

FUGITIVE EMISSIONS FROM EQUIPMENT LEAKS II: CALCULATION PROCEDURES FOR PETROLEUM INDUSTRY FACILITIES

Health and Environmental Affairs Department
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American Petroleum Institute

Environmental, Health, and Safety Mission and Guiding Principles

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Fugitive Emissions From Equipment Leaks II: Calculation Procedures for Petroleum Industry Facilities

Health and Environmental Affairs Department

API PUBLICATION NUMBER 343

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ABSTRACT

The American Petroleum Institute (API) commissioned two manuals to be prepared, providing options and recommendations on procedures for obtaining inspection and maintenance (I/M) data from certain process equipment with the potential to leak "fugitive emissions." These manuals are designed to provide assistance to those who collect fugitive data, ensure regulatory compliance, and calculate emissions associated with these fugitive emissions. The manuals are focused on the recommended fugitive emission practices in the petroleum industry, specifically for refineries, petroleum marketing terminals, and the oil and gas production industries.

This second volume is entitled *Fugitive Emissions from Equipment Leaks II: Calculation Procedures for Petroleum Industry Facilities*. This manual is designed primarily for those who perform the emission calculations associated with fugitive emissions. This manual also discusses equipment categories, provides an overview of available emission estimation approaches, provides sample calculations for different calculation methods, discusses issues that affect the determination of fugitive emissions, and addresses data management.

The first volume, *Fugitive Emissions from Equipment Leaks I: Monitoring Manual* (API Publ. 342), is designed primarily for those who manage or apply fugitive emission I/M programs at a facility. It discusses the compilation of a component inventory, describes monitoring equipment that meet specifications identified in the United States Environmental Protection Agency's (U.S. EPA) Method 21, describes quality control practices, explains the screening procedures, and addresses alternative measurement methods.

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LIST OF ACRONYMS

AC	- actual concentration
API	- American Petroleum Institute
ASTM	- American Society for Testing and Materials
FID	- flame ionization detector
HAP	- hazardous air pollutant
I/M	- inspection and maintenance
ID	- identification
LDAR	- leak detection and repair
MTBE	- methyl tert-butyl ether
NDIR	- nondispersive infrared
NSPS	- New Source Performance Standards
OEL	- open-ended line
OVA	- organic vapor analyzer
PID	- photo ionization detector
ppmv	- parts per million by volume
PRV	- pressure relief valve
RF	- response factor
SOCMI	- Synthetic Organic Chemical Manufacturing Industry
SV	- screening valve
TLV	- threshold limit value
TOC	- total organic compounds
TVA	- total vapor analyzer
U.S. EPA	- United States Environmental Protection Agency
VOC	- volatile organic compound

SECTION 1.0 INTRODUCTION

The American Petroleum Institute (API) initiated the development of this document to provide member companies guidance with up-to-date information on the methods to estimate equipment leak emissions (fugitive emissions) from valves, pump seals, flanges, etc., for the petroleum industry.

The objective of this document is to present in a readily available format the latest recommendations for calculating fugitive emissions from refineries, petroleum marketing terminals, and the oil and gas production industries. This volume is a companion document to Volume I, which provides guidance on monitoring fugitive emissions from process equipment leaks.

Several different emission factors and correlation equations have been developed over nearly twenty years for each sector of the petroleum industry. This document will not list all of these emission factors and emission correlation equations, although many of the studies that produced these factors and equations will be referenced. Generally, only one set of emission correlation equations, pegged component emission factors, and zero component emission factors applicable to refineries, petroleum marketing terminals, and the oil and gas production industries will be presented in this document. The selected factors and equations are the most recent ones that have received United States Environmental Protection Agency (USEPA) approval or are expected to receive U.S. EPA approval. Two sets of average

emission factors for refinery components in heavy liquid service are provided. The first set has received prior U.S. EPA approval. The second set was developed by API and will be reviewed by the U.S. EPA.

Section 2.0 contains a general description of the equipment categories. Section 3.0 provides an overview of available emission estimation approaches for equipment leaks and also includes sample calculations for the different methods. Section 4.0 discusses several issues that affect the determination of emissions. Section 5.0 discusses data management. Finally, Section 6.0 contains the references.

The appendices to this document provide tabulations of relevant information that might be useful in calculating emissions from a wide variety of facilities. These include:

- U.S. EPA guidance on component count estimation methods for refinery units (Appendix A);
- U.S. EPA guidance on methods to account for benefits of an inspection/maintenance program (Appendix B);
- Fugitive emission factors and equations for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) (Appendix C);
- U.S. EPA tabulation of response factors (Appendix D); and
- A calculation example demonstrating the use of published response factors (Appendix E).

SECTION 2.0 EQUIPMENT DESCRIPTION

In order to calculate emissions from process equipment components, it is first necessary to understand the types of equipment that potentially have fugitive emissions. This equipment is described in this section. Control techniques or inspection and maintenance practices that can affect emission calculations are also discussed. In addition, procedures for counting these components for equipment inventories are presented.

Please note that most of the material in this section is essentially the same as that provided in Volume I of this series. It is repeated here for completeness and because these considerations are important both for monitoring and for calculations.

