

PRODUCTION VERIFICATION ENHANCEMENT

FINAL REPORT

SwRI® Project No. 18.16994

Prepared for:

U. S. Department of the Interior
Bureau of Safety and Environmental Enforcement
381 Elden Street
Herndon, Virginia 20170
DOI Contract Number M1JPC00026

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Prepared by:

Flavia Viana
Darin L. George, Ph.D.
Rebecca A. Owston, Ph.D.
Kevin R. Supak
Adam G. Hawley
Adam Ufford

Approved:



Danny M. Deffenbaugh, Vice President
Mechanical Engineering Division

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EXECUTIVE SUMMARY

The royalties collected by the Bureau of Safety and Environmental Enforcement (BSEE) for oil and natural gas production in United States federal land and water leases represent one of the country's largest non-tax sources of revenue. It is critically important that the produced volume from these leases be measured accurately to ensure that the federal government receives its fair share of royalty revenue each year. At the request of BSEE, Southwest Research Institute (SwRI) has developed tools and reference materials that can be used by BSEE to improve its current practices for flow measurement verification.

To assist BSEE inspectors in verifying production volumes, SwRI has prepared procedures for metering inspection and verification. These may be used by BSEE staff to generate checklists and forms for use in inspections. These procedures were developed using research into industry standards, references on best practices in the petroleum and natural gas industry, recent publications from industry schools and conferences, and federal regulations governing royalty and allocation measurement. Use of these inspection procedures will increase the confidence and efficiency of inspections by BSEE personnel, and will promote consistency of verification methods between onshore and offshore inspections.

SwRI has also prepared educational material for BSEE on current oil and natural gas metering technology. The material discusses key properties and characteristics of single-phase and two-phase flows; operating principles of gas, liquid, and multiphase meters; principles of meter calibration; and measurement uncertainties of meters and secondary equipment. This material has also been provided to BSEE in the form of PowerPoint training materials. The training materials will help BSEE staff develop skills necessary for the inspection of current meter technology, and will help them respond to advances in metering technology by identifying necessary changes in inspection procedures and regulations.

Finally, SwRI has developed an application for calculating uncertainties in measured royalty and allocation volumes. The application uses industry-standard methods for estimating uncertainty contributions from primary and secondary instruments, and for combining them into an overall uncertainty in measured volumes. Because uncertainty calculations are specific to the meters involved, the application focuses on the types of single-phase meters currently approved by BSEE for royalty and allocation measurement in the Gulf of Mexico Region. This tool can be used by inspectors to calculate measurement uncertainties during the inspection process, helping to increase confidence in the calculation of produced volumes and to ensure that the federal government receives appropriate royalty revenue for natural gas and oil production.

While the study has addressed many of BSEE's needs within its scope of work, additional needs have been identified regarding future advances in metering technology and the impact of fluid properties on measured volumes. Several recommendations are made in the report for further research to help BSEE achieve its strategic production verification goals and to better position itself for future changes in practices and regulations. The recommendations involve assistance in training BSEE inspectors, implementation of an inspection program using the procedures and tools developed here, preparation of additional material on sampling technology, updates of the current training material with changes in technology, and updates to inspection procedures and the uncertainty calculation tool as new metering technologies are allowed by BSEE in the Gulf of Mexico region. SwRI recommends that BSEE fund additional work in these areas to fill in gaps in the procedures and materials provided here, keep abreast of current measurement technology, and enhance tools and training for effective inspections.

1. INTRODUCTION

In fiscal year 2008, the Minerals Management Service (MMS) collected more than \$12 billion in royalties for oil and natural gas production in United States federal land and water leases (U.S. GAO, 2009). Since these royalties represent one of the country's largest non-tax sources of revenue, it is critically important that the produced volume from these leases be measured accurately to ensure that the federal government receives its fair share of royalty revenue each year.

Recent Government Accountability Office (GAO) audits (U.S. GAO, 2010) suggested that improvements in the verification of oil and gas volumes produced on government leases are needed. Thus, the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) issued a Broad Agency Announcement Solicitation (M11PS00017) as part of the "Proposed Research on Safety of Oil & Gas Operations in the OCS" for the improvement of production verification. Since the publication of this proposal, the duties of the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) have been divided between BOEMRE and the Bureau of Safety and Environmental Enforcement (BSEE). The tasks related to flow measurement verification now fall under the purview of BSEE.

Southwest Research Institute (SwRI) was awarded a contract for the development of tools to improve current practices on flow measurement verification under Topic 8 – *Production Verification Enhancement* of this solicitation. SwRI is an independent non-profit applied research and development organization that is headquartered in San Antonio, Texas. For over 63 years, SwRI has provided multidisciplinary, problem-solving services in a variety of areas in the physical sciences and engineering, including over 30 years of experience in research, development, and testing of single-phase and multiphase hydrocarbon flows. SwRI has performed previous research for the MMS in topics related to natural gas sampling methodologies, water vapor monitoring in natural gas pipe flows, and hydrocarbon dew point determination. SwRI staff frequently contributes to the review and development of relevant flow measurement standards for the American Gas Association, the American Petroleum Institute, and the Gas Processors Association.

This report is one of the deliverables for the contract awarded to SwRI for production verification enhancement and tool development. As requested by BOEMRE, the report provides reference material that BSEE staff can use to become familiar with oil and gas metering technologies, verify meter performance at offshore installations, and estimate measurement uncertainties for meters under inspection. The reference material includes information on a variety of single-phase and multiphase meters that may someday be encountered by BSEE staff. However, as requested by BSEE at the project outset, the metering verification procedures and uncertainty calculation tools are limited to single-phase meters that are currently approved by BSEE for royalty and allocation measurement. Procedures and uncertainty tools for multiphase meters are excluded from the scope of this project, as are procedures for verifying gas and liquid properties through sample analysis, but recommendations for further work in these areas are made at the end of the report.

1.1 Project Objectives

This study is intended to provide reference material and practical tools with which personnel across agencies, e.g., Bureau of Land Management (BLM), Office of Natural

Resources Revenue (ONRR), and BSEE, can verify production volumes in a timely and confident manner, improve the accuracy and consistency of results, and ensure that the Department of the Interior (DOI) receives appropriate royalties for oil and gas volumes produced from federal land and water. In turn, this will help BSEE achieve strategic goals related to production verification and will also help better position BSEE for future changes in practices and regulations.

The deliverables of the project include development of the following resources:

1. References that BSEE inspectors can use to become familiar with offshore oil and gas metering technologies.
 - A PowerPoint presentation that summarizes the current metering technologies for measuring oil and gas and that can be used for training personnel has been delivered. The material included in the slides contains information on metering technologies commonly used for measuring oil and gas in offshore facilities up to the date of completion of this project.
 - Appendices A through L of this report contain written summaries on single-phase and multiphase metering technologies. Single-phase meters include orifice, turbine, ultrasonic, Coriolis, and differential pressure meters. Only mature commercial multiphase meters with a documented history of flow loop testing and field trials have been summarized.
2. Procedures for inspecting and verifying the performance of offshore measurement technologies.
 - A set of procedures for inspecting and verifying the performance of flow measurement technologies for oil and gas commonly used in offshore production facilities has been delivered, a copy of which is included in Appendix M.
3. Computational tools with which inspectors can calculate measurement uncertainties for selected metering technologies in single-phase gas or liquid flows.
 - A calculation program has been delivered for estimating the uncertainty of specific single-phase flow measurement systems for liquid and gas: orifice meters, ultrasonic flow meters, and Coriolis flow meters. These measurement technologies are currently approved by BSEE for royalty and allocation measurement.
 - Appendix N contains the User's Manual for the calculation tool.

1.2 Report Structure

Section 2 of this report begins with technical background on fluid flow and flow metering. Classifications of single-phase and multiphase meters are subsequently discussed. An introduction to concepts related to uncertainty in empirical measurements is then given, followed by specifications of national and international standards relevant to flow metering. Section 3 provides an overview of current metering technology, with single-phase and multiphase technology discussed separately. More information on these topics is offered in Appendix A through Appendix L. Section 4 summarizes the approach taken for developing metering verification procedures for inspectors. A complete copy of the procedures themselves is

included in Appendix M. Section 5 takes into consideration all of the information available on metering operation, uncertainty, inspection, and calibration to identify gaps in current understanding and use of the technology. Section 6 summarizes the methods used to develop the uncertainty calculation tools for the project, as well as a description of the tools themselves. Appendix N provides a copy of the User's Manual for the calculation tools. Sections 7 and 8 close the report with conclusions and recommendations, respectively, for further work to support BSEE's verification goals.

2. TECHNICAL BACKGROUND

This section of the report provides technical background on fluid flow and flow meters that BSEE staff can use to become more familiar with the working principles of natural gas and petroleum meters. The report section begins with basic concepts related to flow measurement, then describes characteristics of single-phase flow and multiphase flow, two-phase gas/liquid flow patterns, and properties of “wet gas.” Next follows a description of different classes of single-phase and multiphase meters, followed by an introduction to basic concepts in measurement uncertainty. The section concludes with a review of national and international standards governing flow meters and their use.

2.1 Basic Concepts

2.1.1 Flow Meter

A flow meter is a device used to measure quantities of fluid moving through a conduit or pipe. Flow meters are available to measure gases, liquids, or mixtures of these phases. Flow meters determine moving fluid quantities through some measurable effect of the fluid flow. Some examples of these effects, as found in meters used by the natural gas and petroleum industries, include:

- The fluid’s mechanical effect on the motion of a turbine or piston;
- The pressure drop in the flow as fluid passes through a restriction;
- The heat transfer by the fluid from a heated element to a temperature sensor;
- Changes in the travel of ultrasonic pulses through the fluid;
- Changes in the motion of vibrating tubes as they carry fluid flow;
- Changes in light transmission through the fluid with changes in flow.

2.1.2 Reynolds Number

The Reynolds number expresses the ratio of inertial forces to viscous forces within a fluid flow. For flow through a pipe, the Reynolds number is the product of fluid density ρ , flow velocity U , and internal pipe diameter D , all divided by the absolute fluid viscosity μ .

$$Re = \frac{\rho UD}{\mu} = \frac{\text{inertial force}}{\text{viscous force}}$$

Viscous flows will have Reynolds numbers much lower than one, meaning that the fluid viscosity dictates the flow behavior. If a flow has a Reynolds number much higher than one, the fluid’s momentum and inertia dominate any viscous effects in the flow.

Note that the Reynolds number is dimensionless – that is, it has no units:

$$Re = \frac{\rho UD}{\mu} \rightarrow \frac{\left(\frac{\text{lb}}{\text{ft}^3}\right)\left(\frac{\text{ft}}{\text{s}}\right)(\text{ft})}{\left(\frac{\text{lb}}{\text{ft}\cdot\text{s}}\right)} \rightarrow \frac{\text{lb}}{\text{ft}\cdot\text{s}} \rightarrow \text{dimensionless}$$

Dimensionless numbers such as the Reynolds number are very useful in flow measurement because they can be used to scale meter performance up and down to different meter sizes and different flow rates. The discharge coefficients of orifice meters and other differential pressure meters are usually correlated to Reynolds number. This can allow a single formula to be used to measure flows in meters of different sizes, fluids of different properties, and flows over a wide range of flow rates. Turbine meter calibration curves can also be correlated to the Reynolds number so that the same meter can measure different fluids with a single calibration curve.

2.1.3 Characteristics of Single-Phase Flows

Several basic properties of fluid flows depend on the Reynolds number. This section describes those concepts for single-phase flows, that is, flows of only liquid or only gas. These concepts guide the design of flow meters and can influence their performance. Since natural gases and petroleum liquids are always transported and measured in cylindrical pipes, this discussion will focus on properties of pipe flows. Much of this discussion is taken from texts by White (1979) and Munson et al. (1990).

Flow regimes in single-phase flow can be visualized by injecting a dye stream into flow through a transparent pipe, as shown in Figure 2-1. At low flow rates, the dye will flow in a well-defined line or streak, remaining at its initial distance from the pipe wall. In such flows, fluid tends to flow smoothly and steadily in “layers” at a constant distance from the pipe centerline, with little or no mixing between layers. Such flows are called laminar flows. At high flow rates, on the other hand, the dye streak immediately spreads out from the injection point, mixing and diffusing across the flow area. This mixing is caused by agitation in the flow, and the flow is called turbulent. At intermediate flow rates, the injected dye starts out as a streak leaving the injector, but before long, it starts to fluctuate and wander irregularly between layers, sometimes dispersing through the flow. This is called a transitional flow, since it marks the transition between the laminar and turbulent flow regimes. In pipe flows, laminar flow moves into the transition regime at a Reynolds number of 2,100 to 2,300, and fully turbulent flow occurs around $Re = 4,000$.

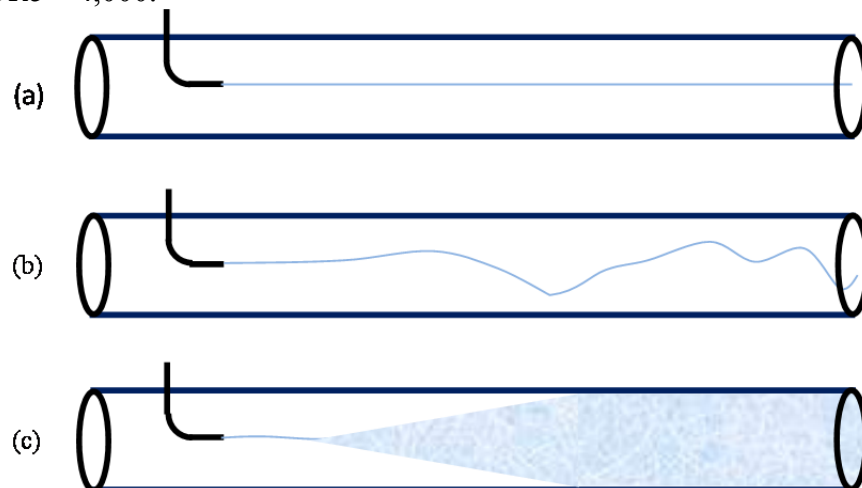


Figure 2-1. Visualizations of different regimes in pipe flows: (a) laminar flow, (b) transitional flow, (c) turbulent flow. Adapted from Munson et al. (1990).

As the Reynolds number increases, the flow transitions to turbulence, the dye streak is carried away from its initial layer by turbulent eddies, and the flow becomes well mixed.

The visualizations in Figure 2-1 show how small “packets” of fluid in the dye streak move along the pipe in various flow regimes. Observing the flow at a specific point in the pipe over time shows other characteristics of these flow regimes. A hot-wire anemometer or fast-response pressure transducer placed at a single point in the flow will show how the velocity parallel to the centerline of the pipe fluctuates over time (Figure 2-2). In laminar flow, any disturbances from the average velocity will dampen out quickly. In transitional flow, sharp bursts of changes in velocity will appear and disappear; this is caused by instability in the laminar flow and the beginning of turbulent fluctuations. In fully turbulent flow, the flow fluctuates constantly due to random turbulence at many different frequencies and local flows perpendicular to the pipe axis. This is the same mechanism that disperses the dye throughout the pipe in Figure 2-1(c).

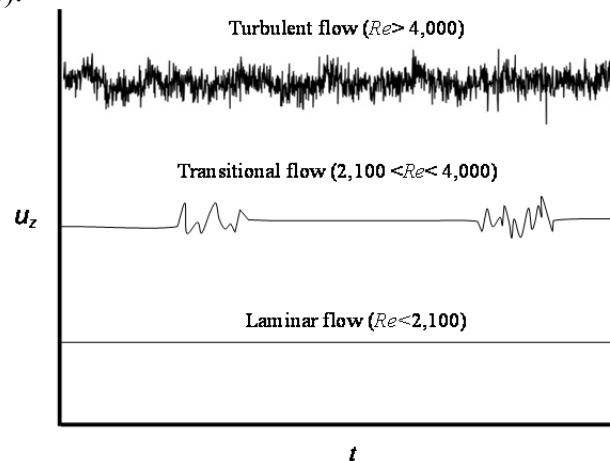


Figure 2-2. Behavior of fluid velocity at a single point in different pipe flow regimes. Adapted from Munson et al., 1990.

In the transitional flow regime, brief turbulent fluctuations create momentary oscillations in the local axial velocity. These fluctuations are absent in laminar flow, but exist throughout turbulent flow.

Inspecting the fluid velocity profile across the entire pipe also provides useful information about the flow, and can explain why different pipe configurations can affect the accuracy of flow meters. Figure 2-3 illustrates how velocity profiles change as the flow enters a pipe or encounters a flow disturbance such as an elbow. The flow within the pipe is affected by the pipe walls, and as flow progresses down a length of straight pipe, the effects of fluid viscosity (even in gases) work their way from the walls into the center of the flow. Near the wall, in the boundary layer, the fluid velocity parallel to the pipe centerline is effectively zero, because viscous effects cause the fluid to “stick” to the wall. The velocity increases further from the walls, and reaches its maximum along the pipe centerline. Far enough from the entrance or flow disturbance, the velocity profile across the pipe is completely defined by the influence of the walls. At this point, the flow is said to be fully developed, since the velocity profile remains unchanged as the flow moves down the straight pipe.

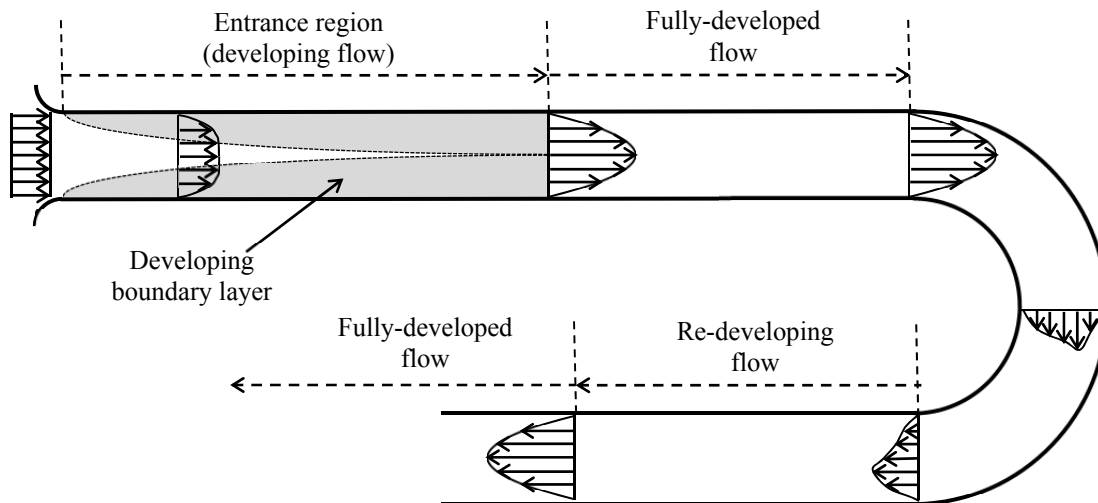


Figure 2-3. Examples of developing flow and fully-developed flow in a pipe system. Adapted from Munson et al., 1990.

Changes in pipe geometry, such as an elbow or a pipe entrance, will alter the velocity profile. After a sufficient length of straight pipe, the velocity will develop into a constant profile.

Nearly all types of single-phase meters are required to be calibrated in a fully-developed velocity profile, or in a profile that produces the same results as a fully-developed profile. Changes from straight pipe, such as elbows or valves, can disturb the profile and cause inaccurate measurements, so industry standards list the required lengths of straight upstream pipe or other upstream hardware that will avoid these measurement errors. For laminar pipe flows, a fully-developed flow profile can be described by a parabolic formula:

$$u(r) = U_{CL} \left[1 - \left(\frac{r}{R} \right)^2 \right]$$

Here, U_{CL} is the maximum velocity at the pipe centerline, R is the pipe radius, and r is the distance of the point of interest from the centerline. For turbulent pipe flows, the profile can be approximated by a correlation known as the power-law velocity profile:

$$\bar{u}(r) = U_{CL} \left[1 - \left(\frac{r}{R} \right) \right]^{\frac{1}{n}}$$

The value of n depends on the Reynolds number, but typically ranges from $n = 6$ to $n = 10$. Figure 2-4 compares these flow profiles.

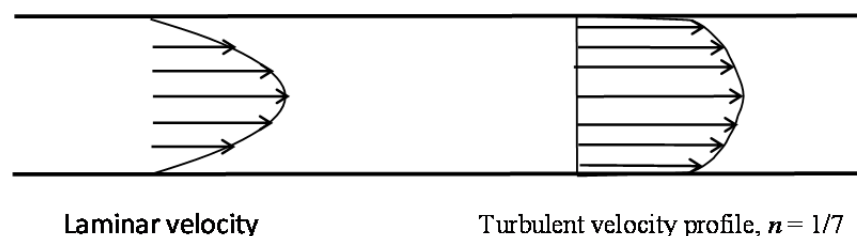


Figure 2-4. Comparison of fully-developed velocity profiles in laminar and turbulent pipe flow. *Because the boundary layer is much thinner in laminar flow than in turbulent flow, the fully-developed velocity profile for turbulent flow is fairly constant across much of the pipe diameter. Velocity vectors in the two profiles are not to the same scale.*

2.1.4 Multiphase Flow

A fluid stream composed of two or more phases flowing in a closed conduit may be considered multiphase flow. For the oil and gas industry specifically, this term implies three phases: natural gas, hydrocarbon liquids, and process water. Unlike single-phase flow, characteristics such as Reynolds number, velocity profile, and boundary layer do not distinguish the nature of the flow. Instead, multiphase flow regimes are defined by the geometrical distribution pattern of the phases within the pipe. Broadly, these are categorized as dispersed, separated, and intermittent. Dispersed flow has a uniform phase distribution in both the axial and radial directions. Bubbly and dispersed bubbly flows are types of dispersed flow, as is mist flow. Separated flow has a non-continuous phase distribution in the radial direction, and a continuous phase distribution in the axial direction. Stratified and annular flows are examples of separated flows. Intermittent flow is non-continuous in the axial direction, appearing locally unsteady. Examples of intermittent flow include plug flow, slug flow, and churn flow. More details on multiphase flow patterns are given in subsection 2.1.5.

Transition between multiphase flow regimes is based on superficial velocities of the liquid and gas. The superficial gas velocity $V_{s,g}$ is the velocity the gas would have if it were the only fluid in the pipe. Mathematically, $V_{s,g} = \frac{Q_g}{A}$, where A is the total cross-sectional area of the pipe and Q_g is the total volumetric gas throughput at actual operating conditions. Likewise, the superficial liquid velocity $V_{s,l}$ is the velocity at which the liquid would flow if it were the only fluid in the pipe, i.e., $V_{s,l} = \frac{Q_l}{A}$, where Q_l is the total volumetric gas output. The phase velocity difference between the liquid and gas superficial velocities is defined as slip velocity, $V_s = \|V_{s,g} - V_{s,l}\|$. Normally, the lighter gas phase will move faster in the pipe than the liquid phase. Thus, the wetted fraction of the pipe area is usually larger than the liquid volume fraction of the flow. This wetted fraction is termed liquid hold-up, expressed as $\lambda_l = \frac{A_l}{A_{pipe}}$, where A_l is the cross-sectional area occupied by the liquid versus that of the entire pipe A_{pipe} . Similarly, gas hold-up (also known as gas void fraction, or GVF) is defined as $\lambda_g = \frac{A_g}{A_{pipe}}$, where A_g is the cross-sectional area occupied by the gas.

Another term commonly used in multiphase flow measurements is “water cut.” This is defined as the water volume flow rate, relative to the total liquid volume flow rate (the combined oil and water stream), at the actual operating conditions (pressure and temperature). This parameter is normally expressed as a percentage of the total liquid volume flow.

Multiphase flow meters (MFMs) are complex systems that consist of primary devices and subsystems closely integrated in a single unit and coupled with algorithms for the determination of the flow rate of the gas and liquid phases. Ideally, direct independent measurements of phase fraction, phase velocity, and phase density would be combined to obtain the mass flow rate of each phase. However, such technology does not exist at present. Instead, flow rates are inferred indirectly through measurement of parameters such as GVF, bulk volumetric flow rate, and water cut. Densities are generally estimated at operating conditions using pressure, volume, and temperature (PVT) data. Upstream flow conditioning, either mixing or separation of the phases, may be required for some MFM technologies.

2.1.5 Two-Phase Gas/Liquid Flow Patterns

Multiphase flow regimes are defined by the distribution pattern between the phases. Gas/liquid flow regime maps are created to indicate the transition between flow patterns in terms of superficial liquid and superficial gas velocities. However, transition is a gradual process and highly dependent on operating conditions, fluid properties, flow rates, and orientation and geometry of the pipe (API RP-86, 2005). Thus, maps tend to be unique to a given set of operating conditions. Nevertheless, flow regimes may be broadly grouped through qualitative classification using flow quality and flow rate. Flow quality is defined as the fraction of vapor mass flow to total mass flow through the pipe, i.e., $\frac{\dot{m}_v}{\dot{m}_v + \dot{m}_l}$. Flow patterns tend to be axially symmetric for vertically-oriented flows. However, for horizontal flows, the influence of gravity tends to pull the heavier liquids toward the bottom of the pipe. To simplify analysis, most multiphase meter manufacturers specify installation in the vertical orientation.

Table 2-1 indicates the various flow patterns that may arise for flow through a vertical pipe. When the flow has a low flow quality, the liquid phase is continuous; the pattern will be bubbly at low flow rates and will have finely dispersed bubbles at high flow rates. While liquid hold-up is relatively high for bubbly flow due to slippage between the phases, in dispersed bubbly flow there is very little slippage between the phases and the flow is considered homogeneous. At intermediate qualities and low-to-intermediate flow rates, the pattern will tend toward slug flow. This is characterized by successive gas pockets and liquid slugs alternating through the pipe. Churn flow is similar to slug flow; however, the distinction between the phases is less pronounced as a result of the higher flow rate. For high-quality flows with a high flow rate, the flow regime is annular; a liquid film will form on the pipe walls around a gas core with entrained liquid droplets. The liquid film moves slowly relative to the gas core. At the point where a liquid film is no longer present (due to insufficient liquid or forced evaporation), the gas core with entrained droplets is simply defined as mist flow.

Table 2-1. Qualitative classification of gas/liquid vertical flow patterns.

The transition point between flow regimes is dependent on operating conditions, fluid properties, flow rates, and orientation and geometry of the pipe. However, multiphase flow regimes for a vertical orientation may be broadly grouped as shown (Buongiorno, 2010).

FLOW QUALITY	FLOW RATE	FLOW REGIME
Low	Low and Intermediate	Bubbly
	High	Dispersed Bubbly
Intermediate	Low and Intermediate	Plug/Slug
	High	Churn
High	High	Annular
	High (post-dryout of film)	Mist

2.1.6 Wet Gas

Various definitions are used for the term wet gas. The most basic definition qualitatively describes this as the form of multiphase flow in which the dominant fluid is gas with a small amount of liquid (API RP-86, 2005). Others base their classification on a quantitative cutoff value for the Lockhart-Martinelli parameter. This may be expressed as $LM = \frac{Q_l}{Q_g} \sqrt{\frac{\rho_l}{\rho_g}}$, where Q_l

and Q_g represent the liquid and dry gas volume flow rates, respectively, and density of the liquid and gas are denoted by ρ_l and ρ_g . An increase in the Lockhart-Martinelli (LM) value indicates an increase in the liquid fraction of the flow. The Norwegian Handbook of Multiphase Flow Metering stipulates that flows with LM values less than 0.3 are classified as wet gas (NFOGM, 2005). The Alaska Oil & Gas Conservation Commission divides wet gas into three subcategories, as shown in Table 2-2 (Mehdizadeh & Williamson, 2004(a) and 2004(b)). For very low LM values, single-phase commercial gas meters are typically used with a correction factor to compensate for volumetric over-reading due to the presence of liquid. At higher LM values, the metering systems employed are generally multiphase meters designed to measure all three phases. Examples of these systems are discussed in Appendix F through Appendix L of this report.

Table 2-2. Wet gas flow classification and applications.

Wet gas flow types are classified based on the Lockhart-Martinelli (LM) parameter (Mehdizadeh & Williamson, 2004).

CLASS	LOCKHART-MARTINELLI PARAMETER	TYPICAL APPLICATIONS
Type 1	≤ 0.025	• Gas production wellheads • Unprocessed gas pipelines • Separators • Allocation points • Well test facilities
Type 2	0.025 – 0.30	• Flow stream at the production wellhead • Commingled flow line • Well test applications
Type 3	> 0.3	• Gas Condensate wells • Gas lift wells

2.1.7 Calibration Concepts

All parties involved in the measurement of petroleum and natural gas must be confident that meters are accurately measuring fluid volumes. This is true whether the measurement is for allocation of produced fluids or for custody transfer of the end product. Calibration serves to minimize errors, correct drift of equipment over time, and document equipment accuracy. This section describes concepts related to meter calibration and proving.

As defined by Upp and LaNasa (2002), calibration is “the process or procedure of adjusting an instrument or a meter so that its indication or registration is in close agreement with a referenced standard.” The U.S. National Institute of Standards and Technology (NIST) and other national measurement institutes hold reference objects for weights and measures, such as the reference kilogram and reference meter. These are kept in controlled conditions and used as references for other standards used in industries to calibrate meters and instruments. Some quantities, such as length and time, are also defined using physical constants such as the wavelength of light emitted by krypton-86 or the electronic oscillation of cesium atoms. While there are references for time, length, and volume, there are no national or international standards for flow rate. Flow measurement standards combine measurements of time and volume to arrive at flow rate.

The chain of comparisons or calibrations by which a meter or instrument is compared to a measurement standard is known as its traceability. Laboratory standards that are traceable to reference objects often serve as the start of a traceability chain for flow measurement devices. A platinum resistance thermometer for temperature is an example of a laboratory standard used to calibrate temperature transmitters for field use; deadweight testers are laboratory standards used to calibrate pressure transmitters.

Flow standards are commonly classified as primary or secondary, depending upon the reference quantities they represent. Primary flow standards determine the flow rate from measurements of mass, length or volume, and time. A weigh tank standard, one example of a primary flow standard, measures the mass flowing from a pipe over a given time interval, and produces a reference mass flow rate against which a meter in the pipe can be calibrated. In a piston prover, such as the one shown in Figure 2-5, flow causes a piston to move within a barrel. The time required for the piston to travel the known distance between two detector switches is measured. The reference volume flow rate is computed from the known travel distance, the area of the barrel, and the piston's travel time along the known distance. Secondary flow standards require the use of experimental calibration coefficients to compensate for nonideal behavior in the standard. Turbine meters or critical flow Venturi nozzles are examples of secondary flow standards that must be calibrated to relate their output (number of rotor rotations or pressure drop) to flow rate or total volume.

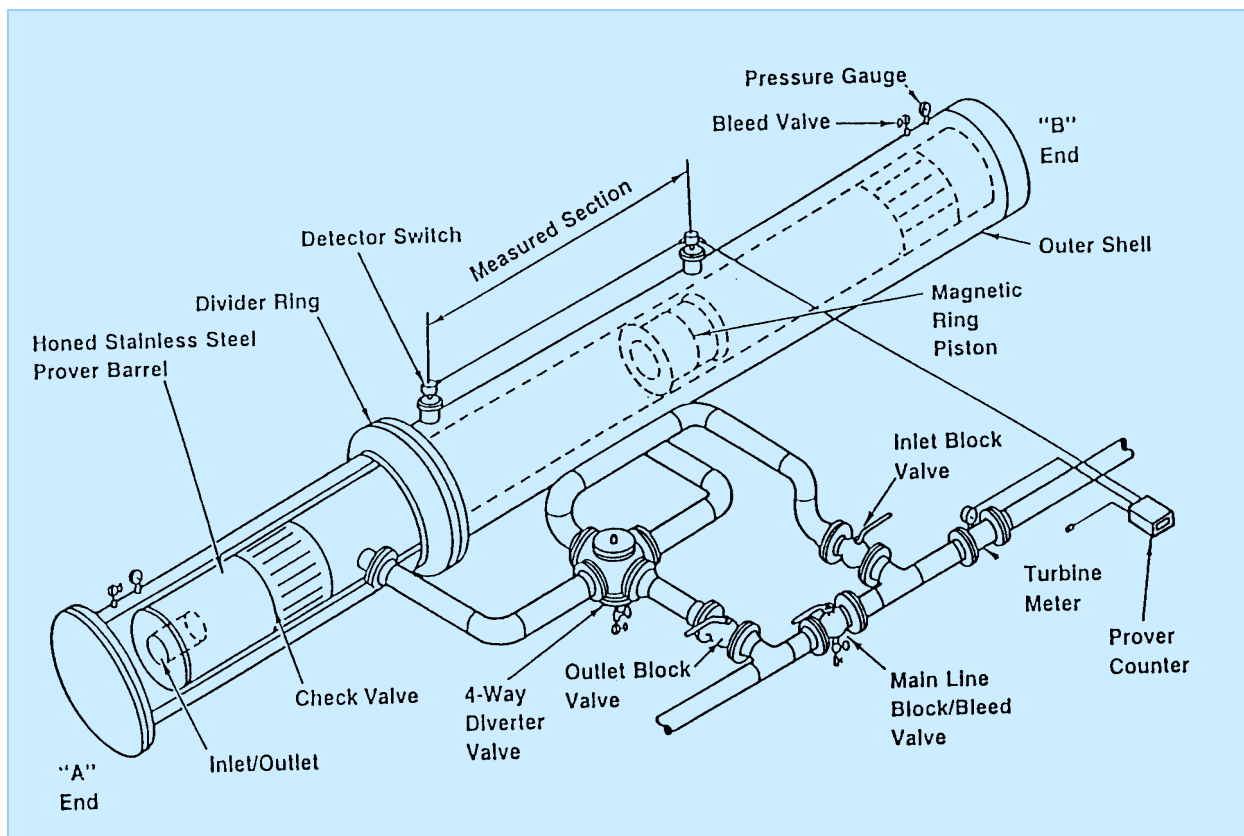


Figure 2-5. Example of a gas piston prover used for field calibration at a meter station.

The time required for the floating piston to travel between the detector switches, the distance between the switches, and the area of the barrel are used to calculate a reference volume flow rate. The turbine meter is then calibrated using this reference flow rate. Illustration courtesy of Amoco.

Transfer proving refers to the practice of calibrating meters and other instruments in the field against a flow standard (Upp and LaNasa, 2002). In common practice, field equipment is calibrated against a master meter or a certified temperature or pressure device. This master meter or certified instrument is a primary or secondary flow standard, and is therefore carefully controlled and handled, and recertified regularly. For calibration, field equipment is typically sent to the laboratory where the flow standard resides. However, some field sites have piston provers permanently installed, particularly if the value of the fluid being measured at the site justifies regular meter calibration.

Meters should be proved or calibrated over the entire range for which they are expected to give acceptable accuracy. This range is often described as a turndown ratio, the ratio of the maximum flow rate to the minimum flow rate for the meter. This is also sometimes referred to as the rangeability of the meter. Flow standards or transfer provers used to calibrate or prove the meter should themselves be able to accurately measure flow over the same range of flow rates as the meter being tested so that the full meter calibration is valid.

Upp and LaNasa (2002) recommend that meters and secondary instruments be tested as part of a regular maintenance schedule, and calibrated according to agreements by all parties involved. Maintenance may be weekly or even daily, while calibration intervals may be based on manufacturer recommendations or the value of the fluid being measured. Since all measurements by the meter and secondary instruments combine to produce a flow measurement, all instruments should be considered in the calibration schedule. For most flow meters, the standards described later in subsection 2.5 are performance-based standards, which require the meter to be calibrated to demonstrate their measurement accuracy. The orifice meter standard used by the natural gas and petroleum industries is an exception. It is a specification-based standard that gives the calibration coefficients and measurement uncertainties for orifice meter runs that meet stated dimensional specifications. Although orifice meters that meet these specifications are not required to be calibrated by the standard, users sometimes have them calibrated to identify and correct causes of bias. The concept of bias is explained in subsection 2.4.

2.2 Single-Phase Flow Meter Classification

As noted by Miller (1996), well over 100 different types of flow meters are commercially available. The best meter for a particular application can depend on the fluid being measured, operating temperature and pressure, flowing conditions, desired accuracy, and literally dozens of other criteria. At the broadest level, Miller (1996) and Upp and LaNasa (2002) both group meters for single-phase flow measurement into differential producing meters and linear meters.

Differential producing meters, sometimes called differential pressure meters, differential producers, or DP meters, apply the Bernoulli principle to determine flow rate. A pressure drop is measured across an obstruction in the flow, and the flow rate is proportional to the square root of the pressure drop. The proportional constant depends on the shape and dimensions of the obstruction, and on other design features of the meter; in many cases, the relationship between pressure drop and flow rate is best found by calibration. The orifice meter has been used by the petroleum and natural gas industries since the early 1900s, and is the oldest example of a differential producer. More recent designs for DP meters used by the hydrocarbon energy industry include cone-type meters, wedge meters, and Venturi meters. These meter designs,

their performance, and parameters influencing their performance are discussed further in subsection 3.1.

Linear meters are so named because the meter output is linearly proportional to flow rate, or very nearly so. This proportionality is distinct from the square-root relationship between differential pressure and flow rate in differential producing meters. Either the operating principle of the meter yields a linear output, or electronics in the meter produce an output linearly proportional to volume or mass flow rate (Miller, 1996). The speed of a rotor in a liquid or gas turbine meter increases linearly with flow velocity. By using magnetic detectors to measure the rotor speed, and multiplying by a constant calibration factor (or K factor), the flow rate can be computed directly. Ultrasonic meters measure the transit time or changes in frequency of ultrasonic pressure pulses through the flow, and through appropriate weighting, compute the average flow velocity through the meter. Coriolis meters apply an oscillation to tubes or pipes carrying the flow, and in turn, the fluid responds with a Coriolis acceleration and force on the tubes. By measuring the amplitude, phase difference, or other properties of the net tube displacement, the mass flow rate of the fluid can be measured. More details on these linear meters, and their applications in petroleum or natural gas measurement, can also be found in subsection 3.1.

2.3 Multiphase Flow Meter Classification

Unlike single-phase flow, multiple sensors are needed as part of a multiphase flow meter. The flow rate of each phase is determined using a combination of individual parameter measurements such as gas volume fraction (GVF), water cut, bulk volumetric flow, etc. Methods for obtaining necessary measurements differ among meter manufacturers. However, the following main categories have been proposed (NFOGM, 2005):

- In-line meters
- Wet gas meters
- Separation meters
- Virtual meters

As indicated by the name, in-line meters perform all measurements directly in the multiphase flow line without requiring separation or sampling of the phases. The flow rate of each phase is computed as the area fraction in the pipe multiplied by the velocity of each phase. This requires a minimum determination of six parameters; however, this number may be reduced if it is assumed that two or all of the phases travel at the same velocity. Methods for obtaining necessary measurements can include combinations of the following techniques:

- Electromagnetic measurements (microwave, capacitance, conductance)
- Gamma-ray densitometry/spectroscopy
- Differential pressure measurement across flow restriction
- Positive displacement volumetric measurement
- Coriolis force measurement
- Ultrasonic measurement
- Cross-correlation of signals to infer flow velocities (pressure, electrical, gamma-ray, etc.)

Wet gas meters often employ similar techniques to in-line meters for determining phase flow rates. However, wet gas can also be measured using single-phase meters with correction

factors to compensate for trace liquids in the gas. The metering application is the primary factor in determining how complex a wet gas meter need be. For example, if the objective is simply to measure the gas phase, a single-phase meter that merely corrects for entrained liquid fraction may be employed. On the other hand, if the application requires independent measurement of gas, oil, water, and salinity simultaneously, then the wet gas meter will require more sensors.

Separation meters operate on the principle of full or partial separation of the multiphase stream prior to in-line measurement of the separated phases. These may be sub-categorized as (1) full two-phase gas/liquid separation, (2) partial separation, or (3) sample line separation. Full two-phase separation uses a separator to isolate the gas for subsequent measurement using a single-phase meter. Likewise, the liquid is measured with a single-phase meter and a water-cut meter is used to determine the water-in-liquid ratio. Partial separation meters route only part of the gas through a secondary loop to perform wet gas measurement. The remaining reduced-GVF multiphase stream is handled in a similar manner to in-line meters. This type of meter is commonly used when GVF conditions are outside the accepted operating envelope of an in-line meter. Finally, sample line separation meters perform diagnostics on a bypassed sample flow, commonly providing a water-cut measurement. The total gas/liquid flow rate and ratio are measured in the main flow line.

Virtual multiphase meters include signal processing and process simulation systems. Under signal processing, flow rates may be estimated using pattern-recognition or statistical signal processing of time-variant signals from existing sensors in the multiphase line. Process simulation systems are predictive algorithms that infer, but do not directly measure, the flow at the point of arrival at the meter. For example, pressure and temperature at two points axially along the pipe may be used in conjunction with measured or assumed fluid properties to estimate flow rates of the various phases.

2.4 Uncertainty Concepts

An analysis of measurement uncertainty provides producers (and parties involved in custody transfer) with confidence in their measurements, allows for equitable transactions, and can be used to make instrumentation budgets more cost-effective. Manufacturers and users describe instrument performance with terms such as precision, accuracy, and linearity. These terms have specific meanings based on statistics, and defensible uncertainty analyses are created through statistical analysis. Knowledge of a few statistical concepts is enough to understand common uncertainty terms. This section will define these concepts and terms; more information can be found in the references cited below.

Two key terms with specific meanings are precision and bias. Precision is a measure of how tightly a set of repeat measurements of the same quantity are grouped together. Bias is a measure of how close the measurements come to the true value of the quantity being measured. Suppose a property *X* is measured many times in the same test under the same conditions by four different instruments. The four bell-shaped curves in Figure 2-6 show the frequency at which each instrument produces a particular measurement value. Frequency is plotted on the vertical axis against the measured value on the horizontal axis. In Figure 2-6(a), two bell curves represent datasets from two instruments whose measurements are both centered on the true value. Since the center values are close to the true value, the measurements are said to be unbiased. The data set forming the narrower bell curve is clustered more tightly about the center

value, so the instrument that produced it is more precise than the instrument that produced the broader bell curve.

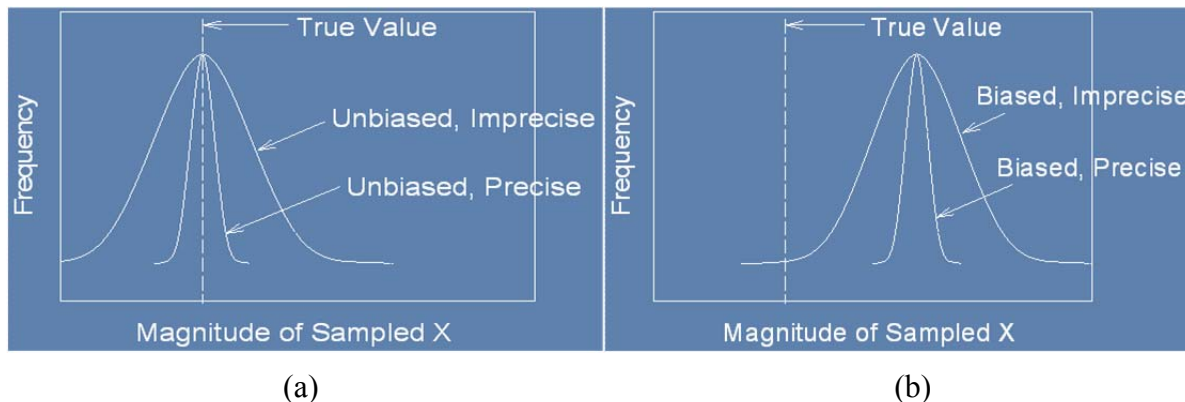


Figure 2-6. Examples of precision and bias in data.

The data sets represented by the curves in graph (a) are centered on the true value, and thus have less bias than the data sets in graph (b). Narrower curves come from instruments that produce more precise measurements.

In Figure 2-6(b), measurements from the other two instruments are shown to be biased, since their central or most common measurements are away from the true value. One of the instruments is precise, meaning its results are very repeatable, but its large bias means that its results do not represent the true value.

Precision uncertainties are often associated with random fluctuations, either in the quantity being measured or in the instrument itself. An instrument's precision may be quantified using the mean and standard deviation of its repeat measurements. If n measurements of a quantity x are collected by the instrument, the mean value $\bar{x}$ can be computed as:

$$\bar{x} = \frac{1}{n} \sum_{i=1}^n x_i$$

If the scatter in the data is assumed to be random, the sample standard deviation s of the set of measurements can be computed as:

$$s = \sqrt{\frac{1}{n-1} \sum_{i=1}^n (x_i - \bar{x})^2}$$

The sample standard deviation can then be multiplied by a coverage factor that predicts the likelihood of a single measurement falling within a certain band about the mean value. The precision of an instrument is often quantified as a 95% confidence interval, which is the band around the mean where 95% of measurements by the instrument should fall. If more than 5% of a set of repeat measurements fall outside this interval, it may indicate a source of bias or some other problem with the device. The larger the set of data used to characterize the instrument's precision, the smaller the 95% confidence interval and the better the instrument's behavior can be characterized.

Note that the total uncertainty in an instrument's measurement is a combination of its precision and bias uncertainties. When a sensor or flow meter is calibrated, the total uncertainty

in the calibration process becomes “fossilized” in the calibration. Biases have a consistent sign and magnitude, and can often be reduced or eliminated by proper inspection of the installation and calibration equipment before calibration begins. In the field, bias errors may be caused by such things as changes from calibration conditions or “drift” of the meter itself. Experienced personnel can identify and correct these causes and minimize the measurement bias. Precision uncertainties, on the other hand, can be reduced but cannot be completely eliminated.

When several measured variables are combined to obtain a flow rate, heating value, or another final quantity, the uncertainties of all measurements affect the final result. How strongly each measurement uncertainty affects the final result depends on the mathematical formulas used to combine them. Uncertainty budgets can be used to find the contributions of individual measurement uncertainties to the combined flow rate uncertainty. The most efficient way to reduce overall uncertainty can often be found by inspecting an uncertainty budget for a measurement station. If bias dominates, it can be reduced by improving mathematical modeling in the calibration, the calibration process itself, or correcting fluid property values. If precision dominates, it can be reduced by improving flow stability or the stability of sensors or data acquisition hardware.

Several other uncertainty terms used in petroleum and natural gas metering are defined below. Some of these definitions are specific to flow metering, and other definitions are used when the terms are applied to gas chromatographs or laboratory equipment.

- Linearity is the largest deviation between any data point in a dataset and a straight line fit to the dataset.
- Repeatability, when used in the context of flow meters, is the variation in a set of *consecutive* measurements, carried out under the same conditions of measurement. Repeatability is also referred to as precision error.
- Reproducibility in the context of flow meters is the variation in a set of measurements taken *over a long period of time* at approximately the same flow conditions.

2.5 Measurement Standards

Industry publications such as American Gas Association (AGA) reports and the American Petroleum Institute (API) Manual of Petroleum Measurement Standards (MPMS) document best practices for flow measurement of natural gas and hydrocarbon liquids. Other organizations such as the International Organization for Standardization (ISO) and the American Society of Mechanical Engineers (ASME) have also published standards useful in measuring fluid flows. Table 2-3 lists current industry standards that provide guidance and best practices for installing, calibrating, and using meters for single-phase gas and liquid flows. Many of these standards were used as the basis for material in this report, such as inspection procedures and uncertainty calculations. The list includes only the types of meters discussed in this report.

Unlike single-phase metering, there is no U.S. standard currently available for qualification of multiphase meters. However, Table 2-4 presents available published guidelines for multiphase flow measurement that may be reviewed for information purposes.

Table 2-3. Current standards for metering of single-phase hydrocarbon liquids and gases.
The American Petroleum Institute publishes many standards for liquid measurement, while American Gas Association standards focus on gas measurement. ASME and ISO standards are concerned with both gas and liquid flows.

Differential producing meters	Liquid and gas measurement standards	
Orifice meters	• API MPMS Chapter 14.3, Parts 1 – 4, (also published as AGA Report No. 3, Parts 1 – 4) • ASME MFC-3M-2004 • ISO 5167-1:2003 • ISO 5167-2:2003	
Differential pressure meters (Venturi meters, cone meters, wedge meters, others)	• API MPMS Ch. 22.2 • ASME MFC-3M-2004 • ISO 5167-1:2003 • ISO 5167-3:2003 • ISO 5167-4:2003	
Linear meters	Liquid measurement standards	Gas measurement standards
Turbine meters	• API MPMS Ch. 5.3 • ASME MFC-22-2007 • ISO 2715:1981	• AGA Report No. 7 • ASME MFC-4M-1986 • ISO 9951:1993
Ultrasonic meters	• API MPMS Ch. 5.8 • ASME MFC-5.1-2011	• AGA Report No. 9 • ISO 17089-1:2010
Coriolis meters	• API MPMS Ch. 5.6 • ASME MFC-11-2006 • ISO 10790:1999	• AGA Report No. 11 • ASME MFC-11-2006 • ISO 10790:1999

Table 2-4. Published guidelines for metering of multiphase hydrocarbon liquids and gases.
While no definitive U.S. standard is available for regulators, this table presents informative references on the topic of multiphase flow metering.

Guideline Designation	Issuing Organization; Title
ASME MFC-19G-2008	American Society of Mechanical Engineers (2008); <i>Wet Gas Metering Guideline</i>
API RP-85	American Petroleum Institute (2005); <i>Use of Subsea Wet Gas Flowmeters in Allocation Measurement Systems</i>
API RP-86	American Petroleum Institute (2005); <i>API Recommended Practice for Measurement of Multiphase Flow</i>
None	Norwegian Society for Oil and Gas Measurement (2005); <i>Handbook of Multiphase Flow Metering</i>
API Std 2566	American Petroleum Institute (2004); <i>State of the Art Multiphase Flow Metering</i>
None	Alaska Oil and Gas Conservation Commission (2004); <i>Principles of Multiphase Measurements</i> Alaska Oil and Gas Conservation Commission (2004); <i>Guidelines for Qualification of Multiphase Metering Systems for Well Testing</i>
API MPMS Ch. 20.1	American Petroleum Institute (2002); <i>Manual of Petroleum Measurement Standards – Allocation Measurement</i>

Besides the standards for meters used in petroleum and natural gas, other relevant standards give guidance in determining fluid properties and estimating measurement uncertainties. A widely-used document for computing uncertainties is the *ISO Guide to the Expression of Uncertainty in Measurement*, or ISO GUM (ISO/IEC 98-3:2008). While the ISO GUM is not a standard – that is, it does not provide criteria that meters and devices must meet – it does establish general rules for evaluating and expressing measurement uncertainty that have

been widely accepted in many fields, including fluid measurement. Much of the material in subsection 2.4 of this report is discussed in more detail in ISO GUM.

An ASME standard that is also widely used for uncertainty determination is ASME MFC-2M, *Measurement Uncertainty for Fluid Flow in Closed Conduits*. The standard is tailored directly to fluid metering, with concepts and examples that apply to the meters used for petroleum and natural gas measurement. Specific guidance on estimating uncertainties for certain meter types can be found in the appropriate standards. For example, uncertainty estimates for orifice meter measurements can be found in API MPMS Chapter 14.3, Part 1, while API MPMS Chapter 22.2 gives instructions on estimating uncertainties for other differential pressure meters from their calibration data.

A topic beyond the scope of this document is the determination of fluid properties such as density, viscosity, and composition. For some meter types, these properties are necessary to compute the volume flow rate; in other situations, the properties are needed to compute the energy flow rate, which is the basis for fiscal custody transfer. For natural gas, these properties are often determined by sampling of the gas stream and analysis of the sample in a laboratory. API MPMS Chapter 14.1, *Collecting and Handling of Natural Gas Samples for Custody Transfer*, concentrates on the proper design of sampling systems and collection of natural gas samples. The document includes sections on the physics of natural gas sampling and phenomena that can distort samples so that users can apply these principles when collecting samples. For petroleum liquids, API MPMS Chapter 8, Sections 1, 2, and 3 provide similar guidance.

3. REVIEW OF METERING TECHNOLOGIES

3.1 Single-Phase Flow Meters

Appendices A through E give details of the five most common meter types used for measuring petroleum and natural gas: orifice, turbine, ultrasonic, Coriolis, and differential pressure meters. Experience with the performance of these meters has identified best practices for their calibration, installation, and use, as documented in the standards listed in subsection 2.5. The appendices give detailed information on the operating principles for these meters, their flow capacities, installation and calibration requirements, typical accuracies, and sources of potential bias. Table 3-1 summarizes these key features of each meter type; the reader is referred to Appendices A through E for details.

Of the single-phase meters used for measuring liquid and gaseous hydrocarbon flows, the orifice meter has the longest history. Work to standardize the orifice meter and develop equations governing its behavior dates back to the early 20th century. Extensive testing has led to correlations for flow rate as a function of fluid density, pressure, and temperature, and meter geometry. Investigations continue to refine the correlations for the behavior of gases in orifice meters and recommend efficient meter run geometries. The orifice meter is unique in that if the meter run, orifice plate, and equipment meet certain specifications, standard correlations can be used to infer flow rates without calibrating the meter. Because differential pressures across the orifice are used to infer the flow rate, and the inferential relationship is nonlinear, the useful range of flow rates for an orifice meter is often limited to a 3:1 range, unless the orifice plate can be changed to compensate for changes in flow. Other differential-producing meter designs have been introduced within the last two decades that have larger working ranges, but because the body of performance data is much smaller for these new designs, standards call for them to be calibrated before use.

Of the linear meters used for single-phase metering, the turbine meter has the longest history within the liquid and gas industries. Turbine meters commonly have turndown ratios of 10:1 or larger, and calibrations in one fluid can be applied to many other fluids if the calibration curve is a linear function of Reynolds number. Corrections for changes in gas density at low flows can be created and applied to calibration curves as needed. The bearings and moving parts require lubrication and maintenance, a disadvantage unique to turbine meters. Ultrasonic meters and Coriolis meters are relatively new, and ultrasonic meters, in particular, have been available for liquid measurement longer than for gas measurement. While research has specified effective meter run arrangements to avoid flow profile biases in ultrasonic meters, Coriolis meters in the small line sizes available to date (typically six-inch-diameter lines and below) are relatively immune to flow profile effects. However, both types require calibration for best performance, and research to identify sources of potential measurement bias for both types is continuing.

Table 3-1. Summary of features of single-phase meters used for hydrocarbon fluids.

Each meter type has advantages and disadvantages related to available line diameters, turndown ratios, and measurement uncertainties. More details on these meters can be found in Appendices A through E.

Meter	Orifice	Differential pressure	Turbine	Ultrasonic	Coriolis
Meter type	Differential producer	Differential producer	Linear	Linear	Linear
Available line diameters	2 to 48 inches	Varies with meter design	Liquid: ¼ inch to 20 inches Gas: ¾ inch to 30 inches	Liquid: 4 to 64 inches (inline meters) Gas: 4 to 56 inches (inline meters)	1 to 14 inches
Turndown ratio	Depends on available orifice plates and differential pressure (DP) transmitters; typically 3:1 for a single plate and transmitter	Varies with meter design	10:1 for liquid meters and gas meters at near-atmospheric pressures, 100:1 listed by gas turbine manufacturers at elevated pressures	10:1 for liquid and gas meters	Varies with low-end accuracy and susceptibility to liquid cavitation
Calibration required	No, if meter meets design specs	Yes, due to individual designs	Yes	Yes	Yes
Secondary instruments	Temperature transmitter, static and DP transmitters	Temperature transmitter, static and DP transmitters	Temperature and static pressure transmitters, pulse counter	Temperature and static pressure transmitters; some meters require density measurements	Temperature and static pressure transmitters
Directly measured quantity	ΔP	ΔP	Pulses generated by rotating turbine	Sound transit time or Doppler shifts in sound waves	Motion of primary device
Flow quantity measured or inferred	Mass flow rate	Varies with meter design	Volume flow rate	Volume flow rate	Mass flow rate
Typical uncertainty	Within $\pm 1\%$	Varies with meter design	Within $\pm 0.5\%$, if meter is calibrated before use; maximum allowed values in standards	Better than $\pm 0.2\%$, if meter is calibrated before use; $\pm 0.5\%$ to $\pm 1.0\%$ if uncalibrated	$\pm 0.5\%$ to $\pm 1.0\%$ under good operating conditions
Potential sources of bias	Pulsations, surface finish, contamination, damaged or incorrectly installed orifice plates, asymmetric flow profiles	Varies with meter design	Grime, damage to rotor or bearings, pulsations, fluid properties that deviate from calibration conditions, asymmetric flow profiles	Pulsations, asymmetric flow profiles, fouling and contamination, acoustic interference from control valves and compressors	Pulsations, fouling and contamination, shifts in zero with changes in fluid temperature and pressure

3.2 Multiphase Flow Meters

Multiphase flow metering (MFM) remains a rapidly developing field. While single-phase meters can be used to measure multiphase flows if the phases are separated before metering, fluid separation is not always possible at locations where flow rates need to be monitored. Thus, the current state of MFM technology regarding accuracy and performance is of great interest, particularly for the energy industry in land, offshore, and subsea applications. Well testing, production monitoring, flow assurance, gas lift, and allocation metering are all practical examples of areas where multiphase flow meters are currently being used. Note also that MFM has been successfully employed during field trials with light, heavy, and extra heavy oil. Heavy oil in particular presents challenges for separators, either due to high viscosities with cold production or high temperatures with hot production. The ability to bypass the separation stage is an attractive alternative. Another advantage of MFM is the typically greater mobility of multiphase meters in comparison to separators. Many meters come designed as compact mobile units for spot monitoring of different gas/oil fields.

Though various companies are currently developing prototypes, or have even recently released multiphase flow meters for purchase, this report focuses on more mature commercial multiphase meters with a documented history of flow loop testing and field trials. Specifically, the following vendors have been selected for review: Agar Corporation, McCrometer, MPM, Pietro Fiorentini, Roxar, Schlumberger, and Weatherford International. Appendix F through Appendix L provide a detailed summary for each meter discussing its major components, operation, specifications, and performance. A synopsis of this information is provided previously.

While some meter models are designed to handle a wide range of three-phase flows (oil, water, and gas), others target specific niches. For example, the McCrometer V-cone meter is designed specifically for handling wet gas applications under high GVF conditions. It does not provide water-cut analysis, nor is it meant to measure liquid-dominated flows. On the opposite extreme, other manufacturers highlight that their meters handle all flow regimes (e.g., bubbly, wavy, slug, annular, etc.) and operating conditions (e.g., 0-100% GVF and water cut). In this case, several different models are often available where additional sensors are added to units requiring more versatile capabilities.

Among the meters reviewed, all share the requirement that multiple sensors are needed to interpret the complexities of multiphase flow. Table 3-2 provides an example of the various sensor technologies that can make up a multiphase meter system. A commonality among all of the systems is the need for pressure and temperature measurements as input to calculations of fluid properties, such as gas/liquid density or speed of sound. Different technologies are used for sensing water cut, including conductivity/impedance sensors, electromagnetic wave sensors, and spectroscopy. Note that conductivity/impedance probes may also be used for determining salinity content of water. MPM systems can also use radio frequencies (EM wave sensors) to create a three-dimensional topographical map for verification of GVF. Agar units employ Coriolis meters for measurement of total mass flow rate and multiphase density.

Differential pressure sensing across a flow restriction is by far one of the most popular measurement techniques of MFM systems for acquiring bulk flow rate. Agar, MPM, Pietro Fiorentini, Roxar, Schlumberger, and Weatherford (VS/R and VS/RD) all employ a Venturi meter as the flow restriction. McCrometer takes an inverted approach, placing a solid

obstruction in the center of the pipe and allowing flow around it toward the pipe walls. Weatherford's optical system is unique in that it remains full-bore throughout its length – creating negligible pressure drop. Instead, fiber-optic cables are used to sense time-varying fluid properties convecting with the flow. From these data, bulk velocity, and thus flow rate, may be computed.

Gamma-ray detectors may be found in five of the eight metering systems reviewed. However, for some manufacturers, this sensor is an optional part of the unit, included to expand its operating range. Radiation detectors are used as densitometers to provide a multiphase density measurement independent of equations of state or GVF assumptions. They may also be tuned to allow simultaneous calculation of phase fractions for each component in a mixture. The primary drawback to this sensing technology is the international nuclear source accountability requirements associated with each metering system.

Table 3-2. Component sensor technologies of multiphase flow meter systems.

Various component technologies are used together in each of the manufacturer-specific multiphase flow metering systems reviewed here.

	AGAR (MPFM-50)	MCCROMETER (V-cone)	MPM	PIETRO FIORENTINI (Flowatch HS)	ROXAR (2600)	SCHLUMBERGER (Vx)	WEATHERFORD (Optical)	WEATHERFORD (VS/R and VS/RD)
Pressure Transducer	X	X	X	X	X	X	X	X
Temperature Transducer	X	X	X	X	X	X	X	X
DP Measured Across Flow Restriction	X	X	X	X	X	X		X
Gamma-Ray Detector			X	X	X	X		X ²
Conductivity/Impedance Sensor	X ¹		X	X	X			
Electromagnetic Wave Sensor	X ¹		X					
Multiphase Coriolis Flow Meter	X							
Spectroscopy								X
Fiber-Optic Sensors							X	

¹ The Agar multiphase metering system employs a water-cut meter dependent on either conductance or electromagnetic wave sensing technology, not both.

² The Weatherford VS/RD uses a gamma-ray detector for density measurement, while the VS/R does not include this feature.

One primary area of interest in deciding whether to use MFM technology for a specific application is the expected performance of the meter. Table 3-3 lists the range of manufacturer-specified uncertainties for the indicated models and flow conditions. Uncertainties in liquid and gas rates range from about $\pm 2\%$ to $\pm 20\%$ of readings, while water-cut absolute accuracy varies from $\pm 2\%$ to $\pm 10\%$ over specified ranges. Note that these values are, in general, significantly higher than those advertised for single phase meters (typically $\pm 1\%$ or less). However, multiphase flow meter uncertainty depends on the combined accuracy of all component sensors, as well as error due to any empirical correlations or interpolation. Use of separators in conjunction with single-phase meters does not, in practice, provide overall performance

comparable to single-phase meters alone. For example, Weatherford offers a Red Eye Multiphase Metering System (REMMS) composed of a separator, level gauges, and single-phase flow meters. Specified accuracy of this system is claimed to be $\pm 5\%$ on both gas and liquid flow rates. Other MFM field trials using surface separators as a reference have also reported that the single-phase metering approaches with and without separators have comparable accuracy. In addition, MFM offers distinct advantages for mixtures resistant to separation, or for operating conditions that would require long separator residence time.

Table 3-3. Manufacturer-specified multiphase meter uncertainties.

Uncertainties in liquid and gas flow rates range from $\pm 2\%$ to $\pm 20\%$ of readings, while water-cut absolute accuracy varies from $\pm 2\%$ to about $\pm 10\%$ over specified ranges.

	GAS RATE UNCERTAINTY	LIQUID RATE UNCERTAINTY	WATER-CUT UNCERTAINTY
Agar	$\pm 2\%$ of full-scale gas reading $\pm 5\%$ of reading	$\pm 2\%$ of full-scale liquid reading $\pm 5\%$ of reading	unspecified
McCrometer	$\pm 2\%$ of reading	unspecified	unspecified
MPM	$\pm 2.5\%$ to $\pm 3.5\%$ of reading	$\pm 2\%$ to $\pm 10\%$ of reading	unspecified
Pietro Fiorentini (Flowatch HS)	$\pm 6\%$ of reading	$\pm 2\%$ to $\pm 5\%$ of reading	$\pm 1\%$ to $\pm 3\%$ (absolute)
Roxar (2600)	$\pm 6\%$ to $\pm 8\%$ of reading	$\pm 3\%$ to $\pm 8\%$ of reading	$\pm 2\%$ to $\pm 4.5\%$ (absolute)
Schlumberger (oil mode)	$\pm 5\%$ to $\pm 15\%$ of reading	$\pm 2.5\%$ to $\pm 10\%$ of reading	$\pm 2.5\%$ to $\pm 8\%$ (absolute)
Weatherford (Optical)	$\pm 10\%$ of reading	$\pm 5\%$ to $\pm 20\%$ of reading	$\pm 10\%$ (absolute) up to 30% GVF
Weatherford (VS/RD)	$\pm 5\%$ to $\pm 10\%$ of reading	$\pm 5\%$ to $\pm 10\%$ of reading up to 98% GVF (± 75 bpd above 98% GVF)	$\pm 2\%$ to $\pm 10\%$ (absolute)

4. PROCEDURES FOR MEASUREMENT INSPECTION AND VERIFICATION

Measurement inspection and verification procedures are used to ensure that meters and other measurement devices are installed and used as specified by the manufacturer and by recognized standards so that the devices measure flows to within acceptable accuracy. Deviations from industry standards or from manufacturer specifications can result in inaccurate flow measurements from petroleum or gas sources. Procedures have been developed and are presented in Appendix M that can be used to improve current practices and regulations used by inspectors for verifying the accuracy of metering systems used in gas and oil well production sites.

To develop thorough procedures, a literature search was performed for information relevant to metering inspection and verification. Existing procedures from BSEE were collected and evaluated for possible use in the inspection procedures. In particular, the BSEE Production Inspection Form Procedural Handbook (BSEE, 2011) included a section on meter inspection guidelines. These guidelines were generic in nature, but provided a basis for the more detailed inspection procedure included here. Standards from the American Petroleum Institute (API), the American Gas Association (AGA), and other standards cited in fluid measurement references (Upp & LaNasa, 2002) were also reviewed; useful items for inspection and verification were drawn from these standards and included here. Specifically, orifice meter inspection guidelines follow those found in API MPMS Chapter 14, Section 3, Appendix 2B, and Upp and LaNasa (2002). Coriolis meter inspection procedures are derived primarily from Upp and LaNasa (2002), API MPMS Chapter 5, Section 6 (for liquid Coriolis meters), and applicable portions of AGA Report No. 11 (the current standard for Coriolis meters in gas service). Ultrasonic meter inspection procedures are derived primarily from AGA Report No. 9 (for ultrasonic meters in gas service) and applicable portions of API MPMS Chapter 5, Section 8 (for liquid ultrasonic meters).

After reviewing a draft of the inspection procedures, BSEE staff provided additional internal procedures for inspecting and verifying orifice, Coriolis, and ultrasonic meters. BSEE staff also noted sections of Title 30 of the Code of Federal Regulations (CFR) governing the installation, calibration, and required accuracy of meters used for sales, royalty, and allocation measurements. These procedures and regulations were incorporated into the final inspection procedures. It should be noted that several API standards, including those cited above for orifice and Coriolis meters, are incorporated by reference into 30 CFR 250. As a result, no conflicts arose between the requirements of 30 CFR 250 and the API standards referenced in the procedures.

The general approach followed in organizing the procedures was to compile the necessary information and generate a recommended step-by-step process for verifying oil and gas production measurements. The inspection procedures reflect the order in which tasks should be performed during an inspection. The first section of the procedure includes tasks that would be performed during an office inspection of station records, and tasks related to inspection of a meter run during assembly and before onsite installation. The second section includes tasks that must be performed at the field site. As stated in the scope of work for this project, the procedures cover three metering technologies that are commonly found in the oil and gas industry: orifice, Coriolis, and ultrasonic flow meters. Accordingly, each major section of the

procedure is grouped into tasks that are independent of the type of meter at the site, then into tasks specific to the type of meter found at the site (orifice, ultrasonic, or Coriolis), and finally into tasks related to other equipment or data collection (sample analysis, flow computer results, etc.).

Often, the station operator will keep extensive records pertaining to the meters it uses on site. The inspection and verification procedures also give guidance on the records, logs, manufacturer specifications, and measurements that should be obtained when performing an inspection. Where such records are not available, the procedures also give guidance on collecting such data through inspections or through the download of instrument logs. These can serve as historical data over the course of several inspections, and will aid in identifying causes of meter inaccuracies over time.

It is important to note that the final set of procedures in Appendix M is intended to serve as guidelines for generating forms, flowcharts, and/or other desired tools for performing inspection tasks, both at the field site and before installation of the meters in the field. Additional efforts will be required to implement these procedures and to improve current forms and tools used during production inspections. It is left to BSEE to coordinate such efforts in the final development of practical tools for use by inspectors. It is important to note that these procedures should only be used as an inspection guideline for single-phase meters, and are not valid for inspection of multiphase meters. Similarly, these procedures do not cover safety or environmental inspections of meters or facility operations because those assessments fall outside the scope for this project.

5. GAP ANALYSIS

At the beginning of this project, it was anticipated that some information would be lacking to verify the performance of some existing metering technologies, or that some sources of uncertainty could not be quantified or reliably estimated. Information was unavailable in the case of multiphase metering technology, but the exclusion of gas and liquid sampling and analysis from the scope of work was also found to be a deficiency in the deliverables for this project. This report section identifies the specific gaps between resources found in the project deliverables and what is needed for successful verification and uncertainty analysis. Recommendations are listed as a suggested road map for future work to address these gaps.

A key requirement for accurate measurement that is outside the scope of this report is the measurement of fluid properties. While this report discusses meters used to measure volume and mass flow rates of gas, liquid, and multiphase flows, several of these meters also require values of fluid density in their governing equations for flow rate. Similarly, custody transfer of natural gas is based on its energy content, not just the flowing volume, so the gas composition must be determined by analysis to compute its heating value.

Depending upon the fiscal value of the petroleum or natural gas being metered, samples may be collected and sent to a lab for property analysis, or a densitometer or gas chromatograph may be installed on site for real-time analysis. Biases in fluid properties can contribute significantly to the overall measurement uncertainty at a metering location, and several industry standards describe best practices for sampling liquids and gases, measuring fluid densities, and analyzing other fluid properties. Recommendation 1 is that further work for BSEE to support its production verification goals should provide guidance on verifying proper sampling and analysis methods. This would permit inspectors to verify all aspects of measurement at meter locations, not just volume measurement.

The field of multiphase flow metering is relatively new, as demonstrated by the fact that no definitive standard currently exists for regulating their use. Recommendations on best practices for installation, inspection, and maintenance of MFMs are left at present to individual manufacturers. Due to the array of sensors with various working principles among different MFMs, providing guidance on their use is not straightforward. Recommendation 2 is that a set of standard procedures for MFM verification be adapted from those for single-phase and other sub-instruments used in MFMs (water-cut meter, differential pressure transmitters, GVF meter, etc.).

Acceptance testing and calibration of MFMs is another area left up to manufacturers at present. Consequently, various calibration methods are used. In general, static calibration and adjustments are performed during the factory acceptance test, while dynamic calibration is optional (NFOGM, 2005). However, some meters require dynamic flow loop calibration as part of the acceptance testing process so as to adjust the meter to achieve proper functionality. Three methods for dynamic calibration include factory calibration, test facility calibration, and in-situ calibration. Ideally, the calibration facility should have the ability to reproduce expected field conditions (including working fluids), while providing high-accuracy reference flow measurements. Regardless of the calibration method used, repeating the reference testing on a scheduled interval as a check for meter changes in the field should be part of any maintenance plan. Recommendation 3 is that research be performed on practical options and schedules for regular calibration or field proving of MFMs. This work will further the understanding of MFM

performance and may assist in the eventual acceptance of MFMs by BSEE for allocation or royalty measurement.

A final item regarding MFMs is the frequently ambiguous nature of the manufacturer's stated uncertainty. Sometimes the uncertainty is calculated based on the propagation of uncertainty for the individual sensors making up the MFM (using quadrature, perturbation analysis with root-sum-square calculations, or Monte Carlo simulations). However, specified uncertainties of the individual sensors are typically for ideal single-phase conditions, which can be misleading (API-86, 2005). Some meters specify the uncertainty of the MFM based on flow loop or field testing. In the case of field testing, the reference data generally come from well test separators that can have an uncertainty greater than or equal to that of the MFM itself. Recommendation 4 is that studies be performed to verify the uncertainties of various MFMs, using uncertainties of the individual sensors under field conditions. The resulting information would be useful in expanding the uncertainty calculation tools discussed in the next section for use with MFMs.

The four recommendations listed in this section have been made to fill in information gaps discovered during preparation of the verification procedures and uncertainty calculation tools for BSEE. While the first recommendation is relevant to the measurement of single-phase flows currently permitted by BSEE, the rest will expand BSEE's knowledge of multiphase flow metering technology, an area that is growing and may eventually find use in royalty and measurement of federal oil and gas resources.

6. UNCERTAINTY CALCULATION TOOLS

Uncertainty propagation methods have been developed for gas and liquid measurement systems and are well documented in American Gas Association (AGA) and International Organization of Standardization (ISO) Standards. Available computer programs for flow measurement uncertainty estimation are limited in scope, specific either to a single vendor, flow meter technology, or fluid. One software tool is available for measurement uncertainty analysis conforming to ISO and ANSI standards, but is intended for use in a wide variety of situations and requires technical input on specific causes of uncertainty in oil and gas metering. Another tool in use by the Bureau of Land Management (BLM) estimates uncertainties based on input of specific equipment and meter configurations, but is limited to use with orifice and cone-type meters in the measurement of natural gas flow.

In this project, custom uncertainty tools were developed to assist BSEE with the collection and quantification of uncertainty information in flow metering systems. The tools were developed to address both liquid and natural gas hydrocarbon flows measured by orifice flow meters, Coriolis flow meters, and ultrasonic flow meters. The calculation methods used by the tools follow applicable reference standards, and the computer tools are constructed to be portable and customizable for user-specific applications.

6.1 Uncertainty Calculation Method

Uncertainty calculation methods in the uncertainty tools follow applicable measurement reference standards, as summarized in Table 6-1. Uncertainty calculation methods for ultrasonic flow meters (adapted from AGA-9) and Coriolis flow meters (adapted from AGA-11) were extended for liquid hydrocarbon measurement.

Table 6-1. Uncertainty calculation methods were adapted from applicable measurement standards.

MEASUREMENT TECHNOLOGY	APPLICABLE REFERENCE STANDARD
Orifice Flow Meter	API MPMS Chapter 14.3
Ultrasonic Flow Meter	AGA-9
Coriolis Flow Meter	AGA-11

The uncertainty calculation methods used in each standard (and in the computational tools provided) perform uncertainty propagation by use of sensitivity coefficients. Additional details on the use of sensitivity coefficients in these calculations are available in the Flow Measurement Uncertainty Calculation Tools User's Manual, provided in Appendix N.

6.2 Computer Program

Three pieces of software were developed and delivered to assist in the collection and quantification of uncertainty in production flow systems. First, a dynamic linked library (DLL) was developed to encapsulate all of the subroutines required to estimate measurement uncertainty for single-phase liquid and natural gas hydrocarbon flow in orifice flow meters, ultrasonic flow meters, and Coriolis flow meters. This DLL was developed so that the subroutines can be used with or called from user-developed programs within the Windows operating system.

Second, an example user interface was developed in Microsoft Excel 2010. This piece of software includes a form-based interface for each of the three metering technologies in both single-phase gas and single-phase liquid hydrocarbon flows. An additional example of a spreadsheet-based DLL interface is included in the same software.

Lastly, a standalone Windows executable (EXE) program was developed using the Microsoft .NET framework. The subroutines included in the DLL package are “hard-coded” into the EXE utility so that no DLL is included in the distribution. This EXE program was developed to install onto a Windows machine from an installation CD with no other dependencies for maximum portability.

Complete details on the installation, use, and customization of the delivered computational tools are provided in the Flow Measurement Uncertainty Calculation Tools User’s Manual, provided in Appendix N.

7. CONCLUSIONS

The royalties collected by the Department of the Interior for oil and natural gas production in United States federal land and water leases represent one of the country's largest non-tax sources of revenue. It is critically important that the produced volume from these leases be measured accurately to ensure that the federal government receives its fair share of royalty revenue each year. At the request of BSEE, SwRI has developed tools that can be used by BSEE to improve current practices on flow measurement verification. The material produced by this study falls into three categories: educational material on metering technologies, procedures for metering inspection and verification, and computational tools for estimating measurement uncertainties.

To assist BSEE inspectors in their work to verify produced volumes, SwRI has prepared procedures for metering inspection and verification. These are intended for use by BSEE staff to generate checklists and forms for their own use in inspection tasks, or as an aid in updating current procedures that BSEE may wish to maintain. These procedures were developed by SwRI using research into industry standards, references on best practices in the petroleum and natural gas industry, and recent publications from industry schools and conferences. BSEE staff reviewed a draft of these procedures and provided SwRI with feedback on making the procedures more practical. Based on the feedback, the final procedures have been organized according to the inspection location (operator offices, field sites, etc.) and according to the types of meters installed. BSEE also identified federal regulations governing royalty and allocation measurement, and the procedures include steps to ensure compliance with those regulations. Use of these inspection procedures will increase the confidence and efficiency of inspections by BSEE personnel, and represent a step toward consistency of verification methods between onshore and offshore inspections.

As another deliverable of this project, SwRI has prepared educational material on current metering technology used by the oil and natural gas industry. The material can be used by new and current BSEE personnel to become more familiar with meters that are currently approved by BSEE for royalty and allocation measurement, as well as meters used in the industry that inspectors may encounter in the future. The written training material in this report begins with a primer on key properties and characteristics of single-phase and two-phase flows. The material then presents metering concepts relevant to BSEE personnel, such as meter classifications; operating principles of gas, liquid, and multiphase meters; meter calibration; and measurement uncertainties of meters and secondary equipment. Relevant industry metering standards are also reviewed, since these have a bearing on calibration requirements, installations, and other items of interest to BSEE inspectors. Much of this written material has also been provided to BSEE in the form of PowerPoint training materials. The training materials will help BSEE staff develop the essential skills necessary for inspection of current meter technology, and will help them respond to advances in metering technology by identifying necessary changes in inspection procedures and regulations.

The third major deliverable provided by SwRI is an application for calculating uncertainties in measured royalty and allocation volumes. The application uses industry-standard methods for estimating uncertainty contributions from primary and secondary instruments, and for combining them into an overall uncertainty in measured volumes. Because uncertainty calculations are specific to the type of meter and instrumentation, the application

prepared by SwRI focuses on the three types of single-phase meters currently approved by BSEE for royalty and allocation measurement in the Gulf of Mexico Region: orifice meters, Coriolis meters, and ultrasonic meters. This tool can be used by inspectors to calculate measurement uncertainties during the inspection and verification process, helping to increase confidence in the calculation of produced volumes and to ensure that the federal government receives appropriate royalty revenue for natural gas and oil production.

In summary, this study by SwRI has provided reference material and practical tools with which personnel across federal agencies (including the Bureau of Land Management as well as BSEE) can verify production volumes in a timely and confident manner, improve the accuracy and consistency of results, and ensure that the Department of the Interior (DOI) receives appropriate royalties for oil and gas volumes produced from federal land and water. While the study has addressed many of BSEE's needs within its scope of work, additional needs have been identified during the project; these needs are related to recent advances in multiphase metering technology and the need to understand the impact of fluid properties while verifying measured volumes. The next report section describes several recommendations for further research to help BSEE achieve its strategic goals related to production verification and better position itself for future changes in practices and regulations.

8. RECOMMENDATIONS

This project has produced training materials, inspection procedures, and calculational tools requested by BSEE in the pursuit of its goal to improve production verification practices and personnel training. BSEE inspectors can use this material to become familiar with offshore oil and gas metering technologies, inspect and verify the performance of offshore meters and installations, and calculate measurement uncertainties of relevant metering technologies in single-phase flows.

At the start of this project, it was anticipated that information might be lacking to verify the performance of some metering technologies, or that tools or knowledge needed to perform uncertainty calculations or inspection procedures might not exist. Some information gaps have indeed been identified, and are discussed in Section 6. During the project, limitations in the project scope were also noted, specifically the focus on measurement technologies permitted by federal regulations for production measurement, and the focus on measurement of gas and liquid volumes rather than composition. Work to develop procedures and training materials on topics outside the scope of the original project will also enhance BSEE's ability to verify production quantities and estimate measurement uncertainties.

Given this, a list of topics for further work has been developed. SwRI recommends that BSEE consider funding additional work in these areas to fill in gaps in the procedures and materials provided here, keep abreast of current measurement technology, enhance training of inspection staff, and enhance tools for effective inspections.

