PROCESS

METERING

TRAINING MANUAL
COURSE EXP- PR-PR090
Revision 0.1

PROCESS

METERING

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1. OBJECTIVES

The main objective of metering is to measure and / or determine flowrates and / or quantities of hydrocarbon or non-hydrocarbon effluents present in oil installations.

Operations and measurements that help determine the different components in the effluents measures are, by extension, part of the metering activity (sampling, on-site analysis…).

2. METERING

2.1. WHAT IS METERING USED FOR?

The measurement of fluid quantities produced is used to monitor the life of a well or a whole field, and to make forecasts about the changes in the reservoir. It is also used to quantify the finished products, particularly for sale.

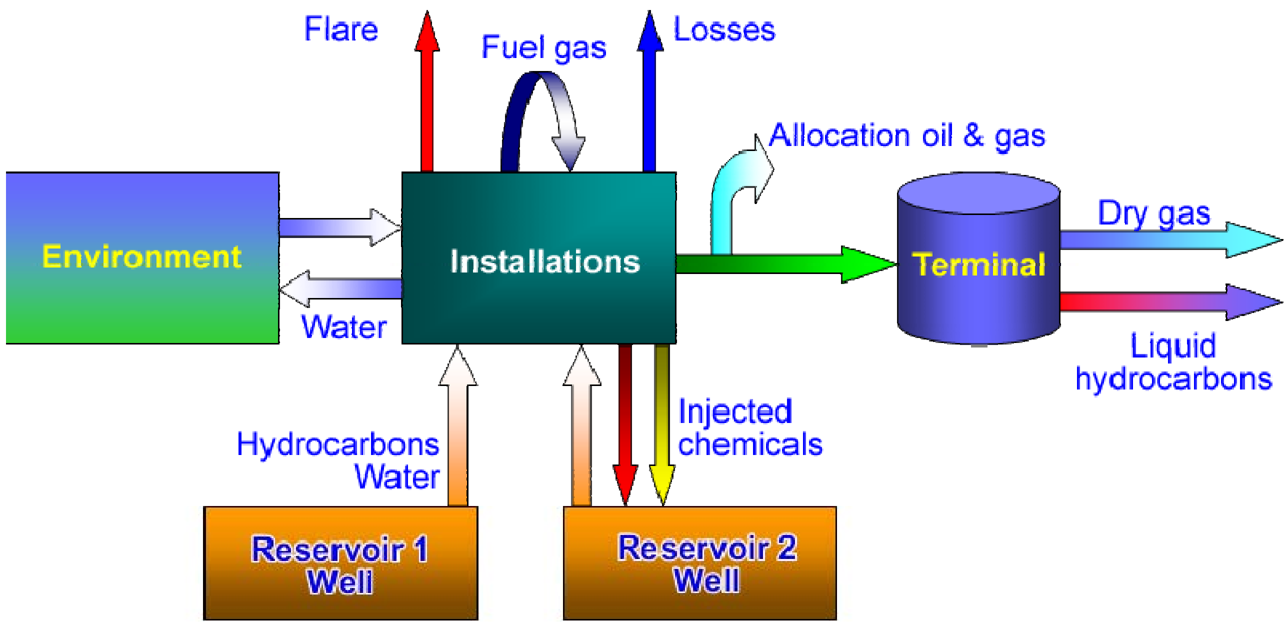


Figure 1: Measured and calculated flow rates

Metering can be broken down into two domains:

- The **custody transfer domain,** which includes contracts, purchasing, sales and transport.

  This corresponds to allocation metering and high-accuracy (<1%) commercial metering.

  They measure the quantities of liquid or gas due to each partner or which are sold. The measurement systems and their operating procedures must be approved by the stakeholders: partner, seller, buyer, carrier, official bodies, etc.

- The **technical domain** is an activity under the direct responsibility of Field Operations, which supplies data to various users (reservoir, production) for:

  - Field (reservoir monitoring) and well monitoring.

- Production balances: effluents produced, discharged, exported, injected and consumed. These balances can be compiled by well, by platform and by field.
- Installation control and checks.

This domain is subjected mainly to internal rules and instructions, with accuracy levels of between 1 and 10% depending on the case.

Example: to be able to carry out the Reservoir - Formation studies, we must know the amount of water and oil produced by each well.

2.2. FINISHED PRODUCT

The effluents to be measured:

2.2.1. Production effluents

An oilfield produces effluent which comprises:

- crude oil or condensate,
- water,
- gas,
- sediments.

This is what is called the **TOTAL production**. After passing through the treatment installation, the gas and part of the water and sediments are removed.

2.2.2. Gross production and net quantity

GROSS production is, in the case of oil, the treated effuent comprising:

- crude oil,
- water and sediments in suspension.

Since it is impossible to completely separate the crude (which is the only marketable product) in the storage installations, the transaction is very often based on the GROSS quantity: we then have to determine the NET oil quantity (representing the portion of crude purchased) as accurately as possible.

Figure 2: LNG sales metering before departure of the gas carriers

To do this, we therefore determine the portion of unmarketable products contained in the GROSS quantity.

The NET quantity will be expressed in m3 at 15°C (or in barrels at 60°F). To express these values in tonnes, we must determine this product's density at 15°C.

We will therefore have to take a representative sample of the GROSS quantity exchanged.

2.3. The metering installations

The metering facilities range from a simple flowmeter to the complex metering bench for quantifying the oil before exporting it.

The diagram below shows the path the fluid takes, passing successively from storage to the metering bench and then pressurised further by means of the pumps in order to go to the loading buoy to which the tanker is connected.

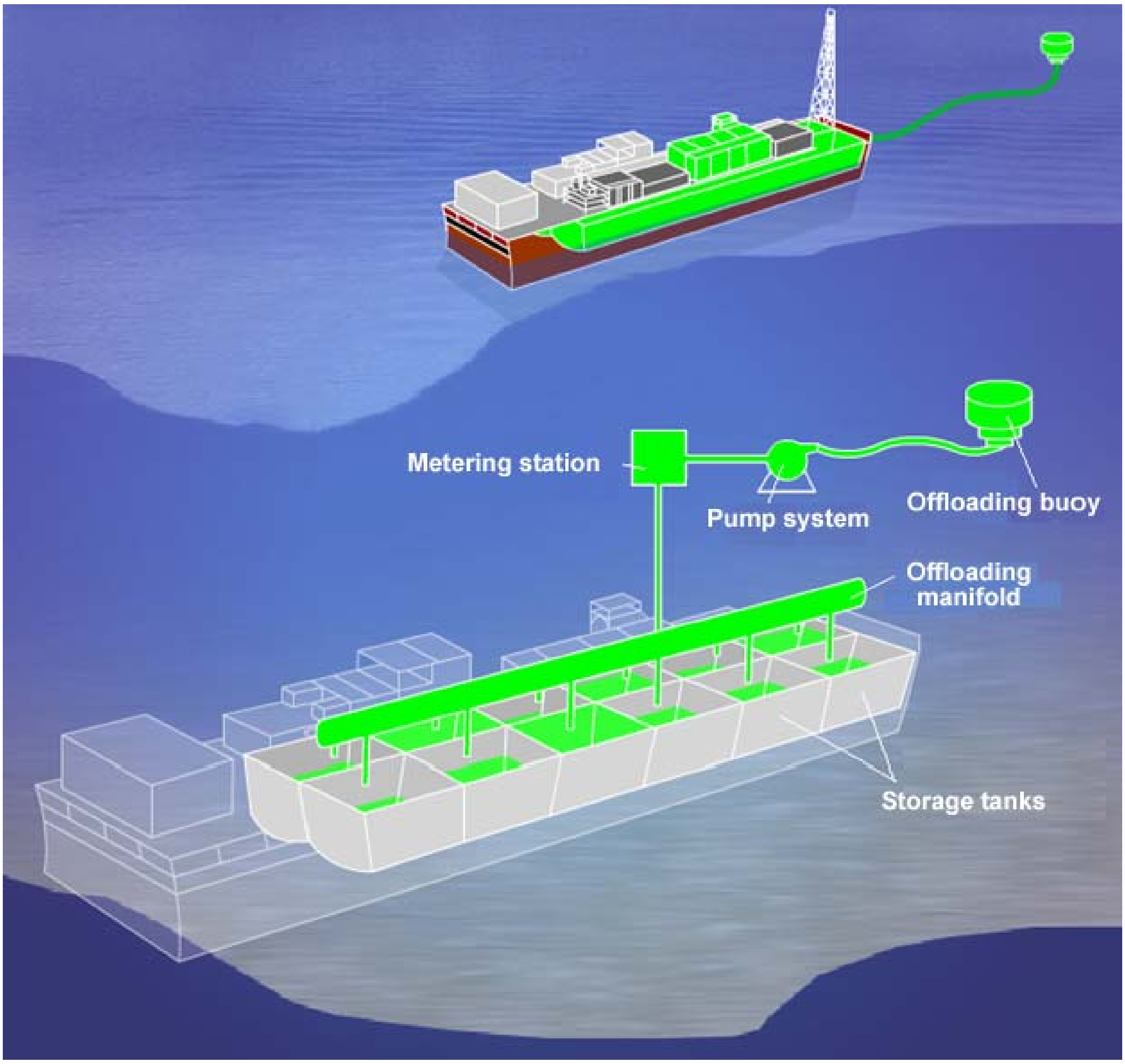


Figure 3 : Route taken by the oil from its storage point on the Girassol FPSO to its offloading buoy

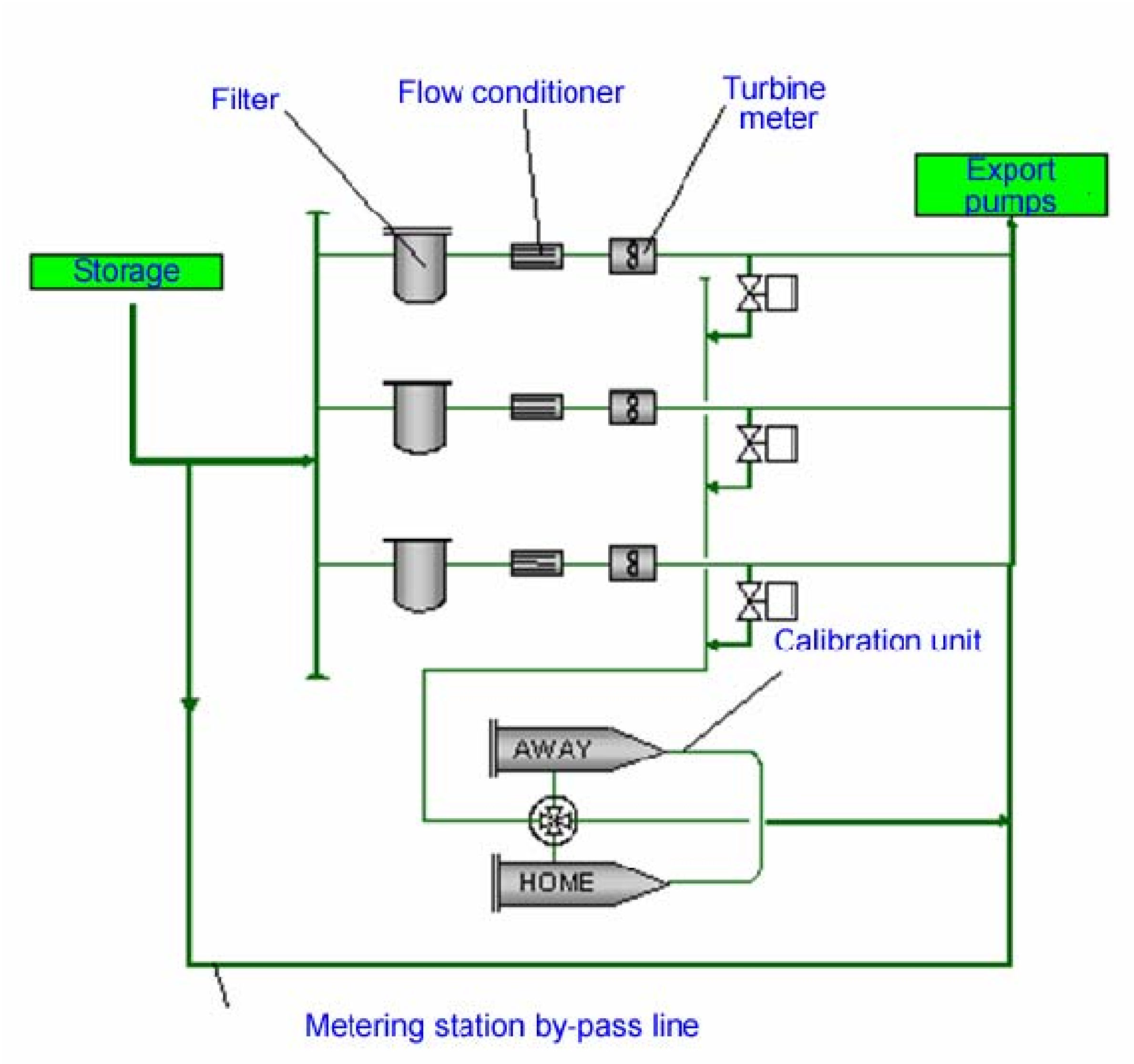


Figure 4 : Girassol metering station flow diagram

The above metering station consists of:

- 3 runs for metering the exported oil stream, each run comprising:
  - 1 filter
  - 1 flow conditioner (also called a flow straightener)
  - 1 turbine meter
- 1 calibration unit
- 1 bypass

2.4. Fluid and flow aspects

The characteristics and physical properties of the fluids metered must be taken into account when designing and operating the metering facilities (measurements, calculation of quantities).

Since technical metering is concerned with quantities, metering conditions and also with the quantities obtained in other conditions, the variations in the properties due to the treatment conditions or just due to the pressure and temperature must be well understood.

2.4.1. State of the fluids under metering conditions

Under metering conditions, the petroleum effluents may be:

- in **single phase state** (liquid, vapour) consisting of one or more components (anhydrous oil, gas mixture, etc.), or pseudo-single phase state (low hydrated homogenous oil),
- in **multiphase state**, comprising two simultaneous phases (liquid and vapour).

The single phase effluents may be saturated effluents or unsaturated effluents.

The saturated effluents are either liquids at bubble point, or vapours at dew point (e.g. separator gas).

2.4.2. Changes in the fluids during the process

The petroleum fluids (gas, liquid) change according to the temperature and pressure conditions and new phases may appear.

Therefore, when we wish to express the quantities/volumes/ratios measured or determined in real conditions (observed quantities) as quantities/volumes/ratios in different reference conditions (storage, end of process) we must take into account the change in the fluid after the switch from measurement conditions to reference conditions.

Therefore we must differentiate between stabilised liquids and non-stabilised liquids on the one hand, and between wet gas and dry gas on the other hand.

- **Stabilised liquid**: liquid which does not produce a vapour phase when it switches to the storage conditions or other reference conditions.
- **Non-stabilised liquid**: liquid which, in the same conditions as above, produces vapour.

- **Wet gas**: gas in which condensates will appear (water and/or hydrocarbons) during the treatment process.
- **Dry gas**: a dry gas (also called a treated gas) is a gas in which no condensates will appear during production.
- **Raw gas**: the gas effluent from the well before going through the treatment process.

2.5. EXERCISES

1. Among other things, the quantity of fluid produced in a determined time enables us to:

   ❑ Monitor the life of a well

   ❑ Monitor the life of a whole field

   ❑ Forecast changes in the reservoir

   ❑ Determine the quantities of the finished products for sale

2. Metering can be divided into two domains. What are they?

3. Allocation metering does not have to be approved by an official body.

   ❑ True

   ❑ False

4. Internal metering is an activity carried out by Field Operations.

   ❑ True

   ❑ False

5. In the TOTAL production, the effluent contains:.

   ❑ Crude oil

   ❑ Water

   ❑ Gas

   ❑ Sediments

6. After passing through the treatment installation, the gas and part of the water and sediments are removed. We then obtain a GROSS production.

   ❑ True

   ❑ False

7. The NET oil quantity is the GROSS quantity, minus the portion of unmarketable products contained in the GROSS quantity.

   ❑ True

   ❑ False

8. A multiphase state is when two phases are present simultaneously (liquid and vapour).

   ❑ True

   ❑ False

9. Petroleum fluids (gas, liquid) do not change according to the temperature and pressure conditions and cannot give rise to the appearance of new phases.

   ❑ True

   ❑ False

10. 10. Which of the following liquids do not produce a vapour phase on switching to storage conditions or other reference conditions.

   ❑ Non-stabilised liquid

   ❑ Stabilised liquid

11. Which of the following gases will produce condensates (water and/or hydrocarbons) during the treatment process.

   ❑ Wet gas

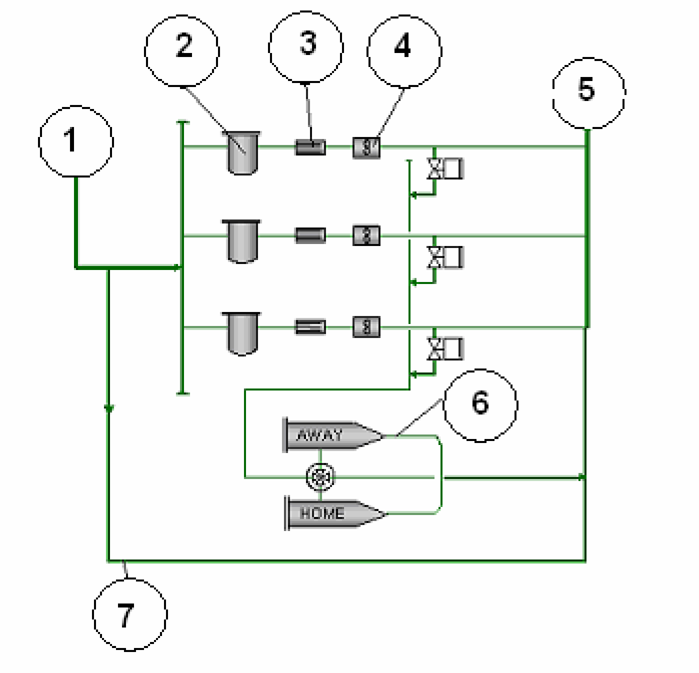
   ❑ Dry gas

12. Raw gas is the gas effluent from the well before the treatment process.

❑ True

❑ False

13. Find the basic parts of the following metering station:



_____: Turbine

_____: Export pumps

_____: Bypass line

_____: Calibration unit

_____: Storage

_____: Filter

_____: Flow conditioner

3. OPERATING PRINCIPLES

3.1. THEORY RECAP

Most metering methods measure moving fluids (dynamic measurements). A reminder of the main characteristics of the flows and their effect on the measurements is therefore useful.

3.1.1. Fluid homogeneity

A fluid will be considered to be **homogenous** (ISO 3171 definition) if its fluid properties (density and composition) do not significantly vary: this is the case for a single phase effluent or, by extension, a mixture of two components in which the second component is finely dispersed in the first and has a very similar density.

Example: oil/water mixture.

Conversely, a **non-homogenous** flow comprises a fluid of variable density in space, formed of several components (liquids or gas and liquid) which can move at different velocities (one sliding against the others).

The effects due to the differences in density, viscosity, surface velocity (velocity of each phase considered as if it were alone) and gravity will create variable flow characteristics.

3.1.2. Disturbance in the flows

The following may be seen in the flows:

- rotation and swirl phenomena,
- backflow phenomena,
- non-symmetrical or non-established velocity profiles.

These effects influence the metering accuracy (turbines, negative pressure elements, vortex). They depend on the configuration of the upstream and downstream pipes (bends, non-coplanar bends, accessories, expanders).

They can be reduced by using straight pipes of a sufficiently long length, or flow conditioners (also called straighteners).

The following Table provides information on the disturbances created during gas metering.

Accessory type	**Disturbance generated**				
	Axi-symmetrical	Asymmetrical	Swirl	Turbulence	Variation over time
Bend					
Tee					
2 coplanar bends					
2 non-coplanar bends					
U bend					
Hairpin pipe					
Expander					
Convergent					
Divergent					
Roughness					

	Negligible intensity		*Moderate intensity*
	Low intensity		*Intensity possibly very high*

Table 1: Metering disturbances according to the type of accessory present upstream

3.1.3. Pulses in the flows

The flowmeter performances and the standards concern flow rate measurements for stable flows, or at least for flows with a slow variation over time.

The short period pulses (or velocity variations) due to compressors and reciprocating pumps can generate errors that are far from negligible.

3.1.4. Pressures and pressure drop in flows and equipment

The pressure drop in the measuring equipment must be calculated to check that it is compatible with the process requirements and the fluid characteristics.

3.1.5. Cavitation

Cavitation is the implosion of gas bubbles formed in a liquid when the line pressure is close to or less than the liquid's vapour pressure.

This phenomenon may be observed downstream of equipment which generates pressure drops (valves, restrictions, orifices, vortex, etc.).

3.1.6. Entrainment / Deposits / Presence of impurities

When gas entrainment or solid particles are present, their possible effect must be evaluated. They must be removed if necessary (filters, de-aerators, etc.).

The presence of liquid or gas impurities will generally be taken into consideration in the choice and operation of the metering systems.

A second problem related to the fluid and its flow is the possibility of more or less extensive deposits: where this possibility exists, it must be quantified (deposition rate, critical thickness, formation conditions, etc.).

3.2. Units and equivalences

3.2.1. Units most commonly used for flow rates

gallons / minute	barrels / day
gallons / hour	cubic metres / hour
cubic feet / minute	cubic metres / day
cubic feet / hour	litres / day
barrels / hour	litres / day.

3.2.2. Reminder of the equivalences

1 gallon (US) = 3.78533 litres

1 cubic foot = 28.3168 litres

1 barrel = 42 gallons = 158.988 litres

3.3. OPERATION OF A GAS METERING STATION

3.3.1. Representation of the gas metering station

The following diagram shows the main components of a metering installation:

- Instrumented inlet manifold (analysers + sensors)
- Meter run(s) with instruments
- Output manifold (analysers + sensors)

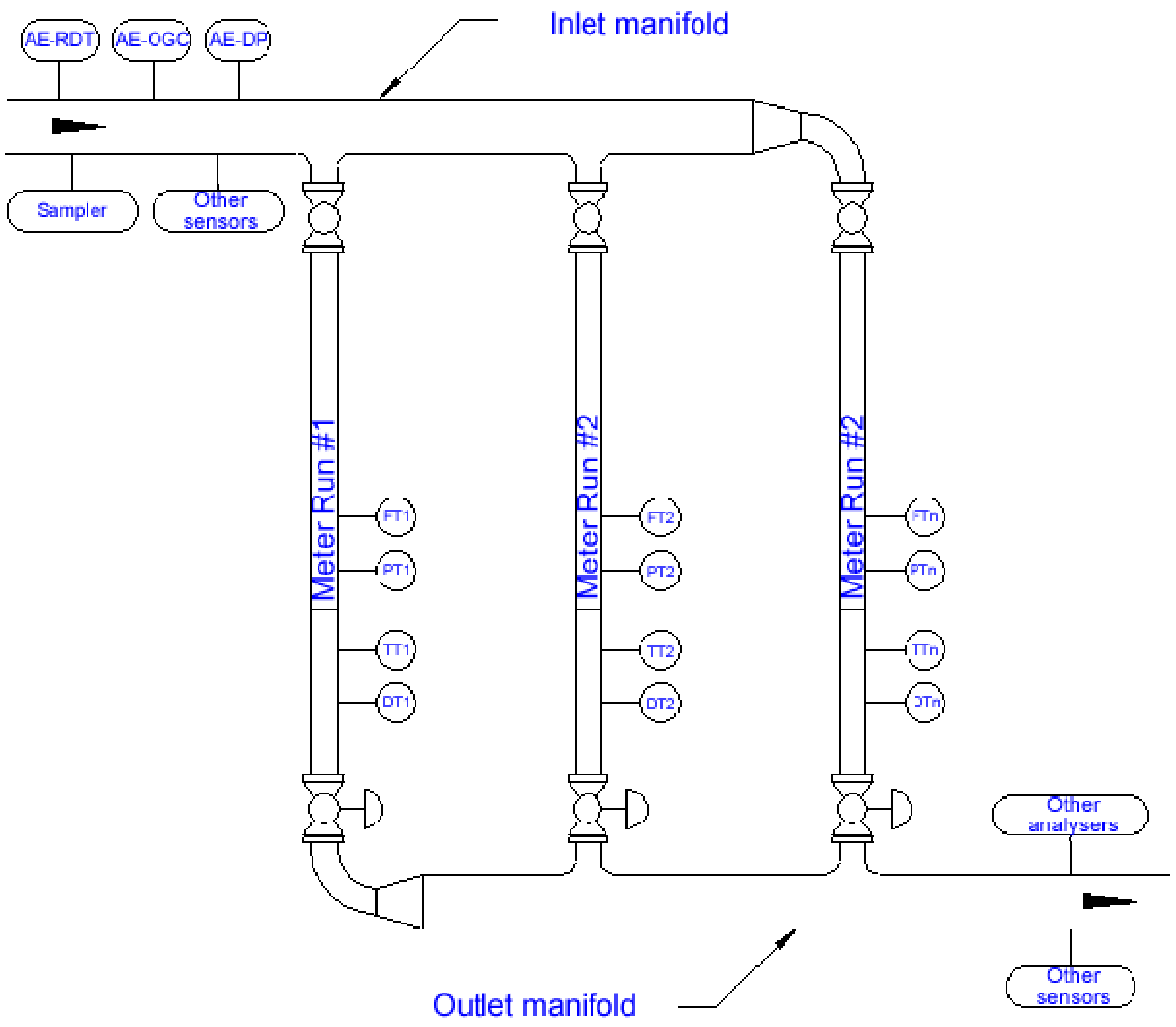


Figure 5: Gas metering station

The other components of the installation are described in the installation drawing.

