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Guide

Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities

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Overview

This handbook is presented to assist oil and gas production companies in quantifying volumes of natural gas vented and flared at typical upstream oil and gas facilities.

The following have been identified as continuous sources of vented and flared gas:

Continuous Sources

- Casing Gas Vents,
- Associated/Solution Gas,
- Venting from Glycol Dehydrators,
- Production Storage Tanks, and
- Pneumatic Devices.

The following have been identified as intermittent venting/flaring sources.

Intermittent Sources

- Well Blowdowns,
- Accidental Releases,
- Pressure Relief/Pressure Safety Valves, and
- Facility Blowdowns.

The focus of this document is to provide methodologies and example calculations for estimating volumes of gas released from each of the sources listed above. For each source a variety of estimation methods are presented ranging from simple emission factors to complex process simulation. This is not, however, an exhaustive compendium of all possible estimation methods.

In most cases, the simple methods should be adequate. Occasionally, the more complex methods may be appropriate. The intent is simply to present some of the valid alternatives rather than to prescribe measurement methods. Companies should choose the approaches best suited to their particular situations, and the relative importance of the given sources.

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1 Introduction

In June 1999 the Alberta Energy and Utilities Board released *Guide 60: Upstream Petroleum Industry Flaring Requirements*. The guide (G-60) outlines the requirements and expectations of oil and gas operators with regard to flaring. The following is a brief summary of the G-60 requirements:

- A firm provincial solution gas volume reduction schedule. A 15 percent reduction from 1996 levels by the end of 2000 and a 25 percent reduction by the end of 2001.
- New performance requirements for all flares.
- Evaluation of all solution gas flares using a flaring management decision tree by December 31, 2002 and all other flares by December 31, 2004.

As part of these general requirements, all operators are expected to ensure that flared and vented gas volumes from all operations are accurately reported on the appropriate production accounting reports (i.e., S-Reports).

As per EUB ID 94-01, the EUB has established maximum uncertainty limits for different streams. The requirements for gas measurement are outlined below:

Table 1-1 Summary of EUB ID 94-01 Measurement Criteria

EUB ID 94-01 Summary			
BatteryType	Gas Rate	Gas Type	Uncertainty Allowed (%)
oil	>0.5 e ³ m ³ /day	battery sales	3
oil	>0.5 e ³ m ³ /day	battery flare	5
oil	<0.5 e ³ m ³ /day	battery stream	20
oil	>16.9 e ³ m ³ /day	well	3
oil	<0.5 e ³ m ³ /day & >16.9 e ³ m ³ /day	well	5
oil	<0.5 e ³ m ³ /day	well	20
gas	any	battery	3
gas	>16.9 e ³ m ³ /day	well	3
gas	< 16.9 e ³ m ³ /day	well	5

Notwithstanding the above uncertainty limits, the EUB requires operators to report gas flared or vented to the nearest **0.1 e³ m³** per month (at standard conditions of 101.325 kPa and 15°C). The requirement to report all vented or flared gas includes volumes from routine operations, emergency conditions, and the

depressurization of pipeline, compression and processing systems. Note that the EUB intends to release an update to ID 94-01 in 2002 to address measurement **accuracy** issues.

As per Guide 60 Section 10.1.1, the following streams should **generally** be metered:

- 1) Acid gas flared
- 2) Make-up gas for acid gas flaring
- 3) Routine flares in conventional oil and gas facilities where average annual volumes exceed 0.5 e3m3/day
- 4) Heavy oil or bitumen solution gas where the average annual volume exceeds 2.0 e3m3/day.

Where operators can show these flows can be accurately estimated the EUB may accept estimated measurements. It is preferred that other flared and vented gas be metered with appropriate measurement equipment. However, where it is not practicable to meter the vented or flared gas, accurate estimates of the gas volumes are acceptable to the EUB. If volume estimation methods are used, operators must be able to demonstrate that a reliable and accurate flare or vent gas estimating-and-reporting system is in place and that it is consistently used.

The intention of this document is to provide guidance to CAPP members that require assistance with estimation of flared and vented gas volumes. This guide does not provide an exhaustive compendium of flared and vented gas volume estimation methods. Therefore, operators may choose alternate estimation methods. The methods presented for each source are described in the order of increasing sophistication and accuracy. Operators should select the most appropriate methodology considering the magnitude of the volume being estimated. In general, the simplest method will suffice.

Section 2 provides an overview of the sources of vented and flared gas volumes at upstream oil and gas facilities. Each of the sources is described in Section 3 along with suggested estimation methods and sample calculations.

2 Source Characterization

The upstream oil and gas industry comprises all infrastructure used to find, produce, process/treat and transport natural gas, liquified petroleum gas, condensate, crude oil, heavy oil and crude bitumen to market. The industry may be divided into several sectors depending on the types of activities that are performed:

- wells,
- oil production facilities,
- gas production facilities, and
- gas processing plants.

Each of these sectors may have several potential sources of vented or flared gas that must be reported to EUB as part of the production accounting process. The following sections provide a brief description of each of the sectors. The potential sources of flared/vented gas for each sector are presented in Table 1.

2.1 Wells

A well site is a surface facility that is used to produce oil and gas from a hydrocarbon reservoir. It consists of the wellhead and may or may not have metering facilities and some production equipment (e.g., pumpjack, compressor, line heater, dehydrator, storage tank, etc).

2.2 Oil Production Facilities

A battery is a production unit where the effluent from a well(s) is separated into its constituent phases (oil, gas and water) for metering and appropriate disposition. The oil is pumped into a nearby crude oil pipeline, or is shipped by truck to a location where this may be done. A treater is used to remove any emulsified water from the oil before it is put in the crude oil pipeline. The gas is either flared, reinjected, or compressed into a nearby gas gathering system, depending on the type of oil recovery scheme and the economics of the situation. The last two options would require that compression and, possibly, dehydration facilities be installed. The water is reinjected as part of an enhanced recovery scheme, or is shipped to a nearby disposal well.

A single-well production unit is the simplest type of oil battery. Typically, each is inspected once per day; otherwise, it is unattended. At a minimum, it is equipped with separation, metering, storage, loading and flaring facilities. Depending on the amount and nature of the production, it may also comprise selected treatment, pumping and compression facilities.

A satellite battery is an intermediate production facility. It is located between a group of wells and a central battery, and, usually, it is inspected once per day.

There are two separators and associated sets of metering equipment at each satellite battery. One train is used to compile proration data on the commingled effluent from all but one of the group of wells. The other is used to test the remaining well. A regular test is performed on each of the wells.

After separation and measurement, the production is often recombined into a single flow line for shipment to the central battery. Sometimes, however, each phase is transported in a separate pipeline. In this case a dehydrator may be required for the gas pipeline. Typically, there are no storage nor treatment facilities at satellite batteries, and no gas is flared. Consequently, the only source of vented gas is the use of fuel gas to operate instrument controllers.

A central battery is the same as a single-well battery except that it receives production from more than one well and is usually much larger. Often, it is manned continuously during the day.

2.3 Gas Production Facilities

The surface pressure, flowing temperature and composition of natural gas at a well have a strong influence on the equipment required to handle and transmit the well effluent to a gas processing plant. These factors are also critical to the formation of hydrates in the production tubing, vessels, piping and pipeline. The types of gathering systems may be categorized as low pressure, heated and dehydrated systems.

There is a substantial network of low pressure pipelines used to gather production from shallow gas wells. These systems are often operated at very low pressures (e.g., less than 525 kPa).

Heated gathering systems guard against the formation of hydrates by maintaining the gas temperature above some critical value. This critical value is dependent on the composition and pressure of the gas. Consequently, this value varies from one system to the next.

Dehydrated gathering systems prevent the formation of hydrates by removing water vapour from the process gas. There are several different dehydration technologies that are used: absorption using diethylene or triethylene glycol; adsorption using solid desiccants such as activated alumina, gels, or molecular sieve; and the chem-sorption process using calcium chloride. The glycol-based absorption process is the most widely used.

A gas battery is a production unit that is used when gas processing is not required. Only compression and simple treating (e.g., dehydration and/or non-regenerative sweetening with less than 0.1 tonnes/day total Sulphur) may be needed to upgrade gas to market specifications. Typically, this type of gas comes from low-pressure, shallow gas wells. It is characterized by low concentrations of non-methane

hydrocarbons and is called "dry gas."

The basic functions of a gas battery are to separate the effluent from one or more gas wells into gas and water, measure the flow rate of each of these phases from each well, and provide any gas treating and compression that may be required. The water is disposed of and the gas is sent to market.

2.4 Gas Processing Plants

A gas processing plant is a facility for extracting condensable hydrocarbons from natural gas, and for upgrading the quality of the gas to market specifications (i.e., removing contaminants such as H₂O, H₂S and CO₂). Some compression may also be required. Each facility may comprise a variety of treatment and extraction processes, and for each of these there is often a range of technologies that may be used.

There are several types of gas processing facilities: sweet plants, sour plants that flare their waste gas, sour plants that extract elemental sulphur from their waste gas, sour plants that inject the acid gas into a subsurface formation and straddle plants. The first four types are fed by gathering systems and prepare natural gas for transmission to market. The last type is located on major gas transmission lines and is used to extract residual ethane and heavier hydrocarbons from the natural gas.

2.5 Relative Magnitude of Flaring/Venting Volumes

To determine where estimation efforts should be focused it is important to understand where each emission source may be found and the relative magnitude of each source. Table 2-1 provides a summary of potential sources of flared/vented gas for each sector of the upstream oil and gas industry.

Table 2-1 Summary of Potential Flare and Vent Gas Sources by Sector

Flared/Vented Gas Source	Wells	Oil Production	Gas Production	Gas Processing
Continuous Sources				
Casing Gas Venting	P			
Solution Gas	P	P	P	P
Glycol Dehydrator Off-Gas		P	P	P
SCVF's	P			
Gas Migration	P			
Production Storage Tanks	P	P	P	P

Pneumatic Devices (i.e., controllers, chemical injection pumps)	P	P	P	P
Intermittent Sources				
Well Blowouts	P			
Well Blowdowns	P			
Pipeline Ruptures	P	P	P	P
Pressure Relief/Pressure Safety Valves		P	P	P
Blowdowns of Process Vessels and Piping / Upsets		P	P	P

Table 2-2 provides a summary of provincial totals for broad categories of flaring and venting sources. This table, along with company specific information, may be useful in assessing the relative importance of the various sources of vented and flared emissions. For certain operations some sources may be considered negligible. Venting from glycol dehydration units has been specifically excluded as a source of flared or vented volumes that are required to be reported under EUB G-60.