- Assistance in training BSEE inspectors. In previous experiences where SwRI has prepared training material for a client, additional participation by SwRI staff in the training process has helped the client take full advantage of the material. For example, SwRI would prepare a training session in which SwRI personnel teach the material, and one or more of BSEE's subject matter experts in the field would attend and participate in the training. One or two more sessions would be held in which the material is taught by one subject matter expert from SwRI and one expert from BSEE. Afterward, BSEE staff would take over and use the material prepared for internal training. This approach is recommended as a way to ensure that BSEE gains the most benefit from the training material.
- Assistance in implementing an inspection program using the new procedures and tools. SwRI has provided educational materials, inspection procedures, and an uncertainty calculational tool with which BSEE can develop an updated and consistent inspection program for verifying production volumes. To help BSEE in developing this program, SwRI would assist further by preparing a program guide, forms, and checklists based on the material produced in this study. To confirm the effectiveness of the training material and inspection procedures, SwRI would participate in inspections performed by BSEE personnel trained using the new material. Specifically, SwRI staff would assist in verification inspections at operator offices, field sites, and fabrication facilities, and would witness proving of master meters and proving or calibration of royalty meters, if requested by BSEE. The goal would be to use the field experience to and feedback from BSEE inspectors to identify any needed improvements in the training material, uncertainty calculator, and inspection procedures. SwRI would

then work with BSEE staff to create a final program guide and related forms, ensuring that the procedures and material can be implemented efficiently and provide maximum benefit to BSEE and the DOI.

- Additional material on sampling methods and technology. The instructional material and inspection procedures created in this project focus on the meters used to measure volume and mass flow rates of gas, liquid, and multiphase flows. Several of these meters require values of fluid density in their governing equations for flow rate. Similarly, custody transfer of natural gas is based on its energy content, not just the flowing volume, so the gas composition must be determined by analysis to compute its heating value. Biases in fluid properties can contribute significantly to the overall measurement uncertainty at a metering location. Knowledge of the methods used to sample gas or liquid and determine fluid properties can help avoid these biases. To fill this gap, SwRI would develop instructional materials on gas and liquid sampling methods and analysis methods, drawing on the experience of SwRI staff in this area and current industry standards for gas and liquid sampling. SwRI would also prepare sampling inspection procedures to use in confirming that proper sampling and analysis methods are used at production sites subject to BSEE verification. These would permit BSEE inspectors to verify all aspects of measurement at metering locations, not just volume measurement.
- Updated instructional materials and procedures to reflect changes in technology. BSEE currently permits single-phase gas and liquid royalty measurement using only orifice meters, Coriolis meters, or ultrasonic meters. While orifice meter designs are relatively fixed, advances in ultrasonic and Coriolis meters occur regularly. Differential pressure type meters and turbine meters, which are also discussed in the training material, see technical improvements as well. Refinements to these meters may allow better communications with flow computers and SCADA systems, may help with diagnosing and correcting for abnormal flow conditions, or may improve meter performance in some other way. Multiphase technology is not as standardized as single-phase technologies, and multiphase meters may be introduced that apply new technologies or apply existing technologies in new ways. SwRI would assist BSEE in updating the training materials and inspection tools as advances in these technologies occur. SwRI can gather information through its regular participation in industry standards committees, conferences, and review of industry journals, and provide BSEE with updated material at regular intervals.
- Additional inspection procedures as new meters are permitted for royalty measurement. As noted above, BSEE currently permits single-phase gas and liquid royalty measurement using only orifice meters, ultrasonic meters, and Coriolis meters. Should BSEE approve applications for other single-phase meter types, inspection procedures will be required for these meters also. Examples of other single-phase meters that BSEE staff have expressed interest in include differential pressure meters (such as V-cone meters), thermal mass meters, and turbine meters. These may only require minor changes to procedures appearing in Appendix M, or may require completely new procedures. Similarly, multiphase

metering technology is finding more application in production measurement, but is not included in the scope of the inspection procedures requested by BSEE for this project. Multiphase meters may involve combinations of one or more single-phase meters, or may involve other technologies unique to multiphase flows. If BSEE were to accept applications for production measurement using multiphase metering, inspection and verification of the installation would require unique procedures tailored to the technology. SwRI's experience in evaluating multiphase meter performance would be of benefit in creating new inspection procedures for these installations.

- Upgrade of uncertainty calculation tools for other single-phase metering technologies. The uncertainty calculation tool created as part of this project can be used to verify the performance of those meters currently allowed by BSEE for allocation and royalty measurement, namely orifice meters, Coriolis meters, and ultrasonic meters. Should BSEE approve applications for the use of other single-phase meter types, such as those listed in the item above, SwRI would modify the tool to include uncertainty calculations for these meters. In particular, existing standards and industry experience would provide the information needed to estimate measurement uncertainties for turbine meters and differential pressure type meters. These calculations would be incorporated into the existing calculational tool, which BSEE personnel would already be familiar with. As a part of this follow-on work, SwRI staff would also address any comments and feedback by BSEE staff from their experience and use of the original version of the tool. The proposed additions could include an uncertainty calculation tool for multiphase meters; however, because of the variety of multiphase meters that use unique instruments, and because of the lack of standards for multiphase metering technology, guidance on multiphase measurement uncertainties is lacking, and development of such a tool would require extensive effort on the part of SwRI.

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APPENDIX A

Review of Orifice Metering Technology

A. REVIEW OF ORIFICE METERING TECHNOLOGY

The following section provides a review on the subject of orifice meters used for the measurement of single-phase fluids. This includes both liquid and gas applications. A basic overview of the technology is first presented, followed by specific applications that use orifice meters, general specifications, major manufacturers, and finally performance characteristics.

A.1 Basics of the Technology

An overview of orifice metering begins with a description of the basic principles of the technology. Primary, secondary, and tertiary components have been listed, including their relevance to the larger assembly. Finally, progression through the flow equations from primitive measured variables to overall computed flow rate is discussed.

A.1.1 Principles of Operation and Device Geometry

Orifice meters are inferential devices in which the flow rate is inferred from the pressure drop through an orifice plate. Auxiliary knowledge of fluid properties and geometry of the metering setup allow for calculation of fluid velocity and flow rate. Though various authors have dealt with orifice meter application to multiphase flow, the current review is limited to single-phase usage.

The primary components of the device include an orifice plate, an orifice plate holder, a meter tube of adjacent piping sections, and pressure taps. Illustrative placement of these devices is shown in the schematic of Figure A.1.

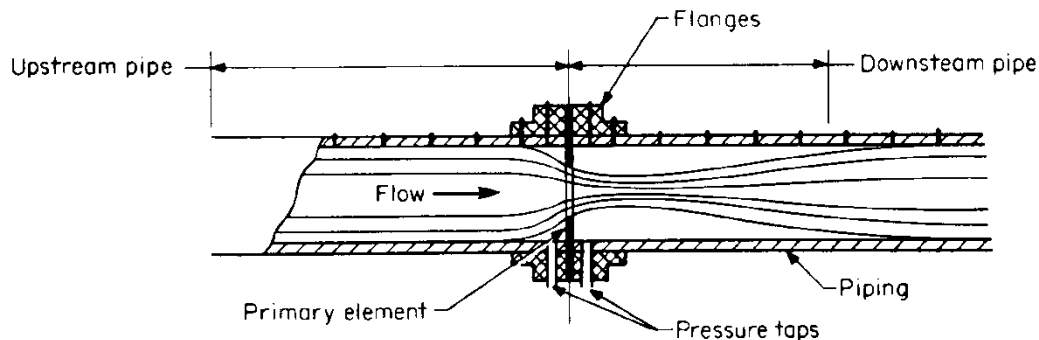


Figure A.1. Elements of Primary Device
Streamline illustrations depict approximate location of vena contracta.

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The orifice plate is the central component of the metering system, and is composed of a flat plate with a circular concentrically-bored orifice having sharp edges. Variation of its geometry through change to the bore diameter leads to change in the pressure drop through the meter at the same flow rate. The flow rate varies with the square root of pressure drop, as will be demonstrated in Section A.1.3.

An orifice plate holder is generally either a set of orifice flanges or an orifice fitting. Its basic function is to contain and position (perpendicular and concentric to the flow) the orifice plate in the piping system.

The meter tube is the upstream and downstream length of pipe, relative to the orifice plate, through which the fluid flows. Sizing of this component is important for achieving optimal accuracy. Recommended orifice to meter tube internal diameter ratio, i.e., “beta ratio,” and minimum straight upstream piping lengths are specified in standards (see Section A.3.6). Specifics of installation requirements will be discussed more in Section A.3.3. The use of flow conditioners can minimize the installation length of a meter tube (saving space and capital costs). Essentially, these are devices that ‘condition’ or shape the flow field at or near a flow meter inlet. They provide a means for minimizing or eliminating the adverse influence of the fluid dynamics (e.g., velocity profile asymmetry, swirl, etc.) on meter performance.

There are two categories of flow conditioners: flow straighteners and high-performance flow conditioners. Section 2.5.5 of AGA-3, Part 2 states: “Flow straighteners are devices that effectively remove or reduce the swirl component of a flowing stream, but may have limited ability to produce the flow conditions necessary to accurately replicate the orifice plate coefficient of discharge database values.” Conversely, “Isolating flow conditioners are devices that effectively remove the swirl component from the flowing stream while redistributing the stream to produce the flow conditions that accurately replicate the orifice plate coefficient database values.” (That is, the flow profile downstream of the conditioner is axisymmetric and has minimal swirl.) AGA-3, Part 2 does not recommend any particular type of flow conditioner. Specifically, it is stated:

“It is not the intent of this standard to recommend any particular type of flow conditioner. However, in an effort to eliminate or reduce the potential for flow measurement bias in existing installations and to provide guidance for improved measurement accuracy in new installations, this standard provides installation recommendation for the 19-tube uniform concentric tube bundle flow straighteners cited in the installation effects research. Due to the significant (outside the designated uncertainty band) coefficient of discharge differences experienced from variations in straightening vane tube bundle construction, only those tube bundle flow straighteners meeting the following criteria are specified to produce ‘no additional uncertainty’ when installed as recommended. All other tube bundles should be considered as ‘other’ flow conditioners.”

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Pressure taps for impulse lines that connect to the differential pressure element are formed by drilling a hole radially in the wall of the meter or orifice plate holder. The hole is to be smooth and flush with meter internals, as shown in Figure A.1. Taps can be placed in several different locations, the five most common being: flange taps, corner taps, vena contracta taps, radius taps, and pipe taps [Liptak, 1993]. Flange taps are the most common in the United States, where the tap center is to be one inch upstream and downstream of the nearest plate face for upstream flange and downstream flange taps, respectively [AGA-3]. Corner taps are similar to flange taps, except that pressure is measured at the corner between the orifice plate and the pipe wall. These are very common in European applications. Vena contracta taps have a tap located one diameter upstream of the orifice plate, and the second downstream at the point of minimum pressure. Unfortunately, the downstream location will change with changing orifice plate sizes. Thus, radius taps are more frequently prescribed, where the downstream tap is standardized to be located one half pipe diameter from the orifice plate. Finally, in the case of pipe taps, the upstream tap center is located 2.5 times the inside pipe diameter upstream from the nearest plate

face, and the downstream tap center is located eight times the inside pipe diameter downstream from the nearest plate face.

Referring again to Figure A.1, it is shown that the streamlines contract to a minimum just downstream of the orifice plate. This location of minimum cross-sectional area is known as the “*vena contracta*.” As flow approaches the plate from upstream, the static pressure rises slightly along the meter tube wall, leading to bending of streamlines toward the open bore. Downstream of the plate static pressure reaches a minimum value, after which stream lines expand to again fill the meter tube – thereby marginally increasing the static pressure.

For a pure analytical solution of the flow equations based on differential pressure measurements, the *vena contracta* would be used for the minimal cross-sectional area. However, there is not a straight-forward method for measuring this jet area. Thus, the orifice bore diameter is used in practice, and a correction for the amount of contraction is added based on empirical measurements. This correction factor, which also includes frictional and unaccounted viscosity/turbulence effects, is termed the “coefficient of discharge,” and essentially represents the ratio of the true flow to the theoretical flow. The Law of Similarity is utilized to be able to apply experimental correlations to dynamically similar meters. The concept is based on the idea that two geometrically similar meters with identical initial flow directions will have geometrically similar streamlines. Thus, an experimental flow system must be a scale model of field installations. The dimensionless Reynolds number, which represents the ratio of inertial to viscous forces, captures the significant effects for orifice meters. Thus, the coefficient of discharge is primarily dependent on the Reynolds number, sensing tap location, meter tube diameter, and the beta ratio [AGA-3, Part 1]. The U.S. energy industry relies upon AGA-3 for natural gas and oil measurement with concentric, square-edged orifice meters. Deviation from the meter specifications for the primary device requires a new flow calibration to determine the actual relationship between flow rate and pressure drop.

A.1.2 Secondary and Tertiary Devices Required

Secondary devices needed for mass flow inference from an orifice meter include the differential pressure measuring device, connecting piping, and devices for measuring other important fluid variables, such as the static pressure and temperature. Various types of differential pressure gauges may be used. Manometers filled with water, oil, or mercury are used very infrequently, mostly for gas or liquid flow measurement in a laboratory setting. Pressure transducers that produce an electrical signal proportional to differential pressure are typically used for process and field measurements. According to API MPMS Chapter 21, Section 1.2.1, in electronic measurement systems, the secondary device is an electromechanical transducer that responds to an input of pressure, temperature, differential pressure, frequency, relative density (specific gravity), or other variables. Note that transducers respond to changes in the measured parameters with a corresponding change in electrical values, whereas transmitters are specially designed to enhance the transmission of information from one location to another by the addition of an electrical circuit that converts the transducer output to a standard signal in analog, digital, or frequency form.

Figure A.2 shows the common configuration of secondary devices. Many in the U.S. natural gas and oil industry have traditionally employed the downstream differential pressure tap for the measurement of static pressure. This, though, requires the calculation of supercompressibility twice, thus complicating the calculation procedures and, perhaps, the audit

trail process. Even though either pressure tap may be used, the AGA-3 standard currently recommends using the upstream pressure tap. Flowing gas temperature is commonly measured downstream of the orifice plate. Gas temperature may also be measured upstream, but the temperature sensing element can adversely disturb the flow field at the orifice plate. In practice, the upstream and downstream temperatures are not identical, but may differ by only a small fraction of a degree. This difference is usually too small to adversely affect metering accuracy.

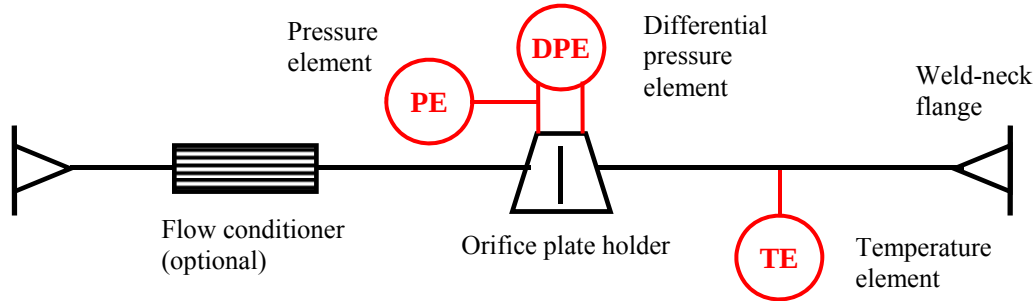


Figure A.2. Orifice Meter Schematic Showing Common Placement of Components
Instruments shown in red are secondary devices.

The tertiary device is typically an electronic computer, programmed to correctly calculate flow rate (or total volume) within specified limits. According to API MPMS Chapter 21, Section 1.2.1, the electronic signals from the secondary devices transmit the information to the tertiary device (electronic flow computer). The tertiary device receives the information, combines it with programmed instructions, and calculates the flow rate through the primary device. Equations of state relate pressure and temperature data to allow for calculating of density.

A.1.3 Flow Equations

The following equations outline the procedure for computing mass flow rate in orifice meters. Note that these apply for gas or liquid fluids that are single-phase, homogeneous, and Newtonian with pipe Reynolds numbers of 4,000 or greater [AGA-3]. The pipe Reynolds number can be calculated as $Re_D = \frac{4q_m}{\pi\mu D}$, where q_m is the mass flow rate, μ is the absolute viscosity of the fluid, and D is the meter tube internal diameter at the flowing temperature.

The equation for mass flow rate is given as $q_m = N_1 C_D E_v Y d^2 \sqrt{\rho_{T,P} \Delta P}$. Variables used in the equation are defined thus:

- $d \rightarrow$ orifice plate bore diameter at flow temperature
- $E_v \rightarrow$ velocity of approach factor
- $C_D \rightarrow$ orifice place coefficient of discharge
- $Y \rightarrow$ expansion factor
- $N_1 \rightarrow$ unit conversion factor
- $\rho_{T,P} \rightarrow$ density of the fluid at flow conditions (pressure, temperature)
- $\Delta P \rightarrow$ orifice differential pressure

These are now described in further detail, with auxiliary definitions provided as needed.

The orifice plate bore diameter d is referenced to flowing conditions, and may be defined as $d = d_r [1 + \alpha_l (T_f - T_r)]$. In the preceding equation, α_l is the linear coefficient of thermal expansion for the orifice plate material, T_f and T_r are the flowing fluid and reference

temperatures, respectively, and d_r is the reference orifice plate bore diameter at the reference temperature. Note that T_r is generally taken as 68°F (20°C) [AGA-3].

The velocity of approach factor may be calculated as $E_v \frac{1}{\sqrt{1-\beta^4}}$, where β represents the “beta ratio” of orifice plate to meter tube diameters, d/D . Note that, like the orifice plate bore diameter, the meter tube internal diameter is defined at flowing conditions. It may be computed as: $D = D_r[1 + \alpha_2(T_f - T_r)]$, where α_2 is the linear coefficient of thermal expansion of the meter tube material, and D_r is the reference meter tube internal diameter at the reference temperature T_r . Note that D_r determination should be made consistent with recommendations in AGA-3, Part 2.

The empirical Reader-Harris/Gallagher (RG) correlation is used to estimate the discharge coefficient of flange-tapped orifice meters. It was named after the developers, Dr. Michael Reader-Harris at the National Engineering Laboratory in East Kilbride, Scotland and Dr. Jim Gallagher at Shell Oil in Houston, Texas. The equation was developed from a regression fit to C_D data. The regression data set consisted of 5,734 data points for flange-tapped orifice plates for nominal pipe diameters of two, three, four, six and ten inches and nominal β ratios of 0.10, 0.20, 0.375, 0.50, 0.575, 0.66, and 0.75. An additional 2,298 data points were taken with corner taps (often used in Europe), and 2,160 data points with radius taps. The total number of data points in the regression data set is 10,192.

Data for orifice bore diameters less than 0.45 inches were excluded due to increased uncertainty associated with the relative sharpness of the orifice bore upstream edge. Re_D is generally limited to greater than or equal to 4,000 using the equation. Note that C_D is a strong function of Reynolds number for $\beta = 0.75$, but is only slightly dependent upon Reynolds number for $\beta = 0.20$. The RG correlation for a flange-tapped orifice meter is defined as:

$$C_D(FT) = C_i(FT) + 0.000511 \left[\frac{10^6 \beta}{Re_D} \right]^{0.7} + (0.0210 + 0.0049A)\beta^4 C$$

- coefficient of discharge at $Re_D = \infty$ for flange-tapped orifice meter, $C_i(FT) = C_i(CT) + \text{Upstream Tap Term} + \text{Downstream Tap Term}$
- coefficient of discharge at $Re_D = \infty$ for corner-tapped orifice meter, $C_i(CT) = 0.5961 + 0.0291\beta^2 - 0.2290\beta^8 + 0.003(1 - \beta)M_1$
- Upstream Tap Term = $[0.0433 + 0.0712e^{-8.5L_1} - 0.1145e^{-6.0L_1}](1 - 0.23A)B$
- Downstream Tap Term = $-0.0116[M_2 - 0.52M_2^{1.3}]\beta^{1.1}(1 - 0.14A)$
- $A = \left[\frac{19,000\beta}{Re_D} \right]^{0.8}$, $B = \left[\frac{\beta^4}{1-\beta^4} \right]$, $C = \left[\frac{10^6}{Re_D} \right]^{0.35}$
- $M_1 = \max\left(2.8 - \frac{D_R}{N_4}, 0.0\right)$, $M_2 = \left(\frac{2L_2}{1-\beta}\right)$
- $L_1 = L_2 = \text{dimensionless correction for tap location } (N_4/D_r \text{ for flange taps})$
- $N_4 = \begin{matrix} 1.0 \text{ when } D_r \text{ is in inches} \\ 25.4 \text{ when } D_r \text{ is in millimeters} \end{matrix}$

The expansion factor, Y , is defined as $\frac{C_{D1}}{C_{D2}}$, where C_{D1} is the coefficient of discharge from compressible fluid tests and C_{D2} is the coefficient of discharge from incompressible fluid tests. For incompressible liquid flow, Y would equal 1.0. The expansion factor may be taken at either the upstream or downstream location. Due to its simplicity, the upstream expansion factor is more commonly employed.

If absolute static pressure is measured on the upstream side of the differential pressure tap, the expansion coefficient is computed as: $Y_1 = 1 - (0.41 + 0.35\beta^4) \frac{x_1}{k}$, where $x_1 = \frac{\Delta P}{N_3 P_{f1}}$. This is valid for flange-tapped orifice meters over the following ranges: $0.1 < \beta < 0.75$ and $0 < x_1 < 0.2$ (or $0.8 < P_{f2}/P_{f1} < 1$). Variables in the preceding equations are defined as:

- $\Delta P \rightarrow$ orifice differential pressure
- $k \rightarrow$ isentropic exponent
- $N_3 \rightarrow$ unit conversion factor (assuming static and differential pressure have consistent units, N_3 will be 1.0)
- $P_{f1} \rightarrow$ absolute static pressure at the upstream tap
- $P_{f2} \rightarrow$ absolute static pressure at the downstream tap

For static pressure measured on the downstream side of the differential pressure tap (infrequent), the expansion coefficient may be expressed as $Y_2 = Y_1 \sqrt{\frac{P_{f1} Z_{f2}}{P_{f2} Z_{f1}}}$, where $x_1 = \frac{\Delta P}{N_3 P_{f2} + \Delta P}$. Here Z_{f1} and Z_{f2} are the fluid compressibility at the upstream and downstream pressure taps, respectively. It should be noted that an update to the expansion coefficient relationship based on further experimentation will be included in the forthcoming AGA-3 2012 edition. The reader is encouraged to stay abreast of future updates to standards.

A.2 Applications

Orifice meters may be used in most flow measurement applications, either for metering gas or liquid. In the energy industry, they are often used as custody transfer references for natural gas. They may also be used for liquid hydrocarbons metering as well. Numerous examples of their applications onshore (upstream, midstream, and downstream oil sectors), offshore, and subsea are available.

It should be noted that a primary limitation of orifice meter usage for industrial applications is space constraints in the process line. As will be discussed in Section A.3.3, certain minimum distance thresholds exist for the length of straight pipe upstream of the orifice plate. Additionally, the plate must be in an accessible location to inspect and switch out (depending on the flow range). During inspection, the meter run must either be bypassed or the process flow stopped and blocked in. The ability to depressurize and purge the isolated region near the plate must also be accounted for when considering an orifice meter for an application.

A.3 Typical Specifications

Orifice meter specifications, including: flow capacity and rangeability, flow conditions, installation requirements, operating environment, calibration requirements, and applicable industry standards are now discussed.

A.3.1 Flow Capacity and Rangeability

The flow capacity and rangeability of an orifice meter are essentially limited only through the selection of meter run/plate diameter and the operating range of secondary devices. However, at the micro-scale, flow must still adhere to the continuum hypothesis in order to use orifice meter technology that depends on the standard flow equations. At the macro scale, plates

for process line sizes, even up to five feet in diameter, may be ordered from standard suppliers [Cameron].

Although AGA-3 recommends a beta ratio range of 0.15 to 0.7 for flange taps (0.2 to 0.67 for pipe taps), AGA XQ9011 suggests keeping the beta ratio between 0.4 and 0.6 for custody transfer applications. Furthermore, it is recommended that the range of the differential and static pressure elements should be selected to maintain the reference measurement between 50%-100% of the full scale. If flow varies over a wide range, two or more orifice tubes may be installed in parallel. However, the ratio of ranges on differential pressure devices on each of the parallel meters should not exceed 5 to 1 in order to allow for some measurement overlap [AGA XQ9011].

A.3.2 Flowing Conditions

According to AGA-3, Part 1, certain flow condition limitations must be adhered to in order to minimize uncertainty. These include:

- Fluids should be clean, single-phase, homogeneous, and Newtonian, and flows should be at steady state during measurements.
- Fluid should not undergo any phase change during metering.
- Fluid should remain consistently subsonic during metering.
- The Reynolds number should be within the specified limitations of the empirical coefficients.
- No bypass of flow around the orifice shall occur during metering.

A.3.3 Installation Requirements

Orifice plates are usually manufactured with a beveled downstream face. When such a plate is accidentally installed backwards, the resistance to the flow is reduced even further than in the case of an orifice plate with a dull leading edge, and the flow is significantly under-reported. Thus, care should be taken to install plates correctly. For situations where a backwards installation has occurred for some time, a correlation is available for prediction of associated errors. This is discussed more in Section 1.5.3.

Pressure taps should be placed in accordance with AGA-3 recommendations. For flange taps, this is one inch upstream and downstream of the orifice plate. For pipe taps this is 2.5 times the pipe ID upstream, and eight times the pipe ID downstream. Impulse lines leading to secondary devices should be kept as short as possible. They should also have a slight slope throughout the horizontal distance in order to facilitate drainage. Taps should be periodically vented to ensure obstruction-free lines. Note that impulse line sizes vary from 1/4-inch to 1/2-inch, with 3/8-inch being the most common.

Although an orifice run may be installed in any position, horizontal is typically recommended – especially for gas measurements in order to avoid creating a liquid trap [AGA XQ9011]. The meter run should be well supported so that it will remain straight while minimizing vibration. AGA-3, Part 2 provides recommendations for minimum upstream lengths of straight pipe for common field installation configurations. The reasoning behind this standardization is given in the excerpt below:

“To ensure accurate flow measurement, the fluid should enter the orifice plate with a fully-developed, swirl-free flow profile. Such a condition is best achieved through the use of flow conditioners and associated pipe lengths or adequate lengths of straight pipe upstream and downstream from the orifice plate. Any serious distortion of the average (time mean) flow profile or significantly increased flow pulsation level will produce flow measurement errors.”

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Any upstream piping configuration not specifically referenced in AGA-3, Part 2 must meet the installation requirements of the “catch all” installation configuration. As stated in the report (underlining added for emphasis),

“For applications that are not explicitly addressed in the installation Tables 2-7 and 2-8, the required lengths and the 1998 Uniform Concentric 19-Tube Bundle Straightener locations of the “any other configuration” classification from Tables 2-7 and 2-8 should be followed.”

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The sketch of Figure A.3 displays an example layout of an orifice meter run. Here S represents the separation distance (expressed in pipe diameters, D) between two elbows in series. This separation distance is of interest for 90° elbows, 45° elbows, or tees. UL represents the upstream length measured from the inlet of the meter tube (where it is attached to the elbow either by weld or by a flanged fitting) to the orifice plate. UL is expressed in pipe diameters. DL represents the downstream length measured from the orifice plate to the end of the meter tube, where it attaches to the downstream pipe fitting. DL is also expressed in pipe diameters.

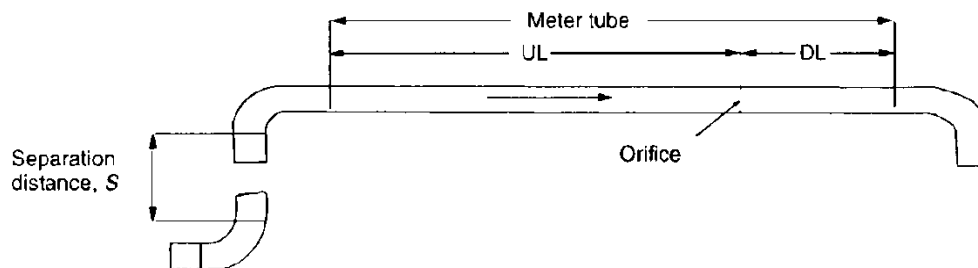


Figure A.3. Orifice Meter Tube Layout for Flange or Welded Inlet

The sketch represents an orifice meter installed in the field without a flow conditioner. The notation is consistent with AGA-3.

Figure © American Gas Association. All rights reserved. Reprinted with permission. Table A.1 displays orifice meter installation requirements without a flow conditioner from AGA-3, Part 2. Note that the values of DL are independent of the upstream disturbance. The tolerance on specified lengths for UL and for DL is $\pm 0.25D$. There are several items of particular interest in Table A.1. The two elbows out of plane separated by less than $5D$ of pipe create Type 1 swirl (solid-body rotation), with a single vortex and an asymmetric profile. Type 1 swirl is more structured and takes longer to decay than the Type 2 swirl (characterized by two counter-rotating vortices) created by the other configurations. While the concentric reducer looks like it would make a good, inexpensive flow conditioner, remember that these results were obtained with fully-developed, swirl-free flow entering the reducer. The table demonstrates the pipe length needed to restore fully-developed flow after the reducer distorts the flow. In summary, the key to meter station design is to not ignore the upstream flow profile when installing an orifice meter run.

Table A.1. Orifice Meter Upstream Minimum Length Requirements without a Flow Conditioner

The requirements are taken from AGA-3, Part 2, Table 2-7.

Diameter ratio β	Minimum Straight Unobstructed Meter Tube Length from the Upstream Side of the Orifice Plate (in multiples of published internal pipe diameter, D_i)										Downstream meter tube length
	a. Single 90° elbow b. Two 90° elbows in the same plane with $S > 30D_i$ c. Two 90° elbows in perpendicular planes with $S > 15D_i$	Two 90° elbows in the same plane, "S" configuration spacer $S \leq 10D_i$	Two 90° elbows in the same plane, "S" configuration $10D_i < S < 30D_i$	Two 90° elbows in perpendicular planes, $S < 5D_i$	Two 90° elbows in perpendicular planes, $5D_i \leq S \leq 15D_i$	Single 90° tee used as an elbow, but not as a header element	a. Single 90° elbow b. Two 45° elbows in the same plane, "S" configuration $S \geq 22D_i$	Gate valve at least 50% open	Concentric reducer	Any other configuration (catch-all category)	
	UL	UL	UL	UL	UL	UL	UL	UL	UL	UL	DL
≤ 0.20	6	10	10	50	19	9	30	17	6	70	2.8
0.30	11	10	12	50	32	9	30	19	6	108	3.0
0.40	16	10	13	50	44	9	30	21	6	145	3.2
0.50	30	30	18	95	44	19	30	25	7	145	3.5
0.60	44	44	30	95	44	29	30	30	9	145	3.9
0.67	44	44	44	95	44	36	44	35	11	145	4.2
0.75	44	44	44	95	44	44	44	44	13	145	4.5
Recommend ed length for maximum range $\beta \leq 0.75$	44	44	44	95	44	44	44	44	13	145	4.5

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A flow distortion may propagate through a series of piping elements (e.g., pipe bends, valves, contractions/expansions, etc.) without fully dissipating. In some instances, a flow distortion may actually increase in severity as it passes through a series of piping elements. A 90° elbow, tee, and partially-closed gate valve are common piping elements that can produce velocity profile asymmetry. Headers and out-of-plane elbow combinations can produce Type 1 swirl (solid body rotation). In general, velocity profile asymmetry can persist for over 50 pipe diameters and swirl can persist for over 200 pipe diameters. For this reason, flow conditioners are often more practical than extensive upstream straight piping.

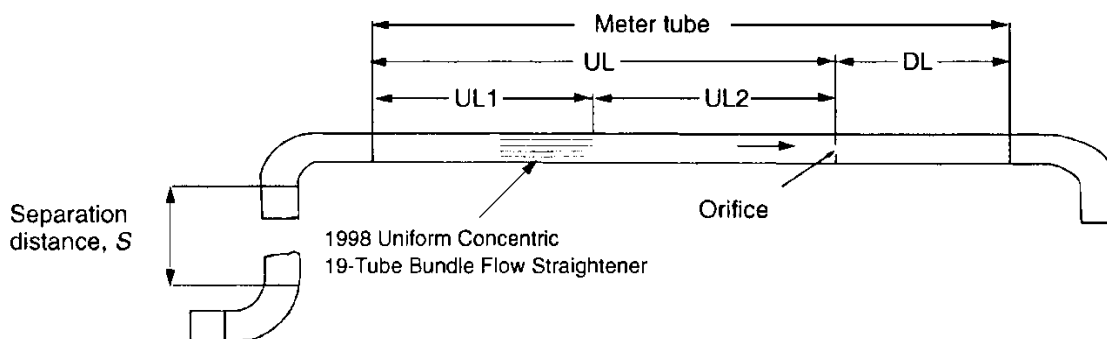


Figure A.4. Orifice Meter Tube Layout with Flow Conditioner for Flange or Welded Inlet
The sketch represents an orifice meter installed in the field with a flow conditioner. The notation is consistent with AGA-3.

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Figure A.4 displays the layout of an orifice meter run with an installed flow conditioner. Label abbreviations are the same as given for Figure A.3, though UL1 refers to the upstream length from the orifice plate prior to the flow conditioner, and UL2 is the upstream length after the flow conditioner. Table A.2 and Table A.3 provide the upstream lengths using a uniform concentric 19-tube bundle flow straightener. Note that R is the radius of curvature of the elbow. It is interesting to compare the catch-all required lengths to the requirements when no flow conditioner is present ($UL \geq 145D$). By reducing swirl, the tube bundle significantly reduces the required upstream length. Unfortunately, available test data do not support the use of the tube bundle for large beta ratios.

Isolating flow conditioners have the potential to minimize ΔC_D for any type of upstream disturbance and for any value of upstream meter tube length. The 4th edition of AGA-3, Part 2 requires that each isolating flow conditioner concept be tested. The performance evaluation of new flow conditioner designs is addressed in Appendix 2-D. Specific installation calibration tests are discussed in Appendix 2-C.

A flow conditioner performance test consists of an Application test and a Type approval test. The Application test approves the use of a flow conditioner for any type of upstream installation, including headers, but for a specific line size and Reynolds number range. The test is limited to just the tested line size and a narrow range of Reynolds numbers associated with the tested β -ratio range and differential pressure range used. The Type approval test approves use of a tested flow conditioner for any type of upstream installation, any line size, and any Reynolds number. The Type approval test confers broad approval of the flow conditioner. Specific requirements of the Type approval test are listed in Section D2 of Appendix 2-D in AGA-3, Part 2. It is the manufacturer's responsibility to see that the required tests are performed. Note that test data should be available for inspection by a prospective buyer of a flow conditioner.

Table A.2. Orifice Meter Upstream Minimum Length Requirements with a Uniform Concentric 19-Tube Bundle Flow Straightener for Meter Tube Upstream Length of $17D_i \leq UL \leq 29D_i$

The requirements are taken from AGA-3, Part 2, Table 2-8a.

Diameter ratio β	Single 90° elbow $R/D_i=1.5$	Two 90° elbows out of plane, $S \leq 2D_i$, $R/D_i=1.5$	Single 90° tee used as an elbow, but not as a header element	Partially-closed valves (at least 50% open)	High swirl combined with single 90° tee	Any fitting (catch- all category)	Downstream meter tube length
	UL2	UL2	UL2	UL2	UL2	UL2	DL
0.10	5-14.5	5-14.5	5-14.5	5-11	5-13	5-11.5	2.8
0.20	5-14.5	5-14.5	5-14.5	5-11	5-13	5-11.5	2.8
0.30	5-14.5	5-14.5	5-14.5	5-11	5-13	5-11.5	3.0
0.40	5-14.5	5-14.5	5-14.5	5-11	5-13	5-11.5	3.2
0.50	11.5-14.5	9.5-14.5	11-13	9.5 D_i allowed for up to $\beta=0.47$	11-13	9.5 D_i allowed for up to $\beta=0.46$	3.5
0.60	12-13	13.5-14.5	13 D_i allowed for up to $\beta=0.54$	Not allowed	13 D_i allowed for up to $\beta=0.54$	Not allowed	3.9
0.67	13	13-14.5	Not allowed	Not allowed	Not allowed	Not allowed	4.2
0.75	14	Not allowed	Not allowed	Not allowed	Not allowed	Not allowed	4.5
Recommended tube bundle length for maximum range of β	13 $\beta \leq 0.67$	13.5-14.5 $\beta \leq 0.67$	13 $\beta \leq 0.54$	9.5 $\beta \leq 0.47$	13 $\beta \leq 0.54$	9.5 $\beta \leq 0.46$	4.5

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Table A.3. Orifice Meter Upstream Minimum Length Requirements with a Uniform Concentric 19-Tube Bundle Flow Straightener for Meter Tube Upstream Length of $UL \geq 29D_i$

The requirements are taken from AGA-3, Part 2, Table 2-8b.

Diameter ratio β	Single 90° elbow $R/D_i=1.5$	Two 90° elbows out of plane, $SS \leq D_i$, $R/D_i=1.5$	Single 90° tee used as an elbow, but not as a header element	Partially-closed valves (at least 50% open)	High swirl combined with single 90° tee	Any fitting (catch-all category)	Downstream meter tube length
	UL2	UL2	UL2	UL2	UL2	UL2	DL
0.10	5-25	5-25	5-25	5-13	5-23	5-13	2.8
0.20	5-25	5-25	5-25	5-13	5-23	5-13	2.8
0.30	5-25	5-25	5-25	5-13	5-23	5-13	3.0
0.40	5-25	5-25	5-25	5-13	5-23	5-13	3.2
0.50	11.5-25	9-25	9-23	7.5-15	9-19.5	11.5-14.5	3.5
0.60	12-25	9-25	11-16	10-17	11-16	12-16	3.9
0.67	13-16.5	10-16	11-13	10-13	11-13	13	4.2
0.75	14-16.5	12-12.5	12-14	11-12.5	14	Not allowed	4.5
Recommended tube bundle length for maximum range of β	13 $\beta \leq 0.75$	12-12.5 $\beta \leq 0.75$	12-13 $\beta \leq 0.75$	11-12.5 $\beta \leq 0.75$	13 $\beta \leq 0.75$	13 $\beta \leq 0.67$	4.5

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For both types of performance tests, the use of the flow conditioner in the field is restricted to those locations within the meter run where the ΔC_D of the tested flow conditioner was one-half of the uncertainty limits $\pm 2\sigma$ of the RG equation. This is of the order of $\Delta C_D \sim 0.25\%$ from the reference calibration value. The five tests listed below must be performed for each test.

- Test 1: Baseline calibration (without flow conditioner)
- Test 2: Good flow conditions
- Test 3: Two 90° elbows in perpendicular planes
- Test 4: Gate valve 50% closed
- Test 5: High swirl

The baseline calibration test is used to establish a reference calibration. The reference calibration should fall within the 2σ uncertainty interval for the RG orifice equation. The baseline C_D value is used in calculating ΔC_D . A “good flow conditions” test evaluates the signature of the flow conditioner. That is, if the velocity profile approaching the flow conditioner is fully developed (turbulent pipe flow, without swirl), what profile does the flow conditioner produce? The test with two 90° elbows is designed to confirm that the flow conditioner is effective in removing swirl from the flow. Test 4 with the gate valve closed 50% is designed to confirm that the flow conditioner is effective in eliminating axial velocity profile asymmetry. The final test with high swirl is designed to provide assurance that the flow conditioner will perform well when installed in a header configuration. Velocity profile studies in some meter tubes installed between headers have shown very large swirl angles, up to $\pm 30^\circ$ at the meter tube surface.

Some last thoughts on installation requirements for meter runs conclude this subsection. First, design criteria for new installations should be the lengths quoted for $\beta = 0.75$. Upstream meter tubes longer than those shown are desirable. However, reduced upstream length requirements for installations with tube bundle straightening vanes are often used. Meter tube lengths are specified so that the “worst case” requirements for the maximum β ratio are satisfied. If the length requirements are satisfied for the “catch-all” category, then it will not matter how or where the meter tube is installed in the field. These maximum length requirements are not always practical to meet though. Sometimes, lengths are specified for the next size larger meter tube. For example, the upstream and downstream lengths may be specified for 6-inch pipe rather than 4-inch pipe. In the event that the flow rate requires a 6-inch meter tube rather than the 4-inch meter tube, enough space would be available for the 6-inch meter run to fit.

A.3.4 Operating Environment

The operating environment of orifice meters is known to potentially affect performance. Low ambient temperature is the most recognized issue of this kind [AGA XQ9011]. Any moisture in the gas stream can lead to hydrate formation in the meter tube, orifice plate, impulse lines, and/or taps when metering natural gas. Furthermore, leakage due to expansion from freezing liquids can be a problem at colder temperatures. If these concerns persist, either some form of controlled environment or change in device specification may be needed. Corrosive atmospheres, which can appear around plant areas or on offshore production platforms, can lead to degradation of meter components. In such cases, stainless steel equipment is generally recommended. Severe winds can cause vibration of the meter, leading to incorrect differential

readings. Additionally, in the case of sand blows, erosion and/or friction in linkage connections may be a matter of concern.

A.3.5 Calibration Requirements

Most types of flow meters require direct flow calibration to periodically verify accuracy. However, a properly-designed orifice meter does not require direct flow calibration if designed and manufactured in accordance with acceptable design practices. Components of the meter though, including the orifice plate, differential pressure element, static pressure element, and temperature element, must be routinely calibrated per established procedures for accuracy within the guidelines of tariffs, contracts and accepted industry and company standards. It is common to perform at least an initial installation calibration test of the entire system as well. This includes a baseline calibration test where flow is benchmarked against another reference meter. The test is performed at four different values of Reynolds number, and using minimum and maximum β -ratio values. If ΔC_D is less than one-half of U95 for RG equation ($\sim 0.25\%$), the performance is acceptable at that location [SGA, 2005].

Meter tubes, though not required to be calibrated per se, should have the following items inspected periodically. First, the meter internal tube diameter should not deviate more than the tolerances given in AGA-3, Part 2, i.e., “the percentage difference between the maximum measured individual internal diameter measurement and the minimum measured individual internal diameter measurement of all upstream meter tube individual internal diameter measurements, including those within the first meter tube diameter upstream of the orifice plate, shall not exceed 0.5% of the mean meter tube diameter D_m .” Within the first tube diameter, this allowance is reduced to $\left| \frac{(\text{any diameter within one } D_m) - D_m}{D_m} * 100 \right| \leq 0.25\%$. Second, the inside pipe walls should not have a roughness exceeding 300 micro-inches, and should be free of any scoring or pitting. Finally, flange gaskets should be inspected for correct centering. Note that there are similar requirements for orifice plates, which are discussed later in greater detail.

A.3.6 Applicable Industry Standards

The primary standard for installation, use, and uncertainty in orifice meters is AGA Report Number 3. This collection is also known as API 14.3, ANSI/API 2530-92, and GPA 8185-92. The standard is published in four parts:

- Part 1 - General Equations and Uncertainty Guidelines
- Part 2 - Specification and Installation Requirements
- Part 3 - Natural Gas Applications
- Part 4 - Background, Development, and Implementation Procedure...

Note that AGA-3 does not cover: gas or fluid sampling systems, chromatographs, chart recorders, or flow computers. Also, the ANSI, AGA, API, and GPA organizations do not “approve” or “certify” specific measurement equipment for use in the industry. Instead, they simply provide guidance on best practices.

Additional standards that are available for orifice meters include:

- AGA Gas Measurement Manual, Part 3.0

- ISO 5167 (-1 & -2)
- API MPMS Chapter 21, Section 1.2.1

Complete reference information may be found for these documents in the references, Section A.7.1.

A.4 Common Orifice Meter Manufacturers

There are a wide variety of manufacturers who provide primary orifice meter elements. Some specialize in small-scale or large-scale applications, while others concentrate on providing equipment to certain sectors, e.g., petroleum or food industries. Most utilize a standard design, such as discussed in Section A.1.1. However, a few provide specialized features. An example is a Senior Orifice Fitting, which provides a meter run designed so that plates can be changed out under pressure without interrupting flow.

A.5 Performance Characteristics

This section deals with the performance of orifice meters. The method of determining accuracy, as well as typical accuracies, is first given. Dependence of accuracy on flow conditions is next discussed. Finally, sources of bias and inaccuracy are emphasized for reader awareness.

A.5.1 Typical Accuracy

Factors contributing to uncertainty come from a variety of different sources. These include: construction tolerances in meter components, tolerances of empirical coefficient of discharge from databases or flow calibrations, uncertainties associated with secondary devices, and uncertainty/variability in fluid physical properties. For the purposes of this report, it is assumed that all fluid properties at flowing conditions are known with 100% accuracy. This is not the case when performing calibrations; however, procedures for determining property uncertainty are beyond the scope of this report.

Recall from Section A.3.5 that orifice meters are not often calibrated as a field unit, since removal for testing or installation of a secondary reference in the line is generally not an attractive option. Instead, the accumulation of uncertainties in each component of the meter is used to determine the overall uncertainty. As given in Section A.1.3, mass flow rate may be computed through the following equation for orifice meters: $q_m = N_1 C_D E_v Y d^2 \sqrt{\rho_{T,P} \Delta P}$.

Uncertainties in some of these measurements will have a larger effect on the flow rate uncertainty than others, though. The relative effects are described by sensitivity coefficients. Sensitivity coefficients (labeled S) are found from the formula that relates the measurements to flow rate. The coefficient for any measured quantity comes from the normalized partial derivative of the flow rate with respect to that quantity. For simple formulas, the sensitivity coefficients can be found intuitively as the exponent of the measured variable. For instance, if some device uses temperature and a K-factor to measure flow rate as $Q = KT^2$, then $S_K = 1$ and $S_T = 2$. For more complex formulas, standards such as API MPMS, Chapter 14.3, Part 1, tabulate the coefficients.

Using differentiation and assuming independent estimates are available for $\frac{\partial C_D}{C_D}$, $\frac{\partial Y}{Y}$, $\frac{\partial d}{d}$, and $\frac{\partial D}{D}$, it can be shown that the uncertainty in the mass flow rate is:

$$\frac{\partial q_m}{q_m} = \left\{ \left(\frac{\partial C_D}{C_D} \right)^2 + \left(\frac{\partial Y}{Y} \right)^2 + \left[\frac{2}{1-\beta^4} \right]^2 \left(\frac{\partial d}{d} \right)^2 + \left[\frac{-2\beta^4}{1-\beta^4} \right]^2 \left(\frac{\partial D}{D} \right)^2 + \frac{1}{4} \left(\frac{\partial \rho}{\rho} \right)^2 + \frac{1}{4} \left(\frac{\partial \Delta P}{\Delta P} \right)^2 \right\}^{0.5}$$

Thus, the sensitivity coefficients for the variables of q_m may be written as shown in Table A.4. Note that E_v has been expanded into its dependent variables, and is therefore not explicitly shown. The conversion factor N_I has no uncertainty associated with it, since it may be precisely determined.

Table A.4. Sensitivity Coefficients for Orifice Meter Mass Flow Rate Equation
The full derivation for the coefficients may be found in AGA-3, Part 1.

Uncertainty Source	C_D	Y	d	D	ΔP	ρ
S	1	1	$\frac{2}{(1-\beta^4)}$	$\frac{-2\beta^4}{(1-\beta^4)}$	0.5	0.5

Recall that C_D is determined through Reynolds' Law of Similarity using RG equation regression to existing empirical data. Sometimes when one calculates a numerical value from a formula, or looks it up from a table, it can be easy to forget that the value may have uncertainty associated with it. This is not from the formula or the table itself, since the uncertainty in the calculation or lookup may be considered negligible. The uncertainty comes from the origin of the equation. It is a regression or least-square-error fit to a database composed of many data points. Some points "fit" better than other points. In fact, the data from some laboratories fit better than data from other laboratories.

Figure A.5(a) represents the 95% confidence interval for the RG equation at infinite Reynolds number (10,000,000 or 10^7 is large enough). Figure A.5(b) provides a multiplicative factor (to be multiplied times the 95% confidence interval at infinite Reynolds number) to allow for the estimation of the 95% confidence interval for other (lower) values of Reynolds number. The significance of the uncertainty estimate is that if the orifice meter installation meets the requirements of AGA-3, then values of orifice coefficient obtained from this installation should fall within the $\pm U_{95}$ confidence limits around the values calculated from the RG equation, 95% of the time. Put another way, if one made a series of 20 independent measurements at the same value of Reynolds number and β , then 19 of the 20 data points should fall within the $\pm U_{95}$ confidence limits around the value calculated from the RG equation for the same Reynolds number and β .

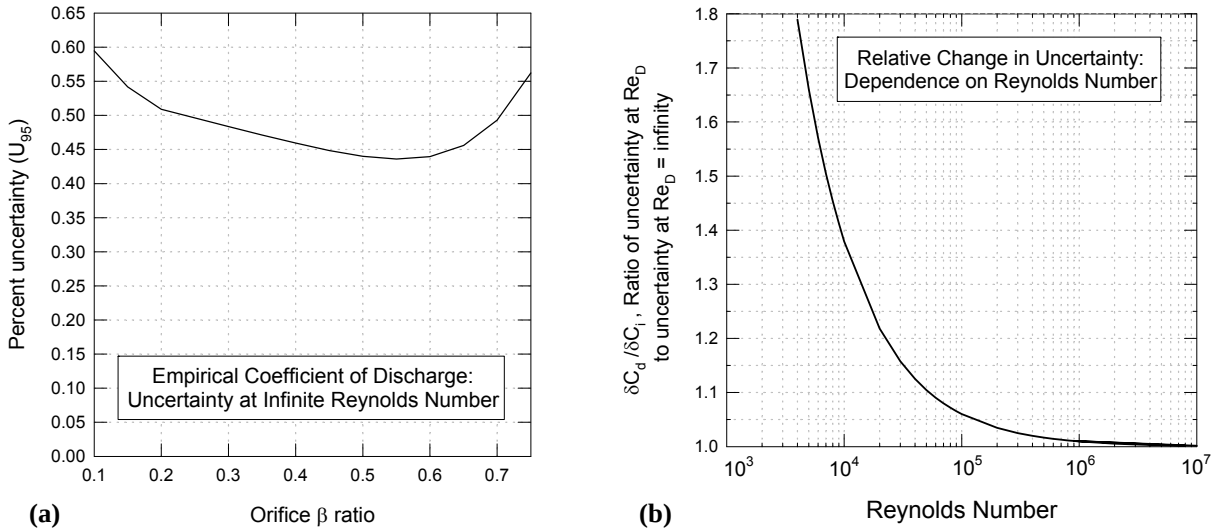


Figure A.5. Uncertainty with Respect to Coefficient of Discharge and Reynolds Number
 Figure (a) shows the empirical coefficient of discharge with uncertainty at infinite Reynolds number;
 Figure (b) shows the relative change in uncertainty with dependence on Reynolds number.

Examples of typical discharge coefficient scatter for various beta ratios are given in Figure A.6. Ninety-five percent confidence interval bands for the RG equation are indicated on the graphs. Figure A.6(a) shows baseline data for a 10-inch diameter meter tube fitted with a $\beta = 0.60$ orifice plate and tested in the SwRI MRF High Pressure Loop compared to baseline data for $\beta = 0.57$ reported from other laboratories that contributed data to the RG regression database. The confidence intervals were calculated using all of the data, over a range of meter tube diameters and Reynolds numbers. This graph is a “snap shot” of all data for 10-inch diameter meter tubes tested with a $\beta = 0.57$ or a $\beta = 0.60$ orifice plate. Figure A.6(b) shows baseline data for a 10-inch diameter meter tube fitted with a $\beta = 0.75$ orifice plate and tested in the SwRI MRF High Pressure Loop compared to baseline data reported from other laboratories that contributed data to the RG regression database. The confidence intervals were calculated using all of the data, over a range of meter tube diameters and Reynolds numbers. Again, this graph is a “snap shot” of all data for 10-inch diameter meter tubes tested with a $\beta = 0.75$ orifice plate. Note that for both of the graphs shown in Figure A.6, data remain generally within the 95% uncertainty bands indicated.

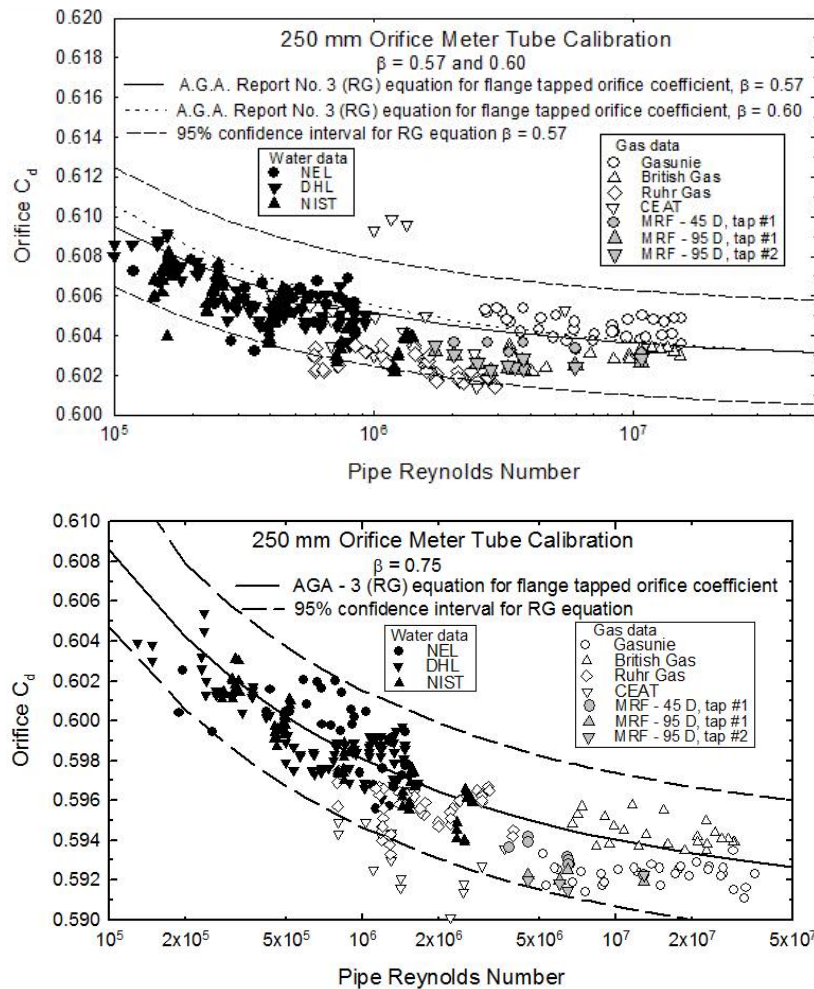


Figure A.6. Experimental Coefficients of Discharge versus Reynolds Number, with 95% Uncertainty Bands Indicated

Figure (a) provides data for $\beta=0.57$ and $\beta=0.6$; Figure (b) shows data for $\beta=0.7$. Data generally remain within 95% confidence interval bands.

To provide a sense of the overall effect of the cumulative uncertainties in an orifice meter, an example from a natural gas flow calculation derived in AGA-3, Part 1 is reproduced here. First, the density is defined as $\rho = \frac{G \cdot MW_{air} \cdot P}{Z \cdot R \cdot T}$, where G is the ideal gas relative density of the gas (MW_{gas}/MW_{air}), P is the static pressure, R is the universal gas constant, T is the flowing temperature, and Z is the fluid compressibility. Using this expression, fluid density uncertainty may be expanded, such that $\frac{1}{4} \left(\frac{\partial \rho}{\rho} \right)^2 = \left[\frac{1}{2} \left(\frac{\partial G}{G} \right) \right]^2 + \left[\frac{1}{2} \left(\frac{\partial P}{P} \right) \right]^2 + \left[-\frac{1}{2} \left(\frac{\partial Z}{Z} \right) \right]^2 + \left[-\frac{1}{2} \left(\frac{\partial T}{T} \right) \right]^2$. Representative values of the uncertainty in each term may then be expressed as shown in Table A.5. Note that the following conditions and assumptions for this example (per AGA-3, Part 1) include:

- For each variable, the uncertainty represents random error only.
- A 4-inch meter with β ratio of 0.5 and static and differential pressures equal to 250 psia and 50 inH₂O, respectively, is used.
- The precision of the ΔP device is ± 0.25 percent of full scale.

Table A.5. Example Uncertainty Estimate for Natural Gas Flow Calculation*The full details of this example may be found in AGA-3, Part 1.*

Uncertainty Source		U_{95} (%)	Sensitivity Coefficient, S	$(U_{95}S)^2$ (% error)
C_D	Discharge Coefficient	0.44	1	0.1936
Y	Expansion Factor	0.03	1	0.0009
d	Orifice Diameter	0.05	$\frac{2}{(1-\beta^4)}$	0.0114
D	Pipe Diameter	0.25	$\frac{-2\beta^4}{(1-\beta^4)}$	0.0011
ΔP	Differential Pressure	0.5	0.5	0.0625
P	Static Pressure	0.5	0.5	0.0625
Z	Compressibility Factor	0.1	-0.5	0.0025
T	Flowing Temperature	0.25	-0.5	0.0156
G	Relative Density	0.60	0.5	0.09000
Sum of Squares				0.4401
Square Root of Sum of Squares				0.6634

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A.5.2 Dependence of Accuracy on Flow Conditions

Often flow conditions do not meet the ideals set forth in standards indicating how to compute orifice meter accuracy. Section A.3.2 lists some of the assumptions about process fluid that are specified in such works. Any deviation from these assumptions introduces errors that are not accounted for using the method outlined in Section A.5.1. Two of the primary issues that tend to arise are inhomogeneous/two-phase flow and unsteady flow/pulsations. Since this report deals specifically with single-phase flows of a homogeneous process fluid, the focus of this subsection will be solely on pulsation effects.

To begin, pulsations are defined as any periodic (cyclic) fluctuations in pressure and flow that vary with time and location. Normally these include fluctuations that occur at a rate of about one cycle per second (1 Hz) or faster. Sources of pulsation include: reciprocating compressors, other compressors, control valves and regulators, flow-induced side branching, vortex shedding, fluidic instabilities, gas lift, and slug flow. Field experience has shown that pulsation exists at many stations, and distance from the source does not significantly reduce pulsation amplitude. With regard to flow pulsations, AGA-3 states that:

- “Accurate measurements of flow...can only be ensured when the RMS over mean differential pressure does not exceed 10%.” (That is to say: $\Delta P_{\text{rms}} / \Delta P_{\text{average}} < 10\%$.)
- “No theoretical or empirical adjustment exists that will maintain the accuracy.”
- “The user should make every effort to eliminate pulsation at the source.”

Three types of errors may be identified with respect to pulsation: square root error (SRE), inertial error, and coefficient shift. SRE is the most common type, defined as $SRE\% = \frac{\sqrt{\Delta P} - \sqrt{\Delta \bar{P}}}{\sqrt{\Delta \bar{P}}}$. It is characterized as always positive, and increasing with increasing pulsation amplitude. In general, the square root of average ΔP is not equal to the average of the square roots of instantaneous ΔP s. For pulsating flow, the average ΔP is higher than the ΔP corresponding to the average flow rate. To avoid SRE, the square root of each ΔP point is taken and averaged with a sampling rate that is sufficient for the pulsation frequency, and then averaged over several cycles. SRE can be measured using fast-response transducers and correct data processing

methods. Figure A.7 gives an indication of how well SRE accounts for pulsation effects. Note that the SRE follows the total measured error trend rather well over the entire pulsation frequency range. Inertial errors generally occur at high frequency or high amplitude, and are smaller than SRE. Coefficient shift errors happen at extreme amplitudes only. Essentially, the shape of the velocity profile is affected, which, in turn, affects the C_D .

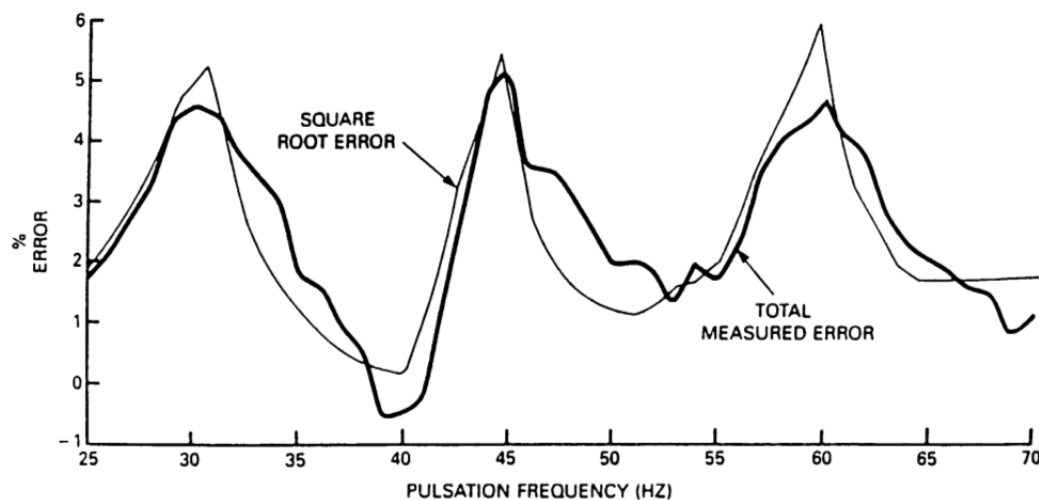


Figure A.7. Example of Measured and Square Root Error versus Pulsation Frequency

Note that the square root error follows the trend of the total error, indicating it is a primary contributor.

Pulsation can seriously impact the accuracy of secondary systems. This includes impulse lines, transducers, charts, and EFMs. Such errors can be as important as primary element errors. For instance, acoustic resonance within impulse lines amplify (or attenuate) pulsation, resulting in a distorted ΔP signal. Furthermore, flow oscillations within an impulse line can produce a pressure gradient or shift along the impulse line, distorting the average differential pressure measurement. Impulse line errors change with line length or pulsation frequency, and SRE cannot be measured at the transducer end of the impulse line. For these reasons, short impulse lines are preferred. Turning attention to other secondary devices, it is noted that chart recorders and measurement-grade transmitters are generally slow response devices that cannot follow pulsation. Fast-response transducers without impulse line distortion are required to detect and measure pulsation effects. However, data sampling and processing rates must match the pulsation and information rate. While API MPMS, Chapter 21.1 recommends one sample per second for electronic transmitters in general, accuracy requirements increase to more than two (and preferable five to ten) samples per pulsation cycle in pulsating flows. Note that rapid sampling of a slow transmitter results in no performance improvement, and sampling too slowly also causes errors.

In conclusion, pulsation flow conditions can result in many problems for a metering system as a whole. These include: noise in the piping, vibration at measurement equipment, vibration and failure of gauge lines, and dependence on operating conditions. These can seriously impact accuracy of an orifice meter. For diagnostics, SRE should be measured at the orifice taps using minimum impulse line lengths and a fast-response ΔP transducer. Industrial-grade pressure transmitters cannot be used to measure SRE. Pulsation levels should never be measured near a chart recorder or transmitter end of impulse lines to determine SRE. Instead, they should be measured as close to the pipe as possible. Recommended methods for controlling

pulsation include: piping/impulse line redesign, judicious placement of control valves and regulators, and use of acoustic filters.

A.5.3 Potential Sources of Bias or Inaccuracy

There are a variety of bias and inaccuracy sources that will affect uncertainty in flow rate measurements of orifice meters. For primary components (meter tube and orifice plate), some of the most common include: surface finish, contamination, edge sharpness, reversed plates, bent orifice plates, and plate eccentricity.

The surface finish of the orifice meter tube, also called roughness, has tolerances as specified by AGA-3, Part 2, 2.5.2. The roughness average, R_a , is “the arithmetic average of the absolute values of the measured profile height deviation taken within the sampling length and measured from the graphical centerline.” The effect of surface roughness is to influence the turbulent “wall shear stress” that affects the shape of the velocity profile. If the surface roughness is so great that the flow is no longer hydrodynamically smooth, then the velocity profile will show an effect of the surface roughness. However, the orifice coefficient database was established from tests with commercial meter tubes, so the roughness effect may already be “fossilized” in the database.

The surface roughness is often measured with a small, portable electronic-averaging-type device called a profilometer. It traverses a stylus over the surface and measures deviations from a mean line from start to finish. The instrument is calibrated before use by traversing surfaces of known roughness. Average values, R_a , are measured and calculated over several consecutive segments of the same traverse. These segments are called the “cutoff” length. Different values of R_a may be measured for different cutoff lengths. Section 2.5.1.1.1 of AGA-3 specifies a cutoff length of not less than 0.03 inches, and requires that the internal surface roughness of the meter tube be measured at approximately the same axial locations as used to determine the meter tube internal diameter.

Changing the wall roughness (for example, by honing the meter tube over the last 10D upstream of the orifice plate) changes the local wall friction factor, but the velocity profile that is produced needs time (or downstream length) to adjust fully to the new surface. It can take 45D before a new, equilibrium velocity profile is formed. Experimental data show that the effect on C_D of a change of surface roughness is greatest for large values of β and is barely detectable for small values of β . For meter runs $D \leq 12$ inches [AGA-3]:

- Internal surface roughness, R_a may not exceed 300 μ inches for $\beta < 0.6$.
- Internal surface roughness, R_a may not exceed 250 μ inches for $\beta > 0.6$.

For meter runs $D > 12$ inches:

- Internal surface roughness, R_a may not exceed 600 μ inches for $\beta < 0.6$.
- Internal surface roughness, R_a may not exceed 500 μ inches for $\beta > 0.6$.
- The minimum surface roughness shall not be less than 34 μ inches.

Note that the effect of surface roughness on C_D can be significant, even for meter tubes that meet the AGA-3 surface roughness criteria. A conservative approach is to set a lower limit for roughness equal to the minimum value for meter tubes that were used to generate the orifice coefficient database.

Contamination can produce the same effect as surface roughness, where an increase in roughness due to rust or dirt affects meter accuracy. Oil deposits on the inside surface of the meter tube can also lead to the same effect. Valve maintenance often results in grease spots on the orifice plate that cannot be swept away by the flow, and such effects can be significant if grease is allowed to accumulate on the plate. Ting [1993] states,

“Corrosion, erosion, and oil-film deposits on the surface of the meter tube generally represent an increase of surface roughness from its original specification. A survey of used meter tubes indicated that the surface roughness ranged from 300 to 500 μ inches. Other researchers found that rusty meter tubes can affect test results.”

Johansen [1993] writes of his experiments,

“The results of this investigation clearly show that significant shifts in orifice plate discharge coefficient can occur if liquid coats the orifice flow meter surfaces. Shifts in discharge coefficient due to thin films of liquid are always positive in direction, resulting in under-measurement of flow. The largest shifts in discharge coefficient occurred as a result of liquid on the pipe surfaces of systems with high β .”

In 1971, E. J. Burgin of Florida Gas Transmission Company reported on comprehensive tests on the measurement errors caused by grease deposits on the orifice plate. His tests included a wide range of grease “distributions” on the plates, including random “gobs” or droplets on the plate, plates with the lower half of the upstream face covered by valve grease, and plates completely covered on both sides with different thicknesses of grease. Burgin’s results indicated that if the area of grease is larger, the distortion in metering accuracy will be higher. The results also showed a greater effect of grease on the upstream side of the plate than on the downstream side. Botros [1992] also performed tests to determine the effect of simulated grease spots on orifice meter accuracy. No significant effect on measurement accuracy was observed when the “grease spots” were placed midway between the pipe wall and the orifice bore. When they were adjacent to the orifice bore, however, significant measurement errors were found, as much as -3.25% for $\beta = 0.20$.

The allowable variation in meter tube roundness for maintaining accuracy is specified in AGA-3. The limit on absolute percentage deviation within 1D upstream of the orifice is $\left| \frac{D - D_m}{D_m} * 100 \right| \leq 0.25\%$, where D_m represents the average meter tube diameter. The maximum percent difference between D_{max} and D_{min} within 1D upstream of the orifice plate is specified as $\left| \frac{D_{max} - D_{min}}{D_m} * 100 \right| \leq 0.5\%$, while the limit on absolute percentage deviation downstream of the orifice plate is listed as $\left| \frac{D - D_m}{D_m} * 100 \right| \leq 0.5\%$. The value of the meter tube internal diameter is determined as the average of a minimum of four equally-spaced, individual internal diameter measurements, in a plane one inch upstream of the upstream face of the orifice plate. When measuring the meter tube diameter, it is important to measure and record the temperature of the meter tube as its diameter is measured. This temperature is needed in calculating the thermal expansion of the meter tube when exposed to the flowing fluid.

Note that the check measurements are not used to determine the meter tube diameter, only to verify the roundness of the meter tube. Individual check measurements of the internal diameter of the upstream section of the meter tube must be made at a minimum of two additional

cross sections. Although the locations are not specified, the checks should be made at points that will indicate the maximum and minimum dimensions of the internal diameter of the meter tube's upstream section. One check measurement should be made in a region at least $2D$ from the face of the orifice plate, past the orifice plate holder weld or flange. Diameter check measurements should also be made in the downstream section of the meter tube, in a plane one inch downstream from the downstream face of the orifice plate. Additional check measurements should be made of at least two other cross sections, in a similar manner as on the upstream meter tube section. Abrupt changes of the inside meter tube surface (e.g., shoulders, offsets, ridges, and welding seams), should be avoided. Weld beads on the inside surface of the meter tube, such as between an orifice flange and the pipe, should be ground down carefully.

A protrusion extending into the meter tube significantly increases the local pipe wall roughness, potentially causing local distortion of the velocity profile and decreased accuracy of C_D calculations. The fluid flow over the top of a recess behaves differently, though it still affects C_D through the upstream velocity profile. If the length of a recess is relatively short, the flow will skip over the top of a recess and reattach on the downstream side. AGA-3, Section 2.5.1.4.5 states that recesses larger than 0.5 inches in length, or recesses between 0.25 inches and 0.5 inches that exceed the permissible roundness variation, may introduce additional uncertainty.

The surface finish of orifice plates is another parameter that is controlled to reduce uncertainty. Surface roughness of upstream and downstream faces must not exceed 50 μ inches R_a [AGA-3]. Scratches or abrasions on the plate surface may be the result of careless handling or storage. Orifice plates must be kept clean at all times and free from accumulations of dirt, ice, and other extraneous material. Kamal Botros and coworkers at NOVA tested $\beta = 0.2$ and $\beta = 0.6$ orifice plates in 4-inch and 8-inch meter tubes. Small concentric grooves were machined onto the orifice plate surface with heights of $R_a = 80 \mu$ inch or $R_a = 160 \mu$ inch. They found that for $\beta = 0.20$ and 4-inch piping, the $R_a = 80 \mu$ inch orifice plate did not indicate any change in flow rate in comparison to a standard plate. However, a major effect on measured flow rate (-0.57%) was observed from the $R_a = 80 \mu$ inch plate for 8-inch piping. The plates with $R_a = 160 \mu$ inch significantly affected the measurement in both pipe sizes. In summary, tests of orifice plates rejected by measurement technicians due to nicks on the upstream edge did not show any significant difference in flow rate. Tests with relatively large machined notches caused a significant error when the notch was large enough to change the cross-sectional area of the orifice bore.

Bending or warpage of orifice plates can significantly degrade accuracy. The upstream and downstream faces of the plate must be flat, with flatness deviations not exceeding 1% of the "dam height" [AGA-3]. Note that dam height is defined as $(D_m - d_m)/2$, where D_m and d_m are the meter tube and orifice bore diameters, respectively. This criterion applies to any two points on a plate within D_m . The surface finish of orifice plates is generally very good after they are manufactured. The plates are polished to remove scratches or abrasions. However, they can become bowed or "bent" if subjected to too large a pressure differential, or if struck by an object in the flow. An orifice plate that exceeds the criterion for flatness is considered to be a bent plate. Ting [1993] found in a field study that a typical bent orifice plate in operation had less than a 10° deflection angle. Flow tests using mechanically-bent plates showed that a significant flow measurement error began to appear when the deflection exceeded 1° . The error increased with increasing deflection angle. Ting concluded that

“Except for $\beta = 0.25$, measurement error increases with increasing β ratio and deflection angles. In most practical cases, bent plates will cause up to 4.5% lower flow rate measurement.”

Findings from a recent Joint Industry Project [George, 2007] using various published models for prediction of measurement errors due to bent orifice plates indicated that flow rates could be accurately predicted to within about ± 0.6 - 0.7% over a range of deflection angles.

Orifice plates are bored and finished in a manner to give a sharp orifice plate bore edge. A sharp upstream edge gives a minimum value of C_D . Rounding the edge will increase C_D significantly, leading to decreased accuracy. The “sharpness” of the orifice plate bore edge is difficult to measure, although many have tried and claimed success. While it is possible to traverse a stylus across the edge, from the upstream face to the bore, the radius of the stylus is often of the same order of magnitude as the edge that is being characterized. Thus, stylus tracings show an edge that is not circular. The lead film method involves making an impression of the bore edge on the circumference of a thin lead disk. The impression is magnified using a microscope, and radius gauges are used to estimate the bore edge radius. The casting method is very time consuming, and involves similar steps of acquiring an impression of the edge, then magnifying the image to determine the equivalent edge radius. There are also qualitative tests, including: light reflection from the edge, light passing between the edge and a (concave) machined surface, and thumbnail tests. One may ask, “Where does this lead?” A study performed as part of the SwRI MRF installation effects research program showed that modern, commercial orifice plates from several different manufacturers, contributed by several different companies, have the same level of edge sharpness as the orifice plates that were used to generate the orifice coefficient database [SGA short-course, 2005]. Hence, modern manufacturing methods are sufficient to ensure proper edge sharpness.

Installation of orifice plates backwards is a common mistake that occurs in industry. Plates generally have a bevel angle of $45^\circ \pm 15^\circ$ machined onto the downstream side of the bore. Reversing the orifice plate has the effect of severely rounding the upstream bore edge. When such a plate is accidentally installed backwards, the resistance to the flow is reduced even further than in the case of an orifice plate with a dull leading edge, and the flow is significantly underestimated. George and Morrow [2001] reported on tests at SwRI’s MRF to find the measurement errors caused by installing an orifice plate with the bevel facing upstream. They compared their results to data for backwards orifice plates reported by Ting [1993] and Witte [1997]. The data show that there is a clear dependence on the β ratio, the plate thickness, and the bore thickness. They developed a correlation to predict the percent measurement error caused by a backwards-facing orifice plate. For a plate of thickness E , bore thickness e , and meter tube diameter D , the percent error in the flow rate Q is predicted by:

$$\% \Delta Q = -18.93 + 12.91\beta - 34.04 \left(\frac{E}{D} \right) - 8.9 \left(\frac{e}{E} \right) + 13.64 \left(\frac{e}{E} \right)^2.$$

Uncertainty on the relation is given as $\pm 1.7\%$ at U_{95} .

The final source of bias/inaccuracy to be discussed is orifice plate eccentricity. For this measurement, a pair of measurements (X and X' , see Figure A.8) are made in one plane, on opposite sides of the bore. One half of the difference between the two measurements is the eccentricity in that plane. A second pair of measurements, Y and Y' , may be made to find the eccentricity in a plane perpendicular to the pressure taps. In this way, the eccentricity in planes

aligned with the pressure taps and normal to the pressure taps may be checked. When measurement of the eccentricity of an orifice plate installed in orifice flanges is not possible, two accurately located alignment pins should be used to support and center the orifice plate while the bolts holding the orifice flanges together are tightened.

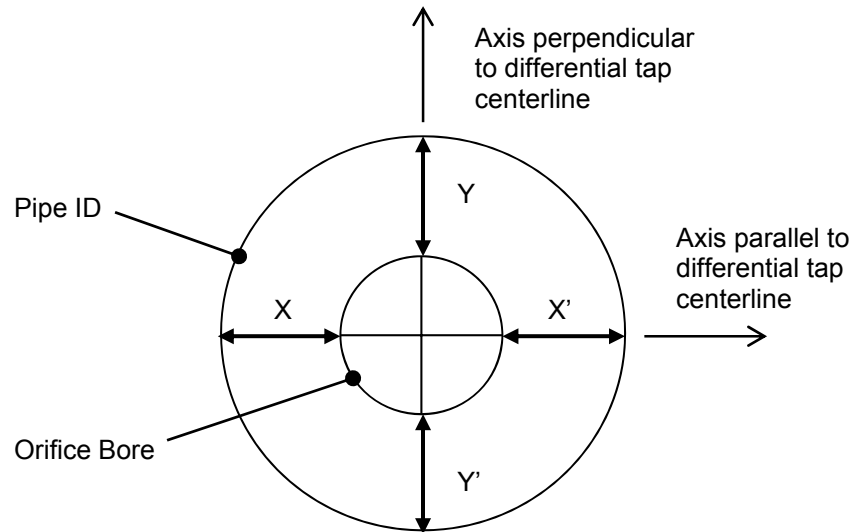


Figure A.8. Eccentricity Measurement – Sampling Method

Four measurements at the indicated locations are used to determine the eccentricity of an orifice plate. Adapted from AGA-3, Part 2 (2000).

The limit for bore eccentricity measured parallel to the pressure tap axis is given by AGA-3, Section 2.6.2.1 as $\varepsilon \leq \frac{0.0025D_m}{0.1+2.3\beta_m^4}$. The component of bore eccentricity perpendicular to the axis of the differential pressure taps (Y to Y') may be up to four times that of the parallel axis – provided eccentricity in the parallel plane does not exceed this limit. Some conclusions of eccentricity effect investigations by Zaki Husain and Ray Teyssandier [1986] for 2-inch meter tubes include:

- The effect of eccentricity on C_D is related only to the β ratio and to the magnitude and direction of the eccentricity.
- Eccentricity toward the pressure tap causes the largest change in C_D . Eccentricity normal to the tap shows the least influence.
- Eccentricity values less than the limit given above should restrict the change in C_D to less than 0.1%.

A.6 Recent Research on Performance of Orifice Meters

Orifice meters are one of the oldest flow measurement technologies, with commercial use dating back to the early 1900s. Thus, much of the mainstream research and experiments have been available in the literature for some time. Some niche areas continue to draw attention to these meters for further investigation though. Such topics include: effects of deviation from ideal flow conditions, novel plate designs, and use of computational fluid dynamics for characterization of complex flow patterns.

Deviation from ideal conditions includes any flow not exhibiting all of the characteristics outlined in Section A.3.2 (e.g., steady-state, single-phase, homogeneous, etc.). Section 0 has already focused on the effect of flow pulsations on accuracy. McKee [1994; 1995] considered pulsation effects on both the orifice meter primary and secondary components. Studzinski et al. [1997] also investigated pulsation effects, performing numerous experiments at the MRF facilities of SwRI. As a second example, while this report considers only single-phase orifice meter applications, many recent papers focus on performance of such meters in two-phase or wet gas flows. One of the challenges associated with this is liquid being held up at the plate resulting in unsteady flow – and consequent unsteady differential pressure readings. Wet gas flow conditions are known to produce a positive bias/over-reading on flow rate predictions. According to Steven [2010], there is currently no way for diagnostics to automatically detect this problem. Under a set of careful assumptions, some orifice correlations have been proposed for wet gas flow [Steven, 2006]. However, these have proven unreliable for a broader range of conditions. In summary, uncertainty arising from non-ideal flow conditions continues to draw interest from the research community.

Plate design/placement has received some attention recently. Bryant et al. [2008] investigated flow patterns upstream of an orifice meter, using various combinations of orifice size/placement and multiple orifices. This resulted in a new potential flow solution proposed for flow behind orifices. For more complex flow patterns, however, there can be a need for computational fluid dynamics (CFD) to fully characterize the flow. For example, CFD has been used to model the effects of a swirl flow conditioner upstream of an orifice meter in the work of Beck and Stanway [2005]. Complicated flow patterns can arise from orifice plates created with an array of slots, rather than a concentric bore. Interest in such designs is at least partially due to the possibility of reduced requirements for flow conditioners or decreased upstream straight pipe lengths. It is claimed that the novel designs make measurements less sensitive to upstream conditions for wet gas flows [Kumar and Bing, 2011]. Due to the intricacy of the resulting flow patterns, CFD has been used to analyze slotted plate designs [Yuxing et al., 2009; Kumar and Bing, 2001].

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APPENDIX B

Review of Turbine Metering Technology

B. REVIEW OF TURBINE METERING TECHNOLOGY

This report contains a review of single-phase flow measurement with turbine meters.

B.1 Basics of the Technology

B.1.1 Principles of Operation and Device Geometry

Turbine meters are inferential flow meters that obtain the velocity flow rate of a fluid by counting the number of revolutions of a rotor. The rotor contains angled blades that are suspended in the flow stream. The flow of the fluid through the rotor blades causes the rotor to turn proportionally to the fluid velocity. With the internal dimensions of the turbine meter known, the volume flow rate can be calculated at line conditions. Turbine meters can be used to meter either liquid or gas. The internals of a turbine meter for liquid metering differ from the internals for gas metering because of the difference in the driving forces of the fluid and fluid properties. A turbine meter that is designed for gas measurement should not be used to measure liquid and vice versa.

