Catalog No. PR000-22605-R01

Design Guideline for Retrofittable Inline Flow Measurement

MEAS-2-01

Contract PR000-22605

Prepared for the

Measurement Technical Committee

Of

Pipeline Research Council International, Inc.

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Release Date: June 29, 2023

Version	Date of Last Revision	Date of Uploading	Comments
1	May 3, 2023	May 3, 3023	Initial draft
2	June 29, 2023	June 29, 2023	Final report
3			
4			
5			

This research was funded in part under the Department of Transportation, Pipeline and Hazardous Materials Safety Administration's Pipeline Safety Research and Development Program. The views and conclusions contained in this document are those of the authors and should not be interpreted as representing the official policies, either expressed or implied, of the Pipeline and Hazardous Materials Safety Administration, or the U.S. Government.

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Pipeline Research Council International Catalog No. PR000-22605-R01

Abstract

This report describes measurement devices suitable for the retrofit installation of inline flow measurements. Retrofit applications are defined as installations where minimal piping modifications are required and, preferably, the modifications can be done without taking the system out of service. The document includes recommendations and best practices that help minimize error as well as methods to perform in situ calibration of those measurement devices.

Acknowledgments

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Glossary

Actual conditions	A volume of a fluid at the density (as driven by the corresponding pressure and temperature) of the fluid at the actual operating conditions.
Compressibility	A factor indicates the deviation from the ideal gas law at a specific pressure/temperature condition.
Hot tap	A device can be installed without taking the system out of service.
Primary flow element	A device located withing flowing fluid that produces a physical property that can be correlated to the corresponding flow rate, for example a diaphragm, turbine blade, or orifice plate.
Retrofittable	Devices that can be installed with minimal disruption to the operation of an in-service pipeline. Assumes that new taps can be installed on the pipeline but cutting the pipe itself is not required.
Secondary flow elements	Transducers used to measure the physical property produced by the primary flow element as well as the related fluid properties. Examples include frequency/pulse, differential pressure, static pressure, and temperature sensors. Related flow charts/computers are sometimes included in this category.
Standard conditions	A predefined pressure and temperature to convert volumes measured under actual conditions to a basis where the volumes can be compared under like

(standard) conditions. As an example, a standard cubic foot can be defined as the amount of a gaseous fluid occupying a volume of one cubic foot at 60 °F and at a pressure of 14.73 psia.

List of Acronyms

DP	Differential pressure
HART	Highway addressable remote transducer digital communication protocol

List of Nomenclature

C_d	Meter flow coefficient
f	A frequency or pulse rate generated by the meter
F_p	Pressure correction factor
F_t	Temperature correction factor
P_a	Local atmospheric pressure
P_b	Base pressure used for the standard conditions
P_g	Gauge pressure of the fluid
Q_s	Standard flow rate
Sg	Specific gravity of a gaseous fluid relative to air
T_b	Base temperature for the standard conditions
T_f	Flowing temperature of the fluid
Z	Gas compressibility

1 Executive Summary

This document provides a guideline of the types of technologies that are suitable for the purposes of installing inline flow measurement on gas or liquid pipeline systems. Retrofittable technologies are limited to those devices that can be installed with minimal disruption to the operation of an in-service pipeline. The technologies identified can be installed without a cut-out of the pipeline and fall under three broad categories:

- Technologies that do not require any pipeline outage,
- Technologies that can be installed on a live pipeline using hot tapping or similar approaches, and
- Technologies that can be installed in segments where a section pipeline can be isolated, for example, installing an orifice plate between existing flanges within a compressor station yard.
- The installation of inline flow meters can be beneficial for multiple operational purposes including enhancing the performance of leak detection methods, the utilization and performance optimization of pump/compression equipment, and assisting centralized operational control.

This document will not provide all of the specific details needed to determine the best technology for a specific application, for those purposes the reader should refer to PR-363-21601-R01 Flow Sensors for Continuous Equipment Monitoring (1) which includes a selection guidance tool.

The target audience for this document is design engineers and measurement specialists. Consideridation should be given for incorporating portions this document or incorporation by reference into the design standards or specifications of pipeline operating companies.

2 Introduction

For operational purposes, it is advantageous to install inline flow measurement on both gas and liquid pipeline systems. Examples include:

- Flow measurement for the purposes of control, for example:
- Limiting the flow rate in a section of pipeline to minimize flow induced vibrations.
- Adding recycle flow to keep centrifugal compressors from surging.
- Controlling the flow into or out of individual wells on a storage field.
- Controlling the amount of odorant injected into a pipeline.
- Segmenting large pipeline systems into smaller segments for the purposes of identifying sources of lost and unaccounted.

In many cases, the need to add additional inline flow measurement occurs after a pipeline is placed into service. The ability to install additional inline flow measurement with minimal disruption to the operation of the pipeline is usually the preferred approach provided that the corresponding measurement has some degree of reliability and repeatability. There is also a preference that this measurement be relatively low in cost.

It is presumed that inline flow meters will not be flow calibrated and the flow rates can be calculated based on flow factors provided by the equipment manufacture or by using standard equations. Alternatively, the flow factors can sometimes be reverse calculated based on known flows in other sections of the pipeline system.

This report outlines some of the more common approaches for installing inline flow meters and outlines some of the related strengths and weaknesses of each meter. For the purposes of the applications described, the retrofittable meters are expected to be relatively repeatable but not necessarily accurate. The accuracy can be enhanced by utilizing system flow calibration methods that will be described in a separate report produced under this project. For most of the technologies discussed herein, flow equations exist that will provide flow estimates in the range of ±10% with most cases being more accurate than that. This document includes a matrix in the recommendations section that provides more details.

3 Retrofittable Flow Sensors

The measurement devices included in this document were selected from a wide range of flow measurement devices; of those, a subset was identified that are suitable for inline flow measurement in retrofit applications. The author has had experience in using all the devices identified. and has included information on the advantages and potential pitfalls in the use of most of these meters. The measurement devises described are a very narrow subset of all the potential measurement devices possible because of the limitations necessary to be installed in retrofit conditions. These include:

- Must be able to be installed with no or minimal disruption to the operation of the pipeline.
- Must be highly reliable.
- Must allow for safe operation.
- Must be suitable for operation in electrical hazardous areas.

