Flare Measurement Advanced Ultrasonics

John Chitty
Regional Sales Manager
SICK │ MAIHAK, Inc.
15415 International Plaza Drive, Suite 100
Houston, Texas 77032

1.0 Introduction

There has been an increased awareness by oil and gas companies in North America toward emissions monitoring and reduction for both environmental and economical reasons. For years, several countries worldwide have had stringent regulations in place. Regulations were implemented in 1993 relating to the measurement of fuel and flare gas for calculation of CO_2 tax in the petroleum activities on the Norwegian continental shelf. Inevitably, oil companies operating in the region had to comply with these regulations. 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 international regulators such as the Energy Resources Conservation Board in Canada, the European Union, or the Texas Commission of Environment Quality, the technology of choice is important. Several metering technologies have been tested with little success. To understand why the results have been dismal, one needs to fully understand the challenges associated with the application. Further investigation towards the effects of sonic noise generated from high gas velocities, elbows, Ts, and pipe segments, has been conducted and the results detailed in this paper.

2.0 Government Legislation

In Canada, the Energy Resources Conservation Board (ERCB) (www.eub.ca) Directives 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 m3/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.

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.

ERCB 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 ± 5 %.
- Measurement uncertainty for dilution gas ± 3 %
- Measurement uncertainty for acid gas ± 10 %.Accuracy specifications apply to the overall range- ability of the process conditionsThe European Union has followed suit (www.europa.eu). In reference to the guidelines for

the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the council dated 2006, emissions from flares shall include routine flaring and operation flaring (trips, start-up and shutdown as well as emergency reliefs). This is determined by taking the products of the “activity data”, “emission factor”, and “oxidation factor” and considers both the amount of gas flared and the carbon content of the flared gas. The activity data is divided into three tiers. The amount of flare gas used over the reporting period is derived with maximum uncertainties of +- 17.5%, +- 12.5 %, and +- 7.5% for Tier 1 through to Tier 3 respectively.

The selected tier shall reflect for each emission source, the highest level of accuracy that is technically feasible, which will be subject to approval by a competent authority. For the reporting periods 2008-2012 as a minimum tier 2 in Annex XII shall be applied unless technically not feasible.

In the United States, the Texas Commission of Environment Quality (TCEQ, www.tceq.state.tx.us) specifies an uncertainty of +- 5% for a flare gas flow meter at 30, 60, and 90% of range under the installed conditions.

In California, rule 1118 essentially mirrors Texas with uncertainty requirements of +- 5% at flow rates of 0.3 m/s and higher, and +- 20% at velocities of 0.03 to 0.3 m/s.

3.0 Flare Metering Challenges

Flaring systems are used to combust large quantities of waste gas during emergency shutdown (ESD) situations as well as 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_2, H_2S, 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 maximum 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 create mass destruction. Design worst-case events, or greater velocities are infrequent, and it may be required to use additional process data to estimate the flow of such emergencies, such as determining isolated and or de-inventoried units.

4.0 Metering Technologies

An evaluation was conducted on some of the more common technologies believed to be suitable for flare measurement. These included Transit time ultrasonic, Insertion turbine, thermal mass, averaging pitot tubes and optical transit time velocimeters. Thermal and insertion turbines are point sensors that must be inserted in the center 3rd of the pipe, that typically range from 4” to 72” diameters. When subject to high velocities, bending and complete failure has occurred. Both turbines and averaging pitot tubes are limited to approximately 10:1 turndowns. Stacked transmitters will provide higher turndown ratios but still fall short of meeting the requirements. 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. However, changing gas compositions which are common due to multiple plant processes leading to a common flare header adversely affect the measurement. Each gas has different thermal properties that effect convection heat transfer which is the measurement principle of thermal mass meters. Without self-diagnostics, preventative maintenance programs need to be implemented and the sensors extracted quarterly for inspection. Point sensors are limited in their ability to correct for asymmetry or flow profiles that are not fully developed and as a result, require considerable upstream piping to minimize installation effects. This is generally not an option when working with such large pipe diameters.