Figure B.1 shows a typical turbine meter schematic taken from AGA Report Number 7. Each of the items labeled in Figure B.1 are discussed in detail in this section.

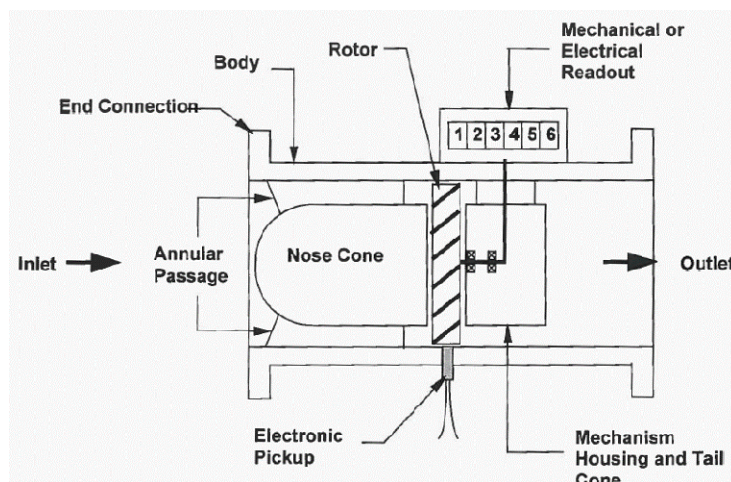


Figure B.1. Turbine Meter Schematic

A cross section of a typical turbine meter can be seen (AGA Report Number 7, 2006).

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Nose Cone and Annular Passage

The nose cone is used to force the fluid flow to the outer pipe walls before it passes through the rotor. An annular passage is created between the nose cone and the pipe wall. As the fluid flows through the annular passage, the velocity profile is redistributed and the velocity of the fluid increases as it passes through the rotor. Some turbine meters have integral flow conditioners imbedded into the nose cone. Research shows that turbine meters with integral flow conditioners are less susceptible to errors from asymmetric velocity profiles and/or swirling flow than turbine meters without integral flow conditioning. Turbine meters designed for gas metering typically have a smaller annular passage than turbine meters designed for liquid

metering. The nose cone for gas metering can block as much as 66% of the flow area versus 20% for a liquid turbine meter (Upp and LaNasa, 2002).

Body and End Connections

The body of a turbine meter is typically made of carbon steel or stainless steel. Since the fluid will be in contact with the meter body, a material should be chosen that is compatible with the process fluid. A wide range of end connections are available for turbine meters. Typically flange or threaded connections are used.

Electronic Pickup

The electronic pickup is used to indicate the revolution frequency of the rotor, which is then used to calculate the flow rate of the fluid. Optical-type pickup devices can also be used to measure the frequency of the rotor rotation.

Mechanical or Electrical Readout

A turbine meter can have a mechanical or electrical readout that displays the equivalent fluid volume that has passed through the meter. The readout is typically calibrated to read volume flow at line conditions. For mechanical readouts, different gearing sets are available so that the flow calibration can be matched to the mechanical readout.

Mechanism Housing and Tail Cone

The mechanism housing contains the mechanical gears and bearings for the rotor.

Rotor

The rotor contains angled or curved blades that are situated so that the fluid passing through the rotor imparts an angular velocity on the rotor. The rate at which the rotor spins is proportional to the fluid velocity.

Some turbine meter designs incorporate a second rotor into the meter to provide additional flow information and diagnostics. The design for the second rotor varies among manufacturers, but typically the blade design for the second rotor is different than the main rotor.

B.1.2 Secondary and Tertiary Devices Required

Temperature and Pressure Measurement

Temperature and pressure measurement of the process fluid is required when using a turbine flow meter. The temperature and pressure are important for fluid property determination. Section B.3.3 describes where the pressure and temperature should be measured in a typical turbine meter installation.

Pulse Counter

A pulse counter is required to record the number of pulses transmitted from the electronic pickup of the flow meter. The data from the pulse counter can be used to calculate the flow rate using the appropriate k-factors from the flow calibration.

Flow Computer

Flow computers are typically used in conjunction with turbine flow meters, as well as other metering technologies, to calculate and log the flow rate data. A flow computer takes

various inputs from the flow meter and secondary devices, such as temperature, pressure, fluid composition data, and calibration k-factors. In the case of a turbine meter, the main input from the meter to the flow computer is the pulse output from the electronic pickup. The flow computer uses the programmed algorithms to calculate the flow rate. Turbine meters can be purchased with a flow computer already installed.

B.1.3 Flow Equations

Different equations are used for liquid and gas turbine meters. Both equations are based on the following general turbine meter equation (Upp and LaNasa, 2002)

$$q_b = q_f M_f \left(\frac{\rho_f}{\rho_b} \right)$$

Where: q_b = flow rate at base conditions;
 q_f = flow rate at flowing conditions;
 M_f = meter factor to correct meter output based on calibration;
 ρ_f = density at flowing conditions;
 ρ_b = density at base conditions.

The equation for flow rate through a gas turbine meter is as follows:

$$q_b = q_f M_f \left(\frac{P_f T_b Z_b}{P_b T_f Z_f} \right) \text{ and } \left(\frac{P_f T_b Z_b}{P_b T_f Z_f} \right) = \frac{\rho_f}{\rho_b}$$

Where: P_f = absolute pressure at flowing conditions;
 P_b = absolute pressure at base conditions;
 T_f = absolute temperature at flowing conditions;
 T_b = absolute temperature at base conditions;
 Z_f = compressibility at flowing conditions;
 Z_b = compressibility at base conditions.

The equation for flow rate through a liquid turbine meter is as follows:

$$q_b = q_f M_f F_t F_p \text{ and } \left(F_t F_p = \frac{\rho_f}{\rho_b} \right)$$

Where: F_t = factor to correct fluid from flowing temperature to base temperature;
 F_p = factor to correct fluid from flowing pressure to base pressure.

B.2 Applications

Turbine meters can be used in both liquid and gas applications. Turbine meters are used very widely throughout the oil and gas industry (onshore, offshore, and subsea; production, midstream, and transmission). In natural gas applications, turbine meters are used in custody transfer applications due to their good accuracy and repeatability.

B.3 Typical Specifications

B.3.1 Flow Capacity and Rangeability

Rangeability for a turbine meter is dependent upon process fluid density, viscosity, and fluid type. For gas turbine meters, the rangeability is typically reported as 10:1 at pressures near atmospheric and as high as 100:1 at elevated pressures. Liquid turbine meters have a turn down ratio of 10:1 with a reduction in rangeability with higher viscosity and lower densities (Upp and LaNasa, 2002).

For turbine meters, rangeability is typically limited by rotor speed and pressure drop across the rotor. Turbine meters can be damaged if they are operated above the recommended flow range. Elevated levels of pressure drop can damage the rotor blades and excessive velocity can over spin bearings (Upp and LaNasa, 2002).

B.3.2 Installation Requirements

Turbine meter performance can be affected by swirl and an asymmetric velocity profile introduced by upstream piping bends, partially open valves, strainers, etc. Installation requirements have been established for turbine meters for both liquid and gas metering to mitigate the effects of upstream piping disturbances.

Gas Turbine Meter Installation Requirements

American Gas Association (AGA) Report Number 7 recommends a turbine meter installation with a minimum of ten nominal pipe diameters upstream and five nominal pipe diameters downstream. A straightening vane element is required in the upstream piping section. Other flow conditioners may be used if they have been shown through testing to produce acceptable accuracy by the turbine meter; their locations in the upstream tube should be guided by test results and manufacturer recommendations. Static pressure measurements should be taken at the pressure port on the flow meter and temperature should be measured 1-5 nominal diameters downstream of the flow meter. Figure B.2 shows a schematic of the recommended installation.

An optional “short-coupled” or “close coupled” installation is recommended in AGA Report Number 7 if space for the meter run is limited. For both of these installations, an integral flow conditioner is required in the turbine meter. AGA Report Number 7 cites research where the short-coupled and close-coupled installations were tested. In both installations, the measurement bias did not exceed $\pm 0.4\%$ of reading (George, 2001). Figure B.3 and Figure B.4 show schematics of the “short-coupled” and “close coupled” installations, respectively.

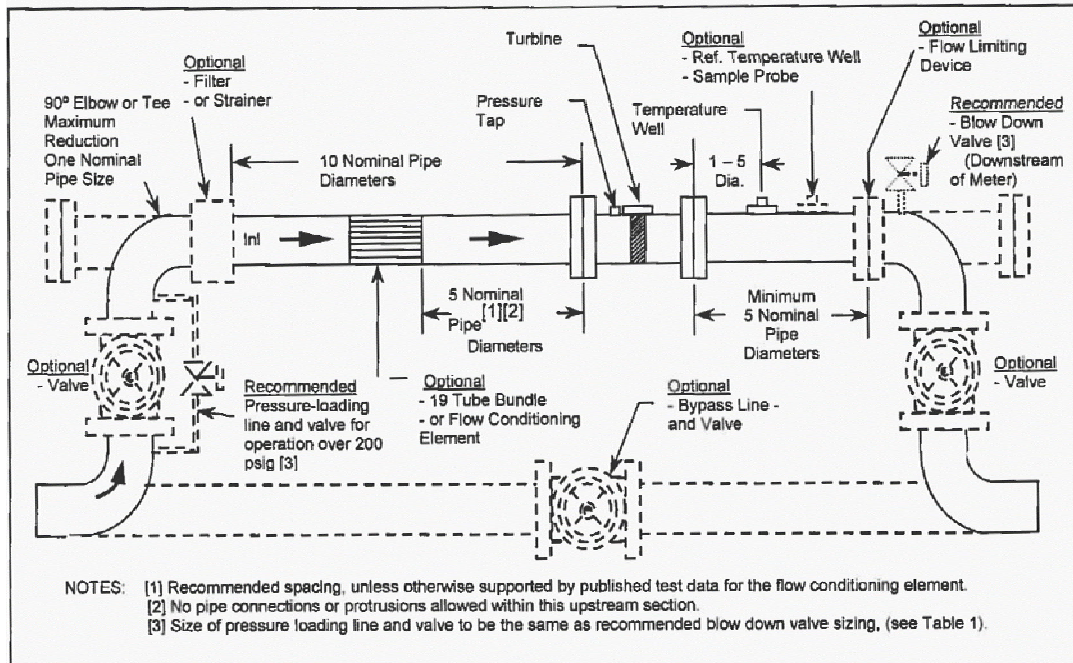


Figure B.2. AGA Report Number 7 Recommended Installation Schematic

The schematic represents the recommended installation for gas turbine meters according to AGA Report Number 7.

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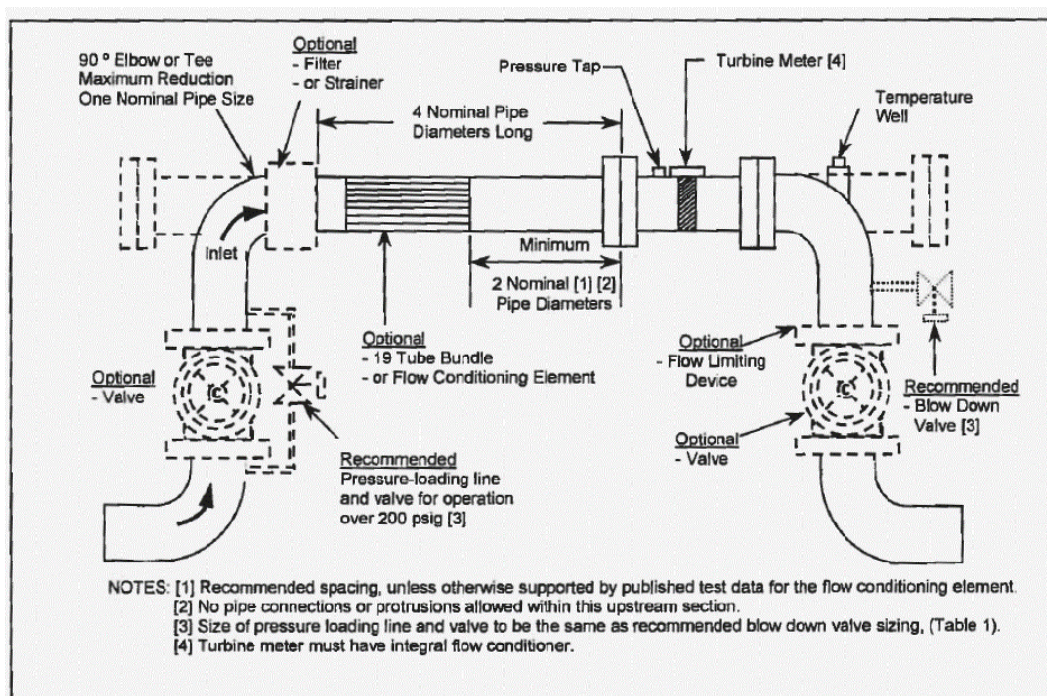


Figure B.3. AGA Report Number 7 Short-Coupled Installation Schematic

The schematic represents the recommended installation for short-coupled turbine meters according to AGA Report Number 7. A turbine meter with an integral flow conditioner is required for this installation.

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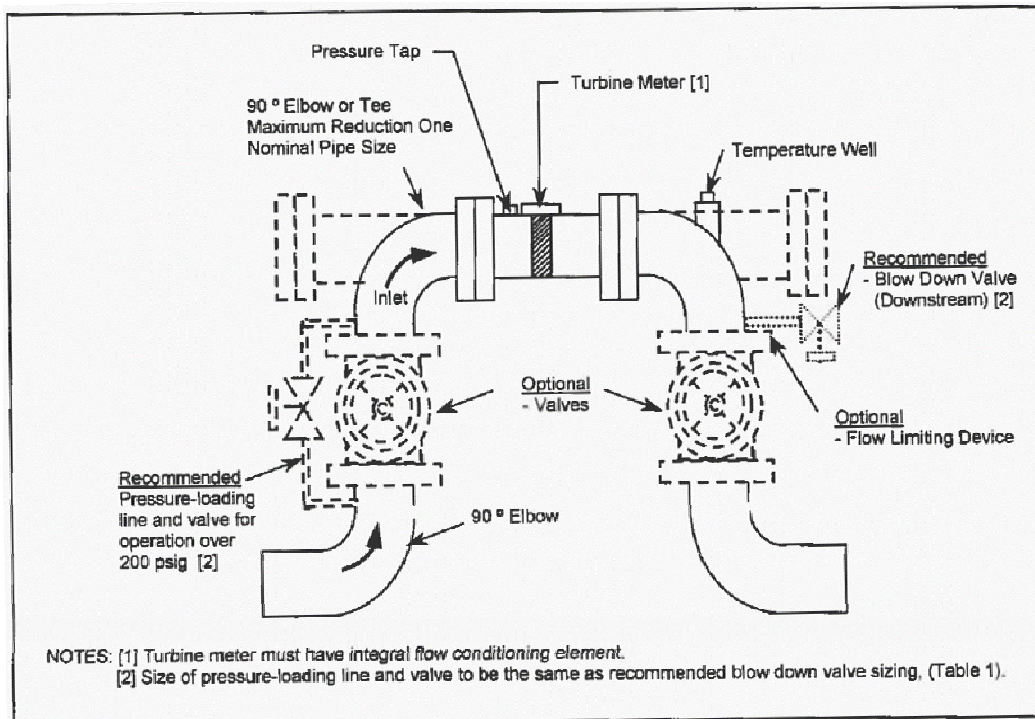


Figure B.4. AGA Report Number 7 Close-Coupled Installation Schematic

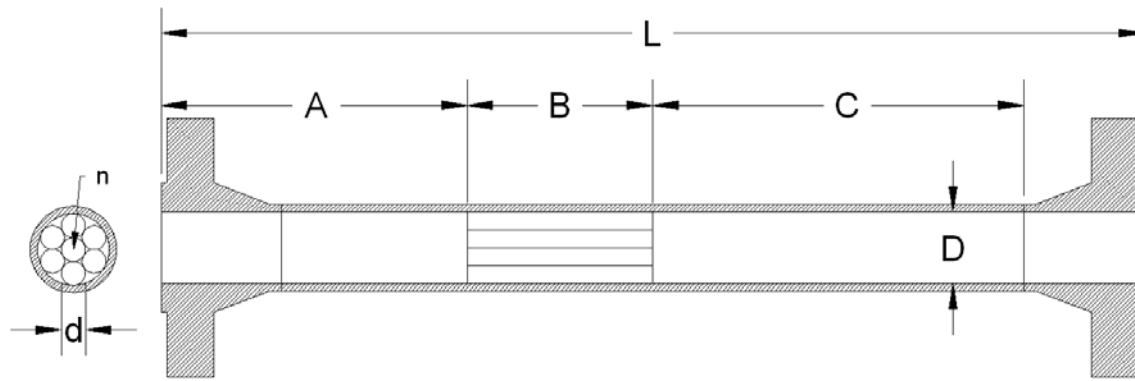
The schematic represents the recommended installation for short-coupled turbine meters according to AGA Report Number 7. A turbine meter with an integral flow conditioner is required for this installation.

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When using turbine meters for gas metering, it is recommended that a flow limiting device be used to ensure that the turbine meter is not over spun and potentially damaged. AGA Report Number 7 contains a table that can be used to size a sonic nozzle or a critical orifice to be used downstream of a turbine meter to limit the flow through the meter run to 120% of the rated turbine meter maximum. Over spinning of a turbine meter can also happen during normal blowdown procedures. AGA Report Number 7 recommends specific valve sizes for a blowdown valve, depending on the nominal size of the valve.

Liquid Turbine Meter Installation Requirements

Liquid turbine meter installation requirements are similar to gas requirements. Swirl and asymmetric velocity profiles in liquid flow can cause a measurement bias when using turbine meters. API 5.3 recommends long lengths of undisturbed upstream piping or flow conditioning to remove any asymmetric or swirling flow. Figure B.5 displays a schematic from API 5.3 for the recommended upstream piping for a turbine meter installation with a flow conditioner. As noted in the figure, a minimum of ten nominal pipe diameters are required upstream and five nominal diameters of straight piping should be installed downstream of the turbine meter. Figure B.5 displays a vane-type flow conditioner in the upstream piping section. API 5.3 also recommends that high performance type flow conditioners can also be used and should be considered in place of a vane-type flow conditioner.



- L = overall length of straightener assembly ($\geq 10D$).
 A = length of upstream plenum ($2D$ - $3D$).
 B = length of tube of vane-type straightening element ($2D$ - $3D$).
 C = length of downstream plenum ($\geq 5D$)
 D = nominal diameter of meter.
 n = number of individual tubes or vanes (≥ 4)
 d = nominal diameter of individual tubes ($B/d \geq 10$)

Figure B.5. API 5.3 Recommended Upstream Piping with a Flow Conditioner

The schematic shows the recommended upstream piping for a liquid turbine meter (adapted for use from API 5.3).

API 5.3 also provides installation guidance for turbine meters in liquid metering without an upstream flow conditioner. API 5.3 provides an equation that can be used to calculate the minimum straight pipe length required between various disturbances and a turbine meter. Inputs to the equation are nominal meter bore, friction factor, and swirl-velocity ratio. The equation in API 5.3 can be used for the following piping disturbances installed upstream of a turbine meter: concentric reducer, sweeping elbow, two in-plane sweeping elbows, two out-of-plane sweeping elbows, and a valve.

B.3.3 Operating Environment

The allowable operating environment of turbine meters is typically specified by the manufacturer and unique to the specific turbine meter design. For example, different turbine meter designs are available for use subsea, metering cryogenics, or metering transmission quality natural gas.

One common operating consideration, when using turbine meters in liquid or gas metering, is ensuring that a homogeneous single-phase flow is flowing through the turbine meter. Slugs of liquid in gas metering and the presence of gas in liquid metering can cause damage to the turbine meter and cause a measurement discrepancy. Solids in the fluid stream are also a concern when using turbine meters. Solids can damage rotor blades and cause a meter measurement bias.

B.3.4 Calibration Requirements

Gas Turbine Meter Calibration Requirements

AGA Report Number 7 recommends that all gas turbine meters should be flow calibrated, “under conditions acceptable to and agreed upon between the parties to the transaction.” To ensure the best performance of a gas turbine meter, the calibration conditions should be similar

to the actual flowing conditions that the turbine meter will be metering. The two most important parameters to match between a calibration and the actual metering conditions are the Reynolds number and gas density. Figure B.6 shows a graph of Reynolds Number versus rotor speed for a typical gas turbine meter calibration at multiple pressures over a range of Reynolds numbers (Miller 1996). From Figure B.6, it can be seen that operation at low Reynolds numbers showed the greatest variation in the calibration curve at different pressures (or densities). Turbine meters show the best linearity and independence from density effects at higher Reynolds numbers. Ideally, a turbine meter should be sized so it can be used in the most linear range at sufficiently high Reynolds numbers. If a turbine meter is to be used over a range of gas pressures, a calibration can be conducted at multiple pressures to obtain different calibration curves.

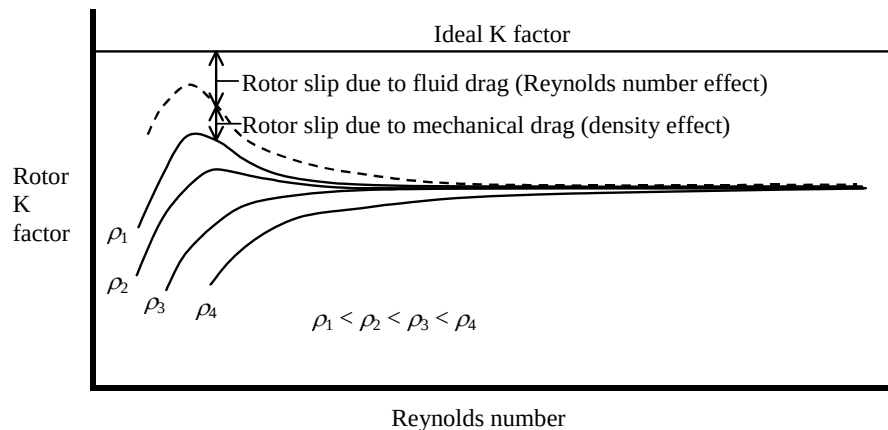


Figure B.6. Gas Turbine Meter Flow Performance at Low Reynolds Numbers

Variations in the calibration curve for the turbine meter can be seen at the lowest Reynolds numbers with changes in pressure and density (adapted from Miller, 1996).

AGA Report Number 7 cites research that was conducted to show that a turbine meter could be calibrated using different gas compositions (natural gas versus nitrogen) (George, 2004) (George et al., 2004). The results showed that calibrating a gas turbine meter using a gas of a different composition than the composition of the gas that would be metered was acceptable. As stated before, the parameter of greater importance for calibration is matching the density and Reynolds number between the calibration and the actual operating conditions.

Liquid Turbine Meter Calibration Requirements

Similar to the recommendations for gas turbine meters, liquid flow meters should be calibrated (proven) at conditions similar to the operating conditions of the flow meter. For liquid turbine meters, the parameters that affect the calibration the greatest are fluid viscosity, density, temperature, and pressure.

Matching the liquid viscosity from the calibration to the actual operating conditions of the flow meter is one of the most important parameters in liquid turbine meter calibration. Similar to the effects of density on gas turbine meters, different calibration curves will be obtained over a range of liquid viscosities. These effects will be most prominent at low flow rates. As explained in Miller, “In general, blade friction increases with viscosity, resulting in a decrease in speed for the same flow rate. The effect of viscosity is, however, difficult to predict, because bearing friction, tip clearance, drag, velocity profile and blade friction are also viscosity-dependent (Miller 1996).” Pressure and temperature are important calibration parameters because the fluid viscosity is a function of pressure and temperature. Figure B.7 shows an

example of calibration curves for a liquid turbine meter exposed to different viscosity fluids. It can be seen that variations in viscosity resulted in different calibration curves. The changes are the most prominent at lower flow rates.

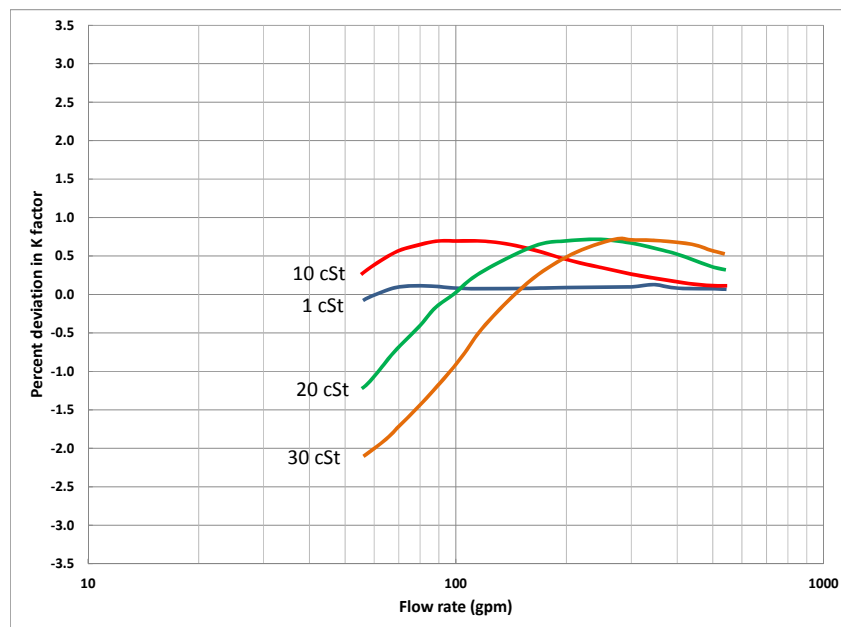


Figure B.7. Liquid Turbine Meter Flow Performance at Different Viscosities

Variations in the calibration curve for the turbine meter can be seen with changes in viscosity (adapted from Miller, 1996).

B.3.5 Applicable Industry Standards

Applicable industry standards for both gas and liquid turbine meters are listed below. Actual citations can be found in the reference section of this report:

- Gas
 - o American Gas Association Report No. 7
 - o ISO 9951:1993
- Liquid
 - o American Petroleum Institute 21.2
 - o American Petroleum Institute 5.3
 - o American Petroleum Institute 12.2.3

B.4 Common Turbine Meter Manufacturers

Meter manufacturers for both liquid and gas turbine meters include: Daniel (Emerson), Elster (Instromet and American Meter), Cameron, FMC, Omega, Blancett, Sensus, Endress and Hauser, and Hoffer. This list is not all-inclusive.

B.5 Performance Characteristics

B.5.1 Typical Accuracy

AGA Report Number 7 cites the following general performance characteristics for natural gas flow meters at atmospheric pressure. Figure B.8 shows a graphical version of the same information:

Repeatability:	$\pm 0.2\%$ from $Q_{\min}$ to $Q_{\max}$
Maximum peak-to-peak error:	$\pm 1.0\%$ above Q_t
Maximum error:	$\pm 1.0\%$ from Q_t to $Q_{\max}$ and $\pm 1.5\%$ from $Q_{\min}$ to Q_t
Transition flow rate:	Q_t not greater than $0.2 Q_{\max}$

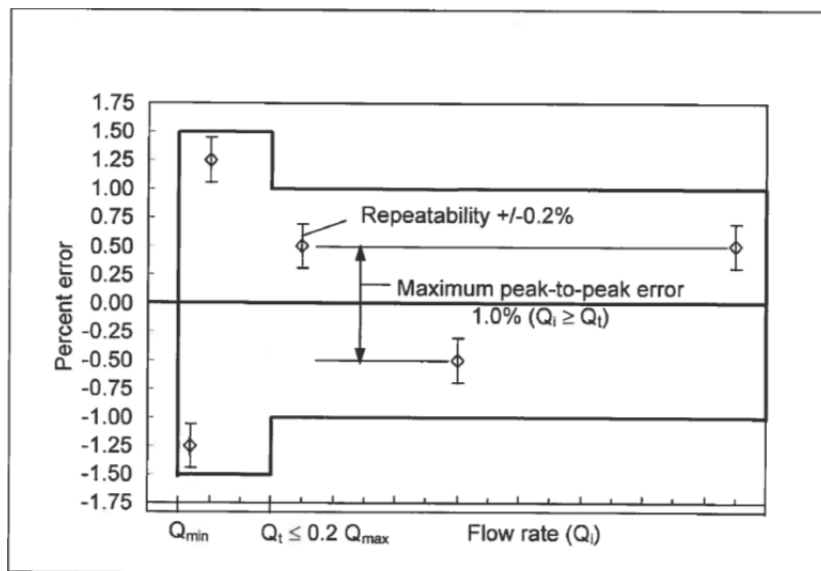


Figure B.8. AGA Report Number 7 Gas Turbine Meter Requirements

The figure shows the accuracy requirements for gas metering at atmospheric pressure.

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AGA Report Number 7 states that the performance of gas turbine meters should be expected to improve with higher pressures. Accuracy is largely dependent on the flow calibration, uncertainties of the flow lab, and how closely the fluid properties from the calibration match the actual operating conditions. If operating conditions are carefully matched and a turbine meter is calibrated at a high-accuracy calibration facility, flow accuracies better than $\pm 0.5\%$ are obtainable for liquid and gas flow meters.

Ultimately, the flow accuracy will depend on multiple variables discussed throughout this document (see subsection B.5.3). The flow meter manufacturer should be consulted for further information on the specific accuracy of the turbine meter application. In general, accuracies better than $\pm 0.5\%$ can be expected for both liquid and gas turbine meters, especially if they are properly flow calibrated prior to use.

B.5.2 Dependence of Accuracy on Flow Conditions

As discussed in previous sections, liquid and gas turbine meters can experience a measurement bias when exposed to asymmetric or swirling velocity profiles. Asymmetric velocity profiles can cause the meter to over register as the fluid velocity will not be evenly distributed throughout the annular passage. Swirling flow can either cause the turbine meter to over register or under register based on the direction of the swirl. If the swirl in the fluid is in the same direction as the rotor rotation, the turbine meter will over register. Conversely, if the swirl is in the direction opposite the rotor rotation, the turbine meter will under register.

Pulsations in the fluid stream can also cause a measurement discrepancy for turbine meters. Pulsations cause velocity spikes in the fluid stream. As the velocity spikes pass through the turbine meter, the rotor will speed up. As the velocity quickly decreases from the pulsation, the rotor speed might not accurately track the reduction in fluid velocity because of the residual energy from the velocity spike. As a result, pulsations can cause an over registration for flow measurement with turbine meters.

B.5.3 Potential Sources of Bias or Inaccuracy

Common sources of bias or inaccuracy for liquid or gas turbine meters are listed below:

- Using a turbine meter with a fluid that has properties that are significantly different from the properties of the fluid used for the calibration.
- Non-homogeneous fluid flow through the meter (gas in liquids, liquid in gas, solids).
- Grime buildup on the meter rotor.
- Damage to the meter rotor due to solids, grime, overspinning, or exceeding the designed differential pressure across the meter.
- Damaged or worn-out rotor bearings.
- An asymmetric or swirling fluid velocity profile entering the flow meter (typically due to improper installation and/or no flow conditioning).
- Pulsations in the fluid flow.

B.6 References

- E. L. Upp and Paul J. LaNasa, *Fluid Flow Measurement: A Practical Guide to Accurate Flow Measurement*, Second Edition, Gulf Professional Publishing Co., 2002.
- R. W. Miller, *Flow Measurement Engineering Handbook*, Third Edition, McGraw-Hill, 1996.
- R. Kalivoda, "Fundamentals of Liquid Turbine Meters," FMC Technical Paper 103B, August 1998.
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- D. L. George, “Metering Research Facility Program: Turbine Meter Research in Support of the Planned AGA Report No. 7 Revision,” Gas Research Institute Report No. GRI-01/0226, January 2003.
- *API Manual of Petroleum Measurement Standards*, Chapter 5 – *Metering*, Section 3 – *Measurement of Liquid Hydrocarbons by Turbine Meters*, 5th Edition, September 2005, with Addendum, American Petroleum Institute, July 2009.
- AGA Report No. 7, *Measurement of Natural Gas by Turbine Meters*, American Gas Association, February 2006.

APPENDIX C

Review of Ultrasonic Metering Technology

C. REVIEW OF ULTRASONIC METERING TECHNOLOGY

C.1 Basics of the Technology

C.1.1 Principles of Operation and Device Geometry

Ultrasonic meters are instruments that provide flow rate data based on measuring the average velocity of the fluid. The meter technology is dependent on ultrasonic signals that are influenced by the flowing stream velocity. Ultrasonic meters are applicable to all pipeline sizes for liquids and gases (Upp & LaNasa, 2002). Permanent pressure loss is less than that for orifice or turbine meters (Kelner). Two main types of ultrasonic meters are the Doppler frequency shift and the transit time change, where the transit time is generally more accurate than Doppler (Upp & LaNasa, 2002).

Transit-time methods measure the time intervals associated with transmission of acoustic signals across the pipe in opposite directions. Transit time can be measured with single or multiple transducers that can be installed directly into the flowing stream (Upp & LaNasa, 2002). Figure C.1 provides a graphical representation of a single-path transit-time method.

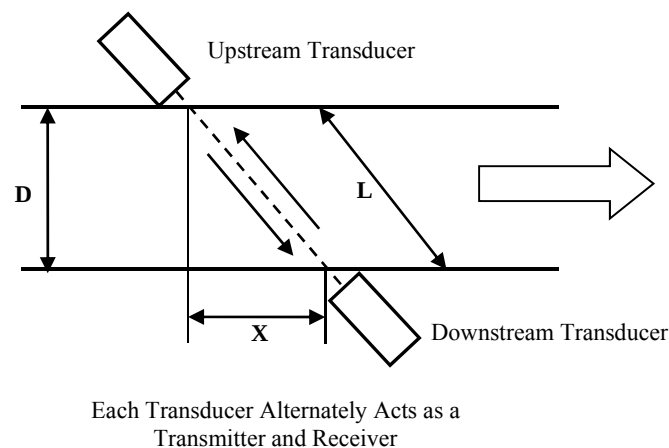


Figure C.1 Ultrasonic Meter with Transit-Time Configuration Showing Angles and Dimensions
This figure is adapted from Fluid Flow Measurement, A Practical Guide to Accurate Flow Measurement (Upp & LaNasa 2002). Transit-time ultrasonic meters rely on measuring the acoustic signal delay time between the transmitting and receiving transducer. The transit-time configuration relies on clean flows for accurate measurements.

Doppler frequency shift is a method used on liquids and gases and transducers for this method can be installed directly in the stream or via a clamp-on model (fixed or portable) that can be utilized without shutting the stream down. In the Doppler configuration, the ultrasonic signal is reflected off particles traveling at the same speed as the main flow. Figure C.2 shows a schematic of the Doppler configuration.

C.1.2 Secondary and Tertiary Devices Required

At a minimum, an ultrasonic meter requires pressure and temperature measurements downstream of the flow to send to the meter computer for processing the flow rate (Kelner). Additionally, some meters require temperature test thermowells and density measurements to accurately represent the actual metering conditions (API 5.8, 2011).

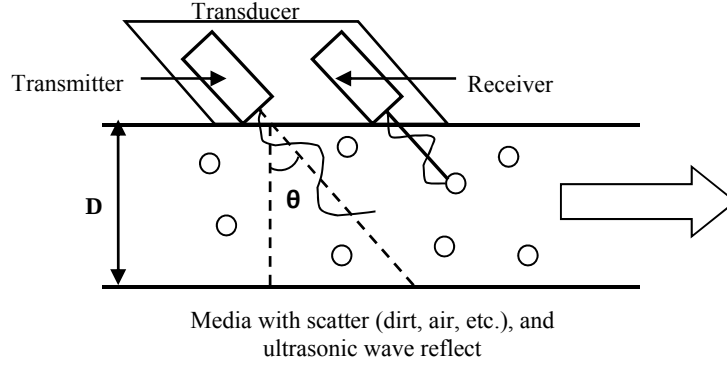


Figure C.2. Ultrasonic Doppler Reflection Meter

This figure is adapted from Fluid Flow Measurement, A Practical Guide to Accurate Flow Measurement (Upp & LaNasa 2002). The Doppler configuration only works with flows that contain particulates that reflect ultrasonic signals. Ultrasonic meters are commonly used on un-refined or “dirty” fluids.

C.1.3 Flow Equations

The governing equations for the transit-time, single-path configuration are the following:

$$t_{ud} = \frac{L}{c + V_m \frac{X}{L}}$$

$$t_{du} = \frac{L}{c - V_m \frac{X}{L}}$$

$$V_m = \frac{L^2}{2X} \left(\frac{t_{du} - t_{ud}}{t_{du} t_{ud}} \right)$$

$$Q = V_m \left(\frac{\pi D^2}{4} \right)$$

where t_{ud} is the transit time from the upstream to downstream transducer, and t_{du} is the transit time from the downstream to upstream transducer. The velocity of sound in the fluid is c , V_m is the mean velocity of the flow, and Q is the volumetric flow rate (Upp & LaNasa, 2002).

In the Doppler configuration, the ultrasonic signal is reflected off particles traveling at the same speed as the main flow. The average flow velocity is measured from the shift in frequency of this ultrasonic signal. The governing equation for the Doppler shift meter is:

$$Q = \left(\frac{\pi D^2}{4} \frac{c}{\sin \theta} \right) \frac{\Delta f_{Hz}}{f_{Hz}}$$

where θ is the beam angle relative to pipe diameter, Δf_{Hz} is the Doppler frequency shift, and f_{Hz} is the transmitters' fixed frequency (Miller, 1996).

C.2 Applications

Typical ultrasonic transit-time flow meters are used at production facilities, transmission pipelines, storage facilities, distribution systems and large end-use customer meter sets (AGA Report No. 9, 2007). The meter depends on having a flow stream with very few particulates for accurate measurements of transit time. Doppler meters are used on pipelines with “dirty” flows that contain entrained particles, such as air bubbles, sediment, or other scattering materials. Doppler meters can also measure fibrous and abrasive slurry flow (Miller, 1996).

C.3 Typical Specifications

C.3.1 Flow Capacity and Rangeability

Gas ultrasonic meters have a maximum velocity limit typically between 70 ft/s and 100 ft/s (AGA Report No. 9, 2007). Although a typical liquid limit is not specified in API 5.8, FMC and Daniel both manufacture meters that can measure liquid velocities between 35 ft/s to 45 ft/s and 40 ft/s to 48 ft/s, respectively (FMC Technologies, 2001) (Daniel, 2001). Liquid and gas meters generally have a rangeability of 10:1 (Upp & LaNasa, 2002).

C.3.2 Flowing Conditions

The temperature limits for flowing gas through an ultrasonic meter should be between -4°F to 140°F, but the manufacturer should be consulted with the designers expected temperature range (AGA Report No. 9, 2007). Other information suggests that the general fluid temperature for gas meters is between -200° and 300°F and -4° to 185°F for liquid (Upp & LaNasa, 2002). The ultrasonic gas meter shall operate, as a minimum requirement, with natural gas mixtures of relative densities between 0.554 kg/m³ (pure methane) and 0.87 kg/m³ (AGA Report No. 9, 2007).

The maximum operating pressure shall be determined by the codes for the jurisdiction in which the meter will be operated and for the specified environmental temperature range (AGA Report No. 9, 2007). AGA Report No. 9 states that the maximum design pressure of the meter should be the lowest of the maximum design operating pressure for the meter body, flanges, transducer connections, and transducer assemblies. Other sources also suggest that the upper pressure limit for gas and liquid meters is ANSI 2500 flange design (Upp & LaNasa, 2002).

Efforts should be made to minimize air, vapor, or water in the stream in a liquid ultrasonic transit-time meter to minimize measurement error, but specific percent limitations cannot be given due to the number of possible variables and the manufacturer should be consulted for the limits (API 5.8, 2011).

C.3.3 Installation Requirements

Ultrasonic meters attain maximum accuracy when the flow is axially symmetric and steady. To achieve these conditions, meters are typically installed with straight pipe lengths upstream and downstream of the meter, along with flow conditioners. Liquid meters are typically installed with straight pipe lengths of 10 nominal diameters with a flow conditioning element upstream of the meter and straight pipe lengths of 5 nominal diameters downstream of the meter (API 5.8, 2011).

Gas ultrasonic meters in a uni-directional configuration should be installed with straight pipe lengths of 20 nominal diameters upstream of the meter. A flow conditioner located at 10 nominal diameters upstream is also recommended, along with straight pipe lengths of 2 to 5 nominal diameters downstream of the meter. Gas ultrasonic meters in a bi-directional configuration should be installed with straight pipe lengths of 20 nominal diameters on either side of the meter. Flow conditioners should be installed on each side of the meter at a distance of 10 nominal diameters (AGA Report No. 9, 2007).

The meter is also installed so that transducers are not located on the top or bottom of the pipe to minimize the effects of air or sediment affecting the transducer bores (API 5.8, 2011).

C.3.4 Operating Environment

AGA Report No. 9 states that the manufacturer should be consulted for the ambient air temperature specification, but suggests that ultrasonic meters should operate between -40°F to 140° F and sun shield should be considered to protect electronics.

C.3.5 Calibration Requirements

The meter is calibrated using static and flow conditions. Static calibration includes a mechanical inspection to determine the path length of the ultrasonic signals, characterize transducer delay times, and determine a zero flow offset with the meter flanged at both ends. Flowing calibrations are performed with the meter in the recommended installation. The most accurate calibration should be run against volume standards or master meters as covered in AGA Report No. 9 and API Ch. 5.8.

C.3.6 Applicable Industry Standards

The meter body, pressure-containing structures, and external electronic components shall be designed and constructed of materials suitable for the service conditions for which the meter is rated (AGA Report No. 9, 2007).

Meters are available in sizes from 4 inches to 40 inches and have ANSI flange classes from #300 to over #1500 (Kelner). The meter should also be marked with the following information affixed to the body with a plate that will not deteriorate:

- Manufacturer, model and serial numbers, month and year manufactured
- Nominal meter size, ANSI flange class, and total weight
- Internal diameter
- Maximum and minimum storage temperatures
- Body design code and material, flange material
- Maximum and minimum operating pressure and temperature
- Direction of primary or forward flow

AGA Report No. 9 states that gas ultrasonic meters have pre-calibrated, or “out of the box,” performance requirements for actual flow rate (q_i) related to the manufacturer’s stated minimum flow rate (q_{min}), maximum flow rate (q_{max}), and the flow rate at which the meter error limit and allowable peak-to-peak error limit changes (q_t , $q_t \leq 0.1 q_{max}$). Table C.1 summarizes these pre-calibrated standards. Smaller meters generally have their accuracy figures slightly relaxed because of the difficulty in measuring acoustic transit times in turbulent gas flow due to shorter path length.

Table C.1. AGA Report No. 9 Pre-Calibrated Meter Performance Requirements

Repeatability	$\pm 0.2\% q_t \leq q_i \leq q_{\max}$
	$\pm 0.4\% q_{\min} \leq q_i < q_t$
Resolution	0.003 ft/s (0.001 m/s)
Velocity Sampling Interval	≤ 1 second
Zero-Flow Reading	< 0.020 ft/s (6 mm/s) for each acoustic path
Speed-of-Sound Deviation	$\pm 0.2\%$
Maximum SOS Path Spread	1.5 ft/s (0.5 m/s)

	Large Meter (12-inch diameter or larger)	Small Meter (less than 12- inch diameter)
Max Error $q_t \leq q_i \leq q_{\max}$	$\pm 0.7\%$	$\pm 1.0\%$
Max Error $q_{\min} \leq q_i < q_t$	$\pm 1.4\%$	$\pm 1.4\%$
Max Peak-To-Peak Error $q_t \leq q_i \leq q_{\max}$	0.7%	1.0%
Max Peak-To-Peak Error $q_{\min} \leq q_i < q_t$	1.4%	1.4%

API 5.8 does not list pre-calibrated performance requirements, however both FMC and Daniel manufacture meters that state a $\pm 0.15\%$ pre-calibrated accuracy over their flow range (FMC Technologies, 2001) (Daniel, 2001).

C.4 Common Ultrasonic Meter Manufacturers

Ultrasonic meter manufacturers include, but are not limited to, Elster-Instromet, Emerson Daniel, FMC, Sick Maihak, Controlotron, KROHNE, Herman, Caldon, and GE.

C.5 Performance Characteristics

Ultrasonic meters are regarded as some of the most accurate meters in the industry when installed in the proper configuration, and if they are maintained in accordance with the manufacturer's specifications.

C.5.1 Typical Accuracy

Gas accuracy without flow calibration is $\pm 0.5\%$ to $\pm 1\%$, but accuracies of $\pm 0.1\%$ to $\pm 0.2\%$ are achievable with proper meter setup and calibration (flow conditioners, development length, ultrasonic transmitter locations) (Kelner).

Table C.2 and Table C.3 are recreated for this summary from Reference 1 and should be used as general categories and performances of Ultrasonic flow meters. The data are a decade old and most manufacturers claim better performance than listed here. However, the author indicates the tables are more typical of actual field conditions for properly installed and maintained meters (Upp & LaNasa, 2002).

Table C.2. Typical Ultrasonic Gas Meter Characteristics

Ultrasonic Meter Type	Accuracy of Sensor (%)		Rangeability (Range for stated accuracy)	Reynolds Number (Minimum)	API Upstream Piping (X-Diam)	Pressure Limit (psig)	Temp. Limit (F)
	Proved (+/-)	Unproved (+/-)					
Doppler	2.00	5.00	10:1	3,000	10	ANSI 2500	-300 to 200
Transit Time	0.50	1.00	10:1	5,000	10	ANSI 2500	-300 to 200

Table C.3. Typical Ultrasonic Liquid Meter Characteristics

Ultrasonic Meter Type	Accuracy of Sensor (%)		Rangeability (Range for stated accuracy)	Reynolds Number (Minimum)	API Upstream Piping (X-Diam)	Pressure Limit (psig)	Temp. Limit (F)
	Proved (+/-)	Unproved (+/-)					
Doppler	2.00	5.00	10:1	-	10	ANSI 2500	-4 to 185
Transit Time	0.50	1.00	10:1	-	10	ANSI 2500	-4 to 185

C.5.2 Dependence of Accuracy on Flow Conditions

Modern ultrasonic meters utilize multi-path transducers so that the meter can accurately compensate for fluid swirl, thus requiring less development length prior to entering the meter. However, it is still recommended to have flow conditioners prior to any ultrasonic flow meter (Kelner). Single-path designs are more sensitive to irregularities in the flow pattern and generally provide less accuracy without flow conditioning. Doppler flow meter accuracy depends on particle concentration, distribution, and relative velocity between the particles and the fluid and will not work on “clean” liquid flows (Miller, 1996).

Flow pulsation can also affect meter accuracy. Tests by the research facility NOVA Metcon indicate errors of 4% to 7% could result from pulsations (Kelner).

C.5.3 Potential Sources of Bias or Inaccuracy

Ultrasonic meters are affected by fouling because changing the cross-sectional flow area has the largest influence on measurement uncertainty. A 0.1% change in the flow area leads to a 0.2% measurement error (Upp & LaNasa, 2002).

Fouling on ultrasonic bore walls and transducer surfaces can also cause error through:

- Signal attenuation
- Decreased path lengths
- Changes in flow profile and possibly swirl angle
- Changes in signal strength

Cleaning must be performed on the meter transducers and flow areas for dirty fluids to reduce these sources of error.

Ultrasonic meters are also affected by acoustic interference from certain types of control valves, vibrations associated with high-velocity flow through the pipeline, or from other sources if the frequency range is coincident with the meter's operating frequency. Modern flow meters are usually equipped with enhanced signal processing for ultrasonic pulse recognition and detection (AGA Report No. 9, 2007).

C.6 Recent Research on Performance of Ultrasonic Meters

Companies research ways to achieve accurate measurement within low flow conditions so that a single meter can be used rather than two meters in a series (Upp & LaNasa, 2002). Researchers also study the effects of line pressure variations, pulsations, and acoustic noise on ultrasonic meters (Miller, 1996). If the noise has a known frequency, the manufacturer can sometimes compensate for it, but noise with varying amplitudes and frequencies pose a problem.

Manufacturers are utilizing multipath measurements to account for flow profile, swirl, and turbulence, and also multiple measuring chords enable the flowmeter to adjust its measurement to account for dirt and grime build-up on the inside of the meter (Yoder, 2001). However, fully understanding the effects of contaminants and flow disturbances is still being studied.

Custody transfer is driving technology developments for ultrasonic meters because end-users are looking for higher accuracy and greater reliability as the value and volume of the measured fluid increases. Providing higher capability diagnostics is also another source of technology development to allow the end-user to identify sources of acoustic noise or other general health issues associated with the meter (Yoder, 2011).

C.7 References

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APPENDIX D

Review of Coriolis Metering Technology

D. REVIEW OF CORIOLIS METERING TECHNOLOGY

This section provides a review of Coriolis flow meter technology for metering single-phase gas and liquid fluids. An overview of the technology is given initially, followed by examples of applications. Section D.3 discusses specifications for proper usage of equipment, while Section D.4 provides a list of current major manufacturers. The section closes by discussing performance characteristics and briefly reviewing recent research on Coriolis meters.

D.1 Basics of the Technology

The summary of Coriolis metering technology begins with the principles of operation. Secondary and tertiary devices are then outlined. Finally, flow equations used for Coriolis operations are presented.

D.1.1 Principles of Operation and Device Geometry

Coriolis meters are named after the operating principle on which the technology is based, i.e., the Coriolis force. When a fluid particle inside the rotating body moves in a direction toward or away from a center of rotation, the particle generates an inertial force on the body. Flow meter manufacturers take advantage of this physical phenomenon by intentionally setting up tube(s) that vibrate to create a rotating motion. The Coriolis force acts to cause twisting of the tubes, and the resulting deflection of the tubes is directly proportional to the mass flow rate. In addition to providing a measurement of mass flow rate q_m , independent measurement of density ρ may also be made through monitoring oscillation frequency of the vibrating tube. From density and mass flow measurements, the volumetric flow rate may be inferred through calculation, i.e. $q_v = \frac{q_m}{\rho}$.

The Coriolis meter physically consists of a sensor and transmitter. Figure D.1 shows a schematic of a typical sensor design. The sensor is considered the “primary device,” and generally has one or two tubes through which the process fluid flows. An electromagnetic driving mechanism vibrates the tubes at their natural or harmonic frequencies. Tubes come in a variety of geometries. The most common are straight tubes, “U” shaped, “Ω” shaped, oval, and helix. Each design has its own distinct advantages, and the following considerations should be taken into account when choosing a specific type [API 5.6]:

- Pressure drop across meter
- Minimum/maximum flow rates
- Susceptibility to erosion, flashing, and cavitation
- Susceptibility to coating and clogging
- Achievable accuracy

Bent tube meters have historically had better accuracy than straight due to less rigidity that allows for higher sensitivity. However, straight tubes minimize pressure drop through the meters. Later designs tended to use two tubes to allow measurement of the relative movement between the tubes, thus decreasing sensitivity to vibration from the surrounding piping. Recent

designs have even implemented four tubes in a sensor to allow relative movement compensation in two dimensions [Nuber, 2011].

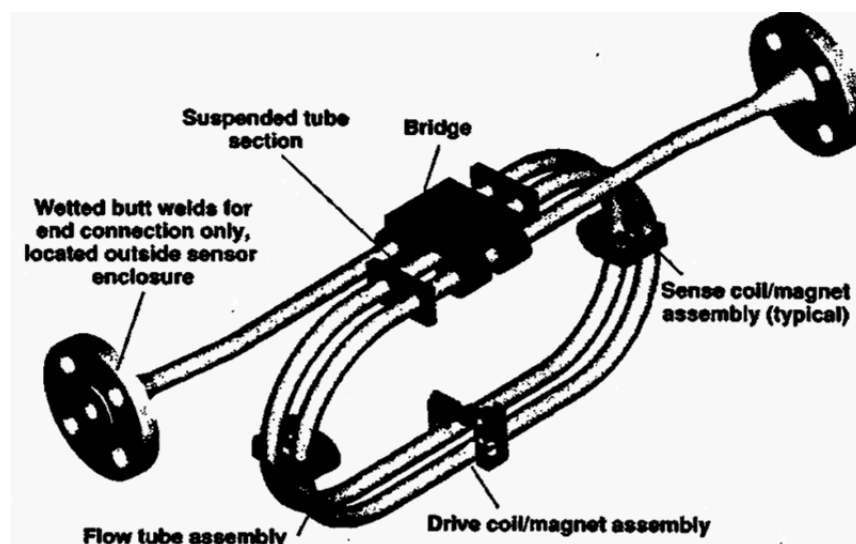


Figure D.1. Components of Coriolis Meter [Babb, 1992]
Example of oval tube design displaying general components of a Coriolis meter.

D.1.2 Secondary and Tertiary Devices Required

The secondary device of a Coriolis meter is the transmitter [SGA, 2005]. The transmitter is an electronics system that includes a power supply, microcomputer, processing circuits for the drive signals, signal barriers for safe installation, and output circuits [AGA-11]. Its function is to control the driver, receive and interpret signals from the sensor, and provide process variable outputs. Analog output protocols can include 4-20 mA, frequency, RS-485, while various digital protocols are also available such as HART, MODBUS, FieldBus, etc. The transmitter may be used “as-is,” or in conjunction with tertiary devices, such as a flow computer, Programmable Logic Controller (PLC), or Distributed Control System (DCS).

It is worth noting that, unlike turbine meters, Coriolis sensors do not generate a raw pulse output representing mass or volume. The transmitter performs calculations to output a pulse each time a user-configured mass or volume of fluid passes through the meter. The pulse scaling factor is entered into the transmitter to adjust the pulse to a specified volume frequency.

D.1.3 Flow Equations

The Coriolis force was named after its discoverer, French mathematician Gustave-Gaspard de Coriolis. Attempts to adapt the concept for flow metering purposes during the ‘50s incorporated strain gages, but these did not perform well. Coriolis meters first became practical during the ‘70s, when nanosecond time delays could be easily measured [SGA, 2005].

The concept of the Coriolis force can be illustrated using the schematic in Figure D.2. This shows a control volume of fluid with a certain mass δ_m flowing through a tube with a velocity v . The tube body itself is rotating about point P with an angular momentum ω . This results in two components of acceleration – radial and transverse. Radial acceleration a_r , also known as centripetal acceleration, may be computed as $a_r = \omega^2 r$ directed towards point P. Transverse acceleration, i.e., Coriolis, is perpendicular to a_r and may be computed as $a_t = 2\omega v$.

To achieve the Coriolis acceleration, the oscillating tube directs a force in the direction of acceleration. The reaction to this force back on the tube is the Coriolis force, which can be computed as $F_c = 2\omega v\delta_m$.

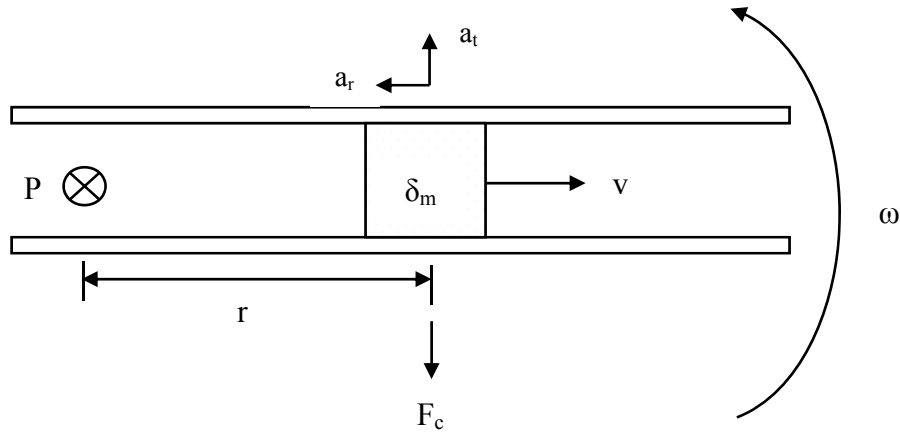


Figure D.2. Illustration of Coriolis Force

Rotation of tube is about point "P," resulting in Coriolis force F_c on indicated control volume of fluid.

To use the principle outlined previously for metering technology, the Coriolis force must be written in terms of meter-measurable variables and related to mass flow rate. Twist angle of the tube is the means of forming this connection. In a Coriolis meter, the force of the fluid on the far section of pipe is equal to and opposite the force of the fluid on the near section of pipe because the velocity vector changes direction (see Figure D.3). This results in a torque being applied to the tube, which causes a twisting motion. If ρ , ω , and the meter's cross-sectional area are held constant, the twist angle (amplitude of deflection) is proportional to the mass flow rate of the fluid flowing through the meter.

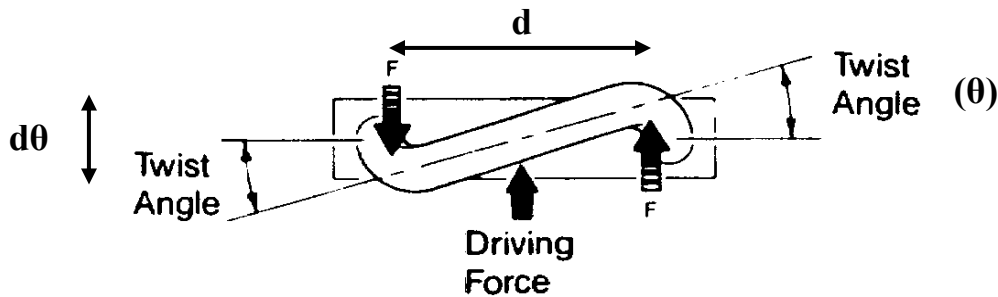


Figure D.3. Illustration of Tube Twist from Coriolis Force [Miller, 1996]

Twist angle (amplitude of deflection) is proportional to the mass flow rate.

Figure reprinted from *Flow Measurement Engineering Handbook, Third Edition*, by Richard W. Miller. © The McGraw-Hill Companies. All rights reserved. Reprinted with permission.

The torque on the tube is the product of the distance between applied forces, and the force, i.e., $T = dF_c = 2d\omega v\delta_m$. Mass is given by $\delta_m = \rho AL$ so that $T = dF_c = 2d\omega v\rho AL$. Note in the former equations, A is the cross-sectional area of the tube and L is the axial length of one leg. Since mass flow rate may be expressed as $q_m = \rho Av$, then $T = dF_c = 2d\omega Lq_m$. Torque can also be written as the product of the tube stiffness/spring constant and the twist angle, $T = K_s\theta$. Thus, $q_m = \frac{K_s\theta}{2Ld\omega}$.

As shown in Figure D.3, when the tube is in torsion the distance between the two sides is $d\theta$. This distance is equal to the velocity of the tube multiplied by the time to cover the distance, $v\tau = L\omega\tau = d\theta$; thus, $\tau = \frac{d\theta}{L\omega}$, where τ is the transit time. Note the transit time increases as the twist angle increases. Substituting into the mass flow rate equation gives $q_m = \frac{K_s\tau}{2d^2}$, which indicates that the mass flow is proportional to the time delay. The transit time (usually in microseconds) is measured and a K-factor that incorporates the other terms (provided by the manufacturer) is multiplied by this to give q_m in field operations.

Recall that it was stated that independent density measurements can be made with Coriolis meters, in addition to mass flow rate. This is done through modeling the meter as a mass-spring system to obtain density. Natural frequency depends on mass (i.e., density), according to the equation $\omega_{natural} = \sqrt{\frac{k}{m}}$, where k is the spring constant. The manufacturer calibrates the meter at multiple densities (different fluids), then interpolates to determine intermediate densities. The accuracy of the density measurement depends on how well the interpolation reflects reality.

To conclude the section, Coriolis meters have varying benefits, depending on the application. Advantages to using a Coriolis meter include the fact that mass flow rate is being directly measured, density measurement may also be made independently of mass flow, viscosity can be calculated from pressure drop and flow rate, only a transmitter is required as a secondary element, and most Coriolis meters are set up for bi-directional flow capability. Disadvantages in general include sensitivity to vibration/pulsation, vibration induction through high velocity in tubes, high pressure drop, and overall bulkiness compared with some other meter types.

D.2 Applications

Coriolis meters may be used to meter a variety of flows. Typical applications include processes requiring measurement of mass flow rate, including: clean liquids, dirty liquids, slurries, and gas [SGA, 2005]. The meters are common for use in custody transfer for liquid hydrocarbons [API 5.6] and natural gas [AGA-11]. Coriolis meters can be found throughout the energy industry in onshore, offshore, and subsea processes.

D.3 Typical Specifications

Coriolis meter specifications, including: flow capacity and rangeability, flow conditions, installation requirements, operating environment, calibration requirements, and applicable industry standards are now discussed.

D.3.1 Flow Capacity and Rangeability

Flow capacity of Coriolis meters is primarily limited by pressure drop and cavitation concerns (for liquid meters) at the upper end, and accuracy concerns at the lower end of the flow rate range. Excessive stream velocity and pressure drop in the flow sensor lead to cavitation, which results in inaccurate measurement and potential damage to the sensor. A guideline for avoiding cavitation is to maintain the pressure at the outlet of the meter above the following backpressure requirement [API 5.6]: $P_b = 2\Delta P + 1.25P_e$, where ΔP is the pressure drop through the flow meter at the maximum operating flow rate (psi), and P_e is the equilibrium vapor pressure of liquid at the operating temperature (psia).

Pressure drop may be calculated according to $\Delta P = \frac{K \rho_f v^2}{2C}$, where K is the pressure loss coefficient specified by the manufacturer, ρ_f is the flowing density, v is the flow velocity, and C is a dimensional conversion constant [SGA, 2005]. Since pressure drop increases with the square root of velocity, a larger diameter meter tends to significantly lower pressure drop. When the pressure drop is deemed too high to handle flow and a larger meter cannot be used, consideration should be given to installing a bank of Coriolis meters in parallel.

In general, manufacturers provide guidelines on acceptable upper flow capacity limits to prevent cavitation for each specific meter type. If greater capacity is needed, a larger meter should be chosen. While line sizes have been limited to about six inches in the past, various vendors are now offering meters with up to 14-inch diameter connections [Yoder, 2011]. Rangeability is limited by acceptable accuracy tolerances at the lower end of the flow spectrum.

D.3.2 Flowing Conditions

Coriolis meters can be built to withstand a range of extreme flow conditions. For example, Micro Motion offers meters rated for pressures up to 6,000 psi and temperatures from -400°F to +400°F [Micro Motion, 2011a]. Fluids must have viscosities sufficiently low to be considered “flowable” for accurate measurement. Hydraulic pulsations can also lead to poor performance, and should be avoided. Furthermore, shock loading from rapid opening/closing valves can cause damage to the sensor.

D.3.3 Installation Requirements

Manufacturer-specific instructions for proper installation of a Coriolis meter should be consulted as part of any facility design/modification. AGA-11 [2008] and API 5.6 [2008] provide general guidelines for best practices though. Highlights from these standards are now reviewed.

Different manufacturers have various requirements regarding orientation of the sensor in the piping. However, in general, meters should be oriented in a position that allows tubes to be completely filled with fluid under both static and flowing conditions. Thus, meters should be positioned to gravity drain for gas processes and fill for liquid processes. Note that a drain should be installed to allow for purging of any settled solids.

Valve(s) should be installed to block in the flow to zero or re-zero the meter. It is preferred that a valve be installed on both the upstream and downstream sides of the meter. Zero offset can be adversely affected by axial bending and/or torsional stresses, hence the need for zero flow during this procedure. Piping should be anchored to avoid any stress transference to the sensor. It is recommended that a spool piece with equal length and connections be used for alignment of piping prior to installation of the sensor itself.

A pressure transmitter should be installed near the flow sensor. In applications where high turndowns are required and a high pressure drop across the meter may exist, it is recommended that the pressure tap be located upstream of the sensor where the line pressure will tend to vary less [AGA-11]. This pressure is used for meter factor computations, and can be used in density calculations for converting to volumetric flow rate. Pressure measurements may also be used to compensate for pressure effects on meter performance. Thermowells should also be installed near the Coriolis sensor to provide a temperature measurement that is representative

of the fluid temperature internal to the sensor. Generally, the thermowell is installed downstream of the meter [API 5.6]. Strainers or other filtering equipment should be located upstream of the Coriolis meter to prevent entry of foreign objects, which cause measurement error and can damage the sensor. Note, though, that strainers can cause additional pressure loss for the facility.

Sensors should not be installed near sources of flow pulsation or vibration, which can interfere with measurement accuracy. Pulsation dampeners may be required in situations where piping redesign is not practical. Note that when several Coriolis sensors are installed in close proximity, either in series or parallel, there is a risk that the vibrations generated from the meters can interfere with each other to cause degraded performance. This is termed “crosstalk”. Ways to mitigate this include: altering piping, installation of vibration dampeners, or using different drive frequencies for meters in close proximity (manufacturer alteration).

The sensor, transmitter, and connecting cables are susceptible to electromagnetic and radio frequency interference. Thus, any interference from nearby electrical equipment and wiring should be removed either by relocating or shielding [API 5.6]. Sources such as variable frequency motors, transformers, radio transmitters, and high-voltage cables should be avoided.

D.3.4 Operating Environment

Temperature and humidity extremes can lead to equipment malfunction. Weather-proofing, fungus-proofing, and/or corrosion mitigation should be considered where appropriate [API 5.6]. Weather-proofing for extreme ambient temperatures can include: painting the meter white, providing shade to reduce solar radiation in direct sunlight, and insulating the meter [AGA-11].

D.3.5 Calibration Requirements

The flow sensor manufacturer should provide a calibration certificate and test results upon purchase. It should be verified whether no change in the manufacturer calibration factors occurred since the last calibration. This ensures no unexplained meter factor shift can occur.

Meters should be calibrated against recognized or international measurement standard(s) over a flow range representative of the process rates, and sufficient to establish meter accuracy and linearity. According to Micro Motion representatives, there is no recommended interval for calibration. Each facility/user decides this based on regulatory/contractual requirements, and from the performance history of the meter. However, guidelines from API 5.6 [2008] recommend proving the meter if any of the following events occur:

- After any re-zeroing of the meter
- After any sensor installation or mounting changes
- After density calibration if the Coriolis meter is configured to indicate volumetric flow
- After any repair/replacement of components
- After changes in the fluid temperature, pressure, or density beyond user-defined limits determined through field experience
- If a flow rate change occurs that results in a shift of the meter factor beyond the tolerance limits determined through field experience
- At the request of parties involved in a custody transfer

- Based on a schedule that measures throughput, elapsed time, or per contract
- Anytime the accuracy of the meter is in question
- When changing the direction of flow if a meter factor has not been determined for the new direction

Calibration methods include direct mass proving (gravimetric weigh tank or mass master meter) and inferred mass proving (calculation based on volumetric proving and reference density). Factory calibration for mass flow rate is generally performed using a weigh tank as the reference. Note that replacement of circuit boards or the transmitter may affect the Coriolis meter's calibration. Thus, the sensor should always be calibrated with the transmitter that will be used in field operation.

Meter proving can be performed either in the field or at a laboratory/manufacturer facility. The advantage of field proving is that the meter factor is determined under actual operating conditions, which can influence the meter's accuracy and repeatability. According to API 5.6 [2008], "Metering systems should be provided with either manual or automatic means to permit proving the meter under conditions of flow rate, pressure, temperature, and fluid characteristics that exist during the normal operation of the meter." It is generally recommended that the sensor be located upstream of the proving connection. Another benefit to *in situ* proving is that it can be very difficult to remove the meter from the process line to send it for calibration.

When proving a meter in place is not practical, or it is desirable to have a common setup among a group of meters located in different facilities, the meter can be removed and sent for calibration off site. Laboratory/manufacturer calibrations are performed under ideal conditions on a stable fluid, which has the advantage of minimizing outside influences on meter accuracy. However, it also requires zeroing the meter twice: prior to performing the bench calibration and after it is reinstalled in the process line.

For natural gas metering, the AGA-11 standard states that a minimum of three tests are to be performed (in each direction for bidirectional meters) moving upward and downward within the flow range to demonstrate potential hysteresis and repeatability effects. Furthermore, if any calibration factors are adjusted, it is recommended that at least one verification point be run. Factors that can affect Coriolis meter readings are shown in Figure D.4.

Adjustment from indicated to actual quantity can be made by varying the meter factor or K-factor. The meter factor is defined as a scalar factor that may be applied to the meter's output(s) value(s) to change the output(s) value(s) by a constant percentage at all flow rates, compensating for systematic error. The K-factor represents the pulses per unit quantity (volume or mass). This coefficient is entered into the accessory equipment by a user, which relates a frequency (mass or volume) input from the Coriolis transmitter to a flow rate. The preferred method for adjustment is to vary the meter factor in the accessory equipment for audit trail purposes [API 5.6]. When this is done, the K-factor in the tertiary equipment will match the pulse scaling factor in the Coriolis transmitter (see Figure D.4). If the K-factor itself is adjusted, the meter factor must be set to one in the transmitter and tertiary equipment, while the pulse scaling factor (pulses per unit quantity) in the transmitter reverts back to what it was during the calibration. Only the K-factor in the tertiary equipment is changed. More information on each specific factor can be found in API 5.6 [2008].

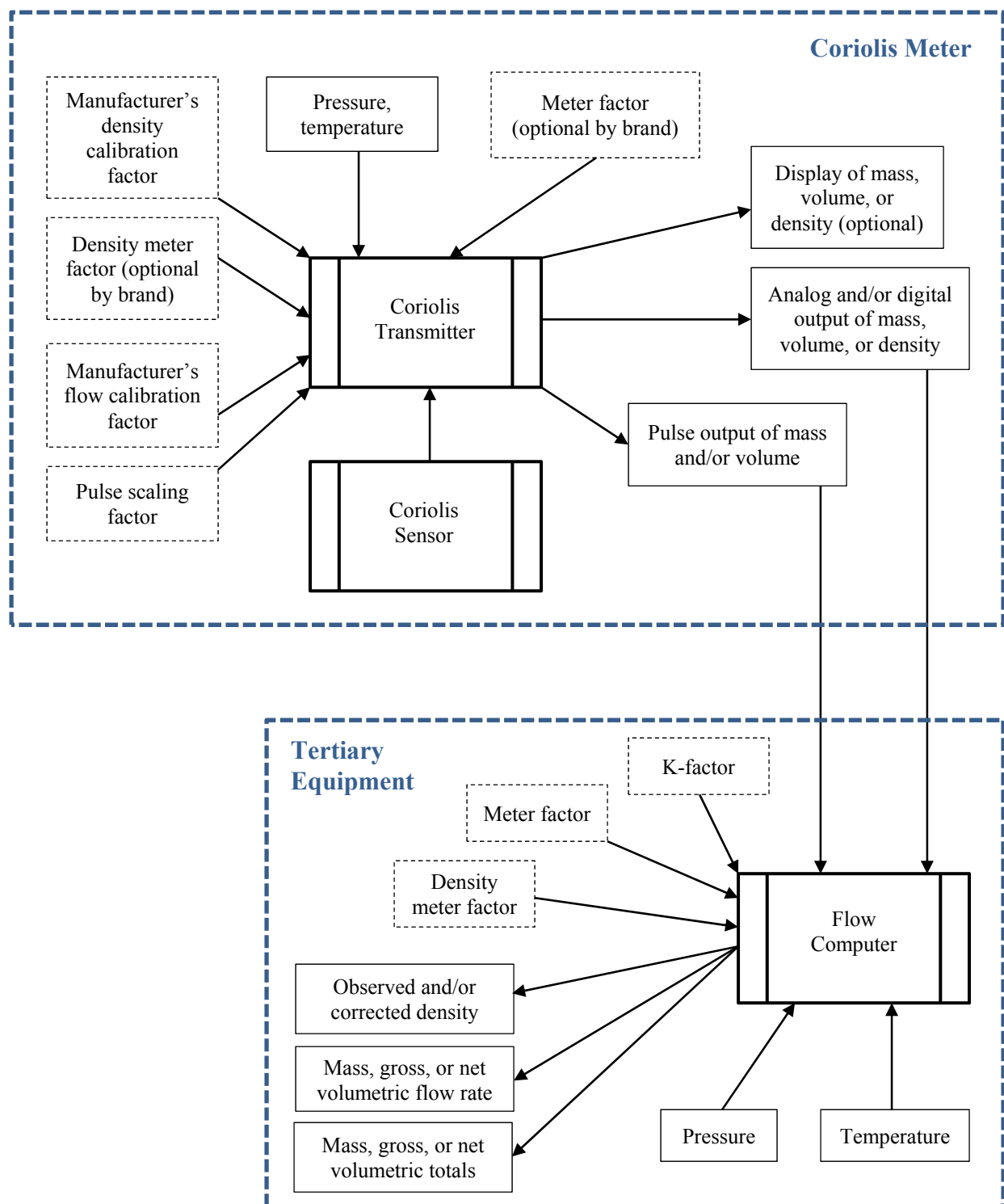


Figure D.4. Factors Affecting Coriolis Meter Outputs [adapted from API 5.6, 2008]
Dashed lines about text boxes indicate configurable input variables, while solid lines denote signal output.

After a calibration/proving, users should confirm the correct scaling factors have been entered into the transmitter. The Coriolis meter should then be re-zeroed before being returned to operation [API 5.6]. The zero value is determined by the Coriolis transmitter during the zeroing procedure. Although each manufacturer may have its own procedure, typical steps for zeroing a Coriolis meter include:

- Open bypass valve, if available.
- Stop flow through the sensor by closing the downstream block valve.
- Close upstream valve, if available.
- Initiate zeroing procedure in the transmitter.

Verification of the stored zero should be performed periodically. Changes to fluid properties or installation can cause a shift. Re-zeroing should be performed if the zero value is outside the specified zero offset limits.

D.3.6 Applicable Industry Standards

Standards for installation, use, and calibration of Coriolis meters include the following:

- American Gas Association Report No. 11, *Measurement of Natural Gas by Coriolis Meter* [AGA-11] (also known as API MPMS 14.9).
- ISO 10790, *Measurement of Fluid Flow in Closed Conduits - Coriolis Mass Flowmeters* [ISO, 1999].
- ASME MFC 11-M, *Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters* [ASME, 2006].
- API MPMS Chapter 5.6, *Measurement of Liquid Hydrocarbons by Coriolis Meters* [API 5.6].

Note that the American Gas Association is set to release a new edition of AGA-11 in the coming year. Currently the March 2011 ballot copy is in circulation among members.

D.4 Common Coriolis Meter Manufacturers

Although there are numerous vendors that offer Coriolis metering technology, some of the major manufacturers include Siemens, Yokogawa, FMC, Rheonik, Endress+Hauser, Micro Motion, and KROHNE. Among these, Rheonik, Endress+Hauser, Micro Motion, and KROHNE [Yoder, 2011] offer sensors with line sizes above six inches, e.g., 8-inch 10-inch, 12-inch, and 14-inch.

D.5 Performance Characteristics

This section deals with the performance of Coriolis meters. The method of determining accuracy, as well as typical accuracies are first given. Dependence of accuracy on flow conditions is next discussed. Finally, sources of bias and inaccuracy are emphasized for reader awareness.

D.5.1 Typical Accuracy

Accuracy of a Coriolis meter is a function of the mass flow rate through the sensor. Generally, manufacturers provide an accuracy curve that displays accuracy from 100% of flow capacity down to a small percentage of this flow rate. Uncertainty is minimized near full flow capacity, and increases as the flow rate approaches zero. Typical accuracy under good operating conditions is about $\pm 0.5\%$ to $\pm 1.0\%$ [SGA, 2005]. Note that for Coriolis meters arranged to operate in parallel, the combined uncertainty may be less than that of individual meter runs. Annex J of ISO 5168 [2005] should be consulted for more information on this topic.

For natural gas applications, the following minimum performance requirements, as supplied directly from the manufacturer and prior to any calibration factor adjustments, are to be upheld per AGA-11:

$$\text{Repeatability: } \begin{array}{l} \pm 0.35\% \text{ of reading for } Q_t \leq Q_i \leq Q_{max} \\ \pm 0.1\% \text{ of reading for } Q_{min} \leq Q_i \leq Q_t \end{array}$$

$$\text{Maximum Mean Error: } \begin{array}{l} \pm 0.7\% \text{ of reading for } Q_t \leq Q_i \leq Q_{max} \\ \pm 1.4\% \text{ of reading for } Q_{min} \leq Q_i \leq Q_t \end{array}$$

$$\text{Maximum Peak – to – Peak Error: } \begin{array}{l} 0.7\% \text{ of reading for } Q_t \leq Q_i \leq Q_{max} \\ 1.4\% \text{ of reading for } Q_{min} \leq Q_i \leq Q_t \end{array}$$

Furthermore, for meters calibrated using fluids other than natural gas, additional natural gas calibration results using meters of the same design/type and size must be provided by manufacturers.

D.5.2 Dependence of Accuracy on Flow Conditions

Sensitivity to changes in operating pressure, i.e., “flow pressure effect,” can create a negative bias in measured flow rate at operating pressures above the calibration pressure, and vice versa. The magnitude of error associated with this is manufacturer dependent. Typically, the flow pressure effect increases with meter size, with performance diminishing with increasing wall thickness and diameter [API 5.6]. The pressure effect can be compensated for using an average flowing pressure correction or variable pressure correction with an external pressure measurement device. The flow pressure effect compensation factor F_p is applied to the indicated mass flow from the transmitter $q_{m,transmitter}$ to compute the adjusted mass flow rate, i.e., $q_{m,compensated} = q_{m,transmitter} * F_p$ [AGA-11]. The compensation factor may be computed from the calibration static pressure P_{cal} (psig), the flowing fluid static pressure P_f (psig), and the flow pressure effect P_{effect} (% rate/psig) according to the relation: $F_p = \frac{1}{1 + ((P_{effect}/100) * (P_f - P_{cal}))}$.

Hydraulic pulsation near the operating frequency or one of its harmonics can also affect accuracy. Pulsation can be caused by piping design, flow obstructions, rapid regulator valve oscillation, and reciprocating equipment. Research indicates that some bending-mode Coriolis sensors are mostly immune to error from flow pulsation frequencies away from the natural resonant frequency of the tubes [AGA-11]. However, it is recommended that such pulsations be avoided.

Meter manufacturers should be consulted regarding any specific required upstream/downstream piping configurations for flow conditioning. However, non-uniform velocity profile/swirl has been shown in various studies to have little or no effect on Coriolis

meter performance [AGA-11]. Two-phase flow (gas/liquid) can adversely affect meter performance, and metering facilities should consider installing a purge point to prevent accuracy degradation in case of trapped gas/liquid pockets.

D.5.3 Potential Sources of Bias or Inaccuracy

Coriolis meter accuracy can be affected by any condition that interferes with the driven frequency vibration, changes the flexibility of the oscillating tube, and/or changes the stored zero value. Interference with the drive frequency may result from external vibrations from other equipment or hydraulic flow pulsation. To minimize measurement errors, dampeners or equipment relocation should be considered. Changes to the tube properties that may occur with time include coating and erosion. Coatings or deposits in the tube(s) of the sensor can cause a shift in flow calibration – especially if the coating/deposit has a density much different from the process fluid. Erosion/corrosion of the flow sensor affects the tube wall thickness, which in turn changes the stiffness and may even lead to tube failure. This is especially a concern when operating with liquid/solid slurries. Finally, error associated with a shift from the stored zero of a meter acts as a constant offset in flow rate. This results in a percent error that increases as the mass flow rate decreases. The error associated with the zero can be computed as $E_{zero} = \frac{q_o}{q_f} \times 100$, where q_o is the observed zero value and q_f is the flow rate during normal operation [API 5.6]. As stated previously, shifts in the zero occur mainly as a result of stress changes on the tube(s). This can come from extreme changes in temperature, pressure, and/or density. It may also be due to poor installation/anchoring of the meter. Re-zeroing the meter will minimize associated error.

D.6 Recent Research on Performance of Coriolis Meters

Coriolis meter research and development efforts have increased in recent years as the technology makes inroads into various aspects of the energy industry. According to the recent short course conducted through the Southern Gas Association, the following topics continue to be of interest to the research community [SGA, 2005]:

- Density determination methods
- Viscosity determination methods
- Sensitivity to pulsation/vibration
- Installation effects (some proprietary data exists)

Manufacturers are constantly seeking to competitively improve their designs and offer additional features. For example, Endress+Hauser recently introduced their new four-tube design that minimizes external vibration effects by compensating in two dimensions [Nuber, 2011]. They also released a new 14-inch high-capacity version of their Proline Promass Coriolis meter in May 2011 [Yoder, 2011]. This year, Micro Motion released an up to 10-inch stainless-steel model of their ELITE series geared toward corrosive oil/gas applications [Micro Motion, 2011b].

