Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement

Section 10—Measurement of Flow to Flares

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Measurement Coordination Department

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Chapter 14—Natural Gas Fluids Measurement
Section 10—Measurement of Flow to Flares

1 Introduction

1.1 SCOPE

The standard addresses measurement of flow to flares, and includes:

- Application considerations.
- Selection criteria and other considerations for flare meters and related instrumentation.
- Installation considerations.
- Limitations of flare measurement technologies.
- Calibration.
- Operation.
- Uncertainty and propagation of error.
- Calculations.

The scope of this Standard does not include analytical instrumentation.

1.2 BACKGROUND

Measurement of flow to flares is important from accounting, mass balance, energy conservation, emissions reduction, and regulatory perspectives. However, measurement of flow to flares remains distinctly different from traditional flow measurement for accounting or custody transfer. Flares are safety relief systems which typically receive highly unpredictable rates of flow and varying compositions, and for safety reasons do not often lend themselves to being taken out of service to accommodate measurement concerns, even for short periods. Therefore, some of the traditional paradigms applicable to custody transfer measurement systems (reasonably predictable flow rates and composition, the use of in-line proving, capability to readily remove meters from the piping system, the use of by-pass connections, the use of master meters, etc.) must be abandoned altogether or highly modified in flare measurement applications.

1.3 FIELD OF APPLICATION

For safety and other considerations, it is highly undesirable to directly flare multiphase mixtures of liquids and gases. Therefore, this Standard is primarily concerned with flare flow measurement in the gas or vapor phase. However, considering that fouling substances (liquid droplets and or mist or other contaminants) may be present even in well designed flare systems, this Standard provides appropriate cautionary detail as to the effects of such contaminants which may impact flare flow measurements.

Most flare header applications are designed to operate during non-upset conditions at near atmospheric pressure and ambient temperature, where compressibility of the mixture is near unity. Extreme conditions have been noted to be between –3.4 kPa-g (–0.5 psig) and 414 kPa-a (60 psia), and between –100°C (–148°F) and 300°C (572°F). Flare gas compositions are highly variable, and can range from average molecular weights approaching that of hydrogen to that of C5+ or higher. The uncertainty in flare gas density associated with varying pressure, temperature, and composition is discussed in more detail in 10.4.

Most flare headers are designed to operate at velocities less than 91 m/s (300 ft/s), with extremes up to 183 m/s (600 ft/s). This Standard does not exclude pressures, temperatures, and velocity ranges different than those suggested above, if flare flow measurement system (FFMS) uncertainty requirements are met.

As with most flow measurement applications, the accurate determination of flow involves more elements than just the flow meter. Flare flow measurement also involves the measurement or prediction, based upon historical data, of composition, pressure, temperature, and/or density. In mixtures with widely varying compositions, typical of flare applications, the analytical instrumentation used in conjunction with flare metering may be critical to achieving the targeted level of accuracy. However, analytical instrumentation is discussed in this Standard only from the perspective of its effects on accuracy. The relative sensitivity of the flare volume measurement to composition variances is a function of meter technology type (see 4.6 for details).

This Standard addresses the following elements of the FFMS: the primary devices (meter components), secondary devices (pressure and temperature instrumentation), and tertiary devices (e.g., flow computer, DCS [Distributed Control System], PLC [Programmable Logic Controller], DAS [Data Acquisition System], etc.).

Since the secondary and tertiary components of an FFMS are of the same types commonly employed in many other measurement applications, it is not the intent of this Standard to provide detailed requirements of these devices.

See Figure 1 for a graphical representation of an FFMS and its components. This figure is designed to depict which instruments are primary, secondary, and tertiary. For more guidance on specific location of components, see 4.8.1.

In Figure 1, the following apply:

- FE is flow element,
- FT, PT, TT, and AT are flow, pressure, temperature, and analyzer transmitters, respectively,
- FI, PI, TI, and AI are flow, pressure, temperature, and analyzer indications, respectively, in the DCS or other tertiary device.

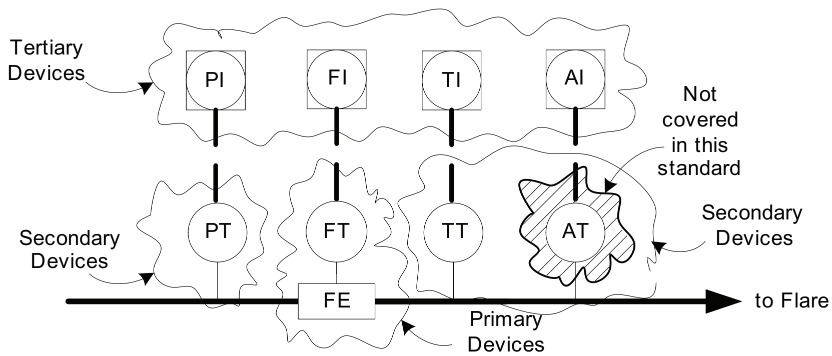


Figure 1—Flare Flow Measurement System (FFMS)
Graphical Representation of an FFMS and its Relation to Other Devices

For guidance on the appropriate use of analytical instrumentation in flare systems, the user should consult appropriate analytical standards, or the manufacturer of the analytical system. The meter manufacturer should also be consulted as to the correct use of analytical instrumentation in conjunction with the metering system.

Targeted uncertainty for flare metering applications is ±5% of actual volumetric or mass flow rate, measured at 30%, 60%, and 90% of the full scale for the flare meter. Since an FFMS is comprised of multiple devices (e.g., flow, pressure and temperature instrumentation, and calculation components) and may be used in conjunction with analytical equipment, the overall uncertainty of final calculated results may be higher. This Standard provides guidance on the calculation of overall FFMS measurement uncertainty.

1.4 FLARE METERING TECHNOLOGIES

It is the intent of this Standard that no flare measurement technology be excluded. The examples presented represent meter types that were known to be in flare measurement use by the drafting committee at the time this Standard was generated. The examples are not intended to either endorse or limit the use of these meter types. The examples are rather intended to show how different metering technologies can be used as part of an FFMS.

These flow meters may be in-line devices or insertion-type devices.

1.4.1 Differential Pressure Flow Meters

Differential pressure flow meters operate on the principle of introducing a flow restriction that produces a pressure difference between the meters' upstream and downstream pressure sensing points. In most cases, the relationship between the pressure and velocity is described by the Bernoulli equation. The differential pressure is related to flow and meter-specific equations have been developed to calculate inferred mass or volumetric flow.

Examples of differential pressure flow meters are averaging Pitot tube, venturi and orifice meters.

Averaging Pitot tube meters utilize a tube that is inserted across and perpendicular to the pipe flow. Multiple inlet ports are used to average the high pressures at the front face of the probe to create the meter inlet pressure, which is typically the stagnation pressure. The low pressure is measured, depending on probe design, at the side or back of the probe.

Venturi meters are comprised of the upstream pressure tap located on the upstream piping, the venturi tube (a piece of pipe that is smaller than the inlet pipe and contains the downstream pressure tap), the inlet piping reducer, and the outlet piping expander.

Orifice meters are comprised of pressure taps located upstream and downstream of a flat plate with a circular opening that is inserted into the pipe and placed perpendicular to the flow.

1.4.2 Optical Meters

Optical meters operate on the principle of measuring the time of flight of small localized disturbances or particles in the gas stream. The major components of an optical meter are optical transmitter(s), optical receiver(s), and control electronics.

Examples of optical meters include optical scintillation and laser 2-focus meters.

Optical scintillation meters utilize effects which are caused by optical refraction occurring in small parcels of gas whose temperature and density differ from their surroundings and cause changes in the apparent position or brightness of an object when viewed through the atmosphere or gas. The speed of movement of this scintillation is related to the average velocity along the optical path of the meter.

Laser 2-focus meters measure the transit time of naturally occurring small particulates passing through two laser beams focused in a pipe by illuminating optics. Upstream and downstream photodetectors detect scattered light as the particle crosses the laser beams and the meter calculates the time of flight between the beams. The average velocity of these particles is related to the average flare gas velocity at the focal point of the meter.

1.4.3 Thermal Flow Meters

Thermal flow meters (often referred to as thermal mass meters) operate on the principle of thermal convection or dispersion. The major components of thermal flow meters are resistance temperature detectors (RTDs), a heater, and control electronics.

Two examples of thermal flow meters are constant differential temperature and constant power thermal flow meters.

Constant differential temperature thermal flow meters use a heated RTD which is compared and continually adjusted to maintain a constant temperature difference with respect to the process temperature measured by a second RTD. The power required to maintain the constant temperature difference is proportional to the rate of heat loss from the heated RTD.

Constant power thermal flow meters apply constant power to heat the active RTD and measure the temperature difference between the active RTD and the process temperature measured by a second RTD.

In both types, the rate of heat loss is related to the heat transfer coefficient of the gas mixture and the flow rate in close proximity to the sensor.

1.4.4 Ultrasonic Flare Meters

Ultrasonic flare meters operate on the principle of measuring the transit times of high frequency sound pulses. Transit times are measured for sound pulses traveling downstream with the gas flow and upstream against the gas flow. The difference in these transit times is related to the average velocity along the acoustic path.

1.4.5 Vortex Shedding Meters

Vortex shedding meters operate on the principle of vortex shedding caused by a flowing medium as it passes a bluff body and splits into two paths, causing vortices to shed from alternate sides of the bluff body. The vortices are sensed by a vortex element, which measures their shedding frequency by detecting very small changes in physical properties adjacent to or downstream of the vortex element. The measured frequency is related to the average velocity in close proximity to the bluff body.

2 Reference Publications

API

Std 521	*Guide for Pressure-relieving and Depressuring Systems*
Std 537	*Flare Details for General Refinery and Petrochemical Service*
Std 555	*Process Analyzers*

Manual of Petroleum Measurement Standards (*MPMS*)

Chapter 1	"Vocabulary"
Chapter 7	"Temperature Determination"
Chapter 14.1	"Collecting and Handling of Natural Gas Samples for Custody Transfer"
Chapter 14.3	Parts 1 – 4 "Concentric, Square-edged Orifice Meters"
Chapter 21.1	"Electronic Gas Measurement"
Chapter 22.2	"Testing Protocol-Differential Pressure Flow Measurement Devices"

ASME[1]

MFC-3M-2004 *Measurement of Fluid Flow in Pipes using Orifice, Nozzles, and Venturi*
MFC-6M-1998 *Measurement of Fluid Flow in Pipes Using Vortex Flow Meters*

EPA[2]

40 *CFR* 60.18 *Standard of Performance for New Stationary Sources (NSPS)*

GRI[3]

GRI-99/0262 *Orifice Meter Installation Configurations with and without Flow Conditioners*

ISO[4]

5167-4:2003 *Measurement of Fluid Flow by Means of Pressure Differential Devices Inserted in Circular Cross-Section Conduits Running Full—Part 4: Venturi Tubes*

TUV NEL Ltd.[5]

"The Effect of Gas Properties and Installation Effects on Thermal Flow Flowmeters—Project No. FDMS03, Report No.2002/53 January 2003"

Richard W. Miller, *Flow Measurement Engineering Handbook*, 3rd Edition.

3 Terminology and Definitions

3.1 DEFINITIONS CONSISTENT WITH DEFINITIONS IN API *MPMS* CHAPTER 1

3.1.1 turndown ratio: The maximum usable flow rate of a meter under normal operating conditions divided by the minimum usable flow rate.

3.2 DEFINITIONS UNIQUE TO THIS STANDARD

3.2.1 Flare Flow Measurement System (FFMS)

3.2.1.1 buoyancy seal: A dry vapor seal that minimizes the required purge gas needed to protect flare header from air infiltration. The buoyancy seal functions by trapping a volume of gas lighter or heaver than air in an internal passage that prevents air from displacing the gas and entering the flare stack.

3.2.1.2 calibration: The process or procedure of adjusting an instrument, such as a meter, so that its indication or registration is in satisfactorily close agreement with a reference standard.

3.2.1.3 insertion-type meters: A meter which may be installed through a gland and valving without shutdown of the flare system.

[1]ASME International, 3 Park Avenue, New York, New York 10016, www.asme.org.
[2]U.S. Environmental Protection Agency, Ariel Rios Building, 1200 Pennsylvania Avenue, N.W., Washington, D.C. 20460, www.epa.gov.
[3]Gas Research Institute, 1700 S. Mt. Prospect Road, Des Plaines, Illinois 60018-1804, www.gri.org.
[4]International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211, Geneva 20, Switzerland, www.iso.org.
[5]TUV NEL Ltd, East Kilbride, Glasgow, G75 0QF, United Kingdom, www.tuvnel.com.

3.2.1.4 liquid seal or liquid water seal: A device that directs the flow of relief gases through a liquid (normally water) on its path to the flare burner, used to protect the flare system from air filtration, from flashback, to divert flow, or to create back pressure in the flare header.

3.2.1.5 primary devices: The primary device consists of the flow meter body and/or primary sensing element(s) and transmitter. The term "primary device" in this Standard may be considered a synonym for the term "flow meter." Primary devices are normally viewed as the components purchased from a flow meter manufacturer and may include piping elements such as spool pieces. It is recognized that upstream and downstream piping affects measurement, but for purposes of this Standard, these piping components are not considered to be part of the primary device. See 4.2.2.1 for discussion of piping effects.

3.2.1.6 secondary devices: Other instruments (e.g., pressure, temperature, analytical) which measure process conditions and enable the calculation of flow at conditions other than the output of the meter, such as standard volumetric or mass flow rate.

3.2.1.7 tertiary devices: These devices are calculation and history-logging devices that take the output of the primary and secondary devices to calculate the flare flow rate. Some examples are: DAS (Data Acquisition Systems), indicators, DCS (Distributed Control Systems), RTU (Remote Terminal Unit), PLC (Programmable Logic Controllers), and flow computers.

Note 1: This document does not include a detailed discussion of the specification, operation, and maintenance of the tertiary device(s). (See API *MPMS* Ch. 21.1 "Electronic Gas Measurement.")

Note 2: In the context of this Standard, the output of analytical instrumentation is used, but due to the complex nature of this equipment the operation and selection of this equipment is not included. (see API Std 555 *Process Analyzers*).

3.2.1.8 recognized flow meter test facility: A facility capable of performing assessments of flow meters and whose measurements are traceable to NIST (National Institute of Standards and Technology) or other national standards bodies.

3.2.1.9 uncertainty: The range or interval within which the true value is expected to be within a stated degree of confidence.

3.2.1.10 verification: In the context of this Standard, verification is the process of ensuring that instrument parameters and mechanical integrity meet applicable requirements. Verification includes calibration checks (without adjustments), device inspection, and confirmation that operating and configuration parameters are within manufacturer's specification.

4 Application Considerations for Meters in Flare Systems

4.1 GENERAL CONSIDERATIONS

This section of the standard includes information and guidelines for the selection and design of an FFMS.

The ideal integration of a flare meter into a flare system is to plan for the meter when designing the overall flare system. This is not always possible, especially for older flare systems where new metering requirements are imposed. See Appendix A-4 for greater detail on overall flare design.

The designer of an FFMS should choose components of the system which will achieve the desired requirements in terms of accuracy. The uncertainty method provided in Section 10 should be used to predict overall FFMS composite uncertainty.

The overall FFMS performance may be improved through the proper selection of a specific meter type, careful planning, proper design, precise fabrication, correct installation, and ongoing maintenance, resulting in a reduced (better) measurement uncertainty. Where an increased overall measurement uncertainty is acceptable, less stringent requirements may be adequate.

Flare flow measurement by its nature provides unique challenges in terms of extreme turndown, large pipe sizes/limited straight lengths, and variations in process pressure, temperature, and fluid composition.

For flow measurement technologies such as Pitot, orifice, venturi, vortex, and ultrasonic meters, the upstream straight length requirements and the effects of varying gas composition are documented. For technologies such as optical techniques and thermal flow meters, where influence parameters such as flow profile effects or varying gas composition are not as well documented, users should evaluate and assess the performance capabilities of the equipment to ensure that the application of the technology is appropriate.

It is recommended that manufacturers be able to provide test reports quantifying the effects of various influence parameters on their devices to substantiate their performance specifications on request. Such reports should be based on flow loop data from a recognized flow meter test facility.

Where considering existing FFMS components against new requirements, the basic guidance in this section applies. The process for evaluating an existing FFMS against new requirements may involve both the original manufacturer and the owner (see Sections 7 and 8).

4.2 LOCATION OF FLARE METERS

4.2.1 Safety Considerations

During flaring events, equipment and workers in close proximity to the flare will be exposed to radiant heat. Instruments could be damaged or readings could drift. API Std 521 provides information regarding the exposure of workers and equipment to flame radiation including recommended limits on the period of exposure, particularly for flare headers which are elevated above grade.

The flow meter and associated instrumentation must be accessible for verification, repair, or calibration. Unless the flare system is shut down for installation of the flare flow measurement instruments, the work plan shall include a safety review to consider such issues as air leakage into the flare header or gas leakage out of the header. Consideration should be given to worker access and egress and the possible need for shielding of workers and/or equipment. In some cases, it may be possible to use the flare header as a shield against heat radiation to instruments.