- Safety equipment (safety valves, blowdown lines, etc.)
- Manifolds and instrumentation cabinet
- Junction box(es)
- Electric cubicle (power)
- Metering computers
- Supervision and printout systems
- Communications instrumentation – transmitters – computer – supervision – etc.

3.3.2. Operating principle

The gas is analysed at the inlet manifold. The data gathered are sent to each computer via the installation's supervision system.

The manifold is designed to distribute the flow uniformly over the different meter runs allowing for at least one backup run.

Each meter run delivers data (differential pressure or pulses, static pressure, temperature, density) to its dedicated computer.

Each computer determines the quantities transferred to the associated meter run, and sends this calculated data to the supervision system for real time or batch processing.

The metered and analysed gas finally enters the outlet manifold and is transferred to the downstream installations.

At the end of the transaction, the measured quantities (expressed in volume, masse and/or energy), and all the events relating to the current delivery (alarms, threshold overshoots, etc.) are available via the supervision system for transmission and/or printing (reports).

3.3.3. Manifold and Instrumentation

The inlet and outlet manifolds are oversized to keep the flow velocities low, to limit flow disturbances and to distribute the flows into the meter runs. Recommended practice is to use manifolds (inlet and outlet) with a cross sectional area greater than 1.5 times the sum of the cross section areas of the meter runs.

The "Z" geometry of the run assembly ensures that the pressure drops, and therefore the flow velocities, are uniform throughout the installation, whichever runs are active.

The manifolds have a recommended nominal diameter greater than: $D\sqrt{1.5xN}$

D: Pipe diameter (measurement line)
N: Number of measurement lines (in parallel)

The inlet manifold has tappings allowing the following equipment to be connected:

- Quick sampling loop
- To an in-line chromatograph
- To a water dew point analyser
- Densimeter
- Water dew point analyser (if none on the quick sampling loop)
- An automatic sampler

The measurements performed using this equipment are sent to each dedicated computer to calculate the influence quantity necessary to determine the transferred quantities.

3.3.4. Isolating valves

Isolating valves are installed upstream and downstream of each meter run. They are double block and bleed valves, offering a double seal.

The manually operated inlet valve is designed only to isolate the measuring line during maintenance operations (decompression, orifice plate change, inspection, etc.).

The outlet valve, which is also used during maintenance operations, is motorised and can be controlled:

- Remotely, by the operator from the control room
- Locally, by a site operator
- Remotely, via the supervision system (Alarms), particularly to:
    - Open a run that has been isolated on appearance of an excess flow on one or more of the active runs.

- Close an active run on appearance of a flow rate lower than the configured threshold or on a transmitter fault.

The manual or motorised valves are equipped with end-of-travel detectors, which indicate their status to the control room.

3.3.5. Meter runs

The metering installation consists of "n" meter runs mounted in parallel. During normal operation, at least one of the runs is isolated so that it may be available in case a run in service fails, or to perform a maintenance operation on one of these runs.

3.3.6. Meter run pipes

Each meter run is configured in compliance with the requirements of the ISO 5167 standard, particularly relating to the following points:

- Straight lengths upstream and downstream
- Type of flow conditioner used (where applicable)
- Pipe circularity and cylindricality
- Position of the orifice plate

3.3.7. Orifice plate holder

The orifice plate holders installed on each meter run are defined by:

- Model/Manufacturer
- Type of assembly: (welded – flanged – mixed)
- Type of seal: (where applicable)
- Size: Nominal diameter (ND)
- Pressure class
- Pressure takeoff

It is recommended that the line be isolated and depressurised before changing a pressurised orifice plate, even when a dual chamber orifice plate holder is used, permitting an orifice plate change under pressure.

3.3.8. Orifice plate

The orifice plates used on the meter runs must meet the requirements of the ISO 5167 standard (sizing and configuration).

For one-way metering, the downstream side of the orifice is bevelled and the flow direction is indicated and visible on each orifice plate.

Each orifice plate has an identification number (serial number, identification number, etc.) which is shown on the calibration certificates (initial and periodic calibration).

3.3.9. Flow conditioner

Depending on the configuration of the meter runs, it may be necessary to incorporate a flow conditioner (also called a flow straightener) downstream of the orifice plate so as to guarantee acceptable flow conditions for the required uncertainty level.
Reference standard ISO 5167 specifies the conditions of use for this type of device as well as the straight pipe lengths to be used. The 2003 issue of ISO 5167 specifies the "certified" types of flow conditioners:

- 19-tube bundle flow straightener (1998)
- Zanker flow conditioner plate
- Gallagher flow conditioner
- K-Lab (NOVA) flow conditioner

If such a device is installed on the meter runs, it must be fully documented.

3.3.10. Filters

If required by the type of gas to be metered (humidity, impurities, etc.), it may be necessary to place a filtration system upstream of the meter runs.
These devices must be specifically defined (manufacturer's documentation) in terms of:

- Degree of filtration (mesh size)

- Pressure drop (clean/clogged)
- Absorptive capacity (humidity)

Filter clogging, beyond the maximum permissible value, due to the pressure drop threshold being exceeded, results in an alarm being sent to the supervisor system and to the control room.

3.3.11. Safety Equipment

The metering installation is equipped with "Gas" and "Fire" safety protection systems described in the General Documentation specific to the installation.

- Relief valves
- Thermal safety valves
- Pressure switches
- Blowdown lines
- etc.

The seals used in the installation are designed to resist the effects of severe depressurisation.

3.3.12. Calibration Equipment

The installation is designed and operated to guarantee the specified uncertainty level (regulations, contract, etc.) established at the origin. The stability of the initial uncertainty level can be obtained only by perfectly controlling the uncertainties due to the different factors involved in its estimation.

This control is guaranteed by the implementation of a surveillance process for each source of uncertainty (transmitter, sensor, computer, process, etc.), which includes verification, calibration or adjustment of the transmitters or sensors concerned. These regular operations consist in confirming that the measurements carried out by the system composed of the transmitter (or sensor) and the computer remain within an interval defined at the origin as being the Maximum Permissible Error (MTE).

All the equipment used in these operations and which has an effect on the final result has Calibration Certificates showing their traceability to the reference standards (national or international).

The verification and calibration equipment is managed by the installation's Metering Supervisor who must, in particular:

- Validate the calibration and verification procedures for the installation's equipment
- Ensure that these procedures are correctly applied at the appropriate dates.
- Ensure that the calibration equipment is stored and conserved in the correct conditions
- Define the acceptability limits for the calibration equipment
- Ensure that the calibration equipment connections are correct

4. THE DIFFERENT TYPES OF METERS

4.1. GENERAL

4.1.1. Metering developments

Tank gauging was the first metering method used. It is still frequently employed where tanks are still used: marine terminals, product depots, etc.

The use of meters was slowed down by routine and bureaucratic red tape. The have enjoyed a return in favour with the appearance of new operating principles: pipeline, offshore, etc.

The first meters to be used were volumetric meters. Flowmeters are currently preferred to volumetric meters for weight, size and cost reasons.

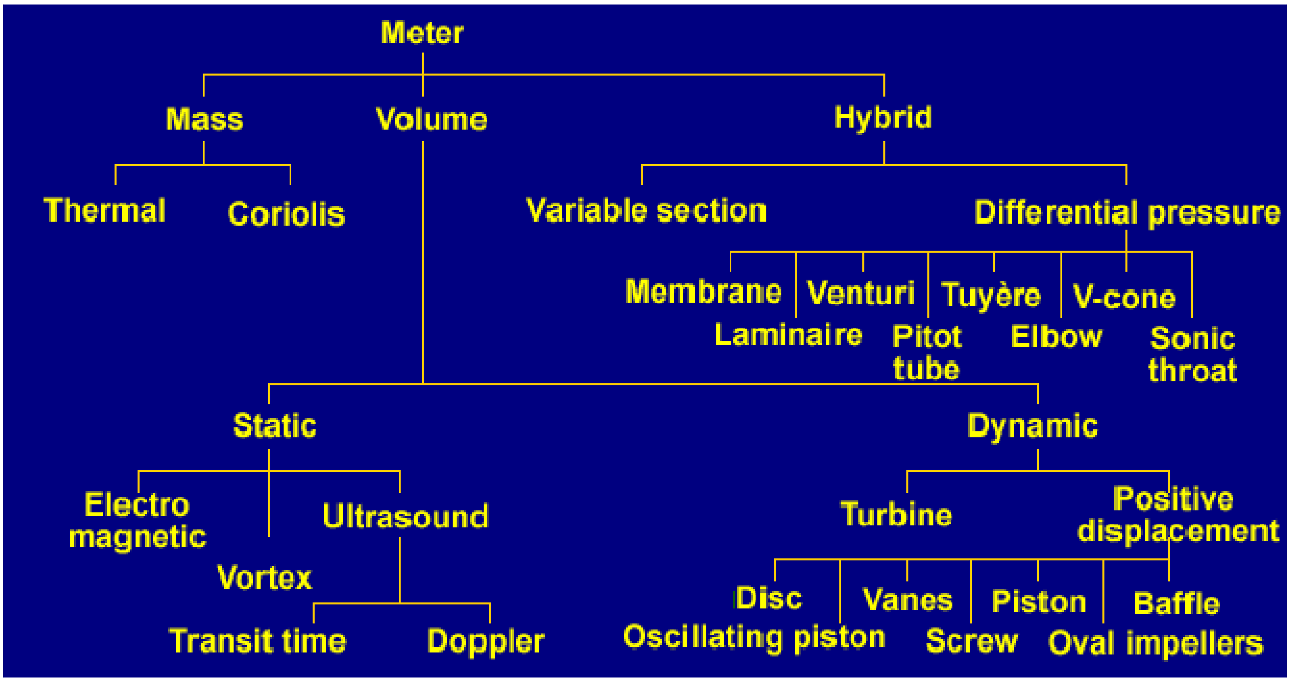


Figure 6: Tree diagram of the different types of measuring systems

4.1.2. Liquid metering

4.1.2.1. Static methods: gauging, weighing

These measurements are little used for metering in the production sequence except for storage terminals. These methods are used for:

- Gauging of wells.
- Calibrating flowmeters.
- Calculating the quantities received at the end of the line (terminal storage facilities).

4.1.2.2. Dynamic methods (or flow measurements)

Flowmeters are routinely used for metering liquid quantities and especially for determining instantaneous flow rates.

Although, in theory, users can choose from a large number of types of equipment, based on a variety of operating principles, in practice only a limited number of operating principles/technologies can be used for the technical metering of liquids.

The techniques developed in the context of this manual are those which have proved themselves in the oil industry environment and/or which can be used in a satisfactory manner for our applications:

- pressure differential devices,
- Coriolis flowmeter,
- turbine meters,
- volumetric meters,
- electromagnetic flowmeters (for water only),
- Vortex flowmeters.
- Ultrasonic flowmeters

4.1.3. Gas metering

The most currently used technologies in the technical metering sector are:

- Pressure differential devices,
- Vortex flowmeters,
- Pitot and Annubar tubes,
- Ultrasonic flowmeters.

4.1.4. Custody transfer metering of liquids

Most dynamic metering systems used for sales transactions today utilise turbine meters or volumetric meters (positive displacement) to comply with API MPMS 5.1.

The use of other techniques remains very limited (ultrasonic, Coriolis effect) and subject to approval by the different entities involved.

4.1.5. Custody transfer metering of gases

The most currently used principle for custody transfer gas metering is the **orifice plate**.

However, for custody transfer metering of "large" volumes of gas, other measurement principles can be used, such as:

- **Turbines**

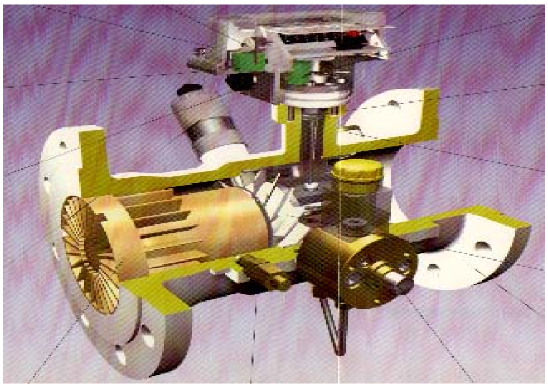


Figure 7: Turbine flowmeter for gas metering

- **Ultrasonic**

Figure 8: Ultrasonic meter on a gas pipe

4.2. PRESSURE DIFFERENTIAL DEVICE

The principle consists of measuring the differential pressure ΔP generated by a primary element (orifice plate, nozzle, Venturi) placed in the pipe through which the fluid flows.

Very many technologies can be used to measure an instantaneous flow rate, a volume or a mass of fluid.

Each of them has advantages and disadvantages for the process envisaged, and very many parameters have to be factored into consideration when making the choice:

- Mass or Volume?
- Liquid, Gas, Vapour?
- Flow rate or Quantity?
- Type of signal?
- Local display?
- Corrosive fluid?
- Environmental constraints?
- Clean fluid?
- Electric power?
- etc.
- Measuring range?
- Level of accuracy?
- Budget?
- Maintenance?
- Operating range?
- Admissible pressure loss?
- Conductive fluid?
- Viscosity, Density, etc.?
- Primary measuring equipment?

4.2.1. Pressure differential device – Diaphragm – Orifice plate

4.2.1.1. Principle

When a fluid passes through a restriction it undergoes acceleration. The resulting increase in kinetic energy corresponds to a pressure reduction (ΔP).

This is the physical phenomenon used to measure flow rates by pressure differential devices (and in particular by orifice plates).

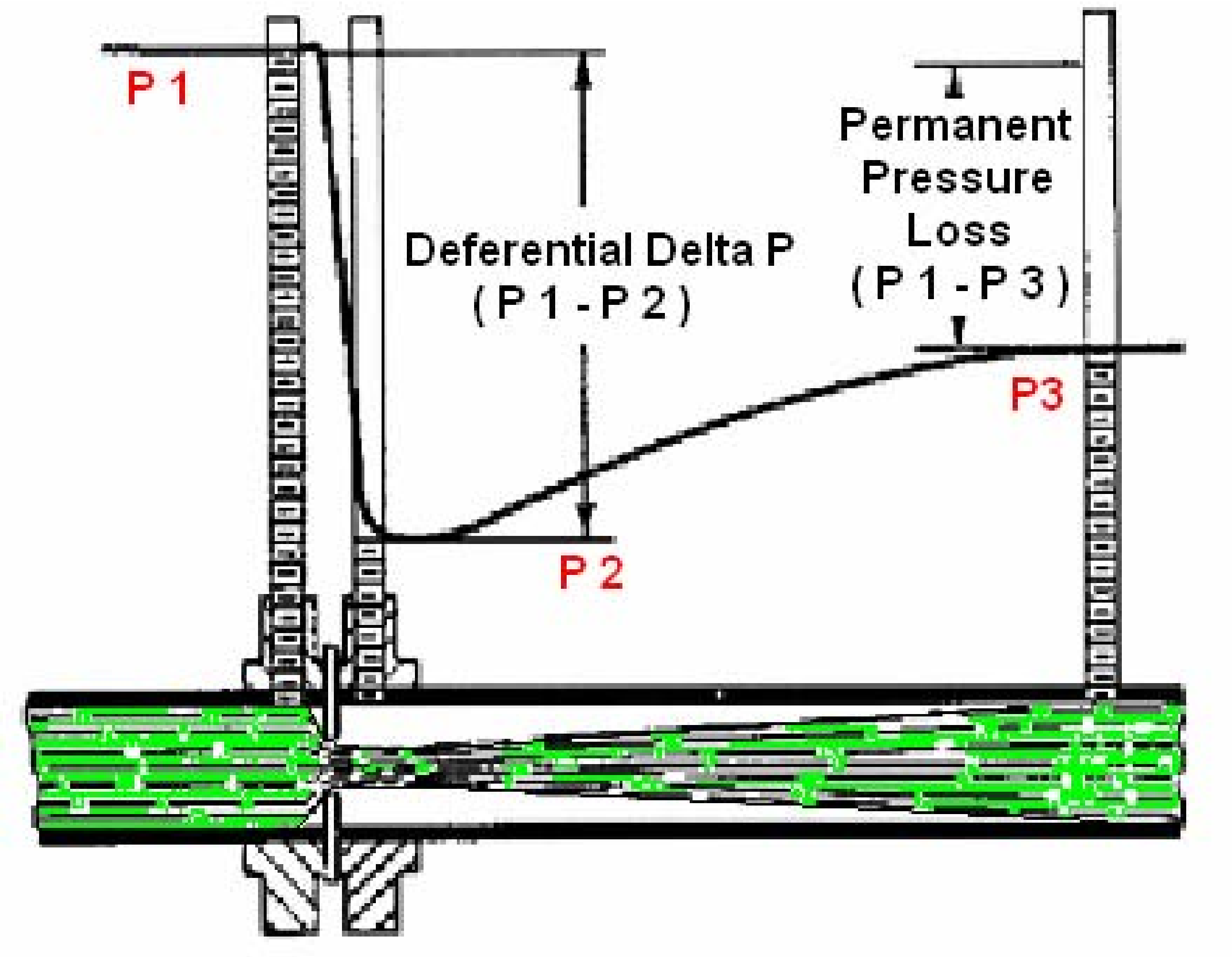


Figure 9 : Pressure drop through a pressure differential device

The flowrate is measured through a diaphragm placed downstream of the flow nozzle. The equation relating the flowrate to the pressure gradient measured at the diaphragm is:

$$Q = \alpha\pi\frac{d^2}{4}\sqrt{2\frac{\Delta P}{\rho}}$$

where:
d = diameter of the liquid stream at maximum restriction, in metres,
$\Delta P = P_1 - P_2$
P_1 = upstream pressure tap (before restriction),
P_2 = downstream pressure tap (at maximum restriction)
The coefficient α is called the flowrate coefficient of the differential pressure device. It factors in the contraction of the fluid stream, pressure losses and upstream and downstream sections.
ρ = density of the fluid in real flow conditions, in kg/m3,

4.2.1.2. Primary elements such as orifice plates and diaphragms

- **Orifice plate flowmeter**

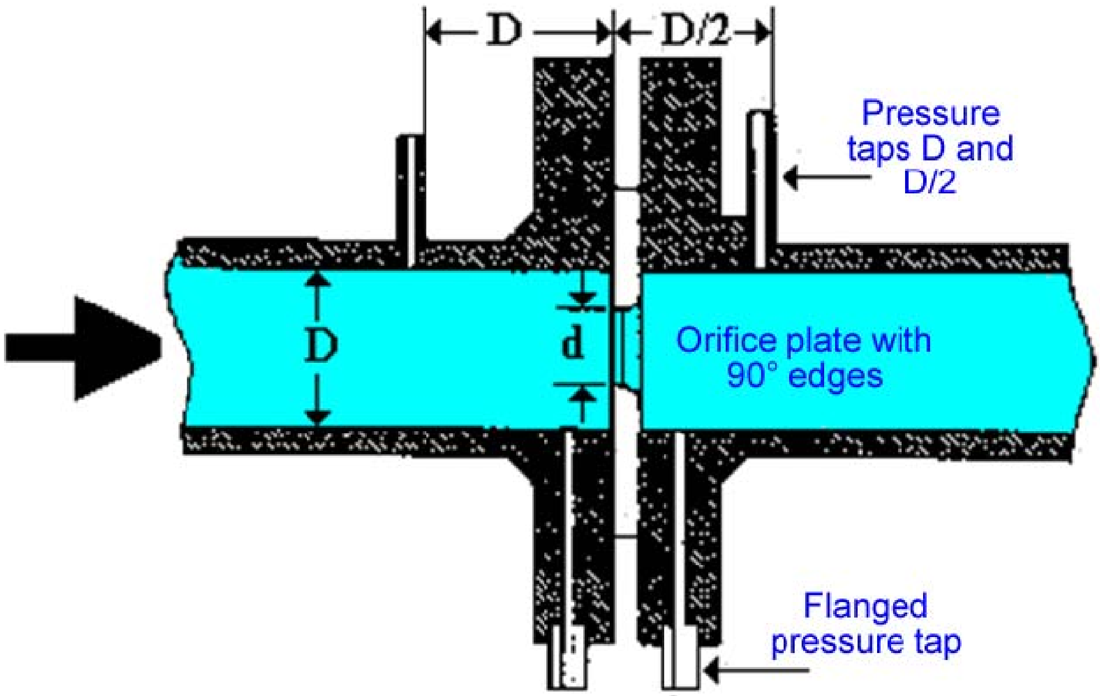


Figure 10: Orifice plate flowmeter operating principle

This flowmeter consists of a disk, with a hole at its centre, made of a material compatible with the liquid used. The concentric orifice plate compresses the fluid flow, which generates a differential pressure on both sides of the orifice plate.

This results in high pressure upstream and low pressure downstream, proportional to the square of the flow velocity.

This is the simplest, cheapest and most compact system.

- scope of use: unsuitable for liquids containing solid impurities since these may build up at the base of the orifice plate. It generates a substantial pressure drop
- pipe diameter: all diameters available
- accuracy: 2 to 5 %

For the orifice plate, the primary element consists of a plate, with a calibrated orifice, fitted perpendicularly to the fluid flow.

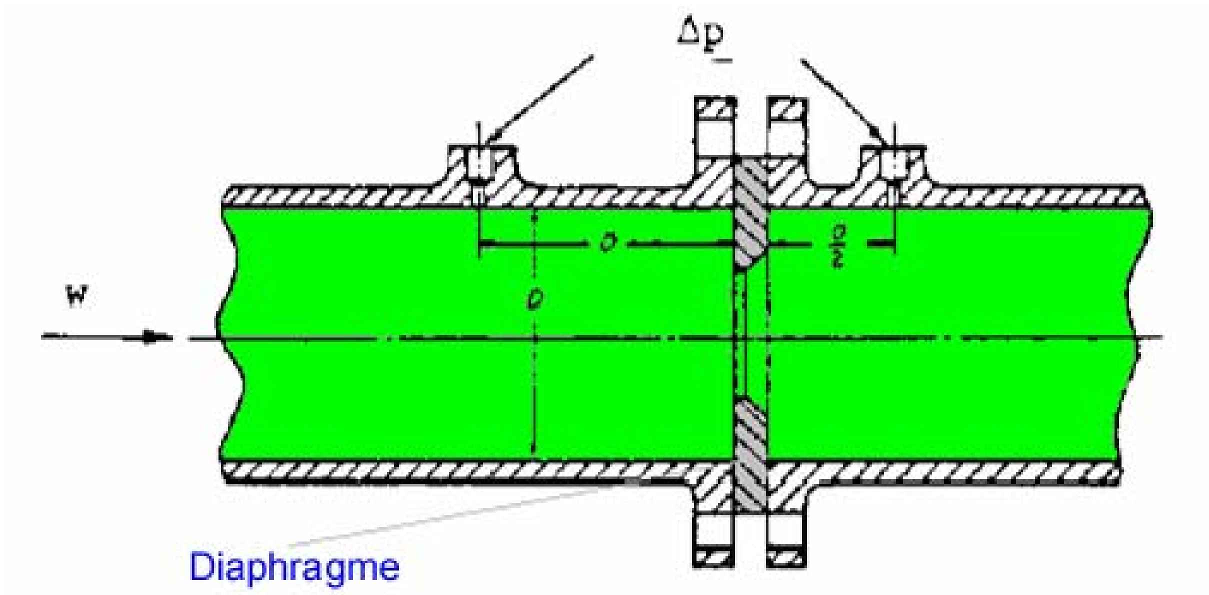


Figure 11 : Orifice plate in place

The upstream edge must be a sharp edge (curve radius ≤ 0.0004d).