One of the newest areas of research is employing Coriolis meters for measurement of multiphase flows. Coriolis meters are currently being used as part of three-phase (oil/water/gas) meter designs [Agar datasheet; Volz et al., 2006; Resnick, 2004]. There is also interest in

attempting to use them solely with empirical correlations for analyzing water cut in oil/water flows or even GVF in liquid-gas flows [Dutton, 2000; Henry et al., 2006].

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APPENDIX E

Review of Differential Pressure Metering Technology

E. REVIEW OF DIFFERENTIAL PRESSURE METERING TECHNOLOGY

E.1 General Principles of Differential Pressure Metering

E.1.1 Basic Principles and Flow Equations

Differential pressure (DP) meters are inferential meters – that is, they use the pressure differential across an obstruction as input to an equation for flow rate. Orifice meters, discussed in Appendix A, are standardized DP meter designs in common use, but several other DP meter designs are also used by the oil and gas industry. The size and shape of the obstruction, the location of the pressure taps, and other features vary between designs, but all use the same general principles discussed in this section.

All differential pressure meters use the Bernoulli equation to relate the pressure, elevation, and velocity between any two points in the flow field. The Bernoulli equation is derived by applying the laws of conservation of mass and conservation of energy to two planes perpendicular to the flow through the meter, as shown in Figure E.1 (Fox and McDonald, 1992). For the Bernoulli equation to be accurate, certain assumptions about the flow must be valid:

- The flow is steady in time.
- There is no heat transfer to or from the flow.
- The fluid does no work (for instance, it does not turn a rotor, expand a diaphragm, or perform work by shearing within the flow).
- The flow and the fluid properties are uniform across each plane where measurements are taken.
- The flow is incompressible (density is constant).

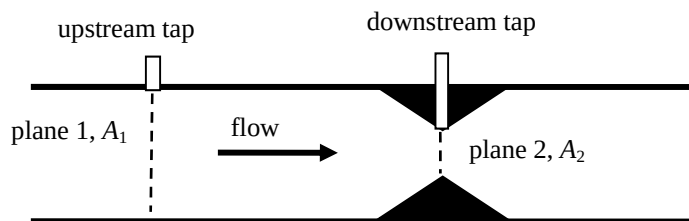


Figure E.1. Example of the Bernoulli Equation Applied to a Differential Pressure Meter

Under these assumptions, the Bernoulli equation can be written as:

$$\frac{p_1}{\rho} + \frac{V_1^2}{2} + gz_1 = \frac{p_2}{\rho} + \frac{V_2^2}{2} + gz_2 = \text{constant}$$

where:

- p_n = pressure in the flow at plane n ($n = 1, 2$)
- ρ = fluid density
- V_n = velocity of the flow across plane n ($n = 1, 2$)
- g = constant of gravitational acceleration
- z_n = elevation of plane n ($n = 1, 2$)

Each term in the Bernoulli equation represents a different form of energy. The Bernoulli equation states that the energy in the flow can shift between these forms, but the total energy must remain constant.

$$\text{flow energy} + \text{kinetic energy} + \text{potential energy} = \text{constant}$$

To compute a mass flow rate, another assumption is made:

- The measurement planes are at the same elevation, or $z_1 = z_2$.

By the conservation of mass, the mass flow rate $\dot{m}$ is the same through each measurement plane.

$$\dot{m} = \rho V_1 A_1 = \rho V_2 A_2 = \text{constant}$$

Combining this with the Bernoulli equation and solving for $\dot{m}$ gives a theoretical mass flow rate (Fox and McDonald, 1992).

$$\dot{m}_{\text{theoretical}} = \frac{A_2}{\sqrt{1 - (A_2/A_1)^2}} \sqrt{2\rho(p_1 - p_2)}$$

This equation provides an ideal flow rate through the meter based on the assumptions listed above.

The ideal flow rate is higher than the actual flow rate, due to frictional effects, non-uniform velocity profiles, and other non-ideal conditions. Several empirical factors are typically used to adjust the theoretical equation so that it reflects the actual flow rate. These factors are often obtained from calibration of the DP meters and geometric considerations. Three of these factors are listed below.

- The thermal expansion factor, F_{therm} , is typically used when the operating temperature differs significantly (more than 50°F) from the ambient temperature. For normal atmospheric operating temperatures, F_{therm} is taken as 1 (SwRI, 2005).
- The discharge coefficient, C_d , corrects for frictional losses, flow separation from the walls, and other differences from the ideal flow assumptions in the Bernoulli equation. It is obtained by meter calibration, and is defined as the actual flow rate divided by the theoretical flow rate. Typical discharge coefficients range from about 0.6 for orifice meters to over 0.9 for Venturi meters.
- The expansion factor, Y_1 , is the ratio of the discharge coefficient for a compressible flow to the discharge coefficient for an incompressible flow under the same flow conditions. For liquids, Y_1 is 1 by definition; for gases, Y_1 is typically determined by calibration.

In practice, the mass flow rate is then given by

$$\dot{m}_{\text{actual}} = \frac{C_d Y_1 F_{\text{therm}} A_2}{\sqrt{1 - (A_2/A_1)^2}} \sqrt{2\rho(p_1 - p_2)}$$

E.1.2 Permanent Pressure Loss

All components subject to flowing conditions cause a permanent pressure loss. This loss depends on the flow velocity and a loss coefficient, K .

$$\Delta P_{\text{perm}} = \frac{K\rho V^2}{2}$$

Different DP meters can cause different relative pressure losses, as shown in the example of Figure E.2.

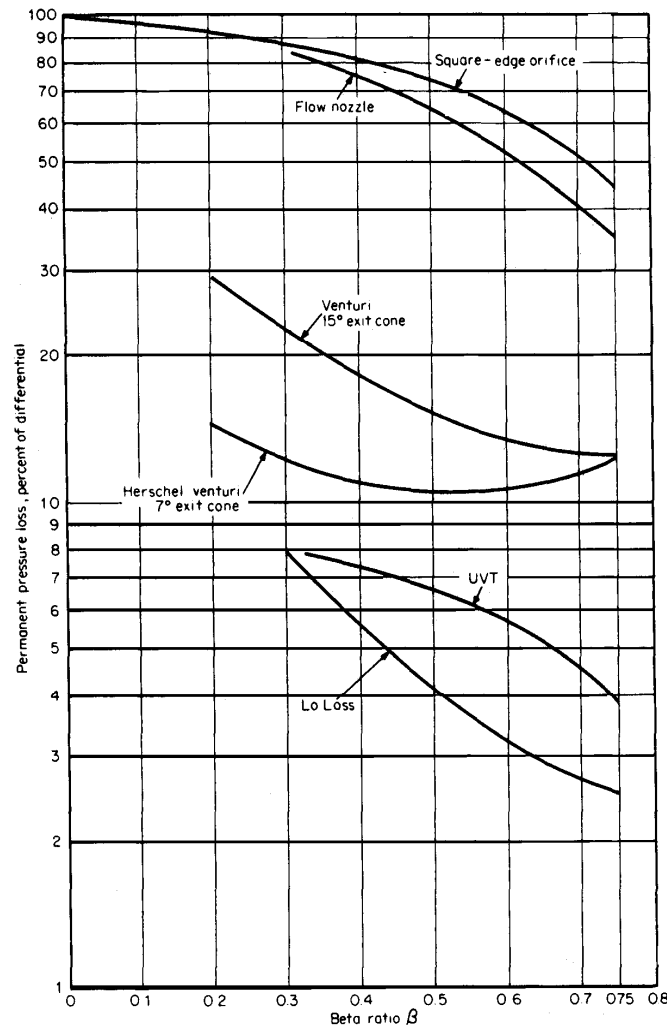


Figure E.2. Examples of Permanent Pressure Loss Curves for Differential Pressure Meters (Miller, 1996)

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E.1.3 Secondary and Tertiary Devices Required

As with orifice meters, DP meters consist of a primary element to restrict the flow and create a pressure drop, secondary elements to measure flowing properties, and a tertiary device to compute flow rate from the measured values (Miller, 1996; Upp and LaNasa, 2002; SwRI, 2005). DP meters require the same secondary devices as orifice meters:

- Differential pressure measurement
- Static line pressure measurement
- Temperature measurement
- Measurement of gas composition

E.1.4 Applicable Industry Standards

For DP meters not specifically addressed by other standards, API MPMS Chapter 22.2, “Testing Protocol for Differential Pressure Flow Measurement Devices,” can be used as a guide (API, 2005; SwRI, 2005). The document defines the testing and reporting protocols for DP flow measurement devices. It covers any flow meter operating on the principle of a local change in flow velocity, caused by the meter geometry, giving a corresponding change of pressure between two reference locations. It does not apply to multiphase flows or non-Newtonian fluid flows, and does not consider pulsation effects. The protocol discusses facility requirements, uncertainty calculations, and data reporting requirements.

Its purposes are to:

- Ensure that the user of a DP flow meter knows the performance characteristics of the meter over a defined range Reynolds numbers.
- Facilitate the understanding and introduction of new technologies.
- Provide a standardized vehicle for validating manufacturer’s performance specifications.
- Quantify the uncertainty of DP flow meters and define the conditions over which stated uncertainties apply.

The test protocol requires baseline tests under fully-developed, ideal flowing conditions, and non-standard tests to evaluate the meter in flow profiles with significant swirl, asymmetry, and other non-ideal conditions. API 22.2 can be used to test meters in liquid flows, gas flows, or both.

E.2 Cone Meters

E.2.1 Device Geometry and General Features

Cone meters, also known as “reverse Venturi” meters, were introduced in the early 1980s (Miller, 1996; SwRI, 2005). In this meter design, the flow restriction is axisymmetric and in the center of the meter body, rather than around the outside (Figure E.3). The basic approach measures the pressure difference between an upstream tap and a tap on the rear face of the cone. One design uses a third tap at the downstream pipe wall to provide additional data for diagnostics (DP Diagnostics, 2011). The flow through the meter passes through the annulus around the cone, rather than through a central bore, and the gradual restriction of the flow area allows the cone to redistribute non-ideal flow profiles for consistent measurements. Because of this geometry, cone meters use a different definition of the beta ratio to correlate the discharge coefficient and other flow parameters.

$$\beta_{\text{cone}} = \sqrt{1 - \frac{d^2}{D^2}}$$

where

- β_{cone} = cone meter beta ratio
- d = outer diameter of the cone
- D = inner diameter of the meter

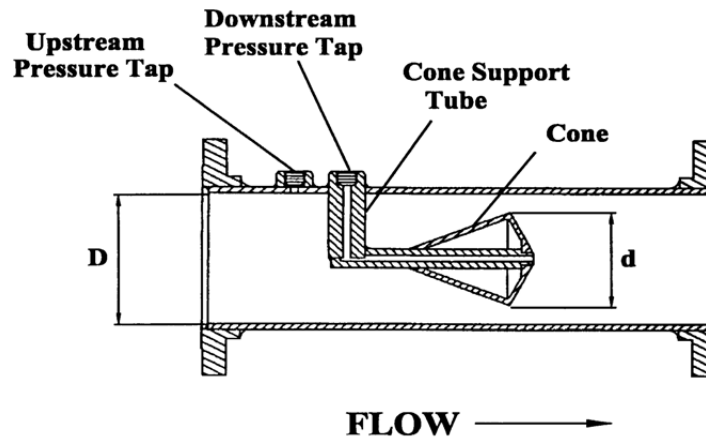


Figure E.3. Cross Section of a Cone Meter (McCrometer, 1997)

All cone meters measure the differential pressure between the upstream wall and the rear of the cone. Specific dimensions and data analysis methods may vary between manufacturers.

E.2.2 Applications

The cone meter can be used to measure liquid and gas flows, both clean and dirty, as well as slurries and steam flows (SwRI, 2005; Miller, 1996). Specific applications include upstream measurements of oil, gas, and produced water at the wellhead and separator; natural gas allocation metering; measurements of coal-bed methane at low pressures; midstream applications; and custody transfer of gas and LNG (Cameron, 2008). The cone meter has an advantage over orifice meters in less-than-ideal flows, in that the solids or liquids can pass along the bottom of the meter without permanently disturbing the flow or becoming “dammed up” by a blunt body at the meter wall.

E.2.3 Typical Specifications

Cone meters are commonly available in line sizes from 1 inch to 48 inches (Cameron, 2008; DP Diagnostics, 2011); some cone meters have been manufactured for meter runs up to 72 inches in diameter (Miller, 1996). Cone meters are available with beta ratios from 0.45 to 0.80 (McCrometer, June 2011). Since the meter geometry is fixed, users must size the meter β ratio for different expected flow rates. The permanent pressure drop through a cone meter is lower than that of an orifice meter.

Flow capacity and rangeability. Manufacturers generally state a turndown ratio (the ratio of maximum to minimum flow velocity) of 10:1 for cone meters, though Miller (1996) reports that ratios of 15:1 are possible. The extended low flow limit is made possible by the reshaping of the velocity profile by the cone. By comparison, the turndown ratio for a single orifice plate is typically 3:1 or 4:1, although if a meter run uses a series of orifice plates ranging from $\beta = 0.2$ to 0.75, the meter’s turndown ratio can extend up to 10:1 or more.

Flowing conditions. Miller (1996) reports that cone meters can measure flows at pressures up to 600 psig. The temperature of the flow is often limited by the working range of the temperature transmitter, typically -22°F to 250°F, though with special temperature devices, operation in flows up to 700°F is possible. Liquid flows with Reynolds numbers as low as 100 can be measured by cone meters using discharge coefficient curve fits to the Reynolds number; a

typical minimum value with a standard calibration is $Re_{min} = 8,000$ (Miller, 1996; McCrometer, June 2011).

Installation requirements. Manufacturers state that cone meters are less prone to installation effects, due to the meter's ability to redistribute the velocity profile. Typical installation specifications include a straight upstream pipe length of zero to three pipe diameters (3D) ahead of the cone meter, depending on the nearest upstream disturbance, and 1D of straight pipe downstream of the meter (McCrometer, June 2011; DP Diagnostics, 2011).

For a horizontal meter installation, differential pressure taps should be located at the top of the meter so that contaminants are not ingested by the pressure lines. Pressure taps may be installed at any radial position around a vertical meter run. The DP transmitter should be located as close to the taps as possible for faster response and minimal attenuation in the pressure lines, and the same diameter tubing should be used on both sides of the primary element (Miller, 1996).

Calibration requirements and applicable industry standards. Cone meters must be calibrated under flowing conditions to obtain values of the discharge coefficient, C_d , and the expansion factor, Y . API Chapter 22.2, "Testing Protocol – Differential Pressure Flow Measurement Devices," provides a standard method for calibrating cone meters, reporting on their performance, and quantifying measurement uncertainties (API, 2005). The protocol defines the limits on flowing conditions for meters to be tested, the requirements of the facilities performing the tests, the fluids to be used in tests, and the ranges for pressure, differential pressure, temperature, and Reynolds number. The reporting procedures under API 22.2 are intended to ensure that the performance of meters tested under the protocol can be compared on an equal basis. It was created for use with meters whose calibrations are not already addressed by another standard, such as API 14.3 (for orifice meters) or ISO 5167-4 (for Venturi meters).

The test protocol includes a matrix of mandatory meter tests, with various upstream piping installations producing both well-conditioned and worst-case flow profiles. These tests were originally used to verify the required upstream and downstream pipe lengths now recommended for cone meters. Procedures are also given for applying calibration data from one size of meter to larger or smaller meters that are geometrically similar.

E.2.4 Cone Meter Manufacturers

McCrometer markets a cone meter trademarked as the V-Cone® (McCrometer, 2011); other available brands include the NuFlo™ Cone Meter (Cameron, 2008) and the DP Diagnostics Cone Meter (DP Diagnostics, 2011). These all follow the same general configuration, but designs can vary in the location of pressure taps, support structures, and other details.

E.2.5 Performance Characteristics

Typical accuracy. Current cone meter manufacturers list an accuracy of $\pm 0.5\%$ and a repeatability of $\pm 0.1\%$ over their normal operating range (Miller, 1996; Cameron, 2008; McCrometer, June 2011; DP Diagnostics, 2011). These values only apply to cone meters that have been calibrated before use. Cone meters used without prior calibration can have accuracies as wide as $\pm 1.5\%$ to $\pm 5\%$ of their full-scale flow rate (Miller, 1996).

Potential sources of bias or inaccuracy. For differential pressure meters such as cone meters, the condition of the pipe wall, mating of pipe sections, pressure-tap design, incorrect

lengths of straight pipe upstream and downstream of the meter, and properties of the lead lines to the differential pressure transmitter can all affect measurement accuracy. Some of these may have a minor effect, while others can introduce biases as large as 10% (Miller, 1996). The accuracy of cone meters can also be affected by the tap location; for contaminated or two-phase flows, cone meters should be installed with the taps at the top to avoid ingesting liquids or contaminants into the pressure lead lines.

One manufacturer (DP Diagnostics, 2011) has developed diagnostics for its cone meter from pressure measurements at three tap locations, including the two typical locations and a third downstream wall tap. According to the manufacturer, the diagnostics can detect two-phase flows, debris or contamination in the meter body, blocked impulse lines, a damaged primary element, and similar causes of measurement bias.

At flowing conditions, meter dimensions will increase or decrease in size with changes in pressure and temperature. While the effect due to pressure is usually neglected, typical formulas for thermal expansion may be used to correct for changes in dimensions from the temperature at which the nominal meter dimensions were determined (Miller, 1996). If not accounted for, these dimensional changes may lead to small inaccuracies in flow measurement.

E.2.6 Research on Performance of Cone Meters

Possible research topics proposed for cone meters include lab studies of their performance in unsteady or pulsating gas flows, testing of upstream piping installation effects, and tests of tap location effects.

E.3 Venturi Meters

E.3.1 Device Geometry and General Features

Venturi meters, sometimes called Herschel Venturi tubes, are most commonly found in Europe, but may be found in the United States in liquid measurement applications (SwRI, 2005; Upp and LaNasa, 2002). Classical Venturi meters incorporate a convergent inlet section, a cylindrical throat, and a gradually divergent exit section (Figure E.4). This design minimizes the permanent pressure drop across the meter and also allows contaminant solids or droplets to pass through the Venturi more easily than through other types of DP meters.

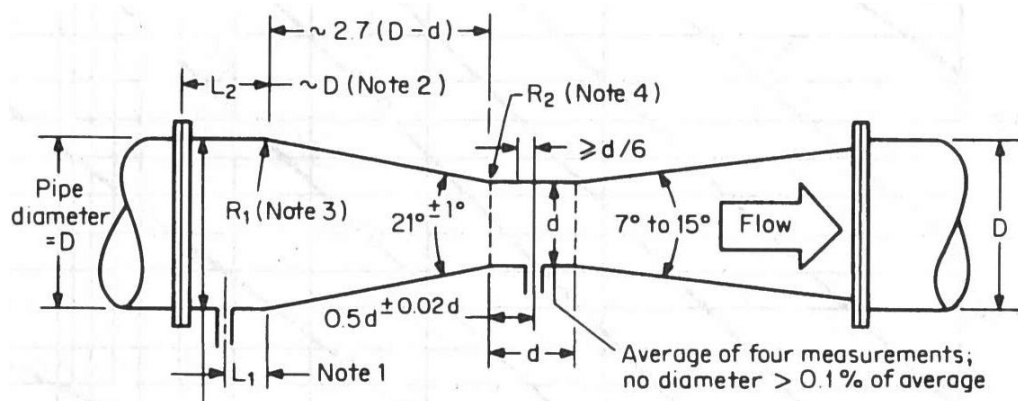


Figure E.4. Dimensions of a Standard Venturi Meter (Miller, 1996)

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In a Venturi meter, the pressure difference is measured between the upstream convergent section and the throat. Venturi meters must be calibrated before use to compensate for manufacturing variations, but geometric similarity can sometimes be used to limit the number of meter sizes for which calibrations are needed. Calibration of the Venturi meter can increase the initial expense of installation, but its low permanent pressure drop can reduce operating costs and achieve an overall net savings.

Standards such as ISO 5167-1:2003, ISO 5167-4:2004, and ASME MFC-3M (American Society of Mechanical Engineers, 2004) specify Venturi meter geometries and tolerances on their dimensions. Since the geometry of a Venturi meter gradually contracts and expands, flows experience fewer losses and less flow separation through Venturi meters than through other DP meters. As a result, the actual flow conditions in a Venturi meter are closer to theoretical flow conditions. The flow equations for Venturi meters are the same as for orifice meters and other DP meters, except for the value of the discharge coefficient. Typical discharge coefficients for Venturi meters range from 0.94 to 0.99, whereas for an orifice meter, C_d is close to 0.6 (SwRI, 2005). Unlike other DP meters, C_d for a Venturi meter is typically constant over a wide range of Reynolds numbers (ISO 5167-4:2003). The permanent pressure loss through a Venturi meter is between 5% and 20%, smaller than through an orifice meter (ISO 5167-4:2003).

E.3.2 Applications

Like cone meters, Venturi meters can be used to measure clean or dirty liquid flows, clean or dirty gas flows, vapor flows, and slurries (SwRI, 2005). The gradual changes in Venturi geometry help to sweep dirt, solids, and entrained phases past the flow restriction, and allow Venturi meters to handle dirty flows without a loss of accuracy.

E.3.3 Typical Specifications

Standards typically limit Venturi meters to a range of line sizes from 2 inches to 48 inches, although meters for 120-inch-diameter pipes have been fabricated (Miller, 1996; ISO 5167-4:2003). Smaller Venturi meters (4 inches to 32 inches in diameter) are typically cast in a sand mold, with the smallest meters having machined inlets to eliminate the effects of surface roughness. Larger Venturi meters (8 inches in diameter up to 48 inches) are welded from sheet iron. Entrance sections have an angle of $21^\circ \pm 1^\circ$; exit cones with angles between 7° and 15° are permitted, though angles of 7° to 8° are preferred. The upstream pressure taps are located upstream of the plane where the cylindrical upstream entrance meets the upstream convergent section; the distance from this plane is one-half the diameter of the cylindrical upstream section. The throat pressure taps are located exactly halfway along the length of the throat between the inlet convergence and outlet divergence.

Flow capacity and rangeability. Venturi meters typically have a turndown ratio of 3:1 or 4:1 (SwRI, 2005; Upp and LaNasa, 2002). One disadvantage of Venturi meters is that, unlike orifice meters, Venturis do not have an adjustable flow range. However, the turndown ratio can be increased by “stacking” differential pressure transmitters. In this procedure, two transmitters with different measurement ranges are connected across the same pair of pressure taps. The transmitter with the lower maximum DP is used at lower flow rates, and the transmitter with the higher maximum DP is used once the differential pressure across the taps is above its lower threshold for accurate measurement.

Flowing conditions. Upp and LaNasa (2002) report that the pressure and temperature limits on Venturi meters are typically set by the material limits of the meter itself; for example, the pressure rating of the Venturi walls and flanges will define the maximum flowing pressure of the meter. The temperature of the flow is often limited by the measurable range of the temperature transmitter, typically -22°F to 248°F (Miller, 1996). Venturis can measure flows with Reynolds numbers as low as 7,500, but are typically used for gas or liquid flows at Reynolds numbers of 100,000 or higher (Upp and LaNasa, 2002).

Installation requirements. Installation requirements for piping depend upon the upstream fittings (elbows, valves, etc.). Table E.1 lists standard straight pipe installation requirements for various disturbances upstream of Venturi meters (ISO 5167-4:2003). The minimum length of straight piping upstream of a Venturi meter can range from 5 to 30 nominal pipe diameters, but this is generally shorter than the upstream length for an orifice meter with the same beta ratio (Upp and LaNasa, 2002). Venturi meters are susceptible to installation effects, particularly swirl (SwRI, 2005; Upp and LaNasa, 2002). ISO 5167-1:2003 gives compliance tests for flow conditioners that may be used upstream of a Venturi meter. These include tests in good flow conditions, flow downstream of a partly-closed gate valve, and tests downstream of a swirl generator. Flow conditioners that pass the compliance tests may be installed using the findings of the tests to guide upstream pipe lengths.

Table E.1. Examples of Required Straight Lengths of Pipe Between Flow Disturbances and Venturi Meters (ISO 5167-4:2003)

Pipe lengths are given in multiples of the pipe diameter, D. Upstream and downstream lengths of pipe less than those listed will increase the inaccuracy of the Venturi meter. Pipe lengths can be interpolated for intermediate beta ratios.

Upstream disturbance	Venturi beta ratio					
	0.3	0.4	0.5	0.6	0.7	0.75
Single elbow	8D	8D	9D	10D	14D	16D
Two elbows in same plane (“S”) or different planes	8D	8D	10D	10D	18D	22D
Full bore ball or gate valve fully open	2.5D	2.5D	3.5D	4.5D	5.5D	5.5D
Downstream length for all disturbances	4D	4D	4D	4D	4D	4D

For liquid flows in a horizontal meter installation, differential pressure taps should be located at the sides of the meter, no more than $\pm 45^\circ$ from the horizontal, while for horizontal gas meters, it is normally recommended that the taps should be at the top of the meter. Pressure taps may be installed at any radial position around a vertical meter run. The DP transmitter should be located as close to the taps as possible for faster response and minimal attenuation in the pressure lines, and the same diameter tubing should be used on both sides of the primary element (Miller, 1996).

Calibration requirements. ISO 5167-1:2003, ISO 5167-4:2003, and Upp and LaNasa (2002) recommend calibration of a Venturi meter against reference standards, since Venturi meters tend to be more difficult to manufacture precisely than an orifice meter. ISO 5167-4 lists discharge coefficients with uncertainties that can be used in the field if the meter is not calibrated beforehand; an uncalibrated Venturi meter may have accuracy in gas or liquid flows no better than $\pm 1.5\%$. However, a Venturi that has been properly calibrated, installed and maintained may carry an uncertainty in either fluid as low as $\pm 0.5\%$ over its entire flow range.

Applicable industry standards. As noted earlier, the manufacture, installation and use of Venturi meters is guided by ISO 5167, parts 1 and 4. ASME standard MFC-3M is also cited for guidance on Venturi meters, though MFC-3M is based largely on ISO 5167-4.

E.3.4 Common Venturi Meter Manufacturers

Venturi meters are difficult to manufacture, and Venturis for large flow rates are big and heavy, making them difficult to remove for maintenance (SwRI, 2005; Upp and LaNasa, 2002). Current Venturi meter manufacturers include Amity Industries, ABB, and Solartron ISA.

E.3.5 Performance Characteristics

Typical accuracy. Miller (1996) reports a typical accuracy of $\pm 1\%$ to $\pm 2\%$ for Venturi meters when used “out of the box,” that is, before calibration. Upp and LaNasa (2002) note that a Venturi that has been properly calibrated, installed, and maintained may carry an uncertainty in either fluid as low as $\pm 0.5\%$ over its entire flow range.

Potential sources of bias or inaccuracy. A Venturi will perform correctly over time, provided that the surface of the inlet and throat are not changed by corrosion, erosion, or deposits. The inlet cone finish is often specified during the design phase, and if the Venturi is designed to be removed for inspection, the surface finish should be checked and cleaned to avoid bias in the discharge coefficient. Other than cleaning the Venturi, most maintenance to avoid bias involves work with the secondary instruments.

At flowing conditions, meter dimensions will increase or decrease in size with changes in pressure and temperature. While the effect due to pressure is usually neglected, typical formulas for thermal expansion may be used to correct for changes in dimensions from the temperature at which the nominal meter dimensions were determined (Miller, 1996; ISO 5167-1:2003). If not accounted for, these dimensional changes may lead to small inaccuracies in flow measurement.

ISO 5167-1:2003 gives requirements for several characteristics of the piping upstream and downstream of the primary device. The intent is to produce swirl-free, fully-developed flow immediately upstream of the primary device.

- Straightness and circularity of the pipe.
- Roughness and condition of the internal pipe walls.
- Location and number of measurements of average pipe diameter.
- Maximum allowed “step height” where upstream sections of pipe are mated (at flanges, for example). Pockets or obstructions in the upstream or downstream pipe will affect the velocity profile entering the meter, leading to bias. Hence, these disturbances should be far enough upstream of the primary element to ensure that the flow profile has recovered before entering the meter.
- Gaskets or weld beads extending into the pipe will increase turbulence and alter the flow profile, and should be trimmed or ground smooth.

Miller (1996) reports on several quantities that can influence Venturi meter accuracy. Increased roughness of the upstream pipe or conical inlet will cause the meter to measure a higher flow rate than actually exists, as high as 4%, while increased roughness of the downstream conical exit section will cause a negative bias. Oil coatings on the surface of the

Venturi have been shown to cause the meter to read high, but cleaning the internal surfaces can restore the performance of the meter. A particularly significant error can be caused by burrs in the openings of the pressure taps; errors as large as $\pm 30\%$ (in either direction) have been noted.

E.3.6 Research on Performance of Venturi Meters

Possible research topics proposed for Venturi meters include studies of their performance in pulsating flows, testing of upstream piping installation effects, and the potential usefulness of a Venturi meter with an adjustable throat for extended range (SwRI, 2005).

E.4 Wedge Meters

E.4.1 Device Geometry and General Features

Like other DP meters, a wedge flow meter also creates a restriction in the flow and a corresponding pressure drop, but as the name indicates, a sloped wedge shape across the meter tube serves as the flow restriction (Miller, 1996). This geometry forces the streamlines of the flow to the outside pipe wall, causing the entering velocity profile to have a different effect on the DP and discharge coefficient than it would for DP meters with a concentric geometry (Figure E.5). Permanent pressure losses of wedge meters are low compared to other DP meters, particularly orifice meters. Because the wedge is symmetric about its apex, wedge meters can be installed in bi-directional meter stations with proper calibration.

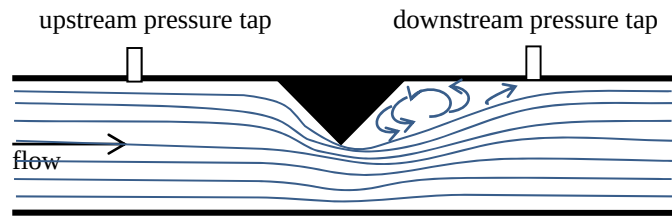


Figure E.5. Flow Profile Within a Wedge Flow Meter (Adapted from Miller, 1996)

Pressure taps are placed one diameter upstream and downstream of the apex of the wedge, on the side of the meter body where the wedge is mounted. The differential pressure across the wedge is a function of the meter body diameter, D , and the height of the wedge segment above the bottom of the meter tube, H . The equivalent beta ratio for a wedge meter is defined below (Miller, 1996).

$$\beta_{\text{wedge}} = \sqrt{\frac{1}{\pi} \left\{ \cos^{-1} \left(1 - \frac{2H}{D} \right) - 2 \left(1 - \frac{2H}{D} \right) \sqrt{\frac{H}{D} - \left(\frac{H}{D} \right)^2} \right\}}$$

E.4.2 Applications

The geometry of the wedge meter allows fluids with entrained solids or other phases to pass through with a minimal chance of blocking the flow. Thus, wedge meters are often used in slurry flows, gas flows with entrained liquids, and liquid flows with entrained gases, as well as in clean liquid and gas flows.

E.4.3 Typical Specifications

Wedge meters are available in line sizes from 0.5 inches to 32 inches (Miller, 1996; Solartron ISA, 2003), with typical H/D ratios of 0.2 to 0.5 (ABB, 2011). Meters may be obtained in pressure ratings from ANSI class 150 to ANSI class 2500.

Flow capacity and rangeability. Though not all manufacturers are specific about their meter's flow capacity, one manufacturer reports a turndown ratio of 10:1 for its wedge meter (Smart Measurement, 2010).

Flowing conditions. Miller (1996) and Smart Measurement (2010) both report that wedge meters can measure flows at pressures up to 6,000 psig. The temperature range of flows measured by the wedge meter is often limited by the working range of the temperature transmitter, typically -22°F to 248°F (Miller, 1996), though with special temperature measurement devices, wedge meter operation in flows as high as 750°F has been cited (Smart Measurement, 2010). Liquid flows with Reynolds numbers as low as 100 can be measured by some wedge meters.

Installation requirements. Miller (1996) reports that wedge meters have been tested with various upstream flow disturbances, including single or multiple elbows, and the effect of these disturbances are negligible if they are placed at least 10 to 20 pipe diameters upstream of the primary element. However, some manufacturers allow shorter upstream pipe diameters; for example, ABB (2011) recommends ten nominal pipe diameters (10D) of straight pipe between the primary device and the upstream flow disturbance, but allows a minimum of 5D of straight pipe. The recommended minimum downstream length of straight pipe is generally 5D. As noted above, meters with proper flow calibration may be used in bidirectional flow installations (ABB, 2011; Smart Measurement, 2010).

Installation instructions from ABB demonstrate that the meter may be mounted with the edge of the wedge nearly vertical, depending upon the application. This arrangement, with the wedge obstruction to one side, will still allow contaminants such as liquids or solids to pass by the wedge. However, the lines from the pressure taps to the differential pressure transmitter must still be installed so that liquid droplets can drain back into the line from above, or entrained gases can rise back into the line from below.

Calibration requirements and applicable industry standards. Wedge meters must be calibrated under flowing conditions to obtain accurate values of the discharge coefficient, C_d , and the expansion factor, Y . API Chapter 22.2, "Testing Protocol – Differential Pressure Flow Measurement Devices," can be used to calibrate wedge meters. This test protocol was discussed earlier in the section on cone meters.

E.4.4 Common Wedge Meter Manufacturers

Wedge meters are not as prevalent in the oil and gas industry as other differential meters, though ABB (2011), Solartron (2003), and smaller manufacturers such as Smart Measurement (2010) make and market wedge meters for gas and liquid applications.

E.4.5 Performance Characteristics

Typical accuracy. Miller (1996) reports a typical accuracy of $\pm 2\%$ to $\pm 4\%$ for wedge meters when used without calibration. The stated accuracy of wedge meters that have been

calibrated varies by manufacturers. ABB (2011) claims a stated accuracy of $\pm 0.5\%$ of actual flow rate and a repeatability of $\pm 0.2\%$ when the meter is calibrated and operated within its calibrated range. Solartron ISA (2003) reports an accuracy for their wedge meter of $\pm 1\%$ after calibration, while Smart Measurement (2010) reports a calibrated meter accuracy of $\pm 0.5\%$ to $\pm 1\%$ and a repeatability of $\pm 0.2\%$.

Potential sources of bias or inaccuracy. At flowing conditions, meter dimensions will increase or decrease in size with changes in pressure and temperature. While the effect due to pressure is usually neglected, typical formulas for thermal expansion may be used to correct for changes in dimensions from the temperature at which the nominal meter dimensions were determined (Miller, 1996). If not accounted for, these dimensional changes may lead to small inaccuracies in flow measurement.

E.5 References

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APPENDIX F

Review of Agar Multiphase Flow Meters

F. REVIEW OF AGAR MULTIPHASE FLOW METERS

Agar Corporation currently offers the MPFM-50 as an affordable multiphase flow metering solution. Information on the MPFM-50, along with some earlier models (MPFM-300 and MPFM-400), is summarized in the following subsections.

F.1 Description and Mode of Operation

The latest multiphase flow meter model produced by Agar Corporation is the MPFM-50 series, shown in Figure F.1. This is available either as an in-line version or a trailer-mountable assembly. It includes three-phase (gas, water, and oil) metering capabilities, and does not require separation of the liquid and gas phases for analyses [Agar, ER No. 5485].

The technology is based on 1) measurement of the mass flow rate and density of the multiphase flow mixture using an Agar-designed Coriolis meter, 2) determination of gas fraction using a dual Venturi meter, and 3) calculation of water-in-liquid percentage via a water-cut meter (either OW-201 microwave transmitter technology or OW-301 permittivity property-based). Data analysis is performed in real time to determine the flow rates of the three phases. A variety of pressure-volume-temperature (PVT) relations to choose from for density calculations come standard, with the option of uploading user-defined available as well [Agar, 2010].

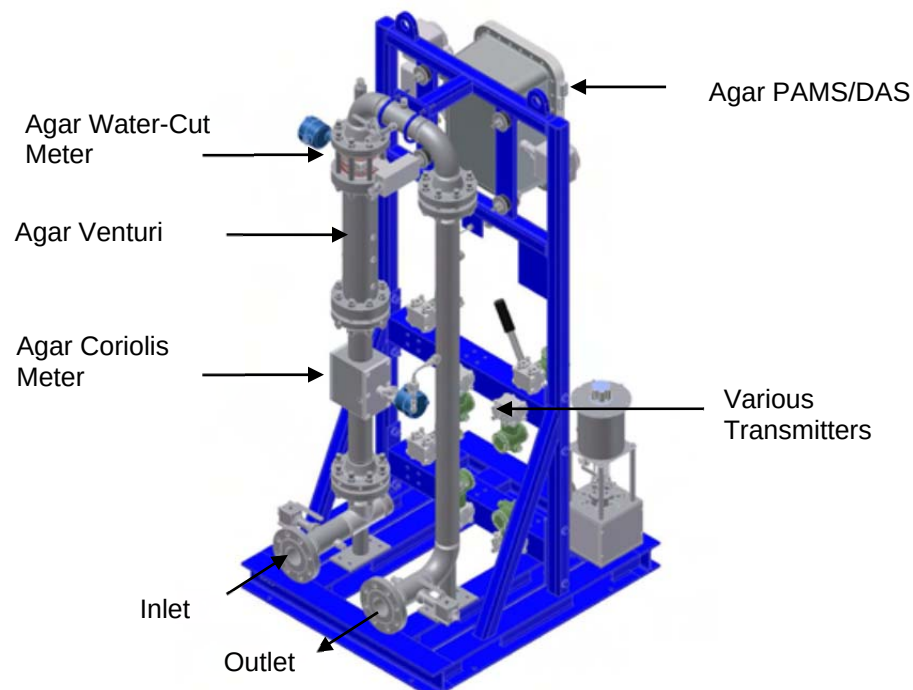


**Figure F.1. MPFM-50 Series Skid Assembly
(Courtesy of Agar Corporation)**

The Agar MPFM-50 is a multiphase flow metering system that combines a Coriolis flow meter, a Venturi-type meter, and a water-cut meter to calculate the gas, oil, and water flow rates in a multiphase flow stream.

As shown in Figure F.1, the flow first enters the Coriolis meter, where the natural frequency of oscillation and Coriolis twist of the tubes are measured. Power consumption is also analyzed to yield a third equation for the final solution matrix. The Venturi meter pressure-drop relation provides a fourth equation. Measurement of dielectric properties of the fluid using the

OW-301 Agar water-cut meter, together with the Brugeman equation, can be used to determine the water cut of the liquid in a fifth equation. A sixth equation is needed if the viscosity is changing drastically. This is procured using pressure-drop measurements across a short straight section of pipe at the exit of the meter. Line pressures and temperatures are also gathered for converting flow rates to standard conditions [Agar, 2010].

Earlier versions of the Agar meter utilized a rotary positive displacement (PD) flow meter to measure bulk flow parameters, as opposed to a Coriolis meter. The MPFM-300 series was used for typical installations, while the MPFM-401 series added a Fluidic Flow Diverter to accommodate higher gas volume fraction (GVF) flows through partial gas diversion and measurement. It should be noted that the PD flow meters were replaced with equipment having no moving parts in later models, due to maintenance issues in field tests with the MPFM-300 and MPFM-401 series (e.g., breakdowns and blockages). Additionally, PD meters are more expensive and bulky for high-pressure/temperature applications compared to Venturi meters [Agar, 2001].

F.2 Applications

According to the manufacturer, the applications of the Agar MPFM-50 flow meter include:

- Multiphase flow metering for field and well optimization
- Well testing
- Production monitoring
- Heavy oil (cold and thermal production) [Agar, 2010; Mehdizadeh et al., 2009; Mehdizadeh, 2005; Bortolin et al., 2004; Padron et al., 1998]

F.3 Specifications [Agar datasheet, 5485]

MPFM-50 series meters are available for line sizes ranging from 1 inch to 4 inches. An optional flow range extender design is offered that consists of a 2-inch MPFM-50 installed on a split stream and a flow nozzle and GVF installed on the main stream.

The general range of operation specified by the manufacturer includes:

- Flow Regimes: all (e.g., bubbly, wavy, slug, annular, etc.)
- GVF: 0% to 100%
- Water Cut: 0% to 100%
- Ambient Temperature: -4°F to 160°F (optional low-temperature model -40°F to 160°F)
- Process Temperature: 32°F to 212°F (optional high-temperature model 32°F to 450°F)
- Pressure Rating: up to 10,000 psi
- Viscosity: 0.1 cP to 30 cP (optional high-viscosity model 0.1 cP to 2,000 cP)

- Salinity: 0% NaCl to 30% NaCl by weight (up to saturation)
- Sand/Particulate: up to 5% by volume; less than 1-mm particle size
- Maximum Pressure Drop: less than 15 psi
- Preferred Installation: vertical upward flow

The MPFM-50-20 (2-inch) meter, measures from approximately 450 bpd of liquid up to 5,000 bpd of liquid at a gas rate of 10,000 scfd. The gas flow range for this meter is from approximately 0.4 MMscfd to 4 MMscfd at a liquid flow rate of 10 bpd. The MPFM-50-40 (4-inch) meter measures from 2,000 bpd to 20,000 bpd at a gas rate of 10,000 scfd, and measures from about 1.5 MMscfd to over 10 MMscfd of gas at a liquid flow rate of 10 bpd. These ranges of flow rates are provided for the case of homogeneous flow.

F.4 Performance

Like all multiphase meters to date, phase fraction measurements are interdependent. Thus, an error in one measurement instrument can have a significant cumulative effect once errors are propagated through calculations [Whitaker, 1996]. MPFM-50 manufacturer-specified accuracies [Agar, ER No. 5485] for flows within the flow meter's operating envelope have been given as:

Water Flow Rate Relative Error	$\pm 2\%$ of full scale (liquid) $\pm 5\%$ of reading
Oil Flow Rate Relative Error	$\pm 2\%$ of full scale (liquid) $\pm 5\%$ of reading
Gas Flow Rate Relative Error	$\pm 2\%$ of full scale (gas) $\pm 5\%$ of reading

F.4.1 MPFM-50 Case Studies:

- **Agar flow loop [Agar, 2010]:** Flow rates shown to be measured within $\pm 2\%$ FS $\pm 5\%$ R. GVF was given within $\pm 2.5\%$ of regular in the multiphase flow regime, and to within $\pm 0.5\%$ in the wet-gas regime ($98\% \leq \text{GVF} \leq 100\%$).
- **Field testing, Romania, Suriname, Mexico, Canada, and U.S. [Agar, 2010]:** MPFM flow rate measurements (low-flow wells) were compared to test-tank references using a 1-inch unit. For the majority of wells, accuracies of $\pm 1\%$ FS $\pm 3\%$ R were obtained.
- **Field testing, New Mexico [Mehdizadeh et al., 2009]:** More than five low-GVF ($< 30\%$) wells underwent qualification testing, indexed against a three-phase separator with single-phase meters on the outlet. Liquid rates of the MPFM were found to be within $\pm 7\%$ of reference measurements, while water-cut values were within $\pm 1\%$. Total liquid rates between about 900 bpd to 3,700 bpd were measured.

F.4.2 MPFM-300 and MPFM-400 Series Case Studies:

- **Nexen temporary installation, Calgary, Alberta, Canada [Spitzer, 2006]:** An Agar meter was installed in a steam-assisted, gravity-drainage tar sands oil production ($T=150^\circ\text{C}$ and $P=5$ bar). Accuracy was good over vapor fractions between 40% and 99%, with existing inaccuracy attributed mostly to insufficient calibration time for the meter.

- **Staatsolie testing, Paramaribo, Surinam [Spitzer, 2006]:** Two portable Agar meters were tested on more than 200 oil wells. They were found to be “efficient and reliable,” with better accuracy and speed than tank measurements.
- **Field testing in heavy oil thermal production [Mehdizadeh, 2005]:** Two operator companies using steam flood processes at two separate field sites evaluated Agar’s multiphase flow meters. Table F.1 presents fluid conditions at the field sites.

Table F.1. Field Test Conditions

Two different sites were tested covering different ranges of flow conditions.

FLOW CONDITION	SITE A	SITE B
Liquid/Emulsion Flow Rate, m ³ /day	53 – 350	200 – 550
Water Cut Range, %	22 – 85	70 – 90
Temperature, °C	87 – 166	130 – 180
Pressure, kPa	770 – 1800	400 – 1100
Gas Volume Fraction, %	14 – 67	10 – 98

An MPFM 301-20 was tested at Site A using tank tests as a reference. Operating under high-temperature conditions, it was reported that the meter provided “reliable” flow rate and water-cut data. Accuracy was found to be “as good as the best tank test procedure” that can be practically achieved in the field. Due to the high GVF at Site B, an MPFM 401-20 model was tested against separated liquid/gas meter and water-cut reference readings. Two pairs of wells were tested over a 30-day period. Some over-reporting of oil and under-reporting of water was noted, though measurements agreed relatively well overall. Error was attributed primarily to uncertainty in the reference water-cut device, and possible deposition of heavy oil components on the probes of the MPFM during a shut-down period in the testing.

- **Production and well testing, Venezuela [Bortolin et al., 2004]:** Heavy oil wells being produced through naphtha injection/dilution were equipped with Agar MPFMs. A pilot test of three wells was first undertaken to verify if diluent slugging, foamy oil, and highly variable density/viscosity properties would cause inaccuracy in the meter. Liquid rates were found to be measured accurately, leading to the procurement and long-term installation of 37 units for the field. Start-up issues included: 1) susceptibility of the positive displacement meter to wear and seizing with sand production in excess of 5%, and 2) bitumen plugging of pressure and differential pressure transmitter impulse tubing. Manufacturer-redesign of the positive displacement meter and tubing lines significantly reduced these issues. After gaining experience with the meters, average reported failure rates of the deployed units decreased to about 0.94 failures per month (0.025 per month per unit).
- **Review of early high-GVF performance and field testing [Nored and George, 2003]:** A review of early tests of the MPFM-400 found that the total flow rate for the combined oil, water, and gas phases were in agreement with the reference meter to about $\pm 2\%$ of reading. However, flow rates for the individual phases were accurate to $\pm 2\%$ of full scale, or $\pm 10\%$ of reading. It was concluded that the MPFM can handle flow conditions with gas volume fractions up to 99.4% accuracy within the vendor’s specifications.

- **Saudi Aramco gas-oil separation plant testing [Al-Taweel and Barlow, 1999]:** An MPFM-401 was indexed against the plant's separator during 30 tests over a wide range of water cuts and gas fractions. It was reported that the meter readings "generally compared well," though some flow rates fell outside of the manufacturer's accuracy bands. No operational/maintenance issues arose during testing.
- **Flow loop and field testing for heavy oil applications [Padron and Guevara, 1998]:** The MPFM-301 model was tested in a flow loop facility using oil with a viscosity of 2,000 cP, water with varying salinity, and natural gas. Temperatures ranged from 60°C to 82°C. Agreement between the flow rates of each of the three phases was reported to be within $\pm 10\%$ for total flow rate ranges between 150 bpd and 4,260 bpd. The meter was then installed at the outlet of a steam-producing well in Venezuela. The hot crude entered the MPFM at temperatures of 15°F to 280°F, and viscosity was reported as 10,000 cP at 100°F. Again, individual phase flow rates were within $\pm 10\%$, with most of the data falling within $\pm 5\%$. The performance of the meter did not appear to be affected by the high viscosity of oil during testing.

F.5 References

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APPENDIX G

Review of McCrometer Cone Meters

G. REVIEW OF McCROMETER CONE METERS

G.1 Description and Mode of Operation

The metering system designed by McCrometer is similar to other technologies that base measurements on differential pressure (DP) readings across a flow restriction. The unique feature of the design is the shape and position of the cone in relation to the pressure taps. According to the manufacturer, the cone itself acts as a flow conditioner for upstream fluid to achieve a flattened well-developed profile. It accomplishes this by disrupting all centralized flow disturbances, resulting in a well-mixed and conditioned flow [McCrometer, 24509-49]. As a result, long runs of straight upstream and/or downstream piping are not required, as they are for some other DP meters. This would be a particular advantage for off-shore applications. For example, the weight penalty can be greater than \$25/lb. in the Gulf of Mexico [McCrometer, 24508-90]. The V-cone weight is approximately 1,444 lbs. for a 16-inch meter with 900# flanges, and 1,161 lbs. for a 14-inch meter, and only about 945 lbs. for a 12-inch meter. Similar-sized orifice meters with necessary upstream and downstream piping are reported to weigh more than 2.5 tons each [McCrometer, 24508-90].

McCrometer lists two models of its meter. As shown in Figure G.1, these include the Precision V-Cone and the Wafer Cone models. The V-Cone meter was first introduced in the 1980s. It has a centrally-mounted cone pointing upstream supported at its nose by a strut. The upstream pressure is measured from a wall tap, and the downstream pressure is read from the center of the back face of the cone. The Wafer Cone meter is also centrally mounted. The cone points upstream and is supported by a downstream strut. Upstream and downstream pressures are read from wall taps, as indicated in Figure G.1(b). The differential pressures are incorporated into a derivation of the Bernoulli equation to determine the fluid flow rate [McCrometer, 24509-54].

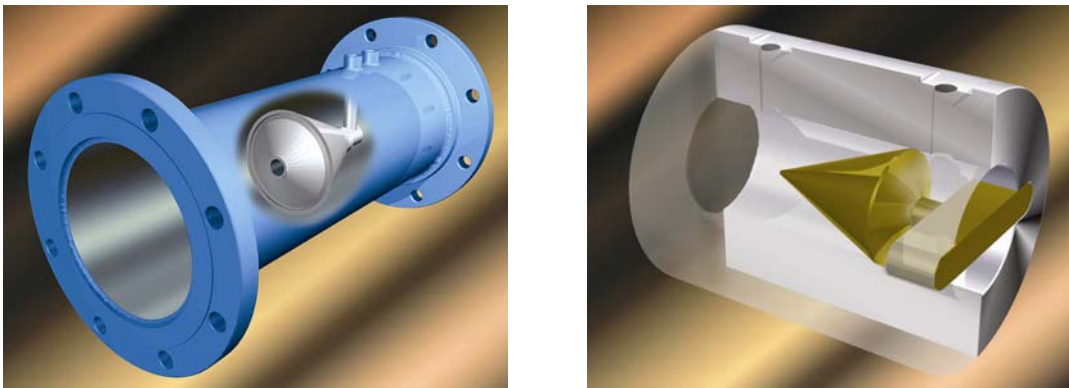


Figure G.1. V-Cone Meter Model Schematics: (a) Precision V-Cone Meter, (b) Wafer Cone Meter, [McCrometer, 24517-16]

Most wet-gas studies have focused on the V-cone meter performance. Like other differential pressure meters, the V-Cone meter is reported to over-read the gas flow rate with a wet gas flow [Steven, 24509-19]. The scale of the error has been shown to be dependent on the Lockhart-Martinelli parameter, pressure, and the gas densimetric Froude number. The over-reading is usually written as the square root of the ratio of the actual differential pressure reading from the wet gas flow over the differential pressure that would be expected if only the gas phase flowed through the meter. McCrometer has conducted a series of flow loop tests to identify and correct for this error.

Longevity of the meter components and calibration is reported to be very good for the V-cone meter, estimated at 25 years or more [McCrometer, 24519-15]. According to the manufacturer, the meter may even be used with abrasive, dirty, and particle-laden flows without significant wear. Similar to orifice meters, the meter has no moving parts, which results in low maintenance. Unlike orifice meters, however, the contoured shape of the cone directs the flow without impacting it against an abrupt surface. Fluid is directed away from the beta edge, reducing wear and increasing the calibration life of the meter. Note that the beta ratio equals the flow area at the largest cross section of the cone (converted to an equivalent diameter) divided by the inside diameter.

A final purported advantage of the V-cone meter is its signal stability. Fluctuation of the signal generated by the primary element is inevitable to some degree, even in steady flow. Using orifice plates, vortices that form directly downstream of the plate tend to create high-amplitude, low-frequency DP signals. Due to the short vortices of flow passing over the cone meter, however, high-frequency/low-amplitude signals are generated that result in greater stability [McCrometer, 24517-16].

G.2 Applications

V-cone applications for the oil and gas industry are advertised as shown in Table G.1 [McCrometer, 24519-15].

Table G.1. V-Cone Applications

APPLICATION	FLUID TYPES
Allocation Measurement	Natural Gas/Crude Oil/Water/Air/Steam
Blending	Liquid Hydrocarbons/Chemicals
Burners	Natural Gas/LPG/LNG
Chimney Stack	Flue Gas
Coal Bed Methane/Shale Gas	Dirty/Wet Natural Gas
Compressors (inlet/outlet, loop/anti-surge control)	Natural Gas
Custody Transfer	Natural Gas/Crude Oil/Water/Air/Steam
Feed Lines to Flare	Natural Gas
Firewater Pumps Testing	Water/Seawater
Fuel Gas	Natural Gas/LPG/LNG
Gas Lift	Natural Gas
Injections/Reinjections	Natural Gas/Water/Steam/CO ₂ (gas and liquid)/Chemical
Oil Sands	Steam/Natural Gas/Crude Oil
Produced Liquids	Liquid Hydrocarbons/Condensate/Water
Production and Test Separators (inlet/outlet)	Natural Gas/Wet Natural Gas/Crude Oil/Water
Lift Pumps	Water/Seawater
Steam	Saturated/Super-Saturated/Super-Heated
Wellhead Measurement	Natural Gas/Wet Natural Gas/Crude Oil/Water
Wet Gas (with known liquid volume)	Wet Natural Gas

G.3 Specifications

Specifications for McCrometer's V-cone meter, per attached datasheets [McCrometer, 24509-49; 24519-15], are now discussed.

- **Flow Ranges:** 10:1 and greater.
- **Standard Beta Ratios:** 0.45 through 0.80. Others available upon request.
- **Head Loss:** In terms of percentage of the differential pressure created at a particular flow rate, $\%P_{\text{loss}} = (1.3 - 1.25\beta) * 100$ [McCrometer, 24509-54].
- **Materials of Construction:** Duplex 2205, 304, or 316 stainless steel, Hastelloy C-276, 254, SMO, carbon steels. Special materials upon request.
- **Line Sizes:** 0.5 inches to 120 inches. Larger sizes available upon request.
- **End Fittings:** Flanged, threaded, hub or weld-end standard. Others available upon request.
- **Configurations:** Precision flow tube and wafer-type (calibrated for customer application; ASME B31.3 construction available).
- **Approvals for Meter:** Canadian custody transfer approved; ISO 9001:2000 certified quality management system; meters in compliance with PED97/23/EC available upon request.

Based on the V-cone meter installation guide [McCrometer, 24517-16], upstream and downstream minimum straight pipe run requirements for various upstream obstructions are given in Table G.2.

Table G.2. Upstream and Downstream Minimum Straight Pipe Run Requirements

For gas metering at a Reynolds number $> 200,000^1$:

Size Range	Obstruction	Upstream	Downstream
All Sizes	1 Elbow	1D	1D
	2 Elbows	1D	1D
	Tees	1D	1D
	Butterfly Valve (control valve)	Not Preferred Position	Valve Downstream 1D
	Butterfly Valve (shutoff valve)	2D	1D
	Full Port Ball Valve (shutoff valve)	1D	1D
	Heat Exchanger (type dependent)	1D	0D
	Expander (0.67D to D) Over a Length of 2.5D	2D	1D
	Reducer (3D to D) Over a Length of 3.5D	0D	0D

¹ For $\beta \geq 0.70$, add 1D. Note that meter and adjoining pipe should have equal IDs.

Table G.2. Upstream and Downstream Minimum Straight Pipe Run Requirements (cont'd)*For liquid metering and gases at a Reynolds number $\leq 200,000^1$:*

Size Range	Obstruction	Upstream	Downstream
All Sizes	1 Elbow	0D	0D
	2 Elbows	0D	0D
	Tees	0D	0D
	Butterfly Valve (control valve)	Not Preferred Position	Valve Downstream 1D
	Butterfly Valve (shutoff valve)	2D	0D
	Full Port Ball Valve (shutoff valve)	0D	0D
	Heat Exchanger (type dependent)	0D	0D
	Expander (0.67D to D) Over a Length of 2.5D	2D	1D
	Reducer (3D to D) Over a Length of 3.5D	0D	0D

G.4 Performance

Accuracy for the V-cone meter has been reported by the manufacturer as $\pm 0.5\%$ of actual flow for single phase [McCrometer, 24509-49; 24519-15]. Note that certain fluids and Reynolds number applications can require special calibrations to achieve this uncertainty level. Flow loop testing for wet gas applications has shown relative error within about $\pm 2\%$ using correlations developed to correct for over-reading.

V-cone Meter Case Studies:

- Longevity, contamination, and beta edge damage test [McCrometer, 24508-90]:** Orifice and V-cone meters were installed at a Marathon Oil hydrocarbon facility in central Wyoming to meter dirty wet gas with H₂s and asphaltenes contaminants. The meters were inspected after three months. Orifice meters showed asphaltenes/paraffin build-up at the upstream-inlet to the meter, and contaminants after the plate in the low pressure region. V-cone units appeared clear of depositions, including the sensing ports. During usage, it was noticed that entrained liquid periodically would slug flow in the orifice meters, allowing liquid to be retained after the plate and requiring the sensing lines to be purged. The lack of liquid hold-up caused this not to be a problem with the V-cone meter.
- Initial wet gas V-cone meter testing [Ifft, 24508-49; 24508-62]:** As of May 1999, the only wet gas testing of the V-cone meter had been completed at Southwest Research Institute. This testing in the early '90s was conducted with nitrogen gas and liquid water using 4-inch V-cone models. The three beta ratio designs tested were 0.45, 0.59, and 0.67. Liquid additions of up to 5% mass fraction in the gas stream were used. With beta ratios of 0.45 and 0.59, the maximum error from reference conditions was 1% of rate. Using a beta ratio of 0.67, the deviation was within 1.5% of rate.
- Flow loop wet gas testing of beta ratio correlation [Steven, 24509-19; Steven et al., 2005]:** Six-inch V-cone meters with beta ratios of 0.55 and 0.75 were tested in 2002 at the NEL facility. Pressures covered 15 bar, 30 bar, and 60 bar; Lockhart-

Martinelli parameters ranged up to 0.3; gas flow rates covered from 400 m³/hr to 1,000 m³/hr. It was found that the meter over-read the gas flow rate with a wet gas flow. As the Lockhart-Martinelli (LM) parameter increased for a set gas-to-liquid density ratio and gas densimetric Froude number, the over-reading increased. If the density ratio increased for a set LM parameter and Froude number, the over-reading reduced. If the Froude number increased for a set LM parameter and the density ratio, the over-reading increased. Based on the data, a wet gas correlation was developed.

The 6-inch meter with a beta ratio of 0.75 was retested at NEL in May 2003. Pressures covered 14 bar and 60 bar; LM parameters ranged up to 0.5; gas flow rates again covered 400 m³/hr to 1,000 m³/hr. A significant obstruction was placed ten diameters upstream of the V-cone meter. Old and new results were then compared using the correlation for correction of the over-reading. It was found that data collected under the same conditions were repeatable from one test to the next. After correction, the final gas flow rate prediction was about $\pm 2\%$. No significant effect on results was observed as a result of the obstruction ten diameters upstream.

It was desired to further test the correlation based on NEL data for correction of a known liquid flow rate at different conditions. Thus, results from data taken in 2002 at the CEESI wet gas loop using a 4-inch V-cone meter with a beta ratio of 0.75 were revisited. CEESI test conditions included natural gas with decane at 50 bar, 150-m³/hr to 400-m³/hr gas rates, and up to a LM parameter of 0.25. Like the previous NEL data, results showed that as the Froude number increased for a set LM parameter and pressure, the over-reading increased. After further analyses, it was concluded that the correlation can be used with some confidence for different pipe sizes, gas flow rates, and fluid types. Furthermore, it was shown that similar DP meter behavior was produced, even though pipe size, gas flow rate range, and fluid types were different.

After the addition of a 2-inch wet gas facility at CEESI in 2004, McCrometer tested a 2-inch V-cone meter with 0.7 beta ratio. Using the same correlation as for previous NEL testing, it was found that flow rate data, again, was within 2% uncertainty of reference conditions. Thus, no significant scaling effect has been shown between 6-inch, 4-inch, and 2-inch meter data based on multiple flow loop tests.

Further investigation of the 6-inch 0.75 beta ratio V-cone meter was conducted in 2005 at the K-Lab test facility in Norway. It was again shown that results were within 2% using the correction correlation for Froude numbers up to 4.37. However, when the higher Froude number of 6.75 was tested, it was observed that the correlation prediction diverged. Thus, it has been suggested that the wet gas correlation be used with a Froude number cap of 5.0. McCrometer has created a new wet gas correlation for Froude numbers in the range of 5.0 to 8.75 with a slightly higher uncertainty based on test data.

G.5 References

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APPENDIX H

Review of Multi Phase Meters AS Multiphase Flow Meters

H. REVIEW OF MULTI PHASE METERS AS MULTIPHASE FLOW METERS

Multi Phase Meters AS offers their MPM meter for topside installations, as well as subsea applications. The following subsections provide a description of the MPM meter, its principle of operation, common applications, and technical specifications. Finally, a summary of the data and general information on the meter's performance are presented.

H.1 Meter Description and Principle of Operation

Unless otherwise noted, the information presented in this subsection was obtained from the MPM Topside and Subsea Technical Descriptions (TDS-001, 2011) (TDS-002, 2011). The MPM meter is a flow measurement instrument that is designed to accommodate 0% to 100% water/liquid ratio (WLR) and 0% to 100% GVF, including slug flow conditions. The meter measures the gas, liquid, and water flow rates without separation via the following major instruments: a Venturi meter, tomographic sensors, a gamma densitometer, and conductivity probes. Figure H.1 gives a graphical representation of the meter.

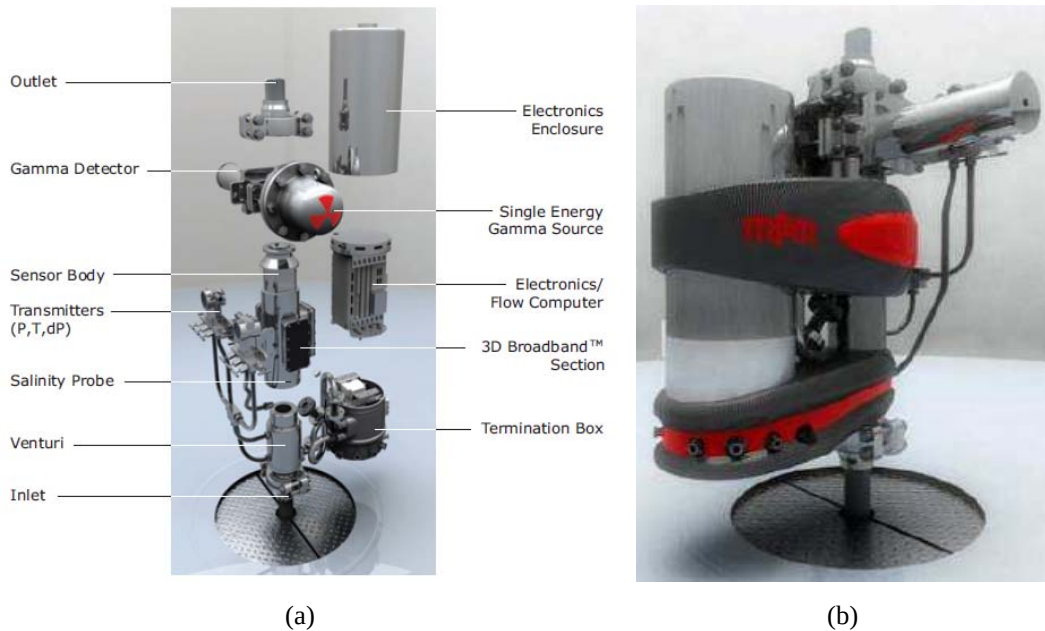


Figure H.1. MPM Multiphase Flow Meter: (a) Components; (b) Subsea Model

The MPM meter incorporates a Venturi meter, tomography sensors, conductivity probes, and a gamma densitometer, along with other components and electronics to measure the multiphase stream. A subsea version is also available. Images used with permission from Multi Phase Meters AS.

The flow first passes through a Venturi meter, which is used to measure the total mass flow rate and to create radial symmetrical flow conditions prior to entering the patented 3D Broadband™ section, which provides high-frequency tomography of the flow geometry. The gamma densitometer is used to calculate fluid densities and the meter utilizes temperature and pressure transmitters. Tomography and 3D measurements eliminate the error effect of gas concentration in pipe cross sections.

The MPM meter measures the conductivity (for determining salinity) and density of the water in water continuous flow. This water property measurement capability could be used to

detect formation water break-through in the well. The meter also offers in-situ sampling to measure and compensate for fluid property changes. MPM states that this reduces, or in many cases eliminates, the need for fluid sampling (Wee & Farestvedt, 2011).

The meter offers multiphase (GVFs up to 90% to 95%) and wet-gas (GVF > 95%) modes and can automatically or manually switch between them. For a very high GVF, typically in the range from 99% to 100%, the Droplet Count mode is used to provide measurements of the water fraction and fluid properties.

H.2 Applications

The MPM meter is designed to achieve accurate flow rate measurements for all types of wells (land, offshore, subsea) and is intended for production monitoring, well testing, and allocation metering purposes (TDS-001).

H.3 Technical Specifications

The meter specifications are primarily attained from the Topside and Subsea Technical Descriptions (TDS-001, 2011) (TDS-002, 2011). The MPM meter must be installed vertically, downstream of a blinded tee. Flow can be vertically up, or vertically down through the meter. The piping in between the tee and the MPM meter must have the same inner diameter as the meter. Table H.1 lists the dimensions of the MPM flow meters that have been produced to date.

Table H.1. MPM Flow Meter Dimensions

MPM meters have been fabricated with diameters between two inches and 14 inches.

PIPE SIZE	MPM SENSOR	ID (mm)
2" – 3"	2"	50
3" – 4"	3"	74
5" – 6"	5"	110
7" – 8"	7"	155
10" – 12"	10"	220
14" – 16"	14"	306

The meter can handle pressures up to 1,000 bar (15,000 psi) and a temperature range of -50°C to 250°C (-58°F to 480°F). The subsea version of the MPM meter can also be submerged to 3,500-m (10,000-ft.) depths. The instrumentation for the meter also consumes 70 watts of electrical power. The viscosity limits for the MPM meter were not found in the open literature.

H.4 Performance Information

The MPM meter has been blind tested at several facilities and operational field locations. Table H.2 gives the conditions and test information. Through this culmination of data, MPM has stated that the meter measured flow rates of oil, water, and gas to within 1.5% of the reference instrumentation across all tests, but indicates that well testing and short measurement periods (instantaneous) show slightly higher uncertainties (TDS-001, 2011). MPM claims that the culmination of all of their test data is a better way of comparing results because the meter is designed for fiscal and allocation metering applications (long duration use) (Stobie & Wee, 2011).

The tests covered a large variety of operating conditions with pressures up to 120 bar. All tests were supervised and witnessed by independent parties, including the JIP Oil Companies (Stobie & Wee, 2011). Table H.3 shows the cumulative measured uncertainty for each test.

Table H.2. Test Locations and Conditions

The MPM meter has been evaluated at several test facilities covering multiphase and wet-gas conditions. Table recreated from (Stobie & Wee, 2011).

	MPM Lab (Sep '06)	K-Lab (Oct '06)	Gulfaks (Dec '06)	Gulfaks (Jan '07)	SwRI (Nov '07)
No. of Test Points	220	46	13	10	50
GVF, %	0 - 99.9	25 - 99.9	40 - 96	20 - 95	95 - 99.5
WLR, %	0 - 95	0 - 70	2 - 78	2 - 85	0 - 25
Pressure, bar	< 10	120	60	60	120
Temperature, °C	15 - 25	48 - 52	20 - 60	20 - 60	38 - 48
Oil Type	Exxol D 140	Condensate	Crude	Crude	Condensate
Oil Density, kg/m³	830 kg/m ³	620 kg/m ³	780 - 840 kg/m ³	780 - 840 kg/m ³	560 - 620 kg/m ³

Table H.3. Cumulative Difference between the MPM Meter and Reference System

The differences between the MPM meter and reference gas and oil flow rates on an accumulated basis fell within a 95% confidence level. Table recreated from (Stobie & Wee, 2011).

	MPM Lab ('06)	K-Lab ('06)	Gulfaks (Dec '06)	Gulfaks (Jan '07)	SwRI (Nov '07)
Oil Flow Rate	1.10%	0.10%	3.40%	1.40%	0.70%
Gas Flow Rate	1.40%	1.30%	1.40%	0.10%	1.20%

MPM further states their cumulative measurement uncertainties in Table H.4, if the following assumptions are made (Stobie & Wee, 2011):

- The operating pressures are above 20 bar.
- The differential pressures (DPs) over the Venturi are above 50 mBar.
- Measurements are performed for test periods of 24 hours or more for a combined set of wells with variation in GVF and WLR.
- MPM DualMode® and automatic water salinity configuration are implemented, if appropriate.
- There is a confidence interval of 95%.

A separate field test was performed by ConocoPhillips in 2009 at the Alpine Field site on the North Shore of Alaska. Data from the MPM meter, without using the in-situ measured gas density, resulted in liquid (oil and water) flow rate deviations of less than $\pm 5\%$ and a positive bias of +7% for the gas flow rate when compared with flow rates from a test separator. By using the in-situ measured gas density (instead of the PVT calculated gas density), the discrepancy in flow rate measurements is better than $\pm 3\%$ for all fluids (Stobie & Wee, 2011).

Table H.4. Cumulative Measurement Uncertainties of the MPM Meter

The measurement error is broken down into various GVF ranges. Higher GVFs yield higher uncertainties in the oil flow rate. Table recreated from (Stobie & Wee, 2011).

	Gas Volume Fraction			
	0% - 80%	80% - 95%	95% - 99%	99+%
Oil Volume Flow	2%	2.50%	3.50%	10%
Gas Volume Flow	3.50%	3%	2.50%	2.50%
Hydrocarbon Mass Flow	2%	2%	2%	2%

Table H.5 shows the difference based on the accumulated flow rate for all of the wells. These numbers are the accumulated difference between the MPM meter and test separator for all of the 88 well tests performed over the entire test period covering over 880 hours of flow. As seen from Table H.5, the accumulated difference for oil and water is within -5.4%, whereas the accumulated difference for gas is +7.3% based on the PVT calculated gas density and +1.9% based on the in-situ measured gas density. The accumulated water cut (WLR) is -0.4% (absolute). Excluding two of the wells where the Venturi DP during peak periods saturated at 5,000 mBar, the difference for the oil rate is -2.1%, water rate is -3.1%, and gas mass rate (in-situ density) is -0.4%.

Table H.5. Accumulated Difference between Test Separator and MPM Meter

The measurement error is summarized for all of the wells and for excluding two of the wells in which the Venturi DP was saturated. Table recreated from (Stobie & Wee, 2011).

	Liquid Vol. [%]	Oil Vol. [%]	Water Vol. [%]	Gas Mass ¹ [%]	Gas Mass ² [%]	Water Cut [%abs]
All Wells	-4.7	-3.7	-5.4	7.3	1.9	-0.4
Excluding Two Wells with Saturated DP	-2.6	-2.1	-3	7	-0.4	-0.2

Notes:

1) Gas mass rate based on PVT calculated gas density.

2) Gas mass rate based on in-situ measured gas density.

Additionally, using Droplet Count and Wet-Gas Modes, additional testing has shown that the MPM meter can accurately detect water fraction changes down to one one-thousandths of a percent (TDS-001, 2011).

MPM offers a specific Application Evaluation to be performed to evaluate the suitability of the MPM meter for a particular application, which includes measurement uncertainty specifications (TDS-001, 2011).

From conversations with MPM representatives, it is known that the MPM meter was tested in 2007 at the Petrobras test center NUEx in Atalaia, Brazil. Testing was performed using oil with 22.9 °API. The objective of the testing was to evaluate the performance of the MPM meter with a heavy oil and qualify the meter for well testing and allocation metering. Results from this testing are not available in the open literature. MPM also indicated that one of their meters is undergoing testing under heavy oil conditions with API gravity between 18 °API and 20 °API.

H.5 References

- MPM Topside Technical Description, TDS-001 - MPM-Meter - Topside - Technical Description v4.doc 2.09, MPM Email Communication, November 2011.

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APPENDIX I

Review of Pietro Fiorentini Multiphase Flow Meters

I. REVIEW OF PIETRO FIORENTINI MULTIPHASE FLOW METERS

I.1 Description and Mode of Operation

Pietro Fiorentini currently has two multiphase flow meters available and one high GVF skid option. The two options of flow meter are the Flowatch 3I and Flowatch HS. Figure I.1 shows pictures of the Flowatch 3I and Flowatch HS.

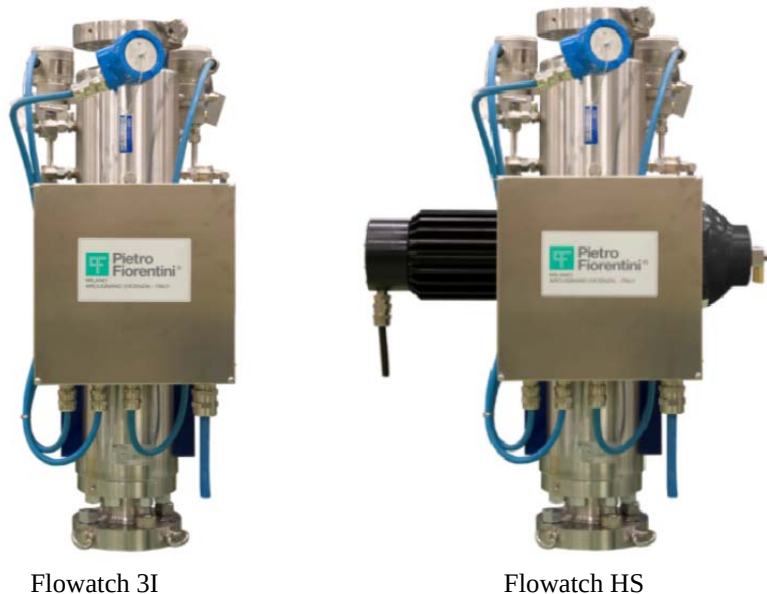


Figure I.1. Photographs of Pietro Fiorentini's Flowatch 3I and HS (Pietro Fiorentini, 2011)

The Flowatch 3I was developed in 2010. It is the second generation of the original Flowatch developed in 2004. The Flowatch 3I uses a Venturi meter to measure flow rate and capacitance and conductance measurements along with a cross correlation to determine the velocity of each phase.

The Flowatch HS was developed in 2011. The Flowatch HS uses a Venturi meter to measure flow rate, a gamma densitometer to measure density, and electrode sensors along with a cross correlation to determine the three-phase flow rate. The main difference between the Flowatch HS and the Flowatch 3I is the addition of the gamma densitometer for the Flowatch HS.

Pietro Fiorentini recommends using their high GVF skid option for gas volume fractions (GVFs) above 92%. Figure I.2 shows a picture and schematic of the high GVF skid option with the Flowatch 3I installed.

The high GVF skid option uses a partial gas separation device to separate a portion of the gas phase through a dedicated gas Venturi meter. The liquids and gas left over from imperfect separation are routed through either the Flowatch 3I or HS flow meter at a lower GVF. The recommended GVF range for the high GVF skid option is 93% to 100%. The high GVF skid is Pietro Fiorentini's only high GVF / wet gas multiphase metering option.

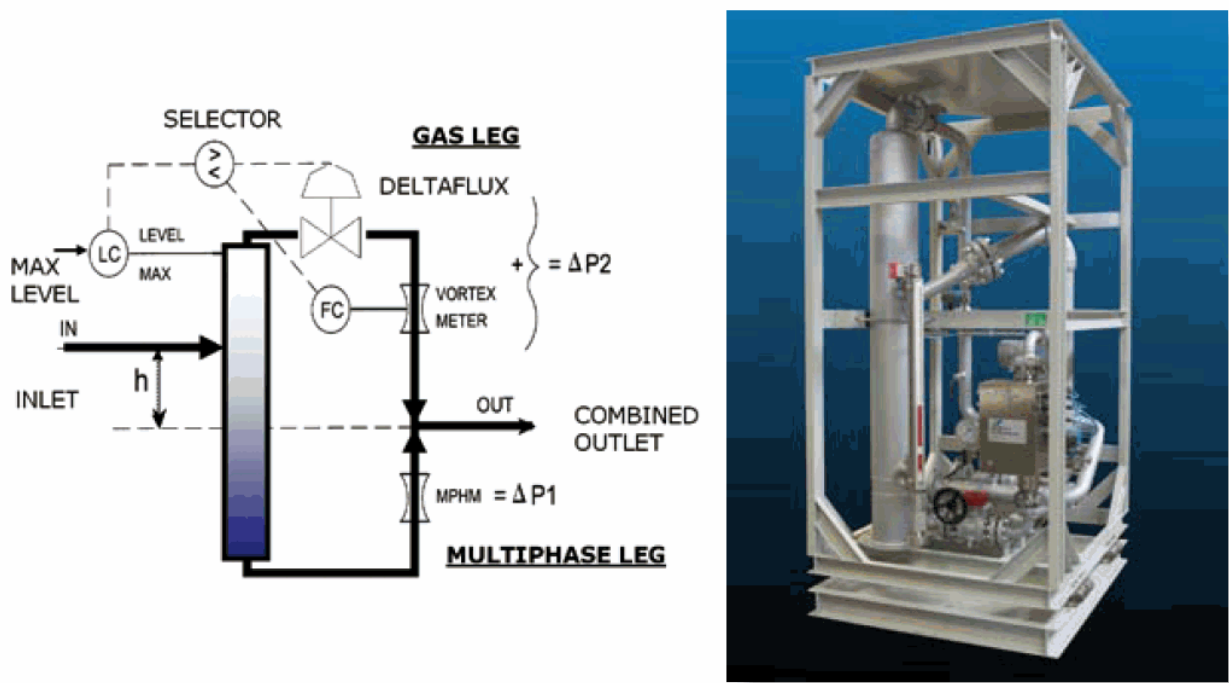


Figure I.2. Photograph and Schematic of Pietro Fiorentini's High GVF Skid Option (Pietro Fiorentini, 2010)

I.2 Applications

The Flowatch meters can be used in both onshore and offshore applications. A subsea model is not currently available. The manufacturer's literature recommends that the meter is suitable for mobile applications (mounted on a truck or trailer). The mobility of the meter would lend itself well to well testing.

I.3 Specifications

The Flowatch HS has a better stated accuracy than the Flowatch 3I, but has the same operating range. From Pietro Fiorentini's literature, the metering capabilities of the Flowatch HS and Flowatch 3I are as follows:

- 0% to 100% water cut;
- 0% to 97% gas volume fraction;
- All flow regimes;
- All oil densities and viscosities;
- All water salinities.

The specifications for the Flowatch 3I and Flowatch HS are shown in Figure I.3 and Figure I.4, respectively.

