

Engineering Encyclopedia

Saudi Aramco DeskTop Standards

Determining Appropriate Flow Measurement Devices For Saudi Aramco Applications

Note: The source of the technical material in this volume is the Professional Engineering Development Program (PEDP) of Engineering Services.

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FLOW MEASUREMENT: PURPOSE, TERMINOLOGY AND SYMBOLOGY, INSTRUMENT CATEGORIES, UNITS OF MEASURE, AND HYDRODYNAMIC PRINCIPLES

Flow measurement begins with sound engineering practices that range from the selection of flow measurement devices through the installation, application, and interpretation of the results. This section of the course module introduces the Participant to the following flow measurement topics:

- Purpose of flow measurement
- Terminology and symbology
- General categories of flow instruments
- Units of measure
- Hydrodynamic principles

Purpose of Flow Measurement

Accurate measurement of flow is essential in many process control applications. The measurements are used to monitor and control the flow rates at various Saudi Aramco process facilities. The flow measurement, along with measurements of temperature, pressure, and composition, are used to develop material and energy balances on processes. Also, in some applications, controlling the feed rate in a particular upstream process helps to sustain the efficiency and to minimize waste in downstream processing operations.

The purpose of flow measurement is described under the following topics:

- The importance of flow measurement
- Typical Saudi Aramco flow control loop

Importance of Flow Measurement

Given that oil processing plants require material flows through successive operations, flow measurement is central to oil processing equipment design and operations. Accurate flow measurements are fundamental to:

- Conversion and yield determinations
- Material balances in separation processes
- Pumps and compressor operations
- Custody transfer operations

One can observe from the previous list that flow measurement device selection becomes a major part of process plant design and operations.

Typical Saudi Aramco Flow Control Loop

A typical flow control loop is shown in Figure 1. The flow element (FE) is an orifice plate, which is the most common flow measuring device.

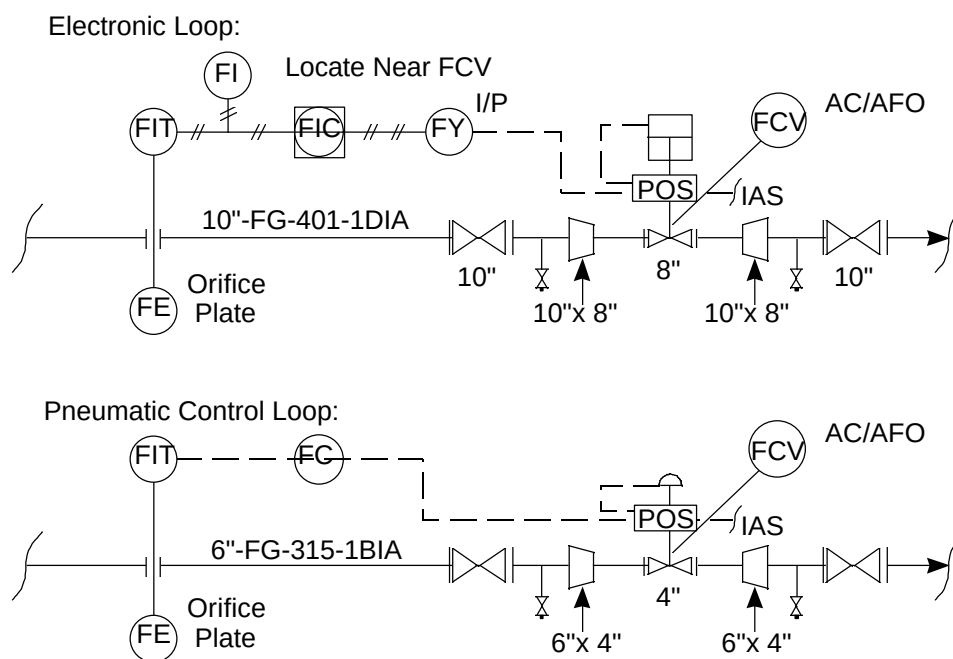


Figure 1: Typical Flow Control Loop

Terminology and Symbology

The terminology and symbology used in flow measurement are described in the following discussion regarding

- Flowmeter definition
- Typical examples
- Drawing symbols

Flowmeter Definition

A flowmeter is defined as “A device that measures the rate of flow or quantity of a moving fluid in an open or closed conduit. It usually consists of a primary device and a secondary device.” (Source: “Process Measurement and Analysis,” Page 16, Bela Liptak)

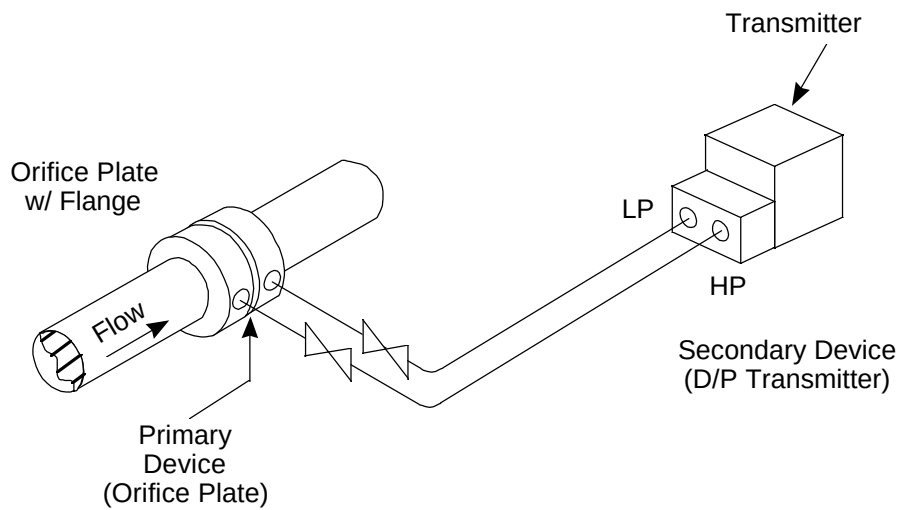
Primary Device Definition – A primary device is defined as “The device mounted internally or externally to the fluid conduit that produces a signal with a defined relationship to the fluid flow in accordance with known physical laws relating the interaction of the fluid to the presence of the primary device.” (Source: “Process Measurement and Analysis,” Page 16, Bela Liptak)

Secondary Device Definition – A secondary device is defined as “The device that responds to the signal from the primary device and converts it to a display or to an output signal that can be translated relative to flow rate or quantity. ”

Note: The secondary device may consist of one or more elements as needed to translate the primary device signal into standardized or nonstandardized display or transmitted units. (Source: “Process Measurement and Analysis,” Page 16, Bela Liptak)

Typical Examples

An orifice meter is one of the most common of flowmeter installations. In the orifice meter installation (Figure 2), the primary device consists of the meter tubing (also called a meter run) and a constricting element. The constrictive element in this flowmeter is the orifice plate. The secondary device measures the pressure drop caused by the primary element. The secondary device in this example is a pressure-sensing device such as a differential pressure transmitter (flow transmitter).



Similarly in place of the Orifice Plate w/ Flange, a Venturi or Flow Nozzle may be used.

Figure 2: Flowmeter Definition

Drawing Symbols

Typical flow measurement symbols are shown in Figures 3 and 4. The symbols conform to Saudi Aramco requirements specified in SAES-J-004 (Instrument Symbols and Identification).

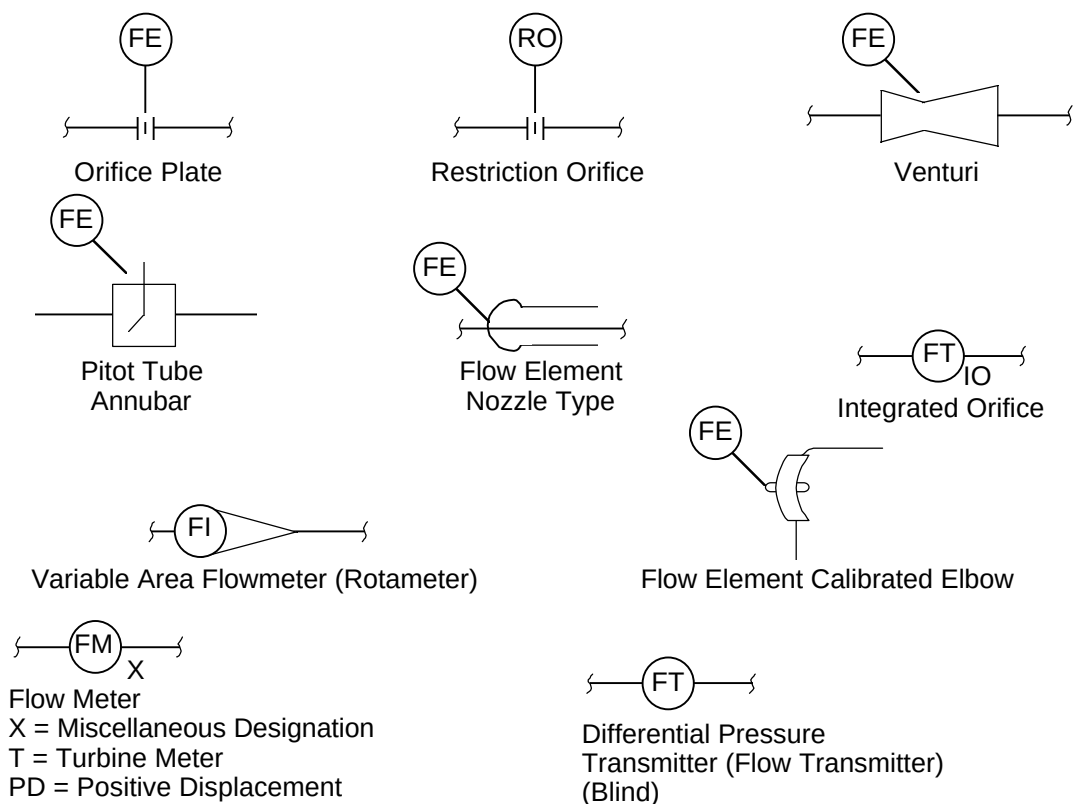


Figure 3: Drawing Symbols

Note that the line symbols for electrical and pneumatic signals that have been used at Saudi Aramco are the reverse of Instrument Society and industry symbol usage.

The line symbology, as defined in ISA S5.1-1984, shall be used for all “grass root” projects. For an existing plant or an expansion to an existing plant, the line symbology being used for that plant shall be used. An existing plant may use ISA S5.1-1984 line symbology, with concurrence of the Proponent and Chief Draftsman, Dhahran.

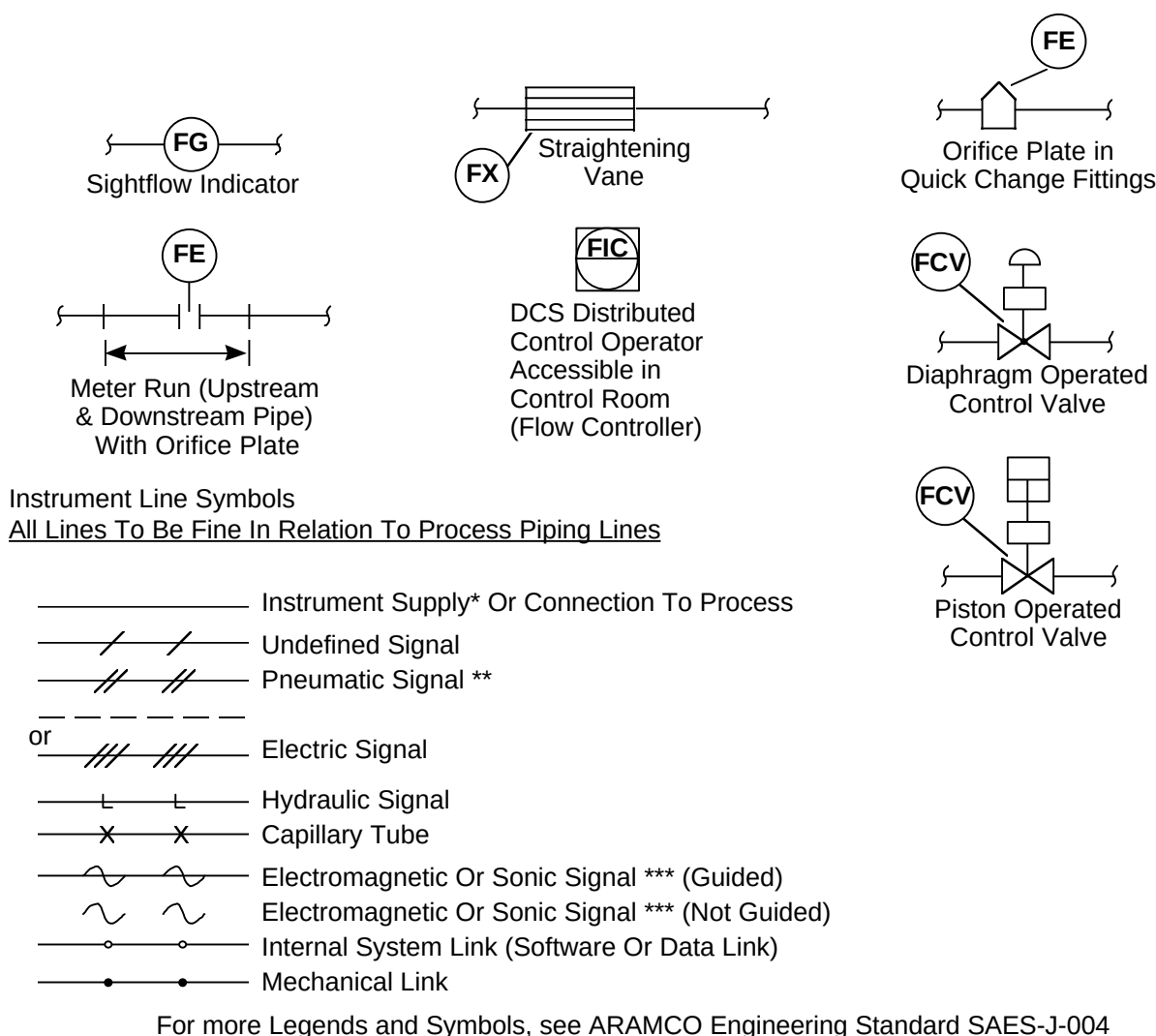


Figure 4: Drawing Symbols

General Categories of Flow Instruments

Flow instrument categorization often varies. It is not unusual to see users describe up to nine flowmeter categories. Two approaches to meter categorization are to describe flowmeters in terms of:

- Rate or quantity type.
- Energy usage type.

Classifications Approach

One of the earliest ways of classifying flowmeters is to place a meter into a category that measures flow in terms of flow rate or one that measures flow quantity.

Rate Meter versus Quantity Meter – Rate meters are the most common classification of flowmeters. Rate meters measure the process fluid's velocity. Velocity is expressed in terms of distance per time, such as meters/second or feet/second. Because a pipe's cross sectional area is known, the velocity is then used to calculate the flow rate. A flow rate, such as meter³/second or ft³/second, represents the amount of fluid volume at a particular location and at a particular time during which the measurement is taken.

A rate meter can either infer the flow rate or measure the velocity of the flowing fluid to determine the flow rate. For example, a differential pressure flowmeter infers the flow rate from the differential pressure across a restriction in a line. The flow rate in this case is inferred from the measured differential pressure and accepted correlations to rate. A velocity measurement, as in the case of a turbine meter, uses the velocity of the fluid times the area through which the fluid is flowing to determine the flow rate.

Quantity meters continuously divide the flowing material into predetermined volume segments. Quantity meters count and keep track of the number of these volume segments. An example of a quantity meter is a positive displacement meter. Whenever you refill your car with gasoline, the gas flows through a positive displacement meter that counts the number of liters of gasoline that you have purchased.

Meters that directly measure mass can also be considered either as a quantity meter or as a mass flow rate meter.

A brief summary of the meter classification by quantity versus rate is shown in Figure 5.

Type of device	Quantity		
	Direct mass measurement	Direct volume measurement	Flow rate
Positive displacement • rotating paddle • oscillating piston • fluted rotor • oval-shaped gear		X	
Turbine meters			X
Differential pressure • orifice • venturi • flow nozzle • pitot			X
Magnetic flowmeters			X
Mass flowmeters (Coriolis and thermal)	X		X
Ultrasonic flow			X
Vortex			X
Variable area flow meters (rotameters)			X

Figure 5: Quantity versus Rate

Energy Approach

Another way of categorizing flowmeters is to use a method called the energy approach. Flowmeters either take from or introduce energy to the process media, which leads to the following two subclassifications:

- Extractive energy approach
- Additive energy approach

Extractive Energy Approach – In this category, flowmeters take energy from the fluid flow. These flowmeters, because they are intrusive, often introduce pressure losses into the fluid flow. An orifice plate is an example of an extractive-type device.

Additive Energy Approach – In this category, flowmeters introduce some form of energy into the fluid flow. These flowmeters, because they are nonintrusive, do not produce pressure losses in the fluid flow. The energy—electromagnetic, acoustic, or mechanical—is required for the flowmeter to operate. A magnetic flowmeter is an example of an additive type device.

Units of Measure

According to Saudi Aramco Design Practice SADP-J-100, Section 2.1, “The normal units of measure for process flow, temperature, and pressure (or differential pressure) are the International System of Units (SI) as referenced in SAES-J-103. Corresponding conventional units may be shown in parentheses.” Flow measurement units based on SAES-J-003, Section 10, are listed in Figure 6.

Standard conditions of temperature and pressure are standard as an agreement between the buyer and seller. SAES-J-100 26 Sep 89, Section 4.1, calls for 14.73 PSIA and 60°F as the standard. These numbers are consistent with AGA-3, also called API 14.3.

Fluid	SI-Metric Units	English units
Water	• m³/h (cubic meters per hour) • m³/d (cubic meters per day)	• GPM (gallons per minute) • BPD (barrels per day)
Oil, in plant process liquids, steam condensate, gas (except GOSP gas)	• m³/h (cubic meters per hour) • m³/d (cubic meters per day) • kg/h (kilograms per hour)	• BPH (barrels per hour), BPD (barrels per day) • LB/HR (pounds per hour) • SCFH (standard cubic feet per Hour) • SCFD (standard cubic feet per day) • MMSCFD (millions of standard cubic feet per day) Note: prefix MM = Million
GOSP gas, crude oil product	• m³/d (cubic meters per day)	• SCFD (standard cubic feet per day) • MMSCFD (millions of standard cubic feet per day) • BPD (barrels per day)

Figure 6: Units of Measure

Meter Run

According to SADP-J-100, Section 3, a meter run or meter tube is defined as “The upstream and downstream length of pipe containing the orifice flanges and orifice plate or orifice plate with or without quick change fittings. No other pipe connections should be made within the normal meter tube dimensions except for pressure taps and thermowells.” A meter tube is an important part of a flowmeter installation. The meter tube must create an acceptable flow pattern (velocity profile) for the fluid when it reaches the orifice plate. Distortions occurring in the flow pattern result in pressure drop errors.

Pipe Diameter

Pipe diameter represents the inside diameter of a pipe. To calculate the inside diameter of a pipe, use the outside diameter of a pipe minus 2 x the wall thickness of the pipe. Pipe data tables give the inside diameter (I.D.) as a function of nominal pipe size, pipe material, and schedule.

Flow Straighteners

Flow straighteners are also called flow conditioners (Figure 7). Flow straighteners help to provide accurate measurement when a distorted flow pattern is expected. The flow pattern, called a flow profile, is distorted by sources such as pipe area changes, partially open valves, or valve and elbow combinations. When flow straighteners are installed in the pipe, a predictable flow pattern (flow profile) occurs at the outlet of the flow straightener. Flow straighteners are installed in the upstream section of meter tube. Flow straightening vanes reduce the upstream meter tube length requirement.

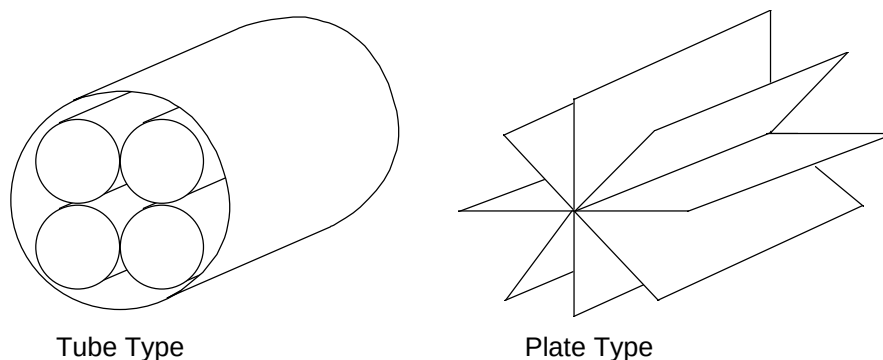


Figure 7: Flow Conditioners

Flow Rate

Flow rate is an indication of how fast a substance moves through a conduit from one place to another. Flow rate can also be used to determine the distance a substance moves over a period of time. Flow rate is usually expressed as

- Volume flow rate
- Mass flow rate

Volume Flow Rate represents the volume of fluid that passes a measurement point over a period of time. An example measurement unit is barrels per day. The volume flow rate can be calculated if the average flow velocity and inside pipe diameter are known. The calculation is based on the formula

$$Q = A \times v$$

where

Q = volumetric flow rate

A = cross-sectional area of the pipe

v = average flow velocity (flow rate)

Mass Flow Rate represents the amount of mass that passes a specific point over a period of time. Mass flow rates are used to measure the weight or mass of a substance flowing through a process operation. If the volumetric flow rate and density are known, the calculation is based on the formula

$$W = Q \times \rho$$

where

W = mass flow rate

Q = volumetric flow rate

ρ = density (ρ = density “rho”)

Compressible versus Incompressible Flow

Temperature and pressure changes cause the volume of a fluid to change. The change in volume is much more extreme in gases than in liquids. Compressibility represents the change per unit volume of a fluid caused by a unit change in pressure at constant temperature. When accurate gas flow measurements are needed, a factor for compressibility is often included in the measurement. (The compressibility factor represents the ratio of the actual volume of gas at a given temperature and pressure to the volume of a gas calculated by the Ideal Gas Law.)

$$z = \frac{PV}{nRT}$$

The shapes of the compressibility factor curves for methane, propane, and isobutane gases at constant temperature are shown in Figure 8. Methane has a lower boiling point than propane. Propane has a lower boiling point than isobutane. Methane shows the least deviation of the three for an ideal gas effect.

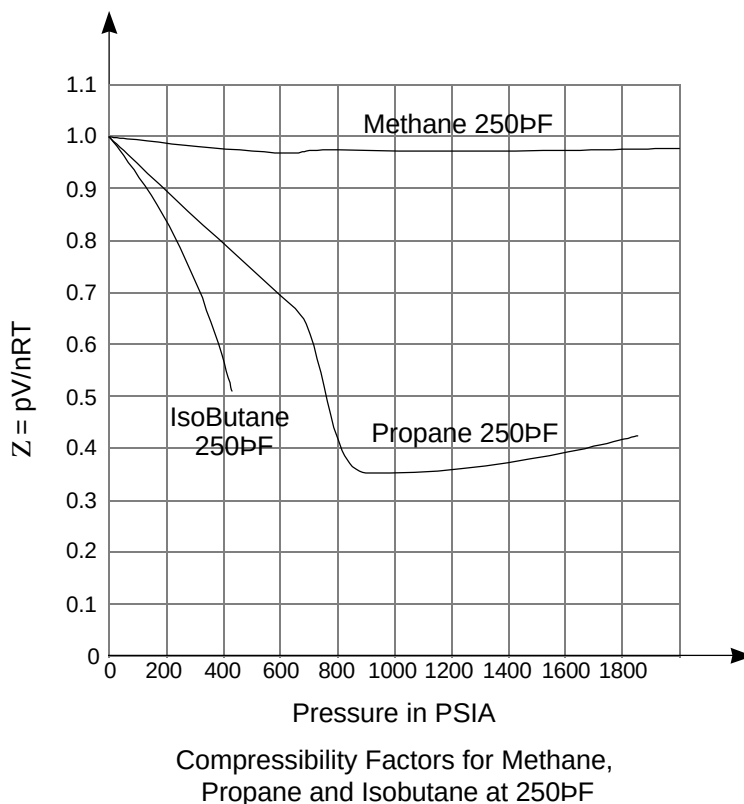


Figure 8: Compressibility Curves

Viscosity

Viscosity is frequently described as a fluid's resistance to flow. Viscosity can have a dramatic effect on the accuracy of flow measurement. Viscosity has a role in flow measurement when a fluid is in motion, but not when a fluid is at rest. Resistance to flow occurs because fluids have combined actions of cohesion and adhesion that create internal friction between layers in the fluid. Water, for example, having low viscosity has less resistance to flow. While viscosity is often described as a fluid's stickiness or thick appearance (or lack of either stickiness or thickness), those descriptions do not fully describe viscosity.

Viscosity is a subject of a scientific discipline called fluid mechanics. Fluid mechanics deals with fluids in motion, which includes the property of viscosity. When a fluid is in motion, layers of fluid are subject to tangential shearing forces, causing the fluid to deform. Viscosity, then, is more accurately defined as the property of a fluid that resists the rate at which deformation occurs when tangential shearing forces act upon the fluid. Liptak, page 1256 Table 8.59b, shows viscosity of various oils.

Using the example of water's low viscosity, one can observe that when a fluid has low viscosity (i.e., low ability to resist deformation), it would not be worthwhile to consider its low viscosity in a flow measurement. That is, a fluid's low viscosity does not become an influential property of the fluid upon flow measurement. However, when measuring the flow rate of a fluid with high viscosity, the viscosity does become an influential property in flow measurement.

Accuracy Reference

Accuracy is measured in terms of maximum positive and negative deviation observed in the testing a device under a specified condition and specified procedure. The accuracy rating includes the total effect of conformity, repeatability, dead-band, and hysteresis errors.

The accuracy of a flowmeter is expressed in several ways. Flowmeter accuracy is expressed as one of the following:

- Percent of rate accuracy
- Percent of full scale flow
- Percent of maximum differential pressure

Percent of Rate Accuracy refers to an accuracy that is based upon the actual flow rate. The accuracy applies to meters such as turbine meters, DC magnetic meters, vortex meters, and Coriolis meters. The accuracy can be expressed as

$$\% \text{ of rate accuracy} = \pm \frac{\text{flow uncertainty}}{\text{instantaneous flow rate}} \times 100$$

Percent of Full Scale Flow refers to the accuracy of primary meters such as rotameters and AC magnetic meters. The accuracy can be expressed as

$$\% \text{ of full scale accuracy} = \pm \frac{\text{flow uncertainty}}{\text{full scale flow rate}} \times 100$$

Percent of Maximum Differential Pressure applies to differential pressure flow transmitters. The accuracy can be expressed as

$$\% \text{ maximum } \Delta P \text{ accuracy} = \pm \frac{\Delta P \text{ uncertainty}}{\text{maximum } \Delta P} \times 100$$

As one may observe from the accuracy reference, it is important to know in what terms the accuracy reference is made. An accuracy reference of simply "2%" is incomplete. One would have to know if that accuracy reference is in terms of instantaneous flow rate, full scale flow rate, or maximum ΔP .

System Accuracy

In order to combine the component's accuracy statements to arrive at a System Accuracy Statement, it is first necessary to determine that all component statements are of the same type, i.e. % of Max. Flow, % of Rate, etc. This usually means that at least some of the components will have varying accuracy at different flow rates. Then the system accuracy must be calculated at various flow rates to produce a useful statement.

A common method to combine accuracies of series connected components is to calculate the square root of the sum of their squares.

$$\text{Syst. Acc.} = \pm \sqrt{(\text{Acc.1})^2 + (\text{Acc.2})^2 + (\text{Acc.3})^2 - - -}$$

This method takes into account, in part, the fact that the various errors will probably not all be either positive or negative at one time and that the resulting uncertainty should not reflect the "worst case" of arithmetic addition of errors.

Totalization

Totalization represents the process of counting the amount of fluid that has passed through a flowmeter. The purpose of totalization is to have periodic (daily or monthly) readings of the material usage or production. The totalization data is used for billings for material usage or production.

Custody Transfer

Flow measurement for custody transfer, where ownership of a product transfers, is on occasion regarded as a separate flow measurement topic. There are two types of custody transfer in flow measurement:

- Legal, which falls under weight and measure requirements.
- Contract, which is a mutual agreement between seller and buyer.

One reason for that distinction is that custody transfer flow measurement becomes essentially a money measurement. Because the purpose is primarily for billing, the perspective on flow measurement changes to one where accuracy becomes very important. In process control applications, the accuracy requirement may be several percent, but for custody transfer operations the accuracy requirement may be in tenths of a percent.

Hydrodynamic Principles

In order to choose the proper measurement instrument, one must have an understanding of a fluid's properties, particularly when that fluid is in motion. The study of fluids in motion is called hydrodynamics. It is important to consider a fluid's properties as being unique prior to flow measurement device selection. Hydrodynamic principles that bear on flow measurement device selection are described as the following:

- Bernoulli and basic hydraulic equations
- Relationship governing Newtonian versus non-Newtonian fluids
- Viscosity

Bernoulli and Basic Hydraulic Equations

When a liquid flows from one place to another it may undergo a change in potential energy or in kinetic energy, but if it moves without waste of energy caused by friction, the units total energy remains unchanged, in accordance with the law of conservation of energy. Consider a liquid flow steadily through a tube of any section as illustrated in Figure 9, and imagine that the liquid is incompressible and frictionless and that its velocity at any cross-section is uniform throughout that section. During a short interval of time, particles of liquid at section 1 and at section 2 will move as indicated by the arrows. Let the cross-sectional areas at these sections be respectively A_1 and A_2 , the corresponding velocities of the liquid be v_1 and v_2 , the elevations of the sections above a convenient datum plane be respectively Z_1 and Z_2 , and the pressures of the liquid be respectively p_1 and p_2 .

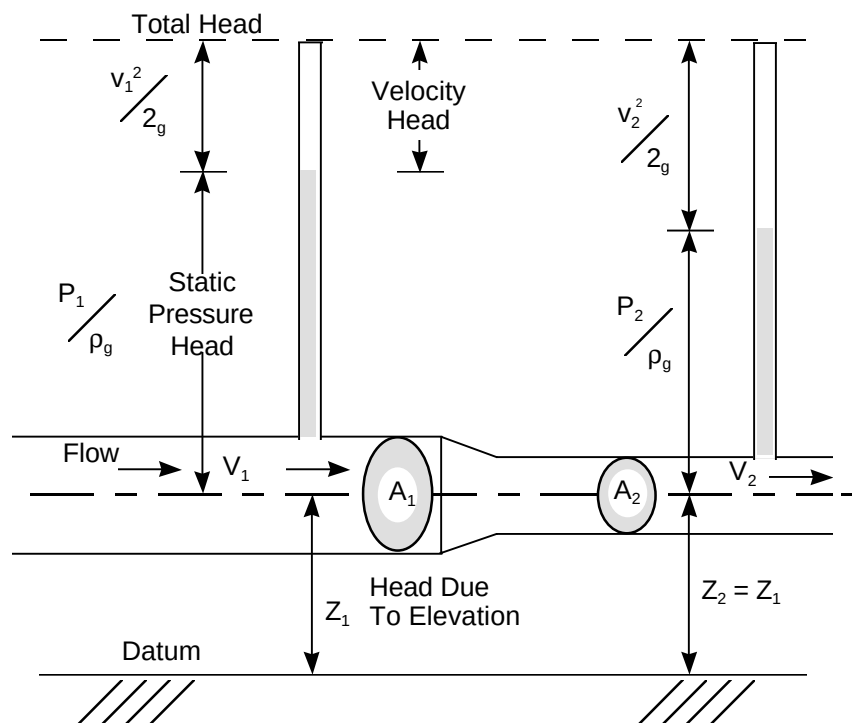


Figure 9: Bernoulli and Basic Hydraulic Equations

Then because the liquid is incompressible, the same mass “m” will pass any section of the tube in a given time t ; the volume of this mass will be $V = m/\rho$, where ρ is the density of the liquid. The work that must have been done on this mass of liquid to bring it to the conditions existing at section 1 consists of three parts: mgZ_1 to elevate it to the height Z_1 above the datum plane; $\frac{1}{2}mv_1^2$ to give it the velocity v_1 ; and p_1V or $p_1 m/\rho$ to force it into a region of pressure p_1 . Because the liquid is frictionless, the same amount of work would be required to bring this mass of liquid to the conditions existing at section 2; consequently

$$mgZ_1 + \frac{1}{2}mv_1^2 + p_1\frac{m}{\rho} = mgZ_2 + \frac{1}{2}mv_2^2 + p_2\frac{m}{\rho}$$

The corresponding expression for the total work per unit weight of liquid at any section is obtained herefrom by dividing each term by the weight mg , thus

$$Z_1 + \frac{v_1^2}{2g} + \frac{p_1}{\rho g} = Z_2 + \frac{v_2^2}{2g} + \frac{p_2}{\rho g}$$

This summation is spoken of by engineers as *total head*, the respective terms being called Z = elevation head, $v^2/2g$ = velocity head, and $p/\rho g$ = pressure head.

Daniel Bernoulli's total head equation, above, says "If there is a constant sum of energy the components can be varied, with each contributing more or less depending upon their condition. A change in velocity will result in an inverse change in pressure. If the flow area is reduced, the velocity will increase. This velocity increase through a narrowed flow area is the basis for all variable differential pressure types of flowmeters.

- P = Static Pressure (pounds force per sq. ft)
- ρ = Density (rho) (pounds mass per cubic ft)
- v = Velocity (feet per second)
- g = Acceleration of Gravity (feet per second²)
- Z = Elevation Head Above a Reference Datum (feet)

Other basic hydraulic concepts that describe fluid flow characteristics are

- The Equation of Continuity
- Reynolds numbers

The Equation of Continuity is the basis for describing how all velocity-type flow instruments operate. The Equation of Continuity states that the volumetric flow rate can be calculated by multiplying the cross sectional area of the pipe at a given point by the average velocity at that point. The equation is based on the formula

$$Q = A \times v$$

where

- Q = volume flow rate (cubic feet per minute)
- A = pipe cross-sectional area (square feet)
- v = average fluid velocity (feet per minute)

Reynolds Number

In 1882, Sir Osborne Reynolds wrote the seminal paper on flowing fluid characteristics. He defined the major distinctive quality of fluid flow as the ratio of Inertial Forces to Viscous Forces. when two samples of flowing fluid have the same nondimensional ratio value, they have similar flow characteristics.

Laminar flow is defined by low Reynolds numbers with the largest flowing fluid moving coherently without intermixing. Turbulent flow is defined by high Reynolds numbers with much mixing. Both flow extremes are beneficial depending upon requirements. Turbulent flow is best when high heat transfer is wanted, while laminar flow is best when flowing fluid is to be delivered through a pipe with low friction losses.

Flow is considered laminar when the Reynolds number is below 2,000. Turbulent flow occurs when the Reynolds number is above 4,000. Between these numbers, the flow characteristics have not been defined.

When choosing flowmeters, the flow's Reynolds number must be within the range of the meter's design. If not, the measurement will be suspect.

Reynolds number is defined by the following equations:

For liquid flow

$$Re = \frac{50.7 \rho Q}{D\mu} \text{ or } Re = \frac{6.32 W}{D\mu}$$

where

Re = Reynolds number (dimensionless)

ρ = density ($\frac{\text{lb}}{\text{ft}^3}$) at flowing temperature

Q = flow rate ($\frac{\text{gal}}{\text{min}}$)

D = internal tube diameter (in.)

μ = viscosity of flowing temperature (centipoise)

W = flow rate ($\frac{\text{lb}}{\text{hr}}$)

For gas flow

$$Re = \frac{6.32 \rho Q}{D\mu} \text{ or } Re = \frac{6.32 W}{D\mu}$$

where

ρ = density at standard conditions ($\frac{\text{lb}}{\text{ft}^3}$)

Q = flow rate (scfh)
and other units are defined the same as for liquid

Example Calculation

What is the Reynolds number for 68°F water flowing in a 6 inch schedule 40 pipe at 50 feet per second?

$$\begin{aligned} Re &= \frac{6.32 W}{D\mu} \\ &= \frac{6.32 (50) \text{ ft/sec} (6.065/12)^2 \times \pi/4 \text{ ft}^2 \times 3600 \text{ sec/hr} \times 62.4 \text{ lb/ft}^3}{6.065 \text{ in} \times 1 \text{ cp}} \\ &= \frac{6.32 \times 50 \times 6.065 \times \pi \times 3600 \times 62.4}{12^2 \times 4} \\ &= \frac{6.32 \times 6.065 \times \pi \times 3.750 \times 62.4}{12} \\ &= 2,350,000 \end{aligned}$$

Because the Reynolds number is greater than 10,000, the flow is turbulent.

Incompressible Flow

Fluids are materials that flow. Liquids are fluids that flow without changes in density. The previous development of a Bernoulli theorem considered a flowing liquid with other simplifying assumptions. That primitive analysis can be expanded by considering real life deviations from the simplifying assumptions.

An example of an incompressible fluid is water. For the purist, water does change density in its temperature excursion from ice (solid) to steam (vapor or gas), but ever so slightly. Water is most dense at 4°C. Ice floats on water as ice is less dense than water at freezing temperatures and below.

Water is a Newtonian fluid that shows certain fluid mechanics' properties. Hydrocarbons, generally, are non-Newtonian in their flowing characteristics. These variations will be discussed.

Liquids tend to hug the bottom of any container in which they are placed. Gases, compressible fluids, tend to distribute uniformly throughout the enclosing container.

Compressible Flow

Gases are fluids that have variable densities because of the pressure and temperature conditions. The Ideal Gas Law correlates these conditions, incorporating Boyle's and Charles' laws:

$$PV = nRT$$

where

- P = Absolute Pressure
- V = Volume
- n = Mass (number of molecules)
- R = Universal Gas Constant
- T = Absolute Temperature

The Ideal Gas Law is not always true. A deviation can be recognized by the Compressibility Factor, Z, which has been introduced previously.

As another example, consider the flow of a gas through a meter. At low velocities the gas may behave as an incompressible fluid and the Reynolds number may provide a suitable parameter for correlating data. At high velocities, however, compressibility effects may be present and it may be necessary to use the Mach number in order to correlate the data.

Laminar Flow refers to a smooth, streamlined flow pattern (Figure 10). The flow pattern appears as if there are several plates or laminations of flowing particles that flow parallel to each other. Consider the growth rings of a tree. Each layer or ring flows at a constant speed.

The flow pattern nearest the pipe walls is slower than the flow pattern in the center of the fluid because of friction that occurs between a fluid and the pipe's walls.

Turbulent Flow refers to a flow pattern that is the opposite of laminar flow. The flow pattern is distorted, rough, and irregular. A turbulent flow pattern has small whirlpool-type eddy currents that appear to go in all directions.

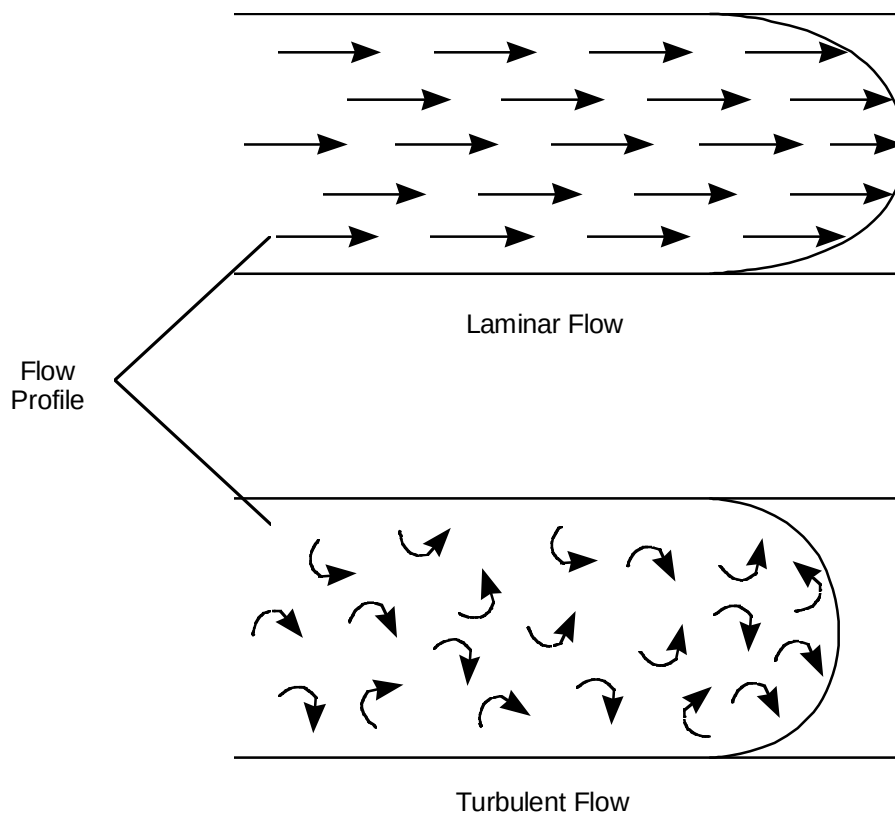


Figure 10: Flow Profile

Relationship Governing Newtonian versus non-Newtonian Fluids

In Newtonian fluids, the resistance to deformation when subjected to shear (consistency of fluid) is constant if temperature and pressure are fixed. Whereas in a non-Newtonian fluid, resistance to deformation is dependent on shear stress even though the pressure and temperature are fixed. The relationship is further described in the following terms:

- Hagen-Poiseuille Law
- Rheograms
- Newtonian fluids
- Non-Newtonian fluids

Hagen-Poiseuille Law defines viscosity in more practical terms. Newton's definition of viscosity is the ratio of shear stress divided by shear rate. Hagen-Poiseuille defines it as the ratio of shear stress divided by shear rate at the wall of a capillary tube:

$$\mu = \text{shear stress} / \text{shear rate} = (PR/2L)/(4Q / \pi R^3) = (\pi PR^4)/(8QL)$$

where

$$\mu = \text{absolute (dynamic) viscosity} \left(\frac{\text{pounds}}{\text{foot} \cdot \text{second}} \right)$$

$$P = \text{pressure differential across liquid in the tube} \left(\frac{\text{pounds}}{\text{square foot}} \right)$$

$$R = \text{inside radius of the tube (feet)}$$

$$L = \text{length of the tube (feet)}$$

$$Q = \text{volume rate of flow of liquid} \left(\frac{\text{cubic feet}}{\text{second}} \right)$$

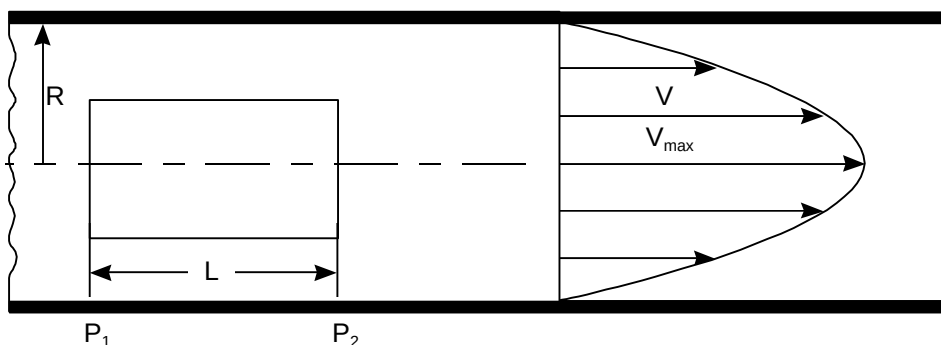


Figure 11: Hagen Poisuille Law

Rheograms can be used to determine the characteristics of any fluid. Rheograms evolved from the science of rheology, which studies flow. (“Rheo,” derived from the Greek language, means “a flowing.”) Rheograms are useful as an aid to interpret viscosity measurements.