EUB Guide 60, Section 8, defines venting as releases from compressor vents, instrument gas systems, pneumatic devices, dehydrators and storage tanks. It specifically excludes “fugitive” emissions from piping and equipment leaks and as such, the EUB does not require these sources to be estimated or measured. However, those wishing to assess these emissions are directed to *A Detailed Inventory of CH₄ and VOC Emissions from Upstream Oil and Gas Operations in Canada* (CAPP, 1999a), *Global Climate Change Voluntary Challenge Guide* (CAPP, 1999b), and *A Suggested Approach to Completing the National Pollutant Release Inventory (NPRI) for the Upstream Oil and Gas Industry* (CAPP, 2001). These documents present the required methodologies, average emission factors and equipment component schedules necessary to assess these emissions.

Table 2-2 Summary of Flare and Vent Sources and Volumes for 2000

Source	Vent Volume (10⁶ m³)	Flare Volume (10⁶ m³)	TOTAL (10⁶ m³)
Solution/Associated Gas conventional oil	150	755	905
Solution/Associated Gas (bitumen)	554	76	630
Well Testing	7	335	342
Gas Plants (flared and vented total)		196	196
Gas Batteries	12	36	48

Gas Gathering Systems (flared and vented total)		48	48
Transmission lines	12	0	12

1 Source: EUB. 2001. Upstream Petroleum Industry Flaring Report. ST 2001-60B.

3 Assessment Procedures

3.1 Continuous Sources

3.1.1 Casing Gas Vents

Casing gas vents are a particular concern for heavy oil and crude bitumen wells. Heavy oil wells are relatively shallow (typically 300 to 900 m deep) and, thus, are characterized by low reservoir pressures (typically 4000 kPa or less). To achieve reasonable flow potential it is necessary to relieve gas pressure from the well bore (down hole pressure of about 250 kPa is maintained). Appropriately, the wells are not usually equipped with a production packer (a device that isolates the annulus from the formation). This allows the well pressure to be controlled using the casing vent. Because of the low volumes of gas associated with primary heavy oil casing gas, the gas is typically vented directly to atmosphere. Recently more conservation schemes are being implemented, however. For thermal heavy oil projects, the gas is usually flared or conserved because of the potential for H₂S in the gas.

Estimation Methods

The volume of casing gas vented or flared is primarily a function of the quantity of gas in the reservoir (i.e., the gas-to-oil ratio [GOR]) and wellhead conditions. Gas-to-oil ratios may vary substantially from well-to-well even for wells producing from the same pool. The reported range of GOR's is approximately 1 - 200 m³ of gas per m³ of oil production.

Because of this wide variation in GOR's, estimation of casing gas flows necessarily involves establishing an accurate gas-to-oil ratio by measurement. A gas-to-oil ratio for a well should be established as per the EUB ID 91-03 summarized below. Various gas flow measurement methods may be employed depending on the casing gas flow rate and the amount of pressure drop and backpressure that can be tolerated. A summary of some suggested measurement methods is provided in Table 3-1. Each of the methods listed is capable of measuring a totalized flow over a 24 hour period as required for a GOR test.

The Energy and Utilities Board has established a required testing frequency for Heavy Oil and Bitumen wells depending on the casing gas flow rate and whether or not the well is in a Designated Oil Sands Area (EUB ID 91-03):

Outside Designated Oil Sands Areas

- annual GOR tests for casing gas flows of • 500 m³/d,
- semi-annual GOR tests for casing gas flows of >500 m³/d and • 1000 m³/d, and
- monthly GOR tests for casing gas flows of >1000 m³/d and • 2000 m³/d.

- continuous measurement for casing gas flows over 2000 m³/d.

Within Designated Oil Sands Areas

- annual GOR tests where the GOR is greater than 100 m³/m³, and
- every three years where the GOR is less than 100 m³/m³.

Similarly, conventional oil wells with gas production less than 500 m³/day may be tested annually for a representative GOR rather than normal testing requirements. This exemption is detailed in EUB IL 91-09.

Table 3-1 Summary of Possible Casing Gas Measurement Methods

Casing Gas Flow Range	Possible Casing Gas Measurement Methods
Low to Medium Casing Gas Flows	Diaphragm Meter
	Rotary Meter
	Turbine Meter
High Casing Gas Flows	Orifice Meter
	Critical Flow Prover

Since casing gas is generally water saturated, care must be taken to avoid accumulation of ice within the measurement apparatus when measurements are made in the winter. Often it is desirable to conduct these measurements in the warm summer months when freeze-up is not an issue.

Once an accurate GOR has been established, casing gas flows may be estimated from monthly oil production levels.

The amount of solution gas vented from production storage tanks located at the sites may be estimated using the methods described in Section 3.1.4. It is common practice to use the GOR in combination with a tank vent factor in order to report the total monthly vent volume for the battery.

Example Calculation

A GOR test was conducted on a heavy oil well located outside a Designated Oil Sands Area. During the 24 hour test the total measured volumes of casing gas and oil were 400 m³ and 4 m³, respectively. The total oil production for the current month is 125 m³.

The GOR from the test data is:

$$GOR = \frac{400 \text{ m}^3 \text{ of casing gas}}{4 \text{ m}^3 \text{ of oil production}} = 100 \text{ m}^3 / \text{m}^3$$

The estimated casing gas vent rate for the current month is then:

$$\begin{aligned} V &= \text{GOR production} \\ V &= 100 \text{ M}^3/\text{m}^3 \cdot 125 \text{ m}^3 \\ V &= 12.5 \times 10^3 \text{ m}^3 \end{aligned}$$

Note: Since the measured daily casing gas flow rate is • 500 m³/d, annual GOR tests are required.

3.1.2 Associated/Solution Gas

At oil production facilities a certain quantity of natural gas is produced along with the hydrocarbon liquids. The quantity of gas produced is dependent, primarily, on the conditions in the reservoir. The bulk of the produced gas is separated from the liquids and metered at the inlet separator. This is frequently referred to as free or associated gas. A certain amount of gas remains in solution with the produced liquids and is subsequently released as the hydrocarbons are further processed. This gas may be vented, flared or conserved depending on the quantity of gas, regulatory requirements and the economics of the situation.

This section provides methodologies to estimate volumes of solution gas released, and subsequently vented or flared, from emulsion treaters and gas boots. The free or associated gas volume is metered so an estimation of this volume is not required. Solution gas emissions from storage tanks are addressed in Section 3.1.4.

Estimation Methods

The basic strategy for estimating solution gas emissions from emulsion treaters and gas boots is to collect sufficient process data to enable simulation of the associated process units. Actual flow measurements and sampling need only be performed when insufficient data are available for this purpose. There are a variety of simulation methods available to estimate solution gas emissions. Some of the more common methods are (in the order of increasing sophistication and accuracy):

- EUB rule-of-thumb,
- Standing correlation,
- Vasquez and Beggs correlation, and
- rigorous modeling using a process simulator.

In the sections that follow each of these methods is described along with some of their strengths and limitations.

EUB Rule-of-Thumb

The rule-of-thumb is a simple correlation which relates the solution gas volume to the oil production volume and the amount of pressure drop between the last

upstream vessel and the current vessel (EUB).

$$V_s = 0.0257 \cdot V_o \cdot \Delta P$$

Where

$$\begin{aligned} V_s &= \text{volume of solution gas released (m}^3\text{),} \\ V_o &= \text{oil production volume (m}^3\text{), and} \\ \Delta P &= \text{pressure drop (kPa).} \end{aligned}$$

The correlation is recommended for use in estimating solution gas volumes from stock tanks but should also be acceptable in estimating the volumes of solution gas emitted from treaters and gas boots.

The rule-of-thumb tends to yield conservative (i.e., high) solution gas volumes and is recommended for facilities with low oil volumes, established pools, mature pools with declining GOR's and some heavy oil production facilities (EUB).

Standing and Vasquez & Beggs Correlations

These correlations are based on the regression of experimentally determined bubble point pressures for a variety of crude oil systems. The range of parameters for which each of the correlations were derived is presented in Table 3-2

Table 3-2 Summary of Range of Data Used to Develop Each of the Correlations

Parameter	Standing Correlation	Vasquez & Beggs Correlation
Size of Dataset	105	5 008
Bubble Pressure (kPa)	895 to 48 250	345 to 36 190
Reservoir Temperature (°C)	38 to 126	21 to 146
Solution Gas-to-Oil Ratio at Bubble Point Pressure (m ³ /m ³)	3.5 to 254	3.5 to 369
Oil Specific Gravity (°API)	16.5 to 63.8	16 to 58
Vapour Specific Gravity	0.59 to 0.95	0.56 to 1.18

1 Source: Beggs, Dale H. 1987. *Petroleum Engineering Handbook*. Chapter 22. Oil System Correlations.

Each of these correlations is accurate to within 10 percent more than 85 percent of the time when input data in the range of values listed in Table 3-2 are used. They may also be used with data outside the range of values for which they were derived but with reduced accuracy.

The correlations are as follows:

Standing

$$R_s = g_g \left(\frac{p}{519.7 \times 10^{y_g}} \right)^{1.204}$$

where:

$$\begin{aligned} R_s &= \text{solution gas-to-oil ratio (m}^3\text{/m}^3\text{)}, \\ g_g &= \text{specific gravity of the solution gas with respect to air (dimensionless),} \\ p &= \text{absolute pressure in the vessel of interest (kPa (abs)),} \\ &\quad 1.225 + 0.00164T - \frac{1.769}{g_o} \\ y_g &= \\ T &= \text{temperature of interest (K), and} \\ g_o &= \text{specific gravity of oil with respect to water (dimensionless).} \\ &\quad \frac{141.5}{131.5 + {}^0API} \end{aligned}$$

Vasquez & Beggs

$$R_s = C_1 g_g p^{C_2} \exp \left(\frac{C_3}{g_o T} - \frac{C_4}{T} \right)$$

where:

	$g_o < 0.876$	$g_o \geq 0.876$
C_1	3.204×10^{-4}	7.803×10^{-4}
C_2	1.1870	1.0937
C_3	1 881.24	2 022.19
C_4	1 748.29	1 879.28

g_g = specific gravity of the solution gas with respect to air (dimensionless)

$$= \frac{\text{Molecular Weight of Solution Gas}}{\text{Molecular Weight of Air}}$$

T = temperature of interest (K), and

p = absolute pressure in the vessel of interest (kPa (abs))

Process Simulators

Simulation of the process units may be performed with any one of a number of commercially available process simulators. Table 3-3 provides a list of some commercially available simulators and their suppliers.