The measured flow should be repeatable but is not likely to be flow calibrated. Statistical methods may be required to ‘calibrate’ the meter.

Flow sensors fall under three broad categories:

- Sensors that measure the velocity of the gas directly and infer the volume flow based on the corresponding area of the pipe. The corresponding mass flow rate is inferred from the volume flow rate corrected by fluid density which requires information on fluid composition and the corresponding operating pressure and temperature. These will be referred to as velocity flow sensors.
- Sensors that infer the velocity of the gas based on a differential pressure (DP) across a flow restriction. Using the same methods as velocity sensors, volume and mass flow can then be calculated. These will be referred to as differential pressure flow sensors.
- Sensors that infer or directly measure a mass flow rate. The corresponding volume flow rate and velocity can then be calculated with corrections based on the fluid density. These will be referred to as mass flow sensors.

There are many types of flow sensors that fall under these categories. The subset of these sensors that are considered to be suitable for retrofit applications include:

- Velocity:
  - Clamp-on ultrasonic flow meter
  - Insertion ultrasonic
  - Sonar flow meter
  - Insertion turbine flow meter
  - Insertion vortex flow meter
- Differential pressure:
  - Orifice plate
  - Averaging pitot tube
  - Elbow flow meter
  - Eye of the Impeller
  - Other piping flow restrictions
  - Control valve
- Mass:
  - Insertion thermal mass flow meter

For descriptions and additional detail on these meters, please see Retrofittable Flow Sensors.

4 Conclusions & Overall Recommendations

4.1 Special Design Considerations for Retrofit Measurement

4.1.1 General

General guidelines for the design and installation of retrofit flow sensors:

- Follow any specific guidelines or standards a recommended by the manufacture.
- Each application is likely to require unique design considerations, do not expect a sensor or an associated design to be applicable all applications.
- Gather the information necessary to make informed decisions on the design and safe installation/operation of the equipment including pipe yield strength, wall thickness, diameter, design factor, maximum operating pressure, temperature ranges, flow velocity range, and fluid density range.
- Assess the relative importance of the applicability, accuracy, reliability, repeatability, installation & maintenance, and costs.

4.1.2 Insertion Designs

Where the piping is tapped to allow a meter to be inserted into the piping, the design must include an analysis to determine if additional reinforcement (e.g., a saddle pad) is necessary to account for the material removed for the tap. ASME B31.3 (2) is one standard for calculating area reinforcement requirements.

Insertion designs, especially if the meter is designed to be inserted or removed while under pressure, tend to extend well above the pipeline. This cantilevered mass can result in situations where the meter can vibrate excessively. Avoid installing meters of this design in locations where piping vibrations and/or pressure pulsations are likely or expected (e.g., close to reciprocating compressors).

Insertion meters can also be subject to vortex shedding induced vibrations. Check with the instrument designer for specific design considerations to minimize this issue. For example, some averaging pitot tube designs include supports on the opposite end of the pipe to prevent or minimize the movement of that end of the instrument.

4.1.3 Wafer Designs

Wafer type meters are intended to be installed between an existing set of flanges and generally require very little physical spacing for installation. However, they are only suited in retrofit applications where the original flanges were installed with a spacer to accommodate a future installation of a wafer type device. In situations where a suitable pair of flanges exist but they were not installed with a spacer to accommodate a wafer style meter, one flange can be cut out and a new flange installed with the necessary spacing with minimal piping modifications but technically does not fit the definition of retrofittable measurement as defined in this document.

If piping modifications are being considered to accommodate wafer type meters, consideration should be given to assess if there is sufficient spacing to accommodate a full sized ultrasonic, turbine, or Coriolis meter because of their higher accuracy albeit generally at a higher capital cost.

4.1.4 Minimizing Upstream Disturbances

If possible, install inline measurement where there is a large amount (10 to 30 diameters) of straight run piping upstream of the primary flow element. This will help assure that there is a uniform flow profile entering the meter. The length of straight run piping can be reduced if flow conditioners are used. The exception would be for the case where a flow control valve is used as the primary flow element as the flow conditions are dominated by the constricted flow through the valve port area.

Some meters also require straight run piping downstream of the meter.

4.1.5 Small Diameter Piping

When valves are designed/installed for future use as pressure taps, it is important to minimize the potential for fatigue of small diameter piping between the carrier pipe and the valve. (3) This is best achieved by:

- Use welded connections rather than threaded connections if possible.
- When threaded connections cannot be avoided:
- Use rolled rather than cut threads.
- Use extra strong pipe nipples.
- Use the shortest possible length of pipe between the valve and the carrier pipe.
- Avoid installation in areas where vibrations or pulsations exist.

4.2 Differential Pressure Measurement

When installing measurement that relies on DP measurement, the layout of the gauge lines is important. The gauge lines can cause distortions in the measurement if operating in areas where pulsations in the fluid pressure are likely. The length of the gauge line will determine the natural resonance frequency of the gauge line which, if coincident with the frequency of the pulsation, will cause significant measurement errors (gauge line distortion and square root error). (4) (5) (6)

Care must be made with the layout of gauge lines to avoid trapping of liquids in gas applications (e.g., install the pressure transmitter above the pipeline pressure taps without loops or bends where liquids can accumulate). Likewise, locations of gas accumulation should be avoided for liquid measurement applications.

Generally, the shortest gauge lines possible should be used. In some cases, a valving manifold can be directly mounted between the meter and the measurement transducer thereby eliminating the gauge lines altogether.

4.3 Process Transmitters

In addition to a primary flow element, secondary flow elements are necessary to determine the flow rate. Commonly, the measurement of pressure and temperature are required to perform density corrections. For DP type primary flow elements, obviously DP measurement is also required. For velocity type meters, an input is needed to represent the flow velocity; this is most commonly provided as a pulse signal.