2.1 EQUIPMENT TYPES

The primary equipment types (or component types) that are fugitive emission sources are:

- Agitators;
- Compressors;
- Connectors;
- Open-ended lines;
- Pressure relief devices;
- Pumps;
- Sampling connections;
- Valves; and
- Others.

Graphical depictions of these types of components are shown in Section 5.0 of Volume I.

Note that the terminology in this document for leaks from "pumps," "agitators" and "compressors" is used interchangeably with the words "pump seals," "agitator seals" and "compressor seals." Other terminology is also often used interchangeably to describe equipment leaks. For example, "connectors" can also be referred to as "fittings."

Subsequent sections of this report give a description of these component types and information related to how these components leak.

2.1.1 Agitators

Agitators are used to stir or blend chemicals. Four seal arrangements are commonly used with agitators: packed seals, mechanical seals, hydraulic seals, and lip seals.

A packed seal consists of a cavity, called a *stuffing box*, in the agitator casing filled with a packing gland to form a seal around the shaft. There are several types of single mechanical seals, with many variations to their basic design and arrangement, but all have a lapped seal face between a stationary element and a rotating seal ring. There are also many variations of dual and tandem mechanical seals. Dual mechanical seals with the following characteristics are considered to be leak free (and therefore typically do not require monitoring):

- Barrier fluids pressurized higher than the agitator cavity;
- A barrier fluid reservoir vented to a control device; and
- A pressure tight barrier fluid with a pressure alarm indicator.

In a hydraulic seal, an annular cup attached to the process vessel contains a liquid that contacts an inverted cup attached to the rotating agitator shaft. Although it is the simplest agitator shaft seal, the hydraulic seal is limited to low temperature/low pressure applications and can handle only very small pressure changes. A lip seal consists of a spring-loaded, non-lubricated elastomer element, and is limited in application to low-pressure, top-entering agitators.

Agitator seals can leak because of poor installation, aging, and deterioration of the seals themselves, thermal stress, and vibration.

2.1.2 Compressors

Compressors provide the force to transport gases through a process unit in much the same way that pumps transport liquids. There are centrifugal, reciprocating, and rotary compressors in use by industries affected by equipment leak regulations. The sealing mechanisms for compressors are similar to the packed and mechanical seals for agitators.

2.1.3 Connectors

Connectors are used to join sections of piping and equipment. Connectors can be flanges, screwed or threaded connectors, union

connectors, tubing connectors, caps, plugs, etc. For the recent petroleum industry studies, flanges were analyzed separately from the other connectors.

Flanges are bolted, gasket-sealed connectors. Flanges are normally used for pipes with diameters of 2.0 inches or greater. The primary causes of flange leakage are poor installation, aging and deterioration of the gasket, thermal stress, and vibration. Flanges can also leak if improper gasket material is used.

The non-flange connectors (screwed, union, tubing, plugs) typically are used to connect piping and equipment having diameters of 2.0 inches or less. Emissions can occur as the sealant ages and eventually cracks. Leakage can also occur as the result of poor assembly or sealant application, or from thermal stress or vibration on the piping and fittings.

2.1.4 Open-ended Lines

Some valves are installed in a system so that they function with the downstream line open to the atmosphere. A faulty valve seat or incompletely closed valve on such an open-ended line would result in leakage through the open end.

The primary control technology is installing a cap, plug or blind flange. However, even the cap, plug or blind flange can leak from improper installation and aging and deterioration of the gasket or threads. These leaks are similar to those found in connectors, and when an open-ended line is controlled in this way, it should be

considered a connector for emission calculation purposes.

2.1.5 Pressure Relief Devices

Pressure relief devices are safety devices commonly used in petroleum and chemical facilities to prevent operating pressures from exceeding the maximum allowable working pressures of the process equipment. Note that when a pressure relief device functions as designed during an over-pressure incident and allows pressure to be reduced, it is not considered an equipment leak. Equipment leaks from pressure relief devices occur when material escapes from the pressure relief device when it is in the closed position. These leaks can occur from the aging and deterioration of packing or sealing materials.

The most common pressure relief device is a spring-loaded pressure relief valve (PRV). The PRV is designed to open when the operating pressure exceeds a set pressure and to reseal after the operating pressure has decreased to below the set pressure.

Another pressure relief device used in the petroleum industry is a rupture disk. These disks rupture when a set pressure is exceeded, thereby allowing the system to depressurize. When the rupture disk pressure is exceeded, the rupture disk must be replaced. Rupture disks do not permit emissions during normal operations and PRV emission factors should not be applied. During normal operation it should be assumed that rupture disks do not have any fugitive emissions. It should also be noted, as a precaution, that rupture disks are generally not

advisable for small diameters due to restriction of flow.

2.1.6 Pumps

Pumps are used extensively in the petroleum industry for the movement of liquids. The centrifugal pump is the most widely used pump type in the petroleum industry; however, other types, such as the positive displacement (reciprocating) pump, are also used. Liquids transferred by pump can leak at the point of contact between the moving shaft and the stationary casing. Consequently, all pumps except the sealless, such as canned-motor, magnetic drive, and diaphragm pumps, require a seal at the point where the shaft penetrates the housing in order to isolate the pumped fluid from the environment. Pumps without seals do not have fugitive emissions.

