TECHNICAL REPORT

Guidelines on Flare and Vent Measurement

PREPARED FOR

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EXECUTIVE SUMMARY

This guideline presents recommendations on best industry practice for measuring flare and vent volumes. Both continuous and intermittent systems are addressed. Improving the reliability, completeness and accuracy of flare and vent data is expected to promote flare reduction activities and investments. Furthermore, data improvements at the country level will support efforts of the Global Gas Flare Reduction (GGFR) Partnership to enhance the quality of data on flare and vent volumes at the global level.

Accurate measuring of flare and vent volumes is vital for effective, consistent and fair enforcement of flaring regulations. Reliable data also informs operators of the potential economic losses for the resource wastage.

Background

Flare and vent systems are widely used in the oil and natural gas industry to dispose of waste volumes of hydrocarbon gases and vapours. Continuous applications most commonly occur at oil production facilities where associated gas production in excess of onsite energy needs is uneconomical to conserve (e.g., because there is a lack of economic access to a local market or gas gathering system), and there is insufficient economic benefit to re-injecting the gas to maintain reservoir pressures. At natural gas facilities, continuous flaring or venting may be associated with the disposal of waste streams (e.g., acid gas from the gas sweetening process and still-column overheads from glycol dehydrators) and gaseous by-product streams that are uneconomical to conserve (e.g., instrument vent gas and sometimes stabilizer overheads and process flash gas).

Intermittent venting and flaring is associated with a wide range of activities including well testing and servicing, manual or instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and removal of hydrates from pipelines.

Current global flaring and venting of associated gas is estimated by the GGFR Partnership at 150 to 170 billion cubic meters per year. This is a significant waste of a valuable non-renewable energy resource and harms the environment through greenhouse gas (GHG) and other emissions. Flaring and venting measurement has been identified as an important cross-cutting issue where the GGFR could make a meaningful contribution to the global flaring reduction agenda by collecting and disseminating a best practice.

Until recently, associated gas has been often considered as a by-product to be disposed of for lack of commercial opportunities for its use or for safety considerations. As a result, neither industry nor supervising or regulatory bodies elevated the issue of flare/vent measurement to the level comparable to the industry practice in measurement of non-associated gas or oil. This in turn led to missed opportunities in associated gas utilization since ‘what gets measured, gets managed’ and vice versa.

Target Audience

There are three audiences that will directly benefit from the presented guidelines:

- Oil companies: by applying the guidelines they will improve the quality of data on their flare/vent volumes and thus, will be better equipped to properly evaluate gas utilization options. This, in turn, will increase opportunities to monetize associated gas.

- Regulators and energy/environmental bodies: reliable data on flare/vent volumes is crucial while monitoring flaring/venting and applying flaring/environmental regulations. Given that continuous metering of flared/vented volumes is not always feasible and/or justified, the guidelines should also assist regulators in designing sensible flare measurement requirements.

- Developers of carbon credit projects: data accuracy, reliability, and transparency are necessary prerequisites for carbon finance investments and transactions.

Overview of the Guidelines

The presented guidelines cover measurement options for both continuous and intermittent flares/vents. A listing of the main measurement options and a qualitative rating of these against a range of important selection criteria is provided in Table I. The best choice will depend on the specific circumstances and application requirements. For existing flares it may be appropriate to first perform a manual measurement or estimation of the flow rate to assess the need for, and requirements of, a permanent flow measurement system. For new applications, this approach may prove more expensive as installing equipment at a later stage is normally costly.

In most cases involving solution gas venting or flaring the gas will be wet and potentially dirty. At facilities where gas processing is being performed or the produced gas is being supplied by a variety of sources having differing compositions, the measurement technology will either need to be composition independent or easily corrected for variations in the gas composition. In the latter case, regular gas analyses may need to be performed. The cost of installing a flow meter, the ability to do so without requiring a facility shutdown and the ongoing calibration requirements will also be important considerations. Historically, the cost of running electric power and communications wiring to an instrument was a major consideration; however, the use of solar panels and wireless connections to data acquisition systems may now be considered in these situations. Measurement technologies that do not require electric power and only provide local readout are also an option.

Ultrasonic flow meters are the preferred choice in most permanent vent or flare applications involving wet and dirty gas, provided the liquid content does not exceed about 0.5 percent by volume. Ultrasonic flow meters offer excellent rangeability, good accuracy, do not require frequent calibration, are not composition dependent and do not pose a significant flow restriction. If greater amounts of liquids are anticipated then a liquids knockout system should be installed immediately upstream of the flow meter. Orifice and venturi meters may be considered instead of ultrasonic flow meters in applications involving stable wet or dirty flows. They are more tolerant of the presence of dirt and/or liquids, but have much less rangeability and need frequent calibration especially if the gas composition is variable.

In applications where spot checks are proposed, the preferred choice is to employ a mobile (or portable) flow measurement system similar to a permanent solution that can be easily and safely connected to, and disconnected from, the vent or flare system. Alternatively, adequate ports should be provided on the flare or vent system to allow periodic tracer tests or flow measurements using a velocity probe. Methodologies for performing both types of flow tests are presented and relevant safety considerations are noted. A micro-tip vane anemometer is a reasonable choice for performing velocity traverses but must be kept clean. A thermal anemometer or a Thermal Mass Flowmeter offers much greater rangeability but it is not suitable for use in wet streams, it is highly composition dependent and convenient corrections for these dependencies generally are not available.

Three different methods for estimating flow rates are provided, namely: use of gas-to-oil ratios (GORs), mass balances and process simulations. The limitations and potential accuracies of these methods, as well as recommendations for their use, are provided. These estimation methods are perhaps the most common ways currently utilized by the oil industry to assess flare/vent volumes in the absence of continuous metering. Where conditions are relatively stable or well behaved, the required input activity data and factors are accurately known, and high accuracy is not required, these estimation methods can offer an acceptable alternative to continuous flow measurements. Still, it is the user's responsibility to be able to demonstrate the actual accuracy and repeatability of the results and comply with any relevant local production accounting requirements. In the absence of any such requirements, it is recommended that GOR values be developed based on at least 24-hour tests and that these results be updated annually for stable or well behaved wells that are able to meet the desired accuracy and repeatability targets (e.g., with ±15 percent or better). Otherwise, the GOR values should be updated at such greater frequencies as may be required to achieve these targets. GOR values should also be re-evaluated whenever noteworthy changes in production or pumping rates occur (e.g., greater than ±25 percent of value) since this may impact the stability and magnitude of the well's GOR.

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Table I. Listing and qualitative rating of options for measuring flare and vent gas volumes.											
Flow Meter		**Tolerant of Wet or Dirty Gas**	**Calibration Frequency**	**Composition Dependent***	**Flow Capacity**	**Rangeability**	**Accuracy**	**Straight Pipe Requirements**	**Shutdown Required To Install**	**Installed Costs**	**Electric Power Required**
Category	**Type**										
Inline	Venturi Tube	High	High	Yes	High	Low	High	High	Yes	High	No
	Orifice Plate	High	High	Yes	High	Low	High	High	Yes	High	No
	Bellows (or Diaphragm)	None	Low	No	Low	Moderate	Very High	None	Yes	Moderate	No
	Turbine	None	Low	No	Moderate	Moderate	Very High	Moderate	Yes	High	No
	Vortex Shedding	Moderate	Low	No	Moderate	Moderate	High	High	Yes	High	Yes
	Ultrasonic Flow Meter	Moderate	Low	No	High	High	High	High	Yes	High	Yes
	Optical	Moderate	Low	No	High	High	High	High	Yes	High	Yes
Insertion	Thermal Anemometer	None	Low	Yes	High	High	Moderate	Moderate	No	Low	Yes
	Rotameter	Low	Low	Yes	Low	Low	Low to Moderate	None	No	Low	No
	Micro-tip Vane Anemometers	Low	Moderate	No	Moderate	Low	Moderate	Moderate	No	Low	Yes
	Pitot Tube	Low	Low	Yes	High	Very Low	Moderate	Moderate	No	Low	No
	Optical	Moderate	Low	No	High	High	High	High	No	High	Yes

* Applies only to measurement of volume flow rates. To measure mass flow rates, gas density data is required for all meters other than the Thermal Anemometer which responds to mass flow directly.