In some cases where multiple meter runs are installed in parallel, there may be a single static pressure and temperature measurement that is used for all meter runs at the facility. This is generally acceptable but may result in small errors on very large facilities where the static pressure losses in the header are significant such that the static pressure and/or temperature are significantly different between the meter runs.

4.3.1 <u>Conventional Transducers</u>

It is very common than secondary flow elements include individual sensors to measure each individual parameter. Some examples are shown in Figure 1.

Figure 1 – Endress+Hauser Cerabar static pressure, Deltabar differential pressure transmitter, and iTemp temperature transmitters (courtesy of Endress+Hauser)

4.3.2 Multivariant Transducers

Most of the flow measurement devices outlined in this document require the measurement of pressure and temperature to perform density corrections. For DP type primary flow elements, obviously DP measurement is also required.

Many manufactures of transmitters offer multivariant transmitters that can measure pressure, temperature, and/or DP. Their usage is commonly less expensive than purchasing individual transmitters to perform the same function. Furthermore, they commonly include the ability to perform some flow calculations within the transmitter. The transmittal of calculated flow information commonly requires a digital communications protocol, for example, highway addressable remote transducer (HART) protocol.

Figure 2 – Rosemount 3051S Multivariable transmitter with integral valve manifold (courtesy of Emerson)

4.3.3 Temperature Measurement for Retrofit Applications

For custody transfer measurement, thermowells are typically installed into the piping. This can be difficult to do in many retrofit applications. Temperature from another source that is relatively nearby can be used if it is reliable (for example, a suction temperature measurement on a compressor unit could be used provided the transmitter reliably measures the temperature even when the compressor is shut down).

Where an alternate temperature source is not available, measuring the external surface temperature of the piping is adequate provided that the adjacent piping is insulated to protect from solar radiation and ambient heat transfer effects. Surface temperatures can be measured using conventional or multivariant temperature transmitters using a very short temperature probe mounted inside a pipe nipple screwed into a half coupling welded onto the pipe (but not tapped into the pipe). The temperature probe should protrude as close to the pipe as possible, even to the point of contact with the external surface of the pipe. The nipple should be filled with thermal conductive paste and thermally insulated. The nipple should be as short as possible and follow the Small Diameter Piping recommendations noted above.

4.4 Designing for Future Installation

When designing new facilities, it is recommended to leave space accommodations for future inline flow meters. These accommodations should be noted on the drawings (‘space reserved for a future inline flow meter’). Examples of accommodations include:

Installing spacers between flanges for the future installation of inline flow measurement, especially where the piping can be isolated. Examples:

- An orifice plate.
- A wafer vortex meter.
- Leaving straight runs of piping, preferably above grade.
- Locating those piping sections in areas where they can readily be isolated for the installation of a meter.
- Installing pressure aps and the associated instrumentation valves.

4.5 In situ Calibration

Retrofit installations by definition preclude the capability to calibrate a meter and the associated piping prior to installation. Many retrofit meters (such as the ultrasonic and orifice meters) will have empirical calculations that will reasonably approximate the flow through the pipeline. Other methods (eye of the impeller) will not have reliable means to produce a flow coefficient.

In those situations, the flow coefficient needs to be calculated using system calibration methods as outlined in System Calibration.

4.6 Summary Applicability

Table 1 below provides a summary of the applicability of different types of meter technologies and their capabilities.

Table 1 – Summary of meter applicability

Meter Type	Measurement Type	Calculation Type	Fluids	Hot tap capable
Clamp-on ultrasonic	Velocity	Direct/hybrid	Gas and many liquids	Yes
Insertion ultrasonic	Velocity	Direct/hybrid	Gas and many liquids	Generally, no
Sonar meter	Velocity	Indirect	Liquids	No
Insertion turbine	Velocity	Direct	Both gas and liquids	Generally, no
Insertion vortex	Velocity	Direct	Both gas and liquids	Generally, no
Orifice plate	DP	Direct	Both gas and liquids	No
Averaging pitot tube	DP	Direct	Both gas and liquids	Generally, no
Elbow measurement	DP	Hybrid	Both gas and liquids	Yes
Eye of the impeller	DP	Indirect	Both gas and liquids	No
Other piping flow restrictions	DP	Indirect	Both gas and liquids	No
Control valve	DP	Direct	Both	Yes
Insertion thermal mass	Mass	Direct/hybrid	Gas	Generally, no

For meters identified as having ‘generally, no’ for the hot tap capability, some manufactures make some designs that are capable of hot tap installation, but most designs of this meter type are not capable of hot tap installation. For the calculation type, see Table 2 for further details.

Table 2 – Flow calculation type descriptions

Calculation Type	Description
Direct	A flow rate can be determined specifically given the configuration and measurement parameters.
Hybrid	A flow rate can be calculated based on a general form of an equation, but back

	calculation of a flow coefficient or other key calculation parameter is recommended
Indirect	A flow rate can be calculated based on a general form of an equation, but a flow coefficient or other key calculation parameter must be back calculated from reference data.

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Appendix A. Retrofittable Flow Sensors

A.1. Velocity Based

Velocity based meters measure the gas velocity in the pipeline and calculate the volume flow rate based on the corresponding area of the piping. For gas applications and some liquid applications, pressure and temperature measurements are also required to convert the flow rate to standard and/or mass flow rate conditions.

A.1.1 <u>Clamp-on Ultrasonic Meters</u>

Clamp-on ultrasonic flow meters are installed externally to the pipeline and use signals that transmit through the wall of the pipe and are picked up via another ultrasonic sensor listening for the signal. Changes in the timing between the signals traveling upstream vs. the timing of the signal as it flows downstream are used to determine the velocity of the gas. An example of a clamp-on ultrasonic meter can be seen in Figure 3. These meters can be installed without tapping into the piping provided that pressure and temperature measurements are already available if they are needed for density correction.