Packed and mechanical seals for pumps are similar in design and application to packed and mechanical seals for agitators. Packed seals can be used on both reciprocating and centrifugal pumps. Mechanical seals are limited in application to pumps with rotating shafts.

2.1.7 Sampling Connections

Sampling connections are fittings where samples are routinely taken to characterize the process and to control quality. A sampling connection can leak from a faulty valve seat or incompletely closed valve that is upstream of the sampling connection. A sampling connection can also emit from the flushing of the line during the sampling process.

The sampling connection emission factor takes into account the emissions during flushing of the line and filling of the sample container, as opposed to an open-ended line emission factor which estimates the leakage through the open-end when the valve is closed and no flow is intended. Emissions from sampling connections can be reduced by using a closed-loop sampling system or by collecting the purged process fluid and transferring it to a control device or back to the process.

2.1.8 Valves

Except for connectors, valves are the most common process equipment type found in the petroleum industry. Valves are available in many designs, and most contain a valve stem that operates to restrict or allow fluid flow. Typically, the stem is sealed by a packing gland or O-ring to prevent leakage of process fluid to the atmosphere. Emissions from valves occur at the stem or gland area of the valve body when the packing or O-ring in the valve deteriorates. Some emissions could also occur from the valve housing, generally at the bonnet flange.

Bellows valves and rubber diaphragm valves have negligible emissions as long as there is not a break in the bellows or the diaphragm. As long as there is no break in the bellows or the diaphragm, no fugitive emissions should be assigned to these valves. If a break does occur, the screening value associated with these valves should be used to calculate emissions.

2.1.9 Others

Other component types can also be a source of fugitive emissions. These other types are usually small in number at a facility, and they might be unique to one sector of the petroleum industry. Other equipment types that are not listed above that may be considered as sources of fugitive emissions are: instruments, loading arms, stuffing boxes, site glasses, vents, dump lever arms, diaphragms, drains, hatches, meters, and polished rods. These component types can leak for a variety of reasons including improper installation, aging and deterioration, thermal stress, and vibration.

2.2 COUNTING COMPONENTS

An accurate inventory of components is essential for a precise determination of fugitive emissions as well as to ensure that all appropriate components are monitored. The first step in developing this inventory is to define the process unit boundaries. A process unit is the smallest set of process equipment that can operate independently and includes all operations necessary to achieve its process objective. All of the components, by component type, need to be specified within that process unit.

Components can, in some cases, be identified from process flow diagrams. However, process flow diagrams may not include all of the components that emit fugitive emissions, because all changes in the number of valves or connectors may not have been included on the flow diagrams. Therefore, it is usually necessary to systematically follow process streams while counting, categorizing, and labeling components

as you go. Even after this systematic approach, it is recommended to divide the process unit into a grid to search for components (usually connectors) that were missed on the initial survey.

Some components may be monitored at a reduced frequency or may not be monitored at all, but still need to be included in component counts for emission calculation purposes. Examples of these components are ones defined as "inaccessible," "difficult to reach," unsafe-to-monitor" or in "heavy liquid" service. This often necessitates counting more components for emission estimation purposes than need to be monitored as part of a leak detection and repair program.

Other components may not need to be monitored or included in emission estimations. For example, leakless components (such as welded connectors), components not in VOC or HAP service, or components under a vacuum should be excluded from inventories used for monitoring or emission calculation purposes.

Some facilities may only need estimates of component counts in order to estimate emissions. Detailed component count estimation methods for refineries are found in Appendix A (Wetherold, 1984). Other estimation techniques can be found in *Improving Air Quality: Guidance for Estimating Fugitive Emissions from Equipment* (Chemical Manufacturers Association, 1989).

The components need to be counted in accordance with the governing regulation. If

emission calculations are being performed for submittal to a regulatory agency, it should be noted that each agency may define differently what constitutes a component. Therefore, it is critical to understand the regulations that govern the inspection and maintenance activities for each facility.

2.2.1 Agitators

Each agitator seal is associated with a single agitator housing penetration. Therefore, an agitator may have a single housing penetration equipped with either a single or double mechanical seal that is counted as one agitator seal. Some agitators, however, have a shaft that penetrates both sides of the agitator housing with a separate seal on both the inboard and outboard sides. This type of arrangement is counted as two agitator seals.

2.2.2 Compressors

Compressors can have housing penetrations and seals that are similar to agitators and are counted in the same fashion. A compressor may have a single housing penetration equipped with either a single or double mechanical seal that is counted as one compressor seal. However, if the compressor has a shaft that penetrates both sides of the compressor housing with a separate seal on both the inboard and outboard sides, it should be counted as two compressor seals.

Large compressors often include several other component types that are needed for the compressor to function. For instance, a compressor could also include valves on

cylinders and multiple connectors on the compressor housing or piping. These other component types, although attached to the compressor, should be counted separately as components themselves and not included as a part of the compressor.

2.2.3 Connectors

A connector is typically defined for equipment leak purposes as any fitting used to join two pieces of pipe and/or components together, with the exception of welded connectors which are assumed to be leak free. This definition includes flanges, threaded connectors, unions, tubing fittings, caps, plugs, etc.