- **Orifice plate**

Quadrant-edged orifice plate: the orifice has a rounded edge with a radius which depends on the orifice diameter.

It is used when the Reynolds number is less than the permissible limits for circular sharp-edged orifices, particularly for viscous fluids.

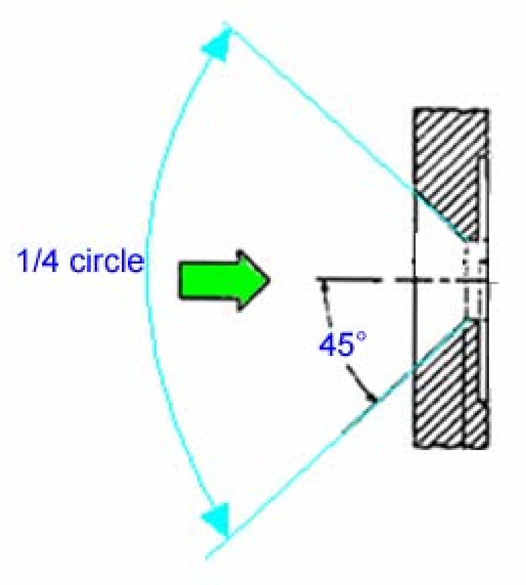


Figure 12 : Quadrant-edged orifice plate

Tapered inlet orifice plate:

the plate has a 45° angle on the upstream side.

Same operating conditions as for the quadrant edged plates but the tapered inlet orifice plate is preferred over these.

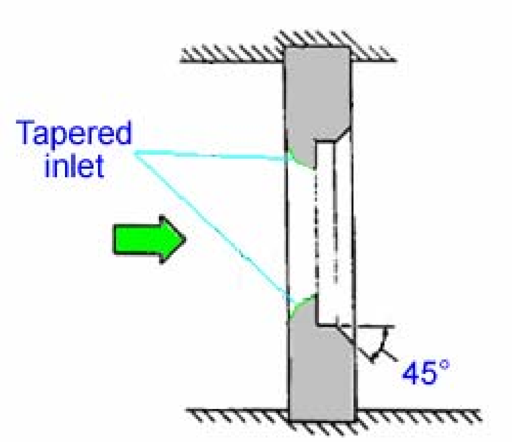
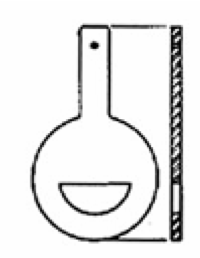


Figure 13 : Tapered inlet orifice plate



Segmental bore orifice plate:

Figure 14: Segmental bore orifice plate

Eccentric orifice plate: this is recommended for use with mixed liquid/gas phases.

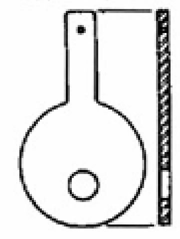


Figure 15: Eccentric orifice plate

4.2.1.3. Assembly of orifice plates

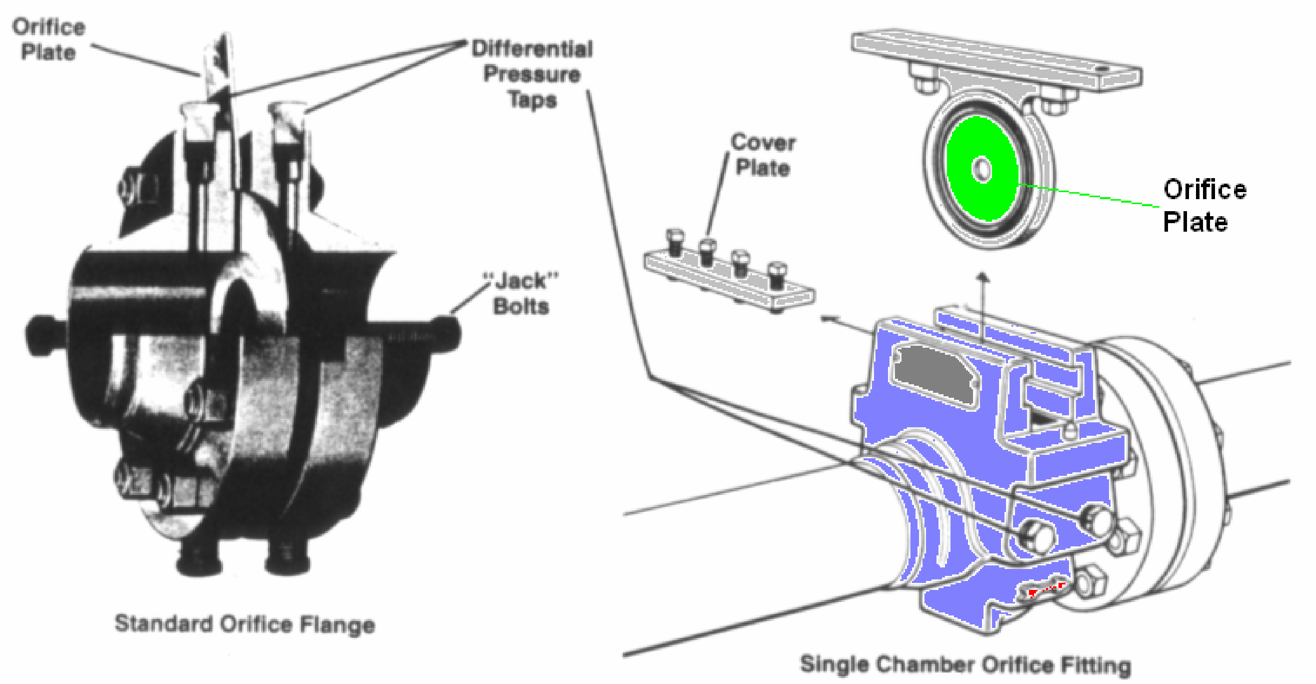
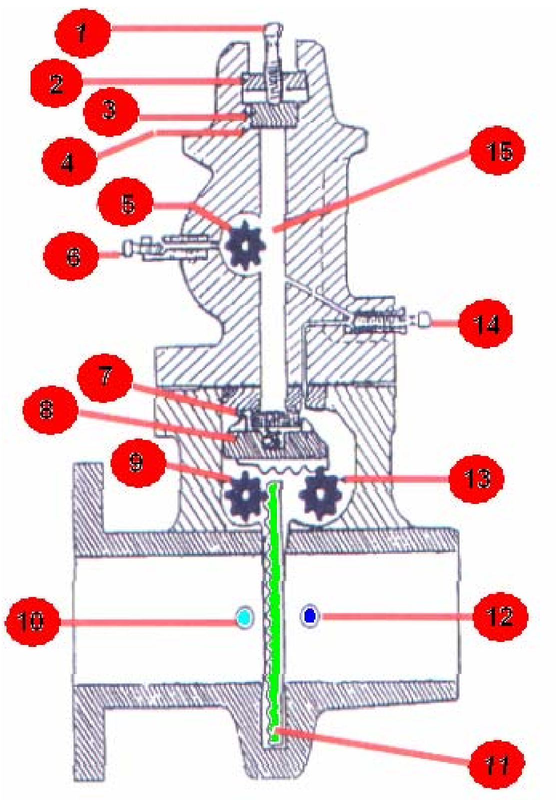


Figure 16: Orifice plate holder



1. *Locking screw*
2. *Locking plate*
3. *Cover plate*
4. *Seal*
5. *Rack drive gear*
6. *Bleed*
7. *Slide seat (cover plate)*
8. *Rack slide*
9. *Rack drive gear*
10. *LP outlet*
11. *Rack gear*
12. *HP outlet*
13. *Rack gear*
14. *Equaliser*
15. *Chamber*

Figure 17 : Orifice plate meter components

4.2.1.4. Uses

- Fluids
  - All liquids.
  - Gas or solid entrainments are tolerated.
- Applications for liquids
  - Water discharge, water injection.
  - Anhydrous oil metering.
  - Hydrated oil metering in association with WLR (BSW) measurements (separators, export)).

Figure 18 : Orifice plate meter

- Applications for gases
  - injected gas,
  - gas-lift gas,
  - production and test separator gas,
  - fuel gas,
  - vents.

4.2.1.5. Specifications

Pressure	Depends on the sensors
Temperature	Same + materials
Measurement range	3 to 10
Response	Square root
Accuracy	± 0.6% FS p, discharge coefficient C_D
Connections	Between flanges

- Sizes — Depend on pipe
- Advantages — Cost - Maintenance - Robustness
- Disadvantages — Installation conditions - Accuracy

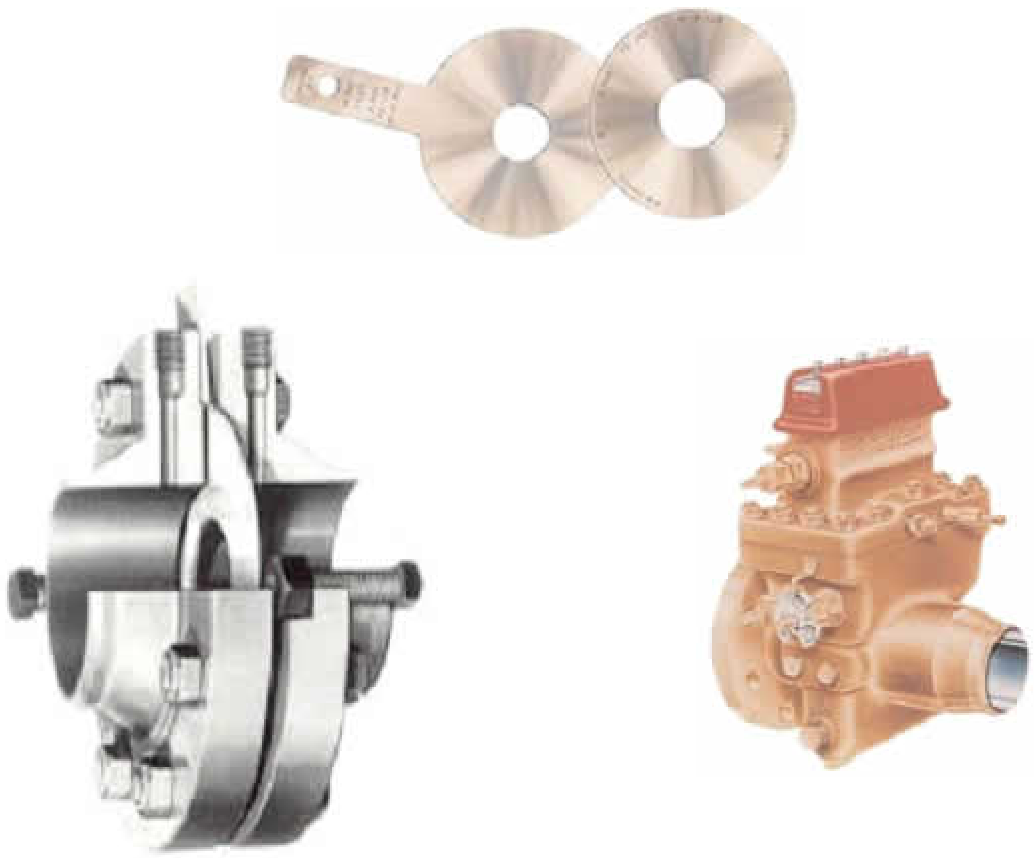


Figure 19 : Plaques Orifice plates and plate meter

The overall precision is a function of the precision on C_D, and the precision on the other parameters as well (d, D, ρ, Δp, etc…).

4.2.2. Pressure differential device – V-cone

4.2.2.1. Principle

This proprietary system uses the same differential measuring principles as the venturi system.

This time, the reduction in the cross sectional area is achieved at the outside diameter of a fixed element (cone) placed in the centre of the pipe.

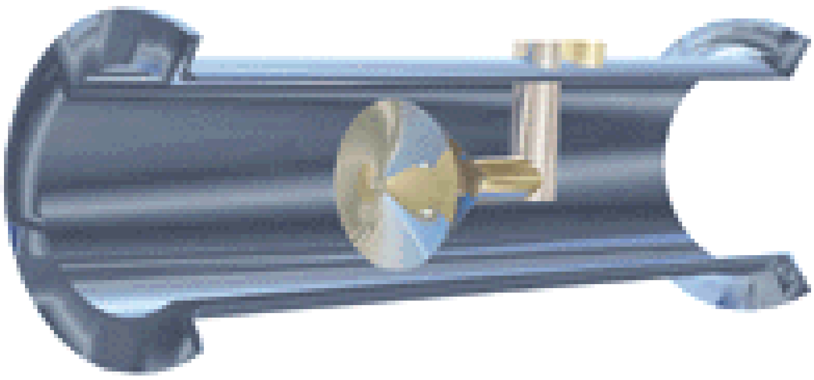


Figure 20: Pressure differential device – V-cone

4.2.2.2. Specifications

- Fluids — Liquids, Gases, Vapours
- Pressure — Depends on sensors
- Temperature — same + materials
- Measuring range — 3 to 10 m^3/h
- Response — Square root
- Accuracy — ± 1.0% (8:1)
- Connections — Flanges or insertion
- Sizes — Depend on pipe (up to 2000 mm)
- Advantages — Contaminated fluids – Pressure drop
- Disadvantages — Installation conditions – Cost – Intrusiveness

4.2.3. Differential pressure device - Venturi

4.2.3.1. Principle

For the Venturi, the primary element consists of a conical convergent followed by a cylindrical section and then a divergent.

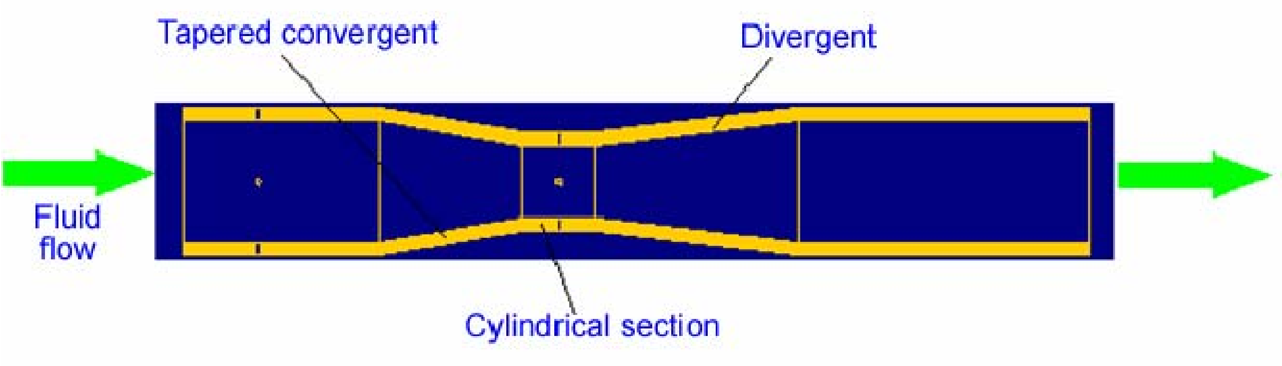


Figure 21: Venturi principle

The mass flow rate is expressed using the same relation as for the orifice plate.

4.2.3.2. Specifications

- Fluids — Liquids, Gases, Vapours
- Pressure — Depends on the sensors
- Temperature — Same + materials
- Measuring dynamics — from 3 to 10 m^3/h
- Response — Square root
- Accuracy — ± 1.0% on discharge coefficient C_D
- Connections — Flanges
- Sizes — Depend on pipe (up to 2000 mm)
- Advantages — Contaminated fluids – Pressure drop
- Disadvantages — Installation conditions – Cost

Figure 22: Examples of Venturi devices

4.2.4. Pitot tube or equivalent

4.2.4.1. Principle

Pitot probes, also called Pitot tubes, are used to determine local velocities by measuring the difference between the dynamic pressure and the static pressure.

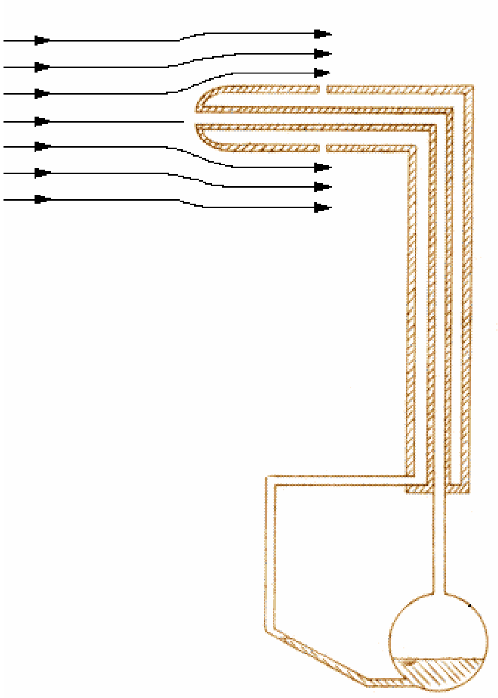


Figure 23: Pitot tube

"Averaging" systems are used to measure average velocities (Annubar type).

4.2.4.2. Uses of the Annubar system

Annubar systems can be used:

- when a very low pressure drop is required,
- when the accuracy of the measurement is not essential,
- on large diameter pipes.

They cannot be used for vapour or charged fluids.

They can be removed without shutting down the line (chamber and isolating valve). For pipes above ND > ND 200, the instrument must be guided on both sides of the pipe.

Care must be taken to ensure that if the measuring tube breaks, there is no risk of damaging downstream equipment (e.g. compressor).

4.2.4.3. Recommendations for use and application

- Clean fluids.
- Suitable for large diameter ducts and pipes.

4.2.4.4. Specifications

Fluids	Liquids and Gases
Pressure	Depends on sensors
Temperature	Same + materials
Measuring range	Depends on pipe (velocity measurement)
Response	Square root
Precision	± 2.5% FS (4:1) (0.5 to 3 % for annubar)
Connections	Insertion
Advantages	Cost – Averaging systems
Disadvantages	Local measurement

Figure 24: Examples of Pitot tubes

4.3. TURBINE

4.3.1. Operation of a turbine flowmeter

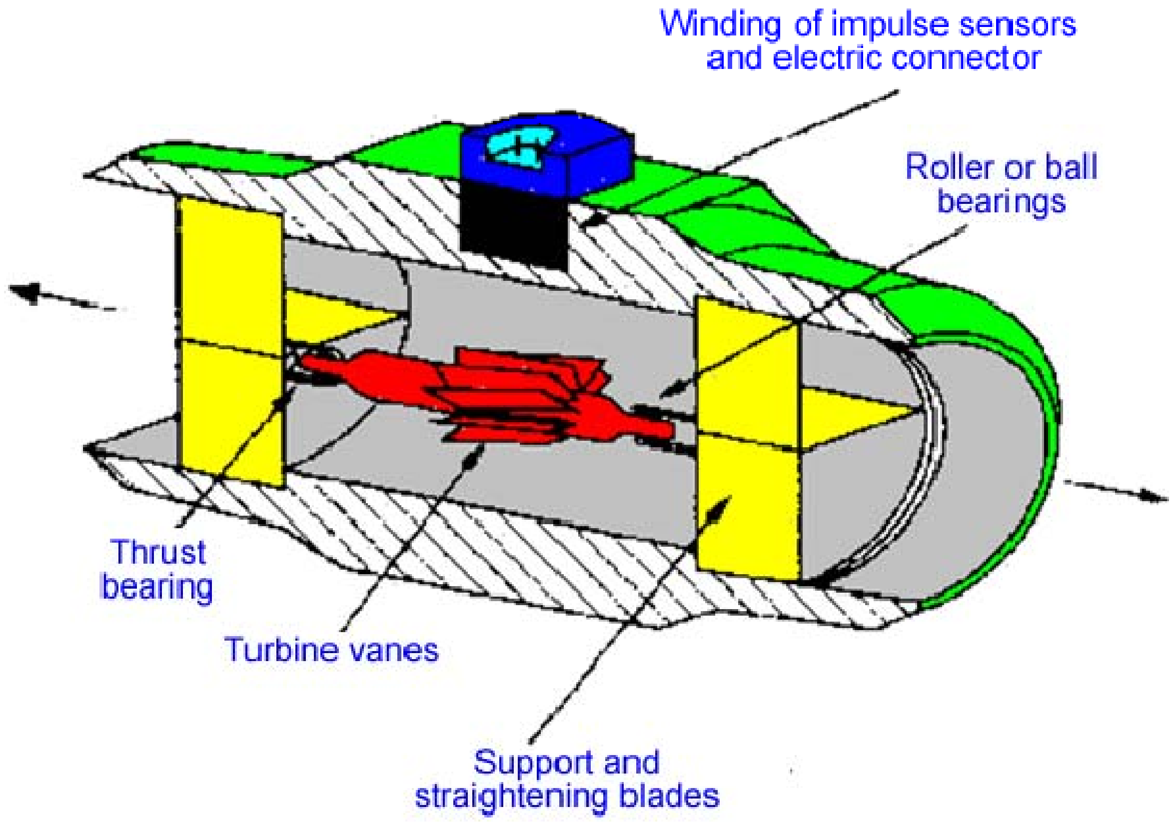


Figure 25: Exploded view of a turbine flowmeter

The fluid flow rotates a turbine (multivane rotor mounted on bearings) placed in the measurement chamber; the rotational speed of the rotor is proportional to the fluid velocity, and thus to the total volumetric flow rate. The rotational speed is measured by counting the vane passage frequency detected using a coil (a permanent magnet is sometimes integral with the rotor).

Each pulse represents a distinct volume of liquid.

There has been little or no development of turbine metering for technical metering but it is widely used for custody transfer or fiscal metering (allocation).

Turbines procure greater accuracy than orifices.

Owing to the problems involved with technical metering (entrainments, overspeed), turbines are used very little or not at all.

4.3.2. Principle

Measuring fluid flow rate by a turbine consists in measuring the rotational speed of a rotor or blades rotating freely in the fluid stream.

This rotational speed which is transmitted in the form of frequency (pulse train) is "approximately" linear according to the volumetric flow rate passing through the pipe.

The friction (bearings) and the product viscosity variations generate non-linearities that are particularly significant at low regimes.

Different technologies can be used to meter liquids:

- Flat blade turbines (limited to low viscosity products)

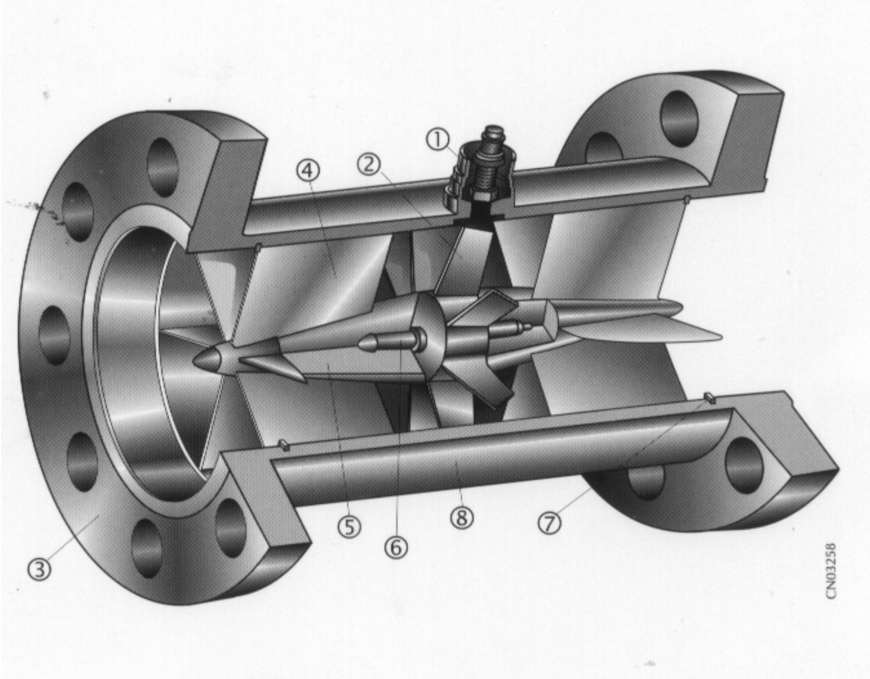


Figure 26: Example of a flat-blade turbine meter (exploded view)

- Helical blade turbines (much less sensitive to fluid viscosity variations).

