is desirable to avoid using default emission factors, it is impractical to directly measure or test all sources for all pollutants under all operating scenarios. However, such factors will not capture emission trends over time, due to changing operation.
- When multiple emission factors are available for a given criteria pollutant/toxic air contaminant, use the following order of preference:
    1. CATEF*,
    2. EEPPR,
    3. AP-42.

  *Usage of CATEF should be consistent with the California Air Resources Board's "*Emission Inventory Criteria and Guidelines For the Air Toxics 'Hot Spots' Program*". Per Section IX (Source Testing and Emission Factors) Part D (*ARB-Approved Emission Factors Derived from "Hot Spots" Source Tests*) Subpart (1) (*Proposal to Use ARB-Approved Emission Factors*), "high level" facilities (such as refineries) are required to use the maximum factor unless the facility can demonstrate to the District that emissions could not exceed the levels calculated using the average value of the emission factor range.

Section 3: Source-Specific Emission Calculation Procedures

The section outlines source-specific guidance for broad categories of emission-producing sources and activities. However, a petroleum refinery is a complex facility with thousands of activities and hundreds of thousands of components that may cause emissions. Therefore, it is not practical to list guidance for every activity and/or source that may emit. Nevertheless, although these guidelines may not provide guidance for a specific emission-producing activity and/or source, a facility is still required to estimate and report emissions for that activity and/or source. For those cases, those activities and/or sources, the facility should contact the District's Engineering Division for clarification on how to estimate emission. Those activities and/or sources should be identified within the submitted emission inventory as not covered by these guidelines. If warranted, the procedures of Section 10 (Guidelines Revision Procedure) may be followed to update the guidelines.

To aid comprehension and implementation, each section contains the following headings with section-specific information.

Approved Methods

Specifies the District-approved emission estimation methodologies and their ranking in relation to each other. Emission inventories should employ the highest ranking methodology **for which data is available** (i.e. if emissions can be estimated using a Rank 2 and Rank 4 method, emissions should be estimated using the Rank 2 method).

District-approved default emission factors that may not exist or may differ from one published by either ARB or EPA are listed with the technical basis in Appendix A.

Data Needs

Lists data required to estimate emissions per listed emission estimation methodologies.

Supporting Documentation

Details documentation that a facility should maintain in order to estimate emissions using a specific method. At a minimum, the listed documentation should be included in the facility's quality assurance program (discussed in Section 6).

Reports

Lists reports required elsewhere (District, ARB, EPA, etc.) that may be used in estimating emissions.

Definitions

Includes section-specific definitions that are either important or may differ from another section.

Assumptions

Enumerates assumptions used in an emission estimation methodology (e.g. a single source test result is representative of normal, continuous operation).

Section 3.1: Fugitive Emission Leaks

Equipment leaks (also known as fugitive emissions) occur throughout the refinery at various equipment components, including valves, flanges, pumps, compressors, relief valves, etc.

Approved Methods

Fugitive equipment leak emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.1-1.

Table 3.1-1: Summary of Equipment Leak Emission Estimate Methodologies

Rank	Measurement Method	Correlation Equations or Emission Factor	Compositional Analysis Data[1]
1	Direct measurement (bagging)	Not necessary	Speciation of collected gas samples
2	EPA Method 21	Correlation Equation[2]	a) Process-specific, equipment-specific concentrations b) Process-specific average concentrations c) Refinery average stream concentrations
3	No monitoring; facility-specific component counts	Default average emission factors[3]	a) Process-specific, service-specific concentrations b) Process-specific average concentrations c) Refinery average stream concentrations d) Default process compositions
4	No monitoring; default process component counts[4]	Default average factors[3]	

Notes:
1. The letters represent ranking sublevels. For example, Rank 2a consists of using the correlation equation to estimate the total VOC emissions and using process-specific and equipment-specific process fluid concentration data to estimate speciated emissions.
2. CAPCOA 1999 *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* – Table IV-3a (Method 3)
3. CAPCOA 1999 *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* – Table IV-1a (Method 1)
4. Default process component counts estimated using the multipliers in Table 3-1-2

Table 3.1-2: Heavy Liquid Multipliers

Process Unit	Heavy Liquid Multipliers[(1)]			
	Valves	Pumps	Pressure Relief Devices	Connectors
Crude distillation	1.13	0.93	2.40	1.07
Alkylation (sulfuric acid)	0.00	0.00	0.00	0.45
Alkylation (HF)	0.21	0.62	0.09	0.14
Catalytic reforming	0.22	0.17	0.00	0.16
Hydrocracking	0.47	0.55	0.00	0.37
Hydrotreating/hydrorefining	0.79	0.86	2.00	0.83
Catalytic cracking	1.58	1.00	1.44	1.19
Thermal cracking (visbreaking)	0.53	0.86	5.00	0.83
Thermal cracking (coking)	0.81	0.92	2.00	1.06
Hydrogen plant	0.00	51.43[(2)]	0.00	0.00
Asphalt plant	0.00	0.00	0.00	0.00
Product blending	0.44	1.00	0.38	0.71
Sulfur plant	0.88	0.38	1.00	0.39

Process Unit	Heavy Liquid Multipliers(1)			
	Valves	Pumps	Pressure Relief Devices	Connectors
Vacuum distillation	4.14	6.00	4.00	7.88
Full-range distillation	0.13	0.14	0.25	0.21
Isomerization	0.26	0.56	0.40	0.49
Polymerization	0.23	0.33	2.33	0.30
MEK dewaxing	0.12	0.34	3.00	0.12
Other lube oil processes	1.99	3.20	3.33	6.74

Notes:

1. Derived using counts listed in EPA's "*Emission Estimation Protocol for Petroleum Refineries*", Version 2.1.1 – Table 2-5.
2. Refineries should use the actual count of heavy liquid pumps in hydrogen plants.

Data Needs

Depending on the approved measurement method used, the following data is required to estimate mass emissions from equipment leaks.

Table 3.1-3: Data Needs for Fugitive Emission Estimation Methods

Approved Measurement Method	Needed Data
Direct Measurement	Mass emissions
EPA Method 21	Component inventory (type, count)
	Screening values
	Repair history
No monitoring facility-specific component counts	Component inventory (type, count)
No monitoring; default process component counts	Component inventory (type, count)

Supporting Documentation

The following supporting documentation should be maintained.

Table 3.1-4: Supporting Documentation Required by Fugitive Emission Estimation Methods

Approved Method	Needed Data	Required Documentation
Direct Measurement	Mass emissions	Source test report
EPA Method 21	Component Screening Values	Leak Detection and Repair (LDAR) database
	Component Types	
	Background Screening Values	
	Screening date	
	Repair History	Work Orders
	Calibration Sheet	Calibration Gas Certifications
No monitoring facility-specific component counts	Component inventory (type, count)	LDAR database
No monitoring; default process component counts	Component inventory (type, count)	LDAR database

Reports
District Regulation 8, Rule 18 annual inventory report

Definitions
The following definitions apply when estimating emissions according to this section.

Heavy Liquid	liquids with an ASTM D86 10 percent distillation temperature greater than or equal to 150 degrees Celsius (302 degrees Fahrenheit)
LDAR	Leak Detection and Repair

Assumptions
The following assumptions are used in this section.

Item	Assumption
Correlation Equations	Correlation equations represent mass emissions from entire range of components and operating ranges.
Heavy Liquid Service Components	Distribution of heavy liquid service components are similar to those included in EPA's "*Emission Estimation Protocol for Petroleum Refineries*", Version 2.1.1 – Table 2-5

Section 3.2: Storage Tanks

Emissions from storage tanks depend on the storage tank type, tank dimensions and characteristics, stored materials, and activity.

Emissions should be estimated for all:

- External floating roof tanks
- Internal floating roof tanks
- Geodesic dome roof tanks, and
- Fixed roof tanks vented to the atmosphere
- Fixed roof tanks vented to a control devices

Emissions from fixed roof tanks that are abated by a combustion-based control device (e.g. thermal oxidizer, furnace, etc.) should be estimated using the procedures listed here and apply an abatement efficiency to the tank emissions.

Emissions generated by the combustion-based control device should be estimated per the procedures outlined in Section 3.3 (Stationary Combustion).

Storage tank emissions should be calculated and itemized for the following emission activities:

Routine:

- Standing losses (emissions occurring through diurnal changes)
- Working losses (emissions occurring through liquid movement)
- Stock changes (change of service)
- Tank landings
- Tank degassing
- Tank cleaning

Non-Routine:

- Leaking pontoons
- Non-routine pressure relief device venting

Emission estimates should account for seasonal and stock changes. At a minimum, emissions should be estimated on a monthly basis and then aggregated on annual basis.

Approved Methods

Storage tank emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.2-1.

Table 3.2-1: Summary of Storage Tank Emission Estimate Methodologies

Rank	Measurement Method	Application	Compositional Analysis Data
1	Direct measurement	Covered and vented storage tanks	Stored material properties (e.g. lab analyses, crude assays)
2	Tank-specific modeling[1]	All petroleum liquid storage tanks	Default composition profiles

Notes:

1. Using the equations listed in Chapter 7.1 (Organic Liquid Storage Tanks) of U.S. EPA's *Compilation of Air Pollutant Emission Factors* (AP-42).

When estimating emissions using Rank 2 methodology, the U.S. EPA TANKS software program should not be used as it is no longer supported and has known issues (e.g. TANKS uses a temperature of 630 °F rather than treating temperature as a variable for fixed roof tank working losses, TANKS does not allow for elevated liquid stock bulk temperature for non-heated tanks, does not account for liquid heel when computing fixed-roof tank working capacity, etc.). When using Rank 2 methodology the equations listed in Chapter 7.1 of U.S. EPA's *Compilation of Air Pollution Emission Factors* (AP-42) should be used directly.

However, although Chapter 7.1 of AP-42 provides default material properties, ambient conditions (temperature, wind speed, solar insolation), and tank fittings; facilities should use site-specific, tank-specific, and material-specific data rather than the defaults listed in Chapter 7.1.

Data Needs

Depending on the approved measurement method used, the following data is required to estimate mass emissions from storage tanks.

Table 3.2-2: Summary of Data Needs for Storage Tank Emission Estimate Methodologies

Approved Method	Needed Data
Direct Measurement	Constituent concentration and data
Tank-specific modeling	Tank type and dimensions
	Stored liquid properties (e.g. vapor pressure, density, etc.) and constituent concentrations
	Tank condition/fitting information
	Stored material throughputs
	Stock changes
	Degassing information

Supporting Documentation

The following supporting documentation should be maintained.

Table 3.2-3 Supporting Documentation Required by Storage Tank Estimation Methods

Approved Method	Needed Data	Required Documentation
Direct Measurement	Constituent concentration and data	Source test results
Tank-specific modeling	Tank type and dimensions	Design drawings
	Stored liquid properties (vapor pressure, API gravity, etc.) and constituent concentrations	Crude assays (for crude tanks) Lab analyses
	Tank condition/fitting information	Installation records Maintenance records Turnaround reports
	Stored material throughputs	Flow meter records
	Ambient conditions (temperature, wind speed)	Onsite meteorological records
	Stock changes	Stock change records
	Degassing information	Degassing records, source test results

Reports

District Regulation 8, Rule 5 reports

Definitions

Crude Assay a laboratory test of petroleum crude oil that provides an extensive detailed hydrocarbon analysis data

Assumptions

Monthly average emission estimates adequately represent daily changes in temperature, wind speed, and stored materials.

Section 3.3: Stationary Combustion

Stationary Combustion emissions occur throughout the refinery at various combustion sources, including process heaters, boilers, CO boilers, internal combustion engines and combustion turbines.

Approved Methods

Stationary Combustion emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.3-1.

Table 3.3-1: Summary of Stationary Combustion Emission Estimates

Rank	Measurement Method	Applicability	Qualifications
1	Direct measurement (continuous emission monitoring systems [CEMS]) for both flow rate and gas composition)	Unlimited	CEMS must be District approved and certified.
2	Direct measurement (CEMS) for gas composition Use of F factors	Use with calculated F factors	CEMS must be District approved and certified. Calculated F factor must trend fuel properties[2].
3A	Fuel analysis/mass balance	GHG, SO_2, TAC, HAP emissions for uncontrolled sources	Fuel analysis must be in sufficient detail. Conversion and destruction efficiency must be supported and District approved.
3B	Source-specific stack testing to calculate source specific emission correlations or factors	Unlimited (GHG, TAC, HAP, Criteria Pollutants)	District approved source test representative of normal operation. Data substitution not allowed[1].
4	Default emission factors		Default emission factors are based on gaseous fuel usage only and will not accurately track emissions when fuel source or quality changes.

Notes:
1. The actual emissions are required. Therefore, data substitution (e.g., as allowed for NOx emissions in Regulation 9, Rule 10) is not acceptable.
2. Fuel properties must be determined quarterly for each period of F factor calculation.

Data Needs

Depending on the approved measurement method used, the following data is required to estimate mass emissions from stationary combustion sources.

Table 3.3-2: Data Needs for Stationary Combustion Emission Estimates

Approved Measurement Method	Needed Data
Direct Measurement (CEMS)	Mass emissions
Direct Measurement (CEMS using F factor)	Mass emissions
	Fuel composition
	F factor calculations
Fuel analysis/mass balance	Mass emissions

Approved Measurement Method	Needed Data
	Fuel composition
	Conversion factors
	Destruction efficiencies
Source-specific stack testing to calculate source specific emission correlations or factors	Mass Emissions
	Speciated emission factors
	Fuel usage
Default emission factors	Mass Emissions
	Speciated emission factors
	Fuel usage

Supporting Documentation

The following supporting documentation should be maintained according the approved method used to estimate emissions.

Table 3.3-3: Supporting Documentation for Stationary Combustion Emission Estimates

Approved Method	Needed Data	Required Documentation
Direct Measurement (CEMS)	Mass emissions	Summary of CEMS certification and periodic accuracy testing.
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission concentration readings in volume % dry basis, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet).
Direct Measurement (CEMS using F factor)	Mass emissions	Summary of CEMS certification and periodic accuracy testing.
		Spreadsheet with raw fuel gas flowrate in SCFM (dry), percent flue gas oxygen content (dry), F factor used in dscf/MMBtu, fuel gas HHV in MMBtu/SCF, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission concentration readings in volume % dry basis, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized by month, totalized for year (can be combined with spreadsheet above).
	Fuel properties	Periodic fuel gas analysis
		Fuel gas composition in volume fraction of each component
	F factor calculations	Spreadsheet for F factor calculation, including fuel gas composition with the volume fraction of each component in the fuel gas, molar exhaust volume for each fuel gas component in dscf/mol, and molar heat content for each fuel gas component in BTU/mol.

Approved Method	Needed Data	Required Documentation
Fuel analysis/mass balance	Mass Emissions	Spreadsheet with raw fuel gas flowrate, fuel gas composition, conversion or destruction efficiency used, and mass emissions
		Spreadsheet with mass emissions summarized by month, totalized for year (can be combined with spreadsheet above).
	Fuel properties	Periodic fuel gas analysis
		Fuel gas composition in volume fraction of each component
	Stoichiometric data	Documentation of stoichiometric basis
	Destruction data	Documentation of basis for species destruction
Source-specific stack testing to calculate source specific emission correlations or factors	Mass Emissions	Spreadsheet with raw fuel gas flowrate, emission factors used and mass emissions.
		Spreadsheet with mass emissions summarized by month, totalized for year (can be combined with spreadsheet above).
	Source Operation[2]	Spreadsheet for daily operating parameters including fuel flow, fire box temperature and pressure, combustion air flow (flowrate or damper setting), flue gas temperature and pressure, and flue gas oxygen content.
	Source Test	Summary of source test report including all operating parameters and test results
Default emission factors	Mass Emissions	Spreadsheet with raw fuel gas flowrate, emission factors used, and mass emissions.
		Spreadsheet with mass emissions summarized by month, totalized for year (can be combined with spreadsheet above)
	Source Operation[2]	Spreadsheet for daily operating parameters including fuel flow, fire box temperature and pressure, combustion air flow (flowrate or damper setting), flue gas temperature and pressure, and flue gas oxygen content
	Emission Factor	Documentation for basis of emission factor including, assumptions or constraints for specified emission factor, range of applicability of the emission factor, and confirmation that source operation is consistent with the applicability of the specified default emission factor

Notes:

1. All required spreadsheets must be in format that data can be analyzed by the District. If pdf format is provided, a spreadsheet format must accompany the submission.
2. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. The minimum source operation data is listed. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions.

Reports

Regulation 1-522 reports

Definitions
None

Assumptions
The following assumptions are used in this section.

Item	Assumption
F-factor	Combustion exhaust gas flow rates can be estimated via calculation
Source test	Source test results represent emission rates during non-test periods

Section 3.4: Process Vents

Typically, vent gases are collected and routed to a vapor recovery or fuel gas system. This section is for estimating emissions from vent gasses that are not collected. There are calculation methods specific to several different process units.

Section 3.4.1 – Catalytic Cracking Units

Approved Methods

Catalytic cracking unit emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.1-1.

Table 3.4.1-1: Summary of Approved Catalytic Cracking Unit Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change
Notes: 1. Fuel properties must be determined quarterly for each period of F factor calculation.			

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.1-2: Summary of Data Needs for Catalytic Cracking Units

Approved Measurement Method	Needed Data
Unit Information	One Time: Unit Design, Process, Permitting and Ancillary Equipment Information
	One Time: Selected Emissions Measurement Method
	Annually: Unit and Method Changes, Volume of Feed Material (Barrels), Coke Burn Rate (tons)
NO_X, SO_2, CO: Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point	Mass emissions
PM: Continuous gas composition analyzer (COM) with continuous vent gas flow measurement, measured at discharge point	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion
PM: Source tests with measured process rates (if no COM correlation available)	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion
GHG, VOC, HAPs, TACs: Source tests with measured process rates	Mass emissions
	Speciated emission factors

Approved Measurement Method	Needed Data
Default emission factors	Process throughput

Supporting Documentation

The following supporting documentation should be maintained according the approved method used to estimate emissions.

Table 3.4.1-3: Supporting Documentation for Catalytic Cracking Units

Approved Method	Needed Data	Required Documentation
NO_X, SO_2, CO: Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point.	Mass emissions	Summary of CEMS certification and periodic accuracy testing
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission concentration readings in volume % dry basis, and mass emissions in lbs or tons
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet)
PM: Continuous gas composition analyzer (COM) with continuous vent gas flow measurement, measured at discharge point	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion	Correlation used to derive PM emissions from COM
		Summary of CEMS certification and periodic accuracy testing
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, opacity readings, factors used to convert opacity to PM and mass emissions in lbs or tons
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet)
PM: Source tests with measured process rates (if no COM correlation available)	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion	Source test report summary with operating parameters[2], concentrations speciated by PM_{10} filterable, PM_{10} condensable, $PM_{2.5}$ filterable, and $PM_{2.5}$ condensable.
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, opacity readings, factors used for each PM species, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized (for each PM species) by month, totalized for year, in lbs or tons (can be combined with first spreadsheet).
GHG, VOC, HAPs, TACs: Source tests with measured process rates	Mass emissions	Source test report summary with operating data[2], concentrations speciated by HAP/TAC.
		Spreadsheet including daily CCU feed in barrels, maximum and minimum flowrate for the day, stack gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission factor used, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet).
Default emission factors	Process throughput	Process throughput records

Notes:

1. All required spreadsheets must be in format that data can be analyzed by the District. If pdf format is provided, a spreadsheet format must accompany the submission.
2. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. If source operation data is listed, this is the minimum required. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions.

Reports
None

Definitions
None

Assumptions
None

Section 3.4.2 – Fluid Coking Units

Approved Methods
Fluid coking unit emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.2-1.

Table 3.4.2-1: Summary of Approved Catalytic Cracking Unit Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change
Notes: 1. Fuel properties must be determined quarterly for each period of F factor calculation.			

Data Needs
Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.1-2: Summary of Data Needs for Fluid Coking Units

Approved Measurement Method	Needed Data
Unit Information	One Time: Unit Design, Process, Permitting and Ancillary Equipment Information
	One Time: Selected Emissions Measurement Method
	Annually: Unit and Method Changes, Volume of Feed Material (Barrels)
NO_X, SO_2, CO: Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point	Mass emissions
PM: Continuous gas composition analyzer (COM) with continuous vent gas flow measurement, measured at discharge point	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion
PM: Source tests with measured process rates (if no	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both

Approved Measurement Method	Needed Data
COM correlation available)	the filterable portion and the condensable portion
GHG, VOC, HAPs, TACs: Source tests with measured process rates	Mass emissions
	Speciated emission factors

Supporting Documentation

The following supporting documentation should be maintained according the approved method used to estimate emissions.

Table 3.4.2-3: Supporting Documentation for Fluid Coking Units

Approved Method	Needed Data	Required Documentation
NO_X, SO_2, CO: Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point.	Mass emissions	Summary of CEMS certification and periodic accuracy testing
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission concentration readings in volume % dry basis, and mass emissions in lbs or tons
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet)
PM: Continuous gas composition analyzer (COM) with continuous vent gas flow measurement, measured at discharge point	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion	Correlation used to derive PM emissions from COM
		Summary of CEMS certification and periodic accuracy testing
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, opacity readings, factors used to convert opacity to PM and mass emissions in lbs or tons
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet)
PM: Source tests with measured process rates (if no COM correlation available)	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion	Source test report summary with operating parameters[2], concentrations speciated by PM_{10} filterable, PM_{10} condensable, $PM_{2.5}$ filterable, and $PM_{2.5}$ condensable.
		Basis for emission factors used in emission calculation
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, opacity readings, factors used for each PM species, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized (for each PM species) by month, totalized for year, in lbs or tons (can be combined with first spreadsheet).
GHG, VOC, HAPs, TACs: (Source tests)	Mass emissions	Source test report summary with operating data, concentrations speciated by HAP/TAC.
		Basis for emission factors used in emission calculation
		Spreadsheet including daily fluid coking unit feed in barrels, maximum and minimum flowrate for the day, stack gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission factor used, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet)
GHG, VOC, HAPs, TACs: (Default emission factors)	Mass emissions	Spreadsheet showing for each decoking cycle, coke drum coke and water mass, the mass of steam generated, coke drum overhead temperature, the default emission factor used, and mass emissions
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet).
Notes:		

Approved Method	Needed Data	Required Documentation
1. All required spreadsheets must be in format that data can be analyzed by the District. If pdf format is provided, a spreadsheet format must accompany the submission. 2. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. If source operation data is listed, this is the minimum required. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions.		

Reports

None

Definitions

None

Assumptions

None

Section 3.4.3 – Delayed Coking Units

Approved Methods

Fluid coking unit emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.3-1.

Table 3.4.3-1: Summary of Approved Delayed Coking Unit Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change
Notes: 1. Fuel properties must be determined quarterly for each period of F factor calculation.			

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.3-2: Summary of Data Needs for Delayed Coking Units and Drain Vents

Approved Measurement Method	Needed Data
Unit Information	One Time: Unit Design, Process, Permitting and Ancillary Equipment Information
	One Time: Selected Emissions Measurement Method
	Annually: Unit and Method Changes, Coke Production, Overhead Line Temperature and Pressure when Vent Opened, Volume of Feed

Approved Measurement Method	Needed Data
	Material (Barrels)
NO_X, SO_2, CO: Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point	Mass emissions
PM: Continuous gas composition analyzer (COM) with continuous vent gas flow measurement, measured at discharge point	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion
PM: Source tests with measured process rates (if no COM correlation available)	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion
GHG, VOC, HAPs, TACs: Source tests with measured process rates	Mass emissions
	Speciated emission factors

Supporting Documentation

The following supporting documentation should be maintained according the approved method used to estimate emissions.

