FLARE MEASUREMENT

A Global Perspective

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Flare gas measurement remains a key element of oil & gas operations today. The World Bank estimates that over 150 billion cubic meters of natural gas is flared or vented annually, an amount worth approximately 30.6 billion dollars, equivalent to 25% of the United States' gas consumption or 30% of the European Union's gas consumption per year.

CO2-based flaring emissions are also equivalent to the annual emissions of 77 million cars. Initiatives and government regulators including the European Union Emissions Trading Scheme, the Environmental Protection Agency (EPA) in the USA, and the World Bank's Global Gas Flaring Reduction Initiative require industrialized countries to reduce greenhouse gas emissions by complying to recent directives. The International Energy Agency and member countries from the G8 are all flagging the issue of flaring. Closer to home, the Oil & Gas Commission (OGC) in British Colombia and the Alberta Energy Regulator (AER) have also implemented Directives. AER Directive 60 – Upstream Petroleum Industry Flaring, Incinerating and Venting, dated November 3, 2011, references AER Directive 17 – Measurement Requirements For Oil and Gas Operations, dated May 15, 2013. The British Columbia Oil and Gas Commission Measurement Guidelines for Upstream Oil and Gas Operations Dated June 1, 2013 essentially mirror the AER Directives.

Directive 60 states meters designed for the expected flow conditions and range must be used to measure continuous or intermittent flare and vent sources at all oil and gas production and processing facilities (excluding cold heavy oil and crude bitumen) where annual average total flared and vented volumes per facility exceed 500 m3/day (excluding
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, must be measured. Fuel (dilution or purge) gas added to acid gas to meet minimum acid gas heating value requirements must also be measured.

In Directive 17 under Standards of Accuracy, there are two categories that apply to flare measurement; Oil Systems and Gas Systems. Under the category of Oil Systems, total battery gas includes produced gas that is vented, flared or used as fuel gas, also referred to as associated gas. This is gas produced in association with oil production. Single point flare measurement uncertainty for oil systems is dependent on production;> 16.9 103 m3/d = 3.0%, > 0.50 103 m3/d but ≤ 16.9 103 m3/d = 3.0%, ≤ 0.50 103 m3/d = 10.0%. These uncertainties do not apply to gas produced in association with heavy oil (density of 920 kg/m3 or greater @ 15 degrees C).

The category of Gas Systems includes flare and vent gas, acid gas and dilution gas. Single point measurement uncertainty for flare and vent gas is 5%, dilution gas is 3% and acid gas before compression is 10%. The Directive also states under System Design and Installation of Measurement Devices, meters that depend on gas density to determine volume are not recommended for use at gas plant flare stacks. To understand why, one need look no further than testing conducted by API. Several metering technologies were calibrated and tested
first using a fixed gas composition, and then again using three very different scenarios. The fixed gas composition consisted of 1% CO2, 0.9% H2S, 97% methane, 1% ethane and 1% propane. The changes made are outlined in the following three cases and deviations shown in the table below.

Case 1 – Propane Increased	Actual Volume	Standard Volume	Mass
Differential Pressure Meter	~34%	~34%	~25%
Thermal Flow Meter	~2% to 15%	~2% to 15%	~35% to 45%
Velocity Meter (Ultrasonic, Vortex, etc.)	~0%	~0%	~44%
Case 2 – Hydrogen Added	**Actual Volume**	**Standard Volume**	**Mass**
Differential Pressure Meter	~31%	~31%	~45%
Thermal Flow Meter	~100% to ~300%	~100% to ~300%	~300% to ~700%
Velocity Meter (Ultrasonic, Vortex, etc.)	~0%	~0%	~112%
Case 3 – CO2 Increased	**Actual Volume**	**Actual Volume**	**Mass**
Differential Pressure Meter	~9%	~9%	~8%
Thermal Flow Meter	~2% to ~5%	~2% to ~5%	~15% to ~20%
Velocity Meter (Ultrasonic, Vortex, etc.)	~0%	~0%	~15%

• Case 1 – 0.53% CO2, 0.47% H2S, 51.08% methane, 0.53% ethane, 47.39% propane
• Case 2 – 0.4% CO2, 0.36% H2S, 38.8% methane, 0.4% ethane, 0.04% propane, 60% hydrogen
• Case 3 – 12% CO2, 0.8% H2S, 86.22% methane, 0.89% ethane, 0.09% propane

In all cases, changing gas composition had no affect on ultrasonic meters. The differential meters were affected due to the square root calculation, and thermal meters influenced by the heating properties of the gas.

For this reason, it is easy to see why today single path, ultrasonic meters are the technology of choice for flare measurement. However, there are limitations. Single path, centerline meters are very susceptible to gas swirl and undeveloped flow profiles. The American Gas Association conducted tests that are published in AGA 3. Without the use of a flow conditioner, and when downstream of two elbows out of plane or a header, the upstream pipe diameters required to provide a fully developed flow profile and minimize swirl is 146D. Using existing flow conditioners in a flare application is not an option and for that reason, it is difficult to replicate laboratory conditions. Accuracy requirements noted above may seem acceptable when compared to custody transfer applications, but realistically, without calibration using identical upstream pipe configurations, its difficult to quantify the error.

It is anticipated API will release test results in spring of 2014 for single path meters using various upstream piping configurations, at which point one of two scenarios will take place. Either government regulations will be relaxed, or we will see industry demand for increased accuracy from manufacturers. This may consist of multi path ultrasonic meters specific for flare applications and or transducers with multi beam capabilities to increase resolution, and will help compensate for non-ideal flow conditions. or now, the future remains to be seen.