SPECIFICATIONS	
Operating Range	• 0-100% water cut • 0-97% gas volume fraction (GVF)
Size	From 0,5" up to 8"
Design Pressure & Temperature	Up to 5.000 psi, up to 302°F (150°C)
Body Material	AISI316, Duplex, Inconel 625, others on request
Venturi	Insert field replaceable, std Beta 0.6, max pressure drop <1 Bar
Communication Interface	Communication ports: • RS-485/422 single or redundant, Ethernet Communication protocols: • Modbus ASCII/RTU, TCP/IP
Electrical Specifications	• ATEX certification Ex ia IIB T4 Ga • Ambient temperature -40° C/ + 70° C
Flow Computer	• Real Time controller, Operating system VxWorks • Ambient temperature -40° C/ + 70° C • Power supply: 24VDC, or 110÷240 V 50÷60Hz • Power consumption: 15W • Enclosure for safety area or for hazardous area • Weather protection: IP 65 • Stainless steel or aluminium enclosure • With local display (as optional)
HMI	HMI for Windows XP, Vista, and 7 TCP/IP Wireless

Figure I.3. Flowatch 3I Specifications (Pietro Fiorentini, 2011)

SPECIFICATIONS	
Operating Range	• 0-100% water cut • 0-97% gas volume fraction (GVF)
Typical uncertainty (95% confidence int.)	• Liquid flow rate: +/-3% relative • Water cut: +/-2% absolute • Gas flow rate: +/-5% relative
Size	From 0,5" up to 8"
Design Pressure & Temperature	Up to 5.000 psi, up to 302°F (150°C)
Body Material	AISI316, Duplex, Inconel 625, others on request
Venturi	Insert field replaceable, std Beta 0.6, max pressure drop <1 Bar
Density measurement	• Gamma Source: Cs-137, 50 mCi, Half-life 30.1 yrs • Dose level 0,1µSv/h @0cm (natural background) • Detector: Pietro Fiorentini Fast Gamma • Counts per second: 2 millions • ATEX certification Ex d IIB T4
Communication Interface	Communication ports: • RS-485/422 single or redundant, Ethernet Communication protocols: • Modbus ASCII/RTU, TCP/IP
Electrical Specifications	• ATEX certification Ex ia IIB T4 Ga • Ambient temperature -40° C/ + 70° C
Flow Computer	• Real Time controller, Operating system VxWorks • Ambient temperature -40° C/ + 70° C • Power supply: 24VDC, or 110÷240 V 50÷60Hz • Power consumption: 15W • Enclosure for safety area or for hazardous area • Weather protection: IP 65 • Stainless steel or aluminium enclosure • With local display (as optional)
HMI	HMI for Windows XP, Vista, and 7 TCP/IP Wireless

Figure I.4. Flowatch HC Specifications (Pietro Fiorentini, 2011)

The maximum and minimum flow rate for both the Flowatch 3I and Flowatch HC are limited by the minimum and maximum differential pressure allowed through the Venturi meter. The typical upper limit for differential pressure across the Venturi meter in the Flowatch 3I and Flowatch HC is 1 bar. The lower limit is not specified in the manufacturer's literature (Pietro Fiorentini, 2011).

I.4 Performance

The uncertainties of the Flowatch 3I and Flowatch HC, based on the manufacturer's data, are shown in Figure I.5 and Figure I.6, respectively. The water-cut error for both the Flowatch 3I and Flowatch HS are expressed as absolute error, while the flow rate error is expressed as relative error.

Flowatch 3I						
GVF Range (%)	0-25	25-60	60-70	70-85	85-92	92-97
Liquid Flow Rate	4%		6%		9%	10%
Gas Flow Rate	-	10%				
Water Cut	2% ABS			3% ABS		4% ABS

Figure I.5. Flowatch 3I Performance (Pietro Fiorentini, 2011)

Flowatch HS						
GVF Range (%)	0-25	25-60	60-70	70-85	85-92	92-97
Liquid Flow Rate	2%		3%		4%	5%
Gas Flow Rate	-	6%				
Water Cut	1% ABS			2% ABS		3% ABS

Figure I.6. Flowatch HS Performance (Pietro Fiorentini, 2011)

The performance of the Flowatch 3I and Flowatch HC in conjunction with the high GVF skid will depend on the GVF that is actually reaching the multiphase meter. Pietro Fiorentini recommends that the high GVF skid will be able to maintain a 40% to 60% GVF at the multiphase flow meter with a 93%+ GVF entering the separation skid (Pietro Fiorentini, 2010).

I.5 References

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- Pietro Fiorentini Multiphase Flowmeter Flowatch HS – Specifications Sheet, Pietro Fiorentini, V.1.0, 2011.

APPENDIX J

Review of Schlumberger Vx Meters

J. REVIEW OF SCHLUMBERGER Vx METERS

Schlumberger, in partnership with Framo Engineering AS, formed 3-PHASE Measurements AS and combined their multiphase flow experience to develop the Vx meter. The following provides a description of the operation, specifications, and performance of the Vx meter, especially under heavy oil applications.

J.1 Description and Mode of Operation

The Schlumberger Vx system, illustrated in Figure J.1, is composed of the following stationary elements: a Venturi tube, nuclear source and detector, pressure and differential pressure transmitters, a process fluid temperature sensor upstream of the Venturi (not shown), and a flow computer. All sensors (except temperature) are co-located at the throat of the Venturi section, requiring no correlations between events measured at different places. Data processing in the flow computer is based on three primary models/assumptions [Pinguet et al., 2011]:

- Describing gas-liquid slippage based on an experience-based semi-empirical model
- Equal oil and water velocities (zero slippage in liquid phase)
- Modeled “shape factor” for multiphase environments

According to the manufacturer, the Vx meter handles a wide range of flow regimes, and requires no process control. Furthermore, it is reputed to be insensitive to changes in flow rate, phase holdup, and pressure regime. A blind tee is recommended for installation upstream of the measuring unit to act as a filter to force a predictable shape onto the flow stream.

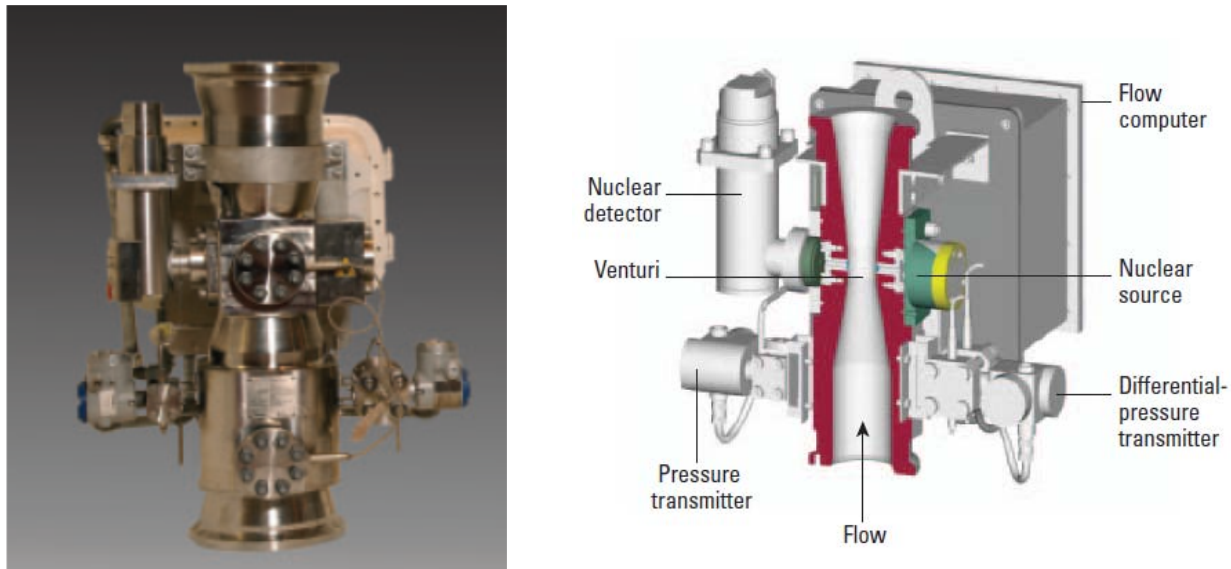


Figure J.1. Schlumberger Vx Meter Photograph and Schematic (Figure courtesy of Schlumberger)
The Vx meter comprises a Venturi meter; a gamma densitometer; various pressure, temperature, and differential pressure transmitters; and a flow computer.

The differential pressure reading across the Venturi allows for computation of the total flow rate through the tube. The nuclear element utilizes multiple-energy gamma-ray technology to provide simultaneous measurement of the fraction of each component present in the mixture,

i.e., gas, oil, and water. The gamma detector is capable of processing over one million data points per second, allowing computation of all three phase fractions every 22 milliseconds. The detector produces a signature count rate over higher and lower energy bands as a function of the measured medium, since different fluids attenuate gamma rays to varying degrees. This allows calculation of all three phases using a triangular solution of the phase holdup. For each phase, the ratio of high-energy count rate versus source strength is plotted against the ratio of low-energy count rate versus source strength on an x-y chart. These points become the apexes of a triangle, as shown in Figure J.2 [07-WT-080, 2007]. The phase holdup may then be determined by intersection of the two lines inside the triangle. The first line represents the gas/liquid ratio, while the second connects the 100% gas point to the oil/water ratio point.

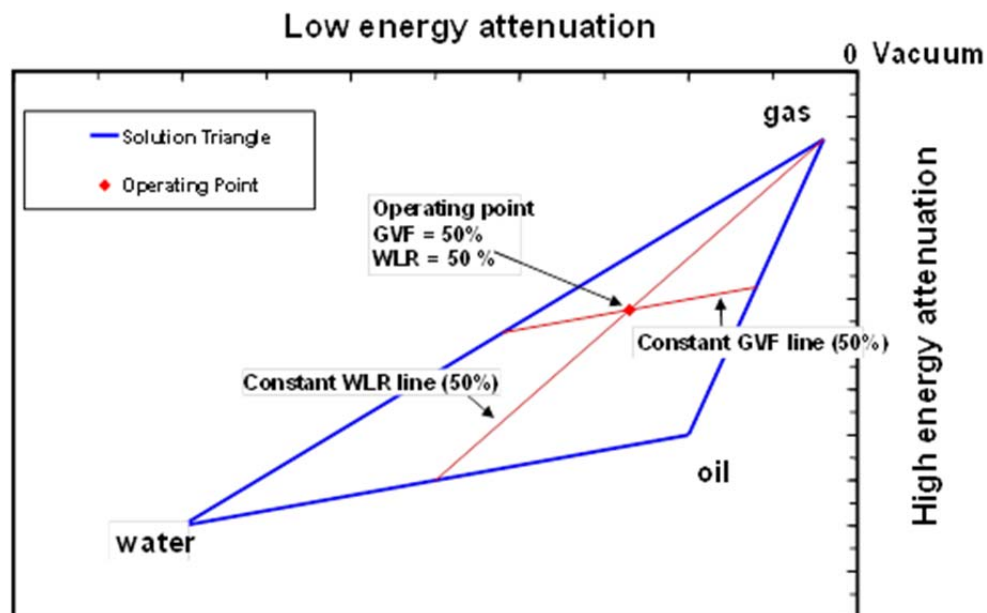


Figure J.2. Triangle of Gamma Detector Count Rates (Figure courtesy of Schlumberger)
The figure illustrates a cross-point solution of a 50% gas holdup with 50% water cut.

From the liquid fractions, the water cut is calculated. Pressure and temperature sensors may be used with an onboard PVT package to compute the expected density of each phase at standard conditions. The phase densities, combined with the fractional components, allow for calculation of mixture density. Total mass flow rate can then be computed using the dynamic pressure drop across the Venturi. While the basic principle of a Venturi meter operated in multiphase flow is not unique to the Vx meter, characterization of the Venturi response in flow over a large range of flow conditions and fluid types is proprietary. A limited number of details on discharge coefficient response with respect to Reynolds number for the Vx meter have been given by Pinguet et al. [2009b; 2011].

J.2 Applications

The Vx meter is intended for a wide range of applications in land and offshore installations. A subsea version of the meter is also available. A significant number of case studies discussing the use of the Vx meter in various areas was found in the literature [07-WT-162, 2007; Hompoth et al., 2008; Pinguet et al., 2008; 08-WT-0012, 2008; Pinguet et al., 2009a; 2009b; Pinguet, 2010]. These case studies cover the use of the Vx meter in cold production (gas lift, downhole pumping, surface pumping, etc.), as well as hot production (surface heating,

SAGD, cyclic steam stimulation, etc.). Other applications include diluents production and well testing. A comprehensive list of the experience of the Vx meter in various applications has been summarized by Pinguet et al. [2011], and reproduced in Table J.1.

Table J.1 Current Vx Meter Experience with Heavy Oil Production Techniques

TECHNIQUE	PROCESS	VX TECHNOLOGY EXPERIENCE	GENERAL CHALLENGES FOR MPFM
Cold Production	Gas Lift	Yes	• Low Reynolds Number • High GVF • High Viscosity
	Downhole Pumping (ESP)	Yes	• Low and very High Reynolds Number • High Viscosity • Low Production
	Surface Pumping (PCP)	Yes	• Low and very High Reynolds Number • High Viscosity • Low Production
	Rod Pump	Yes	• Intermittent Flow • Very Low Reynolds Number • High Viscosity • Low Production
Hot Production	Surface Heating	Yes	• No Specific Limitation • (T<150°C generally)
	In-Situ Combustion	No	• High Temperature (>100°C) not an issue for Vx • Low Producer
	THAI	No	• High Temperature (>170°C) • High GVF
	SAGD or In-Situ Thermal Process with Pumping Topside or Downhole	Yes	• High Temperature (>150°C) • High GVF • High Water Cut • Emulsions
	Cyclic Steam Stimulation	Yes	• Moderate Temperature not an issue for Vx • Low Producer • Low Pressure
	Vapor Extraction	No	• Same as SAGD
	SAGD with Gas Lift	Yes	• High Temperature • Very High GVF • High Water Cut • Several Gases Present
Solid Production	CHOPS	No (2011)	• Low Reynolds Number • Low GVF • Low Producer • High Quantity of Solids
Diluents Production	Diluents	Yes	• Low GVF • Low Producer • Low Pressure • Several Fluids Present (viscosity change)

J.3 Specifications

The Vx meter is offered in three different sizes: 29-mm, 52-mm, and 88-mm (3-inch, 5-inch, and 8-inch connections, respectively). The range of flow conditions covered by the Vx meter is summarized in Table J.2, while the operating envelope is shown in Figure J.3. Further mode-detailed specifications can be found in the flow meter's data sheet [05-WT-062, 2006].

Table J.2. Operational Range for the Vx Meter

The Vx meter can operate in multiphase (oil mode) and wet-gas (gas mode) conditions.

PARAMETER	RANGE
Maximum working pressure, psi	5,000 (optional 15,000)
Temperature rating, °F	-4 to 302 (optional 392)
Liquid viscosity, cP	0.1 to 2,000
Water/Liquid ratio, %	0 to 100
Gas Volume Fraction, %	0 to 98 (oil mode) 90 to 100 (gas mode)

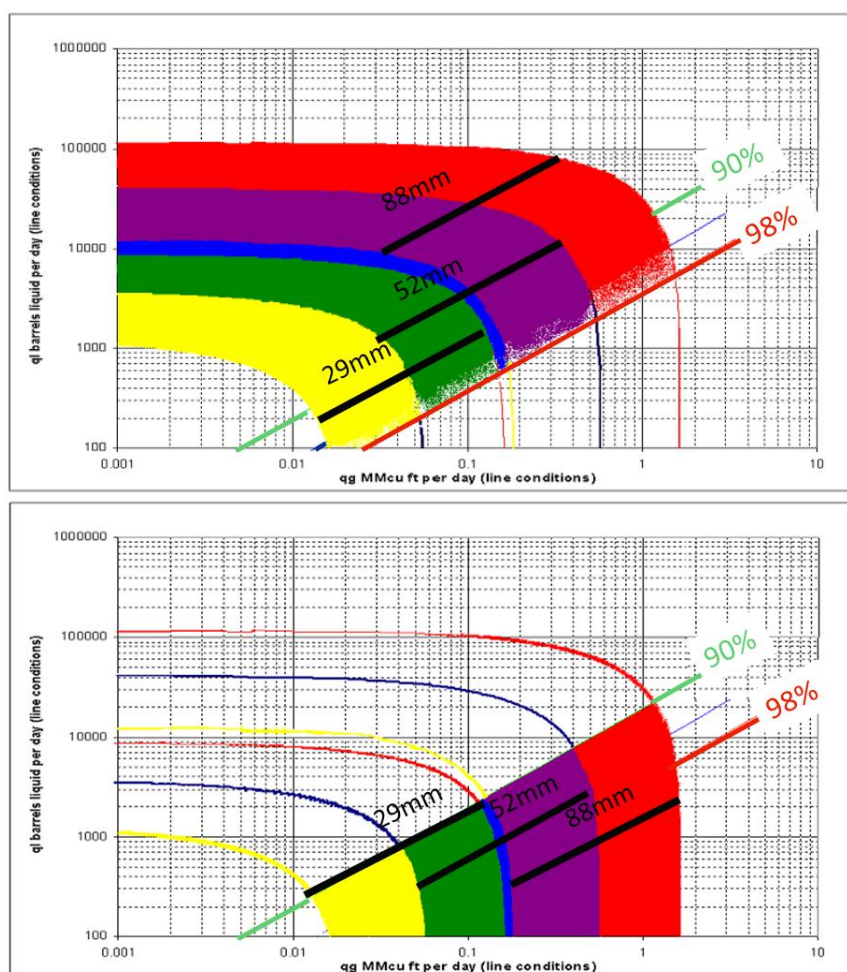


Figure J.3. Operational Envelope of Vx Meter: Oil Mode (top), Gas Mode (bottom) (Figures courtesy of Schlumberger)

The oil and gas modes together bracket flow conditions ranging from approximately 100 bpd to 100,000 bpd liquid, and 0.001 MMcfd to 1.8 MMcfd gas.

J.4 Performance

The software of the Vx meter has two interpretation models. Oil mode performance is expressed in terms of relative uncertainty for gas and liquid flow rates. Gas mode performance is given in terms of relative uncertainty for the gas flow rate and the maximum relative uncertainty and absolute uncertainty for liquid flow rates. The water cut has approximately the same level of accuracy using either modes independent of flow rate, and is expressed in terms of absolute uncertainty.

In the oil mode (GVF range between 0% and 98%), the gas flow rate relative uncertainty stated by the manufacturer ranges from $\pm 5\%$ to $\pm 15\%$, depending on the pressure. In this mode, the manufacturer's stated liquid flow rate relative uncertainty ranges from $\pm 2.5\%$ to $\pm 10\%$ and the water/liquid ratio absolute uncertainty ranges from $\pm 2.5\%$ to $\pm 8\%$ [08-WT-0037, 2008]. A complete set of uncertainty specifications for the Vx meter in gas mode and for the various meter sizes can be found in the manufacturer's specification sheet provided in 08-WT-0037 [2008].

Vx meter accuracy levels have been studied in a variety of flow loop test programs [08-WT-0037, 2008]. This subsection provides a summary of relevant case studies and performance data from flow loop and field tests.

- **NEL flow loop, summer 2006 [Pinguet et al., 2009a; 2009b]:** Flow loop tests were preceded by laboratory investigations to optimize chemical surfactants, concentration levels, and mixing methods to create water/crude-oil emulsions similar to those experienced in oilfield development. Results were used to then generate full-scale flowing emulsions with similar water-cut dependent viscosities to that of oilfield samples. During flow loop testing, samples were collected, and the viscosities tested using the Haake Falling Ball Viscometer method to verify the artificial emulsions at water cuts ranging from 0% to 100%. Viscosities at line conditions ranged from less than 10 cP to more than 600 cP.

The oil used during this testing was a mixture of Forties/Oseberg crude, water was a magnesium sulphate solution, and compressed nitrogen was employed for the gas. A range of flow rates, GVFs, process temperatures, and liquid viscosities were tested – first with conventional 3-phase flow, and then with artificially emulsified flow. Note that for a given water cut, the separator was filled with an emulsion and testing was conducted by changing only the gas hold-up and flow rate. A new batch of emulsion with a different water cut was used to change conditions. Liquid viscosities of the artificial emulsions at different water cuts and temperatures were measured after extraction from the flow loop. From this data estimates of viscosities were extrapolated.

Water cut was monitored through density output of a reference Coriolis meter and a reference densitometer, as well as periodically checked through sampling and offline Karl-Fischer analysis. The Coriolis, densitometer, and sampled emulsion water cut results were within 1% absolute uncertainty of each other over the test program. For emulsified flow tests only the “water” side of the test separator was utilized. Surfactant was injected into the multiphase flow stream in measured volumes until the desired water cut was reached for each condition. Mixed fluids were circulated for up to one hour until stable and uniform emulsion was achieved due to the induced turbulence from recirculation.

Results indicated the water cut difference versus GVF was within $\pm 3.5\%$ absolute (95% confidence level), and within $\pm 2.2\%$ for the 0% to 95% GVF range (90% confidence level) for the test meter plus reference instruments. Removing the flow loop uncertainty, the Vx meter water cut uncertainty is estimated at 2-3% (95% confidence level). Under a heavy oil conditions with Reynolds number ranging from 400 to 24,000 the Vx meter volumetric flow rate exhibited an uncertainty of 3-3.5% for a GVF range of 0% to 95% (95% confidence level), with uncertainty reduced to 2% for Reynolds numbers above 1,500.

- **CEPRO flow loop, 2004 [Pinguet, 2011; Pinguet et al., 2009a; 2009b]:** Flow loop testing consisted of more than 100 blinded data points taken under various flow conditions for three months at the Venezuelan facility. Natural crude oil, water, and natural gas supplied directly from production facilities were the fluids employed. Coriolis meters were used as single-phase references for all three fluids. Viscosity ranged from 75 cP to 2,750 cP. GVFs ranged from 0% to 99%, and water cuts from 0% to 80% with changing salinities. In 2005, the data were revisited with a new interpretation model to improve accuracy. With the new analysis, total liquid flow rates fell within $\pm 2.5\%$ of reading, or ± 100 bpd (95% confidence level). Note that this was within the accuracy of the entire flow loop, estimated at ± 1 -2%. The gas flow rate accuracy was reported to be within ± 5 -10%.
- **NEL flow loop, 2008 [Pinguet, 2011]:** Flow loop testing using nitrogen gas and Paraflex synthetic oil was conducted using 20-minute or less duration test points. Small amounts of water were initially added to the flow loop to avoid emulsion and stabilization issues. Thus, the separator was used only as a two-phase separator for gas and liquid. The Vx meter was installed on a horizontal 3-inch flow line, downstream of the gas injection point, with the inlet and outlet at 90-degree elbows. Over 171 points at two primary viscosities were recorded. The performance for groups of points broken down by percent GVF is shown in Table J.3 in terms of the root mean square parameter (RMS). Note that the viscosity is 500 cP, pressure is 80 psia, oil density is 900 kg/m^3 , and water cut is 0.5% for the majority of these points (133 points).

Table J.3. RMS Performance versus GVF Segmentation

The higher the RMS value, the higher the difference between the Vx meter measurement and the reference value.

GVF [%]	0-1	<10	<20	<40	<60	<75	<90	<95	<100
Number of Pts.	27	8	16	38	31	19	22	7	2
Water Cut, RMS	0.42	0.53	0.49	0.46	0.42	0.38	0.30	0.24	0.34
Number of Pts.	22	8	16	32	23	13	14	1	2
Q_m, RMS	0.08	0.04	0.07	0.07	0.07	0.12	0.06	0.07	0.3
Q_{v,liquid}, RMS	0.32	0.36	0.28	0.32	0.31	0.42	0.27	0.3	1.2
Q_{v,gas}, RMS	0.12	0.45	0.83	1.96	3.65	2.98	8.86	1.1	8.4

- **High viscosity well field testing [07-WT-162, 2007]:** Field testing was conducted in over 300 active wells, and the four most challenging in terms of high-emulsion

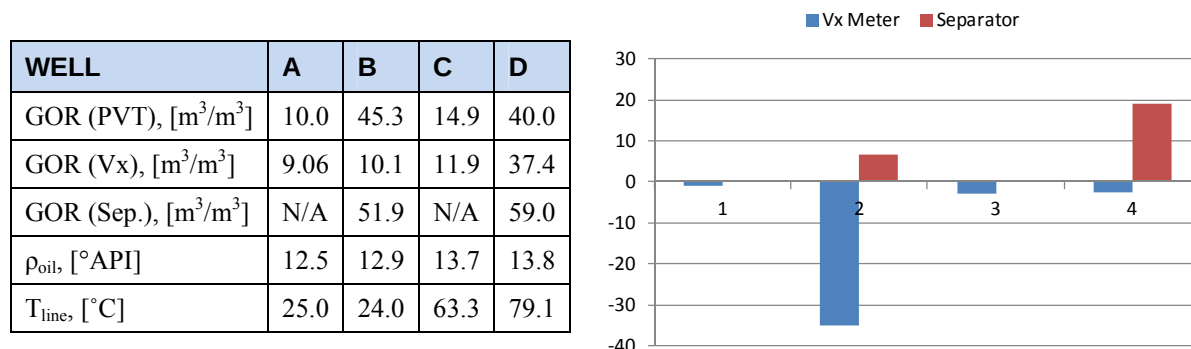
production were selected for analysis. Line condition viscosities ranged from 400 cP to 6,000 cP. Table J.4 summarizes the average conditions and relative error measured by the Vx meter.

Table J.4. Results of Vx Technology-Based Operations in Four High-Emulsion Wells
Relative errors on the liquid flow rate up to -10% and on the gas flow rate up to +18% were obtained with liquid viscosities between 400 cP and 6,000 cP.

LINE CONDITION					RELATIVE ERROR, %	
WELL	PRESSURE, psi	TEMPERATURE, °F	GVF, %	DIFF. PRESSURE VOLUME, mBar	LIQUID	GAS
1	154	149	85	1,113	-6	13
2	174	132	90	1,288	-10	12
3	179	140	83	1,543	-8	10
4	183	130	85	1,369	-8	18

- **Heavy oil field testing, Monogas, Venezuela [08-WT-0012, 2008]:** Extra heavy oil in the range of 8.6 °API to 10.6 °API recovered using cold production methods without diluents is lifted by progressive cavity pumps in this field. The viscosity of liquids at line conditions reached up to 6,300 cP. A comparison of Vx metering performance versus tank testing data indicated less than 2% overall uncertainty in relative error of liquid flow rate.
- **Heavy oil field testing, South America [06-WT-083, 2006]:** Gas/oil ratios were measured on four wells using both a Vx meter and a separator. A heater was used to increase line temperature to 50°C to 60°C, lowering the line viscosities with a maximum value up to 24,180 cP. The data were compared to a PVT laboratory analysis. Operational conditions and computed error for each method are summarized in Table J.5. Note that for Wells A and C, the separator was unable to provide a measurement due to flow stabilization issues. On Well B, the viscosity at line conditions was outside the operational envelope for the Vx meter.

Table J.5. Field-Tested Well Operating Conditions (left), and GOR Error Compared with PVT Laboratory Measurements (right)



- Vx metering technology applied to SAGD well production, Canada [Hompoth et al., 2008; Pinguet et al., 2008; Pinguet et al., 2010]: Steam Assisted Gravity Drainage (SAGD) is based on the concept of using two horizontal wells – one on the bottom to capture heavy oil, and one on top for steam injection. SAGD wells produce challenging flows for meters, characterized by high temperatures, unstable flow regimes, H₂S, abrasive sand, steam flashing, and emulsified foamy oil.

Field testing of the Vx metering technology on SAGD-produced wells was first undertaken in 2007 on a Suncor well in Alberta, Canada. Benchmarking was performed against a test separator with a Coriolis meter at the outlet. Prior to testing, property data were gathered for incorporation into the Vx meter models. Emulsion sample analyses showed the inversion point to be between 55% and 65%. During testing, bitumen viscosity at line conditions was approximately 4.9 cP, with line temperatures of 170°C to 180°C. Sensitivity studies that varied salinity, viscosity, inversion point, and gas steam ratio over a wide range showed these parameters to have minimal effect on the Vx-measured net oil flow rate (Q_v, oil at standard conditions). The overall liquid flow rate relative error of the Vx meter was observed to be less than 2.5%, and the water cut was within 2% to 5% up to a GVF of 60%. The data were observed to be less noisy compared to the data from the separator.

A second SAGD field trial in 2009 was conducted in three stages. The first stage tested nine wells for two months against a test separator. The second stage shortened the flow period from 12 hours to six hours, in an effort to demonstrate reproducibility of the flow measurements over a shorter duration of testing. The third stage reprocessed the 12-hour test data taken in the first stage for four hours to determine the ability to shorten testing time even further. Uncertainties for all of the phases were computed for the testing as follows:

- ±2% uncertainty on water
- ±2% uncertainty on liquid rate
- ±2% uncertainty on total gas flow rate

Data reprocessed for a four-hour interval showed very good consistency with 12-hour test results. This indicated testing for shorter time periods would be acceptable, thereby allowing for faster optimization of production.

J.5 References

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APPENDIX K

Review of Roxar Multiphase Flow Meters

K. REVIEW OF ROXAR MULTIPHASE FLOW METERS

This summary covers the Roxar 1900VI multiphase flow meter and the new generation Roxar 2600 meter. Unless otherwise stated, the information presented applies to both the Roxar 1900VI and Roxar 2600 meters. The following subsections provide a description of the Roxar meter, its principle of operation, common applications, and technical specifications. Finally, a summary of the data and general information on the meter's performance is presented.

K.1 Meter Description and Principle of Operation

The Roxar multiphase flow meter is a flow measurement instrument that is designed to accommodate 0% to 100% water/liquid ratios (WLRs) and 0% to 100% GVF's (Roxar 1900VI Datasheet) (Roxar 2600 Datasheet). The meter calculates gas, liquid, and water flow rates without separation through measuring the fluid electrical impedance and sizing the Venturi discharge coefficient for the expected fluids extracted from the reservoir. Correlations are used to determine the phase velocities and distributions. The Roxar meter measures pressure, delta pressure, temperature, multiple velocities, near wall measurements, and real-time characterization of flow patterns. Figure K.1 and Figure K.2 provide graphical representations of the Roxar 1900VI and Roxar 2600 meters, respectively.

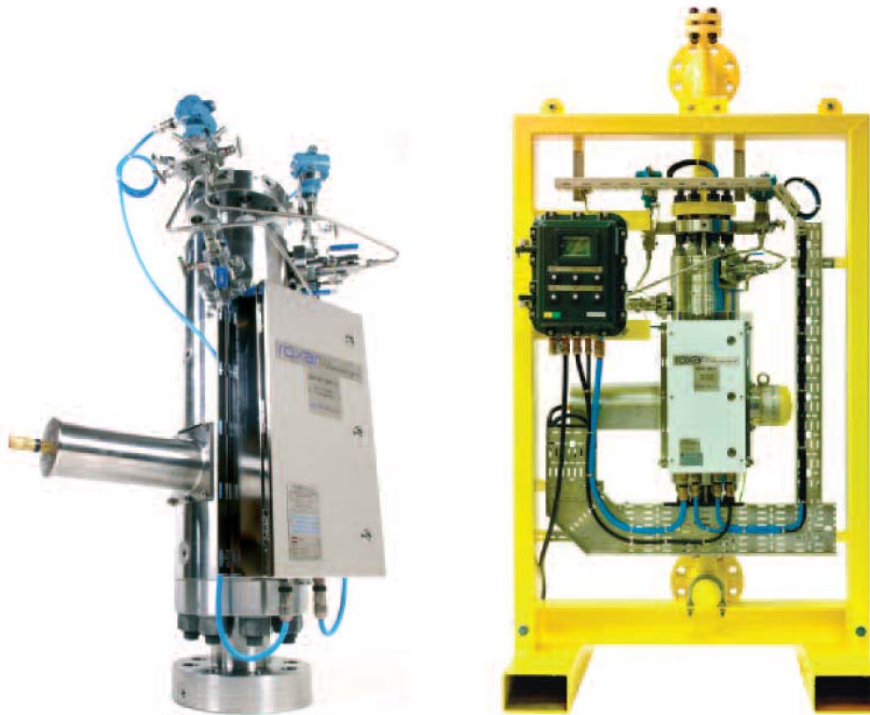


Figure K.1. Roxar 1900VI Multiphase Flow Meter

The Roxar 1900VI is a second generation flow meter and has been in service at least 15 years. The meter is manufactured for onshore (left) and offshore (right) applications. Images used with permission from Roxar.

A gamma densitometer is used for density measurements within high GVF conditions. Non-gamma versions are also available for low GVF applications.

The velocity measurements are based on a cross correlation between the electrodes for the gas velocity and Venturi equations are used for the liquid velocity (Roxar Technical Bulletin, 2011). The Roxar multiphase flow meter employs an adapted Bruggeman mixed permittivity model to aid permittivity calculations. This model allows the meter to not be influenced by emulsions and, therefore, provides a basis for heavy oil applications (Roxar Technical Bulletin, 2011). The Roxar multiphase meter technology used for the velocity measurements can be used for applications with emulsions and high viscosity below 90% GVF and with the correct meter configuration (RFM-TD-01676-191, 2006)

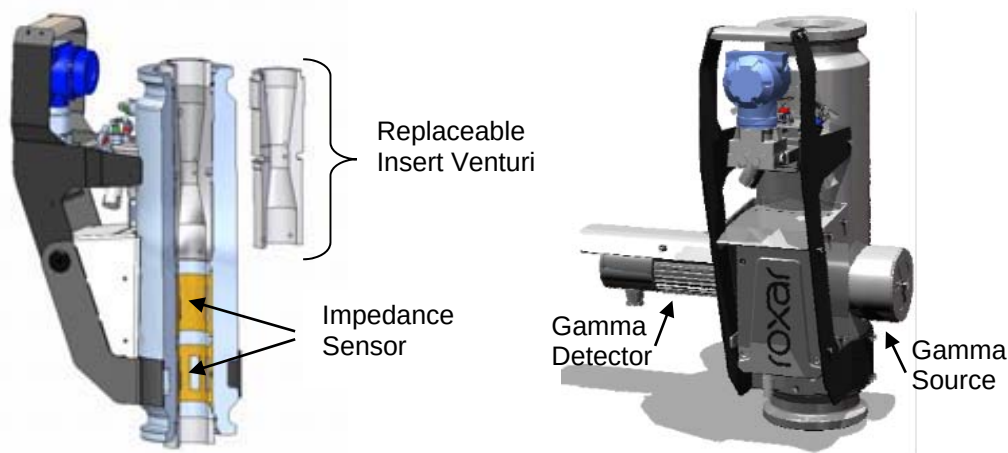


Figure K.2. Roxar 2600 Multiphase Flow Meter

The Roxar 2600 meter has a sleeve design Venturi for easy replacement (left). Impedance sensors (left) allow phase fraction measurement of gas, oil, and water. Non-gamma (left) and gamma (right) options are available. Images used with permission from Roxar.

The meter requires certain input parameters to yield the multiphase flow rates. Reference oil, water, and gas densities, prevailing pressure and temperature conditions, as well as oil permittivity and water salinity are all required inputs.

The Roxar 2600 can optionally be supplied with a Gas/Wet-Gas software module, specially designed for ultra-high GVF applications (95% to 100 % GVF). PVT data and WLR must be given as input data to the software (Roxar Internal Document 091989, 2011). The Roxar 2600 also offers a field-replaceable Venturi for evolving flow conditions. The 1900VI does not support either of these capabilities.

K.2 Applications

The Roxar meter is designed for land, offshore, and subsea applications. The meter can also accommodate light, heavy, and extra heavy oil and has been field tested under these conditions (Roxar Technical Bulletin, 2011). The Roxar multiphase meter is able to handle oil densities up to $1,050 \text{ kg/m}^3$ and viscosities up to 10,000 cP (Roxar Technical Bulletin, 2011).

The meter is designed for well testing (production, exploration), production monitoring, and allocation metering (Roxar 1900VI Datasheet) (Roxar 2600 Datasheet).

K.3 Technical Specifications

The meter must be installed vertically with a blind tee. The Roxar 1900VI meter can handle pressures up to 10,000 psig and temperatures up to 302°F. Roxar has manufactured the 1900VI model meters between 2-inch and 12-inch pipe sizes, with the 3-inch being four feet tall. The Roxar 1900VI 3-inch model is 600 kg and all sizes consume 12 watts of electrical power. For low GVF conditions, the Roxar 1900VI meter is designed for velocities between 1.5 m/s to 15 m/s and for high GVFs, it can handle between 3.5 m/s and 35 m/s.

The Roxar 2600 meter can handle pressures up to 5,000 psig and temperatures up to 302°F. Roxar has manufactured the 2600 model meters between 2-inch and 6-inch pipe sizes, with the 3-inch being 26 inches tall. The Roxar 2600 3-inch model is 110 kg and all sizes consume 12 watts of electrical power while providing 12,000 measurements per second.

K.4 Performance Information

The standard specifications for the Roxar 1900VI meter provide typical uncertainties within a 95% confidence interval of: +4% relative for the liquid rate; +3% absolute for the water cut, and +8% relative for the gas rate (Roxar 1900VI Datasheet). For the Roxar 2600 meter, the manufacturer's specified typical uncertainty for a 95% confidence interval is $\pm 2\%$ relative for the liquid rate, $\pm 2\%$ absolute for the water cut, and $\pm 5\%$ relative for the gas rate (Roxar 2600 Datasheet).

The Roxar 1900VI multiphase meters are deployed in the PEMEX oil fields (Mexico) by an international well testing company. The wells vary from extra heavy oil (10 °API) to light crude (30 °API). The maximum allowed error in the well testing contracts is $\pm 7\%$ oil relative uncertainty. More than 25,000 well test measurements have shown that the Roxar multiphase meter handles all flow conditions (Roxar Technical Bulletin, 2011).

In 2008, a field verification test was performed on a 2-inch Roxar 1900VI in Venezuela. The oil was more than 1,000 kg/m³ and classified as extra heavy oil. The liquid rate uncertainties were within $\pm 15\%$ and the gas rate uncertainties were within $\pm 10\%$ (Roxar Technical Bulletin, 2011). Roxar states that the larger uncertainties are due to the well flow rates being much less than the design pressure drop for the 2-inch meter.

Roxar has also published what influential quantities have an effect on their meter accuracy (Roxar Internal Document 091980, 2011). Variations in water salinity have no effect on water-cut readings under all process conditions with less than 60% to 80% water cut. Since sand has dielectric properties very close to oil, any sand will be measured as a part of the oil. However, dielectric measurements are volume based; sand will have little effect on the performance of the meter. Wax present in the flow or deposited inside the sensor will be measured as oil because the density and dielectric properties of wax and oil are similar.

An expanded measurement uncertainty table is provided from the Roxar 2600 functional description and presented in Table K.1 (Roxar Internal Document 091980, 2011).

Table K.1. Measurement Uncertainty for the Roxar MPFM 2600 Multiphase Meter*The reported uncertainties correspond to a 95% confidence interval.*

		COMBINED EXPANDED UNCERTAINTIES, %		
SUB RANGE	GVF RANGE	GAS	LIQUID	WLR
A	0-25 %	$\pm 8^{(1)}$	± 3	± 2
B	25-85%	± 6	± 3.5	± 2.5
C	85-96%		± 5	± 3.5
D	96-98%		$\pm 8^{(2)}$	$\pm 4.5^{(2)}$
E	98-100%		See Wet-Gas Mode Specification ^(2,3)	See Wet-Gas Mode Specification ^(2,3)
REPEATABILITY:		± 0.25	± 0.25	± 0.25
The uncertainties above are valid for line pressure > 10 barg. For line pressure < 10 barg, the above uncertainty specification must be multiplied by a factor of 1.3.				
The MPFM 2600 can optionally be supplied in a non-radioactive/non-gamma version. In such a case, the above uncertainty table must be multiplied by 1.2 for sub-ranges A & B. For sub-range C (maximum 95% GVF), the multiplication factor is 1.5.				
⁽¹⁾ For GVF > 5%.				
⁽²⁾ The MPFM 2600 can optionally be supplied with a Gas/Wet-Gas software module, specially designed for ultra-high GVF applications (95% to 100% GVF). Please refer to the separate uncertainty specification for the Wet-Gas Mode.				
⁽³⁾ Wet-Gas Mode specification: PVT data and WLR must be given as input data. Gas mass flow uncertainty: 2.5% rel. within calibrated pressure range. Liquid mass flow uncertainty: 5% rel. within calibrated pressure range. WLR uncertainty: N.A. The uncertainties in Wet-Gas Mode are only valid for line pressure > 10 barg.				

The Roxar 2600 was also independently evaluated by the research group NEL and third parties in 2009. NEL indicated that the meter performed well during the tests and published the following results (Report No: 2009/265, 2009):

- Maximum error in measured liquid flow rate in oil continuous flow was -2.81% and in water continuous flow was -3.5% with a total spread of 6.1%, mean offset of -0.59% and a standard deviation of 1.77%.
- Maximum error in gas flow was -8.78% with a total spread of 15.77%, mean offset of -2.45%, and a standard deviation of 4.7%.
- In oil continuous flow, maximum deviation from the reference water cut was 1.41%. In water continuous flow it was 2.75%. Water-cut errors gave a total spread of 3.78% with a mean offset of 0.42% and a standard deviation of 0.89%.

NEL also indicated oil flow rate measurements were within the meter's stated uncertainties (Report No: 2009/265, 2009).

K.5 References

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APPENDIX L

Review of Weatherford Multiphase Flow Meters

L. REVIEW OF WEATHERFORD MULTIPHASE FLOW METERS

Weatherford offers a suite of flow metering technologies for a variety of applications and operating conditions:

- Weatherford's Alpha VS/R and VS/RD Wet-Gas/Multiphase flow meters comprise an in-line multiphase flow metering system that combines different technologies to estimate the flow rates of gas, oil, and water.
- Red Eye Multiphase Metering System (REMMS) uses partial separation combined with conventional gas/liquid flow measurement.
- Weatherford's optical flow meter is designed for downhole multiphase flow measurement.

The following subsections provide more details about the operation, specifications, and performance of the various meters.

L.1 Alpha Meter

Weatherford produces three Alpha-series flow meter modules, which are combinations of the following primary instruments: Venturi-nozzle, Sonar flow meter, Red Eye water cut meter, and a densitometer. They may be arranged in the following ways for the indicated applications:

- VS (Venturi-nozzle and Sonar): wet gas (fixed water cut)
- (Venturi-nozzle, Sonar, and Red Eye): wet gas (0% to 100% water cut)
- VS/RD (Venturi-nozzle, Sonar, Red Eye, and Densitometer): full multiphase (0% to 100% GVF and water cut)

An Alpha VS/RD assembly is shown in Figure L.1, with an illustrative schematic of the internals of a VS spool. The Venturi and Sonar combination can provide gas and liquid flow rates as described below.

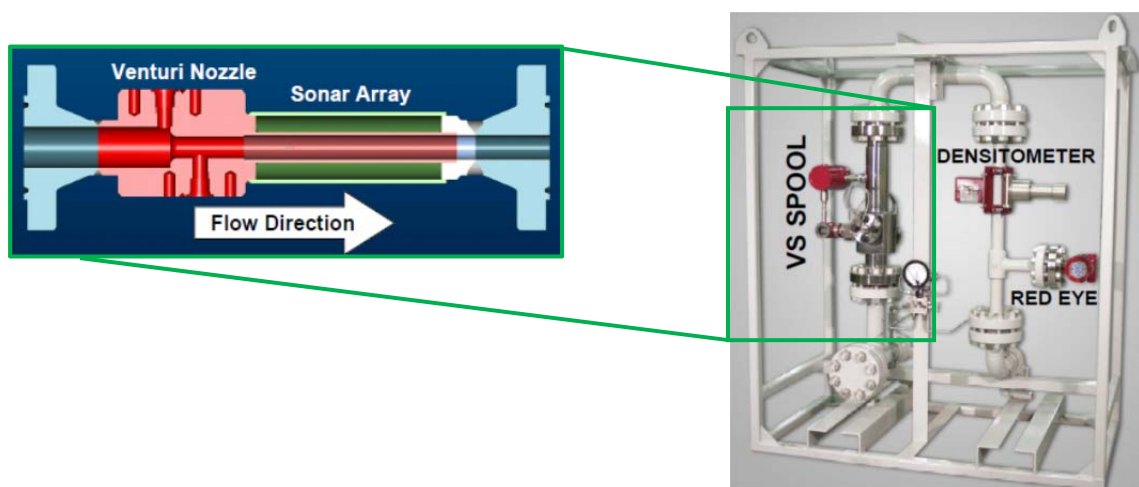


Figure L.1. Alpha VS/RD Meter with Illustration of VS Spool Internals

The flow enters the skid horizontally, flows through a blind tee, flows upward through the Venturi-Sonar (VS) spool, and then downwards through a pipe section where the gamma densitometer is installed followed by the Red Eye water-cut meter.

The Sonar meter provides a measurement of bulk flow rate in the pipe, using the principle of direct proportionality of volumetric mixture flow rate to convective mixture velocity. The meter is composed of an array of piezoelectric film/strain sensors circumferentially mounted and axially distributed in the throat section of the Venturi. These sensors detect “time-of-flight” dynamic pressure fluctuations resulting from turbulent eddies that convect with the fluid. Negligible over-reading in wet gas has been found by the manufacturer.

The Venturi-nozzle is an extended throat meter, following ISA 1932 geometry. Static pressure drop across the converging section is measured, and is proportional to the momentum of the stream. Over-reading is much more pronounced than in sonar meters and is a function of GVF. The nozzle has discharge coefficients that have been extensively characterized with respect to flow Reynolds numbers. Thus, the over-reading contrast between the Sonar and Venturi may be used to provide total gas and liquid flow rates in real time according to the manufacturer. Accuracy is reported to diminish outside the wet-gas flow regime when solely using the VS spool to compute liquid/gas flow rate.

The third instrument is a Red Eye water-cut meter (0% to 100%). This is a filter spectrometer that uses near-infrared absorption to measure water content in the stream. It is reported to operate independent of flow regime, flow rates, water salinity, GVF (up to 99.5%), and in the presence of hydrate inhibitors. Calibration is needed prior to operation, requiring that the sensor gap be filled with a “dry” oil sample from the reservoir for recording of photocurrents. Default factory calibration values are typically used in lieu of water-phase calibration.

The final instrument that can be added, specifically for measuring multiphase flows with low GVF (< 90%), is a gamma densitometer. This device uses a single-beam single-energy-level Caesium-137 source (662 keV) to provide a direct measurement of the liquid holdup (mixture density) in the pipe. This, combined with knowledge of three-phase component densities, allows for calculation of GVF outside the wet-gas regime. Gas, oil, and water densities are determined via PVT relations, while the Red Eye provides an additional independent measurement of the liquid phase density. This minimizes uncertainty interaction between the GVF and water-cut calculations compared to a VS/R meter alone. No iterative solution is required since GVF and water cut are measured independently, and the cross-checks between total flow using the Venturi nozzle (VRD mode) and Sonar (SRD mode) allow flagging of potential problems [Rodriguez, 2011].

L.1.1 Applications

The Alpha VS/RD flow meter has been primarily used in land operations. According to the manufacturer, the main applications of the Alpha VS/RD meter include:

- Well monitoring, providing real-time production data.
- Replacement of test separators, providing a faster and more compact solution to well testing operations.
- Wet-gas and multiphase applications.
- Heavy oil applications.

L.1.2 Specifications

Specifications for the Alpha VS/RD multiphase flow meter and the Alpha VS/R wet-gas flow meter are summarized in Table L.1 [Weatherford 7950.00, 2010; Weatherford 6018.00, 2009].

Table L.1. Specifications for Alpha Flow Meters

Incorporation of the gamma densitometer allows covering multiphase and wet-gas scenarios within a single unit.

SPECIFICATION	ALPHA VS/RD	ALPHA VS/R
Available Line Size	2, 3, 4, 6, 8, or 10 inches	3, 4, 6, 8, or 10 inches
Flow Regimes	All	All
GVF	0% to 100%	$X_{LM} < 0.4$ (wet gas)
Water Cut	0% to 100%	0% to 100%
Ambient Temperature	14°F to 140°F (flow computer)	14°F to 140°F (flow computer)
Process Temperature	-4°F to 185°F	-4°F to 185°F
Pressure Rating	up to 3,000 psi	up to 3,000 psi
Viscosity	unspecified ¹	unspecified ¹
Salinity	Saturated	Saturated
Gamma Densitometer	Yes	No
Corrosive Media	Yes (SS, Duplex, CRA)	Yes (SS, Duplex, CRA)
Max Liquid Rate	10,000 bpd	10,000 bpd
Max Gas Rate (@ 100 psig)	100 MMscfd	100 MMscfd

L.1.3 Performance

A summary of Weatherford's specified uncertainties for the Alpha VS/RD multiphase flow meter is shown in Table L.2 for different GVFs [Weatherford 7950.00, 2010]. The manufacturer's stated uncertainties for the Alpha VS/R wet-gas meter are given in Table L.3 in terms of the Lockhart-Martinelli parameter X_{LM} [Weatherford 6018.00, 2009].

Table L.2. Alpha VS/RD Multiphase Flow Meter Accuracy [Weatherford 7950.00, 2010]

The manufacturer's stated uncertainties are summarized according to the GVF range.

	GVF < 20%	20% < GVF < 90%	90% < GVF < 98%	GVF > 98%
Gas flow rate relative uncertainty	±10%	±7%	±5%	±5%
Gas flow rate repeatability	±0.1%	±0.1%	±0.05%	±0.05%
Liquid flow rate relative uncertainty	±5%	±7%	±10%	±75 bpd
	GVF < 20%	20% < GVF < 95%	95% < GVF < 98%	90% < GVF < 99.5%
Liquid flow rate repeatability	±0.05%	±0.1%	±0.1%	±10%
Water-cut absolute uncertainty	±2%	±3%	±4%	±10%
Water-cut absolute repeatability	±0.2%	±0.5%	±1%	±3%

¹ Results from field trials have shown success flowing high-viscosity 18 °API crude at temperatures of 50°F to 70°F.

Table L.3. Alpha VS/R Wet-Gas Flow Meter Accuracy [Weatherford 6018.01, 2008-2009]*The meter uncertainties are given in terms of the Lockhart-Martinelli parameter X_{LM} .*

Liquid loading/approx. GVF @ 100 bar	Type I Wet Gas	Type II Wet Gas	Multiphase
	$0.02 > X_{LM} > 0.00$ 99% to 100% GVF	$0.40 > X_{LM} > 0.02$ 90% to 99% GVF	$X_{LM} > 1.00$ 0% to 80% GVF
Gas flow rate	±5% (rel.)	±5% (rel.)	±20% (rel.)
Liquid flow rate	±150 bpd (1 m ³ /hr)	±20% (rel.)	±10% (rel.)
	95% < GVF < 99.5%	20% < GVF < 95%	0% < GVF < 20%
Water cut	±10%	±5%	±2%

A summary of case studies and flow meter performance is presented here:

- **Wet-gas and multiphase flow loop testing [Rodriguez, 2011a; Johansen et al., 2007]:** Wet-gas testing conducted at CEESI and NEL was carried out at both low and high gas densimetric Froude number flow conditions. Most Type II wet-gas points fell within ±20% relative error bands on liquid flow rate, while Type I points fell within ±0.5 m³/hr, regardless of Froude number. Gas flow rates remained generally confined to ±5% relative error. Multiphase testing at SwRI was conducted on flows spanning the entire GVF range. Results for both liquid and gas flow rates remained generally within ±10% relative error. The algorithm was set to operate under VRD mode. However, it was found that the performance of the SRD mode closely matched that of the VRD, though some test conditions were below the minimum threshold for Sonar operation.
- **Field deployment performance [Rodriguez, 2011a]:** Permanent onshore and offshore installations of four oil companies received Alpha flow meters, primarily as replacements for portable or existing test separators. Performance agreed with accuracy specifications from flow loop testing. In one instance, the meter has been approved for use in allocation purposes.
- **Testing and deployment, Kuwait [Johansen, 2011]:** Kuwait Oil Company pilot tested an Alpha VS/RD and the results met company accuracy tolerances. After testing, the meter was approved for deployment in a number of locations for possible replacement of conventional test separation facilities.
- **Well testing, United States [Lievais, 2010a]:** Existing test separators were replaced at five gas-lifted well locations with Alpha VS/RD meters. Overall test times were reduced by eliminating previously necessary purges, and making it easier to establish whether stable flow conditions had been reached. Advantages also included improved well test repeatability, and reduced risks associated with large onsite pressurized separators.
- **Field testing, Prudhoe Bay, Alaska [Ramakrishnan et al., 2009; Lievais, 2010b]:** Testing of both VS/R and VS/RD meters at 15 gas-lifted wells in a BP-operated field was conducted. Average GVF of the tests ranged from 84% to 98%, while the average water cut spanned from 2% to above 90%. Results were compared against a portable separator with single-phase outlet reference meters. VS/RD gas results were within ±7% relative to reference data, liquid rates were within ±8%, and water cut was within ±5 (absolute). Gas flow results using the VS/R meter had comparable

accuracy. However, higher relative errors were seen in liquid rates (primarily bias/systematic error) compared to the VS/RD meter.

L.2 REMMS

The Red Eye Multiphase Metering System (REMMS) manufactured by Weatherford is based on partial separation technology combined with classic liquid/gas metering. REMMS is composed of the following three primary components: a gas-liquid cylindrical cyclone separator, flow metering instruments, and level control valves. Figure L.2 shows a drawing of an example system, along with a flow schematic.

Separation of the gas and liquid phases first occurs in the cyclone separator, after which the individual streams are measured using conventional flow meters. An optical Red Eye water-cut meter is installed on the liquid stream to provide water-cut data. Liquid and gas control valves, together with differential pressure transmitter level indicators, are used to maintain an optimal level in the separator. The gas and liquid streams can be either recombined at the outlet of the system, or allowed to continue into separate flow lines.

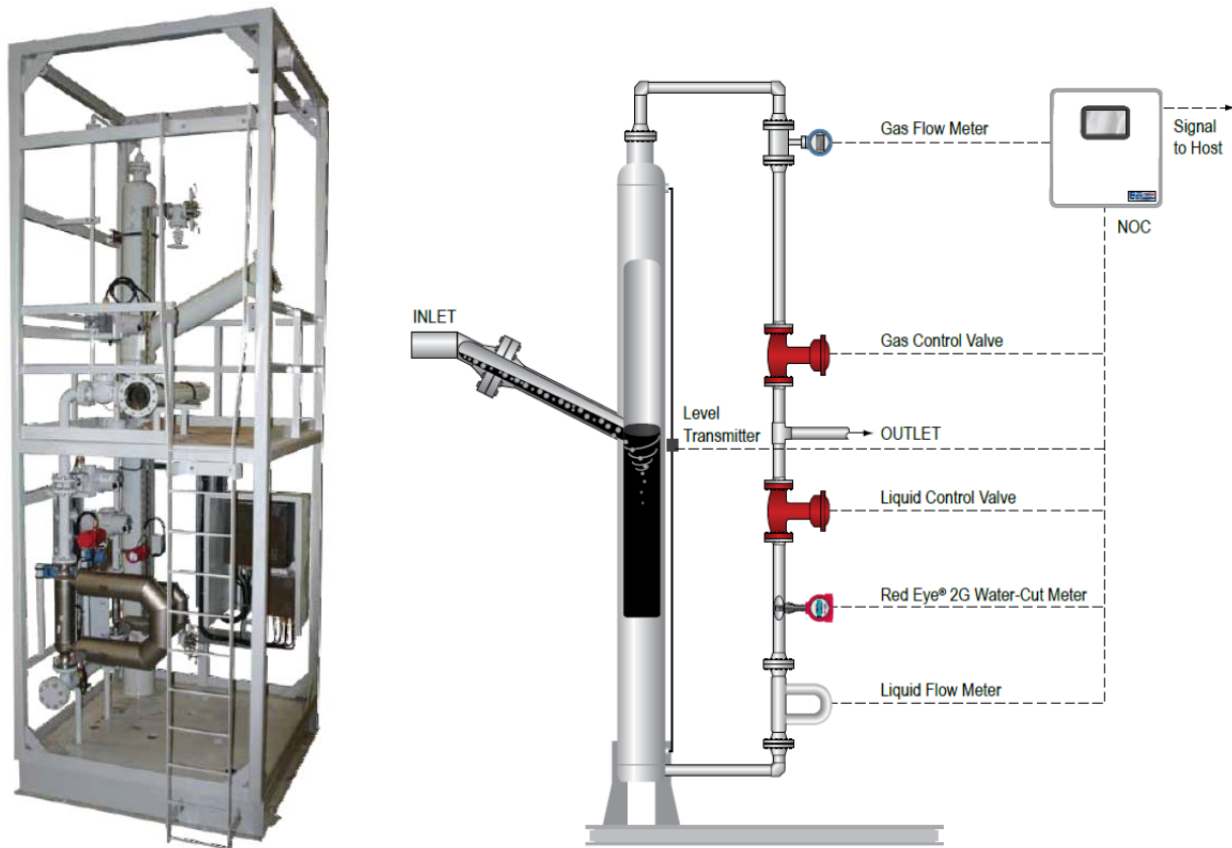


Figure L.2. REMMS Assembly and Flow Schematic

REMMS technology is based on separation of the liquid from gas, metering both streams independently, and checking water cut of the liquid downstream.

L.2.1 Applications

The REMMS assembly is primarily for use in land operations, but may also be used offshore. According to the manufacturer, the main applications of the Alpha VS/RD meter include:

- Well testing
- Production monitoring and flow assurance
- Heavy oil metering [Lievois, 2010c]

L.2.2 Specifications

Specifications for the REMMS are outlined below per Weatherford datasheets [Weatherford 5317.00, 2009; Rodríguez, 2011b] (see Table L.4).

- Non-nuclear
- 0% to 100% water cut
- Salinity up to saturation
- Turn-down ratios from 40:1 with single meters, and up to 100:1 with multiple meters
- Process temperature up to 450°F
- Suitable for portable applications ($\sim 1/8^{\text{th}}$ the wet weight of a vertical separator, and $\sim 1/64^{\text{th}}$ the wet weight of a horizontal separator)
- Suitable for all flow conditions (steady to slug flow)

Table L.4. REMMS Specifications
Pressure, temperature, and other limits are shown for two REMMS models [Rodríguez, 2011b].

PARAMETER	REMMS-C	REMMS
Pressure Rating	up to ANSI 900#	up to ANSI 900#
Process Temperature	Limited by Red Eye	Limited by Red Eye
Max Liquid Rate	10,000 bpd	20,000 bpd
Max Gas Rate (@100 psig)	5 MMSCFD	20 MMSCFD
Corrosive Media	Not preferred. SS system can be used but are very expensive.	Not preferred. SS system can be used but are very expensive.
MP Envelope Limits	Up to 95% GVF*	Up to 95% GVF*
Viscosity	1000 cP	1000 cP

*0-100% GVF if Alpha VS/R is installed downstream of the unit.

L.2.3 Performance

The Red Eye Multiphase Metering System accuracy specifications have been given by the manufacturer as shown in Table L.5 below [Rodríguez, 2011b]. However, units can be customized for client-specific requirements, including: size, metering options, accuracy, redundancy, and integration with existing infrastructure.

Table L.5. REMMS Manufacturer Uncertainty

Accuracy estimates indicate a relative gas and liquid flow uncertainty of $\pm 5\%$ [Rodríguez, 2011b].

PARAMETER	REMMS-C	REMMS
Gas (rel.)	$\pm 5\%$	$\pm 5\%$
Liquid (rel.)	$\pm 5\%$	$\pm 5\%$
Water Cut (abs)	$\pm 2\%$	$\pm 2\%$
Permanent Pressure Loss	0.5 to 1 bar	0.5 to 1 bar

A summary of a case study on REMMS performance is now presented.

- **Well testing and optimization, Alberta, Canada [Lievoy, 2010c]:** A REMMS was designed and manufactured for use in a heavy-oil tar-sand field being produced under steam-assisted gravity drainage. Operating temperature and pressure were 322°F and 110 psig, respectively. The system included a cyclonic two-phase separation system with conventional flow meters for gas and liquid outlets. Automation of well testing, optimization of steam injection, and production monitoring were primary advantages of the new system.

L.3 Optical Meter

According to Weatherford, their optical flow meter is designed for real-time measurement of downhole oil, gas, and water flow rates. Figure L.3 shows the various components of the assembly with the integrated pressure/temperature sensor. The upper assembly contains the optical pressure and temperature transducers, while the lower assembly is the flow meter. Through-bore access along its length allows for negligible pressure drop through the meter. The pressure and temperature sensors provide inputs for determining property data of the flow components.

The flow meter itself is composed of an inner sensor tube, an outer sleeve, fiber-optic flow and phase fraction sensors, and an optical bulkhead connector. The optical sensors are applied to the outside of the sensor tube and encapsulated within a hermetically-sealed annular cavity via welding of an outer sleeve to upsets on the sensor tube. The array of optical Bragg grating (BG) sensors is multiplexed on a single fiber-optic cable. According to Drakeley et al. [2008], “Bragg Gratings are wavelength-dependent mirrors that can be inscribed into the glass core of an optical waveguide.” For further details on BGs and their use in the Weatherford optical flow meter, see the former reference.

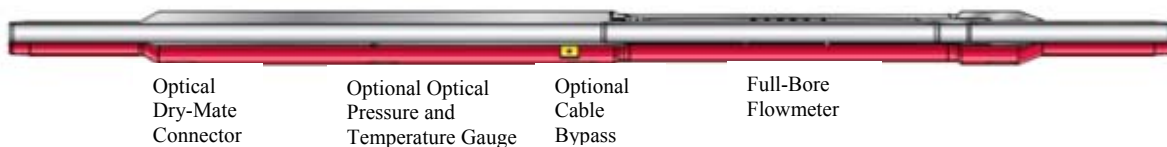


Figure L.3. Weatherford Optical Flow Meter Assembly

The two-phase optical flow meter is composed of an upper assembly with pressure and temperature sensors and a lower flow meter assembly.

Measurements of dynamic pressures in the flow stream allow for the deduction of two parameters: momentum averaged flow velocity (volumetric flow rate), and acoustic velocity in the mixture (speed of sound). Bulk velocity may be acquired through axially-displaced measurements of a time-varying fluid property that convects with the flow. Cross-correlation of

convective pressure disturbances (time lag of pressure waves) is used in this instance. For the speed of sound measurement, unsteady pressure measurements from any production-associated source (downhole choke valves, gas bubble breakout, ESPs, etc.) are obtained at multiple locations within the meter. This provides sufficient spatial and temporal resolution to determine the propagation of sound in the mixture, according to the manufacturer. The speed of sound may then be correlated to volume fractions of oil, water, and gas. Figure L.4 presents a schematic illustrating the flow measurements and resulting data flow.

Note that the optic flow meter alone measures only two phases, and may be set to either oil-water or liquid-gas (assuming a constant water cut). However, a three-phase configuration is possible by deploying the flow meter with a second P/T gauge separated by some significant vertical distance (usually less than 50 meters). The vertically-separated P/T gauges measure absolute pressure at each location. Flow rate data from the flow meter can then be used to calculate frictional pressure loss, and determine an accurate hydrostatic head and density of the mixture [Ferraris & Gonzalez, 2010].

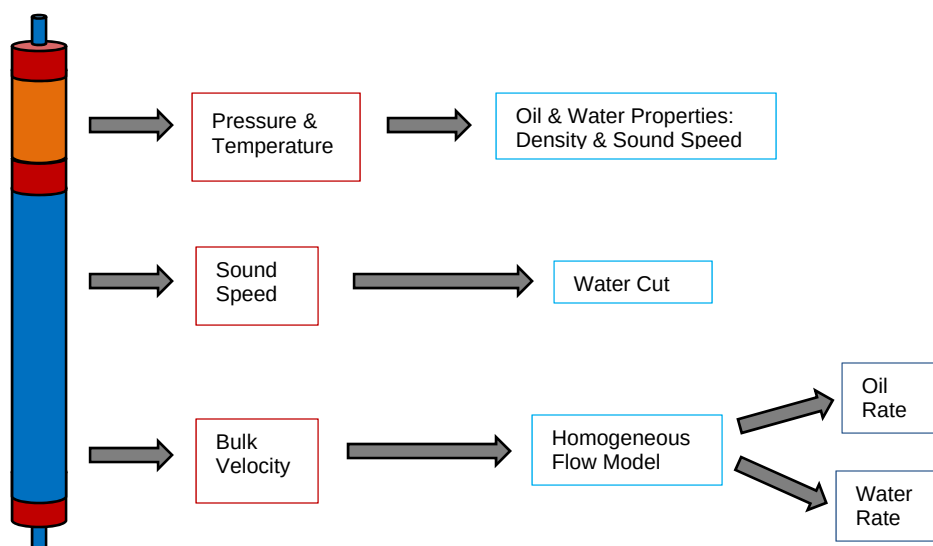


Figure L.4. Flow Diagram for Optical Meter Parameter Calculations
Pressure, temperature, speed of sound, and bulk velocity measurements allow for calculation of multiphase flow rates.

L.3.1 Applications

The optical flow meter is primarily intended for downhole monitoring of flow conditions. This includes the following application areas:

- Well testing
- Production monitoring and flow assurance (allows comingled production from different zones)
- Heavy oil

L.3.2 Specifications

The flow meter is 100% optical, with no moving parts and no sensors exposed to process fluids. No electrical energy is reportedly required downhole or at the wellhead, making the meter intrinsically safe. Furthermore, the flow meter is said to be capable of bi-directional measurements, allowing for logging inter-zonal cross flow in multi-zone completions. Optical connectors for both horizontal and vertical trees are available as optional add-ons. According to Weatherford, a distance of up to 31 miles between the optical flow meter and the surface integration system is possible without excessive attenuation of the signal. Manufacturer specifications for the optical multiphase flow meter are presented in Table L.6.

Table L.6. Specifications for Optical Flow Meter

Specifications for the optical flow meter are taken from the manufacturer datasheet [Weatherford 1510.03, 2008].

Available Line Size²	2 3/8-inch, 2 7/8-inch, 3 1/2-inch, 4 1/2-inch, 5 1/2-inch
Flow Regimes	not recommended for stratified or slug flows
GVF³	0 to 100%
Water Cut²	0 to 100%
Process Temperature	-58°F to 257°F (high temperature option: up to 302°F)
Storage Temperature	-58°F to 257°F (high temperature option: up to 302°F)
Pressure Rating	up to 15,000 psi
Viscosity	insensitive (have operated even with high μ mud flows)
Salinity	insensitive
Turndown Ratio	greater than 20
Minimum Flow Velocity	liquid: 3 ft/s, gas: pressure dependent ⁴

L.3.3 Performance

Optical downhole multiphase flow meter accuracy has been reported based on flow loop testing as [Unalmis, in preparation] as shown in Table L.7.

Table L.7. Optical Meter Uncertainty

Accuracy estimates indicate a total relative flow rate error of $\pm 5\%$ over the full range of GVF conditions [Unalmis, in preparation].

GVF Range	Total Flow Rate¹	Liquid Rate^{1,2}	Gas Rate¹	Water Fraction³
0-30%	$\pm 5\%$	$\pm 5\%$	$\pm 10\%$	$\pm 10\%$
30-90%	$\pm 5\%$	$\pm 20\%$	$\pm 10\%$	Unreliable
90-100%	$\pm 5\%$	$\pm 5\%$	$\pm 10\%$	Unreliable
¹ Relative error, ² Relative error to total flow rate, ³ Absolute error, all 95% CI (2σ).				

² Technology can be applied to various non-standard sizes, per customer request.

³ Compatibility range based on total flow rates.

⁴ Minimum gas threshold velocity is defined as the velocity that makes the flow dynamic pressure $0.5\rho V^2 = 500 \text{ Pa}$. For water flow under atmospheric conditions, this velocity is 1 m/s.

A summary of case studies and flow meter performance is presented here:

- **Field testing, Mahogany Field, Offshore Trinidad [Kragas et al., 2003; Drakeley et al., 2006]:** A 5 ½-inch outer diameter optical flow meter was deployed with the production tubing string to a depth of 12,114 feet during well completion. Performance over a nine-month period was noted to be excellent. Since water content was very low, the assumption of fixed water cut was used, and the three-phase mixture was treated as a gas-liquid system. Oil, water, and gas rates agreed with well test results to within $\pm 10\%$ overall. For GVF less than 30%, or 90% to 100%, uncertainty in total flow rate was found to be within $\pm 5\%$. Between 30% and 90% uncertainties were higher. It is noted that, given some well test data to characterize the speed of sound for pure gas, uncertainties of less than $\pm 10\%$ total flow rate were achievable – even up to 75% GVF.
- **Field testing of three-phase flow meter [von Flatern, 2003]:** A comparison article on three different multiphase meters reported Weatherford had modified its two-phase flow meter by adding a vertically separated second pressure-temperature mandrel for an independent determination of mixture density. This modification allowed for an additional equation in the algorithm, leading to three-phase measurement capability. An unspecified operator is noted to be in field trials at the time of the article, comparing the three-phase flow meter against well test data. Preliminary results were reported as encouraging.
- **Flow loop testing and heavy oil field trial [Kragas et al., 2002]:** Flow loop benchmarking of an optical meter has been conducted at various facilities, including: Texaco Humble Test Facility, Southwest Research Institute, Norsk Hydro's loop in Porsgrunn, Norway, and at the Shell loop in Rijswijk, The Netherlands. Among these tests, the one performed at the Shell facility was the most comprehensive. Testing parameters included liquid flow rates up to 60 m³/hr, and water cuts ranging from 0% to 100%. Two oils were used, a 38 °API gravity oil and a heavier 27.5 °API gravity oil. The latter oil had a viscosity of 300 cP at 50°C. It was shown that both volumetric flow rate and phase fraction remained within $\pm 5\%$ accuracy bands for the majority of the 143 test points. Field deployment of the meter in the Gulf of Mexico was carried out placing the meter at a depth of 21,138 feet in 2,940 feet of water. Good agreement with test separator data during startup was observed. A second field trial in two wells at PDO's Nimr field in Oman took place to benchmark the response to heavy, viscous crude. The reference meter was a Coriolis mass flow meter at the surface. In one well, accuracy between the test and reference meter was reported as $\pm 2\%$ on water cut and $\pm 3\%$ on total flow rate. In the other well, it was not possible to obtain good data due to interference of the passive listening sensor by high acoustic noise in the intermittent flow combined with structural noise from a nearby beam pump.
- **Field testing of two-phase MPM, Buzzard Field, North Sea [Smith et al., 2008]:** Downhole water-oil optical flow meters were deployed on 13 wells within the field. Total flow rate differences varied from 0% to 6% compared to surface separator reference data. Disregarding one well, all measurements were within a $\pm 5\%$ band. Note that after the initial calibration at installation, no changes were made to the

software. It was found that the flow meter did not provide reliable data (invalid/blank points) during production ramp up after a shut down. This was due to flow rates being below the minimum operating threshold (5,000 bpd for the 5.5-inch flow meter design). A hardware failure occurred at one point while the wells were flowing, leading to underreporting of volumes. However, the problem was quickly resolved due to the fact that all electronic and software components were readily accessible at the surface.

L.4 References

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APPENDIX M

Procedures for Measurement Inspection

M. PROCEDURES FOR MEASUREMENT INSPECTION

These procedures were created for use by the Department of the Interior, Bureau of Safety and Environmental Enforcement (BSEE) for metering inspection and verification of orifice meters used for liquid and gas measurement, Coriolis meters used for liquid measurement, and ultrasonic meters used for natural gas measurement. Inspection procedures for other types of meters are outside of the scope of this report. It is important to note that these procedures should only be used as an inspection guideline for single-phase meters, not multiphase meters.

Included herein are general procedures that are applicable to all types of meters listed above, as well as checklists related to specific meter types. These procedures are intended to serve as a guideline for generating forms, flowcharts, and/or other desired tools for performing inspection tasks both at the field site and before installation of the meters in the field. Additional efforts will be required to implement these procedures and to improve current forms and tools used during production inspections. It is left to BSEE to coordinate such efforts in the final development of practical tools for use by inspectors.

Based on a review and comments by BSEE of a draft version of these procedures, the inspection procedures have been arranged to reflect the order in which tasks will be performed. The first major section includes tasks that are performed during an office inspection, and tasks related to the inspection of a meter run during assembly and before installation on site. The second major section includes tasks that must be performed at the field site. Part of the procedure for office inspections includes the collection of information that should be taken to the field side for onsite inspections. Within each major section, procedures are further grouped into tasks that are independent of the type of meter at the site; tasks specific to orifice, Coriolis, or ultrasonic meters, and tasks related to other equipment or data (sample analysis, flow computer results, etc.).

Note that while Coriolis technology is common in both the oil and gas industry, Coriolis meters for gas measurement have not been approved by BSEE for test, allocation, or royalty measurement in the Gulf of Mexico. For this reason, the procedures apply only to Coriolis meters used for liquid hydrocarbon measurement. Similarly, ultrasonic meters for liquid measurement have not been approved by BSEE for test, allocation, or royalty measurement in the Gulf of Mexico, and the procedures only apply to ultrasonic meters for natural gas measurement. Orifice meter specifications for gas measurement and liquid measurement are virtually identical, so the procedures found here apply to orifice meters used to measure either natural gas or liquid hydrocarbons.

Information in this section was compiled from existing BSEE procedures, various industry standards for flow measurement by the American Petroleum Institute (API) and the American Gas Association (AGA), and other auditing and inspection guidelines for fluid measurement (Upp and LaNasa, 2002). Orifice inspection guidelines follow those found in API MPMS Chapter 14, Section 3, Appendix 2B, and Upp and LaNasa (2002). Coriolis inspection procedures are derived primarily from Upp and LaNasa (2002), API MPMS Chapter 5, Section 6 (for liquid Coriolis meters), and applicable portions of AGA Report No. 11 (the current standard for Coriolis meters in gas service). Ultrasonic inspection procedures are derived primarily from AGA Report No. 9 (for ultrasonic meters in gas service) and applicable portions of API MPMS

Chapter 5, Section 8 (for liquid ultrasonic meters). A full list of references is provided at the end of the procedures.

During their review of the draft inspection procedures, BSEE staff requested examples of calibration reports or proving sheets for each of the meter types considered. Examples of offsite calibration reports have been included as addenda to this procedure where practical. In other cases, the procedure refers to examples in API standards. It should be noted that the standards for Coriolis and ultrasonic meters are performance-based, and require regular calibration of these meter types. The API standard for orifice meters, API MPMS Chapter 14.3, is a specification-based standard, and presumes regular inspection of the orifice meter elements to ensure accurate measurement. Procedures in this appendix allow for review of orifice meter inspection documents if they are available, but give guidance for performing the inspections if they have not been performed or documents are not available.

The following naming conventions are used in these procedures:

- Names of American Petroleum Institute standards are shortened to the form “API MPMS Chapter X.X.” For instance, API MPMS Chapter 14, Section 1 is referred to as “API MPMS Chapter 14.1.”
- Names of federal regulations are shortened to the form “XX CFR §XXX.XXX.” For instance, Title 30, Code of Federal Regulations, Part 250, Section 1203 is referred to as “30 CFR §250.1203.”
- Following industry naming conventions and conventions found in federal regulations, the calibration of a meter used for liquid measurement is referred to as “proving,” and a calibrated liquid meter is said to have been “proved.” The words “calibration” and “calibrated” are used exclusively for meters in natural gas service.
- The following naming conventions come from definitions found in 30 CFR §250.1201.
 - “Royalty meters” refer to devices in the field used to measure the volume of liquid hydrocarbons or natural gas removed, saved, or sold from a federal lease.
 - “Allocation meters” refer to devices in the field used to determine the portion of hydrocarbons attributable to one or more platforms, leases, units, or wells, in relation to the total production from a royalty or allocation measurement point.
 - “Sales meters” are meters at which custody transfer takes place. Sales meters are not necessarily royalty meters.
 - Onsite devices used to calibrate or prove royalty meters are referred to as “master meters” or “provers.”
- “Verification” refers to the process of confirming a meter’s proof or calibration without altering its calibration factors. “Calibration” or “proving” may involve adjustments to the meter’s calibration factors.

When conducting an inspection, it is important to provide a detailed explanation of any discrepancies found. Historical data should be recorded (when noted in the procedure) and retained for use in later inspections. Historical data provide a baseline for comparison and will aid in identifying meter inaccuracies.

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1. INSPECTION TASKS BEFORE THE FIELD SITE VISIT

Certain inspection tasks require data that are most effectively gathered away from the field site where the royalty meters are found. Some data can be collected from records at the operator's office, while other data on the meter and meter run must be obtained as the run is being assembled before installation at the field site. This section lists procedures to verify such information.

1.1 General Tasks

- Record the date of the inspection. If the inspection is performed over several days, record the first and last dates of the inspection.
- Record whether the inspection is announced or unannounced.
- Record the producer or operator for the lease under inspection and their operator ID.
- Record the name of the producer or operator's representative and their contact information (including phone number).
- Record the lease number or other lease identifying information.
- Record the facility measurement point (FMP) number assigned by BSEE.
 - Confirm that this number matches the number in the Technical Information Management System (TIMS) database.
 - Confirm that the type of facility measurement point (all liquid, all gas, inventory tank, royalty tank, sales/royalty measurement, allocation measurement, etc.) matches the information contained in the FMP number.
- Record the measurement station name and location.
 - For export meters, record the station number assigned by the pipeline company.
 - For offshore platforms, record the platform name and surface location.
- Record information on the fluid being measured at the station. Recorded information shall include, at a minimum, the following:
 - Natural gas or hydrocarbon liquids.
 - Whether produced fluids are unprocessed or have been processed to remove certain components (heavy hydrocarbons, water, etc.).
- Record the type of meter(s) documented as being in use at the station.
 - Meter technologies covered in this procedure are limited to orifice, Coriolis, and ultrasonic meters.
- Record the documented meter status (active or inactive).
 - Active meters can be classified as "operating" or "non-operating."

- An active “operating” meter is used for royalty or allocation measurement during a proving/calibration cycle, and is required to be proved/calibrated per 30 CFR §250, Subpart L.
 - An active “non-operating” meter is an idle meter that is not used for royalty or allocation measurement and does not need to be proved/calibrated for that cycle. The valves located upstream and downstream of a “non-operating” meter shall be closed, but do not need to be sealed. A “non-operating” meter shall be proved/calibrated prior to being returned to service.
- Inactive meters shall be isolated with block valves and numbered seals located both upstream and downstream of the meter. Approval shall be obtained from the appropriate regional office prior to changing a meter from an inactive to active status, and inactive meters shall be proved/calibrated prior to being returned to service.
- See BOEMRE Notice to Lessees (NTL) No. 2010-N-08 for further definitions related to active and inactive meters.
- Obtain a copy of the meter approval documentation. The approval documentation should include the following:
 - Documentation of the brand and model of the flow computer associated with the measurement location. If the meter is used for royalty-basis measurements, the serial number of the associated flow computer shall also be obtained.
 - A statement that the installation, operation, performance, and testing of the flow meter will be in accordance with the manufacturer’s recommendations, the pipeline company’s recommendations, and the recommendations as set forth in the appropriate industry standard (API MPMS Chapter 14.3 for orifice meters, AGA Report No. 9 for ultrasonic gas meters, or API MPMS Chapter 5.6 for Coriolis liquid meters).
- Obtain a copy of the following information for later use in the inspection:
 - A statement indicating whether the meter(s) will be used for sales/royalty or allocation measurement, along with the number and type of meters that will be installed at each measurement point.
 - Documentation on the type, brand, model, size, and flow capacity of each meter to be installed. For ultrasonic and Coriolis meters, the serial numbers of the meters shall also be documented.
 - A configuration schematic of the meter run as planned or installed, including the position of the flow conditioner, the positions of pressure and temperature devices, the position of the sample probe (if present), and the upstream and downstream distances to the first flow disturbance or obstruction. Instructions are given in subsection 1.2 of this procedure for confirming that meter run configurations meet the requirements of the appropriate metering standard.

- A copy of the flow conditioner performance verification test, if a proprietary flow conditioner is installed in the meter run. If an orifice meter run incorporates a 19-tube bundle as described in API MPMS Chapter 14.3, Part 2, a performance verification test is not required.
- A procedure for meter verification/calibration on a monthly basis (not to exceed 42 days) as required in 30 CFR §250.1203. The results of the verification/calibration shall be retained at the field location for two years and shall be made available to BSEE representatives upon request.
- A procedure for secondary instruments (such as pressure and temperature transmitters) to be calibrated/verified on a monthly basis (not to exceed 42 days) in accordance with API MPMS Chapter 21.1. The results of the verification/calibration shall be retained at the field location for two years and shall be made available to BSEE representatives upon request.
- For orifice meters, the reference meter tube inside diameter and the temperature at which it was determined (typically 68°F). The meter tube diameter shall be stamped on the meter tube or meter fitting nameplate, to at least three decimal places.
- For ultrasonic or Coriolis meters, a NIST-traceable flow calibration report for each meter, calibrated with its meter run package. Calibrations shall meet the requirements of AGA Report No. 9, Section 6 (for ultrasonic meters in gas service) or API MPMS Chapter 5.6 (for Coriolis meters in liquid service).
- Documentation of the brands and models of the pressure and temperature transmitters to be used with the meter(s).
- Documentation of the brand and model of any gas chromatograph(s) or composite sampler(s) associated with the meter location.
- Obtain copies of records, drawings, work orders, etc., of any facility modifications since the last inspection period.