4.2.2 Location Considerations

The potential for two-phase or liquid flow through the meter should be avoided if at all possible by locating the meter downstream of knock-out drums. The ideal flare meter arrangement consists of a single flare meter, located downstream of the final vent system liquid removal equipment, and in horizontal piping before the entry point into the vertical flare header.

If the meter cannot be located downstream of the final liquid removal equipment, it may be located upstream, provided the quantity of liquid present at the measurement point does not degrade measurement accuracy and meter reliability below acceptable levels. In such cases, a meter which cannot re-establish normal gas-phase operation upon subjection to temporary multiphase flow conditions would not be a viable choice. Location in the vertical flare header is the least preferred location, due to accessibility and personnel safety concerns.

Flare meters should be located downstream of all lateral vents feeding the vent system, including sweep (purge) gas or sweetener gas (methane). This requirement does not apply to buoyancy seals, where the flow rate of the buoyancy seal is less than 5% of the minimum flare vent flow.

Some flare systems do not lend themselves to this single-meter design because the flare header system was not originally designed with a flare meter in mind. In some cases, multiple vent streams may be incompatible or reactive and must combine as close to the flare exit as possible. In such applications, multiple flare meters are required (see 4.2.2.2).

4.2.2.1 Piping Runs

Meters typically perform best when flow profile through the pipe in the location of the meter is repeatable and known. In flare operations, this is best accomplished by having adequate straight runs of upstream and downstream round piping. The use of flow conditioners is generally not practiced in flare headers due to the pressure drop imposed by these devices or risks of plugging during high velocity emergency flaring operations.

A generally accepted minimum number of header diameters are 20 pipe diameters upstream, and 10 diameters downstream. However, these minimums can vary depending upon upstream and downstream piping configuration and flow meter technology. The manufacturer should be consulted for specific applications (Appendix A-6 is intended to provide guidance at an introductory level on the effect of non-ideal flow profile on meter performance).

Out-of-round piping will result in greater uncertainty of flow measurement. The manufacturer should be consulted in this case.

4.2.2.2 Multiple Flare Meters (Metering Branches Individually)

Some flare designs have multiple headers entering the flare system near the final flare vertical header because of reactive chemical issues or extreme temperature differences. In such cases, the use of a single flare meter may be impossible. Under such conditions, upstream meters in parallel laterals may be used, provided all gas in parallel laterals is measured, each meter meets accuracy and output units requirements so that they may be summed correctly for total flow to the flare, and each meter is functionally independent, having its own sensors (e.g., pressure transducers, temperature transducers, and analytical instrumentation).

Metering of multiple parallel branches should be minimized, due to increased requirements for secondary instrumentation, and the added complexity of calculations. Consideration should be given to re-routing flare header piping to avoid metering too many branch connections. In practice, metering of more than two branches may become undesirable due to cost and complexity issues.

4.2.2.2.1 Total Flare Exit Mass Flow and Heating Value

To reduce uncertainty of total flare exit mass flow and heating value, stream composition must be known or measured for each branch which is metered. This typically requires analytical instrumentation, and pressure and temperature instrumentation for each metered branch. The calculation required to compute combined (total) flare heating value at the flare exit is listed in A-2.5.2.

4.2.2.2.2 Total Flare Exit Standard Volumetric Flow Rate

To calculate total flare exit standard volumetric flow rate, pressure and temperature instrumentation, and in some cases composition, are required for each metered branch. Standard volumetric flow rate for each branch may be calculated using the appropriate equations in A-2.1, and may be summed to provide a total flare exit standard volumetric flow rate according to A-2.3. For flare tip exit velocity calculations, see A-2.4.

4.3 APPLICATION-SPECIFIC FACTORS AFFECTING FLOW METER PERFORMANCE

In a new FFMS, only flow meters suitable for the specific flare measurement application should be considered. It is recommended that users require the manufacturer to document performance specifications based on test data from a recognized flow meter test facility encompassing the user's operating envelope and similar piping configuration. The data should clearly show that the specific meter design, style, and type are suitable for the intended use, especially where liquids may occasionally be present or where a large flow turndown ratio exists.

Note: Although liquid or mixed-phase flow is outside the scope of this Standard, it is recognized that upset conditions can bring about occasional liquid entrainment, in which case the ability of the meter to re-establish proper operation should be considered.

The following should be considered when evaluating the performance of an FFMS:

- Minimum flow rate.
- Maximum flow rate.
- Minimum gas velocity.
- Maximum gas velocity.
- Flow rate-of-change.
- Average or typical gas flow rate and velocity.
- Gas composition determination methodology.
- Gas composition sampling rate.
- Typical gas composition.
- Presence of liquid mists or contaminants.
- Changes to gas composition.
- Gas density range.
- Gas pressure range.
- Gas temperature range.
- Ambient temperature range.
- Other ambient conditions.
- Meter location relative to flare.
- Effects of flare radiant heat and use of equipment heat shields.
- Meter location relative to tertiary equipment.
- Upstream and downstream piping geometry.
- Other piping components.
- Equipment grounding.
- RFI (Radio Frequency Interference).
- EMI (Electromagnetic Interference).

- Maintainability.
- Other on-site components.

4.4 METER SIZING

All gas flow meters have a finite range of use. It is important to account for the entire range of flare flow rates. Low flow rates should not be ignored if their cumulative flare gas volumes are significant. Flow rates higher than a meter's known performance range will result in flare gas volume that is not measured and increase overall measurement uncertainty. In some cases, more than one meter type may be installed in series to allow low flow rates to be measured by one meter type and higher flow rates to be measured by the other type. In other cases, the high flow rate may be estimated from plant upset conditions due to the low frequency of occurrences.

Flare applications typically involve widely changing gas mixtures and large turndown ratios. Therefore, reliable and detailed process stream information is critical to meter sizing.

A process stream data sheet should be developed for the flare meter which captures the most likely composition and flow rate scenarios at minimum, normal, and maximum (upset) conditions. Special attention should be given to high hydrogen compositions because the properties of hydrogen (e.g., density, thermal conductivity, sound attenuation) are so different from other components commonly found in flares. The process stream data sheet should account for and document flare stream mixture composition and flowing conditions under most likely relief scenarios (see Appendix A-1). Caution is recommended when designing a system based on a single set of operating conditions.

4.5 MEASUREMENT UNCERTAINTY

The combined uncertainty of the primary, secondary and tertiary components of the FFMS should be considered in determining the overall uncertainty of the measured gas flowing to the flare. Credible uncertainty analysis of any flow meter or measurement system depends on many variables, and relies on the selection of an appropriate uncertainty analysis method.

See Section 10, which provides methods for understanding and predicting overall metering system uncertainty.

4.6 FLOW METER SELECTION

Many different flow meter types are used to measure gas flow to flares. No single type or design of flow meter is suitable in all flare gas measurement applications. One flow meter type may perform better than another in a specific flare gas measurement application. The selection of a suitable meter(s) for a particular flare gas measurement application is based on a combination of operating conditions and end user requirements. An FFMS may include more than one meter type to meet uncertainty requirements over the entire operating envelope.

The type and accuracy of secondary instrumentation required to meet FFMS accuracy requirements is also dependent on the meter technology selected (see Section 10).

Influence parameters such as piping geometry and changing gas composition can significantly affect meter performance. For proper meter selection, the user must provide the manufacturer a detailed process stream data sheet (see Appendix A-1 for an example) describing the meters operating envelope and a drawing describing the proposed piping geometry. Gas composition at minimum, normal, and maximum flow rates, and maximum hydrogen conditions are crucial considerations when selecting a meter type.

Particular attention should be given to manufacturers' specifications which denote a meter is immune to influence parameters which are known to affect most types of meters such as variances in gas composition, flowing temperature and pressure, upstream piping effects (e.g., swirl, abnormal gas velocity profile), noise (any source), pulsation, and multi-phase flow. In such instances, it is recommended that the user require that the manufacturer provide performance test data from a recognized flow meter test facility to demonstrate that the proposed meter type will meet the manufacturer's specifications for the operating envelope described in the process stream data sheet and piping geometry drawing.

Installation effects on velocity profile, the meter's determination of velocity, and area weighting have significant effects on metering accuracy. See Appendix A-6 for additional guidance.

4.6.1 Meter Outputs

Flare meters are typically expected to perform over wide ranges of flow (i.e., high turndown).

- For analog outputs, separate flow output ranges should be considered to accommodate at least one flow range for each order of magnitude in turndown. For example, a 1000:1 turndown meter should have a low range, medium range, and high ranges of operation. A 10:1 turndown meter, therefore, requires only one range.
- For digital communication, one digital output will suffice for the entire range of the meter.

Other output requirements:

- Ranges should be programmable by the user.
- Ranges should be capable of being overlapped, or “split-ranged.”
- Units of flow should be available for both customary (English) and SI (International System) units.
- Units should allow for difference of scaling between outputs
- Outputs should be available to the owner’s DCS, PLC, or other data acquisition device, according to common industry protocols. Such protocols include, but are not limited to, the following:
    - 4 ma – 20 ma current output,
    - RS232 serial,
    - RS485.
- Depending upon meter technology, outputs other than flow rate may also be provided. Examples are velocity, speed of sound, inferred density, and inferred molecular weight.

4.6.2 Component Compatibility

Primary, secondary, and tertiary measurement components must be compatible with each other.

The manufacturer of the flow meter should be consulted about compatibility of secondary, tertiary, and analytical devices used in conjunction with his equipment, including communication protocols between these devices.

4.6.3 Sensitivity to Entrained Mist, Liquid, and Fouling

All flow meter technologies are affected by entrained mist, liquid, and fouling, depending on the process. See Table 1 for general guidance. Consult the manufacturer for specific applications.

Entrained mist and liquid are typically transient effects, whereas fouling effects are irreversible without maintenance.

Table 1

Technology	Sensitivity to Entrained Mist or Liquid	Sensitivity to Fouling	Ability to Detect Fouling
Differential Pressure	Low to Moderate (varies with liquid load)	Moderate	Physical Inspection
Thermal Flow	High	High	Physical Inspection
Optical	Moderate	High	Meter Diagnostics
Ultrasonic	Low (unless sensor is immersed in liquid, then very high)	High	Meter Diagnostics
Vortex	Low (if meter is installed in horizontal line and bluff body is horizontal)	Low to High (varies with meter design)	Physical Inspection

4.6.4 Diagnostic Software

Some meters are equipped with diagnostic software that can be used to monitor/check the operation of the meter while it is in service. In many cases, this information can be used to detect sensor fouling and other conditions affecting meter accuracy. Use of this capability should be considered during meter selection and when developing operating and maintenance procedures.

4.6.5 Commissioning and Initial Field Calibration

A detailed procedure from the manufacturer is required for commissioning and startup. For more information on commissioning, see Section 6.

4.6.6 Preparation of Personnel

The manufacturer should be consulted for available training for end-user personnel who will be involved in commissioning, operation, and periodic verifications.

4.7 SPECIFIC METER CONSIDERATIONS

Meters which are required to report in other than their fundamental (uncorrected) output are typically used in conjunction with pressure, temperature, and in some cases, analytical instrumentation (see Figure 1). Conversion of the fundamental measurement to the required output is then performed in a flow computer, DCS, meter electronics, or DAS. For example, meters which have an uncorrected output of actual volumetric flow rate are required to have secondary devices to obtain mass output.

For flares where composition, pressure, or temperature may be considered constant, those parameters may be input to the computational devices as fixed values.

See Table 2 for guidance on installation effects and secondary instrument requirements.

Flare meters are expected to operate over a wide range of velocities. Meters operating at close to atmospheric pressure and velocities <0.3 m/s – 0.6 m/s (1 ft/s – 2 ft/s) can be operating in transition from turbulent to laminar flow or laminar flow. The meter manufacturer should be consulted on how the meter handles flow in this difficult area and the effect on metering accuracy. The user is also cautioned that operation at these low velocities may also subject the meter to flow instabilities caused by ambient operating conditions such as wind blowing across the flare outlet, dissimilar thermal heating of the flare piping, etc.

Manufacturer's electronics for meters can force the output signal to zero at some preset low flow rate. The user is cautioned to discuss the issue of low-flow cutoff with the manufacturer for each flare flow application.

Meters operating at high flow rates may experience loss of meter output or meter over-ranging. The meter manufacturer should be consulted on the maximum velocity that can be measured and how the meter handles flare flow that exceeds these limits.

4.7.1 Differential Pressure Flow Meters

For flare meter applications, the primary device must not create a significant permanent pressure drop. Examples of such differential pressure devices are low loss venturi meters and averaging Pitot tubes.

Differential pressure producers are sensitive to the flowing density for mass measurements and to the flowing and base density for volumetric measurements. Therefore, they are very sensitive to variations in fluid molecular weight (i.e., composition), compressibility, and flowing temperature and pressure.

The square root relationship between velocity and produced differential pressure restricts the turndown of differential pressure producers. This limitation may be reduced but not eliminated through the use of multiple differential pressure transmitters.

The primary element shall produce a sufficient differential pressure for an accurate and repeatable measurement.

4.7.1.1 Averaging Pitot Tube

To minimize installation effects, the meter manufacturer should be consulted on probe orientation and minimum upstream piping requirements based on the inlet piping configuration. Averaging Pitot tubes are typically mounted through a nozzle in the pipe wall, and may be provided with extraction hardware to allow for ease of inspection or repair. Care must be taken to insert the meter to the proper depth and aligned to the flow within manufacturer's limits to achieve stated metering accuracy.

Averaging Pitot tubes produce very small permanent pressure drops. Thus, they are suitable for use in high velocity applications where other technologies may be limited, and may be used as high range meters in flares, which may handle large process upset events. For velocities below 4.5 m/s (15 ft/s), the user should exercise due diligence to ensure that measurement uncertainty requirements are met. Specifically, at very low velocity, the differential pressure produced by an averaging Pitot tube may be difficult to measure, particularly in the presence of pulsations or swings in ambient temperature.

Table 2

	Installation Effect Sensitivity	Actual Volume		Standard Volume		Mass	
		Pressure/ Temperature	Composition Required to Calculate	Pressure/ Temperature	Composition Required to Calculate	Pressure/ Temperature	Composition Required to Calculate
Differential Pressure Meters							
Pitot Tube	Point or Multipoint Averaging	YES	Square Root of Density (Note 1)	YES	Base Density and Square Root of Flowing Density	YES	Square Root of Density
Orifice	Path Averaging						
Venturi	Path Averaging						
Thermal Flow Meters							
Thermal Flow	Point or Multipoint Averaging	YES	Thermal Conductivity, Viscosity and Prandtl Number; Compressibility (Note 2)	NO	Thermal Conductivity, Viscosity, and Prandtl Number	NO	Standard Density, Thermal Conductivity, Viscosity, and Prandtl Number
Optical Meters							
Optical Scintillation	Path Averaging Velocity	NO	NO (Note 3)	YES	Compressibility (Note 2)	YES	Density
Laser 2-focus	Point Velocity						
Ultrasonic Flow Meters							
Ultrasonic	Path Averaging Velocity	NO	NO (Note 3)	YES	Compressibility (Note 2)	YES	Density
Vortex Flow Meters							
Vortex Shedding	Point/Path Velocity	NO	NO (Note 3)	YES	Compressibility (Note 2)	YES	Density

Note 1: Actual volume is normally not required for differential pressure flow meters for flare measurement.

Note 2: Compressibility effects are typically << 1% (see Appendix A-3).

Note 3: Velocity or actual volumetric flow rate is the meter's fundamental measurement.

Note 4: For errors related to composition changes:

- Meters requiring density have the largest error.
- Meters requiring the square root of density have approximately $^1/_2$ the error of meters requiring density.
- Meters requiring only compressibility have the smallest errors.
  (Measurement at pressure close to atmospheric pressure often neglected compressibility.)
- See Section 10 for how to estimate density and compressibility errors.

4.7.1.2 Venturi

Venturi meters are in-line meters which are not easily removed for serving while flare headers are in service. Although the permanent pressure loss of venturi meters is lower than orifice meters, it is still significant for flare application and therefore venturi meters are typically not used as flare meters.

For flare metering, vertical taps should be used. To minimize installation effects, ISO 5167-4:2003(E) or ASME MFC-3M-2004 should be consulted on minimum upstream piping requirements based on the inlet piping configuration.

4.7.1.3 Orifice

Orifice meters, which produce significant permanent pressure loss, are typically not suitable as flare meters, with the exception of measuring the addition to the flare system of such streams such as nitrogen sweep gas or fuel gas.

To minimize installation effects, AGA-3/API *MPMS* Ch. 14.3 should be consulted on pressure tap orientation and minimum upstream piping requirements based on the inlet piping configuration. Because AGA-3/API *MPMS* Ch. 14.3 is focused on custody transfer metering accuracy, the Gas Research Institute report GRI-99/0262 "Orifice Meter Installation Configurations with and without Flow Conditioners, White Paper Prepared for API 14.3 p. 2," may be referenced for handling shorter piping lengths with increased measurement inaccuracy.