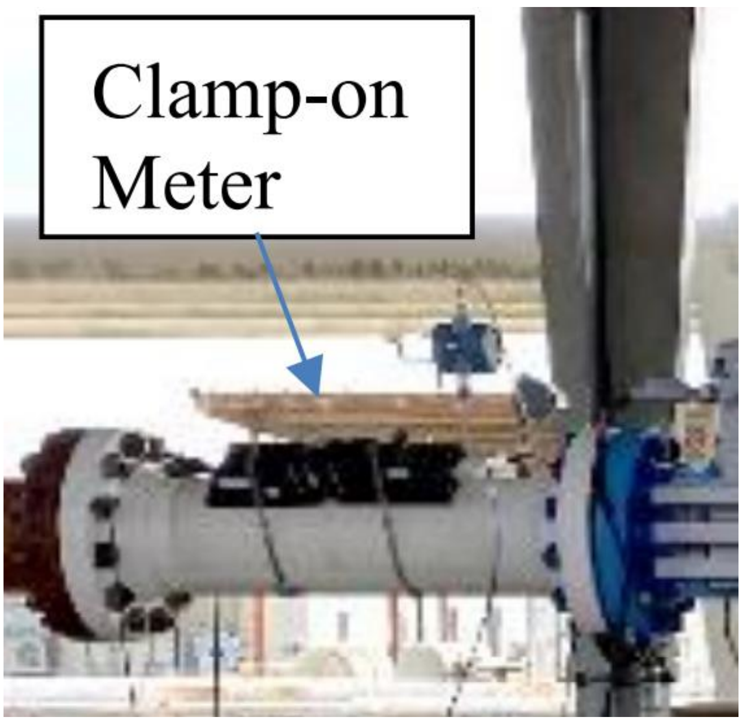

Figure 3 – Clamp-on ultrasonic meter as installed

The flow profile of the fluid inside the piping can affect the accuracy and repeatability of these meters; straight run piping upstream of the installation of a clamp-on ultrasonic meter is recommended to be at least 15 pipe diameters. These devices are limited in the minimum velocity that can be measured and should generally operate in conditions where the fluid velocity is 2 m/s (6 ft/s) or higher.

Some flow laboratory generated data (7) has shown that the repeatability of a clamp-on ultrasonic meter has some scatter. The scatter was higher as the gas velocity increased. The reason for the scatter was not determined (see Figure 4 – Repeatability of a clamp-on ultrasonic meter). Likewise, some crosstalk may exist between ultrasonic transducers. (8)

The fluid density within the pipe needs to be high enough such that acoustic signal is transmitted through the fluid but not so high that the signal cannot penetrate the fluid and reach the listening sensor. Ultrasonic meters can be used to measure bi-directional flows if there is sufficient straight run piping on both sides of the meter.

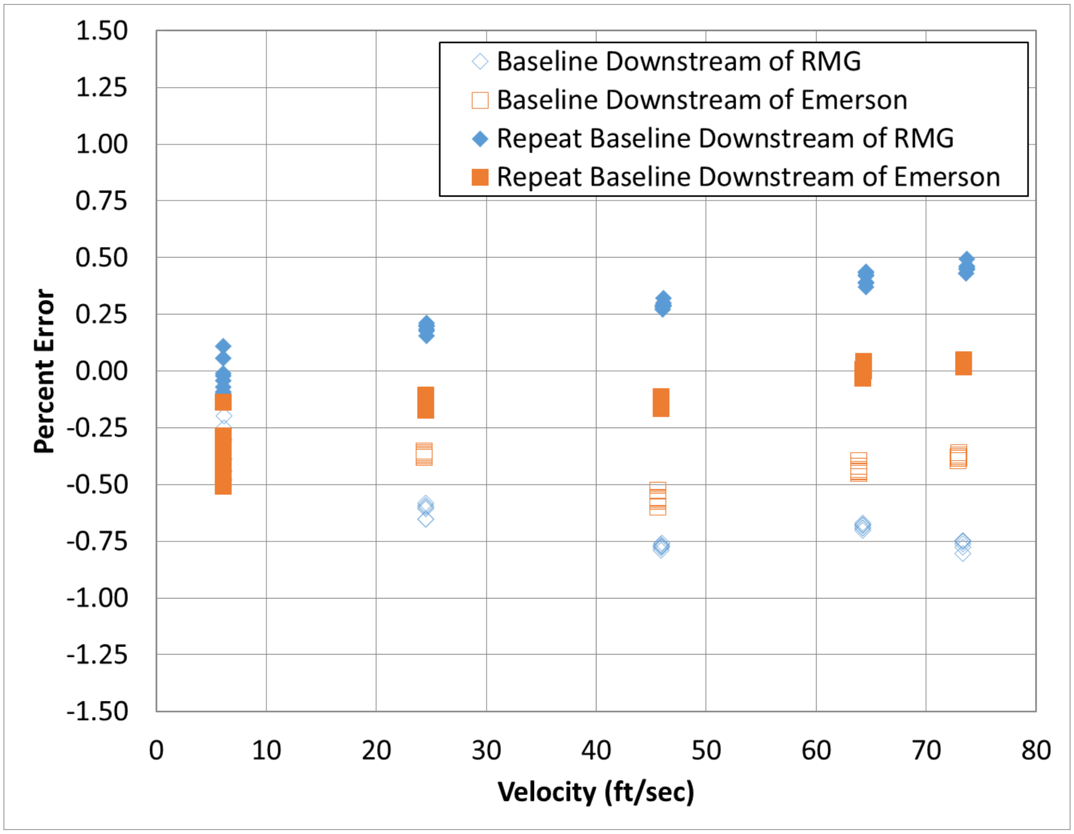

Figure 4 – Repeatability of a clamp-on ultrasonic meter

Clamp-on ultrasonic may not be suitable in all locations. For example, some meters are known to have difficulties transmitting signals through heavy wall piping; low density fluids, and locations where there is a large amount of mechanical noise (such as close to reciprocating compressors) may not be suitable. These meters are generally not suitable for mixed phase flow measurement.