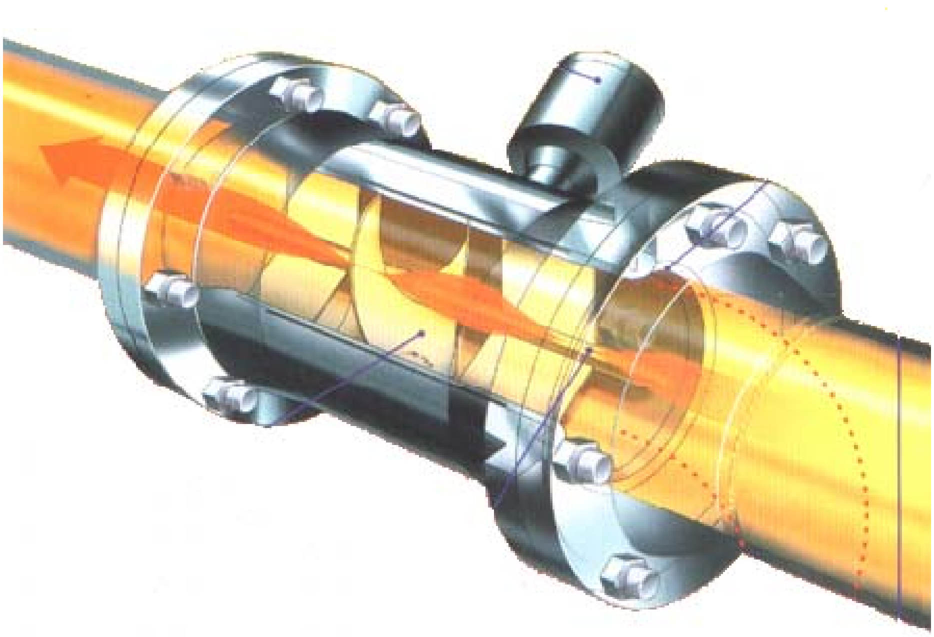


Figure 27: High performance helical blade turbine

4.3.3. Choice of turbine type

For precision applications, the use of helical blade turbines rather than flat blade turbines is recommended as the former have:

- better flow stability,
- lower sensitivity to the crude viscosity variations,
- very good linearity (+/- 0.15% or better),
- greater operating flexibility owing to the possibility of less frequent calibration and of using performance tables or curves (K-factor versus flow rate): ISO 4124 or API MPMS 5.3.

4.3.4. Data supplied

- Volumetric flow rate in the P and T m^3/h conditions.
- Cumulated volume if a totaliser is associated with the sensor.

4.3.5. Use of turbine meters

- All types of fluids.
- Although for fiscal metering, the use of turbine meters is recommended for fluids with viscosity less than 25-30 Cst, their use for technical metering could be extended to viscosities of the order of 80 Cst and above (insertion devices).
- For liquids, they are often used:
    - At the production separator outlet.
    - At the departure point from the field.
    - At the arrival point at the treatment platform or terminal platform.
- For gases, they are often used essentially for clean gases:
    - Fiscal metering the gas at the test and production separator outlets.

4.3.6. Installation

4.3.6.1. Assembly

The turbine meters are normally configured with or without a flow conditioner; they should preferably be installed in a horizontal pipe.

Although there are approximate formulas for evaluating the straight pipe lengths needed according to the line configuration, the minimum straight lengths upstream and downstream are specified by the Group and its standards.

Isolating valves and bypasses must be used in the start-up phases.

Where gas slugs are present the installation of deaerators is recommended.

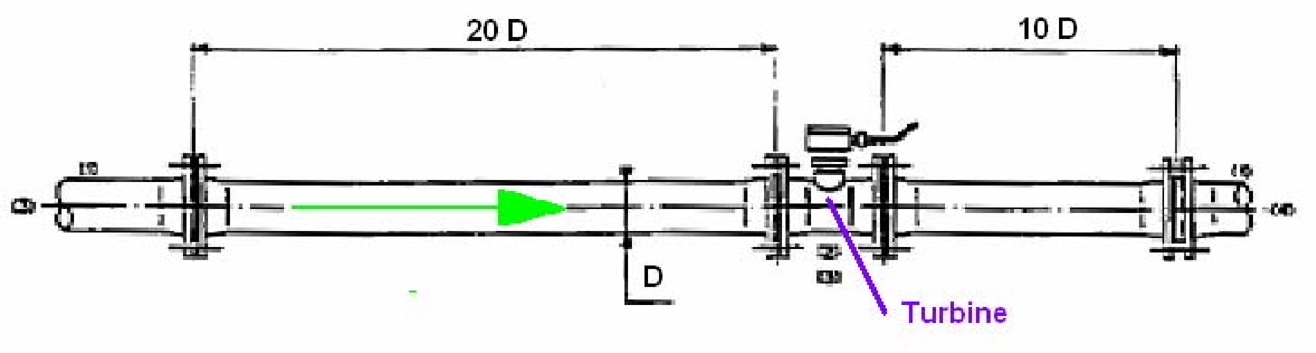


Figure 28: Installation of a turbine without a flow conditioner

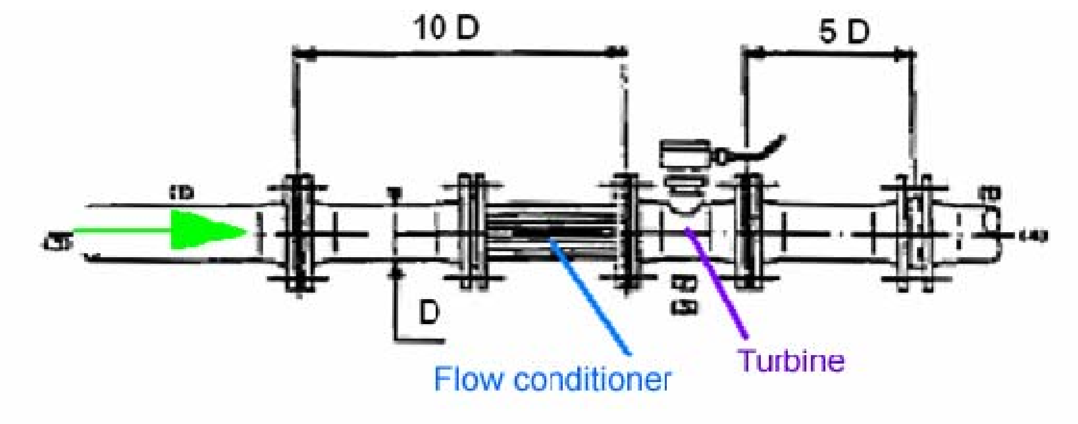


Figure 29: Installation of a turbine with a flow conditioner

Notes:

- The upstream and downstream pipes must be secured fast, to avoid any mechanical stress on the turbine.
- The turbine must be installed on straight sections of pipe with no flow disrupting elements (valves, reduction, etc.).
- The liquid measured must be free of solids and gas so the appropriate equipment must be provided (filter, deaerator, etc.).
- The turbine must preferably be installed in a horizontal pipe and be pressurised to prevent the risk of cavitation (pressurised tank, pump delivery, etc.).
- In the exceptional case of a turbine being installed on a vertical pipe, the liquid must flow from bottom to top.

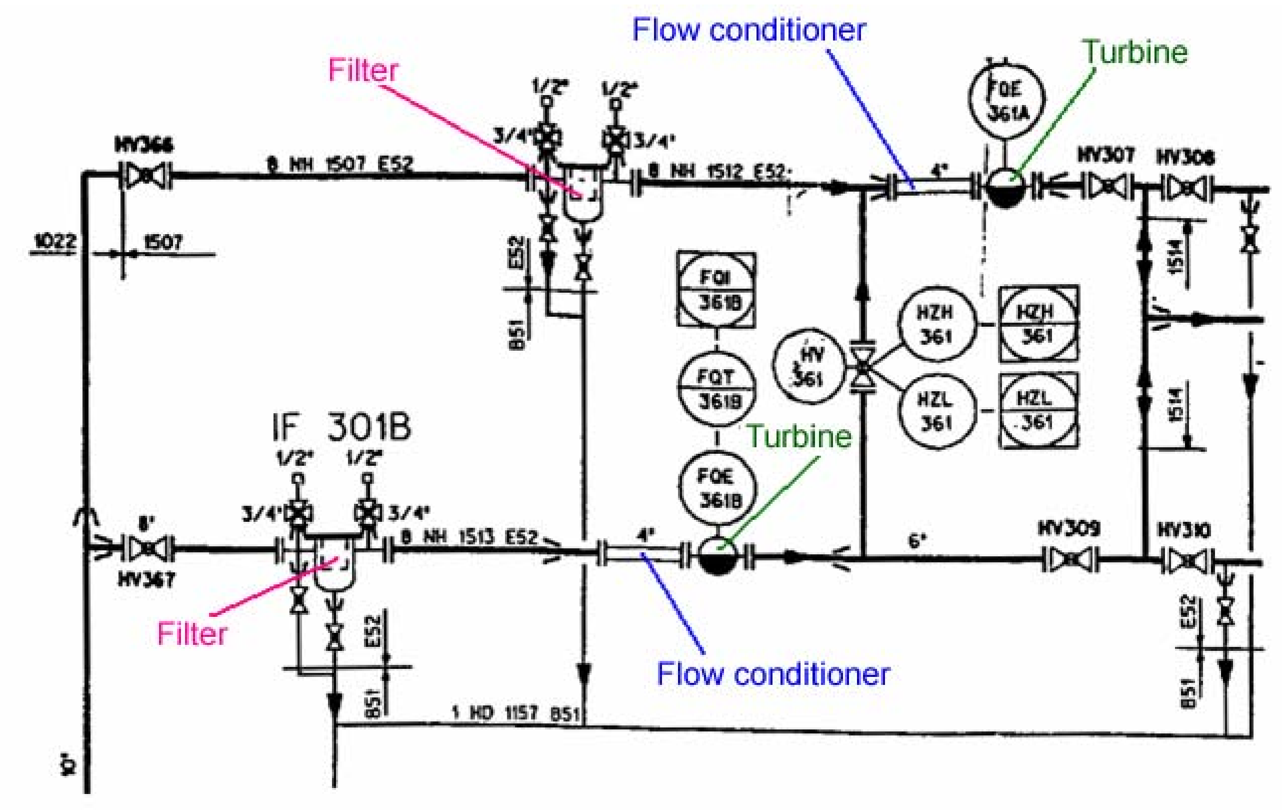


Figure 30: Example of turbine positioning

4.3.6.2. Filtering devices

Filtering devices are compulsory due to the sensitivity to entrainment of solids (a study of the filter rating and volume must be carried out).

4.3.6.3. Equipment

- The choice of the type of mechanical equipment (bearings, hub components, etc.) is critical.
- The type of rotor (helical or not) may play a role in the turbine performance (rotors are less sensitive to viscosity).

4.3.6.4. Preamplifiers

- There are specific electronic preamplifiers available for each turbine module. "Dubious" electronic adaptations must be avoided since the frequency and pulse level are specific to each piece of equipment.
- The amplifiers should be protected in difficult environments (sun and spray).

4.3.7. Implementation

Recommendations (ISO 2715, API MPMS 5.3)

- Turbine meters should be installed horizontally.
- Install long straight lengths upstream and downstream to obtain an established flow profile without vortices or, failing this, install a flow conditioner or a flow straightener (vortices or pulses can cause excess meter readings due to overspeed).
- It is essential to install filtration devices upstream. They should be equipped with a differential pressure indicator to check the state of clogging.
- Install a pressure and/or flow control valve downstream of each meter to maintain a pressure greater than the vapour pressure of the measured fluid (degassing) and to keep the flow rate within the meter's operating range.
- Install a deaerator if there is a risk of gas being present upstream (the flow rate is overestimated if gas is present in the liquid).

- For fiscal metering, the regulations require the presence of a device preventing product backflow (e.g. non-return valve).

- It is preferable to have a enough parallel meter runs to allow one run to be isolated and the full flow to be handled by the other runs, without exceeding each one's metering limits.

- Use the turbines within their operating range.

- Carry out calibration operations (calibration loop, master turbine, placing 2 meter runs in series, etc.) to pinpoint any discrepancies and to correct the meter factors (change in viscosity, in temperature, presence of deposits, wear of hub components, etc.).

- Recalibrate if there is an increase in flow rate or viscosity.

- Provide a housing for a mercury thermometer near the temperature sensors so that they can be checked at regular intervals.

- Ensure that the electronics are carefully protected and the cables are properly insulated.

- Each run of a turbine metering station must have a manual isolation valve, a filter, a flow conditioner, a metering turbine, P and T sensors, a flow control valve, a non-return valve, a block and bleed valve for sending the flow to the calibration loop.

Note: sales metering using turbines generates very few incidents. Conversely, for non-sales metering, the same equipment is used but the installation rules are rarely or never respected (filtration quality low, water hammer effects, etc.), resulting in low equipment availability and high operating and maintenance costs.

4.3.8. Problems encountered

- Leaks in the valves (not turbine-related).

- Drift with wear of moving parts and the presence of deposits requiring calibrations and readjustment of the K-factor.

- Calibration flow rate outside the stability range for the considered turbine's K-factor.

- Failure to count the pulses generated due to the sensitivity being set too low or an electrical fault.

- Signals from an outside source seen as pulses (electrical power sources, welding sets, radio transmitter, etc.).

Specific case of a floating support vessel: depending on the sea conditions, the movements of the vessel may generate fluid displacements in the meter runs which, although they are of very low amplitude when isolated (loading not in progress), are sufficient to increment the number of pulses transmitted by the turbines.

4.3.9. Specifications

Fluids	Liquids, Gases, Vapours
Pressure	Up to 400 bars
Temperature	-230 / +260 °C
Measuring range	10
Response	Linear
Accuracy	± 0.25% (10:1) – liquid
	± 1.0% (10:1) – gas
Connections	Threaded / Flanges
Sizes	Up to 600 mm
Advantages	Accuracy – Self-contained – Low pressure drop.
Disadvantages	Straight lengths – Viscosity

Figure 31: Examples of turbines

4.4. VOLUMETRIC METER

4.4.1. Principles

Unlike all the other flow, mass or volume measurement systems, volumetric meters (also called positive displacement meters) take direct measurements.

To find out the volume transferred, it suffices to count the number of discrete volumes actually displaced.

Very many technologies are used industrially, among them:

- Vane meter
- Oscillating piston meters
- Screw meter
- Oval gear meter
- Gear meter
- etc.

4.4.2. Types of volumetric meters

4.4.2.1. Rotary piston meter

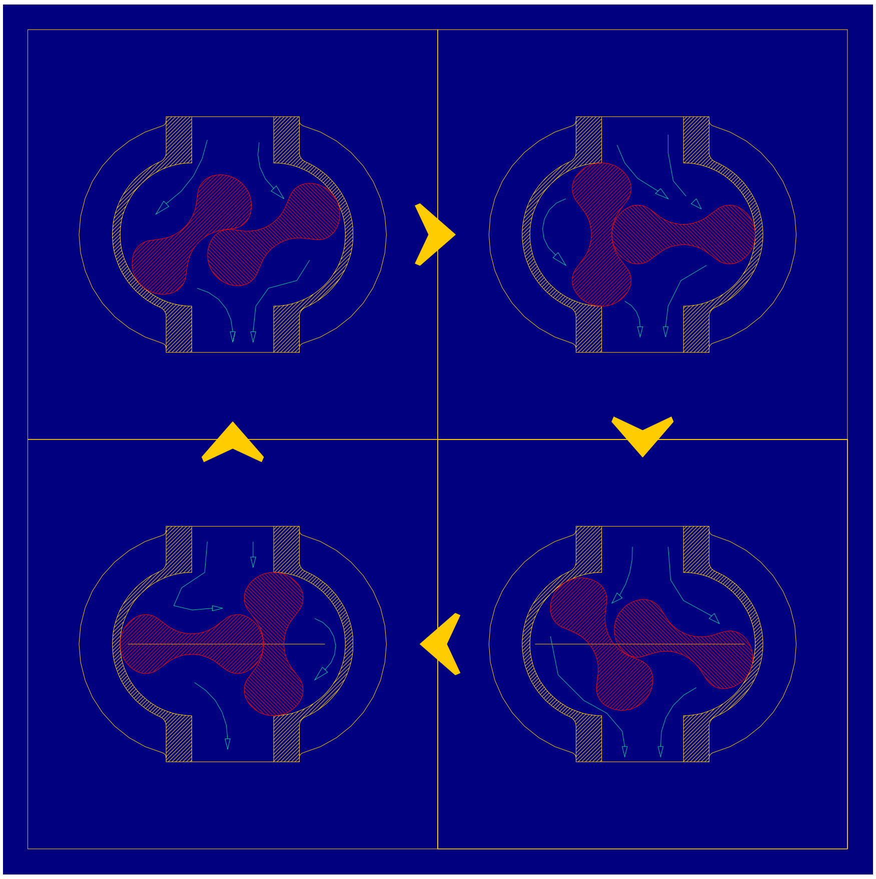


Figure 32: Rotary piston meter

4.4.2.2. Reciprocating piston meter

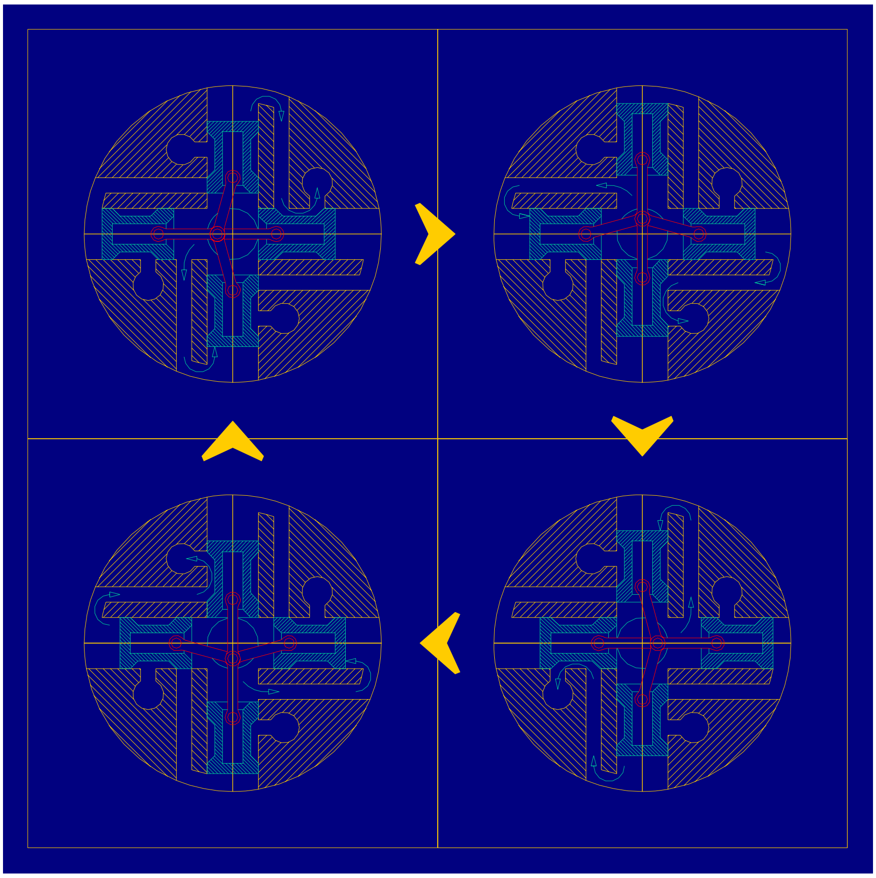


Figure 33: Reciprocating piston meter

4.4.2.3. Oscillating piston meter

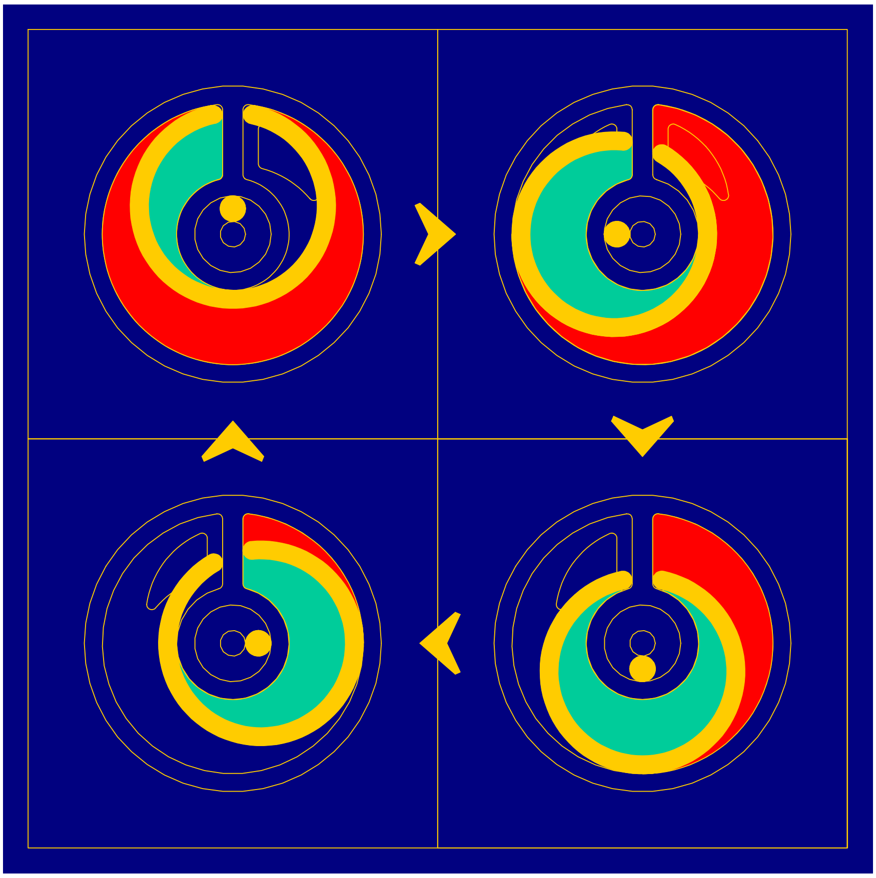


Figure 34: Oscillating piston meter

4.4.2.4. Vane meter

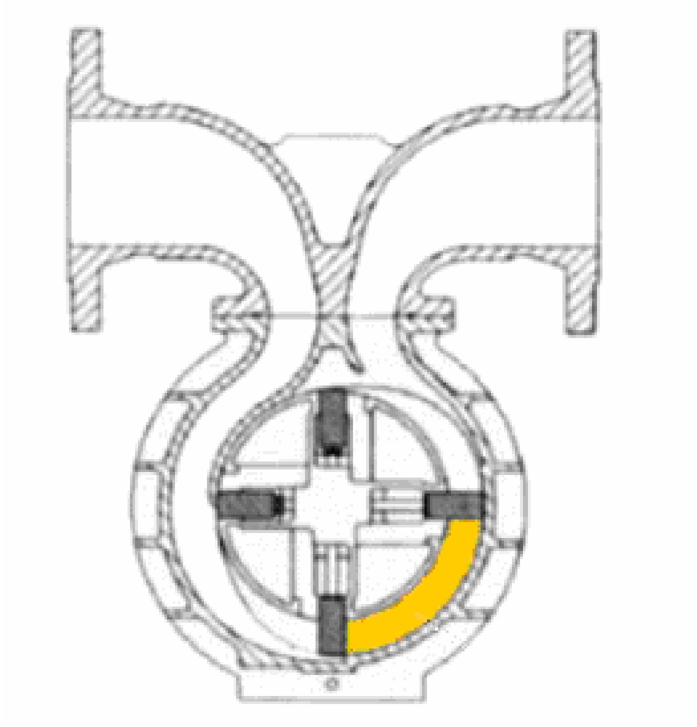


Figure 35: Vane meter

4.4.2.5. Screw meter

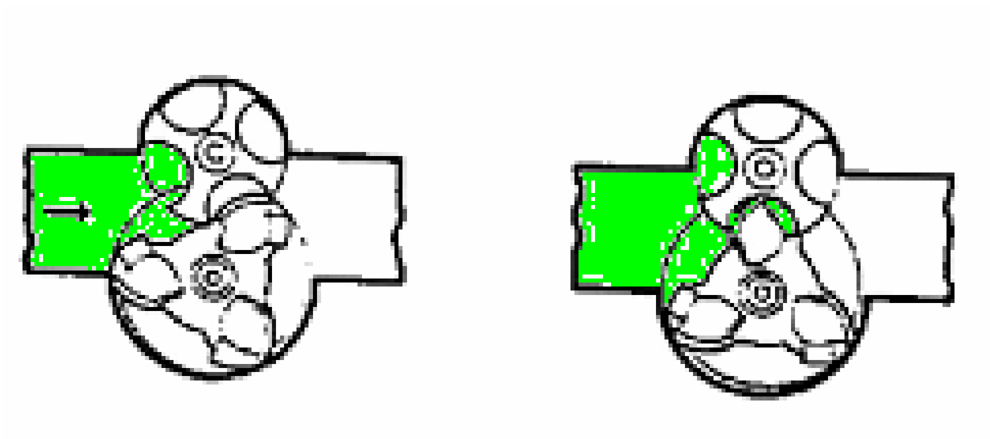


Figure 36: Screw meters

4.4.3. Uses

- For viscous hydrocarbon fluids without solid particles (sand, etc.).
- Low sensitivity to variations in the fluid properties (composition, viscosity).
- Insensitive to flow disturbances.
- Export platform / treatment centre.