Newtonian Fluids – A Newtonian fluid exhibits the constant ratio of shear stress to shear rate (flow velocity) when subjected to shear and continuous deformation. When a fluid's temperature is fixed, the fluid exhibits the same viscosity through changing shear rates. Viscosity is not affected by shear rate (flow velocity). The relationship is linear between the shear stress (force) and velocity (resulting flow). Newtonian fluids are generally homogeneous fluids. Gasoline, kerosene, mineral oil, water and salt solutions in water are examples of Newtonian fluids.

Non-Newtonian Fluids – Fluids that do not show a constant ratio of shear stress to shear rate are defined as non-Newtonian fluids. Fluids exhibit different viscosity at different shear rates. In non-Newtonian fluids, there is a nonlinear relation between the magnitude of applied shear stress and the rate of angular deformation. Non-Newtonian fluids, which have different classifications, tend to be liquid mixtures of suspended particles. Thick hydrocarbon fluids are considered non-Newtonian fluids.

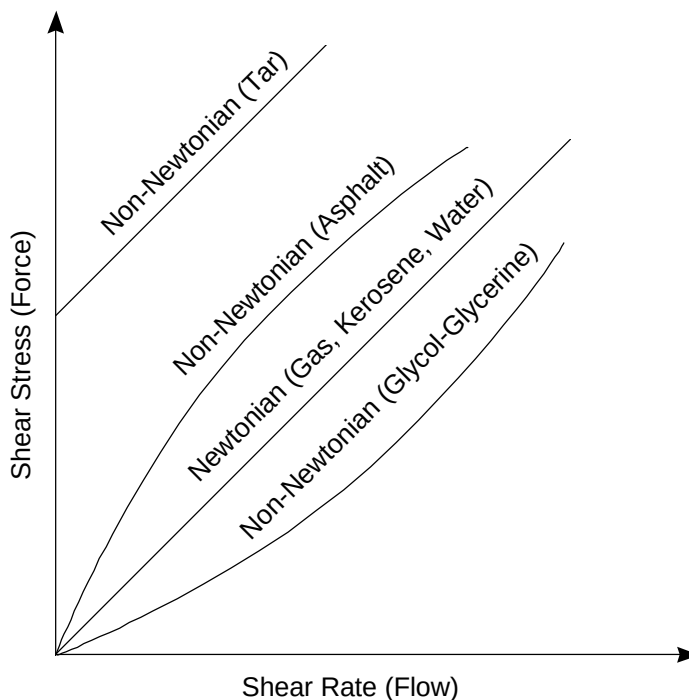


Figure 12: Newtonian versus Non-Newtonian

Viscosity

Viscosity is a property of a fluid which affects the fluid's behavior. Viscosity is defined as a fluid's internal resistance to flow. If a fluid undergoes continuous deformation when subjected to a shear stress, than the resistance (consistency) offered by the fluid can be stated for such deformation. Viscosity is often expressed in terms of the following:

- Dynamic viscosity
- Kinematic viscosity
- Viscosity index
- Viscosity scales

Dynamic Viscosity (Absolute Viscosity) represents a fundamental viscosity measurement of a fluid. Density of fluid does not play a part in the viscosity measurement. Absolute viscosity is a ratio of applied shear stress to resulting shear velocity, the resistance offered by the fluid to such deformation. If static pressure and temperature are fixed and consistency is constant for gases and Newtonian liquids, the viscosity is called absolute viscosity (μ).

One method to measure viscosity is to rotate a disk in the fluid at a particular rotational speed. The rotational torque required to keep the disk rotating divided by the speed of rotation and by the disk contacting surface area is a measure of absolute viscosity. The measurement units for dynamic (absolute) viscosity are centipoise, Pascal-seconds, or lb/ft-second.

Another viscosity measurement that can be used for liquids and gases is the falling sphere viscometer (viscosimeter).

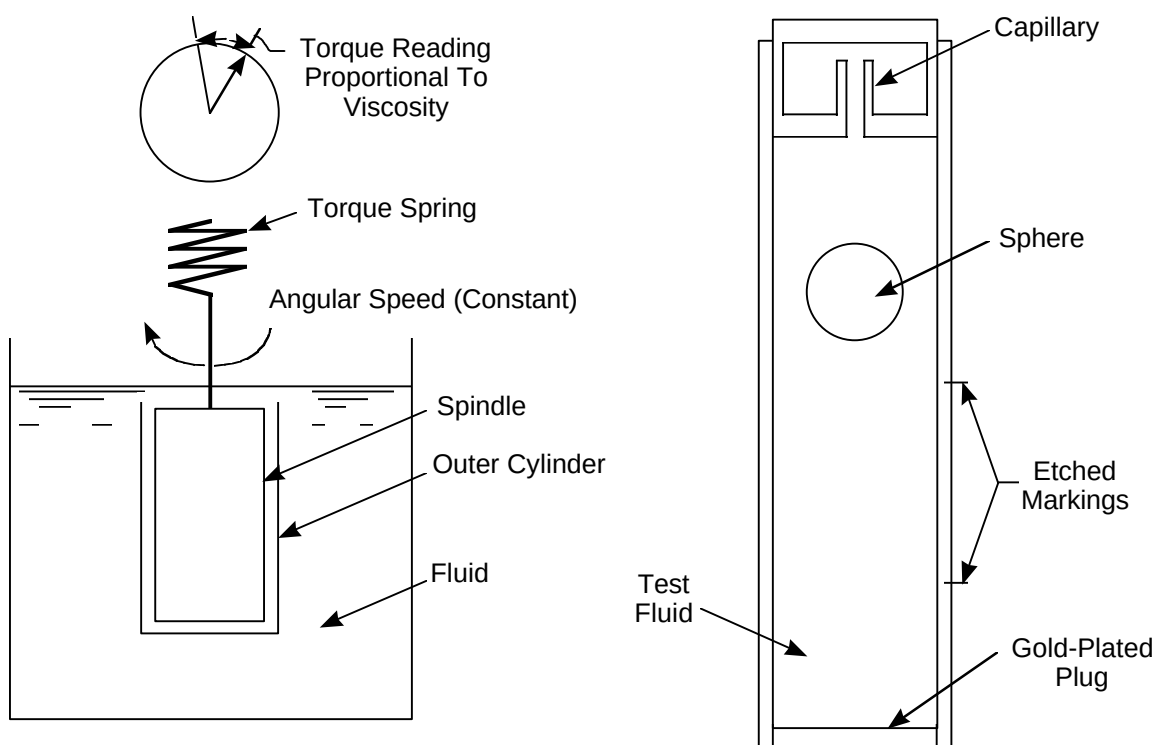


Figure 13: Rotational and Falling Sphere Viscometers

Kinematic Viscosity (ν) represents a ratio of dynamic (absolute) viscosity to the density of the fluid and is expressed in stokes ($\nu = \mu / \rho$). In liquids, an increasing temperature usually results in lowering the kinematic viscosity. In gases, an increasing temperature increases the kinematic viscosity. The method for determining kinematic viscosity involves measuring the time to drain a certain volume of liquid by gravity out of a container through a capillary tube or some type of restriction. The time it takes to drain a liquid is directly related to viscosity and is recorded in seconds. The flow rate of fluids by gravity, which is the force causing the flow, depends upon the density of the fluids. Viscosity measured by this method is called the kinematic viscosity. The measurement units for kinematic viscosity are either centistokes, meter²/second, or ft²/second. The centipoise (cP) is equal to centistokes multiplied by the density of the fluid.

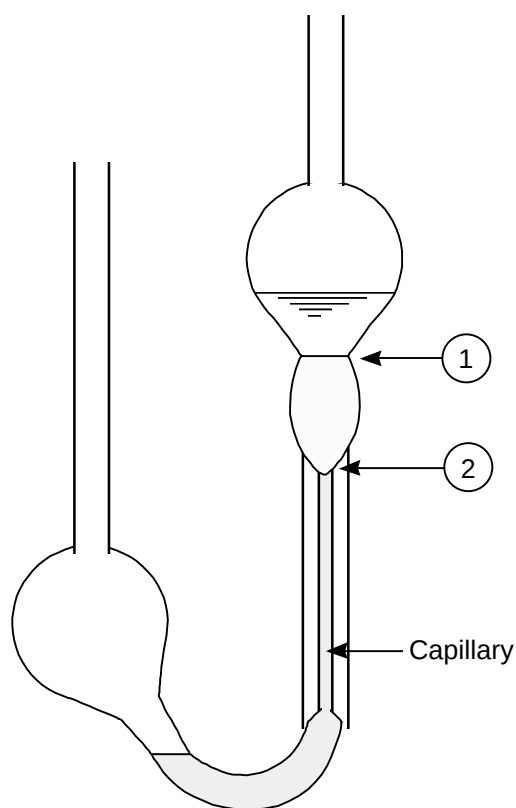


Figure 14: Ostwald Capillary Viscometer

Viscosity Index represents the change in viscosity with respect to temperature. Viscosity index is used with reference to petroleum products. A high viscosity index number means that the fluid's viscosity does not change very much for a given temperature. A low viscosity index number indicates that the fluid's viscosity does change significantly for a given temperature.

Viscosity Scales present viscosity measurements in time units. Viscosity scales that are commonly used include the following:

- Saybolt Furol scales
- Redwood scales
- Engler scales

The three scales express kinematic viscosity in time units rather than centistokes. For example, if the kinematic viscosity of a fluid at 122° F is 900 centistokes, on the Saybolt Furol scale the equivalent viscosity is expressed as 424.5 seconds (centistokes x 0.4717). Flow engineering reference manuals often provide conversion formulas between centistokes and the respective viscosity scale. Note that dynamic viscosity can be derived from the kinematic viscosity.

FLOW MEASURING DEVICE SELECTION CRITERIA

Flowmeter selection can be a very complex task, given the wide range of technologies and application requirements that must be accommodated. Several approaches to flowmeter selection begin by a process of elimination—the number of flowmeters is narrowed to a few acceptable choices. That does not mean that the “acceptable” choices are necessarily the “perfect” choice. The meters that have been selected as suitable for the application often represent a tradeoff between meter service, process conditions, and a company’s policy on instrumentation.

A flowmeter selection process takes into account the following:

- Application fundamentals
- Specifications
- Safety considerations
- Metallurgy
- Installation considerations
- Maintenance and calibration
- Compatibility with existing process instrumentation
- Custody transfer concerns
- Economic considerations
- Technical direction

Application Fundamentals

All flowmeter selection begins with a rather simple, though understated, premise — what is the instrument expected to do? From that simple question, however, one can use approaches to flowmeter selection that, to a large degree, require an understanding of the intended application. Two common approaches embed application fundamentals in their selection approach. The approaches use one of the following:

- Flowchart
- Checklist of selection criteria

Flowchart

A structured flowchart approach is shown in Figure 15. The selection process begins with determining the process fluid characteristics through comparing costs and performance.

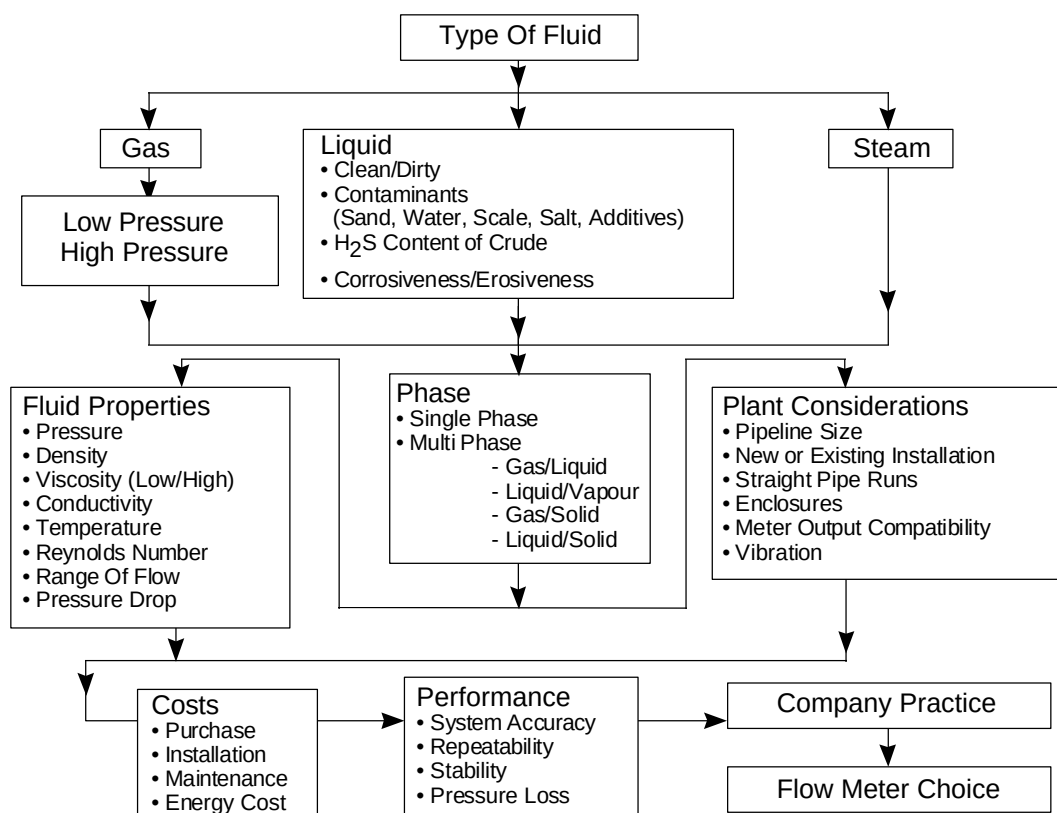


Figure 15: Flowchart Approach to Meter Selection

Checklist of Selection Criteria

Vendor's also provide flowmeter checklists that assist an engineer in the selection process. A checklist, like the sample list that follows, may include the following items:

- Flow stream conditions:
 - volume
 - temperature
 - pressure
 - density
 - viscosity
 - flow velocity
- Flow measurement goals.
- Accuracy requirements.
- Range requirements.
- Acceptable pressure drops.
- Display and system requirements.
- Potential problems (i.e., vibration).
- Flow stream erosive/corrosive materials, entrained gases and solids (if any).
- Available installation space and pipe geometry.
- Economic factors (cost of ownership).

For another flowmeter selection approach, review the method described in the Instrument Engineer's Handbook, Process Measurement, Chapter 2.1. Regardless of the flowmeter selection approach that is followed, the selection begins with an evaluation of the fluid's characteristics.

Specifications

Specifications for individual flowmeter selections are listed in SADP-J-100, Attachment 1. The specifications include:

- Type of service
- Accuracy
- Rangeability
- Pipe size
- Reynolds number limits
- Temperature
- Pressure
- Cost

Selection guidelines from SADP-J-100, Attachment 1, are shown in Figure 16 and Figure 17.

Meter Type		Service											
		Clean Liqs.	Dirty Liqs.	Corrosive Liqs.	Viscous Liqs.	Abrasive Slurries	Low Vel Flows	Vapor or Gas	Dirty Gas or Vapor	High Temp. Service	Cryogenic Service	Semi-Filled Pipes	Non-Newtonians
Differential Pressure	Orifice	D	C	A	A	C	D	D	C	D	D	NA	C
	Venturi	D	A	C	C	C	C	D	NA	C	C	NA	C
	Flow	D	C	C	C	C	C	D	NA	C	C	NA	C
	Nozzle & Tubes												
	Pitot Tubes	D	C	A	C	NA	C	D	NA	C	C	NA	NA
Magnetic		D	D	D	A	D	A	NA	NA	C	NA	C	A
Mass	Coriolis	D	D	A	D	D	A	C	NA	C	C	NA	D
	Thermal	D	C	C	C	C	A	D	NA	C	NA	NA	C
Oscillatory Vortex Shedding		D	A	A	C	NA	NA	D	NA	C	C	NA	NA
Positive Displacement		D	NA	C	D	NA	D	D	NA	C	C	NA	NA
Target		D	A	A	A	C	C	D	NA	C	C	NA	C
Turbine		D	C	C	C	NA	C	D	NA	C	C	NA	NA
Ultrasonic	Transit-T	D	C	C	C	NA	C	C	C	NA	C	NA	NA
	Doppler	NA	D	C	C	A	C	NA	NA	NA	NA	NA	C
Variable Area		D	C	A	A	NA	C	D	NA	A	NA	NA	NA

Flowmeter Applications

D - Designed
For Service

A - Normally
Applicable
For This
Service

C - Conditional
Usage Only

NA - Not
Applicable
For This
Service

Figure 16: Flowmeter Applications

Determining Appropriate Flow Measurement Devices For Saudi Aramco Applications

Flowmeter	Accuracy	Range-ability	Pipe Size Inches	Reynolds No. (R) Limits	Temperature (F)	Pressure (PSIG)	Cost (\$)
Orifice: • Square-Edge • Quadrant-Edge • Segmental • Integral	+/- 2 % FS +/- 2 % FS +/- 2 % FS +/- 2 to 5 % FS	3:1 3:1 3:1 3:1	>2.0 >2.0 >4 <0.5	R>2000 300<R<3300 R>10000 R>100	Process: To 1000F Transmitter: -20 To 250F	Pipe Rating To 6000 PSIG	316ss Plate \$100 to \$400 \$1,500 for Transmitter 1" Integral Orifice with Transmitter \$2,000
Target	+/- 2 to 5 % FS	3:1	0.5 to 4	R>100			\$1,400 to 2,000
Venturi	+/- 1 to 2 % FS	3:1	>2	R>75000			2" CS \$1,200 8" CS \$3,500
Flow Nozzle	+/- 1 to 2 % FS	3:1	>2	R>10000			Same as Venturi meters
Flow Tube	+/- 1 to 2 % FS	3:1	>3	R>12500			Same as Venturi meters
Pitot	+/- 5 % FS	3:1	>3	No Limit			6" with Transmitter \$2,000
Annubar	+/- 1 to 2 % FS	3:1	>1	R>10000			3" \$800 12" \$1,400 \$2,000 with Transmitter
Pos. Displacement (P/D)	Liq. +/- 0.25 % (Rate) Gas +/- 1 % FS	10:1	Liq 2 to 16 Gas 1 to 16	Cs<8000	Liquid: 600F Gas: 250F	< 1440 PSIG	2" CS \$2-3,000 6" CS \$6-8,000
Turbine • Inline • Insertion	Liq. +/- 0.25-1.0 % Gas +/- 0.5 % of Rate +/- 5-10 % FS	10:1	0.25 to 24 0.25 to 24 line size>1.5	2 to 15 Cs	-300 To 500F -300 To 500F -50 To 500F	<3000 PSIG <3000 PSIG <1440 PSIG	4" \$2 to 3,500 6" \$3 to 5,000 \$2 to 4,000
Ultrasonic • Transit Time • Doppler	+/- 1% of Rate to 5% FS +/- 5 % FS	>10:1 10:1	>0.5 >0.25	No Limit No Limit	-300 To 500F -300 To 500F	Pipe Rating Pipe Rating	4" \$3 to 5,000 4" \$2 to 3,000
Magnetic	+/- 1 % FS	10:1	0.1 to 72	No Limit	Up To 300F	< 1440 PSIG	\$3 to 10,000
Mass Flow • Coriolis • Thermal	+/- .25-1.0% of Rate +/- 1% FS	>10:1 >10:1	1/16 to 6 >1	No Limit No Limit	-400 To 400F -50 To 350F	Pipe Rating Pipe Rating	\$1 to 20,000 \$1 to 15,000
Variable Area	+/- 0.5% of Rate To +/- 10% FS	5:1 to 12:1	<6	To Highly Viscous Fluids	Glass:< 400F Metal: <1000F	Glass:350 PSIG Metal: 720 PSIG	1" \$600 3" \$1,000
Vortex Shedding	+/- .75 to 1.5 % of Rate	8:1 to 15:1	0.5 to 16	R>10.000	-300 To 400F	Pipe Rating	4" \$2,500 8" \$5,000

Figure 17: Flowmeter Applications (Continued)

Safety Considerations

Safety considerations that influence flowmeter selection are described in terms of

- Providing protection to the flowmeter
- Hazardous area requirements
- Personnel protection

Providing Protection to the Flowmeter

Flowmeters can be protected through the use of

- Strainers
- Deaerators
- Isolation valves
- Block and bleed valves
- Control valves

Strainers are used to protect meters from debris in a liquid stream. Strainers are not intended for filtering a liquid. Strainers should be carefully selected to ensure that they have a low pressure drop when used with high velocity flowmeters.

Deaerators are air elimination devices that protect the meter from receiving a large slug of air. The air elimination device separates that air from the liquid through the use of special baffles. In the case of some positive displacement meters, a large slug of air can completely damage the meter. In the case of a turbine meter, air may not cause damage, but will cause errors in readings (registrations).

Isolation Valves are typically provided at a meter inlet to permit meter repairability without shutting down the process.

Block and Bleed Valves are used in meter runs to provide a means for calibration. These valves divert the flow to the meter prover loop.

Control Valves provide a means of controlling flowrate and/or back pressure. For example, flowrate control is necessary to prevent a positive displacement meter from overspeeding. While control valve selection is beyond the scope of this participant module, the proper valve selection is important to the measurement system's accuracy.

Hazardous Area Requirements

When a flowmeter is installed in a hazardous location or used to measure an explosive fluid, various safety standards specify the necessary precautions. Vendors provide designs that are approved by third party agencies such as UL (Underwriters Laboratories), FM (Factory Mutual), and CSA (Canadian Standards Association). The hazardous atmospheres, described in an earlier participant module, are defined in the National Electric Code (NEC) Articles 500 through 503. The NEC articles indicate the types of required protection and precautions.

Personnel Protection

Personnel protection is provided through

- Good design practices
- Proper installation practices
- Proper maintenance procedures

Good Design Practices include proper selection of materials of construction, which if not properly selected, can present hazards in applications where the metal reacts with the process media. An additional safety concern is the avoidance of toxic leakage, which increases as the number of manifolds, taps, and other meter components increases. Practices may also include designing in an extra margin of safety. For example, a vortex meter with a flanged body is safer than a vortex meter with a wafer body, especially if hazardous fluids are measured.

Proper Installation Practices are defined in the vendor's documentation and should be closely followed. Several common scenarios illustrate the need for safe practices. For example, flowmeters have their pressure ratings stamped on the outside of the meter. Likewise, flange ratings also are stamped with their pressure ratings. Users must not mistake the flange rating which can be significantly different than the meter, for the meter body rating. Otherwise, meter damage and possible harm to personnel will result. Another example of safe installation practices involves grounding. In the case of the magnetic flowmeter (magmeter), proper grounding is necessary to avoid shocking personnel.

Proper Maintenance Procedures include wearing protective clothing, opening valves slowly and carefully, de-energizing electric circuits to prevent shocks, using proper tools, and following vendor guidelines for their equipment.

In summary, safety begins with good design and installation practices.

Metallurgy

Metallurgy considerations involve selecting meter materials of construction that

- Provide chemical resistance
- Avoid reaction with process media
- Provide corrosion/erosion resistance
- Meet special requirements for hydrogen sulfides

Provide Chemical Resistance

Chemical resistance charts are available that describe how well a material resists chemical attack. An example series of charts can be found in Appendix A.3, Process Measurement, Liptak, Third Edition. Charts generally use a format similar to the one shown in Figure 18. Additionally, vendors provide charts that summarize metal resistance to environmental conditions. (Refer to the Work Aids for an example vendor chart.)

	X: Very Good Service +: Moderate Service -: Limited Service 0: Unsatisfactory : (Blank) No Data Available		
	Carbon Steel	304 Stainless Steel	316 Stainless Steel
Benzene	+	x	x
Carbon Dioxide (Dry)	x	x	x
Carbon Dioxide (Wet)	-	x	x
Water, Distilled	0	x	x

Figure 18: Example Chemical Resistance Chart**Avoid Reaction with Process Media**

The meter's materials of construction must not react with the process media. Fluids such as oxygen can present explosive hazards if they chemically react with certain materials. Steels, for example, can present hazards if they are not clean and polished when used in oxygen-enriched, high pressure, and high flow rate applications.

Provide Corrosion/Erosion Resistance

The meter's material of construction must also resist corrosion and erosion. Corrosive and erosive factors prevalent in Saudi Aramco applications include sulfur compounds, hydrocarbons, chlorides, dust, and sand. Chemicals tend to have corrosive effects, while particulates have erosive effects. High temperature sulfur corrosion is very common in oil processing environments. Carpenter 20, an alloy of nickel and chromium, and Hastelloy B2 provide excellent corrosion protection from sulfuric acids.

Special Requirements for Hydrogen Sulfides

According to SADP-J-100 Section 5.2.3, “When wet, sour fluids are to be metered, NACE standard MR-01-75 shall be used as a reference for determining the type of materials to be used for the wetted flow meter elements. Careful attention must be given to the selection of orifice metering components to ensure that they are compatible with process fluids.”

NACE MR 01-75 covers the metallic requirements for resistance to sulfide stress cracking. (Refer to the PCI 101.02 Participant Module for an extended discussion of sulfide stress corrosion.) Sulfide stress cracking refers to the fracturing of metal in response to pressure and a corrosive fluid. If sulfides, such as H_2S , are present in a fluid, then carbon and low alloy steels are susceptible to sulfide stress cracking. For example, if crude oil is too sour (over 3% H_2S), then a typical industry approach is to provide a meter, such as positive displacement meter, with special iron trim, bearings, seals, and gear shaft.

Installation Considerations

Installation considerations are described in terms of:

- Upstream and downstream piping requirements
- Meter orientation
- Piping supports
- Piping and flow conditioners

Upstream and Downstream Piping Requirements

Upstream piping length requirements are often specified by meter type. The upstream pipe must also be straight. Less obvious are the downstream piping requirements. Downstream piping may encounter control valves or obstructions that can create effects opposite to the flow direction. The effects can be large enough to back up to the meter, enter the meter, and alter the measurement.

Piping requirements that have an influence on flow measurement also include:

- The correct use of gaskets – Gaskets should not protrude into or be recessed from the flow streams. If gaskets are not flush with the piping, they can create a flow disturbance.
- Centering the pipe with the meter – Vendors often provide centering devices to ensure that the meter body is centered in the piping.

Meter Orientation

The meter's orientation is important so that the flowmeter can make an accurate measurement. For example, the electrodes of magnetic flowmeters should be in the horizontal plane. If a flow is likely to have a large amount of air, the magmeter can be installed vertically. The vertical installation helps ensure that the pipes and meter are kept full of liquid. The vertical installation also helps keep the electrode from fouling. Note that some meters, such as variable area type meters, must be installed in vertical runs of pipe.

All flow meters are to be installed, according to their service, following Standard Drawings:

AC 036231

AC 036232

AC 036233

AC 036234

AC 036235

Think in terms of whether the fluid is homogeneous; i.e., single or two-phase flow and whether the pipe line is full. If the pipe is partially full, the conditions under which the primary element was originally considered are not met and the results will be spurious.

Pipe Supports

Flowmeters are not intended to be piping supports. Although smaller meters may be able to handle pipe stresses, larger meters do not handle stresses well. Large meters are often mounted upon concrete slabs at ground level. Larger meters — such as Coriolis, magmeter, turbine, positive displacement — may require supports and anchors to limit piping stresses.

Piping and Flow Conditioners

Upstream piping should provide enough fluid mixing so that the flow profile at the meter is close to the flow profile used to calibrate the meter. Some flowing fluids experience jets and swirls that affect the flow profile. The two approaches to get the right profile are to use either longer lengths of pipe or flow conditioners. Flow conditioners reshape a swirling profile. Flow conditioners are available that can handle a full range of flow profiles. Note that an engineer should be aware that flow conditioners contribute to a pressure (head) loss.

Figure 17 references installation practices that influence flowmeter selection. Review these references (as well as the vendor's supporting documentation) for additional detail when determining a device's suitability for an application.

Saudi Aramco Reference	Reason for use	Summary
SAES-J-100, Section 5.2	PD meter installation	Install horizontally
SAES-J-100, Section 5.3	Turbine meter installation	• Liquid meter must comply with Chapter 5, Section 5.3 of MPMS • Gas meters must comply with AGA Report No. 7 • Install horizontally
SAES-J-100, Section 5.4	Orifice plate installation	Orientation per AD-036004
SAES-J-100, Section 5.5	Flow nozzle installation	Pipe section requirements
SAES-J-100, Section 5.6	Interconnecting piping	• Minimum bends and fittings • Avoid straightening vanes • Tubing requirements • Seal liquids • Impulse line sloping
SAES-J-100, Section 5.7	Local indication	Transmitter, recorder, and indicator mounting.
API RP 551, Section 2.2.3	Accessibility	Flow devices should be accessible
API RP 551, Section 2.2.4	Local indication	Mountings
API RP 551, Section 2.2.5	Vibration	Most flowmeters are susceptible to vibration damage; supports required
API RP 551, Section 2.2.6	Pulsation	Flow measurement is difficult if fluid pulsates, avoid if possible
API RP 551, Section 2.2.7	Purging and sealing	Protection required if fluids are corrosive or viscous

Figure 19: Installation References

Maintenance and Calibration

Maintenance considerations that influence flowmeter selection are described in terms of:

- Typical maintenance concerns by flowmeter type
- Meter failure concerns

Typical Maintenance Concerns by Flowmeter Type

Typical maintenance concerns by flowmeter type are shown in Figure 20.

Flowmeter	Flow Element	Maintenance Concerns
Differential Pressure	• Orifice Plate • Pitot • Venturi	• Simple, no moving parts • Susceptible to wear in dirty services except vertically • Orifice edge sharpness affects accuracy
Turbine	• Rotor	• Moving parts can wear
Vortex	• Bluff Body	• No moving parts; bluff body can corrode
Positive Displacement (PD)	• Oval Gear • Sliding Vane • Nutating Disk	• Many moving parts subject to wear • Prefilters for dirty service
Magnetic Field (Magmeter)	• AC Field • DC Field	• Low maintenance element, although electrode may foul
Ultrasonic		• Very low maintenance, nonintrusive
Mass	• Coriolis • Thermal Mass	• Very low maintenance, nonintrusive (Coriolis) • No moving parts, corrosive fluid may effect element (Thermal Mass)

Figure 20: Maintenance Concerns

Meter Failure Concerns

Flowmeters will, at some time in their life cycle, need repair. With that in mind, the engineer should review the following failure concerns:

- Repairability of flowmeter.
- Spare parts availability.
- Whether the failure would be catastrophic or not.
- What consequences will result if the meter fails.

Compatibility with Existing Process Instrumentation

Compatibility with existing process instrumentation is described in terms of:

- Relationship to metering system.
- General transmission practices.
- Signal levels to receiving devices.

Relationship to Metering System

Flowmeter selection is just one aspect in designing a liquid metering system. It should be noted that it is common to use meters in parallel. For greater accuracy, the same orifice primary can be connected to two differential pressure transmitters. A typical dual-range system can have transmitters sized to a 10-to-1 pressure ratio that, when square-rooted, works out to a 3-to-1 flow ratio. Whether the meter is in parallel or not, the following list of design criteria is reviewed by the engineer. Along with selecting the correct meter and meter size, the engineer considers the following:

- The minimum and maximum flow rates.
- What system pressure drops occur.
- The minimum back pressure for the meter run.
- The length of meter run.
- What isolation, block, or bleed valves are needed.
- What flow control and back pressure valves are necessary.
- Temperature and pressure indicators.
- Readout devices.

The intent of the previous discussion is to illustrate that metering system design is more than just selecting the correct flowmeter. While metering system design is beyond the scope of this Participant Module, the selection and installation of the above devices has a major influence on the flowmeter's accuracy. It can become a very complex process to design a liquid metering system, because the design involves more than just selecting the correct flowmeter.

General Transmission Practices

According to SADP-J-100, Section 5.2.2, "Receiving instruments (e.g., transmitters, transducers, switches, etc.) should be located to provide convenient access for their operation, maintenance, and removal. Refer to Saudi Aramco Standard Drawings AC-36231, 36232, 36323, 36234 and 36235 for instrument arrangement details."

According to API/RP551, Section 2.2.2. "Hydrocarbons or other process fluids should not be piped to any instruments located in a control room. Standard industry practice is to convert the flow measurement to an electrical or pneumatic signal and transmit the signal to remote receiving instruments."

Signal Levels to Receiving Devices

Control systems and/or computers that interface to flow measurement systems/meters must interface with four common types of input and output signals:

- Analog input/output signals
- Computer communication protocols
- Contact closures
- Frequency signals

Analog Input/Output Signals – Input signals are traditionally the 4 mA to 20 mA dc signal representation of a process variable. Analog inputs provide the portion of data that represents the temperature, pressure, and flow rate data. Analog output signals provide the variable signals for recorders, display, or control functions.

Computer Communication Protocols – Flow measurement computers use common protocols such as RS-232C and RS422. The measurement system's speed and compatibility with an existing system's protocol are common selection considerations.

Contact Closures – Discrete digital inputs can come from valves, pressure switches, or push buttons. Digital outputs from the computer system can control devices, transmit totalization data, and initiate alarm annunciators. The most common interface voltage is 24 Vdc.

Frequency Signals – Flowmeters can generate pulses that represent an amount of product. The receiving device counts the number of pulses generated during the flow’s duration. The main concern here is that the receiving device and flowmeter are compatible in the minimum and maximum frequencies. The receiving device is also evaluated for the capability to sense a pulsed waveform’s positive and negative thresholds.

Custody Transfer Concerns

Custody transfer concerns are described in terms of:

- Reasons for metering hydrocarbons
- Classifications of custody transfer measurements
- Metering approaches
- Meter provers required

Reasons for Metering Hydrocarbons

In typical oil processing plants, liquid hydrocarbons are metered at each custody transfer point and often at points where custody does not change. Several reasons for the metering are:

- Corporate accounting requires data
- Billing is dependent upon accurate measurements
- Losses are detectable
- Business decisions are based on the measurement data
- Assist negotiations, if necessary
- Provide auditable, historical records

Classification of Custody Transfer Measurements

For a custody transfer measurement of a liquid hydrocarbon, a contract requires a volumetric measurement at standard conditions of temperature and pressure. The techniques to do this are broadly categorized as “static” and “dynamic.” Static measurements are accomplished through automatic tank gauging. (Another example of a static measurement is the measurement of a marine cargo tank.) Approximately 30% of custody transfer occurs this way at Saudi Aramco. Dynamic measurements are accomplished through liquid metering methods. The majority of custody transfer occurs using liquid metering methods at Saudi Aramco.

According to SADP-J-100, Section 4.3, “All flow meter installations involving royalty and custody transfer metering of hydrocarbon gases or liquids shall comply with Saudi Aramco Standards SAES-J-101 and SAES-J-102.”

Metering Approaches

Two types of meters are traditionally used in most industries for custody transfer of liquid hydrocarbons—the turbine meter and positive displacement meter. While turbine meters and positive displacement meters are described in more detail later in this course module, several custody transfer concerns can be mentioned in terms of the following:

- Turbine meter custody transfer considerations.
- Positive displacement custody transfer considerations.

Turbine Meter Custody Transfer Considerations are best seen by reviewing how a turbine calculates flowrate. A turbine meter measures flowrate based on the calculation

$$Q = V \times A$$

where

Q = volumetric flowrate

V = measured flow velocity

A = constant flow area

Thus, anything that affects A or V has a direct bearing on Q, the volumetric flowrate. The custody transfer concerns are summarized as:

- over registering
- under registering

Over registering – The meter over registers when the constant flow area is reduced. The reduction in flow area causes the flow velocity to increase. The flow area is reduced either through coating buildups or debris caught on the final conditioning element.

A coating buildup of 0.001 inch on a 4 inch turbine meter internal parts can have a 0.5% effect on its registration. Coating effects are proportional to the square of the meter size. Thus, a 0.001 inch coating causes a 2% shift on a 2 inch meter. Turbine meters used to measure high paraffin content products have a tendency to buildup coatings.

Under registering – The meter under-registers if the flow area, A , increases. The increased flow area decreases the flow velocity. Under registering occurs when swirling occurs near the leading edge of a turbine rotor. Flow conditioners installed according to API standards prevents this occurrence.

Positive Displacement Meter Custody Transfer Considerations– Unlike turbine meters, positive displacement meters transfer fixed volumes of liquids. The flowing stream is sent into measuring chambers; the meter totalizes the fixed volumes transferred through the measuring chambers.

A typical approach is to use displacement meters for custody transfer operations. Several reasons for this are the following:

- Historically, the positive displacement meter has been successful
- Electrical power not required
- Smaller than turbine meters (less space required)
- Can be temperature compensated
- Crude oil provides good lubrication to the PD meter

A positive displacement meter's custody transfer performance is a function of slippage and wear. Slippage represents the amount of product that passes the seal in the measuring chamber of a positive displacement meter. Slippage is dependent on the clearances in the measuring chamber remaining constant. However, if the viscosity or flowrate changes, the amount of slippage changes.

Meter Provers Required

Any flowmeter's indication of a volume represents an unknown volume unless the volume can be compared to a known volume. The known volumes are called "meter provers." For a meter to be considered accurate, the meter must be proved at the same conditions of flowrate, temperature pressure, and product viscosity. Meter provers are described in more detail later in this course module.

Economic Considerations

Economic considerations are described in terms of:

- Cost of ownership
- Pumping costs

Cost of Ownership

Cost of ownership can easily exceed the initial purchase price of the meter. Cost of ownership includes the following factors:

- Meter Cost – The initial purchase price of a meter is the most obvious cost. As a general rule, meter costs increase as greater accuracy is required. Cost should include primary and secondary devices and auxiliary equipment.
- Accuracy – The cost of accuracy (or inaccuracy) is best seen in custody transfer operations, where the cost of unaccounted for products can be quantified.
- Repeatability – If a device became inaccurate because of wear or process damage, its repeatability may still be acceptable for continued process use.
- Installation – Cost including labor and materials.
- Mean time between failure (MTBF)
- Number of mechanical parts – as the number of moving and exposed parts increases, so does the probability of repair.
- Process downtimes caused by failure or scheduled maintenance and calibration.
- Cost to Repair – some flowmeters may require specialized personnel skills or equipment.
- Implementation Costs – If the device can interface and share data with other instrumentation, the costs are obviously lower.
- Disposal Costs – A device exposed to toxic chemicals may contain hazardous chemicals.

Pumping Costs

Pumping costs account for the energy costs in overcoming the pressure losses through a flowmeter. Calculations are available for determining the operating cost of a flowmeter. For a simple orifice plate, these costs can reach thousands of Riyals per year. (Refer to Chapter 2.1 “Process Measurement,” Liptak, Third Edition, for pumping cost calculations.)

Technical Direction

Technical directions in flow instrumentation improvements are occurring in the following areas:

- Improvement in overall design
- Increasing integration of microprocessor technology
- Improvements in vortex and mass based meter designs
- Introduction of multivariable transmitters
- Evolution of Fieldbus standard

Improvements in Overall Designs

Flowmeter manufacturers have improved the meter's design in order to facilitate flowmeter cleaning and disposal. Product redesigns eliminate or minimize the number of crevices or openings where process fluids accumulate.

Increasing Integration of Microprocessor Technology

Increasing integration of microprocessor technology has led to flowmeters that have increased performance functionality and communication capabilities. The improvements in performance are seen in better accuracies and improved effect specifications. A temperature effect specification, for example, is improved in mass flowmeters because of ambient measurements that compensate for the thermal expansion coefficients in the flowmeter's materials of construction.

Increased functionality includes the flowmeter's ability to access additional process variables. The additional process variables can include process density, process temperature, and gravimetric flow rates.

Use of microprocessor based differential pressure transmitters in flow applications can significantly improve performance without the need to replace the orifice plates (or other primary element). In pre-existing applications that have a conventional transmitter, there is usually no need to shut down the process or make new process tap connections.