The definition of what is a connector may, however, vary by regulation. In some cases, connectors have been identified as only including flanges. In other cases, all types of connectors, including screwed (threaded), union, tubing, etc. are included. These other types of connectors have occasionally been found to leak. Therefore, if it is desired to develop the most accurate estimate of fugitive emissions, these other types of connectors should be included in component inventories.

There has been some confusion over how to count the many varieties of connectors. Much of this confusion arises from the use of aggregate component names that include multiple connectors. For instance, an elbow fitting is a common fitting in petroleum facilities that would have a connector on each end of a 90 degree bend of pipe. (See Figure 2-1). Although many

people think of an elbow as one fitting, there are actually two connectors, either of which can leak independently of the other. Similarly, a "Tee" fitting would be counted as three connectors. A spool piece or swage piece would be counted as two connectors. The most difficult fitting to explain is the union connector, which has two potential leak sites (one at the threads and one at the back of the collar nut) but is counted as a single connector.

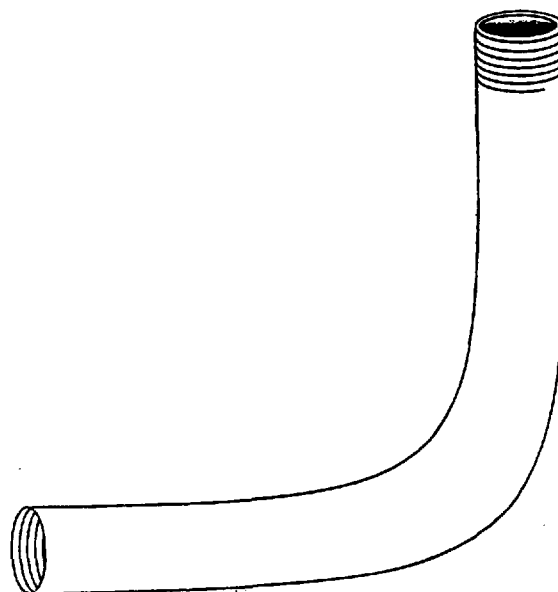


Figure 2-1. Threaded Connector Elbow

Heat exchangers have flanged ends and often have several screwed connectors. Some facilities and regulators count these components in inventories and others do not. Again, regulatory direction and facility operating practice for maintenance of these components should be followed. However, note that these flanged ends and screwed connectors have also been found to leak on occasion.

2.2.4 Open-ended Lines

Open-ended lines are generally easy to count. Some confusion does occur when a potentially open-ended line is controlled with a cap, plug, or blind flange. Such a controlled potentially open-ended line is counted as a connector, because that is the effective leak sealing mechanism.

2.2.5 Pressure Relief Devices

The most common pressure relief device is a spring-loaded pressure relief valve (PRV). Another pressure relief device is a rupture disk. Both pressure relief valves and rupture disks should be counted in the same fashion as valves. It is recommended that the flange on the upstream side of pressure relief devices be counted as a separate component from the pressure relief device. The downstream flange should also be counted as a separate component if the downstream line is not exposed to the atmosphere (such as a line connected to a different process vessel).

2.2.6 Pump Seals

Like agitators, each pump seal is associated with a single pump housing penetration. Therefore, a pump may have a single housing penetration equipped with either a single or double mechanical seal that is counted as one pump seal. Some pumps, however, have a shaft that penetrates both sides of the pump housing with a separate seal on both the inboard and outboard sides. This type of arrangement is counted as two pump seals.

2.2.7 Sampling Connections

Each uncontrolled sampling connection should be counted uniquely. Sampling connections can have emissions reduced by using a closed-loop system or collecting purged process fluid and transferring it to a control device or back to the process.

The distinction between sampling connections and other open-ended lines is dependent on both the configuration and use. An open-ended line that is used for routine sampling would be counted as both an open-ended line and a sampling connection. If equipped with a cap or plug, the same system would be counted as a connector (threads of the cap or plug) and a sampling connection. On the other hand, an open-ended line that is used as a drain or a high point vent would not be counted as a sampling connection.

2.2.8 Valves

Valves are most commonly defined for counting purposes as including the stem seal, the packing gland, and the connection between the parts of a multi-part valve body (like the bonnet flange). This definition should provide the most accuracy in calculating emissions, because it is the same definition that was used in the bagging studies from which the average factors and the emission correlation equations were developed (Ricks, 1993; Ricks, 1994; Webb, 1993). Most regulatory agencies also use this definition for valves.

Although not supported by methods used to develop emission factors and emission correlation equations, some regulatory agencies may define a valve for inspection and maintenance purposes as including the flanges on either side of the valve. Figure 2-2 shows the locations of these flanges on some valves. Regulations may provide conflicting definitions of a valve, or may not provide a definition at all. The result is that facilities across the nation may differ in their counting practices. Some include the flanges on either side as part of the valve, and some facilities count these flanges as separate components. Therefore, one needs to refer to regulations for the appropriate action.

2.2.9 Others

Other component types such as: instruments, loading arms, stuffing boxes, site glasses, vents, diaphragms, drains, hatches, meters, and polished rods may also need to be counted to develop a complete inventory of potential fugitive emission sources. Again, one needs to refer to regulations for appropriate counting of these other types of components.