4.4.4. Implementation (Recommendations)

Identical to the recommendations for the turbine metering stations except for the straight lengths or flow conditioners which are not required.

Provision should be made however for:

- a speed limiter,
- sufficient space for maintenance.

Moreover, the following must be planed for on the installations:

- Use filters with a delta P measurement.
- Install horizontally.
- No flow conditioner or straight length.
- If gas present, use deaerators.
- Speed limiter.
- Allow sufficient space for maintenance.

4.4.5. Problems encountered

- damage due to overspeeds,
- cavitation,
- mechanical deterioration due to possible solids,

- liquid leakage or slip at low flow rates,
- metered values too high if entrained gas present,
- drifts due to mechanical wear,
- mechanical transmission problems.

4.4.6. Application

- For accurate metering at the production centre outlet.
- Located upstream, this device is reserved more for liquid metering.
- For metering fluids with variable properties (water + oil) without gas and without solids.
- For metering in applications where turbines cannot be used (due to high viscosity).

4.4.7. Specifications

Fluids	"Clean" Liquids
Pressure	Up to 100 bars
Temperature	Up to 300°C (liquid)
Measurement range	10 to 20
Response	Linear
Accuracy	± 0.25% to 0.5, depending on the technologies
Connections	Threaded / Flanges
Sizes	Up to 300 mm
Advantages	Accuracy – Viscosity - Installation
Disadvantages	Maintenance – Bulky Flow rate limited due to high rotation speeds

Figure 37: Examples of volumetric meters

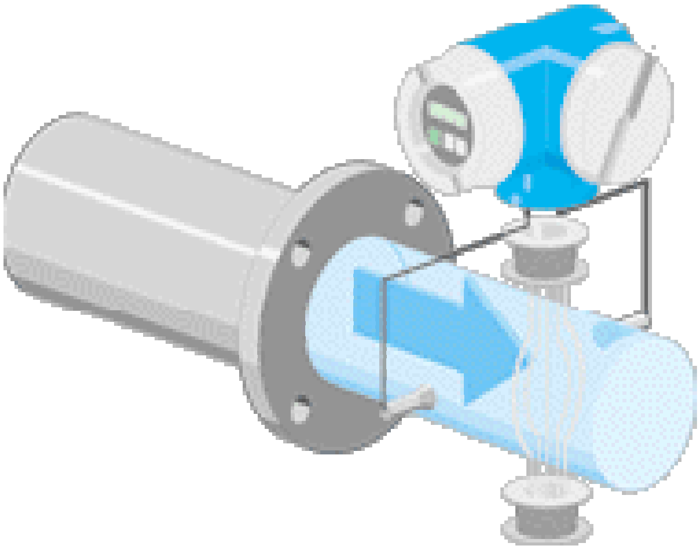
4.5. ELECTROMAGNETIC FLOWMETER

4.5.1. Electromagnetic flowmeter operation

Faraday's induction law states that a conductor moving through a magnetic field generates an induced voltage. In the case of an electromagnetic flowmeter, it is the moving fluid which represents the moving conductor.

The constant electromagnetic field is generated by 2 coils, one on each side of the measuring tube.

Two measuring electrodes are installed inside the tube, at 90° to the coils, to measure the induced voltage generated by the movement of the fluid in the electromagnetic field. The induced voltage is proportional to the fluid velocity and thus to the volumetric flow rate.



The electromagnetic field is generated by a pulsed DC current with alternating polarities. This provides a stable zero point and renders the measurement insensitive to the effects of multi-phase, non-homogenous, or low conductivity liquids.

Figure 38: Electromagnetic flowmeter operating principle

4.5.2. Principle

An electric conductor (the fluid) passes through a magnetic field of intensity B. A voltage U, which is directly proportional to the average flow velocity V is induced in the fluid.

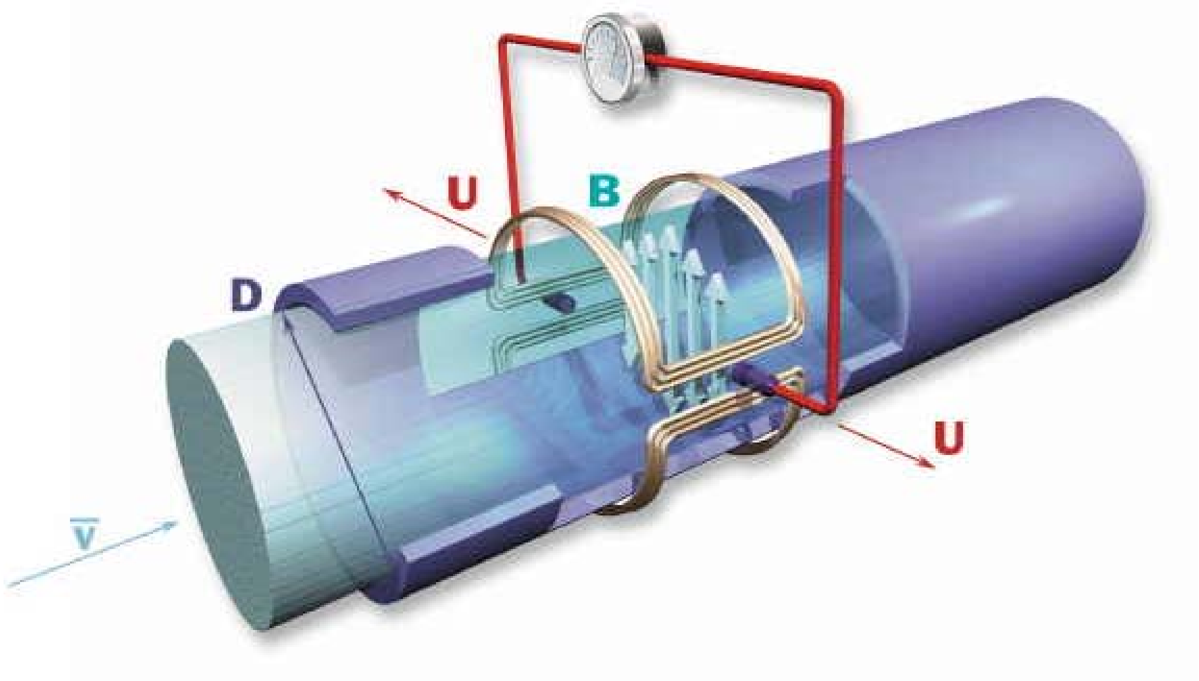


Figure 39: Electromagnetic flowmeter principle

The induced voltage signal is picked up by the two measuring electrodes in contact with the fluid or by a contactless capacitance system.

We measure the EMF (electromotive force) induced by the displacement of the fluid (which must be a conductor) in a magnetic field (Faraday's Law)

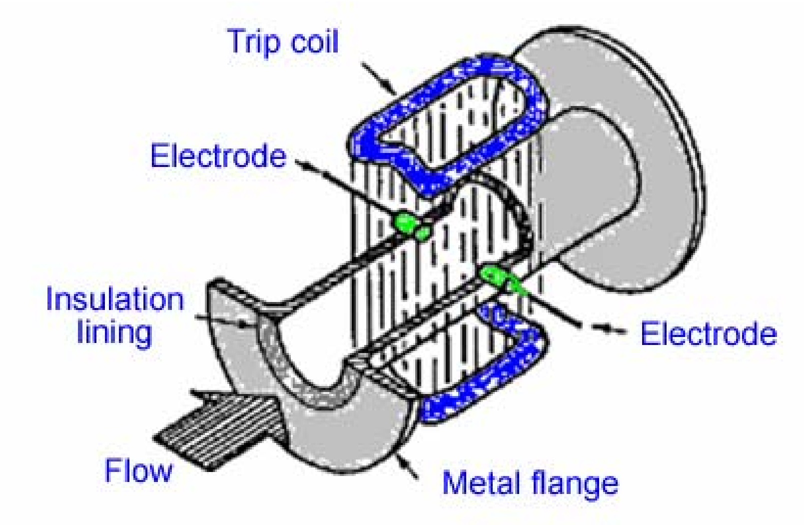


Figure 40: Electromagnetic flowmeter principle

4.5.3. Data supplied

The volumetric flow rate at metering conditions, from the liquid displacement velocity measurement.

4.5.4. Use

It is reserved for fluids with sufficient conductivity (sea water, formation water, etc.). Used for water only.

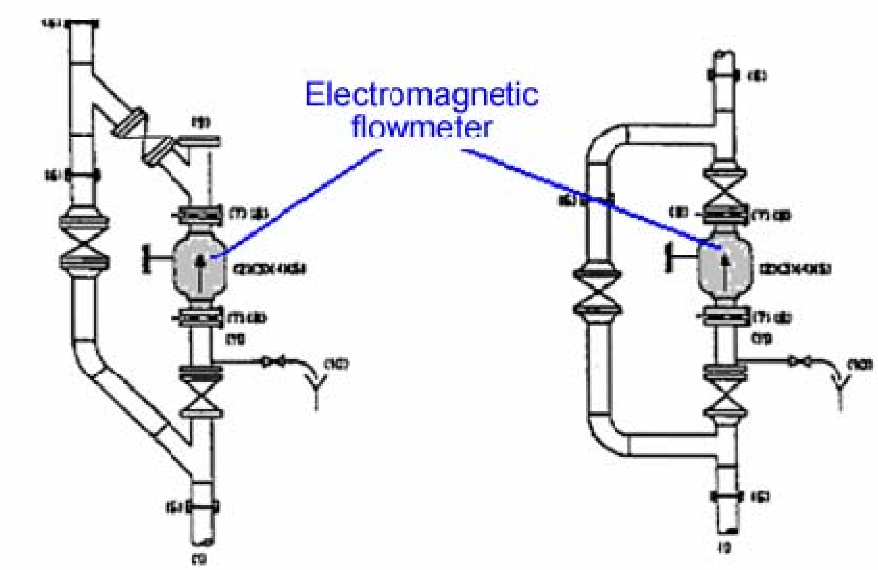
The fluid's measurable minimum conductivity must be 5µs/cm. Minimum flow velocities must be respected (e.g. 0.5 m/s).

4.5.5. Equipment

The flowmeters have a fragile electrical insulation (Teflon, ceramic). Some manufacturers provide a centring ring.

Figure 41: Electromagnetic flowmeter

4.5.6. Installation



The flowmeter should preferably be installed on vertical pipes. However, installation on horizontal pipes is possible.

Figure 42: Installation on vertical pipe

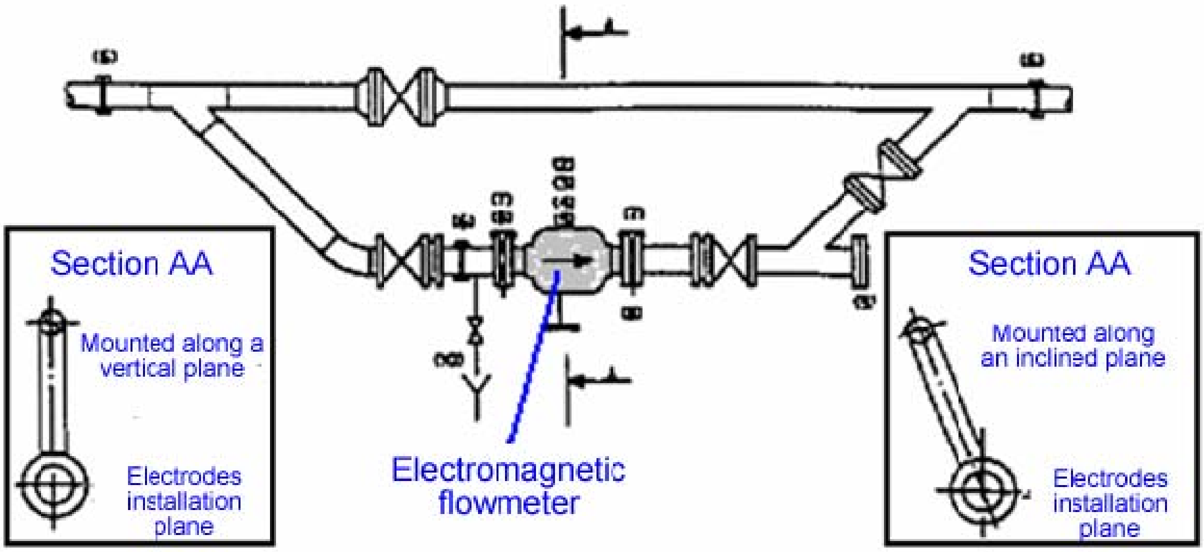


Figure 43: Installation on horizontal pipe

- The flowmeter must always be full of liquid.
- A filter must be installed upstream if elements dangerous for the coating can be entrained by the flow.
- Important: the transmitter **must be installed on the pipe in the presence of an instrument technician.**
- Torque loadings must be respected to prevent damage to the external coatings.
- The connections to the pipes must be installed such as to prevent incorrect alignment.
- An assembly support must be used to ensure that the measuring tube and the pipes are aligned. If one of the components forms an angle with respect to another, the insulation elements (ceramic or Teflon) may be damaged.
- The highest accuracy will be obtained using upstream straight lengths of 5D or 10D (5D after Tee , open valve; 10D after expander or control valve).
- Electromagnetic flowmeters must not be used beside equipment likely to create interference (motors, transformers, etc.).
- The earthing must be installed with care.
- According to the manufacturers' recommendations, isolation valves and bypass valves should be installed to facilitate checks and adjustments.

4.5.7. Typical applications

- Water at the separator outlets which does not create isolating deposits.
- Water on water treatment installations.
- Injection water.

Only salt water applications are recommended.

4.5.8. Specifications

- Fluids Conductive liquids
- Pressure Up to 50 bars
- Temperature Up to 180 °C
- Measuring range 2 l/h to 115000 m3/h
- Response Linear
- Accuracy ± 0.5% (10:1)
- Connections Flanges
- Sizes 2.5 – 2500 mm
- Advantages Pressure drop - bi-directional
- Disadvantages Conductive liquids

Figure 44: Example of an electromagnetic flowmeter

4.6. VORTEX FLOWMETER

4.6.1. Vortex flowmeter operation

This measurement principle is based on the formation of vortices downstream of an obstacle placed in the fluid flow, such as the pillar of a bridge in a river. This phenomenon is known as the *Karman Vortex Street*.

When a fluid passes over a body placed in the measurement tube and disturbing flow, vortices are formed alternatively on each side of this body. The vortex shedding frequency, alternatively on each side of the body, is directly proportional to the flow velocity and thus to the volumetric flow rate. The pressure variations generated by these vortices are detected by a capacitance probe which sends a primary linear digital signal to the control system processor.

The measurement signal is not subject to drift. So vortex flowmeters can function continuously without requiring recalibration during their service life.

The capacitance probe with integrated temperature measurement can directly register the mass flow rate of saturated steam, for example.

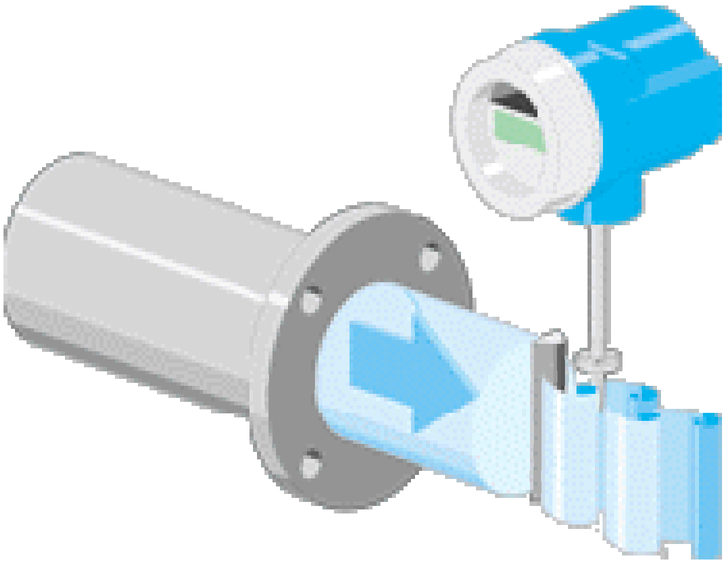


Figure 45: Vortex flowmeter operating principle

4.6.2. Principle

The measurement principle consists in detecting the vortex shedding frequency which, for a given obstacle geometry, is proportional to the flow velocity.

An obstacle placed in a fluid flow (liquid or gas) creates vortices (whose shedding frequency is proportional to the velocity of the fluid, V).

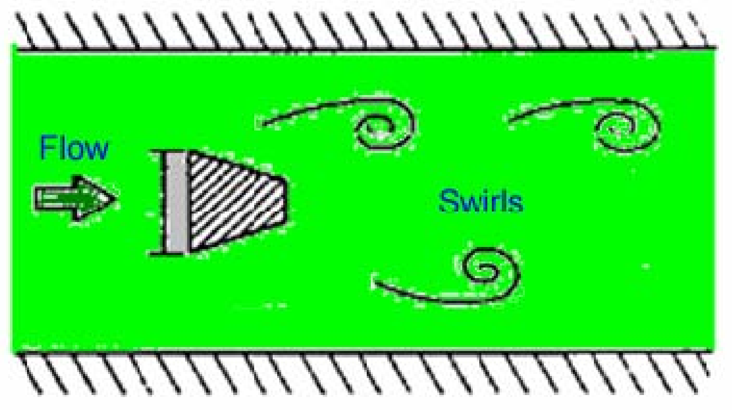


Figure 46: Vortex flowmeter principle

4.6.3. Data supplied

The sensor delivers frequency data which are processed to provide the user with volumetric flow rate data in the meter run conditions.

4.6.4. Equipment

The technologies differ by the type of obstacle used and the vortex shedding frequency measurement techniques.

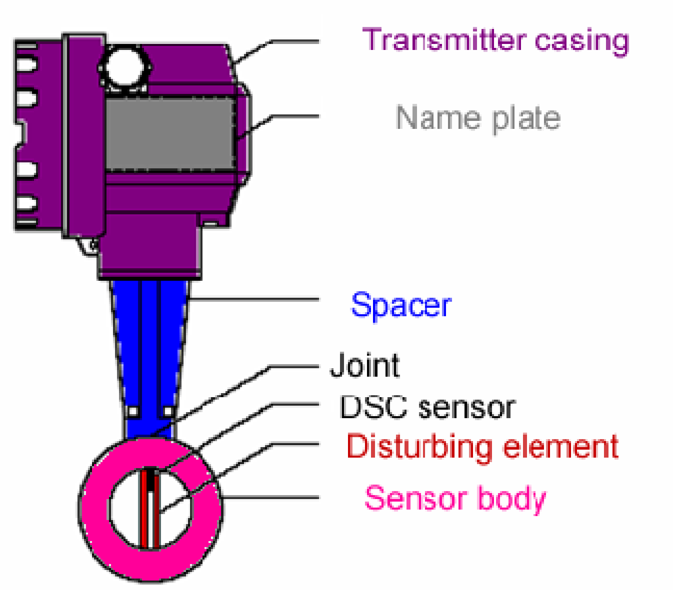


Figure 47: Main components of a Vortex flowmeter

4.6.5. Installation

To prevent a liquid from degassing or vaporising, there must be minimal backpressure.

Refer to the installation standard which specifies:

- straight lengths of 20D to 30D downstream,
- 10D upstream,
- the upstream and downstream pipes must be secured in such a way as to prevent shocks or eccentricities,

- installation of the meter on the straight sections free of flow-disrupting elements,
- the use of a flow conditioner if the straight lengths cannot be respected.

The manufacturer documentation specifies the installation requirements according to the pipe configuration (after reducer, after valve, after bend, after expander, etc.).

There are recommendations for the positions of the temperature and pressure take-offs.

Care must be taken to ensure that the flowmeters have the same diameter as the pipes or a smaller diameter, where necessary.

The flow direction must correspond to the arrow indicated on the meter.
If the flowmeter is installed vertically, the flow must be from bottom to top.

Figure 48: Vortex flowmeter

4.6.6. Typical applications

4.6.6.1. For liquids

- Metering of light condensates (< 5 cSst).
- Water metering.

This technique is not very widely used for metering liquids in production due to the frequent presence of viscous products.

4.6.6.2. For gases

- Metering gas at the test and production separator outlets.
- Metering gas injection.

IMPORTANT: functions *only* with Reynolds' numbers > 10 000**!!!**

4.6.7. Specifications

Fluids	Liquids, Gases, Vapours
Pressure	Up to 250 bars
Temperature	Up to 400 °C
Measurement range	10 to 20
Response	Linear at Reynolds' numbers > 10 000 – 20 000
Accuracy	± 1.0% (10:1) – liquid ± 2.0% (15:1) – gas
Connections	Threaded / Flanges
Sizes	10 – 200 mm
Advantages	No moving parts – Q/P ratio
Disadvantages	Straight lengths

Figure 49: Examples of Vortex flowmeters

4.7. ULTRASONIC FLOWMETER – "TRANSIT" TIME

Swimming against the current requires more energy and takes longer than swimming with the current. The ultrasonic flow rate measurement is based on this fundamental principle of the difference in transit time.

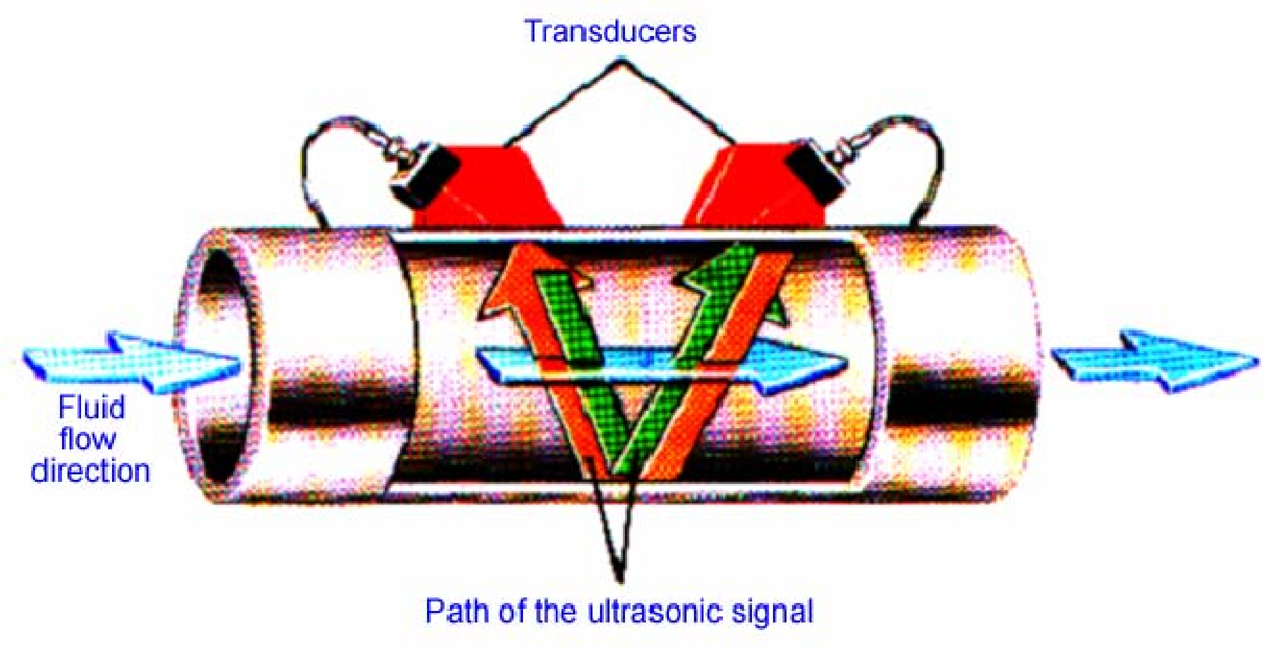
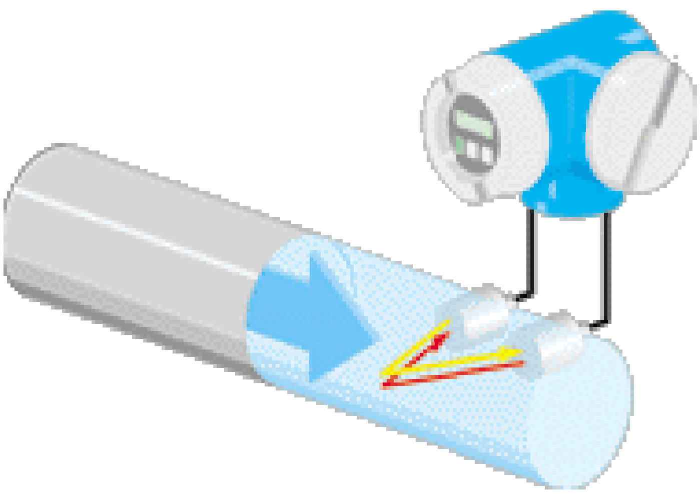


Figure 50: Ultrasonic flowmeter principle

Two sensors are installed on a pipe and simultaneously act as ultrasonic pulse transmitters and receivers. At zero flow, the two transmitters both receive the ultrasound waves at the same time, with a zero transit time.