Manufactures of clamp-on ultrasonic meters include:[1]

- Endress+Hauser
- Siemens

[1] Here and throughout the document, where specific suppliers of equipment are discussed, the information is supplied as is. PRCI is not recommending or endorsing any of these products, rather, PRCI is simply supping information on some of the companies that provide these types of meters.

- Flexim
- Keyence
- Badger
- Panametrics
- Onicon
- Honeywell

Figure 5 – Endress+Hauser Proline Prosonic P 500 clamp-on ultrasonic meter (courtesy of Endress+Hauser)

See Clamp-On Ultrasonic Flow Meters for Oil and Gas Flow Meter Verification Clamp-On Meter Installation Guidelines (9) for more information.

A.1.2 <u>Insertion Ultrasonic</u>

Insertion ultrasonic flow meters function similarly to clamp-on ultrasonics except the ultrasonic transducers are inserted through taps in the pipe and into fluid. mounting s to enable the probe to be inserted into the pipe and in direct contact with the fluid. This installation tends to result in measurement that is more stable, accurate, and repeatable than a clamp-on ultrasonic meters.

Insertion ultrasonic meters are suitable for gas and most liquids provided the fluid is within the density range as specified by the meter manufacture. The straight run piping requirements are akin to those of clamp-on ultrasonic meters.

Manufactures include:

- SICK
- Teledyne ISCO
- R&B Instruments
- Manas Microsystems

Figure 6 – SICK FLOWSIC300 insertion ultrasonic meter (courtesy of SICK)

A.1.3 *Sonar Meter*

Like clamp-on ultrasonic meters, sonar meters are meters mounted externally to the pipeline that measure flow by monitoring the acoustics generated by the product flow inside the pipeline. Multiple acoustic sensors are used combined with processing methods to calculate the speed that flow eddies are moving withing the pipeline. These meters can be installed without tapping into the piping provided that pressure and temperature measurements are already available if they are needed for density correction.

Because the technology relies on sensing flow eddies migrate within the pipeline, these meters require sufficiently high flow velocity to produce those eddies. These meters can work in mixed phase flow.

Manufactures include:

- Expro
- CiDRA

Typically, vendor support is required to install and commission these sensors. A minimum of 20 diameters of straight run pipe length is recommended upstream of the measurement sensor and 10 diameters downstream. These sensors are susceptible to interference from piping vibration/noise.

A.1.4 __Insertion Turbine Meter__

Like the name implies, insertion turbine meters are small rotary turbine meters installed at the end of an insertion stem. They measure a point velocity in the fluid stream and as such the accuracy is dependent on how close the velocity at the insertion point is to the average velocity of the fluid. A good rule of thumb is that the meter should be inserted to 1/3 of the diameter of the pipeline where the flow profile is close to the average velocity across the entire flow range. They are suitable for a large range of piping diameters, typically larger than 6” (nominally 150 mm) piping. The insertion length should be designed such that the sensor tip is located approximately 1/3 of the pipe diameter where the profile approximates the average velocity.

Insertion turbine meters are mechanical devices and have the potential that the turbine wheel can be damaged, bearings fail, or the wheel can fall off. Care must be taken such that vortex shedding forces do not result fatigue failure to either the insertion meter or the corresponding mounting components.

At least 10 diameters of straight run piping upstream of the meter and 3 diameters downstream of the meter are recommended. Turbine meters tend to have a higher uncertainty when operating in the laminar flow regime. (10)

Manufactures include:

- Onicon
- Hoffer Flow Controls
- Flow Metrics
- Turbo-Flo
- GPI Meters

A.1.5 __Insertion Vortex Meter__

Insertion vortex meters measure the fluid velocity at a point in the pipe using the von Kármán effect. As flow passes a blunt body, a repeating pattern of flow vortices are generated. The meter measures the frequency of occurrence of the vortices and infers that back to a corresponding flow velocity which, in turn, can be used to calculate the fluid flow rate. These meters can be used in both gas and liquid applications but more commonly in gas. The meters require the flow past the sensor to be turbulent and thus may not be suited for locations where very low flow velocities would be expected (e.g., Reynolds > 10,000). The insertion length should be designed such that the sensor tip is located approximately 1/3 of the pipe diameter where the profile approximates the average velocity.

These meters are relatively robust and repeatable but should have at least 15 diameters of straight run piping upstream of the meter and 3 diameters downstream of the meter. There usage should be avoided if pulsating flow or mechanical piping vibrations are expected. Some designs can be inserted under pressure (hot tap).

Figure 7 – Rosemuont 8800 Wafer vortex flow meter (courtesy of Emerson)

Figure 8 – Endress+Hauser Proline Prowirl D 200 vortex flow meter (courtesy of Endress+Hauser)

Manufactures include:

- Emerson Rosemont
- Endress+Hauser
- EMCO V-Bar
- Spirax Sarco

A.2. Differential Pressure Based

A.2.1 <u>Orifice Plate</u>

Orifice plate meters are one of the most established methods of flow metering. It is suitable for measuring both gas and liquid applications. In some retrofit applications, existing flanges can be spread apart, and an orifice plate installed. Uncalibrated orifice meters can reasonably estimate the flow based on empirical equations.

Orifice meters are sensitive to installation effects. (11). They generally require long lengths of straight piping upstream or the use of flow conditioning elements and some straight piping downstream of the meter. In retrofit applications, it is unlikely that flange taps will be available so most retrofit installations would utilize pipe tap configurations. For more details, see AGA 3 pre 2000 editions. (12) (13) Compact versions are also available that incorporate the flow transmitter directly into the orifice plate. (14)

Orifice plates are commonly beveled. It is important that orifice plate is installed such that the bevel is installed on the downstream side. Beveled orifice plates are not suitable for bidirectional applications.

Flow calculation for orifice plates, including pipe tap orifice runs, can be found in section D.1.

Manufactures include:

- Emerson
- Kelly Instrument Machine, Inc
- Wyatt Engineering

Figure 9 – Emerson Rosemount 1495 orifice plate (courtesy of Emerson)

A.2.2 <u>Averaging Pitot Tube</u>

Averaging pitot tubes measure static and dynamic pressures at multiple points across the cross section of the pipe. They can be used for both gas and liquid fluids. They have good repeatability and can be installed by insertion under pressure (hot tap) but those design can be difficult to use.