Table 3.4.2-3: Supporting Documentation for Delayed Coking Units

Approved Method	Needed Data	Required Documentation
NO_X, SO_2, CO: Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point.	Mass emissions	Summary of CEMS certification and periodic accuracy testing
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission concentration readings in volume % dry basis, and mass emissions in lbs or tons
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet)
PM: Continuous gas composition analyzer (COM) with continuous vent gas flow measurement, measured at discharge point	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion	Correlation used to derive PM emissions from COM
		Summary of CEMS certification and periodic accuracy testing
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, opacity readings, factors used to convert opacity to PM and mass emissions in lbs or tons
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet)
PM: Source tests with measured process rates (if no COM correlation available)	Mass emissions broken down into PM_{10} and $PM_{2.5}$, each showing both the filterable portion and the condensable portion	Source test report summary with operating parameters[2], concentrations speciated by PM_{10} filterable, PM_{10} condensable, $PM_{2.5}$ filterable, and $PM_{2.5}$ condensable.
		Basis for emission factors used in emission calculation
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, opacity readings, factors used for each PM species, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized (for each PM species) by month, totalized for year, in lbs or tons (can be combined with first spreadsheet).
GHG, VOC, HAPs, TACs: (Source tests)	Mass emissions	Source test report summary with operating data, concentrations speciated by HAP/TAC
		Basis for emission factors used in emission calculation
		Spreadsheet including daily feed in barrels, maximum and minimum flowrate for the day, stack gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission factor used, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet).

Approved Method	Needed Data	Required Documentation
GHG, VOC, HAPs, TACs: (Default emission factors)	Mass emissions	Spreadsheet showing for each decoking cycle, coke drum coke and water mass, the mass of steam generated, coke drum overhead temperature, the default emission factor used, and mass emissions.
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet).

Notes:
1. All required spreadsheets must be in format that data can be analyzed by the District. If pdf format is provided, a spreadsheet format must accompany the submission.
2. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. If source operation data is listed, this is the minimum required. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions.

Reports
None

Definitions
None

Assumptions
None

Section 3.4.4 – Catalytic Reforming Units

Approved Methods
Catalytic reforming unit emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.4-1.

Table 3.4.4-1: Summary of Approved Catalytic Reforming Unit Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change

Notes:
1. Fuel properties must be determined quarterly for each period of F factor calculation.

Data Needs
Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.4-2: Summary of Data Needs for Catalytic Cracking Reforming Units

Approved Measurement Method	Needed Data
Unit Information	One Time: Unit Design, Process, Permitting and Ancillary Equipment Information
	One Time: Selected Emissions Measurement Method
	Annually: Unit and Method Changes, Volume of Feed Material (Barrels)
VOC, HAPs, TACs: (Source tests with measured or calculated process rates)	Mass emissions
	Speciated emission factors
VOC, HAPs, TACs: (Default emission factors)	Mass emissions
	Speciated emission factors

Supporting Documentation

The supporting documentation of Table 3.4.4-3 should be maintained according to the emission estimation methodology employed.

Table 3.4.4-3 Documentation Required for Catalytic Cracking Reforming Unit Emission Estimates

Needed Data	Supporting Documentation
One Time: Unit Design, Process, Permitting and Ancillary Equipment Information	Piping and Instrumentation Diagrams Process Flow Diagrams
One Time: Selected Emissions Measurement Method	Calculation spreadsheet
Annually: Unit and Method Changes, Volume of Feed Material	Work orders/ capital expenditure requests Turnaround reports Throughput records
Mass emissions	Calculation spreadsheets
Speciated emission factors	Lab analysis reports Source test reports

Reports

None

Definitions

None

Assumptions

None

Section 3.4.5 – Sulfur Recovery Plants

Approved Methods

Sulfur recovery plant emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.5-1.

Table 3.4.5-1: Summary of Approved Sulfur Recovery Plant Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous		Sampling must be District approved.

Rank	Measurement Method	Applicability	Qualifications
	vent gas flow measurement or engineering estimates		Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change
Notes: 1. Fuel properties must be determined quarterly for each period of F factor calculation.			

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.5-2: Summary of Data Needs for Sulfur Recovery Plants

Approved Measurement Method	Needed Data
Unit Information	One Time: Unit Design, Process, Permitting and Ancillary Equipment Information
	One Time: Selected Emissions Measurement Method
	Annually: Unit and Method Changes, Hydrocarbon Content of Feed, Sulfur Production
SO_2: Continuous gas composition analyzer with continuous vent gas flow measurement, measured at discharge point	Mass emissions
GHG: Calculated Emissions	Feed Stream(s) Hydrocarbon content
CO, NO_X, VOC, HAPs, TACs: (Source tests with measured or calculated process rates)	Mass emissions
	Speciated emission factors
CO, NOx, VOC, HAPs, TACs: (Default emission factors)	Mass emissions
	Speciated emission factors

Supporting Documentation

The supporting documentation of Table 3.4.5-3 should be maintained according to the emission estimation methodology employed.

Table 3.4.5-3 Documentation Required for Sulfur Recovery Plants

Needed Data	Supporting Documentation
One Time: Unit Design, Process, Permitting and Ancillary Equipment Information	Piping and Instrumentation Diagrams Process Flow Diagrams
One Time: Selected Emissions Measurement Method	Calculation spreadsheet
Annually: Unit and Method Changes, Volume of Feed Material	Work orders/ capital expenditure requests Turnaround reports Throughput records
Feed Stream(s) Hydrocarbon content	Lab analysis reports
Mass emissions	Calculation spreadsheets
Speciated emission factors	Lab analysis reports Source test reports

Reports

None

Definitions

None

Assumptions

None

Section 3.4.6 – Other Miscellaneous Process Vents

Section 3.4.6.1 – Hydrogen Plant Vents

Approved Methods

Hydrogen plant vent emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.6.1-1.

Table 3.4.6.1-1: Summary of Approved Hydrogen Plant Vent Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change
Notes: 1. Fuel properties must be determined quarterly for each period of F factor calculation.			

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.6.1-2: Summary of Data Needs for Hydrogen Plant Vents

Approved Measurement Method	Needed Data
Unit Information	One Time: Unit Design, Process, Permitting and Ancillary Equipment Information
	One Time: Selected Emissions Measurement Method
	Annually: Unit and Method Changes, Hydrogen Production
GHG, VOC, HAPs, TACs: (Source tests with measured or calculated process rates)	Mass emissions
	Speciated emission factors

Supporting Documentation

The supporting documentation of Table 3.4.6.1-3 should be maintained according to the emission estimation methodology employed.

Table 3.4.6.1-3 Documentation Required for Hydrogen Plant Vents

Needed Data	Supporting Documentation
One Time: Unit Design, Process, Permitting and Ancillary Equipment Information	Piping and Instrumentation Diagrams Process Flow Diagrams
One Time: Selected Emissions Measurement Method	Calculation spreadsheet
Annually: Unit and Method Changes, Hydrogen Production	Work orders/ capital expenditure requests Turnaround reports Hydrogen production records Throughput records
Mass emissions	Calculation spreadsheets
Speciated emission factors	Lab analysis reports Source test reports

Reports

None

Definitions

None

Assumptions

None

Section 3.4.6.2 – Asphalt Plant Vents

Approved Methods

Asphalt plant vent emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.6.2-1.

Table 3.4.6.2-1: Summary of Approved Asphalt Plant Vent Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change
Notes: 1. Fuel properties must be determined quarterly for each period of F factor calculation.			

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.6.2-2: Summary of Data Needs for Asphalt Plant Vents

Approved Measurement Method	Needed Data
Unit Information	One Time: Unit Design, Process, Permitting and Ancillary Equipment Information
	One Time: Selected Emissions Measurement Method
	Annually: Unit and Method Changes, Quantity of Asphalt Processed, Thermal Oxidizer fuel rate.
PM, VOC, HAPs, TACs: (Source tests with measured or calculated process rates)	Mass emissions
	Speciated emission factors
PM, VOC, HAPs, TACs: (Default emission factors)	Mass emissions
	Speciated emission factors

Supporting Documentation

The supporting documentation of Table 3.4.6.2-3 should be maintained according to the emission estimation methodology employed.

Table 3.4.6.2-3 Documentation Required for Asphalt Plant Vents

Needed Data	Supporting Documentation
One Time: Unit Design, Process, Permitting and Ancillary Equipment Information	Piping and Instrumentation Diagrams Process Flow Diagrams
One Time: Selected Emissions Measurement Method	Calculation spreadsheet
Annually: Unit and Method Changes, Quantity of Asphalt Processed, Thermal Oxidizer fuel rate.	Work orders/ capital expenditure requests Turnaround reports Throughput records Thermal oxidizer fuel flow records
Mass emissions	Calculation spreadsheets
Speciated emission factors	Lab analysis reports Source test reports

Reports

None

Definitions

None

Assumptions

None

Section 3.4.6.3 – Coke Calcining

Approved Methods

Coke calcining emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.6.3-1.

Table 3.4.6.3-1: Summary of Approved Coke Calcining Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel

Rank	Measurement Method	Applicability	Qualifications
			properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change
Notes: 1. Fuel properties must be determined quarterly for each period of F factor calculation.			

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.6.3-2: Summary of Data Needs for Coke Calcining

Approved Measurement Method	Needed Data
Unit Information	One Time: Unit Design, Process, Permitting and Ancillary Equipment Information
	One Time: Selected Emissions Measurement Method
	Annually: Unit and Method Changes, Quantity of Coke Processed, Thermal Oxidizer fuel rate.
HAPs, TACs: (Source tests with measured or calculated process rates)	Mass emissions
	Speciated emission factors
HAPs, TACs: (Default emission factors)	Mass emissions
	Speciated emission factors

Supporting Documentation

The supporting documentation of Table 3.4.6.3-3 should be maintained according to the emission estimation methodology employed.

Table 3.4.6.3-3 Documentation Required for Coke Calcining

Needed Data	Supporting Documentation
One Time: Unit Design, Process, Permitting and Ancillary Equipment Information	Piping and Instrumentation Diagrams Process Flow Diagrams
One Time: Selected Emissions Measurement Method	Calculation spreadsheet
Annually: Unit and Method Changes, Quantity of Coke Processed, Thermal Oxidizer fuel rate.	Work orders/ capital expenditure requests Turnaround reports Throughput records Thermal oxidizer fuel flow records
Mass emissions	Calculation spreadsheets
Speciated emission factors	Lab analysis reports Source test reports

Reports

None

Definitions

None

Assumptions

None

Section 3.4.6.4 – Blowdown Systems

Approved Methods

Blowdown system emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.6.4-1.

Table 3.4.6.4-1: Summary of Approved Blowdown System Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors (based on total refinery feed[2]) with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change

Notes:
1. Fuel properties must be determined quarterly for each period of F factor calculation.
2. Table 5-12 (*Default Emission Factors for Blowdown Systems*), U.S. EPA Emissions Estimation Protocol for Petroleum Refineries, April 2015

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.6.4-2: Summary of Data Needs for Blowdown Systems

Approved Measurement Method	Needed Data
Default emission factors	Event Information, Composition and Volume of Blowdown, Disposition of Blowdown. Total Refinery Feed[1]
VOC, HAPs, TACs: (Source tests or process calculations with measured or calculated process rates)	Mass emissions Speciated emission factors
VOC: (Default emission factors)	Mass emissions

Notes:
1. Per Table 5-12 of the EPPR, total refinery feed is required to estimate emissions using default emission factors

Supporting Documentation

The supporting documentation of Table 3.4.6.4-3 should be maintained according to the emission estimation methodology employed.

Table 3.4.6.4-3 Documentation Required for Blowdown Systems

Needed Data	Supporting Documentation
Event Information, Composition and Volume of Blowdown, Disposition of Blowdown. Total Refinery Feed.	Lab analysis reports Throughput records Refinery feed records

Mass emissions	Calculation spreadsheet
Speciated emission factors	Lab analysis reports, source test reports

Reports
None

Definitions
None

Assumptions
None

Section 3.4.6.5 – Vacuum Producing Systems

Approved Methods
Vacuum producing system emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.4.6.5-1.

Table 3.4.6.5-1: Summary of Vacuum Producing System Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates	Monitors must be District approved and certified
2	Continuous gas composition analyzer with engineering estimates (e.g., F factor)	Use with calculated F factors	Monitors must be District approved and certified. Calculated F factor must trend fuel properties[1]
3	Occasional grab sample with continuous vent gas flow measurement or engineering estimates		Sampling must be District approved. Calculated F factor must trend fuel properties[1]
4	Source tests with measured process rates		District approved source test representative of normal operation.
5	Default emission factors with measured process rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change

Notes:
1. Fuel properties must be determined quarterly for each period of F factor calculation.

Data Needs
Depending on the approved measurement method used, the data required to estimate mass emissions from the process vent is summarized below.

Table 3.4.6.5-2: Summary of Data Needs for Vacuum Producing Systems

Approved Measurement Method	Needed Data
Unit Information	One Time: Unit Design. Process, Permitting and Ancillary Equipment Information.
	One Time: Selected Emissions Measurement Method.
	Annually: Unit and Method Changes, Quantity of Vacuum Unit Feed, Vent Gas and/or Condensed Liquid Composition.
VOC, HAPs, TACs: (Source tests, samples, or process calculations with measured or calculated process rates)	Mass emissions
	Speciated emission factors
VOC: (Default emission factors)	Speciated emission factors
	Mass emissions

Supporting Documentation

The supporting documentation of Table 3.4.6.5-3 should be maintained according to the emission estimation methodology employed.

Table 3.4.6.4-3 Documentation Required for Blowdown Systems

Needed Data	Supporting Documentation
One Time: Unit Design. Process, Permitting and Ancillary Equipment Information.	Piping and Instrumentation Diagrams Process Flow Diagrams
One Time: Selected Emissions Measurement Method.	Calculation spreadsheet
Annually: Unit and Method Changes, Quantity of Vacuum Unit Feed, Vent Gas and/or Condensed Liquid Composition.	Work orders/ capital expenditure requests Turnaround reports Throughput records Lab analysis reports
Mass emissions	Calculation spreadsheets
Speciated emission factors	Source test reports Lab analysis reports

Reports

None

Definitions

None

Assumptions

None

Section 3.5: Flares

Refinery Flares are routinely a source of emissions from continuous pilot and purge gas. Most refinery flares are also a source of emissions when vent gas is directed to the flares for malfunctions, unplanned shutdowns, startups, and scheduled shutdowns and turnarounds. There are also a select number of flares at a refinery that are dedicated abatement devices that are routinely used to control emissions from sources such as a tank or marine terminal.

There has been a recent effort to standardize the reporting of flare emissions. The refineries were notified of this standardization in January, 2015, for implementation in the 2015 annual update. Pilot and purge gas emissions are reported as combustion emissions at the flare source number. Emissions due to vent gas combustion are reported in the fugitive source S-32110. For inventory purposes, all flare emissions need to be included, regardless of whether they are reportable events or whether or not the flare is subject to Regulations 12-11 or 12-12. Emissions must include criteria pollutants, greenhouse gases (GHGs), toxic air contaminants (TACs) and hazardous air pollutants (HAPs).

Approved Methods

Flare emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.5-1.

Table 3.5-1: Summary of Flare Emission Estimates

Rank	Measurement Method	Applicability	Qualifications
1	Continuous composition monitoring (or manual sampling at least once every 3 hours during flaring events) and continuous flow rate monitoring of the gas sent to the flare	Any flare event where the vent gas exceeds the 12-11 sampling requirement (330 scfm for any consecutive 15 minute period).	Base SO_2 emissions on total sulfur content of vent gas. The Reg. 12-11-401.9 98% destruction efficiency may be used for inventory purposes if flares combust high heat content vent gas and are properly operated for high temperature optimum combustion (93% for flexi-gas flares or flares combusting < 300 Btu/scf vent gas).
2	Continuous flow rate monitoring and daily or weekly compositional analysis	Any flare event where the vent gas is below the 12-11 sampling requirement trigger.	Sampling and/or compositional analysis must be representative of combusted vent gas for the flaring duration.
3	Continuous flow rate and heating value monitoring	Purge and pilot gas.	Heating value monitoring not required if natural gas is used.
4	Engineering calculations	Any flare not subject to 12-11 and/or 12-12.	Process operating data monitored as needed.
5	Emission factors based on energy consumption	PM, NO_X, CO, GHG emissions	
6	Default emission factors based on refinery or process throughput	Use if no other method applies.	

Data Needs

Depending on the approved measurement method used, the following data is required to estimate mass emissions from flares.

Table 3.5-2: Summary of Data Needs for Estimating Emissions from Flares

Approved Measurement Method	Needed Data
All Methods	Flare Event Information
	Vent Gas Composition
	Basis for Emissions Calculations
Continuous composition monitoring (or manual sampling at least once every 3 hours during flaring events) and continuous flow rate monitoring of the gas sent to the flare	Vent Gas Quantity
	Duration of Event
	Flare Rating
	Mass Emissions
Continuous flow rate monitoring and daily or weekly compositional analysis	Vent Gas Quantity
	Duration of Event
	Flare Rating
	Mass Emissions
Continuous flow rate and heating value monitoring	Pilot Gas Quantity
	Purge Gas Quantity
	Destruction and Combustion Efficiency
	Gas Composition and Heating Value if other than natural gas
	Mass emissions
Engineering calculations	Vent Gas Quantity
	Duration of Event
	Flare Rating
	Mass Emissions
Emission factors based on energy consumption	Vent Gas Quantity
	Duration of Event
	Flare Rating
	Mass Emissions
Default emission factors based on refinery or process throughput	Crude Processing Capacity
	Emission Factor
	Mass Emissions

Supporting Documentation

The following supporting documentation should be maintained according the approved method used to estimate emissions.

Table 3.5-3: Supporting Documentation Required for Estimating Emissions from Flares

Approved Method	Needed Data	Required Documentation
All methods	Flare System Drawings and Specifications	A overall drawing for each flare system that shows the configuration, the flare description and source numbers, vent gas meter locations, purge gas meter locations, pilot gas meter locations, sulfur monitors, and sampling systems.
		Flare design specification that includes information to determine flare rating and vent gas velocities.
	Vent Gas Composition	Spreadsheet that shows results of all vent gas sampling.
		Vent gas composition compilation that was the basis for the emission calculations.
	Event Information	Spreadsheet that shows the raw vent gas flowrates and durations that were the basis for the total vent gas quantity.

Approved Method	Needed Data	Required Documentation
Continuous composition monitoring (or manual sampling at least once every 3 hours during flaring events) and continuous flow rate monitoring of the gas sent to the flare	Vent Gas Flowrate	Spreadsheet that shows raw vent gas flowrate, temperatures and pressures, and calculated vent gas flowrate in SCFM.
	Destruction and Combustion Efficiency	Basis for combustion efficiency and destruction efficiency used in emissions calculation, including operating data that demonstrates flares are properly operated if high efficiencies (greater than 95 percent) are used.
	Mass Emissions	Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons.
Continuous flow rate monitoring and daily or weekly compositional analysis	Vent Gas Flowrate	Spreadsheet that shows raw vent gas flowrate, temperatures and pressures, and calculated vent gas flowrate in SCFM.
	Destruction and Combustion Efficiency	Basis for combustion efficiency and destruction efficiency used in emissions calculation, including operating data that demonstrates flares are properly operated if high efficiencies (greater than 95 percent) are used.
	Mass Emissions	Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons.
Continuous flow rate and heating value monitoring	Pilot Gas Flowrate	Spreadsheet that shows raw pilot gas flowrate, temperatures and pressures, and calculated gas flowrate in SCFM
	Purge Gas Flowrate	Spreadsheet that shows raw purge gas flowrate, temperatures and pressures, and calculated gas flowrate in SCFM
	Destruction And Combustion Efficiency	Basis for combustion efficiency and destruction efficiency used in emissions calculation, including operating data that demonstrates flares are properly operated at high temperatures (if high efficiencies are used).
	Gas Composition if other than natural gas	Gas composition from each sample and a compilation that was the basis for the heating value used in the emission calculations.
	Mass Emissions	Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons.
Engineering calculations	Vent Gas Flowrate	Spreadsheet that shows raw vent gas flowrate, temperatures and pressures, and calculated vent gas flowrate in SCFM.
	Vent Gas Composition	Vent gas composition from each process that was evaluated and a compilation that was the basis for the emission calculations.
	Destruction And Combustion Efficiency	Basis for combustion efficiency and destruction efficiency used in emissions calculation, including operating data that demonstrates flares are properly operated at high temperatures (if high efficiencies are used).
	Mass Emissions	Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons.
Emission factors based on energy consumption	Vent Gas Flowrate	Spreadsheet that shows raw vent gas flowrate, temperatures and pressures, and calculated vent gas flowrate in SCFM.
	Vent Gas Composition	Vent gas composition and basis that was used to derive the vent gas LHV (or other unit that is the basis of the emission factors) used in the emission calculations.

Approved Method	Needed Data	Required Documentation
	Emission Factors	Basis for the energy consumption based emission factors used in the emission calculations.
	Mass Emissions	Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons.
Default emission factors based on refinery or process throughput	Process Unit Specification	Design drawings or specifications that demonstrate the unit capacity that was the basis of the emission calculation.
	Emission Factors	Basis for the unit capacity based emission factors used in the emission calculations.
	Mass Emissions	Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons.

Reports

The following reports and records are associated with this section.

BAAQMD Regulation 12, Rule 11, Flare Monitoring at Petroleum Refineries.

- Regulation 12-11-401, Flare Data Reporting Requirements: Monthly report showing hourly flaring data.
- Regulation 12-11-402, Flow Verification Report. Semiannual report verifying accuracy of vent gas flow monitoring.

BAAQMD Regulation 12, Rule 12, Flares at Petroleum Refineries.

- Regulation 12-12-401 and 12-12-404, Flare Minimization Plans (FMP). Initial and annual updates of FMP.
- Regulation 12-12-405, Notification of Flaring. Written notification when vent gas exceeds 500,000 SCF in a calendar day.
- Regulation 12-12-406, Determination and Reporting of Cause. A report indicating the cause and prevention of a flaring event.

Definitions

The following definitions apply when estimating emissions according to this section.

Vent Gas Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

Assumptions

The following assumptions are used in this section.

Item	Assumption
Total Flare Emissions	Emissions from flares include all vent gas combusted at the flares plus emissions from pilot and purge gas combustion.
Total Vent Gas Flow	There are no provisions to bypass the vent gas flow monitors.

Section 3.6: Wastewater

Wastewater systems consist of a variety of components, including collection systems, weirs, oil-water separators, flotation units, biological treatment and polishing. Because of the Benzene Waste NESHAP requirements, many of the components (equalization tanks, oil-water separators, flotation units) are enclosed and/or abated, and therefore, can be measured directly. Emissions from open units can be calculated using predictive modeling or emission factors.

Approved Methods

Wastewater emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.6-1.

Table 3.6-1: Summary of Approved Wastewater Emission Estimation Methodologies

Rank	Measurement Method or Emission Factor	Application
1	Direct measurement	Covered and vented units
2A	Predictive modeling with site-specific factors and biodegradation rates followed by validation	Uncovered units
2B	Predictive modeling with site-specific factors and biodegradation rates	Uncovered units
2C	Predictive modeling with site-specific factors	Uncovered units
3A	Engineering estimates based on wastewater treatment plant load	Uncovered units
3B	Engineering estimates based on crude throughput	Uncovered units

Data Needs

The following data is required to estimate mass emissions from cooling towers.