The microprocessor based instruments can be expected to develop into a spectrum of performance levels. On the low end of the spectrum, flowmeters with remote communication capabilities would be used in hard to reach locations. On the high end of the spectrum, flowmeters that offer higher accuracies and functionality will find use in applications such as custody transfer.

As microprocessor based flowmeters evolve, and the meter's related performance improvements become common place, product differentiators will be the meter's added software capabilities. The capabilities are hard to predict, but could include data collection, predictive maintenance, embedded control, or other software functions.

Improvements in Vortex and Mass Based Meter Designs

Although the orifice plate and differential pressure transmitter are the most commonly applied flowmeter, advances in flowmeter designs have created new interest in other flowmeters, such as vortex and mass based flowmeters.

Vortex meters have been successfully used in sulfur and crude oil operations that traditionally are measured with orifice plates. Vortex meters prices have been decreasing and are slightly higher than an orifice plate. The reliability for a vortex meter is better than that of an orifice plate, which wears because of corrosive/erosive flows. Vortex meters also offer higher turndown ratios.

Mass-based flowmeters are finding use in applications that require higher accuracies, measurements in terms of mass instead of volume, or nonintrusive measurements. A Coriolis flowmeter, for example, can measure low flow rates. The rangeability for a Coriolis flowmeter is greater than that of an orifice plate's.

Introduction of Multivariable Transmitters

In measuring flow, temperature is required to compensate for changes in density. Correct placement of a temperature probe (process temp. not body temp.) is required whether measuring with a multivariable technique or the old fashioned way.

A multivariable transmitter is essentially four transmitters in one package. A multivariable transmitter (Figure 19) measures differential pressure, absolute pressure, and process temperature. The multivariable transmitter also calculates the compensated flow. Traditionally, three separate transmitters and flow calculation were required for this measurement.

The multivariable transmitter incorporates microprocessor based technology which provides the advantages of better readability and tighter integration. Additionally, the multivariable transmitter reduces installation costs, spares inventories, and commissioning times. The transmitter has the flexibility to be used in applications such as custody transfer, energy and material balances, and advanced control and optimization.

Determining Appropriate Flow Measurement
Devices For Saudi Aramco Applications

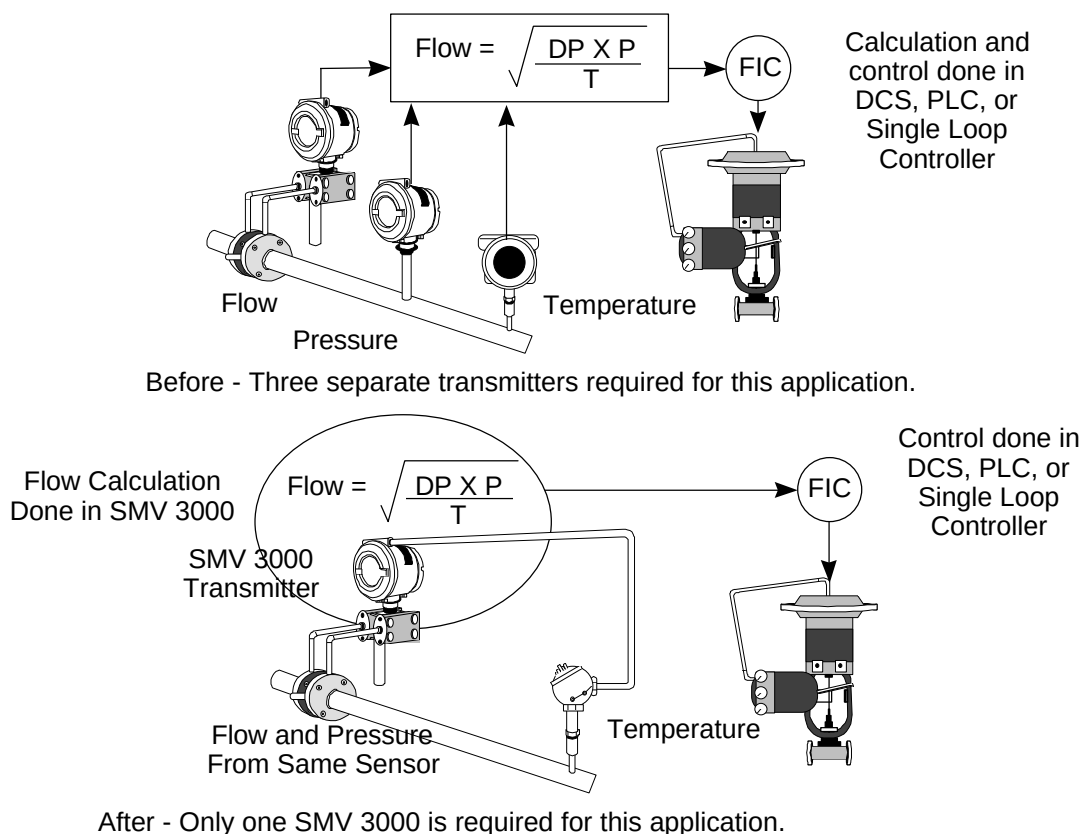


Figure 21: Multivariable Transmitter Example

Evolution of Fieldbus Standard

Improved communications are accomplished through the use of proprietary digital communications protocols and/or a standardized fieldbus. The improved communications provide tighter control, better reporting, and data collection. The development of a Fieldbus standard, as mentioned earlier in this course, has the potential for the following:

- Reduced wiring costs.
- Interoperability among field devices.
- Field devices that send messages to the control system or other field devices.
- Reduced need for controller I/O hardware.
- Reduction of maintenance costs.
- More precise control.
- Migration of control to field devices.
- Reduced need for conventional “nonsmart” flowmeters.

DETERMINING WHETHER AN ORIFICE PLATE FLOW MEASURING DEVICE MEETS APPLICATION REQUIREMENTS

Differential pressure flowmeters work on Bernoulli's Energy equation applied to a streamline principle.

The principle states that when a restriction is placed in a pipe where fluid flow occurs, the kinetic energy increases at the expense of the static pressure. The differential pressure (h) produced by the restriction can be measured and is related to the flow ratio.

Basic Flow Metering Equation

The equations used in flow metering calculations are derived from the fundamental concepts of fluid mechanics, using the following assumptions:

1. That the flow is steady – This means that the flow metering equations cannot be used for flow measurements made during periods when the rate of flow is varying.
2. That this flow is one-dimensional – This means that the velocity profile is assumed to be uniform and that the velocity is computed from

$$V = \frac{Q}{A}$$

where:

V = average velocity ($\frac{\text{ft}}{\text{sec}}$)

Q = volumetric flow rate ($\frac{\text{ft}^3}{\text{sec}}$)

A = passage area (ft^2)

3. That the flow is frictionless – This means that the Bernoulli equation in the “HEAD” form can be used:

$$z_1 + \frac{V_1^2}{2g} + h_1 = z_2 + \frac{V_2^2}{2g} + h_2$$

where:

z = elevation above a datum (ft)

h = pressure (ft) (ρ/pg)

and subscripts 1 and 2 pertain to inlet and outlet sections respectively.

4. That the flow meter is horizontal – This means that $z_1 = z_2$, so that the Bernoulli equation can be written in the following form:

$$h_1 + \frac{V_1^2}{2g} = h_2 + \frac{V_2^2}{2g}$$

5. That the fluid is incompressible – This means that the equation of continuity can be written in the following form:

$$Q = A_1 V_1 = A_2 V_2 = \left(\frac{\pi D^2}{4}\right) V_1 = \left(\frac{\pi d^2}{4}\right) V_2 \quad \text{or}$$

$$V_1 = \left(\frac{d}{D}\right)^2 V_2 = \beta^2 V_2$$

where:

D = internal pipe diameter (ft)

d = primary element internal diameter (ft)

β = beta ratio = $\frac{d}{D}$ dimensionless

A_2 = area of primary element (ft²)

Ideal Flow Rate

For computing the ideal volumetric flow rate, the above equations can be combined to obtain

$$Q_{\text{ideal}} = \frac{A_2 \sqrt{2g(h_1 - h_2)}}{\sqrt{1 - \beta^4}}$$

Working Equation for Flow Meters

For calculating the actual flow of fluids through a differential flow meter, the following working equation is used to adjust the ideal flow to the actual:

$$W = N C E d^2 F_a Y \sqrt{h_w \rho_1}$$

where:

W = mass flow rate $\frac{\text{lbm}}{\text{hr}}$

N = number for unit conversion
= 358.93 for m in $\frac{\text{lb}}{\text{hr}}$

C = discharge coefficient-ratio of actual to ideal flow

E = Velocity of approach factor ratio
 $= \frac{1}{\sqrt{1 - \beta^4}}$

d = primary element diameter measured at 68°F (20°C) inches

F_a = thermal expansion factor ratio
takes into account the expansion of the primary element and the pipe when metering is at other than 68°F

Y = expansion factor ratio
takes into account the compressibility of fluids. For incompressible fluids (liquids) $Y = 1$

h_w = pressure differential inches of water at 68°F

ρ_1 = fluid density $\frac{\text{lbm}}{\text{ft}^3}$

Figure 22 illustrates this notation.

Discharge Coefficient C

The discharge coefficient C is a function of

R_d	Reynolds No.	}	Velocity profile
$\frac{\varepsilon}{D}$	Relative Roughness		
$\frac{L}{D}$	Tap Location Ratios	}	Pressure gradient
$\frac{d}{D}$	Beta Ratio		
M	Mach No.		

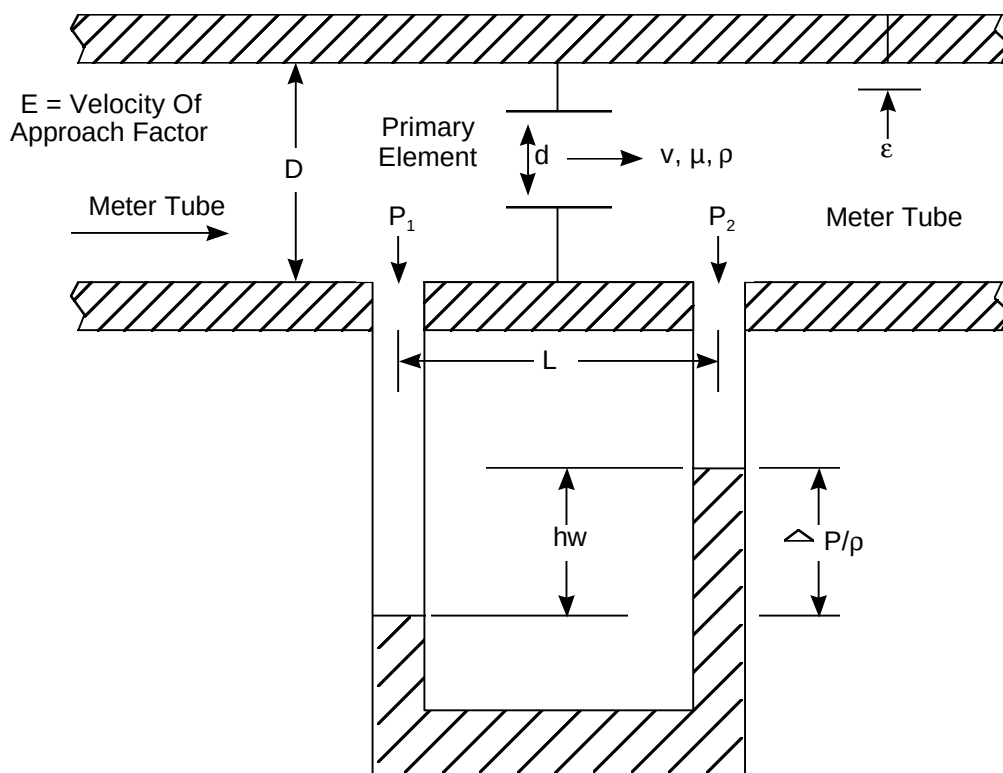


Figure 22: Differential Pressure Flowmeter Principle

The volumetric flow rate through the cross-sectional area is represented as

$$Q = A \times v$$

where

- Q = volumetric flow rate
- A = flow in cross sectional area
- v = the average fluid velocity

The average fluid velocity can be calculated as follows:

$$v \propto \sqrt{2gh}$$

where

- g = acceleration caused by gravity
- h = change in height (differential head)

Substituting for v , the continuity equation can be written as

$$Q \propto A \times \sqrt{2gh}$$

where:

- A = upstream area

Volumetric flow rate can also be calculated by using the equation

$$Q = K A \sqrt{\frac{h}{\rho}}$$

Mass flow rate can also be calculated by using the equation

$$W = K A \sqrt{h\rho}$$

where

W = mass flow rate

h = differential pressure

ρ = fluid density

K = constant based upon dimensions, thermal and expansion factors, and units

Differential pressure flowmeters are also known as head meters. The differential pressure flowmeter is suitable for a variety of applications — including gas, liquid, viscous, and corrosive fluid measurements. Differential pressure flowmeters have no significant pipe size or flow rate limitations. Differential pressure flowmeters have no moving components; however, measurement accuracy is reduced when an uncalibrated orifice plate or improperly calibrated meter is installed in the pipe.

All differential pressure flowmeters show a square root relationship between differential pressure head and flow rate (Figure 23). The square root relationship limits the usable flow range for any service. For example, 50% of flow rate produces 25% of full differential pressure. When maximum accuracy is required, it is generally recommended that the maximum-to-minimum flow ratio shall not exceed 3 to 1. If flow measurement has a 10 to 1 ratio, use two primary elements sized for different capacities, or two differential pressure transmitters with different ranges on a single primary element.

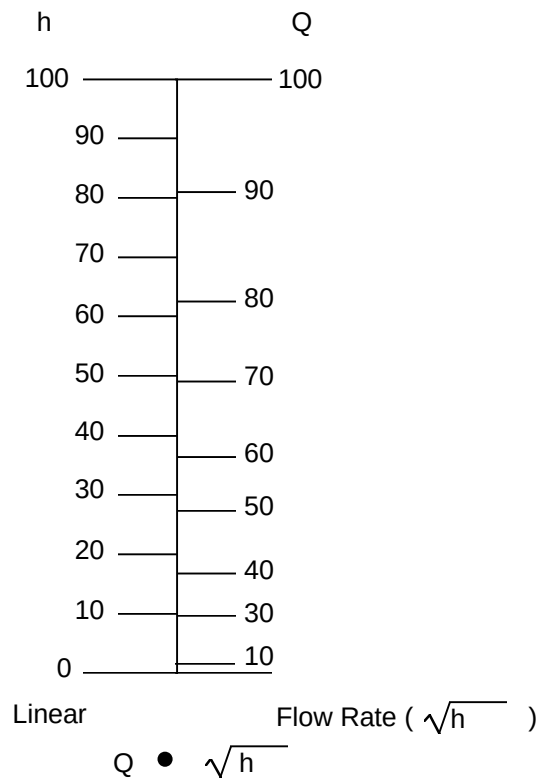


Figure 23: Differential Pressure to Flowrate Relationship

The following are the most commonly used differential pressure flowmeters:

- Orifice plates
- Venturi
- Flow nozzles
- Pitot tube / annubar
- Elbow or wedge meter

This section of the course module introduces to the Participant the following flow measurement topics:

- Orifice plates
- Software versus manual calculations for orifice plate sizing

- Software versus manual calculations for flow rate
- Software versus manual calculations for pressure drop
- Instrument Specification Sheets (ISS)
- Computer programs for sizing orifice plates
- Expected accuracy
- Review orifice flow meter auditing/troubleshooting

Orifice Plate

General Description

An orifice plate is the main element within an orifice meter tube. An orifice plate is the simplest and most economical type of all differential pressure flowmeters. An orifice plate is constructed as a thin, concentric, flat metal plate. The plate has an opening or “orifice.” An orifice plate is installed perpendicular to the fluid flow between the two flanges of a pipe. As the fluid passes through the orifice, the restriction causes an increase in fluid velocity and a decrease in pressure. The potential energy (static pressure) is converted into kinetic energy (velocity). As the fluid leaves the orifice, fluid velocity decreases and pressure increases as kinetic energy is converted back into potential energy (static pressure). Orifice plates always experience some energy loss – that is, a permanent pressure loss caused by the friction in the plate. The Beta ratio is defined as the ratio of the diameter of orifice bore to internal pipe diameter. The most common holding system for an orifice plate is a pair of flanges, upstream and downstream piping, and a pressure tap (Figure 24). The pressure taps are located either on orifice flanges or upstream and downstream of the pipe from the orifice plate.

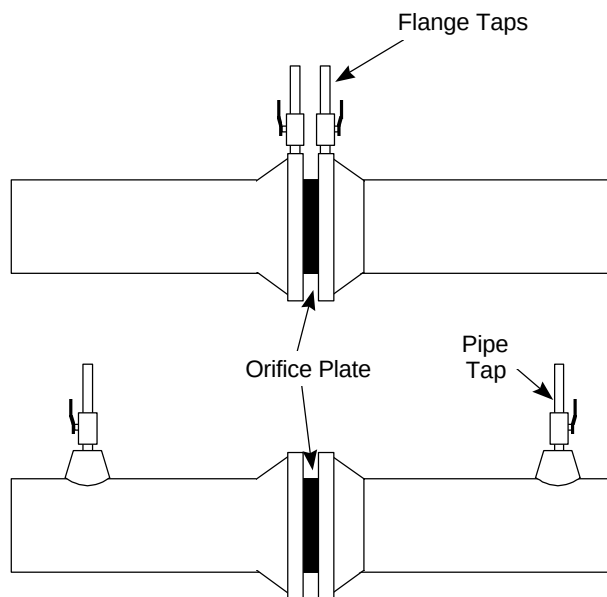


Figure 24: Orifice Plate Pressure Tap Configurations

Several types of orifice bore designs are available for orifice plates; concentric, segmental, and eccentric orifice plates. The plates are used for a wide range of applications. For precise measurement, various types of fittings are used; junior fittings, senior fittings, and simplex fittings. The fittings provide easy installation of an orifice plate, removal of the plate for changes in flow rate services, and convenient removal for inspection and maintenance. Limitations of orifice plates include a high irrecoverable pressure and a deterioration in accuracy and long term repeatability because of edge wear.

Two types of orifice plates designs are available — paddle type and universal type. The paddle type orifice plate, used with an orifice flange, has a handle for easy installation between flanges. On the paddle type plate, the orifice bore, pressure rating (flange rating), bore diameter, Beta ratio (β), and nominal line size are stamped on the upstream face of the plate. The outside diameter of a paddle plate varies with the ANSI pressure rating of the flanges.

The universal orifice plate is designed for use in quick change fittings, or in the plate holder of the ring type joint (RTJ) orifice flanges. The universal plate is placed in a plate holder, the outside diameter is the same for all pressure ratings for any given size. When using orifice fittings, the internal diameter of the meter tube must be specified because the orifice plate is held in an orifice plate sealing unit. The sealing unit is made of metal, viton, or rubber material.

Some orifice plates have a small hole in the orifice plate besides an orifice bore, either above or below the center of the plate that is called a weep hole. The purpose of the weep hole is to allow the passage of any condensate in a gas application or passage of gas in liquid service applications. The area of the weep hole must be considered when sizing an orifice plate. An orifice plate with a weep hole should not be used when accurate measurement is required in a flow measurement application, such as in gas sales service. (See Standard Drawing: AB 036094 NOTE 8.)

Figure 25 shows a paddle-type orifice plate and a universal orifice plate assembly.

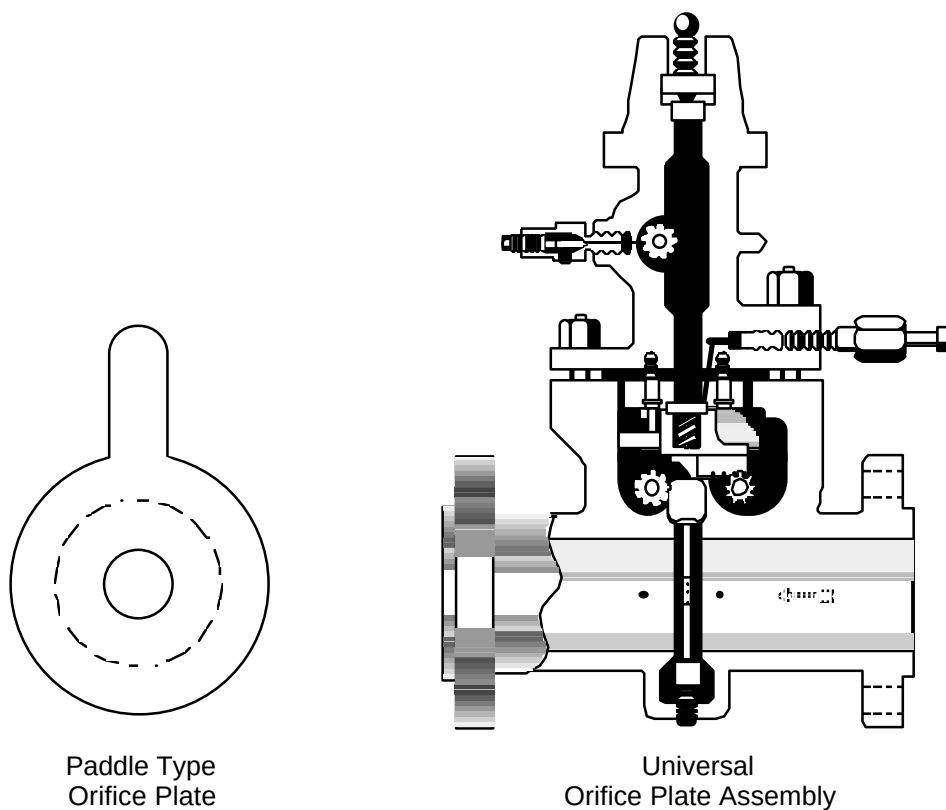


Figure 25: Paddle Versus Universal Orifice

Figure 26 shows a concentric orifice plate.

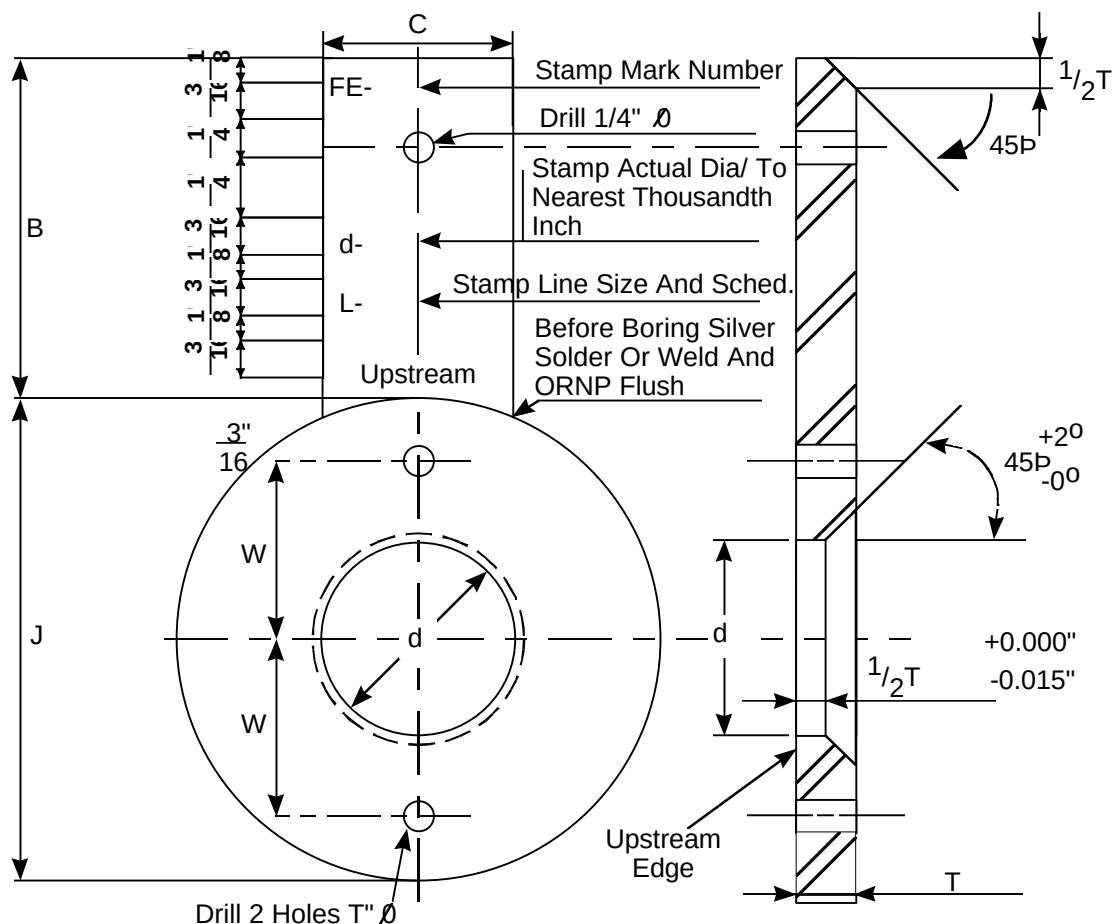


Figure 26: Concentric Orifice Plate

The orifice plate, although a relatively simple element, is a precision measuring instrument and should be treated accordingly. Critical items considered when evaluating orifice plates are the following:

- Flatness, smoothness, and cleanliness of the orifice plate.
- The sharpness of the upstream orifice edge.
- The bore diameter and thickness of the orifice plate.

Cutouts – Figure 27 shows a bevel-edge cutout of an orifice plate face.

- d represents the bore of the orifice plate.
- D represents the pipe inside diameter.
- The upstream and downstream sides of the orifice plate are flat. Flatness of the orifice plate is specified as ≤ 0.010 inch per inch of dam height. Dam height represents the difference of pipe inner diameter and diameter of bore divided by 2.
- T represents the thickness of the plate.
- e represents the orifice plate bore thickness which is $1/2 T$
- θ is called orifice plate bevel angle. " θ " is 45° , $+20^\circ -0^\circ$.

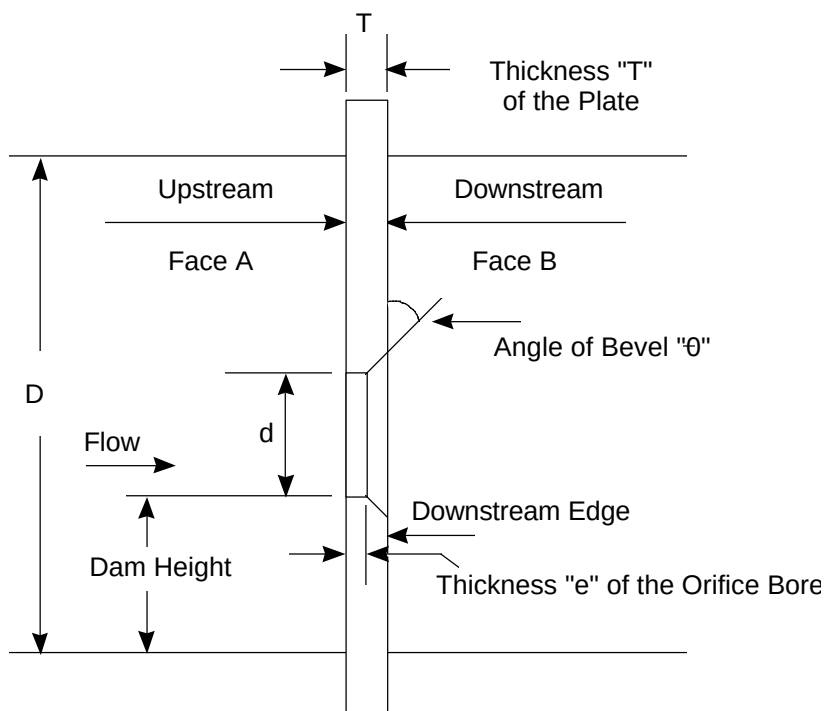


Figure 27: Orifice Plate Dimensions

Thickness – According to S.A. 990J AB 036094 Std Dwg., the recommended value of the orifice plate thicknesses are

- 1/8 inch thickness for pipe size nominal diameters from 2 inches to 12 inches,
- 1/4 inch thickness for pipe size nominal diameters from 14 inches and 30 inches,
- 3/8 inch thickness for pipe size nominal diameters from 32 inches to 42 inches,
- 1/2 inch thickness for pipe size nominal diameters of 44 inches and above.

(For specific applications, contact the orifice plate's vendor for technical assistance.)

Tolerance – According to AGA Report Number 3, the absolute value of the percentage difference between the meter tube's internal diameter D and any individual diameter within a distance of 1 meter upstream of the plate should not exceed 0.25% of D .

$$\left(\frac{\text{Any diameter within one } D - D}{D} \times 100 \right) \leq 0.25 \%$$

For more details on tolerances, refer to AGA Report Number 3, Orifice Metering for Natural Gas and Hydrocarbon Fluid. Reference 2.5.1.3.1.1 (also Amoco Meas. and Control, Vol. 1, pg 1-667).

Orifice Plate Bevel Angle (θ) – The plate bevel angle is defined as the angle between the bevel and the downstream face of the plate. According to S.A. 990J AB 036094 Std Dwg., bevel angle of the orifice plate should be 45° , $+20^\circ$ -0° .

Beta Ratio (β) – Meter head depends upon a restriction in the flow path to generate a change in fluid velocity. For a circular pipe, beta ratio represents the ratio between the diameter of restriction bore (d) and the inside diameter of the pipe (D). The ratio between the fluid velocity in the pipe and velocity at the restricted bore is equal to the ratio of area. For a noncircular pipe, β (beta) is defined as the square root of the ratio of area of the restriction bore to the area of the pipe. For an orifice plate to provide accurate flow measurement, select a beta (β) ratio between 0.2 to 0.70. (AGA allows 0.1 to 0.75.)

Four Basic Orifice Plate Types

The orifice plate with a bevel edge and concentric bore is used for general applications. Four basic types (Figure 28) of orifice plate bores are the following:

- Concentric
- Eccentric
- Segmental
- Quadrant or conical edge

Concentric Plates – The concentric orifice bore plates are used in general flow measurement applications. The concentric orifice plate has an orifice bore in the center of the plate. The center of bore is either beveled or straight. The beta ratio for the concentric plate is between 0.1 to 0.75. The beta ratios of the plate is “ $\beta = d/D$,” where “ d ” is the diameter of the bore and “ D ” is the diameter of the plate or internal diameter of the pipe. The concentric bore plate is used for clean fluid services, as well as for applications requiring accurate flow measurement.

Eccentric Plates – The eccentric orifice plate is similar to a concentric plate, but the eccentric plate has the bore in an offset position. The eccentric orifice plate is used when dirty fluids are measured, to avoid the tendency of hole plugging if a concentric plate were used. Flow coefficient data is limited for eccentric orifices; therefore, it provides less accurate measurement. In an eccentric orifice plate, the hole is bored tangent to the inside wall of the pipe or, more commonly, tangent to a more concentric circle with a diameter not smaller than 98% of the pipe's internal diameter. When lacking specific process data for the eccentric orifice plate, the concentric orifice plate data may be applied as long as accuracy is not a major issue. During the installation of an eccentric plate, make sure that flanges or gaskets do not interfere with the plate hole.

In an eccentric orifice plate, the line size ranges from 4 inches minimum to 14 inches maximum. The eccentric plate can be made smaller than a 4 inch size as long as the orifice bore does not require a beveling edge. Beta (β) ratio is limited between 0.3 to 0.8. Flange taps are recommended for eccentric orifice plate installations. In an eccentric plate, the pressure taps should be located in the quadrants directly opposite the hole. The tabs on these plate should be stamped after installation to indicate the type of bore that the plate has.

Segmental Plates – The segmental orifice plate's bore looks like a segment of a circle. The segmented circle hole is offset from the plate's center. In a segmental orifice plate, the orifice hole is bored tangent to the inside wall of the pipe or, more commonly, tangent to a more concentric circle with a diameter not smaller than 98% of the pipe internal diameter. The plate arc is parallel to the pipe wall. During the installation of the segmental plate, make sure that the flange or gasket does not interfere with the plate hole. The beta ratio (β) for the segmental orifice plate is expressed as $\beta = \sqrt{a/A}$, where "a" is the area of the hole segment and "A" is the area of the internal pipe. Beta ratio is limited between 0.3 to 0.8. In a segmental orifice plate, the line size ranges from 4 inches minimum to a maximum of 14 inches. Reynolds number for segmental plate is limited to $20,000D$, where "D" is the diameter of the pipe. However, the Reynolds number should not be less than 10,000. Flange taps are recommended for segmental orifice plate installations. The taps for the segmental orifice plate should always be in the line with the maximum dam height. The tabs on this plate should be stamped after installation to indicate the plate's type of bore.

Quadrant Edge Plates – Quadrant edge bore (quarter circle) orifice plates are used for lower pipe Reynolds numbers where flow coefficients for sharp-edge orifice plates are highly variable. The Reynolds numbers range from 500 to 10,000; maximum allowable pipe Reynolds numbers range from $500,000 \times (\beta - 0.1)$. The stability of flow coefficient will be increased by a factor of 10. The quadrant edge orifice plate is used for viscous clean liquid applications. Nominal pipe size ranges between 1 and 6 inches.

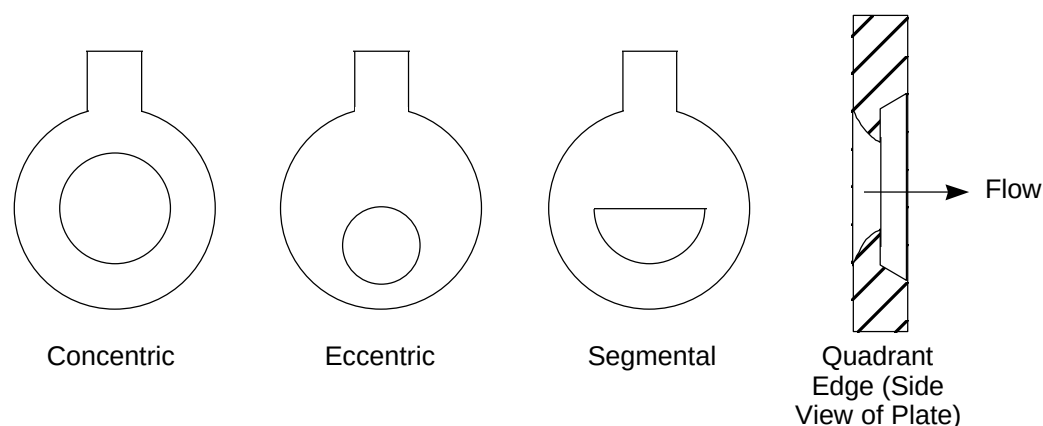


Figure 28: Types of Orifice Plates

Orifice Plate Parameters – The orifice plate is a simple and accurate flow measuring device. The accuracy of measurement depends on the quality, installation, and maintenance of the orifice plate. The following are the main parameters of an orifice plate, refer to Figure 28 as needed.

(1) Orifice flow rate: The orifice flow rate represents the mass or volume of flow through an orifice meter per unit of time.

(2) Pipe line size and pressure rating: When sizing or specifying the orifice plate, the pipe line size, schedule, and pressure rating need to be specified. For example, 4 inches, schedule 40, and pressure or flange rating 300 # RFSF are example specifications. For a pipe size of 4 inches, schedule 40, the internal diameter of pipe is 4.026 inches. The internal diameter of pipe is specified as parameter “D”.

(3) Thickness of orifice plate: It is important to specify the thickness of the plate. The thickness of the plate is from 1/4 inch to 1/2 inch in size. The specified thickness depends on the size of the plate, the operating pressure, and the differential pressure across the orifice plate.

(4) Orifice Bore (d): The orifice bore is simply the hole opening in the plate. An orifice bore is either in the center of the plate or offset from the center of the plate. The orifice plate bore diameter(d) is calculated at flowing temperatures under physical and chemical conditions. The orifice bore is calculated either manually or through the use of commercially available orifice sizing programs.

(5) Orifice plate holders: The orifice plate holder includes orifice flanges, orifice fittings (simplex, junior or senior fittings), or regular flanges (if it is a restriction orifice plate).

(6) Beta Ratio (β): The beta ratio is also called a diameter ratio. The beta ratio is defined as the calculated orifice bore’s diameter to the internal pipe’s diameter.

(7) Differential Pressure (ΔP): The differential pressure represents the static pressure difference upstream and downstream of the plate. Generally differential pressures across the plate range from 0-50, 0-100, 0-200 inches of water column. Note that the differential pressure is used in calculations for the orifice plate bore or flow rate.

(8) Temperature: The temperature represents the fluid temperature flowing through a pipe. The flowing fluid temperature is measured in degrees Fahrenheit or degrees Celsius. Temperature is used to determine the density of the fluid. The temperature of the fluid value can be converted to an absolute temperature value in degrees Rankine or Kelvin.

(9) Reynolds Number (Re): In an ideal condition fluid with no viscosity, the velocity profile of the fluid in a pipe would be uniform. In a real condition fluid with a viscosity, the fluid slows down near the pipe wall and velocity is zero. The flow profile is nonuniform across the pipe wall. The pipe Reynolds number represents a dimensionless ratio of density of fluid times the internal diameter of the pipe times the velocity of the fluid to the viscosity of the fluid.

$$Re = \frac{v D \rho}{\mu}$$

At low Reynolds numbers below 2,000, the flow is laminar. The flow can be visualized as a group of concentric shells where each shell reacts in a viscous manner on adjacent shells, the velocity profile across the diameter is substantially parabolic. At higher Reynolds numbers, flow is turbulent. Turbulent flow creates eddies between the body of the flowing fluid and the boundary layer, and propagates through the flowing stream pattern. For Reynolds numbers above 10,000, flow is turbulent. The coefficient of discharge of the various head type flowmeters changes as the Reynolds number changes.

(10) Pressure taps: Taps are holes drilled radially in the wall of the pipe or in a pair of orifice flanges. A differential pressure measuring device is piped to an orifice plate through the taps. Several types of taps are available for the orifice metering device and are described later in this section.

The following parameters are required to calculate the orifice bore

(1) Flow rate: The rate of the flow flowing through a pipe per unit of times at a flowing temperature. Normal and maximum flow rate are required. If the normal flow rate is not available, then use 80 % of the maximum design flow rate.

(2) Temperature: The temperature of a flowing fluid is required at flowing and base conditions. The unit of temperature is in degrees F or degrees C. The temperature can be converted into absolute temperature in degrees Rankine or Kelvin.

(3) Pipe diameter: The internal pipe diameter equals the outside nominal pipe diameter minus twice the wall thickness (I.D. = O. D - 2 x wall thickness).

(4) Pressure rating: Pressure ratings are important because selection of the thickness of the plate depends on the pressure rating. For example, specifications can be in terms of 150#, 300#, 600#, 1500#, 2500# class ratings.

(5) Operating pressure: The operating pressure of fluid flowing through a pipe can be expressed in psia (pounds per square inch absolute) or KiloPascal units.

(6) Differential pressure (ΔP): The differential pressure represents the static pressure difference across the upstream and downstream of the plate. Typical units of differential pressure are: inches of water column for the orifice plate, venturis, flow nozzles, annubar, or pitot tube and psia or KiloPascal for the restriction orifice plate.

(7) Density of fluids: The density of homogeneous fluid represents the ratio of its mass to its volume. The density varies with temperature changes. The density of fluid is expressed in mass per unit volume at a specified temperature and its units are lb/ft^3 , or kg/m^3 .

(8) Viscosity: Viscosity represents the fluid's property of shearing stress on fluid velocity at a flowing temperature. Units of viscosity are Centistokes (Cs) or Centipoise (Cp).

(9) Specific gravity: The specific gravities of fluid at operating temperature and base temperature are required for the calculation.

(10) Supercompressibility: Compressibility represents the change in volume per unit of volume of a fluid caused by a unit change in pressure at a constant temperature. The ideal gas law does not fully explain gas behavior when pressures are above 100 psig. In order to explain gas behavior, supercompressibility factors are required for gas flow measurements when pressures over 100 PSIG are encountered.

(11) Molecular weight (M_w) / Specific heat ratio (C_p/C_v): Molecular weight of gas is required as an input for the calculation. Specific heat represents the ratio of specific heat at constant pressure C_p to specific heat at constant volumes at operating temperature (that is, $k = C_p / C_v$).

(12) Base conditions: Also called standard conditions, base conditions represent pressure and temperature conditions to which measured volumes are referenced to. For example:

Base pressure and base temperature : 14.7 PSIA @ 60°F

Base pressure and temperature in SI unit 100 kPa @ 15.6°C

(13) Plate Thickness: Thickness of the plate specified in inches.

(14) Vent or Drain Hole: Also called a weep hole, the engineer determines whether it is required or not on the orifice plate (Weep holes are described in this section of the course material).

Differential Pressure Range (ΔP) represents the drop in pressure across a head device at specified pressure tap locations. The pressure drop is generally measured in inches or millimeters of water column. The differential pressure is the most important variable factor for differential head meters, because it is used to calculate flow rate. When errors in flow measurement occur with a differential head meter, the error is seen in this measurement.

Differential pressure for orifice meter tubes, venturi and flow nozzles, is typically 0-100 inches of water column (0 to 25 kPa) for a full scale flow. The 100 inches in span permits a 2:1 flow rate change in either direction to accommodate changes in operating conditions. The pressure loss in an orifice is about 65% when a beta ratio of 0.75 is used. The higher the differential pressure, the lower the beta ratio. An application where the pressure loss is up to 3.5 psi becomes expensive. If a high-range differential pressure transmitter is not available, it can be handled by the selection of a lower differential pressure or venturi tube.