Averaging pitot tubes should only be used for clean, single-phase fluids as the pressure holes in the pitot tube can get plugged with debris. Averaging pitot tubes can also be subject to vortex shedding vibrations. They are relatively inexpensive to purchase and are very reliable when used in clean fluids. Empirical equations, with flow coefficients provided by the equipment manufacture, are used to calculate uncalibrated flow rates.

Manufactures include:

- Emerson
- KROHNE
- Endress+Hauser
- VERIS
- SIEMENS
- ABB

Figure 10 – Emerson Rosemount Annubar averaging pitot tube in single mount insertion, wafer, and opposite side support in severe service design. The single mount and wafer designs include an integral valve manifold and the differential pressure transmitter (courtesy of Emerson)

Figure 11 – KROHNE OPTIBAR averaging pitot tube (courtesy of KROHNE)

A.2.3 Elbow Measurement

Elbow measurement is achieved by measuring the DP between the inside radius and outside radius of a 90° elbow. They can be hot taped onto any existing elbow and are applicable to both gas and liquid applications provided that the fluid is clean and in a single phase. The DP is relatively low compared to other DP-based flow meters. While there are some empirical equations that can be used to estimate the flow rate using elbow measurement, the accuracy is very low, and the use of system calibration methods are recommended. Elbow measurement is best utilized where there are minimal obstructions upstream of the elbow for at least 10 diameters of pipe.

Empirical calculations exist to estimate the flow rate through an elbow. However, the accuracy of those equations varies significantly depending on the specific geometry of the elbow and the precise location of the pressure taps. (15) As such, system calibration methods are recommended for these meters.

See D.2 Elbow for Gas Measurement and D.3 Elbow for Liquid Measurement for example code for elbow flow measurement.

A.2.4 Eye of the Impeller

The eye of the impeller utilizes the DP from the suction piping to the center (eye) of an impeller on a centrifugal compressor or pump. The square root of this differential being proportional to the flow rate. The flow coefficient for this method of measurement must be calibrated either using system calibration or back calculated from some other (even if temporary as in the example of a clamp-on ultrasonic) meter.

Obviously, the flow rate is only calculated while the corresponding rotatory equipment is operational. Unlike most other differential flow measurement devices, this technique is relatively insensitive to the length of straight run piping upstream of the meter.

A.2.5 Other Piping Flow Restrictions

Any flow element that produces a significant and predictable pressure drop over a relatively short distance can be used as DP flow measurement device. For example, gas aftercoolers, choke tubes, and gas heaters. The flow element must be sufficiently short such that a DP transmitter can be reasonably installed.

Generally, the flow coefficients for these applications are empirically generated or estimated based on specification supplied by the manufacture. Care must be given to using these components when fouling would be expected. For example, gas aftercoolers that use acceleration rods (and therefore have very small passages) in conditions where compressor oil and/or dust is expected in the gas can lead to plugging in the cooler tubes which will alter the flow calculation accuracy.

It is common that flow elements that produce high pressure losses are located within compressor or pump stations. As such, provisions need to be made to ignore the measurement from these elements whenever the station is not operating, and the flow element is bypassed.

A.2.6 *<u>Control Valve</u>*

Control valves, used in either pressure or flow control modes can be used to estimate the flow through a segment of piping. This is applicable to both gas and liquid flows. The process involves:

- Having flow equations for the valve, either as supplied by the valve manufacture or by using industry standards. (16)
- Pressures measured upstream and downstream of the valve.
- Temperature measured upstream of the valve.
- An indicator of how widely open the valve is:
  - Ideally this would be from a position feedback sensor mounted directly to the valve.
  - If a feedback sensor is not available, a control signal being sent to the valve can be used if the controls are calibrated (e.g., 0% output corresponds with the valve being closed, 100% to the valve being fully opened). Note that some valves are reverse acting meaning that 0% output represents that the valve is fully open.
  - Regardless, the flow calculation requires a method that converts either output to or feedback from the valve to a valve position (in either % of travel for linearly actuated valves or degrees open for rotary valves).
- Fluid properties including specific gravity and compressibility (if applicable).
- Having the corresponding flow coefficients as a function of the position of the valve. This is usually provided in tabular format.
- A method to interpolate flow coefficients for operating points between the tabular values.

The uncalibrated flows using this approach are not generally very accurate and system calibration is recommended. This technique has been successfully used for wellhead management in gas storage fields and should be applicable to other applications as well. In general, this method is less accurate when the valve is nearly full open, or when there is negligible pressure difference between the inlet and the outlet of the valve. The method can work in bidirectional flow applications but may require a separate set of valve flow coefficients for the backward flow mode. Note that not all control valves are designed for backward flow.

A.3. Mass Flow Based

A.3.1 <u>Insertion Thermal Mass Meter</u>

Insertion thermal mass meters function based on the heat absorbed by a fluid is proportional to the mass flow rate. They are generally only applicable to gas flow measurement. They can be used in hot tap applications and typically have a wide flow range. The insertion length should be designed such that the sensor tip is located approximately 1/3 of the pipe diameter where the profile approximates the average velocity.

These meters are relatively inexpensive and have a wide turndown in flow range (100:1).

They require around 10 straight pipe diameters upstream and 5 diameters downstream. It is recommended that the meter be laboratory calibrated to the expected fluid unless system calibration is to be utilized.

Manufactures include:

- Endress+Hauser
- Fluid Components International
- Spirax Sarco MTI10/MTL10

Figure 12 – Endress+Hauser Proline t-mass I 300 thermal mass flow meter (courtesy of Endress+Hauser)

Appendix B. System Calibration

System calibration is simply a process used to statistically back calculate a flow coefficient for a meter based upon the coefficient of needed to make the flows of the upstream section of piping match the flows of the downstream section of piping.