Table 3.6-2: Summary of Data Needs for Wastewater Estimation Methodologies

Approved Method	Needed Data
Direct measurement	Constituent load and speciation of collected gas samples
Predictive modeling with site-specific factors and biodegradation rates followed by validation	Constituent load and speciation of process wastewaters Site-specific biodegradation rates Model validation by a direct measurement method
Predictive modeling with site-specific factors and biodegradation rates	Constituent load and speciation of process wastewaters Site-specific biodegradation rates
Predictive modeling with site-specific factors	Constituent load and speciation of process wastewaters
Engineering estimates based on wastewater treatment plant load	Constituent load and speciation of process wastewaters
Engineering estimates based on crude throughput	Crude throughput

Supporting Documentation

The following data is required to estimate mass emissions from wastewater treatment operations.

Table 3.6-3: Summary of Supporting Documentation Needed for Wastewater Estimation Methodologies

Needed Data	Documentation
Constituent load and speciation of collected gas samples	Lab analysis reports, field data sheets Flow rates
Constituent load and speciation of process wastewaters Site-specific biodegradation rates Model validation by a direct measurement method	Lab analysis reports Flow rate/throughput records Model assumptions, equations, and calculations Direct measurement records
Constituent load and speciation of process wastewaters Site-specific biodegradation rates	Flow rates Model assumptions, equations, and calculations
Constituent load and speciation of process wastewaters	Flow rates, model assumptions, equations, and calculations
Constituent load and speciation of process wastewaters	Throughput records
Crude throughput	Throughput records

Reports
None

Definitions
None

Assumptions
None

Section 3.7: Cooling Towers

This section is for estimating POC, HAP, chlorine and particulate emissions from cooling towers. Organic contaminants are introduced into the cooling water through leaks in heat exchangers and condensers, and then stripped out of the cooling water to the atmosphere.

Emissions of precursor organic compounds (POCs) and toxic air contaminants (TACs) result when leaks occur in heat exchangers or condensers served by cooling towers. Particulate matter (PM_{10}) emissions result due to stripping in the cooling tower and drift loss.

Approved Methods

Cooling tower emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.7-1.

Table 3.7-1: Summary of Approved Cooling Tower Emission Estimation Methodologies

Rank	Measurement Method or Emission Factor	Compositional Analysis Data
1	Direct water measurement (continuous)	Speciated lab analysis (POC[1], TAC[1], TDS[2])
2	Direct water measurement (periodic)	Speciated lab analysis (POC[1], TAC[1], TDS[2])
3	Default emission factors	Default PM_{10}[3], POC[4], and TAC[5] emission factors

Notes:

[1] Site-specific and source-specific POC and TAC emissions shall be estimated using Equation 8-5 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

[2] If TDS concentration in cooling tower water is monitored, site-specific and source-specific PM_{10} emissions shall be estimated using Equation 8-9 assuming EF_{Drift} of 1,700 lb/MMgal from Table 5 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015. Else, PM_{10} emissions shall be estimated using Equation 8-8 and 8-9 assuming EF_{Drift} of 1,700 lb/MMgal from Table 5 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

[3] PM_{10} emissions shall be estimated using default emission factors for EF_{Unc} provided in Table 8-5 in Equation 8-10 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

[4] POC emissions shall be estimated using default emission factors for EF_{Unc} provided in Table 8-5 in Equation 8-6 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

[5] TAC emissions shall be estimated using default emission factors for EF_{Unc} provided in Table 8-5 and the average percent by weight of TACs provided in Table A-1 of Appendix A for process unit streams served by the cooling tower in Equation 8-7 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.

If Rank 1 or 2 is used, consecutive monitoring events can be used to estimate emissions by assigning each measurement to half of the time period between monitoring/sampling events.

Data Needs

The following data is required to estimate mass emissions from cooling towers.

Table 3.7-2: Summary of Data Needs for Cooling Tower Emission Estimation Methodologies

Approved Method	Needed Data
Direct water measurement (continuous)	POC, TAC, TDS concentration (in ppmw)
	If TDS is monitored, site-specific & source-specific TDS concentration (in ppmw) in cooling tower water.
	If TDS is not monitored, site-specific & source-specific parameter (conductivity, etc.) monitored to estimate TDS concentration (in ppmw) in cooling tower water.
	Cooling tower water flow recirculation rates (in GPM)
Direct water measurement	POC, TAC, TDS concentration (in ppmw)

Approved Method	Needed Data
(periodic)	If TDS is monitored, site-specific & source-specific TDS concentration (in ppmw) in cooling tower water.
	If TDS is not monitored, site-specific & source-specific parameter (conductivity, etc.) monitored to estimate TDS concentration (in ppmw) in cooling tower water.
	Cooling tower water flow recirculation rates (in GPM)
	Length of time of monitoring period
Default emission factors	Default POC emission factor from Table 8-5 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.
	Default TAC emission factors for process unit streams served by the cooling tower from Table A-1 of Appendix A in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.
	Default PM_{10} emission factor from Table 8-5 in "Emissions Estimation Protocol for Petroleum Refineries", Version 3, dated April 2015.
	Cooling tower water flow recirculation rates (in GPM)

Supporting Documentation

Logs/reports summarized in Table 3.7-3 shall be maintained when estimating mass emissions from cooling towers.

Table 3.7-3 Summary of Supporting Documentation Needed for Cooling Tower Emission Methodologies

Approved Method	Needed Data	Required Documentation
Direct water measurement (continuous)	POC, TAC, TDS concentrations (ppmw)	Continuous analyzer readings
	Cooling tower water recirculation rate (GPM)	Continuous measurements from pump flow rate curves, rotameters, or similar methods
Direct water measurement (periodic)	POC, TAC, TDS concentrations (in ppmw)	Periodic cooling tower water sampling logs containing monitoring info such as date, time, and sampling location.
		Lab results for cooling tower water samples for POC and TAC (in ppmw) If TDS monitored, site-specific & source-specific lab results for TDS (in ppmw) in cooling tower water. If TDS is not monitored, site-specific & source-specific lab results/District approved analyzer readings for parameter (conductivity, etc.) monitored to estimate TDS concentration (in ppmw) in cooling tower water.
		Emission calculations for POC and TAC based on lab results. If TDS monitored, emission calculations for PM_{10} based on lab results. If TDS not monitored, emission calculations for PM_{10} and supporting assumptions.
	Length of time of monitoring period	Assume measured concentration has occurred for half of the time period since the last sampling date; if a leak occurs, then add the time period it takes to repair the leak
	Cooling tower water flow recirculation rates (GPM)	Continuous measurements from pump flow rate curves, rotameters, or APCO-approved methods (in GPM)
	Cooling tower water flow recirculation rates (GPM)	PFDs showing process units, heat exchangers/condensers served by the cooling tower
Default emission factors	Emission factors	Emission calculation for VOC, TAC, and TDS
	Cooling tower water flow recirculation rate (GPM)	Continuous measurements from pump flow rate curves, rotameters, or APCO-approved methods (in GPM)

Reports

Regulation 11, Rule 10

Definitions

TDS	the quantity of dissolved material in a given volume of water

Assumptions

Measured concentrations during periodic sampling occurred half of the time between sampling events.

Section 3.8: Loading Operations

Organic and HAP/TAC emissions result from the loading of liquids into drums, trucks, railcars, and marine vessels.

Approved Methods

Loading operation emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.8-1.

Table 3.8-1: Summary of Loading Operations Emission Estimates

Rank	Measurement Method	Applicability	Qualifications
1A	Continuous gas composition analyzer with continuous vent gas flow measurement	Unlimited. Provides accurate emission rates.	Monitors must be District approved and certified.
1B	Continuous gas total hydrocarbon (THC) analyzer and continuous vent gas flow measurement, HAP/TAC speciation from periodic sampling	Unlimited with annual sampling frequency	Monitors must be District approved and certified.
2	Loading rate and speciated site specific emissions factor from EPA Method 18 source tests	Unlimited with annual source test frequency	District approved source test representative of normal operation
3	Loading rate and speciated estimated or default emission factors applied to NMOC source tests	Use calculated emissions factors based on loaded liquid composition.	District approved source test representative of normal operation.
4	Default emission factors with measured loading rates		Default emission factors are based on unit rates and will not accurately track emissions when as process parameters change.

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the Loading Operations is summarized below.

Table 3.8-2: Summary of Data Needs for Estimating Emissions from Loading Operations

Approved Measurement Method	Needed Data
Continuous compositional and flow measurement	Mass emissions
Continuous THC and flow measurement	Mass emissions
	Speciated emission factors
Loading rate and speciated site specific emissions factor from EPA Method 18 source tests	Mass emissions
	Loading rate
	Speciated emission factors
	Source Tests
Loading rate and speciated estimated or default emission factors applied to NMOC source tests	Mass Emissions
	Loading rate
	Speciated emission factors
	Source Tests
Default emission factors	Mass Emissions
	Loading rate
	Speciated emission factors

Supporting Documentation

The following supporting documentation should be maintained according the approved method used to estimate emissions.

Table 3.8-3: Supporting Documentation Required for Estimating Emissions from Loading Operations

Approved Method	Needed Data	Required Documentation
Continuous compositional and flow measurement	Mass emissions	Summary of CEMS certification and periodic accuracy testing.
		Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission concentration readings in ppm or volume % dry basis, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized by month, totalized for year, in lbs or tons (can be combined with first spreadsheet).
Continuous THC and flow measurement	Mass emissions	Summary of CEMS certification and periodic accuracy testing.
		Spreadsheet with raw fuel gas flowrate in SCFM (dry), percent flue gas oxygen content (dry), moisture content in percentage by volume, temperature in F or R, pressure in psia or atmospheres, emission concentration readings in ppm or volume % dry basis, and mass emissions in lbs or tons.
		Spreadsheet with mass emissions summarized by month, totalized for year (can be combined with spreadsheet above).
	Speciated emission factors	Documentation for basis of emission factor including, assumptions or constraints for specified emission factor, range of applicability of the emission factor, and confirmation that source operation is consistent with the applicability of the specified emission factor
		Emission factor calculations.
Loading rate and speciated site specific emissions factor from EPA Method 18 source tests	Mass emissions	Spreadsheet with daily loading rate, emissions factor, and mass emissions
		Spreadsheet with mass emissions summarized by month, totalized for year (can be combined with spreadsheet above).
	Loading rate	Loading records including material loaded, material properties, and total material loaded.
		Loading rate used in emission calculation.
	Speciated emission factors	Documentation for basis of emission factor including, assumptions or constraints for specified emission factor, range of applicability of the emission factor, and confirmation that source operation is consistent with the applicability of the specified emission factor
		Emission factors used in emission calculations.
	Source Test	Summary of source test report including all operating parameters and test results

Approved Method	Needed Data	Required Documentation
Loading rate and speciated estimated or default emission factors applied to NMOC source tests	Mass emissions	Spreadsheet with daily loading rate, emissions factor, and mass emissions
		Spreadsheet with mass emissions summarized by month, totalized for year (can be combined with spreadsheet above)
	Loading rate	Loading records including material loaded, material properties, and total material loaded.
		Loading rate used in emission calculation.
	Speciated emission factors	Documentation for basis of emission factor including, assumptions or constraints for specified emission factor, range of applicability of the emission factor, and confirmation that source operation is consistent with the applicability of the specified emission factor
		Emission factors used in emission calculations.
	Source Test	Summary of source test report including all operating parameters and test results
Default emission factors	Mass emissions	Spreadsheet with daily loading rate, emissions factor, and mass emissions
		Spreadsheet with mass emissions summarized by month, totalized for year (can be combined with spreadsheet above)
	Loading rate	Loading records including material loaded, material properties, and total material loaded
		Loading rate used in emission calculation.
	Speciated emission factors	Documentation for basis of emission factor if different that specified default AP-42 factor

Notes:

1. All required spreadsheets must be in format that data can be analyzed by the District. If pdf format is provided, a spreadsheet format must accompany the submission.
2. Source operating data is a list of key operating parameters that impact source emissions. Emission factors derived during source tests are only valid if the source test is conducted under conditions representative of normal operation. Comparison of the source daily operating data and the source operation during the source test will confirm the emission factor results from the source test are applicable for calculating source emissions. The minimum source operation data is listed. Similarly, source operating data is required to demonstrate the default emission factors are applicable for calculating source emissions.

Reports

None

Definitions

None

Assumptions

None

Section 3.9: Fugitive Dust

This section provides particulate emission calculations for three operations at refineries:

- roads (paved and unpaved),
- FCCU catalyst handling, and
- coke handling and storage.

Approved Methods

Emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.9-1.

Table 3.9-1: Summary of Fugitive Dust Emission Estimate Methodologies

Source	Rank	Measurement Method
Paved road	1	Calculated emission factor[1] (measured silt loading)
	2	Calculated emission factor[1] (default silt loading content)
Unpaved road	1	Calculated emission factor[2] (measured silt loading)
	2	Calculated emission factor[2] (default silt loading)
FCCU catalyst handling	1	Calculated emission factor[3] (measured silt and moisture content)
	2	Calculated emission factor[3] (default silt and moisture content)
Petroleum coke handling	1	Calculated emission factor[3] (measured silt and moisture content)
	2	Calculated emission factor[3] (default silt and moisture content)
Stock piles	1	Calculated emission factor[4]

Notes:
1. Use Equation 1 of Section 13.2.1.3 of AP-42 (U.S. EPA, 1995a)
2. Use Equation 1a of Section 13.2.2.2. of AP-42 (U.S. EPA, 1995a)
3. Use Equation 1 of Section 13.2.4.3 of AP-42 (U.S. EPA, 1995a)
4. Use Equations 1 through 7 of Section 13.2.5 of AP-42 (U.S. EPA, 1995a)

If silt loading and/or moisture content data is not available, the default values listed in Table 3.9-2 should be used.

Table 3.9-2: Default Values for Fugitive Dust Emission Estimate Methodologies

Source	Variable Description	Units	Activity	Default Value
Paved road	Silt loading	g/m^2	Coke or sulfur pit	70
			Other	10
Unpaved road	Silt loading	%	All	7
FCCU catalyst handling "drops"	Silt content	%	FCCU	50
	Moisture content	%		8
FCU or calcined coke "drops"	Silt content	%	Fluid coker	5
	Moisture content	%		8
Delayed coking unit coke "drops"	Silt content	%	Delayed coking	5
	Moisture content	%		10
Flexicoking or petroleum coke ash	Silt content	%	Flexicoking	13
	Moisture content	%		7

To estimate emissions occurring from paved and unpaved roads, the total vehicle miles traveled is required. However, it may not be practical to track every vehicle to every location visited within a refinery.

The following methods may be used to estimate vehicle miles traveled by vehicle type for vehicles where vehicle miles traveled are not tracked. The total vehicle miles traveled is the summation of all individual vehicle miles traveled.

Table 3.9-3: Methods for Estimating Vehicle Miles Traveled

Vehicle	Travel Location	VMT Estimation Method
Refinery vehicle	Never leaves refinery	For each vehicle, subtract the odometer reading at the beginning of the year from the odometer reading at the end of the year
	Leaves refinery	For each vehicle, multiply the difference in odometer readings at the beginning and end of the year by an estimated percentage of vehicle miles traveled while onsite.
Employee-owned vehicle (Used for Work Purposes)	Leaves refinery	For each employee, estimate the distance between the refinery entry/exit gate and their jobsite (e.g. office, parking lot, etc.), multiply by two for the round trip, and multiply by an estimated number of days worked
Contractor vehicle (Non-routine)[1]	Never leaves refinery during job	For each vehicle, subtract the odometer reading at the beginning of the job from the odometer reading at the end of the job
	Leaves refinery during job	For each vehicle, multiply the difference in odometer readings at the beginning and end of the job by an estimated percentage of vehicle miles traveled while onsite.
Contractor vehicle (Routine)[2]	Leaves refinery after job	For each vehicle, estimate the distance between the refinery contractor entry/exit gate and the jobsite (e.g. truck loading rack, office, etc.) and multiply by two for the round trip.

Notes:
1. Vehicles onsite for a specific project (e.g. turnaround, maintenance, etc.) and mileage may be tracked.
2. Vehicles onsite as normal part of business (e.g. crude oil truck deliveries, sulfur trucks, gasoline trucks, etc.)

Data Needs

The following data is required to estimate mass emissions from activities creating fugitive dust.

Table 3.9-4: Summary of Data Needs for Fugitive Dust Emission Estimate Methodologies

Source	Measurement Method	Needed Data
Paved road	Calculated emission factor (measured silt loading)	Road surface silt loading Average weight of vehicles Vehicle miles traveled
	Calculated emission factor (default silt loading content)	Average weight of vehicles Vehicle miles traveled
Unpaved road	Calculated emission factor (measured silt loading)	Road surface silt loading Average weight of vehicles Vehicle miles traveled
	Calculated emission factor (default silt loading)	Average weight of vehicles Vehicle miles traveled
FCCU catalyst handling	Calculated emission factor (measured silt and moisture content)	Mean wind speed Material moisture content Quantity of material transferred
	Calculated emission factor (default silt and moisture content)	Mean wind speed Quantity of material transferred
Petroleum coke handling	Calculated emission factor (measured silt and moisture content)	Mean wind speed Material moisture content Quantity of material transferred

Source	Measurement Method	Needed Data
	Calculated emission factor (default silt and moisture content)	Mean wind speed Quantity of material transferred
Stock piles	Calculated emission factor	Mean and fastest recorded wind speed Pile surface area

Supporting Documentation

The following data is required to estimate mass emissions from activities creating fugitive dust.

Table 3.9-5: Summary of Supporting Documentation Needed for Fugitive Dust Emission Estimate Methodologies

Source	Measurement Method	Needed Data	Documentation
Paved road	Calculated emission factor (measured silt loading)	Road surface silt loading Average weight of vehicles Vehicle miles traveled	Silt loading test results Weight calculations Odometer logs/VMT calculations
	Calculated emission factor (default silt loading content)	Average weight of vehicles Vehicle miles traveled	Weight calculations Odometer logs/VMT calculations
Unpaved road	Calculated emission factor (measured silt loading)	Road surface silt loading Average weight of vehicles Vehicle miles traveled	Silt loading test results Weight calculations Odometer logs/VMT calculations
	Calculated emission factor (default silt loading)	Average weight of vehicles Vehicle miles traveled	Weight calculations Odometer logs/VMT calculations
FCCU catalyst handling	Calculated emission factor (measured silt, moisture content)	Mean wind speed Material moisture content Quantity of material transferred	Meteorological records Moisture test results Throughput records
	Calculated emission factor (default silt and moisture content)	Mean wind speed Quantity of material transferred	Meteorological records Throughput records
Petroleum coke handling	Calculated emission factor (measured silt, moisture content)	Mean wind speed Material moisture content Quantity of material transferred	Meteorological records Moisture test results Throughput records
	Calculated emission factor (default silt and moisture content)	Mean wind speed Quantity of material transferred	Meteorological records Throughput records
Stock piles	Calculated emission factor	Mean and fastest recorded wind speed Pile surface area	Meteorological records Surface area calculations

Reports

None

Definitions

Silt any particulate, including but not limited to catalyst, coal, coke, or sulfur with a particle size less than 75 micrometers in diameter as measured by a No. 200 sieve

Vehicle mile traveled a measurement of miles traveled by vehicles

Assumptions

The following assumptions are used in this section.

Item	Assumption
Vehicle miles traveled	Estimated vehicle miles traveled
Average vehicle weight	Estimated average vehicle weight is representative of actual average vehicle weight

Section 3.10: Startup and Shutdown

Much of the emission estimates included in this guideline are for normal refinery operation. This section is intended to capture emissions from the non-routine emissions that occur during abnormal operation. Key non-routine operation is during Startup and Shutdown, when there can be discharges to atmosphere that normally do not occur. However, the EPA ICR states that it is beyond the scope of the ICR protocol to provide methods of estimating emissions during all possible startup or shutdown scenarios or events. This is true for this guideline section as well. The sole emission estimate for this section, as in the ICR, is for vessel depressurization. If there are other startup, shutdown or non-routine events that merit inclusion in this guideline, this addition will be included is a future version. However, if there are any non-routine events that cause emissions during Startup or Shutdown, provisions are available to identify these and estimate the emissions.

Vessels can be depressurized at any time that the process is no longer in operation, often for maintenance or inspection. In order to perform internal maintenance on a vessel, or to perform the periodic inspections required by ASME or other codes, vessels need to be purged of process materials and made suitable for safe vessel entry. Most of the vessel content is usually directed to a vapor recovery system where the gas is reprocessed, used for fuel gas, or flared. Organic and HAP/TAC emissions result from the final steps of vessel depressurization where the residual fluids are discharged to atmosphere. Often the vessel will be pressured and depressured repeatedly with inerts (i.e., nitrogen) to prevent hazardous environments when the vessel is made safe with the proper breathing air for vessel entry. The vessel discharge to atmosphere could be due to vessel pressures being too low to drive the materials for any more recovery, or the residual materials are of no value, or the residual material is so rich in inert gas that it will not combust or will affect the fuel gas system in a detrimental manner.

This section covers all startup/shutdown emissions, regardless of whether the emissions are generated at the equipment site or if the emissions are collected in a blowdown system and generated remotely. This section does not include emissions that are covered in other sections (e.g., emissions sent to a combustion device or a flare).

Approved Methods

Two methods are approved to estimate emissions from Process Vessel Depressurization, one for a vessel containing only gas and one for vessels that also contain a liquid "heel".

Table 3.10-1: Summary of Approved Process Vessel Depressurization Emission Estimate Methodologies

Rank	Measurement Method	Applicability	Qualifications
1A[1]	Engineering estimate based on ideal gas law	Vessels in gas service	May underestimate emissions if solid material in the vessel absorbs gas during process conditions and desorbs at startup/shutdown conditions.
1B[2]	Engineering estimate based on all residual liquids (the liquid "heel") vaporizing	Vessels in liquid service	Assumes the mass of the "heel" will be large in comparison to the mass in the gas phase.
1C	Engineering estimate based on both the ideal gas law and the liquid "heel"	Vessels in very volatile liquid service	Use for gasoline and similar volatile materials[3]

Notes:
1. EPA Emissions Estimation Protocol for Petroleum Refineries, April 2015, Section 11.1, Gaseous Process Vessel Depressurization and Purging
2. EPA Emissions Estimation Protocol for Petroleum Refineries, April 2015, Section 11.2, Liquid Process Vessel Depressurization and Purging
3. As recommended in Section 11.2, Liquid Process Vessel Depressurization and Purging

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the Startup and Shutdown Operations is summarized below. This information will be added to the Startup/Shutdown spreadsheet that accompanies this guideline.

Table 3.10-2: Summary of Data Needs for Process Vessel Depressurization Emission Estimate Methodologies

Approved Measurement Method	Needed Data
All Methods	Vessel (or tank) information for each event
	Event information
	Abatement information (if applicable)
	Process information for each event
Engineering estimate based on ideal gas law	Gas composition for each event
	Emission calculations
Engineering estimate based on all residual liquids (the liquid "heel") vaporizing	Liquid volume and composition for each event
	Emission calculations
Engineering estimate based on ideal gas law and the liquid "heel"	Gas composition for each event
	Liquid volume and composition for each event
	Emission calculations

Supporting Documentation

The following supporting documentation should be maintained according the approved method used to estimate emissions.

Table 3.10-3: Required Documentation for Process Vessel Depressurization Emission Estimate Methodologies

Approved Method	Needed Data	Required Documentation
All methods	Vessel Information	Equipment description including tag number, service, and content.
		Design drawings with sufficient information to determine equipment volume and void fraction.
	Event Information	Event information including purpose, notification, duration, steps taken prior to release to atmosphere, and process conditions prior to release to atmosphere.
		Operating procedures for depressurizing event.
		Operator log showing process parameters prior to release to atmosphere.
	Gas Composition for each vessel	Documentation of the gas composition for each vessel that was the basis of the emission estimate (e.g., material balance, flash calculations, sample analyses, or source test reports).
	Liquid Volume and Composition for each vessel (if applicable)	The liquid "heel" volume and the basis or assumption used to determine the volume
		Documentation of the liquid composition for each vessel that was the basis of the emission estimate (e.g., material balance, flash calculations, sample analyses, or source test reports)
	Abatement Device (devices not included in other sections)	Owner Information (if different from refinery owner)
		Abatement Device Permit to Operate
		Design drawings with sufficient information to determine destruction efficiency

Approved Method	Needed Data	Required Documentation
		Operator log showing process parameters during service.
		Source test report and date of submission to District (if basis for destruction efficiency used in emission calculations)

Records/Reports

The following reports and records are associated with this section.