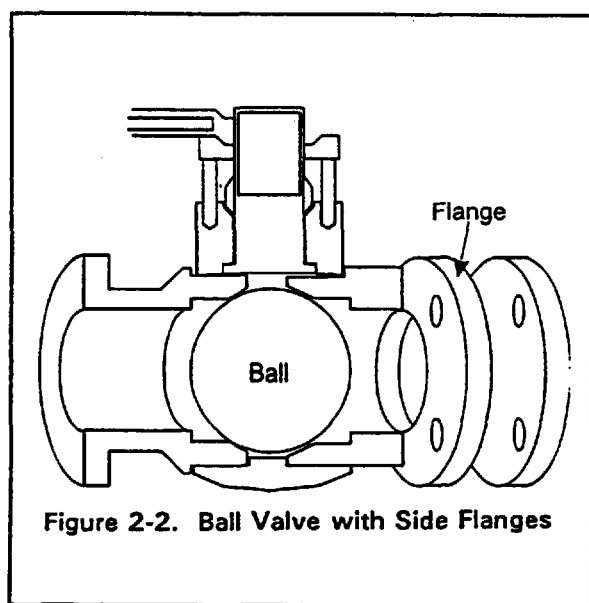


Figure 2-2. Ball Valve with Side Flanges

SECTION 3.0

EMISSION ESTIMATION METHODS

Over the years, a variety of methods to calculate fugitive emissions from components have been developed for use in the petroleum industry. The approaches for each industry type are listed as follows:

- Average emission factor method;
- Screening ranges method;
- U.S. EPA emission correlation equation method; and
- Unit-specific correlation equation method.

The methods are listed in increasing complexity and in the amount of data collection and analysis required. A discussion of these methods is found in the *Protocol for Equipment Leak Emission Estimates* (Epperson, 1995), also referred to in this document as the U.S. EPA Protocols Document. Generally, a method lower on the above list provides more accurate information (i.e., the screening ranges method provides more accurate information than the average emission factor method). The last method requires bagging of individual components to develop unit-specific correlation equations. Because of the limited use of this method due to costs of bagging, it is not addressed here. For more information on this method refer to the U.S. EPA Protocols Document.

The type of estimating method used depends on the amount of information available to a

facility and the intended use of the data. Measured hydrocarbon concentrations in parts per million by volume (ppmv), called screening values, for each component can be determined by a portable hydrocarbon analyzer. More details on the use of hydrocarbon analyzers to generate screening values can be found in Volume I of this series: Monitoring Manual. Facilities that do not have individual screening values for components should use the average emission factor method.

The screening ranges method divides screening values into distinct categories by ppmv ranges. The screening values have been divided into two ranges, 0 to 9,999 ppmv and $\geq 10,000$ ppmv. The screening ranges method has been used to reduce the amount of data that must be recorded and the number of required calculations compared with using the emission correlation equation method. The trade-off is that generally the emission correlation equation method provides more accurate results.

The emission correlation equation method equates a specific mass emission rate for each screening value for each component screened. Emission correlation equations provide a more exact determination of emissions from a facility than do average emission factors or factors based on the screening ranges method. With more and more availability of data management programs that can manipulate the large amounts of data in a fugitive emission monitoring program, it is becoming increasingly easier to use the emission correlation equation method.

If emission correlation equations are used, separate factors need to be used for components that are screened at background hydrocarbon concentrations (zero components) and also for components that are screened beyond the range of the screening instrument (pegged components). The recommended zero component emission rates and pegged component emission rates for refineries, petroleum marketing terminals, and the oil and gas industry are included in this section.

Note that the emissions estimate for an entire facility might include a combination of emission estimating methods.

Also discussed in this section are recommendations on fugitive emission estimation methods for petrochemical facilities and the recommended method to estimate equipment leak emissions of inorganic compounds.

3.1 AVERAGE EMISSION FACTOR METHOD

Average emission factors do not require individual screening values for each component. Usually, the only necessary information is the number of components in each component (e.g., valves, connectors, etc.) and service type (gas, light liquid, heavy liquid) categories. The number of components in each category is multiplied by the appropriate average emission factor. The resulting mass emissions for each category can then be added together to determine the total hourly emissions from the facility. Annual emissions are obtained by multiplying hourly emissions by the number of hours during

the year that the line was in service (i.e., contained product):

$$\begin{aligned} & \text{Number of comp.} \times \text{emission factor (kg/hr/comp)} \\ & \times \frac{\text{hr}}{\text{yr}} \text{ in service} = \text{annual emissions } \left(\frac{\text{kg}}{\text{yr}} \right) \end{aligned}$$

(Eq. 3-1)

Average emission factors are typically used in facilities that do not have leak detection and repair programs. They can also be used to estimate emissions when new equipment is being added to a facility (i.e., a new process unit) and no screening values have yet been gathered from the new equipment. They are also used to estimate emissions from components that are not routinely monitored as part of leak detection and repair programs (such as "unsafe-to-monitor," or those in heavy liquid service).