As an example, assume an inline meter is installed at a point in the piping system having upstream receipt accumulations totaling 100 and deliveries of 20 in a given period of time and the corresponding piping system downstream of the meter has net receipts of 20 and deliveries of 105. Using the data from the upstream system, the flow through the inline meter would be 100 - 20 = 80. Using the same method to estimate the flow through the inline meter using downstream data, the flow through the meter would be 105 - 20 = 85. Averaging the two flows yields 82.5. Using this number (and corresponding compressibility, temperature, etc. corrections and the general flow equation for the meter, the flow coefficient for the meter can thus be calculated.

Appendix C. General Flow Equation for Gasses

C.1. *Flowing Volume Corrected to Standard Conditions*

The generalized formula to correct a flow rate under actual flow conditions to a reference condition is: (17)

$$Q_S = \frac{F_p\ F_t\ Q_a}{Z} \qquad \text{Eq 1}$$

Where:

Q_s is the standard flow rate (e.g., in thousand standard cubic feet per hour AKA MSCFH),
F_p is the pressure correction factor as defined in Eq 2,
F_t is the temperature correction factor as defined in Eq 3,
Qa is the actual flow rate based on the velocity and density of the product under the actual flowing conditions (e.g., in thousand cubic feet per hour AKA MCFH), and
Z is the compressibility of the gas.

$$F_p = \frac{P_g + P_a}{P_b} \qquad \text{Eq 2}$$

Where:

P_b is the base pressure used for the standard conditions (e.g., 14.73, or sometimes 14.696, psia),
P_g is the gauge pressure of the fluid in the same engineering units as P_b, and
P_a is the local atmospheric pressure in the same engineering units as P_b.

$$F_t = \frac{459.67 + T_b}{459.67 + T_f} \qquad \text{Eq 3}$$

Where:

T_b is temperature at standard conditions in °F, typically 60 °F,
T_f is the flowing temperature of the fluid in °F.[2]

C.2. *Velocity Based*

The generalized formula to calculate gas flow in standard conditions for velocity based devices is:

$$Q_a = C_d\ f \qquad \text{Eq 4}$$

[2] Note that some standards use 460 as the constant in this equation. Note that if the temperature is in °C, the constant in this equation is 274.15.

Where:

C_d is a flow coefficient as defined by the equipment supplier, back calibrated, or derived based on standards. This parameter includes conversion factors to produce the engineering units of interest, and
f is a frequency or pulse rate generated by the meter.

C.3. Differential Pressure Based

The generalized formula to calculate gas flow in standard conditions is:

$$Q_a = C_d \sqrt{\frac{(P_g + P_a)\, P_d}{Z\, Sg}} \qquad \text{Eq 5}$$

Where:

P_d is the differential pressure across the meter and
Sg is the specific gravity of the gaseous fluid relative to air.

C.4. Gas Compressibility

Gas compressibility is calculated using equation of state libraries such as AGA 8 and other methods.

Appendix D. VBA Source Code for Orifice Measurement

D.1. Orifice for Gas Measurement

```
Function OrifCalc(Pipe, Orif, Pf, Pa, Dif, Tf, SG, Z, Pb, Tb, Locn, Tap)
' AGA3 orifice flow measurement in MMSCF/D
' Pipe is inside pipe diameter in inches
' Orif is orifice plate diameter in inches
' Pf is the gas pressure in psig
' Pa is the atmospheric pressure in psia
' Dif is the differential pressure across the orifice plate in "H2O
' Tf is the gas temperature in °F
' SG is the specific gravity of the gas (air = 1.0)
' Z is the compressibility of the gas
' Pb is the pressure base in psia (normally 14.73)
' Tb is the temperature base in °F (normally 60°F)
' Locn is the location of the static pressure, "U" for upstream, "D" for
downstream
' Tap is type of taps, "F" for flange, "P" for pipe

 Diff = Abs(Dif)
 Beta = Orif / Pipe
'*************************************************************************
'                        Calculate Fb factor
'*************************************************************************
 Select Case Tap
 Case "F"  'flange tap
      A23 = ((0.07 + 0.5 / Pipe) - Beta)
          If (A23 > 0!) Then
             A23 = A23 ^ 2.5
          Else: A23 = 0!
          End If
      A34 = (0.5 - Beta)
          If (A34 > 0!) Then
             A34 = A34 ^ 1.5
          Else: A34 = 0!
          End If
      A45 = (Beta - 0.7)
          If (A45 > 0!) Then
             A45 = A45 ^ 2.5
          Else: A45 = 0!
          End If
      A00 = 0.5993 + 0.007 / Pipe
      A11 = (0.364 + 0.076 / Sqr(Pipe)) * Beta ^ 4
      A22 = 0.4 * (1.6 - 1! / Pipe) ^ 5
      A33 = (0.009 + 0.034 / Pipe)
      A44 = (65! / Pipe ^ 2 + 3!)
      Ke = A00 + A11 + (A22 * A23) - (A33 * A34) + (A44 * A45)
      BIGB = 530 / Pipe ^ 0.5
```

```
 Case "P"   'pipe tap
      A00 = 0.5925 + 0.0182 / Pipe
      A11 = (0.44 - 0.06 / Pipe) * Beta ^ 2
      A22 = (0.935 + 0.225 / Pipe) * Beta ^ 5
      A33 = 1.35 * (Beta ^ 14)
      A44 = (0.25 - Beta)
          If (A44 > 0!) Then
             A44 = A44 ^ 2.5
          Else: A44 = 0
          End If
      Ke = A00 + A11 + A22 + A33 + (1.43 / Sqr(Pipe)) * A44
      BIGB = 875 / Pipe + 75!
 End Select
 E = Orif * (830 - 5000 * Beta + 9000 * Beta ^ 2 - 4200 * Beta ^ 3 + BIGB)
 Ko = Ke / (1 + (15 * E / (1000000! * Orif)))
 Fb = 338.178 * (Orif ^ 2) * Ko

 Fpb = 14.73 / Pb
 Ftb = DegR(Tb) / 519.67
 Ttf = (519.67 / DegR(Tf)) ^ 0.5
 Fg = (1 / SG) ^ 0.5
 Fa = 1 + (0.0000185 * (Tf - 68))
 '**********************************************************************
 '                        Calculate Y factor
 '**********************************************************************
 X2 = Diff / (27.707 * (Pf + Pa))
 Y1 = (0.41 + 0.35 * Beta ^ 4) / 1.3
 Y = 1 - Y1 * X2
 If (Locn = "D") Then Y = Y * (1 / (1 - X2)) ^ 0.5
 '***********************************************************************
 '                        Calculate Fpv factor
 '***********************************************************************
 FPV = (1 / Z) ^ 0.5
'**************************** Kcal ****************************************
'                Calculates K for pipe or flange taps
'**************************************************************************
 If Tap = "F" Then  'Flange tap
    k = 0.604 / ((1 - Beta ^ 4) ^ 0.5)
 Else   'Pipe tap
    k = 0.607
    If Beta > 0.1125 Then k = 0.608
    If Beta > 0.1375 Then k = 0.611
    If Beta > 0.1625 Then k = 0.614
    If Beta > 0.1875 Then k = 0.618
    If Beta > 0.2125 Then k = 0.623
    If Beta > 0.2375 Then k = 0.628
    If Beta > 0.2625 Then k = 0.634
    If Beta > 0.2875 Then k = 0.641
    If Beta > 0.3125 Then k = 0.65
```

```
    If Beta > 0.3375 Then k = 0.658
    If Beta > 0.3625 Then k = 0.668
    If Beta > 0.3875 Then k = 0.68
    If Beta > 0.4125 Then k = 0.692
    If Beta > 0.4375 Then k = 0.707
    If Beta > 0.4625 Then k = 0.724
    If Beta > 0.4875 Then k = 0.742
    If Beta > 0.5125 Then k = 0.763
    If Beta > 0.5375 Then k = 0.785
    If Beta > 0.5625 Then k = 0.81
    If Beta > 0.5875 Then k = 0.837
    If Beta > 0.6125 Then k = 0.869
    If Beta > 0.6375 Then k = 0.904
    If Beta > 0.6625 Then k = 0.943
    If Beta > 0.6875 Then k = 0.988
 End If
 B = E / (12835 * Orif * k)
 EXT = ((Pf + Pa) * Diff) ^ 0.5
 Fr = 1 + (B / EXT)
 '*********************************************************************
 '                       Calculate CPRIME & Volume
 '*********************************************************************
  Cprime = Fb * Fr * Y * Fpb * Ftb * Ttf * Fg * FPV * Fa
  If Dif > 0 Then
    OrifCalc = (EXT * Cprime) / 1000000 * 24  'MMSCF/D
  Else
    OrifCalc = (EXT * Cprime) / 1000000 * 24 * -1 'MMSCF/D
  End If
End Function
```