1.2 Inspection of Physical Meter Runs Before Field Installation

The procedures in this section assume that the inspector has access to the meters, meter runs, and equipment at the fabrication shop or at another location before the meter is installed at the measurement point.

1.2.1 General Meter Inspection Tasks

- Check the meter for a nameplate. The nameplate(s) shall be made of materials that will not deteriorate, fade, or peel. Record the following information from the nameplate, and confirm that these data agree with records on the meters to be installed at the station.
 - Meter manufacturer.
 - Model number.
 - Serial number.

- o Nominal meter diameter.
- o Maximum flow capacity (and, if on the nameplate, minimum flow capacity).

1.2.2 Tasks Specific to Orifice Meters

1.2.2.1 Inspection of Orifice Meter Run Geometry

- Obtain a copy of the installation configuration drawings found on the request for approval submitted by the producer or station operator.
- Record the following information from the installation configuration drawings.
 - o Pipe diameter of the meter tube (nominal diameter and schedule).
 - o Type of orifice fitting:
 - Flanged fitting (requires the meter run to be bled down and the flanges to be separated for the orifice plate to be removed).
 - Single-chambered fitting (sometimes referred to as “junior” fitting; requires the meter run to be bled down for removal of the orifice plate, but no disassembly of the meter run is required.).
 - Dual-chambered fitting (sometimes referred to as “senior” fitting; the orifice plate can be removed without bleeding down the meter run).
 - o Brand and/or model, line diameter, and pipe schedule of the flow conditioner or straightening vane.
 - o Dimension UL, the total upstream pipe length between the orifice plate and the nearest upstream flow disturbance (elbow, tee, valve, etc.), expressed in multiples of the meter tube diameter.
 - o Dimension UL2, the distance between the outlet of the uniform concentric 19-tube bundle or upstream flow conditioner (if present) and the orifice plate, expressed in multiples of the meter tube diameter.
 - o Dimension $UL1 = UL - UL2$.
 - o Dimension DL, the pipe length between the orifice plate and the nearest downstream flow disturbance (elbow, tee, valve, thermowell, or sample probe), expressed in multiples of the meter tube diameter.
 - o Types and locations of all secondary devices connected to or inserted into the meter run, relative to the orifice plate. These may include:
 - Static and differential pressure transmitters.
 - Thermowells, RTDs, or other temperature measurement devices.
 - Thermometers are often used for reference temperature measurements, while resistance temperature devices (RTDs) connected to a temperature transmitter may be used in normal applications, particularly in situations requiring a

rugged device. These sensors are commonly inserted in a thermowell, which is then placed in the flow. Refer to API MPMS Chapter 7 for details on the use of various temperature measurement devices.

- Where multiple meters are installed in parallel, thermowells and temperature sensors should be installed in each meter run. If flowing temperatures vary between parallel meter runs, the use of individual measurements for each meter will avoid biases related to these temperature differences.
 - Sample probes, if present.
 - Densitometers, if present (commonly used for liquid density measurements).
- Record the brand and/or model, line diameter, and pipe schedule of the flow conditioner installed in the meter run, and confirm that these agree with the installation configuration drawings.
 - This information may be stamped on the flow conditioner flange. If these data are not visible on the flow conditioner itself, obtain these data from fabrication records.
 - A flow conditioner made for a pipe schedule smaller than the pipe schedule of the meter tube may not be correctly centered in the pipe.
 - If the flow conditioner is directional, confirm that the arrows on the flange are pointing in the direction of flow through the meter run.
 - Record the method by which the flow conditioner is fastened to the meter run (pinned, welded, or held in place by a flange).
- Confirm that the meter configuration in the drawings meets the appropriate configuration requirements.
 - Meter runs without flow conditioners shall conform to requirements of API MPMS Chapter 14.3, Part 2, as reproduced in Figure 1 and Table 1.
 - Meter runs with a uniform concentric 19-tube bundle flow straightener shall conform to requirements of API MPMS Chapter 14.3, Part 2, as reproduced in Figure 2, Table 2, and Table 3.
 - Meter runs with a CPA 50E flow conditioner shall conform to published minimum lengths of $UL1 \geq 5$ pipe diameters and $UL2 \geq 8$ pipe diameters. BSEE will accept a minimum distance for $UL2$ of 7 pipe diameters, provided that the beta ratio never exceeds 0.67.
 - For other flow conditioners, consult the flow conditioner manufacturer's performance test results for installation requirements. Flow conditioner performance tests shall be performed according to API 14.3, Part 2, Appendix 2-D. A copy of the performance test should be kept on hand at the fabrication shop, producer's or operator's office, or field site.

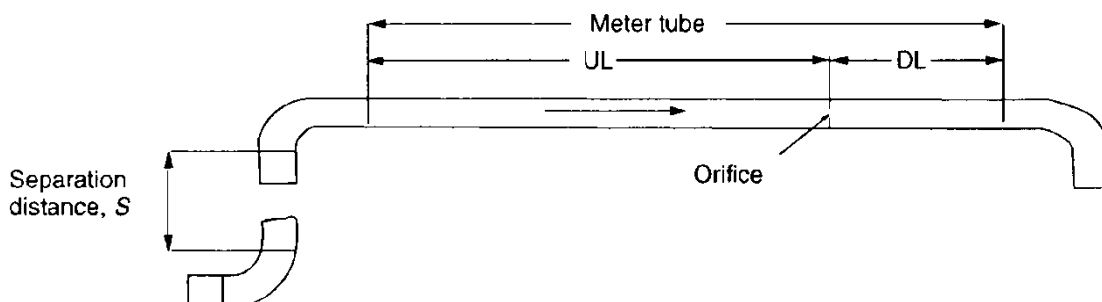


Figure 1. Dimensions of Allowable Meter Tube Configurations for Orifice Meter Runs Without Flow Conditioners

The notation is consistent with API MPMS Chapter 14.3, Part 2. Allowable values for all dimensions are listed in Table 1.

Table 1. Minimum Length Requirements for Orifice Meter Runs Without Flow Conditioners
Values are reproduced from API MPMS Chapter 14.3, Part 2, Table 2-7. Variables are defined in Figure 1.

Diameter ratio β	Minimum Straight Unobstructed Meter Tube Length from the Upstream Side of the Orifice Plate (in multiples of published internal pipe diameter, D_i)										Downstream meter tube length
	a. Single 90° elbow b. Two 90° elbows in the same plane with $S > 30D_i$ c. Two 90° elbows in perpendicular planes with $S > 15D_i$	Two 90° elbows in the same plane, "S" configuration, spacer $S \leq 10D_i$	Two 90° elbows in the same plane, "S" configuration $10D_i < S < 30D_i$	Two 90° elbows in perpendicular planes, $S < 5D_i$	Two 90° elbows in perpendicular planes, $5D_i \leq S \leq 15D_i$	Single 90° tee used as an elbow, but not as a header element	a. Single 90° elbow b. Two 45° elbows in the same plane, "S" configuration $S \geq 22D_i$	Gate valve at least 50% open	Concentric reducer	Any other configuration (catch-all category)	
	UL	UL	UL	UL	UL	UL	UL	UL	UL	UL	DL
≤ 0.20	6	10	10	50	19	9	30	17	6	70	2.8
0.30	11	10	12	50	32	9	30	19	6	108	3.0
0.40	16	10	13	50	44	9	30	21	6	145	3.2
0.50	30	30	18	95	44	19	30	25	7	145	3.5
0.60	44	44	30	95	44	29	30	30	9	145	3.9
0.67	44	44	44	95	44	36	44	35	11	145	4.2
0.75	44	44	44	95	44	44	44	44	13	145	4.5
Recommended length for maximum range, $\beta \leq 0.75$	44	44	44	95	44	44	44	44	13	145	4.5

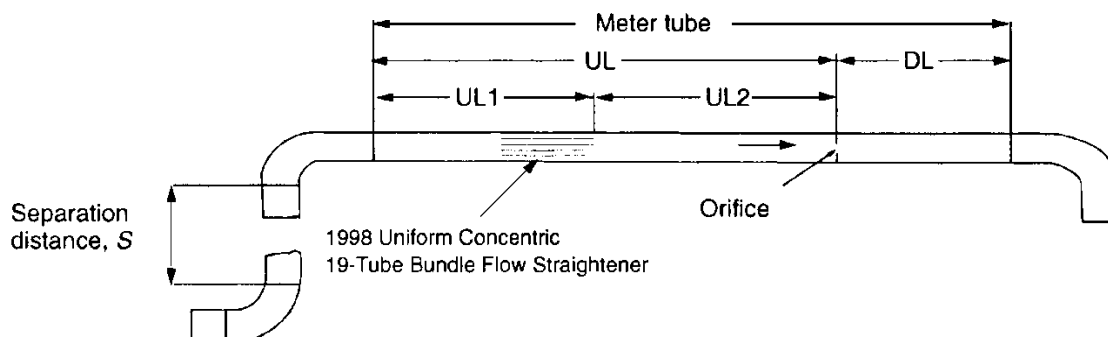


Figure 2. Dimensions of Allowable Meter Tube Configurations for Orifice Meter Runs with a Uniform Concentric 19-Tube Bundle

The notation is consistent with API MPMS Chapter 14.3, Part 2. Allowable values for all dimensions are listed in Table 2 and Table 3.

Table 2. Minimum Length Requirements for Orifice Meter Runs With a Uniform Concentric 19-Tube Bundle Flow Straightener and Upstream Meter Tube Lengths of $17D_i \leq UL \leq 29D_i$.

Values are reproduced from API MPMS Chapter 14.3, Part 2, Table 2-8a. Variables are defined in Figure 2.

Diameter ratio β	Single 90° elbow $R/D_i=1.5$	Two 90° elbows out of plane, $S \leq 2D_i$, $R/D_i=1.5$	Single 90° tee used as an elbow, but not as a header element	Partially-closed valves (at least 50% open)	High swirl combined with single 90° tee	Any fitting (catch- all category)	Downstream meter tube length
	UL2	UL2	UL2	UL2	UL2	UL2	DL
0.10	5-14.5	5-14.5	5-14.5	5-11	5-13	5-11.5	2.8
0.20	5-14.5	5-14.5	5-14.5	5-11	5-13	5-11.5	2.8
0.30	5-14.5	5-14.5	5-14.5	5-11	5-13	5-11.5	3.0
0.40	5-14.5	5-14.5	5-14.5	5-11	5-13	5-11.5	3.2
0.50	11.5-14.5	9.5-14.5	11-13	9.5 (allowed for $\beta \leq 0.47$)	11-13	9.5 (allowed for $\beta \leq 0.46$)	3.5
0.60	12-13	13.5-14.5	13 (allowed for $\beta \leq 0.54$)	Not allowed	13 (allowed for $\beta \leq 0.54$)	Not allowed	3.9
0.67	13	13-14.5	Not allowed	Not allowed	Not allowed	Not allowed	4.2
0.75	14	Not allowed	Not allowed	Not allowed	Not allowed	Not allowed	4.5
Recommended length for maximum range of β	13 (allowed for $\beta \leq 0.67$)	13.5-14.5 (allowed for $\beta \leq 0.67$)	13 (allowed for $\beta \leq 0.54$)	9.5 (allowed for $\beta \leq 0.47$)	13 allowed for $\beta \leq 0.54$)	9.5 (allowed for $\beta \leq 0.46$)	4.5

Table 3. Minimum Length Requirements for Orifice Meter Runs With a Uniform Concentric 19-Tube Bundle Flow Straightener and Upstream Meter Tube Lengths of $UL > 29D_i$.

Values are reproduced from API MPMS Chapter 14.3, Part 2, Table 2-8b. Variables are defined in Figure 2.

Diameter ratio β	Single 90° elbow $R/D_i=1.5$	Two 90° elbows out of plane, $S \leq 2D_i$, $R/D_i=1.5$	Single 90° tee used as an elbow, but not as a header element	Partially-closed valves (at least 50% open)	High swirl combined with single 90° tee	Any fitting (catch-all category)	Downstream meter tube length
	UL2	UL2	UL2	UL2	UL2	UL2	DL
0.10	5-25	5-25	5-25	5-13	5-23	5-13	2.8
0.20	5-25	5-25	5-25	5-13	5-23	5-13	2.8
0.30	5-25	5-25	5-25	5-13	5-23	5-13	3.0
0.40	5-25	5-25	5-25	5-13	5-23	5-13	3.2
0.50	11.5-25	9-25	9-23	7.5-15	9-19.5	11.5-14.5	3.5
0.60	12-25	9-25	11-16	10-17	11-16	12-16	3.9
0.67	13-16.5	10-16	11-13	10-13	11-13	13	4.2
0.75	14-16.5	12-12.5	12-14	11-12.5	14	Not allowed	4.5
Recommended length for maximum range of β	13 (allowed for $\beta \leq 0.75$)	12-12.5 (allowed for $\beta \leq 0.75$)	12-13 (allowed for $\beta \leq 0.75$)	11-12.5 (allowed for $\beta \leq 0.75$)	13 (allowed for $\beta \leq 0.75$)	13 (allowed for $\beta \leq 0.67$)	4.5

- Confirm that the installation of all secondary instruments conforms to the manufacturer's guidelines, where applicable. In particular, the temperature sensor shall be mounted downstream of the orifice plate according to the requirements of API MPMS Chapter 14.3, at a minimum distance of DL from the orifice plate.
- Measure and record the actual upstream and downstream pipe lengths, the location of the flow conditioner, and the positions of thermowells and sampling probes using consistent measurement tools and practices. Steel tape measures are acceptable for this purpose.
- Confirm that the actual upstream and downstream pipe lengths, the position and specifications of the flow conditioner, and the positions of secondary devices agree with the meter run configuration shown in the fabrication or approval drawings.

1.2.2.2 Internal Inspection of Orifice Meter Runs

Acquire and review inspection records for the pressure taps, internal roundness, orifice bore eccentricity, and inside surface roughness. Acceptance criteria for orifice meter tubes are listed in the procedures below. If an inspection record is not available, perform inspections following the procedures below, adapted from API MPMS Chapter 14.3, Part 2. Measurements may be made using measurement tools and practices listed within the procedures.

- Visually inspect the inside of the meter tube to confirm that the pipe sections are aligned, that no flange gaskets protrude into the meter run, and that the flow conditioner is centered in the meter run.

- Confirm that the distance from the centerline of the pressure tap holes (both upstream and downstream) to the nearest face of the orifice plate is one inch. Tap distances other than one inch from the orifice plate do not fall within the range of applicability of API MPMS Chapter 14.3.
- Inspection of pressure tap diameters:
 - Pressure tap diameters may be measured using Vernier calipers or similar instruments.
 - For meter runs with nominal diameters of two inches or three inches, the tap diameter shall be 0.375 inch $\pm$ 0.016 inch.
 - For meter runs with nominal diameters of four inches or larger, the tap diameter shall be 0.500 inch $\pm$ 0.016 inch.
- Inspection of meter tube roundness:
 - Inside micrometers with a resolution of 0.001 inches or better are acceptable instruments for this purpose.
 - Obtain four equally-spaced internal diameter measurements in a plane one inch upstream of the orifice plate face (nominally in the plane of the upstream pressure taps). The average of these individual measurements is defined as the measured meter tube internal diameter, D_m .
 - For acceptable meter tube roundness, the absolute percentage difference between any individual measured diameter at this location and the measured meter tube internal diameter, D_m , shall not exceed 0.25% of D_m .

$$\left| \frac{\left(\text{Any upstream diameter within one } D_m \text{ of the plate} \right) - D_m}{D_m} \times 100\% \right| \leq 0.25\%$$

- Obtain at least two check measurements of the internal diameter of the upstream meter tube. These may be made at any location around the tube circumference.
 - One check measurement shall be in a plane at least two pipe diameters upstream of the orifice plate face.
 - The other check measurement(s) shall be made at selected points within the upstream length UL, defined above.
- For acceptable meter tube roundness, the absolute percentage difference between the maximum measured diameter and the minimum measured diameter at all upstream locations, including the measurements in a plane one inch upstream of the orifice plate, shall not exceed 0.5% of D_m .

$$\left| \frac{\text{maximum diameter} - \text{minimum diameter}}{D_m} \times 100\% \right| \leq 0.5\%$$

- o Obtain four equally-spaced internal diameter measurements in a plane one inch downstream of the orifice plate face (nominally in the plane of the downstream pressure taps).
- o Obtain at least two check measurements of the internal diameter of the downstream meter tube. These may be made at any location around the tube circumference.
 - The check measurement(s) shall be made at selected points within the downstream length DL, defined above.
- o For acceptable meter tube roundness, the absolute percentage difference between any individual measured diameter downstream of the orifice plate and the measured meter tube internal diameter, D_m , shall not exceed 0.5% of D_m .

$$\left| \frac{\langle \text{Any downstream diameter} \rangle - D_m}{D_m} \times 100\% \right| \leq 0.5\%$$
- o Record the meter tube temperature at which the measurements were made, to the nearest degree Fahrenheit.
- o Irregularities such as grooves, scoring, ridges, or seams that affect the inside diameter by more than these tolerances shall not be permitted.
- Inspection of orifice bore eccentricity:
 - o Inside micrometers are acceptable tools for this inspection.
 - o If the orifice meter uses a flange fitting, note the method of plate alignment (if present): alignment pins, a male/female alignment fitting, or another method.
 - o Measure the distance from the bore edge to the pipe wall along the two axes parallel and perpendicular to the differential tap centerline. Measurements should be made at the four “compass points” shown in Figure 3, and assigned to the variables shown in the figure.
 - o Measure the meter tube inside diameter in a plane one inch upstream of the orifice plate. The diameter should be measured along four independent axes, such as the four axes shown in Figure 4. The calculated average of the four measurements is defined as the measured meter tube diameter, D_m .
 - o Place an orifice plate into the fitting. Measure the orifice bore diameter along four independent axes, such as the four axes shown in Figure 5. The calculated average of the four measurements is defined as the measured orifice bore diameter, d_m .
 - o Calculate the measured beta ratio using the measured bore diameter, d_m , and meter tube diameter, D_m .

$$\beta_m = d_m/D_m$$

- o Calculate the bore eccentricity parallel to the differential pressure tap axis, ε_X , and the bore eccentricity perpendicular to the differential pressure tap axis, ε_Y , using the formulas below.

$$\varepsilon_X = \left| \frac{X - X'}{2} \right| \quad \varepsilon_Y = \left| \frac{Y - Y'}{2} \right|$$

- o To be acceptable, orifice bore eccentricities shall be less than the tolerances given by the formulas below.

$$\varepsilon_X \leq \frac{0.0025D_m}{0.1 + 2.3\beta_m^4} \quad \varepsilon_Y \leq \frac{0.01D_m}{0.1 + 2.3\beta_m^4}$$

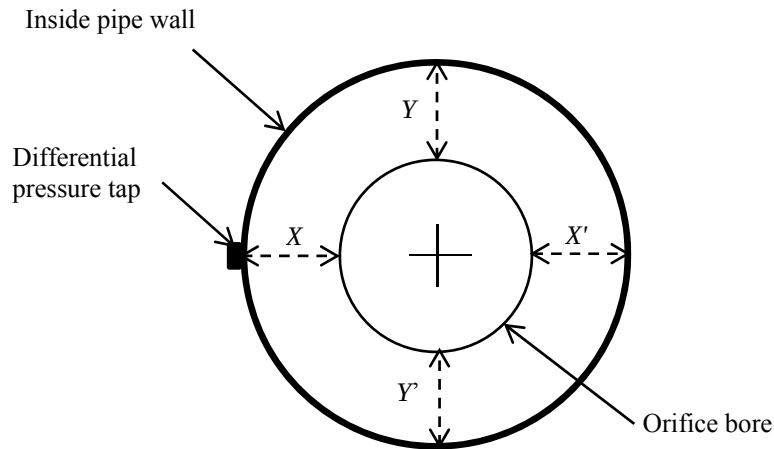


Figure 3. Locations for Orifice Bore Eccentricity Measurements

This illustration is adapted from API MPMS Chapter 14.3, Part 2.

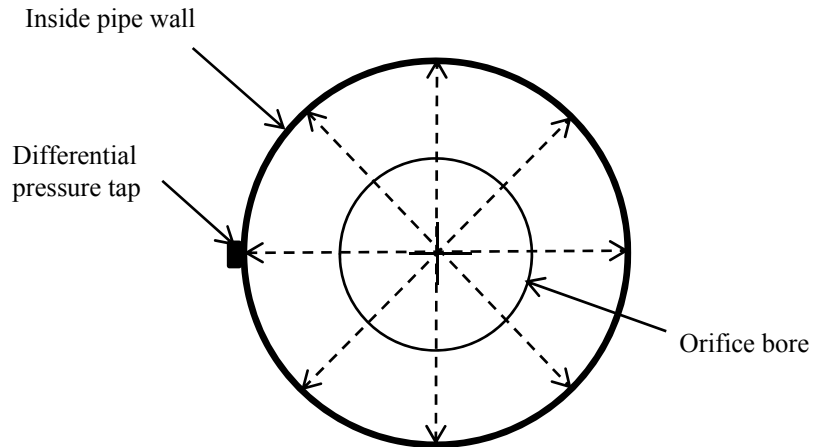


Figure 4. Recommended Axes for Meter Tube Diameter Measurements

The recommended axes, shown by the dotted lines, are based on requirements of API MPMS Chapter 14.3, Part 2.

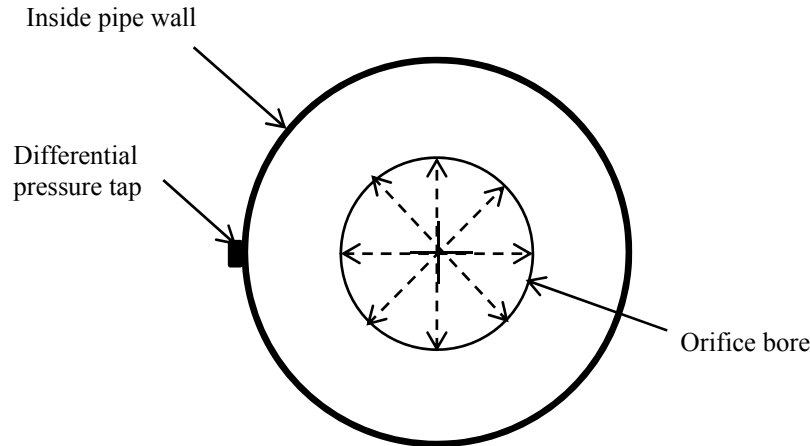


Figure 5. Recommended Axes for Orifice Bore Diameter Measurements
The recommended axes, shown by the dotted lines, are based on requirements of API MPMS Chapter 14.3, Part 2.

- Inspection of the meter tube inside surface roughness:
 - The surface roughness may be measured using an electronic-averaging-type surface roughness instrument and the procedure below. Other measurement devices that meet the requirements of API MPMS Chapter 14.3, Part 2 are also acceptable. Refer to ANSI Standard B46.1 for the definition of the pipe roughness, R_a .
 - Perform at least four measurements of the internal pipe wall surface roughness at a distance of one inch from the upstream face of the orifice plate. These should be made at approximately the same locations used to measure the internal pipe diameter, and should be recorded in units of microinches (μin). The average of these measurements is defined as the meter tube internal surface roughness, R_a .
 - To be acceptable, the meter tube roughness shall meet the following criteria. Note that the surface roughness of the meter tube may limit the orifice plate beta ratios used in the meter.
 - For meter runs with nominal tube diameters of 12 inches or less:
 - For $\beta \leq 0.6$, the wall roughness shall fall within the range $34 \mu\text{in} \leq R_a \leq 300 \mu\text{in}$.
 - For $\beta \geq 0.6$, the wall roughness shall fall within the range $34 \mu\text{in} \leq R_a \leq 250 \mu\text{in}$.
 - For meter runs with nominal tube diameters greater than 12 inches:
 - For $\beta \leq 0.6$, the wall roughness shall fall within the range $34 \mu\text{in} \leq R_a \leq 600 \mu\text{in}$.
 - For $\beta \geq 0.6$, the wall roughness shall fall within the range $34 \mu\text{in} \leq R_a \leq 500 \mu\text{in}$.

- o Pits in the surface of the meter tube that exceed these roughness criteria shall not be permitted.

1.2.3 Tasks Specific to Coriolis Meters

These procedures apply only to Coriolis meters used for liquid hydrocarbon measurement. Coriolis meters for gas measurement have not been approved by BSEE for test, allocation, or royalty measurement in the Gulf of Mexico. The installation, operation, maintenance, and proving of Coriolis meters for liquid hydrocarbon measurement shall be consistent with the manufacturer's recommendations, the pipeline operator's recommendations, the recommendations as set forth in API MPMS Chapter 5.6, and applicable regulations in 30 CFR §250.1202 and 30 CFR §250.1205.

1.2.3.1 Inspection of Coriolis Meter Installation Geometry

- Obtain a copy of the installation configuration drawings from the meter run fabricator or station operator.
- Confirm that the meter configuration shown in the drawings conforms to the configuration requirements of API MPMS Chapter 5.6.
 - o Confirm that the locations of all secondary devices connected to or inserted into the meter run conform to guidelines in API MPMS Chapter 5.6, Figure 2. Installation of these devices should also conform to the manufacturer's guidelines, where applicable. Secondary devices to be documented include the following:
 - Static pressure transmitter (required).
 - Thermowell, RTD, or other temperature measurement device (required).
 - Thermometers may be used for reference temperature measurements, while a resistance temperature device (RTD) connected to a temperature transmitter may be used in normal applications, particularly in situations requiring a rugged device. These sensors are commonly inserted in a thermowell, which is then placed in the flow. Refer to API MPMS Chapter 7 for details on the use of various temperature measurement devices.
 - Some liquid meter designs may allow for the temperature sensor to be mounted on the meter body, to reduce differences between the temperature of the fluid being measured and the temperature at the sensor. If this is not the case, the sensor shall be mounted downstream of the meter according to API MPMS Chapter 5.6.
 - Where multiple meters are installed in parallel, thermowells should be installed in each meter run. In the event that flowing temperatures vary between parallel meter runs, the

use of individual measurements for each meter will avoid biases related to these temperature differences.

- Sample probe (as needed).
- Densitometer, as needed (commonly used for liquid density measurements).
- Although Figure 2 of API MPMS Chapter 5.6 includes a bypass in the diagram, bypasses of any type around active liquid hydrocarbon royalty meters, natural gas royalty meters, and platform export meters are not allowed, per 30 CFR §250, Subpart L.
- Measure and record the upstream and downstream pipe lengths and the positions of inserted devices using consistent measurement tools and practices. Steel tape measures are acceptable for this purpose.
- Visually inspect the inside of the meter tube connected to the inlet and outlet of the Coriolis meter to confirm that the pipe sections are aligned, and that no flange gaskets protrude into the meter run.
 - Record the pipe diameter (nominal diameter and schedule) and ANSI rating of the meter run upstream and downstream of the meter. Confirm that the Coriolis meter is designed for use with the size and rating of the pipe.
- Confirm that the upstream and downstream pipe lengths and positions of inserted devices agree with the meter run configuration shown in the fabrication drawings or approval drawings.

1.2.3.2 Inspection of Coriolis Meter Design

- Confirm that the Coriolis meter incorporates multiple tubes. Single-tube Coriolis meters have not been approved by BSEE for royalty or allocation measurement.
- The meter shall be equipped with a totalizer (a device recording the total volume measured by the meter) that cannot be reset.
- The meter shall be equipped to output pulses at a rate proportional to the flow rate through the meter.

1.2.4 Tasks Specific to Ultrasonic Meters

These procedures apply only to ultrasonic meters used for natural gas measurement. Ultrasonic meters for liquid hydrocarbon measurement have not been approved by BSEE for test, allocation, or royalty measurement in the Gulf of Mexico. The installation, operation, maintenance, and proving of ultrasonic meters for natural gas measurement shall be consistent with the manufacturer's recommendations, the pipeline operator's recommendations, the recommendations as set forth in AGA Report No. 9, and applicable regulations in 30 CFR §250.1202 and 30 CFR §250.1205.

1.2.4.1 Inspection of Ultrasonic Meter Installation Geometry

- Obtain a copy of the drawings of the installation configuration from the meter run fabricator or station operator.
- Confirm that the meter configuration shown in the drawings conforms to the configuration requirements of AGA Report No. 9 and the flow conditioner manufacturer. In particular, confirm the following:
 - Pipe diameter (nominal diameter and schedule) of the meter tube.
 - Brand, model, line diameter, and pipe schedule of the flow conditioner, if present. (Ultrasonic meter runs are typically assembled with a proprietary flow conditioner.)
 - This information may be stamped on the flow conditioner flange. If these data are not visible on the flow conditioner itself, obtain these data from fabrication records.
 - A flow conditioner made for a pipe schedule smaller than the pipe schedule of the meter tube may not be correctly centered in the pipe.
 - Record the method by which the flow conditioner is fastened to the meter run (pinned, welded, or held in place by a flange).
 - Confirm that the flow conditioner installed in the meter run is that specified in the drawings used for fabrication or submitted with the request for approval.
 - Total upstream pipe length between the ultrasonic meter inlet and the nearest upstream flow disturbance (elbow, tee, valve, etc.). Per AGA Report No. 9, the meter run shall have 20 nominal diameters of straight pipe upstream of the meter.
 - Distance between the upstream flow conditioner (if present) and the ultrasonic meter inlet.
 - The flow conditioner shall be installed ten nominal diameters upstream of the meter inlet, or in the location specified by the flow conditioner manufacturer's performance tests.
 - If the meter run is approved by BSEE to be bidirectional, flow conditioners shall be installed ten nominal diameters both upstream and downstream of the meter, or in locations specified by the flow conditioner manufacturer's performance tests.
 - A copy of the flow conditioner performance tests should be kept on hand by the fabrication shop for review.
 - Downstream pipe length between the ultrasonic meter outlet and the nearest flow disturbance (elbow, tee, valve, etc.).

- Per AGA Report No. 9, the meter run shall have at least five nominal diameters of straight pipe between the meter and the nearest downstream flow disturbance if the run is unidirectional.
 - If the meter run is approved by BSEE to be bidirectional, the meter run shall have 20 nominal diameters of straight pipe both upstream and downstream of the meter.
- o Locations of all secondary devices connected to or inserted into the meter run. Installation of these devices should also conform to the manufacturer's guidelines, where applicable.
- Static pressure transmitters.
 - Thermowell, RTD, or other temperature measurement device.
 - Thermometers may be used for reference temperature measurements, while a resistance temperature device (RTD) connected to a temperature transmitter may be used in normal applications, particularly in situations requiring a rugged device. These sensors are commonly inserted in a thermowell, which is then placed in the flow. Refer to API MPMS Chapter 7 for details on the use of various temperature measurement devices.
 - The temperature sensor shall be mounted downstream of the ultrasonic meter body, at a point between two to five nominal pipe diameters of the meter outlet, according to the requirements of AGA Report No. 9. If the meter run is approved by BSEE to be bidirectional, temperature sensors shall be mounted at a point between three to five nominal pipe diameters of both the meter inlet and meter outlet.
 - The temperature sensor shall be inserted far enough into the flowing stream to ensure fast response and accuracy, but not so far as to be likely to fail via resonance vibration in the flow. The insertion length for thermowells recommended by AGA Report No. 9 is between one-tenth (1/10) and one-third (1/3) of the nominal pipe diameter.
 - Where multiple meters are installed in parallel, thermowells should be installed in each meter run. In the event that flowing temperatures vary between parallel meter runs, the use of individual measurements for each meter will avoid biases related to these temperature differences.
 - Sample probe and/or densitometer, if present.
 - The mounting locations for sample probes and densitometers permitted by AGA Report No. 9 are identical to those permitted for temperature measurement devices.

- Ultrasonic meters used for royalty and/or allocation measurement shall be installed in unidirectional installations, unless a departure for a bidirectional installation has been approved by BSEE.
- Measure and record the upstream and downstream pipe lengths, the position of the flow conditioner, and the positions of inserted devices using consistent measurement tools and practices. Steel tape measures are acceptable for this purpose.
- Visually inspect the inside of the meter tube to confirm that the pipe sections are aligned, that no flange gaskets protrude into the meter run, and that the flow conditioner is centered in the meter run.
 - If the flow conditioner is directional, confirm that the arrows on the flange are pointing in the direction of flow through the meter run.
- Confirm that the upstream and downstream pipe lengths, position and specifications of the flow conditioner, and positions of inserted devices agree with the meter run configuration shown in the drawings.

1.2.4.2 Inspection of Ultrasonic Meter Design

- Ultrasonic meters used for royalty or allocation measurements shall be multipath; they shall contain at least three acoustic paths, each with an independent pair of transducers.

1.3 Flow Computer Inspection Tasks

Depending upon the communications setup, information from flow computers may be collected remotely from operator offices, or locally at the measurement site. It is assumed here that configuration data and logs are collected remotely for an initial review, and then taken to the field site for later use as needed. If remote access is not possible, perform these tasks at the field site.

- Obtain and review a hardcopy of the flow measurement configuration parameters and logs used by the flow computer while the meter is in operation.
 - Confirm that configuration parameters and settings are tamper proof or have software security for preventing unauthorized or undocumented changes. This can be achieved by passwords and/or tamper-proof seals or locks on site.
 - Review the logs for any changes to the configuration parameters. If any changes occur during an accounting period, investigate and record the justification for the changes.
 - Record the meter factors and densitometer factors entered into the flow computer. Confirm that these factors agree with the factors obtained in the most recent meter proving or calibration reports (see subsection 1.4.3).
- Obtain and review a hardcopy of any event or alarm logs from the flow computer. Note the following information.
 - Sign-on and sign-off times for password-protected systems.

- o Records of a default value being forced in calculations in place of a live input or output. If such records are found in the event logs, investigate and record the justification for forcing the new value.
- o Download time to install a new program or configuration file, during which data were not collected.
- o Alarm logs of flow ranges exceeded, device failures, power failures, instrument restarts, or other abnormal conditions. If such records are found, investigate and record actions taken to alleviate the abnormal conditions.

1.4 Record Review

The following tasks should be performed at the producer or operator's offices, or at another location where the information is accessible. Records typically kept at the field site are discussed in subsection 2.5.

1.4.1 Gas and Liquid Analysis Records

1.4.1.1 Gas-Specific Records

- Review the most recent natural gas analysis report.
 - o If the gas analysis is based on a spot sample or composite sample, confirm that the most recent sample is less than six months old, in accordance with 30 CFR §250.1203(b)(5).
 - o If the gas analysis is based on a composite sample, confirm the rate at which the composite sampler injects a sample into the accumulator. Per API MPMS Chapter 14.1, samples taken at a rate proportional to pipeline flow rate are preferred to samples taken at regular time intervals.
 - o Record the contact information of the laboratory that analyzes the samples.
 - o Document the method used to compute gas properties (density, compressibility, heating values, etc.) from the analysis.
 - o Confirm that heating values are calculated and reported at base conditions (60°F, 14.73 psia).
 - o Confirm that the analysis and/or computed properties have been programmed into the flow computer.
 - o Confirm that the analysis and/or computed properties have been used in the corresponding Quantity Transaction Report.
- Obtain a copy of the certified composition for the GC calibration gas(es). A copy of the certified composition shall be available at the operator's offices, and should also be available at the field site.
 - o Confirm that the date of certification of the calibration gas is less than one year old. Calibration gases over one year old shall be replaced.

- Confirm that the serial number on the certificate matches the serial number on the calibration gas cylinder.
- Compare the calibration gas composition to the most recent gas analysis report. Per industry best practices, each component in the calibration gas should be within the span of one-half to twice the amount of the same component in the analyzed gas stream.
- Obtain printouts of the GC analysis method and most recent calibration report.
 - Confirm that the component concentrations on the calibration gas certificate have been input correctly into the gas chromatograph.

1.4.1.2 Liquid-Specific Records

- Review the most recent hydrocarbon liquid analysis report.
 - Document the method used to collect samples or measure liquid properties, and note any related industry standards governing the sampling method.
 - Record the contact information of the laboratory that analyzes the samples.
 - Document the standard test method used to determine liquid properties (density, specific gravity, API gravity, etc.) from the analysis.
 - Confirm that the analysis and/or computed properties have been programmed into the flow computer.
 - Confirm that the analysis and/or computed properties have been used in the corresponding Quantity Transaction Report.

1.4.2 Meter-Specific Records

1.4.2.1 Orifice Meters

- Obtain and review the most recent onsite inspection records for any orifice meters located in the field. At a minimum, the items listed below shall be included in the inspection. Data to be collected during these inspections are described in subsection 1.2.2 and subsection 2.2.2 of this procedure.
 - Inspection of the inside meter tube walls for cleanliness, deposits, and changes in surface roughness upstream and downstream of the orifice plate. Inspection may be performed with a borescope to avoid disassembly of the orifice meter run.
 - Integrity of pressure taps upstream and downstream of the orifice plate.
 - Removal and inspection of the orifice plate for oil (in a natural gas meter) or deposits (in liquid or gas meters).
 - API MPMS Chapter 14.3 does not address the frequency at which meter tubes should be inspected for cleanliness. However, if orifice plates are consistently dirty or oily when removed for inspection, it is accepted practice to increase the frequency of

meter tube inspections so that the pipe wall can be maintained within roughness specifications.

- Obtain and review any cleaning records for the orifice meter primary elements. If the meter has been disassembled for cleaning, the cleaning process shall be recorded. Inspection of the following items should also be performed while the meter is disassembled for cleaning. Data to be collected during these inspections are described in subsection 1.2.2.
 - Alignment of meter tube sections and flow conditioner.
 - Distance from the centerline of the pressure tap holes to the nearest face of the orifice plate.
 - Pressure tap diameters.
 - Roundness or eccentricity of the meter tube.
 - Orifice bore eccentricity.
 - Meter tube surface roughness.
- Obtain and review the last onsite orifice plate inspection report. The report shall include the following items. See subsection 2.2.2.2 of this procedure for details on orifice plate inspection procedures.
 - Date of last inspection. Plate inspections shall occur monthly (not to exceed 42 days) as required by 30 CFR §250.1203(b)(2).
 - Plate manufacturer.
 - Material of construction. Plate materials referenced by API MPMS Chapter 14.3 include Type 304 stainless steel, type 316 stainless steel, Monel, and carbon steel.
 - Nominal orifice bore diameter stamped on the orifice plate.
 - Temperature at which the nominal bore diameter was measured (if recorded on the plate; this is typically 68°F.)
 - Orifice bore edge sharpness.
 - Measured orifice bore diameter.
 - Temperature at which the bore diameter was measured.
 - Measured orifice plate thickness.
 - Measured orifice plate flatness.
 - Measured orifice plate surface roughness.
 - Any contaminants on the plate (liquids, deposits) and patterns of their deposition on the plate.
- Review records of orifice plate changes. Note the following information:
 - Date of plate change.

- o Orifice bore diameter of old and new orifice plates.
 - o Comments on the condition of the plate removed from service (oily, dirty, damaged, etc.)
- Review recent differential pressure data to ensure that the maximum allowable differential pressure for the orifice plate has not been exceeded. Limits on differential pressure can be found in API MPMS Chapter 14.3, Part 2, Appendix 2-E.
- If the orifice fitting is of the single-chamber (“junior”) or dual-chamber (“senior”) type, obtain and review inspection records of the orifice fitting. These shall include the following:
 - o Documentation of the type of seal and its material of construction.
 - o Measurements of the orifice seat width.
 - o Measurements of the orifice seal width and comparison to the seat width.
 - o Results of the pressure tap leak test.
 - o Results of the plate bypass leak test (if applicable).

1.4.2.2 Coriolis Meters

- Review records, drawings, work orders, etc. of any facility modifications that may affect the vibration levels or piping stress on the Coriolis meter since the last inspection period.

1.4.2.3 Ultrasonic Meters

- If the ultrasonic meter(s) are used for sales/royalty or allocation measurement, confirm that the meter approval application includes the following statements:
 - o The ultrasonic meter(s) in use shall be multipath, and shall contain at least three independent acoustic paths.
 - o The ultrasonic meter(s) shall be installed in unidirectional installations, unless a departure has been approved by BSEE for bi-directional flow through the meter(s).
- Obtain and review the most recent onsite inspection records for any ultrasonic meters located in the field. At a minimum, the items listed below shall be included in the inspection.
 - o Confirm that the inside diameter of the meter has been kept clean and free of deposits.
 - o Confirm that transducer ports were inspected for accumulation of solids, erosion, or other damage that would affect meter performance.
 - o Confirm that transducer surfaces were inspected for contamination and cleaned as necessary.

1.4.3 Calibration and Proving Reports

Records of meter calibration or proving will depend upon the meter involved. API MPMS Chapter 14.3 for orifice meters is a specification-based standard, rather than a performance-based standard. If the orifice meter and its components meet the physical specifications of the standard, then the equations found in the standard may be used to compute flow rates from orifice meter measurements, and the measurement uncertainties may also be found in the standard. Thus, inspection of the orifice meter and its components is critical to assuring meter accuracy. Standards for Coriolis and ultrasonic meters are performance-based, requiring them to be calibrated or proved at regular intervals. While inspection of the meter station is still required, calibration or proving reports shall be obtained and reviewed for these meters.

Liquid meter proving can be performed on site if a meter prover (a prover loop, a master meter, or a tank prover) is permanently installed or transported to the location. Natural gas meters are typically removed from the site and sent to a calibration facility, although portable calibration equipment for natural gas meters has historically been available. This section provides guidance for reviewing meter proving and calibration reports.

- If available, review copies of operator procedures for onsite verification/calibration of royalty or allocation meters, secondary instrumentation, and flow computers.
- If an onsite prover was used to calibrate a sales/royalty or allocation meter, record the following information on the prover:
 - Prover identifier and serial number.
 - Base prover volume.
 - Data used to correct for changes in the base prover volume:
 - Inside diameter for prover.
 - Wall thickness.
 - Metallurgical data to calculate Correction for Temperature on Steel of a Prover (CTSp) and Correction for Pressure on Steel of a Prover (CPSp).

1.4.3.1 Orifice Meters

- If an orifice meter has been proved against an onsite prover or master meter, review the last proving report to confirm that the orifice meter accuracy is within appropriate tolerances.
- Addendum 1 is an example of an orifice meter calibration report in natural gas, comparing the flow rates measured with the orifice meter to those computed per API MPMS Chapter 14.3.

1.4.3.2 Coriolis Meters

- Examples of Coriolis proving reports for liquid service can be found in API MPMS Chapter 5.6, Appendix C. (The example reports are too extensive to reproduce here.)

- Review the meter manufacturer's last calibration report or last onsite verification/proving report for comparison with more recent data.
 - The report shall document the performance of all measurement instruments, including temperature and pressure transducers, and shall include any applicable meter diagnostics.
 - If the meter was proved on site, confirm that the proving process was witnessed by a third-party inspector or BSEE inspector.
 - Re-zeroing of a Coriolis meter shall be required if the observed zero value is outside the meter manufacturer's specified zero offset limits. However, a Coriolis meter shall be proved prior to being re-zeroed. Therefore, needless re-zeroing should be avoided to minimize potential errors associated with meter factor reproducibility.
 - The Coriolis meter factor from the volumetric meter proving report shall be applied to the associated meter run ticket.
- Note the date of the last proving or verification event. Confirm that the frequency of meter proving/verification meets the requirements of 30 CFR §250.1202 for liquid meters.
 - Coriolis meters used for sales/royalty measurement shall be proved or verified monthly, with verification intervals not to exceed 42 days. Verification tasks shall include verification of the stored zero value of the Coriolis meter. Volumetric proving should also be performed when changes in the flow (such as changes in pressure, temperature, density, or viscosity) are known to alter the meter factor.
 - Allocation meters shall be proved monthly if they measure 50 or more barrels per day during the previous month, or quarterly if they measure less than 50 barrels per day during the previous month.
 - If a force majeure event prevents a required monthly proving, royalty and allocation meters shall be proved within 15 days of being returned to service.
- For royalty meters, confirm that the following requirements of 30 CFR §250.1202 have been met:
 - If a verification run produces a meter factor different from the previous meter factor by more than 0.0025, the Coriolis meter shall be removed from service, inspected for damage or wear, adjusted or repaired, and reproved.
 - If using a mechanical displacement prover, five out of six consecutive proving runs shall be recorded that achieve a difference between individual runs of no greater than 0.05%. If this criterion is not met within six proving runs, additional runs may be performed until the range limits listed in API MPMS Chapter 4.8, Table A-1 are satisfied. The average of the accepted runs shall be used to compute the meter factor.

- If using a master meter, three consecutive proving runs shall produce a total meter factor difference of no greater than 0.0005. The flow rate through the meter during proving shall be within 10% of the rate at which liquid is expected to flow through the meter during operation. The average of the meter factors from the three consecutive runs shall be applied in the Coriolis meter as the new meter factor.
 - If using a tank prover, two consecutive proving runs shall produce meter factors with a difference no greater than 0.0005. The average of the meter factors from the two consecutive runs shall be applied in the Coriolis meter as the new meter factor.
- For allocation meters, confirm that the following requirements of 30 CFR §250.1202(k) have been met:
 - If the meter factor produced by a proof differs from the previous meter factor by less than 2%, adjustment of the meter factor is not necessary.
 - If the new meter factor differs from the previous meter factor by more than 2% and less than 7%, the meter shall be removed from service, inspected, adjusted (through revision of the meter factors, etc.) and reproved.
 - If the new meter factor differs from the previous meter factor by more than 7%, the meter shall be repaired and reproved or replaced.

1.4.3.3 Ultrasonic Meters

- Addendum 2 is an example of an ultrasonic meter calibration report in natural gas, conforming to AGA Report No. 9. The report documents meter measurement errors relative to the test facility's flow references, which are calibrated traceable to NIST. Errors are presented for the meter "as found" (before adjustment) and "as left."
- Review the meter manufacturer's last offsite calibration report or last onsite verification/calibration report for comparison with more recent data.
 - The report shall document the performance of all measurement instruments, including temperature and pressure transducers, and shall include any applicable meter diagnostics.
 - If the meter was calibrated on site, confirm that the calibration process was witnessed by a third-party inspector or BSEE inspector.
 - Figure 6 presents the performance requirements for ultrasonic meters in natural gas service under AGA Report No. 9.
- Note the date of the last verification/calibration. Confirm that the frequency of meter verification/calibration meets the requirements of 30 CFR §250.1203 for meters measuring natural gas.
 - Natural gas meters shall be verified or calibrated monthly, with verification intervals not to exceed 42 days.

- If a force majeure event prevents a required monthly proving, natural gas meters shall be verified or calibrated within 15 days of being returned to service.
- Gas royalty meters shall be calibrated using the manufacturer's specifications, and shall be calibrated at a flow rate as close as possible to the average hourly flow rate measured by the meter since the last calibration. Calibration reports for the last two years shall be retained at the field site for inspection.
 - If the meter readings during calibration fall outside contractual tolerances, the meter shall be adjusted to function properly or removed and replaced.
- Confirm that the ultrasonic meter was calibrated as a unit with the upstream and downstream piping used in the field installation, or in an identical piping configuration.

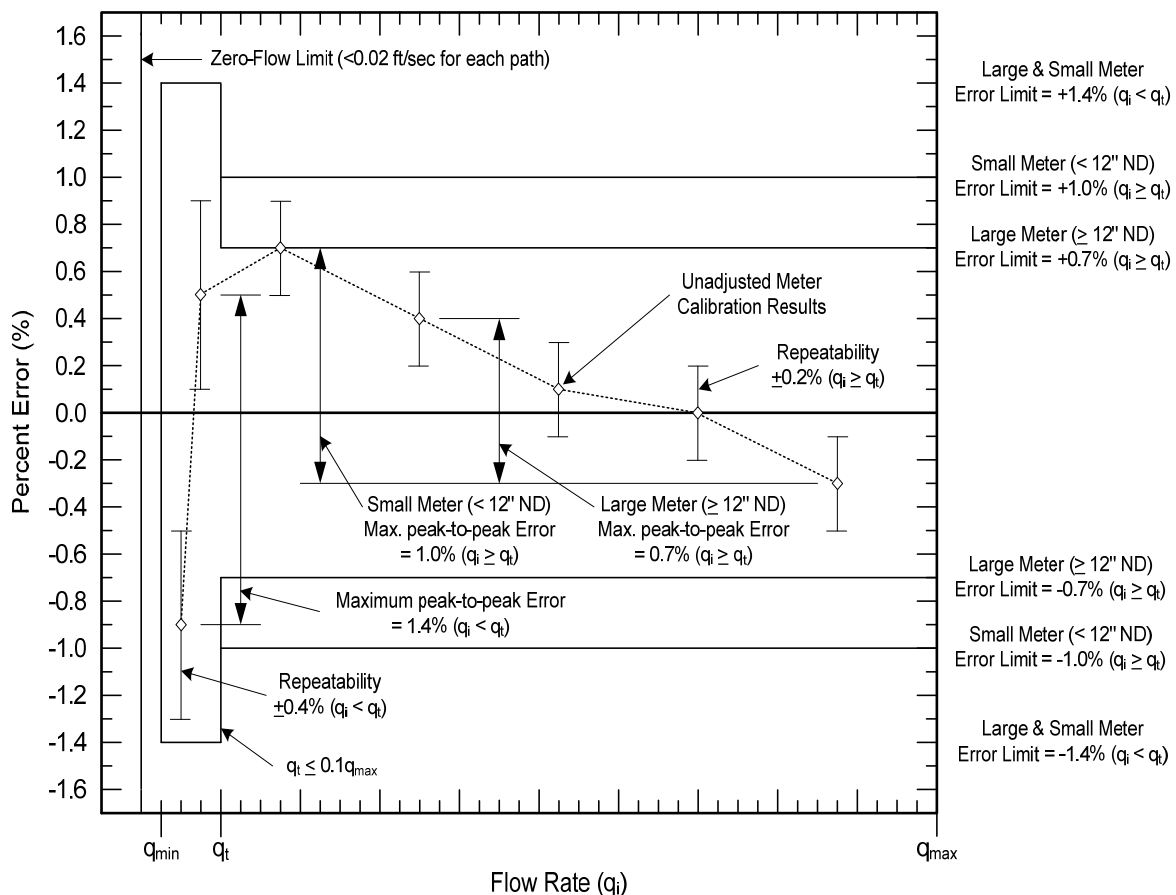


Figure 6. Performance Specifications for Ultrasonic Meters in Natural Gas Service (Adapted from AGA Report No. 9)

Small meters are defined as meters with nominal diameters less than 12 inches. The parameters q_{min} and q_{max} define the range of working flow rates for the meter. More details can be found in AGA Report No. 9.

1.4.3.4 Master Meters or Meter Provers

- Acquire copies of calibration records for master meters or provers located at the site. Any calibrated mechanical displacement prover, master meter, or tank

prover installed at a field location shall be calibrated in accordance with 30 CFR §250.1202, paragraph (e) or (f), as appropriate.

- Confirm that the master meter(s) or prover(s) have been calibrated using references certified and/or traceable to NIST.
- Record the last date of calibration for each master meter or prover.
 - Master meters used to prove royalty meters shall be calibrated before being used to determine meter factors for royalty meters. The master meters shall also be calibrated monthly, with calibration intervals not to exceed 42 days. Further details can be found in 30 CFR §250.1202(e)(4).
 - Mechanical displacement provers and tank provers used to prove royalty meters shall be calibrated at least once every five years.
 - Master meters shall be calibrated on fluids of similar density, temperature, and flow rate (and for liquids, viscosity) as the fluids being measured by the royalty meter.
 - Note the national or international reference standards to which the master meter or prover was calibrated and tested.

1.4.3.5 Secondary Instrumentation

- Review the most recent calibration/verification reports for secondary instrumentation. Per API MPMS Chapter 21.1, Section 1.8, the following instruments require verification/calibration at specified intervals:
 - Static pressure transmitters.
 - Differential pressure transmitters.
 - Temperature transmitters.
 - Pulse generators and counters.
 - Online analyzers, where applicable.
 - Densitometers/gravimeters.
- Verification tests are conducted by comparing the value produced by an instrument and its associated transmitter, as recorded by the flow computer, to the value determined by a certified calibration reference standard. At a minimum, verification of all secondary instruments shall be performed quarterly, per federal regulations.
 - For differential or static pressure devices, verification tests shall be performed (at a minimum) at approximately 0, 50, and 100 percent of scale as the pressure increases, and at approximately 80, 20, and 0 percent of scale as the pressure decreases. Verification at additional points is acceptable.
 - Verification of static pressure transmitters should find that the transmitter accuracy falls within the tolerances in Table 4 below.

If a transmitter exceeds these tolerances, a recalibration shall be requested.

Table 4. Accuracy Requirements for Pressure Transmitters after Calibration

The requirements are taken from existing BSEE guidelines.

Pressure range	Tolerance at atmospheric pressure	Tolerance at operating pressure
0 – 1,000 psig	±0.5 psig	±1.0 psig
0 – 2,000 psig	±0.5 psig	±1.5 psig
0 – 3,000 psig	±0.5 psig	±2.0 psig

- For temperature devices, a verification test shall be performed at one or more temperatures. For resistance temperature detectors (RTDs), the resistance reference or ice point should be verified in a properly prepared ice bath or ice bath substitute. Results shall be compared to a certified reference thermometer, and the value recorded by the flow computer shall agree with the reference thermometer value to within ±0.5°F.
 - If the verification of a temperature transmitter finds that the transmitter accuracy falls outside ±0.5°F, a recalibration shall be requested.
 - Guidance on verification tests for other secondary devices can be found in API MPMS Chapter 21.1, Section 1.8.3.
- Note the last date of calibration for secondary instrumentation. Per API MPMS Chapter 21.1, Appendix C, calibration stickers or tags shall be attached to the secondary instruments showing the date of calibration or verification, the party or person performing the inspection, and the due date of the next calibration.
- Calibration of secondary instrumentation for all meter types (i.e., pressure and temperature transmitters) shall be performed at the following events and intervals:
 - Upon initial installation.
 - Upon replacement.
 - When verification of the instrument produces an unacceptable difference between the recorded measurement and the value determined by the reference standard.
 - Once every two years or as recommended by the instrument manufacturer, whichever is shorter, in accordance with API MPMS Chapter 21.1, Appendix C.
- Calibrations shall be performed according to manufacturer’s guidelines, and adjustments shall be made to the devices to return readings to within acceptable errors.
- After calibrating a device, an “as left” verification test shall be conducted. The minimum uncertainty requirement for calibration/verification equipment shall be a factor of two better than the specified uncertainty of the transmitter, transducer,

or other associated device to be calibrated. However, for practical purposes, calibration system uncertainties better than 0.05% are not normally required.

- All reference instruments and/or standards used for calibration/verification shall be traceable to primary standards maintained by an internationally-recognized standards organization such as NIST. Reference instruments used in secondary instrument calibration/verification shall be checked and calibrated once every two years or as recommended by the instrument manufacturer, whichever period is shorter.

1.4.4 Quantity Transaction Records

A Quantity Transaction Record (QTR) is a collection of information relating to the custody transfer of natural gas or liquid hydrocarbons. A QTR contains the set of unedited historical data and information supporting the accounted quantity or quantities of volume, mass, or energy. A QTR is used to convey information about fluid movement from operations to accounting and between parties in a custody transfer agreement. Retaining historical volumetric calculations and custody transfer quantities provides reasonable information for the flow history of the source in the event of failure or for a comparative analysis.

Inspection guidelines in this section are taken primarily from API MPMS Chapter 21.1 and Chapter 21.2. Refer to these documents for more information.

- Acquire copies of all quantity transaction records (QTRs), original and corrected, for the current inspection period.
- The following information shall be included in a QTR:
 - Opening and closing date and time of the transaction.
 - Opening and closing readings. These are often abbreviated as MRo and MRc, respectively.
 - Product type identifier (natural gas, liquids, etc.) where multiple products are measured with a single meter.
 - Meter bank identifier where there is more than one bank of meters used in measurements.
 - Meter identifier.
 - Meter factor (MF), composite meter factor (CMF), and/or K-factor (KF).
 - Average temperature correction factor (CTL).
 - Average pressure correction factor (CPL).
 - Flowing density and temperature, when a sample or analysis is used to determine density at base conditions.
 - Relative density, energy content, and composition, if taken from live inputs.
 - Weighted average pressure (PWA).
 - Weighted average temperature (TWA).

- o Weighted average density (DWA) or default density at reference conditions.
 - o Sediment and water (S&W) quantity or correction for S&W (CSW) where water or sediment exists in non-marketable quantities.
 - o Net standard volume (NSV).
 - o QTR identifier (e.g., meter ticket number).
 - o Gross standard volume (GSV); NSV = GSV where no sediment or water exist in the custody transfer stream.
- For orifice meters, the following data shall also be included in the QTR (see API MPMS Chapter 21.1 for more information).
 - o Measured quantities of volume, mass, and/or energy.
 - o Reference meter tube inside diameter at 68°F, as stamped on the meter tube or fitting nameplate. The meter tube diameter shall be recorded to at least three decimal places.
 - o Differential pressure average.
 - Note that the average differential pressure should not be used in independent calculations of the average volumetric flow, since volumetric flow is proportional to the square root of the differential pressure.
 - o Static pressure average.
 - o Temperature average.
 - o Integral value or average extension.
 - The integral value is the value resulting from the integration of the factored portion of the flow rate equations that best defines the conditions of continually changing flow over a specified time period.
 - The average extension is the integral value divided by the flow time.
 - See MPMS Chapter 21.1 for more information.
 - o Flow time corresponding to the integral value and/or average extension.
- Confirm that quantities are calculated on an hourly and daily basis.
 - o Hourly records are useful in batch QTRs that take less than one day to complete. Daily QTRs contain a summation of all of the information from the hourly QTRs.
- Confirm that values in the QTR are reported with enough significant digits to allow recreation of the results by independent calculation to within 50 parts per million.

- Confirm that the units of measure for values reported in the QTR are explicitly stated.
- Review the configuration log, event log, logged data, transaction records, and any field test reports.
 - The configuration log shall contain and identify all constant flow parameters, calculation methods and algorithms, and other information used in the generation of a QTR.
 - Unique identifiers shall be provided to identify the version of the software used in creating the QTR.
 - If data in a QTR shall be modified, the original QTR shall be kept and a corrected QTR shall be created, including the name and identifier code for the party making the revision.
 - The reason for any correction or edit to the QTR shall be documented.
- QTRs should be kept on site for a minimum of seven days, and shall be kept off site for a period of time specified in regulations or custody transfer contracts.
- A QTR is normally signed or marked with an identifier by the person or parties who confirm that the information is correct.
- All of the required QTRs may not be completed at the time of the transfer. This is acceptable if both parties agree, however, all required information shall ultimately be captured.
- Multiple QTRs may be used during a single accounting period.

2. FIELD INSPECTION PROCEDURES

This section lists procedures that require access to equipment at the field site, such as downloading diagnostic information from meters or inspection of orifice plates. Some procedures in Section 1 have been duplicated here for completeness.

2.1 General Field Inspection Tasks

If the inspection of records began before the site visit, these data may already have been collected under subsection 1.1 of this procedure. If so, confirm that any information collected on site agrees with the information collected earlier.

- Record the date of the inspection. If the inspection is performed over several days, record the first and last dates of the inspection.
- Record whether the inspection is announced or unannounced.
- Record the producer or operating company for the lease under inspection and their operator ID.
- Record the name of the producer or operator's representative and their contact information (including phone number).
- Record the lease number or other lease identifying information.
- Record the facility measurement point (FMP) number assigned by BSEE.
 - Confirm that this number matches the number in the Technical Information Management System (TIMS) database.
 - Confirm that the type of facility measurement point (all liquid, all gas, inventory tank, royalty tank, sales/royalty measurement, allocation measurement, etc.) matches the information contained in the FMP number.
- Record the measurement station name and location.
 - For export meters, record the station number assigned by the pipeline company.
 - For offshore platforms, record the platform name and surface location.
- Record information on the fluid being measured at the station. Useful information may include, but not be limited to, the following:
 - Natural gas or hydrocarbon liquids.
 - Unprocessed or processed to remove certain components (heavy hydrocarbons, water, etc.).
- Confirm that the actual status of the meter(s) (active and operating, active and non-operating, or inactive) agrees with the documented meter status. See subsection 1.1 for details.
- Check for bypass piping around the meter.

- Bypasses of any type around active liquid hydrocarbon royalty meters, natural gas royalty meters, and platform export meters are not allowed. See 30 CFR §250 Subpart L for details.
- Check for commingled production.
 - Confirm that written approval has been obtained from the Regional Supervisor for surface commingling of production from different leases.
 - If requested by the Regional Supervisor, lessees who deliver state lease production into a federal commingling system shall provide volumetric or fractional analysis data on the state lease production, per 30 CFR §250.1204(b)(2).
 - If there is commingled production, record the lease number or other identifying information for each well whose production is being commingled.

2.2 Inspection of Physical Meter Runs at the Field Site

2.2.1 General Tasks

- Check each royalty meter for a nameplate. Nameplate(s) shall be made of materials that will not deteriorate, fade, or peel. Record the following information from the nameplate, and confirm the information against recorded data on the royalty meters installed at the station.
 - Meter manufacturer.
 - Model number.
 - Serial number.
 - Nominal meter diameter.
 - Maximum flow capacity (and, if on the nameplate, minimum flow capacity).
- If available, record normal operating conditions at the measurement location. Confirm that these conditions fall within meter specifications.
 - Pressure.
 - Temperature.
 - Flow rate (maximum, minimum, and average).
 - Density or specific gravity.
- Inspect meter seals and seal records.
 - Confirm that seals are secured to the royalty meter(s) and have not been tampered with.
 - Confirm that seals include seal numbers.
 - Confirm seal numbers against operator records.

- Confirm that the flow is single-phase. The metering standards used to develop this inspection procedure assume single-phase flow, and multiphase flows will compromise measurement accuracy. There are no methods in the relevant standards for confirming single-phase flow in a meter installation. However, the following methods can be used by inspectors to look for multiphase or gas-liquid flows.
 - If a vent has been installed on a line connecting a pressure transmitter to the meter, and if the vent can be safely opened, the vent may be opened to look for liquid in a gas flow or gas in a liquid flow. Personal protective equipment (such as safety glasses) shall be worn while performing this procedure.
 - Vents on liquid scrubbers upstream of a gas meter may be opened to look for liquid that has collected in the scrubber. Liquid will indicate that two-phase flow has been present at some time, but will not necessarily indicate that the current flow is two-phase.
 - Review records of the measured flow rate over time. Frequent spikes (positive or negative) in the flow rate over an extended period of time may indicate multiphase flow. Note that this method is not a quantitative measure of multiphase flow, because the magnitude and frequency of the spikes in flow rate cannot be generalized to flow rates of the different phases.
- Record the number of royalty meters in the installation, including meters in series and in parallel.
 - Confirm that the number of meters and meter runs agree with the approved measurement configuration.

2.2.2 Inspection of Orifice Meters

Document and confirm that the installed meter run configuration remains as approved. If the meter run was inspected previously, either before or after installation, document any changes from the last recorded configuration.

2.2.2.1 Inspection of the Orifice Meter Run as Installed

- Confirm the brand and type of orifice fitting (flanged, single-chamber, or double-chamber) against the type listed in BSEE records, or against the request for approval submitted by the producer or station operator.
- Measure and/or record the following equipment locations and dimensions using consistent measurement tools and practices. Steel tape measures are acceptable for this purpose.
 - Pipe diameter (nominal diameter and schedule). This information should appear on the meter tube pipe flanges or the orifice fitting.
 - The reference meter tube inside diameter, as stamped on the meter tube or fitting nameplate. The stamped meter tube diameter shall include at least three decimal places.

- Reference temperature at which the meter tube diameter was determined. This should appear on the orifice fitting, and is typically 68°F.
- Total upstream pipe length between the orifice plate and the nearest upstream flow disturbance (elbow, tee, valve, etc.).
- Distance between the upstream flow conditioner (if present) and the orifice plate.
- Brand and/or model, line diameter, and pipe schedule of the flow conditioner (if visible from the outside of the meter run).
 - Note the use of a flow conditioner made for a pipe schedule smaller than the pipe schedule of the meter tube, since such a flow conditioner may not be correctly centered in the pipe.
 - If the flow conditioner is directional, confirm that the arrows on the flange are pointing in the direction of flow through the meter run.
- Downstream pipe length between the orifice plate and the nearest flow disturbance (elbow, tee, valve, etc.)
- Locations of all secondary devices connected to or inserted into the meter run. Installation of these devices should also conform to the manufacturer's guidelines, where applicable.
 - Static and differential pressure transmitters.
 - Note whether the static pressure transmitter is connected to an upstream or downstream tap.
 - Thermowell, RTD, or other temperature measurement device.
 - Thermometers may be used for reference temperature measurements, while a resistance temperature device (RTD) connected to a temperature transmitter may be used in normal applications, particularly in situations requiring a rugged device. These sensors are commonly inserted in a thermowell, which is then placed in the flow. Refer to API MPMS Chapter 7 for details on the use of various temperature measurement devices.
 - The temperature sensor shall be mounted downstream of the orifice plate according to the requirements of API MPMS Chapter 14.3.
 - Where multiple meters are installed in parallel, thermowells should be installed in each meter run. In the event that flowing temperatures vary between parallel meter runs, the use of individual measurements for each meter will avoid biases related to these temperature differences.
 - Sample probe, if present.

- Densitometer, if present (commonly used for liquid density measurements).
- Accepted practice states that meter taps should not be shared between secondary devices, and that each tap on the meter run should be connected to a single device. There are two exceptions to this practice:
 - The static pressure transmitter shall measure static pressure at either an upstream or downstream tap on the orifice fitting, which will also be used by the differential pressure transmitter.
 - Stacked differential pressure transmitters (multiple transmitters with different measurement ranges) may be connected to the same pair of pressure taps to increase the measurement range of the orifice meter.
- Confirm that the upstream and downstream pipe lengths, position, and specifications of the flow conditioner, and positions of secondary devices meet the configuration requirements of API MPMS Chapter 14.3, Part 2 and the flow conditioner manufacturer.
- Record the orifice bore diameter, reference meter tube diameter, and beta ratio of the orifice plate in service at the time of inspection.
 - $\beta = (\text{orifice bore diameter} / \text{reference meter tube diameter}) = d_r / D_r$.
 - If the orifice fitting is a flange type, the orifice bore diameter should be stamped on the plate handle extending from the meter run.
 - If the orifice fitting is a double-chambered (“senior”) type, request that the plate be removed for inspection (this can be done without bleeding down the meter run). The plate dimensions will typically be stamped on the outer edge, and may be hidden under the gasket used to hold the plate in the chamber.
 - If the orifice fitting is a single-chambered (“junior”) type, and bleed-down of the meter run for plate inspection is impractical, request these data for the current orifice plate from station records.
 - Confirm that the beta ratio is within the range of 0.10 to 0.75 permitted by API MPMS Chapter 14.3.
- Document the orientation of the differential pressure taps and transducer lines.
 - Taps at the side of the orifice fitting with side-mounted transducers are the preferred installation arrangement.
 - Taps at the bottom of the fitting and bottom-mounted transducer lines are unfavorable in meters for gas because of the potential for sediment deposits in the transducer lines.

- Taps at the top of the meter run and top-mounted transducer lines are unfavorable in liquid meters because of the potential for gas bubbles to become trapped in the transducer lines.
- Document the length of the pressure gauge lines.
 - Gauge lines for differential pressure transmitters can amplify or attenuate pulsations from compressors, regulating valves, and flow instabilities. The resulting measurement errors depend on how closely the resonance frequency of the gauge lines matches the frequency of the flow pulsations. There are no standards for gauge line length to avoid pulsation errors, since pulsations can vary between installations and even within an installation. However, since resonance frequencies increase with decreasing gauge line length, making the pressure gauge line length as short as feasible will reduce or avoid gauge line errors by moving the resonance of the gauge lines up to frequencies above common compressor pulsation frequencies.

2.2.2.2 Inspection of Orifice Plates

Obtain and review inspection records for the orifice plate currently installed in the meter run. Acceptance criteria for orifice plate dimensions are listed in the procedures below. If an inspection record is not available, remove the orifice plate and perform inspections of the following dimensions and features. Procedures are drawn from API MPMS Chapter 14.3, Part 2.

- Orifice plate flatness (see API MPMS Chapter 14.3, Part 2, Section 2.4.1):
 - The deviation from plate flatness, δ , can be measured using a bar or straight edge of the same length as the meter tube diameter, laid across the orifice plate as shown in Figure 7. Deviations from flatness greater than 1% of the “dam height” are not allowed. The dam height is calculated as half the difference between the measured meter tube diameter D_m and the measured orifice bore diameter d_m . This criterion applies to any two points on the orifice plate within the inside diameter of the pipe.

$$\text{dam height} = (D_m - d_m)/2$$

$$\text{maximum allowable departure from flatness } \delta \leq 0.005(D_m - d_m)$$

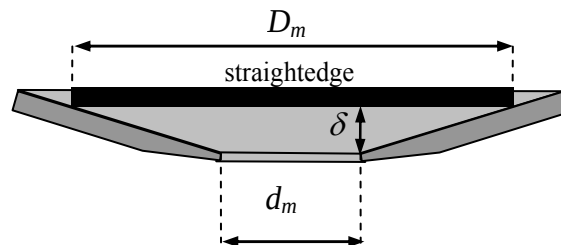


Figure 7. Method for Measuring Orifice Plate Departure from Flatness

The suggested measurement location for the flatness deviation, δ , is from the upstream edge of the orifice bore to the straight edge.

- Orifice plate surface roughness (see API MPMS Chapter 14.3, Part 2, Section 2.4.3):

- Measurements can be performed using an electronic averaging surface roughness instrument, or by visual comparison to a reference device with surface roughnesses of different levels. Further guidance can be found in API MPMS Chapter 14.3, Section 2.4.1 and ANSI B46.1. The surface plate roughness average, R_a , shall not exceed 50 microinches (50 μin), including abrasions or scratches.
- Orifice plate bore:
 - The upstream edge of the orifice plate bore shall be square and sharp. Per API MPMS Chapter 14.3, Section 2.4.1, “the orifice bore edge is considered too dull for accurate measurement if the upstream edge reflects a beam of light when viewed without magnification.” Note that there is no practical quantitative method for determining edge sharpness.
 - The upstream and downstream edges of the orifice plate bore shall be free from visible defects, such as flat spots, burrs, nicks, pits, or notches.
 - The inside surface of the orifice bore shall have no defects visible to the naked eye, such as grooves, ridges, pits, or lumps.
 - The orifice plate bore thickness e , the length of the cylinder formed by the bore in the direction of flow, shall meet the following limits from API MPMS Chapter 14.3, Part 2, Section 2.4.4. Steel rulers or Vernier calipers are acceptable for these measurements.
 - Minimum allowable bore thickness shall be defined as $e \geq 0.01 d_r$ or $e \geq 0.005$ inches, whichever is larger.
 - Maximum allowable bore thickness shall be defined as $e \leq 0.02 D_r$ or $e \leq 0.125 d_r$, whichever is larger.
 - The bore thickness shall not be greater than the plate thickness (that is, the bore shall not extend beyond the flat surface on either side of the plate).
 - Measure the orifice bore diameter along four independent axes, such as the four axes shown in Figure 5. Inside micrometers are acceptable for this purpose. The calculated average of the four measurements is defined as the measured orifice bore diameter, d_m .
 - Measure the temperature of the orifice plate, T_m , at the time the bore diameter measurements are taken.
 - None of the four bore diameter measurements shall vary from the average value by more than the tolerances given in Table 5.
 - Compare the measured average bore diameter, d_m , to the reference bore diameter, d_r , stamped on the plate. Changes between the temperature T_m at the time of measurement and the reference temperature T_r of the reference orifice plate bore diameter can be accounted for using the

following equation. Here, α is the linear coefficient of thermal expansion of the orifice plate material, listed in Table 6.

$$d_r = d_m[1 + \alpha(T_r - T_m)]$$

Table 5. Roundness Tolerances for the Orifice Plate Bore Diameter, d_m

None of the individual bore diameters shall vary from the average value by more than the tolerances in the table. The tolerances are taken from API MPMS Chapter 14.3, Part 2, Table 2-1.

Orifice bore diameter, d_m (inches)	Tolerance (inches)
≤ 0.250	± 0.0003
0.251 to 0.375	± 0.0004
0.376 to 1.000	± 0.0005
> 1.000	± 0.0005 inch per inch of diameter

Table 6. Reference Linear Coefficients of Thermal Expansion, α

The recommended values are taken from API MPMS Chapter 14.3, Part 2, Table 2-2.

Material	α [inch/(inch-°F)]
Type 304 or 316 stainless steel	9.25×10^{-6}
Monel	7.95×10^{-6}
Carbon steel	6.20×10^{-6}

- Orifice plate bevel:
 - Orifice plates for which the maximum bore thickness is less than the plate thickness shall have a bevel on the downstream face, unless the plate is used in a bi-directional orifice meter run.
 - The allowable value for the plate bevel angle is $45^\circ \pm 15^\circ$, measured between a line parallel to the downstream face of the plate and the bevel itself.
 - The bevel surface shall have no defects visible to the naked eye, such as grooves, ridges, pits, or lumps.
- Orifice plate thickness:
 - Plate thickness, measured with Vernier calipers, shall fall within the minimum and maximum ranges specified in API MPMS Chapter 14.3, Part 2, Table 2-3.

2.2.3 Inspection of Coriolis Meter Runs

Document and confirm the meter run configuration as installed. If the meter run was inspected previously, either before or after installation, document any changes from the last recorded configuration.

- Measure and/or record the following equipment locations and dimensions using consistent measurement tools and practices. Steel tape measures are acceptable for this purpose.

- o Pipe diameter (nominal diameter and schedule) of the meter tube, if stamped on the flanges.
- o Locations of all secondary devices connected to or inserted into the meter run. Installation of these devices should also conform to the manufacturer's guidelines, where applicable.
 - Static pressure transmitters.
 - Thermowell, RTD, or other temperature measurement device.
 - Thermometers may be used for reference temperature measurements, while a resistance temperature device (RTD) connected to a temperature transmitter may be used in normal applications, particularly in situations requiring a rugged device. These sensors are commonly inserted in a thermowell, which is then placed in the flow. Refer to API MPMS Chapter 7 for details on the use of various temperature measurement devices.
 - Some liquid meter designs may allow for the temperature sensor to be mounted on the meter body, to reduce differences between the temperature of the fluid being measured and the temperature at the sensor. If this is not the case, the sensor shall be mounted downstream of the meter according to API MPMS Chapter 5.6.
 - Where multiple meters are installed in parallel, thermowells should be installed in each meter run. In the event that flowing temperatures vary between parallel meter runs, the use of individual measurements for each meter will avoid biases related to these temperature differences.
 - Sample probe, if present.
 - Densitometer, if present (commonly used for liquid density measurements).
- o Although Figure 2 of API MPMS Chapter 5.6 includes a bypass in the diagram, bypasses of any type around active liquid hydrocarbon royalty meters, natural gas royalty meters, and platform export meters are not allowed, per 30 CFR §250, Subpart L.
- Confirm that the upstream and downstream pipe lengths and positions of secondary devices meet the configuration requirements of API MPMS Chapter 5.6.
- Confirm that the following equipment and other requirements are met at the field site. Many of these requirements can be found in 30 CFR §250.
 - o The installation shall be equipped with a strainer or other protective device upstream of the meter to remove foreign objects which may cause measurement error.

- o The installation shall be equipped with air/vapor eliminator equipment upstream of the meter so that measurement accuracy is not degraded by two-phase (liquid/gas) flow.
- o The installation shall include valves to stop flow through the Coriolis meter to allow zeroing and stored zero value verification, and shall include valves that control or block flow during metering or proving.
- o The installation shall be equipped with devices to prevent flow reversal through the Coriolis meter if the meter is not bi-directional.
- o The installation shall be equipped with a sediment and water monitor with a probe upstream of the Coriolis meter and upstream diverting valve.
- o A backpressure valve shall be located downstream of the Coriolis meter. This valve should maintain pressure in and immediately downstream of the Coriolis meter sufficient to minimize or eliminate vaporization or cavitation.
- o Coriolis meters shall not be installed near sources of flow pulsation or vibration, which can interfere with measurement accuracy. Equipment shall be installed to prevent the meter from being subjected to shock pressures greater than its maximum allowable working pressure.
- o Check that the Coriolis meter is well supported. The meter case should not be used to support the meter or other equipment.
- o The Coriolis meters should be oriented in a position that allows tubes to be completely filled with fluid under all static and flowing conditions.
 - Dual-tube meters should be positioned vertically so that the meter fills with liquid by gravity, and that any entrained gas in the liquid rises out of the tubes.
- o Piping should be anchored to avoid any stress transference to the Coriolis meter itself.
- o The Coriolis meter station shall be equipped with a calibrated mechanical displacement prover, master meter, or tank prover. The displacement prover, master meter, or tank prover itself shall be calibrated in accordance with 30 CFR 250.1202, paragraph (e) or (f), as appropriate.

2.2.4 Inspection of Ultrasonic Meter Runs

Document and confirm the meter run configuration as installed. If the meter run was inspected previously, either before or after installation, document any changes from the last recorded configuration. See subsection 1.2.4.1 of this procedure for meter run geometry specifications.

2.2.4.1 Inspection of Ultrasonic Installation Geometry

- Measure and record the following equipment locations and dimensions using consistent measurement tools and practices. Steel tape measures are acceptable for this purpose.

- o Pipe diameter (nominal diameter and schedule) of the meter tube, if stamped on the flanges.
- o Brand, model, line diameter, and pipe schedule of the flow conditioner (if visible from the outside of the meter run).
 - Note the use of a flow conditioner made for a pipe schedule smaller than the pipe schedule of the meter tube, since such a flow conditioner may not be correctly centered in the pipe.
 - If the flow conditioner is directional, confirm that the arrows on the flange are pointing in the direction of flow through the meter run.
- o Total upstream pipe length between the ultrasonic meter inlet and the nearest upstream flow disturbance (elbow, tee, valve, etc.). Per AGA Report No. 9, the meter run shall have 20 nominal diameters of straight pipe upstream of the meter.
- o Distance between the upstream flow conditioner (if present) and the ultrasonic meter inlet.
- o Downstream pipe length between the ultrasonic meter outlet and the nearest flow disturbance (elbow, tee, valve, etc.)
- o Locations of all secondary devices connected to or inserted into the meter run. Installation of these devices should also conform to the manufacturer's guidelines, where applicable.
 - Static pressure transmitters (often mounted on the meter body, rather than on the meter run).
 - Thermowell, RTD, or other temperature measurement device.
 - Sample probe, if present.
 - Densitometer, if present (these are not common in natural gas applications).
- Confirm that the upstream and downstream pipe lengths, position, and specifications of the flow conditioner, and positions of secondary devices meet the configuration requirements of AGA Report No. 9 and the flow conditioner manufacturer.
- Confirm that the meter has a sunshield if the manufacturer recommends one to protect meter electronics.
- Inspect the area upstream and downstream of the ultrasonic meter run for potential sources of pulsations or ultrasonic noise, such as reciprocating compressors or regulating valves. If potential sources are present, determine if the meter has been calibrated in place to compensate for the pulsations or noise, or if the meter has been designed to operate in such an environment.

2.2.4.2 Inspection of Ultrasonic Meter Design

- If the ultrasonic meter has transducer wells that face upward or upstream, confirm that the transducers and wells are cleaned or checked regularly for sediment and debris.

2.3 Onsite Flow Computer and Electronics Inspection Tasks

Depending upon the communications setup, information from flow computers may be collected remotely from operator offices, or locally at the measurement site. A list of tasks that may be performed remotely can be found in subsection 1.3. If remote access is not possible, the tasks listed in that section should be performed at the field site. This section lists tasks to be performed on site, related to both the flow computer and electronics on board Coriolis and ultrasonic meters.

2.3.1 Tasks Specific to Flow Computers Used with Orifice Meters

- Note the reference inside meter tube diameter and the reference temperature that are used by the flow computer in calculations. These values are used to correct calculated flow rates for thermal expansion and contraction of the meter tube. Confirm that these values agree with the values found on the orifice fitting.
- Confirm that the flow computer calculates the correct expansion factor for the position of the static pressure transmitter (upstream versus downstream pressure tap).
- If the metering system performs calculations off site, confirm that the following minimum data set is generated by a flow computer on site. See subsection 1.4.4 for more information.
 - Date and time.
 - Integral value or average extension.
 - Flow time corresponding to the integral value and/or average extension.
 - Differential pressure average.
 - Static pressure average.
 - Temperature average.