The process data that are normally available at a facility and that may be useful in simulating emulsion treaters and gas boots include:

- composition of the inlet gas (on a dry basis),
- composition of the final stabilized oil/condensate product from the stock tanks,
- gas flow rate off the inlet separator,
- oil and water production rates to the stock tanks, and
- operating temperatures and pressures of the various process vessels at the facility.

The inlet production for the facility may be closely approximated by combining the gas stream from the inlet separator with the stabilized hydrocarbon and produced water streams at the inlet temperature and pressure. Having defined the inlet production and knowing the operating temperature and pressure of the downstream vessels, it is a simple matter to simulate the amount of gas vented or flared from each of the process vessels.

If the composition and/or flow rate of the bulk process stream are not known at a particular point, it is usually necessary to simulate all process units between the inlet separator and the target unit.

Table 3-3 List of Commercially Available Process Simulation Packages

Package	Vendor
Alpha Sim	Alpha Sim Technology 5870 Hwy. 6 North, Suite 303 Houston, TX 77084 USA
ASPEN PLUS	Aspen Technology Inc. Ten Canal Park Cambridge, Mass 02141-2200 USA
CHEMCAD III	Chem Stations 2901 Wilcrest Drive, Suite 305 Houston, TX 77081 USA

Design II	Winsim Inc. P.O. Box 1885 Houston TX 77251 USA
Hysim, Hysys	Hyprotech Ltd. 800, 707 – 8 th Avenue S.W. Calgary, AB Canada
Process, PRO/II, Dynsym	Simulation Sciences Inc. 601 S. Valencia Avenue, Suite 100 Brea, CA 92823-6346 USA

Example Calculation

An oil battery is processing crude oil with an API gravity of 40°API. The facility has an inlet separator and an emulsion treater. The temperature and pressure in the separator are 25°C and 450 kPa, while those in the treater are 40°C and 250 kPa. The molecular weight of the solution gas is 44 kg/kmole. The estimated monthly volume of solution gas released from the emulsion treater with an oil production rate of 500 m³/month is as follows:

EUB Rule-of-Thumb

The change in pressure between the separator and treater is 200 kPa.

$$R_s = 0.0257 \times 200 \text{ kPa} = 5.14 \text{ m}^3/\text{m}^3$$

$$V_s = 5.14 \times 500 = 2.6 \times 10^3 \text{ m}^3/\text{month}$$

Standing Correlation

The temperature and pressure in the separator are 25°C and 450 kPa, while those in the treater are 40°C and 250 kPa.

$$g_o = \frac{141.5}{131.5 + 40} = 0.8251$$

$$g_g = \frac{\text{Molecular Weight of Solution Gas}}{\text{Molecular Weight of Air}} = \frac{44 \text{ kg / kmole}}{28.96 \text{ kg / kmole}} = 1.5193$$

For the separator:

$$y_g^S = 1.255 + 0.00164 \times 298.15 - \frac{1.769}{0.8251} = -0.4000$$

$$R_S^S = 1.5193 \left(\frac{450 + 101.325}{519.7 \times 10^{-0.4000}} \right)^{1.204} = 4.9446 \text{ m}^3/\text{m}^3$$

For the treater:

$$y_g^T = 1.255 + 0.00164 \times 313.15 - \frac{1.769}{0.8251} = -0.3918$$

$$R_S^T = 1.5193 \left(\frac{250 + 101.325}{519.7 \times 10^{-0.3918}} \right)^{1.204} = 2.8095 \text{ m}^3/\text{m}^3$$

Solution gas vented:

$$V_S = (4.9446 - 2.8095) \times 500 = 1.1 \times 10^3 \text{ m}^3$$

Vasquez & Beggs

$$g_o = \frac{141.5}{131.5 + 40} = 0.8251$$

For the separator:

$$R_S^S = 3.204 \times 10^{-4} \cdot 1.5193 \cdot (450 + 101.325)^{1.1870} \exp \left(\frac{1881.24}{0.8251 \cdot 298.15} - \frac{1748.29}{298.15} \right) = 5.20 \text{ m}^3/\text{m}^3$$

For the treater:

$$R_S^T = 3.204 \times 10^{-4} \cdot 1.5193 \cdot (250 + 101.325)^{1.1870} \exp \left(\frac{1881.24}{0.8251 \cdot 313.15} - \frac{1748.29}{313.15} \right) = 2.77 \text{ m}^3/\text{m}^3$$

Solution gas vented:

$$V_S = (5.20 - 2.77) \times 500 = 1.2 \times 10^3 \text{ m}^3$$

3.1.3 Venting from Glycol Dehydrators

As per EUB Guide 60, the measurement and reporting of vent volumes from glycol dehydrators is not required. However, since operators calculate this volume in conjunction with benzene emission calculations, the EUB encourages operators

to report this volume. Glycol dehydration is a continuous liquid desiccant process in which water or water vapour is removed from hydrocarbon streams by selective absorption and the glycol is regenerated or reconcentrated by thermal desorption. The use of triethylene glycol (TEG) is standard for dehydration of natural gas.

The primary causes of venting from a glycol dehydrator are secondary absorption/desorption by the TEG, entrainment of some gas from the contactor in the rich TEG, and use of stripping gas in the reboiler.

Estimation Methods

The simplest, but least accurate, method of estimating the quantity of natural gas vented from the glycol regenerator still column is to use average emission factors. These factors yield relatively accurate results on average. However, if the dehydrator operating conditions differ significantly from the average then the estimated vented volume will not reflect this. The volume of gas vented from a glycol dehydrator still column may be estimated using the following relation:

$$V = Q \cdot (K_{SC} + K_{SG} + K_{GP})$$

where:

Q	=	gas throughput (10^3 m^3),
K_{SC}	=	still column off-gas factor ($\text{m}^3/10^3 \text{ m}^3$),
	=	0.00357 if there is a flash tank,
	=	0.1751 if there is no flash tank,
K_{SG}	=	stripping gas factor ($\text{m}^3/10^3 \text{ m}^3$),
	=	0.670 if stripping gas is used,
	=	0.000 if stripping gas is not used, and
K_{GP}	=	Kimray pump factor ($\text{m}^3/10^3 \text{ m}^3$),
	=	0.1777

The presented factors were derived by modeling typical glycol dehydration units at gas production and processing facilities in the U.S. (Meyers, 1996).

Note that if an electric glycol pump is used, then the glycol pump factor is zero. Similarly, if a gas driven glycol pump is used then the vent gas rate for the pump should be estimated using the methods described in Section 3.1.5.

Perhaps the most convenient method of estimating methane emissions from a glycol dehydrator is to use the simulation program GRI-GLYCalc developed for, and available at a nominal cost from, GTI (Thompson et al., 1994). GRI-GLYCalc is primarily presented as a tool for estimating the amount benzene, toluene, ethylbenzene and xylene (BTEX) emitted by a glycol dehydrator (significant amounts of this material may be preferentially absorbed by the glycol and released off the flash tank and still column). However, in performing a rigorous simulation

of the dehydration process, the program also provides information on the amount of hydrocarbons emitted. Furthermore, the program can assess the emission reduction that may be achieved from use of selected control devices (e.g., condensers and incinerators). The required input data includes,

- gas composition and flow rate,
- glycol circulation rate,
- temperature and pressure in the absorber column,
- type of glycol pump,
- operating pressure of the flash tank (if one is used) and amount of flash gas used by the process (if at all),
- type of glycol (TEG or DEG), and
- stripping gas usage.

Alternatively, estimates may be made using commercial general-purpose process simulation packages (e.g., HYSIM™ by Hyprotech, PRO/II™ by Simulation Sciences, and PROSIM™ by Bryan Research & Engineering, Inc.). These will, potentially, provide more accurate results but require greater effort and expertise to use. Moreover, they are quite expensive and probably could not be justified for the subject application alone.

Example Calculation

A glycol dehydrator processes $300 \times 10^3 \text{ m}^3$ per day of wet natural gas. The dehydrator is equipped with a flash tank and Kimray glycol pump and uses stripping gas in the glycol reboiler.

$$Q = 300 \times 10^3 \text{ m}^3 \text{ per day} \times 30 \text{ days} = 9000 \times 10^3 \text{ m}^3 \text{ per month,}$$

$$K_{SC} = 0.00357 \text{ m}^3/10^3 \text{ m}^3$$

$$K_{SG} = 0.670 \text{ m}^3/10^3 \text{ m}^3$$

$$K_{GP} = 0.1777 \text{ m}^3/10^3 \text{ m}^3$$

$$V = 9000(0.00357 + 0.670 + 0.1777)$$

$$V = 7.6 \times 10^3 \text{ m}^3/\text{month}$$

3.1.4 Production Storage Tanks

Production facilities are typically equipped with a set of fixed-roof tanks for temporary storage of the produced hydrocarbon liquids (i.e., oil or condensate). If these tanks are vented to the atmosphere, they are sources of storage losses (i.e., product is lost to the atmosphere due to evaporation effects). These losses are a source of organic-compound emissions in the upstream oil and gas industry.

There are three types of storage losses that may occur from vented fixed-roof storage tanks: breathing/standing, working (i.e., filling and emptying) and flashing. The first two types are common to all such tanks and tend to be relatively small in comparison to flashing/solution gas losses. The empirical relations for

breathing/standing and working losses are well documented in the literature (API, 1991). Except in extraordinary circumstances, only flashing losses need to be accounted for. As such, the focus of this section is flashing losses, which occur when products with vapour pressures above atmospheric pressure are produced into the tanks, as is the case at many oil and gas production facilities.

Estimation Methods

Produced hydrocarbon liquids at production facilities often contain a certain amount of gas in solution; the amount is determined by the temperature and pressure in the first vessel upstream of the stock tanks where the oil is in contact with a hydrocarbon gas or vapour phase. When the product enters the tank, the solution gas flashes/boils off causing a higher degree of saturation in the vapour space than would be expected based on the vapour pressure of the weathered product already in the tank.

If this process is examined in terms of vapour pressures, the produced liquid has an initial value approximately equal to the operating pressure of the first upstream vessel. When the product is placed in the stock tank its vapour pressure decreases rapidly towards local barometric pressure, and then more slowly as the rate of evaporation stabilizes. A weathered crude oil will typically have a vapour pressure of 35 to 45 kPa at stock tank conditions.

The material that flashes from the product in going to a "stable" state is referred to as solution gas. There are several approaches for estimating flashing losses from storage tanks. These methods include the use of emission factors, estimation with empirical correlations, and rigorous thermodynamic calculations using a process simulator. The applicability of each of these methods is dependent upon the specific conditions that exist at the production site.