Average refinery emission factors recommended by the U.S. EPA are shown in Table 3-1 (Epperson, 1995). The U.S. EPA 1980 refinery average emission factors are based on data collected in the late 1970s. Note that this table has different emission factors for different component types and different service types. Light liquids are defined, for the average factors shown, as a liquid having a vapor pressure greater than 0.1 psia at 100°F or 689 Pa at 38°C. However, individual regulations may have different definitions for light liquids, heavy liquids, and gas. For instance, the regulation NSPS Subpart GGG defines a light liquid as having a vapor pressure greater than 0.3 k PA at 20°C for one or more constituents, or a 10% evaporation point at 150°C using ASTM Method

Table 3-1. Refinery Average Emission Factors^a
(kg/hr/component)

Equipment Type	Service	Emission Factor ^b
Valves	Gas	0.0268
	Light Liquid	0.0109
	Heavy Liquid	0.00023
Pump Seals ^c	Light Liquid	0.114
	Heavy Liquid	0.021
Compressor Seals	Gas	0.636
Pressure Relief Valves	Gas	0.16
Connectors	All	0.00025
Open-ended Lines	All	0.0023
Sampling Connections ^d	All	0.0150

^a Source: Radian, 1980; Epperson, 1995.

^b These factors are for non-methane organic compound emission rates. These factors are for uncontrolled components.

^c The light liquid pump seal factor can be used to estimate the leak rate from agitator seals.

^d Emission factors for sampling connections are related to the amount of fluid "flushed" from the sampling connection lines when these lines are purged.

D-86. The definition for applicable regulations should be followed.

Table 3-2 contains new average refinery emission factors for components in heavy liquid service. These factors are from a recent API study (Hal Taback Company, 1996). Note that these new average emission factors have not yet received U.S. EPA endorsement.

3.1.1 Reduction Factors

The original refinery average emission factors were developed using data from facilities that did not have any inspection and maintenance (I/M) program. An I/M program is the leak detection and repair activity related to components that potentially emit fugitives. These factors were developed as uncontrolled average emission factors.

The U.S. EPA allows for reductions in the refinery average emission factors based on having an I/M program. The U.S. EPA Protocols Document (Epperson, 1995) includes reduction factors for a number of different component types, for monthly and quarterly monitoring frequencies. This information is shown on Table 3-3. We recommend using the factors from Table 3-3 if they are applicable to the I/M program that a facility intends to use. However, if none of the factors are applicable, then the U.S. EPA previously released another estimation method to calculate reduction factors (Radian, 1982).

A detailed explanation of alternative reduction factors is found in Appendix B. This

explanation is a reprint of a portion of *VOC Fugitive Emissions in Petroleum Refining Industry - Background Information for Proposed Standards, Draft EIS*, (Radian, 1982). The reduction efficiency from this document is based on four factors, referred to as "A," "B," "C," and "D." The A factor is from Table 4-2 in Appendix B. The B, C, and D factors are from Table 4-3 in Appendix B. These factors are defined as follows:

- A factor: percent of total mass emissions affected at various leak definitions (theoretical maximum control efficiency);
- B factor: leak occurrence and recurrence factor (function of inspection interval);
- C factor: non-instantaneous repair correction factor (function of allowable repair time); and
- D factor: imperfect repair correction factor (accounts for fact that some components which are repaired are not reduced to zero ppmv leaks).

The above factors were developed for leak definitions of 1,000 ppmv or greater. Unless additional factors are developed, the 1,000 ppmv factors should be used for lower leak definitions.

An example of using this alternative method to estimate a reduction factor would be a valve in gas service with a 10,000 ppmv leak definition, quarterly inspections, and a 15 day allowable repair time. Given this information

**Table 3-2. Refinery Average Emission Factors for Components
in Heavy Liquid Service^{a,b}
(kg/hr/component)**

Equipment Type	Emission Factor
Valves	8.12 E-05
Pump Seals	3.76 E-03
Connectors (flanged and unflanged)	3.63 E-05
Flanges	3.70 E-05
Open-ended Lines	1.79 E-05
Other	2.82 E-05

^a From Hal Taback Company, 1996. Factors are from combined southern California and Washington State data. Factors are for uncontrolled emissions.

^b Not yet endorsed by the U.S. EPA.

**Table 3-3. Reduction Factors for an I/M Program
at a Refinery Process Unit**

	Valves - gas	Valves - light liquid	Pumps - light liquid	Connectors - all
	88	76	68	a
	70	61	45	a

^a Data are not available to estimate control effectiveness.

Source: Epperson, 1995.

and utilizing Tables 4-2 and 4-3 in Appendix B, the above factors would be as follows:

- A = 0.98 (Appendix B, Table 4-2);
- B = 0.90 (Appendix B, Table 4-3);
- C = 0.979 (Appendix B, Table 4-3); and
- D = 0.996 (Appendix B, Table 4-3).

The combined reduction factor would be:

$$\text{Reduction Efficiency} = A \times B \times C \times D$$

(Eq. 3-2)

$$0.98 \times 0.90 \times 0.979 \times 0.996 = 0.860.$$

This means that the average refinery emission factor shown in Table 3-1 for valves in gas service (0.0268 kg/hr) could be reduced 86.0% by having the I/M program discussed, resulting in a revised emission factor of $(1-0.86) \times 0.0268 = 0.00375$ kg/hr. If the factors from Table 3-3 had been used, the reduction factor would have been 70% for a quarterly monitoring program with a 10,000 ppmv leak definition. Note that the U.S. EPA methodology also allows a facility to estimate the benefits of having different levels of I/M programs.

