

# Flare Measurement Challenges and Methodologies

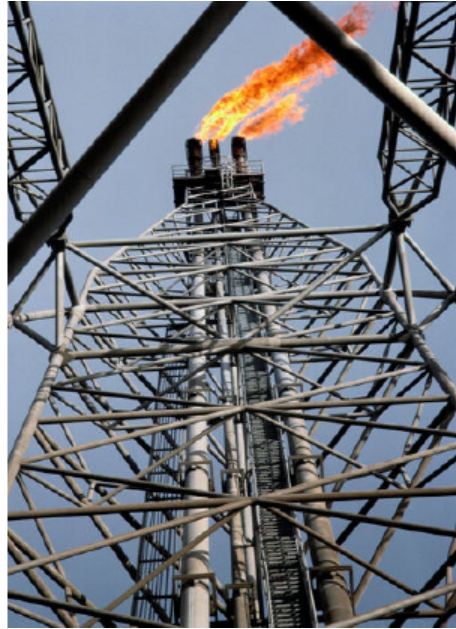
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## 1.0 Introduction

There has been an increased awareness by oil and gas companies in North America towards emissions monitoring and reduction for both environmental and economical reasons. For years, several countries worldwide have had stringent regulation in place. Regulations were implemented back in 1993 relating to the measurement of fuel and flare gas for calculation of CO<sub>2</sub> tax in the petroleum activities on the Norwegian continental shelf. Inevitably, oil companies operating on the region had to comply to this regulation. With new government legislation, producers, refineries and chemical companies have been looking for a cost effective solution to reduce emissions, and to provide tighter control for both leak detection, and mass balance. To tolerate the extreme process conditions often found in a flare line, yet provide accurate measurement to comply with regulators such as the Energy and Utilities Board, the technology of choice is of most importance. Several metering technologies have been tried and tested, and continue to be with little success today. To understand why the results have been dismal, one needs to fully understand the application and the limitations of the various flow-metering technologies used.

## 2.0 Government Legislation

The Alberta Energy and Utilities Board (AEUB) Directive 60 states in section 10, Metering Requirements and Guidelines, that meters designed for the expected flow conditions and range must be used to measure the following flare and vent streams; Continuous or routine flare and vent sources at **all oil and gas production and processing facilities (including heavy oil and crude bitumen)** where annual average total flared and vented volumes per facility exceed 500 m<sup>3</sup>/day, (exceeding pilot, purge, or dilution gas); If all solution gas is flared or vented from any



production facilities, the measured produced gas (less fuel gas use) may be used to report volumes flared or vented; In such situations, specific flare or vent gas meters are not required.

Acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume; and

Fuel (dilution or purge) gas added to acid gas to meet minimum acid gas heating value requirements, or Alberta ambient air quality objectives.

EUB Directive 60 references Directive 17. Measurement Requirements for Upstream Oil and Gas Operations and specifies the following uncertainties must be met.

- Measurement uncertainty for flare gas  $\pm 5\%$ .
- Measurement uncertainty for dilution gas  $\pm 3\%$
- Measurement uncertainty for acid gas  $\pm 10\%$ .
- Accuracy specifications apply to the overall range- ability of the process conditions

## 3.0 Flare Metering Challenges

Flaring systems are used to combust large quantities of waste gas during emergency shut down (ESD) situations. Additionally, facilities will flare smaller quantities of hydrocarbons that are uneconomical to process.

Two of the most important considerations when installing flare meters are flow profile and gas composition. There are other challenges when

trying to measure flare gas, including large pipe diameters, high flow velocities over wide measuring ranges, low pressure, dirt, wax, CO<sub>2</sub>, H<sub>2</sub>S, and condensate. Flare headers operate at near atmospheric conditions with some upstream relief valves relieving at as low as 5 psi. To ensure adequate flow from all process relief systems, a max pressure drop specification is often set to 0.5 psi. There can be great changes in the gas composition going to flare, in terms of molecular weight, which can significantly impact the uncertainty of many flow-metering technologies.

Velocities ranging from 0.05 m/s to over 100 m/s in emergency shut down situations have been recorded. To put that in perspective, 100 m/s is equivalent to 360 km/hr. Category 5 hurricanes reach wind speeds of 249 km/hr and have the ability to blow away large trees, and destroy complete buildings. Design worst-case events, and or greater velocities are infrequent, and it may be acceptable to use other process data to estimate the flow of such emergencies, such as determining isolated and or de-inventoried units.