When the fluid is in movement, the ultrasound waves do not reach the two sensors at the same time.

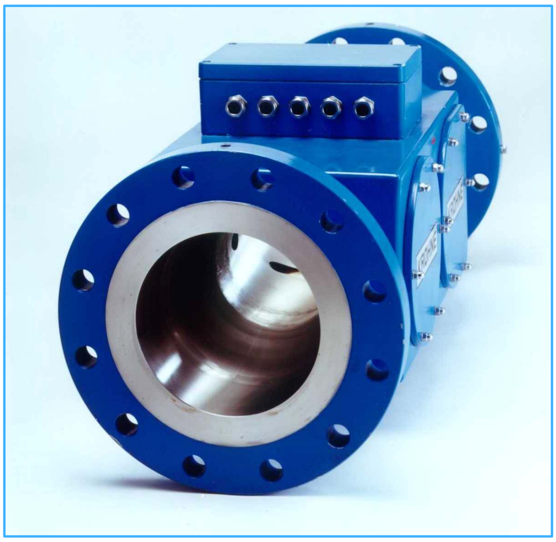
This measurement of the difference in transit time is directly proportional to the flow velocity and thus to the volumetric flow rate.

Figure 51: Ultrasonic flowmeter operating principle

4.7.1. Principle

We are also now seeing the development of ultrasonic flowmeters which may, in the future, be used alongside the "conventional" techniques (accuracy, high dynamics, no pressure drop).

Figure 52: Ultrasonic meter for liquids



Measuring the flow velocity by the transit time consists in measuring the difference in the time taken by an ultrasound wave to travel in the flow direction and in the reverse flow direction.

In the flow direction, the distance is travelled at a velocity equal to the sum of the velocity of sound and of the average flow velocity. In the reverse direction, the average flow velocity must be subtracted from the velocity of sound.

Figure 53: Ultrasonic flowmeter

4.7.2. Specifications

Fluids	"Clean" Liquids and Gases
Pressure	Up to 100 bars (transducers)
Temperature	-180 / +260 °C
Measurement range	10 to 20 (up to 100 in certain cases)
Response	Linear
Accuracy	± 0.25% (10:1) – liquid ± 0.5% (10:1) – gas
Connections	Flanges
Sizes	10 – 800 mm

- Advantages No moving parts – Bi-directional
- Disadvantages Straight lengths – Clean fluids

Figure 54: Examples of ultrasonic flowmeters

4.8. ULTRASONIC FLOWMETER – DOPPLER

4.8.1. Principle

Determining the velocity by Doppler effect consists in measuring the difference in the transmission and reception frequencies of an ultrasonic signal reflected by a "reflector".

The term "reflector" is used here because the aim is to "reflect" an ultrasonic wave back towards the transmission source. The motor car is the best known reflector, but for fluid flow velocity measurement applications, the gas bubbles in a liquid, liquid bubbles in a gas, or even solid particles in the flow allow this principle to be used to measure velocities.

4.8.2. Specifications

Fluids	Liquids or Gases with tracers
Pressure	Up to 70 bars (transducers)
Temperature	-180 / +260 °C
Measurement range	10 to 20
Response	Linear
Accuracy	± 2.0% FS (10:1)
Fixations	Clamp-on
Sizes	> 6 mm
Advantages	Installation under pressure
Disadvantages	Straight lengths – Tracers (mostly)

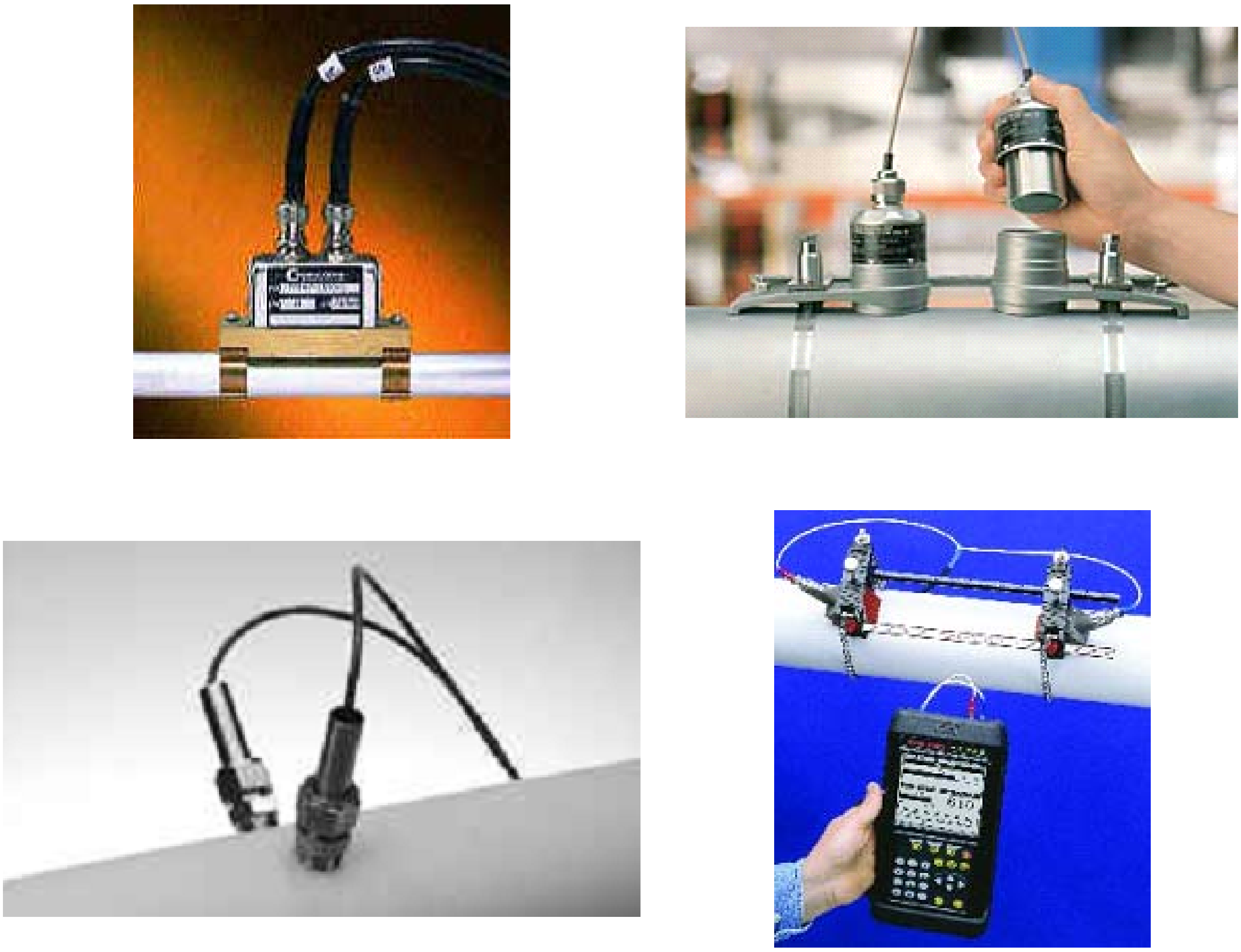


Figure 55: Examples of ultrasonic flowmeters – Doppler

4.9. CORIOLIS FLOWMETER

4.9.1. Coriolis forces

Coriolis forces appear in rotating systems if a fluid mass is translated towards the axis of rotation or towards its periphery. An exciter coil subjects the measuring tube to a straight oscillating movement around the rest axis.

When the fluid particles move at velocity V in the tube, they generate Coriolis forces which act on the two halves of the tube in opposite directions.

These forces are directly proportional to the mass flow rate and generate a distortion of the measuring tube. Upstream of the excitation system, the fluid particles are accelerated by the tube rotation. Downstream of the excitation system they are decelerated.

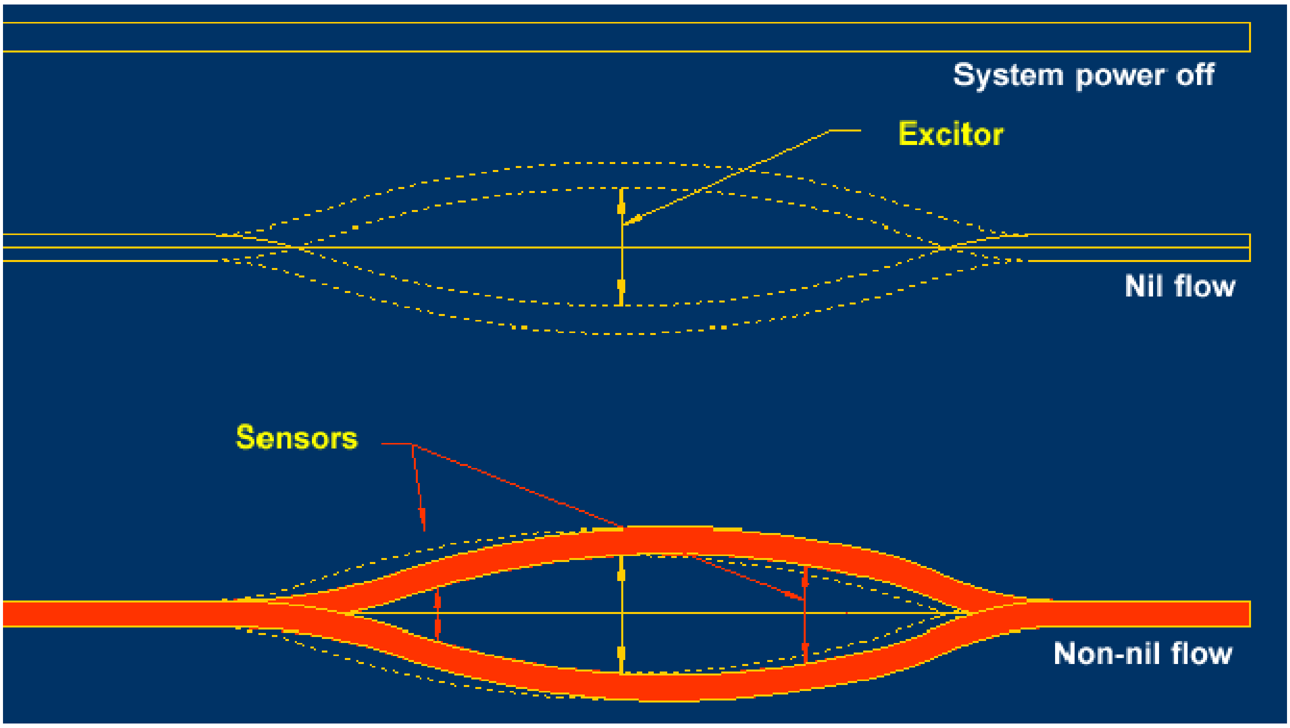
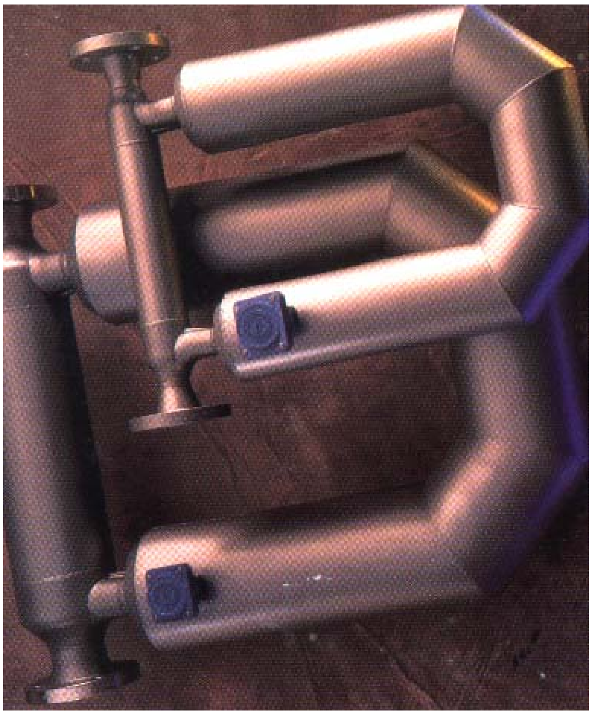


Figure 56: Coriolis flowmeter principle

4.9.2. Operation of the Coriolis mass flowmeters



If a moving mass undergoes an oscillation perpendicular to its direction of movement, a Coriolis force is generated, proportional to the mass flow.

Figure 57: Coriolis mass flowmeters

The Coriolis mass flowmeter has measuring tubes which oscillate to generate precisely this effect.

The Coriolis force is generated when a fluid (= mass) flows through these oscillating tubes. The inlet and outlet sensors record the phase shift resulting from the change in geometry of the oscillating tubes.

The processor analyses this data and uses it to calculate the mass flow rate.

The oscillation frequency of the measurement tubes directly represents the density of the fluid measured.

The measurement tube temperature is also recorded so as to compensate for the thermal influences.

This signal corresponds to the process temperature and can also be available as an output signal.

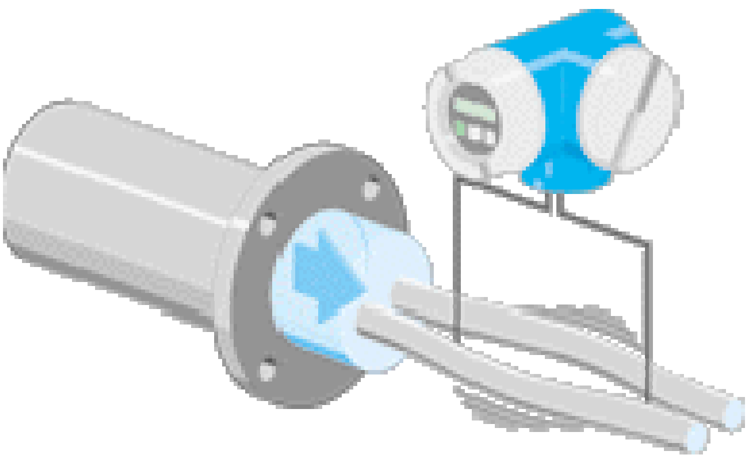


Figure 58: Coriolis mass flowmeter operating principle

4.9.3. Measurement principle

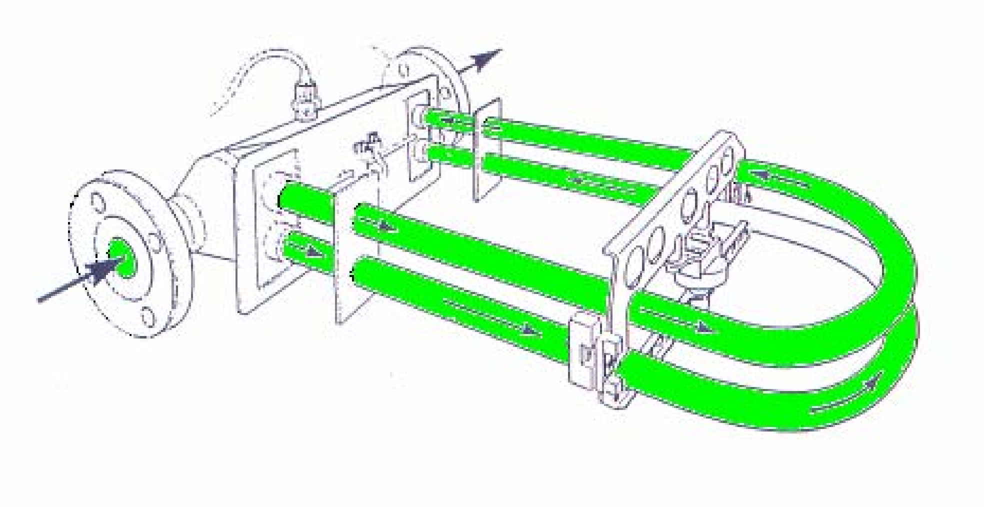


Figure 59: Coriolis mass flowmeters

4.9.3.1. Flow measurement

A fluid flowing through a vibrating tube generates reactive forces which twist the tube due to the Coriolis effect. These forces are directly proportional to the mass flow rate (See following figure).

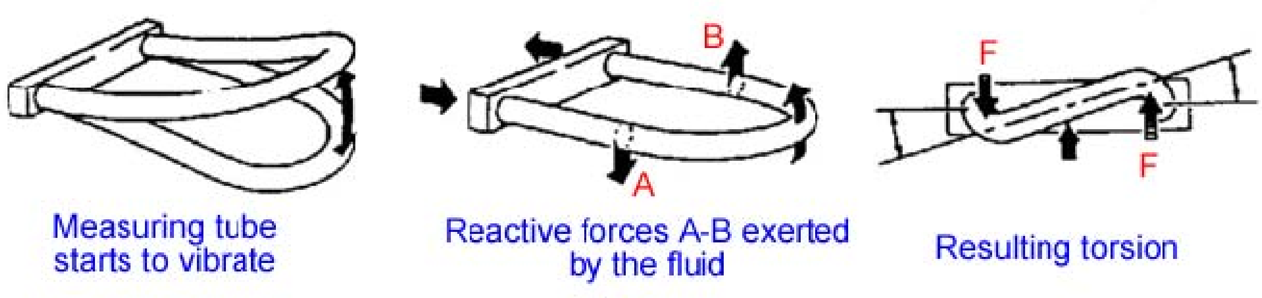


Figure 60: Coriolis flowmeter operating principle

4.9.3.2. Density measurement

The density of the fluid can be measured from the resonant frequency of the tube. If the fluid is a mixture of two components (oil + water), and if we know the density, we can determine the water/liquid and oil/liquid fractions.

4.9.4. Primary data

- Mass flow rate in kg/g or tonnes/hour.
- Density in kg/m^3.

4.9.5. Use of Coriolis mass flowmeters

4.9.5.1. Fluid

- Mass metering of hydrocarbon fluids and hydrocarbons + water.
- Stabilised or non-stabilised.
- This type of meter can be used with incipient gas.

4.9.5.2. Location

- At the test separator outlets.
- Export.
- Field metering.

4.9.6. Equipment

- The systems currently found in use on installations use essentially curved tubes.

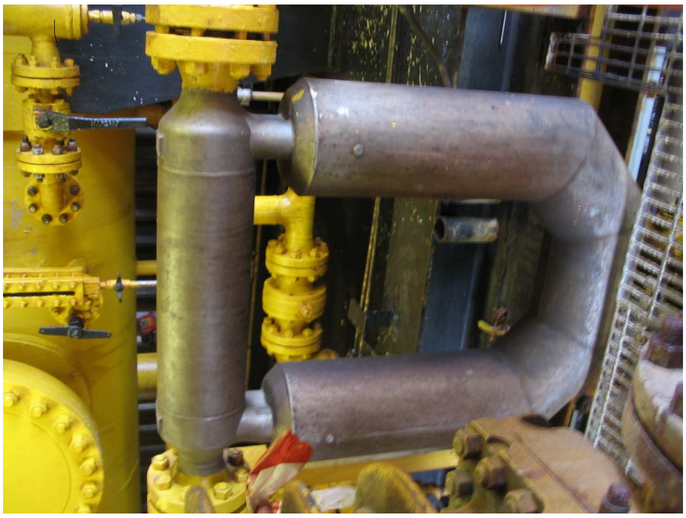


Figure 61: Coriolis mass flowmeter with curved tubes

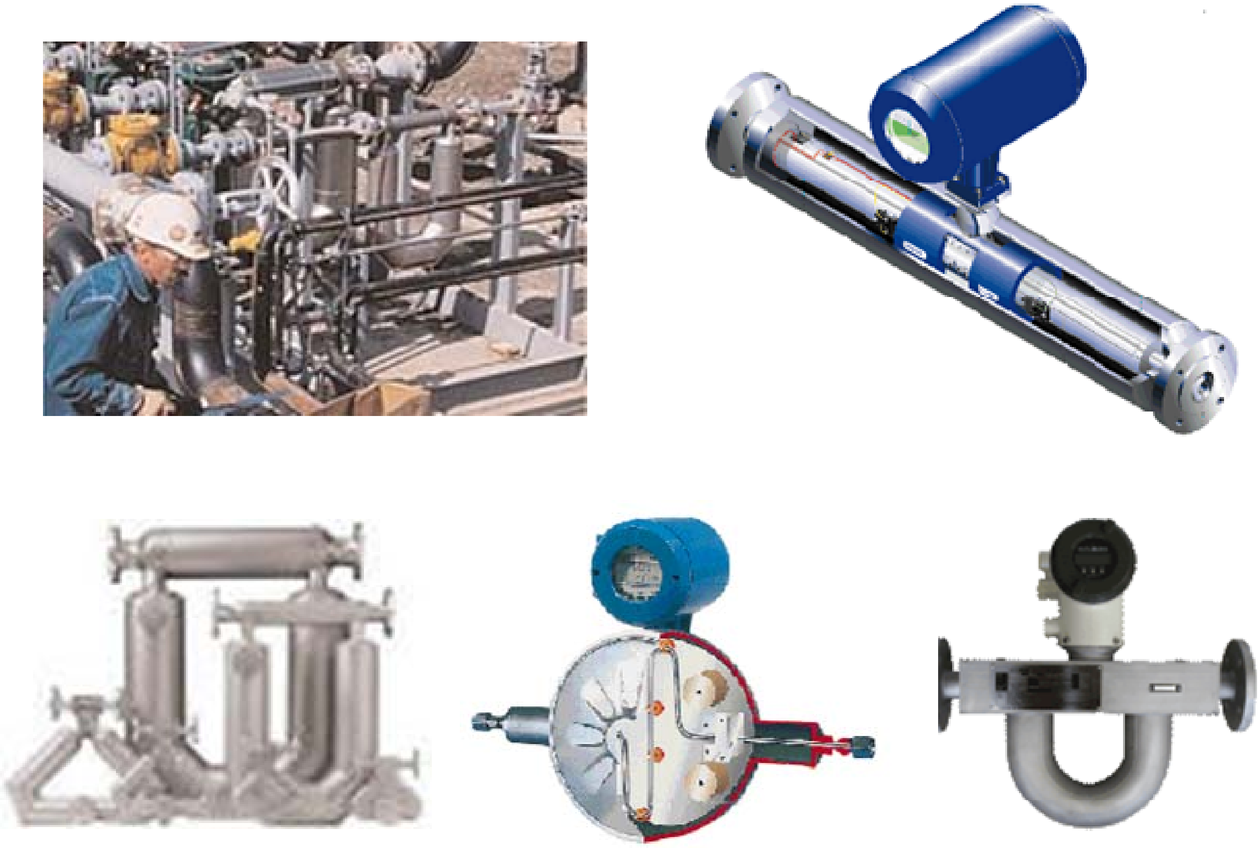


Figure 62: Examples of Coriolis flowmeters

4.9.7. Installation

4.9.7.1. General

In all cases they must be installed so that:

- the flowmeter can easily be removed and checked,
- there are no vibrations,
- the sensor is always full of liquid.

The recommended installation configurations are described in the Group's standards or the manufacturers' documentation and must be followed.

When the flowmeter is used at the test separator outlet, a backpressure must be provided to prevent degassing (hydrostatic). The flowmeter must be installed as close as possible to the separator outlet to minimise the pressure drop in the pipes and thus the degassing. It must be installed upstream of the control valves.

If the system introduces a pressure drop which adversely affects the test separator operation, the use of a pump may be necessary.

4.9.7.2. Mounting

Refer to the manufacturer documentation and to the company's standards for:

- the mechanical connections,
- the support system (use of Silentbloc chocks (see diagram)),
- the connections to the process.