BAAQMD Regulation 8, Rule 5, Storage of Organic Liquids.

- Regulation 8-5-328.3, Tank Degassing Requirements: Written notification 3 days prior to tank degassing operation.
- Regulation 8-5-403, Inspection Requirements for Pressure Relief Devices: Inspection records.
- Regulation 8-5-404, Inspection, Abatement Efficiency Determination and Source Test Reports: Report required within 60 days of any inspection, abatement efficiency determination or source test.
- Regulation 8-5-501.1, Records: Accurate records of material stored.
- Regulation 8-5-501.4, Records: Engineering data sheets for pressure vacuum valves.
- Regulation 8-5-502.2, Source Test Requirements: Source test during tank degassing or cleaning event.

BAAQMD Regulation 8, Rule 10, Process Vessel Depressurization

- Regulation 8-10-401, Reporting: Annual report due February 1 of each year.
- Regulation 8-10-503, Records: Content of annual report.

Refinery MACT 40 CFR 63.641: HAP content in stored liquid.

Refinery MACT 40 CFR 63.654: Records.

Definitions

The following definitions apply when estimating emissions according to this section.

Vessel any equipment that is vented to atmosphere including equipment such as a process pressure vessel, a reactor, a column, or a storage tank. Any piping or other ancillary equipment that is vented to atmosphere, whether associated with the vessel or independently depressured to atmosphere is also included in this section.

Assumptions

The following assumptions are used in this section.

Item	Assumption
Vessel depressurization	No emissions to atmosphere occur through pressure relief devices.

Section 3-11: Malfunctions/Upsets

During malfunction/upset events, emissions may be significantly higher than the emissions that occur under normal operating conditions. Three malfunction/upset events scenarios are addressed in this section:

- Control device malfunction
- Process vessel over pressurization

- Liquid spills

Specific malfunction/upset events that require emission estimates are shown below. This list is not intended to be an exhaustive list.

- Any instance when a control or abatement device is bypassed or is not functioning properly.
- Any instance when a fuel gas treatment system or a sulfur recovery plant if offline or is not operating at normal efficiencies.
- Any instance where a flare is over-steamed.
- Any instance where the operating conditions of a flare do not satisfy 40 CFR 60.18 (e.g., BTU content, exit velocities).
- Any instance when a spill or other similar release occurs.

Specific events that are not covered by this section are shown below:

- Leaks identified by the refinery LDAR program (as long as the leaks do not cause a liquid puddle). Covered in Section 3.1.
- Flare emissions when the flare operating conditions satisfy the design requirements of 40 CFR 60.18. Covered in Section 3.5.
- Storage tank emissions from unintentional tank roof landings. Covered in Section 3.2.

Approved Methods

Emissions shall be estimated by using the highest ranking method for which data is available as listed in Table 3.11-1.

Table 3.11-1: Summary of Malfunction/Upset Events Emission Estimates

Rank	Measurement Method	Applicability	Qualifications
1	Direct measurement (CEM for both flow rate and gas composition)	Unlimited (CEM-monitored operation)	CEM must be District approved/certified CEM monitoring range must include uncontrolled emission levels
2	Emission calculations (specified multiplier derived from normal control device efficiency)	Control Device Malfunction	Multiplier = 1/(1-normal efficiency)
	Emission calculations (relief device flow rate)	Vessel Overpressurization (discharged to atmosphere)	Also applies to discharges recovered to fuel gas or sent to flare if not accounted for in another section (e.g., if default emission factors are used)
	Emission calculations (mass transfer coefficients[1] and liquid properties)	Large Liquid Spills	Use for spills > 500 gallons.
	Calculations (assume all materials in spill emitted to the atmosphere)	Small Liquid Spills	Use for spills < 500 gallons

Notes:
1. As listed in Section 12.3 *Spills* of the EEPPR, mass transfer coefficients provided in Appendix B, *Wastewater Treatment System Equations*, Section B.2.1, *Oil Water Separators*

Data Needs

Depending on the approved measurement method used, the data required to estimate mass emissions from the Malfunction/Upset Events is summarized below.

Table 3.11-2: Summary of Data Needs for Estimating Emissions from Malfunction/Upset Events

Event	Approved Measurement Method	Needed Data
Control Device Malfunction	Direct measurement (CEMS)	Mass emissions
	Calculations	Mass emissions
		Controlled Emissions Multiplier
Vessel Overpressurization	Calculations	Mass emissions
		Gas Composition
		Emissions point (fuel gas, flare or direct to atmosphere)
Liquid Spills < 500 gallons	Calculations	Mass Emissions
		Total spill volume and mass
		Liquid Composition
Liquid Spills > 500 gallons	Calculations	Mass Emissions
		Total spill duration, volume and mass
		Liquid Composition
		Mass Transfer Coefficients

Supporting Documentation

The following supporting documentation should be maintained according the approved method used to estimate emissions.

Table 3.11-3: Supporting Documentation Required for Estimating Emissions from Malfunction/Upset Events **Event**	**Approved Method**	**Needed Data**	**Required Documentation**
Control Device Malfunction (separate documentation for each control device)	Direct measurement (CEMS)	Mass emissions	Summary of CEMS certification and periodic accuracy testing
			Spreadsheet with raw flue gas flowrate in SCFM, moisture content in cubic feet of water per cubic feet of exhaust gas, temperature in F or R, pressure in psia or atmospheres, emission concentration readings in volume % dry basis, and mass emissions in lbs or tons.
			Spreadsheet for each control device with description of event including date and duration, mass emissions summarized by event, and mass emissions totalized for year, in lbs or tons (can be combined with first spreadsheet)
	Calculations	Mass emissions	Spreadsheet for each control device with description of event including date and duration, normal daily controlled emissions, controlled emissions multiplier, and mass emissions in lbs or tons

Table 3.11-3: Supporting Documentation Required for Estimating Emissions from Malfunction/Upset Events **Event**	**Approved Method**	**Needed Data**	**Required Documentation**
			Spreadsheet for each control device with mass emissions summarized by event, and mass emissions totalized for year, in lbs or tons (can be combined with first spreadsheet).
Vessel Overpressurization	Calculations	Mass emissions	Spreadsheet with description of event including vessel, date and duration, vessel or process unit source number, sonic or subsonic flow, mach number, vent outlet description and cross-sectional area, vessel pressure and temperature, gas molecular weight, and mass emissions in lbs or tons.
			Spreadsheet with mass emissions summarized by event, and mass emissions totalized for year, in lbs or tons (can be combined with first spreadsheet).
		Gas Composition	Documentation of basis of composition used in emission calculations.
			Spreadsheet with details of physical or thermal properties derived from gas composition (e.g., MW, k values [$k=C_p/C_v$])
		Emission Points	Description of emission point
			Basis for emission reductions if emissions not direct to atmosphere (e.g., if emissions are reduced by flaring, amount of reductions and basis for destruction efficiency of flare.)
Liquid Spills	Calculations	Mass Emissions	Spreadsheet with description of event including spill origin and date, equipment or process unit source number, liquid description, temperature and vapor pressure, and mass emissions in lbs or tons.
		Total spill duration, volume and mass	Spreadsheet detailing for each spill the volume and mass of the liquid. For spills > 500 gallons, also show the duration of the spill.
		Liquid Composition	Documentation of basis of composition used in calculations.
			For spills > 500 gallons, a spreadsheet with details of physical or thermal properties derived from liquid composition
		Mass Transfer Coefficients (spills > 500 gallons)	Spreadsheet with the detailed calculations resulting in the mass transfer coefficient used in the emissions calculations.

Reports

A report of each malfunction or upset event and the emission impacts of each event.

Definitions
None

Assumptions
None

Section 3.12: Miscellaneous Sources

In addition to the major category of emission producing sources discussed in other sections, there are several relatively infrequent and/or minor activities at petroleum refineries. These include:

- non-retail gasoline and diesel dispensing facilities,
- equipment painting (architectural coatings and paint booths),
- abrasive blasting
- solvent degreasers
- soil remediation, and
- ground water remediation.

Section 3.12.1: Non-Retail Gasoline and Diesel Dispensing Facility

Petroleum refineries employ a fleet of vehicles (maintenance trucks, cranes, etc.) that require fueling onsite. Fueling is often done at non-retail gasoline and diesel dispensing facilities.

Approved Methods
Emissions shall be estimated by using the method as listed in Table 3.12.1-1.

Table 3.12.1-1: Summary of Emission Estimate Methodology

Rank	Measurement Method	Compositional Analysis Data
1	Default Emission Factors	Material (e.g. gasoline, diesel, etc.) speciation

Data Needs
The following data is required to estimate mass emissions from fuel dispensing activities.

Table 3.12.1-2 Summary of Data Needs for Emission Estimation

Approved Method	Needed Data
Default Emission Factors	Material (e.g. gasoline, diesel, etc.) throughput
	Material (e.g. gasoline, diesel, etc.) speciation
	Abatement efficiency

Supporting Documentation
The following supporting documentation should be maintained.

Table 3.12.1-2 Supporting Documentation Required by Fuel Dispensing Emission Estimation

Approved Method	Needed Data	Required Documentation
Default Emission Factors	Material (e.g. gasoline, diesel, etc.) throughput	Throughput records
	Material (e.g. gasoline, diesel, etc.) speciation	Lab analyses
	Abatement efficiency	Source test reports

Reports
BAAQMD Regulation 8, Rule 7 (Gasoline Dispensing Facilities)

Definitions
None

Assumptions

The following assumptions are used in this section.

Item	Assumption
Default Emission Factor	Emission factor is representative of emissions

Section 3.12.2: Architectural or Equipment Painting

Occasionally, equipment or buildings may be painted. Emissions should be estimated from all painting activities that occur within refinery boundaries whether by petroleum refinery staff or third party contractors.

Approved Methods

Emissions from painting activities should be estimated using a material balance (Table 3.12.2-1) and assuming that 100 percent of organic compounds are emitted.

Table 3.12.2-1: Summary of Architectural or Equipment Painting Emission Estimate Methodologies

Rank	Measurement Method	Compositional Analysis Data
1	Material balance	Coating characterization including POC and NPOC content

Data Needs

The following data is required to estimate mass emissions from painting activities.

Table 3.12.2-2 Summary of Data Needs for Painting Emission Estimation

Approved Method	Needed Data
Material balance	Material (e.g. solvent, paint, etc.) usages
	Material characteristics including POC and NPOC content

Supporting Documentation

The following supporting documentation should be maintained.

Table 3.12.2-3 Supporting Documentation Required by Painting Emission Estimation

Approved Method	Needed Data	Required Documentation
Material balance	Material (e.g. solvent, paint, etc.) usages	Usage records Purchase and disposal records Work orders
	Material characteristics	Material Safety Data Sheets

Reports

None

Definitions

Architectural Coating A coating applied to stationary structures and their appurtenances at the site of installation, to portable buildings at the site of installation, to pavements, or to curbs.

Appurtenances Any accessory to a stationary structure coated at the site of installation, whether installed or detached, including but not limited to: bathroom and kitchen fixtures; cabinets; concrete forms; doors; elevators; fences; hand railings; heating equipment, air conditioning equipment, and other fixed mechanical equipment or stationary tools; lampposts; partitions; pipes and piping systems; rain gutters and downspouts; stairways, fixed ladders, catwalks, and fire escapes; and window screens.

Assumptions

The following assumptions are used in this section.

Item	Assumption
Evaporation rate	100% of volatiles evaporate and are emitted to atmosphere

Section 3.12.3: Abrasive Blasting

Abrasive blasting is the cleaning or preparing of a surface by forcibly propelling a stream of abrasive material against the surface using sand, glass bead, aluminum oxide, grit, slag, garnet, steel shot, slag, walnut shells, and others.

Abrasive blasting may be confined or unconfined and is used to:

- Remove rust, scale, and paint;
- Roughen surfaces in preparation for bonding, painting or coating;
- Remove burr, and/or
- Develop a matte surface finish.

In a petroleum refinery, abrasive blasting is mainly used for cleaning and painting of aboveground storage tanks or building and removing rust or other debris from pressure vessels, furnaces, boilers, etc.

Approved Methods

Emissions shall be estimated by using the method as listed in Table 3.12.3-1.

Table 3.12.3-1: Summary of Abrasive Blasting Emission Estimate Methodologies

Rank	Measurement Method	Compositional Analysis Data
1	Default Emission Factors	Abrasive characterization

Data Needs

The following data is required to estimate mass emissions from abrasive blasting activities.

Table 3.12.3-2 Summary of Data Needs for Abrasive Blasting Emission Estimation

Approved Method	Needed Data
Default Emission Factors	Abrasive usage
	Abrasive characteristics
	Abatement efficiencies (capture efficiency and control efficiency), if available

Supporting Documentation

The following supporting documentation should be maintained.

Table 3.12.3-3 Supporting Documentation Required by Abrasive Blasting Emission Estimation

Approved Method	Needed Data	Required Documentation
Default Emission Factors	Abrasive usage	Abrasive usage records
	Abrasive characteristics	Material Safety Data Sheets

Approved Method	Needed Data	Required Documentation
	Abatement efficiencies	Capture efficiency calculation Source test reports

Reports
None

Definitions
None

Assumptions
The following assumptions are used in this section.

Item	Assumption
Default Emission Factor	Emission factor is representative of emissions

Section 3.12.4: Solvent Degreaser

Solvent degreasers are typically used in maintenance shops to clean tools and parts. Emissions from solvent degreasers are required to be estimated.

Approved Methods
Emissions from solvent degreasers should be estimated by multiplying the net solvent usage by the density of the solvent and assuming the solvent to be 100 percent volatile and emitted to the atmosphere.

Data Needs
The following data is required to estimate mass emissions from soil vapor extraction activities.

Table 3.12.4-1 Summary of Data Needs for Solvent Degreaser Emission Estimation

Approved Method	Needed Data
Material balance	Solvent usage
	Solvent characteristics including POC and NPOC content

Supporting Documentation
The following supporting documentation should be maintained.

Table 3.12.4-2 Supporting Documentation Required by Solvent Degreaser Emission Estimation

Approved Method	Needed Data	Required Documentation
Material balance	Solvent usage	Solvent usage records
	Solvent characteristics	Material Safety Data Sheets

Reports
None

Definitions
None

Assumptions

The following assumptions are used in this section.

Item	Assumption
Evaporation rate	100% of solvent is emitted to atmosphere

Section 3.12.5: Soil Remediation

Soil remediation is the process of removing pollutants from soil contaminated either accidentally (e.g. spills, leaking underground storage tanks, etc.) or intentionally (historical dumping or burying of barrels).

Contaminated soil may be decontaminated using soil vapor extraction (either venting of soil or applying a vacuum) or soil excavation where contaminated soil may be aerated and/or sent offsite for treatment.

Exhaust air from decontamination activities is typically directed to a carbon abatement system or to a thermal oxidizer.

Emissions from all temporary or permanent soil and soil excavation activities should be estimated as well as emissions created by any abatement devices (e.g. thermal oxidizer).

Approved Methods

Emissions shall be estimated by using the method listed in Table 3.12.5-1.

Table 3.12.5-1: Summary of Soil Remediation Emission Estimate Methodologies

Rank	Measurement Method	Compositional Analysis Data
1	Material balance	Pollutant plume characterization (lab analysis)

Data Needs

The following data is required to estimate mass emissions from soil vapor extraction activities.

Table 3.12.5-2: Summary of Data Needs for Soil Remediation Emission Estimates

Approved Method	Needed Data
Material balance	Influent concentrations (TOC, individual TACs)
	Influent flow rate
	Abatement device efficiency

Supporting Documentation

The following supporting documentation should be maintained.

Table 3.12.5-3 Supporting Documentation Required by Soil Remediation Emission Estimation

Approved Method	Needed Data	Required Documentation
Material balance	Influent concentrations	Lab analysis
	Influent flow rate	Equipment design specifications (e.g. vacuum blower maximum capacity)
	Abatement device efficiency	Source test results

Reports

District Regulation 8, Rule 40 (Aeration of Contaminated Soil and Removal of Underground Storage Tanks)

- Report – Removal or Replacement of Tanks (Reg. 8-40-401)
- Report – Excavation of Contaminated Soil (Reg. 8-40-402)
- Report – Aeration of Soil (Reg. 8-40-403)
- Report – Contaminated Soil Excavation During Organic Liquid Service Pipeline Repairs (Reg. 8-40-404)
- Report – Contaminated Soil Excavations Unrelated to Underground Storage Tank Activities (Reg. 8-40-405)

District Regulation 8, Rule 47 (Air Stripping and Soil Vapor Extraction Operations)

- Report – Superfund Amendments and Reauthorization Act Sites (Reg. 8-47-401)
- Report – Less than 1 Pound per Day Petition (Reg. 8-47-402)

Definitions

None.

Assumptions

The following assumptions are used in this section.

Item	Assumption
Stripped contaminants	100% of contaminants are stripped from the soil

Section 3.12.6: Groundwater Remediation (Air Stripping)

Similar to contaminated soil, groundwater may become contaminated and require remediation.
Ground water is typically remediation via air stripping where water is sprayed inside a packed tower or aeration tank and air is forced, countercurrent to the water flow. Volatile contaminants are transferred from contaminated water to air.

Approved Methods

Emissions shall be estimated by using the method listed in Table 3.12.6-1.

Table 3.12.6-1: Summary of Soil Remediation or Soil Excavation Emission Estimate Methodologies

Rank	Measurement Method	Compositional Analysis Data
1	Material balance	Water analysis

Data Needs

The following data is required to estimate mass emissions from air stripping activities.

Table 3.12.6-2: Summary of Data Needs for Air Stripping Emission Estimates

Approved Method	Needed Data
Material balance	Influent concentrations (TOC, individual TACs)
	Influent flow rate
	Abatement device efficiency

Supporting Documentation

The following supporting documentation should be maintained.

Table 3.12.6-3 Supporting Documentation Required by Air Stripping Emission Estimation

Approved Method	Needed Data	Required Documentation
Material balance	Influent concentrations	Lab analysis
	Influent flow rate	Equipment design specifications (e.g. air stripping blower maximum capacity)
	Abatement device efficiency	Source test results

Reports

District Regulation 8, Rule 47 (Air Stripping and Soil Vapor Extraction Operations)

- Report – Superfund Amendments and Reauthorization Act Sites (Reg. 8-47-401)
- Report – Less than 1 Pound per Day Petition (Reg. 8-47-402)

Definitions

None

Assumptions

The following assumptions are used in this section.

Item	Assumption
Contaminant transfer	100 percent of contaminants are stripped from contaminated water

Section 3.12.7: Contractor Operations

Emissions resulting from contractor operations at a petroleum refinery should be included in that facility's emission inventory using the guidance provided in these guidelines.

The following are examples of contractor operations for which emissions are required to be estimated and reported:

- De-coking
- Catalyst replacement
- Vessel cleaning
- Tank cleaning/degassing
- Hydroblasting
- Tank painting
- Pipeline pigging
- Refractory conditioning

Section 3.13: Cargo Carriers

In addition to through pipeline, petroleum refineries receive and ship out crude oil, intermediates, and finished products by marine vessels and rail.

Section 3.13.1 – Marine

This section shall be used to estimate marine emissions of diesel particulate matter (DPM), PM_{10}, $PM_{2.5}$, POC, NOx, SO_2, CO, TACs, and greenhouse gases (GHG) resulting from fuels combusted in ocean going vessels (OGV) and harbor craft (barges and tugs) that transport/assist in the transport of feedstocks, blend stocks, refined products into and out of refineries.

Approved Methods

Emissions shall be estimate using the highest ranking method listed in Table 3.13.1-1.

Table 3.13.1-1: Summary of Marine Emission Estimation Methodologies

Rank	Measurement Method or Emission Factor	Compositional Data Analysis
1	Direct measurement (continuous emission monitoring systems [CEMS] for both flow rate and gas composition)	Speciation of organic compounds
2	Direct measurement (CEMS) for gas composition Use of F factors	Speciation of organic compounds
3A	Fuel analysis/mass balance	
3B	Source-specific stack testing to calculate source-specific emission correlations or factors	Speciated PM_{10}, POC, and TAC analysis
4	Default emission factors	None
5	Emission calculations	Fuel analysis/fuel oil vendor certification

Rank 5 – Emission Calculations

When estimating emissions using emission calculations, the following equation shall be used to estimate emissions from propulsion & auxiliary engines and auxiliary boilers for each **OGV** calling at the refinery:

$$E = P \times LF \times A \times EF \times LLAM \times FCF \qquad \text{[Equation 3.13.1-1]}$$

Where E = Emissions (grams [g])
P = Maximum Continuous Rating Power (kilowatts [kW])
LF = Load Factor (percent of vessel's total propulsion or auxiliary power [dimensionless])
A = Operating mode specific activity (hours [h])
EF = Emission Factor (grams per kilowatt-hour [g/kW-hour])
LLAM = Low Load Adjustment Multiplier when LF < 20% (dimensionless)
FCF = Fuel Correction Factor (dimensionless)

The following equation shall be used to estimate emissions of PM_{10}, POC, NOx, and CO from propulsion and auxiliary engines on **tug boats escorting and/or assisting each OGV** calling at the refinery, from auxiliary engines on each **barge**[1] calling at the refinery, and from propulsion and auxiliary engines on **tug boats**[2] **assisting each barge** at the refinery:

$E_{Non\text{-}SO2} = EF_0 \times F \times (1 + D \times A/UL) \times P \times LF \times H$ [Equation 3.13.1-2]

Where E = Emissions (grams [g])
EF_0 = Emission factor (g/HP-hour) based on engine model year, horsepower, and use (propulsion/main "ME" or auxiliary "AE")
LF = Load Factor based on vessel type and use (propulsion or auxiliary)
F = Fuel Correction Factor for NOx and PM (dimensionless)
D = Engine Deterioration Factor (dimensionless)
A = Age of the engine when emissions are estimated (years)
UL = Useful life in years based on vessel type and use (propulsion or auxiliary)
P = Rated horsepower of the engine
H = Operating hours of engines during the call

Fuel consumed by propulsion and auxiliary engines on **tug boats escorting and/or assisting each OGV** calling at the refinery, from auxiliary engines on each **barge** calling at the refinery, and from propulsion and auxiliary engines on **tug boats assisting each barge** calling at the refinery shall be estimated by the following equation:

$F_c = P \times LF \times H \times BSFC$ [Equation 3.13.1-3]

Where F_c = Fuel consumed per engine during the call (gallons)
P = Rated power of the engines (HP or kW)[3]
LF = Load Factor based on vessel type and use (propulsion or auxiliary)
H = Operating hours of engines during the call
BSFC = brake specific fuel consumption (0.078 gal/kW-hour or 184 g/hp-hr)

SO_2 emissions from propulsion and auxiliary engines on **tug boats escorting and/or assisting each OGV** calling at the refinery, from auxiliary engines on each **barge** calling at the refinery, and from propulsion and auxiliary engines on **tug boats assisting each barge** calling at the refinery shall be estimated by the following equation:

$E_{SO2} = F_c \times (\%\text{ by weight sulfur in fuel}) \times (\text{density of fuel [lb/gal]}) \times 2$ [Equation 3.13.1-4]

Data Needs

The following data is required to estimate mass emissions form OGV propulsion and auxiliary engines.