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API	-	American Petroleum Institute
BERR	-	Department for Business, Enterprise and Regulatory Reform (UK)
BMP	-	Best Management Practice
CAPP	-	Canadian Association of Petroleum Producers
CDM	-	Clean Development Mechanism
CER	-	Certified Emission Reduction
DTI	-	Department of Trade and Industry (UK) (replaced by BERR)
EPA	-	Environmental Protection Agency
EUB	-	Energy and Utilities Board (Alberta)
GHG	-	Greenhouse Gas
GOR	-	Gas-to-Oil Ratio
JI	-	Joint Implementation
NPS	-	Nominal Pipe Size (Inches)
RP	-	Recommended Practice
SCADA	-	Supervisory Control and Data Acquisition
UNFCCC	-	United Nations Framework Convention on Climate Change

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1 INTRODUCTION

This document provides guidance on quantifying flare and vent rates at oil and natural gas facilities. While the focus is primarily on continuous vent and flare systems, guidance is also provided for intermittent systems.

Section 2 presents related information of interest, including a description of the target sources of venting and flaring, information on relevant studies delineating alternatives to venting and flaring, design and operating practices and international regulations.

Section 3 presents key constraints and considerations to be addressed when selecting a continuous flow measurement system for both new and existing flare and vent systems. Recommendations on record keeping and flow verification are also provided.

Section 4 provides a review of measurement techniques that may be used to perform periodic flow tests on vent and flare systems.

Section 5 provides a review of selected estimation techniques which are sometimes used to estimate vent and flare rates.

Appendix I provides a comparison of the main gas flow measurement technologies currently available, and potentially applicable to vent and flare applications.

2 BACKGROUND

Flare and vent systems exist in essentially all segments of the oil and gas industry and are used for two basic types of waste gas disposal: intermittent and continuous. Intermittent applications may include the disposal of waste volumes from emergency pressure relief episodes, operator initiated or instrumented depressurization events (e.g., depressurization of process equipment for inspection or maintenance purposes, or depressurization of sections of piping for tie-ins or repairs), plant or system upsets, well servicing and testing, pigging events, and routine blowdown of instruments, drip pots and scrubbers. Continuous applications may include disposal of associated gas, treater off-gas and tank vapors at oil production facilities where gas conservation is uneconomical or until such economics can be evaluated, casing gas at heavy oil wells, process waste or byproduct streams that either have little or no value or are uneconomical to recover (e.g., vent gas from glycol dehydrators, acid gas from gas sweetening units, and sometimes overheads from stabilizers and flash drums), and vent gas from gas-operated devices where natural gas is used as the supply medium (e.g., instrument control loops, chemical injection pumps, samplers, compressor start systems, etc.). Typically, waste gas volumes are flared if they pose an odor, health or safety concern, and otherwise are vented.

2.1 Alternatives to Venting and Flaring

It is preferable to utilize or conserve waste gas streams rather than to simply vent or flare them without benefit. Where utilization or conservation is not practicable, flaring is environmentally preferable to venting since this tends to reduce GHG, VOC and air toxic emissions.

Specific opportunities to utilize or conserve vent and flare gas include, but are not limited to, the following:

- Electric power generation for consumption onsite or within an industrial system.
- Cogeneration of steam and electricity for local applications.
- Re-injection of gas into the producing reservoir.
- Injection of gas into an aquifer
- Collection and delivery to a nearby gas-gathering system.
- Pooling of gas resources or clustering gas from several batteries into a single location to achieve volumes sufficient to justify conservation or utilization schemes.

2.2 Design and Operating Practices

Table 1 summarizes the key standards and practices that presently exist for the design and operation of vent and flare systems.

Table 1. Summary of standards and industry practices for the design and operation of vent and flare systems.			
Type	**Document Title**	**Author/Sponsoring Agency**	**Description**
Design	Standard 521/ISO 23251: Guide for Pressure-relieving and Depressuring Systems	API	This Standard applies to pressure-relieving and vapor depressuring systems intended for use primarily in oil refineries, although it is also applicable to petrochemical facilities, gas plants, liquefied natural gas (LNG) facilities, and oil and gas production facilities. The Standard specifies requirements and gives guidelines for examining the principal causes of overpressure; determining individual relieving rates; and selecting and designing disposal systems, including such component parts as piping, vessels, flares, and vent stacks. The information provided is designed to aid in the selection of the system that is most appropriate for the risks and circumstances involved in various installations.
Design	Standard 537: Flare Details for General Refinery and Petrochemical Service	API	This Standard is applicable to flares used in pressure relieving and vapor-depressuring systems used in general refinery and petrochemical services. The information provided is intended to aid in the design and selection of a flare system that is most appropriate for the risks and circumstances. Although this standard is primarily intended for new flares and facilities, it may be used as a guideline in the evaluation of existing facilities together with appropriate cost and risk assessment considerations. It is intended to supplement the practices set forth in API Std 521, *Guide for Pressure Relieving and Depressuring Systems*. It describes the mechanical design, operation and maintenance of three types of flares: Elevated Flares, Multi-burner Staged Flares, and Enclosed Flares.
Design & operating	Manual of Petroleum Measurement Standards Chapter 14 – Natural Gas Fluids Measurement Section 10 – Measurement of Flow to Flares July, 2007	API	This Standard is specific to measurement of flows to flares and addesses: • Application considerations • Selection criteria • Installation considerations • Limitations of technologies • Calibration • Operation • Uncertainty and errors
Interpretation	HM 58 Guidelines for Determination of Flare Quantities from Upstream Oil and Gas Facilities May, 2008	Energy Institute, London, UK	This document addresses the application of flare measurement systems to ensure they conform to the requirements of the EU Emissions Trading Scheme for carbon emissions. It addresses operational considerations, methodologies to determine flare quantities, metering technologies, flare gas composition, installation issues, uncertainty in measurements and calibration requirements.
Operating	Best Management Practices for Facility Flare Reduction	CAPP	This Best Management Practice (BMP) document provides design and operating staff with a recommended approach to identify routine and non-routine flare sources and quantities, and assesses the opportunity for reduction of flare volumes and frequency at their operated facilities. The guidance provided in this BMP can also apply to routine and non-routine venting.
Operating	Best Management Practice for Reducing Fuel Consumption in Flaring Operations (Draft)	CAPP	This BMP promotes more efficient use of the fuel gas consumed in flaring operations in the upstream oil and gas sector by: This BMP: • Outlining the basic improvement strategy for reducing fuel consumption in flaring. • Identifying sources of fuel consumption in flaring operation. • Discussing metering for waste gas and fuel consumption to support the identification and evaluation of reduction opportunities. • Identifying and discusses various reduction opportunities that are available. • Outlining suggestions for recordkeeping to support a reduction program.
Operating	Guide for Estimation of Flaring and Venting Volumes	CAPP	This document assists oil and gas production companies in quantifying volumes of natural gas vented and flared at typical upstream petroleum facilities as required by EUB Guide 60. Methodologies are presented in the order of increasing sophistication and accuracy, though it is up to the Operator to pick the most appropriate approach given the magnitude of the volume being estimated.

2.3 International Regulatory Overview

A global overview of regulatory practices on gas flaring and venting, including relevant lessons and conclusions from international experience on how best to reduce flare and venting volumes, is presented in a report by the World Bank (2004). Norway, the United Kingdom (BERR Guidance Notes) and Alberta (ERCB Directive 60) are identified as having the most comprehensive regulations regarding flaring and venting.

The "best practice" regulatory regimes require that the amount of flared gas is continuously metered, although in some countries this is only required when the quantity of gas flared exceeds a certain threshold. All flare and vented gas must be metered in Norway, whereas the threshold for metering is 50 tons/day (70 000 m^3/d) in the UK and 800 m^3/day in Alberta.

Although aimed at the full range of production accounting metering applications, the following references are examples of existing measurement guidelines for oil and gas operators:

- ERCB Directive 17 – Measurement Requirements for Upstream Oil and Gas Operators.
- DTI (2003) – Guidance Notes for Petroleum Measurement.
- ERCB Directive 046 – Production Audit Handbook.