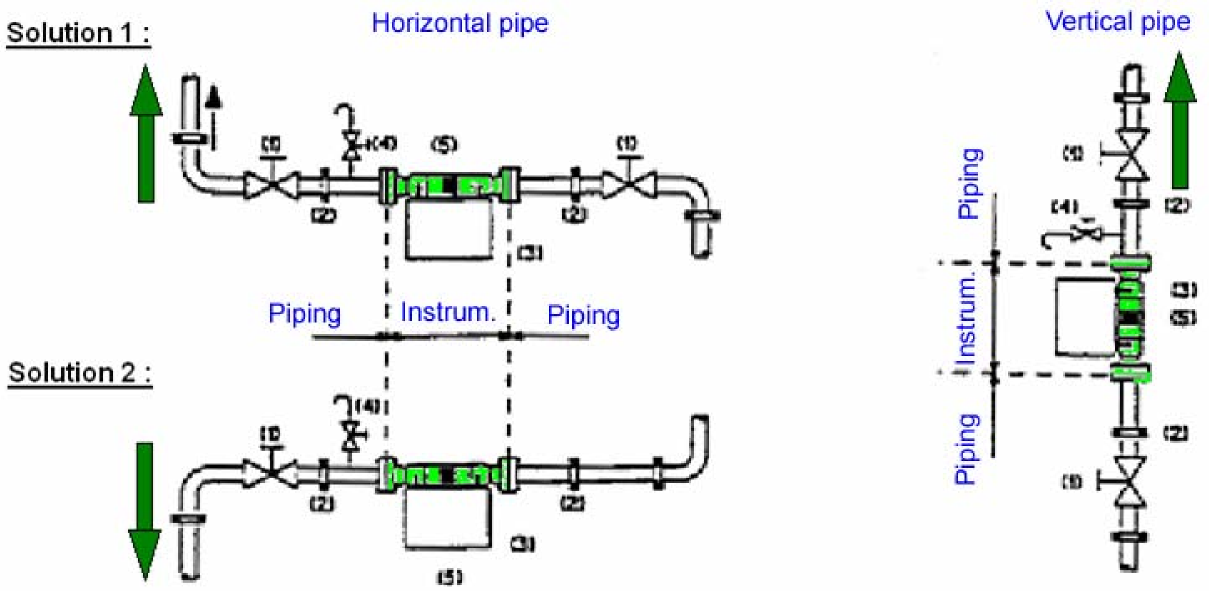


Figure 63: Installation of Coriolis flowmeters

Notes:

- Install a valve downstream of the sensor to check the zero. If the transmitter is installed at a high point, fit a valve upstream and a valve downstream.
- The piping upstream and downstream of the sensor must be fixed by clamps. If substantial vibrations is induced by the piping, use clamps with dampers (Silentbloc type) and secure the unit.
- The transmitter must be installed at least 2 metres away from equipment liable to produce high magnetic fields (motors, power supplies, etc.).

- Provide a bleed valve for putting the meter into service and zeroing.
- If production cannot be stopped to carry out the zeroing, configure the flowmeter with a bypass.

4.9.8. Specifications of Coriolis flowmeters

Fluids	Liquids and Gases
Pressure	Up to 200 bars
Temperature	Up to 200 °C
Measurement range	10 to 20
Response	Linear
Accuracy	± 0.25% (10:1)
Connections	Threaded / Flanges
Sizes	1.5 – 150 mm
Advantages	Direct mass – Difficult applications
Disadvantages	Pressure drop – Calibration

4.10. THERMAL FLOWMETER – HOT WIRE

4.10.1. Principle

This type of equipment measures the quantity of heat lost due to the fluid flow.

The probe (resistor, thermistor, thermocouple or film) is supplied with a constant electric power and the flow velocity is measured as a function of the probe cooling (Wheatstone or standard bridge circuit, etc.)

This type of equipment measures the resultant effect of the controlled heating of the flow between two temperature measurement points.

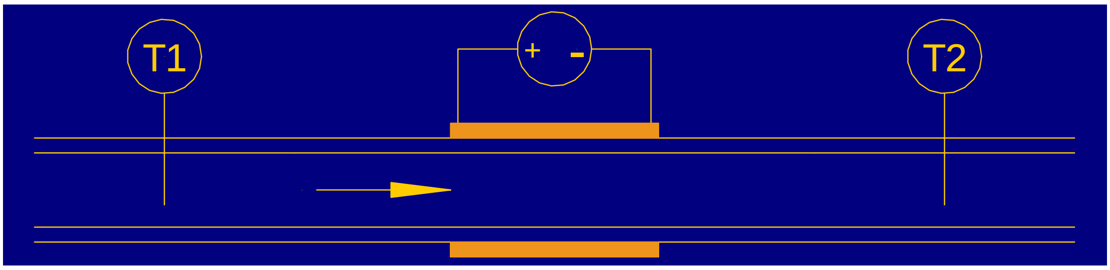


Figure 64: Thermal flowmeter principle (1)

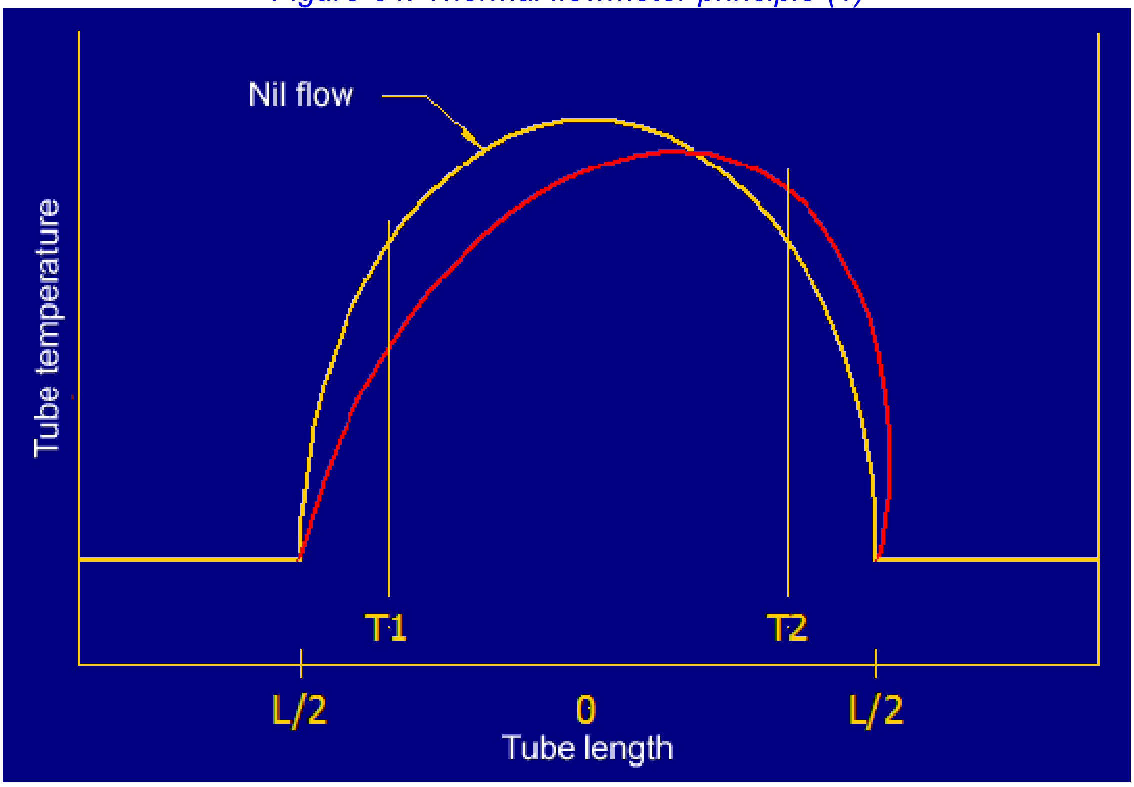


Figure 65: Thermal flowmeter principle (2)

4.10.2. Specifications

- Fluids Gas (Liquids)
- Pressure Greater than 35 bars
- Temperature Up to 100 °C
- Measuring range 20
- Response Exponential
- Accuracy ± 1.0% FS to 2.0 %
- Connections Threaded / Flanges / Insertion
- Sizes 3 – 250 mm
- Advantages Pressure drop – Low velocities (gas)
- Disadvantages Fragile – Sensitive to deposits

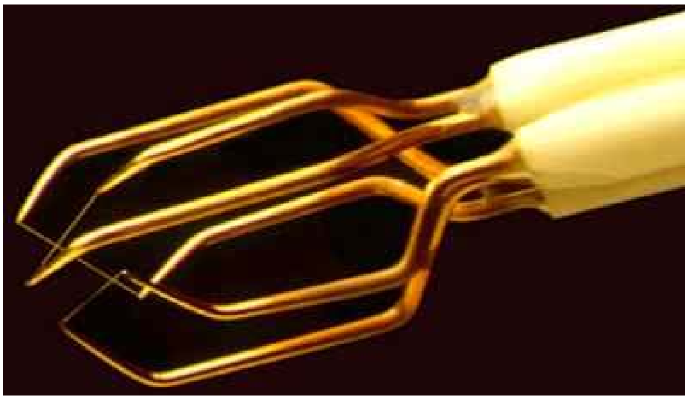


Figure 66: Examples of thermal flowmeters

4.11. MULTIPHASE METERING

4.11.1. Introduction

Multiphase metering was developed to measure the flow rates of each phase of the oil effluents in line, without prior separation.

This type of metering can also be used for in-line measurement of well productions, multiphase metering of field productions, and for allocation.

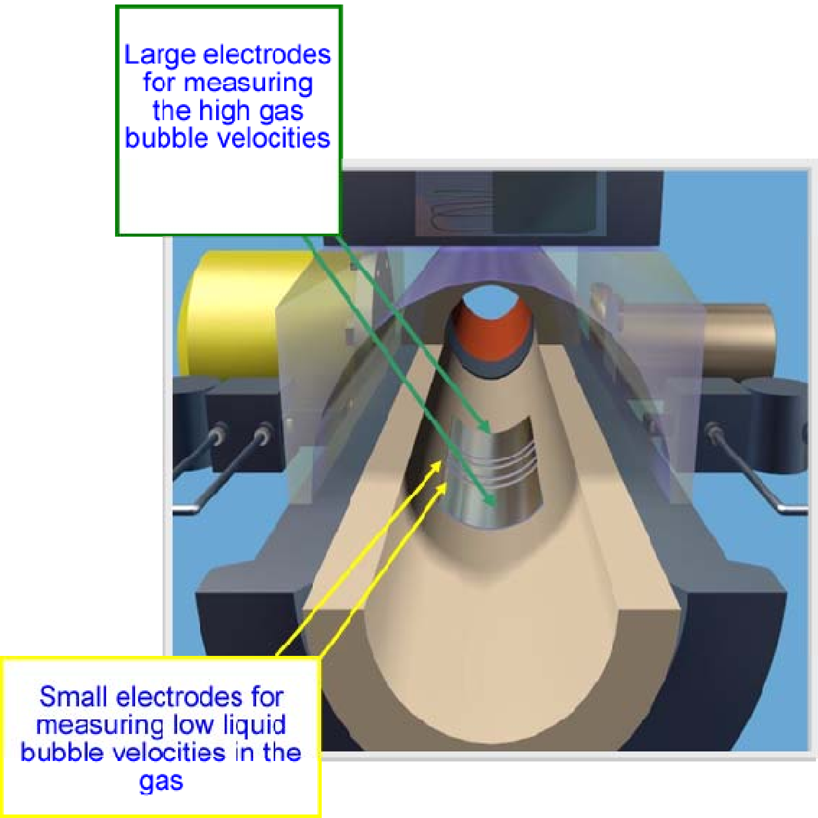


Figure 67: Example of a ROXAR multiphase meter (MPFM 1900 VI)

The industry makes a rather arbitrary distinction between multiphase meters and wet gas meters. The latter are for use in applications where the predominant phase is gas; they deliver the flow rate of the gas phase (gas corrected for the liquid effect) or, more generally, the flow rates of two phases (gas + liquid, or gas + water) or three phases.

Wet gas metering applies to the gas and condensate gas fields.

4.11.2. Multiphase flow

There are different types of flows depending on the surface velocities of the fluid in movement. These are shown in the following diagrams.

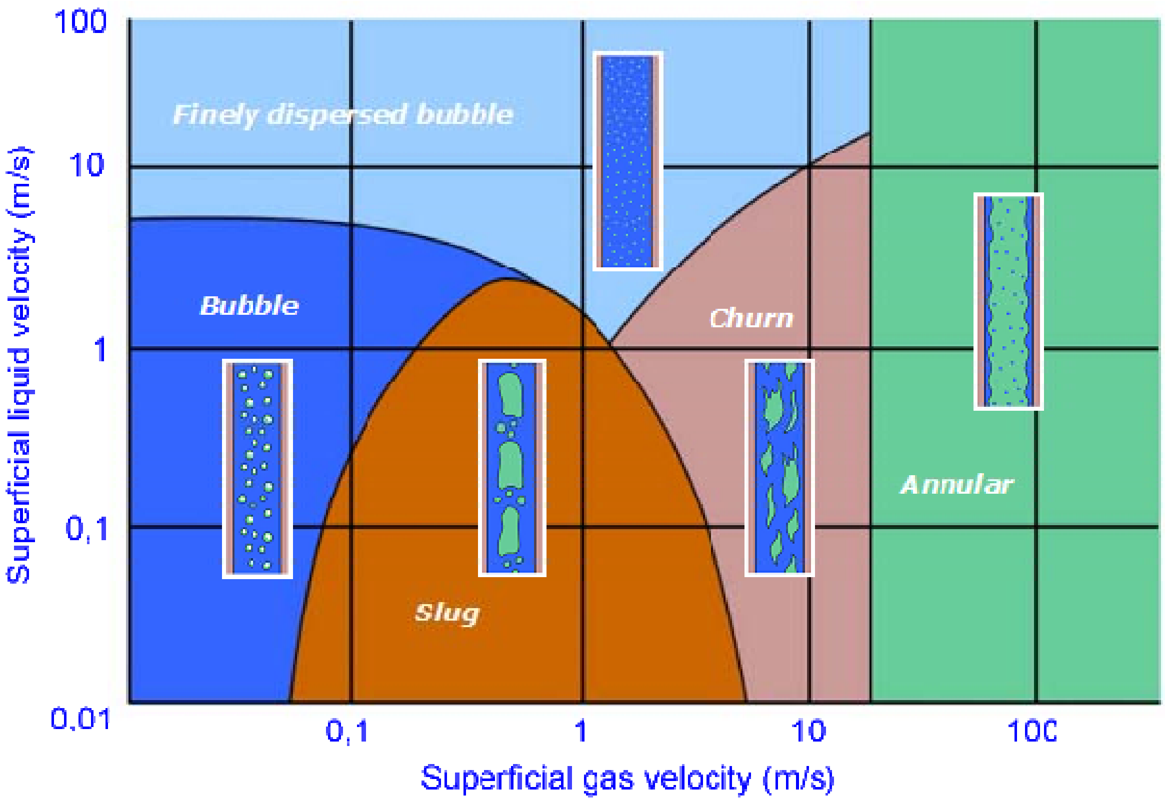


Figure 68: Types of flow according to the surface velocities (Liquid / Gas)

4.11.3. Scope of application of multiphase meters

- Well testing: Alternative to test separator
- Multiphase export measurements
- Allocation - marginal fields
- Subsea well metering
- Difficult cases: high viscosity, HP, HT
- Mobile well testing
- Diagnosis for well production optimisation

4.11.4. Data associated with fluid characterisation

It is important to give the manufacturer a maximum amount of information concerning the other characteristics of the fluids in contact with the MPFM (Multi Phase Flow Meter) internals to assess the potential risks to the MPFM in service, namely:

- Hydrates: send the hydrate formation graph.
- Emulsion: risk of formation of a stable emulsion in the measuring conditions (have bottle tests been carried out?)
- Waxes: do we know the risks of deposits in the metering conditions?
- Calcium carbonates: what are the risks associated with the produced water?
- Barium sulphate: concentration in the formation water and associated risks of scale formation?
- Asphaltenes: probability of deposits.
- Salts: probability of formation.
- Sand: risks associated with Venturi erosion?
- Chemicals: list of products which may come into contact with the MPFM internals => acids during well cleaning, muds, methanol, various inhibitors, bactericides, etc.

4.11.5. Examples of multiphase metering

4.11.5.1. Dual gamma Ofon

The Schlumberger / Framo technology combines the "flow rate and fraction measurement" functions in a single venturi tube (here on Ofon)

Figure 69: SCHLUMBERGER – FRAMO Vx TECHNOLOGY multiphase meter

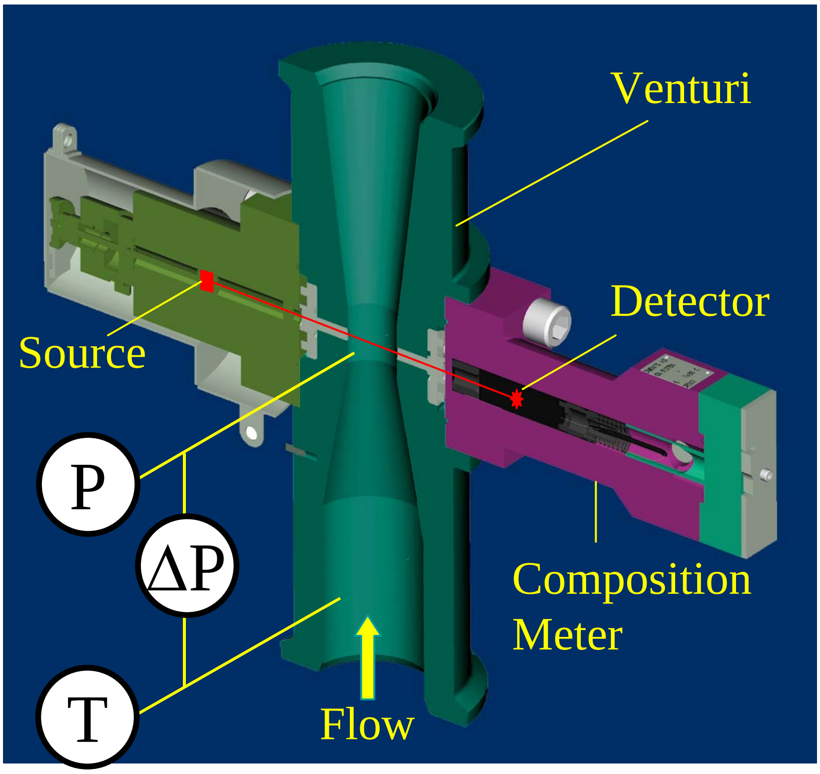


Figure 70: Exploded view of a SCHLUMBERGER – FRAMO Vx TECHNOLOGY multiphase meter

4.11.5.2. Gamma + electric (Northern sector in the Congo)

Six extremely compact MFI/Roxar meters are installed on 4 satellite fields (Tchibouela, Tchibeli, Kombi and Likalala. They are used in the gas fraction ranges (GVF), up to 90% for well tests and field metering.

Figure 71: Very compact multiphase meter on a satellite platform in the Congo

4.11.5.3. Sincor

Multiphase metering has established itself as the ideal well metering solution in this heavy crude development, where the test separator option has turned out to be costly and very difficult to use due to the rheology of the effluents.

The Roxar technology (gammametry + microwaves) was chosen after a qualification process, and 32 multiphase meters are now in operation.

The success of this operation is due to the high involvement of the various reservoir and production specialities during the different deployment phases: design, commissioning and production.

Figure 72: Installation of a skid-mounted meter on Sincor

4.11.6. Implementation

Multiphase metering technology is now field proven; it can be used in unmanned and subsea environments.

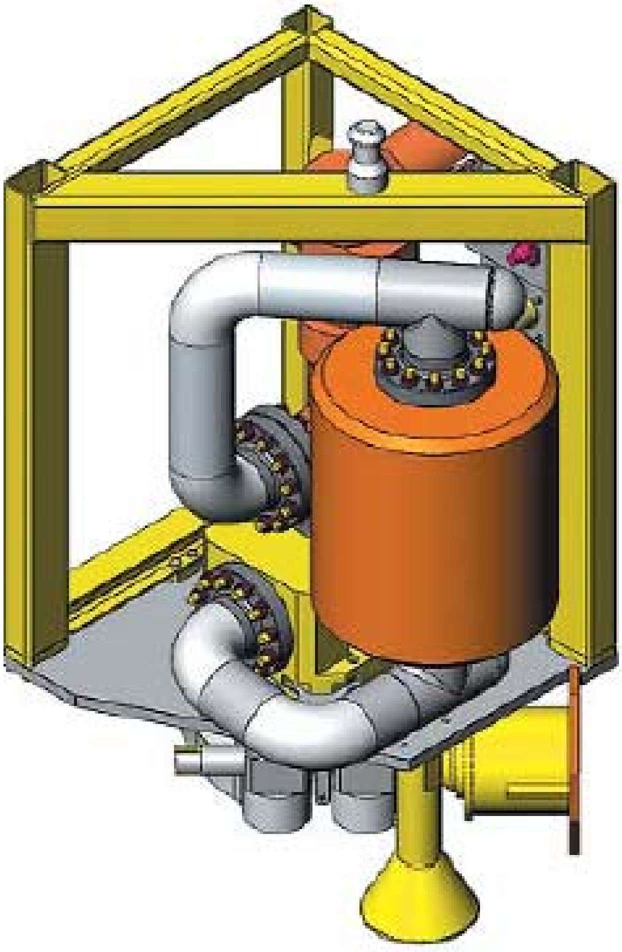


Figure 73: Multiphase meter for integration on a subsea wellhead (Dalia project)

Certain rules must, however, be respected in the field deployment phases: verify the operating range, choose the right dimensions, characterise the fluids to be metered (also valid for other technologies).

A PVT analysis (Pressure, Volume, Temperature) is recommended at design stage, and the fluid properties should be monitored throughout the life of the field (e.g. salinity, water density) if good accuracy is to be maintained.

The multiphase metering solution also has an indisputable advantage in terms of metering and well monitoring: streamlining of installations (no test line), continuous measurements for production monitoring, reduction in production losses due to switchover solutions, etc.

Other spin-off benefits are expected in terms of additional barrels of oil or m3 of gas thanks to the use of multiphase metering systems in the domain of flow and event monitoring, and their management (slugs, water inflows, clean up management, etc.).

4.12. ADVANTAGES AND DISADVANTAGES

4.12.1. Pressure differential orifices

Advantages

- Simple and robust.
- On-site calibration facilities.
- No bypass required if an orifice holder with chamber is used.
- Very good performance in the presence of gas.
- Relatively insensitive to viscosity variations.
- The P at the pressure differential device can be controlled.
- The plate can be checked and replaced (if no chamber in the orifice holder, the installation must be shut down).

Disadvantages

- Low Dynamics of scale (of the order of 3), due to the quadratic scale (but can be extended to 10 with electronic transmitters).
- Sensitive to pulsed flows.

<u>Note</u>: The residual delta P is 30% of the delta P at the pressure differential device**.**

4.12.2. Pitot and Annubar tubes

Advantages

- Low pressure drop.
- Easy to install.
- High dynamics.
- Low cost.

- No moving parts.

Disadvantages

- Local velocity measurement (except for Annubar).
- Low accuracy 5% (0.5 to 3% for Annubar).
- Limited to velocities > 3 m/s.

4.12.3. Turbine meters

Advantages

- Low pressure drop.

Disadvantages

- Overestimation of flow rate if gas present.
- Sensitive to erosion and abrasion; for charged fluids, particular attention must be given to the choice of internals; a filtration system is compulsory.
- Sensitive to the variations in the fluid characteristics (mainly viscosity). To partially overcome this problem we can, during initial calibration, obtain a flow curve allowing for different viscosities, within a limit of 80 cSt.
- Isolation and bypass valves required (start-up phases).
- Wear of internal moving parts.
- Sensitive to the flow profile.

4.12.4. Volumetric (positive displacement) meters

Advantages

- High dynamics, of the order of 20.
- Adapted to the measurement of viscous fluids (> 1,000 cSt).

Disadvantages

- Sensitive to erosion and abrasion (requires a filtration system).
- Overestimation of flow rate when gas present.
- Pressure drops not negligible.
- Heavy and bulky.
- Wear of internal moving parts.

4.12.5. Electromagnetic flowmeters

Advantages

- Non-intrusive, no pressure drop.
- High dynamics (> 10).