As an alternative to estimation of emissions, solution gas emitted from the production tank vent may be measured. To be useful, 24 hour test (similar to what is required for GOR tests) must be conducted whereby both the solution gas and oil production to the tank are measured. In practice, accurate measurement of solution gas vented from a typical storage tank is difficult. Tanks commonly vent gas not only from the central vent but also from the thief hatch and tank gauge well. Sealing these openings to ensure that all gas exits through the flow meter is difficult as the solution gas is typically saturated with condensable hydrocarbons and water. As well, care must be taken not to overpressure the tank.

Empirical Correlations

The empirical correlations presented previously for estimating associated/solution gas emissions may be used to estimate solution gas emissions from production storage tanks. The correlations are:

- EUB Rule-of-Thumb,
- Standing Correlation, and
- Vasquez & Beggs Correlation.

Refer to Section 3.1.2 for a description of each of these correlations.

Rigorous Thermodynamic Simulations

The use of a process simulator potentially provides the most accurate estimate of flashing/solution gas losses from production storage tanks. Analyses of both the hydrocarbon liquid and solution gas streams as well as process temperatures and pressures are generally required before a solution gas emission estimate can be calculated. While, use of a process simulator requires substantially more effort than correlations presented in Section 3.1.4.1.2, there may be circumstances where it is the preferred method because the correlations or emission factors do not yield acceptable results.

Estimation of solution gas emissions with a process simulator relies on the ability to predict the liquid composition at the last vessel upstream of the storage tanks using an equation of state. Flash calculations are then performed to determine the quantity and composition of vapour released when the product is brought to stock tank conditions. General process simulators such as Hysys, Prosim, Aspen, etc. (see Table 6) are appropriate tools for estimating flashing losses. Alternately, a more specialized package, E&P Tank (DB Robinson, 1997), may be used. An added advantage of E&P Tank is that standing, working and flashing losses may all be estimated using the same package.

E&P Tanks

E&P Tank is a software simulation package for estimating emissions from hydrocarbon production tanks. The program was prepared by D.B. Robinson Research Limited for American Petroleum Institute and Gas Research Institute and is available from API. The model estimates production tank flashing losses using thermodynamic principles and simulates working and standing losses by one of several methods.

The storage tank to be simulated may be represented as shown in Figure 3-1. The minimum information requirements for flashing loss calculations are:

- upstream vessel temperature and pressure,
- upstream vessel oil composition (at the temperature and pressure of the upstream vessel) – a C_1 to C_{10+} hydrocarbon analysis is required,
- atmospheric pressure (or the pressure inside the storage tank),
- RVP (Reid vapour pressure) of the sales oil, and
- API gravity of the sales oil.

If oil composition is not known, the program contains a fluid composition

database of 103 oil analyses.

Once the appropriate data have been entered, flashing losses are estimated by flashing the upstream oil stream to atmospheric pressure. Normal evaporation losses are then inferred by matching the oil properties obtained from the flash calculations to the specified sales oil RVP and API gravity.

Process Simulators

Use of a process simulator offers somewhat more flexibility in estimating flashing losses from storage tanks. The basic information requirements are essentially the same as for E&P Tank, however, there is more flexibility in determining compositional data from other information. For instance, if composition of the oil in the upstream vessel is not known, it may be determined from the sales oil and solution gas compositions by recombining these streams at the temperature and pressure of the upstream vessel.

A schematic diagram that shows the basic information requirements is presented in Figure 3-2. For Case 1, where the oil composition in the upstream vessel is known, flashing losses may be estimated by flashing the known oil stream to the temperature and pressure conditions that exist within the storage tank. This yields the phase fractions, and compositions of the sales oil and vapour emissions. The emission rate of vapour may then be calculated knowing the molar flow of oil and the liquid and vapour phase fractions.

Figure 3-1 Process Diagram Showing the Information Requirements for Estimating Flashing Losses From Oil Storage Tanks Using E&P Tank

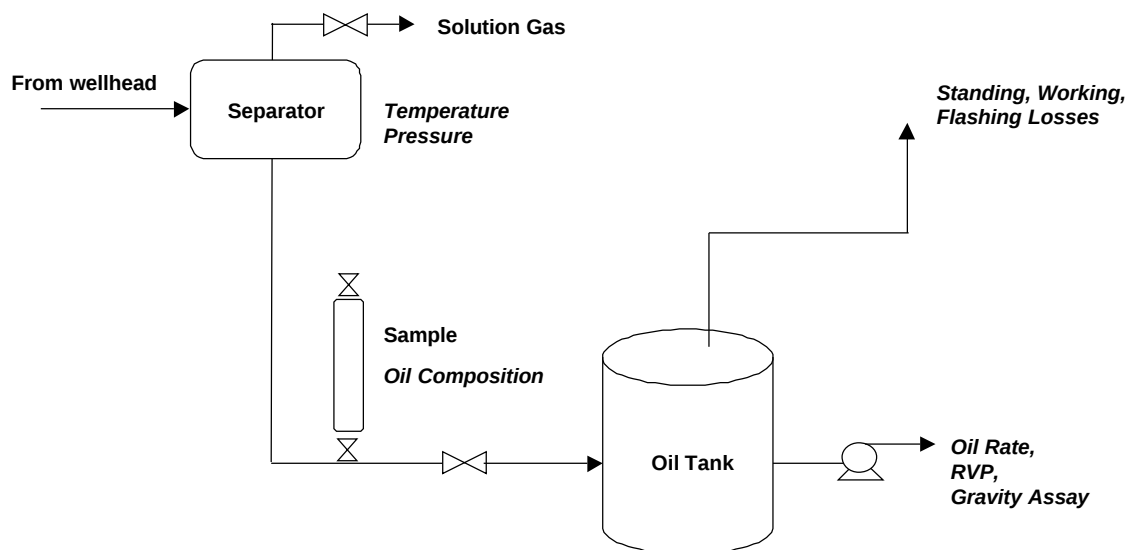
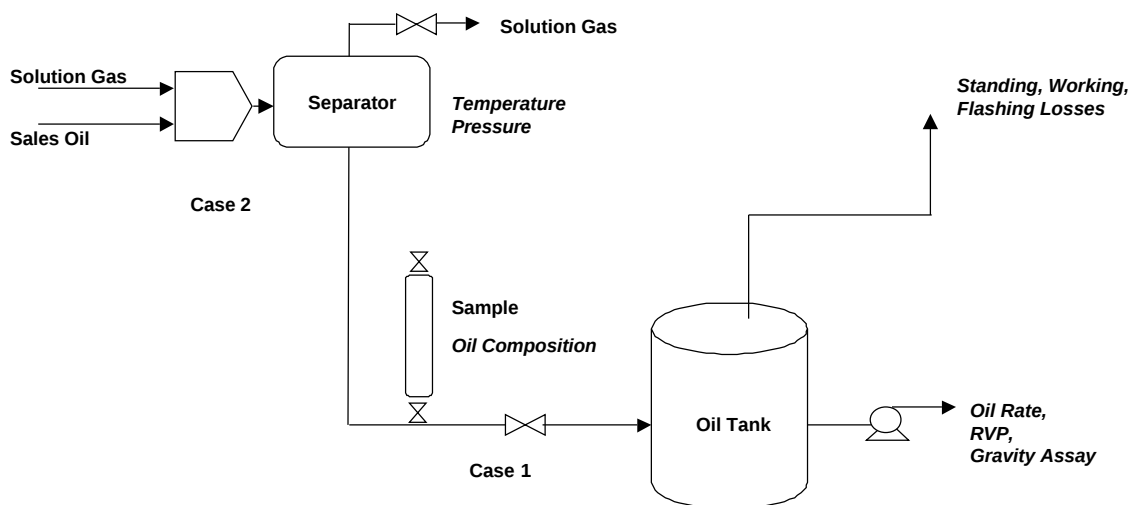


Figure 3-2 Schematic Diagram Showing Information Requirements for Estimating Flashing Losses From Oil Storage Tanks Using a Process Simulator



Example Calculations

Process Simulator

A single well oil battery reports oil deliveries of 200 m³ per month. The facility has an inlet separator, an emulsion treater and oil storage tank. The conditions in the treater and storage tank are as follows:

Treater T = 40°C P = 350 kPag

Storage Tank T = 25°C P = 90 kPaa

The solution gas and sales oil compositions are known and are given below (in mole percent). The density of the sales oil is 800 kg/m³.

Component	Solution Gas	Sales Oil	Treater Oil
N ₂	0.62	0.00	5.26e-3
CO ₂	5.24	0.00	0.3140
C ₁	73.25	0.00	0.0150
C ₂	11.97	0.00	0.0107
C ₃	5.32	0.10	0.0131
iC ₄	0.88	0.10	0.423
nC ₄	1.70	0.49	1.10
iC ₅	0.36	0.89	0.869
nC ₅	0.38	1.17	1.15
C ₆	0.24	2.23	2.16
C ₇	0.04	2.69	2.52
C ₈	----	4.94	4.65
C ₉	----	6.18	5.86
C ₁₀	----	13.66	12.98
C ₁₁	----	18.49	17.59
C ₁₂	----	11.92	11.34
C ₁₃	----	11.28	10.74
C ₁₄	----	6.32	6.01
C ₁₅	----	3.85	3.66
C ₁₆	----	2.70	2.57
C ₁₇	----	1.39	1.32
C ₁₈	----	0.81	0.771
C ₁₉	----	0.62	0.590
C ₂₀₊	----	2.94	2.80
Cyclopentane	----	0.02	1.55e-3
Methylcyclopentane	----	0.61	0.529
Cyclohexane	----	0.53	3.46e-2
Methylcyclohexane	----	0.98	0.463
Benzene	----	0.04	0.900
Toluene	----	0.87	0.802
Ethylbenzene	----	0.00	0.000
Xylene	----	2.92	2.75
124-Trimethylbenzene	----	1.26	1.20

To calculate flashing losses, the composition of the liquid entering the storage tank from the treater must be known. Since the solution gas and sales oil compositions are known, the recombination of these streams at the conditions of the treater will yield the flow and composition of the oil entering the tank. Equal moles of solution gas and sales oil are mixed and a flash calculation is performed at 40°C and 350 kPag (440 kPaa). This yields the treater oil composition presented in the table above as well as the molar flow of the treater oil (i.e., 1.0255 times the sales oil molar flow). Vapour emissions from the storage tank are then determined by performing a mass balance between the liquid stream entering the tank and the sales oil.