2.3.2 Tasks Specific to Coriolis Meter Electronics

- Review a copy of the Coriolis meter alarm logs for indications of flow ranges exceeded, device failures, power failures, instrument restarts, or other abnormal conditions. If such records are found, investigate and record actions taken to alleviate the abnormal conditions.
- Review the Coriolis meter's firmware/software configuration.
 - A change in checksum indicates a change in meter configuration and possibly meter performance.

- Changes to the firmware, flow measurement configuration parameters, or other settings shall be documented with a notation of the reason for the change and the individual who performed the change.
- Confirm that the following factors have been entered correctly into the Coriolis meter.
 - Flow calibration factors(s).
 - Density calibration factor(s). Conversions and corrections from mass flow rate to volume flow rate are generally made using liquid density values from an external source, since density values measured by Coriolis meters are generally not sufficiently accurate.
 - If the Coriolis meter output uses an externally-supplied density calibration factor, note the source of the density value (secondary densitometer, sample analysis, etc.).
 - Pulse calibration factor (pulses output per unit volume).
- Compare the density measured by the Coriolis meter to the density of the liquid obtained externally (by densitometer or sample analysis), and to density values reported by the Coriolis meter during previous inspections.
 - While the meter's measured values may not agree with external values, drift in the measured density over time may indicate deposits or collection of material in the Coriolis meter body.

2.3.3 Tasks Specific to Ultrasonic Meter Electronics

- Review the ultrasonic meter's firmware/software configuration.
 - A change in checksum indicates a change in meter configuration and possibly meter performance.
 - Changes to the firmware, flow measurement configuration parameters, or other settings shall be documented with a notation of the reason for the change and the individual who performed the change.
- Obtain and review the ultrasonic meter's configuration parameters. Items recorded from the configuration file should include, at a minimum:
 - Calibration constants.
 - Configuration parameters.
 - Meter dimensions.
 - Time averaging period.
 - Sampling rate.
- Review the ultrasonic meter output. At a minimum, an onsite computer or control room display should show and/or record the following measurements for review:
 - Flow rate at line conditions.

- o Mean velocity through the meter.
 - o Average speed of sound.
 - o Speed of sound along each acoustic path.
 - o Ultrasonic signal quality received by each transducer (signal-to-noise ratio).
- Review a copy of the ultrasonic meter logs for indications of meter performance. The parameters listed below, calculated for each transducer path, are commonly monitored. Diagnostic alarms should be generated when one or more of these parameters fall outside acceptable limits. An alarm condition on one path does not mean that all flow measurement has been lost, since multipath ultrasonic meters can continue to function with the loss of one measurement path; however, flow measurement accuracy may be compromised. Record any alarms and the loss of any measurement paths on the meter.
 - o Gain
 - High gain values indicate greater attenuation of the signal along that path.
 - High gain values can be caused by the presence of solids, liquid in a gas flow, or possibly a weakening acoustic transducer.
 - When the gain reaches maximum amplification, it is an indication that no signal is being received along the path, and an alarm is generated.
 - o Signal-to-noise ratio (SNR)
 - High SNRs generally indicate good performance on a path, but excessively high SNRs may be caused by improper grounding or electrical interference.
 - Low SNRs typically indicate poor transducer performance, and may be caused by solids in the flow, liquid in a gas flow, or other abnormal flow conditions.
 - SNR data from successive inspections should be recorded and compared to more easily identify transducer problems. A significant difference between the SNR from one inspection to the next could indicate a problem with the transducers on the path of interest.
 - o Pathwise flow velocity ratios
 - If the ratio of path velocity along one path to the average axial flow velocity is significantly different from the ratios from the other paths, this may indicate debris in an upstream strainer or flow conditioner, or a similar obstruction in the flow.
 - o Velocity profile across the meter

- The flow profile through the meter should be axisymmetric. An asymmetric flow profile suggests a blockage upstream of the meter or contamination along the upstream pipe wall.
- o Turbulence levels
 - The standard deviation of the flow velocity measured along each path is used as an indicator of the turbulence intensity.
 - High turbulence levels may indicate partial blockages of upstream flow conditioners, changes in pipe wall roughness, or other abnormalities in the flow profile.
- o Speed of sound
 - Comparison of the speed of sound reported by the meter for each path to known values of the speed of sound for the measured fluid can help to identify problems with the meter or meter run.
 - The speed of sound of natural gas is highly dependent on pressure, temperature, and composition. Reference tables for the speed of sound of natural gas mixtures can be found in AGA Report No. 9 and AGA Report No. 10. Alternatively, the speed of sound can be calculated using a component analysis of the gas stream and the AGA-10 equation of state. The speed of sound indicated by the meter should agree with the speed of sound calculated using the AGA-10 equation of state to within ± 2 ft/s. Differences outside this tolerance may indicate measurement errors by the ultrasonic meter.
 - Reference values of the speed of sound of some gases at atmospheric pressure and 60°F:
 - Air: 1,118.05 ft/s
 - Natural Gas: 1,300 ft/s to 1,500 ft/s (depending on composition)
 - Methane: 1,449.8 ft/s
 - Ethane: 1,006.7 ft/s
 - Compare the speed of sound among the paths.
 - Good agreement in sound speed between paths indicates that transit-time measurement and measured distances between transducers are within acceptable accuracy limits.
 - Variations in the speed of sound from top to bottom may indicate temperature stratification (found at low flows) or a density gradient.

- A single path that shows a difference in speed-of-sound measurements from the other paths may indicate contamination on the transducer faces.

2.4 Inspection of Fluid Property Analyses

Properties of gases and liquids are required to calculate volumes involved in sales or royalty transactions or allocation calculations. For example, where transactions are based on gas volumes at standard or reference conditions, reference densities are used to convert volume flow rates at flowing conditions to reference conditions. Natural gas compressibility factors are also involved in flow rate calculations for orifice and ultrasonic meters. Changes in liquid density may shift the zero value of a Coriolis meter, requiring the meter to be re-zeroed and possibly recalibrated. This subsection includes inspection tasks for secondary equipment and methods used to determine gas and liquid properties.

2.4.1 Tasks Related to Gas Analyses

- Record the method used to determine natural gas compositions and/or properties (gas chromatograph, calorimeter, spot sample collection, composite sampler, etc.).
- Confirm that samples are drawn by the device or sampling technician from a location that conforms to the requirements for the meter run. This is best done by witnessing a sample collection on site.
- If one or more online gas chromatographs (GCs) are used to analyze the gas stream:
 - Record the number and location of gas chromatographs.
 - Record the frequency of calibration for the GC. Daily calibrations are often performed to account for effects of ambient conditions on GC response factors.
 - Obtain a copy of the certified composition for the GC calibration gas(es), if this has not been done during the office inspection beforehand.
 - Confirm that the date of certification of the calibration gas is less than one year old. Calibration gases over one year old shall be replaced.
 - Confirm that the serial number on the certificate matches the serial number on the calibration gas cylinder.
 - Compare the calibration gas composition to the most recent gas analysis report. Per industry best practices, each component in the calibration gas should be within the span of one-half to twice the amount of the same component in the analyzed gas stream.
 - Obtain printouts of the GC analysis method and most recent calibration report, if this has not been done during the office inspection beforehand.
 - Confirm that the component concentrations on the calibration gas certificate have been input correctly into the gas chromatograph.

- If other online analysis devices are used:
 - Record their number and location.
 - Confirm that the installation points of the devices conform to the requirements for the meter run.
 - Record the frequency of calibration for each device. Confirm that the devices are calibrated in accordance with manufacturer recommendations.
- If spot samples of the gas stream are collected for analysis at a laboratory:
 - Confirm that one or more of the sampling methods described in API MPMS Chapter 14.1 are used to collect samples.
 - Confirm that the most recent sample is less than six months old, in accordance with 30 CFR §250.1203(b)(5).
 - Record the contact information of the laboratory that analyzes the samples.
 - Document the method used to compute gas properties (density, compressibility, heating values, etc.) from the analysis.
 - Confirm that sample cylinders are cleaned before each use, following cleaning procedures described in API MPMS Chapter 14.1.
- If an automated composite sampler is used to collect samples for analysis at a laboratory:
 - Confirm the rate at which the composite sampler injects a sample into the accumulator. Per API MPMS Chapter 14.1, samples taken at a rate proportional to pipeline flow rate are preferred to samples taken at regular time intervals.
 - Confirm that the most recent composite sample is less than six months old, in accordance with 30 CFR §250.1203(b)(5).
 - Record the contact information of the laboratory that analyzes the samples.
 - Document the method used to compute gas properties (density, compressibility, heating values, etc.) from the analysis.
 - Confirm that sample accumulators are cleaned before each use, following cleaning procedures described in API MPMS Chapter 14.1.

2.4.2 Tasks Related to Liquid Analyses

- Record the method(s) used to determine hydrocarbon liquid compositions and/or properties.
- Confirm that samples are drawn by the device or sampling technician from a location that conforms to the requirements for the meter run, in accordance with 30 CFR §250.1202(b)(4).

- Confirm that the liquid sample probe is in a location that ensures the collection of a representative liquid sample. Sample conditioning can be achieved with adequate velocity in the pipe, or with power mixers or static mixers. Guidance can be found in API MPMS Chapter 8.2, Section 8.
- If hydrocarbon liquid samples are collected and analyzed, review the most recent analysis report. (This may be available at the operator's offices, rather than on site.)
 - Document the method used to collect samples, and any related industry standards governing the sampling method.
 - Review the most recent analysis report. Confirm that the analysis has been used in the corresponding Quantity Transaction Report.
 - Record the contact information of the laboratory that analyzes the samples.
 - Document the standard test method used to determine liquid properties (density, specific gravity, API gravity, etc.) from the analysis.
 - Confirm that sample containers are cleaned before each use.
- If online analysis devices such as hydrometers or densitometers are used to obtain liquid properties on site:
 - Record their number and location.
 - Document the standard method used to determine liquid properties (density, specific gravity, API gravity, etc.) from the analysis. (For example, API MPMS Chapters 9.1 and 9.2 are the standards for using hydrometers to determine liquid density.)
 - Confirm that the installation points of the devices conform to the requirements for the meter run.
 - Record the frequency of calibration for each device. Confirm that the devices are calibrated in accordance with manufacturer recommendations.

2.5 Onsite Record Review

2.5.1 General Records

- If not obtained during the offsite inspection, acquire copies of calibration records for master meters or provers at the field site. Any calibrated mechanical displacement prover, master meter, or tank prover installed at a field location shall be calibrated in accordance with 30 CFR 250.1202, paragraph (e) or (f), as appropriate.
- If available, review copies of operator procedures for onsite verification/calibration of royalty or allocation meters, secondary instrumentation, and flow computers.

2.5.2 Meter-Specific Records

2.5.2.1 Orifice Meters

- Review the differential pressures recently recorded by the flow computer to ensure that the maximum allowable differential pressure for the orifice plate has not been exceeded. Limits on differential pressure can be found in API MPMS Chapter 14.3, Part 2, Appendix 2-E.

2.5.2.2 Coriolis Meters

- Obtain and review records of Coriolis meter verification and re-zeroing on site.
 - Periodic verification of the stored zero value of a Coriolis meter (with the meter shut in at zero flow) shall be performed monthly (not to exceed 42 days) in accordance with 30 CFR Part 250, Subpart L, and shall be documented.
 - A Coriolis meter shall be re-zeroed if the zero value observed during verification is outside the meter manufacturer's specified zero offset limits.
 - Re-zeroing of a Coriolis meter may be required if the meter is operating at a different flowing pressure than the pressure at which it was calibrated.
 - Unnecessary re-zeroing should be avoided to minimize potential errors associated with meter factor reproducibility.
 - Records of meter zeroing or re-zeroing shall contain:
 - Date and time of zeroing or re-zeroing.
 - Reason for re-zeroing.
 - As-found and as-left zero values.
 - Measurement of zero stability, if available.

2.5.2.3 Ultrasonic Meters

- Obtain and review records of ultrasonic meter verification on site.
 - Periodic verification of the zero-flow value of an ultrasonic meter (with the meter shut in at zero flow) shall be performed monthly (not to exceed 42 days) in accordance with 30 CFR Part 250, Subpart L, and shall be documented.
 - An ultrasonic meter shall be re-zeroed if the zero value observed during verification is outside the meter manufacturer's specified zero offset limits.
- Confirm that the following diagnostics were performed during the ultrasonic meter verification. More information on these diagnostics can be found in subsection 2.3.3.
 - Zero-flow verification.
 - Speed-of-sound measurement analysis for each path.

- o Analysis of signal gain along each path.
- o Review of signal-to-noise ratio on each path.
- o Review of the velocity profile through the meter.
- o Changes in path velocity ratios.
- o Profile factors (as recommended by the manufacturer).

3. REFERENCES

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3. AGA Report No. 11, *Measurement of Natural Gas by Coriolis Meter*, American Gas Association ballot draft, March 2011.
4. ANSI B46.1, *Surface Texture (Surface Roughness, Waviness, and Lay)*, American National Standards Institute, 2009.
5. *API Manual of Petroleum Measurement Standards*, Chapter 4 – *Proving Systems*, Section 8 – *Operation of Proving Systems*, First Edition, American Petroleum Institute, reaffirmed March 2007.
6. *API Manual of Petroleum Measurement Standards*, Chapter 5 – *Metering*, Section 6 – *Measurement of Liquid Hydrocarbons by Coriolis Meters*, First Edition, American Petroleum Institute, October 2002.
7. *API Manual of Petroleum Measurement Standards*, Chapter 5 – *Metering*, Section 8 – *Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters*, Second Edition, American Petroleum Institute, November 2011.
8. *API Manual of Petroleum Measurement Standards*, Chapter 8 – *Sampling*, Section 2 – *Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products*, Second Edition, American Petroleum Institute, June 2005.
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11. *API Manual of Petroleum Measurement Standards*, Chapter 21 – *Flow Measurement Using Electronic Metering Systems*, Section 1 – *Electronic Gas Measurement*, First Edition, American Petroleum Institute, August 1993.
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17. Bureau of Safety and Environmental Enforcement, RIN 1014-AA01, Production Measurement Documents Incorporated by Reference into 30 CFR Part 250, *Federal Register*, Vol. 77, No. 61, pp. 18916-18922, March 29, 2012.
18. Upp, E. L., and LaNasa, P. J., *Fluid Flow Measurement: A Practical Guide to Accurate Flow Measurement*, Second Edition, Gulf Professional Publishing Co., 2002.
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Addendum 1
Example Orifice Meter Calibration Report

TEST REPORT

Calibration of a 10-inch Orifice Flow Meter
Meter No. XXXXX, Beta = 0.60

Prepared for:

Company Name
Company Address
City, State Zip

Prepared by:

Metering Research Facility
at
Southwest Research Institute®
6220 Culebra Road
San Antonio, Texas 78238-5166

Client Purchase Order No. XXXXXX
SwRI Project No. 18.18031.01.XXX
MRF Report No. XXXX

Month and Year of Report

Approved:



SOUTHWEST RESEARCH INSTITUTE®
SAN ANTONIO HOUSTON
DETROIT WASHINGTON, DC

ADVERTISING, CONFIDENTIALITY, AND RECORD RETENTION POLICY

Metering Research Facility at Southwest Research Institute®

Southwest Research Institute (SwRI) policies specifically prohibit the use in advertising of both the Company name and the results provided by our studies. The following paragraph, extracted verbatim from SwRI contractual documents, clarifies this point:

SwRI shall not publish or make known to others the subject matter or results of the Project or any information obtained in connection therewith that is proprietary and confidential to Client without Client's written approval. No advertising or publicity containing any reference to SwRI, or any of their employees, either directly or by implication, shall be made use of by Client or on Client's behalf without SwRI's written approval. In the event Client distributes any report issued by SwRI on this Project outside its own organization, such report shall be used in its entirety, unless SwRI approves a summary of abridgment for distribution.

Southwest Research Institute will retain a record copy of the test report for a period of three (3) years. This permits us to answer questions that may be raised after a report is mailed and provides a basis for additional work, if required. The contents of the report and any information that comes into our possession during the course of a study are held confidential to the company conducting the study and are not disclosed to anyone without the Client's prior permission.

METERING RESEARCH FACILITY (MRF)

Meter Calibration Sheet

Calibration Date: XXXX
Report Date: XXXX

MRF Report No.: XXX
SwRI Project No.: 18031.01.XXX
Client P.O. No.: XXX

Title: Calibration of a 10-inch Orifice Flow Meter

Client Information:

Company Name: XXXX
Address: XXXX
City: XXXX
State, ZIP: XXXX
Client Representative: XXXX
Telephone Number: XXXX
FAX Number: XXXX
E-mail Address: XXXX

Meter Information:

Manufacturer:	American	Junior Fitting No.:	XXXXXX
Type:	Orifice	Meter Tube No.:	XXXXXX
Size:	10-inch		
Model:	Flange Tap, A-88		
Meter No.:	XXXXX, Beta = 0.60		

Calibration Facility: X HPL LPL

Test Conditions:

Gas: Natural Gas
Pressure (psia): 745
Temperature (°F): 70

Gas Composition:

Component	Mole Fraction (%)
Methane	94.9524
Ethane	2.2032
Carbon Dioxide	1.2257
Nitrogen	1.0084
Propane	0.4084
Isobutane	0.0465
n-Butane	0.0795
Isopentane	0.0215
n-Pentane	0.0180
n-Hexane	0.0147
n-Heptane	0.0122
n-Octane	0.0080
n-Nonane	0.0015
TOTAL	100.0000

Heat Content (no H₂O vapor present, "dry") (BTU/ft³) 1020.41
Density @ STP (lb/ft³) 0.044
Std. Conditions: T = 60 deg F, P = 14.73 psi

Metering Research Facility at Southwest Research Institute®

Mailing Address:
P.O. Drawer 28510
San Antonio, Texas 78228-0510

Shipping Address:
6220 Culebra Road
San Antonio, Texas 78238-5166

Contact: Michael Robertson
Telephone: (210) 522-5922
FAX No: (210) 522-2369

METERING RESEARCH FACILITY (MRF)

Meter Calibration Sheet

Calibration Date: XXXX
Report Date: XXXX

MRF Report No.: XXX
SwRI Project No.: 18031.01.XXX
Client P.O. No.: XXX

Calibration Information:

1. The client provided the orifice plate and the meter tube. The meter tube was approximately 189" in length and contained a 19-tube bundle installed on the upstream side and an orifice fitting on the downstream side. The tube was installed downstream of two in-plane 45° elbows, provided by the client.
2. The meter tube internal diameter was 10.025 inches and the orifice plate bore diameter was 6.00 inches, which yielded a beta ratio of 0.5985. The orifice plate provided by the client had a non-beveled edge on the upstream side.
3. In order to test the meter at the MRF in the required installation, the 45° elbows were turned to the left of the upstream piping. In this configuration, the fitting was oriented at 90° to the left of the vertical, to reflect its actual orientation at the client field site, relative to the upstream elbows.
4. Static pressure was measured at the orifice plate as well as differential pressure. Differential pressure was measured using the same tap set used at the field site. The taps were located on the bottom side of the meter tube (for this installation). Gas temperature was measured with a bare RTD located nominally 67" (6.7D) downstream of the meter discharge plate.
5. A photograph of the installation is shown on page 3.
6. MRF pressure and temperature instrumentation was used for the flow calibration.
7. This record of flow calibration includes a table of test data and graphs of measured Cd versus pipe Reynolds number and meter error versus volumetric flow rate. The tabulated data headings are as follows. Note, uncertainty, U, is total uncertainty and reflects both bias and precision uncertainties.

Pdn = flow static pressure at the meter

T = gas temperature

rho = gas density at flowing conditions

DP = differential pressure across the meter using the available tap set

ReD = pipe Reynolds number

Cd = measured orifice discharge coefficient according to the reference sonic nozzle mass flow rate

Y1 = expansion factor used in calculating Cd

Beta = orifice plate beta ratio based on orifice plate bore diameter and the meter tube inside diameter

Qv = volumetric flow rate at the meter according to the reference flow rate

md = sonic nozzle mass flow rate

URd, UCd, and Umd = total measurement uncertainty in indicated parameters

Cd RG equation = orifice discharge coefficient calculated by Reader-Harris Gallagher flow equation according to AGA-3.

% Error = error in orifice discharge coefficient according to: $100 \cdot (Cd_{RGEquation} - Cd) / (Cd)$.

(This would be the error in the discharge coefficient and resulting mass flow rate if the RG equation were used at the client field site to calculate Cd.)

8. The average orifice discharge coefficient, Cd, for this calibration was 0.6096. The average error was -0.915%.
9. Witnesses for calibration test:
Name: XXXXX Company: XXXX

Metering Research Facility at Southwest Research Institute®

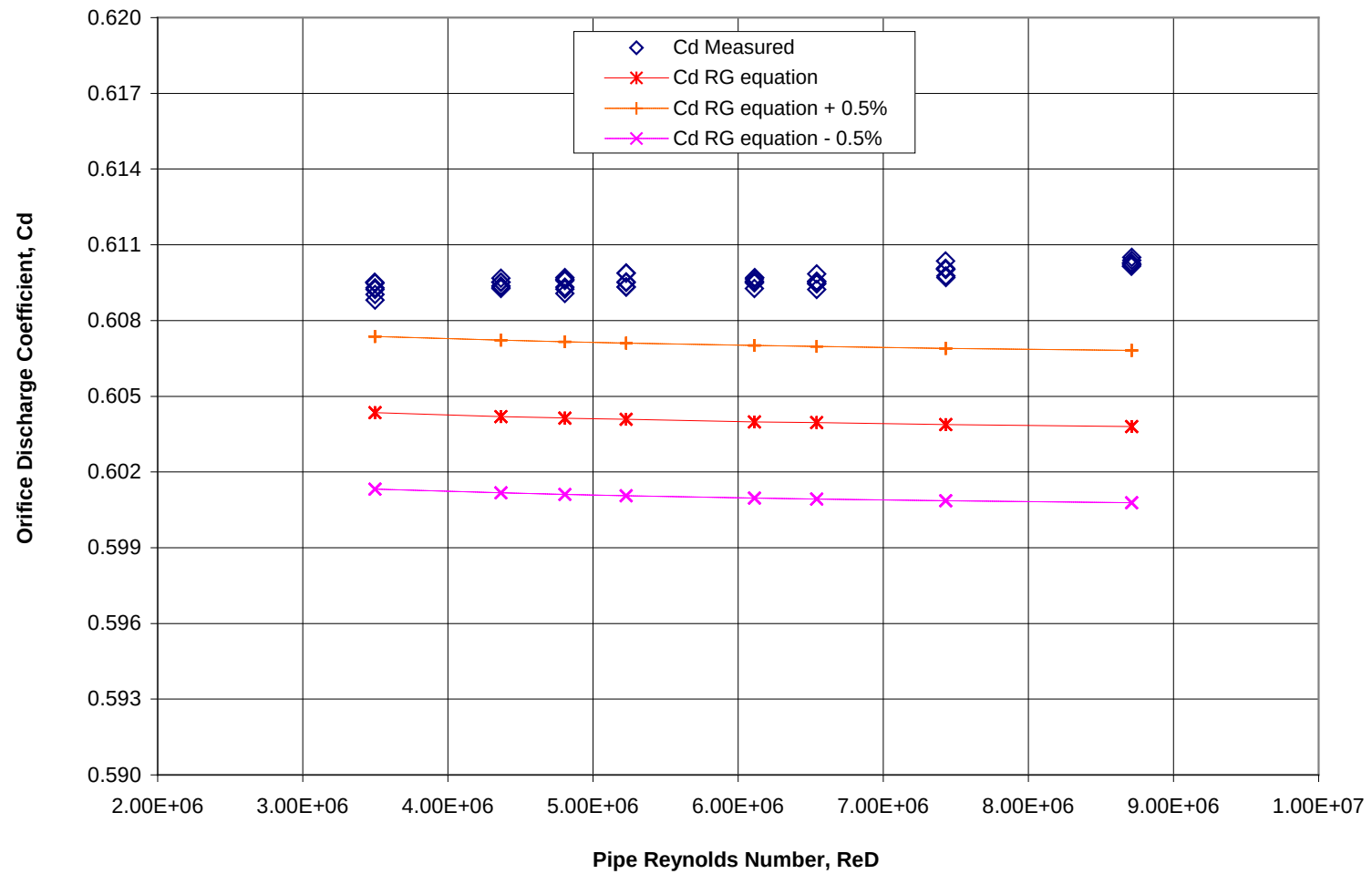
Mailing Address:
P.O. Drawer 28510
San Antonio, Texas 78228-0510

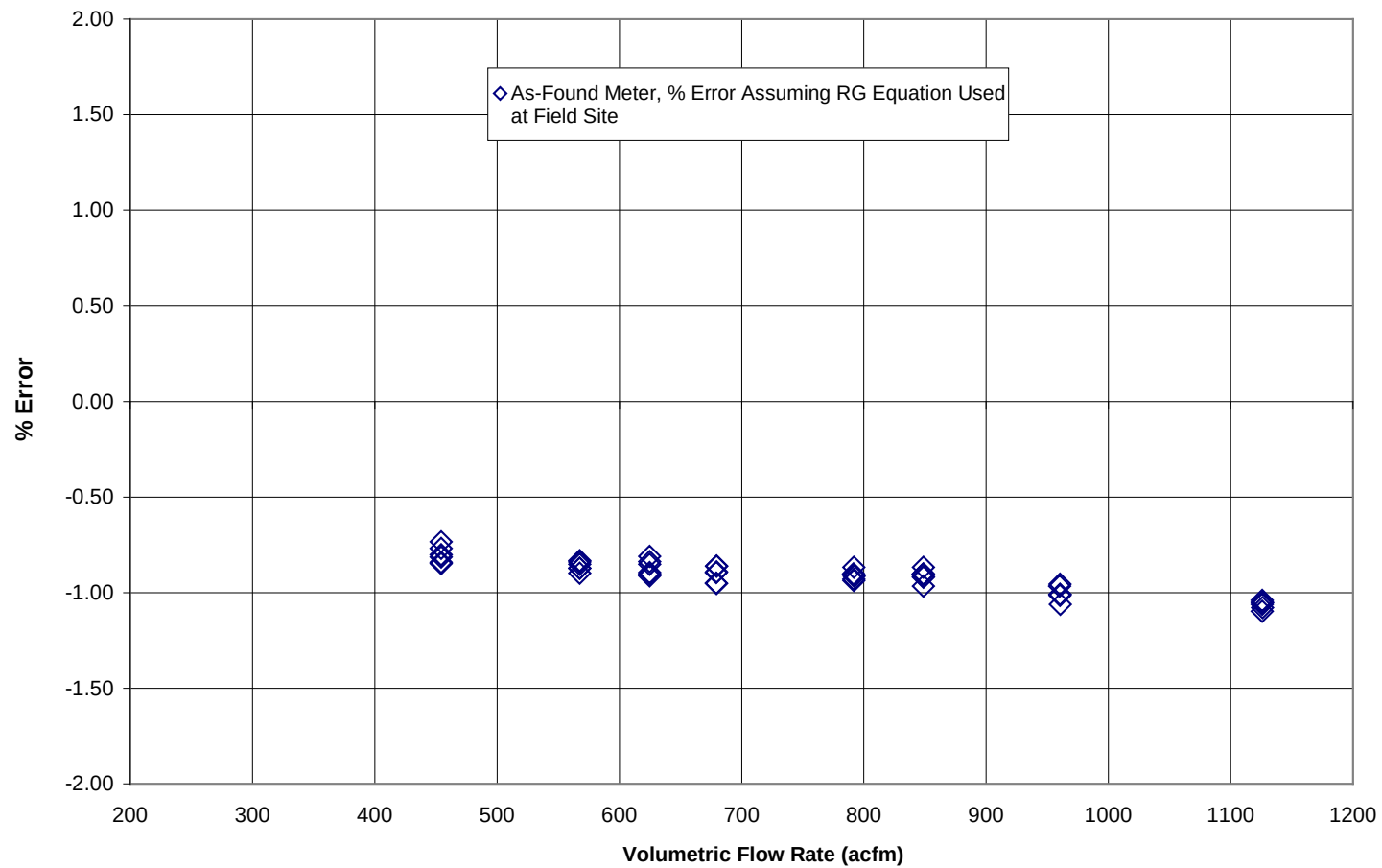
Shipping Address:
6220 Culebra Road
San Antonio, Texas 78238-5166

Contact: Michael Robertson
Telephone: (210) 522-5922
FAX No: (210) 522-2369



MRF HPL Test Installation





Orifice Meter No. XXXX, Beta = 0.60

File	Date	Time	Pdn(psia)	T(F)	rho(lb/ft3)	DP(psid)	ReD	URED(%)	Cd	UCd(%)	Y1	Beta	Qv (acfm)	md(lb/s)	Umd(%)	Cd (RG equation)	% Error	
F040303.106	30403	214618	744.71	70.72	2.4881	5.7635	8712649	0.322	0.61050	0.24	0.9974	0.5985	1125.7	46.683	0.217	0.60380	-1.098	
F040303.107	30403	214816	744.73	70.77	2.4879	5.7669	8712562	0.322	0.61039	0.239	0.9974	0.5985	1125.9	46.685	0.217	0.60380	-1.079	
F040303.108	30403	215026	744.61	70.75	2.4876	5.7692	8711776	0.322	0.61022	0.239	0.9974	0.5985	1125.9	46.679	0.217	0.60380	-1.053	
F040303.109	30403	215224	744.69	70.77	2.4877	5.7699	8711148	0.322	0.61014	0.239	0.9974	0.5985	1125.8	46.677	0.217	0.60380	-1.040	
F040303.110	30403	215423	744.61	70.73	2.4876	5.7684	8711465	0.322	0.61021	0.241	0.9974	0.5985	1125.8	46.676	0.217	0.60380	-1.050	
F040303.111	30403	215622	744.46	70.68	2.4874	5.7652	8710381	0.322	0.61028	0.24	0.9974	0.5985	1125.7	46.666	0.217	0.60380	-1.061	
F040303.058	30403	185657	745.51	70.63	2.4876	4.1937	7430359	0.344	0.61004	0.271	0.9981	0.5985	960.3	39.815	0.249	0.60388	-1.009	
F040303.059	30403	185933	745.57	70.60	2.4881	4.1973	7431033	0.344	0.60977	0.272	0.9981	0.5985	960.2	39.818	0.250	0.60388	-0.965	
F040303.060	30403	190131	745.53	70.61	2.4876	4.1945	7431193	0.344	0.61004	0.271	0.9981	0.5985	960.4	39.818	0.250	0.60388	-1.009	
F040303.061	30403	190329	745.55	70.62	2.4876	4.1987	7430804	0.344	0.60971	0.271	0.9981	0.5985	960.4	39.817	0.250	0.60388	-0.955	
F040303.062	30403	190528	745.46	70.61	2.4873	4.1935	7430253	0.344	0.61007	0.272	0.9981	0.5985	960.4	39.813	0.250	0.60388	-1.014	
F040303.063	30403	190726	745.39	70.65	2.4866	4.1900	7429347	0.344	0.61035	0.271	0.9981	0.5985	960.6	39.809	0.250	0.60388	-1.060	
F040303.064	30403	192910	744.41	70.67	2.4784	3.2649	6541686	0.277	0.60946	0.185	0.9985	0.5985	848.4	35.047	0.144	0.60395	-0.904	
F040303.065	30403	193108	744.37	70.69	2.4778	3.2610	6541032	0.277	0.60985	0.184	0.9985	0.5985	848.6	35.044	0.144	0.60395	-0.966	
F040303.066	30403	193307	744.31	70.72	2.4774	3.2652	6540473	0.277	0.60945	0.184	0.9985	0.5985	848.6	35.041	0.143	0.60395	-0.902	
F040303.067	30403	193506	744.35	70.71	2.4776	3.2672	6540382	0.277	0.60924	0.182	0.9985	0.5985	848.6	35.041	0.144	0.60395	-0.867	
F040303.068	30403	193704	744.33	70.70	2.4776	3.2638	6540549	0.277	0.60955	0.183	0.9985	0.5985	848.6	35.041	0.144	0.60395	-0.919	
F040303.069	30403	193903	744.28	70.71	2.4774	3.2639	6539981	0.277	0.60953	0.185	0.9985	0.5985	848.6	35.038	0.144	0.60395	-0.915	
F040303.070	30403	194610	745.95	70.64	2.4824	2.8451	6111496	0.282	0.60949	0.197	0.9987	0.5985	791.6	32.750	0.153	0.60399	-0.902	
F040303.071	30403	194832	746.24	70.79	2.4825	2.8468	6112866	0.282	0.60956	0.198	0.9987	0.5985	791.9	32.765	0.153	0.60399	-0.914	
F040303.072	30403	195031	746.16	70.72	2.4826	2.8451	6113077	0.282	0.60970	0.197	0.9987	0.5985	791.8	32.763	0.153	0.60399	-0.936	
F040303.073	30403	195229	746.08	70.72	2.4823	2.8483	6111953	0.282	0.60928	0.195	0.9987	0.5985	791.8	32.757	0.153	0.60399	-0.868	
F040303.074	30403	195428	746.07	70.73	2.4823	2.8459	6111757	0.282	0.60952	0.197	0.9987	0.5985	791.7	32.755	0.153	0.60399	-0.907	
F040303.075	30403	195627	746.20	70.75	2.4826	2.8452	6112558	0.282	0.60965	0.198	0.9987	0.5985	791.8	32.761	0.153	0.60399	-0.929	
F040303.076	30403	200523	744.59	70.80	2.4736	2.0893	5228699	0.294	0.60932	0.226	0.9991	0.5985	679.6	28.017	0.174	0.60408	-0.860	
F040303.077	30403	200745	744.49	70.76	2.4735	2.0849	5228228	0.294	0.60989	0.228	0.9991	0.5985	679.5	28.013	0.174	0.60408	-0.953	
F040303.078	30403	201011	744.39	70.69	2.4736	2.0868	5227994	0.294	0.60951	0.229	0.9991	0.5985	679.4	28.009	0.174	0.60408	-0.891	
F040303.079	30403	201210	744.39	70.70	2.4736	2.0866	5227854	0.294	0.60954	0.229	0.9991	0.5985	679.4	28.009	0.174	0.60408	-0.895	
F040303.080	30403	201408	744.28	70.68	2.4733	2.0841	5227595	0.294	0.60988	0.229	0.9991	0.5985	679.4	28.006	0.174	0.60408	-0.950	
F040303.081	30403	201630	744.21	70.67	2.4731	2.0877	5227333	0.294	0.60934	0.229	0.9991	0.5985	679.4	28.004	0.174	0.60408	-0.863	
F040303.088	30403	204704	744.57	70.73	2.4728	1.7627	4805864	0.295	0.60970	0.242	0.9992	0.5985	624.8	25.750	0.176	0.60413	-0.913	
F040303.089	30403	204902	744.45	70.71	2.4726	1.7632	4805633	0.295	0.60959	0.242	0.9992	0.5985	624.8	25.747	0.176	0.60413	-0.895	
F040303.090	30403	205101	744.51	70.71	2.4728	1.7647	4805746	0.295	0.60933	0.242	0.9992	0.5985	624.8	25.748	0.176	0.60413	-0.852	
F040303.091	30403	205300	744.49	70.73	2.4726	1.7650	4805348	0.295	0.60924	0.243	0.9992	0.5985	624.8	25.746	0.176	0.60413	-0.839	
F040303.092	30403	205458	744.50	70.73	2.4726	1.7629	4805469	0.295	0.60963	0.242	0.9992	0.5985	624.8	25.747	0.176	0.60413	-0.902	
F040303.093	30403	205657	744.40	70.73	2.4722	1.7660	4804905	0.295	0.60907	0.242	0.9992	0.5985	624.8	25.744	0.176	0.60413	-0.810	
F040303.094	30403	210345	744.96	70.74	2.4731	1.4562	4365614	0.305	0.60927	0.271	0.9993	0.5985	567.5	23.393	0.192	0.60420	-0.833	
F040303.095	30403	210543	744.94	70.75	2.4730	1.4557	4365500	0.305	0.60938	0.272	0.9993	0.5985	567.5	23.392	0.192	0.60420	-0.851	
F040303.096	30403	210742	744.83	70.76	2.4726	1.4549	4364925	0.305	0.60952	0.272	0.9993	0.5985	567.6	23.389	0.192	0.60420	-0.873	
F040303.097	30403	210940	744.82	70.74	2.4726	1.4548	4364808	0.305	0.60952	0.269	0.9993	0.5985	567.5	23.388	0.192	0.60420	-0.873	
F040303.098	30403	211139	744.83	70.75	2.4726	1.4539	4364637	0.305	0.60967	0.272	0.9993	0.5985	567.5	23.387	0.192	0.60420	-0.899	
F040303.099	30403	211338	744.75	70.73	2.4724	1.4557	4364820	0.305	0.60932	0.271	0.9993	0.5985	567.6	23.387	0.192	0.60420	-0.840	
F040303.100	30403	211808	746.22	70.71	2.4760	0.9350	3497667	0.332	0.60881	0.365	0.9996	0.5985	454.3	18.746	0.233	0.60435	-0.734	
F040303.101	30403	212007	746.21	70.73	2.4759	0.9330	3497599	0.332	0.60948	0.365	0.9996	0.5985	454.3	18.746	0.233	0.60435	-0.842	
F040303.102	30403	212229	746.21	70.75	2.4758	0.9345	3497590	0.332	0.60903	0.366	0.9996	0.5985	454.3	18.746	0.233	0.60435	-0.769	
F040303.103	30403	212427	746.11	70.76	2.4753	0.9339	3497292	0.332	0.60923	0.364	0.9996	0.5985	454.4	18.745	0.233	0.60435	-0.802	
F040303.104	30403	212626	746.02	70.76	2.4750	0.9334	3496711	0.332	0.60930	0.366	0.9996	0.5985	454.3	18.741	0.233	0.60435	-0.813	
F040303.105	30403	212825	745.92	70.76	2.4747	0.9328	3496471	0.332	0.60951	0.366	0.9996	0.5985	454.3	18.739	0.233	0.60435	-0.848	
Average =									0.6096	Average =								-0.9150

Addendum 2
Example Ultrasonic Meter Calibration Report

TEST REPORT

Calibration of an 8-inch Ultrasonic Flow Meter
Serial No. XXXXXX

Prepared for:

Company Name
Company Address

Prepared by:

Metering Research Facility
at
Southwest Research Institute
6220 Culebra Road
San Antonio, Texas 78238-5166

Client Purchase Order No.
SwRI[®] Project No. 18.XXXXXXX
MRF Report No. XX-XX

Date of Calibration / Test

Approved:



Terrence A. Grimley
Program Coordinator



SOUTHWEST RESEARCH INSTITUTE[®]
SAN ANTONIO HOUSTON
DETROIT WASHINGTON, DC

ADVERTISING, CONFIDENTIALITY, AND RECORD RETENTION POLICY

Metering Research Facility at Southwest Research Institute

Southwest Research Institute (SwRI) policies specifically prohibit the use in advertising of both the Company name and the results provided by our studies. The following paragraph, extracted verbatim from SwRI contractual documents, clarifies this point:

SwRI shall not publish or make known to others the subject matter or results of the Project or any information obtained in connection therewith that is proprietary and confidential to Client without Client's written approval. No advertising or publicity containing any reference to SwRI, or any of their employees, either directly or by implication, shall be made use of by Client or on Client's behalf without SwRI's written approval. In the event Client distributes any report issued by SwRI on this Project outside its own organization, such report shall be used in its entirety, unless SwRI approves a summary of abridgment for distribution.

Southwest Research Institute will retain a record copy of the test report for a period of three (3) years. This permits us to answer questions that may be raised after a report is mailed and provides a basis for additional work, if required. The contents of the report and any information that comes into our possession during the course of a study are held confidential to the company conducting the study and are not disclosed to anyone without the Client's prior permission.

METERING RESEARCH FACILITY (MRF)

Meter Calibration Sheet

Calibration Date: XXXXX
Report Date: XXXXX

MRF Report No.: XX-XX
SwRI Project No.: 18.XXXXXX
Client P.O. No.: XXXX

Title: Calibration of an 8-inch Ultrasonic Flow Meter

Client Information:

Company Name:
Address:
City:
State, ZIP:
Client Representative:
Telephone Number:
FAX Number:
E-mail Address:

Meter Information:

Manufacturer: XXXXX
Type: Ultrasonic
Size: 8-inch
Model No.: XXXX
Meter Serial No.: XXXXX

Calibration Facility: X HPL LPL

Test Conditions:

Gas: Natural Gas
Pressure (psia): 765 (nominal)
Temperature (°F): 65 (nominal)

Gas Composition:

Component	Mole Fraction (%)
Methane	95.3286
Ethane	2.1579
Carbon Dioxide	1.0714
Nitrogen	0.9367
Propane	0.3284
Isobutane	0.0404
n-Butane	0.0705
Isopentane	0.0197
n-Pentane	0.0168
n-Hexane	0.0135
n-Heptane	0.0102
n-Octane	0.0049
n-Nonane	<u>0.0010</u>
TOTAL	100.0000

Heat Content (no H₂O vapor present, "dry") (BTU/ft³) 1020.31
Density @ STP (lb/ft³) 0.045
Std. Conditions: T = 60 deg F, P = 14.73 psi

Metering Research Facility at Southwest Research Institute

Mailing Address:
P.O. Drawer 28510
San Antonio, Texas 78228-0510

Shipping Address:
6220 Culebra Road
San Antonio, Texas 78238-5166

Contact: Michael Robertson
Telephone: (210) 522-5922
FAX No: (210) 522-2369

METERING RESEARCH FACILITY (MRF)

Meter Calibration Sheet

Calibration Date: XXXXX
Report Date: XXXXX

MRF Report No.: XX-XX
SwRI Project No.: 18.XXXXX
Client P.O. No.: XXXX

Calibration Information:

1. The client provided the test meter and the flow conditioner. The meter was installed in the HPL header. The installation included a CPA 50E Type A plate flow conditioner installed at 10D upstream of the meter, an additional 29D of 8-inch pipe upstream of the flow conditioner, and an additional 8D of 8-inch pipe downstream of the meter. A photograph of the installation is shown on page 3.
2. Temperature was measured with a bare RTD located in a threadolet 3D downstream of the meter. Pressure was measured at the meter body.
3. The as-found calibration was performed with the meter calibration factors set equal to XXXX by the manufacturer.
4. Six data points were collected at each flow velocity.
5. Following the as-found calibration, the meter calibration factors were adjusted based on manufacturer software. The calibration factors were changed to XXXXX, and the adjustment was flow-verified at 5.4 and 64.9 ft/sec.
6. The results of these tests are contained in the plot and table that follow and use the nomenclature shown below:

p = pressure measured at the meter body

T = gas temperature measured downstream of the meter

Rho = gas density based on p, T and the gas composition

V*AGA8 = speed of sound based on AGA-8 equations of state

md = sonic nozzle mass flow rate

Umd = total uncertainty in sonic nozzle mass flow measurement

Vavg = average velocity at the meter body calculated from the nozzle flow rate

ReD = pipe Reynolds number

Time = data sampling time

V* = speed of sound reported by the meter

SOS Error = error in meter reported speed of sound relative to that based on AGA-8

Cal = meter factor [meter reported flow rate * Cal = reference flow rate]

Error = meter error relative to sonic nozzle flow rate

Est Err = estimated meter error based on flow-weighted correction to the initial Adjust Factor

VSNDX = meter reported speed of sound on path X, where X = 1, 2 or 3

VELX = meter reported gas velocity on path X, where X = as above

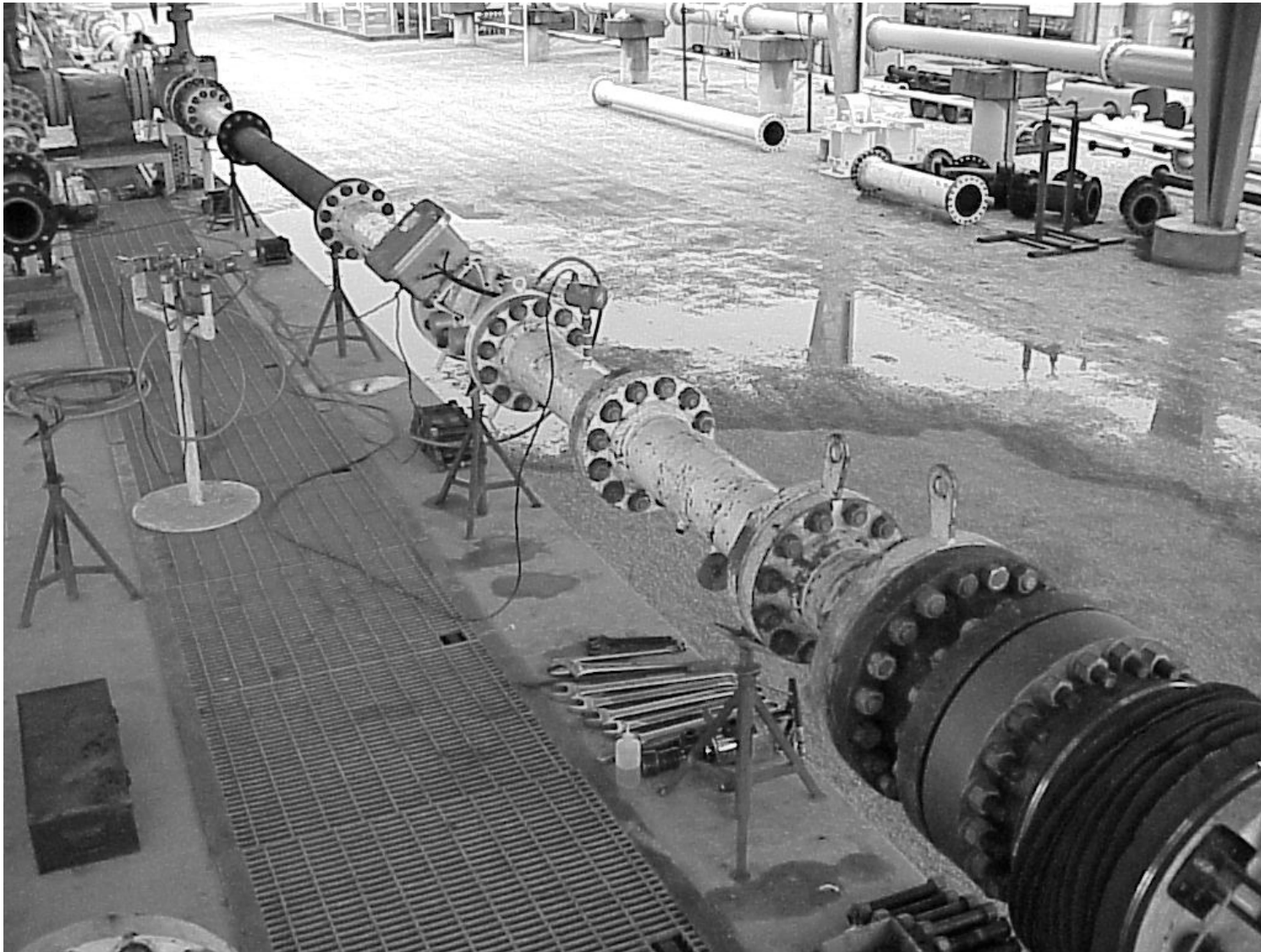
7. Witnesses for calibration test: (no witness present)

Metering Research Facility at Southwest Research Institute

Mailing Address:
P.O. Drawer 28510
San Antonio, Texas 78228-0510

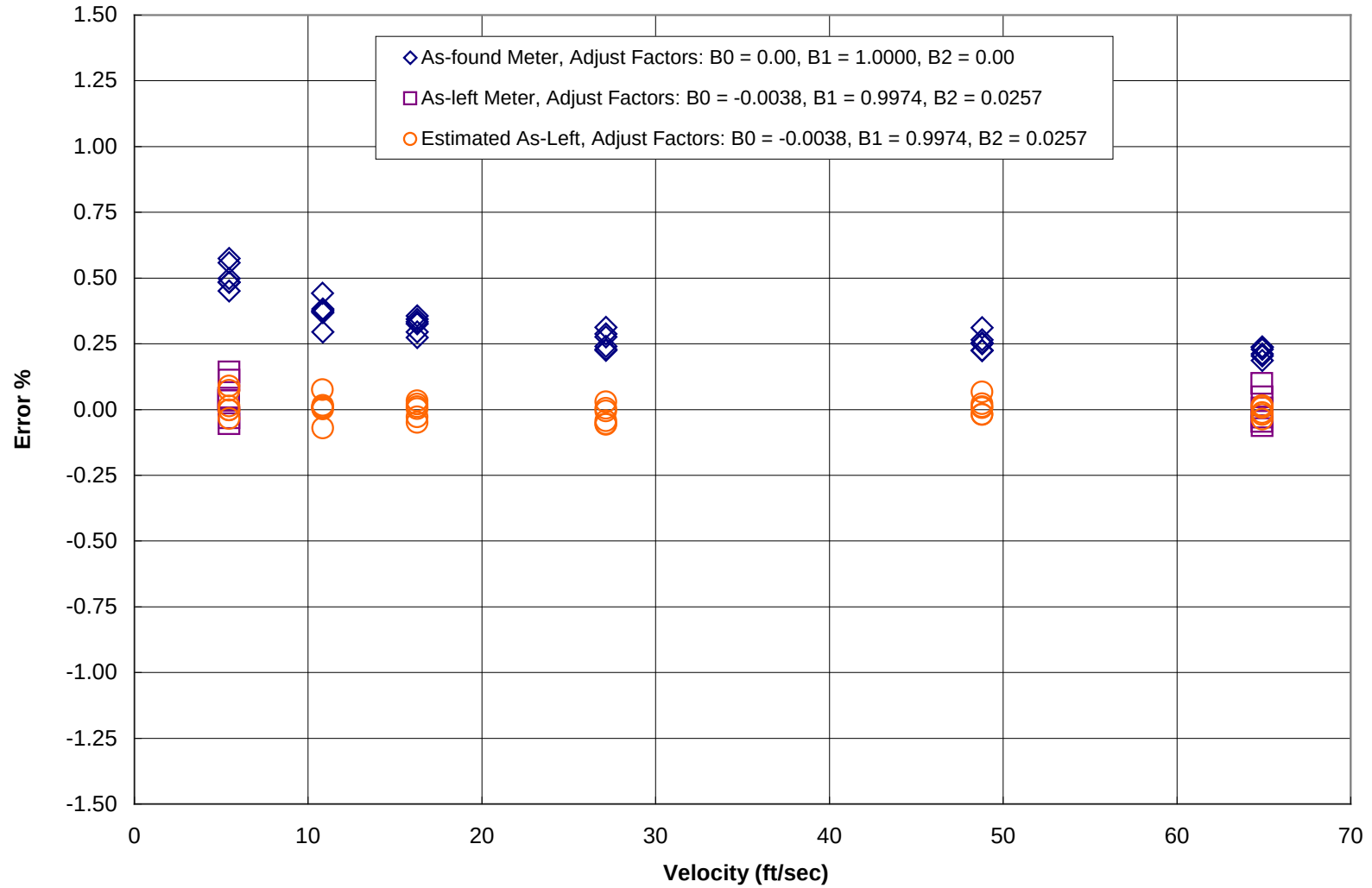
Shipping Address:
6220 Culebra Road
San Antonio, Texas 78238-5166

Contact: Michael Robertson
Telephone: (210) 522-5922
FAX No: (210) 522-2369



MRF HPL Test Installation

Meter Serial No. XXXX-XXXX



Meter Serial Number XXXX-XXXX

File	Date	Time	p(psia)	T(F)	rho(lb/ft3)	V*AGA8(ft/s)	md(lb/s)	Umd(%)	Vavg(ft/s)	ReD	Time(sec)	V*(ft/s)	SOS Err(%)	Cal	Error(%)	Est Err(%)
F022103.000	030221	91646	766.35	65.50	2.56676	1367.21	57.9326	0.193	64.9023	13645790	90	1367.86	0.048	0.99814	0.186	-0.0366
F022103.001	030221	91911	766.25	65.51	2.56632	1367.23	57.9260	0.193	64.9062	13647740	90	1367.86	0.046	0.99789	0.212	-0.0115
F022103.002	030221	92122	766.18	65.50	2.56612	1367.21	57.9178	0.193	64.9019	13648620	90	1367.85	0.047	0.99771	0.229	0.0063
F022103.003	030221	92320	766.14	65.49	2.56602	1367.20	57.9146	0.193	64.9009	13644620	90	1367.86	0.048	0.99797	0.204	-0.0193
F022103.004	030221	92536	766.03	65.51	2.56547	1367.25	57.9032	0.193	64.9020	13646460	90	1367.89	0.047	0.99763	0.237	0.0144
F022103.005	030221	92741	765.97	65.51	2.56526	1367.24	57.9008	0.193	64.9045	13646180	90	1367.88	0.047	0.99763	0.238	0.0146
F022103.006	030221	94711	765.45	65.54	2.56308	1367.32	43.4798	0.237	48.7807	10249450	90	1367.99	0.049	0.99750	0.250	0.0067
F022103.007	030221	94910	765.38	65.55	2.56272	1367.35	43.4753	0.237	48.7825	10254510	90	1368.02	0.049	0.99690	0.311	0.0671
F022103.008	030221	95133	765.30	65.55	2.56248	1367.34	43.4700	0.237	48.7812	10248880	90	1368.00	0.048	0.99735	0.266	0.0220
F022103.009	030221	95333	765.25	65.54	2.56230	1367.34	43.4656	0.237	48.7796	10243790	90	1368.00	0.048	0.99776	0.225	-0.0187
F022103.010	030221	95611	765.17	65.54	2.56203	1367.34	43.4646	0.237	48.7836	10246680	90	1368.00	0.049	0.99747	0.254	0.0101
F022103.011	030221	95822	765.12	65.57	2.56164	1367.39	43.4588	0.237	48.7846	10242080	90	1368.04	0.048	0.99777	0.224	-0.0198
F022103.012	030221	101906	764.90	65.61	2.56047	1367.48	24.1635	0.192	27.1371	5695549	90	1368.17	0.050	0.99761	0.240	-0.0430
F022103.013	030221	102105	764.89	65.59	2.56059	1367.44	24.1636	0.192	27.1359	5698480	90	1368.12	0.050	0.99713	0.288	0.0047
F022103.014	030221	102305	765.12	65.60	2.56140	1367.45	24.1712	0.192	27.1358	5696423	90	1368.15	0.051	0.99775	0.226	-0.0573
F022103.015	030221	102505	765.06	65.61	2.56107	1367.48	24.1692	0.192	27.1370	5700834	90	1368.15	0.049	0.99689	0.312	0.0295
F022103.016	030221	102705	765.00	65.60	2.56094	1367.46	24.1683	0.192	27.1375	5698765	90	1368.15	0.050	0.99724	0.277	-0.0060
F022103.017	030221	102905	764.94	65.60	2.56069	1367.46	24.1650	0.192	27.1364	5695337	90	1368.14	0.050	0.99772	0.229	-0.0538
F022103.018	030221	104726	764.60	65.73	2.55847	1367.71	14.4799	0.177	16.2745	3415743	90	1368.37	0.048	0.99675	0.326	0.0031
F022103.019	030221	104925	764.42	65.67	2.55822	1367.61	14.4766	0.177	16.2724	3413522	90	1368.28	0.049	0.99727	0.273	-0.0497
F022103.020	030221	105147	764.41	65.65	2.55830	1367.58	14.4757	0.177	16.2709	3414090	90	1368.27	0.050	0.99706	0.294	-0.0287
F022103.021	030221	105346	764.36	65.66	2.55806	1367.60	14.4747	0.177	16.2713	3415937	90	1368.28	0.049	0.99646	0.356	0.0325
F022103.022	030221	105546	764.38	65.67	2.55803	1367.62	14.4748	0.177	16.2716	3415527	90	1368.30	0.050	0.99657	0.344	0.0210
F022103.023	030221	105745	764.41	65.69	2.55803	1367.65	14.4752	0.177	16.2721	3415168	90	1368.34	0.050	0.99667	0.334	0.0107
F022103.024	030221	110321	764.40	65.57	2.55884	1367.45	9.6395	0.237	10.8326	2275486	90	1368.13	0.050	0.99627	0.374	0.0074
F022103.025	030221	110520	764.42	65.57	2.55894	1367.44	9.6407	0.238	10.8335	2277310	90	1368.11	0.049	0.99560	0.442	0.0752
F022103.026	030221	110743	764.42	65.61	2.55867	1367.51	9.6416	0.238	10.8357	2276078	90	1368.19	0.050	0.99619	0.383	0.0160
F022103.027	030221	110954	764.57	65.67	2.55883	1367.60	9.6435	0.238	10.8372	2276151	90	1368.28	0.050	0.99626	0.376	0.0090
F022103.028	030221	111206	764.60	65.74	2.55840	1367.73	9.6436	0.238	10.8391	2275809	90	1368.39	0.048	0.99633	0.369	0.0021
F022103.029	030221	111406	764.76	65.82	2.55840	1367.87	9.6458	0.238	10.8416	2274402	90	1368.51	0.047	0.99705	0.296	-0.0707
F022103.030	030221	113050	764.37	65.70	2.55791	1367.65	4.8415	0.235	5.4428	1144835	90	1368.32	0.049	0.99444	0.559	0.0731
F022103.031	030221	113250	764.44	65.74	2.55783	1367.72	4.8423	0.235	5.4438	1144254	90	1368.38	0.048	0.99504	0.499	0.0130
F022103.032	030221	113449	764.46	65.80	2.55748	1367.82	4.8426	0.235	5.4449	1144087	90	1368.49	0.048	0.99518	0.484	-0.0013
F022103.033	030221	113649	764.42	65.83	2.55709	1367.89	4.8425	0.235	5.4456	1145056	90	1368.57	0.049	0.99428	0.575	0.0892
F022103.034	030221	113848	764.45	65.90	2.55672	1368.01	4.8424	0.235	5.4463	1143891	90	1368.65	0.047	0.99519	0.483	-0.0021
F022103.035	030221	114048	764.42	65.93	2.55642	1368.05	4.8422	0.235	5.4467	1143451	90	1368.70	0.048	0.99551	0.451	-0.0340
Flow Verification Runs After Final Adjustment																
F022103.036	30221	155229	766.66	65.41	2.56844	1367.07	57.9563	0.193	64.8865	13620490	90	1367.72	0.048	1.00046	-0.046	
F022103.037	30221	155440	766.69	65.47	2.56817	1367.16	57.9613	0.193	64.8988	13640410	90	1367.82	0.048	0.99901	0.099	
F022103.038	30221	155640	766.60	65.50	2.56764	1367.22	57.9544	0.193	64.9045	13616590	90	1367.86	0.047	1.00062	-0.062	
F022103.039	30221	155851	766.51	65.46	2.56745	1367.20	57.9469	0.193	64.9011	13630590	90	1367.81	0.045	0.99953	0.048	
F022103.040	30221	160051	766.53	65.48	2.56737	1367.23	57.9484	0.193	64.9047	13624810	90	1367.83	0.044	0.99995	0.005	
F022103.041	30221	160251	766.56	65.48	2.56747	1367.23	57.9506	0.193	64.9046	13620540	90	1367.81	0.043	1.00030	-0.030	
F022103.042	30221	161738	765.24	65.38	2.56324	1367.11	4.8475	0.235	5.4381	1140590	90	1367.77	0.049	0.99957	0.043	
F022103.043	30221	161937	765.30	65.46	2.56295	1367.23	4.8482	0.235	5.4395	1140546	90	1367.90	0.050	0.99965	0.035	
F022103.044	30221	162136	765.34	65.55	2.56247	1367.38	4.8489	0.235	5.4414	1139834	90	1368.05	0.048	1.00032	-0.032	
F022103.045	30221	162336	765.37	65.61	2.56213	1367.49	4.8494	0.235	5.4426	1141848	90	1368.18	0.050	0.99858	0.143	
F022103.046	30221	162536	765.46	65.69	2.56191	1367.63	4.8497	0.235	5.4434	1139548	90	1368.30	0.050	1.00054	-0.054	
F022103.047	30221	162736	765.41	65.73	2.56129	1367.74	4.8495	0.235	5.4445	1141341	90	1368.38	0.047	0.99889	0.111	

Meter Serial Number XXXX-XXXX

File	Date	Time	VSND1	VSND2	VSND3	VEL1	VEL2	VEL3
F022103.000	030221	91646	1367	1367	1367	64.79	67.79	63.92
F022103.001	030221	91911	1367	1367	1367	64.72	67.86	64.02
F022103.002	030221	92122	1367	1367	1367	64.78	67.90	63.96
F022103.003	030221	92320	1367	1367	1367	64.73	67.90	63.97
F022103.004	030221	92536	1367	1367	1367	64.82	67.83	63.95
F022103.005	030221	92741	1367	1367	1367	64.79	67.87	63.98
F022103.006	030221	94711	1367	1367	1367	48.71	51.01	48.11
F022103.007	030221	94910	1367	1367	1367	48.75	50.96	48.16
F022103.008	030221	95133	1367	1367	1367	48.70	51.01	48.13
F022103.009	030221	95333	1367	1367	1367	48.68	50.98	48.11
F022103.010	030221	95611	1367	1367	1367	48.69	50.97	48.15
F022103.011	030221	95822	1367	1367	1367	48.70	51.00	48.10
F022103.012	030221	101906	1368	1368	1368	27.08	28.40	26.79
F022103.013	030221	102105	1368	1368	1368	27.10	28.38	26.81
F022103.014	030221	102305	1368	1368	1368	27.09	28.36	26.78
F022103.015	030221	102505	1368	1368	1368	27.12	28.39	26.80
F022103.016	030221	102705	1368	1368	1368	27.09	28.36	26.82
F022103.017	030221	102905	1368	1368	1368	27.07	28.38	26.80
F022103.018	030221	104726	1368	1368	1368	16.24	17.02	16.12
F022103.019	030221	104925	1368	1368	1368	16.24	17.04	16.09
F022103.020	030221	105147	1368	1368	1368	16.25	17.03	16.09
F022103.021	030221	105346	1368	1368	1368	16.24	17.03	16.12
F022103.022	030221	105546	1368	1368	1368	16.25	17.02	16.12
F022103.023	030221	105745	1368	1368	1368	16.24	17.03	16.12
F022103.024	030221	110321	1368	1368	1368	10.83	11.34	10.72
F022103.025	030221	110520	1368	1368	1368	10.85	11.33	10.73
F022103.026	030221	110743	1368	1368	1368	10.83	11.33	10.74
F022103.027	030221	110954	1368	1368	1368	10.83	11.35	10.73
F022103.028	030221	111206	1368	1368	1368	10.84	11.33	10.74
F022103.029	030221	111406	1369	1368	1369	10.83	11.36	10.72
F022103.030	030221	113050	1368	1368	1368	5.45	5.71	5.41
F022103.031	030221	113250	1368	1368	1368	5.44	5.71	5.41
F022103.032	030221	113449	1369	1368	1369	5.44	5.72	5.41
F022103.033	030221	113649	1369	1368	1369	5.45	5.70	5.42
F022103.034	030221	113848	1369	1369	1369	5.45	5.71	5.40
F022103.035	030221	114048	1369	1369	1369	5.45	5.69	5.41
Flow Verification Runs After Final Adjustment								
F022103.036	30221	155229	1367	1367	1367	64.71	67.83	63.93
F022103.037	30221	155440	1367	1367	1367	64.89	67.87	64.00
F022103.038	30221	155640	1367	1367	1367	64.71	67.89	63.93
F022103.039	30221	155851	1367	1367	1367	64.80	67.87	64.01
F022103.040	30221	160051	1367	1367	1367	64.83	67.82	63.94
F022103.041	30221	160251	1367	1367	1367	64.79	67.88	63.91
F022103.042	30221	161738	1368	1368	1368	5.45	5.70	5.40
F022103.043	30221	161937	1368	1368	1368	5.44	5.71	5.40
F022103.044	30221	162136	1368	1368	1368	5.44	5.70	5.40
F022103.045	30221	162336	1368	1368	1368	5.45	5.71	5.42
F022103.046	30221	162536	1368	1368	1368	5.44	5.70	5.41
F022103.047	30221	162736	1368	1368	1368	5.45	5.71	5.42

As-left Configuration File for Meter Serial No. XXXX-XXXX

```
*****
*      Ultrasonic Flow Meter      *
*      Configuration Information   *
*
```

Parameter Set-up:

=====

Parameter 1: 0xC102
Parameter 2: 0xA0
Parameter 3: 0x0064
Parameter 4: 0x07
Parameter 5: 0x6575

PROSON-II Info:

Serial Number: 1383
SW Version: V5.10
Id String: 901-42-03F027, 01-1001-Q308064

Spoolpiece Parameters:

Diameter: 7.985 in.
L1:
Path Length: 23.200 in.
Beam Angle: 63.44 degrees
L2:
Path Length: 20.632 in.
Beam Angle: 50.77 degrees
L3:
Path Length: 23.186 in.
Beam Angle: 63.44 degrees

V-Module Parameters:

Application-specific Parameters:

V.o.S. Range:
Lower Limit: 1000.00 ft/s
Upper Limit: 1600.00 ft/s
Gas Velocity Range:
Lower Limit: -130.00 ft/s
Upper Limit: 130.00 ft/s

Device-specific Parameters:

Sample Rate: 15 Hz
Timing Constant: 830
Timing Constant 2: 0
Timing Constant 3: 0
Pulse Length: 70

Velocity Profile Correction:

Density: 2.573 lb/cu.ft
Dynamic Viscosity: 1.02e-002 cp.
Profile Correction Coefficients:
Axial Path(s):
p1: 3792.0000
p2: 26.0000
p3: 0.7502
p4: 0.9711

p5: 0.0231
 p6: -3.3190
 Swirl Paths:
 p1: 3401.0000
 p2: 66.0000
 p3: 1.0037
 p4: 1.0137
 p5: 0.0204
 p6: -3.2056

Calibration Parameters:

Coefficients:	c1	c2	c3	c4
S=1:	0.1650	0.8350	0.0300	0.0000
S=2:	0.0300	0.0200	0.0500	0.0000
S=3:	0.0500	0.0060	-0.0038	0.0257
S=4:	0.0300	0.0000	0.0000	0.0000
S=5:	0.0000	1.0000	0.0424	0.0000
S=6:	1.0000	0.0000	0.0000	0.0000

Adjust Factor: 0.9974

Low Pass Filter: Off

Low Flow Cut-off: Off

Frequency Output: Vol.Flow (Line Cond.)

Vol.Flow (Line Cond.) Range:

Lower Limit: 0.0 CFH

Upper Limit: 150000.0 CFH

Frequency Range:

Lower Limit: 0.0 Hz

Upper Limit: 5000.0 Hz

Error Frequency: 6000.0 Hz

Meter Factor: 120.000 impulses/CF

APPENDIX N

Flow Measurement Uncertainty Calculation Tools User's Manual

**U.S. Department of the Interior (DOI)
Bureau of Safety and Environmental
Enforcement (BSEE)**

USER'S MANUAL

**Flow Measurement Uncertainty
Calculation Tools**

SwRI® Project No. 18.16994

DOI Contract M11PC00026

June 18, 2012



SOUTHWEST RESEARCH INSTITUTE®

SAN ANTONIO
DETROIT

HOUSTON
WASHINGTON, DC

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1. INTRODUCTION

Uncertainty propagation methods have been developed for gas measurement systems and are well documented in American Gas Association (AGA) and International Organization of Standardization (ISO) standards. Current computer programs for estimating flow measurement uncertainties are limited to gas flow meters for the selection of metering technologies.

This User's Manual describes the capabilities of computational tools developed by Southwest Research Institute (SwRI) for the Bureau of Safety and Environmental Enforcement (BSEE) to estimate the uncertainty of flow meters measuring single-phase gas and liquid flows. The flow meter types included in the uncertainty calculation tools are: orifice, ultrasonic, and Coriolis flow meters. The general approach to estimating uncertainty and the parameters that affect the overall uncertainty for each of the metering technologies are also described within this manual.

2. QUICK START INSTRUCTIONS

The functions that estimate the overall uncertainty of a flow meter technology and the support functions used to calculate parameters for the overall uncertainty estimation are written in C++ and compiled into a dynamic linked library (DLL). The use of a DLL allows the same source code to be utilized within a Microsoft Excel©-based interface and other customized software tools. In addition to the DLL and Excel interface, a portable Windows executable application (EXE) is provided. The functions of the uncertainty DLL have been directly incorporated into the EXE application for maximum portability.

An Excel spreadsheet example has been developed that references this library of functions for each of the meter technologies. This spreadsheet contains multiple examples for using the DLL within an Excel form (which utilizes Excel Visual Basic for Applications [VBA] functions) and a simple cell-based approach. The advantage of the spreadsheet is that the user will be able to call specific functions from the DLL to create their own custom calculations and forms by referring to the examples provided with these software tools.

The functions included in the DLL have also been incorporated within a portable Windows© EXE, which will run on any Windows-based machine (given the operating system is at least 32-bit). This application is less configurable than the Excel-based forms, but the EXE will provide the same meter uncertainty calculations from user input fields. The EXE is portable between machines and does not require the installation of Excel, the uncertainty DLL, or other software tools.

2.1 How to Use This Manual

The following sections provide step-by-step instructions on how to use the uncertainty calculation tools. Section 2.2 provides details on the installation and use of the Excel Spreadsheet, while Section 2.3 describes the use of the Windows executable (EXE) version.

A detailed description of the uncertainty calculation approach can be found in Section 3. This section starts with a review of the uncertainty propagation equations, field uncertainties, and describes the common uncertainty parameters that are relevant to the overall uncertainty calculation of the three selected flow meter types (orifice, Coriolis, and ultrasonic flow meters). Then, the uncertainty calculation approach for each one of the flow meter types included in these tools and the common support functions used within the calculations are also presented in Section 3.

Appendix A contains a table of the function error codes which the user may encounter when invalid inputs are entered into the functions. This manual also contains a table of all the functions within the DLL and is presented in Appendix B. This table can be used as a quick reference guide for the function description, inputs, and outputs.

2.2 Excel Spreadsheet

The Excel calculation tool is separated into several form-based spreadsheets that provide the uncertainty calculations for Coriolis, ultrasonic and orifice meters. It also contains a non-

form-based spreadsheet demonstrating how the user can construct custom calculation sheets from the functions provided in the DLL.

2.2.1 Installation Instructions

The Excel uncertainty calculation tool does not require a Win32 installation package. When copying between folders or machines, the user must ensure that the DLL is present in the same folder as the Excel spreadsheet. The DLL cannot be renamed. The Excel spreadsheets must have macros enabled to ensure that the calculations can be called from the DLL and so that the VBA functions can be executed.

2.2.2 Getting Started

Upon opening the spreadsheet, a message box will notify the user if macros are properly enabled. If this message box is not seen, enable macros and restart Excel. Once this message has cleared, the user will be presented with tabs for each of the metering technologies, as shown in Figure 2.1. The user will be required to input the values into the form entries not contained within the output box. Invalid inputs will be flagged by the software and the user will be required to correct these inputs before the calculation will continue. Any changes to the input fields will cause the output uncertainty calculation(s) to clear, which ensures the user that the output is not current.

The output box contains the “calculation button,” the “error code box,” the overall uncertainty calculation(s) for the meter, and a “Copy Case” button. The calculate button will execute the functions that estimate the meter uncertainty and will display the results in the output box. If there is a problem with the uncertainty calculation, an error code will be displayed within the “error code box.” If the user wishes to copy the form to save a particular calculation, then the “Copy Case” button can be pressed, which will prompt the user for a case name (will be the tabbed spreadsheet name) and will subsequently copy the form to another spreadsheet within the workbook. The current spreadsheet will continue to be the active sheet after “Copy Case” has been executed.

The spreadsheets are delivered “unprotected.” Therefore, the user is cautioned upon making changes in the Visual Basic code or within the forms themselves to ensure that the form continues to function correctly. It is suggested that a master protected workbook be implemented by BSEE for back-up purposes.

Figure 2.1. Flow Meter Excel Form – Liquid Coriolis Uncertainty

Each flow meter technology-specific form provides text box entries for each of the required inputs for the meter uncertainty estimation.

2.3 Windows Executable

In addition to the dynamic linked library (DLL) and Excel interface, a portable Windows executable application (EXE) is provided. The functions of the uncertainty DLL have been directly incorporated into the EXE application for maximum portability, and the EXE application can function on Windows systems (Windows XP SP3 or later) without installation of Excel or the Uncertainty DLL.

This section is intended for use as a quick reference tool for use of the EXE application. The function of the application and the calculations performed closely follow the Uncertainty DLL and Excel interface tool. These calculation methods are described in detail in Section 3 of this User's Manual document.

2.3.1 Installation Instructions

The Windows executable application is provided in a Windows installation package CD. To install the EXE application, open the provided CD and run the *setup.exe* file, located in the main directory. The installer package will install the EXE application (and dependencies, if required) and place a shortcut in the Start Menu and on the Desktop. The EXE application can be uninstalled using the Windows Control Panel's *Add/Remove Program* utility.

2.3.2 Getting Started

The application enters at the Entry Form, as pictured in Figure 2.2.

Inspection Detail Information

Operating Company
Operator A

Operator ID
ID Number 001

Lease Number
Lease Number 002

Station Number
Station Number 003

Facility Measurement Point Number
Not Available

Flow Meter Calculation Buttons

Gas Orifice

Liquid Orifice

Gas Ultrasonic

Liquid Ultrasonic

Gas Coriolis

Liquid Coriolis

Figure 2.2. Entry Form

The Entry Form allows for a central entry of common inspection details and provides linked buttons to the individual meter technology calculation forms.

Text Box prompts are provided for the entry of common inspection details. The entry of these details is optional and these entries are not required for subsequent calculations. Buttons, linked to additional forms for uncertainty calculations based on specific flow meter technology, are provided on the right side of the Entry Form.

To perform an uncertainty calculation, click on one of the provided flow meter technology buttons. When clicked, the flow meter technology button opens an additional form with additional inputs based on the specific flow meter technology. As an example, the Liquid Coriolis Meter Form is shown in Figure 2.3.

The inspection detail information (shown at the top of the Flow Meter Form) is copied from the information provided in the Entry Form. In addition to the inspection details, each Flow Meter Form has an Inputs section and a Result section.

In order to perform an uncertainty estimation calculation, complete the required input sections and click the “Calculate” button. Inputs are error checked, and any errors are reported via message boxes. If no errors are found, the result is displayed in the “Percent Total Uncertainty” box.

The Select Printer drop-down box is populated with the host system’s installed printers. The Print button allows the simple form (including inspection detail information, Inputs section, and Result section) to be printed to a system printer. This function is expected to be particularly useful when paired with an installed PDF printer for easy reporting.

Liquid Coriolis Uncertainty

Operating Company: Operator A

Operator ID: ID Number 001

Lease Number: Lease Number 002

Station Number: Station Number 003

Facility Measurement Point Number: Not Available

Inputs

Percent Uncertainty - Mass Flow Rate 0.25

Percent Uncertainty - Flow Pressure Effect Correction Factor 0.1

Percent Uncertainty - Base Density 0.2

Result

Percent Total Uncertainty 0.34 **Calculate**

Select Printer - Adobe PDF **Print**

Inspection Detail Information (Populated from Entry Form)

Required Inputs

Calculated Result

Selected Printer

Figure 2.3. Flow Meter Form – Liquid Coriolis Meter

Each flow meter technology-specific form provides text box entry of the required inputs for uncertainty estimation. The inspection detail information (top) is copied from the Entry Form, and the form is printable for ease of use.

3. UNCERTAINTY CALCULATION DETAILS

3.1 General Uncertainty Equation

The output quantity of a model, denoted by Y , can be generalized in the form of Equation 1 where the input quantities are denoted by $X_1, \dots, X_N$. If the true values of the input quantities $X_1, \dots, X_N$ are unknown, estimates of the input values, denoted by $x_1, \dots, x_N$, are often obtained from certificates and reports, manufacturers' specifications, the analysis of measurement data, and so on. For the i_{th} input quantity, consider the standard uncertainty, given by the symbol $u_{x_i}^*$, to be defined as the standard deviation of the input quantity.

Sensitivity coefficients, denoted by $c_1, \dots, c_N$, describe how the estimate of Y , which is denoted by y , would be influenced by small changes in the estimates $x_1, \dots, x_N$ of the input quantities $X_1, \dots, X_N$. For the measurement model given by Equation 1, the sensitivity coefficient c_i equals the partial derivative of the first order of Y with respect to X_i evaluated at $X_1 = x_1, X_2 = x_2$, etc. Assuming that $X_1, \dots, X_N$ are independent, a change in x_i equal to $u_{x_i}^*$ would give a change $c_i u_{x_i}^*$ in y . Therefore, the standard uncertainty u_y^* associated with the estimate of y for the output quantity Y is the quadrature sum (square root of the sum of squares) of the uncertainties associated with the estimates of the input values that are given by Equation 2. If a more detailed explanation of measurement uncertainty is required by the user, refer to Figliola and Beasley, 2000.

$$Y = f(X_1, \dots, X_N)$$

Equation 1

$$u_y^{*2} = c_1^{*2} u_{x_1}^{*2} + \dots + c_N^{*2} u_{x_N}^{*2}$$

Equation 2

3.2 Estimating Field Uncertainties

AGA Report No. 9 and AGA Report No. 11 suggest that the uncertainty of a measurement device such as a flow meter or temperature transmitter should include an additional uncertainty term for estimating field uncertainty (Equation 3), along with the calibrated uncertainty. The estimate of field uncertainty can include the effect of ambient conditions, equipment age, and other factors that affect the device's measurement. In some cases, the field equipment vendor can provide an estimate of the field uncertainty based on the conditions in which the device is installed. It should be noted that there is inherent difficulty for the user to estimate field uncertainty of installed devices if they are not instrumentation experts. In many cases, it may be best to neglect this term if the user feels that the device has been recently calibrated or maintained regularly. For completeness, the field uncertainty variables are included in this User's Manual and it is left to the user to estimate or disregard their effect on the overall uncertainty of the device.

$$u_{Device}^{*2} = u_{Calibrated}^{*2} + u_{Field}^{*2}$$

Equation 3

3.3 Common Uncertainty Parameters

This section of the User's Manual provides information on common parameters used in uncertainty calculations for the orifice, ultrasonic and Coriolis flow meters.

3.3.1 Uncertainty in the Measurement of Pressure

The total uncertainty in the measurement of pressure at flowing conditions, $u_{P_f}^*$, is composed of uncertainty estimated by the equipment vendor or calibration facility in addition to uncertainty of the equipment under field conditions, as shown by Equation 4.

$$u_{P_f}^{*2} = u_{P_{Cal}}^{*2} + u_{P_{Field}}^{*2}$$

Equation 4

3.3.2 Uncertainty in the Measurement of Temperature

The total uncertainty in the measurement of temperature, $u_{T_f}^*$, is composed of uncertainty estimated by the equipment vendor or calibration facility in addition to uncertainty of the equipment under field conditions, as shown by Equation 5.

$$u_{T_f}^{*2} = u_{T_{Cal}}^{*2} + u_{T_{Field}}^{*2}$$

Equation 5

3.3.3 Uncertainty in the Determination of Density

Orifice, ultrasonic, and Coriolis meters require the fluid density in order to calculate flow rates at the meter flowing conditions and at base conditions. In the United States, base conditions are defined as 14.73 psia and 60°F. Coriolis meters measure the flowing density of the process fluid; however, the density measured is only accurate for liquids, not gases. The purpose of this section is to provide general guidance on how to acquire the uncertainty related to density at the flowing conditions, $u_{\rho_f}^*$, and at the base conditions, $u_{\rho_b}^*$, for the measured fluid. The meter-specific sections of this User's Manual will expand on the density uncertainty calculation related to that meter technology if more detail is required.

The fluid density uncertainty is principally dependent on the source from which the data was obtained. There are usually four potential sources for obtaining the fluid density: a composition analysis coupled with the gas equation of state, a composition analysis coupled with fluid curve fits or correlations (such as API 14.2 (AGA 8), AGA 10 calculations), a composition analysis coupled with tabulated data, or from an inline densitometer installed near the flow meter. It is the responsibility of the user to provide the estimated density uncertainty from the available source(s) to functions in the DLL because it is not feasible to derive a general equation for each of the fluids measured by these meter technologies. The subsequent subsections provide more details for estimating density uncertainty from the sources listed above.