3 CONTINUOUS FLOW MEASUREMENT SYSTEMS

Flare and vent gas flow measurement is a challenging application. Most practical vent and flare gas applications at upstream oil and gas facilities require that the selected technology be tolerant of wet or dirty gas streams, easy to install without a shutdown at existing facilities, and that any composition dependencies be manageable. This greatly reduces the available options; although, some ideal or less demanding situations may still occur (e.g., measuring instrument vent gas and purge, pilot and flare enriching gas flows).

Historically, the main types of flow meter technologies used included differential-pressure, vortex-shedding, and insertion thermal anemometers. Their effectiveness; however, has been somewhat limited because of one or more of the following factors: limited rangeability, inability to follow unsteady flows, corrosion, intolerance of liquid carryover, and sensitivity to changes in gas composition. Ultrasonic technology, because of its superior performance in these aspects, has been the preferred choice in most new applications.

In advance of installing a meter, it is often useful to undertake a cost-benefit analysis before selecting a meter. This entails estimating the measurement accuracy that can be achieved with a variety of different meters and comparing these estimates with the required accuracy for reporting. In estimating the measurement accuracy of a meter it is necessary to evaluate the overall measuring system: i.e. the accuracy of the meter over the range of flow rates expected, the effect of the pipework, the accuracy of secondary data such as gas density and temperature etc. The cost-benefit analysis can then be used to assist in selection of a fit-for-purpose meter. In some cases, where high accuracy is not required, estimating rather than measuring the flowrate may be the most appropriate method to adopt.

3.1 Constraints and Considerations

The following sections delineate specific technical factors to consider in selecting a measurement technology for use on vent and flare systems.

3.1.1 Operating Range

In continuous or steady flow applications the meter should be sized to accommodate the anticipated range of flows. In intermittent flow applications (i.e., emergency relief and blowdown systems) there are two potential flow contributions: the transient flow during a venting or flaring event and the residual flow rate that may occur the rest of the time (i.e., due to any purge gas consumption and leakage into the vent or flare header). Ideally, a single flow meter may be selected which can accommodate the full range of these two flows; otherwise, separate methods or technologies should be considered for monitoring the two contributions. The minimum provisions for monitoring residual flows should comprise a flow switch or indicator which provides visual or other indication when excessive residual flow is occurring, and a suitable access port for manual measurement of the flow if further quantification is warranted.

3.1.2 Accuracy

The minimum required accuracy of the instrument will depend on the final use of the measurement data and applicable regulatory requirements. If the flow meter is used purely for a control function (e.g., to control the operation of a smokeless flare) what is important is the repeatability of the readings rather than their accuracy. For simple economic evaluations accuracies of within ±25 percent are often adequate. For day-to-day process monitoring and environmental reporting, accuracies within at least ±15 percent should be targeted. Some jurisdictions require accuracies within as low as ±5 percent for vent and flare meters. For example, in Texas, the Texas Commission of Environmental Quality (TCEQ, *www.tceq.state.tx.us*) Chapter 115 Regulation requires flare gas flow meters to be accurate to within ±5 percent at 30, 60, and 90 percent of the flow range. In California an updated Rule 1118 has set new state requirements for flare stack emissions. Accuracies within ±5 percent are required for flow velocities of 0.3 m/s (1 ft/s) and higher, along with accuracies of within ±20 percent for flow velocities of 0.03 to 0.3 m/s (0.1 to 1.0 ft/s).

It should be noted that the accuracy of flare or vent measurements depend on the accuracy of not just the selected meter, but also the accuracy in measurement of the factors such as pressure, temperature and gas composition that may affect the measurement.

The factors that can make these standards challenging to meet may include variability of the flow, dirty or wet gas streams, inability to meet the minimum required offsets from upstream and downstream flow disturbances, variability of the gas composition, safety concerns about introducing any flow restrictions or significant pressure drops, high maintenance requirements, and intolerance to vibrations or other environmental factors.

3.1.3 Installation Requirements

The flow meter should be installed at a point where it will measure the total final gas flow to the vent or flare and be located downstream of any liquids knock-out or disengagement drum. Additionally, operators are encourage to separately meter any purge gas or enriching gas contributions to the total flow, as well as pilot gas consumption to allow improved management of these flows. Otherwise, these flows often greatly exceed the minimum requirements and become a costly inefficiency or wastage of fuel gas.

Each meter manufacturer will have specific requirements regarding the minimum upstream and downstream distances between the meter and any flow disturbances (e.g., a vessel, valve, tee or bend in the piping).

Typically, the physical installation requirements will comprise either a flow-through device with an inlet and outlet connection that must be inserted in line, or an insertion device that simply requires an appropriately sized access port on the flare or vent line. In a new (or green-field) application neither type poses any particular challenges; however, on an existing system there are a number of important factors to consider. These may include the following:

- The vent or flare system will need to be taken out of service and purged to install an in-line flow meter which may require a complete facility shutdown. An insertion flow meter can potentially be installed with the flare or vent in service using a hot-tap procedure if an existing port is not available.
- The ideal location for installing the meter may not be where there is convenient access to electric power or a communication line to a data acquisition system if either of these is required. The provision of such services can add significantly to the installation cost, especially if the distances involved are large or upgrades to the data acquisition system are required. In evaluating the need for upgrades to a data acquisition system, check that input slots and cards exist in the controller. The use of solar power and telemetric systems may be a viable option where local power and access to the data acquisition system are not available or practicable to provide. It should be noted that not all flow meters require electric power and local read-out only may be quite acceptable where the flow readings are totalized locally.
- Insertion flow meters should be mounted on the top of the pipe through glanded valves and occupy little flow area to avoid introducing excessive flow resistance or a potential for plugging of the line due to progressive fouling.
- Meters that comprise a small orifice (such as a Pitot) should be avoided as they will almost certainly plug up unless they feature an integral clean purge cycle.
- Depending on the location, the instrument may need to be rated for use in a hazardous location.
- If the instrument will be located outside it will need to be weather resistant. Additionally, if it will be exposed to extreme ambient temperatures it may need to be equipped with temperature control elements.
- If the meter cannot be calibrated in place under live process conditions, special provisions may be needed to be able to remove or take the meter offline without having to shutdown the flare or vent.
- If a thermowell for a temperature transmitter and a tap for a pressure transmitter are needed as part of the flow meter system, these should be installed on top of the header and downstream of the flow sensor. Consider piping the pressure and temperature readouts down to ground-level for ease of viewing.

3.1.4 Maintenance and Calibration Requirements

All flow meters are susceptible to deteriorated performance with time and use; although, some are more robust than others. Most flare and vent systems, because the gas normally has not been treated or cleaned, pose demanding service applications where there is a potential for condensation, fouling (e.g., due to the build-up of paraffin wax and asphaltine deposits), corrosion (e.g., due to the presence of H_2S, moisture, or some air) and possibly abrasion (e.g., due to the presence of debris, dust and corrosion products in the piping and high flow velocities). Pitot tubes, vane anemometers and other meters that are particularly susceptible to fouling should be avoided in these situations.

The manufacturer’s maintenance and calibration requirements should be followed to keep the meter in proper working order. Additionally, there may also be specific regulatory requirements that apply. These requirements may specify the minimum calibration frequency, requirements for maintaining calibration records and the qualifications of the person performing the calibrations.

3.1.5 Composition Monitoring

Most types of flow meters are composition dependent which means their readings are affected by any changes in the composition of the metered fluid and, if the meter has been factory calibrated, any differences between the process fluid and the reference fluid. Not all meters that are composition dependent have a practical method to correct for compositional effects once the flow meter has been installed, which may preclude their use in typical flare and vent applications involving natural gas mixtures (e.g., thermal anemometers).

Where composition corrections are practical to perform, the required type and frequency of composition monitoring will be determined by the degree of the compositional dependency, the variability of the fluid composition, and the desired accuracy of the flow measurements. Additionally, even where there is no compositional dependency, there still may be a need to monitor the fluid composition; for example, to allow a measured volumetric flow to be converted to a mass or energy basis (or vice versa), determine the heating value of the gas for compliance with applicable flaring regulations, to evaluate emissions of specific pollutants of concern such as hydrogen sulphide and sulphur dioxide, or to determine the carbon or greenhouse gas content for greenhouse gas reporting.