Table 3.13.1-2: Data Needed to Estimate OGV Engine Emissions (Rank 5)

Variable	Data Needed
P Maximum Continuous Rating Power (kW)	Propulsion engine power (kW) Auxiliary engine power (kW) Use 13,034 kW and 2,339 kW if vessel specific engine info is not available[4].

[1] Barges are addressed in CARB Appendix C "Updates on the Emissions Inventory for Commercial Harbor Craft Operating in California". However, there is no substantive change in emissions estimation methodology between Appendix B and C.

[2] Barges are assumed to be similar to "Towboat/Pushboat" in Table I-1 of CARB Appendix B "Emissions Estimation Methodology for Commercial Ocean-Going Vessels" dated November 2007

[3] 1 HP = 1.341 x kW

Variable	Data Needed
LF Load Factor – propulsion (dimensionless)	Actual speed (knots[5]) Maximum speed (knots) Assume LF = 0.825 at service or cruise speed. Else, estimate LF via Propeller Law at lower speeds as shown below $LF = (\text{Actual speed} \div \text{Maximum Speed})^3$
LF Load Factor – auxiliary (dimensionless)	Assume LF to be 0.24 for Transit, 0.33 for Maneuver, 0.26 Hoteling (Berth/Anchorage)[6] if vessel specific LF for auxiliary engine is not available.
Activity (hours)	Activity = Transit + Maneuvering + Hoteling – Berth + Hoteling - Anchorage Transit time (travel time from Pilot Buoy to refinery wharf and/or between ports if calling at more than one refinery) = distance travelled (nautical miles) ÷ vessel speed (knots) Maneuvering time (time spent by vessel while in-port) = distance travelled (nautical miles) ÷ vessel speed (knots) + 15 minutes for docking + 15 minutes for undocking Hoteling – Berth time (time spent by vessel in-port when moored to dock) = (time when vessel leaves berth) – (time when vessel ties up at berth) Use 34-hours/visit[7] if vessel specific hoteling time at berth is not available. Hoteling – Anchorage time (time spent by vessel in-port when at anchor) = (time when vessel raises anchor and moves) – (time when vessel drops anchor) Use 23-hours/visit[8] if vessel specific hoteling time at anchorage is not available. All OGVs entering the SF Bay from the open ocean are required to stop at the Pilot Buoy which is located 11 nautical miles from the Golden Gate bridge pick up a pilot and have at least one escort tug and one/more assist tugs accompany the OGV. Therefore, the transit and maneuvering times for each OGV shall be estimated by dividing the nautical miles travelled for each trip segment shown below by the average vessel speed: • Segment 1: Pilot Buoy to Pt. Bonita. • Segment 2: Pt. Bonita to Southampton Shoal. • Segment 3: Southampton Shoal to refinery wharf. • Segment 4: Refinery wharf to Southampton Shoal. • Segment 5: Southampton Shoal to Pt. Bonita. • Segment 6: Pt. Bonita to Pilot Buoy. Note: The number of trip segments travelled by OGVs and the associated transit, maneuvering, and hoteling times could be higher if the OGV stops at more than one refinery/at anchorage before heading back to the open ocean from the SF Bay. Apportioning emissions between refineries under such circumstances is discussed in Section 3.13.3 "Shared Emissions".

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[4] Table II-4 in CARB Appendix D "Emissions Estimation Methodology for Ocean-Going Vessels" dated May 2011

[5] 1 knot = 1 nautical mile per hour (~1.15 miles per hour)

[6] Table II-5 in CARB Appendix D "Emissions Estimation Methodology for Ocean-Going Vessels" dated May 2011

[7] Table II-2 in CARB Appendix D "Emissions Estimation Methodology for Ocean-Going Vessels" dated May 2011

[8] Table II-3 in CARB Appendix D "Emissions Estimation Methodology for Ocean-Going Vessels" dated May 2011

Variable	Data Needed
EF Emission Factor (g/kW-hour)	Emission factors provided in Tables II-6, II-7, II-8 in CARB Appendix D "Emissions Estimation Methodology for Ocean-Going Vessels" dated May 2011.
LLAM Low Load Adjustment Multiplier (dimensionless)	Emission factors provided in Table 3.9 in "Port of Los Angeles Inventory of Air Emissions – 2011" Technical Report ADP# 111129-929 dated July 2012.
FCF Fuel Correction Factor (dimensionless)	Factors provided in Table 3.17 in "Port of Los Angeles Inventory of Air Emissions – 2011" Technical Report ADP# 111129-929 dated July 2012.

The following data is needed to estimate mass emissions from OGV auxiliary boilers.

Table 3.13.1-3: Data Needed to Estimate OGV Auxiliary Boiler Emissions (Rank 5)

Variable	Data Needed
P Maximum Continuous Rating Power (kW)	Auxiliary boiler power (kW) Use 371 kW for Maneuvering, 3,000 kW for Hoteling – Berth, and 371 kW for Hoteling – Anchorage, if vessel specific boiler info is not available[9].
LF Load Factor and LLAM Low Load Adjustment Multiplier (dimensionless)	Assume LF and LLAM to be 1.
Activity (hours)	Activity = Transit + Maneuvering + Hoteling – Berth + Hoteling - Anchorage Transit time (boiler operating hours during OGV transit) = distance travelled by vessel when operating boiler (nautical miles) ÷ vessel speed (knots[10]) Maneuvering time (boiler operating hours when vessel in-port) = distance travelled by vessel when operating boiler (nautical miles) ÷ vessel speed (knots) + 15 minutes for docking + 15 minutes for undocking Hoteling – Berth time (boiler operating hours when vessel in-port moored to dock) = (time when vessel leaves berth) – (time when vessel ties up at berth) Use 34-hours/visit[11] if vessel specific hoteling time at berth is not available. Hoteling – Anchorage time (boiler operating hours when vessel in-port at anchor) = (time when vessel raises anchor and moves) – (time when vessel drops anchor) Use 23-hours/visit[12] if vessel specific hoteling time at anchorage is not available. All OGVs entering the SF Bay from the open ocean are required to stop at the Pilot Buoy which is located 11 nautical miles from the Golden Gate bridge pick up a pilot and have at least one escort tug and one/more assist tugs accompany the OGV. Therefore, the boiler operating hours associated with transit and maneuvering for each OGV shall be estimated by dividing the nautical miles travelled for each trip segment shown below by the average vessel speed: • Segment 1: Pilot Buoy to Pt. Bonita.

[9] Table 3.16 in "Port of Los Angeles Inventory of Air Emissions – 2011" Technical Report ADP# 111129-929 dated July 2012.

[10] 1 knot = 1 nautical mile per hour (~1.15 miles per hour)

[11] Table II-2 in CARB Appendix D "Emissions Estimation Methodology for Ocean-Going Vessels" dated May 2011

[12] Table II-3 in CARB Appendix D "Emissions Estimation Methodology for Ocean-Going Vessels" dated May 2011

Variable	Data Needed
	• Segment 2: Pt. Bonita to Southampton Shoal. • Segment 3: Southampton Shoal to refinery wharf. • Segment 4: Refinery wharf to Southampton Shoal. • Segment 5: Southampton Shoal to Pt. Bonita. • Segment 6: Pt. Bonita to Pilot Buoy. Note: The number of trip segments travelled by OGVs and the associated transit, maneuvering, and hoteling, and boiler operating times could be higher if the OGV stops at more than one refinery/at anchorage before heading back to the open ocean from the SF Bay. Apportioning emissions between refineries under such circumstances is discussed in Section 3.13.3 "Shared Emissions".
EF Emission Factor (g/kW-hour)	Emission factors provided in Tables II-9 in CARB Appendix D "Emissions Estimation Methodology for Ocean-Going Vessels" dated May 2011.
FCF Fuel Correction Factor (dimensionless)	Fuel correction factors provided in Table 3.17 in "Port of Los Angeles Inventory of Air Emissions – 2011" Technical Report ADP# 111129-929 dated July 2012.

The following data is required to estimate emissions from tug boats escorting and/or assisting each OGV.

Table 3.13.1-4: Data Needed to Estimate OGV-Escorting or OGV-Assisting Tug Emissions (Rank 5)

Variable	Data Needed
EF_0 Emission factor (g/HP-hour)	Emission factors provided in Appendix A of CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007.
LF Load factor (dimensionless)	Load factors provided in Table II-3 of CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007. If vessel specific info is not available, use LF equal to 0.50 (for propulsion engine) and 0.31 (for auxiliary engine).
F Fuel correction factor (dimensionless)	Fuel correction factors provided in Table II-4 in CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007.
D Engine deterioration factor (dimensionless)	Engine deterioration factors provided in Table II-5 in CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007.
A Age of engine (years)	Age of the propulsion and auxiliary engine on tug boats escorting and/or assisting OGV.
UL Useful life of engine (years)	Useful life of engine provided in Table II-2 in CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007.
P Power of engine (HP)	Propulsion engine power (HP) for each escort and/or assist tug Auxiliary engine power (HP) for each escort and/or assist tug
H Operating hours of engine	All OGVs entering the SF Bay are required to have at least one escort tug and one/more assist tugs. "H" for each escort tug shall be estimated by dividing the nautical miles travelled for each

Variable	Data Needed
(hours)	trip segment by the average vessel speed: • Segment 1: Escort tug makes a light trip[13] from Pt. Blunt to meet OGV at Pt. Bonita. • Segment 2: Escort tug travels with OGV from Pt. Bonita to Southampton Shoal. • Segment 3: Escort tug makes a light trip from Southampton Shoal to Pt. Blunt. • Segment 4: Escort tug makes a light trip from Pt. Blunt to Southampton Shoal to meet OGV. • Segment 5: Escort tug travels with OGV from Southampton Shoal to Pt. Bonita. • Segment 6: Escort tug makes a light trip from Pt. Bonita to Pt. Blunt. "H" for each assist tug shall be estimated by dividing the nautical miles travelled for each trip segment by the average vessel speed: • Segment 1: Assist tug makes a light trip from Pt. Blunt to meet OGV at Southampton Shoal. • Segment 2: Assist tug travels with OGV from Southampton Shoal to refinery and assists in berthing. • Segment 3: Assist tug makes a light trip from refinery to Pt. Blunt. • Segment 4: Assist tug makes a light trip from Pt. Blunt to refinery. • Segment 5: Assist tug helps OGV de-berth travels with vessel from refinery to Southampton Shoal. • Segment 6: Assist tug makes a light trip from Southampton Shoal to Pt. Blunt. Note: The number of trip segments travelled by tugs and the associated "H" could be a lot more if the OGV stops at more than one refinery/at anchorage before heading back to the open ocean from the SF Bay. Apportioning emissions between refineries under such circumstances is discussed in Section 3.13.3 "Shared Emissions".
Density of fuel (lb/gallon)	Density of fuels combusted in the propulsion and auxiliary engines of the escort and assist tugs by fuel type.

The following data is required to estimate mass emissions from tug boats assisting each barge.

Table 3.13.1-5: Data Needed to Estimate Emissions from Barges and Tugs Assisting Barges (Rank 5)

Variable	Data Needed
EF_0 Emission factor (g/HP-hour)	Emission factors provided in Appendix A of CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007.
LF Load factor (dimensionless)	Load factors provided in Table II-3 in CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007. Use LF equal to 0.50 (for propulsion engine) and 0.31 (for auxiliary engine) if vessel specific info is not available. Use LF equal to 0.68 (for propulsion engine if applicable) and 0.43 (for auxiliary engine) if vessel specific info is not available.

[13] Light trip is when a tug is not escorting/assisting an OGV.

F Fuel correction factor (dimensionless)	Fuel correction factors provided in Table II-4 in CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007.
D Engine deterioration factor (dimensionless)	Engine deterioration factors provided in Table II-5 in CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007.
A Age of engine (years)	Age of the propulsion and auxiliary engine on tug boat assisting barge. Age of the propulsion (if applicable) and auxiliary engine on barge.
UL Useful life of engine (years)	Useful life of engine provided in Table II-2 in CARB Appendix B "Emissions Estimation Methodology for Commercial Harbor Craft Operating in California" dated November 2007.
P Power of engine (HP)	Propulsion engine power (HP) for tug and barge (if applicable) Auxiliary engine power (HP) for tug and barge
H Operating hours of engine (hours)	All barges entering the SF Bay are required to have at least one one/more assist tugs. "H" for each tug assisting the barge shall be estimated by dividing the nautical miles travelled for each trip segment by the average vessel speed: • Segment 1: Assist tug makes light trip from Pt. Blunt to Pilot Buoy • Segment 2: Assist tug travels with barge from Pilot Buoy to refinery and assists in berthing. • Segment 3: Assist tug makes a light trip from refinery to Pt. Blunt. • Segment 4: Assist tug makes a light trip from Pt. Blunt to refinery. • Segment 5: Assist tug helps barge de-berth and travels with vessel from refinery to Pilot Buoy. • Segment 6: Assist tug makes a light trip from Pilot Buoy to Pt. Blunt. Note: The number of trip segments travelled by tugs and the associated "H" could be a lot more if the barge stops at more than one refinery/at anchorage before heading back to the open ocean from the SF Bay. Apportioning emissions between refineries under such circumstances is discussed in Section 3.13.3 "Shared Emissions".
Density of fuel (lb/gallon)	Density of fuels combusted in the propulsion (if applicable) and auxiliary engines of the assist tugs and barge by fuel type.

Supporting Documentation

The logs and/or reports summarized in Table 3.13.1-6 shall be maintained when estimating emissions from marine activities.

Table 3.13.1-6: Summary of Supporting Documentation Needed to Estimate Marine Emissions

Approved Method	Needed Data	Required Documentation
Direct measurement (continuous emission monitoring systems [CEMS] for both flow rate and gas composition)	Pollutant concentrations Flowrate Pressure, temperature, and moisture content	CEM records (digital, physical)
Direct measurement (CEMS) for gas composition Use of F factors	Fuel usage Heat content of fuel	Fuel purchase records Fuel logs Calorimetric fuel analysis
Fuel analysis/mass balance	Fuel usage Assumed destruction efficiency	Fuel purchase records Fuel logs
Source-specific stack testing to calculate source-specific emission correlations or factors	Fuel usage Heat content of fuel	Fuel purchase records Fuel logs
Default emission factors	Fuel usage	Fuel purchase records Fuel logs

Approved Method	Needed Data	Required Documentation
Emission calculations	Dependent on equation (see below)	Dependent on equation (see below)
Equation 3.13.1-1	Transit time (hours) Distance travelled during transit (nm) Maneuvering time (hours) Distance travelled during maneuvering (nm) Docking time (hours) Undocking time (hours) Hoteling –Berth time (hours) Hoteling – Anchorage time (hours) Boiler operating time (hours) – during transit, maneuvering, hoteling – berth, and hoteling – anchorage.	Data shall be provided by one or more of the following sources: Marine Exchange of the San Francisco Bay Region (SFMX) Lloyd's Register of Ships **Vessel Characteristics:** Name Flag name Type (ship, barge, or Power Tug) Lloyds Number MMSI Call sign Owner Operator Draft Net Weight Gross Weight Length Breadth Dead weight Port of registry Year built
Equation 3.13.1-2	Age (in years) of the propulsion and auxiliary engine on tug boats escorting and/or assisting OGV. Propulsion engine power (HP) for each escort and/or assist tug Auxiliary engine power (HP) for each escort and/or assist tug	Data shall be provided by one or more of the following sources: Marine Exchange of the San Francisco Bay Region (SFMX) Lloyd's Register of Ships Nautical charts and maps **Vessel Movements:** Agent From port To port From berth To berth ETA ATA ATD ETD Draft in Draft out Pilot on Pilot off Pilots (In) Pilots (Out) First line Last line Tugs (in) Tugs (out) Power tug (in) Power tug (out) **Escort Data:** Arrival escort Departure escort Date In Time In

Approved Method	Needed Data	Required Documentation
		Date Out Time Out Agent Displacement First Zone Second Zone Third Zone Escort Tugs
Equation 3.13.1-2 Equation 3.13.1-3 Equation 3.13.1-4	Age (in years) of the propulsion and auxiliary engine on tug boats escorting and/or assisting OGV.	Tug boat owner shall provide purchase/maintenance records that confirms the age of the engine(s)
Equation 3.13.1-2 Equation 3.13.1-3 Equation 3.13.1-4	Propulsion engine power (HP) for each escort and/or assist tug Auxiliary engine power (HP) for each escort and/or assist tug.	Tug boat owner shall provide purchase/maintenance records that confirm the power of the engine(s)
Equation 3.13.1-4	Density of fuel	Lab results of fuel analysis/fuel oil vendor certification confirming density (lb/gallon)
Equation 3.13.1-5	Age of the propulsion and auxiliary engine on tug boat assisting barge. Age of the propulsion (if applicable) and auxiliary engine on barge. Propulsion engine power (HP) for tug and barge (if applicable) Auxiliary engine power (HP) for tug and barge	Data shall be provided by one or more of the following sources: Marine Exchange of the San Francisco Bay Region (SFMX) Lloyd's Register of Ships **<u>Vessel Characteristics:</u>** Name Flag name Type (ship, barge, or Power Tug) Lloyds Number MMSI Call sign Owner Operator Draft Net Weight Gross Weight Length Breadth Dead weight Port of registry Year built
Equations 3.13.1-5, 3.13.1-6, 3.13.1-7	Age of the propulsion and auxiliary engine on tug boat assisting barge. Age of the propulsion (if applicable) and auxiliary engine on barge	Tug boat and barge owners shall provide purchase/maintenance records that confirms the age of the engine(s)
Equations 3.13.1-5, 3.13.1-6, 3.13.1-7	Propulsion engine power (HP) for tug and barge (if applicable) Auxiliary engine power (HP) for tug and barge	Tug boat and barge owners shall provide purchase/maintenance records that confirm the power of the engine(s)
Equations 3.13.1-7	Density of fuel	Lab results of fuel analysis/fuel oil vendor certification confirming density (lb/gallon)

Reports

Marine wharf activity logs required by permit conditions.

Definitions

None

Assumptions

None

Section 3.13.2 – Rail

Petroleum refineries receive and ship crude oil, intermediate products, and finished products (LPG, gasoline, etc.) via rail. No refinery has its own rail carriers but contract with freight service providers.

The Bay Area has freight service through two carriers: BNSF Railway and Union Pacific (UP) Railway. Both freight lines transport crude oil, intermediates, and petroleum products to and from the Bay Area, to San Joaquin Valley, north to Sacramento, and south down the Peninsula.

Emissions from rail operations occur during:

- movement into & out of the refinery,
- movement between areas of the refinery,
- idling and movement within location (single area of refinery),
- line-haul, and
- switching of rail cars.

Each emissions inventory should estimate emissions from the operations listed above as well as any other rail-related operations not mentioned. Emission estimating methodologies from loading and unloading of railcars are covered in Section 3.8.

There are generally two classifications of locomotives: line haul (intended for moving trains over long distances) and switch (intended for assembling, disassembling, and moving railroad cars around).
The Bay Area rail network is divided in to rail subdivisions. The freight subdivisions by county are listed in Table 3.13.2-1 and shown in Figure 3.13.2-1.

Table 3.13.2-1: Bay Area Freight Rail Subdivisions by County

County	Subdivision	Starting Location	Ending Location
Alameda	Coastal	San Leandro	Alameda County Line
	Martinez	10th Street, Oakland, CA	Alameda County Line
	Niles	10th Street, Oakland, CA	Newark
	Oakland	San Leandro	Alameda County Line
	Tracy	Contra Costa County Line	Alameda County Line
	Warm Springs	Niles Blvd, Fremont, CA	Alameda County Line
Contra Costa	Martinez	Alameda County Line	Contra Costa County Line
	Tracy	Martinez, CA	Contra Costa County Line
San Francisco	San Francisco	King Street, San Francisco, CA	San Francisco County Line
San Mateo	San Francisco	San Francisco County Line	San Mateo County Line
Santa Clara	Coast	Alameda County Line	Santa Clara County Line
	San Francisco	Santa Clara County Line	San Jose, CA
	Warm Springs	Alameda County Line	San Jose, CA
Solano	Martinez	Contra Costa County Line	Davis, CA

Figure 3.13.2-1

Approved Methods

The approved methods for estimating emissions from rail operations are listed in Table 3.13.2-2.

Table 3.13.2-2: Summary of Locomotive Emission Estimate Methodologies

Rank	Measurement Method
1	Direct measurement (continuous emission monitoring system [CEMS] for both flow rate and gas composition
2	Direct measurement (CEMS) for gas composition Use of F Factors
3A	Fuel analysis/mass balance
3B	Source-specific stack testing to calculate source-specific emission correlations or factors
4A	Default emission factors (hourly basis) Use of refinery-specific data
4B	Default emission factors (fuel basis) Use of refinery-specific data
5	Default emission factors (ton-mile basis) Use of Bay Area averages
6	Default emission factors (ton-mile basis) Use of carrier average
7	Default emission factors (ton-mile basis) Use of national averages

Rank 4 – Default Emission Factors (hourly basis)

Although some locomotives are equipped with liquefied natural gas (LNG) or electric hybrid engines, they operate primarily in the South Coast Air Basin with one operating in the San Joaquin Valley and default emission factors have not been developed. Therefore, there exist default emission factors for only diesel-engine equipped locomotives. Default emission factors for diesel-engine locomotives are listed in Table 3.13.2-3 (for line-haul locomotives) and Table 3.13.2-4 (for switch locomotives).

Table 3.13.2-3: Line-Haul Default Emission Factors *(g/bhp-hr)*

Locomotive Tier	Manufacturer Year	PM_{10}	VOC	NO_X	CO
Uncontrolled	Pre-1973	0.32	0.48	13.00	1.28
Tier 0	1973 – 1992	0.20	0.30	7.20	1.28
Tier 1	1993 – 2004	0.20	0.29	6.7	1.28
Tier 2	2005 - 2011	0.08	0.13	4.95	1.28
Tier 3	2012 – 2014	0.08	0.13	4.95	1.28
Tier 4	2015 +	0.0015	0.04	1.00	1.28
Source: EPA, 2009					

Table 3.13.1-4 Switch Default Emission Factors *(g/bhp-hr)*

Locomotive Tier	Manufacturer Year	PM_{10}	VOC	NO_X	CO
Uncontrolled	Pre-1973	0.44	1.01	17.40	1.83
Tier 0	1973 – 1992	0.23	0.57	10.60	1.83
Tier 1	1993 – 2004	0.23	0.57	9.90	1.83
Tier 2	2005 – 2011	0.11	0.26	4.50	1.83
Tier 3	2012 – 2014	0.08	0.26	4.50	1.83
Tier 4	2015 +	0.015	0.08	1.00	1.83
Source: EPA, 2009					

Rank 4 – Default Emission Factors (fuel basis)

To use the emission factors listed above, the number of hours would have to be tracked. This may be difficult for the refineries to obtain this information. If hourly data is not available, the default emission factors can be converted to a fuel consumption basis (rather than hourly basis) using the following equation:

$$\left(\frac{g}{bhp-hr}\right)\left(\frac{bhp-hr}{gal}\right) = \left(\frac{g}{gal}\right) \qquad \text{[Equation 3.13.2-1]}$$

and the conversion factors listed in Table 3.13.2-5.