Optical transit time velocimeters are relatively new when it comes to flare measurement. They rely on particles in a flowing gas stream to pass through two laser beams focused in a pipe by eluminating optics. Laser light is scattered when a particle crosses the first beam. The detecting optics collects scattered light on a photo detector which generates a pulse signal. If the same particle crosses the second beam, the detecting optics collect scattered light on a second photo detector, generating a second pulse. By measuring a time interval between these pulses, a gas velocity is calculated. The measured value is dependent on the purity of the gas moving through the pipe. This may also be referred to as the number and consistency of particles in the gas stream. Such particles are referred to as dirt. Fewer detectable particles and or lower velocities result in greater uncertainty limiting low flow capabilities. Tests performed at low to high pressures, versus atmospheric will have an impact on gas density and the number of measurable particles per unit volume. The same tests demonstrated that 40D of straight pipe were required to minimize installation effects and to achieve an average uncertainty of approximately +- 2% without the use of a flow conditioner. The majority of field tests were conducted on smaller pipe diameters ranging from 2” to 16”, and it’s the authors believe these tests are ongoing.

5.0 Advanced Ultrasonics

Ultrasonics have been used successfully in flare measurement applications for years but have been limited to approximately 85 m/s For that reason, the focus of this paper has been to further develop the technology as it pertains to flaring, and ultimately improve on the limitations. There are two primary principles; 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. Single path meters utilize two transducers; both receive and transmit ultrasonic pulses. 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.

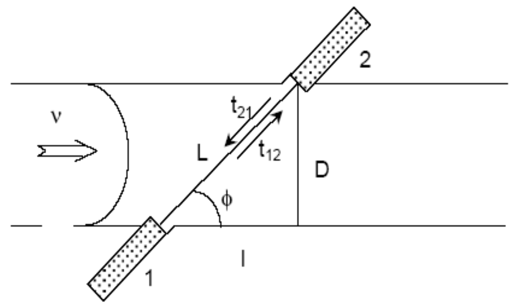


Figure 1

Meters designed for flare measurement must operate under atmospheric pressure and require high efficiency transducers to effectively transmit and receive the ultrasonic pulses. 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 2.

Control Unit

Ultrasonic Transducers

Figure 2

The flow computer controls the transmission and detection of the signals to and from the transducers which perform 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 have both low-end measurement requirements for day to day operations as well as high end for emergency shut down (ESD) situations. Plant leak detection and mass balance are often necessary while the overall range is required for emission monitoring to comply with national legislation. Typical uncertainties are ± 2 ... 5 % of measured value and resolutions ranging from +/- 0,003 m/s at +/- 0.03 m/s up to +/- 0.3 m/s. Reproducibility is generally +/- 1% at 0.15 ... 30 m/s. 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.

Volumetric flow Q_{OS}, through the representative cross sectional area A and the mean gas velocity across the cross-section v_A is defined in equation 1. The control unit determines the representative mean value of the flow velocity on a sound path v (path velocity) between the two transmitter/receiver units. 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 by 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 in equation 3. If the flow in a round pipeline is unimpeded and axial symmetric, Cv1 is equal to the correction factor k.

$Q_{OS} = v_A \cdot A$ Equation 1

$v_A = K \cdot v$ Equation 2

$v_A = Cv2 \cdot v2 + Cv1 \cdot v + Cv0$ Equation 3

Base design conditions for flowing velocities in gas distribution and transmission pipelines are generally limited to 21m/s in accordance to API Report 14E due to internal erosion and vibration components. Velocities at this rate can be measured using frequencies ranging from 135 – 210 KHz. To overcome pulsation effects, and/or control valve noise, one should consider using at least 210 KHz or 340 KHz transducers, combined with higher sampling rates. These frequencies are substantially greater then the noise generated, and the high sampling rates will capture the data throughout the pulsation cycle. When measuring extreme velocities in a flare line, transducers with frequencies such as 42 KHz to 135 KHz should be considered. Just as low frequency base will travel further then high frequency treble from an amplifier, the same is true in ultrasonic flow meters. However, the challenge to measure velocities greater than 85 m/s still existed. Several have attempted to alter the transducer angle in combination with implementing a slight transducer offset as shown in Figure 3. In theory, this would create what is referred to as a ray rescue angle that would help reduce blow away effects from high velocity gases. Although somewhat effective, one needs to consider % CO_2 and pipe diameter. CO_2 attenuates an ultrasonic signal due to fewer molecules. Increased pipe diameters cause further dissipation of the same signal due to an increased time of flight. An offset has the ability to also adversely affect the signal strength and become more of a detriment then an improvement.