There are two primary options for composition monitoring: (1) sampling and subsequent laboratory analysis, or (2) the use of continuous analyzers. These two options are discussed in the subsections below. The preferred choice will depend on the required frequency of the composition monitoring which, in the absence of any relevant regulations, should be determined based on an engineering review of the application specifics with the aim of ensuring the desired flow and emissions accuracy objectives are achieved. At a minimum, details of the engineering review should be documented and maintained on file for reference by facility personnel in the event conditions or circumstances change. Notwithstanding this, the minimum monitoring frequency should be at least once per year.

Most jurisdictions do not establish any regulatory requirements for composition monitoring on vent or flare systems, and typically, where requirements are imposed, this would be done on a case-by-case basis as a condition of the facility’s final operating approval.

3.1.5.1 Sampling and Laboratory Analysis

Manual sampling or sampling using an autosampler with subsequent laboratory analysis is the normal approach used to determine the composition of a vent or flare gas. It is the least-cost solution for low monitoring frequencies, and requires no capital investment beyond a suitable sampling port at a location safely away from any areas of high thermal radiation (i.e., from the flare) and any other local hazards, and possibly the cost of an autosampler. Manual sampling or sampling using an autosampler eliminates the need for a complex sample conditioning train such as those required for continuous analyzers. It should be noted that measurement using either an autosampler or a continuous analyzer is not easy to perform as significant fluctuations in pressure, temperature, flow-rate and compositional variations in the gas flow may often occur. Complex sample receiving equipment might be needed to cope with such situations.

3.1.5.2 Continuous Analyzers

Continuous analyzers are widely used to monitor gas composition for process streams at gas processing plants, refineries and petrochemical facilities; however, these are usually used on relatively clean and predictable product streams. Continuous analyzers are not often used to monitor vent and flare gas streams at upstream oil and gas facilities as these streams can include water, oil, rust and other particles, a very wide range of organic compounds, and high sulfur levels. Therefore, depending on the quality of the gas stream and the requirements of the analyzer, the samples may need to be carefully conditioned to remove water and particles. Use of continuous analyzers may therefore require design and installation of a sample conditioning train and these sample trains may require more maintenance than those in more conventional service.

3.1.6 Temperature and Pressure Corrections

The flow meter will need temperature and pressure compensation features to correct the measured flow to standard conditions (101.325 kPa and 15°C) or normal conditions (101.325 kPa and 0°C). Temperatures may range from -20°C to 80°C (-4°F to 176°F) for typical vent and flare systems and from -150°C to 100°C (-238°F to 212°F) for liquefied natural gas (LNG) flares. Pressures typically range from 5 to 15 kPa (0.7 to 2.2 psig) in normal operation, and during pressure relief events, only up to the design pressure of the knock-out drum at downstream locations which is often only 170 kPag (25 psig).

Ultrasonic flow meters are perhaps the least sensitive (in terms of accuracy) to large temperature and pressure variations due to the speed of the measurements (i.e., on a millisecond time scale) and the absence of any significant non-linear temperature or pressure corrections in the applied measurement principle. Flow meters that would be most sensitive to temperature and pressure fluctuations would be orifice and venturi meters, velocity probes and positive displacement meters.

3.1.7 Multi-phase Capabilities

Normal practice, if there is a potential for liquids in the system, is to install a liquids knock-out or disengaging drum and measure the gas flow rate leaving the drum. If the gas stream contains high concentrations of condensable hydrocarbons (as is the case for vapors from crude oil storage tanks and treaters), the gas flow meter should be installed as close as possible to the knock-out drum and consideration should be given to insulating and heat tracing the line.

Even with the above precautions, the selected flow meter should be able to operate reliably in the presence of some condensation and fouling. Typically, transit time ultrasonic flow meters and orifice or venture meters are most suited to these applications; although, for low flow rates, turbine meters may also be an option.

3.2 Monitoring Records

To comply with typical regulatory requirements, monitoring records should be kept for at least 5 years. These records should comprise the flow measurement data, hours the monitor is in operation, and all servicing and calibration records. Periods of missed monitoring should be limited to 15 consecutive days and no more than 30 days total per calendar year.

During periods when monitors are out of service, flows should be calculated and compositions should be determined by sampling. Monitors should be maintained and calibrated in accordance with the manufacturer’s requirements. Electronic data loggers used to record data should be capable of one-minute averages and should record flow data as one-minute averages. Continuous composition analyzers do not produce one-minute averages, as the cycle for such an analyzer may take 15 minutes or more.

The following information should be documented for each flow meter: type, manufacturer, serial and model number, calibration date, meter factor, method of temperature and pressure compensation, operating limits, accuracy, whether it has a by-pass and servicing requirements and records.

3.3 Flow Verification

Where verifiable flaring or venting rates are desired, the systems should be designed or modified to accommodate secondary flow measurements (see Section 4) to allow an independent check of the primary flow meter(s) while in active service. This generally means providing one or two spare ports on the flare header, depending on the test method to be accommodated. One port should be 1” NPS in size (25.4 mm in diameter) and fitted with full-port valve to allow it to accommodate an insertion probe. The port should be positioned on the top of the flare header at a location where the total flow can be safely measured and where it is 20 pipe diameters downstream and 5 pipe diameters upstream of any flow disturbances. The second port should be located at least 20 pipe diameters upstream of the first port at a point where there will be flow in the header. It would potentially be used to inject a tracer gas. If there is a significant difference between the data produced by the primary flow meter and the verification method, this should trigger further investigation to resolve these discrepancies.

An alternative option for flow verification, as measured by the primary meter, is process simulation (see section 5.3).

Meter manufacturers should always be consulted as they may be able to advise alternative, more easily undertaken, methods of meter verification.

4 FLOW TEST METHODS

The following sections delineate test methods that may be considered for making spot checks or determinations of flows in vent and flare headers (for example, where installation of a permanent monitoring system is not practicable, where preliminary flow information is sought, or as a secondary measurement for verification of a primary monitoring system). In these situations, the practical technologies and methodologies are those that do not require a shutdown to perform. Because of the limited duration of the tests, some methods that would not be suitable for use in continuous applications may be considered (i.e., fouling issues become less of a concern). Most of the presented options involve opening ports on the flare or vent header and potentially having personnel working in close proximity to the flare. Consequently, safe work procedures and field level risk assessments are need to ensure the work is done in a safe manner. The potential for worker exposure to excessive thermal radiation, toxic gas releases or high pressures (i.e., in the event of a pressure relief event) needs to be given particular consideration. Where applicable, it may be necessary to provide supplied breathing air and limit both how close and how far upstream from the vent or flare stack the measurement may be performed.

4.1 Insertion Flow Meters

These methods involve inserting a suitable intrinsically safe velocity probe through a valve and gland assembly on the top of the vent or flare pipe, and conducting a velocity traverse (i.e., measuring the flow velocity at various points across the pipe diameter). The velocity traverse should be conducted in accordance with local regulatory standards for measuring flows in ducts. In the absence of any such standards it is recommended that US EPA Method 1 be used for pipes greater than 12 NPS in size and Method 1A be used for smaller sized pipes.

The port should be located at least 20 pipe diameters downstream and 5 pipe diameters upstream of any flow disturbances at a location where the total flow can be measured. Potential options for the velocity probe include a thermal anemometer (subject to the constraints mentioned in Section 3.2.2), a Pitot or a micro-tip vane anemometer. All probes will need to be rated for use in a Class 1, Division 1 hazardous location and should be long enough to extend across the full pipe diameter. Where a suitable port is not available, consideration should be given to installing one during a shutdown or using a hot tapping technique.

A thermal anemometer or Thermal Mass Flowmeter offers the greatest sensitivity and flow range capability but cannot be used in wet gas applications. Pitot tubes, because of the 90° bend near their tip can be difficult to maneuver through the valve into the pipe, especially if there is a long nipple on the port or the port is too small in diameter. The micro-tip vane anemometer avoids any composition dependencies but will be most susceptible to fouling and may need to be cleaned between replicate measurements.