4.7.2 Optical Flow Meters

Optical flow meters are linear meters which measure flow velocity or actual volumetric flow rate. Optical meters are typically installed through nozzles or thread-o-let connections and may be provided with extraction hardware to allow for ease of inspection or repair. They are sensitive to the fouling of wetted optical components by liquid droplets, mists or contaminants in the process fluid. Some meters incorporate designs which are capable of identifying fouling effects prior to loss of signal.

The meters typically operate at velocities between 0.3 m/s (1 ft/s) and 91 m/s (300 ft/s). They are sensitive to flow disturbances (non-ideal flow profile). The meter manufacturer should be consulted on the accuracy impact of Reynolds number, random uncertainty of velocity measurement, probe effects on flow profile, and inlet piping installation effects.

4.7.2.1 Optical Scintillation Meters

Optical scintillation meters utilize effects which are caused by optical refraction occurring in small parcels of gas whose temperature and density differ from their surroundings and cause changes in the apparent position or brightness of an object when viewed through the atmosphere or gas. To minimize installation effects, the meter manufacturer should be consulted on path orientation and minimum upstream piping requirements based on the inlet piping configuration. Care must be taken to install and align the meter within manufacturer's limits to achieve stated metering uncertainty. In some cases, purging of the optical surfaces may be necessary to ensure reliable measurement.

4.7.2.2 Laser 2-focus Meters

Laser 2-focus meters depend on the presence of naturally occurring particulate matter entrained within the gas mixture. Care must be taken to insert the meter to the manufacturer's specified depth and aligned to the flow direction within manufacturer's limits to achieve stated metering accuracy.

4.7.3 Thermal Flow Meters

Thermal flow meters utilize designs that are manufacturer-specific. These design differences result in response differences related to flow rate (similar to differences between different types of differential pressure producers) and composition. This requires each manufacturer to develop and maintain design specific databases of flow and composition response data and to develop meter-specific correction factors based on regression of these data.

It is recommended that users require data from a recognized flow meter test facility for the user's application flow and composition range from meter manufacturers. The data should clearly demonstrate that the specific meter design, style, and type are suitable for the intended use and should validate the accuracy of the manufacturer's composition correction factors for the meter.

For meters intended for use with analytical composition instrumentation, the user is advised to consult the manufacturer on how to interface their equipment to the analytical instrumentation. Attention to analysis delay and how this will be handled by the meter should be considered (see 10.4.2).

Thermal flow meters have significant sensitivity to variations in gas composition (see 10.4.3). Thermal flow meters are not recommended for applications where liquid droplets or liquid mist are normally present due to their extreme sensitivity to these substances.

The manufacturer should be consulted for the effects of varying gas composition and process pressure over the operating envelope of the meter. For variations in flare gas compositions, the user must provide detailed process stream composition data to the manufacturer for multiple factory calibrations, as required. In such applications, an analyzer or other means must be taken to allow the meter to select the appropriate calibration.

Thermal flow meters are insertion type meters, which may have either single- or multiple-point sensing locations. These meters are typically calibrated in standard velocity units.

Care must be taken to insert the meter to the manufacturer's specified depth and aligned to the flow direction within manufacturer's limits to achieve stated metering accuracy.

4.7.4 Ultrasonic Flow Meters

Ultrasonic flow meters are linear meters which measure flow velocity or actual volumetric flow rate. They can either be a spool piece design or installed through thread-o-let connections on existing flare pipe. They may be provided with extraction hardware to allow for ease of inspection or repair and can be sensitive to the fouling of wetted components by liquid droplets, mists or contaminants in the process fluid. Some meters incorporate designs that are capable of identifying fouling effects prior to loss of signal.

Some ultrasonic meters may be configured to derive molecular weight from the measured speed of sound utilizing proprietary correlations. Combined with measured flowing temperature and pressure, the inferred molecular weight can be used to calculate flowing density and hence mass flow rate. The inferred molecular weight may also be used to characterize and determine the source of gas to assist in flare gas volume reduction. The choice of this configuration may be more desirable if a gas chromatograph will not be employed to determine gas composition. For this type of operation, pressure and temperature measurements are usually hard-wired into the meter.

For meters using derived molecular weight, it is recommended that users require the manufacturer to provide test data from a recognized test facility. These data should demonstrate the accuracy of the density correction of the meter over the user's application composition range.

Care must be taken to insert the transducers to the manufacturer's specified depth, spacing, and alignment within manufacturer's specifications to achieve stated metering accuracy.

4.7.5 Vortex Shedding Flow Meters

Vortex meters may have sensitivity to entrained liquid and therefore should be installed with the shedder bar in the horizontal plane or at a 45-degree angle to minimize such effects. Some models are sensitive to fouling.

Vortex shedding meters may be installed as either in-line or insertion devices. In-line vortex shedding meters are normally applicable to small flare header sizes (below 25 cm [10 in.]).

In-line vortex shedding meters develop significant permanent pressure loss and therefore are not typically used as flare meters. The application of vortex meters as flare meters is further limited by their inability to measure flow rate at very low velocity or in larger sizes at low gas density.

Vortex meters may be used successfully to measure the addition to the flare system of such streams such as nitrogen sweep gas or fuel gas, or to measure relatively constant flow relief flares.

4.8 SECONDARY INSTRUMENTATION

For the determination of measured flare gas quantities (e.g., mass, standard volume), the gas composition, pressure, and temperature must be known. The use of fixed values for gas composition, pressure, and temperature will lead to greater measurement uncertainty, but may be acceptable in steady-state systems or where this uncertainty is acceptable.

4.8.1 Location of Secondary Device Connections

Depending upon the flare flow meter technology selected, the ideal location of process connections for secondary devices (pressure, temperature and analytical sampling) may vary. In general, temperature and analytical connections should be downstream of all primary FFMS components, unless the location upstream does not cause significant disturbance of flow profile. See Table 3 for the suggested upstream or downstream location of pressure devices relative to the flare flow meter.

Table 3

Flow Meter Technology	Pressure Instrument Location
Averaging Pitot Tube	UPSTREAM or INTEGRAL
Venturi	UP or DOWNSTREAM
Orifice	UP or DOWNSTREAM
Optical	UP or DOWNSTREAM
Thermal Flow	N/A
Ultrasonic	UP or DOWNSTREAM
Vortex Shedding	DOWNSTREAM

The process conditions at the location of secondary devices should be representative of process conditions at the primary device location. For more specific guidance on optimal distances upstream or downstream of the flare flow meter, see the manufacturer's guidelines or applicable standards.

4.9 CODES AND STANDARDS

The FFMS should be designed and installed to meet all applicable codes and standards.

4.9.1 Electrical Area Classification

Electrical area classification requirements should be provided to the manufacturer by the end user.

4.9.2 Mechanical

Flare meters operate under variable and sometimes high velocity flow rates. The meter manufacturer should be consulted about specific installation requirements to address mechanical vibration and stress (e.g., the effects of flow harmonics, rapid flare flow rate changes, liquid impingement). For insertion type meters, opposite wall pinning or multiple entry points should be considered.

The manufacturer must be provided accurate process stream data by the user to ensure structural integrity of the measuring element and installation.

4.10 MAINTENANCE CONSIDERATIONS

Equipment maintenance is an integral part of any well designed FFMS. The following list includes maintenance-related items that should be considered when designing an FFMS.

- Provide adequate space for personnel to perform maintenance duties.
- Ensure other equipment, including piping, does not interfere with measurement system maintenance.
- The meter, piping, and other metering components should be designed so that they can be removed, as necessary, for inspection, cleaning, replacement, or other testing in the course of performing periodic verifications or other maintenance.
- Protect measurement system equipment from adverse ambient conditions.
- Identify sources of noise, vibration, and pulsation under operational conditions that would affect measurement equipment maintenance.
- Plan for inspection and cleaning of meter components (meter body, upstream piping, downstream piping, flow conditioners, etc.) in piping and equipment design.
- Locate pressure, temperature, and other transducers and transmitters to provide access for inspection, verification, and replacement.
- Design and install valves, meter manifolds, test connections and other secondary equipment components to allow checking and verification of various transducers and transmitters.
- Provide hoists and lifting lugs at appropriate points for all equipment, as necessary.
- Allow for metering equipment set-down space when maintenance is performed.
- Provide adequate ingress and egress to metering installations for test and other equipment.

4.11 RECORD-KEEPING

Documentation requirements of Section 11 should be met for all measurement equipment and associated instrumentation (flow meters, pressure transmitters, temperature transmitters, gas chromatographs, densitometers, etc.).

5 Factory Calibrations/Verifications

5.1 FLOW METER

Flow meters shall be either individually tested, or verified by type testing at the manufacturer's flow laboratory or a third-party flow testing laboratory.

The requirements for initial calibrations vary with meter type. For example, the primary devices of ultrasonic and optical meters and differential producers such as orifice, venturi, and averaging Pitot tube meters are typically not individually calibrated in flow loops. The primary elements of vortex and thermal flow meters are typically calibrated at the factory.

The overall uncertainty of the flow meter shall be demonstrated to be within ±5% at 30%, 60%, and 90% of the application full scale, or as otherwise required by the user.

For the purposes of this section, performance testing may be performed at the manufacturer's facility or at a recognized flow test facility. All test equipment shall be traceable to NIST or other appropriate national standards bodies.

Type testing/calibration is permitted provided that:

1. Primary element performance has been established using flow loop testing.
2. All primary elements of a given type are shown to have been manufactured to within the manufacturer's tolerance for the original flow meter that was type tested.

Type testing of every size of the flow meter may not be required, provided that it can be demonstrated, based on flow loop testing, that the flow meter's performance is independent of Reynolds number and pipe size.

In the case of water calibration of a gas flow meter, flow loop test data must be provided to demonstrate the effectiveness of using water to calibrate a gas meter (i.e., the water calibration will not impact the meter stated performance specification).

If the user's flow meter will not be used in exactly the same piping configuration used for type testing, it is recommended that the manufacturer demonstrate that the type test data can be extrapolated to predict the performance of the user's flow meter in its operating configuration, based on flow loop testing.

The flow meter electronics should be factory inspected and calibrated over the intended operating range detailed in the instrument data sheet to demonstrate conformation to manufacturer's specifications.

The manufacturer should provide, if requested, a document which describes performance, or otherwise substantiates the manufacturer's accuracy specification over the intended range of operation of the flow meter. The basis of this accuracy specification should be flow loop testing.

In addition to the requirements listed above, for thermal flow meters, a representative sample(s) of gas having a similar set of thermal properties as the flare gas should be used to calibrate the flow meter in a flow laboratory. In the case of a gas correlation using air, the manufacturer should show, based on testing, the effectiveness of using air to calibrate a thermal flow meter for gas of varying composition over the entire operating envelope.

5.2 PRESSURE AND TEMPERATURE INSTRUMENTS

Instruments purchased for FFMS applications are typically no different than those used in standard petrochemical applications. Manufacturers of such instruments have demonstrated acceptable tolerances with type testing data, traceable to NIST or other national standards bodies, which requires no additional testing for use in FFMS applications.

The maximum overall inaccuracy of the pressure instrument shall be demonstrated to be less than ±0.67 kPa (±5 mm Hg or ±0.0967 psi).

The maximum overall inaccuracy of the temperature sensor and transmitter combination shall be demonstrated to be less than ±2°C (±3.6°F).

6 Commissioning and Startup

This section of the standard provides information and guidelines for commissioning and startup. Following installation, commissioning is the final step before putting the meter into service for the first time. Commissioning is important for confirming the mechanical design of the meter and secondary instrumentation and establishing baselines of the hardware and software configuration.

After commissioning, configuration changes should be maintained by management of change (see Appendix A-5) and periodic verifications (see Section 7) referenced back to commissioning documentation (see Section 11).

6.1 EQUIPMENT INSTALLATION

Verify the equipment has been installed according to the mechanical design, paying special attention of location of instrumentation and dimensional data related to the flare meter, inlet/outlet piping, and fittings. Use a management of change process to address any discrepancies and update all documentation.

Verify the mechanical installation of piping, meter, and instrumentation is installed according to accepted industry practices. Verify that the piping is free of foreign material and ready to be placed into service.

Check that the FFMS system primary, secondary, and tertiary equipment are installed and ready to be commissioned. (API *MPMS* Ch. 21.1, Section 1.7 may be referenced for additional details on equipment installation.)

6.2 FFMS COMMISSIONING

Commissioning and verification of the FFMS system is accomplished in four parts as illustrated in Figure 2.

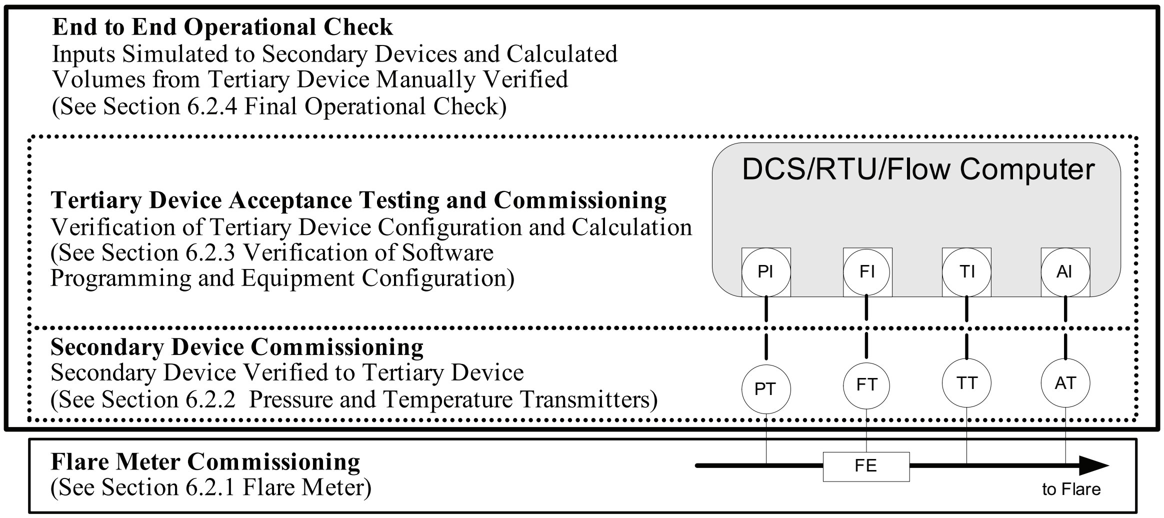


Figure 2

6.2.1 Flare Meter Commissioning

Verify that:

- The flare meter configuration and serial number match the calibration/verification documentation.
- For spool piece meters, the meter and piping are aligned.
- The flare meter has been installed according to the manufacturer's installation and commissioning procedures, including required upstream and downstream piping.
- The average pipe internal diameter at the metering point and any field determined dimensions (path length, insertion depth, alignment, spacing, transducer angle, etc.) have been correctly determined and recorded.
- Any meter-specific operating and configuration parameters such as low flow cut-off, handling of reverse flow, etc., are correctly configured and recorded.

Care should be taken in determining the cross-sectional area of the pipe for non-spool-piece meters. It is recommended that the outside diameter and wall thickness at least four different locations be measured and the average of these readings be used.

Where applicable, use configuration and diagnostic software for flare meters to verify the meter configuration. For future reference and troubleshooting, perform and record the results of all available diagnostics and operating values such as:

- Voltage.
- Transmitter and receiver gains.
- Signal-to-noise ratios.
- Velocity of sound.
- Other operating values.

6.2.2 Pressure and Temperature Transmitters Commissioning

Secondary instrumentation shall be calibrated/verified as part of the commissioning procedure. (API *MPMS* Ch. 7, "Temperature Determination," and API *MPMS* Ch. 21.1, Section 1.8 may be referenced for additional details.)

If required tolerances are more stringent than those referred to below, the user shall abide by those tolerances.

As a minimum:

- Pressure should be verified at three points to demonstrate that the transmitter is within ±0.67 kPa (±5 mm Hg or ±0.0967 psi) or user specified limits.
- Temperature should be verified at three points to demonstrate that the transmitter is within ±2°C (±3.6°F) or user-specified limits.
- Verifications should be done to the DAS, DCS, or other data collection device.
- Documentation of this initial verification should be generated which shows the "as-found" and "as-left" state of the transmitter (see Section 11).

6.2.3 Tertiary Device Acceptance Testing and Commissioning

Follow the meter manufacturer's commissioning procedure to ensure correct configuration of the meter and verify that all electronic devices have the correct configuration parameters. Pay close attention to the pipe dimensions and dimensions specific to the technology being utilized. Incorrect parameters can greatly affect the accuracy of the results obtained from the FFMS.

Once the DAS, DCS, or other data collection device has been configured, the meter and instrumentation ranges and units confirmed, and all programming changes have been completed, a thorough check of the program should be made. This should involve using a combination of fixed and live inputs. The resulting flow should be compared with that from a hand calculation or the vendor's specification sheet.

Collect all the information programmed in the electronics as a backup in the event of an electronics failure and for proper records retention. These data will be used in subsequent periodic verifications.

6.2.4 End-to-End Operational Check

As a final check before the meter is placed in service and after all programming, configurations, and instrumentation hook-up has been completed, simulate or measure values for all FFMS inputs and compare the calculated flow to manual calculations.