Orifice Meter Tube and Straight Pipe Parameters – The meter tube assembly (Figure 29) consists of an orifice plate, orifice plate holders (such as orifice flanges or simplex, junior, or senior fittings), straight pipes runs (upstream and downstream from orifice plate), straightening vanes (at upstream side if required), pressure taps, and temperature taps. The length of the straight upstream pipe and straight downstream pipe of the same diameter depends on beta ratio and configuration of piping layout.

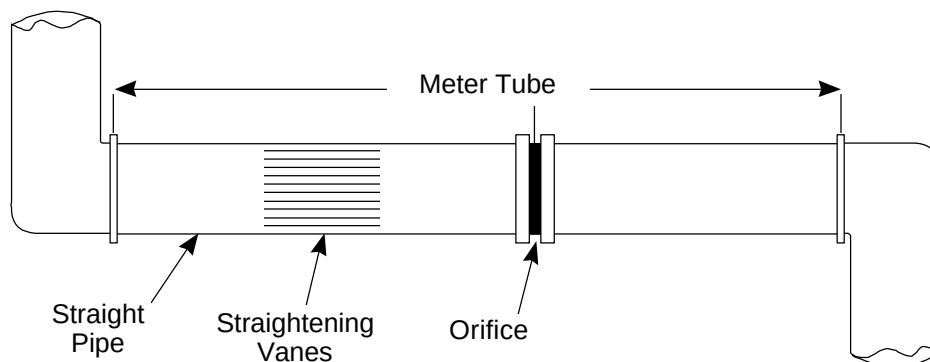


Figure 29: Meter Tube Assembly Example

To assure accurate flow measurement, fluid flow should be free from swirl or vortices. To achieve the best flow free from swirl or vortices, use flow conditioners and adequate lengths of straight pipe runs upstream and downstream from the orifice plate. Normally, upstream straight pipe runs are from 20 to 25 times the diameter of pipe (20D to 25D) and downstream straight pipe runs are from 5 to 7 times the diameter of pipe (5D to 7D) from the orifice plate.

Requirements for a straight upstream pipe will be reduced by use of straightening vanes. No pipe connections should be within these distances other than the orifice pressure taps or temperature connection. Thermowell connections may be installed in the meter tube upstream of the straightening vanes if required. The selection of the meter tube is determined by the volume of the fluid to be measured. For sizing of the meter tube, first determine what range of differential pressure instruments will be used. The beta ratio (β) should be within a range of 0.20 to 0.7 for flange taps, 0.25 to 0.67 for pipe taps. Refer to the manufacturer's catalogue or AGA Report Number 3 for more information on requirements for straight upstream and downstream pipe based upon beta ratio calculations and piping configuration layout. Example charts similar to the one shown in Figure 30 are available to assist the engineer when sizing a meter tube.

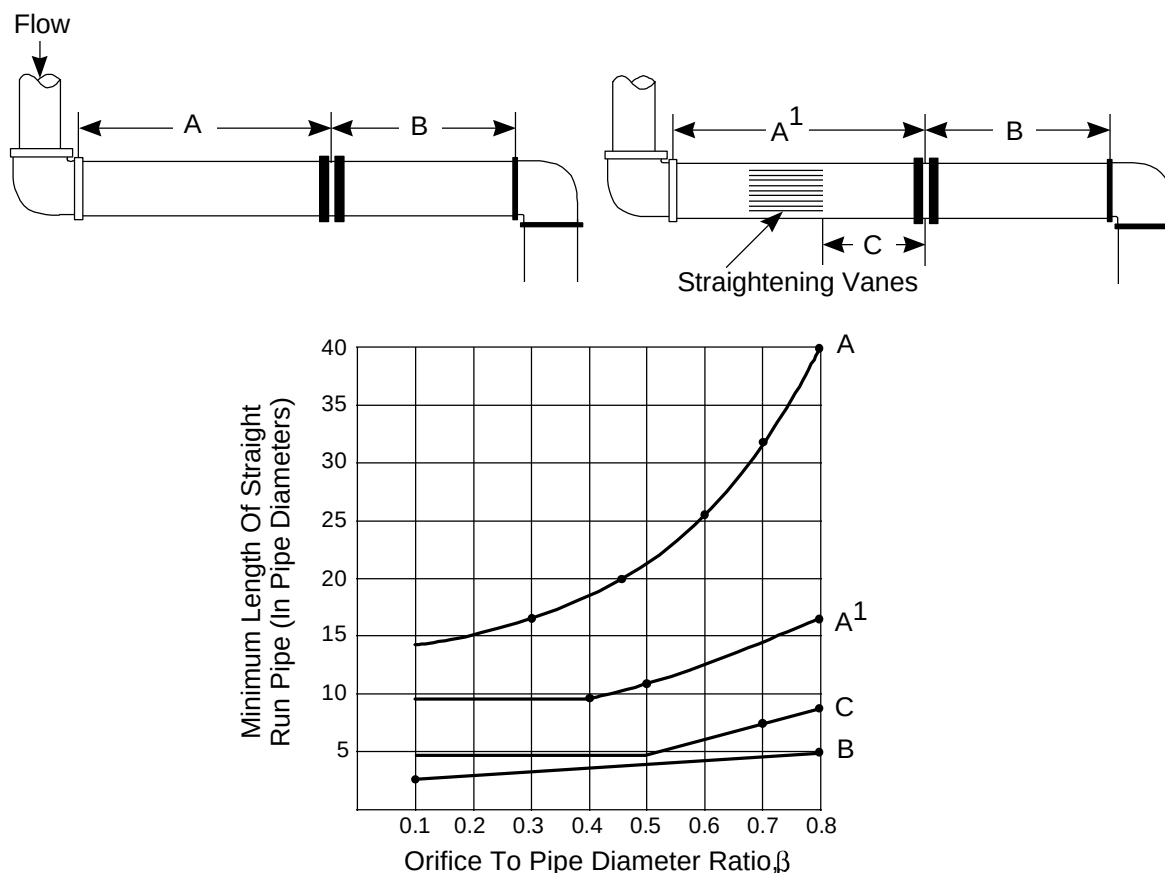


Figure 30: Straight Run Piping Requirements (Elbows)

The guidelines for 6.7 orifice meter runs and straight pipe requirements are stated in SADP-J-100 in the following manner:

“Orifice Meter Runs and Straight Pipe Requirements

6.7.1 Fabrication: Meter runs are normally field fabricated using orifice flanges or fittings (except where precision meter tubes are required) for process monitoring and control. Refer to paragraph 6.8 for precision meter tubes.

6.7.2 Straight Pipe Requirements: To obtain a uniform flow stream hydrodynamic profile, sufficient straight pipe shall be provided upstream and downstream of the primary element, as indicated by Saudi Aramco Standard Dwg. AB-036197.

NOTE: A beta d/D of 0.75 should be used in determining the minimum length of straight pipe required for new meter installations. (Exception: Where space limitations preclude the use of adequate upstream straight run pipe, 0.7 should be used, or flow straightening elements can be installed upstream to reduce straight run requirements.

6.7.3 Pipe Wall Finish: The condition of the pipe walls upstream and down-stream of an orifice shall be round, smooth, and free from roughness. Roughness shall not exceed 7.62 micrometers (300 micro in.) per AGA-3.

6.7.4 Concentricity of the orifice bore should be within 3 percent of the I.D. of the meter tube or fitting along all diameters in order to maintain acceptable metering accuracies. Refer to AGA-3, Part. 2 for specific details.

6.7.5 Orifice piping size limitations: An orifice metering run shall not be sized less than 2 inches in diameter unless the process flow rate is sufficiently low to fall below the minimum recommended beta limit of 0.2.

6.7.6 For very low flow rates, where the 2-inch minimum orifice run size cannot be used, a 1-inch external, or 1/2-inch integral orifice differential pressure transmitter may be used. These transmitters preferably shall be close-coupled to the calibrated orifice run by means of a 3-valve manifold.

6.8 Precision Meter Tubes: When accuracy and repeatability within +/- 1% of full scale measurement is desired, precision meter tubes should be used as specified in SAES-J-101, Custody Transfer Metering of Hydrocarbon Gases.

6.9 Straightening Vanes: The application of straightening vanes to the upstream side of orifice metering runs (in order to correct flow stream profiles or increase primary element accuracy), is permissible provided that adequate straight run lengths are designed according to Saudi Aramco Standard Dwg. J-AA-036197 and AB-036965.”

Four Common Types of Pressure Taps

A tap hole is a hole drilled in the wall of a meter tube or flange of an orifice plate. Four common types of pressure taps (Figure 31) are the following:

- Flange taps
- Pipe taps
- Corner taps
- Vena Contracta taps

Pressure tap holes are drilled radially to meter tube wall or in the flanges for the orifice plate. Generally, differential pressure instruments are close coupled to the pressure taps or connected through a downward sloping connection pipe to allow gas bubbles to flow up and back into the flowline.

Flange Taps

Flange taps are holes drilled into a pair of flanges. The location of the tap hole center is 1 inch upstream and downstream from the face of the orifice plate. Tap holes are drilled radially into the meter tube. The diameter of pressure tap holes are $\frac{3}{8}$ inch $\pm$ $\frac{1}{64}$ inch for a pipe size of nominal diameter 2 and 3 inches. Tap hole sizes are $\frac{1}{2}$ inch $\pm$ $\frac{1}{64}$ inch for a pipe size of nominal diameter of 4 inches or larger. Flange tap holes are not recommended when the pipe size is below 2 inches.

Pipe Taps

Pipe taps are located at 2 1/2 pipe diameters upstream and 8 diameters downstream from the orifice plate. Exact location of the taps is not critical. However, the effect of pipe roughness and dimensional inconsistencies can be severe. The uncertainty of measurement is 50 % greater with full flow taps than with taps close to the orifice. Pipe taps are not normally used unless it is required to install the orifice meter on a existing pipe, or other taps (such as radius taps or vena contracta taps) cannot be used.

Corner Taps

Corner taps are a style of flange taps, the only difference between corner and flange taps is that the pressure is measured at the corner between the orifice plate and the pipe wall. Corner taps are most commonly used in Europe for all sizes of pipe diameters. Some tests indicate inconsistencies with high beta (β) ratio installations that have some instability of flow upstream of the orifice plate. For this situation, an upstream tap is at one pipe diameter upstream of the orifice plate. Corner taps are used when the pipe size is 2 inches or less.

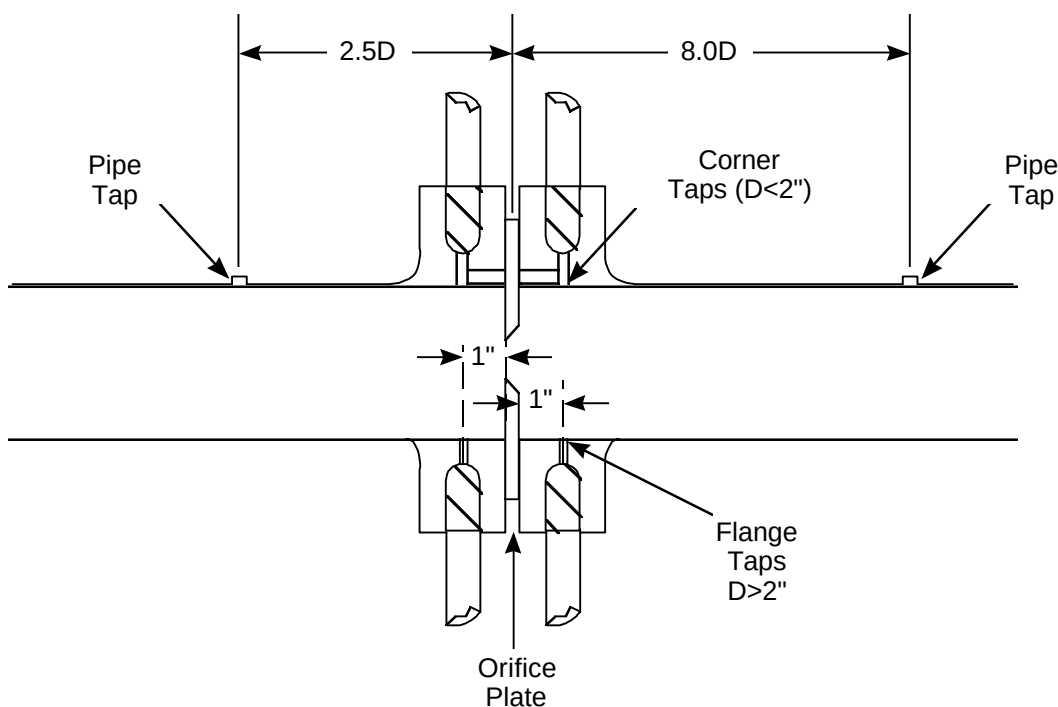


Figure 31: Pressure Taps

Vena Contracta Taps

When an orifice plate is inserted into the flowline, it creates an increase in flow velocity and a decrease in pressure. The section downstream of an orifice bore shows an increase in velocity and decrease in a pressure at a point called a “vena contracta point.” The location of the vena contracta point (Figure 32) is between 0.35 to 0.85 of pipe diameters downstream of the plate, depending on the beta ratio and Reynolds number. Vena Contracta taps are located 1D upstream and at the Vena Contracta location downstream. Vena Contracta Taps are the optimum location for measurement accuracy. They are not used for pipes less than 6” in diameter.

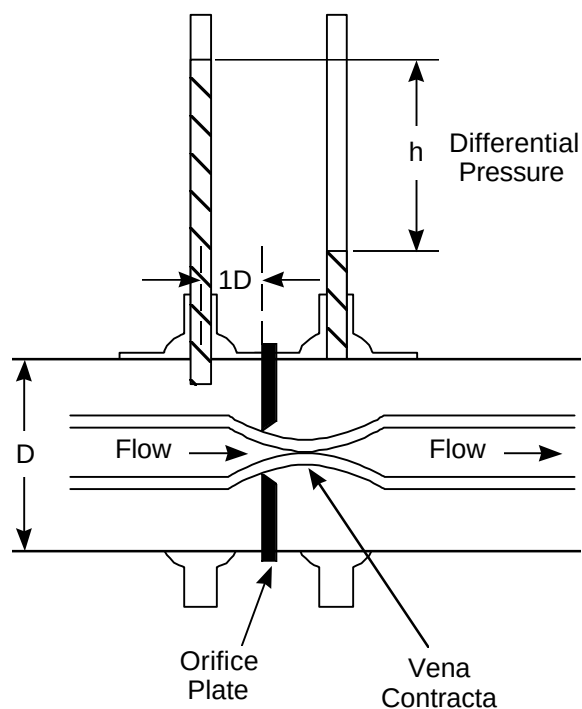


Figure 32: Vena Contracta Taps

Pressure Profile

As the flow approaches the orifice plate, there is a slight increase in pressure on the upstream side of the orifice plate. After passing through the orifice bore restriction, the flow velocity increases and the pressure drops. This is a conversion of pressure head energy to velocity head energy. As the flow leaves the orifice, the velocity decreases and the pressure increases. Although the flow velocity downstream of the orifice recovers to the velocity upstream of the orifice plate, there is a permanent pressure loss across the flowmeter.

Figure 33 shows pressure and flow profile.

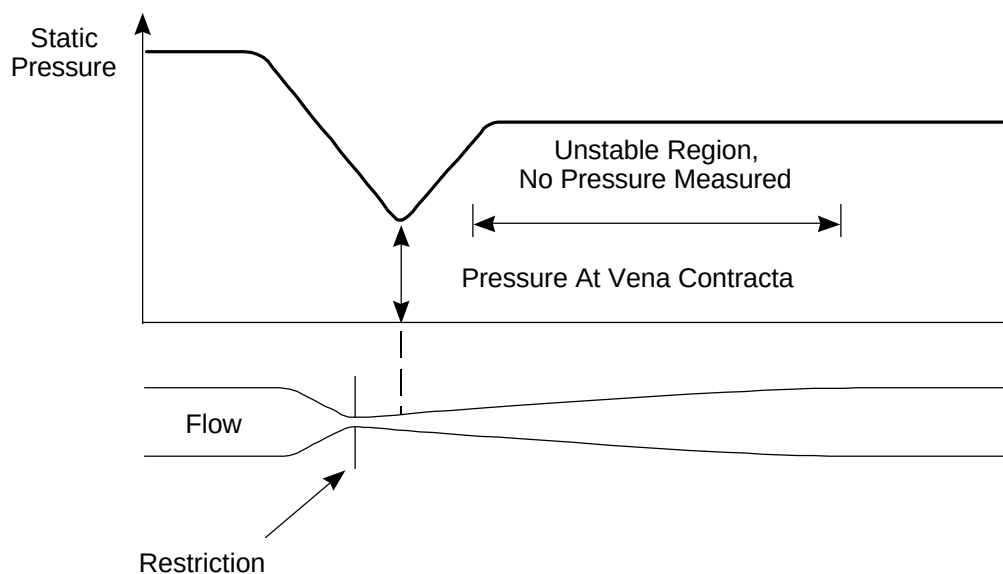


Figure 33: Pressure and Flow Profile

Temperature Measurement

The temperature of the flowing fluid is measured either upstream or downstream of the orifice plate. When the velocity of the fluid is well below sonic levels, you can insert a temperature sensing device in the flowing stream to measure the temperature of a flowing fluid. In meter tube assembly, thermowell connections are upstream of straightening vanes. Temperature is either measured in degrees Fahrenheit or degrees Celsius. In practice, the temperature is assumed to be a static temperature for the flowing fluid. In measurement calculations, the flowing temperature is used to determine the density of fluid at flowing conditions. Temperature units can be converted from degrees F or degrees C to degrees Rankine or absolute temperature in Kelvin using the following conversions:

$$\begin{aligned}\text{°R} &= \text{°F} + 459.6 \\ \text{K} &= \text{°C} + 273.15\end{aligned}$$

Integral Orifice Meter

The integral orifice meter consists of a primary device (orifice plate) and a secondary device (transmitter) combined in a single unit. The meter is designed for application with small flow rates. The integrally mounted restriction consists of an orifice, fittings, and mounting devices. The differential pressure produced is sensed by either a pneumatic or electronic differential pressure transmitter.

The complete assembly is referred to as an integral orifice flow meter. The flow restrictor plates are interchangeable to support a wide range flow rate measurements. The integral orifice meter is used in laboratory, pilot plant, or refinery small flow measurements. To avoid plugging the small hole in an integral orifice assembly, the meter is generally used for clean fluid flow measurements. The integral orifice meter is a proprietary product. Specific performance data is available from the respective manufacturer.

Secondary Instrumentation for Orifice Metering

Secondary instruments that are used in orifice metering to measure the flow rate are most often differential pressure transmitters. In this application, a differential pressure transmitter is either a pneumatic type or an electronic type. Other secondary instruments that measure the flow rate in conjunction with the orifice plate are differential pressure indicators, flow recorders, flow switches, flow totalizers (flow computer), and flow controllers.

Differential Pressure Transmitters

As mentioned above, two types of differential pressure transmitters are often used for measuring the flow — pneumatic transmitters and electronic transmitters.

The differential pressure flowmeters output a nonlinear signal that corresponds to the square of the flow rate. A change in flow at a low rate produces a very small signal change. A change in a large flow rate produces a much larger signal change. For example, a small flow rate from 0 to 10% outputs a signal from 0 to 1%; for a large flow rate, a 90 to 100% flow rate change outputs an 81 to 100 % signal. A transducer called a square root extractor is often used with transmitters. A transducer converts a square root signal to a linear signal. The differential pressure transmitter outputs a signal that is used for control, indication, or totalization. Pneumatic differential pressure transmitters output a signal of 3-15 psig, and electronic differential pressure transmitters output a signal of 4-20 mAdc (Differential pressure transmitters are described in the pressure course module).

Differential pressure transmitters are calibrated in ranges from 0-50 to 0-400 inches of water column depending upon the ΔP used in calculating the orifice bore at full scale flow with 0 to 100 being the most common. To determine the flow rate, it is necessary to take the square root.

Flow Switches

Flow switches are used to determine if the flow rate is above or below a set value. The set value (set point) is fixed or adjustable. The switch activates when the flow reaches or exceeds the set point. Flow switches actuate and remain at that condition until the flow returns to a normal condition. The difference between the “setpoint” and “reactivation point” is called differential or deadband. The differential is either fixed or adjustable. The smaller the differential, the more a switch can fluctuate around its setpoint. Switches have two types of reset — automatic and manual. In an automatic reset switch, when the flow returns to a normal condition, the switch returns to its preactuation state and resets by itself. In a manual reset switch, the switch cannot return to the preactuation state unless it is manually reset by the operator. Manual reset switches allow an operator a chance to review and eliminate any problems caused by the abnormal flow condition before resetting the switch.

Flow switches are either pneumatic or electronic types. Note that a flow measuring device can also be used as a flow switch. A differential pressure switch can be piped to the orifice plate, or a receiver type switch can be connected to the output signal of transmitters. Various designs are available for the flow switches. For example, switches can be differential pressure type, paddle type, thermal type, capacitance type, ultrasonic type, variable area, or piston type.

Flow switches are also available in blind or indicating type models. The switch’s contacts also vary. Some switches are magnetically operated mercury types, while others are snap-action mechanical types. The contact types that are available are SPST, SPDT, DPST, and DPDT. The variety of switch body housings that are available include general purpose, explosion proof, and weather proof types. In a refinery’s hazardous location areas, the explosion proof type NEMA 7, Class I, Group B, C, D, Division 1 or 2 are used. For more detail on classifications, refer to Saudi Aramco design guidelines and NEMA guidelines.

Flow Indicators

A flow indicator is a device that indicates the amount of flow passing through the flowmeter. Flow indicators measure in inches of water column, square root function, or indicate a linear value such as flow rate.

Two types of indicators are available — pneumatic and microprocessor-based, electronic type. Electronic-type flow indicators consist of milliammeters connected to the differential pressure transmitter (flow transmitter) either in series or parallel. Differential pressure flow indicators are piped to the orifice plate. The output shows either in 0-10 square root, 0-100% flow rate, or actual flow rate.

Sight Flow Indicators

A sight flow indicator is a mechanically driven device. Sight flow indicators are used for visual inspection of the process. Three types of sight flow indicators are available, which are the following:

- Paddle
- Flapper
- Drip

Paddle – The paddle type sight flow indicator design has a propeller inside its body. The paddle type indicator is only used for high flow rate applications because the propeller will not turn in a low flow rate. A pressure drop in the paddle type indicator is higher than the pressure in a drip or flapper type indicator. Paddle type sight flow indicators can be installed for flow directions that are horizontal or vertical upward. The paddle type design is used when dark process fluids are present.

Flapper – The flapper type sight flow indicator design has a flapper hinged in the body's center. Bidirectional flappers are also available. The flapper type sight flow indicator are used for transparent or opaque solutions and gas services. Flow direction can be horizontal or vertically upward.

Drip – The drip type design is used when there is a dripping of fluid in a vertically downward direction. The drip type design is used for vertically downward flows that are intermittent.

Sight flow indicators can be installed in an either horizontal or vertical flow direction. Assembly of a sight flow indicator consists of a chamber, glass, gasket, end covers, and bolts. Sight flow indicators are available in sizes ranging from 1/4 inch to 6 inches. Note, however, that it is very difficult to estimate the amount of flow rate from a sight flow indicator.

Totalization

The process of totalization means to totalize or to determine the total amount of fluid flow passing through a flowmeter. Devices used for totalizing flow or indicating the total flow are mechanical or microprocessor based units that track process material usage of chemicals and final products, and provide data for billing purposes. In an electronic device, the volumetric flow is transmitted as electrical pulses that are proportional to the flow rate. The electrical pulses are converted to a digital readout of total flow. A totalizer is often built into flow controllers and recorders.

It is very difficult to determine the accuracy of the flow totalizer, because accuracy of the totalizer depends upon the accuracy of the flowmeter. Generally, accuracy is expressed as a percentage. Accuracy is higher at high flow rates than at low flow rates. Microprocessor based equipment, often used in a flow computer, has the capability of addition, averaging, division, integration, lead/lag signal, signal limiting, square root extraction, subtraction, and more.

Piping Influences

Piping configuration has a tremendous influence on orifice metering. Piping geometry can destroy the flow profile, produce more turbulence, or produce a spinning and swirling flow. Flowmeters require that the pipe installed upstream and downstream of the flowmeter be straight, with a smooth surface inside, and have the same inside diameter as the flowmeter. No fittings should be installed such as tees, elbows, reducers, valves inside the pipes within the upstream/downstream constraints.

Requirements for upstream and downstream piping is expressed as a multiple of the inside pipe diameter and is based on piping configuration and beta ratio from the flow calculation. In a general flow application, if accuracy is not important, than upstream piping can be approximately 10 to 15 pipe diameters (10D to 15D) and downstream piping can be 5 to 7 pipe diameters (5D to 7D). Refer to AGA Report Number 3 and manufacturer's guidelines when installing the flowmeter. Always install the control valve on the downstream side of the flowmeter. Proper support should be provided for upstream and downstream pipe to and from the flowmeter. Proper support ensures that no load or torque passes over to the meter, vibration is minimized, and meter removal is easier between flow services.

Installation Criteria

The following discussion describes installation criteria for liquid, gas, and steam services.

Liquid Service

Tap Locations – The pressure tap location in liquid service orifice meters should be located to prevent accumulation of gas or vapor in the connection between the pipe and the differential pressure instrument. Generally, pressure taps are located in the horizontal plane of the horizontal pipe's center line. The differential pressure instrument should be close to the pressure taps or connected through downward sloping connecting pipe of sufficient diameter to allow gas bubbles to flow back into the line.

Transmitter Installation – The installation of differential pressure transmitters should be located below the pipe and sloping upwards toward the pipe to prevent the collection of gas bubbles in the impulse tubing.

Drain and Vent Holes are required for venting of any gas in a liquid service. Location of the vent hole in a liquid service is at the top of a pipe, above the center line. The size of hole is 1/64" ± the tolerance listed in API 2540.

Gas Services

Tap Locations – Pressure tap locations in a gas service must be installed in the top of the line with upward sloping connections towards a pipe. The differential pressure measuring instrument may be close-coupled to the pressure taps in the side of the lines or connected through upward sloping connecting pipe of sufficient diameter to prevent liquid from accumulating in the line.

Transmitter Installation – The installation of differential pressure transmitters should be located above the pipe with the impulse tubing sloping downward towards the pipe so that any condensate drains into the pipe.

Drain and Vent Holes – A drain hole is required for draining of any liquid in a gas service. Location of the drain hole is below the center line of the pipe. The size of hole is 1/32" ± the tolerance listed in AGA Report Number 3.

Steam Services

Tap Locations require the use of condensing chambers in steam or vapor applications because condensate can occur at ambient temperatures. Generally, the pressure tap connection has a downward sloping connection from the side of the pipe to the measuring device.

Transmitter Installation – The installation of differential pressure transmitters should be located above the pipe with the impulse tubing sloping downward towards the pipe so that any condensate drains into the pipe.

Drain and Vent Holes – A drain hole is required for draining of any condensate liquid in a steam service. The location of a drain hole is below the center line of the pipe.

Software versus Manual Calculations for Orifice Plate Sizing

Calculating the orifice bore for a given flow rate or differential pressure can be done manually or through the use of commercially available calculation programs. Orifice sizing slide rules are also available to estimate the Beta ratio for an orifice plate. The slide rule also can be used to estimate flow rate for a given differential pressure and Beta ratio.

Manual calculations are lengthy and somewhat tedious, because many parameters are entered. Computer programs are simple, self-explanatory, and only require the input of process conditions.

Standard Flow

Flow measurement of a fluid stated in volume units at base (standard) conditions of pressure and temperature is called standard flow. For crude petroleum and its liquid products, the vapor pressure is equal to or less than atmospheric pressure at base temperature of 14.696 psia (101.325 kPa) at a temperature of 60°F (15.56°C). For a hydrocarbon liquid, when vapor pressure is greater than atmospheric pressure at base temperature, the base pressure is called equilibrium vapor pressure. The base condition for natural gases is defined as a pressure of 14.73 psia (101.56 kPa) at a temperature of 60 °F (15.56°C).

Compensated Flow

Compensated flow represents a flow under fluid conditions that may vary. The conditions are measured and used along with flowmeter signal to compute the true flow rate from the flowmeter. The output signal from a flowmeter represents the true flow rate value under specified fluid conditions. For a liquid service, variations in density or viscosity can change the meter's accuracy. For gas services, a change in temperature, pressure, and molecular weight can ruin the accuracy of the meter.

The American Society of Mechanical Engineers publishes "The Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi" (ASME MFC-3M-1989-R1991). This standard derives from Ohio State University 1920's flow tests. The basic data has stood the test of time but the regression analysis is not up to modern mathematics.

The American Gas Association report no. 3, the American Petroleum Institute API 14.3, and the Gas Producers Association GPA 8195-90 publication "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids" come in Parts 1 through 4. These three standards-making bodies put their names and reputations on the document. The experimental data base is still the 1920's Ohio State tests but the regression analysis is better than the ASME and, consequently, is more widely accepted.

Software versus Manual Calculations for Flow Rate

Several commercial computer programs are available for sizing orifice flowmeters, venturi meters, flow nozzles, restriction orifice plates, and other flow elements. Saudi Aramco uses a program called ORICALC-2. The other available programs are called Flowel, Flow Consultant (from Dick Miller), MTS, and others. The programs are self explanatory with easy to follow screen menu selections for each step by step operation. The programs calculate beta ratio, flow rate, or differential pressure.

The following equations are used to manually calculate orifice bore for liquid, gas, and steam services. The various formulas are provided in either AGA Report Number 3, "Process and Measurement Analysis," by Bela Liptak, or "Principles and Practice of Flow Meter Engineering" by L. K. Spink.

For liquid flow:
$$Z = \frac{5.663ER\sqrt{hG_f}}{QG_t}$$

For gas:
$$Z = \frac{7727ERY}{Q} \sqrt{\frac{hP_f}{GT_f}}$$

For steam :
$$Z = \frac{358.9ERY}{Q} \sqrt{\frac{h}{V}}$$

where

- E = Area factor, determine from curve C Liptak page 162 (approximately from 0.995 to 1.002 for 316 SS plate, temperature. 0 to 200°F)
- R = Pipe constant (calculate $R = 0.00593 (I.D.)^2$)
- Q = Flow rate (liquid in GPM, gas in SCFH, steam in pounds mass/hour (lbm/hr))
- G = Specific gravity of gas (air = 1.0)
- G_f = Specific gravity of liquid at operating temperature
- G_t = Specific gravity of liquid at 60 °F (15.6 °C)
- h = Pressure differential across orifice in inches of water
- Y = Compressibility factor determine from curve B Liptak page 162 based on pressure loss ratio ($X = h/2P_f$) and beta ratio.
Compressibility factor between 0.840 to 1.00)
- V = Specific volume (ft³/lbm) from steam table.
- T_f = Flowing temperature expressed in °R (°F + 460)
- P_f = Flowing pressure in PSIA
- X = Pressure loss ratio defined as $h/2P_f$
- Z = Flow factor (Fig. 2.145 Liptak page 162)
- B d/D = Orifice ratio determined from curve A - 1 or A₂ Liptak page 162.

A simple problem will illustrate the manual calculation:

A sharp-edged, thin-plate concentric monel orifice in a 4 in. schedule 40 steel pipe with 70°F water having maximum flow of 200 gpm flange-tap pressure differential of 100 inches of water. The data is entered on ISS 8020-115.ENG.

The formula $Z = \frac{5.663 ER\sqrt{hG_f}}{QG_t}$ will be used.

The terms of the equation are

- G_f = 0.9987 (Specific Gravity @ 78°F Liptak page 1357) 4 in. sched. 40 ID = 4.026 in. (Liptak page 163)
- E = 0.999 (curve C Liptak page 162)
- R = 0.0961 (Fig. 2.145 Liptak page 162)
- G_t = 1.000 (Liptak page 1357)

$$Z = \frac{5.663 (0.999) (0.0961) \sqrt{(100) (0.9987)}}{200 \times 1.000}$$

$$Z = \frac{(0.5437) (9.994)}{200} = 0.02717$$

Orifice ratio $\beta = 0.58$ (curve A2 Liptak page 162)

$$\beta = \frac{d}{D} = 0.58 = \frac{d}{4.026} \quad \therefore d = 2.335''$$

ORICALC 2—Orifice Sizing Calculation

Orifice no. 061296 Fluid : Liquid

Maximum Flow	= 200 GPM	Normal Flow	= 100 GPM
Meter dP	= 100" H ₂ O	Perm. Press. Loss	= 2.4 PSI
Pressure	= 100 PSIA	Temperature	= 70°F
SG @ Flow Temp.	= 0.999	Viscosity	= 1.0 cp
SG @ Std Cnd	= 1.000		
FA	= 1	FR	= 1.006943
A	= 5.667	B	= 3163
Beta	= 0.580178	Reynolds No.	= 135408
B2K _O	= 0.2163346		
E _O (Beta, PD)	= 402.4861	K _O (Beta, PD)	= 0.642927
E = E _O * OD	= 940.1257		
Pipe ID	= 4.026	Iterations	= 8
Orifice (d)	= 2.335797	(d) Corrected	= 2.335797

The calculated orifice diameter for practical purposes is identical whether manually or computer calculated.

Software versus Manual Calculations for Pressure Drop

To calculate the pressure drop manually, the above formula can be used. After inputting all necessary data, calculate the differential pressure drop (h) across the meter. To calculate pressure drop by computer program, follow the step by step screen menus, input all the information, and let the program calculate the pressure differential.

Instrument Specification Sheets (ISS)

Instrument Specification Sheets applicable to orifice plate implementation are listed in Figure 34. Blank Instrument Specification Sheets are available in the Work Aids for review. (Three flow exercises using process data and specification sheets are attached.)

Saudi Aramco Form	Reason for Use
3175-ENG	Orifice plate details for 2”-6” RF flanges
3176-ENG	Orifice plate details for segmental plate
3176A-ENG	Orifice plate details for restriction plate
3177-ENG	Orifice plate details for quadrant edge
3188-ENG	Meter reading tables
6078-ENG	ISS for flow instruments
8020-111M	ISS for flow transmitters
8020-115	Metering orifice calculation
8020-115M	Metering orifice calculation, SI units
8020-115A	Orifice plate detail, size 8” and up
8020-124	Restriction orifice calculation
8020-124M	Restriction orifice calculation, SI units

Figure 34: ISS Forms Applicable to Orifice Plate Implementation

Computer Programs for Sizing Orifice Plates

Several commercial computer programs are available for sizing of the orifice plate: ORICALC-2, EA-25, ORSPEC, FLOWEL, INSTRUCALC, ORIFICE2, and FLOW CONSTANT are representative.

Expected Accuracy

Because accuracy is important to the flowmeter measurement, the precision of bore calculation is critical; otherwise, an approximate calculation of bore gives good repeatable performance, but not absolute accuracy. Accuracy of the orifice meter is improved by using a microprocessor based (“smart”) differential pressure transmitter. The smart d/p transmitters that are currently available have 0.1% or better of span accuracy.

To size an orifice plate accurately, one needs a thorough knowledge of the variables. Published coefficients are not to be relied upon. An accurate transmitter is desired but not paramount. If an orifice coefficient is $\pm 1\%$ and the transmitter accuracy is $\pm 0.1\%$, the system accuracy is not the simple sum of the two accuracies $\pm 1.1\%$. To really improve the accuracy, a wet flow calibration of the orifice plate in the meter run is required.

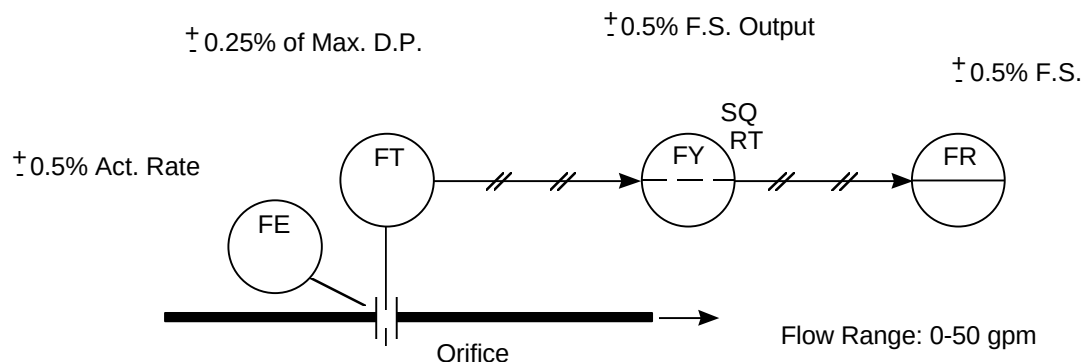
Total Probable Error (TPE) Calculation

To combine flow rate accuracy statements, they must all be in the same mathematical form. An accuracy statement in $\pm\%$ of full scale cannot be combined with an accuracy statement in $\pm\%$ of rate. The total probable error (TPE) is the square root of the sums of the squares of the uncertainties.

The AGA-3 part 1 uncertainty estimate for natural gas flow lists nine uncertainty variables. They all must be squared, massaged by sensitivity coefficients, summed, and square-rooted to obtain an acceptable uncertainty estimate.

To Illustrate the TPE Principle

Let’s use an orifice in a liquid flow line with a transmitter, square root extractor, and recorder with each element’s accuracy statement in usual format. Figure 35 shows the various flow rates in gallons per minute and each element’s accuracy statement given in $\pm\text{gpm}$. The TPE is calculated for each flow rate by summing the squares of the $\pm\text{gpm}$ errors and then taking the square root. The TPE is shown in % of the flow rate by dividing the TPE in gpm by the flow rate in gpm.



Flow Rate (gpm)	Flow Error ($\pm$ gpm)				Total Probable Error ($\pm$ gpm)	T.P.E. %
	FE	FT	FY	FR		
50	.25	.0625	.25	.25	$\pm .437$	$\pm .87\%$
40	.2	.0781	.25	.25	$\pm .414$	$\pm 1.03\%$
30	.15	.104	.25	.25	$\pm .398$	$\pm 1.33\%$
20	.1	.156	.25	.25	$\pm .399$	$\pm 1.99\%$
10	.05	.312	.25	.25	$\pm .474$	$\pm 4.74\%$

Figure 35: Total Probable Error

Common Troubleshooting Scenarios

Orifice meter troubleshooting classifies typical errors that occur as either

- Common primary element errors
- Common secondary element errors

Common primary element errors are the following:

- Beta ratio is too large for the meter run
- Orifice plate is not flat, it is concave or convex
- Orifice does not have sharp edges
- Orifice plate is installed backwards
- Orifice plate is damaged through poor handling
- An incorrect size is used for the orifice meter tube or plate
- Orifice plate is not centered in the line

- Orifice meter tube is corroded
- Tap locations are incorrect
- Contaminants build up on orifice plate
- Contaminants build up on meter run
- Hydrates build up on meter run and orifice plate
- Flow conditioners are dislodged and move closer to plate
- Leaks occur around orifice plate
- Pressure tap or thermowell installed upstream of meter
- Welding meter supports distorts meter run

Common secondary element errors are the following:

- Gauge lines are too small
- Gauge lines are too long
- Gauge lines leak
- Gauge lines have sags or loops that collect condensates
- Gauge line slopes are not correct
- Incorrect ranges are used on secondary instruments
- Differential pressure transmitter was not zeroed properly
- Excessive dampening is used in secondary instrument

EVALUATING OTHER DIFFERENTIAL PRESSURE FLOW MEASURING DEVICES FOR SUITABILITY IN A SAUDI ARAMCO APPLICATION

In addition to the orifice plate, other differential pressure flowmeters (Figure 36) are available. This section of the course module introduces to the Participant the following differential procedures:

- Restriction orifice plates
- Flow nozzles
- Venturis
- Pitot tubes
- Annubars

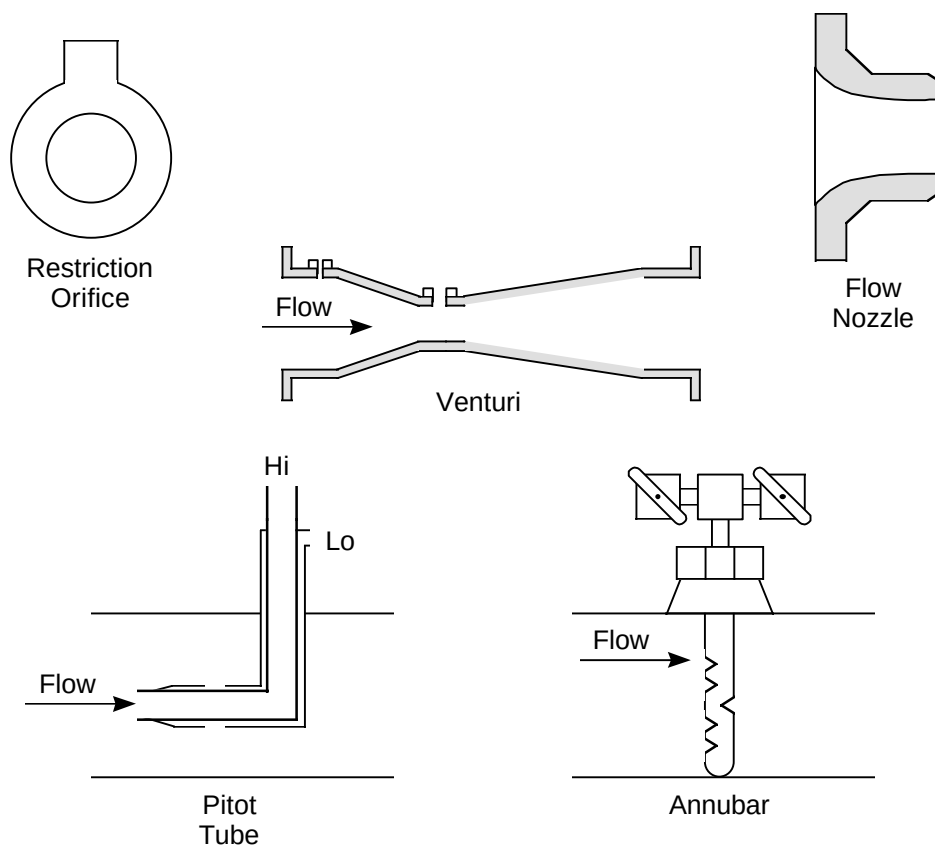


Figure 36: Other Differential Pressure Flowmeters

Restriction Orifice Plates

Principles

Bernoulli's theorem applies the conservation of energy to flowing fluids. Energy can neither be created nor destroyed — only transformed. All differential producers transform energy.