4.2 End-of-pipe Flow Measurements

The velocity traverses discussed in Section 4.1 may be performed at the open end of a vent system, provided safe access to this point is available and there is no potential for an unsafe condition to arise while the measurement is being performed (e.g., due to a sudden pressure relief episode or the presence of H_2S in the gas). Additionally, some types of in-line flow meters (e.g., diaphragm or turbine meters) may be connected directly to the end of the vent, or by using a piping or hose extension. This is subject to the same safety issues as for 'open-end' measurements. As well, it must be ensured that the meter will not introduce an excessive backpressure on the vent system and that the pressure limits of the meter are not exceeded. Bagging techniques may also be an option for low flow rates; this involves measuring the time to fill an impermeable bag of known volume which is used to capture the total flow from the vent.

4.3 Tracer Dilution Techniques

This method involves injecting a tracer gas at a known rate into the vent or flare header and analyzing samples of the gas taken from a suitable downstream location, both before and during the test, to determine background and test concentrations of the tracer compound. A mass balance may then be performed to determine the total gas flow needed at the sample point to produce the observed amount of tracer dilution.

The tracer can be injected at any convenient upstream location where there is at least partial flow in the header. The downstream location must be at a location where total vent or flare gas flow occurs and where the tracer has become fully mixed with the header gas (i.e., at least 20 pipe diameters downstream of the injection point). To obtain reliable data, full mixing of the tracer is essential. At least one sample should be taken before the start of the tracer injection for the background determination and triplicate samples should be taken during the test to allow flow variance to be determined. Sufficient time must be allowed after starting the tracer injection for the tracer gas to reach the downstream sample location. The selected tracer gas should be a stable or inert substance that can be detected at very low concentrations, non-hazardous and readily available at a reasonable price (e.g. sulphur hexafluoride, SF_6). While onsite analysis of the samples is preferable to allow early feedback on whether the test has been successful, off-site analysis by a reputable commercial laboratory is also acceptable.

4.4 Pulse velocity technique

This technique is usually performed using gaseous radioactive tracers. The use of this technique is fully described in BS 5857-2.4 1980, ISO 4053-1V:1978.

A sharp pulse of suitable gaseous radioactive tracer is injected into the flare gas line downstream of the flare gas knock out drum, and its passage recorded by two suitably spaced externally mounted detectors downstream of the injection point. The first detector needs to be sufficiently far from the injection point to ensure lateral mixing of the tracer. The second detector should be sufficiently downstream of the first detector such that the transit time between the detectors is greater than the mean spatial dispersion of the tracer at each of the detector positions to ensure that the detections do not overlap.

The transit time of the tracer between the two detectors is determined from the difference in times between the centre of gravity of the response curve at each detector. From the pipe diameter, detector spacing and the tracer transit time, the volume flowrate can be calculated.

The uncertainties in flowrate measurement are affected by a number of factors such as determination of the transit time, the physical separation of detectors and knowing the effective cross sectional area. These factors can be minimized by measuring the pipe wall thickness and ovality.

Whilst it is difficult to accurately estimate the uncertainties before performing such measurements, experience has shown typical uncertainty values of 3 to 4% under normal conditions and of 1% or better under ideal conditions.

5 ESTIMATION METHODS

5.1 Use of GOR Data

Relevant applications for this method are where oil production at a facility is measured but gas production is not. In these cases, it is reasonable to estimate vented and flared volumes using gas-to-oil ratio (GOR) data for the wells feeding the facility, provided these data are accurate, repeatable and applicable to the crude oil production rates at the time, and that accurate corrections are made for any onsite uses of the gas (e.g., fuel, supply medium for pneumatic devices, blanket gas). The overall objective should be to achieve a vented or flared volume estimate consistent with the accuracy targets presented in Section 3.1.2.

GOR values vary with the crude oil production rate, change with the extent of reservoir depletion and may become erratic at certain critical flow rates (e.g., due to slug flow conditions, reciprocating pumping actions, gas breakthrough in the reservoir, and other effects). Accordingly, the quality and applicability of the available GOR data needs to be established based on the trend data for at least a 24-hour continuous test conducted at the normal production rate. If the data are erratic or noteworthy transient effects are apparent, additional or longer tests may be needed to achieve reliable steady-state results. Supporting documentation on the GOR data should include the following:

- Description of the test apparatus used.
- Graphical summary of the oil and gas flow rates during the test period.
- Details on the types of flow meters used for both the oil and gas measurements.
- Meter calibration records.
- Criteria used to evaluate the measurement results and determine the success or failure of the test.

A GOR is determined by separating the well effluent into its constituent phases (e.g., oil, water and gas) and separately measuring the flow of each of these phases. The results are then corrected to account for any gas or water vapor that may remain in solution in the oil phase. The instantaneous measurement accuracies typically expected are with ±0.25 percent for liquid phases and within ±1 percent for gas. Turbine or Coriolis meters are most commonly used for the liquid phases.

The actual accuracy of a given GOR value when subsequently used to estimate gas production rates will depended on a number of factors including the variability of the flow during the test, the duration of the test, the applicability of those conditions to the current operating conditions and any changes in the well’s characteristics since the test was performed. Typically, if a 24-hour or longer test has been conducted, the test conditions are representative of the current operating conditions and the flow was stable during the test period and remains stable, the GOR may be expected to be accurate to within ±10 percent. If the flow conditions are cyclic or erratic, the determined GOR value may only be accurate to within ±50 percent. GOR values determined based on short duration tests (i.e., less than 24 hours long) involving unstable flow, substantially different flow conditions than current operations or where well characteristics have changed with time can easily be in error by ±400 percent or more.

The application of a GOR value to total oil production provides an estimate of total gas production. To determine total vented or flared gas, this value must be discounted to reflect all other fates of the gas (e.g., re-injected, fuel, conserved, storage tank flashing losses, process off-gas, etc). Namely, a mass balance must be performed as described in Section 5.2. Where GOR values are declining with time, which is often the case in the absence of any gas reinjection, there will be a tendency to overestimate gas production if the GOR data have aged. Although, trapped gas can eventually break through and cause occasional spikes in gas flows (primarily for older producing wells) resulting in an underestimate of gas production. If the GOR values are increasing with time, there will be a tendency to underestimate gas production.

5.2 Mass Balance

Total continuous venting or flaring at a facility may be estimated as the difference between the measured or calculated flow rate of all input and output gas and vapor streams less any quantifiable onsite uses and process shrinkage. This approach should only be used where the determined venting or flaring rate is large enough, relative to the absolute errors in the other data used in the calculation, to achieve the accuracy targets presented in Section 3.1.2.

One problem with these types of mass balances is that the accuracy of the flow measurements on the raw inlet streams may be much less than for the final output streams. This is partly because the raw inlet streams may be more technically challenging to measure (e.g., due to greater fouling potential and possibly variability in stream composition) and the fact financial accounting is normally done based on the readings from the final sales meters so their accuracy is more carefully maintained and monitored. Additionally, there may not be meters on all withdraws (e.g., fuel use may be estimated rather than measured).

Total intermittent venting or flaring at a facility may be estimated based on the number and type of contributing events, and a mass balance assessment of the amount of gas or vapor released per event for each type. For example, the amount of gas released from a blowdown or depressurization event can be estimated based on the internal volume of the vessels, piping and equipment being depressurized and their initial and final pressures and temperatures. Similarly, emissions from activities such as compressor starts can be estimated based the manufacture's data for the pneumatic starter. It is good practice to either program these calculations into the facility's control system, or prepare look-up charts and event tracking tables for use by the facility operators.

Where a mass balance approach is used to determine total flared volumes, there will be an inherent assumption that emissions due to fugitive equipment leaks, evaporation losses and any other activities or sources that may release natural gas and crude oil vapors directly to the atmosphere are negligible. Some of these contributions may be estimated using standard emissions inventory methods; however, these estimates will be highly inaccurate for individual or small numbers of sources.

The accuracy of a vented or flared volume determined using the mass balance approach is highly dependent on the magnitude of the volume relative to the total gas production and the accuracy of the available input and output flow measurements. At oil production facilities where most of the produced gas is vented or flared, the accuracy of the mass balance approach might be expected to be within ±15 to ±25 percent. If the determined vented or flared volume is less than the combined error in the input and output volumes, then the result will be meaningless.