7 Periodic Verification

7.1 GENERAL

After commissioning and startup, an FFMS should be periodically verified in the field, normally once per year. The objective of the periodic verification is to demonstrate that the FFMS continues to operate at the required performance level for accuracy and reliability. Over time, it is possible that flare operating conditions may change (composition, operating flow rates, temperatures, pressures, etc.), or that electronic components change their characteristics. Any of these changes may necessitate adjustments to the FFMS physical setup and software/firmware configuration. The periodic verification also ensures that the *current* electronic and mechanical parameters of the FFMS primary, secondary, and tertiary devices remain at their last approved, documented configuration, and are within manufacturers' established tolerances.

Any configuration changes should be appropriately documented (see Section 11).

7.2 PERIODIC VERIFICATION METHOD—FLOW METER

In most cases, complete verification of the primary element for operating flares is not practical. Therefore, annual verification of the flow meter is limited to verifying the configuration and ensuring that the operating parameters are within the manufacturer's limits for proper performance.

It is expected that the manufacturer provide a detailed periodic verification procedure. This procedure may be written specifically for individual flare meter applications, as necessary, and should be maintained by the user.

The periodic verification should consist of the following steps, not necessarily in the order listed. Some of the steps below may require taking the meter out of service and removing transducers or primary elements for purpose of inspection and running diagnostics.

1. Document the current configuration parameters, and perform required electronic diagnostics. Record the results of diagnostics and current configuration data. This defines the "as-found" state of the meter's electronic configuration data.
2. Perform a physical "as-found" inspection of major components, as required. Document the results of the physical inspection.
3. If the "as-found" inspections identify that a drift or change in any settings or parameters have occurred exceeding predetermined limits, the flow meter should be adjusted to bring those settings or parameters back to within the manufacturer's allowed limits. Otherwise, no adjustments should be made.
4. If settings or parameters have changed which cannot be adjusted back to within predetermined limits, repairs shall be implemented as follows:

    a. A major repair, which typically requires change of primary elements or replacement of the entire meter, requires a full re-commissioning of the flow meter per applicable portions of Section 16 of this Standard.
    b. A minor repair, which only involves replacement or repair of minor components, does not require a full re-commissioning.
    c. Repairs and replacements shall be documented.

5. Record results of diagnostics and final configuration data. This defines the baseline or "as-left" state of the meter.
6. Return the flare meter to service, and verify operation.

7.3 PERIODIC VERIFICATION METHOD—SECONDARY DEVICES

Secondary devices (pressure and temperature instrumentation) should be verified yearly, preferably during the same time interval that the flare meter is being verified to minimize overall FFMS unavailability. Procedures for verification of secondary devices are the same as those for initial commissioning.

See 6.2.2 for verification procedures and calibration limits for pressure and temperature transmitters.

8 Re-evaluation of Existing FFMS

If an existing FFMS is required to meet more rigorous accounting or regulatory measurement standards, or if there are significant process changes, the overall FFMS should be re-evaluated. This re-evaluation will determine if components should be added or upgraded to meet the new requirements.

For safety and operational considerations, it is often impractical or impossible to remove an existing meter for flow calibration. Where a meter cannot be removed for a follow-up flow calibration, it should be evaluated in place according to a formal re-evaluation procedure, and then be commissioned again in accordance with Section 6. The reasons for performing both the re-evaluation procedure and the post-installation commissioning procedure are to ensure:

- The meter will operate correctly under current operating conditions.
- To verify that the meter will meet applicable requirements.

Thereafter, at approximately yearly intervals, the meter should undergo the periodic verification procedure in accordance with Section 7.

8.1 RE-EVALUATION PROCEDURE

Elements of a formal re-evaluation procedure should include, but not be limited to the following:

- Review the existing meter specification against the latest process stream data and current application requirements to see if the existing meter specification meets the current flow application requirements. If it does not, the meter should be replaced or upgraded.
- Verify and/or change the meter configuration parameters, where necessary.
- Verify proper primary element or transducer configuration.
- Review upstream/downstream piping and other installation details.
- If the meter can be determined to meet the new requirements, then issue documentation with the manufacturer's statement that the meter can meet the new performance requirements.
- If the meter cannot satisfactorily meet the new requirements, then issue a report with recommendations.
- Overall, FFMS uncertainty may be evaluated using the uncertainty calculations in Section 10.

9 Performance Test Protocol Scope

9.1 GENERAL

A performance test protocol is intended to provide a comparable description and methodology that will allow the evaluation of the various devices used to measure single-phase fluid flow when such devices are used under similar operating conditions.

The detailed requirements and description of an FFMS performance test protocol is beyond the scope of this Standard. However, it is recognized that factory or third-party testing of meters is desirable in many instances and the necessity for the manufacturer or third-party testing facility to abide by a "performance test protocol" is therefore encouraged. The end user should request tests and test results, and test protocol used by the manufacturer.

9.2 GENERAL PERFORMANCE TEST PROTOCOL REQUIREMENTS

The general requirements of a performance test protocol should include the following elements:

1. The test facility should be traceable to NIST or other national standards bodies, and may be an independent flow lab, or the manufacturer's lab.
2. The performance test protocol should ensure that the user of any FFMS understands the standard performance characteristics of the system over a wide range of operating conditions.
3. The performance test protocol should facilitate the understanding and the introduction of new technologies.
4. The performance test protocol should provide a standardized method for validating manufacturer's performance specifications.
5. The performance test protocol should clearly define the minimum performance requirements for the FFMS, based on a detailed and uniformly applied uncertainty analysis that will allow a user to ensure regulatory compliance.
6. The performance test protocol should provide guidance for defining the test limits that will best define the performance of the FFMS metering component under actual operating conditions. The testing protocol should also require that the manufacturer state the effects of pressure, temperature, gas composition, environmental conditions, and installation conditions on the performance of their device, and what secondary instrumentation is required to arrive at a corrected rate of flow.

10 Uncertainty and Propagation of Error

10.1 OBJECTIVE

The purpose of this section is to provide tools for the understanding and prediction of overall FFMS uncertainty. Applications of uncertainty analysis include:

- Determine whether an FFMS will meet requirements.
- Compare FFMS technologies.
- Identify FFMS components where uncertainty improvements can be made.

The method described in 10.3 is intended to be applicable over as wide a range of conditions as possible. It is not intended to provide the rigorous uncertainty analysis typically associated with custody transfer measurement and does not follow the strict uncertainty analysis of the ISO GUM/ISO 5168 (due to the difficulty of translating the effects of fixed and estimated factors frequently used in flare measurement into the values required by these techniques). It does provide a reasonable estimate of size of FFMS uncertainty that can be expected.

10.2 UNCERTAINTY ANALYSIS PROCEDURE

The typical uncertainty analysis procedure consists of the six steps listed below:

Step 1: Determine the equation that defines the output as a function of one or more inputs (components).

The equation is dependent on the meter technology and should be supplied by the vendor, applicable standards or reference material.

Step 2: Determine the sensitivity coefficients for each component in Step 1.

The sensitivity of flow, Q, to any of the inputs use to calculate flow, x_i, is given by:

$$S_{xi} = \left(\frac{\partial Q}{\partial x_i}\right)$$

where

S_{xi} = sensitivity coefficient for input variable x_i,

∂Q = derivative of flow rate,

∂x_i = derivative of input variable x_i.

From a practical standpoint, the sensitivity coefficient can be interpreted as the percent change in Q that results from a 1% shift in x_i divided by 1%.

The sensitivity can be estimated from calculations using the normal expected operating conditions. First, calculate the flow at normal expected operating conditions. Second, recalculate the flow leaving all of the values constant except the input variable for which the sensitivity constant is being determined. Change that value by 1%. The percent change in flow divided by 1% change in the input variable is the sensitivity of that variable. Repeat for each of the input variables to determine all of the sensitivity coefficients.

Sensitivity may change over the operating range. To determine this effect, the sensitivity should also be calculated at minimum and maximum operating conditions in addition to normal expected operating conditions.

Step 3: Obtain numerical values for the uncertainty of each component in Step 1.

Uncertainty of instrumentation may change over the operating range. To determine this effect, the uncertainty should also be calculated at minimum and maximum operating conditions in addition to normal expected operating conditions.

Step 4: Combine the numerical values obtained in Step 3 to give a numerical values for the combined and expanded standard uncertainties.

Uncertainties can be estimated by summing the square of the sensitivity times the uncertainty. The estimated uncertainty is the square root of this sum. Systematic and random uncertainties should be handled separately, with the total uncertainty being estimated by adding the two root mean square uncertainties.

As sensitivity and uncertainty may change over the operating range, the combined uncertainty should be calculated at minimum, maximum and normal operating conditions.

Step 5: Determine the effective degrees of freedom to be used when combining the numerical values in Step 4.

Step 6: Determine the effect of correlated components. Repeat Steps 4 and 5, including correlated components.

10.3 SIMPLIFIED UNCERTAINTY ANALYSIS PROCEDURE

FFMS are subject to:

- Widely varying flow rates.
- Composition that may or may not be instrumented.
- Pressure and temperature that may be measured or fixed values.
- Uncertainties caused by limitations in determining pipe size.
- Inlet/outlet piping installation effects.

To compare the performance of different flare meter and instrumentation combinations, the installed FFMS uncertainty can be estimated by focusing on the primary uncertainties related to temperature, pressure, composition, meter performance, and installation effects. Secondary uncertainties (such as ambient temperature effects on instrumentation, accuracy of pressure and temperature calibration equipment, etc.) can be ignored because these uncertainties are significantly smaller than the primary uncertainties.

For flare measurement, the procedure described in 10.2 can be simplified to:

Step 1: Determine the equation that defines the meter output.

Step 2 and Step 3: Determine the combined sensitivity coefficient and numerical values of the uncertainty for:

- Pressure.
- Temperature.
- Composition.
- Meter.
- Pipe size and other installation effects.

Pressure, Temperature, and Composition

The combined uncertainty can be estimated for pressure, temperature and composition by calculating the meter volume using the calculation from Step 1. Select the reference values of pressure P_r, temperature T_r, composition C_r and meter output M_r based on normal expected operation. Calculate the reference flow rate, Q_r, using P_r, T_r, C_r and M_r.

Estimate the maximum error for pressure P_e, temperature T_e, and composition C_e by changing them one at a time and recalculating the error flow rate.

- Calculate the pressure error flow rate, Q_p, using P_e, T_r, C_r and M_r. The uncertainty caused by pressure is: $(Q_r – Q_p)/Q_r \times 100$

Note: To understand the effect of atmospheric pressure on gauge transmitters this calculation can be performed twice, once for atmospheric pressure changes and once for gauge pressure changes.

- Calculate the temperature error flow rate, Q_t, using P_r, T_e, C_r and M_r. The uncertainty caused by temperature is: $(Q_r – Q_t)/Q_r \times 100$
- Calculate the composition error flow rate, Q_c, using P_r, T_r, C_e and M_r. The uncertainty caused by composition is: $(Q_r – Q_c)/Q_r \times 100$

Meter

The meter error uncertainty can be estimated by determining the maximum meter error over the expected operating range from meter calibration data.

Pipe Size and Other Installation Effects

The uncertainty associated with installation effect is based on errors in the measurement of pipe size and estimation of other installation effects uncertainties from test data. See Appendix A-6 on velocity profile and velocity integration considerations for flare gas measurement.

Note 1: The sensitivity coefficient can be estimate by dividing the % uncertainty calculated for an input variable by the % change in the input variable.

Note 2: Remember to calculate the input variable % change using absolute pressure or temperature.

Step 4: Combine the numerical values obtained in Steps 2 and 3 to give numerical values for the combined and expanded standard uncertainties.

As the changes calculated in Steps 2 and 3 are maximums, they can be thought of as measurement uncertainties that are equivalent to the two standard deviation uncertainties or U_{95}.

Uncertainties can be estimated by summing the square of the errors for pressure, temperature, composition, meter and installation effects. The estimated uncertainty is the square root of this sum.

Note 1: Systematic and random uncertainties should be handled separately, with the total uncertainty being estimated by adding the two root mean square uncertainties.

Note 2: Errors change over the operating range, the combined uncertainty should be calculated for operating conditions at minimum, normal, and maximum flow (see Appendix A-1).

10.4 UNCERTAINTY ESTIMATE FOR FLARE COMPOSITION

Variability in flare composition may be a significant factor in determining the measurement uncertainty of an FFMS system. In some cases, the error caused by uncertainty in the flare composition can become the major factor that determines the FFMS uncertainty.

Table 4—Example Table of Combined Uncertainties

Variable	Combined Sensitivity and Error ($S \times U_{95}$)	$(S \times U_{95})^2$
Pressure	2%	4.00
Temperature	0.1%	0.01
Flare Composition	2%	4.00
Flare Meter	1.4%	1.96
Installation Effects	0.5%	0.25
Sum of Squares		10.22
Square Root of Sum of Squares		3.2%

It is not possible to completely cover all of the impacts related to composition, but the following examples provide some insight into the problem and an order of magnitude of the measurement uncertainty flare composition can cause.

10.4.1 Composition Impact on the Primary Device Measurement

Table 2 from 4.7 shows the major effect of composition on the calculation of actual volume, standard volume, or mass by meter type.

10.4.1.1 Differential Pressure Meters

The output of differential pressure meters is a function of the square root of flare gas density, although the equations for actual volume, standard volume, and mass may also include terms for flowing and/or base density. The approximate meter error for all three measurements is approximately $^1/_2$ of the density error caused by flare gas composition, pressure and temperature uncertainty.

10.4.1.2 Thermal Flow Meters

FFMS that report actual or standard volume require the consideration of the compositional effect on thermal conductivity, dynamic viscosity, and Prandtl number.

FFMS that report mass require the calculation of density in addition to the composition effect on thermal conductivity, dynamic viscosity, and Prandtl number of the flare gas.

10.4.1.3 Velocity Measuring Meters (Optical, Ultrasonic, and Vortex)

FFMS that report actual volume have no direct metering uncertainty due to composition as the output meter output is in actual volume.

FFMS that report standard volume require composition to calculate flare gas compressibility. If the change in volume due to compressibility is an order of magnitude smaller than other FFMS uncertainties, correction for compressibility can be neglected.

FFMS that report mass require composition to calculate flare gas density. The compositional effect on density should be used in the FFMS uncertainty analysis.

10.4.1.4 Reynolds Number

Reynolds number is a function of flare gas composition, pressure, temperature, viscosity, velocity, and pipe diameter. For all meters there are secondary measurement effects related to flow profile caused by changes in Reynolds number for a given flare velocity.

For measurement at high Reynolds number (high velocities) this error is generally small. The effect of Reynolds should be provided by the meter manufacturer and used the FFMS uncertainty analysis.

For measurement at low Reynolds number (low velocities), this error can become significant. Many meters experience a significant change in meter factor as the flow transitions from turbulent to laminar flow. The effect of Reynolds number should be provided by the meter manufacturer and used the FFMS uncertainty analysis. The user is cautioned to pay special attention these errors for flare meters expected to operate below a Reynolds number of ~10,000.

10.4.2 Analyzer Response Time

Some FFMS incorporate an analyzer to correct for flare gas composition. Although this equipment is outside of the scope of this Standard, it is important to note that use of these devices doesn't completely eliminate the errors associated with composition.

Composition errors still need to be considered in the FFMS uncertainty analysis. The analysis delay and spot analysis nature of this equipment can result in significant errors due to:

- Applying the wrong composition to upset flow calculations for 1 to 2 analysis cycles of the analyzer.
- Composition changes due to flare flows upsets that are shorter than the analysis cycle of the analyzer may not be detected.

10.4.2.1 Composition Analysis Delay

Errors related to compositional analysis delay can be estimated by estimating:

- The flare flow rate and composition before/after the upset.
- The flare flow rate and composition of the upset.
- Analyzer cycle time.

The measurement error during upset is approximately:

$$(q_1 - q_2)(1.5\mathrm{CycleTime}_{\mathrm{Analyzer}} + \mathrm{Delay}_{\mathrm{SampleSystem}}) + (q_3 - q_4)(1.5\mathrm{CycleTime}_{\mathrm{Analyzer}} + \mathrm{Delay}_{\mathrm{SampleSystem}})$$

where

q_1 = meter flow rate during the upset using the compositional prior to the upset,

q_2 = meter flow rate during the upset using the compositional of the upset,

q_3 = meter flow rate after the upset using the compositional of the upset,

q_4 = meter flow rate after the upset using the compositional after the upset,

$1.5\mathrm{CycleTime}_{\mathrm{Analyzer}}$ = the compositional analysis delay (The delay is a minimum of 1 analyzer cycle if the analyzer samples just after the start of the upset to a maximum of 2 analyzer cycles if the analyzer samples just before the upset. The average delay is 1.5 analyzer cycles.),

$\mathrm{Delay}_{\mathrm{SampleSystem}}$ = the delay introduced by the analyzer sampling system (regulation, sample line length and sample system flow rate).