A restriction orifice plate restricts the flow in the process by reducing the pressure at the downstream side of the plate. A restriction orifice plate is not used as a measuring device. A restriction orifice plate is required when it is desirable to control the flow rate and reduce the pressure in a system.

Design

A restriction orifice plate's design is similar to an orifice meter plate's design, the only difference is that the restriction orifice plate does not have a bevelled edge to the orifice bore. The bore in the plate has a flat, square edged surface. Two types of restriction orifice plate designs are available — the universal type and paddle type. A restriction orifice plate is held in place by regular pipe flanges or a union. No pressure tap connections are required, because no secondary differential pressure measuring device is used. No limitations on beta ratio or Reynolds number apply when using restriction orifice plates.

Universal Type Plate – A universal type restriction orifice plate is a flat, concentric plate. The universal restriction orifice plate is held in place with a sealing unit in the plate holder. The universal restriction orifice plate is used in ring type joint pipe flanges. Several types of sealing units are available for the different type of fluids encountered in a flow application.

Figure 37 shows a universal orifice plate.

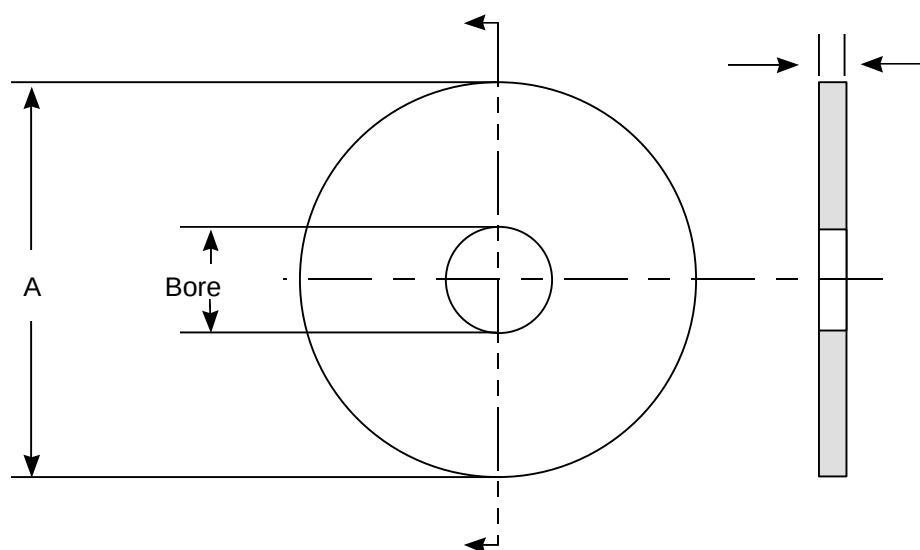


Figure 37: Universal Orifice plate

Paddle Type Plate – The paddle type restriction orifice plate is a flat, concentric metal plate with a handle sticking out as part of the plate. The design of the paddle type restriction orifice plate is similar to that of a metering orifice plate. The paddle type orifice plate is held in place between pipe flanges.

The thickness required for the restriction orifice plate depends upon the size of plate, the pressure drop across the plate at the flowing temperature, and upstream operating pressure.

Performance

A restriction orifice plate is used only to restrict the flowstream. The restriction orifice plate is simple to apply and does not require major maintenance while in service. Note that hole plugging can occur in dirty services because of the very small orifice bore.

Installation

The restriction orifice plate can be installed in any flow direction. The plate and plate holder are installed between regular pipe flanges. The universal type plate is used for ring type joint piping systems; paddle type plates are used for raised face flange piping systems. A drain plug is provided in the pipe flanges to drain out any liquid collected in a gas service.

Applications

Restriction orifices are very useful for creating unrecoverable pressure drops or for establishing minimum flow bypass loops (around pumps, for example), or for enabling multiple stream mixing. Multiple restrictive orifices can, in fact, be installed in series to create large, unrecoverable pressure drops, thereby minimizing requirements for high-pressure letdown devices. A nest application is upstream of a turbine flow meter to prevent the turbine from overspeeding because of too high a flow.

Calculation for Sizing

The sizing procedure for a restriction orifice plate is same as the procedure for sizing a metering orifice plate. Note that the differential pressure for a restriction orifice plate is much higher than that of the metering orifice plate. The manual calculation for a restriction orifice plate, however, is the same as the meter orifice plate's calculation.

The ORICALC2 computer program is available in the Work Aids. The computer program is convenient and easy to use when calculating a restriction orifice plate size.

We can calculate a restriction orifice plate by using the same data as is used for the previous sharp-edged thin-plate orifice with one major change. Instead of a 100 inch water column pressure drop (a standard for a dP meter), we will request a 70 PSI pressure drop.

The formula $Z = \frac{5.663 ER\sqrt{hG_f}}{QG_t}$ will be used for the manual calculation.

The terms of the equation are

$$\begin{aligned}
 G_f &= 0.9987 \text{ (Specific Gravity @ } 70^\circ\text{F — Liptak page 1337)} \\
 &\quad 4 \text{ in. schedule 40 pipe ID} = 4.026 \text{ in. (Liptak page 163)} \\
 E &= 0.999 \text{ (curve C Liptak page 162)} \\
 R &= 0.0961 \text{ (Fig. 2145 Liptak Page 162)} \\
 G_t &= 1.000 \text{ (Liptak page 1357)} \\
 Z &= \frac{5.663 (0.999)(0.961) \sqrt{(1939.9)(0.9987)}}{(200)(1.000)} \\
 &= \frac{(0.5437)(44.016)}{200} = 0.1197
 \end{aligned}$$

Orifice Ratio $\beta = 0.290$
(curve A - 1 Liptak page 162)

Daniel Slide Rule

$$\beta = \frac{d}{D} \therefore d = 0.29 \times 4.026$$

$$\beta = 0.28$$

$$\text{Orifice (d)} = 1.168''$$

$$d = 1.127$$

RO Calculation (ORICALC2)

		Fluid Liquid	
Flow Rate	= 200 GPM	PD REQUEST	= 70 PSI
Upstream Press	= 100 PSI	Cal. Orif. dP	= 79 PSI
Temp.	= 70°F	Perm. Press. Loss	= 70 PSI
SG @ Flow Temp.	= 0.9987	Viscosity	= 0.9748 cp
ID	= 4.026		
FA	= 1	FR	= 1.0006
β	= 0.2789382	Reynolds No.	= 577845.5
ID	= 4.026"	(IT)	= 5
Orif. (d)	1.123055"	(d) corr.	= 1.123055"

The calculated orifice diameter for practical purposes is identical whether calculated manually or by computer.

Determining Appropriate Flow Measurement Devices For Saudi Aramco Applications

Saudi Aramco 8020-124-ENG (7/89)

APPD.		CERT.		CHKD.		DESCRIPTION		BY JO/EWO		DATE		NO.	
SAUDI ARABIAN OIL COMPANY													
INSTRUMENT SPECIFICATION SHEET - RESTRICTION ORIFICE CALCULATION AND SPECIFICATION													
TAG NO.		SERVICE		MOLECULAR WEIGHT MW		SPEC. GRAVITY REL. TO AIR G		COMPRESSIBILITY FACTORS Z ₁		Z ₂		PRESSURE DROP ΔP	
1 FLUID		WATER		11								70 PSI	
2 MEASUREMENT UNITS		GPM											
3 NORMAL FLOW (VOL. UNITS) Q				12		NORMAL FLOW (WEIGHT UNITS) W		13		PRESSURE DROP ΔP		70 PSI	
4 BASE CONDITIONS T _b P _b 60°F 14 PSIA		14		NOMINAL PIPE SIZE		4" - 40		15		PIPE WALL THICKNESS		0.237 INCH	
5 BASE SPEC. GRAVITY G _b 1.0		15		ACTUAL INTERNAL DIAMETER D		4.026 INCH		16		PLATE MATERIAL		304 SS	
6 OPERATING UPSTREAM PRESSURE P _f 100 PSIA		16		PLATE THICKNESS T		0.125 INCH		17		PLATE BORE d		INCH	
7 OPERATING TEMPERATURE T _f 70 °F		17						18					
8 OPERATING SPECIFIC GRAVITY G _f .9987		18						19					
9 OPERATING DENSITY γ _f 62.29 LB/FT ³		19						20					
10 OPERATING ABSOLUTE VISCOSITY μ _f 1.0 CP		20						21					
21 CALCULATION DENSITY													
DENSITY LIQUID: γ _f = G _f X 62.37 = .9987 X 62.37 = $\frac{62.29}{\text{LB/cu. ft.}}$		DENSITY GAS: γ _f = $\frac{2.699 \times G \times P_f}{T_f \times Z_f} = \frac{2.699 \times X}{X} = \frac{\text{LB/cu. ft.}}{\text{LB/cu. ft.}}$											
22 CORRECTIONS													
I PLATE THERMAL EXPANSION T _f = P _R t = P _F F _a = 1.0													
II VISCOSITY (FOR LIQUIDS ONLY) e = RE _d = B $\frac{Q \times G_f}{D \times \mu_f \times \beta_e}$ or RE = B $\frac{W}{D \times \mu_f \times \beta_e}$													
E = RE _d = $\frac{E}{F_f} = 1 + E/RE_d = 1 + \frac{1}{F_f} = F_f =$													
III EXPANSION COEFFICIENT k = c _p /c _v = ΔP/kP _f = Y = 1.0													
IV SUPER COMPRESSIBILITY F _{pv} = Z _b / Z _f = / √ F _{pv} = 1.0													
23 CALCULATION OR ORIFICE BORE A =													
REVISIONS		LIQUIDS (VOLUME)		GASES (VOLUME)		WEIGHT UNITS							
DRAWN BY		$\beta^2 K_0 = \frac{Q \times G_b}{A \times D^2 \times F_a \times F_f \times \sqrt{G_f} \times \sqrt{\Delta P}}$		$\beta^2 K_0 = \frac{Q \times \sqrt{G} \times \sqrt{T_f}}{A \times D^2 \times F_a \times Y \times F_{pv} \times \sqrt{P_f} \times \sqrt{\Delta P}}$		$\beta^2 K_0 = \frac{W}{A \times D^2 \times F_a \times F_f \times \sqrt{\gamma_f} \times \sqrt{\Delta P}}$							
DATE													
CHKD BY													
OPRG. DEPT.		β ² K ₀ = _____ =											
BY		β = _____ d = D X _____ = β X _____ = _____ INCH											
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THIS DRAWING IS NOT TO BE USED FOR CONSTRUCTION OR FOR ORDERING MATERIALS UNTIL CERTIFIED AND DATED.		ISS FOR		PLANT NO.		INDEX		DRAWING NO.		SHT. NO.		REV. NO.	
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		SAUDI ARABIA		JO/EWO -									

Figure38: Example ISS

Flow Nozzles

Principles

The flow nozzle is another type of differential-producing device that follows Bernoulli's theorem. The permanent pressure loss produced by the flow-nozzle device is approximately the same as the permanent pressure loss produced by the orifice plates. The flow nozzle can handle dirty and abrasive fluids better than can an orifice plate. In a flow nozzle with the same line size, flow rate, and beta ratio as an orifice meter, the differential pressure is lower, and the permanent pressure loss is less.

Design

The flow nozzle design is one that has a smooth entry and sharp exit. Several configurations are available, but the most important flow nozzles are ASME long radius nozzle, high or low beta ratio series, and the throat tap nozzle for gas and liquid applications. High beta ratio nozzles are acceptable for a diameter ratio that ranges between 0.45 to 0.80. Low beta ratio nozzles range from 0.25 to 0.50. For best accuracy, beta values between 0.25 and 0.8 are used. The nozzles can be welded in the pipe line, or mounted in a holding ring between flanges. If frequent maintenance inspection of the nozzle is required, then the holding ring design is preferred for flow nozzle mounting. Flow nozzles can be fabricated from any material such as aluminum, fiberglass, stainless steel or chrome-moly steel. The outlet or discharge side of the nozzle is beveled and is the most critical part of the flow nozzle to manufacture

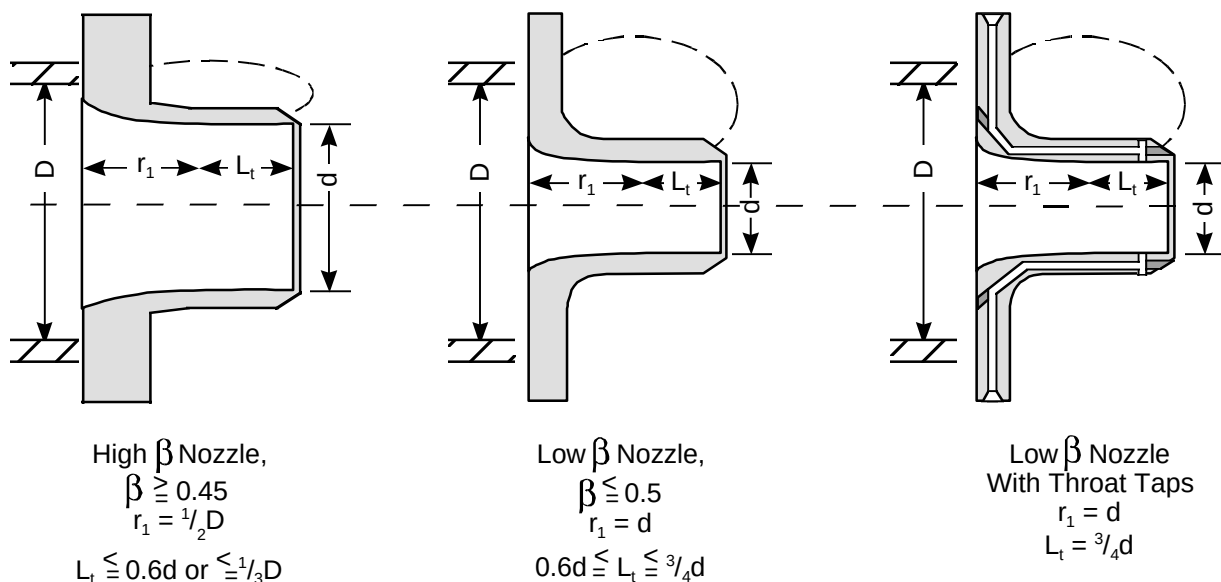


Figure 39: ASME Long-Radius Flow Nozzles

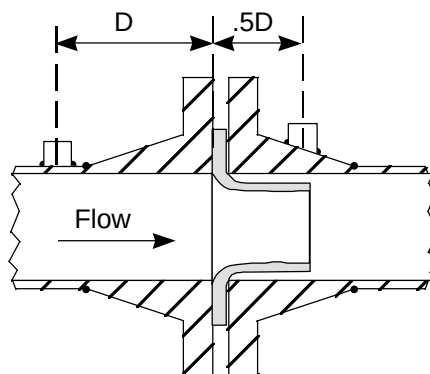
Performance and Applications

Changing a flow nozzle is more difficult than changing an orifice plate when there is a change in flow rate requirements. Flow nozzles are used for steam, high velocity, nonviscous, erosive fluids, fluids with some solids, wet gases, and similar materials. The flow nozzles pass 60% more flow than the orifice plate of the same diameter and differential pressure. A flow nozzle's inaccuracy of $\pm 1\%$ of rate is standard with $\pm 0.25\%$ of rate flow calibrated.

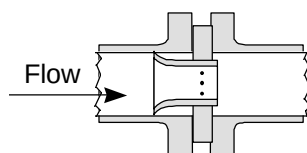
According to SADP-J-100, Section 8.1, flow nozzles are considered an alternative flowmeter and "Alternative flow meters should be considered when it is evident that orifice plates, or precision flow metering devices are not suitable nor practical for metering process fluids caused by process constraints, short meter run lengths, or specified accuracy requirements." Additionally, SADP-J-100, Section 8.4 states that "ASME wall-tap flow nozzles or ISA type flow nozzles should be considered for flow metering applications involving: a) The measurement of wet gases (e.g., saturated steam with condensate in suspension) or b) Entrainment in gas, liquid, or vapor streams (e.g., metering liquids with suspended solids). Note: When metering liquids with suspended solids, the flow of liquids should be oriented vertically downward so that all suspended solids can be swept through the throat of a flow nozzle. Flow nozzles are not recommended for highly viscous fluids or fluids containing large amounts of sticky solids."

Installation

The installation of a flow nozzle (Figure 40) is preferably horizontal, but can be installed in any position. A vertical downflow position is preferred for wet steam or gases and liquid with solid particles. The requirement of upstream and downstream piping is the same as that of an orifice meter's. The location and installation of taps are the same as the orifice plates. The nozzles taps are located in the pipe wall; one pipe diameter upstream and one-half pipe diameter downstream. Corner taps are used if an ISA-1932 nozzle is installed. A spool section shall be provided upstream of the flow nozzle for inspection and maintenance. Pipe sections for the installation of flow nozzles shall be stamped with the number of the element, the element location in the pipe, the pipe internal diameter, and the direction of flow.



Typical Nozzle Installation



Typical Throat Tap Nozzle Installation

Figure 40: Typical Nozzle Installations**Sizing of Flow Nozzles**

Flow nozzles have very high coefficient of discharge, typically 0.99 or higher. By using a typical value of 0.993, approximate flow rate can be calculated as follows:

$$W = 358 d^2 \sqrt{\frac{h\rho}{1 - \beta^4}}$$

and for approximate flow nozzle design

$$\beta = \text{Error!}$$

The terms in these equations are the same as those used in deriving the basic flow metering equation on page 55 of PCI 101.04 Participant Information sheet.

Venturi Meters

Principles

A venturi meter is a flow measuring device whose principle of operation is based upon Bernoulli's theorem. A venturi design can be described as a restriction with a long passage with smooth entry and exit. Venturi tubes produce less permanent pressure loss and more pressure recovery than the other meters. It is one of the more expensive head meters. Whenever low pressure drops are required for nonviscous fluids, the amount of pressure drop becomes dependent on the angle of the downstream cone and the beta ratio of the venturi.

A venturi (Figure 41) consists of a cylindrical inlet section, converging conical section, throat section, and diverging section. The diverging section is called the recovery section. A converging conical section, in which the cross-sectional area decreases, causes an increase in the velocity and decrease in pressure head. A cylindrical throat section, where the velocity of the fluid remains constant, is where the decrease in pressure head can be measured. A diverging recovery cone is where the fluid velocity decreases and most of the pressure is recovered. The unrecovered pressure head is called head loss.

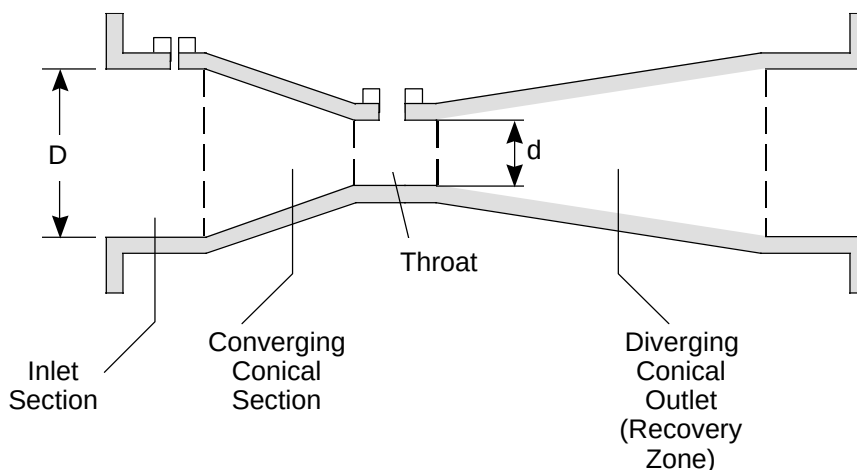


Figure 41: Venturi Principles

Design

Two types of venturi meter designs (Figure 42) are available:

- Classic venturi
- Short form venturi.

(The classic venturi is also called a long form venturi.)

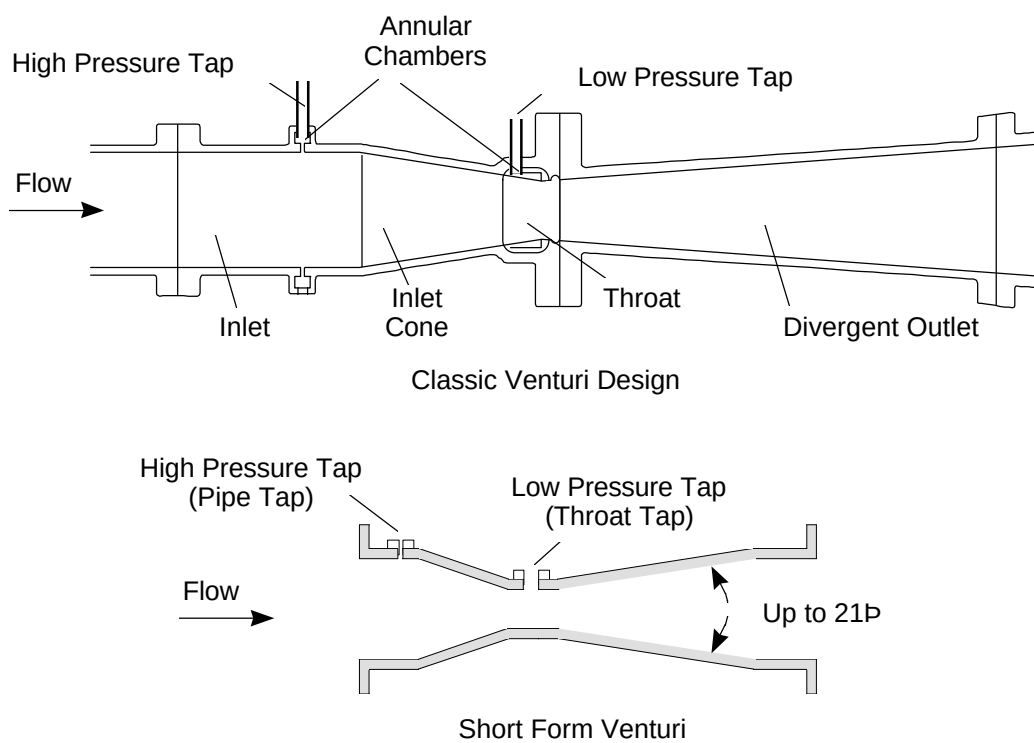
Classic Venturi – The classic venturi is manufactured as a cast iron body, while the throat is made from stainless steel or bronze. Several pressure taps, typically 4 to 6 taps, are at the midpoint of throat, connecting the throat to the annular chamber, so that the throat pressure is averaged. The cross sectional area of the annular chamber is 1.5 times the cross sectional area of the tap. Because no movement of fluids occurs, the pressure sensed at the annular chamber is static pressure. The external taps are offset from the internal taps. The throat pressure is measured through the internal taps. The diverging cone (that is, the recovery cone) sets at an angle of 7 degrees. The classic venturi is limited to clean, noncorrosive liquid and gas applications. If the venturi should be used in a dirty service, the taps can plug up with dirt. If the taps clog up with dirt, it is impossible to clean or flush out the pressure taps. The flow coefficient for the classic long form venturi is 0.984. The overall length of the venturi is 8 times the diameter of pipe.

Short Form Venturi – Because of cost and the longer length of the classic venturi, manufacturers have developed new designs for the venturi called the short form venturi. The internal annular chamber is replaced by single pressure taps. The recovery cone angle is increased from 7 to 21 degrees. The short form venturi can be manufactured using a cast iron body or fabricated from other materials. The flow coefficient of discharge for the short form venturi is 0.985 with an uncertainty tolerance of $\pm 1.5\%$.

The high pressure point tap is located at one-quarter to one-half of the pipe diameter of the inlet cone, the low pressure point tap is located at the middle of the throat. A piezometer ring is used for differential pressure measurement. A piezometer ring consists of a number of holes in the plane of the tap locations.

Each hole of the ring is connected together in an annular ring to provide an average pressure. Piezometer ring connections are used for large tubes or when a more accurate average measurement is desired. A piezometer connection is not advisable for a dirty fluid or slurry service. In a modified short form venturi, all of the cones are shortened. In a short form venturi, the converging cone angle is 21 degrees and the diverging cone angle is 15 degrees.

According to SADP-J-100, Section 7.5.2, “Only industrial quality, low loss venturi-type flow elements with machined convergent tubes shall be used. The minimum nominal line size shall be 2 inch with beta limits (d/D) from 0.30 to 0.75 and a minimum pipe Reynolds number of 100000.”

**Figure 42: Venturi Designs**

Performance

Performance of the venturi is described in terms of

- Performance advantages
- Performance disadvantages

Performance Advantages are the following:

- The long form venturi develops up to 89% pressure recovery for a 0.75 beta ratio and decreases to 86% recovery for a 0.25 beta ratio.
- The short form venturi develops up to 85% recovery at 0.75 beta ratio and decreases to 7 % at 0.25 beta ratio.
- A venturi meter has a low permanent pressure loss and high recovery at higher beta ratios.
- A venturi meter can be used for dirty fluids and slurries.
- Higher accuracy (better than orifice).

Performance Disadvantages are the following:

- A venturi meter is a very expensive measuring device to use.
- A venturi meter has limited rangeability and is only installed when flow rate's rangeability is less than 3 to 1.

Installations

A venturi can be installed either horizontally or vertically. For liquid service applications, a venturi meter always needs to be filled with liquid. Valve and pressure tap locations follow the same requirements as those of an orifice meter. ASME recommends that the use of tubular type straightening vanes reduces the inlet piping requirements. No limitation exists on piping configuration downstream of the venturi to reduce the inlet pipe length. Valves and other devices should not be installed close to the downstream side of the venturi meter.

Applications

A venturi can be used for dirty fluids and slurry services. A venturi meter experiences less permanent loss and exhibits high recovery. According to SADP-J-100, Section 7.5.1, "Venturi tubes shall be considered for special flow measurement applications where higher instrument costs can be economically justified by a lower unrecoverable pressure loss, enhanced flow meter accuracy, or the ability to meter fluids containing suspended solids. (e.g., measuring inlet flow rates to gas compressors)."

Calculations

The general flow equation for venturi is the same as that for the orifice meter, the only difference is that the venturi's coefficient of discharge is 0.984. For a rough cast venturi (long form), the coefficient of discharge is 0.984 with beta ratio between 0.3 to 0.75. For a venturi tube with a machined finish, the coefficient of discharge is 0.995 with a Reynolds number of 200,000 or greater. The ASME calculation for flow and beta ratio follows:

$$W = 353 d^2 \sqrt{\frac{hp}{1 - \beta^4}}$$

Approximate venturi tube beta ratio

$$\beta = \frac{1}{\sqrt[4]{1 + \frac{125000 hp D^4}{W^2}}}$$

For Reynolds number between 50,000 to 200,000, substitute 344 in place of 353 in the calculation. The Work Aids contain Saudi Aramco's ORICALC-2 program, which also can support venturi meter sizing calculations.

Figure 43 references standards and practices that influence venturi meter selection. Review these references (as well as the vendor's supporting documentation) for additional detail when determining a device's suitability for an application.

Saudi Aramco Reference	Reason for use	Summary
SADP-J-100, Section 7.5.1	Application	Application criteria
SADP-J-100, Section 7.5.2 and SAES-J-100, Section 4.3.3	Selection criteria	Use only machined converged tubes
34-SAMSS-116	Specification	Specifications and requirements
API RP 551, Section 2.3.1.1.5	Guidelines	General application comments
Liptak, "Process Measurement," Section 2.27	Venturi meters	Additional reference for selection and implementation

Figure 43: Venturi Meter References

Pitot Tubes

Principles

The previously discussed primary differential pressure flow metering devices utilized the difference in static pressure perpendicular to the direction of flow as a basis for inferring velocity. The actual velocity was not measured, but was calculated after many experimental laboratory measurements and correlations.

The pitot tube senses total pressure in the direction of flow and static pressure perpendicular to the flow. The pitot tube sensing effects are used to derive velocity pressure from which the flowing fluid velocity can be inferred. The pressure relationship is:

$$P_T = P_s + P_v$$

where:

$$P_T = \text{Total, Impact, or Stagnation Pressure, } \frac{\text{lbf}}{\text{ft}^2}$$

$$P_s = \text{Static Pressure, } \frac{\text{lbf}}{\text{ft}^2}$$

$$P_v = \text{Velocity Pressure, } \frac{\text{lbf}}{\text{ft}^2}$$

From energy considerations

$$P_T - P_s = P_v = \frac{\rho (V_p)^2}{2gc}$$

And by Algebra

$$V_p = \frac{C (P_T - P_s)^{0.5}}{\rho} = \frac{C (P_v)^{0.5}}{\rho}$$

where:

$$V_p = \text{Approach velocity at the probe, } \frac{\text{ft}}{\text{sec}}$$

$$\rho = \text{Fluid density, } \frac{\text{lbm}}{\text{ft}^3}$$

$$gc = \text{Dimensional constant} = 32.2 \frac{\text{lbm ft}}{\text{lbf sec}^2}$$

and

$$C = \text{Dimensional constant}$$

$$= 1,096.5 \text{ when } P_v \text{ is in inches of water}$$

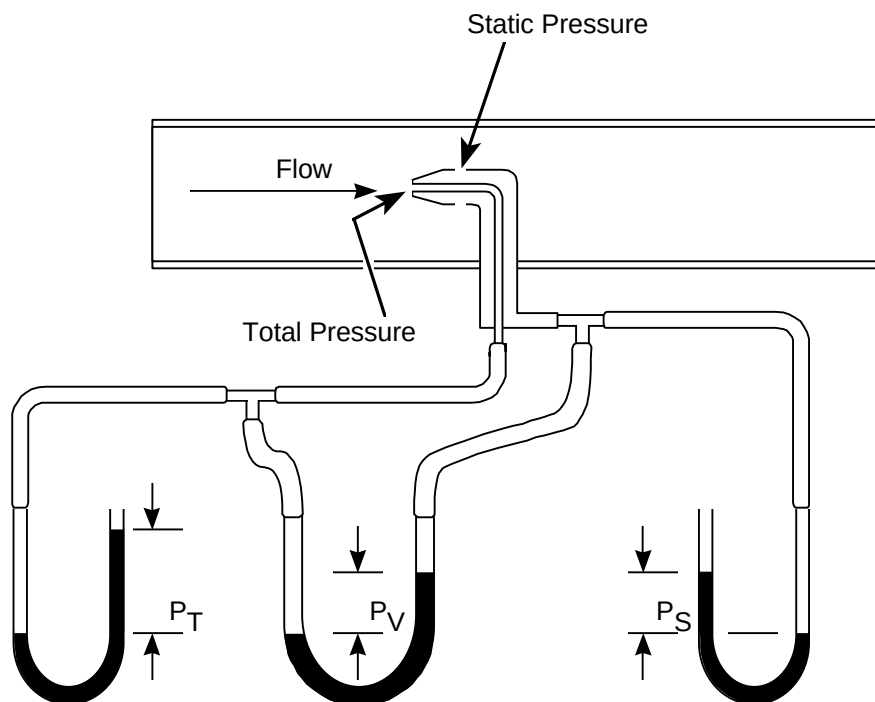


Figure 44: Pitot Tube Principles

A pitot tube is designed to sense pressures in an enclosed moving fluid stream. It is frequently used traversing a duct determining average fluid velocity across the duct. It must be light and portable so that it can be moved to sense in more than a single location. It must be long enough to push in for adequate insertion length. It must be capable of connecting to pressure measurement devices. The static connection must be in the same extended plane as the nose. All pressure sensing holes must be free from nicks and burrs.

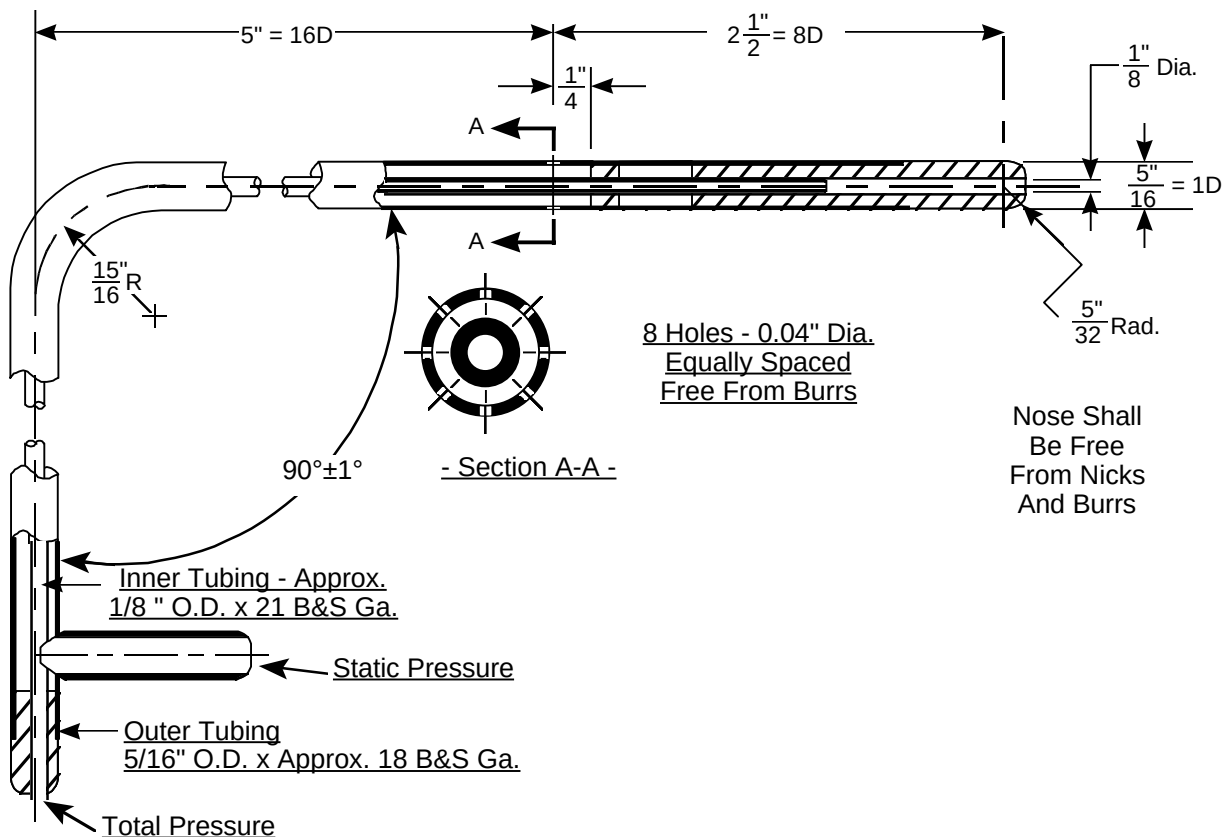


Figure 45: Pitot Tube Design

Performance

Performance is described in terms of

- performance advantages
- performance disadvantages

Performance Advantages are the following:

- A pitot tube has a major advantage in that it creates very little permanent pressure drop and, as a result, is less expensive to operate.
- A pitot tube can be installed on 4-inch and larger pipe sizes.
- Performance of the pitot tube is historically proven.
- A pitot tube's installation and operation costs are low.
- A pitot tube can be a standard differential producing device for all pipe sizes.

Performance Disadvantages are the following:

- Point-type pitot tubes require traversing the flow stream for average velocity.
- Poor rangeability.
- Nonlinear square root characteristic.
- Difficulty of use in dirty flow streams.

Installation

The pitot tube's installation practice is similar to other head meter installation practice, the installation is preferably on a horizontal pipe with the mounting in a vertically upward position. For larger pipe diameters, support is required at the end of pipe. The averaging pitot tube can be installed on an operating pressurized pipeline. The hot tapping capability allows easy installation and removal of the sensor without the need for a plant shutdown.

According to SADP-J-100, Section 8.5.3, "The installation of pitot type meters should meet the following requirements:

- a. All pitot meters should be accessible for maintenance or servicing in accordance with paragraph 6.17.
- b. Pitot tube installations in low pressure service should incorporate an adjustable packing gland which will allow the measuring element to be traversed across the cross sectional area of the pipe. A retaining ring assembly should be incorporated to prevent the removal of the element from the process line in service and to prevent leakage around connections and fittings.
- c. In special situations where increased accuracy is demanded of the pitot element, two pitot elements can be installed with traverses at right angles to each other. This allows the measurement of velocities at all points with the capability of obtaining the average value of a flowing velocity.
- d. Minimum recommended upstream straight meter run lengths vary between 14 and 28 pipe diameters; and downstream, 7 pipe diameters, depending on piping profile."

Applications

The pitot tube is used for flow measurements of liquids, gases, and low flow measurements. A pitot tube is used for control purposes and not for custody transfer purposes. When a single point's flow velocity is measured, accuracy generally ranges to $\pm 5\%$ unless specifically calibrated for higher accuracy.

According to SADP-J-100, Section 8.1, pitot tubes are considered alternative flowmeters and "Alternative flowmeters should be considered when it is evident that orifice plates, or precision flow metering devices are not suitable nor practical for metering process fluids caused by process constraints, short meter run lengths, or specified accuracy requirements." Additionally, SADP-J-100, Section 8.5 states that "Pitot tubes and pitot venturi tubes should be considered only for flow metering applications involving clean liquids or dry gases where a substantial pressure drop cannot be tolerated and where accuracy is of minimal concern."

Figure 46 references standards and practices that influence pitot tube selection. Review these references (as well as the vendor's supporting documentation) for additional detail when determining a device's suitability for an application.

Saudi Aramco Reference	Reason for use	Summary
SADP-J-100, Section 8.5	General criteria	Usage guidelines
SADP-J-100, Section 8.5.1	Calculations	Use Bernoulli's theorem
SADP-J-100, Section 8.5.2	Constraints	Line size and fluid property constraints
SADP-J-100, Section 8.5.3	Installation	Installation guidelines
API RP 551, Section 2.3.1.1.6	Guidelines	General application comments
Liptak, "Process Measurement," Section 2.15	Pitot tubes	Additional reference for selection and implementation

Figure 46: Pitot Tube References

Annubars

Principles

The single-point pitot tube is moved from point to point sensing impact and static pressures in a definite pattern. The sensing points are arrayed along perpendicular diameters with the number of points in each traverse based upon the duct size. The velocity of the moving fluid is calculated from the square root of the differential pressures and averaged to determine a representative velocity. Because $Q = AV$, and the area is a function of the duct diameter, Q (volumetric flow rate) can be easily calculated.

The Annubar is a tradename for an averaging pitot tube. The sensor is inserted athwart a circular duct or pipe. The impact pressure is sensed through the upstream holes, which are placed representing annuluses or rings of the flowing fluid. Static pressure is sensed by a hole or holes downstream — hopefully unaffected by velocity. The double hollow tube with these holes is a bar — hence, annu bar. Impact pressure sensed through an upstream set of four or six holes is averaged in the forward plenum of the bar. Static pressure sensed through one, four, or six holes is averaged in the downstream plenum of the bar. The pressure difference between impact and static is measured by a manometer or a transmitter. The square root is taken of the pressure difference or average velocity pressure to calculate the representative velocity of the flowing fluid just as in the single-point pitot tube.

Design

An annubar is designed to sense impact and static pressure when mounted in a pipe with a flowing fluid. The bar is so placed that it is cutting a diameter of the velocity profile. The holes are large to allow adequate sensitivity to pressure while trying to avoid plugging from dirty material in the flow. Some manufacturers have four upstream sensing holes and others have six. Some manufacturers have only one static pressure sensing hole while others supply four or six. The original bar design was a circular cross-section while the current annubar has a modified diamond with the sensing holes at home plate and second base. Annubar claims less clogging of the sensing holes. The annubar is still sensing at one point in the pipe.