#### 4.0 Metering Technologies

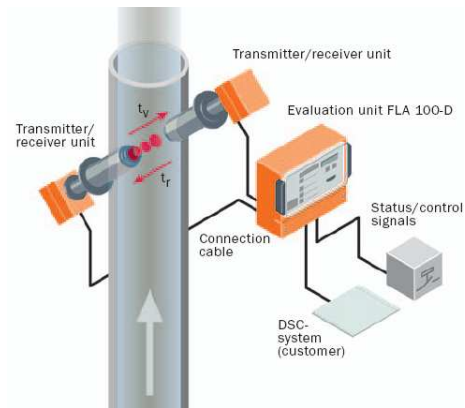
Insertion turbine, thermal, and averaging pitot tubes have all been tested in flare metering applications. Each should be installed as per the manufacturer's specifications. For thermal and insertion turbines, the probe tip must be inserted in the center 3<sup>rd</sup> of the pipe, which can range from 4" to 72" diameters. When subject to high velocities, bending and complete failure can and has taken place. Both turbines and averaging pitot tubes are limited to approximately 10:1 turndowns. Stacked transmitters will provide higher turndown ratios, but are nowhere near the required measuring range. Thermal meters have the ability to reach substantially higher turn down ratios, some up to 1000:1 when flow calibrated on air or natural gas, but they need significant correction for changing gas compositions. Currently, real time correction for changing gas compositions with thermal meters and pitot tubes has not been proven.

With out self-diagnostics, preventative maintenance programs should be implemented and the sensors extracted quarterly. Point sensors do not have the ability to correct for asymmetry or flow profiles that are not fully developed and require considerable upstream pipe diameters. This is generally not an option when working with such large pipe diameters, and therefore performance results will not repeat

those specified by the manufacturer that were obtained under ideal conditions from an accredited flow laboratory. For these reasons, traditional technologies including insertion turbine meters, averaging pitot tubes, and thermal mass meters have difficulty meeting the application requirements.

#### 5.0 Ultrasonic Flow Meters Designed for Flare Measurement

There are two primary principles for ultrasonic



meters, transit time measurement and Doppler effect. If a sound wave is reflected from a moving object, a frequency shift occurs. This frequency shift is the Doppler effect and can also be utilized in flow measurement. However, due to the non-reflective nature of the process conditions at hand, this method is not practical. The transit time gas flow meter is based on the measurement of contra propagating ultrasonic pulses, in which the transit time of the sonic signal is measured along one or more diagonal paths in both the upstream and downstream direction. The flow of gas causes the time for the pulse traveling in the downstream direction to be shorter than for the upstream direction, and this time difference is a measure for the rate of the gas flow as illustrated in figure 1.

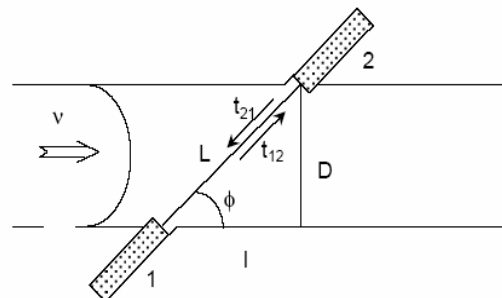


Figure 1

Transit time gas ultrasonic meters have been used successfully for years. For single path meters, there are two transducers, both receive and transmit ultrasonic pulses. Base design conditions for flowing velocities in gas distribution and transmission pipelines are generally limited to 21m/s due to internal erosion and vibration components. Velocities at this rate can be measured using standard transducers. However, to overcome pulsation effects, and or control valve noise, one should consider using 210 KHz or 340 KHz transducers, combined with higher sampling rates. These frequencies are substantially greater than the noise generated, and the high sampling rates will capture the data through out the pulsation cycle. When measuring extreme velocities in a flare line, high-powered transducers such as 42KHz should be used. Just as low frequency base will travel further than high frequency treble from an amplifier, the same is true in ultrasonic flow meters. This combined with the transducer angle which can range from 30 to 60 degrees depending on the application will make the meter immune to the noises and blow away effects from high velocity gases as shown in Fig 2