These errors can be accounted for by the FFMS system if the correct composition is applied to the meter output. Applying the analyzer composition to the meter output offset by the analysis time will reduce the error, but to minimize composition related error to the maximum extent possible requires detecting the flow change related to the composition change and applying the correct composition to the related flow.

An alternative to using the FFMS system to account for this error is to manually correct for this error based on significant changes in flow rate and/or composition.

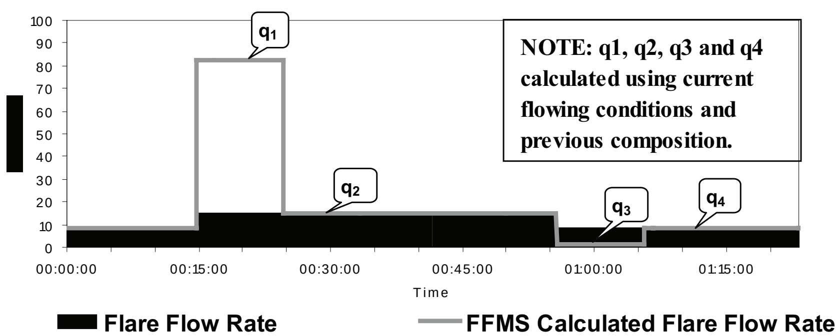


Figure 3—Measurement Error Caused by Gas Composition Analysis Delay

10.4.2.2 Missed Composition Changes

Analyzers analyze a spot sample of flare gas each analysis cycle. As a result, upsets less than the analysis time of the analyzer may go detected. With analysis time of analyzers ranging from 4 to 15 minutes, significant measurement errors caused by incorrect composition can occur. Compositional changes can be missed during analyzer calibration or maintenance.

Manual correction of flare volumes may be possible if significant changes in flare flow rate can be associated with specific operating events and the composition of the flare from this event can be estimated.

10.4.3 Errors Associated with Fixed Composition Assumptions

Flare systems that use fixed composition assumptions in the calculations and meter calibration require the errors associated with composition changes to be estimated. This can be done by calculating the volume for minimum, maximum and normal flare flow rates and the various expected flare compositions. The difference between these flow rates and the flow rate calculated based on the fixed composition provides a range of measurement errors.

10.4.3.1 Three Examples of the Composition Effect

The approximate measurement error caused by using a fixed composition of 1% CO_2, 0.9% H_2S, 97% methane, 1% ethane and 0.1% propane when the flare composition changes to:

- Case 1—0.53% CO_2, 0.47% H_2S, 51.08% methane, 0.53% ethane and 47.39% propane.
- Case 2—0.4% CO_2, 0.36% H_2S, 38.8% methane, 0.4% ethane and 0.04% propane and 60% hydrogen.
- Case 3—12% CO_2, 0.8% H_2S, 86.22% methane, 0.89% ethane and 0.09% propane are shown in Table 5. (To simplify the calculation all flowing conditions are held constant and only the composition is changed.)

Table 5—Errors Related to Use of Fixed Composition for Different Meter and Calculations Types (Absolute Value of Error)

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 (Optical, Ultrasonic, Vortex)	~ 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 (Optical, Ultrasonic, Vortex)	0%	0%	112%

Case 3—CO_2 Increased	Actual Volume	Standard Volume	Mass
Differential Pressure Meter	~9%	~9%	~8%
Thermal Flow Meter	~2% to ~5%	~2% to ~5%	~15% to ~20%
Velocity Meter (Optical, Ultrasonic, Vortex)	~0%	~0%	~15%

Notes:

1. Based on composition errors caused by using fixed composition, the user needs to evaluate the need for composition measurement and correction.
2. Thermal flow meter errors are expressed as a range due to the composition effect being velocity dependent.

10.4.3.2 Measurement Impact of Using Fixed Compositions

To calculate the error impact on daily, weekly or monthly flare volumes requires estimating the frequency, duration and flow rate of the composition error. This information is used to estimate total error for the period of interest and the percent error is calculated by dividing this error by the total flare volume for period of interest.

Manual correction of flare volumes to reduce these composition effects may be possible if significant changes in flare flow rate can be associated with specific operating events and the composition of the flare from this event can be estimated.

The errors calculated from use of fixed composition or remaining after manual correction should be included in the FFMS uncertainty calculations.

- If this error is an order of magnitude larger than any of the remaining measurement uncertainties, this error can be used as an estimate for FFMS measurement uncertainty.
- If this error is less than an order of magnitude larger than any of the remaining measurement uncertainties, this error should be included with the other systematic errors in Step 3 of the uncertainty calculations.

These errors may be minimized by using corrections from on-line analyzers.

10.5 METER-SPECIFIC EXAMPLES

10.5.1 Example 1: Linear Volume Meter Measuring Standard Volumetric Flowrate

10.5.1.1 Step 1: Determine the equation that defines the output as a function of one or more inputs (components).

The basic equation of a linear flow meter at flowing conditions is:

$$q_v = Kr$$

The equation of a linear flow meter at base conditions is:

$$Q_v = Kr\left(\frac{P_f T_b Z_b}{P_b T_f Z_f}\right)$$

The equation of a linear flow meter at base conditions using a gauge pressure transmitter and a temperature transmitter calibrated in degrees Fahrenheit is:

$$Q_v = Kr\left(\frac{(P_{\text{gauge}} + P_{\text{atmos}})(T_b + 459.67)Z_b}{P_b(T_{\text{Fahrenheit}} + 459.67)Z_f}\right)$$

Because K is a function of the flare cross-sectional area and flow profile, additional uncertainty factors for area, Reynolds number correction for flow profile, and flow profile errors caused by piping and the localized effect of the insertion probe must also be considered. The equation expands to:

$$Q_v = \pi(Pipe_{radius})^2 F_{\text{Profile\_Re}} F_{\text{Profile\_Pipe}} F_{\text{Profile\_Probe}} Kr\left(\frac{(P_{\text{gauge}} + P_{\text{atmos}})(T_b + 459.67)Z_b}{P_b(T_f + 459.67)Z_f}\right)$$

where

q_v = volumetric flow rate at flowing conditions,

$Q_{v\text{base}}$ = volumetric flow rate at base conditions,

$\pi(Pipe_{radius}{}^2)$ = pipe cross-sectional area,

$F_{\text{Profile\_Re}}$ = Reynolds number correction,

$F_{\text{Profile\_Pipe}}$ = flow profile correction for inlet piping flow disturbances,

$F_{\text{Profile\_Probe}}$ = flow profile correction for insertion probe flow disturbances,

K = meter K factor/unit conversion factor (i.e., cubic meter/pulse, cubic meter/ma, etc.),

r = meter output (i.e., pulses, 4 ma – 20 ma, etc.) (Some meters may combine the meter K factor/unit conversion factor into the meter output. In this case, K = 1.),

P_{gauge} = flowing gauge pressure,

P_{atmos} = atmospheric pressure,

P_b = base pressure,

T_f = flowing temperature,

T_b = base temperature,

Z_f = flowing compressibility,

Z_b = base compressibility.

10.5.1.2 Step 2/3: Determine the combined sensitivity coefficient and numerical values of the uncertainty.

Variable	Initial Values	Error Values	Combined Sensitivity and Error ($S \times U_{95}$)
Pressure • Operating Pressure • Atmospheric Pressure	 5 psig 14.2 psia	 5.1 psig 14.4 psia	 0.52% 1.04%
Temperature	100°F	100.5°F	0.09%
Flare Composition	80% methane, 20% CO_2	90% methane, 10% CO_2	0.00%
Flare Meter	5 ft/s	Calibration Data	2%
Installation Effects • Random • Systematic • Pipe Size	 6.045 in.	 Estimate Estimate 6.095 in.	 0.50% 1.00% 1.60%

10.5.1.3 Step 4: Combine the numerical values obtained in Step 2/3 to give numerical values for the combined and expanded standard uncertainties.

10.5.1.3.1 Random Uncertainty

Variable	Combined Sensitivity and Error ($S \times U_{95}$)	$(S \times U_{95})^2$
Pressure • Operating Pressure • Atmospheric Pressure	 0.52% 1.04%	 0.2704 1.0816
Temperature	0.09%	0.0081
Flare Composition	0.00%	0.0000
Flare Meter	1.00%	1.0000
Installation Effects • Random	 0.5%	 0.2500
Sum of Squares		2.6101
Square Root of Sum of Squares		1.6%

Note: Variables with the largest $(S \times U_{95})^2$ have the largest effect on the combined uncertainty. In this example, the largest contributor is atmospheric pressure. To reduce combined uncertainty look at improving the accuracy of this measurement by measuring the atmospheric pressure or using absolute pressure transmitters.

10.5.1.3.2 Systematic Uncertainty

Variable	Combined Sensitivity and Error ($S \times U_{95}$)	$(S \times U_{95})^2$
Installation Effects • Systematic • Pipe Size	 1% 1.6%	 1.0000 2.5600
Sum of Squares		3.5600
Square Root of Sum of Squares		1.9%

Note: Variables with the largest $(S \times U_{95})^2$ have the largest effect on the combined uncertainty. In this example, the largest contributor is pipe size.

10.5.1.3.3 Total Uncertainty

Total Uncertainty = Random Uncertainty + Systematic Uncertainty = 1.6%+ 1.9% = 3.5%

10.5.2 Example 2: Averaging Pitot Tube Measuring Standard Volumetric Flowrate

10.5.2.1 Step 1: Determine the equation that defines the output as a function of one or more inputs (components).

The basic equation of an averaging Pitot tube flow meter at flowing conditions is:

$$q_v = K\frac{\sqrt{\rho \Delta P}}{\rho}$$

The equation of an averaging Pitot tube flow meter at base conditions is:

$$Q_v = K\frac{\sqrt{\rho \Delta P}}{\rho_b}$$

The density at operating or base conditions can be calculated from:

$$\rho = \frac{M_r(P_{\text{gauge}} + P_{\text{atmos}})}{Z_f R(T_f + 459.67)} \text{ and } \rho_b = \frac{M_r P_b}{Z_b R(T_b + 459.67)}$$

The equation of an averaging Pitot tube flow meter at base conditions is:

$$Q_v = K\frac{\sqrt{\frac{M_r(P_{\text{gauge}} + P_{\text{atmos}})}{Z_f R(T_f + 459.67)}\Delta P}}{\frac{M_r P_b}{Z_b R(T_b + 459.67)}}$$

Because K is a function of the flare cross-sectional area and flow profile, additional uncertainty factors for area, Reynolds number correction for flow profile, and flow profile errors caused by piping and the localized effect of the insertion probe must also be considered. The equation expands to:

$$Q_v = \pi(\text{Pipe}_{\text{radius}})^2 F_{\text{Profile\_Re}} F_{\text{Profile\_Pipe}} F_{\text{Profile\_Probe}} K\frac{\sqrt{\frac{M_r(P_{\text{gauge}} + P_{\text{atmos}})}{Z_f R(T_f + 459.67)}\Delta P}}{\frac{M_r P_b}{Z_b R(T_b + 459.67)}}$$

where

q_v = volumetric flow rate at flowing conditions,

Q_v = volumetric flow rate at base conditions,

ΔP = differential pressure,

ρ = density at flowing conditions,

ρ_b = density at base conditions,

M_r = molar mass,

R = universal gas constant,

$\pi(Pipe_{radius}{}^2)$ = pipe cross-sectional area,

$F_{\text{Profile\_Re}}$ = Reynolds number correction,

$F_{\text{Profile\_Pipe}}$ = flow profile correction for inlet piping flow disturbances,

$F_{\text{Profile\_Probe}}$ = flow profile correction for insertion probe flow disturbances,

K = meter K factor/unit conversion factor,

P_{gauge} = flowing gauge pressure,

P_{atmos} = atmospheric pressure,

P_b = base pressure,

T_f = flowing temperature,

T_b = base temperature,

Z_f = flowing compressibility,

P_b = base compressibility.

10.5.2.2 Step 2/3: Determine the combined sensitivity coefficient and numerical values of the uncertainty.

Variable	Initial Values	Error Values	Combined Sensitivity and Error ($S \times U_{95}$)
Pressure • Operating Pressure • Atmospheric Pressure	 5 psig 14.2 psia	 5.1 psig 14.4 psia	 0.26% 0.52%
Temperature	100°F	100.5°F	0.045%
Flare Composition	80% methane, 20% CO_2	90% methane, 10% CO_2	7.20%
Flare Meter	5 ft/s	Calibration Data	1%
Installation Effects • Random • Systematic • Pipe Size	 6.045 in.	 Estimate Estimate 6.095 in.	 0.50% 1.00% 1.60%

10.5.2.3 Step 4: Combine the numerical values obtained in Step 2/3 to give numerical values for the combined and expanded standard uncertainties.

10.5.2.3.1 Random Uncertainty

Variable	Combined Sensitivity and Error ($S \times U_{95}$)	$(S \times U_{95})^2$
Pressure • Operating Pressure • Atmospheric Pressure	 0.26% 0.52%	 0.0676 0.2704
Temperature	0.045%	0.0020
Flare Composition	7.2%	51.8400
Flare Meter • Meter • Differential Pressure	 1% 0.66%	 1.0000 0.4422
Installation Effects • Random	 0.5%	 0.2500
Sum of Squares		53.872
Square Root of Sum of Squares		7.3%

Note: Variables with the largest $(S \times U_{95})^2$ have the largest effect on the combined uncertainty. In this example, the largest contributor is composition. To reduce combined uncertainty look at improving the accuracy of this measurement by measuring the composition.

10.5.2.3.2 Systematic Uncertainty

Variable	Combined Sensitivity and Error ($S \times U_{95}$)	$(S \times U_{95})^2$
Installation Effects • Systematic • Pipe Size	 1% 1.6%	 1.0000 2.5600
Sum of Squares		3.5600
Square Root of Sum of Squares		1.9%

Note: Variables with the largest $(S \times U_{95})^2$ have the largest effect on the combined uncertainty. In this example, the largest contributor is pipe size.

10.5.2.3.3 Total Uncertainty

Total Uncertainty = Random Uncertainty + Systematic Uncertainty = 7.3% + 1.9% = 9.2%

10.5.3 Example 3: Thermal Flow Meter Measuring Standard Volumetric Flowrate

10.5.3.1 Step 1: Determine the equation that defines the output as a function of one or more inputs (components).

As stated in 4.7.3:

Thermal flow meters utilize designs that are manufacturer specific. These design differences result in response differences related to flow rate (similar to differences between different types of differential pressure producers) and composition. This requires each manufacturer to develop and maintain design specific databases of flow and composition response data and to develop meter-specific correction factors based on regression of these data.

It is recommended that users require data from a recognized flow meter test facility for the user's application flow and composition range from meter manufacturers. The data should clearly show that the specific meter design, style, and type are suitable for the intended use and the accuracy of the manufacturer's composition correction factors for the meter.

For this reason, calculations in this section are for example purposes only. Calculations have been done on information supplied by thermal flow representatives.

Note 1: The accuracy of the values cannot be verified as the flow equations and gas component interaction coefficients are meter-specific and proprietary to the manufacturer. The user should consult the meter manufacturer for values for their meter.

Note 2: The user should require the meter manufacturer to provide data from a recognized flow meter test facility to demonstrate the accuracy of the correction methodology and the uncertainty of their meter.

10.5.3.2 Step 2/3: Determine the combined sensitivity coefficient and numerical values of the uncertainty.

Variable	Initial Values	Error Values	Combined Sensitivity and Error ($S \times U_{95}$)
Pressure • Operating Pressure • Atmospheric Pressure	 5 psig 14.2 psia	 5.1 psig 14.4 psia	 ~0% ~0%
Temperature	100°F	100.5°F	~0%
Flare Composition	80% methane, 20% CO_2	90% methane, 10% CO_2	5%
Flare Meter	5 ft/s	Calibration Data	2%
Installation Effects • Random • Systematic • Pipe Size	 6.045 in.	 Estimate Estimate 6.095 in.	 0.50% 1.00% 1.60%

Note: The temperature sensitivity of thermal flow meters for 50°F change is approximately 1% due to temperature compensation in the meter, and the pressure sensitivity for a 50 psig change is approximately 1%.

10.5.3.3 Step 4: Combine the numerical values obtained in Step 2/3 to give numerical values for the combined and expanded standard uncertainties.

10.5.3.3.1 Random Uncertainty

Variable	Combined Sensitivity and Error ($S \times U_{95}$)	$(S \times U_{95})^2$
Pressure • Operating Pressure • Atmospheric Pressure	 0% 0%	 0.0000 0.0000
Temperature	0%	0.0000
Flare Composition	5%	25.0000
Flare Meter	2%	4.0000
Installation Effects • Random	 0.5%	 0.2500
Sum of Squares		29.2500
Square Root of Sum of Squares		5.4%

Note: Variables with the largest $(S \times U_{95})^2$ have the largest effect on the combined uncertainty. In this example, the largest contributor is composition. To reduce combined uncertainty, look at improving the accuracy of this measurement by improving the measurement of flare composition.