Table 3.13.2-5 Conversion Factors

Locomotive Application	**Conversion Factors** (bhp-hr/gal)
Large Line-Haul	20.8
Small Line-Haul	18.2
Switching	15.2
Source: EPA, 2009	

Rank 5 – Default Emission Factors (ton-mile basis)

If fuel consumption data is not available, default emission factors may be converted to a ton-mile basis (the amount of emissions emitted carrying one ton over one mile of distance) by dividing the emission factors by an average fuel consumption value as shown in the following equations:

$$\left(\frac{total\ ton-mile}{year}\right) * \left(\frac{total\ gal}{year}\right)^{-1} = \left(\frac{ton-mile}{gal}\right)$$

$$\left(\frac{g}{gal}\right) * \left(\frac{ton-mile}{gal}\right)^{-1} = \left(\frac{g}{ton-mile}\right) \qquad \text{[Equation 3.13.2-2]}$$

To use Equation 3.13.2-2, the average fuel consumed per ton-mile is required. In order of data quality ranking, this average may be either: a Bay Area average, a carrier average, or a national average.

Carrier averages may be determined using data listed in annual financial reports (Class I Railroad Annual Report R-1) required by the United States Surface Transportation Board.

National averages may be accessed through the United States Bureau of Transportation Statistics or the Association of American Railroads.

To estimate emissions using a default emission factor on a ton-mile basis, the cargo weight would be multiplied by the distance traveled.

Unless specific information is available, the railcar weights listed in Table 3.13.2-6 should be used with the distances listed in Table 3.13.2-7.

Table 3.13.2-6 Weight of Railcars

Car Description	**Weight** (tons)
Empty tank car	37
Full tank car	158
Sources:	

49 CFR Subtitle B Chapter I Part 179 Union Pacific "Allowable Gross Weight Map" https://www.up.com/aboutup/reference/maps/allowable_gross_weight/index.htm

Table 3.13.2-7 Approximate One-Way Distances from Refinery Boundaries to District Boundaries

Refinery	Location	**Distance from Refinery to District-Boundary Location** (miles)						
		Orwood (Stockton)	**Fairfield (Sacramento)**	**Mountain House (Tracy)**	**Altamont (Tracy)**	**River Oaks (Watsonville) via UP Coast**	**River Oaks (Watsonville) via UP Niles**	**River Oaks via UP Warm Springs**
Chevron	Richmond	53	44	60	73	96	100	98
Phillips 66	Rodeo	59	36	51	79	102	106	105
Shell	Martinez	72	24	40	93	116	119	118
Tesoro	Martinez	76	26	38	95	118	121	120
Valero	Benicia	74	23	40	94	117	120	119

Example: Estimating roundtrip NO_X emissions from a unit train of 100 full rail cars driven by a Tier 1 large line-haul locomotive to and from the Chevron Richmond Refinery to Roseville

According to the Association of American Railroads[14] the national rail freight fuel consumption average in 2014 was 479 ton-miles per gallon of fuel consumed.

The Tier 1 line-haul NO_X emission factor is first converted to a g per ton-mile basis:

$$\left(6.7\frac{g}{bhp-hr}\right)\left(20.8\frac{bhp-hr}{gal}\right)\left(479\ \frac{ton-mile}{gal}\right)^{-1} = \left(0.29\frac{g}{ton-mile}\right)$$

Then emissions are calculated as follows:

Full Cars: $$\left(0.29\frac{g}{ton-mile}\right)(100\ cars)\left(\frac{158\ tons}{full\ tank\ car}\right)(44\ \ miles)\left(\frac{1\ lb}{453.592\ g}\right) = 444.5\ lbs\ NO_X$$

Empty Cars: $$\left(0.29\frac{g}{ton-mile}\right)(100\ cars)\left(\frac{37\ tons}{full\ tank\ car}\right)(44\ \ miles)\left(\frac{1\ lb}{453.592\ g}\right) = 104.1\ lbs\ NO_X$$

Roundtrip NO_X emissions = 444.5 lbs NO_X (full cars) + 104.1 lbs NO_X (empty cars) = 548.6 lbs NO_X

It is important to note that the emission estimate does not include any emissions occurring from movement within the refinery or any switching done outside of the refinery but only from hauling the unit train from the Chevron boundary to and from the District boundary at the City of Fairfield.

Data Needs

The following data is required to estimate mass emissions from rail operations.

Table 3.13.2-8: Summary of Data Needs for Estimating Emissions from Locomotives

Measurement Method	Additional Data Needed
Direct measurement (continuous emission monitoring system [CEMS] for both flow rate and gas composition	Gas composition concentration readings Flow rates Pressure, temperature, and moisture content

[14] Association of American Railroads. 2015. *The Environmental Benefits of Moving Freight by Rail.* August 2015.

Direct measurement (CEMS) for gas composition Use of EPA Method 19 F Factors	Gas composition concentration readings Fuel gas analysis Fuel heat content and fuel usage
Fuel analysis/mass balance	Sulfur content of fuel Fuel usage
Source-specific stack testing to calculate source-specific emission correlations or factors	Fuel usage Fuel heat content
Default emission factors (hourly basis) Use of refinery-specific data	Total weight of freight Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total hours of rail travel
Default emission factors (fuel basis) Use of refinery-specific data	Total weight of freight Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total amount of fuel used
Default emission factors (ton-mile basis) Use of Bay Area averages	Total weight of freight Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total hours of rail travel Average fuel consumption for Bay Area freight service
Default emission factors (ton-mile basis) Use of carrier average	Total weight of freight Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total hours of rail travel Average fuel consumption for carrier freight service
Default emission factors (ton-mile basis) Use of national averages	Total weight of freight Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total hours of rail travel Average fuel consumption for national freight service

Supporting Documentation

The documentation listed in Table 3.13.2-9 shall be maintained when estimating emissions from rail operations.

Table 3.13.2-9: Supporting Documentation Required for Estimating Emissions from Locomotives

Additional Data Needed	Supporting Documentation
Gas composition concentration readings Flow rates Pressure, temperature, and moisture content	CEM readings, calibration logs, and accuracy tests Flow rate records Pressure, temperature, moisture content records
Gas composition concentration readings Fuel gas analysis Fuel heat content Fuel usage	CEM readings, calibration logs, and accuracy tests Fuel gas lab analysis reports Fuel heat content lab analysis Fuel usage records
Sulfur content of fuel Fuel usage	Fuel specification sheets Fuel usage records
Fuel usage Fuel heat content	Fuel usage records Fuel gas lab analysis reports
Total weight of freight	Freight log manifests

Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total hours of rail travel	Rail maps identifying routes used Transaction records Emission calculations
Total weight of freight Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total amount of fuel used	Freight log manifests Rail maps identifying routes used Transaction records Fuel records Emission calculations
Total weight of freight Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total hours of rail travel Average fuel consumption for Bay Area freight service	Freight log manifests Rail maps identifying routes used Transaction records Bay Area fuel consumption averages Emission calculations
Total weight of freight Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total hours of rail travel Average fuel consumption for carrier freight service	Freight log manifests Rail maps identifying routes used Transaction records Carrier freight service fuel consumption averages Emission calculations
Total weight of freight Total number of rail cars Type of rail cars used Rail route from refinery to District boundary Total hours of rail travel Average fuel consumption for national freight service	Freight log manifests Rail maps identifying routes used Transaction records National freight service fuel consumption averages Emission calculations

Reports

None

Definitions

Large	locomotives with engines larger than 3,000 horsepower
Line-haul	the movement of cargo over long distances
Small	locomotives with engines smaller than 3,000 horsepower
Switching	the assembling, disassembling, and moving railroad cars around.

Assumptions

None

Section 3.13.3 – Shared Emissions

Marine

Ocean going vessels may service multiple refineries. If an ocean going vessel services multiple refineries, the emissions attributed to transit and hoteling while at anchorage shall be apportioned evenly to the all the refineries that are serviced by the ocean going vessel. The emissions attributed to at-berth activities (maneuvering, pumping, hoteling, etc.) during the ship call would not be shared.

However, unless a refinery can provide the data necessary to apportion the emissions accordingly, emissions from each ocean going vessel shall be calculated and reported as if the vessel is only servicing a single refinery.

The Marine Exchange of the San Francisco Bay Region (SFMX) collects and maintains information on ship calls for every wharf two stops prior to and two stops after.

Rail

In the absence of specific information, emissions from rail operations shall be estimated and reported by assuming locomotives only service a single refinery while in the District boundaries (i.e. a locomotive does not pull rail cars from multiple refineries).

However, rail emissions may be apportioned if a refinery can submit documentation specifying locomotives carrying railcars for multiple refineries with specific segments and distances of rail links, freight weight, and other information necessary to correctly allocate emissions to the different refineries being serviced.

Section 3.14: Greenhouse Gas Emissions

Bay Area petroleum refineries currently estimate and report greenhouse gas emissions to two regulatory agencies: the California Air Resources Board (ARB) and the U.S. EPA. However, greenhouse gas emissions occurring from marine (e.g. transit, maneuvering, hoteling, pumping, etc.) and rail (hauling, switching) activities are not required to be reported by either Title 17 California Code of Regulations (CCR) Sections 95100 through 95158 or 40 CFR Part 98.

All emission inventories should include estimates of greenhouse gas emissions from all activities including from:

(1) all continuous, intermittent, predictable, or accidental air releases resulting from petroleum refinery processes at stationary sources at a petroleum refinery, and

(2) all air releases from cargo carriers (e.g. ships and trains), excluding motor vehicles, that load or unload materials at a petroleum refinery including emissions from such carriers while operating within the District or within California Coastal Waters.

Therefore, although some information from greenhouse gas inventories submitted to ARB and to EPA may be replicated in inventories submitted to the District, those inventories are not sufficient by themselves. In some cases, the inventories may differ for certain sources as discussed in the section below.

Approved Methods

Emission inventories should include greenhouse gas emission estimates on an individual source or activity basis and should not be aggregated.

Regardless of any *de minimis* or other provisions allowed by Title 17 CCR Sections 95100 through 95158 or in 40 CFR Part 98, greenhouse gas emissions should be estimated using the highest ranked methodology for which data is available listed in Table 3.14-1.

Table 3.14-1: Summary of Approved Greenhouse Gas Emission Estimate Methodologies

Rank	Approved Measurement or Method	Application
1	Direct measurement (CEM) for both flow rate and gas composition	Stationary fuel combustion sources Electricity generation and cogeneration units Hydrogen plants Marine activities
2	Direct measurement (CEMS) for gas composition Use of F factors	Stationary fuel combustion sources Hydrogen plants Marine activities
3A	Fuel analysis/mass balance	Electricity generation and cogeneration units Hydrogen plants Marine activities
3B	Source-specific stack testing to calculate source specific emission correlations or factors	Stationary fuel combustion sources Marine activities Fugitive emissions
4	Default emission factors	

Rank 4 – Default Emission Factors

40 CFR Part 98 Subpart C lists equations for calculating CO_2 emissions from greenhouse gases using default emission factors. These equations are acceptable to be used. However, when estimating emissions using these equations, annual averages (e.g. fuel usages, heat content, carbon content, etc.) should not be used. These calculations should be done at

an hourly basis and if not available, on a daily basis. The reason for doing this is because multiplying an average by an average may overestimate or underestimate emissions.

Example
A refinery fuel gas-fired furnace operates only four hours in a year and has the following fuel usages and higher heating values:

Hour	**Fuel Usage** (scf)	**Higher Heating Value** (Btu/scf)
1	130,000	800
2	475,000	1300
3	425,000	1155
4	125,000	900

In this example, the furnace combusted 1,155,000 cubic feet of refinery fuel gas with an average heating value of 1039 Btu per scf.

When multiplying the total fuel usage by the average heating value, the result is 1200 million Btu.

However, if the individual measurements are multiplied and summed [e.g. (130,000 x 800) + (475,000 x 1300) +…)], the result would be 1325 million (a 10 percent increase). In this example, using averages underestimated the firing rate by 10 percent and would result in underestimating emissions by 10 percent.

Data Needs
The following data is required to estimate greenhouse gas emissions.

Table 3.14-2: Summary of Data Needs for Estimating Greenhouse Gas Emissions

Measurement Method	Additional Data Needed
Direct measurement (CEM) for both flow rate and gas composition	Pressure, temperature, and moisture content
Direct measurement (CEMS) for gas composition Use of F factors	Fuel usage Heat content of fuel
Fuel analysis/mass balance	Fuel usage
Source-specific stack testing to calculate source specific emission correlations or factors	Fuel usage Heat content of fuel
Default emission factors	Fuel usage Throughput Production quantities

Supporting Documentation
The documentation listed in Table 3.14-3 shall be maintained when estimating greenhouse gas emissions.

Table 3.14-3: Supporting Documentation Required for Estimating Greenhouse Gas Emissions

Additional Data Needed	Supporting Documentation
Pressure, temperature, and moisture content	Instrumentation records
Fuel usage	Fuel records, flow meter readings
Heat content of fuel	Lab analysis, instrumentation data
Throughput	Throughput records
Production quantities	Production records

Reports

Title 40 Code of Federal Regulations Part 98 reports
Title 17 California Code of Regulations Sections 95100 - 95158

Definitions

Greenhouse gas	a single air pollutant made up of a combination of the following six constituents: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, expressed as CO_2 equivalent emissions (CO_2e)

Assumptions

None

Section 3.15: Emission Calculation Spreadsheets

For consistency and comparison purposes and to aid in identifying assumptions and methodologies used, emission inventories prepared according to these guidelines shall use the emission estimation spreadsheet templates listed in Appendix B according to the appropriate methodology used.

Section 4: Procedure for Revising Emission Factor, Methodology, or Ranking

Over time, emission estimation procedures are refined as understanding, techniques, and monitoring equipment improve. Therefore, it may become necessary to revise an approved emission factor, methodology, or ranking.

In such cases, the procedures outlined in this section shall be followed before revising a default emission factor, methodology, or ranking listed in Section 3. However, the lists below are not all inclusive.

The procedures for revising the guidelines itself are listed in Section 10 (Guidelines Revision Procedure). Section 10 addresses the process for identifying when the guidelines should be changed. This section addresses the process of revising an emission estimation methodology.

Section 4.1: Emission Factor Revision

The District may revise an approved emission factor if any of the following occurs:

- underlying data used to develop the emission factor is discredited
- underlying methodology used to develop the emission factor is discredited
- underlying methodology used to develop the emission factor is revised
- an improved methodology to develop an emission becomes available
- better quality data becomes available

The District will exercise its expertise when reviewing and approving emission factors. The emission factor that has the highest degree of confidence and representativeness will be chosen if multiple emission factors are available.

Section 4.2: Emission Estimation Methodology Revision

The District may revise an approved emission estimation methodology if any of the following occurs:

- an approved methodology is discredited
- previously unavailable technology and/or predictive modeling becomes available
- previously unknown pollutant and/or emission source is identified

The District will exercise its expertise when reviewing and approving emission estimation methodologies. The methodology that results in the highest quality of data will be chosen if multiple methodologies are available.

Section 4.3: Ranking Revision

The District may revise the ranking of an approved emission estimation methodology if any of the following occurs:

- an approved methodology is discredited
- previously unavailable technology and/or predictive modeling becomes available
- previously unknown pollutant and/or emission source is identified

The District will exercise its expertise when reviewing and ranking approved emission estimation methodologies. The methodologies that result in the highest quality of data will be ranked higher.

Section 5: Data Usage and Calculations

All data and calculations used to develop an emission inventory should be consistent and follow the proscribed steps listed in the following sections.

Section 5.1: Limit of Detection or Accuracy

All calculations that rely on source test results or instrumentation data should reflect the limitations and/or accuracy of the data source and should not represent a greater degree of accuracy, precision, resolution, or confidence level than warranted.

Definitions

Accuracy – how close a measurement is to the “true” (actual value).

Precision – how close two or more measurements are to each other under the same conditions, regardless of whether those measurements are accurate or not. Precision is a measure of the spread of different readings and reflects the reproducibility of a measurement.

Resolution – the smallest discernible change in the parameter of interest that can be registered by a particular instrument.

Confidence interval – designates the bounds within which a parameter is expected to lie.

Range – the extent over which an instrument can reliably function within the confines of its specification.

Error – the amount by which an assumed value deviates from its true value, error is closely associated with

Examples of accuracy and precision are shown in Figure 5.1.1.

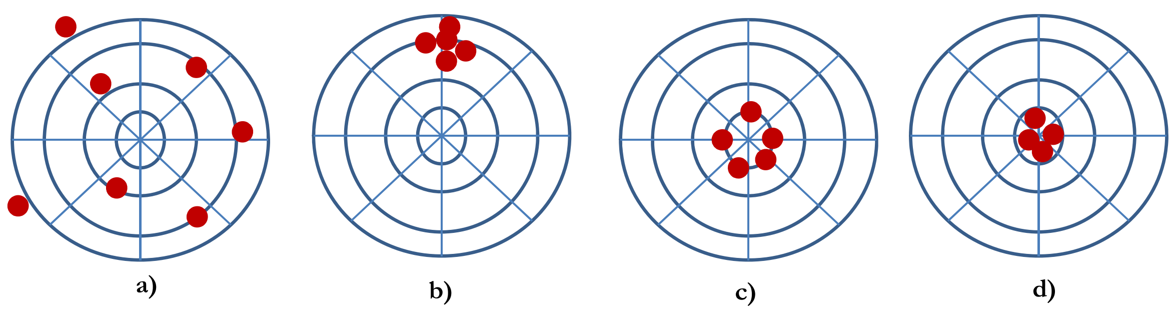


Figure 5.1.1 Example of a) not accurate, not precise, b) not accurate, precise, c) accurate, not precise d) accurate, precise.

Calculation results of two or more measurements should not be more precise than the measurements.

Section 5.1.1 – Limit of Detection

The Limit of Detection (LOD) is the smallest amount of a substance that an analytical method can reliably distinguish from zero.

The Limit of Quantification (LOQ) is the minimum concentration or amount of an analyte that a method can measure with a specified degree of precision.

The following procedures should be used when calculating using data from an analytical test (e.g. source test, GC analysis, calorimeter, etc.).

When several individually reported measurements are averaged to generate a single composite reported value, the averaging should be conducted and reported according to the following methodology:

- If all measured values are below the LOD, then the value reported shall be reported as less than the value represented by the LOD and one half of the LOD should be used in all calculations.

- If all measured values fall above the LOD, the reported value will be the average of the individually reported values. The average of the individually reported values should be used in all calculations.

- If at least one value is below the LOD, then one half of the LOD will be used in place of the below the LOD value to calculate the average of the individually reported values. The average should then be used in all calculations.

If a pollutant has **never** been demonstrated (by BAAQMD, EPA, ARB, other agencies, third parties, etc.) to be emitted from a source-category, then it is not reasonable to use half the LOD. However, if a source category has demonstrated emissions of a pollutant but the specific source has not, then half the LOD should be used. The rationale being that the source has the potential to emit the pollutant, but may not indicate levels above the LOD based on the scale of the monitoring instrument/test method used.

Examples

Table 5.1-1lists examples of the three situations discussed above, provides what the reported average should be, and lists the average to use in calculations. In all examples, the LOD is 2.

Table 5.1-1: Example Measurement Values

Example	Measured Value			Reported Value			Reported Average	Average to Use in Calculations
	Run A	Run B	Run C	Run A	Run B	Run C		
1	1.5	0.5	1.7	<2	<2	<2	<2	1
2	12.0	10.0	14.0	12.0	10.0	14.0	12.0	12.0
3	6.0	7.0	8.0	6.0	7.0	8.0	7.0	7.0
4	0.8	16.0	13.0	<2	16.0	13.0	10.0*	10.0
5	0.8	0.8	3.0	<2	<2	3.0	1.7*	1.7

Note:
* Analyte was less than the detection in some, but not all samples

Section 5.1.2 – Instrumentation Accuracy

Calculations that use data from instrumentation (e.g. flow meters, thermocouples, etc.) shall be based upon the accuracy, precision, and resolution of the instrumentation. Calculations that involve values below the accuracy limit of an instrument should use the accuracy limit of the instrument.

Example:
A cooling tower has permit condition limiting total hydrocarbons in the water to less than 40 ppmv. A continuous total hydrocarbon analyzer is used to verify compliance with the limit and is calibrated to 10 percent of scale (4 ppmv). The analyzer routinely reads less than 1 ppmv.

In this example, any reading below 4 ppmv should be reported as 4 ppmv and 4 ppmv should be used in all emissions calculations. If a facility desires to use lower values, the facility should use an instrument with a smaller scale. To report and use values of 1 ppmv, the analyzer would require a maximum scale of 10 ppmv.

Because the limit is 40 ppmv, the facility would have to request for permit condition limit change.

Lowest analyzer value that can be used in calculations and reports = 0.10 x Scale
In this case, the lowest value that can be reported is 4 ppmv (0.10 x 40 ppmv)

Section 5.2: Calculations Involving Averages

Whenever possible, all calculations shall be made on an individual basis rather than on an averaged basis. At a minimum, calculations shall be done on an hourly basis whenever available. This will prevent either underestimating or overestimating emissions and will lead to more accurate emission inventories.

Example
A refinery fuel gas-fired furnace operates for four hours in a day and does not have a CEM to measure NOX emissions but a recent source test reported 0.2 lbs of NO_X per million Btu (MMBtu). The higher heating value of the refinery fuel gas is continuously measured through use of a calorimeter.

The furnace has the following fuel flows (already corrected for temperature and pressure) and measured higher heating values.

Hour	**Fuel Flow** (scf)	**Higher Heating Value** (Btu/scf)	**NO_X Emission Factor** (lb/ MMBtu)
1	19,500	900	0.20
2	15,620	1000	0.20
3	2,880	1250	0.20
4	26,000	1275	0.20
Average	16,000	1250	0.20

If average fuel flow and higher heat value are used, the average firing rate is 20 MMBtu and NO_X emissions are 160 lbs (four hours x 20 MMBtu/hour average x 0.2 lbs/MMBtu).

However, if calculations are made on an individual (in this case hourly) basis, NO_X emissions total 140 lbs as shown in the following table.

Hour	**Fuel Flow** (scf)	**Higher Heating Value** (Btu/scf)	**Calculated Firing Rate** (MMBtu)	**NO_X Emission Factor** (lb/ MMBtu)	**NO_X Emissions** (lbs)
1	19,500	900	18	0.20	35
2	15,620	1000	16	0.20	31
3	2,880	1250	4	0.20	7

4	26,000	1275	33	0.20	66
		Total	70		140

In this example, using averages overestimated NO_X emissions by approximately 14 percent.

Section 5.3: Data Substitution

When compiling data to be used in an emission inventory, a facility may discover that some or all of the data necessary to estimate emissions from a source or activity is missing.

A missing data period is defined as a time period when a piece of data is:

- not collected, or
- invalid, or
- collected while the measurement device is not in compliance with applicable quality-assurance requirements (e.g. District field accuracy test, relative accuracy test audit, etc.).

When data is missing, there are circumstances where it is appropriate to substitute other data for the missing data. However, there are circumstances where it is not. Whenever missing data is substituted with other data, it should be identified as such (e.g. a unique identifier), have the data substitution method cited, and the justification for the data substitution (e.g. following procedure listed in 40 CFR 75.33, etc.).

If all of the data that is necessary to estimate emissions using a specific method is missing, that method may not be used and a lower ranking emission method may be required.

For example, if a furnace stack has a continuous emission monitor that was inoperative for the entire inventory year, then it may be required to use source test results rather than continuous data to estimate emissions from that furnace.

The following sections outline the procedures that should be followed when data is missing for only a portion of an inventory year.

Section 5.3.1 –Continuous Emission Monitor (CEM)

Missing data from CEMs should following the data substitution procedures listed in of 40 CFR Part 75 (Continuous Emission Monitoring), Subpart D (Missing Data Substitution Procedures).

The procedures outlined in 40 CFR 75 Subpart D are based on the percent of data available and the duration of the missing data period. Depending on the data availability and duration of missing data, substituted data may be based on either: the average of the hour before and hour after the missing period, some percentile (e.g. 90th, 95th, etc.) reading recorded in a given number of hours (e.g. 720 hours, 2160 hours, etc.), or the maximum (or minimum for O_2 or H_2O meters) potential reading.