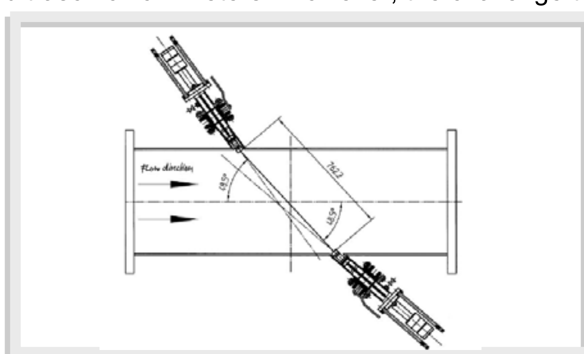


Figure 3

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. Advanced processing capabilities by itself are not enough, primarily at the high end of the velocity spectrum.

Extensive research at an ambient pressure calibration facility in Germany shown in Figure 4 has revealed 3 primary sources that make it difficult to effectively measure the velocities in question. Those are; external noise sources caused from the plant or personnel, noise that occurs at the edge of the transducer face from the flowing gas, and signal drift caused from swirling gas that stimulates the vibrating membrane of the transducer face as shown in figure 5.

These swirls can destroy the ultrasonic wave form which will change the direction of the signal and cause drift. It was determined that by embedding the ultrasonic transducer inside a flow optimized profile shape, the noise and signal drift would be minimized.

Figure 4

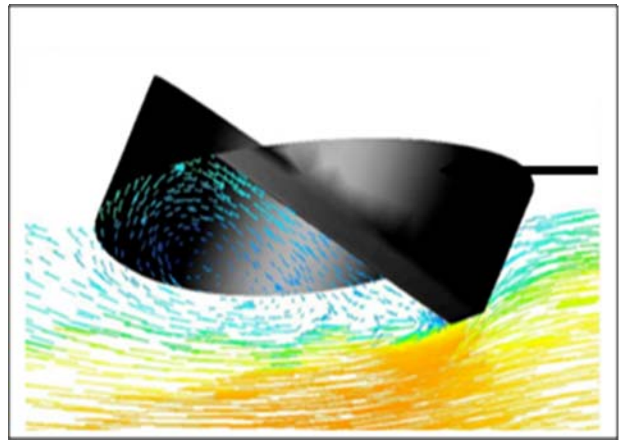


Figure 5

The profile shape referenced closely resembles the Joukowski airfoil as shown in figure 6. Many years ago, the Russian mathematician **Joukowski** developed a mapping function that converts a circular into a family of airfoil shapes. **Conformal mapping** is a mathematical technique used to **convert** (or map) one mathematical problem and solution into another. It involves the study of **complex variables**. The mapping function also converts the entire flow field around the cylinder into the flow field around the airfoil. We know the velocity and pressures in the plane containing the cylinder. The mapping function gives us the velocity and pressures around the airfoil. Knowing the pressure around the airfoil, we can then compute the lift. Process simulation shown in figures 7 through 9 proved that with this design, process gas represented by velocity vectors did not shear away from the surface of the probe. The red line on each figure demonstrates the point on the sensor face that the velocity is measured. There is a slight pressure drop created, as the process velocity increases over the raised section. At each point, there is no effect of flow breaking away from the transducer surface which was caused by the sharp edges of the previous design. Furthermore, the swirl caused by the same sharp edges that stimulated the transducer membrane was practically eliminated. Signal noise was reduced by nearly 50% and signal drift was reduced by 30%. Figure 10 shows the results of the wave forms for both standard transducers as well as the new high speed transducer at 94 m/s. SNR is 19 db, and the error percentage was 62% at atmospheric pressure. Error is defined as the number of pulses per sample effectively being received. With advanced microprocessors, a typical sample rate may be 75 times per second. With a 62% error rate, 38% of the samples were being received, well beyond an alarm threshold that would be set from the factory at 10% before the measurement is degraded.