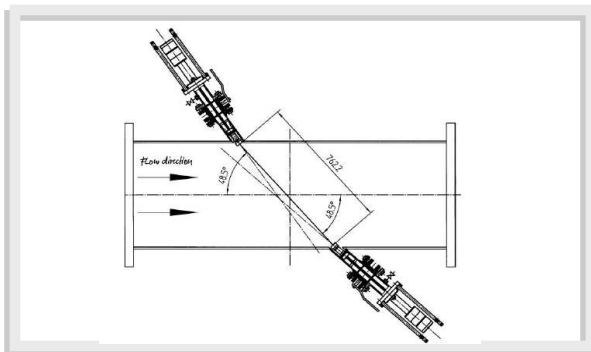


Figure 2

Other designs utilize a continuous sine wave signal in combination with a variable frequency signal, also known as a “Chirp” signal. This signal is given a unique recognizable form characterized by the pulse duration and the varying signal frequency. At higher velocities the instrument uses only these Chirp signals.

Ultrasonic meters designed for flare measurement must operate under atmospheric pressure, and require very high efficiency transducers to effectively transmit and receive each ultrasonic pulse. In all cases, the processing of the information coming from the transducer set is performed in a dedicated control unit like that shown in Figure 3.



Figure 3

The computer controls the transmission and detection of the signals to and from the transducers which performs the critical time measurements. There are multiple outputs configurable for different parameters, and interface is selectable between RS232C, RS422, and RS485. Meter sizes range from 4” to 72” and are capable of measuring velocities from 0.05 to well over 100m/s, resulting in 2000:1 turndown ratios. These low-end capabilities are critical for plant leak detection and mass balance while the overall range is required for emission monitoring to comply with national legislation. Accuracies range from 2.0% of measured value up to 25m/s and 5% of measured value from 25-100 m/s. Wetted sensors that are not considered intrusive create very little pressure drop, and are unaffected by high velocity gas. Most ultrasonic flow meters are capable of correcting for asymmetry and flow profiles that are not fully developed to some degree. This is accomplished two ways; Use the Reynolds number as a measure of the flow profile, and adjust the measured axial flow velocity according to a function based on the Reynolds number estimated. The second method is to measure the entire cross sectional area of the pipe, which will average out the error. Combining the two methods reduces the number of upstream pipe diameter requirements. One shouldn't assume all ultrasonic flow meters are configured this way. Without taking the full cross sectional area into account, the meter behaves similar to that of a point sensor, requiring greater upstream piping diameters for a better developed flow profile and reduced swirl. The volumetric flow  $Q_{OS}$ , through the representative cross sectional area  $A$ , and the mean gas velocity across the cross – section  $v_A$  (surface velocity) is defined by equation 1. The mean velocity is

determined by the flow velocity of a sound path “v” between the two transducers, across the diameter of the pipe. Since the mean values of the path and surface velocity are not identical, a functional, systematic correlation between the calculated path velocity and mean surface velocity similar to the point based flow measurement can be corrected for using equation 2. With an unimpeded, axial – symmetric flow profile, the value for K can be 0.9 to 1.0. When this is not the case, a second-degree calibration function can be implemented to map the correlation between the mean path and surface velocity as shown by equation 3. If the flow in a round pipeline is unimpeded and axial symmetric, Cv1 is equal to the correction factor k.

UFMs meters are unaffected by changing gas composition, there are no mechanical moving parts, and self-diagnostics eliminate preventative maintenance programs. When required, the sensors may be extracted from the flare line with out shutting down the process for cleaning or calibration checks.

$$Q_{OS} = v_A \cdot A \quad \text{Eq. 1}$$

$$v_A = K \cdot v \quad \text{Eq. 2}$$

$$v_A = Cv2 \cdot v2 + Cv1 \cdot v + Cv0 \quad \text{Eq. 3}$$

Based on empirical data, ultrasonic time of flight meters were specified in NORSOK STANDARD I-104, Section 7.1.3.

## 6.0 Conclusion

Ultrasonic flow meters designed for flare gas measurement have been in use since 1987. They have proven to be a cost effective solution to reduce emissions, and to provide tighter

control for both leak detection and mass balance. UFMs are unaffected by changing gas composition, there are no mechanical moving parts, and self-diagnostics minimize maintenance. When required, the sensors may be extracted from the flare line without shutting down the process for cleaning or calibration checks. They provide turn down ratios up to 2000:1, and non-intrusive but wetted sensor designs are not subject to bending or failure, and create no pressure drop. They meet or exceed government legislation, and eliminate risk of non-compliance.

## 7.0 References

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