An example of the different scenario-based procedures for missing data from SO_2 CEMs is shown in Table 5.3.1-1

Table 5.3.1-1: SO_2 CEM – Data Substitution Procedures [40 CFR 75.33(b)]

Data Availability (percent)	**Missing Period** (hours)	**Data Substitution Procedure**

Data Availability (percent)	**Missing Period** (hours)	**Data Substitution Procedure**
Availability ≥ 95	≤ 24	Substitute the average of the hourly readings recorded by the CEM for the hour before and the hour after the missing period
	> 24	Substitute the greater of: • the 90th percentile hourly reading recorded by the CEM during the previous 720 quality-assured monitor operating hours; or • the average of the hourly readings recorded by the CEM for the hour before and the hour after the missing period
90.0 ≤ Availability < 95	≤ 8	Substitute the average of the hourly readings recorded by the CEM for the hour before and the hour after the missing data period
	> 8	Substitute the greater of: • the 95th percentile hourly reading recorded by the CEM during the previous 720 quality-assured monitor operating hours; or • the average of the hourly readings recorded by the CEM for the hour before and the hour after the missing period
80.0 ≤ Availability < 90	> 0	Substitute for that hour of missing data period the maximum hourly reading recorded by the CEM during the previous 720 quality-assured monitor operating hours.
Availability < 80	> 0	Substitute for that hour of the missing data period the maximum potential reading, as defined in 40 CFR Part 75, Subpart D Appendix A, Section 2.1.1.1.

For transparency purposes and to ensure that the proper substitution method was used, whenever data is substituted it should be identified and include the specific method used and a citation for the data substitution method used.

Example (data availability = 93 percent)

Hour	**CEM Reading** (ppmv)	**CEM Reading with Substituted Data** (ppmv)	**Method**	**Data Substitution Method Citation**
07:00	100	100	CEM	CEM
08:00	50	50	CEM	CEM
09:00	Missing	125*	Average**	40 CFR 75.33(b)(2)(i)
10:00	Missing	125*	Average **	40 CFR 75.33(b)(2)(i)
11:00	200	200	CEM	CEM
12:00	85	85	CEM	CEM
*Substituted data ** Average of hour before and hour after readings				

Section 5.3.2 – Parametric Monitor

As defined in District Regulation 1, a parametric monitor is "any monitoring device or system required by District permit condition or regulation to monitor the operational parameters of either a source or an abatement device. Parametric monitors may record temperature, gauge pressure, flowrate, pH, hydrocarbon breakthrough, or other factors."

Per District Regulation 1-523, the petroleum refineries are required to "maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications and the District Manual of Procedures."

In addition, the petroleum refineries are required to report all parametric monitor periods of inoperation greater than 24 continuous hours and periods of inoperation cannot exceed 15 consecutive days per incident or 30 calendar days per consecutive 12-month period.

Therefore, data availability of a parametric monitor should not be lower than 92 percent (335 days per year).

However, when using data from a parametric monitor to estimate emissions, the following data substitution procedure should be used.

Table 5.3.2-1: Data Substitution Procedures for Parametric Monitors

Data Availability (percent)	**Missing Period** (hours)	**Data Substitution Procedure**
Availability ≥ 95	≤ 24	Substitute the average of the hourly readings recorded by the monitor for the hour before and the hour after the missing period
	> 24	Substitute the greater of: • the 90th percentile hourly reading recorded by the monitor during the previous 720 quality-assured monitor operating hours; or • the average of the hourly readings recorded by the monitor for the hour before and the hour after the missing period
90.0 ≤ Availability < 95	≤ 8	Substitute the average of the hourly readings recorded by the monitor for the hour before and the hour after the missing data period
	> 8	Substitute the greater of: • the 95th percentile hourly reading recorded by the monitor during the previous 720 quality-assured monitor operating hours; or • the average of the hourly readings recorded by the monitor for the hour before and the hour after the missing period
80.0 ≤ Availability < 90	> 0	Substitute for that hour of missing data period the maximum hourly reading recorded by the monitor during the previous 720 quality-assured monitor operating hours
Availability < 80	> 0	Substitute for that hour of the missing data period the maximum potential reading

Section 5.3.3 –Non-CEM, Non-Parametric Monitor

Instrumentation that is neither a CEM nor a parametric monitor is not required to meet minimum calibration and/or maintenance requirements. Therefore, the reliability and data quality of data results may be suspect.

For these instruments, the data substitution procedures of Table 5.3.3-1 should be used.

Table 5.3.3-1: Data Substitution Procedures for Non-CEM/Non-Parametric Monitors

Data Availability (percent)	**Data Substitution Procedure**
Availability ≥ 90	Substitute for each missing value with the best available estimate of the parameter, based on all available process data.
80.0 ≤ Availability < 90	Substitute for each missing value with the highest/lowest value recorded for the parameter during the given data year that would result in a conservative (e.g. maximum) emission estimate
Availability < 80	Substitute for each missing value with the highest/lowest value recorded for the parameter within the

	past five years of records that would result in a conservative (e.g. maximum) emission estimate

Section 5.4: Conventions

To ensure consistency, this section outlines conventions regarding significant figures, rounding, standard conditions, and conversion factors.

Section 5.4.1 – Significant Figures

The following list District-accepted conventions regarding significant figures:

- All non-zero digits (1-9) are significant
- All zeros between non-zero digits are always significant
- For numbers that do not contain decimal points, the trailing zeros may or may not be significant. In this situation, the number of significant figures is ambiguous.
- For numbers that do contain decimal points, the trailing zeros are significant.
- If a number is less than 1, zeros that follow the decimal point and are before a non-zero digit are not significant.

Any number based on calculations and/or measurements must have the same number of significant figures as the least precise measurement or number that went into it. The number of significant digits retained must be such that accuracy is neither sacrificed nor exaggerated.

Example

2.18 tons NO_X + 4.1 tons NO_X + 8.967 tons NO_X = 15.2 tons NO_X <u>NOT</u> 15.247 tons NO_X

The reason total NO_X is reported as15.2 tons and not 15.247 tons is because:

2.18 tons NO_X may be any value between 2.175 and 2.184,
4.1 tons NO_X may be any value between 4.050 and 4.149, and
Total NO_X may be any value between 15.192 tons or 15.300

Section 5.4.2 – Rounding

All calculations (intermediate and final) should carry the same number of significant figures as the least precise number.

When rounding, the following procedure should be used:

- **For both calculations and measurements:** If the first digit to be discarded is less than five, the last digit retained should not be changed.

- **For both calculations and measurements** When the first digit to be discarded is greater than five, or if it is a five followed by at least one digit greater than 0, the last figure retained should be increased by one unit.

- **For calculations**: When the first digit is exactly five, followed only by zeros, the last digit retained should be rounded upward.

- **For measurements**: When the first digit is exactly five, followed only by zeros, the last digit retained should be rounded upward if it is an odd number, but no adjustment made if it is an even number.

Examples (Two Significant Figures)

Rounding Convention	Example	Rounding Off (Calculations)	Rounding Off (Measurements)
First digit to be discarded is less than five.	1.24	1.2	1.2
First digit to be discarded is greater than five	1.26	1.3	1.3
First digit to be discarded is exactly five	1.25	1.3	1.2
	1.35	1.4	1.4

Temperature Rounding

When rounding converted measurements, the resulting number should reflect the accuracy and precision of the original measurement.

For example, temperature is typically expressed in degrees Fahrenheit as whole numbers. When converting to Celsius, temperature should be converted to the nearest 0.5 degree Celsius. This is because the magnitude of a degree Celsius is approximately twice the size of a degree Fahrenheit (as shown in the equations below), and rounding to the nearest Celsius would reduce the precision of the original measurement.

Temperature conversion equations: $°F = \frac{9}{5}(°C) + 32$ $°C = \frac{5}{9}(°F - 32)$

Section 5.4.3 –Standard Conditions

Emissions and any intermediate calculations should be converted to standard conditions. Standard conditions are those listed in Table 5.4-1.

Table 5.4-1: Standard Conditions

Parameter	Standard
Temperature	68 degrees Fahrenheit (20 degrees Celsius)
Pressure	14.696 psi (760.00 mm Hg)
Oxygen	20.95%
Molar Volume	385.3 ft^3/lb-mole

Example

To correct sampling volumes (V_s) to District standard (V_{std}) conditions, the following equation is used:

$V_{std} = (V_s)(P_{atm}/P_{std})(T_{std}/T_{atm})$

where:

V_{std} = volume of gas sampled, corrected to the District's standard pressure and standard temperature
V_s = volume of gas sampled at atmospheric pressure (Patm) and temperature (Tatm)
T_{std} = District standard temperature (Kelvin)
P_{std} = District standard pressure (mm Hg)

T_{atm} = average atmospheric temperature during sampling (Kelvin)
P_{atm} = average atmospheric pressure during sampling (mm Hg)

Example
A natural gas-fired furnace has a CO stack reading of 30 ppm at 9.7% O_2. To find the CO concentration at 0% O_2 (to convert to mass emissions), the following equation is used.

$$CO_{std} = (CO_{stack}) \left(\frac{20.95\% O_2 - 0\% O_2}{20.95\%\ O_2 - Stack\ \%\ O_2}\right) = (30\ ppm)\left(\frac{20.95\%\ O_2 - 0\%\ O_2}{20.95\% - 9.7\% O_2}\right) = 56\ ppm\ CO\ at\ 0\%\ O_2$$

Section 5.3.4 –Conversion Factors

Conversion is a multi-step process that involves multiplication or division by a numerical factor, selection of the correct number of significant figures (following procedures listed in Section 5.3.1), and rounding (following procedures listed in Section 5.3.2).

All calculations involving heating value shall be based on the higher heating value of fuel.

To minimize conversion errors and aid in comparing reported emissions, the conversion factors listed in Table 5.4-2 should be used for all emission calculations.

Table 5.4-2: Conversion Factors

Multiply	By	To Obtain		Multiply	By	To Obtain
Mass						
kilogram	2.2046	pound		pound	0.4536	kilogram
ounce	28.349	gram				
	0.0625	pound				
Power						
horsepower (boiler)	33,479	Btu/hr				
horsepower (U.S.)	2542.5	Btu/hr				
	0.7457	kilowatts				
Volume						
bbl	42	gallons				

Section 6: Quality Assurance and Quality Control

To ensure accurate emission inventories, quality assurance (preventing deficiencies) and quality control (identifying deficiencies) procedures should be implemented when developing and reviewing emission inventories.

Implementing quality assurance and quality control processes and procedures will have the following goals:

- Instill confidence in emission estimates
- Improve accuracy of emission estimates
- Improve assessment of emissions on air quality
- Improve transparency of estimates
- Provide an estimation of uncertainty, and
- Provide documentation of quality assurance and quality control activities.

Section 6.1: Quality Assurance

Quality assurance is a set of activities for ensuring quality in the process of developing an emission inventory. Quality assurance aims to prevent deficiencies with a focus on the process used to develop an emission inventory. Quality assurance is a proactive process.

Section 6.1.1 – Quality Assurance Program

Each facility that submits an emission inventory should have and follow a quality assurance program when developing an emission inventory. At a minimum, the program should include three general types of procedures:

- standard operating procedures,
- error identification and correction techniques, and
- data quality assessments.

Standard operating procedures should include organization planning, personnel training, project planning, and the development of step-by-step procedures for technical tasks.

Error finding procedures should include techniques for finding and correcting inconsistencies and errors including identification of potential error sources, location of checkpoints for optimal problem detection, and a provision for timely response when problems occur.

Data quality assessments should include accuracy checks (e.g. calibrations, instrument accuracy, source test accuracy, range, etc.), uncertainty calculations (e.g. error propagation, accuracy, etc.), and any other method for determining the quality of data used in the inventory.

When developing an emission inventory quality assurance program, a facility should:

- analyze the system to identify its components,
- estimate the potential for error and identify the errors having the greatest impact on inventory results, and
- develop techniques for the control and correction of errors.

An example outline of a quality assurance program is included in Appendix C.

Section 6.1.2 –Accuracy

Per Section 5.1.1 (Limit of Detection), calculations involving values below the limit of detection should be adjusted based on the values of the specific test runs. When doing so, each inventory shall identify the adjustment and the limit of detection of the specific source test.

Per Section 5.1.2 (Instrumentation Accuracy), calculations involving values below the accuracy of the instrument should use the accuracy limit of the instrumentation. For assurance and transparency purposes, each inventory shall identify where calculations used values at the accuracy limit and note the accuracy limit.

Per District Regulation 1, parametric monitors are required to be maintained and calibrated according to manufacturer's specifications. Therefore, each emission inventory that uses data from a parametric or other monitor should include a table that lists all monitors used and for each monitor: the accuracy, resolution, manufacturer-recommend calibration and maintenance schedule (e.g. daily, weekly, monthly, semi-annual, annual, etc.), and date of last calibration and/or performance check and maintenance.

Example – Parametric Monitors

					Manufacturer-Recommendations		Dates of Last:	
Parameter	**Instrument**	**Facility ID**	**Accuracy**	**Resolution**	**Calibration Frequency**	**Maintenance Frequency**	**Calibration**	**Maintenance**
Temperature	Rosemount 3114P temperature transmitter	PI 108.789	±0.14°F (0.08 °C)	0.01°F (0.01 °C)	60 months(1)	As needed	8/23/2015	10/6/2015 (replaced gauge cover)
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.

Notes:
1. Calculated using manufacturer-provided calibration frequency equation listed in Section 3.14.1 of Reference Manual 00809-0100-4021, Rev GD May 2015

Section 6.1.3 –Error Prevention

Wherever possible, errors should be eliminated or minimized in the development of an emission inventory.

Typical error source categories include:

- missing or duplicate emission sources
- errors in locating sources (e.g. not all sources identified or source incorrectly attributed to another facility)
- divergent time frames (inclusion of non-inventory year emissions or exclusion of inventory year emissions)
- emission factor reliability
- instrumentation error
- calculation errors
- data entry errors

Each facility submitting an emission inventory should have in place processes, techniques, and procedures for preventing errors.

Section 6.2: Quality Control

Quality control is a set of activities for ensuring quality in a completed emission inventory. Quality control aims to identify and correct deficiencies and measures the performance of the process of developing an emission inventory. Quality control is a reactive process.

Section 6.2.1 – Methods

The following are examples of quality control methods that can be used by facilities to review the efficacy of a quality assurance program:

- Reality checks (e.g. are numbers reasonable? Do they make sense?)
- Peer review (e.g. independent review of calculations, assumptions, and documentation by person with a moderate to high level of technical expertise)
- Sample calculation (e.g. replication of calculations)
- Computerized or automated data checks (check for data format errors, range checks, look-up tables)
- Sensitivity analysis (identify which parameters and errors have largest effect on results)
- Emission estimation validation
- Statistical checks (identify outliers)
- Independent audit

Employing standardized checklists to monitor:

- Data collection
- Data calculations
- Evaluation of data reasonableness
- Evaluation of data completeness
- Data coding and recording
- Data tracking

Example quality control activities include:

- Comparison of emissions to previous inventories
- Using checklists to ensure that all inventory development requirements are met
- Determining outliers by using computer-aided, graphical, or other reviews
- Conducting accuracy checks

Section 6.2.2 – Error Detection and Correction

Each facility submitting an emission inventory should have in place processes, techniques, and procedures for detecting and correcting errors.

Techniques to detect and correct errors may include:

- Peer review
- System audit of quality assurance system

Section 6.3: Uncertainty Analysis

Each inventory calculation involving an emission factor, instrumentation data, source test, or other information that has the potential for uncertainty (degree of accuracy and precision of data) should include a minimum and maximum error range for each point of uncertainty as well as an error propagation (total uncertainty) value.

Each inventory should include for each source in the inventory, a table of the parameters used to calculate emissions for that source with the method used to determine the value of the parameter and uncertainty values for the parameter.

Each emission inventory should include total errors on an individual source basis as well as a refinery-wide basis.

Sources of uncertainty include:

- Assumptions and methods
- Input data (measured values have errors, non-representative emission factors, lack of data, etc.)
- Calculation errors

District Regulation 1, Section 522 requires CEMS to be calibrated daily and maintain accuracies to within specified values. District Regulation 1, Section 523 requires facilities to maintain and calibrate all parametric monitors in accordance with applicable manufacturer's specifications and keep records of all tests, calibrations, adjustments and maintenance. All District-approved source tests are required to following the District's Manual of Procedures, which outlines the minimum accuracy criteria of various test methods. Within the basis of agency-supplied (BAAQMD, ARB, EPA, etc.) default emission factors are listed either the confidence interval or accuracies.

Within each refinery's Title V permit are standard conditions that require the refineries to report any non-compliance within 10 days of discovery as well require the responsible official to certify compliance with all applicable rules and regulations to the best of their knowledge.

It is expected that each refinery can readily obtain and compile accuracies for all CEMS, parametric monitors, source tests, and default emission factors used in a submitted emission inventory.

However, for instruments that are not CEMs or parametric monitors, there are no regulatory-required maintenance or accuracy requirements. As such, compilation and reporting of accuracies from these instruments may be difficult. As such, refineries may have until the third submitted emission inventory to report accuracies for these instruments. In the interim, unless data is available, total uncertainty calculations involving these instruments should treat these instruments as being 100 percent accurate.

Total Uncertainty –Error Propagation

Total uncertainty should be calculated using an error propagation equation (see Equation 6.1.3-1):

$$Total\ Uncertainty = \sqrt{(uncertainty\ 1)^2 + (uncertainty\ 2)^2 + \cdots + (last\ uncertainty)^2} \qquad \text{[Eqn 6.3-1]}$$

<u>*Example*</u>

CO emissions from a furnace are estimated using the following equation:

$$CO(lb/hour) = \frac{CO(ppm)}{1{,}000{,}000}\, x\, \frac{20.95\%\, O_2 - \%\, O_2}{20.95\%\, O_2}\, x\, \frac{28.01\frac{lb}{lb-mol}}{385.3\frac{scf}{lb-mol}}\, x\, \frac{(T°F+459.67)}{(68+459.67)}\, x\, \frac{fuel\ flow\ (scf) x\ HHV\left(\frac{Btu}{scf}\right) x\ \left(\frac{1\ MMBtu}{1{,}000{,}000\ Btu}\right)}{F-Factor\ (dscf/MMBtu)}$$

where:
CO = CO concentration measured using a continuous emission monitor (CEM)
O_2 = O_2 percentage measured using a CEM,
T = temperature measured using a thermocouple
Fuel flow is measured is flow meter,
HHV = higher heating value measured using a calorimeter
F-Factor = volume of combustion components per unit of heat content determined through a gas chromatograph analysis

In this example, there are several instances where errors may be introduced into the final calculation. These include the CO and O_2 CEMs, thermocouple, fuel flow meter, calorimeter, and GC analysis.

Table 6.3-1 lists example uncertainty values for each error-introducing parameter and a total error value.

Table 6.3-1: Example Uncertainty Analysis of CO Emissions from a Furnace

Parameter	Units	Method	Uncertainty	
			(%)	(absolute value)
Fuel flow	scf	Meter	± 2%	± 100 scf
Higher heat value	Btu/scf	Meter	± 10%	± 50 Btu/scf
CO	ppm	CEM	± 10%	± 5 ppm
O_2	%	CEM	± 5%	± 0.5%
Fuel analysis F-factor	dscf/MMBtu	GC	± 1%	± 100 scf/MMBtu
Temperature	°F	Thermocouple	± 5%	± 50 °F
		Total Error	**~± 16%**	

In this example, CO emissions would have a total uncertainty of ± 16%. This total error on both a percentile and absolute basis should be included in the inventory along with the final CO emissions (e.g. CO = 24 tons ± 3.8 tons (± 16%).

In addition to furnace listed in Table 6.1-1, a refinery has one other source of CO emissions whose emissions are 18 tons ± 2.2 tons (± 12%). In this case, the total refinery CO emissions are 42 tons ± 8.4 tons (± 20%).

Total Uncertainty –Monte Carlo Method

If uncertainties are large, have a non-normal distribution, complex algorithms, or correlations exist and uncertainties vary with time; a Monte Carlo simulation may be required rather than Equation 6.1.3-1. The Monte Carlo method requires understanding the shape of the probability density function (PDF) of the equation The PDF is the range and likelihood of possible values and includes the mean, width, and shape (e.g. normal, log-normal, Weibul, Gamma, uniform, triangular, fractile,….).

The Monte Carlo method requires:

- selecting random values of input parameters from their PDF,
- calculating the corresponding emissions,
- repeating many times,
- plotting the results to form a PDF of the result, and
- estimating a mean and uncertainty from the PDF of the results.

Section 6.4: Documentation

All quality assurance and quality control activities, especially changes made as a result of these activities, should be documented and records kept onsite for the benefit of future preparers and District staff.

Each inventory should have a quality assurance report that includes the following information:

- Procedures used
- Technical approach used to implement quality assurance plan
- Any calculation sheets and quality assurance/quality control checklists
- Dates of each audit, and the names of the reviewers
- Responses to quality assurance/quality control audits
- Results of quality assurance activities, including problems found, correction actions, and recommendations
- Discussion of the inventory quality

Every submitted emission inventory should include a quality assurance section with a checklist that identifies the measures taken to ensure the accuracy and reliability of the inventory.

Section 6.5: Quality Assurance Plan

Each facility submitting an emission inventory should have and follow a quality assurance plan when developing the emission inventory.

Each quality assurance plan should include the following elements:

- A description of specific quality assurance and quality control procedures and responsibilities
- Identify a Quality Assurance Coordinator
- Restate the data quality objectives and data quality indicators
- Determine resources needed to implement the quality assurance plan
- Identify authority and responsibility for quality assurance/quality control plan implementation
- Techniques for identifying sources of pollutants
- Data acquisition
- Data validation and usability

Data quality indicators include:

- Representativeness
- Precision
- Bias
- Detectability
- Completeness
- Comparability

Techniques for identifying sources of pollutants may include:

- Documents and tools
- Existing inventories
- Source tests
- Compliance data
- Compliance reports (e.g. risk management reports, accidents/spills, etc.)

- Permits
- Risk assessments

At a minimum, each quality assurance plan should have the sections identified in Table 6.5-1.

Table 6.5-1: Quality Assurance Plan Components

Section	Includes
Policy Statement	Declaration of facility's commitment
Introduction	
Quality Assurance Program Summary	Data flow and points where quality control procedures will be applied
Technical Work Plan	Resources, documentation schedule
Quality Assurance/Quality Control Procedures	Techniques, checkpoints
Inventory Preparation and Quality Assurance/Quality Control Activities	Roles and responsibilities, personnel, reality checks, peer review, sensitivity checks, etc.
Corrective Action Mechanisms	
References	

Section 7: Inventory Usage for Regulatory Compliance

The principle purpose of emission inventories is to track and characterize emissions from petroleum refineries over time. Attempts to compare emission inventory results to existing or previous regulations, permit conditions, or other metrics should be done carefully with a comprehensive understanding of how the inventory was developed and the underlying basis of the regulation under comparison.

Section 7.1: Regulatory Basis

Data used in an inventory report prepared according to these guidelines may also be used to determine compliance with District, California, or Federal regulations. However, emissions results should not be used to determine compliance with a regulation unless the underlying estimation methodologies are understood and determined to be the same, similar, or allowed by the regulation.

When developing regulations, concerns other than actual emissions totals are considered such as startup, shutdown, and malfunction allowances. Therefore, regulations may have different definitions of "hour", "day", "annual", or "year" as well as data substitution allowances. Therefore, unless these definitions are understood, emissions inventories should not be used to justify an assertion of non-compliance on the part of the facility.