$$\dot{n}_{\text{vapour}} = \dot{n}_{\text{Treater Liquid}} - \dot{n}_{\text{Sales Oil}}$$

$$\begin{aligned}\text{Sales Oil Molar Flow} &= 200 \text{ m}^3/\text{mo} \times 800 \text{ kg/m}^3 / 156 \text{ kg/kmole} \\ &= 1\,026 \text{ kmole}\end{aligned}$$

$$\dot{n}_{\text{vapour}} = 1\,026 \cdot (1.0255 - 1.0000) = 26.2 \text{ kmoles}$$

$$V_{\text{Vapour}} = 26.2 \text{ kmoles} \times \frac{8.3145 \frac{\text{kJ}}{\text{kmole} \cdot \text{K}} \times 288.15 \text{ K}}{101.325 \text{ kPa}}$$

$$V_{\text{Vapour}} = 0.6 \times 10^3 \text{ m}^3 \text{ at } 15^\circ \text{C and } 101.325 \text{ kPa}$$

EUB Rule-of-Thumb

The change in pressure between the treater and storage tank is 350 kPa.

$$R_s = 0.0257 \times 350 \text{ kPa} = 8.995 \text{ m}^3/\text{m}^3$$

$$V_{\text{Vapour}} = 8.995 \times 200 = 1.8 \times 10^3 \text{ m}^3/\text{month}$$

Empirical Correlations

Standing Correlation

$$g_o = \frac{141.5}{131.5 + 45} = 0.80$$

$$y_g = 1.255 + 0.00164 \times 313.15 - \frac{1.769}{0.80} = -0.4427$$

$$g_g = \frac{\text{Molecular Weight of Solution Gas}}{\text{Molecular Weight of Air}} = \frac{22.46 \text{ kg/kmole}}{28.96 \text{ kg/kmole}} = 0.7754$$

$$R_s = 0.7754 \left(\frac{350}{519.7 \times 10^{-0.4427}} \right)^{1.204} = 1.644 \text{ m}^3/\text{m}^3$$

$$V_{\text{Vapour}} = 1.644 \times 200 = 0.3 \times 10^3 \text{ m}^3$$

Vasquez & Beggs

$$g_o = \frac{141.5}{131.5 + 40} = 0.80$$

$$R_s = 3.204 \times 10^{-4} \cdot 0.7754 \cdot (350)^{1.1870} \exp \left(\frac{1881.24}{0.80 \cdot 313.15} - \frac{1748.29}{313.15} \right) = 1.785 \text{ m}^3/\text{m}^3$$

$$V_{\text{Vapour}} = 1.785 \times 200 = 0.4 \times 10^3 \text{ m}^3$$

Based on these example calculations, the estimates from emission factors, Standing Correlation and Vasquez & Beggs Correlation produce results which agree with the process simulation. The EUB Rule-of-Thumb yields results that are 2 to 3 times greater than the process simulation.

3.1.5 Pneumatic Devices

At remote locations sweet natural gas is often used as a supply medium for instrumentation and to power devices such as chemical injection pumps. Where such devices are located at oil and gas batteries the natural gas used for these devices often comes from the fuel gas system and, therefore, should be metered and/or estimated and reported to EUB as fuel and NOT as a vented volume. At larger facilities an “instrument air” system and/or electric power are typically used in place of fuel gas to power chemical injection pumps and instrument controllers.

Estimation of venting rates from pneumatic devices involves compiling an inventory of pneumatic devices for each facility and then applying an appropriate vent rate to each of the devices. Unit specific vent rates are available from the manufacturer or from industry average factors. Use of manufacturers’ data will yield more accurate results but the level of effort required to compile the information necessary to estimate vent rates from manufacturers’ data (e.g., make and model of each device, and activity levels) may be prohibitive and probably no more accurate.

Estimation Methods

Estimation of venting from pneumatic devices may be accomplished by applying the average vent rates for pneumatic devices presented in Table 3-4 to the typical device inventory for various facility types listed in Table 3-5.

Table 3-4 Average Vent Rates for Pneumatic Devices Based on Data Collected in Alberta

Pneumatic Device	Average Vent Rate
Instrument Controller	0.1996 m ³ /hour/controller
Gas Operated Chemical Injection Pump	0.3945 m ³ /hour/pump

Table 3-5 Typical Number of Pneumatic Devices at Various Types of Upstream Oil and Gas Facilities

Facility Type	Gas Operated Chemical Injection Pumps	Instrument Controllers
Wellhead	1	0
Gas Gathering System	1	1
Compressor Station	0	4
Gas Battery	0	7
Single-Well Battery	0	3
Satellite Battery	0	2
Central Battery	0	9

Note that the data presented in Tables 3-4 and 3-5 are averages based on a limited dataset. If company specific data are available for average vent rates or the numbers of pneumatic devices at a facility, then the use of these data is preferred.

Example Calculation

The estimated monthly vent rate from a typical gas gathering system is as follows:

Chemical Injection Pump

$$V = 0.3945 \text{ m}^3/\text{hour/pump} \times 1 \text{ pump} \times 24 \text{ hours/day} \times 30 \text{ days}$$

$$V = 0.3 \times 10^3 \text{ m}^3/\text{month}$$

Instrument Controller

$$V = 0.1996 \text{ m}^3/\text{hour/controller} \times 1 \text{ controller} \times 24 \text{ hours/day} \times 30 \text{ days}$$

$$V = 0.1 \times 10^3 \text{ m}^3/\text{month}$$

Similarly for other facility types.

Summary of Typical Vent Rates From Pneumatic Instruments at Various Facility Types.

Facility Type	Vent Rate ($10^3 \text{ m}^3 / \text{month}$)		
	Chemical Injection Pumps	Instrument Controllers	Total
Wellhead	0.3	----	0.3
Gas Gathering System	0.3	0.1	0.4
Compressor Station	----	0.6	0.6
Gas Battery	----	1.0	1.0
Single-Well Battery	----	0.4	0.4
Satellite Battery	----	0.3	0.3
Central Battery	----	1.3	1.3

3.2 Intermittent Sources

3.2.1 Well Blowdowns

Some gas wells must be blown down periodically to remove water that has accumulated in the production tubing. These are primarily shallow (less than 1000 m), low pressure (less than 2000 kPa) gas wells.

During a well blowdown, the well is opened to atmosphere so the downhole pressures may blow water from the tubing to an atmospheric storage tank. Sometimes, sticks of soap are inserted down the production tubing beforehand. This causes a frothing action to occur when the well is opened, which helps to remove the water.

Shallow gas wells are typically sweet and usually are not equipped with flares. Thus the gas that is discharged during the subject blowdown operation is released to the atmosphere unburned. These wells are located mainly in the Medicine Hat and Milk River areas of southeastern Alberta, Area III gas fields of southwestern Saskatchewan and the Cold Lake area of east central Alberta.

Estimation Methods

The volume of gas released during a well blowdown is dependent on the duration of the event, wellhead temperature and pressure, size of the vent line, the properties of the gas and the quantity of water produced. The process may be modeled as the isentropic flow of an ideal gas through a nozzle. Modeling the system as an ideal gas yields good results up to wellhead pressures of about 50 atmospheres (5000 kPa). At wellhead pressures greater than 50 atmospheres more

rigorous equations of state must be used (Shapiro, 1953).

The basic equation used to estimate the mass flow rate of the gas blown down is:

$$\dot{m}_T = A^* \cdot \frac{P_o}{\sqrt{T_o}} \cdot \sqrt{\frac{k}{R}} \cdot \frac{1}{\left(\frac{k+1}{2}\right)^{(k+1)/(2k-2)}} \cdot 1000$$

where:

- $\dot{m}_T$ = the total mass flow rate of gas and water vapour from the blowdown (kg/s),
- A^* = the cross sectional area of the blowdown valve or vent pipe (m²) (see Table 10),
- P_o = wellhead pressure (kPa),
- T_o = wellhead temperature (K),
- k = specific heat ratio $C_p/C_v = 1.32$ for natural gas,
- R = gas constant (kJ/kg K),
= 8314.5 / gas molecular weight.

The amount of gas vented must be discounted by the quantity of water produced during the blow down event. The following equation may be used:

$$\dot{m}_W = \frac{V \cdot \rho_w}{t}$$

where:

- $\dot{m}_W$ = mass flow rate of water produced by the blow down event (kg/s),
- V = volume of liquid water produced by the blow down event (m³),
- ρ_w = density of liquid water (1000 kg/m³),
- t = duration of the blow down event (s).

The net mass flow rate of gas released is then:

$$\dot{m}_V = \dot{m}_T - \dot{m}_W$$

and the volume released may be expressed as:

$$V = \frac{\dot{m}_V \cdot t}{W_V} \cdot 23.6449$$

where:

V = volume of gas released (m^3),
 W_V = molecular weight of the vapour released (kg/kmole), and

The factor 23.6449 is the volume (m^3) occupied by one kmole of an ideal gas at 15°C and 101.325 kPa.

Example Calculations

A shallow gas well is blown down to an atmospheric storage tank through a 2 inch schedule 40 pipe. The well head temperature and pressure are 20°C and 2000 kPa and atmospheric pressure is 90 kPa. The gas has a molecular weight of 17.5 kg/kmole, the duration of the blow down is 5 minutes (300 s) and 1 m^3 of water is recovered.

A 2- inch schedule 40 pipe has a cross sectional area of 0.002165 m^2 (see Table 3-7).