The physical characteristics combined with special optimized signal algorithms including cross correlation make it possible to now effectively measure velocities accurately at normal operating conditions, as well as those experienced in emergency shut down situations.

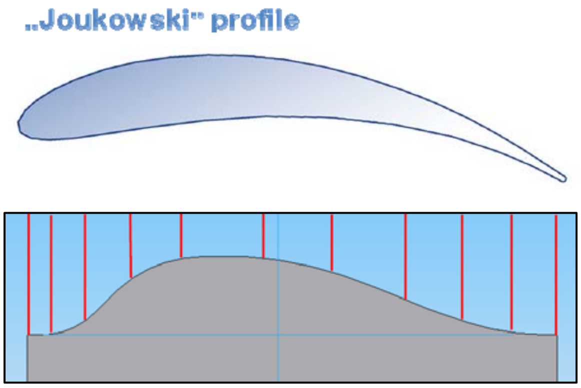


Figure 6

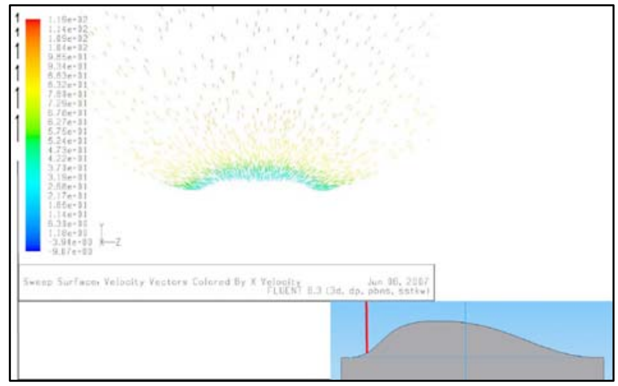


Figure 7

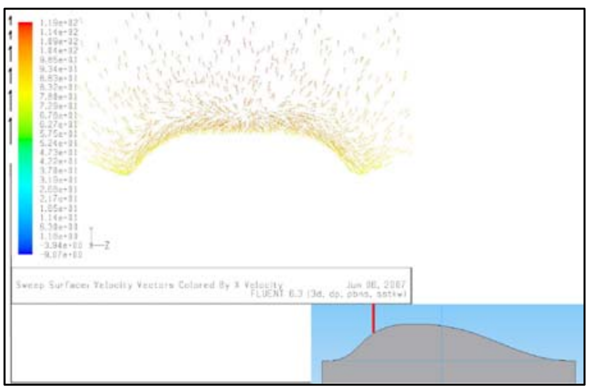


Figure 8

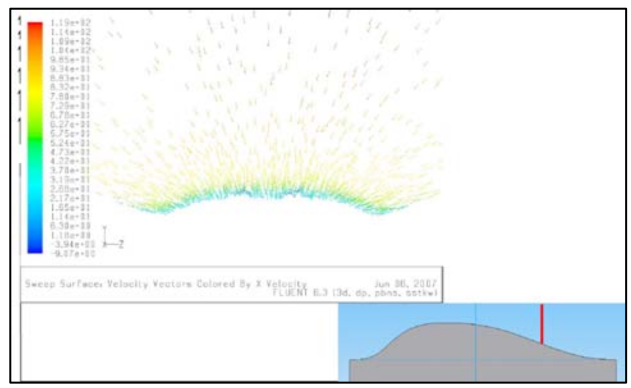


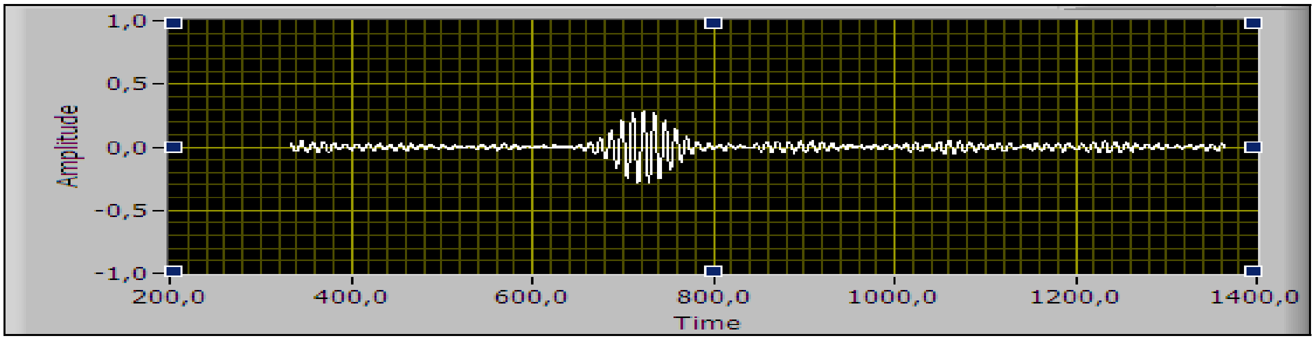
Figure 9

6.0 Conclusion

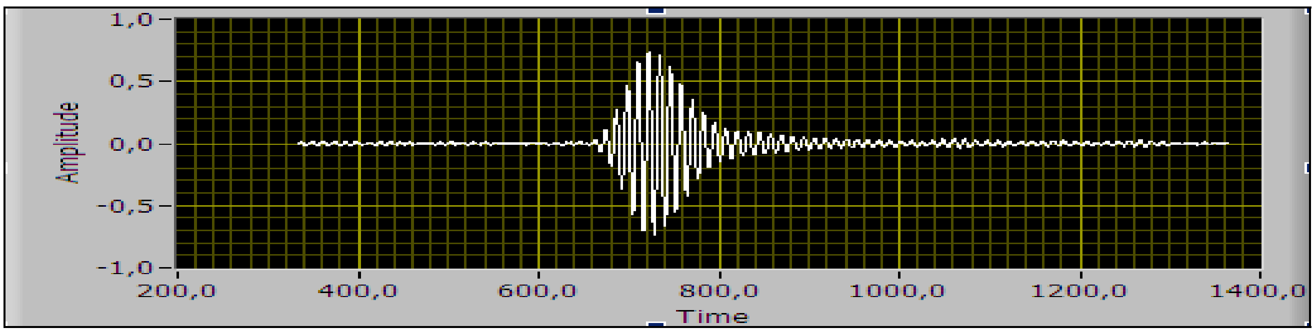
While ultrasonic meters can effectively measure extremely low and high velocities, it is important the user understand what takes place in the pipe at such velocities and what they can realistically expect from their metering system. In one example, 3 meters, all on substantially smaller line sizes, measured an estimated total accumulated gas volume of 2.4 E3M3 per day, prior to the gas flowing into a 30" low pressure line. At atmospheric pressure and temperatures ranging from 0 to 35 degrees C, the calculated velocities through a 30" line fall below 0.1 m/s. The specified uncertainty of one manufacturer's ultrasonic meter at velocities less then 1.95 m/s without installation effects is +- 0.02 m/s. Velocities of 0.1 m/s equates to an uncertainty of +- 20% in laboratory conditions. It is not practical to install flow conditioners upstream in flare meter applications, nor would they be very effective at such low rates. Therefore, an unimpeded, axial-symmetrical flow profile cannot be guaranteed and will add to the overall uncertainty of the meter. It is also important to note certified calibration facilities including CEESI, TransCanada Calibrations and SWRi cannot guarantee reproducibility at velocities below approximately 0.3 m/s due to these same uncertainties. In such cases, it may be more practical to rely on accurate metering from each of the lines leading into the flare header for velocities below 0.5 m/s to comply with government regulations. At extreme velocities, beyond 100 m/s, process noise may drown out the ultrasonic signal making it unrecognizable. In either case, the user should consult with the manufacturer.

Ultrasonic flow meters designed for flare gas measurement have been in use since 1987. They 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 without shutting down the process for cleaning or calibration checks. They have proven to be a cost effective solution to reduce emissions and to provide tighter control for both leak detection and mass balance. They provide turn down ratios up to 3000:1, 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.

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



Standard Sensor



New high speed sensor
Figure 10

7.0 References

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