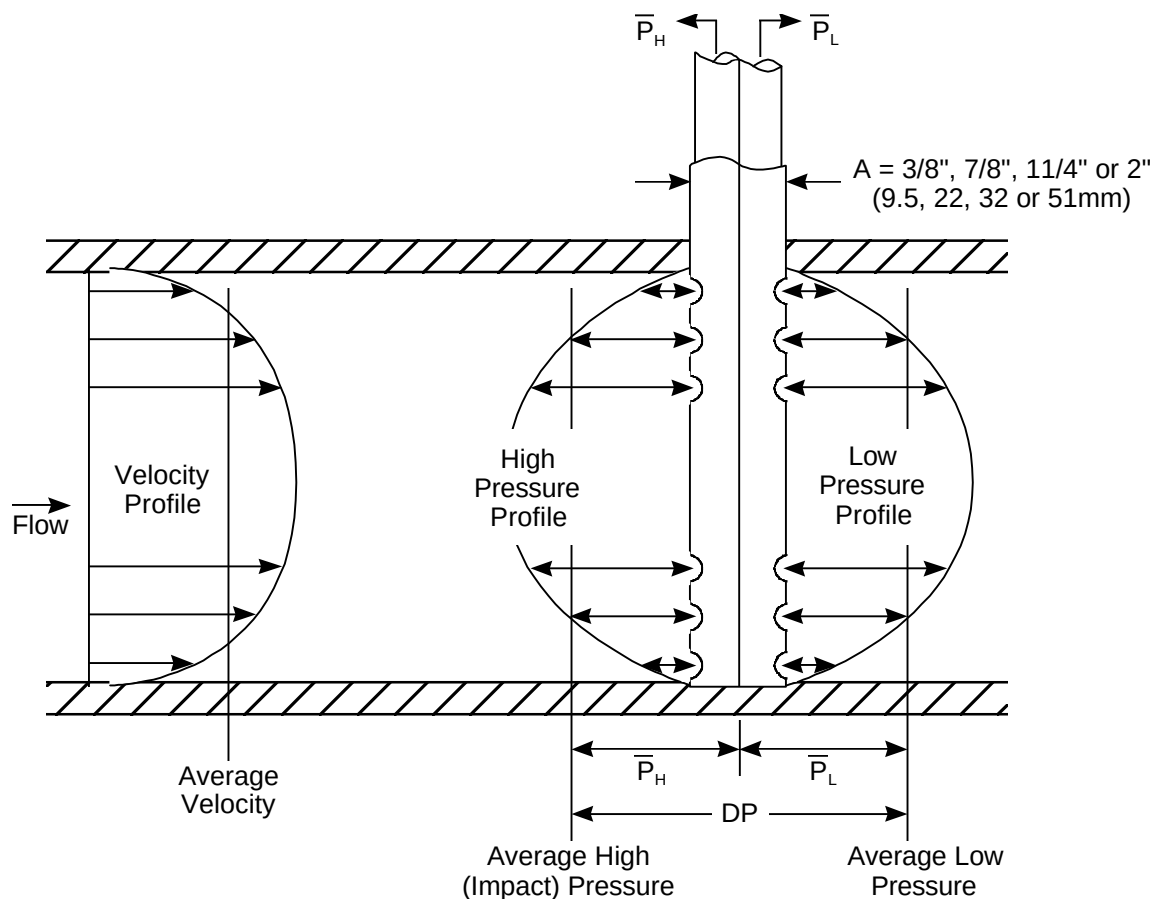


Figure 47: Annubar Design

Performance

Annubars have the following performance characteristics

- The diamond shape annubar has long term accuracy.
- The annubar has an accuracy of $\pm 1\%$ of actual flow and ± 0.1 repeatability of the actual value.
- The annubar has low installation costs; a system shutdown is not required to install the device.
- The annubar produces a repeatable signal even when the run requirements are not met.
- The annubar flow sensor can handle a wide range of flow conditions with two measuring instruments.
- The annubar should not be used if the viscosity approaches 50 centipoise.
- The annubar can be used on two phase flow measurements.

Installation

The annubar can be installed in any direction, preferably on horizontal pipe with vertical mounting. Selecting the correct mounting location of an annubar is important, because disturbance in the flow produced by the pipe layout affects the accuracy of measurement. A uniform diameter is recommended at the upstream and downstream side of the annubar. Provide supports to the annubar at the other end of the pipe when large pipes are used.

Applications

The annubar can be used for liquid and gas flow measurement services. Generally, the annubar is used in clean liquid services to avoid plugging. The annubar can be installed for low and medium pressure applications without shutting down the system.

Sizing of Annubar

To size an annubar, use the computer sizing programs available from annubar manufacturers. The programs are easy to follow and often select the desired model number. Manual sizing equations are also provided in Liptak pages 174 and 175.

Reference	Reason for use	Summary
Liptak, "Process Measurement," Table 2.150	Differential pressure calculations	Calculations for liquid, gas, steam flow
Liptak, "Process Measurement," Table 2.15p	Calculate flow coefficient, K	Metric equivalents
Liptak, "Process Measurement," Table 2.15t	Pressure differentials	Averaging pilot station calculations

Figure 48: Averaging Pitot Tube Equation References

Figure 49 references standards and practices that influence annubar selection. Review these references (as well as the vendor's supporting documentation) for additional detail when determining a device's suitability for an application.

Saudi Aramco Reference	Reason for use	Summary
SADP-J-100, Section 8.5	Annubar application criteria	Same criteria as pitot tube.
SADP-J-100, Section 8.6	Additional criteria	Additional application constraints
Liptak, Chapter 2.15		Basic Information

Figure 49: Annubar References

EVALUATING THE SUITABILITY OF OTHER RATE AND QUANTITY-TYPE FLOW MEASURING DEVICES FOR SAUDI ARAMCO APPLICATION

Flow measurement includes other rate and quantity-type flow measuring devices. This section of the course module describes the flow measuring devices listed in Figure 50.

Type of device	Rate/quantity/mass	Frequency of Use
Positive displacement	volumetric flow detection	medium
Turbine meters	- flow rate sensing - volumetric flow detection	high
Magnetic flowmeters	- flow rate sensing - volumetric flow detection	low
Mass flowmeters (Coriolis)	- flow rate sensing - volumetric flow detection - mass measurement	low
Ultrasonic flow	- flow rate sensing - volumetric flow detection	low
Vortex	- flow rate sensing - volumetric flow detection	low
Variable area flow meters (rotameters)	- flow rate sensing - volumetric flow detection	high

Figure 50: Frequency of Usage at Saudi Aramco

Positive Displacement Meters

Positive displacement (PD) meters (Figure 51) are used for measurement of gas and liquid. Positive displacement meters come in several varieties. Positive displacement meters include rotating paddle meters, oscillating piston meters, oval gear meters, sliding vane meters, and birotor meters. The term “displacement” refers to a discrete volume that is flowing through the meter, displacing (replacing) a previously counted volume. PD meters are mechanically driven meters and have one or more moving parts. The energy required to drive the meter’s mechanical components is generated from the flow stream. The energy to drive the meter creates a pressure loss between inlet and outlet of the meter. A PD meter’s output hardware can convert each unit of volume displacement into an electrical pulse.

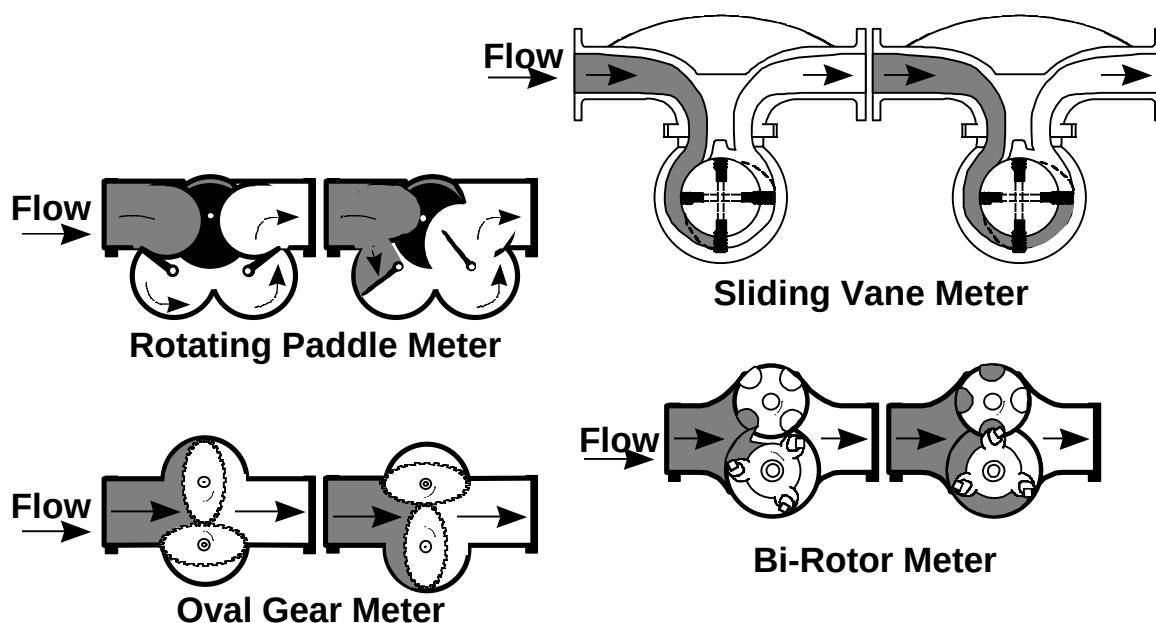


Figure 51: Positive Displacement Meters

Principles

Positive displacement meters precisely separate a flowing stream into discrete volume, count them, then return the discrete volume to the flowing stream. The meter (Figure 52) shows a count of volume, rather than flow rate. For the rotation of the volume measuring element within the meter to occur, there must be a pressure drop. The pressure drop, or pressure difference, between the inlet flow and outlet flow, causes the rotation of the measuring element.

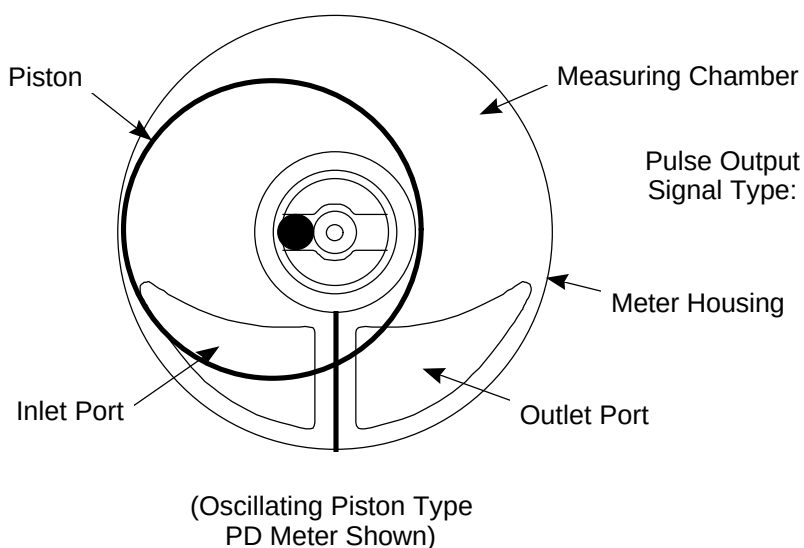


Figure 52: PD Meter Design

Design

Although positive displacement meters come in several varieties, all positive displacement meters have the following in common:

- Measuring element
- Meter housing, and
- Counter drive train

Measuring Element – The most important part of a positive displacement meter design is the measuring element. The measuring element consists of a measuring chamber and displacement mechanism. The function of the measuring element is to precisely separate a flowing fluid into discrete volumes. In order to do that, vendors use precision manufacturing techniques to ensure that metal to metal seals are maintained and any distortions are minimized.

Meter Housing – The housing of the meter is designed to absorb system piping stresses so that critical clearances are maintained in the measuring element. The housing also maintains a pressure balance between inlet and outlet flow so that pressure distortions do not affect measurement accuracy.

Counter Drive Train – The counter drive train transfers the displacement motion occurring within the measuring chamber into a meter's output signal. The counter drive train is typically a mechanical gear arrangement that corresponds mechanical revolutions to volumes of fluid.

Performance

Performance of the positive displacement meter is described in terms of

- Accuracy
- Rangeability
- Repeatability
- Pressure drop
- Performance advantages
- Performance disadvantages
- Output signals

Accuracy for a positive displacement meter in terms of percentage registration is based upon the calculation or percentage variation of the flowmeter factor.

$$\% \text{ registration} = \frac{\text{actual quantity}}{\text{metered quantity}} \times 100$$

At high flow rates, the increase in pressure drop (differential pressure) increases the flow slippage rate, reducing the meter's accuracy. At low flow rates, the meter has low energy because of the lower pressure drop, so the flow is under-counted, again reducing the accuracy. Accuracy of the meter is in the range of ± 0.1 to $\pm 2\%$ of the actual flow.

Rangeability of PD meters typically is 5:1, although 10:1 and greater flow ranges are possible. Maximum-rated capacities often apply to intermittent flow rates. Maximum capacities are sometimes derated if continuous flow is anticipated. The minimum and maximum range of flowmeter depends on flowmeter design and viscosity of the products.

Repeatability, which is the ability to repeat the accuracy of measurement, specifications are typically $\pm 0.05\%$ or better.

Pressure Drop represents the energy loss in driving the flowmeter and its accessories. The pressure drop across the internal of flowmeter creates an unbalanced pressure, which causes the rotation of the rotor.

Output Signals are obtained from the gear driven train. Output signals are available either in mechanical or electrical form as digital pulses or analog sinusoidal signals. Signal compatibility with other meter accessories should be verified.

Following are some advantage and disadvantages of using positive displacement meters.

Performance Advantages are the following:

- Ideal for viscous liquids
- Upstream piping requirements are minimal
- Some versions do not require electrical power
- High rangeability in liquid and gas meter without loss of accuracy
- Operating principle is simple to understand

Performance Disadvantages are the following:

- Not ideal for liquids with suspended particles. Requires filtration or strainer to minimize the damage to the meter.
- Mechanical wear susceptibility reduces accuracy and repeatability.
- Larger meters require extra installation care.
- Some meters can be damaged by overspeeding.
- According to SADP-J-100, Section 7.4.2.d “PD meters have a substantial pressure head loss which is unrecoverable. They also have a limited product throughput for a given meter size.”

Installation

Typical industry installations (Figure 53) include proper mounting and allowing for meter draining. Installation should also allow for maintenance access and meter proving.

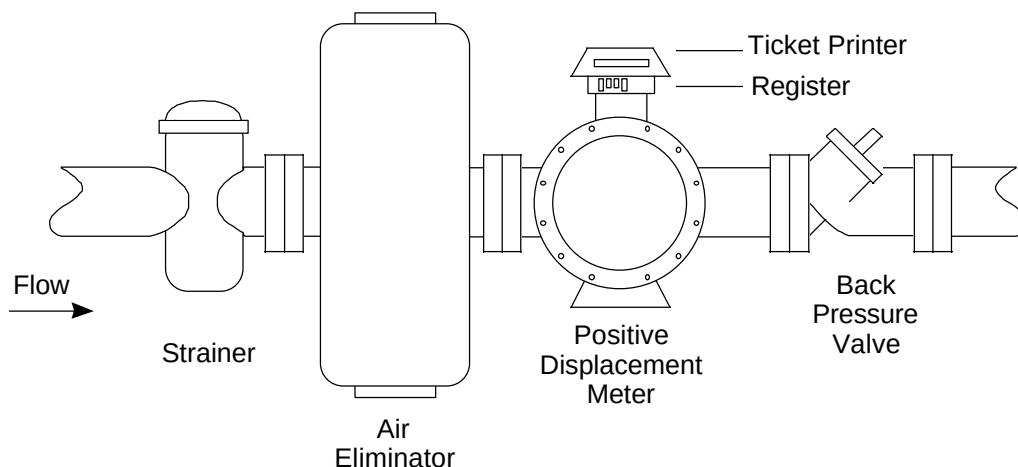


Figure 53: Typical PD Meter Installation

According to SADP-J-100, Section 7.4.4 and Section 7.4.5, “The accuracy and repeatability of PD meters is essentially independent of upstream and downstream piping arrangement. However, all PD meter installations should conform to requirements listed in Chapter 5.2 of the API Manual of Petroleum Measurement. A readily accessible strainer should be installed upstream of the PD meter including a differential pressure indicator to determine its need for cleaning. Pipe supports should be designed to facilitate removal of the PD meter. Piping layout should permit a PD meter to be isolated and drained. Meter bypass piping: PD meter bypass piping should follow the same constraints as bypass piping for turbine meters per paragraph 7.3.6.

Electrical (if any) and mechanical installation requirements for PD meters are essentially the same as those for turbine meters according to Sections 7.3.7 and 7.3.9.”

Applications

Positive displacement meters are used primarily in applications where the goal is to measure volume and not a flow rate. Although fluid viscosity must be accounted for when selecting a positive displacement meter, viscosity differences do not have a significant effect on measurement accuracy. Positive displacement meters are often considered ideal for viscous liquids (Refer to vendor’s data on registration curves for a lengthier discussion about viscosity). Positive displacement meters have limited use when the application is one where the liquid contains solid particles.

Positive displacement meters are often used in combination with other devices, such as pumps and control valves. Because the positive displacement meter must interact with other devices, the positive displacement meter must not be viewed as a stand-alone device. For example, a control valve would have to provide proper flow rate and back pressure for the positive displacement meter to work properly. Interaction with other equipment is described in more detail in the vendor’s supporting documentation.

According to SADP-J-100, Section 7.4.1, Saudi Aramco applications include “Pipeline metering, oil field production, fuel oil metering including gasoline, asphalt plants, additive metering, and tank truck metering (Avoid PD meters in LPG).”

Sizing and Equations

The size of positive displacement meter varies from 1/4 inch to 16 inches. A positive displacement meter should be sized based upon the viscosity of the product and flowrate. The meter should not be operated at a full rate capacity for a long period of time. The sizing equations of the PD meters are the same as those for the turbine meter. The sizing equations are discussed in more detail in the turbine meter section.

Figure 54 references standards and practices that influence positive displacement meter selection. Review these references (as well as the vendor’s supporting documentation) when determining a device’s suitability.

Reference	Reason for use	Summary
SADP-J-100, Section 7.44	Piping configuration	• Strainer installed upstream • Piping supports for removal • Meter bypass piping
SADP-J-100, Section 7.45	Installation requirements	• Horizontal installation • Positioning of register • Electrical requirements
SADP-J-100, Section 7.2	PD meter constraints	Design, application, specification of PD meter
SAES-J-100, Section 4.5	Meter sizing	• Normal flow rate 60% of URV • Comply to 34-SAMSS-118
SAES-J-100, Section 5.2	Installation	Install horizontally
34-SAMSS-118	Specification	Specifications and requirements
API RP 551, Section 2.3.5.2	Installation	• Proper foundation • Liquid presence required • Bypass guidelines • Use of strainers • Avoid air and vapor
API RP 551, Section 2.3.5.3	Commissioning	Follow manufacturer's guidelines to avoid damage during startup
API MPMS, Chapter 5.2.6	Selection criteria	Checklist of 17 items when selecting a positive displacement meter
API MPMS, Chapter 5.2.7	Installation	• Sect. 5.2.7.1 – usage of valves • Sect. 5.2.7.2 – piping • Sect. 5.2.8 – performances • Sect. 5.2.9 – operations and proving
Liptak, "Process Measurement," Section 2.16, 2.17	PD meters	Additional reference for selection and implementation

Figure 54: Positive Displacement Meter References

Turbine Meters

Principles

The turbine meter is so called because it uses a precision turbine wheel that rests on bearings within the meter housing. Flowing fluid forces the turbine wheels to rotate at a speed proportional to the velocity of the fluid. For each revolution of the turbine wheel, a pulse is generated. The rotational speed of shaft and frequency of the pulse corresponds to the volumetric flow rate through the meter.

The rotor blade is mounted at an incidence angle " α " to the flowing stream. The momentum of the flowing fluids stream imparts a rotational velocity on the rotor blade, causing a flow to change in direction, and discharging the flow from the rotor in a twisting and angular direction. The rotational velocity is directly proportional to the velocity of flow rate through the turbine meter.

Design

Separate turbine meters are available for gas or liquid measurements. When a fluid (gas or liquid) enters the turbine meter, it first passes through a flow straightener. The straightener is necessary to minimize any fluid turbulence and smooth the fluid for the turbine wheel. The turbine wheel (also called a rotor) then spins at a rate proportional to the velocity of the fluid passing through the meter.

A turbine meter's sensors are either mechanical or electronic. An electronic sensor that detects the passage of each rotor blade generates a pulse. A mechanical sensor consists of a shaft that is driven by a gear on the rotor shaft that is mounted inside the housing. Mechanical sensors are connected to measuring devices for direct measurement of a flow rate or total flow (totalizer).

Electronic sensors are also called "pick-off" sensors. Three types of "pick-off" sensors are the magnetic inductive, magnetic reluctance, and modulated carrier frequency sensors. The sensors are installed in the body of turbine meters and kept away from the tip of the rotor through a thin membrane or diaphragm. The magnetic reluctance "pick-off" sensor is the most common sensor. An example turbine meter is shown in Figure 55.

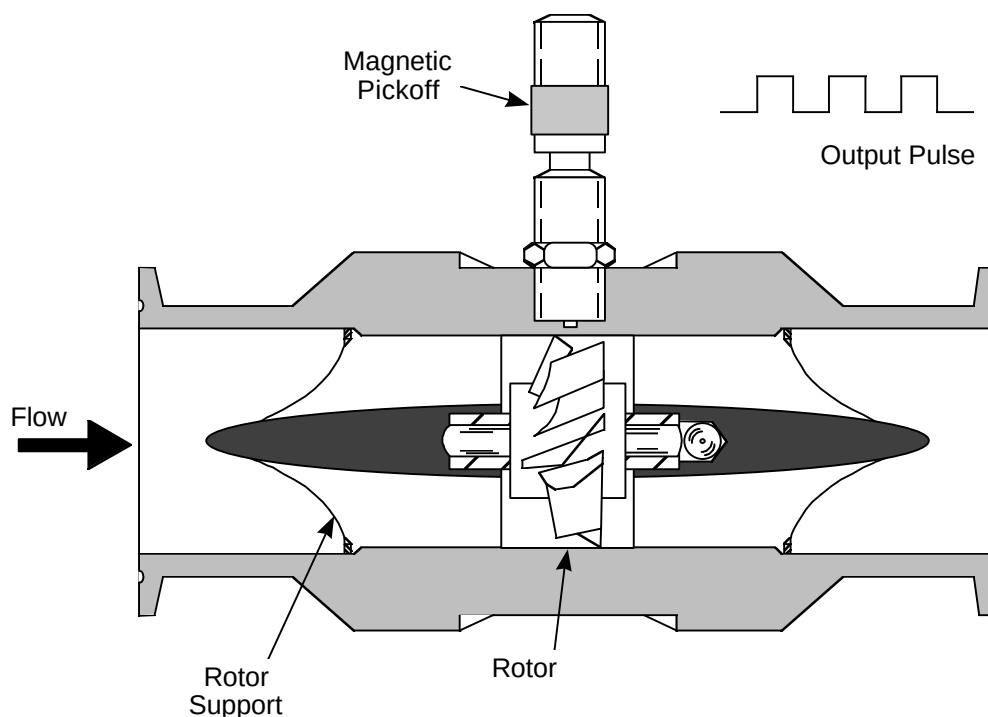


Figure 55: Example Turbine Meter

Performance

Performance of the turbine meter is described in terms of

- Accuracy
- Rangeability
- Repeatability
- Application effects
- Performance advantages
- Performance disadvantages

Accuracy

Turbine meters are highly accurate devices, with accuracy of $\pm 0.5\%$ of readings typical, $\pm 0.25\%$ when measuring rate liquids, and $\pm 1\%$ when measuring rate gas. However, one should note that accuracy is often stated under ideal conditions. Any calibration accuracy should simulate operating conditions for viscosity and lubricity. The calibration accuracy is not dependent upon the meter itself as much as it is a matter of how traceable the standard is for the meter.

Rangeability

Rangeability of a turbine gas meter depends upon pressure. Typically, rangeability is from 10:1 for a gas at atmospheric pressure and from 100:1 when gas pressure is greater than 1000 psig. Rangeability on a liquid turbine meter is about 10:1, but changes caused by viscosity, density, or meter size. If the viscosity of a fluid goes above the viscosity of water, then the meter range drops to as low as 3 to 1.

Repeatability

Repeatability for a precision turbine meter can be as low as $\pm 0.02\%$. When turbine meters are used over an extended range, note that the low flow rates may not have good repeatability. Additionally, the type of service can affect repeatability. For example, gas service repeatability can be $\pm 0.25\%$.

Application Effects

Although turbine meters are highly accurate, application effects can impact measurement accuracy. Improper or missing straightening sections, or operations of the meter at Reynolds numbers different from conditions at calibration, can cause failure. Temperature conditions also affect the performance of the meters. When a turbine meter uses a fixed K factor in an extended range, it is possible to add a percentage error into the meter reading. Linearity of a turbine meter is defined by ISA-RP31.1 as the maximum deviation in K factor:

$$\% \text{ Linearity} = \frac{(K \text{ max.} - K \text{ aver}) \times 100}{K \text{ aver}}$$

The linearity of a turbine flowmeter in liquid measurement is typically $\pm 0.05\%$ of the measured value over a range 10 to 1 at fixed viscosity and temperature. Linearity also depends upon the viscosity of the fluid. A gas turbine meter is more linear in gas than in liquid. The linearity of a gas turbine is expressed as the percentage of a full scale as opposed to an absolute percentage. Linearity is also affected by viscosity, density, and type of electronics sensors.

Performance Advantages

- Excellent accuracy and good rangeability over the full linear range of a meter.
- Low flow rate designs are available.
- Some versions do not require electrical power.
- Overall meter cost is not high. Overall meter cost is considered nominal because a turbine meter can support high flow rate for a given pipe size.
- Output signal from the meter is at a high resolution rate, which helps reduce meter proving.

Performance Disadvantages

- Sensitive to a fluids increasing viscosity.
- Two phase fluids can create usage problems.
- Straight upstream piping or straightening vanes are required in a turbine meter installation to eliminate the flow turbulence into the meter.

Sizing and Selection

Turbine flowmeters are available in a wide variety of sizes and flow capacities. The smallest flow a liquid turbine meter can measure is as low as 0.001GPM; gas turbine meters can measure as low as 0.001CFM. Turbine meters also measure high flow rates. The operating pressure and temperature should be considered in the selection of meter sizes.

Pressure drop is also considered when selecting a turbine flowmeter. A high pressure drop could damage the blade of rotor. High velocity can damage the bearings. The following are the equations for the gas and liquid turbine meters.

Equation for Gas Applications

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

where:

- q_b = Flow rate at base conditions, SCFM @ 14.73 PSIA & 60°F
- q_f = Flow rate operating conditions (meter reading), SCFM
- M_f = Meter factor to correct meter output based on calibration
- P_f = Pressure at flowing conditions, PSIA
- P_b = Base pressure set by agreement near atmosphere pressure, 14.73 PSIA
- T_b = Base temperature by agreement near ambient (60 °F), 520°R
- T_f = Temperature at flowing conditions, °R
- Z_b = Compressibility at base pressure and temperature
- Z_f = Compressibility at flowing pressure and temperature

Equation for Liquid Applications

$$q_b = q_f M_f F_t F_p$$

where:

- q_b = Flow rate at base conditions, GPM
- q_f = Flow rate at flowing conditions, GPM
- M_f = Meter factor to correct output based on calibration
- F_t = Correction from flowing temperature to base temperature
- F_p = Correction from flowing pressure to base pressure

Installation

Installation of turbine meters is described in terms of

- Typical industry installations
- Saudi Aramco installation requirements
- Electrical connections to turbine meter

Typical Industry Installations – Installation of gas turbine meter must be according to AGA-7 or ISO 9951. For custody transfer, installation of liquid turbine meter should be according to the API Manual of Petroleum Measurement Standards.

A common installation practice is to install 10 pipe diameters of straight pipe upstream of the meter to minimize flow velocity profile disturbances for 2 inches and greater pipe size. However, swirl is the most sensitive external influence on a turbine meter, and swirl can exist for up to 100 pipe diameters. Thus flow straighteners are also installed to minimize swirl. For a pipe size 2 inches and under, 20 pipe diameters of straight pipe run upstream of the meter is required.

If there is not enough space upstream of the meter for straightening vanes, and the meter must be installed in a large flow disturbance, it is advisable to install a perforated plate or screen to provide the normal turbulent flow.

A very obvious installation mistake is not observing the direction arrow on the turbine flow meter. If the meter is installed backwards it provides incorrect flow meter readings. In order to minimize the cavitation in the turbine meter, make sure that there is sufficient back pressure in the system. If there is not sufficient back pressure in the system, then installation of a back pressure regulator is necessary at the downstream side of the meter.

For turbine meter installations, a common practice is to purge the flow lines before installation of turbine meter to avoid debris damage to the turbine rotor and rotor blades. The turbine meter is a precision meter and should be treated with the care that a precision device needs. For example, one should avoid blowing compressed air across the blades because it could easily overspeed the meter; overspeeding could damage the bearings.

Saudi Aramco Installation Requirements – Turbine installation requirements are defined in SADP-J-100, Sections 7.3.5 through 7.3.8 in the following manner: “[Section 7.3.5] All turbine meter installations require strainers and/or filters to prevent foreign matter from blocking or partially restricting the flow passages or lodging between the rotor and meter body. The strainer should be capable of removing particles of a size (50 micrometers) that might damage the rotor or bearings.

NOTE: Limitations on strainer or filter mesh may be dependent on process applications in which the pressure drop caused by excessive strainer plugging becomes an important factor. Filters and "Y" type strainers should be installed upstream of the first elbow from the meter, or at least twenty (20) nominal pipe diameters upstream if inline. While concentric cone type strainers may be installed inline, they should never be located closer than ten (10) nominal pipe diameters upstream of the meter. In all cases, provision must be made for the removal of the filter or strainer element for inspection and maintenance.

[Section 7.3.6 Turbine Meter Bypass Piping]

Bypass piping needs shall be determined for each individual process application. For continuous services, involving applications where shutdown is considered undesirable, block and bypass valves should be installed to permit process operation during meter servicing.

[Section 7.3.7 Turbine Meter Installation]

- a. Turbine flow meters should be installed in horizontal lines with flanged connections. The process line should also be relatively free of vibration.
- b. Vertical turbine meter installations should be avoided if at all possible because special meter calibration for that position may become necessary as well as special thrust bearings to prevent excessive rotor wear.
- c. If a turbine meter includes an integrally mounted, direct-reading register, it should be positioned so that it can be easily read and maintained.

[Section 7.3.8 Temperature compensation]: If temperature compensation is necessary for standardizing flow rates, two thermowells are recommended with placement a minimum of two pipe diameters downstream of the meter. One of the thermowells should be designated as a test well used for calibration and/or monitoring purposes. Refer to Saudi Aramco Drawing. AE-036175 for welding boss details for thermowell connections to pipelines and vessels."

Electrical Connections to Turbine Meter – The electrical connection to the meter itself is made to the "pick-off" sensor. Meters are supplied with pigtail wire or connectors. Amplifiers are available for AC or DC power types. Always put the amplifier as close to meter as possible to minimize the signal noise. Always keep the power line and signal lines separate from each other. The shield cable or ground wire is grounded at one point in the system to prevent ground loops.

Electrical installation requirements are defined in SADP-J-100, Section 7.3.9: "The signal from a turbine meter is typically a low-level sinusoidal or square wave pulse which makes it especially susceptible to electrical noise interference. All electrical installations should comply with the requirements listed in the API Manual of Petroleum Measurement Standards, Chapter 5 and RP-550, Sec. 1."

Applications

Applications for turbine meters are dependent upon whether the turbine meter is one of the two types:

- Insertion type turbine meters
- Full bore (also called line size or reduced bore) turbine meters

Insertion type turbine meters are only recommended for the Saudi Aramco application where a nominal accuracy $\pm 5\%$ to $\pm 10\%$ of a flow rate is required. The insertion type meter (Figure 56) is used when the pipe has more than a 4 inch diameter.

According to SADP-J-100, Section 7.3.1, “Turbine meters [full bore types] should be considered for fluid flow measurement when rangeability (10:1), accuracy, and process dynamics of installation parameters suggest their use. Services include the metering of hydrocarbon liquids and gases as well as metering cryogenic fluids.”

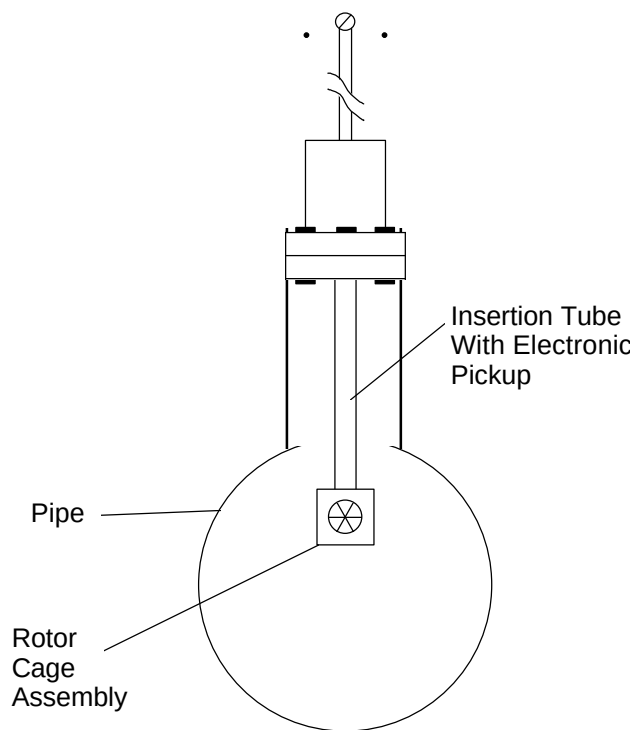


Figure 56: Insertion Type Turbine Meter

Figure 57 references standards and practices that influence turbine flowmeter selection. Review these references (as well as the vendor's supporting documentation) for additional detail when determining a device's suitability for an application.

Saudi Aramco Reference	Reason for use	Summary
SADP-J-100, Section 7.3.4	Piping configuration	• Accuracy, repeatability, and dependency • Flow profile uniformity • Meter bypass piping • Minimum 10 pipe diameters upstream • Throttling device installation
SADP-J-100, Section 7.3.3	Turbine meter constraints	• Avoid flashing and cavitations
SADP-J-100, Section 7.3.6	Turbine meter bypass piping	Install block and bypass valve to permit process operation during meter servicing.
SAES-J-100, Section 4.4	Design criteria	• Process requirements • Comply to 34-SAMSS-117
SAES-J-100, Section 5.3	Installation	Compliance to API MPMS and/or AGA Report No.7
34-SAMSS-117	System specification	Specifications and requirements
API RP 551, Section 2.3.4	Turbine meter practices	Practices regarding piping, bypass piping, strainers, electrical wiring, and commissioning
API MPMS, Chapter 5	Liquid metering for custody transfer	Selection criteria
Liptak, "Process Measurement," Section 2.23	Turbine meters	Additional reference for selection and implementation

Figure 57: Turbine Meter References

Magnetic Flowmeters

Principles

Magnetic flowmeters operate on the principles of Faraday's Law that state that an electrical current or voltage potential is created when a conductive fluid moves through a magnetic field. The axis of the conductive fluid flows at a right angle to the magnetic field. Fluid flowing in this manner causes a voltage that is proportional to the flow rate.

Faraday's Law: $E = KBDV$

The magnitude of induced voltage "E" is directly proportional to the velocity of conductive fluid "V", "D" is conductor width or length of path and "B" is strength of magnetic field density. In the above equation, there is no effect of pressure, temperature, density, or viscosity of the process fluid. A magnetic meter develops its signal independent of those conditions. A magnetic flowmeter, shown In Figure 58, consists of a detector and signal converter.

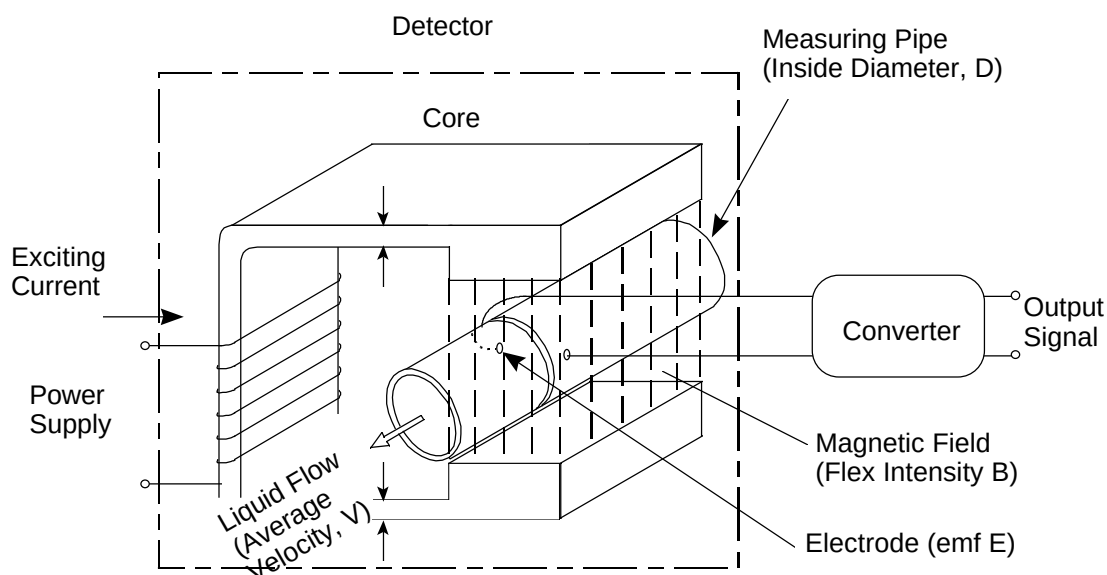


Figure 58: Magnetic Flowmeter Principles

Design

In a magnetic flowmeter, magnetic coils are placed on the opposite side of the pipe. The coils generate the magnetic field. Voltage applied to both of the coils is generally 120 or 240 volts AC at 50 or 60 Hertz. As the current passes through the coils, a magnetic field is generated inside the pipe. A conductive fluid with velocity (V) passes through a pipe at a right angle to the magnetic field. As the conductive process fluid moves through the field, electrodes sense the induced voltage. The magnetic field density is fixed for each meter. The width or length of the conductor is represented by the distance between the electrodes and fixed by the meter size. When a pipe section is manufactured from a conductive material, it is lined with a nonconductive material to insulate the pipe from the electrodes, preventing signals from shorting to the pipe wall. The only variable in this principle is the velocity (V) of the conductive process fluid. Magnetic field density is constant and the distance between the electrodes is fixed; therefore' the output voltage is directly proportional to the average fluid velocity, resulting in a linear output signal fed to the magnetic flowmeter transmitter.

The process fluid particles in the magnetic meter do not move at the same velocity, so they do not generate the voltage of the same magnitude in uniform field. A signal coefficient varies with axial or radial displacement of the liquid particles from the electrodes. An increase in flow rate of the fluid conductor moving through the field results in an increase in the instantaneous value of the voltage generated. The signal voltage generated is equal to the average velocity of the fluid, regardless of flow profile. The magnetic flow meter detects the volumetric flow rate by sensing the linear velocity of the liquid.

A magnetic flowmeter (Figure 59) can include optional flowrate indication.

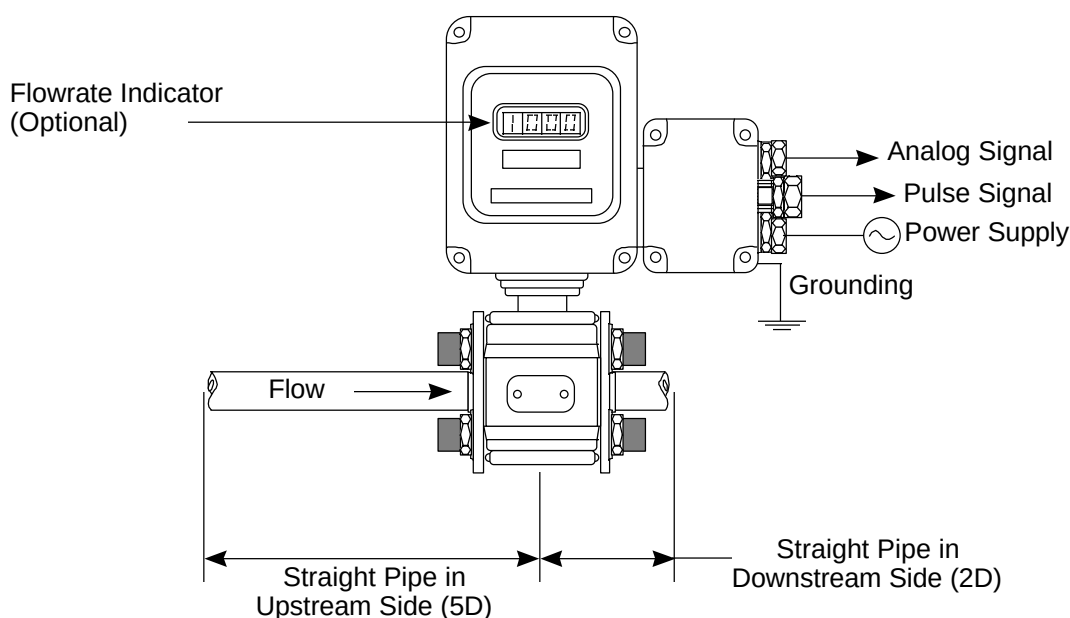


Figure 59: Typical Magnetic Flowmeter

Magnetic flowmeters do an excellent job of averaging the voltage combination across the metering cross-section. The voltage developed at the electrodes has an extremely low level signal. In order to use this low level signal, a transmitter or signal conditioner must provide amplification of the signal in the range of 4-20 mAdc. A 0-1000 Hz frequency output signal is also used in magnetic flowmeters that totalize flow. Magnetic flowmeters are available with remote or integral type transmitters. Each device is individually calibrated. There are two types of magnetic flowmeters:

- AC excitation, and
- DC pulse excitation.

AC Excitation – In an AC type magnetic flowmeter, line voltage (120 or 240 V AC) is applied directly to the magnetic coils. This generates a magnetic field in the outer body that varies with the frequency of the applied voltage. An AC meter's signal has a sine wave pattern. The flow signal at a constant flow velocity also looks like a sine wave. The magnitude of the sine wave is directly proportional to the flow velocity. The system produces an accurate, reliable, fast responding meter. The AC-type system must be periodically energized by stopping the flow and maintaining a full pipe in order to zero out any voltage present at that time, which could cause a potential offset. An AC-type system is normally considered as a percentage of full scale flow system.

DC Pulse Excitation – In a DC type magnetic flowmeter, line voltage is the main source of power, but instead of applying it directly to the coils, it is first applied to a magnet driver circuit. The magnet driver circuit sends low frequency pulses to the coils to generate a magnetic field. While many forms of excitation are in use, on-off excitation and plus-minus excitation are the main types used. The DC pulse system eliminates the zero shift problem that occurs in an AC system.