D.2. Elbow for Gas Measurement

```
Function ElbowGas(Pipe, Pf, Dif, Tf, SG, Z, Pb, Tb)' elbow flow measurement
in MMSCF/D
' Pipe is inside pipe diameter in inches
' Pf is the gas pressure in psig
' Dif is the differential pressure across the elbow in "H2O
' Tf is the gas temperature in °F
' SG is the specific gravity of the gas (air = 1.0)
' Z is the compressibility of the gas
' Pb is the pressure base in psia (normally 14.73)
' Tb is the temperature base in °F (normally 60°F)
 Diff = Abs(Dif)
 Fpb = 14.73 / Pb
 Ftb = DegR(Tb) / 519.67
 Fg = (1 / SG) ^ 0.5
 Fa = 1 + (0.0000185 * (Tf - 68))
 FPV = (1 / Z) ^ 0.5
 Fb = 0.1555519 * Pipe ^ 2
```

```
 If Dif > 0 Then
   ElbowGas = Fb * Fpb * Ftb * Fg * Fa * FPV * (Pf * Diff / DegR(Tf)) ^ 0.5
 Else
   ElbowGas = Fb * Fpb * Ftb * Fg * Fa * FPV * (Pf * Diff / DegR(Tf)) ^ 0.5 *
-1
 End If
End Function
```

D.3. *Elbow for Liquid Measurement*

```
Function ElbowLiquid(Pipe, Dif, Dens)
' elbow flow measurement in GPM
' Pipe is inside pipe diameter in inches
' Dif is the differential pressure across the elbow in "H2O
' Dens is the liquid density in Lbm/Ft^3
 Diff = Abs(Dif)
 Fb = 37.5927 * Pipe ^ 2
 If Dif > 0 Then
   ElbowLiquid = Fb * (Diff / Dens) ^ 0.5
 Else
   ElbowLiquid = Fb * (Diff / Dens) ^ 0.5 * -1
 End If
End Function
```

D.4. *Valve Flow for Gas Measurement*

```
Function QValveGCv(Pin, Pout, Pa, Tf, SG, Cv)
' Calculates the flow capacity (gas) of a valve based
' on Cv coefficients. Flow in MSCF/H
'Pin is the valve inlet pressure in psig
'Pout is the valve outlet pressure in psig
'Pa is the local atmospheric pressure in psia
'Tf is the inlet temperature of the gas in °F
'Sg is the specific gravity of the gas (Air = 1.0)
'Cv is the valve sizing coefficient
'
 If Pin > Pout Then  'forward flow
   FlowDir = 1
   P1 = Pin + Pa
   P2 = Pout + Pa
 Else
   FlowDir = -1
   P1 = Pout + Pa
   P2 = Pin + Pa
 End If
 If P2 > P1 / 2 Then
   QValveGCv = 0.061 * Cv * (P2 * (P1 - P2) * 520 / SG / (Tf + 460)) ^ 0.5 *
FlowDir
 Else  'choked flow
```

```
   QValveGCv = 0.0305 * Cv * P1 * (520 / SG / (Tf + 460)) ^ 0.5 * FlowDir
 End If
End Function
```

D.5. Other Functions

```
Function DegR(T)
'   Converts °F to °R
'   T temperature in °F
  DegR = T + 459.67
End Function
```