The recommended average emission factors for marketing terminal and oil and gas production operations, based on recently conducted studies (1990s), are shown in Tables 3-4 and 3-5, respectively (Epperson, 1995; Webb, 1993).

The same reduction factors used for refineries may also be appropriate for the oil and gas industry. Nearly all of the oil and gas industry data collected for the recent fugitive emission studies were from uncontrolled facilities.

The marketing terminal data collected for the recent fugitive emission studies were from a mixture of controlled and uncontrolled facilities. At this time, no reduction factors have been developed for marketing terminals. Even though the benefits of an I/M program are not being fully accounted for, the use of the marketing terminal average emission factors without any reduction factors is recommended at this time.

Light liquids are defined for the marketing terminals average factors as a liquid having a vapor pressure greater than 0.1 psia at 100°F or 689 Pa at 38°C (Ricks, 1993). Light liquids (oils) are defined as being those with an API gravity ≥ 20 for the oil and gas production operations (Webb, 1993).

Note that no heavy liquid average factors were developed for marketing terminals. Light liquid factors would be expected to be higher than heavy liquid factors if heavy liquid factors were developed. Until heavy liquid average factors are developed, we recommend use of the light liquid factors shown in Table 3-4.

3.1.2 Adjustment for Inorganics

The U.S. EPA (Epperson, 1995) provides an option for the average emission factor method that does not apply to the other emission

**Table 3-4. Average Emission Factors
for Petroleum Marketing Terminals^a
(kg/hr/component)**

Fittings (connectors and flanges) ^b	Gas	4.2E-05
	Light Liquid	8.0E-06
Other ^d (compressor seals and others)	Gas	1.2E-04
	Light Liquid	1.3E-04
Pump Seals	Gas	6.5E-05
	Light Liquid	5.4E-04
Valves	Gas	1.3E-05
	Light Liquid	4.3E-05

^a These factors are for total organic compound emission rates (including non-VOCs such as methane and ethane). These factors apply to uncontrolled and controlled operations.

^b "Fittings" were not identified as flanges or connectors; therefore, the fitting emissions were estimated by averaging the estimates from the connector and the flange equations.

^c For components in heavy liquid service, use the light liquid factors from this table. Average light liquid factors are expected to be higher than average heavy liquid factors.

^d The "other" equipment type should be applied for any equipment type other than fittings, pumps, or valves.

Source: Epperson, 1995.

**Table 3-5. Average Emission Factors for
Oil and Gas Production Operations^a
(kg/hr/component)**

Equipment Type	Equipment Type/Service			
	Gas	Heavy Oil (<20 API Gravity)	Light Oil (≥ 20 API Gravity)	Water/Oil ^b
Connectors	2.0E-04	7.5E-06	2.1E-04	1.1E-04
Flanges	3.9E-04	3.9E-07	1.1E-04	2.9E-06
Open-ended Lines	2.0E-03	1.4E-04	1.4E-03	2.5E-04
Other ^c	8.8E-03	3.2E-05	7.5E-03	1.4E-02
Pump Seals	2.4E-03	NA	1.3E-02	2.4E-05
Valves	4.5E-03	8.4E-06	2.5E-03	9.8E-05

^a These factors are for total organic compound emission rates, including non-VOCs such as methane and ethane, and apply to light crude, heavy crude, gas plant, gas production, and off-shore facilities. These factors apply to uncontrolled components.

^b Water/Oil emission factors apply to water streams in light oil service with a water content greater than 50%, from the point of origin to the point where the water content reaches 99%. For water streams with a water content greater than 99%, the emission rate is considered negligible.

^c The "other" equipment type includes compressors, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

Source: Webb, 1993; Epperson, 1995.

estimation methods. The inorganic concentration in the process lines can be removed from the emission estimates when using the average emission factor method. (Removal of the inorganics is not appropriate for the other methods because each of the other methods is based on actual screening values that measure hydrocarbon concentrations only). For example, if a stream contained 90 weight percent VOC and 10 weight percent water vapor, the emissions calculated by the average emission factor method could be multiplied by 0.90 to determine the VOC portion of the emissions. If a refinery gas valve (0.0268 kg/hr) were part of this example process stream, the estimated emissions would be calculated as follows:

$$VOC = 0.0268 \frac{kg}{hr} \cdot 0.90 = 0.0241 \frac{kg}{hr}$$

3.1.3 Adjustment for Non-VOC Organic Compounds

It should be noted that not all organic compounds detected by a screening instrument are VOCs. These instruments instead often measure Total Organic Compounds (TOCs). In particular, methane and ethane are detected by many screening instruments but are not classified as VOCs. Other organic compounds not classified as VOCs include methylene chloride, 1,1-1-trichloroethane, and several chlorofluorocarbons. The U.S. EPA allows an adjustment to the VOC estimate for the non-VOCs detected by a screening instrument. The VOCs can be determined as follows:

$$VOC = TOC \times \frac{\text{Weight Percent (VOC)}}{\text{Weight Percent (TOC)}}$$

(Eq. 3-3)

The above equation can be used to convert TOC emissions, or a TOC emission factor, to VOC emissions or a VOC emission factor.