10.5.3.3.2 Systematic Uncertainty

Variable	Combined Sensitivity and Error ($S \times U_{95}$)	$(S \times U_{95})^2$
Installation Effects • Systematic • Pipe Size	1% 1.6%	1.0000 2.5600
Sum of Squares		3.5600
Square Root of Sum of Squares		1.9%

Note: Variables with the largest $(S \times U_{95})^2$ have the largest effect on the combined uncertainty. In this example, the largest contributor is pipe size.

10.5.3.3.3 Total Uncertainty

Total Uncertainty = Random Uncertainty + Systematic Uncertainty = 5.4% + 1.9% = 7.3%

11 Documentation

11.1 PROCEDURAL DOCUMENTATION

As a minimum, documentation for meters used to comply with regulatory requirements should be retained following execution of any of the following procedures, including the work performed, the test results (with as-found and as-left readings), and any changes or modifications to the equipment. Local regulatory requirements may be more stringent and must be followed.

Procedure	Responsibility
Factory Acceptance Test (New Meters)	Flare Owner (Life of Equipment) and Manufacturer (10 Years)
Re-evaluation of Existing Meter	Flare Owner (Life of Equipment) and Manufacturer (10 Years)
Commissioning Procedure	Flare Owner (Life of Equipment)
Periodic Verification Procedure	Flare Owner (Life of Equipment)
Equipment Repair or Replacement	Flare Owner (Life of Equipment)
Configuration Changes that Affect FFMS Accuracy	Flare Owner (Life of Equipment)

11.2 SCALING DOCUMENTATION

Scaling documentation relating the output range and units of the flare meter, and secondary devices to the computing device (DCS, etc.) should be maintained and must be consistent for correct calculations of flare quantities.

11.3 OTHER DOCUMENTATION

Depending upon local regulatory or plant requirements, retention of other documentation may be required. Examples of types of documentation are as follows:

1. Documentation of flow meter alarms, meter failures, or meter upgrades which result in service. Details of the work performed should be documented.

Note: Depending upon complexity, meter upgrades may require portions of the commissioning procedure to be re-performed.

2. Documentation of failed flow meter components which were replaced.
3. Documentation of work performed, including calibrations or repair, of secondary devices (pressure and temperature transmitters, analytical instrumentation, etc.) including a record of as-found and as-left readings.

11.4 MANAGEMENT OF CHANGE DOCUMENTATION

Documentation required as a part of management of change (MOC) should be maintained for the life of the plant. Guidance for what constitutes a management of change (MOC) process is found in Appendix A-5.

APPENDIX A-1—EXAMPLE PROCESS STREAM DATA SHEET

Flare Meter Datasheet

GENERAL

1	P&ID No.		Project Name	
2	Service		Plant Name	
3	Location		Area Name	
4	Line No.		Unit Name	
5	Equipment No.		Unit Number	
6	Area Classification Sensors		Ambient Temperature Range	
7	Area Classification Electronics		Site Average Barometric Pressure	
8			Site Standard Temperature/Pressure	

PROCESS CONDITIONS

9		Eng. Units	Case 1	Case 2	Case 3	Combined Range
10	Case Designation		Normal			
11	Fluid		Purge Gas			
12	Temperature	°C, °F				
13	Pressure	kPa a, psia				
14	Flow Rate - At Flowing Conditions	Am^3/h, Aft^3/h				
15	Flow Rate - At Standard Conditions	Sm^3/h, Sft^3/h				
16	Flow Rate - Mass	kg/h, lb/h				
17	Velocity	m/s, ft/s				
18	Available Pressure Loss	kPa, psi				
19	Gas Density at Flowing Conditions	kg/m^3, lb/ft^3				
20	Gas Density at Base Conditions	kg/m^3, lb/ft^3				
21	Viscosity at Flowing Conditions	cP				
22	Molecular Weight	grams/mole				
23	Specific Heat Ratio (k)					
24	Compressibility					
25						
26						

FLUID COMPOSITION

27	**Component**					
28	Methane	Mole %				
29	Ethane	Mole %				
30	Propane	Mole %				
31	Isobutane	Mole %				
32	n-Butane	Mole %				
33	Iso-Pentane	Mole %				
34	n-Pentane	Mole %				
35	n-Hexane	Mole %				
36	Hydrogen	Mole %				
37	Nitrogen	Mole %				
38	Carbon Dioxide	Mole %				
39	Ethylene	Mole %				
40	Propylene	Mole %				
41	1,3-Butadiene	Mole %				
42	Butene Isomers	Mole %				
43	Water	Mole %				
44		Mole %				
45		Mole %				
46		Total %	0.00	0.00	0.00	
47	Corrosives					
48	Particulates					
49	Liquid Mist or Droplets					

METER

50	Manufacturer		I/O	Output Type	Range	Eng. Units
51	Model		Local Display			
52	Accuracy (+/- % full scale)		Fault Contacts			
53	Repeatability (% reading)		Alarm Contacts			
54	Sensor Wetted Material		Analog Output # 1			
55	Electronics Enclosure Type		Analog Output # 2			
56	Power Supply		Analog Output # 3			
57	Retractable Sensors		Pulse Output			
58	Spool Piece Flange Rating		Analog Input # 1			
59	Line Size/Schedule		Analog Input # 2			
60	Piping Material		Analog Input # 3			
61	Line Spec.		Modbus®			
62	Piping Configuration	See Note A	Hart®			
63			Fieldbus™			

NOTES

64	A) Upstream piping components & upstream/downstream straight lengths. Attach diagram.
65	B)
66	C)
67	E)

Note 1: The Publisher hereby grants users of this work the right to reproduce, store in a retrieval system, or transmit the Flare Data Sheets contained in Appendix A-1 of this document as long as there is an attribution to API. Users may modify the data sheets as necessary to indicate the name of their company or organization.

Note 2: Users of forms should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

APPENDIX A-2—FLARE METER CALCULATIONS

For many flare applications, determination of both standard volumetric flow rate (for flare tip exit velocity) and mass flow rate (for speciated component rate) is desired. The way the meter or the user's DCS arrives at these different statements of flow depends upon the metering technology involved. The composition, pressure, and temperature are either measured or estimated from historical operating data.

The appropriate flow unit equations and conversions applicable to specific metering technologies may be determined from Table A-2.1:

Table A-2.1

Meter Technology	Actual Volumetric Output	Standard Volumetric Output	Mass Output
Ultrasonic (Volumetric)	Fundamental Unit of Measurement	Equation A-2.1.1	Equation A-2.1.3
Vortex	Fundamental Unit of Measurement	Equation A-2.1.1	Equation A-2.1.3
Optical	Fundamental Unit of Measurement	Equation A-2.1.1	Equation A-2.1.3
Ultrasonic (Mass)	Equation A-2.1.3	Equation A-2.1.2	Output Unit of Measurement
Thermal Flow	Equation A-2.1.3	Fundamental Unit of Measurement	Equation A-2.1.2

A-2.1 Flow Unit Equations and Conversions

The following flow unit equations are used, as appropriate, depending upon the meter type and application:

A-2.1.1 The equation to convert actual volumetric flow rate to standard volumetric flow rate is:

$$Q_v = q_v\left(\frac{P_f T_b Z_b}{P_b T_f Z_f}\right) \text{ or } Q_v = q_v\left(\frac{P_f T_b}{P_b T_f}\right) \text{ if compressibility change is ignored.}$$

A-2.1.2 The equation to convert mass flow rate to standard volumetric flow rate or vice versa is:

$$Q_v = q_m/(\rho_b) \text{ or } q_m = Q_v(\rho_b)$$

A-2.1.3 The equation to compute mass flow rate from actual volumetric flow rate is:

$$q_m = q_v(\rho_f)$$

where

q_v = volumetric flow rate at flowing conditions,

Q_v = volumetric flow rate at base conditions,

q_m = mass flow rate,

ρ = density at flowing conditions,

ρ_b = density at base conditions,

P_f = flowing pressure (absolute units),

P_b = base pressure,

T_f = flowing temperature (absolute units),

T_b = base temperature,

Z_f = flowing compressibility,

Z_b = base compressibility.

A-2.2 Density and Pressure/Temperature Compensation Equations

Some meters configured for mass output use fixed density assumptions, where design density (ρ_d) is assumed at some design condition of design pressure (P_d), design temperature (T_b) and design compressibility (Z_d). The equations to compensate these meters for actual flowing conditions are listed below.

A-2.2.1 The equation to density compensate mass flow rate for a differential pressure flow meter is:

$$q_m = q_d\sqrt{\frac{\rho}{\rho_d}}$$

A-2.2.2 The equation to pressure/temperature compensate mass flow rate for a differential pressure flow meter is:

$$q_m = q_d\sqrt{\left(\frac{P_fT_dZ_d}{P_dT_fZ_f}\right)} \text{ or } q_m = q_d\sqrt{\left(\frac{P_fT_d}{P_dT_f}\right)} \text{ if compressibility change is ignored.}$$

Note: This compensation equation is only applicable if the mixture components and their respective percent compositions remain fixed. This compensation equation is typically used in simple pressure/temperature compensation schemes where more formal calculation schemes are not attempted, such as in flow computers.

A-2.2.3 The equation to density compensate mass flow rate for a linear meter having a fixed density assumption is:

$$q_m = q_d\sqrt{\frac{\rho}{\rho_d}}$$

A-2.2.4 The equation to pressure/temperature compensate mass flow rate for a linear meter having a fixed density assumption is:

$$q_m = q_d\left(\frac{P_fT_dZ_d}{P_dT_fZ_f}\right) \text{ or } q_m = q_d\left(\frac{P_fT_d}{P_dT_f}\right) \text{ if compressibility change is ignored}$$

Note: This compensation equation is only applicable if the mixture components and their respective percent compositions remain fixed.

where

q_v = volumetric flow rate at flowing conditions,

Q_v = volumetric flow rate at base conditions,

q_m = mass flow rate,

q_d = uncompensated mass flow rate at design reference density (ρ_d),

ρ = density at flowing conditions,

ρ_b = density at base conditions,

ρ_d = density at design reference conditions,

P_f = flowing pressure (absolute units),

P_b = base pressure,

P_d = design reference pressure (absolute units),

T_f = flowing temperature (absolute units),

T_b = base temperature,

T_d = design reference temperature (absolute units),

Z_f = flowing compressibility,

Z_b = base compressibility,

Z_d = design reference compressibility.

A-2.3 The equation to determine total flare exit standard volumetric flow rate for a number of meters in parallel is:

$$Q_{v\_\text{Total}} = \sum_{i=1}^{n} Q_{v\_i}$$

where

Q_{v_1} = standard volumetric flow rate for stream i, for $i = 1$ to n,

n = number of metered flare streams,

Q_{v_Total} = total standard volumetric flow rate at the flare exit.

A-2.4 The equation to determine actual exit velocity at the flare tip is commonly calculated as:

$$V_{\text{Tip}} = \frac{Q_{v\_\text{Total}}}{(A \times 60)}$$

where

V_{Tip} = flare exit velocity in ft/s,

Q_{v_Total} = total standard volumetric flow rate at flare exit in ft^3/min,

A = unobstructed cross-sectional area of the flare tip in ft^2.

Note: For flare exit velocity calculations, the cross-sectional area (actual exit flow area) of the flare exit is required. Sometimes this value is not stated by the flare manufacturer, but rather an equivalent diameter is provided. The equivalent diameter may or may not be the actual tip diameter, depending on the equipment design. Also, the equivalent diameter may be considerably different from the flare header diameter where the flare meter is installed, and should not be confused with that diameter.

Large flare tips may contain steam/air tubes, and the flare gas flows in the annulus around the tubes.

In addition, many of the smaller tips have flame retention tabs that extend into the diameter by about 3.8 cm (1.5 in.) (reducing the diameter by 7.6 cm [3 in.]). If they encircle the entire opening, they need to be taken into account.

The flare manufacturer should be consulted to ascertain either the actual exit flow area, or the equivalent diameter of the flare exit, taking into account all obstructions.

A-2.5 Heating Value Calculations

A-2.5.1 The net heating value of the exit gas from a single meter is computed from:

$$H = \frac{K\sum_{i=1}^{n}(C_i H_i)}{Z_b} \quad \text{or} \quad H = K\sum_{i=1}^{n}(C_i H_i) \quad \text{if base compressibility is assumed to be 1}$$

where

H = net heating value, Mj/scm,

H_i = net heating value of i^{th} component, kcal/g-mole,

C_i = concentration of i^{th} component from analysis, ppm (mole),

n = number of gas components,

K = 1.740×10^{-7} (g-mole MJ)/(ppm scm kcal).

A-2.5.2 The combined net heating value at the flare exit where parallel meters are involved is computed from:

$$H_{\text{Total}} = \frac{\sum_{i=1}^{n} H_i Q_{v\_i}}{Q_{v\_\text{Total}}}$$

where

H_i = net heating value of stream i, for $i = 1$ to n,

Q_{v_i} = standard volumetric flow rate for stream i, for $i = 1$ to n,

n = number of metered flare streams,

Q_{v_Total} = the total standard volumetric flow rate at flare exit.

A-2.6 40 *CFR* 60.18 Maximum Velocity Equations

40 *CFR* 60.18 is the U.S. EPA New Source Performance Standard (NSPS) which is used to establish velocity limits versus heating values for flares where U.S. EPA jurisdiction applies. The flare application should be evaluated to determine if this requirement is applicable. (See the standard for applicable equations.)

A-2.7 Special Considerations for Meter Technologies with Proprietary Calculations

For example, thermal flow meters measure mass flow rate using the thermal properties of a mixture of pre-defined composition. Changes to the flowing mixture require a compensation calculation to be done using calculated thermal properties of the actual mixture. Where the manufacturer's compensation calculations are proprietary, this technology is not recommended for flare applications with changing composition.

APPENDIX A-3—COMPRESSIBILITY EFFECTS ON FLARE GAS MEASUREMENT UNCERTAINTY

Compressibility is a measure of a gas's deviation from the ideal gas laws. The compressibility factor, Z, is used to adjust for this effect. Compressibility factors are often seamlessly incorporated into computations of gas density. Other input parameters to gas density computations are gas composition, pressure, and temperature.

For flare gas measurement applications, compressibility effects in relative terms are typically much less than other influence parameters such as variances in gas composition and flow profile effects. The effect of compressibility is further mitigated by the low operating pressures and the fact that residual errors are a function of the ratio of compressibility factors. Specifically, for linear meters such as ultrasonic, the overall effect of compressibility is assessed using the ratio of the Z_{base} to $Z_{flowing}$ and for differential producers such as averaging Pitot tubes, the ratio of Z_{base} to $\sqrt{Z_{flowing}}$. This provides the option of using fixed values for gas compressibility factors in flow computation equations with less than 1% effect on the calculated flow rate.

Compressibility for simple mixtures or natural gas mixtures are calculated using the gas composition, flowing temperature, pressure, and either equations of state, such as AGA 8, Peng-Robinson, Redlich-Kwong, or validated experimental reference data available through NIST, ISO, API, GPA, and/or other appropriate industry or government standard groups. Equations of state to calculate compressibility often do not exist for complex mixtures commonly found in flares. To ensure that the uncertainty effects associated with compressibility are properly evaluated or computed, it is essential that the technique (e.g., equation of state, reference data) used to compute compressibility is applicable to the gas composition, pressure, and temperature, and most importantly, that the process fluid is entirely in the gas/vapor state (i.e., above its dew point). Specifically, reference data and equations of state are limited to the gas compositions, pressures, and temperatures used in the experimental work upon which they are based and are only applicable to single phase fluids.

APPENDIX A-4—GENERAL FLARE DESIGN CONSIDERATIONS

A-4.1 Flare System Purpose

Refineries, petrochemical plants and other hydrocarbon processing facilities have the need to dispose of combustible waste fluids in order to maintain process control and plant safety. To achieve this, the waste fluids are collected in a flare header system and routed to a flare. The purpose of the flare system is safe, effective disposal or recovery of the waste fluids. In addition to the flare flows generated by process control and safety relief valves, the flare header should be flowing gas intended to keep the flare header and associated system components purged of air. Gas may also be injected into the flare header in order to raise the heat content of the waste gas.

Flare system complexity may range from a simple application such as the disposal of excess gases at a gas-oil well site to multiple component systems servicing a refinery or olefins plant. This appendix will focus on multi-component flare systems.

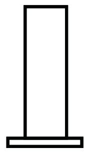
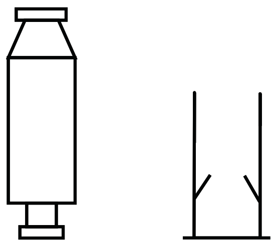
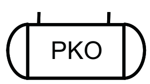
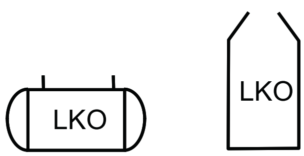
A-4.2 Types of Flare Systems

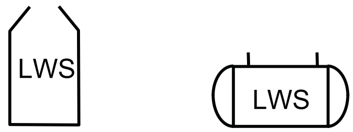
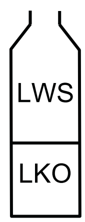
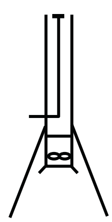
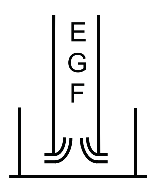
The most common types of flares include single burner, enclosed and multi-burner. Single burner systems almost always include a support structure that places the flare burner outlet in an elevated position relative to its surroundings. In contrast, multi-burner flare systems are almost always located at ground level and are often surrounded by a fence that reduces flame visibility and restricts worker access. Enclosed flares completely conceal the flame from direct view and minimize visibility and sound levels.