5.3 Process Simulation

Process simulations allow a more disaggregated assessment of continuous emissions than a high-level mass balance approach (i.e., vented or flared contributions can be determined by individual process unit), but generally are not applicable to estimating intermittent vented or flared volumes. In addition to the measured flow rates of the primary input and output streams, process simulations require stream composition data and process temperatures and pressures. Commercial process simulators are typically able to predict vented or flared overhead streams from individual process units with accuracies of within ±5 to 10 percent for most oil and gas applications where the input data is accurately known. These simulations do not account for potential leakage into the vent or flare systems or any other unintended or undetected effects that may be occurring.

Process simulations are commonly used to verify flows measured by the primary meter.

6 REFERENCES CITED

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EUB. 2006. Directive 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting. pp. 102.

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7 GLOSSARY

Associated Gas -	hydrocarbon gas produced in association with oil and present as a gas at wellhead or inlet separator conditions.
Control Efficiency -	the extent to which targeted emissions from a given source are reduced by a specific control measure or control device (e.g., vapor recovery, vapor treatment, floating roofs, process optimization, etc.).
Combustion Efficiency -	the extent to which all reactive material in the feed has been completely oxidized.
Combustion System, Enclosed -	a combustion device featuring a chamber (e.g., a refractory lined tube) designed to retain flame heat for a minimum residence time and thereby promote post flame combustion.
Combustion System, Shielded -	a combustion device featuring a barrier designed to shield personnel and equipment from thermal radiation or to obstruct vision of the flame.
Flaring, Emergency -	occasional flaring of unprocessed or semi-processed gas due to temporary process upset conditions or emergency relief events.
Flaring, Routine -	flaring of regular waste gas volumes produced during normal startup, operating, shutdown and maintenance activities. This may include, but is not limited to, all continuous and intermittent waste gas volumes from process vents, and from routine depressurization and purging activities (for example, compressor start gas, treater off-gas, dehydrator off-gas, equipment blowdown, waste stock tank vapors, and waste associated gas).
Hot Tapping -	a technique used for welding on, and cutting holes through, pressurized vessels and piping using special equipment and procedures to ensure that the pressure and fluids are safely contained when access is made. Many companies have specific hot-tap procedures. Specific concern addressed by these procedures include: • Burn-though of the line while installing the nozzles and possible fire. • Malfunction of the hot-tapping machine preventing it from being removed and/or loss of the hot-tap coupon. • Communication of the hot tapping plan between those performing the work and the facility control room.

- Personal Protection Equipment (PPE) and firefighting response.

Oil Battery -	an arrangement of tanks or other surface equipment receiving effluent from one or more wells prior to delivery to market or other dispositions. A battery may include equipment and devices for separating and metering the well effluent into oil, gas and water.
Positive Displacement Meter -	a flow meter that measures the volume or flow rate of a moving fluid or gas by dividing the media into fixed, metered volumes. These devices consist of a chamber that obstructs the media flow and a rotating or reciprocating mechanism that allows the passage of fixed-volume amounts.
Purge Gas -	an inerting or enriching gas supplied to a process piping system and/or vessels to safely maintain conditions therein below the lower flammable limit or safely above the upper flammable limit, respectively. In a flare system, purge gas is used to prevent air infiltration (e.g., burnback at the flare tip), and to maintain conditions throughout the piping system safely outside the flammability envelope.
Solution Gas -	hydrocarbon gas originally in solution with (i.e., dissolved in) the produced oil at wellhead or inlet separator conditions, but released as a vapor when the oil is brought to stock-tank conditions. Solution gas includes treater off-gas, gas-boot off-gas, and stock-tank vapors, as applicable.
Staged Flaring -	a multi-burner flare system in which the number of available burners used is controlled to suit the actual flow rate.
Vapor Collection System -	a piping system (including any associated valves, blowers, fans, flow inductors and safeguarding features) used to collect gas/vapor from one or more sources and transport them to a vapor recovery or disposal unit.
Vapor Recovery Unit -	a system designed to conserve or utilize a waste-gas stream.
Vapor Disposal Unit -	an end-of-pipe device used to dispose and possibly treat waste gas/vapors (e.g., vent, flare, incinerator, carbon adsorption unit, etc.).

8 APPENDIX I - MEASUREMENT TECHNOLOGIES

A comparison of the flow measurement technologies that may be considered in vent and flare gas applications is presented in Table 2; the basic capabilities and limitations are indicated. The noted flow capacity, rangeability (i.e., ratio of the maximum to minimum applicable flow) and inaccuracy of each technology are <u>for ideal conditions</u> involving fully-developed flow of clean dry gas (i.e., to provide a standard basis for comparison.

Table 2. A comparison of gas flow measurement devices.

Type of Flow Meter	Type of Measurement	Applicable Pipe Diameter (D)	Flow Capacity and/or Rangeability	Straight Pipe Requirements	Net Pressure Loss	Inaccuracy	Composition Dependent [2]	Suited for Wet or Dirty Fluid	Other Restrictions
Venturi Tube	ΔP	5 to 120 cm (2 to 48 in)	10:1 flow rangeability[1].	6 to 20 D up 2 to 40 D down	10 to 20% of ΔP depending on β	± 1% to 2% of full scale.	Yes	Yes	Eliminate swirl and pulsations. Gas temperature dependent
Orifice Plate	ΔP	1.3 to 180 cm (1/2 to 72 in)	5:1 flow rangeability.	6 to 20 D up 2 to 40 D down	High relative to other ΔP meters	± 2% to 4% of full scale.	Yes	Yes	Eliminate swirl and pulsations. Gas temperature dependent
Bellows (or Diaphragm)	Volumetric		Maximum of 13, 130 and 283 m^3/h @ 34, 172 and 690 kPa (450, 4600 and 10,000 scf/h @ 10, 25 and 100 psig); Greater than 200:1 flow rangeability.	None	0.5 kPa (0.1 psi)	± 0.1% of flow rate.	No	No	Used for commercial and domestic gas service. A filter is normally installed immediately upstream of the meter to remove particulate.
Turbine	Volumetric	0.64 to 60 cm (1/4 to 24 in)	6,500 m^3/h (230,000 scf/h) 20:1 up to 100:1 flow rangeability for large meters operating at 9,700 kPa (1400 psig).	10 D up 5 D down	34 to 41 kPa (5 to 6 psig) @ 6.1 m/s (20 ft/s)	± 0.1% of flow rate.	No	Limited	Flow straightening vanes beneficial. Do not exceed maximum flow. Susceptible to fouling.
Vortex Shedding	Velocity	2.5 to 30 cm (1 to 12 in)	0.30 to 6.1 m/s (1 to 30 ft/s)	10 to 20D up 5 D down	34 to 41 kPa (5 to 6 psig) @ 6.1 m/s (20 ft/s)	± 2% of flow rate.	No	Limited	Flow straightening vanes beneficial. Susceptible to pulsation and vibration
Transit-time Ultrasonic	Velocity	>0.32 cm (>1/8 in)	0.03 to 100 m/s (0.1 to 328 ft/s). 2000:1 flow rangeability	10 to 30 D up 5 to 10 D down	None	± 2% to 5% of value.	No	Moderate	Elimination of swirl.
Optical	Velocity		0.03 to 100 m/s (0.1 to 328 ft/s). 2000:1 flow rangeability	10 to 30 D up 5 to 10 D down	None	± 2.5% to 7% of value.	No	Moderate	Elimination of swirl.

Table 2. A comparison of gas flow measurement devices.