3.3.3.1 Densitometer Uncertainty

A densitometer will provide density at the meter flow conditions, but density at the base conditions will still be required to obtain base volumetric flow. The total uncertainty in the measurement of density, u_{ρ}^* , is composed of uncertainty estimated by the equipment vendor or calibration facility in addition to uncertainty of the equipment under field conditions, as shown by Equation 6.

$$u_{\rho}^{*2} = u_{\rho_{Cal}}^{*2} + u_{\rho_{Field}}^{*2}$$

Equation 6

3.3.3.2 Fluid Composition Analysis

A composition analysis provides the user with mole fractions of the different chemical components within the mixture and calculates the molecular weight of the measured fluid. It usually provides the uncertainty of the mole fractions and can also provide the overall uncertainty in determining the measured fluid's molecular weight, u^*_{MW} , by performing a quadrature sum over the individual constituent uncertainties. If the overall uncertainty is not available, then it is the responsibility of the user to calculate the overall uncertainty of the mixture based on the individual uncertainties by using Equation 2.

3.3.3.3 Density Curve Fits or Correlations

There are many curve fits or correlations available for hydrocarbon mixtures that provide the fluid density as a function of certain variables, such as molecular weight, relative density, compressibility factor, pressure, and temperature. If a curve fit or correlation is used to determine the density of a fluid and if the uncertainty of the curve fit or correlation is not provided with the equations, then it is strongly recommended that the user seek out or derive the uncertainty of the correlation in order to achieve an accurate calculation of the overall meter uncertainty. It is recommended to calculate the overall uncertainty of density according to Equation 7 if the user is using curve fits or correlations.

$$u^*_{\rho}{}^2 = u^*_{Curve\ Fit/Correlation}{}^2 + u^*_{Variable_1}{}^2 + u^*_{Variable_2}{}^2 + \cdots + u^*_{Variable_N}{}^2$$

Equation 7

API 14.3, Part 3 provides a detailed method for estimating the fluid density from correlated data in Section 1.12.4.7. This method can be followed when the uncertainty from the correlation is not provided.

3.3.3.4 Uncertainty in Determining Liquid Density

Like gas, liquid density changes as a function of temperature and pressure. In applications where the pressure and temperature are similar to base conditions (generally within the same order of magnitude), the compressibility of liquid can often be ignored. However it should be noted that there is always a difference between flowing liquid density and base liquid density and it is up to the user to decide whether to account for this difference when determining the overall uncertainty of the meter. In general, liquid density uncertainties are usually on the order of 0.25% or less.

Correlations for liquid density are usually a function of temperature and pressure. When estimating the flowing liquid density uncertainty, it is helpful to use Equation 7 and modify it to account for the parameters of the correlation (see example Equation 8).

$$u^*_{\rho}{}^2 = u^*_{Curve\ Fit/Correlation}{}^2 + u^*_{Temperature}{}^2 + u^*_{Pressure}{}^2$$

Equation 8

3.3.3.5 Uncertainty in Determining Gas Density and the Compressibility Factor

Real gas density can be calculated from the equation of state given by Equation 9, where MW_{Gas} is the molecular weight of the gas, P is the pressure, Z is the compressibility factor at the pressure and temperature, R is the universal gas constant, and T is the absolute temperature. A function is provided in the DLL that will calculate the real density based on Equation 9 and is described in more detail in subsection 3.7.4. In some cases, the ideal gas

relative density, denoted by G_i (Equation 10), or the real gas relative density, denoted by G_r , is provided. G_i and G_r can be related by Equation 11 where $Z_{b,air}$ and $Z_{b,gas}$ are the base compressibilities of the air and gas. G_r can be used to calculate the real gas density by using Equation 12. The molecular weight of dry air is 28.9625 *lbm/lbmol*, the air base compressibility is 0.99959, and the universal gas constant is 10.7316 *psia ft³/lbmol / °R*, as defined in API 14.3. Natural gas has a relative density approximately equal to 0.6. It is the responsibility of the user to use Equation 10, Equation 11, and Equation 12 to gather the required inputs for Equation 9.

$$\rho_{T,P} = \frac{MW_{Gas} P}{Z_{T,P} RT}$$

Equation 9

$$G_i = \frac{MW_{Gas}}{MW_{Dry Air}}$$

Equation 10

$$G_r = G_i \frac{Z_{b,air}}{Z_{b,gas}}$$

Equation 11

$$\rho = \frac{G_r MW_{Dry Air} P Z_{b,gas}}{Z_{T,P} RT}$$

Equation 12

The uncertainty in determining gas density at flowing conditions can be given by Equation 13. There is no uncertainty associated with the molecular weight of dry air because it is a constant by definition. Because the base temperature and base pressure are also constants by definition, the uncertainty in determining the gas density at base conditions can be given by Equation 14.

$$u_{\rho_f}^{*2} = u_{MW_{Gas}}^{*2} + u_{P_f}^{*2} + u_{T_f}^{*2} + u_{Z_f}^{*2}$$

Equation 13

$$u_{\rho_b}^{*2} = u_{MW_{Gas}}^{*2} + u_{Z_b}^{*2}$$

Equation 14

The calculations available through the API 14.2 (AGA 8) and AGA 10 software tools provide the mixture fluid properties, such as density, gas molecular weight, compressibility factor, and other pertinent variables. The correlations require the user to input the mole percent compositions of each of the components in the mixture and provide the base pressure, base temperature, flowing pressure, and flowing temperature. The user should be aware that the API 14.2 (AGA 8) and AGA 10 calculation outputs are based on correlations and curve fits and it is the responsibility of the user to determine the uncertainty in the parameters acquired from the software. It should be noted that the uncertainty in gas density is primarily a function of the uncertainty gas mixture molecular weight, $u_{MW_{Gas}}^*$, which comes from the composition analysis.

The uncertainty in compressibility, u_{Z}^* , can also be estimated using Equation 7, if the user employs a correlation in which uncertainty is not provided. If the user is calculating gas

compressibility using the calculation tools provided by API 14.2 (AGA 8) or AGA 10, then the uncertainty in compressibility is provided in Figure 3.1. A function that provides the API 14.2 uncertainty in compressibility is also provided in subsection 3.7.3.

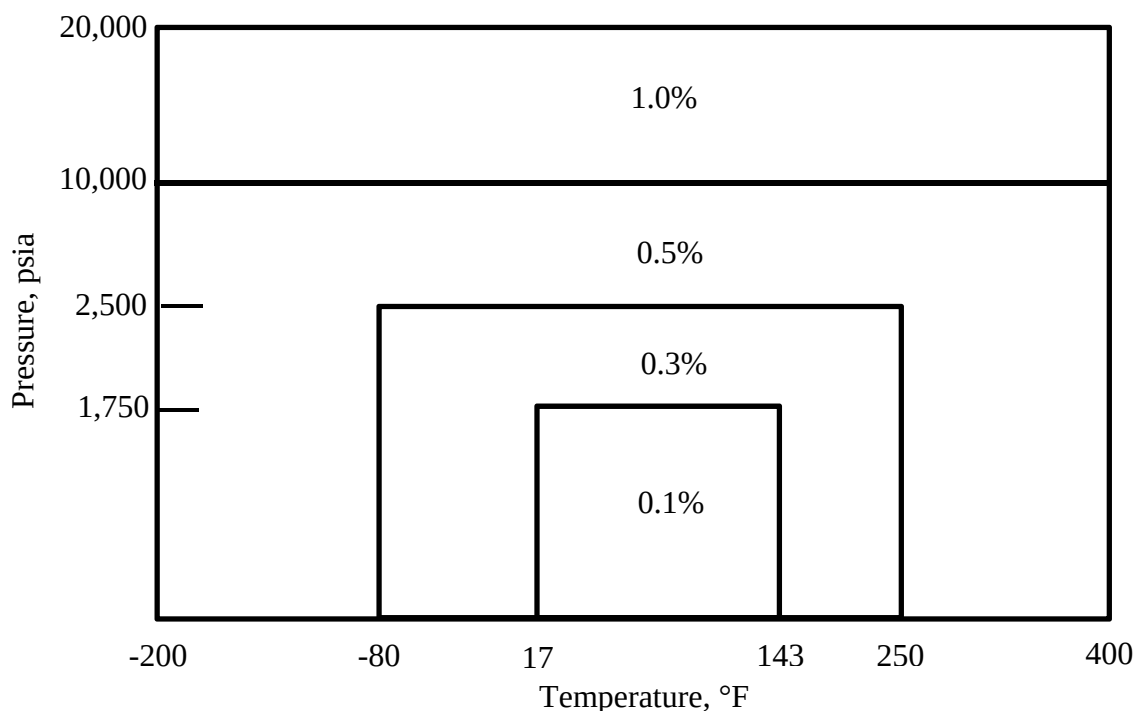


Figure 3.1. API Detail Method – Compressibility Uncertainty Table

This figure is used to estimate the uncertainty in compressibility if API 14.2 calculations are used to determine gas properties. Temperatures or pressures that do not fall within the range of the table are not valid regions for API calculations. This figure has been adapted from API 14.2 with permission.

3.3.4 Determining the Fluid Dynamic Viscosity

The fluid viscosity is typically obtained from the fluid composition analysis. If the gas viscosity cannot be determined, then an average value can be used. For gas flows, the average dynamic viscosity, as defined by API 14.3, Part 3, is 0.010268 cP. Viscosity varies much more with liquid hydrocarbon mixtures (due to temperature and composition) than gas mixtures and it is not feasible to suggest a particular average value. It is left to the user to determine the viscosity of the measured fluid.

3.4 Ultrasonic Uncertainty Calculations

Ultrasonic meters measure the average flow velocity, V_m , and the flow computer calculates volumetric flow at the flow conditions, Q_f , by multiplying the measured velocity and meter cross-sectional area (Equation 15). The determination of V_m is a complex process because modern ultrasonic meters have multiple ultrasonic transducer paths for characterizing the flow profile. It is not feasible to provide a general uncertainty calculation for Q_f , which could encompass the entire range of meter manufacturers. Therefore, the uncertainty associated with Q_f is typically provided by the manufacturer or flow calibration laboratory for the design range.

of the meter. The following sections discuss the details for determining the liquid and gas ultrasonic meter uncertainties at base conditions, Q_b .

$$Q_f = V_m \left(\frac{\pi D^2}{4} \right)$$

Equation 15

3.4.1 Uncertainty in Uncorrected Volume Flow Rate

The total uncertainty in the uncorrected volume flow rate, $u_{Q_f}^*$, is composed of uncertainty provided by the manufacturer or calibration facility, in addition to uncertainty under field conditions as shown by Equation 16. Uncertainty under field conditions can include site-specific installation effects, effects of equipment age, cleanliness of the transducers, and other effects that can cause meter degradation. See subsection 3 for further guidance on field uncertainty.

$$u_{Q_f}^{*2} = u_{Q_{fCal}}^{*2} + u_{Q_{fField}}^{*2}$$

Equation 16

3.4.2 Liquid Ultrasonic Uncertainty Calculation

The liquid volume flow rate at base conditions is given by Equation 17, where ρ_f and ρ_b are the densities of the liquid at the flow and base conditions. Therefore, the uncertainty for liquid flows through ultrasonic meters is given by Equation 18. For incompressible flows, the uncertainty associated with volumetric flow from an ultrasonic meter would simply be $u_{Q_f}^*$.

$$Q_b = Q_f \left(\frac{\rho_f}{\rho_b} \right)$$

Equation 17

$$u_{Q_b}^{*2} = u_{Q_f}^{*2} + u_{\rho_f}^{*2} + u_{\rho_b}^{*2}$$

Equation 18

3.4.2.1 Uncertainty in the Determination of Liquid Density

The uncertainties associated with the liquid densities, $u_{\rho_f}^*$ and $u_{\rho_b}^*$, are principally dependent on the source for which the data are obtained. See subsection 3.3.3 for general guidelines on determining the liquid density uncertainties.

3.4.2.2 Liquid Ultrasonic Uncertainty Function

The DLL contains the function *calculateLiqUltrasonicUncertainty* used to calculate the overall liquid ultrasonic uncertainty. A flowchart that details the inputs for this function is provided in Figure 3.2. If the user wishes to ignore the compressibility of the liquid flow, then zero shall be entered for both the uncertainties in the liquid density at the flowing and base conditions.

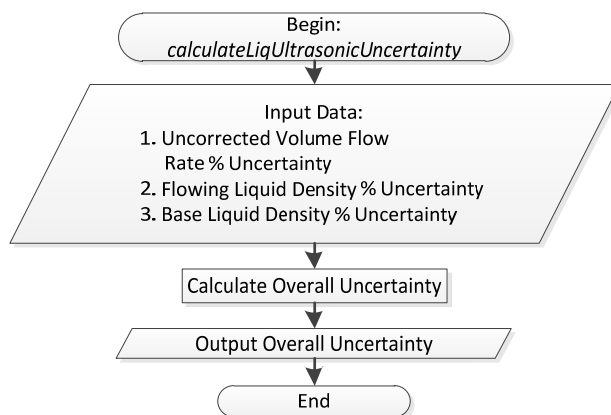


Figure 3.2. Function *calculateLiqUltrasonicUncertainty* Flowchart

This function returns the overall percent uncertainty associated with liquid flows through an ultrasonic meter.

3.4.3 Gas Ultrasonic Uncertainty Calculation

The gas volume flow rate at base conditions is given by Equation 19, where the uncorrected volume flow rate is related to the corrected volume flow rate at base conditions. Because gas is highly compressible, measurements of temperature and pressure and values of the compressibility factor at flowing and base conditions must be provided to convert the volume flow at meter conditions to base conditions. Given that T_b and P_b are constants, Equation 20 can be used to provide the uncertainty of gas flows through an ultrasonic meter.

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

Equation 19

$$u_{Q_b}^2 = u_{Q_f}^2 + u_{P_f}^2 + u_{T_f}^2 + u_{Z_f}^2 + u_{Z_b}^2$$

Equation 20

3.4.3.1 Uncertainty in the Pressure Measurement

The user can estimate the flowing pressure uncertainty through the details provided in subsection 3.3.1.

3.4.3.2 Uncertainty in the Temperature Measurement

The user can estimate the flowing temperature uncertainty through the details provided in subsection 3.3.2.

3.4.3.3 Uncertainty in the Compressibility Factors

The uncertainty associated with the gas compressibility factors is principally dependent on the source for which the data are obtained. See subsection 3.3.3.5 for estimating the compressibility uncertainty for both the flowing and base conditions.

3.4.3.4 Gas Ultrasonic Uncertainty Function

The DLL contains the function *calculateGasUltrasonicUncertainty* used to calculate the overall ultrasonic uncertainty associated with gas flows. A flowchart that details the inputs for this function is provided in Figure 3.3. Users can also choose to use the function described in

subsection 3.4.2.2 to calculate the base volume flow uncertainty if the flowing and base density uncertainties are known.

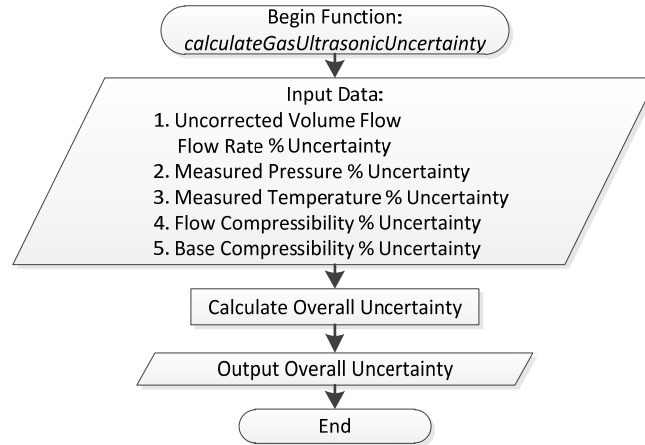


Figure 3.3. Function *calculateGasUltrasonicUncertainty* Flowchart

This function returns the overall percent uncertainty associated with gas flows through an ultrasonic meter.

3.5 Coriolis Uncertainty Calculations

Coriolis meters directly measure mass flow, q_m , by taking advantage of the Coriolis force produced from accelerating the fluid through vibrating tubes. Equation 21 provides a calculation for the mass flow through the Coriolis meter, where τ is the Coriolis tube transit time, K_s is the pipe stiffness, and d is the pipe diameter.

$$q_m = \frac{K_s \tau}{2d^2}$$

Equation 21

Sensitivity to changes in operating pressure, i.e., “the flow pressure effect,” can create a negative bias in measured flow rate at operating pressures above the calibration pressure, and vice versa. The magnitude of error associated with this is manufacturer dependent. Typically, the flow pressure effect increases with meter size, with performance diminishing with increasing wall thickness and diameter [API 5.6]. The compensation factor may be computed from the calibration static pressure P_{cal} (psig), the flowing fluid static pressure P_f (psig), and the flow pressure effect P_{effect} (% rate/psig), according to the relationship given by Equation 22. The mass flow rate can be adjusted as shown in Equation 23, where the flow pressure effect compensation factor F_p is applied to the indicated mass flow from the transmitter $q_{m,transmitter}$ to compute the compensated mass flow rate.

$$F_p = \frac{1}{1 + ((P_{effect}/100) * (P_f - P_{cal}))}$$

Equation 22

$$q_{m,compensated} = q_{m,transmitter} * F_p$$

Equation 23

It is not feasible to provide a general uncertainty calculation for q_m that can encompass the entire range of Coriolis meter manufacturers. Therefore, the uncertainties associated with q_m

and F_p are provided by the manufacturer after calibration for a specific range of flow conditions. The base volumetric flow through a Coriolis meter can be derived from Equation 23 and the fluid density as shown by Equation 24.

$$Q_b = \frac{q_{m,transmitter} * F_p}{\rho_b}$$

Equation 24

3.5.1 Overall Coriolis Uncertainty Calculation

The uncertainty related to mass flow rate from Coriolis meters is given by Equation 25. The volume flow rate uncertainty at base conditions is given by Equation 26, including the addition of the base density uncertainty.

$$u_{q_{m,overall}}^2 = u_{q_m}^2 + u_{F_p}^2$$

Equation 25

$$u_{Q_b}^2 = u_{q_{m,overall}}^2 + u_{\rho_b}^2$$

Equation 26

3.5.1.1 Uncertainty in the Coriolis Mass Flow Rate

The total uncertainty in the mass flow rate, $u_{q_m}^*$, is composed of uncertainty provided by the manufacturer, in addition to uncertainty under field conditions, as shown by Equation 27.

$$u_{q_m}^2 = u_{q_{m,Cal}}^2 + u_{q_{m,Field}}^2$$

Equation 27

3.5.1.2 Uncertainty in the Flow Pressure Effect Compensation Factor

The uncertainty associated with the flow pressure effect compensation factor is given by Equation 28. The uncertainty in F_p is composed of estimates of uncertainty in flowing pressure, P_f , and calibration pressure, P_{cal} , with a sensitivity proportional to pressure effect, P_{Effect} . All of the terms in Equation 28 ($S_{P_{Effect}}$, $u_{P_f}^*$, $u_{P_{cal}}^*$) are estimated by the manufacturer and usually provided as the gross uncertainty in the flow pressure effect compensation factor, $u_{F_p}^*$. This uncertainty is generally very small (on the order of hundredths or even thousandths of a percent) and does not have a large effect on the overall uncertainty.

$$u_{F_p}^{*2} = S_{P_{Effect}} \left(u_{P_f}^{*2} + u_{P_{CAL}}^{*2} \right)$$

Equation 28

3.5.2 Liquid Coriolis Uncertainty Calculation

3.5.2.1 Uncertainty in the Determination of Liquid Density

The uncertainty associated with the base liquid density is principally dependent on the source for which the data are obtained. See subsection 3.3.3 for general guidelines on determining the base density uncertainty for the input required by the liquid uncertainty function.

3.5.2.2 Liquid Coriolis Uncertainty Function

The DLL contains the function *calculateLiqCoriolisUncertainty* used to calculate the overall liquid Coriolis uncertainty for mass and volumetric flows. A flowchart that details the

inputs for this function is provided in Figure 3.4. The difference between volumetric flow uncertainty and mass flow uncertainty is determined by the value entered for the base liquid density uncertainty. Users should enter zero for this value to calculate the liquid mass flow uncertainty. See Equation 26 for proof of this statement.

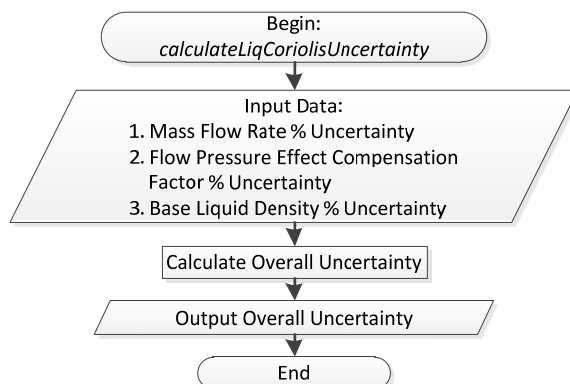


Figure 3.4. Function *calculateLiqCoriolisUncertainty* Flowchart

This function returns the overall percent uncertainty associated with liquid flow through a Coriolis meter.

3.5.3 Gas Coriolis Uncertainty Calculation

The uncertainty associated with gas flows for Coriolis meters differs from the liquid flows because of the determination of the fluid base density. Equation 26 can be modified to account for the uncertainty in the molecular weight and the base gas compressibility, as shown in Equation 29.

$$u_{\rho_b}^{*2} = u_{MW_{Gas}}^{*2} + u_{Z_b}^{*2}$$

Equation 29

3.5.3.1 Uncertainty in the Determination of Gas Density

The uncertainty associated with the gas density is principally dependent on the source for which the data are obtained. See subsection 3.3.3 for general guidelines on determining the base compressibility and molecular weight uncertainties for the inputs required by the liquid uncertainty function.

3.5.3.2 Gas Coriolis Uncertainty Function

The DLL contains the function *calculateGasCoriolisUncertainty* used to calculate the overall liquid Coriolis uncertainty for mass and volumetric flows. A flowchart that details the inputs for this function is provided in Figure 3.5.

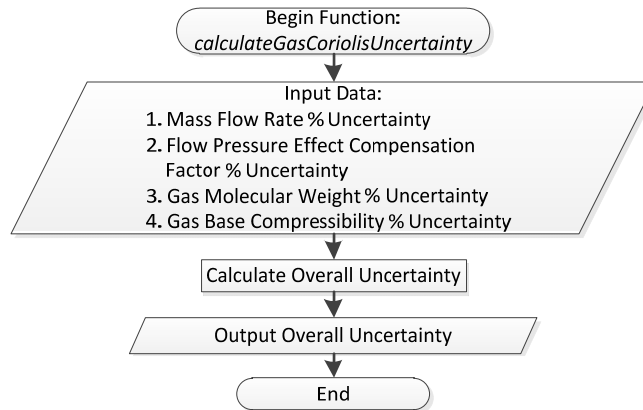


Figure 3.5. Function `calculateGasCoriolisUncertainty` Flowchart

This function returns the overall percent uncertainty associated with gas flow through a Coriolis meter.

The difference between volumetric flow uncertainty and mass flow uncertainty is determined by the values entered for the base gas compressibility and molecular weight uncertainties. Users should enter zero for both of these values to calculate the gas mass flow uncertainty. See Equation 26 for proof of this statement. Users can also choose to use the function described in section 4.2 to calculate the mass flow and base volume flow uncertainties if the base density uncertainty is already known.

3.6 Orifice Uncertainty Calculations

Orifice meters are inferential devices in which the flow rate is inferred from the pressure drop through an orifice plate. Auxiliary knowledge of fluid properties and geometry of the metering setup allow for calculation of fluid velocity and flow rate. The equation for mass flow through an orifice meter is given by Equation 30, where N_1 is a unit conversion constant, C_D is the orifice discharge coefficient, E_v is the velocity approach factor, Y is the expansion factor, d is the orifice diameter, ρ_f is the fluid density at the meter flowing conditions, and ΔP is the differential pressure across the orifice plate. The volumetric flow rate of the orifice meter at base conditions is given by Equation 31, where ρ_b is the density at base conditions.

$$q_m = N_1 C_D E_v Y d^2 \sqrt{\rho_f \Delta P}$$

Equation 30

$$Q_b = \frac{q_m}{\rho_b}$$

Equation 31

3.6.1 Calculating the Orifice Discharge Coefficient

The orifice C_D can be calculated from the Reader-Harris/Gallagher equation [API 14.3, Part 1], which is a correlation between the meter geometry and the Reynolds number of the flow. An iterative process is required to calculate the C_D because it is a non-linear function of Reynolds number and the Reynolds number is a function of C_D . This relationship is solved using a Newton-Raphson scheme that iterates the C_D until convergence is reached [API 14.3, Part 4]. The Reader-Harris/Gallagher equation has limits on the meter geometry and Reynolds number for which the correlation is valid. The forms in the Excel-based calculation tools will warn the user if the correlation limits have been exceeded. See subsection 3.6.5.2 for the details on these

limits. The iteration scheme used by the DLL contains a modified version of the Reader-Harris/Gallagher equation to account for Reynolds numbers less than 4000, but the uncertainty correlations presented in API 14.3, Section 1.12.4.1 have not been extended by API to accommodate this change.

The DLL contains the function *calculateOrificeCd* used to calculate the discharge coefficient for liquid and gas flows. A flowchart that details the inputs for this function is provided in Figure 3.6.

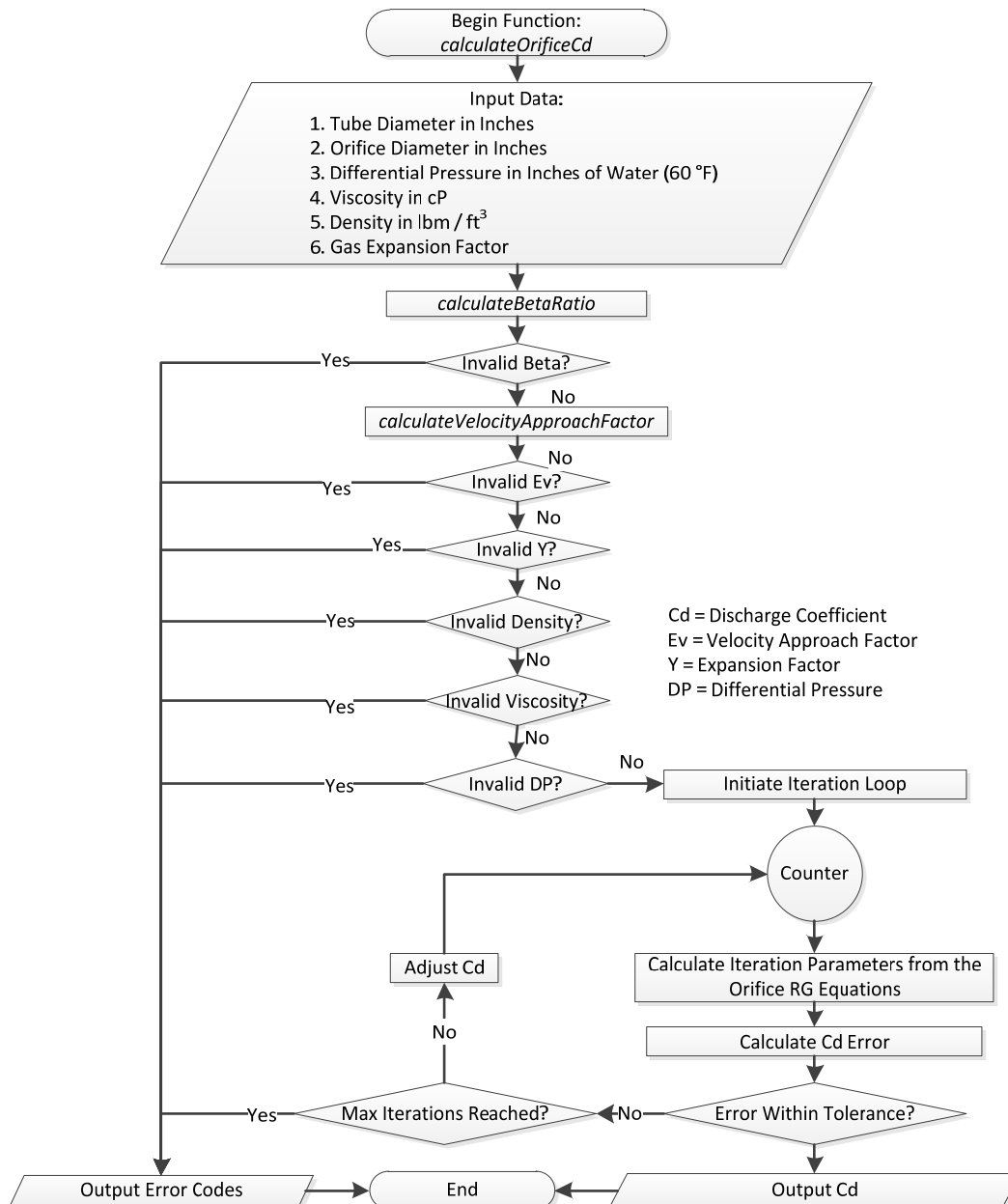


Figure 3.6. Function *calculateOrificeCd* Flowchart

This function returns the orifice discharge coefficient associated with gas and liquid flows through an orifice meter.

3.6.2 Overall Orifice Uncertainty

The uncertainty associated with the mass flow from orifice meters is derived from Equation 30 and is shown by Equation 32 with the variable sensitivity coefficients. For a complete derivation of Equation 32 see API 14.3, Part 1. The uncertainty associated with volumetric flow from the orifice meter is presented in Equation 33. The following sections will break down these equations and discuss the practical parameters that the user must supply to estimate the orifice uncertainty.

$$u_{q_m}^{*2} = u_{c_D}^{*2} + u_Y^{*2} + \left[\frac{2}{1 - \beta^4} \right]^2 (u_d^{*2}) + \left[\frac{-2\beta^4}{1 - \beta^4} \right]^2 (u_D^{*2}) + \frac{u_{\rho_f}^{*2}}{4} + \frac{u_{\Delta P}^{*2}}{4}$$

Equation 32

$$u_{Q_b}^{*2} = u_{q_m}^{*2} + u_{\rho_b}^{*2}$$

Equation 33

3.6.2.1 Uncertainty in the Tube Diameter

The uncertainty in the tube diameter, u_D^* , is usually provided by the manufacturer. If not present, it is suggested to search for the value in the inspection records.

3.6.2.2 Uncertainty in the Orifice Bore Diameter

The uncertainty in the orifice bore diameter, u_d^* , is usually provided with the set of orifice plates by the manufacturer. If not present, it is suggested to search for the value in the inspection records. Orifice plates should come with calibration information having undergone multiple measurements.

3.6.2.3 Uncertainty in the Differential Pressure Measurement

The total uncertainty in the differential pressure measurement, $u_{\Delta P}^*$, is composed of uncertainty provided by the manufacturer in addition to uncertainty under field conditions, as shown by Equation 34. It is the responsibility of the user to account for field uncertainty in the differential pressure measurement when entering the total uncertainty into the functions.

$$u_{\Delta P}^{*2} = u_{\Delta P, Cal}^{*2} + u_{\Delta P, Field}^{*2}$$

Equation 34

3.6.3 Liquid Orifice Uncertainty Calculation

For liquid flows, the general orifice uncertainty (Equation 32) can be modified because the expansion factor is assumed to have a value of 1.0. This modification is presented in Equation 35.

$$u_{q_m}^{*2} = u_{c_D}^{*2} + \left[\frac{2}{1 - \beta^4} \right]^2 (u_d^{*2}) + \left[\frac{-2\beta^4}{1 - \beta^4} \right]^2 (u_D^{*2}) + \frac{u_{\rho_f}^{*2}}{4} + \frac{u_{\Delta P}^{*2}}{4}$$

Equation 35

3.6.3.1 Uncertainty in Determining Liquid Density

The uncertainties associated with the liquid densities, $u_{\rho_b}^*$ and $u_{\rho_f}^*$, are principally dependent on the source for which the data are obtained. See subsection 3.3.3 for general guidelines on determining the liquid density uncertainties.

3.6.3.2 Liquid Orifice Uncertainty Function

The DLL contains the function *calculateLiqOrificeUncertainty* used to calculate the overall liquid mass flow uncertainty associated with liquid orifice meters. This function flowchart, with its respective inputs, is presented in Figure 3.7. The DLL also contains the function *calculateOrificeVolUncertainty* used to calculate the overall volume flow uncertainty. This function flowchart, with its respective inputs, is presented in Figure 3.8.

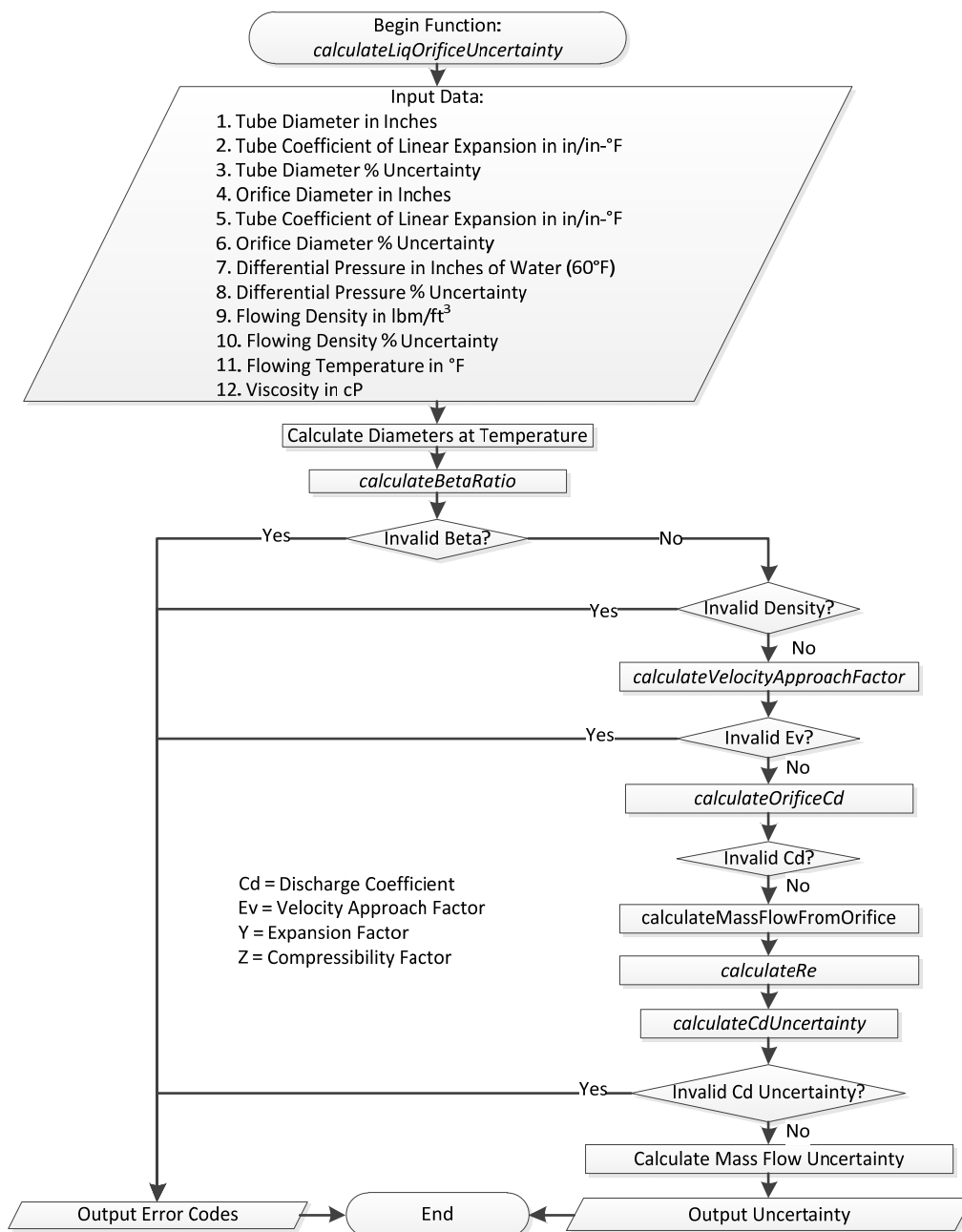


Figure 3.7. Function *calculateLiqOrificeFlowUncertainty* Flowchart
 This function calculates the overall mass flow uncertainty associated with liquid orifice flow.

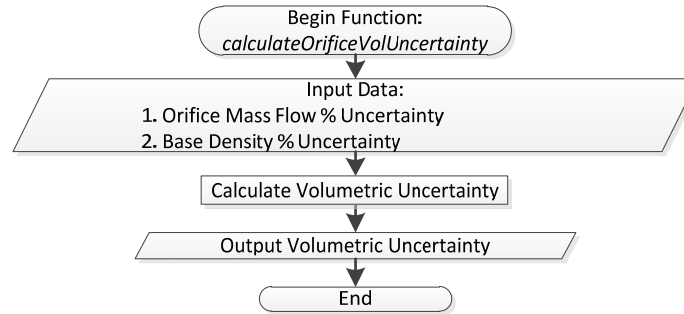


Figure 3.8. Function `calculateOrificeVolUncertainty` Flowchart

This function calculates the overall volume flow associated with liquid orifice flow or gas orifice flow where the based density percent uncertainty is known.

3.6.4 Gas Orifice Uncertainty Calculation

For gas flows, the general orifice uncertainty (Equation 32) must be modified because the fluid density term is expanded into the uncertainties related to the gas equation of state. This modification is presented in Equation 36 and Equation 37. The uncertainty in volumetric flow can be seen in Equation 38.

$$\frac{u_{\rho_f}^2}{4} = \frac{u_{MW}^2}{4} + \frac{u_P^2}{4} + \frac{u_Z^2}{4} + \frac{u_T^2}{4}$$

Equation 36

$$u_{q_m}^2 = u_{c_D}^2 + u_Y^2 + \left[\frac{2}{1 - \beta^4} \right]^2 u_d^2 + \left[\frac{-2\beta^4}{1 - \beta^4} \right]^2 u_D^2 + \frac{u_{MW}^2}{4} + \frac{u_{P_f}^2}{4} + \frac{u_{Z_f}^2}{4} + \frac{u_{T_f}^2}{4} + \frac{u_{\Delta P}^2}{4}$$

Equation 37

$$u_{Q_b}^2 = u_{q_m}^2 + u_{MW}^2 + u_{Z_b}^2$$

Equation 38

3.6.4.1 Gas Orifice Uncertainty Function

The DLL contains the functions `calculateGasOrificeUncertainty` and `calculateGasOrificeUncertaintyFromDensity`, which are used to calculate the overall gas mass flow rate uncertainty. The function `calculateGasOrificeUncertaintyFromDensity` is used when the flowing density is already known. The function `calculateGasOrificeUncertainty` is used when the molecular weight and flowing compressibility of the gas are known. The function flowcharts with their inputs are shown in Figure 3.9 and Figure 3.10, respectively. The function `calculateGasVolOrificeUncertainty` is used to calculate the volumetric flow uncertainty for gas orifice meters. This function flowchart is presented in Figure 3.11. The function described in subsection 3.6.3.2 can be used to calculate the gas orifice volumetric flow uncertainty when the base density uncertainty is known.

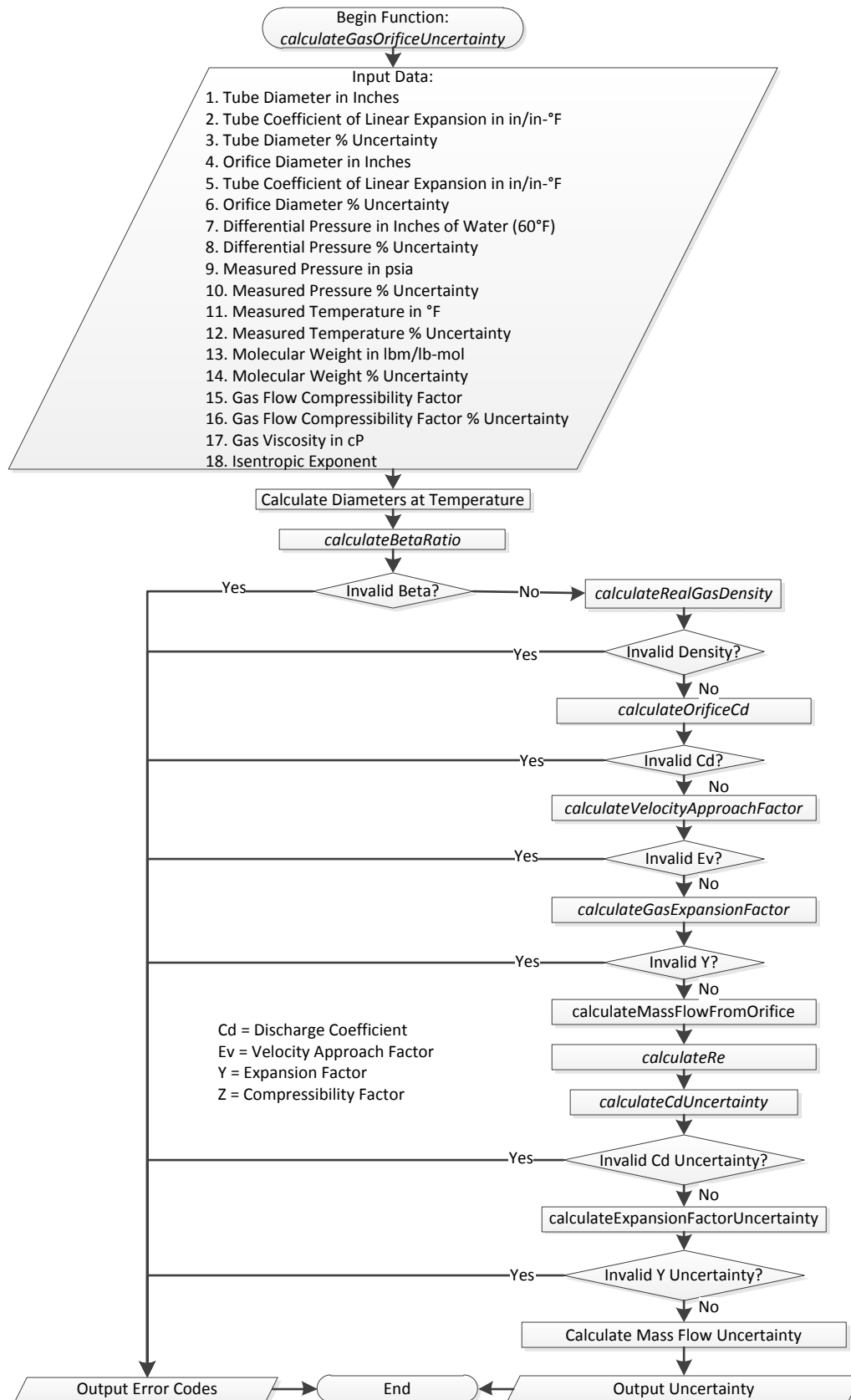


Figure 3.9. Function *calculateGasOrificeUncertainty* Flowchart

This function calculates the overall mass flow uncertainty for gas flow through an orifice meter.

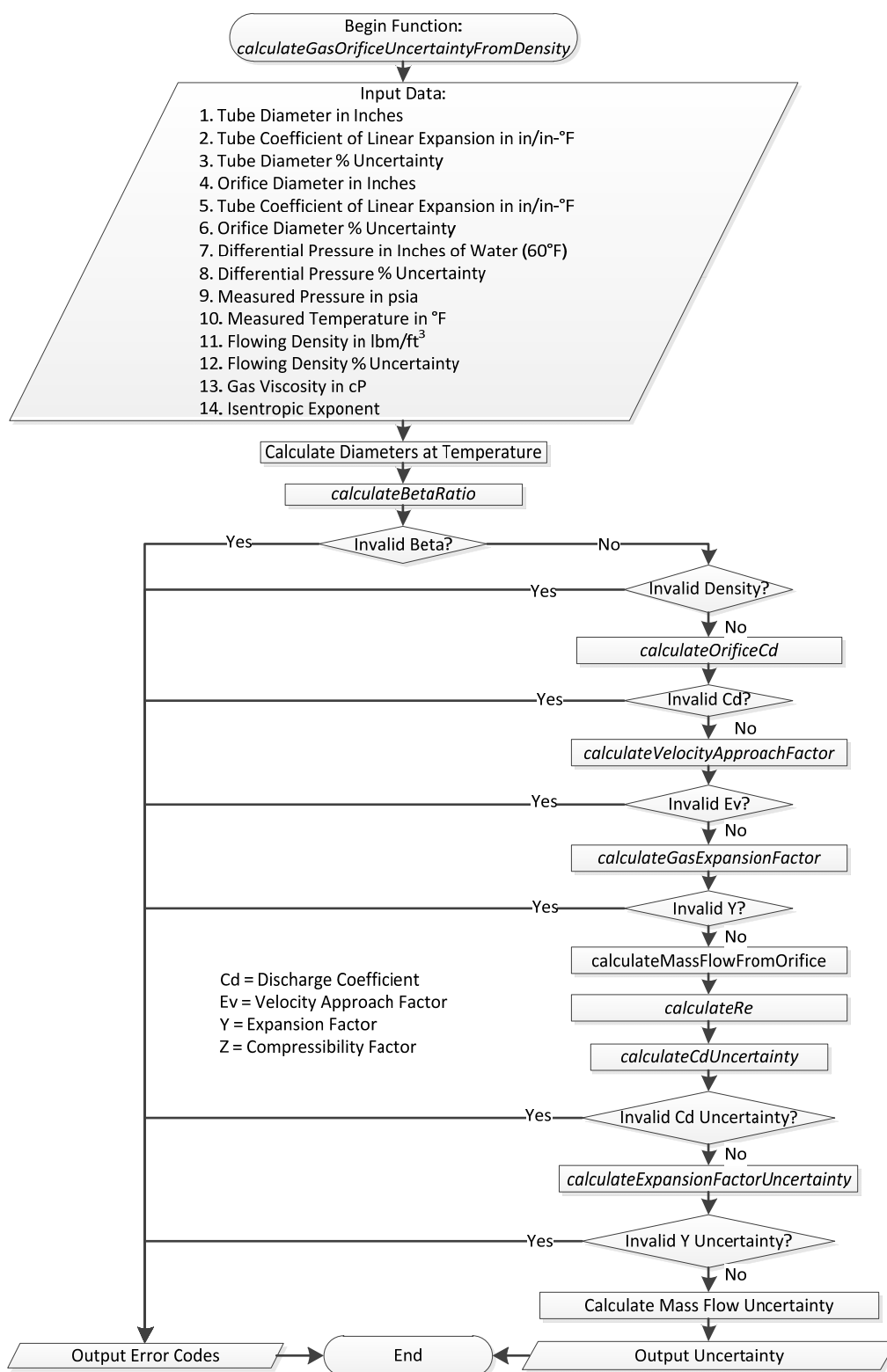


Figure 3.10. Function *calculateGasOrificeUncertaintyFromDensity* Flowchart

This function calculates the overall mass flow uncertainty for a gas orifice meter when the flowing density is known.

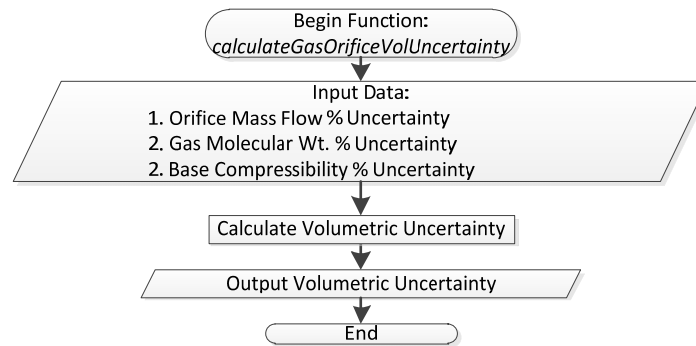


Figure 3.11. Function *calculateGasOrificeVolUncertainty* Flowchart

This function calculates the overall volumetric flow uncertainty associated with orifice gas flow.

3.6.5 Supporting Functions for Orifice Calculations

3.6.5.1 Temperature-Corrected Diameters Function

The DLL contains the function *calculateDiameterAtT* used to calculate the orifice bore and tube diameter as a function of the fluid temperature and material coefficient of linear expansion. This function flowchart, with its respective inputs, is presented in Figure 3.12. Throughout API 14.3, a value of 6.2×10^{-6} in/in-°F is used for the carbon steel coefficient of linear expansion (meter tube) and a value of 9.25×10^{-6} in/in-°F for the 316 / 304 stainless steel coefficient of linear expansion (orifice plate). The reference temperature for the measurement is assumed to be 68°F (the temperature at which most “stamped” diameters are measured). It is the responsibility of the user to ensure that the reference diameter they enter is the measurement at 68°F. See API 14.3, Section 4.3.2.1 for further details on corrected diameter measurements.

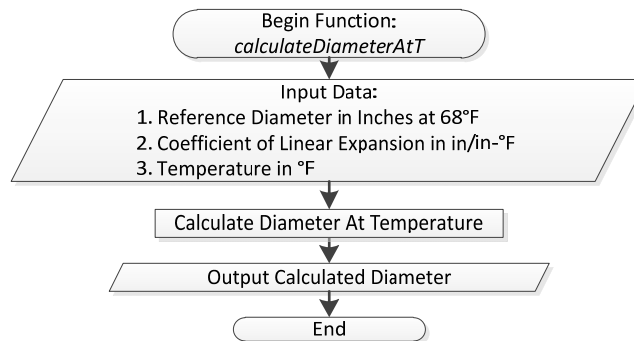


Figure 3.12. Function *calculateDiameterAtT* Flowchart

This function calculates the temperature-corrected diameter of the orifice tube or bore.

3.6.5.2 RG Orifice Discharge Coefficient Function

The DLL contains the function *calculateOrificeCdFromRG* used to calculate the orifice discharge coefficient, C_d , from the Reader-Harris/Gallagher (RG) equation [API 14.3, Part 1]. This correlation is limited to beta ratios between 0.1 and 0.75, a minimum orifice diameter of 0.45 inches, a minimum tube diameter of two inches, and Reynolds numbers greater than 4000. If these limits are exceeded, then the value for the C_D uncertainty is invalid [API 14.3, Section 1.12.4.1]. The function flowchart and inputs are presented in Figure 3.13.

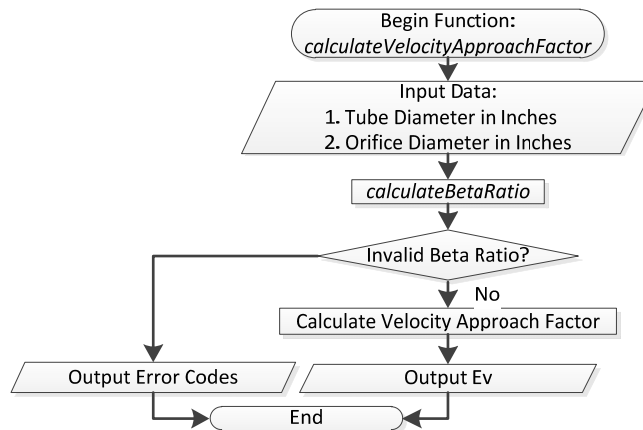


Figure 3.13. Function *calculateOrificeCdFromRG* Flowchart
This function calculates the orifice discharge from the RG Equation.

3.6.5.3 Uncertainty in the Orifice Discharge Coefficient

The DLL contains the function *calculateCdUncertainty*, which estimates the uncertainty in the discharge coefficient as a function of the meter geometry and Reynolds number using curve fits available in API 14.3, Section 1.12.4.1. The limits for this correlation have been discussed in the previous section (3.6.5.2) and warnings from the Excel forms will be displayed if the inputs exceed the limits when calculating the overall meter uncertainty. A function flowchart, with its respective inputs, can be seen in Figure 3.14.

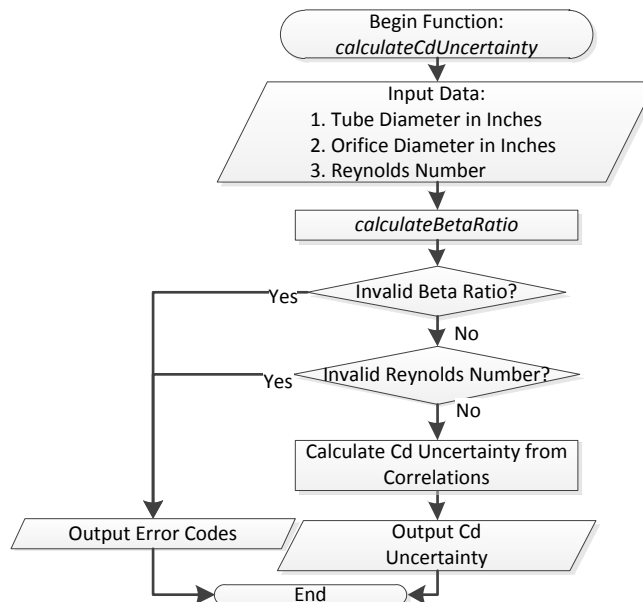


Figure 3.14. Function *calculateCdUncertainty* Flowchart
This function calculates the uncertainty from curve fits to empirical data.

3.6.5.4 Gas Expansion Factor Function

The DLL contains the function *calculateGasExpansionFactor* to calculate the gas expansion factor for orifice meters. This equation can be viewed in API 14.3, Part 1. This equation is valid for $\Delta P/P < 5.5414$ when ΔP is in inches of water at 60°F and pressure is in psia. The Excel forms will provide a warning if this limit is exceeded, but the calculation will

continue. The function will return an error if the differential pressure exceeds the pressure of the flow. The function flowchart is shown in Figure 3.15.

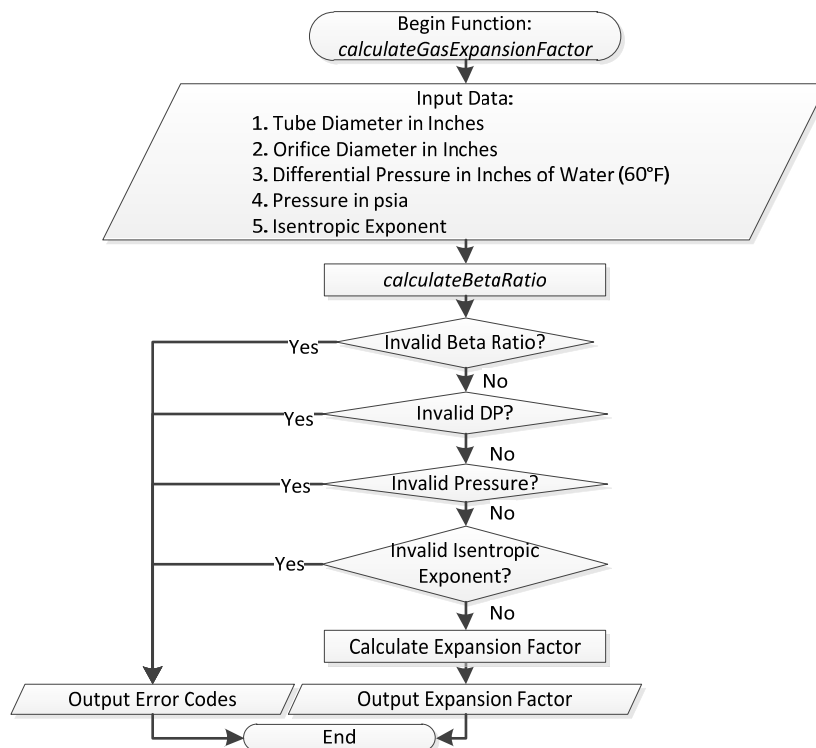


Figure 3.15. Function `calculateGasExpansionFactor` Flowchart

This function calculates the gas expansion factor for orifice gas flow based on correlated data.

3.6.5.5 Uncertainty in the Expansion Factor

The DLL contains the function `calculateGasExpansionFactorUncertainty` used to calculate the gas expansion factor uncertainty for orifice meters. The gas expansion factor uncertainty is computed using Section 1.12.4.2 of API 14.3 for gas flows. This function is valid when the beta ratio is less than or equal to 0.75. Liquids are assumed to be incompressible across the orifice meter and, therefore, do not have an associated expansion factor uncertainty value.

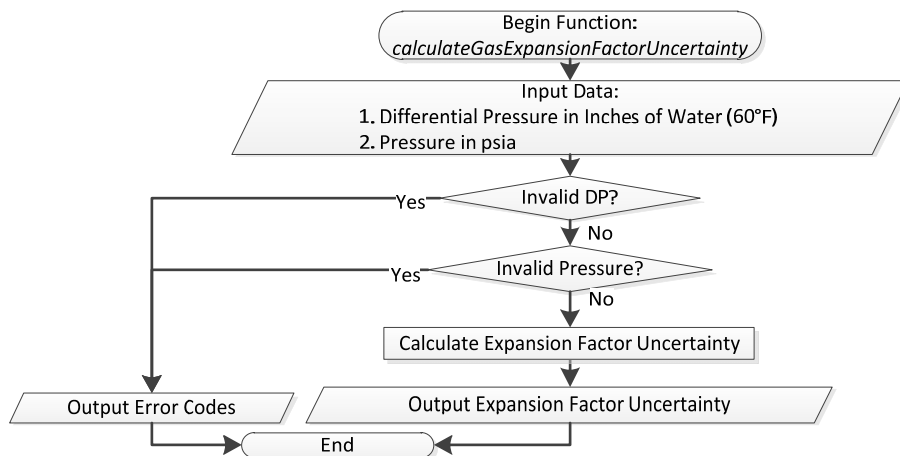


Figure 3.16. Function `calculateGasExpansionFactorUncertainty` Flowchart

This function calculates the uncertainty associated with the gas expansion factor.

3.6.5.6 Orifice Beta Ratio Function

The DLL contains the function *calculateBetaRatio* used to calculate the orifice beta ratio. The function flowchart is presented in Figure 3.17.

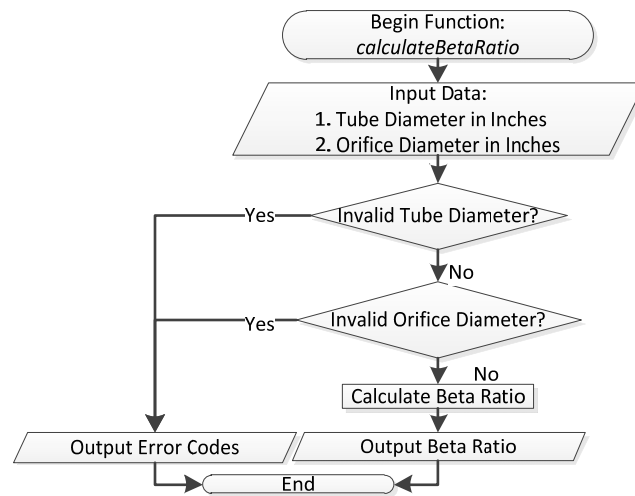


Figure 3.17. Function *calculateOrificeBetaRatio* Flowchart

This function calculates the orifice beta ratio from the meter dimensions and returns error codes for invalid inputs.

3.6.5.7 Orifice Mass Flow Function

The DLL contains the function *calculateMassFlowFromOrifice* used to calculate the mass flow through an orifice meter using the orifice equation. This function flowchart is presented in Figure 3.18.

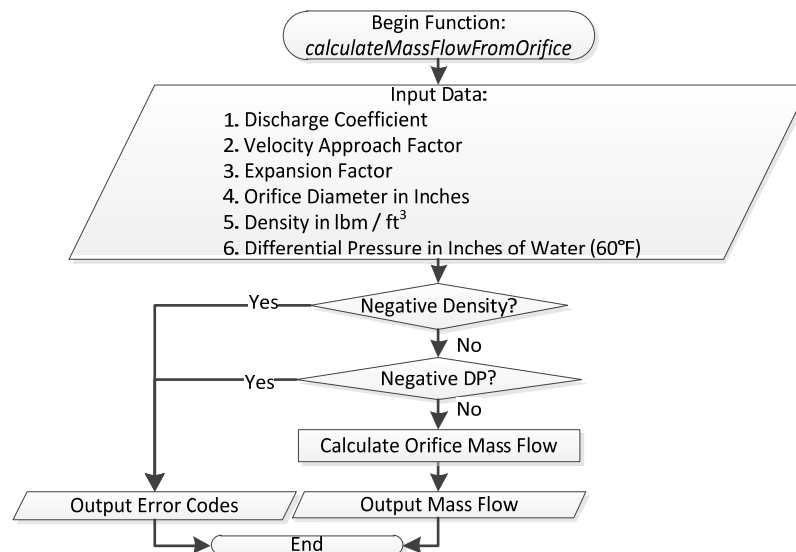


Figure 3.18. Function *calculateMassFlowFromOrifice* Flowchart

This function calculates mass flow from the orifice equation.

3.6.5.8 Orifice Velocity Approach Factor Function

The DLL contains the function *calculateVelocityApproachFactor* used to calculate the orifice velocity approach factor. The function flowchart is presented in Figure 3.19.

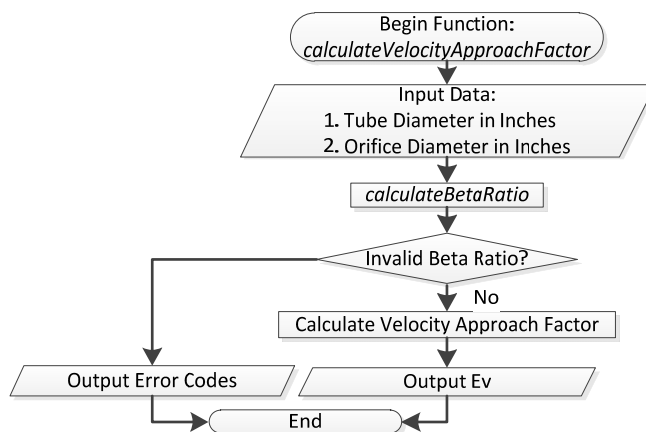


Figure 3.19. Function *calculateVelocityApproachFactor* Flowchart
This function calculates the orifice velocity approach factor.

3.7 Common Functions for Uncertainty Determination

This section presents common functions contained within the DLL used in determining the overall uncertainty of orifice, ultrasonic and Coriolis meter technologies.

3.7.1 Reynolds Number Calculation Function

The DLL contains the function *calculateRe* used to calculate the Reynolds number for fluid flows. Figure 3.20 provides a flowchart for this function.

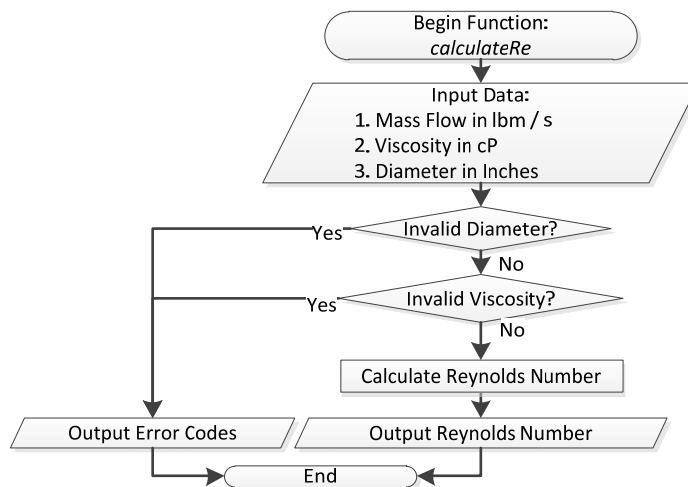


Figure 3.20. Function *calculateRe* Flowchart
This function returns the Reynolds number from the given inputs.

3.7.2 Calculating Mass Flow from Reynolds Number Function

The DLL contains the function *calculateMassFlowFromRe* used to calculate the mass flow in lb_m/s for pipe flows where the Reynolds number, diameter, and viscosity are known. Figure 3.21 provides a flowchart for this function.

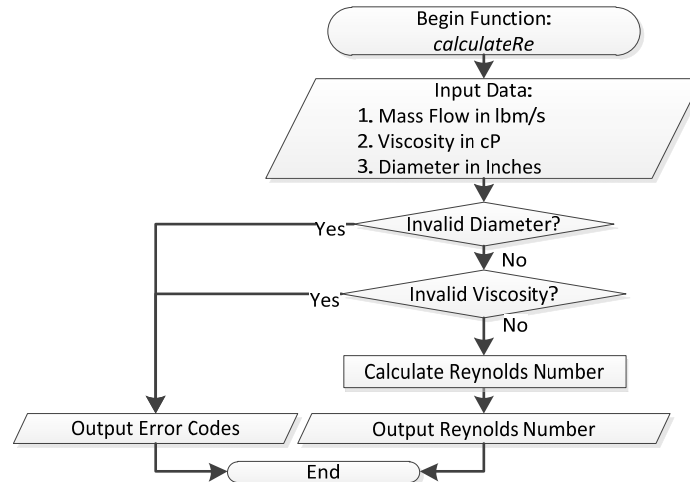


Figure 3.21. Function *calculateMassFlowFromRe* Flowchart
This function returns the mass flow from the Reynolds number.

3.7.3 Gas Compressibility Uncertainty Function

AGA Report No. 8 and Report No. 10 provide a graph for estimating the gas compressibility as a function of pressure and temperature based on Figure 3.1. This method is valid for methane, ethane, carbon dioxide, nitrogen, hydrogen, or a mixture of these gases. The method also allows pressures up to 20,000 psia and temperatures between -200°F and 400°F. The name of this function in the DLL is *calculateGasCompressibilityUncertainty* and the flowchart is provided in Figure 3.22.

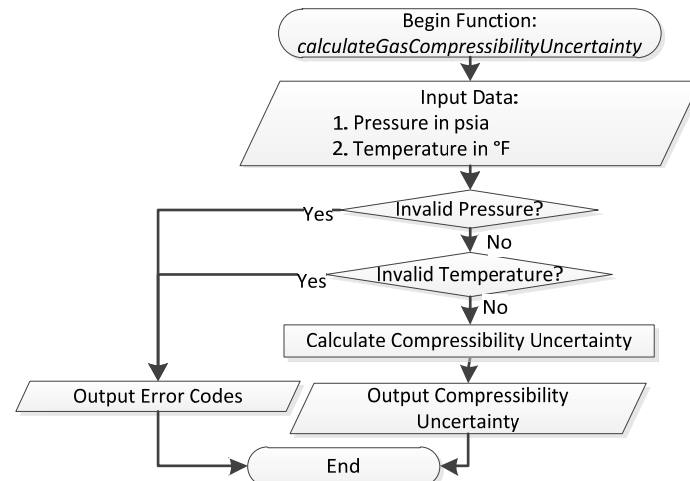


Figure 3.22. Function *calculateGasCompressibilityUncertainty* Flowchart
This function calculates the gas compressibility uncertainty from a plot provided in Figure 1 of AGA Report No. 8.

3.7.4 Gas Density Function

The DLL contains the function *calculateRealGasDensity*, which calculates gas density from Equation 9 in subsection 3.3.3.5. Figure 3.23 provides a flowchart and required inputs for this function.

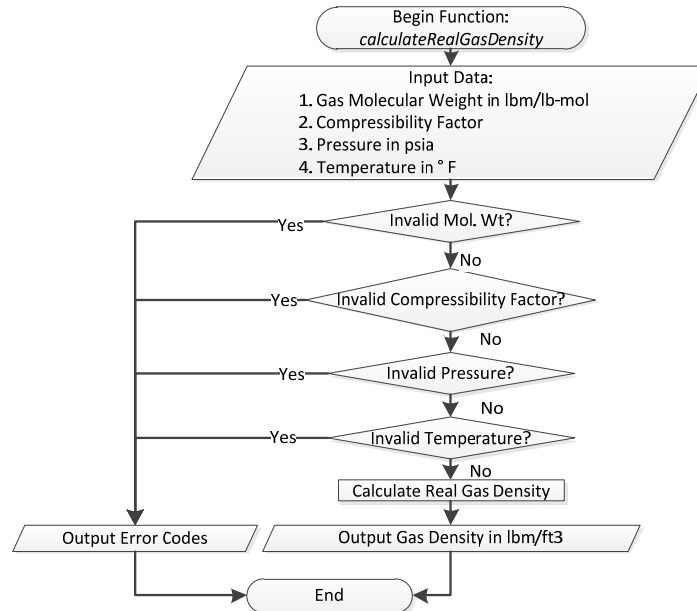


Figure 3.23. Function calculateGasDensity Flowchart

This function calculates the real gas density from the gas equation of state.

4. REFERENCES

1. American Gas Association, AGA Report No. 9, “Measurement of Gas by Multipath Ultrasonic Meters,” Second Edition, April 2007.
2. American Gas Association, AGA Report No. 10, “Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases,” June 2003.
3. American Gas Association, AGA Report No. 11, “Measurement of Natural Gas by Coriolis Meter,” ballot draft, March 2011.
4. American Petroleum Institute, API 14.3, “Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1 – General Equations and Uncertainty Guidelines,” Third Edition, October 1990.
5. American Petroleum Institute, API 14.3, “Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 3 – Natural Gas Applications,” Second Edition, June 2003.
6. American Petroleum Institute, API 14.3, “Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 4 – Background, Development, Implementation Procedure, and Subroutine Documentation for Empirical Flange-Tapped Discharge Coefficient Equation,” Third Edition, November 2003.
7. American Petroleum Institute, API 14.2, “Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases,” Second Edition, Second Printing, 1994.
8. American Petroleum Institute (API), “Manual of Petroleum Measurement Standards, Chapter 5 – Metering, Section 6 – Measurement of Liquid Hydrocarbons by Coriolis Meters,” 1st Edition – October 2002, Reaffirmed – March 2008.
9. Figliola, R. S., Beasley, D. E., “Theory and Design for Mechanical Measurements,” Third Edition, March 2000.

APPENDIX A

Function Error Codes

FUNCTION ERROR CODES

The functions in the DLL will output certain error codes when provided with invalid values as function inputs. Use Table A.1 below to help diagnose error codes output from functions.

Table A.1. C++ Function Error Codes

This table provides the user with Error Code descriptions should a particular function be given invalid inputs. The probable causes are provided for each Error Code.

ERROR CODE	PROBABLE CAUSE(S)
-1	Attempted to take the square root of a negative number.
-2	The orifice tube (pipe) diameter is smaller than the orifice diameter, less than or equal to zero, or equal to the orifice diameter.
-3	The orifice diameter is larger than the tube diameter or less than or equal to zero.
-4	The orifice Reynolds number is negative or zero.
-5	The orifice differential pressure is negative, zero, out of range for the correlation, or greater than the flowing pressure.
-6	The pressure is negative, zero, out of range for the correlation, or less than the meter differential pressure.
-7	The temperature is less than absolute zero or out of range for the correlation.
-8	The isentropic exponent (ratio of specific heats) is negative or equal to zero.
-9	The diameter entered in the Reynolds number function is negative or zero.
-10	The fluid viscosity is negative or zero.
-11	The fluid density is negative or zero.
-12	Maximum iterations have been reached in the determination for C_d .
-13	The gas relative density is negative or zero.
-14	The base or flowing gas compressibility factor is negative or zero.
-15	The orifice expansion factor is negative or zero.

APPENDIX B

Table of C++ Functions in the DLL

TABLE OF C++ FUNCTIONS IN THE DLL

FUNCTION NAME	INPUTS	OUTPUTS
<i>calculateGasUltrasonicUncertainty</i>	1. Uncorrected Volume Flow Rate percent Uncertainty as type Double¹ 2. Measured Pressure percent Uncertainty as type Double 3. Measured Temperature percent Uncertainty as type Double 4. Flow Compressibility percent Uncertainty as type Double 5. Base Compressibility percent Uncertainty as type Double	Returns the overall gas ultrasonic base volumetric flow percent uncertainty as type Double .
<i>calculateLiqUltrasonicUncertainty</i>	1. Uncorrected Volume Flow Rate percent Uncertainty as type Double 2. Flow Liquid Density percent Uncertainty as type Double 3. Base Liquid Density percent Uncertainty as type Double	Returns the overall liquid ultrasonic base volumetric flow percent uncertainty as type Double .
<i>calculateLiqCoriolisUncertainty</i>	1. Mass Flow Rate Percent Uncertainty as type Double 2. Pressure Effect Compensation Factor percent Uncertainty as type Double 3. Base Liquid Density percent Uncertainty as type Double	Returns the overall liquid Coriolis volumetric flow percent uncertainty as type Double. Returns the overall liquid Coriolis mass flow percent uncertainty as type Double if the base density uncertainty is set to 0.0.
<i>calculateGasCoriolisUncertainty</i>	1. Mass Flow Rate percent Uncertainty as type Double 2. Pressure Effect Compensation Factor percent Uncertainty as type Double 3. Gas Molecular Weight percent Uncertainty as type Double 4. Base Compressibility Percent Uncertainty as type Double	Returns the overall gas Coriolis volumetric flow percent uncertainty as type Double. Returns the overall gas Coriolis mass flow percent uncertainty as type Double if the gas molecular weight uncertainty and base compressibility uncertainty are set to 0.0.

¹ The phrase, “as type Double,” refers to the variable type associated with the argument for the function declaration in the source code. A variable of type double in C++ is a double precision floating point number with size 8 bytes (approximately 15 digits).

FUNCTION NAME	INPUTS	OUTPUTS
<i>calculateGasOrificeUncertainty</i>	1. Tube Diameter in Inches as type Double 2. Tube Coefficient of Linear Expansion in in/in-°F as type Double 3. Tube Diameter Percent Uncertainty as type Double 4. Orifice Diameter in Inches as type Double 5. Orifice Coefficient of Linear Expansion in in/in-°F as type Double 6. Orifice Diameter Percent Uncertainty as type Double 7. Differential Pressure Across the Meter in Inches of Water (60°F) as type Double 8. Differential Pressure Percent Uncertainty as type Double 9. Measured Pressure in psia as type Double 10. Measured Pressure percent uncertainty as type Double 11. Measured Temperature in °F as type Double 12. Measured Temperature Uncertainty as type Double 13. Gas Molecular Weight in lbm/lb-mol as type Double 14. Gas Molecular Weight Percent Uncertainty as type Double 15. Gas Flow Compressibility Factor as type Double 16. Gas Flow Compressibility Factor Percent Uncertainty As Double 17. Gas Viscosity in cP as type Double 18. Isentropic Exponent as type Double	Returns the overall orifice mass flow percent uncertainty as type Double for gas flows. This is the main orifice uncertainty function for gas flows and assumes real gas calculations. This code will calculate the API compressibility factor uncertainty if a negative value is entered for the flow compressibility factor uncertainty.
<i>calculateGasOrificeVolUncertainty</i>	1. Orifice Mass Flow Rate Percent Uncertainty as type Double 2. Gas Molecular Weight Percent Uncertainty as type Double 3. Base Compressibility Uncertainty as type Double	Returns the overall volumetric uncertainty associated with orifice gas flows as type Double. This code will calculate the API compressibility factor uncertainty if a negative value is entered for the base compressibility factor uncertainty.

FUNCTION NAME	INPUTS	OUTPUTS
<i>calculateGasOrificeUncertaintyFromDensity</i>	1. Tube Diameter in Inches as type Double 2. Tube Coefficient of Linear Expansion in in/in-°F as type Double 3. Tube Diameter Percent Uncertainty as type Double 4. Orifice Diameter in Inches as type Double 5. Orifice Coefficient of Linear Expansion in in/in-°F as type Double 6. Orifice Diameter Percent Uncertainty as type Double 7. Differential Pressure Across the Meter in Inches of Water (60°F) as type Double 8. Differential Pressure Percent Uncertainty as type Double 9. Measured Pressure in psia as type Double 10. Measured Temperature in °F as type Double 11. Gas Flowing Density in lb_m/ft^3 as type Double 12. Gas Flowing Density Percent Uncertainty as type Double 13. Gas Viscosity in cP as type Double 14. Isentropic Exponent as type Double	Returns the overall orifice mass flow percent uncertainty as type Double for gas flows. This is the main orifice uncertainty function for gas flows and assumes real gas calculations. This code will calculate the API compressibility factor uncertainties if negative values are entered for the base or flow compressibility factor uncertainties.
<i>calculateLiqOrificeUncertainty</i>	1. Tube Diameter in Inches as type Double 2. Tube Diameter Percent Uncertainty as type Double 3. Orifice Diameter in Inches as type Double 4. Orifice Diameter Percent Uncertainty as type Double 5. Differential Pressure Across the Meter in Inches of Water (60°F) as type Double 6. Differential Pressure Percent Uncertainty as type Double 7. Flowing Liquid Density in lb_m/ft^3 as type Double 8. Flowing Liquid Density Uncertainty as type Double 9. Base Liquid Density Uncertainty as type Double - Liquid Viscosity in cP as type Double	Returns the overall orifice mass and volumetric flow uncertainty for liquid flow as type Double. This is the main orifice uncertainty function for liquid flows. This function will return the orifice mass flow uncertainty if the base liquid uncertainty parameter is set to 0.0.
<i>calculateOrificeVolUncertainty</i>	1. Orifice Mass Flow Rate Percent Uncertainty as type Double 2. Base Density Percent Uncertainty as type Double	Returns the overall volumetric uncertainty associated with orifice flows as type Double. This function can be used with gas and liquid flows if the gas base density uncertainty is known.

FUNCTION NAME	INPUTS	OUTPUTS
<i>calculateRe</i>	1. Mass flow in lb_m/s as type Double 2. Viscosity in cP as type Double 3. Diameter in Inches as type Double	Returns the Reynolds number from mass flow as type Double .
<i>calculateMassFlowFromRe</i>	1. Reynolds Number as type Double 2. Viscosity in cP as type Double 3. Diameter in Inches as type Double	Returns the mass flow from the Reynolds number equation as type Double .
<i>calculateGasCompressibilityUncertainty</i>	1. Pressure in psia as type Double 2. Temperature in °F as type Double	Returns the gas compressibility factor uncertainty from API 14.2 as type Double .
<i>calculateCdUncertainty</i>	1. Tube Diameter in Inches as type Double 2. Orifice Diameter in Inches as type Double 3. Reynolds Number as type Double	Returns the orifice discharge coefficient uncertainty as type Double .
<i>calculateVelocityApproachFactor</i>	1. Tube Diameter in Inches as type Double 2. Orifice Diameter in Inches as type Double	Returns the orifice velocity approach factor as type Double .
<i>calculateMassFlowFromOrifice</i>	1. Orifice Discharge Coefficient as type Double 2. Velocity Approach Factor as type Double 3. Expansion Factor as type Double 4. Orifice Diameter as type Double 5. Fluid Density in lb_m/ft³ at Pressure and Temperature as type Double 6. Differential Pressure Across the Meter in Inches of Water (60°F) as type Double	Returns the mass flow from the orifice equation as type Double .
<i>calculateGasExpansionFactor</i>	1. Tube Diameter in Inches as type Double 2. Orifice Diameter in Inches as type Double 3. Differential Pressure Across the Meter in Inches of Water (60°F) as type Double 4. Pressure in psia as type Double 5. Isentropic Exponent as type Double	Returns the orifice gas expansion factor as type Double .
<i>calculateGasExpansionFactorUncertainty</i>	1. Differential Pressure Across the Meter in Inches of Water (60°F) as type Double 2. Pressure in psia as type Double	Returns the orifice gas expansion factor uncertainty as type Double .

FUNCTION NAME	INPUTS	OUTPUTS
<i>calculateOrificeCd</i>	1. Tube Diameter in Inches as type Double 2. Orifice Diameter in Inches as type Double 3. Differential Pressure Across the Meter in Inches of Water (60°F) as type Double 4. Viscosity in cP as type Double 5. Fluid Density in lb_m/ft^3 as type Double 6. Expansion Factor	Returns the orifice discharge coefficient as type Double through an iteration scheme derived in API 14.3, Part 4.
<i>calculateOrificeCdFromRG</i>	1. Tube Diameter in Inches as type Double 2. Orifice Diameter in Inches as type Double 3. Reynolds Number as type Double	Returns the orifice discharge coefficient as type Double if the Reynolds number of the meter is known by using the Reader-Harris/Gallagher equation.
<i>calculateDiameterAtT</i>	1. Diameter in Inches as type Double 2. Material Coefficient of Linear Expansion in in/in-°F as type Double 3. Temperature in °F as type Double	Returns the temperature-corrected diameter as type Double .
<i>calculateBetaRatio</i>	1. Tube Diameter in Inches as type Double 2. Orifice Diameter in Inches as type Double	Returns the orifice beta ratio as type Double .
<i>calculateRealGasDensity</i>	1. Gas Molecular Weight in lbm/lb-mol as type Double 2. Gas Base Compressibility Factor as type Double 3. Gas Flow Compressibility Factor as type Double 4. Measured Pressure in psia as type Double 5. Measured Temperature in °F as type Double	Returns the real gas density as type Double at the pressure and temperature specified.