The gas constant for the natural gas is:

$$R = \frac{8314.5}{17.5} = 475.11$$

The total mass flow is:

$$\dot{m}_T = 0.002165 \cdot \frac{(2\,090)}{\sqrt{(20 + 273.15)}} \cdot \sqrt{\frac{1.32}{475.11}} \cdot \frac{1}{\left(\frac{1.32 + 1}{2}\right)^{(1.32+1)/(2 \cdot 1.32 - 2)}} \cdot 1000 = 8.1337 \text{ kg/s}$$

Mass flow of water recovered:

$$\dot{m}_W = 1.0 \cdot 1000.0 / 300.0 = 3.3333 \text{ kg/s}$$

The net mass flow of vapour released is:

$$\dot{m}_V = (8.1337 - 3.3333) = 4.8004 \text{ kg/s}$$

and the net volume released is:

$$V_V = \frac{4.8004 \cdot 300.0}{17.5} \cdot 23.6449 = 1.9 \times 10^3 \text{ m}^3$$

Table 3-6 Summary of Cross-Sectional Areas for Typical Pipe Sizes

NPS Size	Schedule 40 Pipe		Schedule 60 Pipe		Schedule 80 Pipe		Schedule 100 Pipe		Schedule 120 Pipe		Schedule 140 Pipe		Schedule 160 Pipe	
	in ²	m ²	in ²	m ²	in ²	m ²	in ²	m ²	in ²	m ²	in ²	m ²	in ²	m ²
1	0.8640	5.574e-4			0.7190	4.639e-4							0.5217	3.366e-4
2	3.355	2.165e-3			2.953	1.905e-3							2.241	1.446e-3
3	7.393	4.770e-3			6.605	4.261e-3							5.408	3.489e-3
4	12.73	8.213e-3			11.50	7.419e-3			10.31	6.652e-3			9.28	5.987e-3
6	28.89	1.864e-2			26.07	1.682e-2			23.77	1.534e-2			21.15	1.365e-2
8	50.03	3.228e-2	47.94	3.093e-2	45.66	2.946e-2	43.46	2.804e-2	40.59	2.619e-2	38.50	2.484e-2	36.46	2.352e-2
10	78.86	5.088e-2	74.66	4.817e-2	71.84	4.635e-2	68.13	4.395e-2	64.53	4.163e-2	60.13	3.879e-2	56.75	3.661e-2
12	111.93	7.221e-2	106.16	6.849e-2	101.64	6.557e-2	96.14	6.203e-2	90.76	5.855e-2	86.59	5.586e-2	80.53	5.195e-2
14	135.28	8.728e-2	128.96	8.320e-2	122.72	7.917e-2	115.49	7.451e-2	109.62	7.072e-2	103.87	6.701e-2	98.31	6.343e-2
16	176.72	1.140e-1	169.44	1.093e-1	160.92	1.038e-1	152.58	9.844e-2	144.50	9.323e-2	135.28	8.728e-2	128.96	8.320e-2
18	223.68	1.443e-1	213.83	1.380e-1	204.24	1.318e-1	193.30	1.247e-1	182.66	1.178e-1	173.80	1.121e-1	163.72	1.056e-1
20	278.00	1.794e-1	265.21	1.711e-1	252.72	1.630e-1	238.83	1.541e-1	226.98	1.464e-1	213.82	1.379e-1	202.67	1.308e-1

3.2.2 Accidental Releases

Accidental releases are releases that occur as a result of accidents, human error and extraordinary equipment failures. These releases are not part of normal operational or maintenance activities and exclude such releases as, for example, relief valve emissions.

The most significant types of natural gas emissions in this category are those from pipeline ruptures, well blowouts, surface casing vent blows and gas migration to the surface. For certain types of sources, such as surface casing vent blows and gas migration around the outside of the casing, measurement of the vented gas is preferred.

Estimation Methods

Each of the types of accidental losses is delineated below, along with some methods to estimate the emissions.

Pipeline Ruptures

A pipeline rupture may be approximated using the estimation methods described in the well blowdown and pressure vessel blowdown sections (Sections 3.2.1 and 3.2.4, respectively). The rupture is essentially a blowdown from an infinite reservoir from the time of the rupture until the isolation valves on the pipeline are closed. After that point it is simply the blowdown of a section of pipe from some initial pressure to atmospheric pressure.

Well Blowouts

A well blowout is an uncontrolled release of natural gas caused by a catastrophic failure of some part of a wellhead. A blowout may be a complex system to model, therefore, it is preferred to estimate the volume of gas released from a blowdown based on gas well deliverability tests or absolute open flow potential (AOFP) tests. These tests are described in detail in EUB Guide 40 (Pressure and Deliverability Testing Oil and Gas Wells).

Surface-Casing Vent Flows

The surface casing is a steel liner used to protect the integrity of the well bore as the hole is being drilled and to prevent contamination of any aquifers that may be a source of potable water. It is installed during the initial stages of the drilling program and is cemented in place by pumping cement down the centre of the pipe and forcing it to return up around the outside wall. The depth to which the surface casing extends is determined by regulations and the geological conditions at the site (surface casing may not be required on some shallow wells). When the well is

completed, the production casing is run down the centre of the surface casing and cemented in place in a similar manner. The surface casing vent valve is left open to allow for constant monitoring of the annular space between the production casing and the surface casing. In this manner, any gas or other fluids that may flow out from the surrounding formation or up from below can flow into the casing annulus rather than migrate up around the outside of the surface casing and possibly contaminate aquifers above.

If a vent blow occurs, the exact cause of the flow may be difficult to determine and the required repairs are often costly. The fluid emitted from a vent blow may consist of gas, oil, fresh water, salt water or drilling mud. Some vent blows eventually die out. In some cases the vent flow is produced, in others either it is vented/flared or the vent is blocked-in and pressure is allowed to build-up in the casing. One piece of information that can be useful in determining the nature of the vent flow is the surface casing vent shut-in pressure. By closing the surface casing vent valve and monitoring the shut-in pressure using a suitably accurate gauge, this can be easily determined.

A total of 1851 wells in Alberta have been identified as having non-zero surface-casing vent flows (EUB, February 2002). The reported flow rate varies from 0.5 to 6,657 m³/d. The following table summarizes the data:

	SCVF	Well Count	Gas (e6m3/year)	Avg.Rate (m3/day)
Active Wells	Produced	58	24.5	1155.8
Active Wells	Vented	883	11.9	37.1
Suspended Wells	Vented	910	6.7	20.1

These flows can be measured with an appropriate flow meter. Some methods that may be used to measure the surface casing vent flow are described in Section 3.1.1. The EUB has specific requirements regarding the measurement and reporting of surface casing vent flows detailed in ID 99-03. Operators are also required to report surface casing vent flow volumes where the volume is greater than or equal to 100 m³ / month as per Guide 60, Section 10.1 (February 2001 Updates and Clarifications). This only applies to wells where S reports are routinely submitted.

Gas Migration to the Surface

This problem is characterized by a minute flow of gas around the outside of a well casing. Typically it is caused by gas migrating from one or more shallow, low-productivity gas bearing zones penetrated while drilling or as a result of natural processes in the native soils or muskeg. The problem is most pronounced in the Lloydminster region of east central Alberta and west central Saskatchewan. Data compiled by EUB indicate that 814 wells drilled in 1995 or prior have gas

migration problems.

Estimation of the volume of vented gas requires measurement of the hydrocarbon flux rate in the region of the wellhead. One method of making these measurements is through the use of an isolation flux chamber. Tests of this nature have been conducted by Husky Oil Operations (Erno and Schmitz, 1996 and Schmitz *et al.*, 1996). Based on the data presented in these papers, the average vent rate for wells with gas migration problems is 3.85 m³/d per well. As with surface casing vent flows, the EUB has mandated specific requirements for testing and reporting gas migration in EUB ID 99-03. Operators are required to report gas migration volumes if greater than or equal to 100 m³/month as per Guide 60, Section 10.2 (February 2001 Updates and Clarifications). As with surface casing vent flows, this only applies to wells where S Reports are routinely submitted.

Estimation Methods

A 4" pipeline with an initial temperature and pressure of 20°C and 4000 kPa is ruptured. The automatic isolation valve closes in 2 minutes and the rupture occurs a distance of 1 km from the isolation valve. The molecular weight of the gas is 17.5 kg/kmole and atmospheric pressure is 100 kPa.

Initial 2 minutes

A 4 inch schedule 40 pipe has a cross sectional area of 0.008213 m² (see Table 10).

The gas constant for the natural gas is:

$$R = \frac{8314.5}{17.5} = 475.11$$

The total mass flow is:

$$\dot{m}_T = 0.008213 \cdot \frac{(4100)}{\sqrt{(20 + 273.15)}} \cdot \sqrt{\frac{1.32}{475.11}} \cdot \frac{1}{\left(\frac{1.32 + 1}{2}\right)^{(1.32+1)/(2 \cdot 1.32 - 2)}} \cdot 1000 = 60.53 \text{ kg/s}$$

and the net volume released is:

$$V_v = \frac{60.53 \cdot 120.0}{17.5} \cdot 23.6449 = 9.8 \times 10^3 \text{ m}^3$$

After Isolation Valve Closes

4" schedule 40 pipe

From Table 11.

$$V_A = 1000 \text{ m} \times 8.213\text{E-}03 = 8.213 \text{ m}^3$$

Initial conditions, $P_i = 4100 \text{ kPa}$ and $T_i = 20^\circ\text{C}$:

$$z_i = 0.8947 \text{ (from correlation)}$$

Final conditions, $P_f = 100 \text{ kPa}$ and $T_f = 20^\circ\text{C}$:

$$z_f = 1.000 \text{ (from correlation)}$$

$$V_{STP} = 8.213 \left(\frac{288.15}{101.325} \right) \left(\frac{4100}{0.8947 \cdot 293.15} - \frac{100}{1.0000 \cdot 293.15} \right) = 0.4 \times 10^3 \text{ m}^3$$

The total vented gas is then:

$$V_{Total} = (9.8 + 0.4) \times 10^3 \text{ m}^3 = 10.2 \times 10^3 \text{ m}^3$$

3.2.3 Pressure Relief/Pressure Safety Valves

Pressure relief/pressure safety valve blowdown events may be the source of significant venting or flaring volumes. However, due to the unplanned nature of these events, accurate estimation of the gas volume released may be difficult.

Estimation Methods

The volume of gas released during a pressure relief event is dependent on the duration of the event, the vessel temperature and pressure, throat size of the relief valve, and the properties of the gas. The relief event may be modeled as the isentropic flow of an ideal gas through a nozzle. Modeling the system as an ideal gas yields good results up to pressures of about 50 atmospheres (5000 kPa).

The basic equation used to estimate the mass flow rate of the gas is:

$$\dot{m}_V = A^* \cdot \frac{P_o}{\sqrt{T_o}} \cdot \sqrt{\frac{k}{R}} \cdot \frac{1}{\left(\frac{k+1}{2} \right)^{(k+1)/(2k-2)}} \cdot 1000$$

where:

$$\begin{aligned} \dot{m}_V &= \text{the mass flow rate of gas through the pressure relief valve (kg/s),} \\ A^* &= \text{the cross sectional area of the throat (or orifice) of the valve (m}^2\text{),} \end{aligned}$$

$$\begin{aligned}
P_o &= \text{pressure relief valve set point (kPa),} \\
T_o &= \text{vessel temperature (K),} \\
k &= \text{specific heat ratio } C_p/C_v = 1.32 \text{ for natural gas, and} \\
R &= \text{gas constant (kJ/kg K),} \\
&= 8314.5 / \text{gas molecular weight.}
\end{aligned}$$

The volume released may be expressed as:

$$V = \frac{\dot{m}_V \cdot t}{W_V} \cdot 23.6449$$

where:

$$\begin{aligned}
V &= \text{volume of gas released (m}^3\text{),} \\
W_V &= \text{molecular weight of the vapour released (kg/kmole), and}
\end{aligned}$$

The factor 23.6449 is the volume (m³) occupied by one kmole of an ideal gas at 15°C and 101.325 kPa.