Type of Flow Meter	Type of Measurement	Applicable Pipe Diameter (D)	Flow Capacity and/or Rangeability	Straight Pipe Requirements	Net Pressure Loss	Inaccuracy	Composition Dependent [2]	Suited for Wet or Dirty Fluid	Other Restrictions
Thermal Anemometer (Thermal Mass Flowmeter)	Velocity (mass)		1000:1 flow rangeability.	8 to 10 D up 3 D down	Very low	± 1% to 3% of flow rate.	Yes	No	Probe positioning critical. Highly fluid composition dependent for volume measurement. Gas temperature dependent Susceptible to fouling.
Rotameter	Velocity	1.3 to 10 cm (1/2 to 4 in.)	10:1 flow rangeability.	None	Low	± 1 to 2% of full scale.	Yes	No	Must be mounted vertically. Gas temperature dependent
Micro-tip Vane Anemometer	Velocity	5 to >91 cm (2 to >36 in)	10:1 flow rangeability.	8 to 10 D up 3 D down	Low	± 2% of flow rate.	No	Limited	Probe positioning critical. Susceptible to fouling. Gas temperature dependent
Pitot Tube	Velocity	5 to >183 cm (2 to >72 in)	3:1 flow rangeability.	8 to 10 D up 3 D down	Low	± 0.5 to 5% of full scale.	Yes	Limited	Critically positioned Probes. Highly fluid composition dependent. Susceptible to fouling. Minimum Reynolds number of 20,000 to 50,000.

Note: 1. The flow rangeability is the turndown ratio of the meter expressed as the ratio of the maximum flow to the minimum flow.
2. Applies only to measurement of flow rates. To measure mass flow rates, gas density data is required for all meters.

A key issue that also must always be addressed is the RISK OF BLOCKING THE FLARE OR VENT LINE. This risk is addressed in the design standard for flare systems (ISO 23251).

8.1 <u>Differential Pressure Meters</u>

Differential pressure meters (e.g., orifice meters, venturi meters and annubars) use the pressure drop created within a flow element to determine the flow rate of a fluid. This is determination is made using Bernoulli's Equation, which relates pressure decreases with increased flow velocity. A pressure sensor is installed at a fixed upstream location where the flow is unaffected by the presence of the flow element, and at a downstream location where the flow velocity has reached a maximum due to the restriction caused by the flow element (e.g., at the throat of the venturi or in the short jet region downstream of the orifice plate). The pressure difference between the two sensing points and information on the size of the flow element are used to calculate the gas flow rate. Density corrections are applied to the results based on the composition and absolute temperature and pressure of the fluid. The American Gas Association provides detailed procedures, AGA-3 (or API-2530/ISO-5167), for performing these calculations. Modern differential pressure meters feature an onboard flow computer for performing these calculations.

Overall, differential pressure meters offer a rugged design that can withstand harsh process conditions and tolerate the presence of some liquids. Their main disadvantages are their limited operating range and the flow resistance they introduce, which, for vent and flare gas measurements, tends to exclude them from use on pressure relief systems. Additionally, while they have no moving parts, maintenance can be intensive. Accuracy, under well-behaved conditions, ranges from within ±1 to ±5 percent of full scale. Compensation techniques can improve accuracy to within ±0.5 to ±1.5 percent of full scale.

Orifice and venturi meters are the most common style of differential pressure flow meter. They are inline flow meters and are the most widely used technology for measuring gas flows in upstream oil and gas production accounting applications. They can be used to measure fluid flow in pipes with diameters of approximately 1.3 to 180 cm (0.5 to 72 in.).

8.1.1 Orifice Meters

Orifice meters comprise a removable metallic orifice plate installed perpendicular to the flow. The size of the orifice is determined by the design flow conditions and is machined to tight tolerances. The meter features a changer which allows the orifice plate to be removed and inspected or replaced while the meter is in service so the operating range can be periodically changed if needed. The rangeability is less than 5:1, and accuracy, even under ideal conditions, is moderate at within ±2 to ±4 percent of full scale. Maintenance of good accuracy requires a sharp edge to the upstream side of the orifice plate. This edge will wear and degrade over time.

Pressure loss for orifice plates is high relative to other types of differential pressure elements.

Orifice plates are sensitive to build up of valve lubricant or other coating material and should be checked regularly. A ¼" build-up can introduce errors of up to ~30 percent. Plates should also be checked for warping (a ¼" warp can introduce up to 10 percent error).

8.1.2 Venturi Meters

Venturi meters comprise a converging diverging nozzle. They offer increased durability and accuracy compared to an orifice meter, but their operating range is fixed for the specified process conditions. Pressure loss is low, making it a good choice when little pressure head is available. Rangeability, while better than orifice plates, is less than 6:1, with an accuracy of within ±1 to ±2 percent of full scale under ideal conditions. Flow must be turbulent (i.e., Reynolds numbers > 10,000).

Venturi flow meters are widely used for wet gas applications that involve measurement prior to any form of separation or fluid processing. Among their advantages are the following (DTI, 2003):

- They do not ‘dam’ the flow (unlike orifice plates).
- They can be operated at higher differential pressures than orifice plates without incurring permanent meter damage (practical differential pressures up to about 200 kPa or 29 psi can be contemplated).

- They have a relatively high rangeability (typically 10:1) when used with re-rangeable differential pressure transmitters.

8.2 Insertion Flow Meters or Velocity Probes

An insertion flow meter is a velocity probe that measures the flow velocity at the tip of the probe. The velocity readings are converted to a flow rate based on the diameter of the pipe, the assumed flow profile and the position of the probe tip across the pipe diameter. For permanent installations, the probe tip normally is inserted to the centre third of the pipe diameter and is fixed in this position. With a single-point velocity measurement it is not possible to detect and correct for asymmetrical flow profiles or flow profiles that are not fully developed. Consequently, insertion flow meters require greater offsets than other flow meters in terms of numbers of pipe diameters from any upstream or downstream flow disturbances. These offsets can be difficult to achieve for large pipe diameter applications. Additionally, for large diameter applications, the probe can bend or even fail during high velocity events.

Without self-diagnostics, preventative maintenance programs should be implemented and the probes extracted at least quarterly for inspection and cleaning.

There are three main types of insertion flow meters: thermal anemometers, micro-tip vane anemometers and Pitot tubes. All of these have been tested in flare metering applications. Vane anemometers and Pitot tubes are limited to approximately 3:1 flow rangeability.

8.2.1 Thermal Anemometers (Thermal Mass Flowmeter)

A thermal anemometer – also known as a Thermal Mass Flowmeter - works by either measuring the electric current required to maintain a hot wire or element at a constant reference temperature when inserted into the gas flow, or by measuring the temperature change in the wire/element for a constant supplied heating current. In either case, the heat lost or cooling effect due to fluid convection is a function of the fluid velocity. The thermal conductivity and specific heat of the fluid are assumed to be constant. Changes in density cause calibration shift, and coating of the sensor can cause drift.

Thermal anemometers have fast response times and rangeabilities of up to 1000:1 when flow calibrated using air or methane. They do however need significant correction for changes in gas composition. Accuracy levels typically range from within ±1 to ±3 percent of reading under ideal conditions.

These meters are calibrated at the factory to air or one of a limited number of other gas options offered by the manufacturer (e.g., methane). Features are not provided for routinely correcting the readings for compositional differences between the reference fluid and the actual fluid. Consequently, for quantitative flow measurement, their use is limited to applications involving a relatively consistent gas composition, similar to that of the reference calibration gas. Otherwise, the meter simply provides an indication of the relative changes in flow rather than an accurate reading of the amount of flow.

Thermal anemometers are highly sensitive to the presence of liquids or condensation in the gas stream and therefore are not appropriate for use in applications involving wet or condensing gases (e.g., treater or stabilizer overheads, flash gas or tank vapors). Additionally, they tend to have more stringent temperature limitations than most other types of flow meters.

8.2.2 Pitot Tubes

A Pitot static tube measures the total pressure (or impact pressure) at the nose of a Pitot tube and the static pressure of the gas stream at side ports. The difference of these pressures (i.e. the dynamic or velocity pressure), varies with the square of the gas velocity. This pressure reading is converted to a flow velocity using Bernoulli's Equation and therefore has the same temperature, pressure and composition dependencies as a differential pressure meter (see Section 3.2.1).

With an "annubar", or multi-orifice Pitot probe, the dynamic pressure can be measured across the velocity profile, and the annubar obtains an averaging reading.