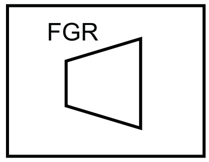
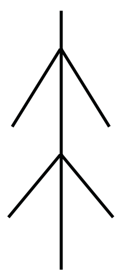
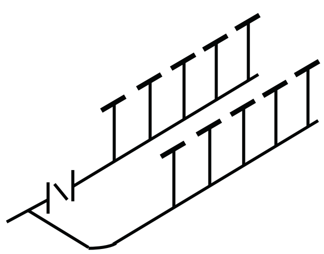
An enclosed or multi-burner flare can be advantageously combined with an elevated flare to minimize open flame burning on a day-to-day basis while maintaining the ability to handle an emergency flaring requirement.

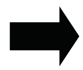
A-4.3 Major Flare System Components

The most common flare system components are discussed below and a symbolic representative assigned to each component. Additional information on these components and their application is available in API Std 537 and/or API Std 521.

Section No.	Symbol	Description or Comment
A-4.3.1		Single point flare burner of the non-assisted or steam-assisted class. This symbol represents a burner complete with appropriate ancillary equipment such as pilots.
A-4.3.2	 (a) (b)	Purge reduction seal (a) buoyancy type and (b) velocity type. A device used to minimize the amount of purge gas required to mitigate air entry. Generally located immediately under the flare burner (a) or in the flare burner (b).
A-4.3.3		Plant or operating unit knock-out drum generally located within the plant or unit boundary. Separated gases are routed on to the flare. Liquids are usually recycled back to the process unit.
A-4.3.4	 (a) (b)	Some flare systems require a local knock-out (LKO) drum near the flare. This local knock-out can remove any condensate formed as the gas travels from the plant to the flare. (The plant to flare distance can vary widely but can often be 0.6 to 1.2 miles [1 to 2 km]). A knock-out drum at the flare can also be useful in implementing a header drainage design. The local drum may be a separate vessel (a) or incorporated into the base of the stack (b). Most knock-out drums of the vertical cylindrical type (b) use a centrifugal separation technique. For both drum designs, the gas flow profile entering the stack or riser can be distorted due to the drum exit.

Section No.	Symbol	Description or Comment
A-4.3.5		A local water seal (LWS) located near the flare or incorporated into the base of the stack can help prevent air ingression into the flare stack from reaching the flare header or a water seal can back pressure the flare header system to ensure that there will be no air leaks into the system. Other uses include acting as a flare staging device or providing a back pressure for a flare gas recovery system. Under certain gas flow conditions the gases flowing out of the drum will contain entrained water.
A-4.3.6		Where both knock-out and water seal attributes are desired, a combination drum located in the base of the stack is utilized. The waste stream first enters the knock-out drum and then flows through an internal passage into the water seal.
A-4.3.7		The use of large volumes of low pressure air to assist combustion is a means to achieve smokeless flaring. An air-assisted flare uses a different flare burner configuration and seldom includes a purge reduction seal. An air-assisted flare installation includes one or more air blowers and risers for waste gas and air.
A-4.3.8		An enclosed ground flare (EGF) is used in situations where it is desirable that flaring be as unobtrusive as possible. Performance characteristics of an EGF include: no directly visible flame, extremely low heat radiation, no smoke, and low noise. EGFs are normally used in conjunction with an elevated flare with the EGF sized to handle startup, shutdown, and day-to-day flaring loads, and the elevated flare handles the emergency flow rates.

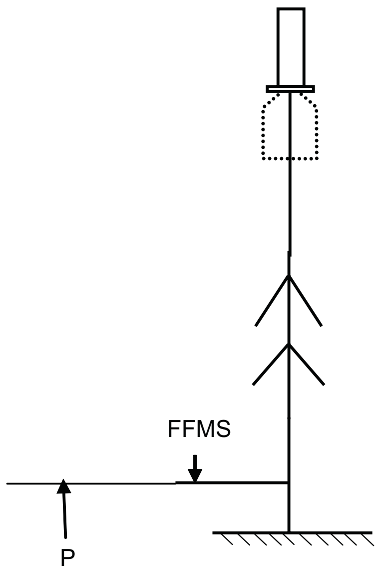
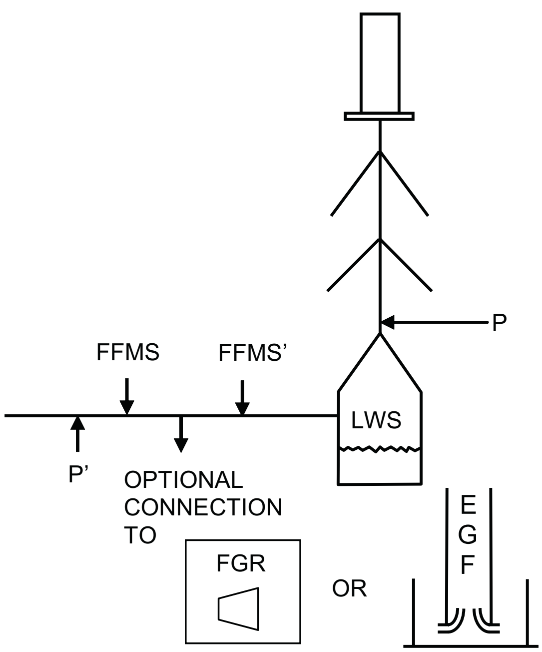
Section No.	Symbol	Description or Comment
A-4.3.9		In some flare systems the quantity and composition of gases going to the flare on a daily basis are such as to make flare gas recovery financially attractive. A flare gas recovery (FGR) unit requires the flare header be pressurized to about one psig. The header is normally pressurized by placing a water seal in the system. When a flare system is operating in a recovery mode, waste gas is diverted from the flare header to the FGR unit and purge gas is injected into the flare header or waste gas riser down stream of the water seal.
A-4.3.10		This symbol represents the waste gas riser which can be self supported, derrick-supported or guy-wire-supported. The gas riser/flare stack may or may not be equipped with ladders and platforms. Flare flow measurements in a self supported stack are more difficult due to the larger cross section of the lower portion of the stack.
A-4.3.11		Smokeless flaring can be achieved without steam or low pressure air by dividing the waste gas flow into a number of small flare burners. Optimal performance is achieved by using a staging concept in which the number of burners flaring is proportional to the waste gas flow rate. This staging of burners results in a rise and fall of flare header pressure as the flow rate changes and burner stages go into or out of operation. Accurate measurement of waste gas pressure is required for mass flow calculation.

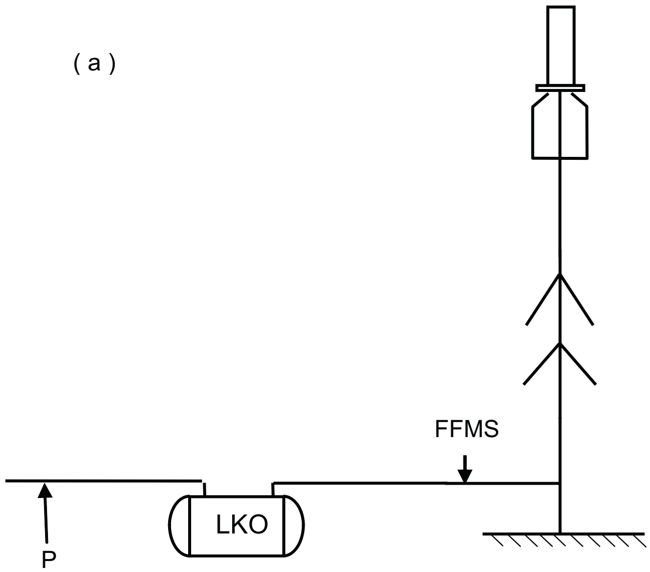
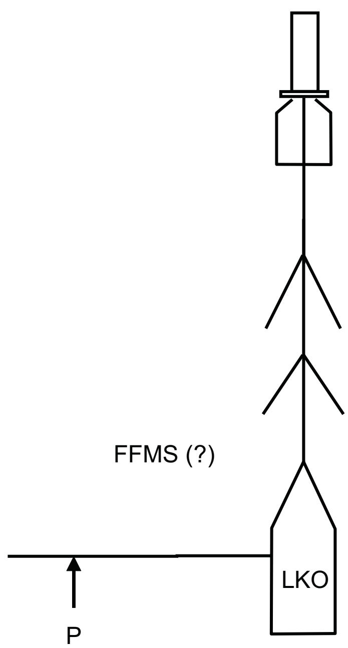
Section No.	Symbol	Description or Comment
A-4.3.12	P 	Purge gas injection point. Purge gas injection instrumentation should include means to measure the rate of injection.
A-4.3.13	A 	Assist gas injection point. If the heating value of the waste gas is below a permitted minimum, assist gas may be added to raise the heating value. Depending on the relative locations of the main flare header flow meter and the assist gas injection point, it may be necessary to meter assist gas flow independently with a dedicated flow meter.

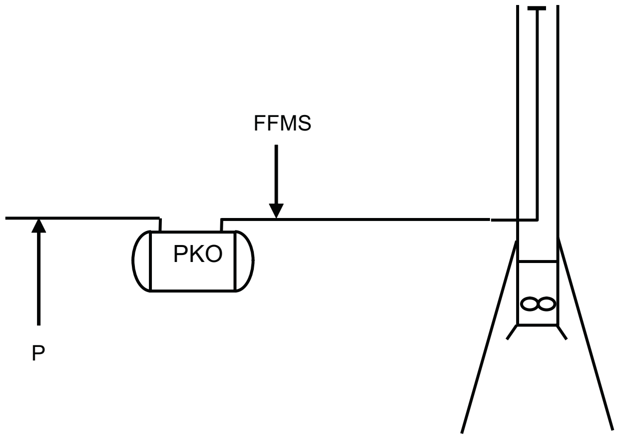
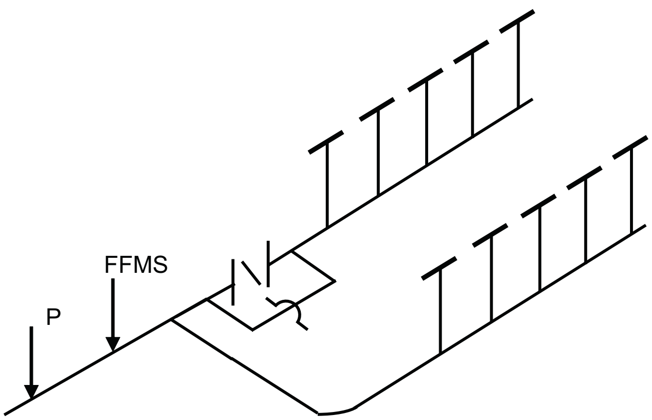
A-4.4 Typical Flare System Process Diagrams

In this section, various flare system components from A-4.3 are combined into typical system arrangements, and simplified flare system process diagrams are provided. The number of systems that could be described using these components exceeds the available space in this document. A range of system complexity is presented. In each system arrangement the objective is to illustrate system related concerns and the possible locations of a waste gas flow meter.

Some installations of a waste gas flow meter are made more difficult by the need to provide an adequate piping arrangement upstream and downstream of the meter site.

Section No.	Simplified Process Diagrams	Comment
A-4.4.1		The simplest flare arrangement. The flare flow metersystem (FFMS) is in a horizontal section somewhere between the process unit and the flare and downstream of the purge injection point. Addition of a purge reduction seal will reduce the minimum flow rate but will not impact the flow meter location.
A-4.4.2		The local water seal can be used to pressurize the flare header so that waste gas flow is diverted to a FGR unit or to an EGF. In either case, purge gas should be injected above the water seal liquid level to minimize air entry into the stack. If the optionally connected equipment is a FGR unit, then only the waste gas flow meter at FFMS is required. In the event that the optionally connected equipment is an EGF, then two meters (FFMS and FFMS') are required as flaring could take place simultaneously at both the EGF and the elevated flare. The purge gas injected above the water seal must be metered and the flow added to any elevated flare flow rate.

Section No.	**Simplified Process Diagrams**	**Comment**
A-4.4.3	(a)  (b) 	The preferred location for the flare flow meter is rather obvious in arrangement (a). However, the location of the flow meter is not as obvious in arrangement (b). Locating the meter upstream of the LKO may expose the meter sensor to gas borne liquid droplets. A meter location downstream of the LKO presents several challenges: (1) location in a vertical riser; (2) access; (3) possible safety considerations; and (4) a potentially distorted flow profile. Substitution of a combination KO and water seal drum for the LKO will not materially change the meter location challenge.

Section No.	Simplified Process Diagrams	Comment
A-4.4.4		Although different in operating principle and equipment arrangement, an air-assisted flare is the same as a steam-assisted flare from the viewpoint of flow meter location. In this system a meter location in the flare header near the exit of the PKO would take advantage of the dry gas.
A-4.4.5		The flow meter selected for a staged multi-burner flare system is faced with the same mass flow turn down challenges as other types of flares and the additional challenge of a variable header pressure. Figure 4 is a typical capacity vs. pressure curve for a three stage system. As illustrated by the figure, the gas pressure may be significantly lower at a given flow rate than it would be at a reduced flow condition.

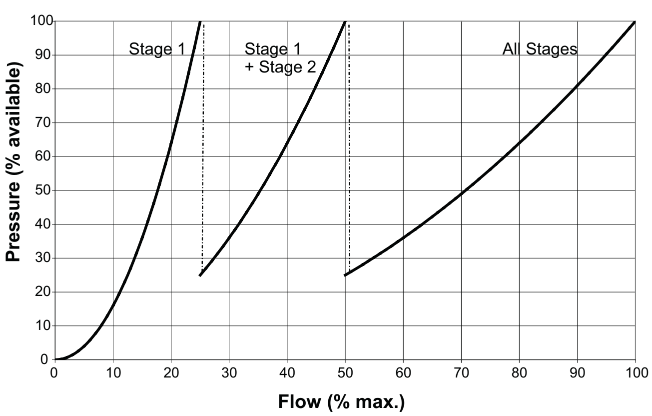


Figure 4—Typical Staging Curve

A-4.5 Flare System Flow Sources and Rates

Waste gas flow rates in a flare system are often notable due to their extremely wide range. That is, the flow rate turndown ratio is, from a practical standpoint, nearly infinity. In addition, there can be wide variations in gas composition. Facilities that include hydrogen generation can have waste gas molecular weight ranging from about 2 to more than 50.

A process unit has a number of sources of waste gas flow. Some examples are discussed below:

A-4.5.1 Purge gas flow is the fundamental system flow rate. All other flows are additive to the purge gas flow rate. A flare system equipped with a buoyancy type purge reduction seal will have a purge gas velocity as low as 0.003 m/s (0.01 ft/s) in the stack or gas riser leading up to the seal. Normally, the purge gas comes from the most reliable gas source available to the plant. In many cases this source is natural gas. While the purge gas rate is the theoretical minimum, the practical minimum is often higher due to valve leakage and/or minor process adjustments. A well operated and maintained process plant can experience minimum flow velocities of less than 0.3 m/s (1.0 ft/s). The purge gas flow is continuous 24 hours per day each day of the year.

A-4.5.2 Maximum waste gas flow is usually triggered by an emergency event such as loss of cooling water, or electrical power. In such a case it is necessary to rapidly de-inventory the gases in the process equipment. Flow velocities in the flare header can reach hundreds of meters per second or feet per second. Depending on the composition of the waste gas, the gas velocity could approach Mach 1.0. The duration of the peak flow is usually relatively short. Plant design can minimize the frequency and duration of emergency flaring.

A-4.5.3 Process upsets that cause an increase in vessel pressure are often controlled by venting the vessel contents into the flare header through a pressure control valve. If the PCV is unable to halt the increase in vessel pressure, one or more pressure relief devices will open to prevent over pressuring the vessel. Flow rates can vary greatly but are usually a small fraction of the maximum emergency flow.

A-4.5.4 A compressor trip out is often the source of the largest non-emergency flaring rate. Flaring may continue for some time as the operators attempt to re-establish compressor operation. The smokeless burning capacity of a flare system may be set to cover the flow rate resulting from a compressor outage.

A-4.6 Equipment Exposure

The physical location of flare flow measurement equipment must be carefully considered from several viewpoints. Previous sections have addressed location relative to other flare system components. Consideration should also be given to environmental conditions near the flare that could limit access, cause errors in measurement, damage instruments or expose workers to possible harm.

During flaring activities, equipment and workers will be exposed to radiant heat from the flame. Flares are designed to meet job specific specifications. Therefore, the maximum possible radiant heat intensity may vary from flare to flare. The radiant heat exposure is normally considered at grade. Since flare headers are usually elevated the radiant heat load to a worker at the header elevation will be higher. Instruments could be damaged or readings drift. API Std 521 provides information regarding the exposure of workers and equipment to flame radiation including recommended limits on the period of exposure.