The orifice cross-sectional area is dependent on the valve size, the inlet and back pressures, and inlet temperature. Therefore, there is no simple relationship between the size of the pressure relief valve and the orifice cross-sectional area and the orifice area must be determined from manufacturers' data for each individual application.

Example Calculation

A vessel has a 3 inch pressure relief valve (throat area = 0.00477 m²) set at 3000 kPag. An overpressure event causes the valve to open for a duration of 1 minute (60 seconds). The molecular weight of the gas in the vessel is 17.5 kg/kmole, the vessel temperature is 50°C and atmospheric pressure is 100 kPa.

The gas constant for the natural gas is:

$$R = \frac{8314.5}{17.5} = 475.11$$

The mass flow rate through the pressure relief valve is:

$$\dot{m}_V = 0.00477 \cdot \frac{(3100)}{\sqrt{(50 + 273.15)}} \cdot \sqrt{\frac{1.32}{475.11}} \cdot \frac{1}{\left(\frac{1.32 + 1}{2}\right)^{(1.32+1)/(2 \cdot 1.32-2)}} \cdot 1000 = 25.3167 \text{ kg/s}$$

The volume of gas released is:

$$V_v = \frac{25.3167 \cdot 60.0}{17.5} \cdot 23.6449 = 2.1 \times 10^3 \text{ m}^3$$

3.2.4 Facility Blowdowns

The estimation of the volume of gas associated with the blowdown of pressure vessels and piping is essentially one of estimating the total volume of gas contained within the equipment at the process temperature and pressure and then converting the calculated volume to standard conditions of 15°C and 101.325 kPa. The appropriate equations and tables of pipe sizes are presented in Section 3.2.4.1.

Estimation Methods

Standard volumes of common pipe sizes are presented in Table 3-8. To determine the actual volume of gas contained within the process piping (i.e., at process conditions), all that is required is to determine the total length of each size of pipe at each temperature and pressure and multiply by the appropriate factor from Table 3-8.

Table 3-8 Volume Occupied by a One-Metre Length of Various Standard Pipe Sizes

NPS Size	Sch 40 m ³ /m	Sch 60 m ³ /m	Sch 80 m ³ /m	Sch 100 m ³ /m	Sch 120 m ³ /m	Sch 140 m ³ /m	Sch 160 m ³ /m
1	5.574e-4		4.639e-4				3.366e-4
2	2.165e-3		1.905e-3				1.446e-3
3	4.770e-3		4.261e-3				3.489e-3
4	8.213e-3		7.419e-3		6.652e-3		5.987e-3
6	1.864e-2		1.682e-2		1.534e-2		1.365e-2
8	3.228e-2	3.093e-2	2.946e-2	2.804e-2	2.619e-2	2.484e-2	2.352e-2
10	5.088e-2	4.817e-2	4.635e-2	4.395e-2	4.163e-2	3.879e-2	3.661e-2
12	7.221e-2	6.849e-2	6.557e-2	6.203e-2	5.855e-2	5.586e-2	5.195e-2
14	8.728e-2	8.320e-2	7.917e-2	7.451e-2	7.072e-2	6.701e-2	6.343e-2
16	1.140e-1	1.093e-1	1.038e-1	9.844e-2	9.323e-2	8.728e-2	8.320e-2
18	1.443e-1	1.380e-1	1.318e-1	1.247e-1	1.178e-1	1.121e-1	1.056e-1
20	1.794e-1	1.711e-1	1.630e-1	1.541e-1	1.464e-1	1.379e-1	1.308e-1

Estimation of the volume of gas released from pressure vessels is somewhat more complicated. For simplicity, pressure vessels may be considered to be cylindrical vessels with hemispherical or ellipsoidal end caps. The vessels may be oriented either horizontally or vertically and may contain liquids. As a simple approximation, the liquids contained in the pressure vessels can be considered to be inert. That is, they simply take up volume that would otherwise be occupied by

gas. In reality, when the blowdown occurs, some solution gas would be released from the liquid (especially if it is a hydrocarbon liquid).

There are essentially six cases that need to be considered:

- 5) a horizontal cylinder,
- 6) horizontally oriented hemispherical end caps,
- 7) horizontally oriented ellipsoidal end caps,
- 8) a vertical cylinder,
- 9) vertically oriented hemispherical end caps, and
- 10) vertically oriented ellipsoidal end caps.

In each case the cylinder and end caps may be filled to some level with liquid. The total volume of gas contained within the pressure vessel is the sum of the volumes of the appropriate cylindrical section and end caps. The following sections provide the necessary equations to estimate the total actual volume of gas (at the process temperature and pressure) in a vessel filled with liquid to an arbitrary level.

Horizontal Cylinder

The volume of gas contained in a horizontal cylindrical vessel partially filled with a liquid is given by:

$$V_C = L \left[\frac{p R^2}{2} - (h - R) \sqrt{2Rh - h^2} + R^2 \sin^{-1} \left(\frac{R - h}{R} \right) \right]$$

where:

- V_C = total volume occupied by gas (m^3) at the process temperature and pressure,
- L = length of the cylindrical section of the pressure vessel (m),
- R = internal radius of the pressure vessel (m),
 $\frac{D - 2t}{2}$,
- D = outside diameter of the pressure vessel (m),
- t = pressure vessel wall thickness (m),
- h = height of liquid in the vessel measured from the inside bottom surface (m), and
- $\sin^{-1}$ = inverse sin of an angle measured in radians.

Hemispherical End Caps – Horizontal Vessel

The volume of two hemispherical end caps containing liquid to an arbitrary level is:

$$V_E = \frac{\rho}{3} [4R^3 - h^2 (3R - h)]$$

Ellipsoidal End Caps – Horizontal Vessel

The volume of two ellipsoidal end caps containing liquid to an arbitrary level is:

$$V_E = \rho r \left[\frac{4}{3} R^2 - \frac{1}{R} \left(R h^2 - \frac{h^3}{3} \right) \right]$$

where:

$$\begin{aligned} R &= \text{internal radius of the major axis (m), and} \\ r &= \text{internal radius of the minor axis (m).} \end{aligned}$$

Vertical Cylinder

The volume of gas contained in a vertical cylindrical vessel partially filled with a liquid is calculated by:

$$V_C = \rho R^2 (L - h_1)$$

where:

$$\begin{aligned} h_1 &= 0 \text{ if } h < R \text{ or } r, \\ &= (h - R) \text{ for hemispherical end caps (m), and} \\ &= (h - r) \text{ for ellipsoidal end caps (m).} \end{aligned}$$

Hemispherical End Caps – Vertical Vessel

The volume of two hemispherical end caps containing liquid to an arbitrary level is:

$$V_E = \rho \left(\frac{4}{3} R^3 - h^2 R + \frac{h^3}{3} \right)$$

Ellipsoidal End Caps – Vertical Vessel

The volume of two ellipsoidal end caps containing liquid to an arbitrary level is:

$$V_E = \frac{4}{6} \rho R^2 (2r - h)$$

The total volume of gas released by blowing down the vessel to atmospheric pressure is then:

$$V_T = (V_C + V_E) \cdot \left(\frac{T_o}{P_o} \right) \cdot \left(\frac{P_i}{z_i \cdot T_i} - \frac{P_f}{z_f \cdot T_f} \right)$$

where:

- V_T = total volume of gas released at standard conditions of 15°C and 101.325 kPa (m³),
- z = compressibility factor for the gas,
- P = process pressure (kPa),
- P_o = standard pressure = 101.325 kPa,
- T_o = standard temperature = 15°C,
- T = process temperature (°C),
- i = refers to initial pressure and temperature conditions, and
- f = refers to final pressure and temperature conditions.

The compressibility factor accounts for the deviation from ideal behavior of a real gas. If this is not known it may be estimated using the correlation:

$$z = a + bP + cT + dP^2 + eT^2 + fPT$$

where:

- P = initial process pressure (kPa), and
- T = initial process temperature (°C).

The coefficients for the correlation are presented in Table 3-9. The correlation is simply a least squares fit to a series of compressibility factors calculated using the Peng-Robinson equation of state for a typical gas plant inlet gas composition.

Table 3-9 Correlation Coefficients for Estimating Compressibility Factors for Typical Gas Plant Inlet Gas.

Correlation Coefficient	Value
a	9.9187E-01
b	-3.3501E-05
c	6.9652E-04
d	6.3134E-10
e	-8.6023E-06
f	2.3290E-07

FlareCheck, a software program produced by Kenonics, provides a simple method of performing the calculations described above. FlareCheck allows the user to

enter each pipe segment and pressure vessel as individually tagged items and to calculate the standard volume of gas released by each item.

Example Calculation

The following equipment is blown down to an atmospheric pressure of 100 kPa:

- 1) 12 m of 6" schedule 40 pipe at 2000 kPag and 30°C,
 - 2) 10 m of 8" schedule 60 pipe at 4000 kPag and 20°C, and
 - 3) A horizontal pressure vessel with hemispherical end caps. The vessel is 1.4 m in diameter, 2.5 m long, and has a wall thickness of 20 mm. The initial temperature and pressure are 4000 kPag and 20°C. The vessel contains 0.5 m of liquid.
- 1) 6" schedule 40 pipe

From Table 4.

$$V_A = 12 \text{ m} \times 1.864\text{E-}02 = 0.2237 \text{ m}^3$$

Initial conditions, $P_i = 2100 \text{ kPa}$ and $T_i = 30^\circ\text{C}$ the compressibility correlation gives:

$$z_i = 0.9521$$

Final conditions, $P_f = 100 \text{ kPa}$ and $T_f = 30^\circ\text{C}$ the compressibility correlation gives:

$$z_f = 1.0024$$

$$V_{STP} = 0.2237 \left(\frac{288.15}{101.325} \right) \left(\frac{2100}{0.9521 \cdot 303.15} - \frac{100}{1.0024 \cdot 303.15} \right) = 4.419 \text{ m}^3$$

- 2) 8" schedule 60 pipe

From Table 5.

$$V_A = 10 \text{ m} \times 3.093\text{E-}02 = 0.3093 \text{ m}^3$$

Initial conditions, $P_i = 4100 \text{ kPa}$ and $T_i = 20^\circ\text{C}$ the compressibility correlation gives:

$$z_i = 0.8947$$

Final conditions, $P_f = 100 \text{ kPa}$ and $T_f = 20^\circ\text{C}$ the compressibility correlation gives:

$$z_f = 0.9994$$

$$V_{STP} = 0.3093 \left(\frac{288.15}{101.325} \right) \left(\frac{4100}{0.8947 \cdot 293.15} - \frac{100}{0.9994 \cdot 293.15} \right) = 13.450 \text{ m}^3$$

3) 3. Pressure Vessel

$$R = \frac{D - 2t}{2} = \frac{1.4 - 2 \cdot (0.020)}{2} = 0.68 \text{ m}$$

$$V_C = 2.5 \left[\frac{p (0.68^2)}{2} - (0.5 - 0.68) \sqrt{2(0.68)(0.5) - 0.5^2} + 0.68^2 \sin^{-1} \left(\frac{0.68 - 0.5}{0.68} \right) \right]$$

$$V_C = 2.42 \text{ m}^3$$

$$V_E = \frac{p}{3} [4(0.68^3) - 0.5^2 (3(0.68) - 0.5)]$$

$$V_E = 0.91 \text{ m}^3$$

$$\text{Total Volume} = 3.33 \text{ m}^3$$

At STP

$$V_{STP} = 3.33 \left(\frac{288.15}{101.325} \right) \left(\frac{4100}{0.8947 \cdot 293.15} - \frac{100}{0.9994 \cdot 293.15} \right) = 144.802 \text{ m}^3$$

Therefore, the total volume released from this blowdown event is:

$$V_T = 4.419 + 13.450 + 144.802 = 0.2 \times 10^3 \text{ m}^3$$

Appendix A Glossary

Associated Gas

A certain quantity of natural gas often accompanies the production of oil from an underground reservoir. This free gas is usually separated from the oil stream at a battery and may be vented, flared or conserved. EUB production accounting rules require that the quantity of gas be metered at the separator and reported on the appropriate production accounting forms.