In a DC pulse system, a reading of induced voltage is taken and stored when the coils are excited. A second reading of induced voltage is taken when the coils are not excited. The voltage induced when coils are energized is a combination of noise and signal. The induced voltage when coils are not energized is noise only. The result of these two signals becomes the final output signal for the flowmeter.

Performance

Performance is described in terms of

- Performance advantages
- Performance disadvantages
- Rangeability and accuracy

Performance Advantages are the following:

- The magnetic flowmeter is nonobstructive and has no moving parts.
- Pressure drop is very little, so pumping costs are minimized.
- DC pulse-type meter electrical power requirements can be as low as 15 to 20 watts.
- The magnetic meter is suitable for acid, bases, water, and aqueous solutions. The lining materials provide good electric insulation and corrosion resistance.
- The magnetic meter can handle extremely low flow rates and can also be used for bidirectional flow measurements.

Performance Disadvantages are the following:

- The meters only measure conductive fluid flows. Hydrocarbons, gases, and pure substances cannot be measured by these meters.
- Proper electrical installation care is required.
- Conventional meters are heavy and larger in size.
- Meters are expensive, but the cost of the meters can be justified by the accurate performance over a wider turndown ratio.

Rangeability and Accuracy – Magnetic flowmeters have excellent rangeability. The AC-type meter has 100:1 rangeability and an accuracy of $\pm 1\%$ of full scale. A pulse DC-type meter has an accuracy of $\pm 1\%$ rate applicable to 10:1 rangeability or, for higher accuracy, $\pm 0.5\%$ of rate over a 2:1 to 5:1 range.

Installation

Proper magnetic flow meter operation is very dependent upon the installation. Indeed, the warranty could become void if the flowmeter is improperly installed. Installation considerations for a magnetic flowmeter primarily involve the following:

- Meter orientation
- Minimum piping requirement
- Grounding

Meter Orientation – A vertically installed flowmeter, with the fluid flowing upwards, is the preferred installation for a magnetic flowmeter. The preference for a vertical installation is that the meter remains full of liquid at all times. A vertical installation also minimizes wear from abrasive particles. A sloping installation, with flow moving upward through the meter, is also acceptable. Horizontal installations, which are very common, are also considered acceptable for most typical process industry flow measurements. A magnetic flowmeter can measure the flow of conductive liquid in both the forward and reverse directions. Flow in the forward direction develops a voltage opposite in phase or polarity from the flow in the reverse direction. If the system is designed for bidirectional flow, it cannot detect this difference. Many meters are built with flow direction arrows to indicate the proper direction for the flow through the meter. If the unidirectional meter is installed in the bidirectional flow line, the flow through the opposite direction remains zero.

Minimum Piping Requirements – General guidelines regarding piping requirements include locating elbows, pumps, and control valves a certain distance from the magnetic meter. Elbows are usually located 3 pipe diameters upstream of the magnetic meter, pumps, and control valves are usually located 10 pipe diameters downstream of the meter. The reason for locating valves and pumps downstream of the meter is to minimize turbulence as well as to provide enough back pressure to keep the magnetic meter full of liquid. If higher accuracy of a magnetic meter is required, the distances should be doubled for those previously mentioned.

Installation guidelines, in terms of orientation and piping, are shown in Figure 60

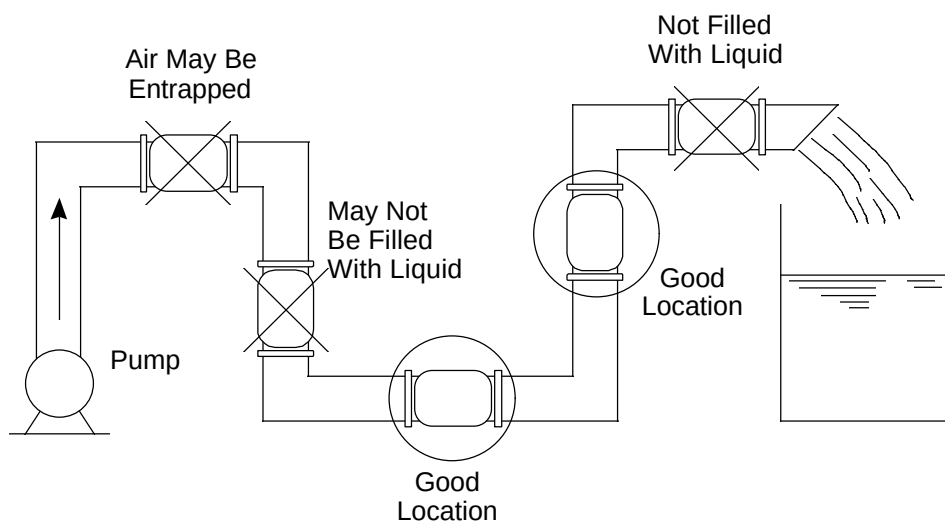


Figure 60: Magnetic Flowmeter Installation Practices

Piping configurations, according to SADP-J-100, Section 7.6.3 are defined as follows: “The magnetic flow transmitter tube should be installed in either a horizontal or vertical position; it must operate liquid full to ensure accurate measurement. If mounted vertically, flow should be from bottom to top to assure a full pipe. When mounted horizontally, the electrode axis should also be horizontal.

Vertical mounting with a straight run on the inlet side and upward flow is recommended if an abrasive slurry is being measured. This arrangement distributes wear evenly.

Magmeters up to 12 inches (nominal) in size require no support other than that required for an equal length of pipe. The magmeter should not however, be used to support adjacent piping. For larger meter sizes, depending upon size, construction, and manufacturer's recommendations, a support structure may be necessary.

Meter run piping should be designed with sufficient flexibility to prevent excessive forces from being transmitted to the electrically insulated flange faces. Particular attention shall be paid to installations in vertical lines to ensure that the excessive weight of the transmitter or piping is not applied to the flange facing. For meter applications which require frequent line cleaning, the magmeter should be installed with block and bypass valves to permit access to the tube interior without interrupting the process. The bypass valves should be of the ball-valve type capable of tight shutoff.”

Grounding is, according to SADP-J-100, Section 7.6.4 “extremely important .. both for the safety of personnel and for satisfactory flow measurement”. Stray electrical currents often develop as leakage from capacitive motor insulation’s ages, or currents develop from inductive coupling from other motor conductors. The currents are carried by the pipe or process fluid. The magnetic meter thus becomes a path for the current. To provide safety and proper measurement, magnetic meter grounding rings and piping grounding are implemented. Grounding practices are explained in more detail in vendor literature and SADP-J-100, Section 7.6.4b. Electronics should be oriented properly so that they are not at the top of the pipe in a horizontal and sloping installation. This prevents air from coming into contact with the electrode, causing errors in the flow signal.

Applications

Magnetic flowmeters are well suited for the flow measurement of slurries and dirty fluids because magnetic flowmeters do not have sensors that enter the flowing stream of fluids. However, the fluid must be conductive, or have some minimal amount of conductivity (20 microSiemens per centimeter or more) for the flowmeters to work properly. The magnetic flowmeter’s limitation of usage on conductive materials means that magnetic flowmeters are not used in the measurement of hydrocarbon fluids.

According to SADP-J-100, Section 7.6, “Magnetic flowmeters are recommended for measurement of conductive fluids, i.e., corrosive acids, sewage, abrasive slurries and crude oil that contains salt water. This type of meter is well suited for bidirectional flow streams requiring virtually no pressure drop.”

Magnetic flowmeters are not affected by viscosity or the consistency of Newtonian or non-Newtonian fluids. The resulting change in flow profile caused by a change in Reynolds number or upstream configuration piping does not change the meter’s performance or accuracy. Follow the manufacturer’s instruction when calibrating flowmeters.

Selection of magnetic flowmeters follow Saudi Aramco Design Practice, SADP-J-100, Section 7-6 Attachment 1, and Saudi Aramco Engineering Standard, SAES-J-100.

Mass Flowmeters (Coriolis Flowmeters)

Mass flowmeters are so named because the mass of the fluid is measured with the flowmeters, as opposed to the fluid volume or flow rate. A changing density or viscosity can affect the performance of a volumetric flowmeter, while a mass flowmeter would not be affected by these changes. Technologies, such as the use of Coriolis flowmeters, allow for the direct measurement of mass. Coriolis meters can also be used on liquid and some gas applications.

The direct measurement of mass is necessary for applications where chemicals are balanced, combustion efficiencies are calculated, or production quantities must be consistent. Often a sale of a product is based on mass, not volume. Of the mass flowmeters, the Coriolis mass flowmeter is the most predominant. If a measurement volume is desired, density corrections are required to measure the fluid at base conditions.

Principles

Coriolis flowmeters are based on Newton’s Second Law of Motion, where $F = ma$ (Force = mass x acceleration). A Coriolis force (Figure 61) is caused by flowing fluid through a tube. The Coriolis force equation is equivalent to Newton’s Second Law of Motion, where

$$F = 2 m \overset{\rightarrow}{\omega} \vec{v}$$

where

m = mass

$\overset{\rightarrow}{\omega}$ = angular motion

$\vec{v}$ = velocity

$$\text{Force} = \text{Mass} * \text{Acceleration}$$
$$\vec{F} = m * 2 * (\vec{v} \times \vec{\omega})$$
$$\vec{F} = \Delta m * 2 * (\Delta \vec{v} \times \vec{\omega})$$

Angular Motion
Frequency Is Constant

Velocity Changes With Flow

Mass Is Constant Unless Density Changes

The Effect Of The Coriolis Force Is Measured

Figure 61: Coriolis Meter Principles

In Coriolis flowmeters, fluid typically flows through an U-shaped tube (Figure 62) that vibrates at its natural frequency. As the fluid flows into the U-shaped tube, the fluid is forced to conform to the vertical momentum of the vibrating tube. If the U-shaped tube is moving upward during its vibration, the fluid flowing into the U-shaped tube resists and pushes downward. However, the fluid now has an upward momentum as it approaches the part of the tube where it must exit. So if that portion of the tube has a downward motion, the fluid resists the downward motion by pushing up on the tube. The U-shape tube then twists. The twisting is called the Coriolis effect. While it is impractical to measure the Coriolis force directly, it is practical to measure the Coriolis effect. The amount of U-shaped tube twisting becomes directly proportional to the mass flow rate flowing through the tube.

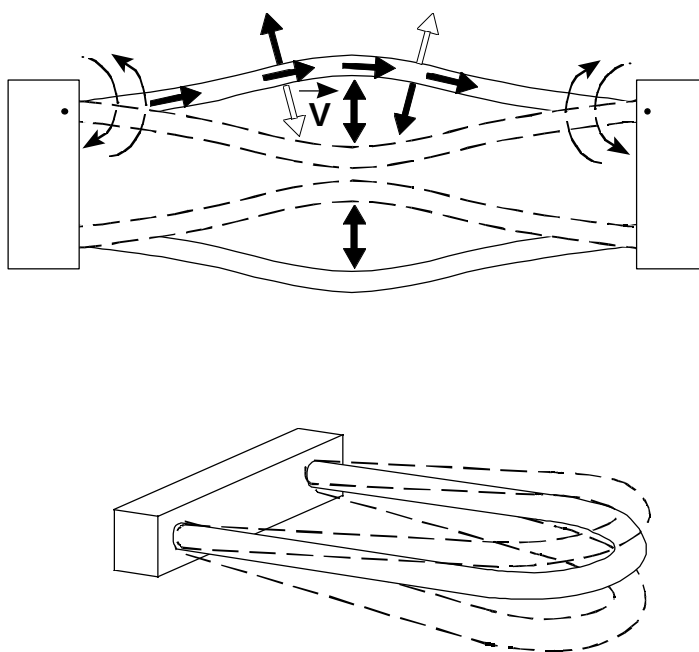


Figure 62: Sensing Element Geometries

Design

A Coriolis meter consists of one or more detectors and a transmitter (Figure 63). The detector senses the amount of tube twisting. To measure the Coriolis effect, the amount of tube twisting is directly proportional to the mass flow rate of the fluid flowing through the tube. The U-shaped tube can be vibrated by an oscillating driver at its natural frequency. Electromagnetic devices, such as velocity detectors, can be located on each side of the tube and be used to measure the velocity of the vibrating tube.

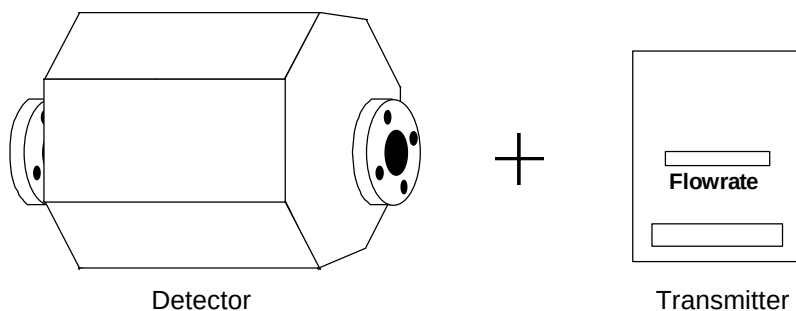


Figure 63: Coriolis Meter Overview

When no fluid flows through the tube, all points move in sequence with the oscillating driver, forming a sine wave. When fluid flows in the tube, twisting occurs. The twisting causes a time difference to occur between the velocity detector's signals. The time difference is directly related to the mass flow rate.

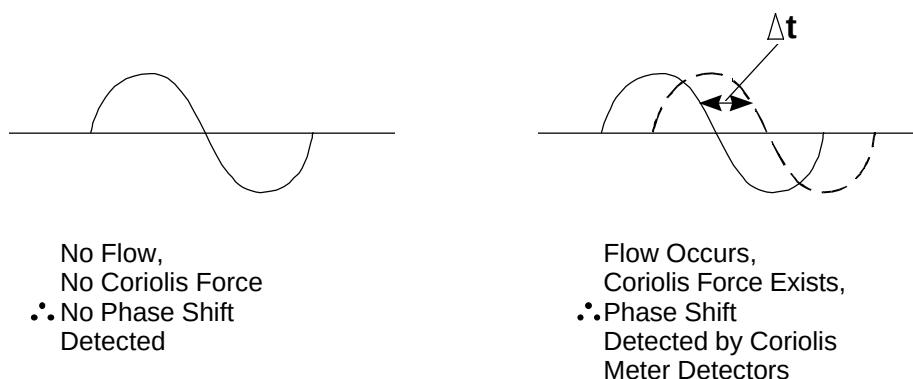


Figure 64: Design Detects Phase Shift

Performance

According to SADP-J-100, a Coriolis meter is described in the following manner: “Coriolis flowmeters are applicable to single-phase liquid metering installations which are not susceptible to gas entrainment problems....Coriolis flowmeters eliminate many of the problems commonly encountered in mass flow measurements. The output of the meter is directly proportional to mass flow rate. Therefore, there is no need to measure the critical parameters of pressure, velocity, temperature, viscosity, or density. Also, it is a nonintrusive meter, i.e., there are no moving parts in the flowing fluid, and the meter is unaffected by erosion, corrosion, or scale buildup in the flow sensor.” Some additional advantages and disadvantages to mass Coriolis flowmeters follow.

Performance Advantages are the following:

- Coriolis flowmeters can handle difficult applications that could, for example, plug an orifice plate. The Coriolis flowmeters are suitable for a large number of fluids, whether Newtonian or non-Newtonian, high or low viscosity that would create problems for other flowmeters. Flowmeters can be used on liquids, slurries, gases, and 2-phase gas and liquid flows.
- The nonintrusive design means less susceptibility to damage, wear, and maintenance.
- Coriolis flowmeters can measure bidirectional flow.

- Accuracy is very good, typically $\pm 0.2\%$ of rate or better. The linearity is usually over the entire flow range. The rangeability is typically 20:1 or better with Coriolis meters.
- The operation of these flowmeters is independent of a fluid's property characteristics. The Coriolis flowmeters are independent of a fluid's Reynolds number, as well as a fluid's turbulence and flow profile.
- The Coriolis meter has a very high turndown ratio.

Performance Disadvantages are the following:

- Some earlier versions of Coriolis flowmeters were susceptible to external vibrations.
- The durability of contoured sensor tubes should be considered if a corrosive fluid is used at high velocities.
- Pressure-drop requirements can be a factor in performance of Coriolis meters. Some Coriolis meters may require, for example, a 10 psi pressure drop. Others may require higher velocities and pressure drops to have an accurate measurement.
- A Coriolis meter is available only up to a maximum 6 inches in size.
- Special installation requirements are followed to isolate the Coriolis meter from mechanical vibration.
- SADP-J-100, Section 7.8.4 states the following constraints: "Avoid using Coriolis meters in piping or meter runs which are prone to substantial vibration, shock, or extreme temperature gradients. External meter piping must be well supported. Avoid using Coriolis meters in liquid services prone to gas entrainment or slugs. Coriolis meters can not be used in gas service."

Installation

In general, the main installation concern for liquid applications is to install the flowmeters so that the meter remains filled with liquid; a partially filled meter will not provide accurate measurement. For gas applications, do not install the meter sensor at the lowest point in the system, condensation may accumulate in the meter sensor.

Typical installation procedures also include considerations such as the following:

- Install a downstream shutoff valve for rezeroing the meter.
- Avoid strong magnetic fields that would affect the meter's velocity detectors.

- Provide proper piping support to avoid abnormal vibration.
- Operations in temperature extremes require taking steps to equalize differential pressures within the sealed meter enclosure.

SADP-J-100, Section 7.8.4 describes installation requirements in the following manner: “Coriolis meters should be installed as per manufacturer's recommendations. Horizontal or vertical meter runs are preferred, however, they must be designed for maintenance accessibility and freedom from external pipe vibration. Recommended upstream and downstream straight pipe run is 5 D respectively. Meters installed in a vertical position should be oriented so that fluid flow is from bottom to top. All external meter piping must be properly supported to prevent sagging, stress, or improper alignment at the meter body.”

Applications

The Coriolis flowmeter is a versatile flowmeter. Applications range from process control, inventory control, blending, and custody transfer. For example, mass flow applications include boiler control applications, where accurate measurements of combustion and preheat flows, along with fuel gas flows, are used for greater heating efficiencies. Other gas flow examples include metering natural gas in pipeline; and gas flow to flare stacks. (Note: Not all Coriolis meters support gas measurement.) Crude oil, asphalt, gasoline, and fuel oil applications are just several examples of process media that are usable with Coriolis meters.

Figure 65 references standards and practices that influence Coriolis meter selection. Review these references (as well as the vendor's supporting documentation) for additional detail when determining a device's suitability for an application.

Saudi Aramco Reference	Reason for use	Summary
SADP-J-100, Section 7.8.1	Design parameters	• Accuracy • Straight pipe requirements • Turndown ratio
SADP-J-100, Section 7.8.2	Constraints	Avoid vibration, shock, temperature extremes
SADP-J-100, Section 7.8.3	Piping	Meter run guidelines
API RP 551, Section 2.3.7.2	Commentary	General discussion of philosophy and usage
Liptak, “Process Measurement,” Section 2.10	Coriolis meters	Additional reference for selection and implementation

Figure 65: Coriolis Meter References

Ultrasonic Flowmeters

The ultrasonic flowmeter category contains a number of different designs for measuring an average velocity of a fluid in a flowing system. Flowmeters that use sound waves to measure flow rate are called ultrasonic flowmeters. The accuracy of the meter relates to the ability of the system to represent the average velocity – the whole stream passing through the meter body hydraulic area.

Principles

Ultrasonic flowmeters use several different principles to determine flow rate, as follows:

- Doppler shift (frequency shift) method
- deflecting beam method
- transit time (aka “frequency difference” or “pulsed type”) method

Doppler Shift Method – Ultrasonic flowmeters using this method transmit a sound wave through the flowing fluid. The sound waves are reflected from the fluid to a receiver on the ultrasonic flowmeter. The frequency of the sound waves sensed at the receiver shift are affected by the Doppler effect. The frequency shift is used to determine flow rate. Several types of meters are available — one type requires installation of a transducer into the flowing stream, the other is a strap-on model where installation of a transducer on the pipe is noninvasive.

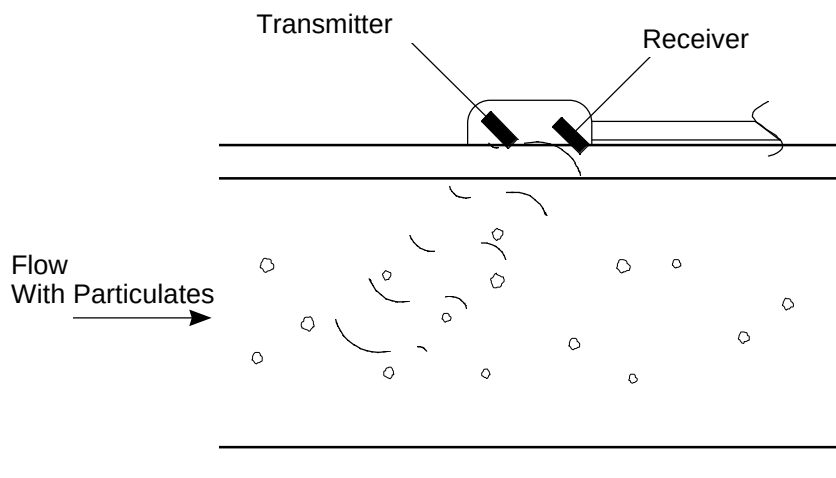


Figure 66: Doppler Meter

Deflecting Beam Method – For ultrasonic flowmeters using this method, the transmitter sends a sound wave that is at a right angle to the flow. Because the liquid carries the sound wave, the sound wave is “pushed” or deflected downstream. The deflection is directly related to the flow rate and is used to determine the flow rate.

Transit Time Method – For ultrasonic flowmeters using this method, the meter sends a diagonal beam across the flow path. The beam is sent with the flow and against the flow. Because sound will travel slower against flowing fluid, a frequency difference can be detected between the ultrasonic signals. As the flow rate increases, the time difference between the signals detected becomes greater. Transit time method ultrasonic flowmeters (Figure 67) are the most commonly used of the ultrasonic flowmeter family.

Transit time meters have been used successfully for homogeneous fluids without entrained bubbles. They are not recommended for heavy slurry-type applications, because of the high acoustic impedance between transducer versus pipe wall coupling.

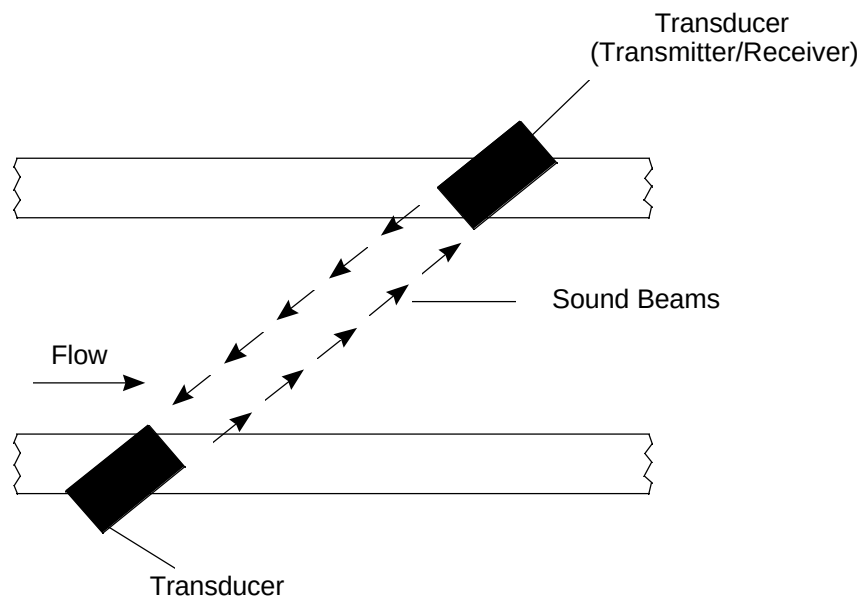


Figure 67: Transit Time Meter

Note that SADP-J-100, Section 8.9 states, “[A transit time flowmeter] is generally more accurate than a Doppler-type meter and therefore, should be given preference over Doppler meters.”

Design

The following discussion describes design aspects of transit time flowmeters. An ultrasonic flowmeter has two transducers installed diagonally to the flow. Each transducer acts as a transmitter and receiver. The transmitter and receiver are never installed directly across from each other. One can measure the time a signal is received downstream and calculate a time difference from the time a signal is received upstream. Changes in the time difference becomes a measurement of changes in flow rate.

The transit time flowmeter is divided into two categories — time domain transmit-types and frequency domain types. Both meters transmit pulses from a transmitting transducer that passes through flowing media to a receiving transducer. The difference between the times of arrival for an upstream and a downstream direction is used to calculate flow velocity in both types. Both meters have the same type of transducers. One meter converts a pulse signal into time and the other one converts it into a frequency signal.

Transmit Time Frequency Domain Meters

Time frequency domain meters send a pulse signal in a given direction and record the time of pulse at the other end of sonic path, then the same signal transmits in the opposite direction and records the time at the arrival. The difference between two time measurements provides information on motion of the fluid in a pipe. The typical equations for a time frequency domain meter are developed using Figure 68.

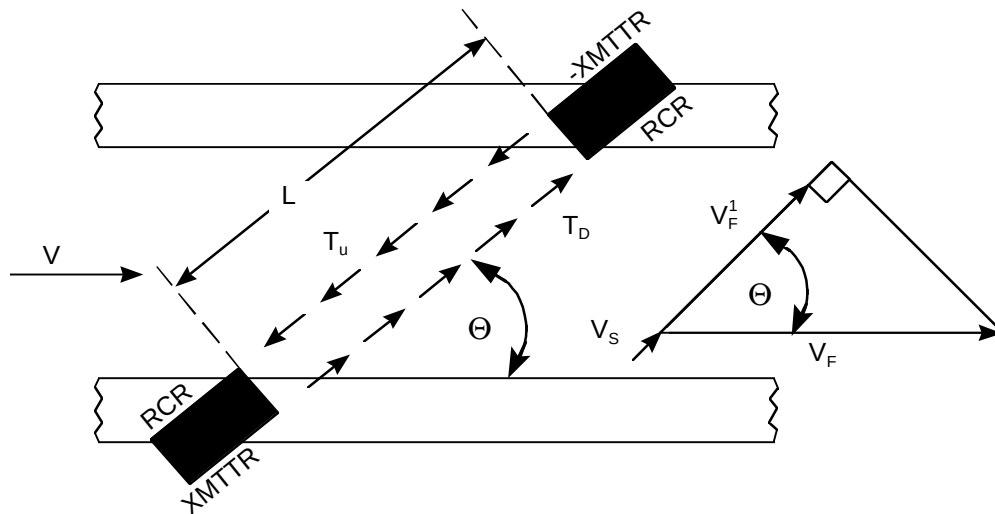


Figure 68: Transit Time Design

The fundamental equation of uniform linear motion, the quotient of distance and velocity equals time, will be applied in both upstream and downstream directions from transmitter to receiver.

$$T_U = \frac{L}{V_s - V_F'} \quad \text{and} \quad T_D = \frac{L}{V_s + V_F'}$$

Frequencies are inverses of time.

$$F_U = \frac{V_s - V_F'}{L} \quad \text{and} \quad F_D = \frac{V_s + V_F'}{L}$$

The frequency difference is

$$F_D - F_U = \Delta F = \frac{V_s + V_F'}{L} - \frac{V_s - V_F'}{L} = \frac{2V_F'}{L}$$

From the vector diagram

$$V_F' = V_F \cos \theta$$

$$\Delta F = \frac{2V_F \cos \theta}{L}$$

so

$$V_F = \frac{\Delta FL}{2 \cos \theta} = \Delta FK$$

therefore

$$\text{Flow} = AV_F = A * \Delta F * K$$

where

- V_F = fluid velocity time based
- V_s = speed of sound in the fluid
- T_U = upstream phase travel time
- T_D = downstream phase travel time
- θ = angle between acoustic path and flow axis
- F_U = upstream phase frequency
- F_D = downstream phase frequency
- ΔF = frequency difference (upstream-downstream frequency)
- L = length of sonic path in the fluid

It is also defined as follows. The time for an ultrasonic pulse signal to travel from sensors A to B in a forward direction is:

$$t_f = \frac{L}{(C + v \cos \theta)}$$

The time for an ultrasonic pulse signal to travel from sensors B to A in the opposite direction is given as:

$$t_r = \frac{L}{(C - v \cos \theta)}$$

$$\Delta t = t_r - t_f = \frac{2 L v \cos \theta}{C}$$

where

- C = speed of sound in the fluid
- Δt = the time difference between the forward and reverse direction of a pulse signal
- L = the sonic path length in a fluid
- θ = the angle of the path with respect to a pipe axis

Frequency Domain Meters

The frequency domain meter uses the same type of transducers as the transit time domain meter. The only difference is in the processing of the signal, where the time pulse signal is converted to a frequency signal. A sonic pulse is received and it is immediately re-sent to convert a pulse repetition rate that represents a frequency proportional to that of a transit time of the pulse. If the path in each direction of flow is used, the sonic path will generate two frequencies. The delta of these two frequencies is directly proportional to flow velocity. Flow velocity of a frequency domain meter is given by the calculation:

$$v = \frac{\Delta f L}{2 \cos \theta}$$

Where

- v= velocity of flow
- Δf = frequency difference (upstream -downstream frequency)
- L= length of sonic path in the fluid
- θ = angle of path with respect to pipe axis

Doppler Flowmeters

The Doppler effect states that a wavelength of a sound moving towards a point (in this case, a sensor) is shorter, while the wavelength of sound moving away from the sensor is longer. A Doppler flowmeter transmits an ultrasonic beam frequency at 0.5 MHz into the flowing fluid and detects a return frequency that is proportional to the fluid velocity. The delta between the transmitted and returned velocities is called the beat frequency. The equation for the flow velocity in Doppler meters is as follows:

$$v = \frac{\Delta f C_t}{(2 f_v \cos \theta)}$$

where

- Δf = difference between transmitted and returned frequency
- f_v = frequency of transmission
- θ = angle of transmitter and receiver with respect to the pipe axis
- C_t = velocity of the sound in the transducer
- v = fluid velocity

Velocity is a linear function of Δf . When the inside diameter of pipe is known, volumetric flow rate can be measured using formula as follows:

$$\text{GPM} = 2.45 \cdot v \cdot (\text{ID})^2$$

The single transducer assembly contains transmitter and receiver that mount on the outside of the pipe.

Performance

For transit time flowmeters to properly indicate volumetric flowrate, the pipe must always be full of liquid. A Doppler-type ultrasonic flowmeter will indicate velocity in a partially full pipe as long as the sensor is mounted below the liquid in the pipe.

The meter has large turndown ratio with higher accuracy for multiple designs compared to other meters. Accuracy is usually specified as a percent of rate, typically for a single pulse meter accuracy is about 1 to 2 % of full scale rate. To increase accuracy for a larger pipe, manufacturers suggest installing another pair of sensors arranged to interrogate a multiple acoustic path.

While some ultrasonic flowmeters can be used to measure gas flow rates, most are used to measure liquids. Ultrasonic flowmeters do not require a pressure drop to measure flow rate because they are nonintrusive. Following are some advantages and disadvantages to ultrasonic flowmeters.

Performance Advantages include the following.

- Clamp-on versions are convenient for retrofits; process downtime is avoided.
- Ultrasonic flowmeters are usually nonintrusive, no pressure drop is required to operate the flowmeter.
- Ultrasonic flowmeters have an accuracy comparable to orifice plates. For transit time ultrasonic flowmeters, this can be $\pm 1\%$ to $\pm 2\%$ of full scale.
- Ultrasonic flowmeters have high rangeability; rangeability can be up to 40:1.
- An ultrasonic flowmeter's high frequency pulse rate output minimizes errors from the effects of pulsation and fluctuating flow.

Performance Disadvantages include the following, summarized from SADP-J-100, Section 8.9.3:

- Applications normally are limited to clean, single-phase liquids.
- Straight piping is required for uniform flow profile.
- Sound wave attenuation may limit transmission path length.
- Averaging methods for large pipes are marginally cost-effective.
- An ultrasonic flowmeter requires power to operate.

Installation

Ultrasonic flowmeters can be installed on either horizontal or vertical pipe. Depending upon the type of meter, a manufacturer specifies the minimum distance from valves, tee, pumps, or other process equipment in order to ensure accurate flowmeter performance. Typically, 10 to 20 diameters are required on the upstream side and 5 diameters required on the downstream side of the meter. The meter relies upon an ultrasonic signal traveling across the pipe. The liquid should be clean and free from air bubbles. Generally, bubbles in the fluid stream cause more alteration of the sonic signal than solid particles.

Large or complex installations of multiple transducers are mounted in the wall of the conduit. The transducers are held in place within the pipe wall by a series of expansion rings kept inside the pipe. Each transducer pair makes an independent measuring path. Each measuring path is mathematically calculated to produce flow measurement independent of the velocity. A special calibration is required for that particular installation, and is usually provided by the meter's manufacturer.

Depending on the process fluid, proper selection of transducer material, and protection must be chosen to prevent the transducer damage caused by the chemical action. A wide variety of pipe sizes and flow conditions are encountered. Several different sensor configurations are available:

- Axial-type
- Radial-type
- Clamp-on-type

Axial-Type Configuration – When pipes of small diameter are encountered, it becomes necessary to pass the sound directly down the axis of the pipe and ensure that there is a sufficient path length to measure the transit time. A path less than 3 inches does not provide adequate time difference for an accurate measurement.

Radial-Type Configuration – In a radial type installation, sonic transducer sensors are placed on the either side of the spool section and normally inclined at 45 degrees to the pipe axis to measure a vector component of the flow. In a radial-type configuration, the lower pipe size limit is about two inches and with an upper limit in excess of 10 feet.

Clamp-on-Type Configuration – Clamp-on-type meters are desirable to have when the pipe wall cannot be penetrated. Clamp-on-type meters can be installed without shutting down the process. Installation of a clamp-on-type meter is very convenient and has an accuracy that is similar to the accuracy of direct wetted transducers. The clamp on type meter is more complex to calibrate. The transducers are mounted on a calibration device and affixed to the pipe wall with grease or epoxy.

Applications

According to SADP-J-100, Section 8.1, ultrasonic meters are considered an alternative flowmeter and “Alternative flow meters should be considered when it is evident that orifice plates, or precision flow metering devices are not suitable nor practical for metering process fluids caused by process constraints, short meter run lengths, or specified accuracy requirements.” Additionally, SADP-J-100, Section 8.9, states that “Ultrasonic flowmeters are suitable for services involving either clean or entrained liquids. They are best suited however, for applications involving large line sizes where noninvasive flow measurement is desired, where low pressure losses are required, or where fluid properties require an ultrasonic-type meter.

Potential ultrasonic meter applications include wastewater streams, slurries, viscous fluids, liquids containing suspended solids or entrained gas bubbles, crude oil measurement, and flare gas flow metering.”

Figure 69 references standards and practices that influence ultrasonic meter selection. Review these references (as well as the vendor’s supporting documentation) for additional detail when determining a device’s suitability for an application.

Saudi Aramco Reference	Reason for use	Summary
SADP-J-100, Section 8.9	General usage	Types of service, theory of operation
SADP-J-100, Section 8.9.1	Design parameters	• Accuracy • Straight pipe requirements • Turndown ratio
SADP-J-100, Section 8.9.2	Doppler type meter constraints	Liquid flows only, pipe must be full, other constraints
SADP-J-100, Section 8.9.3	Transit time meter constraints	Single phase fluids, other constraints
SADP-J-100, Section 8.9.4	Piping	Sensor location
Liptak, “Process Measurement,” Section 2.24	Ultrasonic meters	Additional reference for selection and implementation

Figure 69: Ultrasonic Meter References

Vortex Meters

Three types of vortex meters are available – vortex precession, vortex shedding, and fluidic oscillation. All types of meters utilize fluid oscillation to provide the meter with no moving components, and are suitable for gas, steam, or liquid services. They generally have wide flow range capability, minimal maintenance, good accuracy, and long term repeatability. Only the vortex shedding type will be described here. Vortex shedding meters (Figure 70) are the most common type of vortex meters used by Saudi Aramco.

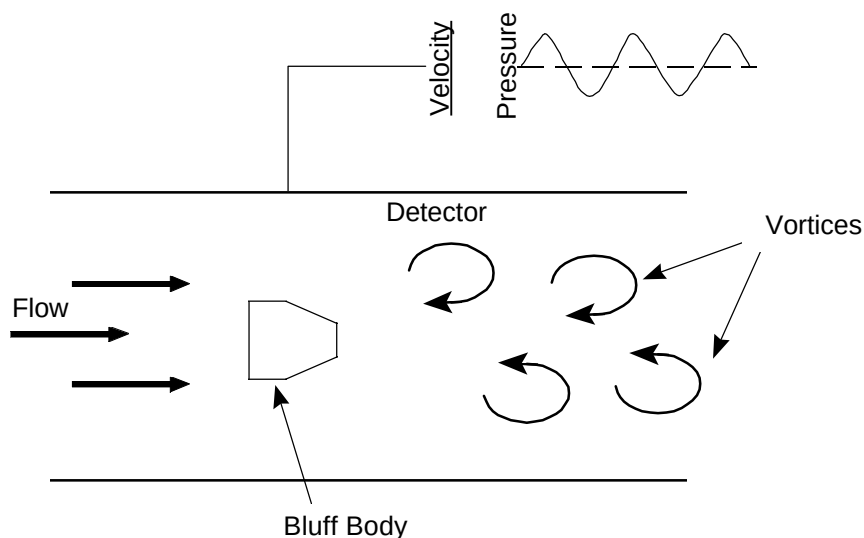


Figure 70: Vortex Meter Overview

Principles

The principle of a vortex flowmeter's operation is based on a phenomenon of vortex shedding known as the Von Karman effect of flow across a bluff body. A bridge pier in a river generates Von Karman vortices. The principle states that flow alternately sheds vortices from one side to the other side of a bluff body. The frequency of the shedding is directly proportional to fluid velocity across the body. As a fluid passes the bluff body it separates and generates small eddies or vortices that are shed alternately along and behind each side of the bluff body.

The output of the vortex flowmeters depends on the K-factor. The K-factor relates the frequency of generated vortices to the fluid velocity. The K-factor varies with the Reynolds number, but is virtually constant over a broad flow range. Figure 71 shows the relationship between two numbers. The formula for fluid velocity is

$$\text{Fluid velocity} = \frac{\text{Vortex frequency}}{\text{K - factor}}$$

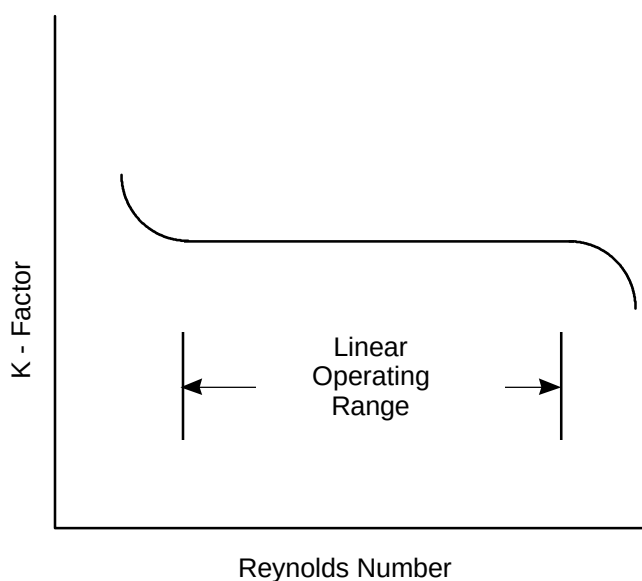


Figure 71: Vortex Meter K Factor

Reynolds Number Equation

The Reynolds number equation shown below combines effect of density (ρ), viscosity (μ_{CP}), pipe inside diameter (D), and flow rate (Q_f).

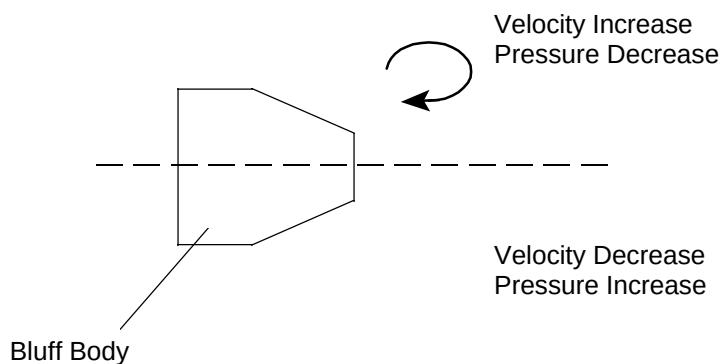
$$Re = \frac{K \times \rho \times Q_f}{D \mu_{CP}}$$

where: $K = 50.7$
 $\rho = \text{\#/ft}^3$
 $Q_f = \text{GPM}$
 $\mu = \text{centipoises}$
 For liquids

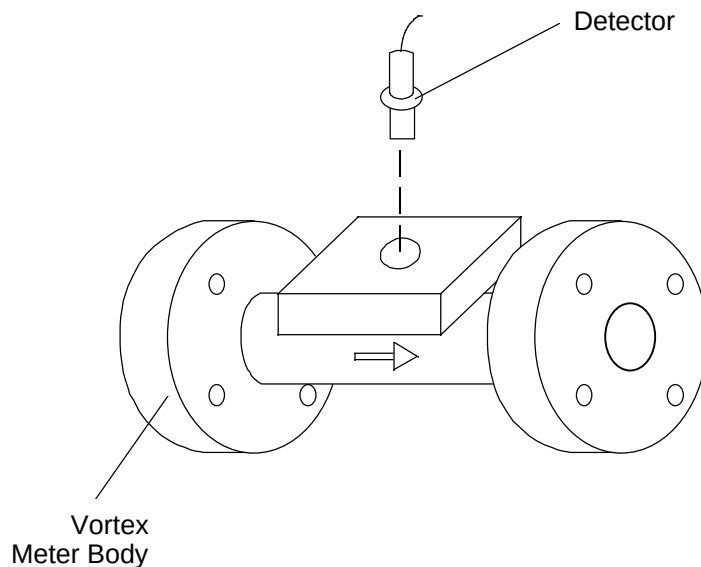
and $K = 6.32$
 $\rho = \text{\#/ft}^3$
 $Q_f = \text{SCFH}$
 $\mu = \text{centipoises}$
 For gases

Design

The meter body contains a shedder bar that acts as an obstruction on a flowing stream. As a vortex is shed from one side of the bluff body, the velocity on that side increases and pressure decreases. On the opposite side of the bluff body, velocity decreases and pressure increases, thus causing a net pressure change across the bluff body. The entire effect is then reversed on the next vortex as it is shed from the opposite side. This results in alternating forces on a small section of the bar at the same frequency as the formation of vortices.