Pitot tubes are not appropriate for low velocity applications or where harmonic vibrations in the probe cannot be avoided. Also, multiphase fluids, such as a gas with significant amounts of entrained liquid are not good applications for this technology. Dirty gas or liquid flows can cause problems with the sensing ports on the Pitot tubes. Purging systems can be used to reduce or eliminate blockage in some of these applications.

The rangeability is 3:1, and accuracies of Pitot tubes vary from ±0.5 to ±5 percent of full scale under ideal conditions.

8.2.3 Micro-tip Vane Anemometers

A micro-tip vane anemometer features a small rotor at the tip. The rotor is designed with a specific number of blades positioned at a precise angle to the flow stream. The gas impinges on the rotor blades causing the rotor to rotate, with the angular velocity of the rotor being directly proportionally to the gas velocity. In permanent application, clean dry gases are required to prevent fouling of the bearings.

Assuming the probe does not occupy a significant portion of the flow area in the pipe, it will cause negligible pressure drop, but due to the local velocity measurement, the measurement uncertainty is higher than for conventional full-bore turbine meters. The typical flow range for such meters is up to 30 m/s and the rangeability is 10:1. Accuracies are ±2 percent of reading under ideal conditions.

Micro-tip vane anemometers rated for use in hazardous environments are not common but are available.

8.3 Vortex Shedding Flow Meters

Vortex shedding flowmeters are an alternative to differential pressure based flowmeters. They feature a bluff body, which, in the presence of fluid flow, causes vortices to be alternately shed on each side of the body resulting in an oscillating pressure gradient. The frequency of the

vortices increases linearly with increasing flow. Vortex flow meters have rangeabilities as high as 30:1 and an accuracy of within ±2 percent under ideal conditions. Additionally, they have low-pressure drops and no moving parts.
Vortex flowmeters in gas service are not suited to situations where pulsation or vibration levels in the gas are high, or the Reynolds number or flow velocity is low (i.e., where Re < 5000).

8.4 Transit-Time Ultrasonic Flow Meters

This type of meter determines flow velocity by measuring the transit time required for an ultrasonic pulse to travel through the flow between two fixed transducers usually positioned diagonally across the pipe diameter. Two sets of transit time measurements are performed, one with the wave traveling with a positive flow component and one in the reverse direction resulting in a negative flow component. This information can then be used to solve for the path-integrated flow velocity and the speed of sound in the gas. The instrument applies its own correction factor to convert the path-integrated flow velocity to an average flow velocity which can then be used to determine flow rate for the given pipe diameter. Velocities as low as 0.03 m/s (0.1 ft/s) and as high as 100 m/s (328 ft/s) can be measured. Accuracies range from ±2.0 percent of measured value up to 25 m/s and ±5 percent of measured value from 25 to 100 m/s. Rangeabilities up to 2000:1 may be achieved.

The transducers must be wetted to the flow (i.e., must be inserted through the pipe wall and brought into direct contact with the flowing fluid) to launch a strong enough ultrasonic pulse able to stand out above normal flow noise. The transducers do not need to extend into the flow so they do not introduce any pressure drop. To ensure proper alignment and positioning, the transducers are normally installed on a spool piece at the factory, which is then installed as an inline flow meter.

Particular advantages of transit-time ultrasonic flow meters, beyond those already mentioned above, are they can tolerate a certain amount of condensed liquid aerosol or dust and are not affected by gas composition; however, they should not be used for the measurement of wet gas if the liquid content is expected to exceed 0.5 percent by volume, as too high a liquid content will cause excessive signal attenuation.

Ultrasonic flow meters also perform well for conditions involving extreme fluctuations in temperature and pressure. They have no internal parts that can drift and cause inherent errors. Calibration needs are greatly reduced compared to other flow meters that have compositional dependencies or are susceptible to fouling such as orifice meters and insertion flow meters. Although not necessary for normal flare and vent applications, transit-time ultrasonic flow meters also determine flow direction.

The speed of sound result can be used to estimate the molecular weight of the gas by assuming perfect gas behavior. This information can be used to help identify the source of the flare gas on emergency flare systems.

8.5 Optical Flow Meters

Optical flow meters, using lasers or LED light, detect the perturbations in light beams resulting from turbulence or small particles in the gas stream. Typically, the specific pattern of each set of perturbations is identified by two optical sensors using correlation techniques. By tracking the time-of-flight of the perturbations between sensors placed a known distance apart, the average velocity, and hence the flow rate, of the gas stream can be calculated.

Optical meters do not interact with the flow and are insensitive to changes in gas composition, pressure or temperature. They are also less prone than other meters to loss of signal at very high flow rates. The sensors are located behind glass windows to protect them from the gas flow, but build-up of residues or dirt on the windows, or fogging in wet gas conditions, may impair the meter's function. Use of heated windows, and/or air-purge systems to remove dirt, may remove this drawback.

Optical meters are available as insertion probes for large diameter lines, with the advantage of easy, weld-free installation. For smaller line sizes (<6 inch diameter), an alternative is a meter that can be installed between flanges is also available.

Rangeability is quoted by manufacturers to be 2000:1 (from 0.03 m/s to 100 m/s), though below 0.1 m/s uncertainty in the measurement increases significantly as the number of detectable perturbations is very much reduced. Above 0.1 m/s, the quoted accuracy is from 2.5% to 7% of measured value.

8.6 Positive Displacement Meters

Bellows (or diaphragm) and rotary vane meters are the primary type of positive displacement meter used for measuring gas flows. They have high accuracies (i.e., up to ±0.1 percent of value), rangeabilities of up to 200:1 but cannot be used on wet or dirty gas streams. Therefore, they are not suited to most flare or venting applications. They are perhaps best suited to measuring instrument vent gas, or purge, pilot, enriching or blanket gas flows.

8.7 Rotameters

A rotameter consists of a tapered vertically oriented glass (or plastic) tube with a larger end at the top, and a metering float which is free to move within the tube. The rotameter operates with a relatively constant pressure drop. The fluid to be measured enters at the bottom of the tube, passes upward around the float, and exits the top. When no flow exists, the float rests at the bottom. When fluid enters, the metering float begins to rise. The position of the float changes as the increasing flow rate opens a larger flow area to pass the flowing fluid. The tube can be calibrated and graduated in appropriate flow units.

Rotameters for use in gas service typically are provided with calibration data and a direct reading scale for air. The readings can be easily corrected to standard pressure and temperature and to account for different gas compositions. Small glass tube rotameters are suitable for working with pressures up to 3450 kPag (500 psig), but the maximum operating pressure of a large (2-in diameter) tube may be as low as 690 kPag (100 psig). The practical temperature limit is about 200°C (400°F). In general, the allowable operating pressure of the tube decreases linearly with increasing operating temperature.

Rotameters typically have a flow rangeability of up to 10:1. The accuracy may be as good as within ±1 to ±2 percent of full scale rating under ideal conditions.

Laboratory rotameters can be calibrated to an accuracy of within ±0.50 percent over a 4:1 range, while the value for industrial rotameters is typically ±1 to ±2 percent of full scale over a 10:1 range. Purge and bypass rotameter errors are in the ±5 percent range.

Rotameter accuracy is not affected by the upstream piping configuration. The meter also can be installed directly after a pipe elbow without adverse effect on metering accuracy. Rotameters offer limited self cleaning capabilities because, as the fluid flows between the tube wall and the float, it produces a light scouring action that can help prevent the buildup of foreign matter (e.g., dry particulate matter). This scouring action is not effective on any sticky residues or wet material that may enter the rotameter; therefore, rotameters should be used only on relatively clean fluids which do not coat the float or the tube.

8.8 Turbine Flowmeters

Turbine meters are an inline flow meter in which axial fluid flow acts on turbine vanes causing them to rotate in direct proportion to the flow rate. The rangeability of these meters can reach 100:1 if the meter measures the rate of a single fluid at constant conditions. Accuracies up to within ±0.1 percent of reading are possible.

Turbine meters are mainly suited for low pressure and smaller volumes of gas; although, they have also been used for high pressure and higher volume applications. They are sensitive to flow profile and vibration, and remain particularly susceptible to damage by any liquids present in the gas. Having moving parts, they usually require frequent calibration. Partially open valves upstream from a turbine meter can cause significant errors. Typically, turbine meters require upstream flow straightening vanes.