In addition to the original installation, the flow meter and associated instrumentation must also be accessible for verification, repair or calibration. Unless the flare system is shut-down for installation of the flare flow measurement instruments, the work plan shall include a safety review to consider such issues as air leakage into the flare header or gas leakage out of the header. Consideration should be given to worker access and egress and the possible need for shielding of workers and/or equipment. Existing flare systems seldom have ladder and platform access to the flare header. In some cases, it may be possible to use the flare header as a shield against heat radiation to instruments.

APPENDIX A-5—GUIDANCE ON MANAGEMENT OF CHANGE PROCESS—FFMS SYSTEMS

It is not the intent of this Standard to require a special management of change (MOC) process to be used for FFMS systems above and beyond what the user may already have in place. However, the guidance listed herein is prudent, and should be reviewed against the owner's existing MOC process. The term "change" is defined by the user.

The suggested steps in a MOC process should include the following:

1. Initiation of a Change—The MOC process should be initiated with a request form or other documentation that addresses the following issues:
   - A description of the change.
   - Details on the scope of the change, including how it will be implemented.
   - The reason why the change is needed (or technical basis for the change).
   - An estimate of the measurable benefit (time, costs, safety, improvements, regulatory, etc.).
   - Whether the change is temporary or permanent.
2. Review and Approval of Change Request—The initiated change request form or initiating documentation must be reviewed and approved by appropriate personnel. For this purpose, descriptive documentation should be attached which satisfies the following: the scope of the change, technical basis, and impact of the change should be clearly understood and documented.

This documentation may take the form of drawings, procedure updates, marked-up documents, calculations, etc. A documentation checklist should be used to identify actions that will need to be taken both before and after the change is made.

3. Approval and Preparation of Final Documentation.

After a change has been approved, all documentation must be completed to make the change. This includes creating or updating all documentation that is associated with the change.

Further, appropriate steps must be taken to ensure that:

- New documentation has been created, where required.
- Outdated documentation has been removed from the plant's operating discipline.
- Updated or new documentation has been added to the plant's operating discipline.

4. Implement the Change.

All affected personnel should be notified at the time the change is put in place.

APPENDIX A-6—VELOCITY PROFILE AND VELOCITY INTEGRATION CONSIDERATIONS FOR FLARE GAS MEASUREMENT

Point, multi-point, and path-averaging flow meters measure the velocity or flow and correct the measured value based on an expected velocity profile. To understand the effect of changing flow profiles on different metering technologies requires an understanding of:

- The area weighting of velocity measurements at different locations in a pipe cross section.
- The type of meter measuring principle used to measure flow velocity or flow volume.
- The expected flow velocity profile.

For example, if a fluid is flowing in a pipe with symmetrical velocity profile, the bulk average velocity is equal to the sum of the annular velocity at radius r times the area of the annulus at radius r as shown in Equation 1 below.

Equation 1
Pipe Bulk Average Velocity Based on Area Weighting of Velocity

$$V_{\text{bulk}} = \frac{\int_{r=0}^{R} (V_r \times \text{Annulus\_Area}_r)}{\text{Pipe\_Area}}$$ (Note: Integral of the annulus area must equal the pipe cross sectional area.)

where

V_{bulk} = the bulk average velocity or the pipe average velocity based on area integration,

V_r = the velocity at radius r,

Annulus_Area_r = area of the annulus at radius r,

Pipe_Area = the cross sectional area of the pipe,

R = full radius of pipe.

The result is a velocity weighting factor that is equal to r/R as shown in Figure 4.

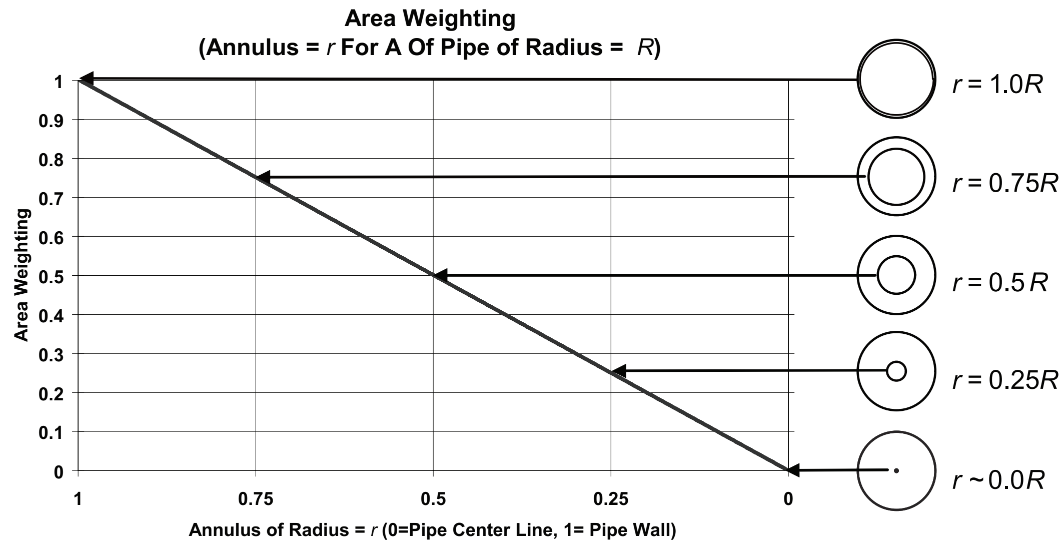


Figure 4—Annulus Area vs. Distance from the Center of the Pipe

Figure 4 illustrates four different annulus area examples. The black circles on the right represent the pipe and the red circles represent the area of the annulus of thickness delta *r* at radius *r*. The results are then normalized to a maximum value of 1 to show the relative area contribution of the annulus as function of radius.

Another way to think of the area weighting is the area contribution to the total pipe cross sectional area. The cross sectional area of:

- The center (first) quartile ($\int_{r=0}^{0.25R}$) is 6.25% of the total cross sectional area.
- The second quartile ($\int_{r=0.25R}^{0.5R}$) is 18.75% of the total cross sectional area.
- The third quartile ($\int_{r=0.5R}^{0.55R}$) is 31.25% of the total cross sectional area.
- The fourth quartile ($\int_{r=0.75R}^{R}$) is 43.75% of the total cross sectional area.

The area weighting has been used to calculate the bulk average velocity in the figure below.

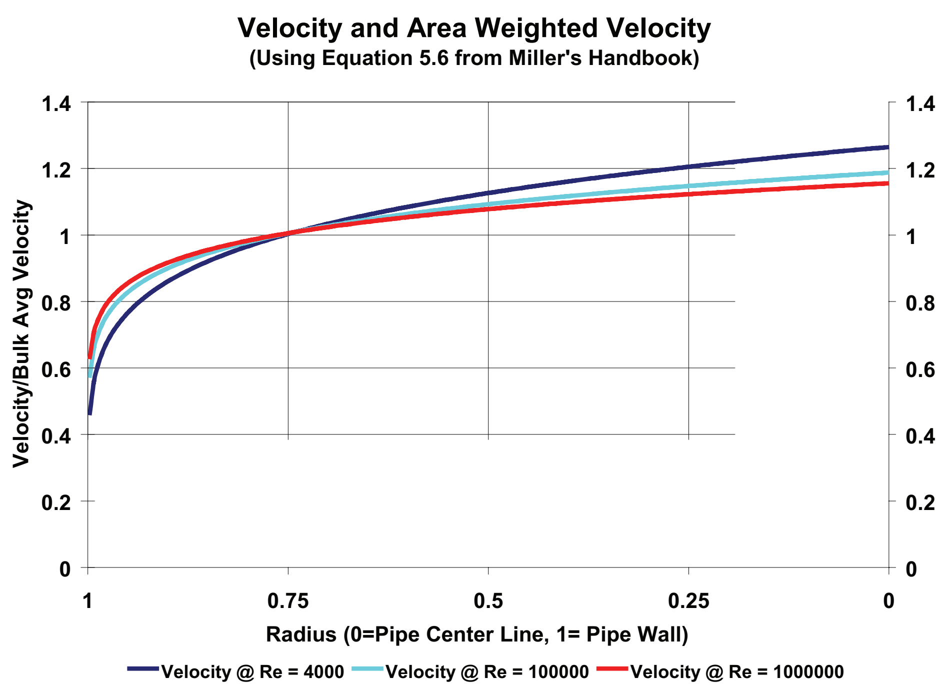


Figure 5—Point Velocity vs. Area Weighted Velocity

The figure shows the velocity for a fully developed flow using Equation 5.6 from *R. W. Miller's Flow Measurement Engineering Handbook* for a Reynolds number of 4,000, 100,000 and 1,000,000. The velocity profile has been normalized to show velocity along the centerline path relative to the bulk average velocity. From this information, different types of meter performance can be estimated.

A single-path ultrasonic meter, which measures the velocity along the centerline cord, can have its output estimated by averaging the velocity at even radius intervals. This type of velocity measurement is often called "path averaged" because it provides an average velocity along the path of the signal between ultrasonic sensors. Since the velocity in Figure 5 is normalized to the bulk average velocity, the difference between the path averaged velocity and 1 becomes the Reynolds number meter correction factor. This information was used to estimate the meter correction as a function of Reynolds number as shown in Table 1. The differences are caused by the flow profile changing with Reynolds number. Velocities should be annulus-area-weighted to reflect their flow contribution, but the path-averaging nature of the single path ultrasonic meter equally weights the velocity across the entire path.

A point velocity meter measures the velocity at one point or one small area. The relationship between the velocity at the location the velocity is measured and the bulk average velocity is used to determine the meter correction factor as a function of Reynolds number. Correction factors for a centerline insertion meter that measures velocity at zero R, and a quarter-radius insertion meter that measures velocity at $0.75R$ are shown in Table 1.

Table 6—Velocity/Pipe Bulk Average Velocity

Meter Type	Re = 4,000	Re = 100,000	Re = 1,000,000
Centerline Path Average Velocity	1.083	1.060	1.050
Centerline Point Velocity	1.264	1.187	1.155
$0.75R$ Point Velocity	1.001	1.004	1.004

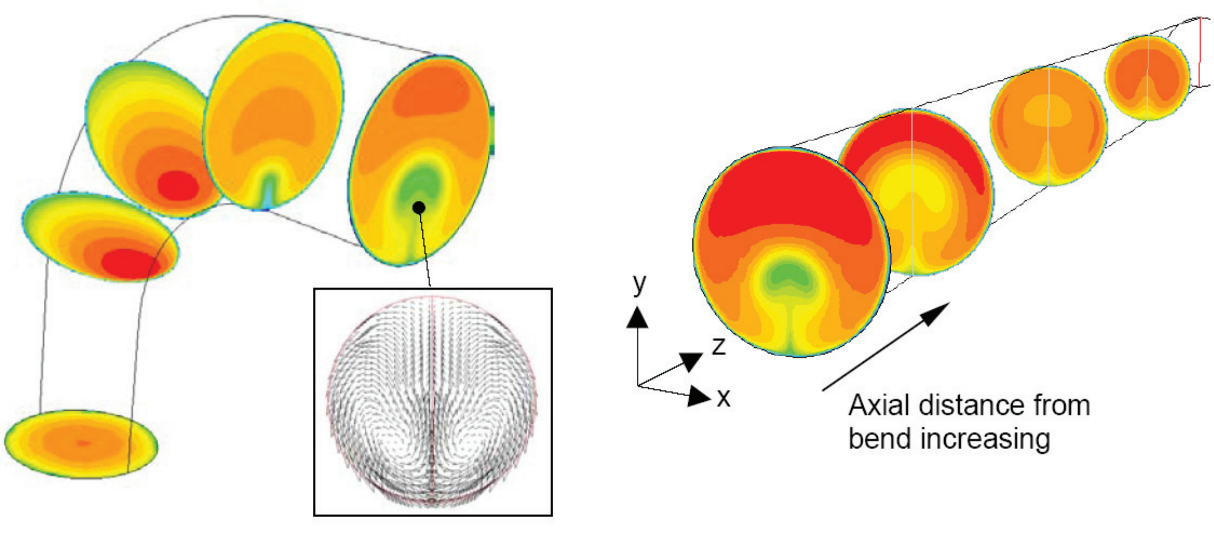
Similar calculations could be done for an averaging Pitot tube if the location of the pressure ports and the relative averaging between the ports is known.

In actual applications, the relationship between path average velocity, point velocity or multi-point velocity measurements and the bulk average velocity should be accounted for in the meter calibration for fully developed flow at different Reynolds numbers.

Piping Effects

What typically is not handled by meter calibration is the installation effect related to flare meter upstream piping components. Comparison of velocity profile differences between fully developed flow and the perturbed flow condition can provide insight into how the meter will perform under these conditions and may even provide correction factors.

For example, a large amount of information is available to describe the velocity profile downstream of a single 90° elbow. The following two figures have been taken from Reference 14, which summarize simulation work done by TUV NEL Ltd and installation effect measurements done by NIST.



a) b)

Figure 6—Predicted Velocity Contours through the Downstream of the Single Bend:
a) Flow through the Bend (Insert—Predicted Vortices), b) Development after the Bend

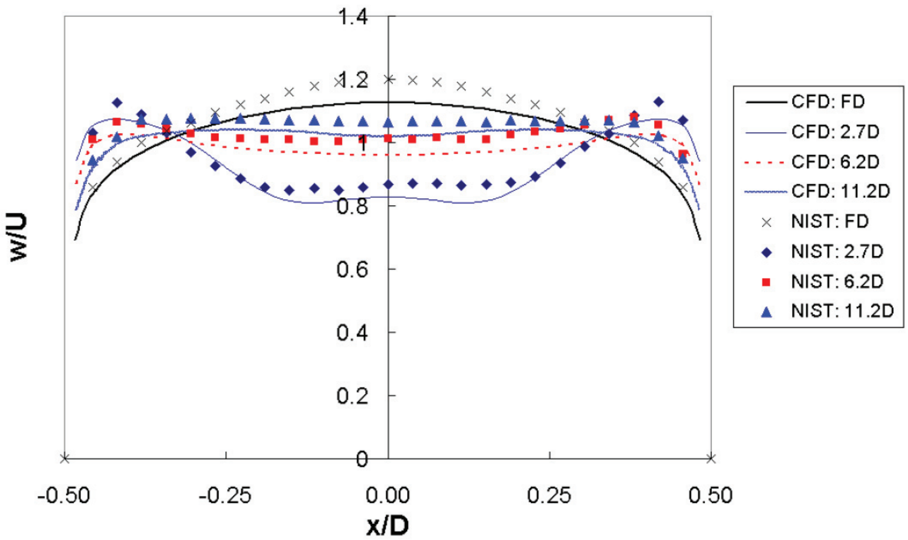


Figure 7—Comparison of Axial Velocity on the Horizontal Axis with NIST Data at Various Axial Distances from the Bend

Review of the NIST: 11.2*D* and the NIST: FD data in Figure 7 provides some insight into how three types of meters would perform if they were installed at this location downstream of a single elbow (w = axial velocity, U = velocity magnitude which is the bulk average velocity, x = traverse distance and D = pipe diameter).

Table 8 summarize the observations and provide an estimate of the meter error based on the observations. For example, if the path average velocity meter assumes a fully developed flow profile, it will report pipe bulk average velocity = path average velocity/1.06, but the path average velocity should only be divided by 1.02 based on the 11.2*D* flow profile.

Table 7—Table of Meter Errors Meter Using the Fully Developed Profile vs. 11.2*D* Profile

Meter Type	NIST: FD	NIST: 11.2*D*	Estimated Meter Bias
Centerline Path Average Velocity	1.06	1.02	~ –4%
Centerline Point Velocity	1.20	1.06	~ –14%
0.75*R* Point Velocity	1.0	1.07	~ +7%

Table 8—Table of Meter Errors Meter Using the Fully Developed Profile vs. 2.7*D* Profile

Meter Type	NIST: FD	NIST: 2.7*D*	Estimated Meter Bias
Centerline Path Average Velocity	1.06	0.95	~ –12%
Centerline Point Velocity	1.20	0.87	~ –38%
0.75*R* Point Velocity	1.0	1.09	~ +9%

Use of meter bias to account for installation effects would add random uncertainty to the measurement. If this random uncertainty was estimated as 25% – 50% of the bias, then a bias of –10% would result in a correction factor of 10% ±2.5% to ±5%. If the meter accuracy in fully developed flow was ±2%, then the meter accuracy after adjusting for the installation effect bias would be ±2% plus ±2.5% to ±5% or ±4.5% to ±9%.

Although use of these techniques to correct for installation effect bias is attractive, it cannot be recommended at this time due to the lack of experimental data which:

- Quantifies the systematic uncertainty of the bias.
- Quantifies the random uncertainty remaining after compensating for the bias.
- Quantifies meter-specific effects to the velocity profile.

The information does point out the fact that the flow profile needs to be understood when trying to estimate how non-ideal installations affect meter performance and can be used in estimating FFMS installation effect uncertainties. It shows that path-averaging velocity meters are affected by non-ideal installations that they aren't always better than point velocity meters.

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