**Figure 72: Vortex Meter Principles**

The alternating forces on a section are transmitted to the sensor. A piezoelectric element inside the sensor detects this movement of the vortices, which creates an electrical signal and transmits it to the electronic module device. The frequency is then converted to an output signal proportional to the volumetric flow rate. The electronic module device receives the piezoelectric sensor signal, digitizes it, and passes the digital information to digital tracking device.

**Figure 73: Vortex Flowmeter Design**

Performance

The vortex shedding meter provides a linear output signal (digital or analog) without the use of a separate transmitter or converter. Meter accuracy is good over a potentially wide flow range. The meter does not have any moving or wearing components, provides improved reliability, and reduces maintenance. Vortex meters have no valves or manifolds that could cause leakage problems. The same meter can be used for a gas or a liquid application.

SADP-J-100, Section 7.7.2, describes vortex meter performance constraints in the following manner: “The minimum number of straight upstream and downstream pipe diameters must be maintained to ensure maximum flowmeter accuracy. Oscillatory type flow meters are sensitive to increases in fluid viscosity, density, and solids entrainment.

It is difficult to calibrate vortex meters in the field. Electronic calibrations are easily performed, but actual flow calibrations are difficult to achieve unless a comparison test is made against a turbine, PD, or D/P meter.

Avoid using vortex meters for metering laminar flows or streams with Reynolds numbers below 10,000. Avoid using insertion type vortex meters where full line-size vortex meters can be used. Potential insertion vortex meters installations must undergo careful investigation and user surveys to determine if they are applicable to Saudi Aramco process situations and environmental constraints.”

Installation

The vortex shedding flowmeter is not attitude sensitive. Flow can be upward or horizontal without affecting meter performance. However, note that SADP-J-100, Section 7.7.3, states that “Vortex meters should be installed in horizontal meter runs...” The line must be kept full of liquid at all times when metering is required. The vortex shedding meter requires the same straight run as the orifice meter run. The flow stream should be smooth for better accuracy. If the flow stream is not smooth and does not have enough upstream piping run, then straightening vanes are required on upstream of the meter.

When mounting the vortex shedding meter on-line, correct installation is important. The mating pipe should be the same diameter as the meter bore. Most manufacturers indicate that the pipe size should be used to mate with meter bore. The pipe sizes are generally schedule 40 or 80. Some vortex shedding meters may be able to function properly in other pipe schedule with or without some adjustment to the meter K-factor (For more installation details review the manufacturer’s guidelines).

Vortex Meter Selection

Manufacturers provide computer programs to aid in the selection of a vortex meter. After inputting the process data, the program calculates the size for the meter. Generally, the selected meter is one size smaller than the pipe size. Note that a reduction in size creates a higher fluid velocity.

Vortex flowmeters work best when there is a high fluid velocity. The high fluid velocity does not have an adverse effect on the meter. Vortex shedding flowmeters are available in sizes from 1-1/2 to 8 inches. Meter connections are wafer-type or flange-type.

Manual calculations are shown as follows.

Equation for Gas Applications

$$q_b = q_f M_f \frac{P_f}{P_b} \frac{T_b}{T_f} \frac{Z_b}{Z_f}$$

where:

- q_b = Flow rate at base conditions, SCFM
- q_f = Flow rate operating conditions (meter reading), ACFM
- M_f = Meter factor to correct meter output based on calibration
- P_f = Pressure at flowing conditions, PSIA
- P_b = Base pressure set by agreement near atmosphere pressure, 14.7 PSIA
- T_b = Base temperature by agreement near ambient (60 °F), 520°R
- T_f = Temperature at flowing conditions, °R
- Z_b = Compressibility at base pressure and temperature
- Z_f = Compressibility at flowing pressure and temperature

Equation for Liquid Applications

$$q_b = q_f M_f F_t F_p$$

where:

- q_b = Flow rate at base conditions
- q_f = Flow rate at flowing conditions
- M_f = Meter factor to correct output based on calibration
- F_t = Correction from flowing temperature to base temperature
- F_p = Correction from flowing pressure to base pressure

Figure 74 references standards and practices that influence vortex meter selection. Review these references (as well as the vendor's supporting documentation) for additional detail when determining a device's suitability for an application.

Saudi Aramco Reference	Reason for use	Summary
SADP-J-100, Section 7.7	General usage	Types of service, theory of operation
SADP-J-100, Section 7.7.1	Design parameters	• Accuracy • Straight pipe requirements • Turndown ratio
SADP-J-100, Section 7.7.2	Constraints	• Accuracy dependent upon upstream/downstream straightness • Avoid usage with laminar flows and Reynold's numbers below 10,000
API RP 551, Section 2.3.6	General guidelines	• Usage guidelines • Installation • Commissioning
Liptak, "Process Measurement," Section 2.28	Vortex meters	Additional reference for selection and implementation

Figure 74: Vortex Meter References**Applications**

The vortex shedding flowmeter can be used for liquid as well as gas applications. The flowmeters are not recommended for viscous and dirty fluid applications. If two phase fluid flows are present, the vortex shedding meter will not provide accurate flow measurement.

When the meter is measuring a gas flow, the operating density becomes very important to measurement accuracy. At some point the density/velocity relation becomes so low that the meter cannot detect the flow signal. At the no flow point, the meter should be calibrated to indicate a no flow condition.

When the meter is measuring a liquid flow, the fluid's Reynolds number becomes very important to measurement accuracy. Refer to manufacturer's guidelines for how low a Reynolds number can be for a particular application. Pressure drop and fluid velocity also must be considered when selecting a vortex meter.

Variable Area Flow Meters (Rotameters)

Several types of variable area flow meters are available. The types are rotameters (float in a tapered unit) type, gravity type, spring and vane or piston type, and open channel variable gate type. Only the rotameters are described in this section. Rotameters are the most common types of variable area flowmeters used at Saudi Aramco.

Principles

The rotameter's operation (Figure 75) is based upon variable area principles, where the flow raises a float in a tapered tube, increasing the area for passage of the flow. The greater the flow, the higher the float is raised. The rate of flow is directly proportional to the height of the float.

The float moves up or down in a tapered tube, proportional to the fluid flow rate and the annular area between the float and tube wall. In a liquid flow measurement application, the float is raised by a combination of the buoyancy of the liquid and the velocity head of the liquid. On a gas application, the buoyancy effect is negligible and the float responds to the velocity head alone. The float reaches a stable position in the tube when the upward force exerted by the flowing fluid equals the downward gravitational force exerted by the weight of the float. A change in flow rate upsets this force balance. The float then moves up or down changing annular area until it again reaches a position where the forces are in equilibrium.

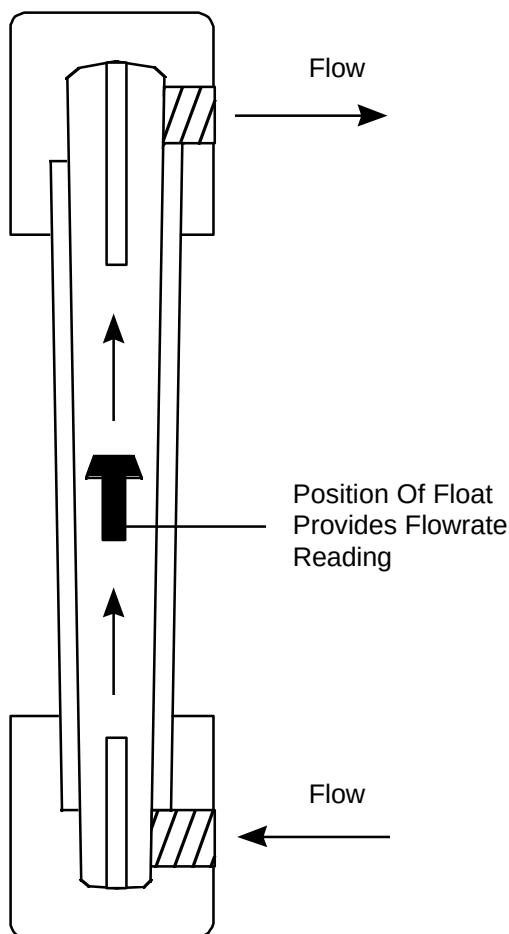


Figure 75: Rotameter Principles

Design

Rotameters are good for low flow measurement because of their low cost, simplicity, low pressure drop, relatively wide rangeability, and linear output. The rotameters consist of a tapered metering tube and a float that is free to move up and down within the tube. Metering tubes are made of glass as well as metal. Glass tubes are limited to their maximum pressure and temperature rating and type of fluid. Metal metering tubes are used in applications where a glass metering tube is not satisfactory to use. The metering tube is mounted vertically with the small end at the bottom. The fluid to be measured enters at the bottom of the tube and passes upward around the float and out the top. When there is no flow through the rotameter, the float is at the bottom of the metering tube, where the maximum diameter of the float is nearly same as the metering tube bore. A small annular opening is present between the float and the meter tube. When fluid enters the metering tube, the buoyant effect of the fluid lightens the float, but because it is greater than the density of fluid, the buoyant effect does not have enough force to raise the float. In a metal metering tube that use the floats, the float position must be determined by either magnetic or electrical techniques. The use of indirect float position sensors also provide functions other than the direct visual indication. Meters can transmit pneumatic, electronic, or time pulse signals for totalizing, recording, and controlling functions.

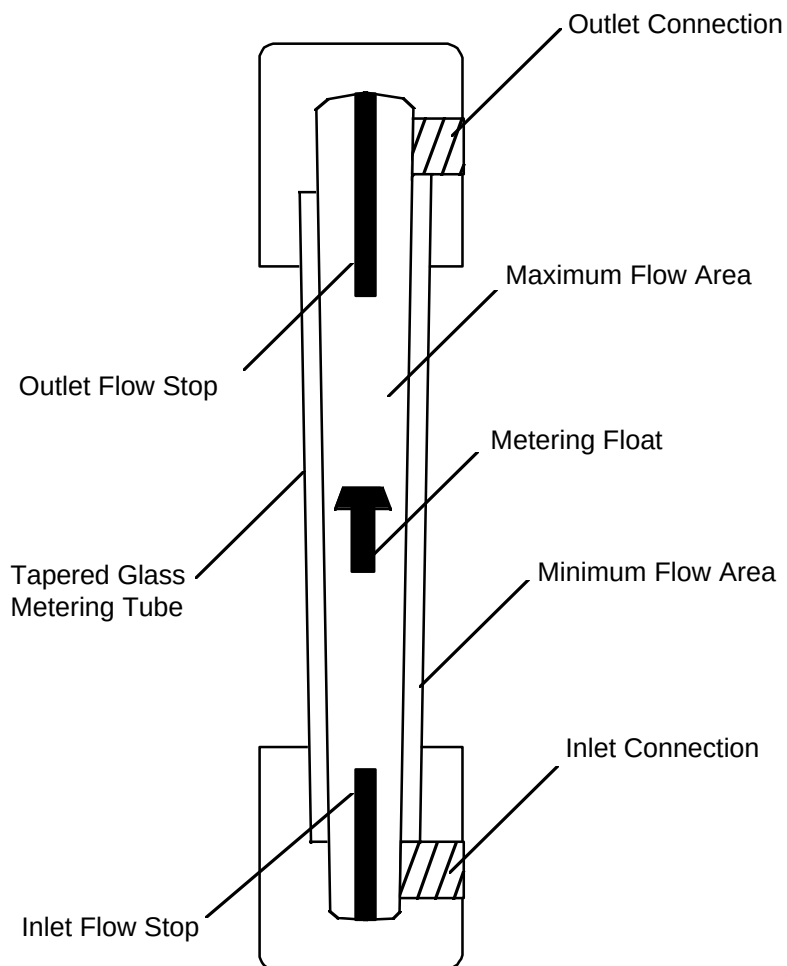


Figure 76: Rotameter Design

Performance

The vast majority of rotameters operate with an error of 2 % to 10 % of full scale. Some are available with percent of rate performance. Logarithm scale meters are designed to give the same percent of rate accuracy at all scale positions over a 10:1 range of the meter. The high accuracy-type meters find the greatest application in laboratory testing, development, and production where the highest accuracy is required. The capacity of the rotameters is changed by changing the float.

Rotameters typically deviate from linearity by approximately 5 percent. When the meter is equipped with a transmitter, linearity adjustments are generally supplied to guarantee linearity of the output versus flow rate. The linearity of transmitters are usually rated at ± 1 % full scale.

Installation

Rotameters are limited to vertical installations. Rotameter installation includes a small needle valve that regulates the flow. The bottom portion of the tube is connected to the pipe inlet where the fluid enters and the upper portion of the tube is connected to the pipe outlet where the fluid leaves after metering the flow. The meter is not affected by an upstream piping effect. The meter can handle any configuration of upstream piping.

Always install some safety device to ensure that the line pressure cannot exceed the pressure rating of the flowmeter. A pressure gauge can be used for gas pressure indication and should be located as close to the outlet of the meter as possible. No valve or any kind of restriction should be present between the meter and pressure gauge. For a gas service application, a throttling device such as valve or pressure regulator should be installed close to the meter outlet. In that case, follow the manufacturer's installation guidelines.

SADP-J-100, Section 8.8.5, states the following: "Rotameters should be mounted vertically in locations which are free from vibration and where sufficient clearance is available for occasional float removal for service or inspection. Meters shall be located so that they are visible and readily accessible for operation and maintenance. In general, when a meter is to be used in regulating service, it should be placed as close as possible to the throttling point, preferably with the valve located at the outlet fitting."

Sizing of Rotameters

To size a rotameter, it is customary to convert actual flow to standard flow. For liquid service, it is necessary to calculate flow in GPM or cc/in./min. of equivalent water. It is also necessary to determine the cc/min. of equivalent air at standard conditions. Capacity tables (provided in a manufacturer's catalogue) and computer programs are available for sizing and selecting meters.

The sizing formula is as follows:

Liquid volume rate:

$$\text{GPM}_b \text{ water equivalent} = \frac{(\text{GPM}) (\rho) (2.65)}{\sqrt{(\rho_f - \rho) \rho}} \quad \text{Liptak} \quad \text{page 234}$$

For gases or vapors at standard volume rate:

$$\text{SCFM air equivalent} = \frac{(Q) (\rho_{g \text{ std}}) (10.34)}{\sqrt{\rho_f (\rho_{g \text{ act}})}} \quad \text{Liptak} \quad \text{page 234}$$

where

GPM =	maximum flow of liquid at metering condition in units of gallons per minute
ρ =	density of flowing liquid at metering condition in units of grams per cubic centimeter
ρ_f =	density of float in units of grams per cubic centimeter
Q =	maximum flow of gas at metering condition in units of SCFM
$\rho_{g \text{ std}}$ =	density of gas at 14.7 psia and 70°F or 14.4 psia and 60°F in units of pounds per cubic foot
$\rho_{g \text{ act}}$ =	density of gas at metering conditions in unit of pounds per cubic foot

Applications

Flowmeters can be used for liquid, slurries, some gas applications, or 2-phase flow applications. Meters can also be used for flow rate measurement with limited supply pressure for a liquid and gas. Rotameters are also used for purging application.

According to SADP-J-100, Section 8.1, rotameters are considered an alternative flowmeter and “Alternative flow meters should be considered when it is evident that orifice plates, or precision flow metering devices are not suitable nor practical for metering process fluids caused by process constraints, short meter run lengths, or specified accuracy requirements.”

Additionally, SADP-J-100, Section 8.8, states that “Rotameters are recommended for metering applications requiring wide rangeability, linear output, measurement of low flows, or where indication only is required. Rotameters are available as indicators, transmitters, recorders, local pneumatic controllers, and totalizers with or without alarm functions.

Typical applications include:

- a. Purge rotameter with integral needle control valve for the measurement of: Inert gases or liquids, seal liquids, small volumes of chemicals, chlorinator flow rates, and air purges for instruments, analyzers or sample flow streams.
- b. Glass taper-tube rotameters for flow indication of: Liquid streams with or without suspended solids or other volatile liquids in nonhazardous services.
- c. Armored – metal taper tube rotameters for measurement of: Hot liquid flows above 40°C (104°F), strong alkalies or acids, steam or slurry services, high pressure fluids, freezing or congealing liquids such as strong chemicals, waxes and asphalts, liquid streams with or without suspended solids, and liquefied petroleum gas (LPG) or other volatile liquids.”

FLOW METER CALIBRATION: IMPORTANCE AND TECHNIQUES

Calibration is typically performed in a laboratory setting at several different flow rates, and uses conditions such as changing densities, pressure, and temperatures. When calibration is performed, the meter's inherent calibration factors are determined. Proving differs from calibration in that it is done in the field, typically under a single set of conditions. When a meter is proved in the field, a meter correction factor is determined that is multiplied by the reading from the meter to offset its indication.

The calibration can be defined as the comparison of a measuring instrument with specified tolerance but an undetermined accuracy, to a measurement standard with known accuracy. The use of noncalibrated instruments creates potentially incorrect measurement and erroneous conclusions and decisions. It is calibration that provides assurance and confidence in measurement that the instrument has an accuracy required to maintain product or process-specified ranges. Calibration can be a simple dimensional check to detect measurement variables. Before starting calibration, a decision must be made for the following:

- Which variables should be measured.
- What accuracy must be maintained.

The calibrated device must show sufficient range and be capable of transferring to the desired level of accuracy. Some element of error exists in all measurements no matter how carefully they are conducted. The magnitude of the error can never be easily determined by experiments; the possible value of the error can be calculated.

This section of the course module introduces to the Participant the following flow measurement topics:

- Methods of calibrations
- Provers
- Weight and volume methods

Method of Calibrations

In general the flow measurement devices are calibrated by three methods:

- Wet calibration uses the actual fluid flow
- Dry calibration uses flow simulation by means of an electronic or mechanical signal.
- A measurement check of the physical dimensions and use of empirical tables relating flow rate to these dimensions is another form of calibration.

Wet Calibration

Wet calibration uses actual fluid flow. Generally it provides high accuracy for a flowmeter and is used when accuracy is a prime concern. Precision flowmeters are usually wet calibrated at the time of manufacture. Depending upon the size of the meters, calibration can be performed at the user site, manufacturer's facility, or laboratory. Wet calibration for flowmeters is usually performed with water, air, or hydrocarbon fuels.

Dry Calibration

Dry calibration is performed on a flowmeter without the presence of a fluid medium. In a wet calibration system, flowing fluid produces the input signal. In a dry calibration system, the input signal is input as a frequency, millivoltage, or differential pressure. Dry calibration measurement is much more uncertain than wet calibration and overall accuracy of the flow device is inferred because the flow transducer is bypassed. The input signal for a dry calibration must be provided by a measurement standard. The value of the output signal requires use of other measurement standards. Follow the manufacturer's guideline and procedures for dry calibration.

Provers

The proving operation verifies the meter's performance and assures the meter users that the metering system is operating properly. The necessity of meter proving depends on how accurate the measurement must be for the product being handled. Larger volume and higher value products are the most important reasons for using a meter prover. Oil industry measurement of crude oil and refined products is an example of where the proving system should be used. The proving system is considered part of the cost of the meter stations and is permanently installed at the facilities. When the product has a lesser value, portable proving systems are used. The following discussion describes

- Reasons for meter proving
- Methods of meter proving

Reasons for Meter Proving

Meter proving is generally conducted in oil processing industries for one of these three reasons:

- Custody transfer
- Quality audit (ISO 9000)
- Environmental audit

Custody Transfer – Proving ensures that product inventory accounting is of the highest accuracy. Two types of custody transfer are possible — legal custody, which falls under weights and measures requirements, and contract, which is a contractual agreement between buyer and seller. Proving must be performed under actual operating conditions. A field reference device is used to prove the meter.

Quality Audit (ISO 9000) – Proving ensures that the product quality is consistent. When a meter is used to control the addition of various fluid components to make a final product, the meter performance must be repeatable to ensure that there is no degradation of the final product.

Environmental Audit – Proving ensures material balances during the manufacturing process and transfers to the pipelines are correct. The main intent is to verify that what went in and what came out was accounted for, so there is no loss of product during the process. It also ensures that there is no violation of environmental regulations. As a part of environmental regulations, it is important to show that the plan is working properly and accurately. Maintain proper records to show that meter verification is being conducted on a regularly scheduled basis.

In general, proving in house is seldom done. Metering is assumed to be correct unless the process goes out of control or breaks down. The proving procedure can be very expensive and time consuming. The ability of these tests to prove a flowmeter's accuracy varies from the very best calibration to a test that has nothing to do with flow accuracy. The ratio of the meter factor is true volume to the indicated or meter volume.

$$\text{Meter Factor} = \frac{\text{True Volume}}{\text{Indicated or Meter Volume}}$$

Methods of Meter Proving

Pipe provers are one of the most common types of provers in industry today. Their popularity is due their accuracy over a wide variety of flow ranges and fluids. Pipe provers allow proving to occur under actual operating conditions. The process does not have to be shut down when proving a meter. Two types of pipe provers are the unidirectional prover and the bidirectional prover. Several methods are used for a proving application; typical approaches include using the following:

- Unidirectional provers
- Bidirectional provers
- Small volume provers
- Master meter method

Unidirectional Provers – The unidirectional prover displaces a known volume by means of a displacer (piston or sphere) traveling in only one direction inside the prover. The displacer's travel is detected by detector switches within the prover. Unidirectional provers are often used in pipeline operations because they can operate at higher displacer velocities. Because the prover allows flow in only one direction, the prover can simulate normal pipeline operations.

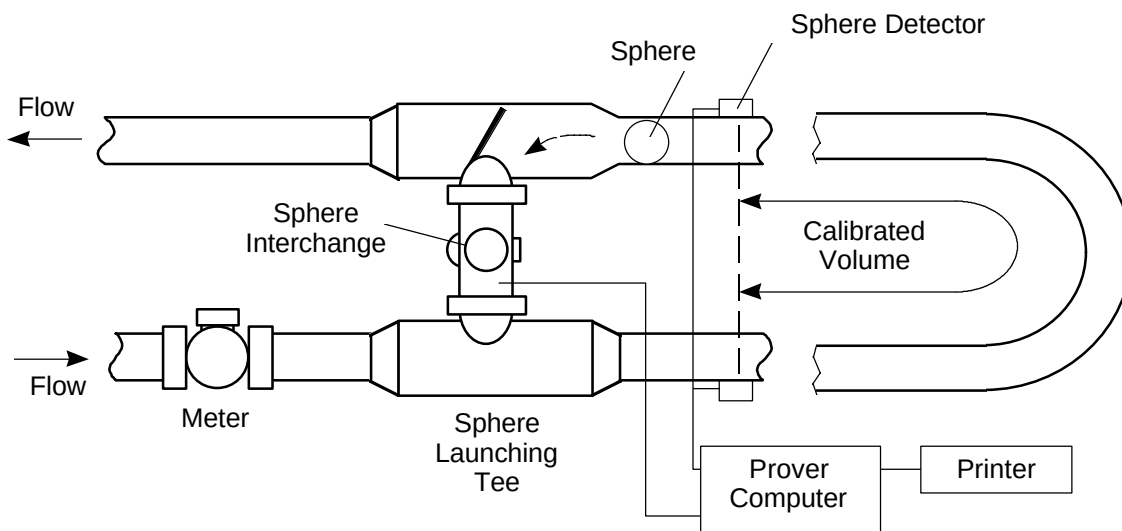


Figure 77: Typical Unidirectional Prover

Unidirectional provers always have the fluid flowing in the same direction through the prover. If the calibrated volume is used only in one direction, there is a potential for the sphere detector switches to develop an error. With bidirectional proving and half-trips in both directions, the detector switches have a chance at cancelling that error. Bidirectional provers are more accurate and more widely used. Usually provers are themselves calibrated by third parties.

Bidirectional Provers – The bidirectional prover (Figure 78) requires a displacer to travel in both directions to complete one prover run. Provers can be u-shaped, folded, or straight pipe depending upon the space requirements or space availability. Fluid is passed through an operating meter into the prover. After stabilizing pressure and temperature, the displacer is put into the system. It will slow down flow in the system for a time until the displacer picks up speed. Some prerun length must be allowed before the displacement of the accurately measured volume starts. After the flow rate stabilization, a switch indicates entry of the displacer into the calibrated section and the meter pulses are sent to the proving counter.

Flow continues to the meter until a sufficient number of pulses has been produced by the operating meter, approximately 10,000 or more. After some time, the exit switch indicates that the calibrated volume has been achieved and pulses to the prover counter are interrupted. Pulses generated by the operating meter are sent to the billing meter's counter. This procedure is repeated several times while recording the stabilized fluid pressure and temperature. Calculations convert the pressure and temperature for the meter and the meter prover at the same condition. The ratio of the prover volume to meter volume is the meter factor for this flow rate.

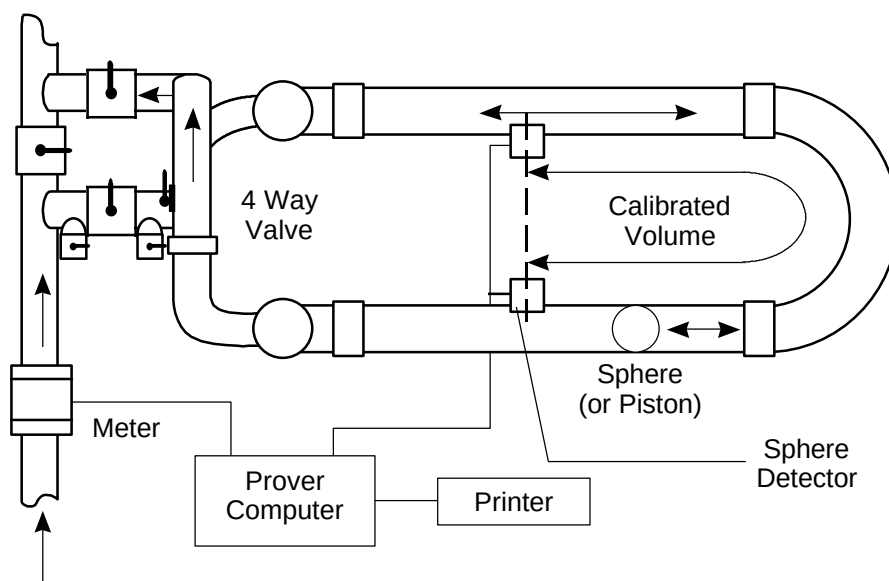


Figure 78: Typical Bidirectional Prover

Small Volume Provers are becoming more widely used over conventional pipe provers because they can accommodate a wide range of flow rates, products, and pressures. Small volume provers are so named because they are compact in size and have less volume than conventional unidirectional and bidirectional pipe provers. The small volume provers use advanced detector switches and pulsed interpolation techniques to measure a known volume. Because of the smaller volumes required, the time to obtain a meter factor is significantly decreased.

Master Meter Method is used when a pipe prover is unavailable. The master meter method uses a known reliable meter configured in series with the meter to be proved. The meter measurements are then compared.

Weight and Volume Methods

Three methods of calibration are in general use when a weight or volume tank is used as the standard. The methods are the following:

- Static calibration
- Dynamic calibration
- Hybrid dynamic start-stop, static reading system

Static Calibration

In the static calibration system, the flow is quickly started to begin the test, held constant during the test, and then shut off at the end of the test. The totalized flow reading from the flowmeters is compared with the weight or volume collected and the performance of the meter is calculated. The static calibration system operates best with flowmeters that have low sensitivity to low flow rates. The static calibration system does not give maximum results with high performance digital output meters such as a vortex meter.

Dynamic Calibration

In the dynamic calibration system, the flow is kept at a constant rate before the beginning of the test. The flow reading from the flow meter and initial weight or volume are read together to start the test and after the desired collection period to end the test. The dynamic calibration systems are limited by the meter's speed of the response.

Hybrid Dynamic Start-Stop, Static Reading System

The hybrid dynamic start and stop, static reading weight, and volume system is more accurate than the static and dynamic methods for liquid calibration. In this system, the desired test flow rate is first obtained as the flow is diverted past the weight or volume flow standard. The test run is initiated by diverting the flow into the standard and then completed by diverting it out of the system. The digital flow signal is turned on and off by the diversion. The weight or volume is read after a configured time and compared with the totalized flowmeters reading. The following figure indicates the basic elements of a standard weighing system.

In this start and stop system, the diverter valve switches the flow in and out of the standard. The diversion time is less than actual collection time, and the flow pattern through the diverter valve is independent of the flow rate. The error can be reduced to less than 0.1 % of the reading. The hybrid dynamic start and stop system is accurate, but relatively few are used because of its cost.

Volumetric Tank Proving Example

Volumetric tank proving uses a start stop method that simulates conditions of vessel loading. The volumetric tank prover is most often used to prove product loading rack meters because a start/stop method is used in actual loading.

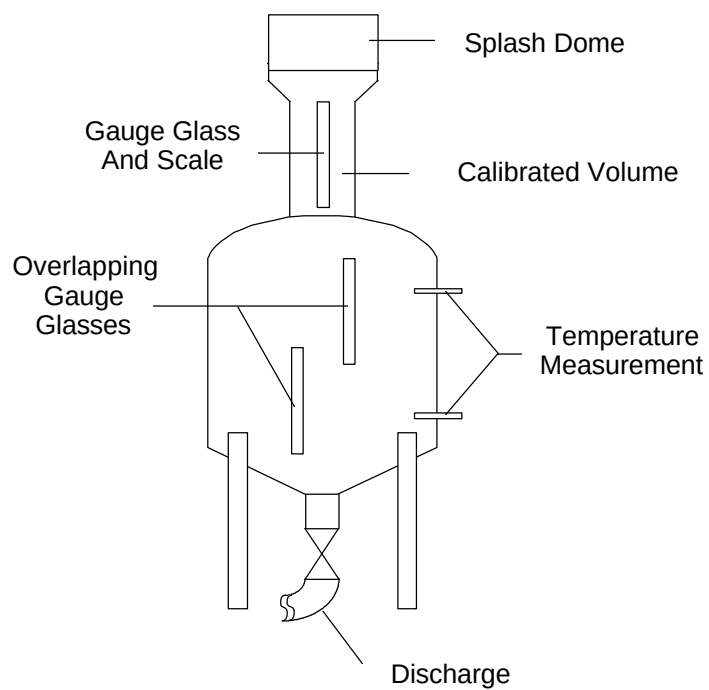


Figure 79: Volumetric Tank Prover

**WORK AID 1: RESOURCES USED TO DETERMINE WHETHER AN ORIFICE
PLATE FLOW MEASURING DEVICE MEETS APPLICATION
REQUIREMENTS**

Work Aid 1A: Vendor Data Sheets

Work Aid 1B: Saudi Aramco Instrument Specification Sheets

FLOW Instrument Specifications Sheets

SA	2517 - ENG (11/90)	Pitot Meter
SA	2778 - ENG (10/89)	Local Flow
SA	2778 - M - ENG (10/89)	Local Flow
SA	2790 - ENG (10/89)	Variable Area Flow
SA	2790 - M - ENG (10/89)	Variable Area Flow
SA	3175 - ENG (3/91)	Orifice Plate 2" - 6"
SA	3176 - ENG (11/89)	Segmental????
SA	3176 - M - ENG (11/89)	Segmental????
SA	3176A - ENG (11/87)	Restriction Orifice
SA	3177 - ENG (7/90)	Quadrant
SA	3188 - ENG (11/89)	Meter Reading Tables
SA	3188 - M - ENG (11/89)	Meter Reading Tables
SA	6078 - ENG (10/89)	Flow Inst.
SA	6078 - M - ENG (10/89)	Flow Inst.
SA	6239 - ENG (1/91)	ISS General
SA	8020-111 - M-ENG (7/89)	Flow Xmttr ΔP
SA	8020-115 - ENG (8/89)	Meter Orif. Cal.
SA	8020-115 - M - ENG (7/89)	Meter Orif. Cal.
SA	8020-115A - ENG (6/91)	Orifice 8" & SI
SA	8020-115A - M - ENG (6/91)	Orifice 8" & SI
SA	8020-116 - M - ENG (7/89)	Venturi
SA	8020-117 - ENG (7/89)	Turbine
SA	8020-117 - M - ENG (7/89)	Turbine
SA	8020-118 - ENG (7/89)	Liq. PD
SA	8020-119 - ENG (7/89)	Bidirect Prover
SA	8020-124 - ENG (7/89)	Rest. Orif. Calc. 8 Spec.
SA	8020-124 - M - ENG (7/89)	Rest. Orif. Calc. 8 Spec.

Work Aid 1C: SAES-J-100 (See Course Handout 2.)

Work Aid 1D: Procedures for Calculation

Orifice Plate Size (from SADP-J-100, Attachment 2)

Total Probable Error for an Orifice Plate

Work Aid 1E: SADP-J-100, Section 6 (See Course Handout 1.)

**WORK AID 2: RESOURCES USED TO EVALUATE OTHER DIFFERENTIAL
PRESSURE FLOW MEASURING DEVICES FOR SUITABILITY IN A
SAUDI ARAMCO APPLICATION**

Work Aid 2A: Vendor Data Sheets

Work Aid 2B: Saudi Aramco Instrument Specification Sheets

Work Aid 2C: SADP-J-100 (See Course Handout 1.)

Work Aid 2D: SAES-J-100 (See Course Handout 2.)

**Work Aid 2E: Procedures for Manual Calculation of Restriction Orifice Plate Size (from
SADP-J-100, Attachment 3)**

**WORK AID 3: RESOURCES USED TO EVALUATE THE SUITABILITY OF OTHER
RATE AND QUANTITY FLOW MEASURING DEVICES FOR
SUITABILITY IN A SAUDI ARAMCO APPLICATION**

Work Aid 3A: Vendor Data Sheets

Work Aid 3B: Saudi Aramco Instrument Specification Sheets

Work Aid 3C: SADP-J-100 (See Course Handout 1.)

Work Aid 3D: SAES-J-100 (See Course Handout 2.)

GLOSSARY

NOTE: The definitions presented are taken from “Glossary of Terms Used in the Measurement of Fluid Flow” (ANSI/ASME MFC-1M-1979).

Absolute Pressure	The combined local pressure induced by some source and the atmospheric pressure at the location of the measurement.
Accuracy	The measure of freedom from error; the degree of conformity of the indicated value to the true value of the measured quantity.
Beta Ratio	The ratio of the diameter of the constriction to the pipe diameter, $\beta = d_{\text{bore}}/D_{\text{pipe}}$.
Bore Reynolds Number	Calculated Reynolds number R_d using V_{bore} , ρ_{bore} , μ_{bore} , d_{bore} ; also $R_d = R_D/\beta$.
Calibration	Determination of the experimental relationship between the quantity being measured and the output of the device that measures it; where the quantity measured is obtained through a recognized standard of measurement.
Centrifugal Force	A force acting in a direction along and outward on the radius of turn for a mass in motion.
Choked Flow	The condition of maximum velocity at the minimum area section of a device corresponding to the speed of sound of the gas flowing through the device.
Coanda Effect	A phenomenon of fluid attachment to one wall in the presence of two walls.
Confidence Level	The probability that the interval quoted will include the true value of the quantity being measured.
Coriolis Force	Results from Coriolis acceleration acting on a mass moving with a velocity radially outward in a rotating plane.
Critical Flow	Same as choked flow.
Differential Pressure	The static pressure difference generated by the primary device when there is no difference in elevation between the upstream and downstream pressure taps.
Dynamic Pressure	The increase in pressure above the static pressure that results from complete transformation of the kinetic energy of the fluid into potential energy.

Expansion Factor	Correction for the change in density between two pressure-measurement stations in a constricted flow.
Flow Rate	Actual velocity of the fluid medium.
Flow-Rate Range	Range of flow rates bounded by the minimum and maximum flow rates.
Flowmeter	A device for measuring the quantity or rate of flow of a moving fluid in a pipe.
Gage Pressure	The difference between the local absolute pressure of the fluid and the atmospheric pressure at the place of the measurement.
Gravitational Constant	A dimensionless conversion factor in English units that arises from Newton's second law ($F = ma$) when mass is expressed in pounds-mass (lb_m). $g_c = 1$ in SI and cgs, units and English units when mass is expressed in "slugs." $g_c = 32.17 \frac{lb_m}{slug}$ in English units when mass is expressed in lb_m.
Head Loss	Pressure loss in terms of a length parameter such as inches of water or millimeters of mercury.
Head Pressure	Expression of a pressure in terms of the height of fluid, $P = \rho y g$, where ρ is fluid density and y is the fluid column height.
Isentropic Exponent	A ratio defined by the specific heat at constant pressure divided by the specific heat at constant volume.
Kinetic Energy	Energy related to the fluid dynamic pressure, $1/2 \rho V^2$.
Laminar Flow	Flow under conditions in which forces caused by viscosity are more significant than forces caused by inertia.
Linearity	The maximum percent deviation of calibration data from a zero-based straight line.
Mach Number	The ratio of the fluid velocity to the velocity of sound in the fluid, at the same temperature and pressure.
Mass-Flow Rate	The product of fluid density, ρ , full closed conduit area, A , and fluid velocity, V .

Meter Run	A flowmeter installed and calibrated in a section of pipe having adequate upstream and downstream length to satisfy standards of flowmeter installation.
Newtonian Flow	Fluid characteristics adhering to the linear relation between shear stress, viscosity, and velocity distribution, $\tau = -\mu \frac{dV}{dy} .$
Percent of Actual	Same accuracy value applies over the entire flow rate range.
Percent of Span	Accuracy value applies only at the maximum-rated flow.
Pipe Reynolds Number	Calculated Reynolds number R_D , using V_{pipe} , ρ_{pipe} , μ_{pipe} , and D_{pipe} .
Potential Energy	Energy related to the position or height above a place to which fluid could possibly flow.
Precision	Or repeatability, a random error caused by numerous small independent influences that prevent a measurement system from delivering the same reading when supplied with the same input value of the quantity being measured.
Primary Device	The part of a flowmeter that generates a signal responding to the flow from which the flow rate can be inferred.
Proving	Determination of flowmeter performance by establishing the relationship between the volume actually passed through the meter and the volume indicated by the meter.
Pulsating Flow	A flow rate that varies with time, but for which the mean flow rate is constant when obtained over a sufficiently long period of time.
Quantity Meter	A flowmeter in which the flow is separated into known isolated quantities that are separately counted to determine the total volume passed through the meter.
Random Error	Precision or repeatability, data that deviate from a mean value in accordance with the laws of chance.
Rangeability	The ratio of the maximum flow rate to the minimum flow rate of a meter.
Repeatability	See precision or random error.
Reproducibility	A measure of the characteristic nature of any flowmeter to be taken off the shelf, installed in a flow line, and deliver a specified performance level.

Resolution	The error associated with the ability to resolve a flowmeter output signal to the smallest measurable unit. For example, only ± 1 pulse is measurable in any pulse output device.
Reynolds Number	The ratio of inertia and viscous forces in a fluid defined by the formula $R_e = \frac{\rho V l}{\mu}$.
Secondary Device	Part of a flowmeter that receives a signal from the primary device and displays, records, and/or transmits it as a measure of the flow rate.
Slip	A term commonly used to express leakage in positive-displacement flowmeters.
Spurious Error	Errors caused by instrument malfunction or human goof-ups.
Stagnation Pressure	The pressure of a fluid one would obtain if one could bring a flowing fluid to a standstill (to rest) isentropically (without any energy loss).
Static Pressure	The pressure of a fluid that is independent of the kinetic energy of the fluid.
Static Weighing	A method in which the net mass of liquid collected is deduced from tare (empty tank) and gross (full tank) weighings respectively made before the flow is diverted into the weighing tank and after it is diverted to the by-pass.
Steady Flow	A flow in which the flow rate in a measuring section does not vary significantly with time.
Systematic Error	That which cannot be reduced by increasing the number of measurements if the equipment and conditions remain unchanged.
Total Pressure	See stagnation pressure
Transitional Flow	Flow between laminar and turbulent flow; generally between a pipe Reynolds number 2000 and 7000.
True Mass Flow	A measurement that is a direct measurement of mass and independent of the properties and the state of the fluid.
Turbulent Flow	Flow in which forces caused by inertia are more significant than forces caused by viscosity and adjacent fluid particles are more or less random in motion.
Uncertainty	The interval within which the flow rate fluctuates randomly with time and for which the mean value is not constant.

Unsteady Flow	A flow in which the flow rate fluctuates randomly with time and for which the mean value is not constant.
Volume Flow Rate	Calculated using the area of the full closed conduit and the average velocity in the form $Q = V \times A$, to arrive at the total quantity of flow.
Working Pressure	Or flowing pressure is the static pressure of the fluid immediately upstream of a primary device.
Working Temperature	The temperature of the fluid immediately upstream of a primary device.