As the purpose of the inventory is to report actual emissions as accurately as possible, reported emissions totals may differ from emissions reported per a specific regulation or permit condition requirement.

For example, a refinery's NO_X emissions reported in an emissions inventory may differ from NO_X emissions reported per District Regulation 9, Rule 10. As compliance with Regulation 9, Rule 10 is based on an average of all furnaces subject to Regulation 9, Rule 10; Regulation 9, Rule 10 includes allowances for various operating scenarios (data substitution) and excludes emissions from startup and shutdown periods. However, the emission inventory does not include such allowances and should reflect actual emissions. In this case, NO_X emissions reported in an inventory may differ (higher or lower) than those reported per Regulation 9, Rule 10. In this case, it is not appropriate to use emission inventory reported NO_X emissions as a demonstration of non-compliance with Regulation 9, Rule 10.

Therefore, emissions results should not be used to determine compliance with a regulation unless it is clearly demonstrated that the methodology used to derive the results are the same as the methodology used in the regulation.

Section 7.2: Regulatory Comparisons

Whenever possible, emission inventories should identify all emissions limits applicable to refinery equipment and include a comparison of emissions totals in the inventory to applicable emission limits. The emission inventory shall identify and include a statement for any emission limit that has a different basis (i.e. methodology, averaging period, definition, etc.) than the inventory. Such comparisons and statements may prevent unwarranted comparisons and faulty conclusions from occurring.

Section 8: Report Formats

To aid reader comprehension and increase efficiency of the District review, emission inventories prepared according to these guidelines should be consistent in how results are reported. An example of an approved format that follows the guidance listed within this section is included in Appendix D.

Section 8.1: Public Version and Confidential Version

Petroleum refineries should submit both a public version and a confidential version of the emission inventory. The two versions shall be identical except that confidential data should be redacted from the public version. The confidential version shall have all confidential information clearly identified. A section at the at the beginning of the confidential version shall summarize all confidential information and have specific statements as to how each information should be considered confidential per California Government Code Section 6250 – 6270 ("California Public Records Act").

The District may differ in its interpretation of what information is considered confidential at which time the District will notify the affected facility and may require a re-submittal of both a revised public version and revised confidential version of the emission inventory.

Section 8.2: Physical and Digital Copies

Refineries shall submit both physical and digital copies of the emissions inventory along with all supporting documentation (intermediate and final calculations, source tests, CEM readings, etc.). Digital copies shall include supporting data and calculations in a spreadsheet-based software program (e.g. Microsoft Excel).

Section 8.3: Emissions Summaries

Each emission inventory shall include summaries of criteria pollutant, greenhouse gases, and toxic air contaminant emissions on a refinery-wide, source category, and District source basis. Refinery-wide, source category, and District source summaries shall be in tabular forms while source category and District source summaries shall also be in a graphic form.

Refinery-wide emissions summaries should be reported on a quantity basis (e.g. tons). Source-category and District source emissions summaries should be reported on a quantity (e.g. tons) and percentile basis (e.g. percentage of total emissions).

Table 8.3.1 includes an example of a refinery-wide criterial pollutant and greenhouse gases emissions summary in tabular form.

Table 8.3.1 Example Refinery-Wide Emissions Summary – Criteria Pollutants and Greenhouse Gases

Refinery-Wide Annual Emissions (tons)						
NO_X	**SO_2**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**GHGs** (metric tons)
100	**200**	**400**	**800**	**50**	**25**	**1,000,000**

Table 8.3.2 includes source categories for which emissions summaries should be reported.

Table 8.3.2 Source-Category Emissions Summary – Criteria Pollutants and Greenhouse Gases

Category	**Annual Emissions** (tons)						
	NO_X	**SO_2**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**GHGs***
Fugitive Emission Leaks							
Storage Tanks							
Stationary Combustion (All)							
Boilers							
Engines							
Furnaces & Process Heaters							
Gas Turbines & HRSGs							
Thermal Oxidizer(s)							
Process Vents (All)							
Catalytic Reformer(s)							
Delayed Coking Unit(s)							
Fluid Coking Unit/CO Boiler(s)							
Fluid Catalytic Cracking Unit							
Hydrogen Plant(s)							
Sulfur Plant(s)/Sulfur Recovery Unit(s)							
Flares							
Pilot/Purge							
Process Gas							
Wastewater							
Heat Exchanger Leaks/Cooling Towers							
Mobile Stationary Sources							
Cargo Carriers							
Shipping							
Rail							
Turnaround Activities							
Startups/Shutdowns							
Malfunctions/Upsets							
Accidents/Spills							
Total							
* metric tons							

Table 8.3.3 includes an example of a criteria pollutant and greenhouse gases emissions summary for District sources.

Table 8.3.3 Example Source-Category Emissions Summary – Criteria Pollutants and Greenhouse Gases

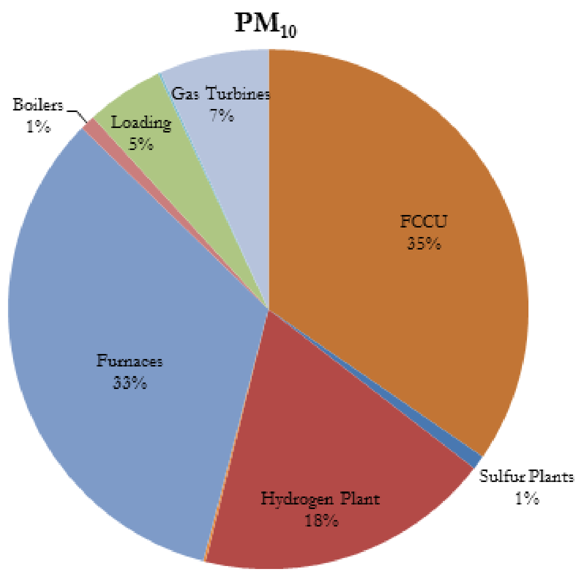
Source #	**Description**	**Permit Status**	**New Source Review Status**	**Annual Emissions** (tons)						
				NO_X	**SO_2**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**GHGs**
S-1	Crude Unit	Permit	Grandfathered							
S-2	Crude Unit Furnace	Permit	NSR							
S-3	Diesel Tank	Exempt	Grandfathered							
.	.	.	.							
.	.	.	.							
			Total (tons)							

Table 8.3.4 lists an example of a District source emissions summary on a percentile basis.

Table 8.3.4 Example Source-Category Emissions Summary Percentile Basis– Criteria Pollutants and Greenhouse Gases

Source #	Description	Permit Status	New Source Review Status	Annual Emissions (% of total)						
				NO_X	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	GHGs
S-1	Crude Unit	Permit	Grandfathered							
S-2	Crude Unit Furnace	Permit	NSR							
S-3	Diesel Tank	Exempt	Grandfathered							
.	.	.	.							
.	.	.	.							
			Total (%)	**100**	**100**	**100**	**100**	**100**	**100**	**100**

Figure 8.3.1 shows examples of source category emission summaries in graphic form.



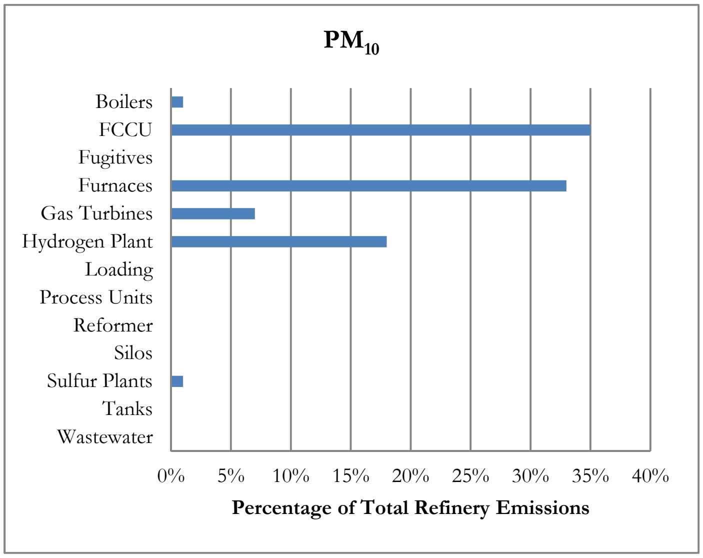


Figure 8.3.1 Example source category PM_{10} emission summary in graphic forms

Section 8.4: Emission Comparisons

Each emission inventory should include a comparison of emission totals (refinery-wide, source category, and District source bases) to the first submitted inventory as well as year on year comparison to previous inventories.

Section 8.4.1 – Comparison to First Inventory

Each inventory shall include a comparison of inventory totals to the first inventory with specific reasons for any totals that exceed the first inventory.

Table 8.4.1 includes an example of a refinery-wide criterial pollutant and greenhouse gases emissions summary in tabular form.

Table 8.4.1 Refinery-Wide Emissions Summary – Criteria Pollutants and Greenhouse Gases

Year	**Refinery-Wide Annual Emissions** (tons)						
	NO_X	**SO_2**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**GHGs** (metric tons)

Section 8.4.2 – Comparison to Previous Inventory and Historical Trend Lines

Each inventory shall include a comparison to the previous inventory that includes emission totals in tons as well as the percentile difference between the two. The inventory shall include a trend line of emissions totals over time as reported in the current and previous inventories.

Section 9: Timeline for Emission Estimation Methodology or Data Revision

Periodically, emission estimation methodologies may be revised or new pollutants may be required to be reported. Such changes may require that new parameters be recorded that were previously not being recorded.

If an emission estimation methodology is revised or a new pollutant is required to be reported and new data that was not previously being recorded is required, the facility may report the relevant emissions using the revised methodology or for the new pollutant for the following inventory report covering the complete calendar year when such new data is available.

For example, if a new pollutant is required to be reported in mid-2016 and the new pollutant requires data not currently being recorded, the facility may report emissions for the new pollutant in the 2018 inventory report covering the calendar year 2017 refinery emissions. However, if the facility has the capability and records required to calculate emissions for the new pollutant, emissions totals for the new pollutant shall be reported in the 2017 year inventory report.

Section 10: Guidelines Revision Procedure

The goal of the procedures described in this Section is to provide for transparency, consistency, and stakeholder participation when these guidelines need to be revised.

Section 10.1: Revision Requirement

These guidelines may be revised under the following circumstances:

- a new emission estimation methodology is developed,
- an existing methodology is changed,
- an acceptable methodology is discredited,
- the accuracy of an existing methodology is revised, requiring a change in ranking,
- a previously unknown pollutant is identified,
- a new regulated pollutant is added, or
- editorial additions and/or corrections.

Section 10.2: Revision Procedure

The following steps will be followed prior to incorporating a change to these guidelines:

Step 1: Identification of Need for Revision
Step 2: Notification of Interested Stakeholders
Step 3: Review Public Comments
Step 4: Publish Revised Guidelines
Step 5: Adoption of Revised Guidelines

Section 10.2.1 – Identification of Need for Revision

A need for a revision to these guidelines may be identified by either:

- District personnel,
- Formal request by an interested stakeholder, or
- A scheduled review by the District occurring at a minimum frequency of once every five years.

Formal requests by stakeholders should be in written form directed to the Engineering Division and should:

- identify the pertinent section(s) of the guidelines requiring a revision,
- explain why the revision is appropriate, and
- include suggested guidelines language for the change.

The District will review any formal requests for guidelines revision and determine whether the steps in Section 10.2 should be followed to put the revision into effect.

Section 10.2.2 – Notification of Interested Stakeholders

If the District determines a guidelines revision is warranted, the District will notify interested stakeholders that a revision is necessary and will:

- identify the pertinent section(s) of the guidelines requiring a revision,
- explain why the revision is appropriate,
- include suggested guidelines language change, and
- request comments on the rationale for justifying a revision and suggested change(s).

Section 10.2.3 – Comment Review

After the close of the comment period (presumptively 30 calendar days), the District will consider all comments received and, as appropriate, revise the proposed guidance text and provide responses to comments received..

Section 10.2.4 – Publication of Revised Guidelines

Once the guidelines have been revised, the District will publish the final emission inventory guidelines on the District's website.

Section 10.2.5 – Adoption of Revised Guidelines

Once the revised guidelines have been published on the District's website, the revised guidelines are considered adopted and should be used by affected facilities.

Section 11: Emission Inventory Review Criteria

While reviewing an emission inventory; the District will determine if an emission inventory is:

- satisfactory,
- requires minor revision,
- requires major revision, or
- must be rejected.

Although it is not possible to list every situation that may result in an emission inventory from requiring revision or being rejected, the following sections outline the major criteria that the District will apply during its review.

These represent minimum measures (i.e. an inventory that does not meet the criteria will result in rejection but an inventory that meets the criteria is not automatically accepted).

Section 11.1: Completeness

The District will determine if emissions from all emission-causing activities and sources are included within the inventory. The District will determine if all pollutants are included in the inventory.

Section 11.2: Methodology

The District will review the emission estimation methodologies that were used and verify that the highest ranking method for which data is available was used. An emission inventory may be rejected if the highest ranking method was not used, if the methodology used is not identified, or the District cannot determine the methodology used.

Section 11.3: Data Quality

The District will review the underlying quality of the data used to estimate emissions. In this review, the District may review the quality assurance and quality control measures implemented by the refinery to ensure data quality.

Section 11.4: Documentation

The District will review all supporting documentation (either submitted with an inventory or retained onsite) and determine if there is documentation to support any assumptions, methodologies, or other metrics used in developing the emission inventory.

Section 11.5: Timing

The District may reject an emission inventory if a facility does not submit an inventory by the regulatory deadline or delays in response to District enquiries regarding an emission inventory.

Section 12: Bibliography

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APPENDIX A

Default Emission Factors

This section lists District-approved default emission factors.

Table A-1 Default NO_X Emission Factors

Source Category	NO_X Emission Factor	
	Value	Units

Table A-2 Default SO_2 Emission Factors

Source Category	SO_2 Emission Factor	
	Value	Units

Table A-3 Default VOC Emission Factors

Source Category	VOC Emission Factor	
	Value	Units

Table A-4 Default CO Emission Factors

Source Category	CO Emission Factor	
	Value	Units

Table A-5 Default PM_{10} Emission Factors

Source Category	PM_{10} Emission Factor	
	Value	Units

Table A-6 Default $PM_{2.5}$ Emission Factors

Source Category	$PM_{2.5}$ Emission Factor	
	Value	Units

APPENDIX B

Emission Calculation Templates

Table B-1: Summary of Emission Estimation Templates

Section	Section Title	Rank	Measurement Method	Template
3.1	Fugitive Emission Leaks	1	Direct measurement	TBD
		2	Correlation equations	TBD
		3 & 4	Average emission factors	TBD
3.2	Storage Tanks	1	Direct measurement	TBD
		2	Tank-specific modeling	TBD
3.3	Stationary Combustion	1	Direct measurement (flow rate and gas composition)	TBD
		2	Direct measurement (F factors)	TBD
		3A	Fuel analysis/mass balance	TBD
		3B	Source-specific stack testing	TBD
		4	Default emission factors	TBD
3.4	Process Vents	1	Continuous gas composition analyzer (flow meter)	TBD
		2	Continuous gas composition analyzer (F-factor)	TBD
		3	Grab samples	TBD
		4	Source tests	TBD
		5	Default emission factors	TBD
3.5	Flares	1	Continuous flow rate monitoring Continuous composition monitoring	TBD
		2	Continuous flow rate monitoring Occasional sampling	TBD
		3	Continuous flow rate & heating value monitoring	TBD
		4	Engineering calculations	TBD
		5	Energy consumption-based emission factors	TBD
		6	Default emission factors	TBD
3.6	Wastewater	1	Direct measurement	TBD
		2	Predictive modeling with site-specific factors & biodegradation rates	TBD
		3A	Engineering estimates (wastewater plant load)	TBD
		3B	Engineering estimates (crude throughput)	TBD
3.7	Cooling Towers	1	Direct water measurement (continuous)	TBD
		2	Direct water measurement (periodic)	TBD
		3	Default emission factors	TBD
3.8	Loading Operations	1A	Continuous gas composition analyzer and continuous vent gas flow measurement	TBD
		1B	Continuous gas THC analyzer with periodic sampling speciation and continuous vent gas flow measurement	TBD
		2	Site specific emission factors (EPA Method 18)	TBD
		3	Default emission factors (NMOC source tests)	TBD
		4	Default emission factors (measured loading rates)	TBD
3.9	Fugitive Dust	1	Calculated emission factor (measured silt loading)	TBD
		2	Calculated emission factor (default silt loading)	TBD
3.10	Startup and Shutdown	1A	Engineering estimate (ideal gas law)	TBD
		1B	Engineer estimate (residual liquids vaporizing)	TBD
		1C	Engineering estimate (ideal gas law, liquid "heel")	TBD
3.11	Malfunctions/ Upsets	1	Direct measurement	TBD
		2	Engineering calculations (control device)	TBD
			Engineering calculations (vessel over pressurization)	TBD
			Engineering calculations (liquid spill)	TBD
3.12	Miscellaneous Sources			
3.12.1	Non-Retail Gasoline Dispensing Facility	1	Default emission factors	TBD
3.12.2	Architectural or	1	Material balance	TBD

Section	Section Title	Rank	Measurement Method	Template
	Equipment Painting			
3.12.3	Abrasive Blasting	1	Default emission factors	TBD
3.12.4	Solvent Degreaser	1	Material balance	TBD
3.12.5	Soil Remediation	1	Material balance	TBD
3.12.6	Air Stripping	1	Material balance	TBD
3.13	Cargo Carriers			
3.13.1	Marine	1	Direct measurement (flow meter)	TBD
		2	Direct measurement (F-factor)	TBD
		3A	Fuel analysis/mass balance	TBD
		3B	Source test (emission correlations or factors)	TBD
		4	Default emission factors	TBD
		5	Emission calculations	TBD
3.13.2	Rail	1	Direct measurement (flow meter)	TBD
		2	Direct measurement (F-factor)	TBD
		3A	Fuel analysis/mass balance	TBD
		3B	Source test (emission correlations or factors)	TBD
		4A	Default emission factors (hourly basis)	TBD
		4B	Default emission factors (fuel basis)	TBD
		5 - 7	Default emission factors (ton-mile basis)	TBD

APPENDIX C

Quality Assurance Program

(Example Outline)

1.0 Quality Assurance Policy Statement

1.1. Purpose of the Program
1.2. Scope

2.0 Summary

a. Organization Chart
b. Emission Inventory Tasks and Responsibilities
c. Information Flow
d. Summary of Control Techniques and Relation to Information Flow
e. Audit Procedures

3.0 Technical

3.1 Task Planning

3.1.1 Training and Staff Qualification
3.1.2 Schedule and Frequency of Updates
3.1.3 Quality Assurance Coordinator – Duties and Responsibilities
3.1.4 Data Sources

3.2 Data Collection

3.2.1 Forms and Procedures
3.2.2 Data Review
3.2.3 Quality Assurance Controls

3.3 Technical Procedures

3.3.1 Emission Factors
3.3.2 Instrumentation
3.3.3 Data Flow
3.3.4 Review Procedures

3.4 Data Recording and Reporting

3.4.1 Recording and Coding Forms
3.4.2 Rules for Data Coding
3.4.3 Data Editing Procedures

4.0 System Audits

4.1 Audit Responsibility and Schedule
4.2 Procedures

4.2.1 Elements
4.2.2 Schedule
4.2.3 Audit Report

APPENDIX D

Emission Inventory Report

(Approved Format)

Date

Engineering Division
Bay Area Air Quality Management Division
375 Beale Street, Suite 600
San Francisco, CA 94105

Emission Inventory – Calendar Year 2016

Enclosed is the emission inventory for the Acme Petroleum Refinery for calendar year 2016.

The table below summaries the refinery-wide emission totals that are detailed in the attached document and a comparison to the previous inventory.

Table 1 – Acme Refinery Emissions for Calendar Year 2016

Year	**NO_X** (tons)	**CO** (tons)	**VOC*** (tons)	**SO_2** (tons)	**PM_{10}** (tons)	**$PM_{2.5}$** (tons)	**TACs** (tons)	**Methane** (tons)	**GHGs** (metric tons)
2016	100	100	200	110	400	300	100	80	2,000,000
2015	102	90	200	120	450	325	200	90	2,100,000
Difference (tons)	**-2**	**+10**	**0**	**-10**	**-50**	**-25**	**-100**	**-10**	**-100,000**
Difference (%)	**-2%**	**+11%**	**0**	**- 8%**	**-11%**	**-8%**	**-50%**	**-11%**	**-5%**
*VOC totals include methane totals									

Table 2 – Acme Refinery Emission Percentages by Source Category

Source Category	**NO_X** (%)	**CO** (%)	**VOC** (%)	**SO_2** (%)	**PM_{10}** (%)	**$PM_{2.5}$** (%)	**TACs** (%)	**Methane** (%)	**GHGs** (%)
Combustion	30	40	10	25	20	10	20	15	40
FCCU	20	15	10	10	60	75	25	10	20
Tanks	0	0	40	0	0	0	20	50	5
Fugitives	0	0	40	0	0	0	15	20	20
.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.
Total	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**

If there are any questions, please contact John Doe via email at john.doe@acmerefinery.com or by telephone at (123) 456-7890.

I certify to the best of my knowledge this is a true, accurate, and complete emission inventory.

Sincerely,

Jane Doe
Environmental Manager

I. Introduction

This section discusses the purpose of the report as well as any necessary information for the reader to be able to understand and interpret the report.

II. Confidentiality

This section includes a table of information considered confidential and has specific statements as to how each information would be considered confidential per California Government Code Section 6250 – 6270 (“California Public Records Act”).

III. Emission Activities and Sources

This section identifies all of the sources and activities covered in the emissions inventory report.

IV. Emission Estimation Methodologies

This section identifies all emission methodologies used and corresponding ranking for each source and activity included in the emissions inventory report.

This section identifies all supporting documentation used (e.g. source test reports, throughput records, etc.) and includes the documentation in Appendix C.

V. Emission Estimates

This section includes summaries of refinery-wide and source category emission estimates with emission estimates for individual sources and activities listed in Appendix A.

Emissions Summary – Criteria Pollutants and Greenhouse Gases

	Annual Emissions (tons)						
Category	**NO_X**	**SO_2**	**VOC**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**GHGs***
Fugitive Emission Leaks							
Storage Tanks							
Stationary Combustion							
Process Vents							
Flares							
Pilot/Purge							
Process Gas							
Wastewater							
Cooling Towers							
Mobile Stationary Sources							
Cargo Carriers							
Shipping							
Rail							
Total							
* metric tons							

VI. Emission Comparisons

This section includes comparisons of emissions totals to the first submitted emissions inventory as well as the previous year and includes a historical emissions trends beginning with the first year that an emissions inventory is submitted. This section also includes a discussion of any anomalies and a justification for each anomaly.

VII. Emission Uncertainty Analysis

This section includes a discussion on emissions uncertainty, the methods used to calculate uncertainties, and overall uncertainties for each refinery-wide pollutant with source-specific uncertainties included with individual emissions estimates in Appendix A.

VIII. Quality Assurance and Quality Control

This section discusses the quality assurance and quality control procedures implemented to ensure reliable and robust data. In particular, this section would discuss the methods employed to ensure that:

- all emission causing sources and activities were identified and included in the report,
- that errors were minimized and/or eliminated,
- the highest ranking emission estimation methodologies were employed, and
- all data used is reliable and accurate.

IX. Conclusions

This section includes any closing remarks regarding the emission inventory and any information that may be useful for the District to consider when reviewing the emission inventory.

Appendix A – Individual Source Emissions
Appendix B – Detailed Emission Calculations
Appendix C – Supporting Documentation

Figures

Figure – Refinery Plot with Emission Activity and Source Locations Identified