As an example, if a stream contained 90 weight percent TOC, of which 10 weight percent was ethane, the weight percent VOC would be:

$$90 \text{ (weight percent TOC)} - 10 \text{ (weight percent ethane)} = 80 \text{ (weight percent VOC)}.$$

The VOCs for this example would be:

$$VOC = \frac{80}{90} TOC = 0.889 TOC.$$

Note that the average refinery emission factors shown in Table 3-1 are based on non-methane organic emissions.

3.1.4 Adjustment for Methane at Refineries for Total Organic Compounds

For refineries only, the U.S. EPA has recommended an additional correction to the average emission factor if a Total Organic Compound (TOC) factor is desired. The refinery average emission factors were based on data that excluded methane. Therefore, if process streams contain methane, the methane percentages need to be added to the non-methane organic compound totals to develop a TOC total. However, only a maximum of 10 percent by weight methane is permitted by the U.S. EPA (even if the streams contain fluid greater than 10 percent methane) because components used to develop these factors typically were part of streams that contained 10 percent or less

methane. The adjustment for methane is calculated as follows:

$$\frac{\text{Weight Fraction TOC}}{\text{Weight Fraction TOC} - \text{Weight Fraction Methane}} \quad (\text{Eq. 3-4})$$

Following is an example of the correction for methane. Given that a refinery gas valve (0.0268 kg/hr) is part of a stream that contains 75 weight percent VOC, 20 weight percent methane (will show as 10 weight percent in the calculation), and 5 weight percent water vapor, what are the emissions? The TOC weight fraction for this example is 75 for VOC plus 20 for methane equals 95. Calculating emissions while adjusting for methane gives:

$$\text{TOC} = 0.0268 \frac{\text{kg}}{\text{hr}} \cdot \frac{95}{95-10} = 0.0300 \frac{\text{kg}}{\text{hr}}$$

Note that, unlike refineries, the marketing terminal and oil and gas industry average emission factors already represent TOC emissions and do not require any adjustment for methane.

3.1.5 Sample Calculation Using Average Emission Factor Method

Emission calculations for a marketing terminal with gas and light liquid streams and that does not have recorded screening values would be calculated using:

$$\text{Emissions} = \text{avg emission factor} \times \# \text{ comp.} \quad (\text{Eq. 3-5})$$

as shown in Table 3-6.

3.2 SCREENING RANGES METHOD

The recommended factors to use for the screening ranges method for refineries, marketing terminals, and oil and gas production are shown on Tables 3-7 to 3-9 (Epperson, 1995).

To calculate emissions, first select the most applicable of the three tables, depending on your type of facility. Next, multiply the number of components of each component type, service type and screening range by the appropriate emission factor from one of the three tables. The resulting mass emissions for each component type and service type can then be added together to determine the total emissions from the facility. An example follows in Section 3.2.1.

Note that the adjustment for inorganics to calculate VOCs is not allowed for by the screening ranges method. However, the adjustment for non-VOC organic compounds is still allowed for the screening ranges method as explained in Section 3.1.3. Furthermore, the adjustment for methane at refineries is still recommended by the U.S. EPA for the screening ranges method as was explained in Section 3.1.4. Examples follow in Section 3.2.2.

Also note that the U.S. EPA is no longer supporting the use of "stratified emission factors" which divide the screening ranges into three screening divisions rather than two screening divisions. The stratified emission factors were released in earlier versions of the U.S. EPA Protocols Document.

**Table 3-6. Sample Calculation for a Petroleum Marketing Terminal
Using the Average Emission Factor Method**

Component	State	Emission Factor (lb/hr/component)	Number of Components	Component Emissions (lb/hr)
Connectors	Gas	4.2E-05	1,000	0.042
	Light Liquid	8.0E-06	3,000	0.024
Valves	Gas	1.3E-05	200	0.0026
	Light Liquid	4.3E-05	600	0.026
Pump Seals	Light Liquid	5.4E-04	20	0.011
Other	Gas	1.2E-04	10	0.0012
	Light Liquid	1.3E-04	10	0.0013
Total			4,840	0.108

^a Arbitrary number of components for purpose of example.

Table 3-7. Screening Ranges Emission Factors for Refineries^a
(kg/hr/component)

Equipment Type	Service	≥10,000 ppmv Emission Factor ^b	<10,000 ppmv Emission Factor ^b
Valves	Gas	0.2626	0.0006
	Light Liquid	0.0852	0.0017
	Heavy Liquid	0.00023	0.00023
Pump Seals ^c	Light Liquid	0.437	0.0120
	Heavy Liquid	0.3885	0.0135
Compressor Seals	Gas	1.608	0.0894
Pressure Relief Valves	Gas	1.691	0.0447
Connectors	All	0.0375	0.00006
Open-ended Lines	All	0.01195	0.00150

^a Source: Epperson, 1995.

^b These factors are for non-methane organic compound emission rates.

^c The light liquid pump seal factors can be applied to estimate the leak rate from agitator seals.