Casing Gas

Gas released from the casing of some heavy oil wells to maintain reasonable flow potential from the well. Down-hole pressures are typically maintained at about 250 kPa by opening the vent valve on the casing. Casing gas may be vented to the atmosphere, collected and flared or incinerated or conserved and used as fuel or further processed.

Central Battery

A central battery is similar to a single-well battery except that it receives production from more than one well and is usually much larger. It is generally equipped with separation, metering, storage, loading, treatment, pumping, compression and flaring facilities. Often, it is manned continuously during the day.

Emulsion Treater

A process by which an oil-water emulsion is separated into its constituent phases (i.e., oil and water) primarily by the addition of heat. The reduction in pressure from the separator and the addition of heat tends to drive solution gas from the produced oil.

Evaporation Losses

Losses of stable (i.e., not boiling or flashing) hydrocarbon product from production storage tanks due to diurnal (i.e., daily) atmospheric temperature and pressure changes and liquid level changes within the tank.

Flared Emissions

Waste gas that is combusted as an open flame at the exit of a flare stack. The flame is maintained by the use of a pilot or electronic igniter. Flares have destruction efficiencies ranging from <70 percent to >98 percent depending on design, composition and heating value of the waste gas, exit velocities and local wind conditions.

Flashing Losses

Losses from hydrocarbon storage tanks resulting from directing a hydrocarbon liquid stream from a vessel, where it has been in contact with hydrocarbon gas at an elevated pressure, into an atmospheric storage tank. The solution gas absorbed in the oil quickly flashes/boils off resulting in increased emissions from the tank.

Gas Battery

The simplest type of gas production facility. It is usually equipped with separation, metering, dehydration and compression facilities.

Gas Boot

Production facilities equipped with a vapour recovery system on the storage tanks often have a gas boot as the final vessel prior to the storage tanks. The purpose of the gas boot is to reduce the pressure of the hydrocarbon liquid stream to as close to atmospheric as possible prior to entering the atmospheric tanks. Gas boots may be operated at temperatures and pressures in the region of 25°C and 25 kPag.

Gas Gathering System

A network of pipelines designed to transport gas from the field to a gas processing plant or to market. Gas gathering systems generally fall into one of three categories depending on the type of equipment installed for hydrate control: low pressure, heated or dehydrated.

Gas Processing Plant

A facility for extracting condensable hydrocarbons from natural gas, and for upgrading the quality of the gas to market specifications (i.e., removing contaminants such as H₂O, H₂S and CO₂). Some compression may also be required. Each facility may comprise a variety of treatment and extraction processes, and for each of these there is often a range of technologies that may be used.

Pressure-Relief Valves

Pressure relief or safety valves are used to protect process piping and vessels from being accidentally over-pressured. They are spring loaded so that they are fully closed when the upstream pressure is below the set point, and only open when the set point is exceeded. Relief valves open in proportion to the amount of overpressure to provide modulated venting. Safety valves pop to a full-open position on activation.

When relief or safety valves reseal after having been activated, they often leak because the original tight seat is not regained either due to damage of the seating surface or a build-up of foreign material on the seat plug. As a result, they are often responsible for fugitive emissions. Another problem develops if the operating pressure is too close to the set pressure, causing the valve to "simmer" or "pop" at the set pressure.

Gas that leaks from a pressure-relief valve may be detected at the end of the vent pipe (or horn). Additionally, there normally is a monitoring port located on the bottom of the horn near the valve.

Satellite Battery

An intermediate production facility located between a group of wells and a central battery. There are two separators and associated sets of metering equipment at each satellite battery. One train is used to compile proration data on the commingled effluent from all but one of the group of wells. The other is used to test the remaining well. A regular test is performed on each of the wells.

Single-Well Battery

The simplest type of oil battery. It is equipped with separation, metering, storage, loading and flaring facilities. Depending on the amount and nature of the production, it may also comprise selected treatment, pumping and compression facilities.

Solution Gas

Refers to gas absorbed in a liquid hydrocarbon stream at an elevated pressure. When the pressure is reduced as a result of processing the hydrocarbons, a new thermodynamic equilibrium is achieved and some solution gas may be desorbed from the liquid stream.

Standard Reference Conditions

Most equipment manufacturers reference flow, concentration and equipment performance data at ISO standard conditions of 15°C, 101.325 kPa, sea level and 0.0 percent relative humidity.

Total Hydrocarbons

All compounds containing at least one hydrogen atom and one carbon atom, with the exception of carbonates and bicarbonates.

Total Organic Compounds (TOC)

TOC comprises all VOCs plus all non-reactive organic compounds (i.e., methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons).

Vented Emissions

Vented emissions are releases to the atmosphere by design or operational practice, and may occur on either a continuous or intermittent basis. The most common causes or sources of these emissions are gas operated devices that use natural gas as the supply medium (e.g., compressor start motors, chemical injection and odourization pumps, instrument control loops, valve actuators, and some types of glycol circulation pumps), equipment blowdowns and purging activities, and venting of still-column off-gas by glycol dehydrators.

Volatile Organic compounds (VOC)

Any compound of carbon, excluding carbon monoxide, and carbon dioxide, which participates in atmospheric chemical reactions. This excludes methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons.

Well

A surface facility that is used to produce oil and gas from a hydrocarbon reservoir. It consists of the wellhead and may or may not have metering facilities and some production equipment (e.g., pumpjack compressor, line heater, dehydrator, storage tank, etc).

Appendix B Acronyms

AOFP	-	Absolute Open Flow Potential
API	-	American Petroleum Institute
BTEX	-	Benzene, Toluene, Ethyl benzene and Xylene (mixed isomers)
CAPP	-	Canadian Association of Petroleum Producers
DEG	-	Diethylene Glycol
EC	-	Environment Canada
EPA	-	Environmental Protection Agency
EUB	-	Energy and Utilities Board (Alberta)
GOR	-	Gas-to-Oil Ratio
GRI	-	Gas Research Institute (now GTI)
GTI	-	Gas Technology International
NPS	-	Nominal Pipe Size
ppb	-	Parts Per Billion
ppm	-	Parts Per Million
PRV	-	Pressure Relief Valve
PSV	-	Pressure Safety Valve
STP	-	Standard Temperature and Pressure (i.e., 15°C and 101.325 kPa)
TEG	-	Triethylene Glycol
THC	-	Total Hydrocarbons
TOC	-	Total Organic Compounds
U.S. EPA	-	U.S. Environmental Protection Agency
VOC	-	Volatile Organic Compound

Appendix C Conversion Factors

USEFUL CONVERSION FACTORS		
Physical Quantity	SI to English Conversion	English to SI Conversion
Length	1 m = 3.2808 ft 1 km = 0.6213712 mi	1 ft = 0.3048 m 1 mi = 1.609344 km
Area	1 m ² = 10.7639 ft ²	1 ft ² = 0.092903 m ²
Volume	1 m ³ = 35.3147 ft ³ 1 m ³ = 6.28981 bbl 1 L = 0.2641720 U.S. gal	1 ft ³ = 0.028317 m ³ 1 bbl = 0.158987 m ³ 1 U.S. gal = 3.785412 L
Velocity	1 m/s = 3.2808 ft/s 1 km/h = 0.6213712 mph	1 ft/s = 0.3048 m/s 1 mph = 1.609344 km/h
Density	1 kg/m ³ = 0.06243 lbm/ft ³	1 lbm/ft ³ = 16.018 kg/m ³
Force	1 N = 0.2248 lb _f	1 lb _f = 4.4482 N
Mass	1 kg = 2.20462 lb _m	1 lb _m = 0.45359737 kg
Pressure	1 kPa = 0.145038 psi 1 kPa = 4.01474" WC	1 psi = 6.89476 kPa 1" WC = 0.249082 kPa
Energy	1 kJ = 0.94783 Btu	1 Btu = 1.05504 kJ
Power	1 W = 3.41219 Btu/h 1 kW = 1.3410 hp	1 Btu/h = 0.29307 W 1 hp = 0.7457 kW
Heat Flux/Unit Area	1 W/m ² = 0.3170 Btu/h·ft ²	1 Btu/h·ft ² = 3.1546 W/m ²
Heat Flux/Unit Length	1 W/m = 1.04003 Btu/h·ft	1 Btu/h·ft = 0.9615 W/m
Heat Generation/Unit Volume	1 W/m ³ = 0.096623 Btu/h·ft ³	1 Btu/h·ft ³ = 10.35 W/m ³
Energy/Unit Mass	1 kJ/kg = 0.4299 Btu/lb _m	1 Btu/lb _m = 2.326 kJ/kg
Specific Heat	1 kJ/kg·°C = 0.23884 Btu/lb _m ·°F	1 Btu/lb _m ·°F = 4.1869 kJ/kg·°C
Thermal Conductivity	1 W/m·°C = 0.5778 Btu/h·ft·°F	1 Btu/h·ft·°F = 1.7307 W/m·°C
Convective Heat Transfer Coefficient	1 W/m ² ·°C = 0.1761 Btu/h·ft ² ·°F	1 Btu/h·ft ² ·°F = 5.6782 W/m ² ·°C

Note: 1 bbl equals 42 U.S. gallons.

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