Disadvantages

- Quality of the internal coating to be selected according to the chemical and mechanical aggressiveness of the fluid.
- Can be used **only with conductive fluids** (unsuitable for oil metering).
- Fragile coatings.
- Installation precautions necessary / Presence of an instrument technician required.

4.12.6. Vortex flowmeters (vortex shedding)

Advantages

- High dynamics (10 to 30).
- No moving parts.
- Low intrusion.
- Low pressure drop.

Disadvantages

- Sensitive to the flow profile.
- Limited to low viscosity fluids, not to be used to measure crude.
- Sensitive to erosion and abrasion.
- Limited to condensates and water.

4.12.7. Coriolis flowmeters

Advantages

- Insensitive to the fluid characteristics and to the flow conditions.
- Good reliability.
- Accommodate the presence of gas in the upper part of the scale range.
- Can provide a density measurement independent of the flow measurement (but in this case gas is not accepted).
- The measurement can be inhibited during the passage of gas slugs.
- No straight lengths necessary.

Disadvantages

- Bulky and heavy.
- May be sensitive to certain vibration ranges.

- High pressure drops.
- Sensitive to the presence of gas in the lower part of the scale.
- Problem of stress corrosion must be taken into account when choosing the material.
- Deposits in the measuring tubes (hydrocarbons or minerals).
- Non-standard calibration of the flow meter part.
- High cost.

4.12.8. Summary of flowmeters for liquid hydrocarbons

Ultrasonic flowmeters, rotameters and electromagnetic flowmeters are not recommended.

Oil	Meters				
	Orifice	Turbine	Volumetric	Coriolis	Vortex
Normal dynamics	3 (expandable)	10	20	20	20
Accuracy in%	3 to 5	1 to 3	1 to 4	1	1 to 3
Presence of vibrations	*	*	*	*	*
Pulsed flows	*	0	*	**	0
Abrasive and erosive fluid	*	0	0	0	0
Viscosity variations	**	*	*	*	*
Low pressure drop required	*	**	*	0	**
Presence of free gas	**	*	*	*	*
Presence of water	**	*	*	**	**
Maintenance	**	*	*	**	**
Ease of calibration	**	*	*	*	*
Adaptation to fluid	**	*	*	*	Light condensates
Cost	**	*	*	*	**

0: Choice incompatible or not recommended **: Can be used with reservations* ***: Suitable*

Table 2: Summary of flowmeters for liquid hydrocarbons

4.13. EXERCISES

14. What was the first metering method used?

15. Turbine meters or volumetric meters are the most commonly used for sales metering of liquids.

❑ True

❑ False

16. The most commonly used principle for gas custody transfer metering is the orifice plate.

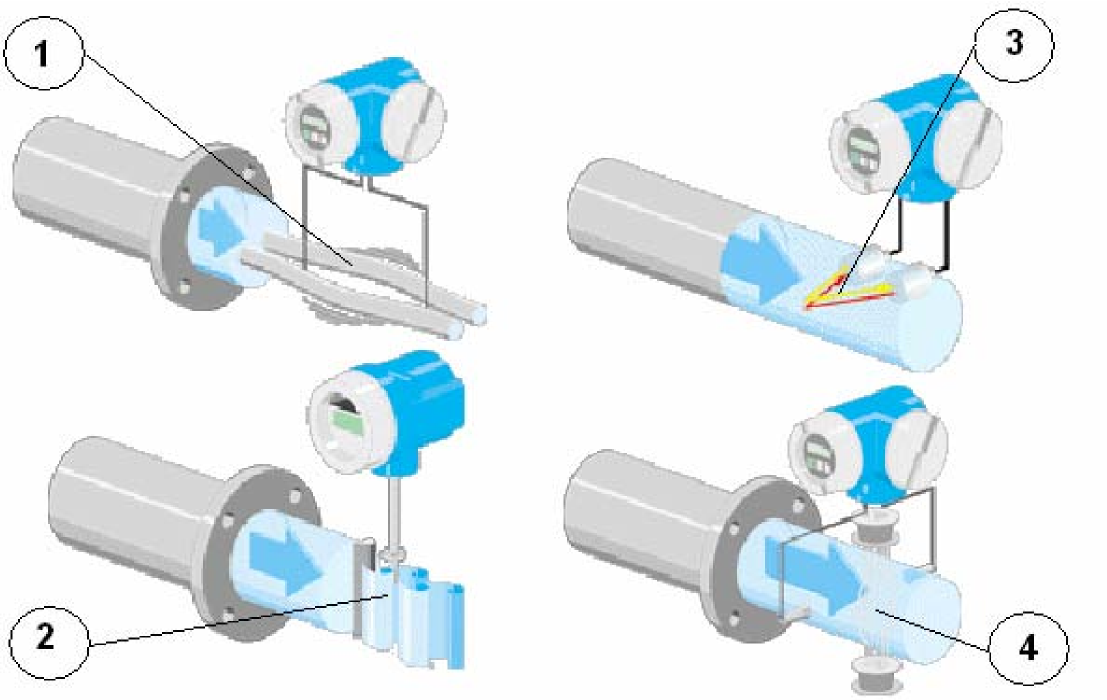
❑ True

❑ False

17. Give 3 different types of meters frequently used in technical metering of liquids:

18. Give 3 different types of meters frequently used in technical metering of gases:

19. What operating principle do these diagrams represent?



1 = ______________________________

2 = ______________________________

3 = ______________________________

4 = ______________________________

20. The principle of this equipment consists in measuring the differential pressure ΔP generated by a primary element (orifice plate, nozzle, venturi) placed in the pipe through which the fluid flows.

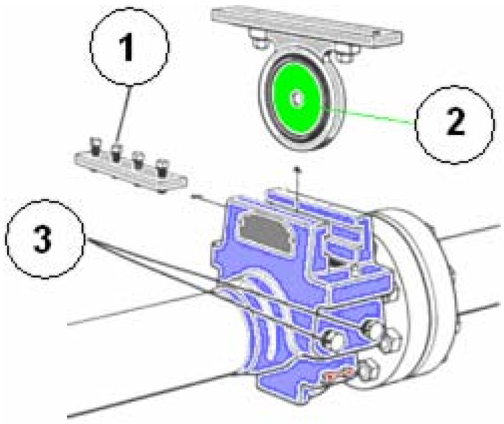
- ❑ Turbine
- ❑ Pressure differential device

21. Identify the basic components of this equipment:

……: Orifice plate

…...: Differential pressure taps

……: Locking plate



22. Turbine metering is used only for technical metering.

❑ True

❑ False

23. Turbines can achieve higher accuracies than orifices.

❑ True

❑ False

24. Fluid flow measurement using turbines consists in measuring the rotational speed of a rotor rotating freely in the fluid stream.

❑ True

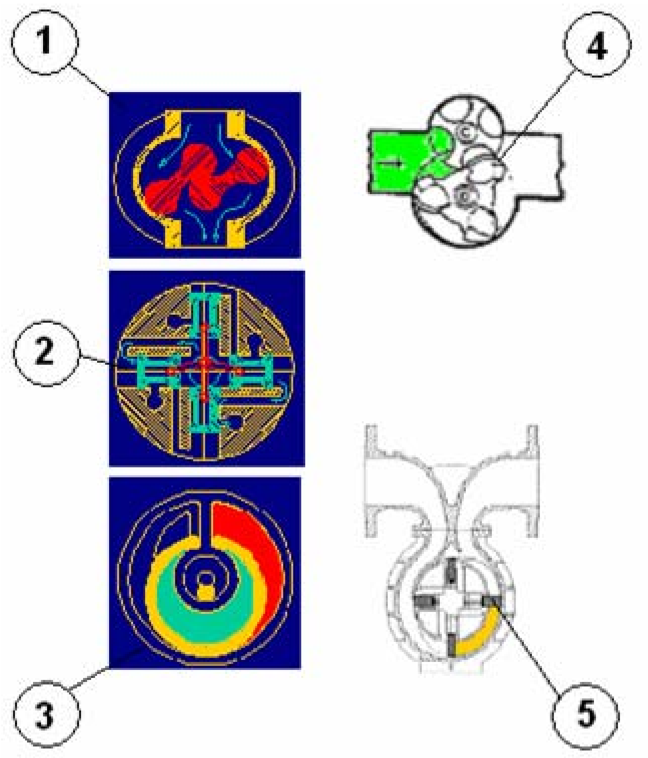
❑ False

25. Unlike all the other flow rate, mass or volume measurement systems, volumetric meters take direct measurements.

❑ True

❑ False

26. Identify the different types of volumetric meters:



……: Screw meter

……: Vane meter

……: Oscillating piston meter

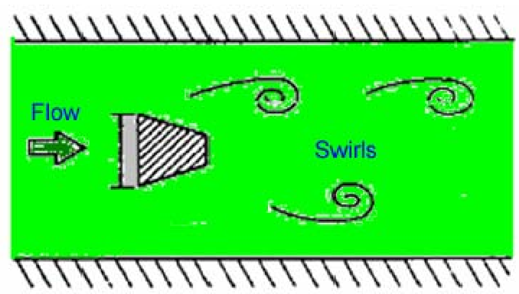
……: Reciprocating piston meter

……: Rotary piston meter

27. Electromagnetic flowmeters are used to meter:

- ❑ Oil
- ❑ Water
- ❑ Gas

28. What type of flowmeter is shown in the diagram:

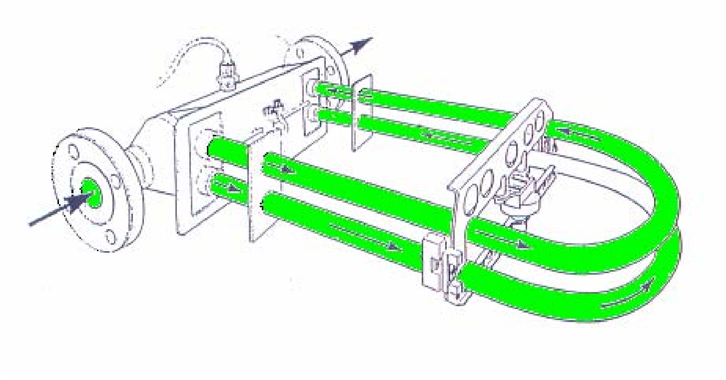


- ❑ Electromagnetic
- ❑ Vortex
- ❑ Turbine

29. Give the names of the two types of ultrasonic flowmeters.

30. What type of flowmeter is shown in the following diagram?

____



31. This type of equipment measures the amount of heat loss due to the fluid flow.

- ❑ Electromagnetic
- ❑ Vortex
- ❑ Turbine

32. Multiphase metering is used to measure the flow rates of each phase of the oil effluents in line without prior separation.

- ❑ True
- ❑ False

33. The prospective applications for the multiphase technology are:

- ❑ Deep subsea
- ❑ Heavy oil
- ❑ Water injection

34. Identify in this list the advantages of pressure differential devices:

- ❑ Simple and robust
- ❑ Low sensitivity to pulsed flows
- ❑ On-site calibration facilities
- ❑ Sensitive to viscosity variations
- ❑ Very good performance in the presence of gas

35. Identify the advantages of Pitot tubes in this list:

- ❑ Low pressure drop
- ❑ Low cost
- ❑ High accuracy

36. Identify the advantages of turbines in this list:

- ❑ Good to average accuracy
- ❑ Low sensitivity to the variations in the fluid characteristics
- ❑ Low wear of internal moving parts

37. Identify the advantages of the volumetric meters in this list:

- ❑ Adapted to the measurement of viscous fluids
- ❑ Do not require a filtration system
- ❑ Low pressure drops

38. Identify the advantages of electromagnetic flowmeters in this list:

- ❑ Good accuracy
- ❑ Can accommodate gas
- ❑ Adapted to oil metering

39. Identify the advantages of the vortex flowmeters in this list:

- ❑ Good accuracy
- ❑ Low pressure drop
- ❑ No moving parts

40. Identify the advantages of the Coriolis flowmeters in this list:

- ❑ Good accuracy
- ❑ Low pressure drop
- ❑ Good reliability
- ❑ Compact

5. METERING REPRESENTATION AND DATA

In this chapter we will describe how a METERING STATION is represented in the main documents available to the Operator:

- Process Fluid Diagram (PFD)
- Piping and Instrumentation Diagram (P&ID)

5.1. PROCESS FLUID DIAGRAM (PFD)

The PFD, issued during the project phase, shows in a simplified format the main process lines and vessels and their main operating parameters.

The example PFD (Process Flow Diagram) shows a Girassol UA312 metering station in its environment.

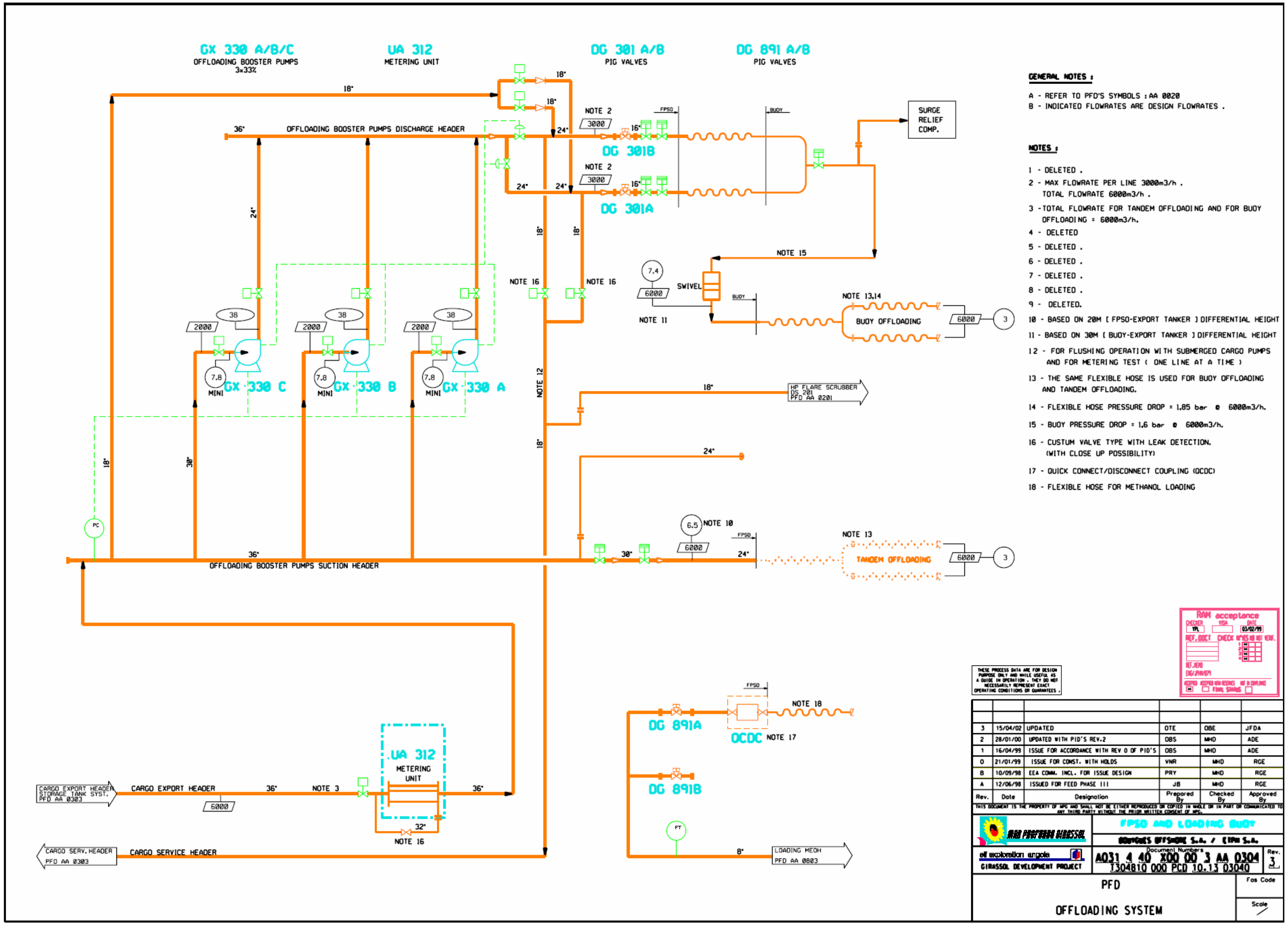


Figure 74: PFD of the Girassol UA312 metering station

5.2. PIPING & INSTRUMENTATION DIAGRAM (PID)

The P&ID, issued during the project phase, shows all the process lines and tanks and all their main operating parameters in a much more complete format than the PFD. It also includes the instrumentation, the safety devices and the start-up lines. It is a complete document.

The following example describes the same situation as the previous one but is represented in a much more detail.

This metering station consists of three meter runs and a calibration loop.

In particular, this metering loop will be described in the following chapter "Typical Example".

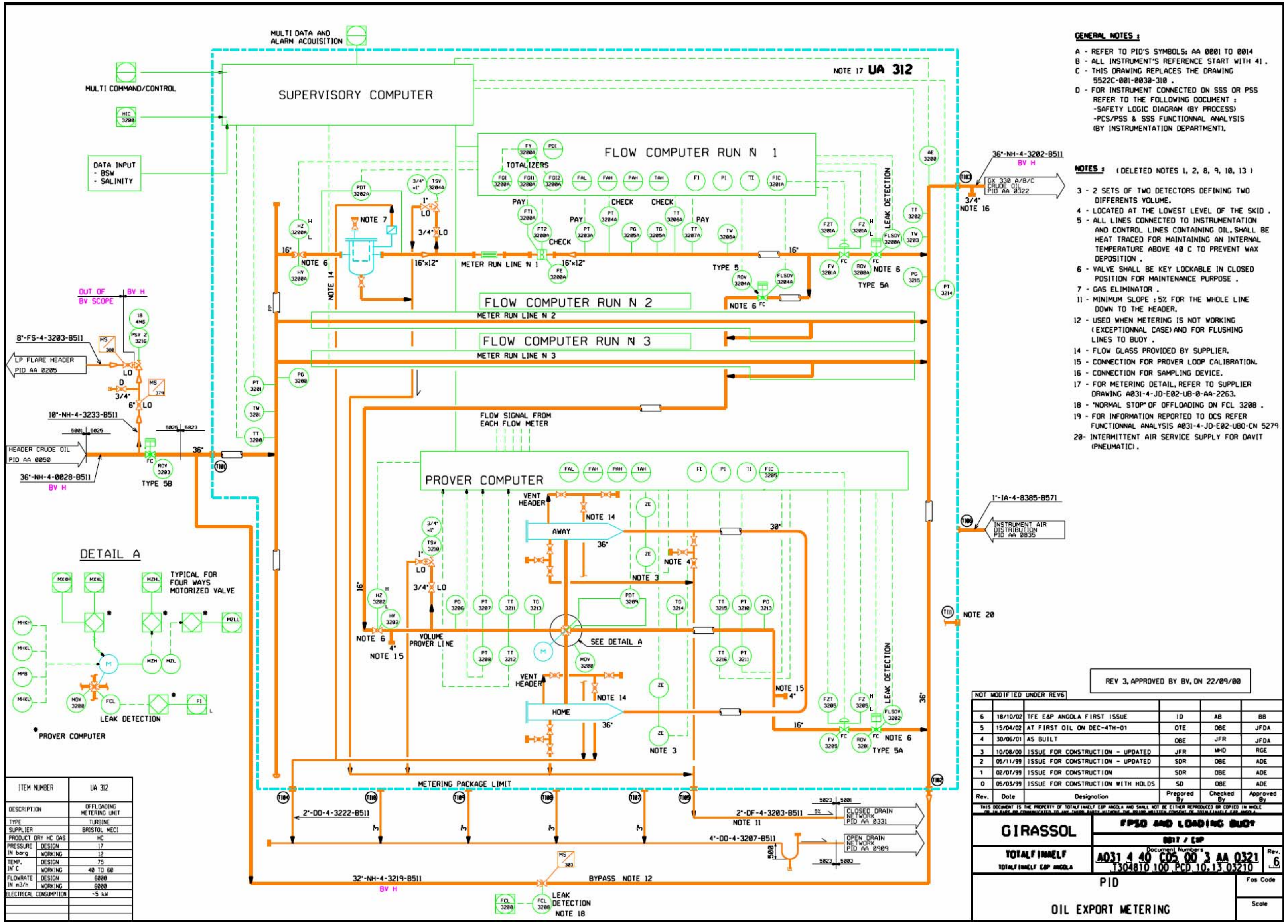


Figure 75: PFD of the Girassol UA312 metering station

5.3. TYPICAL EXAMPLE

The typical example examined here is the metering loop. It is used for sales metering. Sales metering requires optimum quality control due to the importance of the contractual and financial stakes involved.

5.3.1. Description of a typical metering station

A liquid metering station consists of:

- an inlet manifold,
- parallel meter runs with a volumetric or turbine meter, and a flow conditioner (when a turbine meter is used), pressure and temperature measurements, isolating valves and flow control,
- an output manifold,
- a calibration loop containing a section of prover pipe of known volume, delimited by one or two pairs of sphere passage detectors and a sphere launch trap. The fluid is routed by one or more valves. (4-way for a bi-directional loop),
- one or more metering computers.

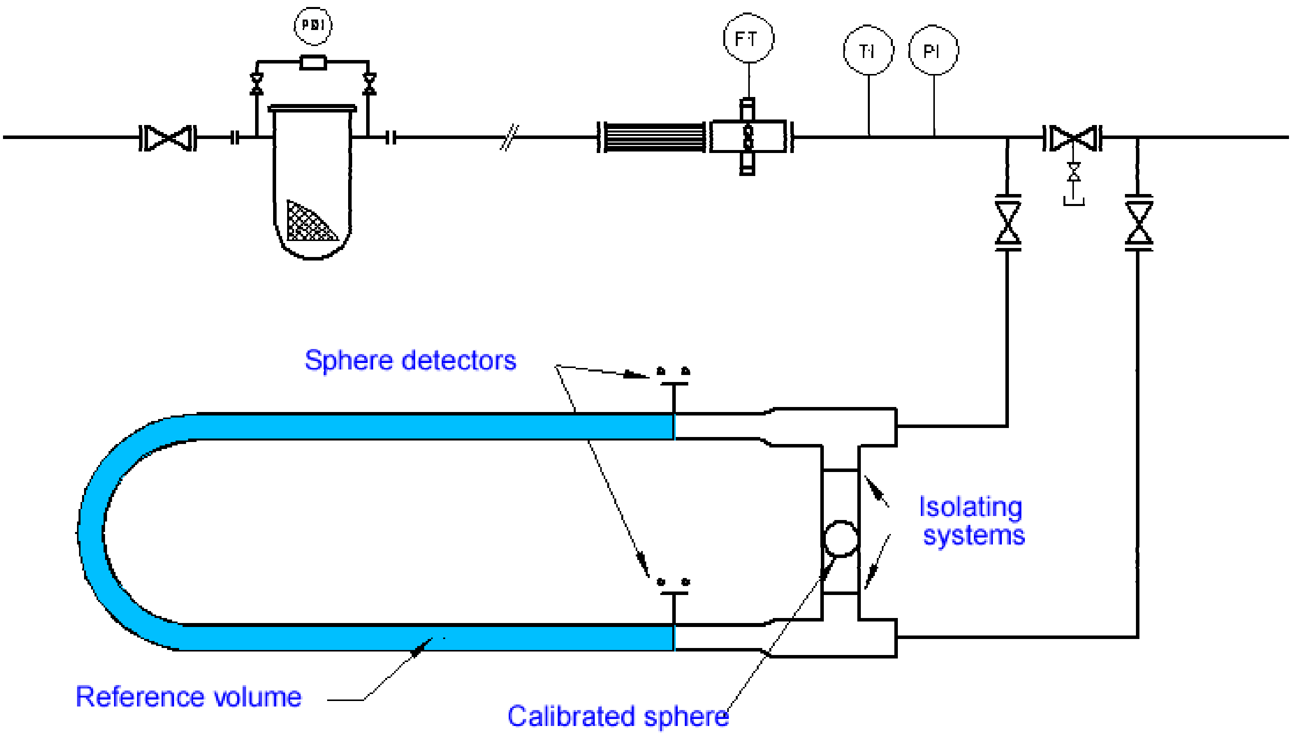


Figure 76: Calibration loop

5.3.2. Description of the Girassol UA 312 metering loop

The UA 312 metering loop, represented in the previous PFD and PID, is used to meter the oil exported to the buoy or offloaded in tandem. The metering station consists of three meter runs, each of 2,000 m3/h nominal (the maximum flow rate per metering line is 2,200 m3/h) and of an automatic calibration run. (See following diagram)

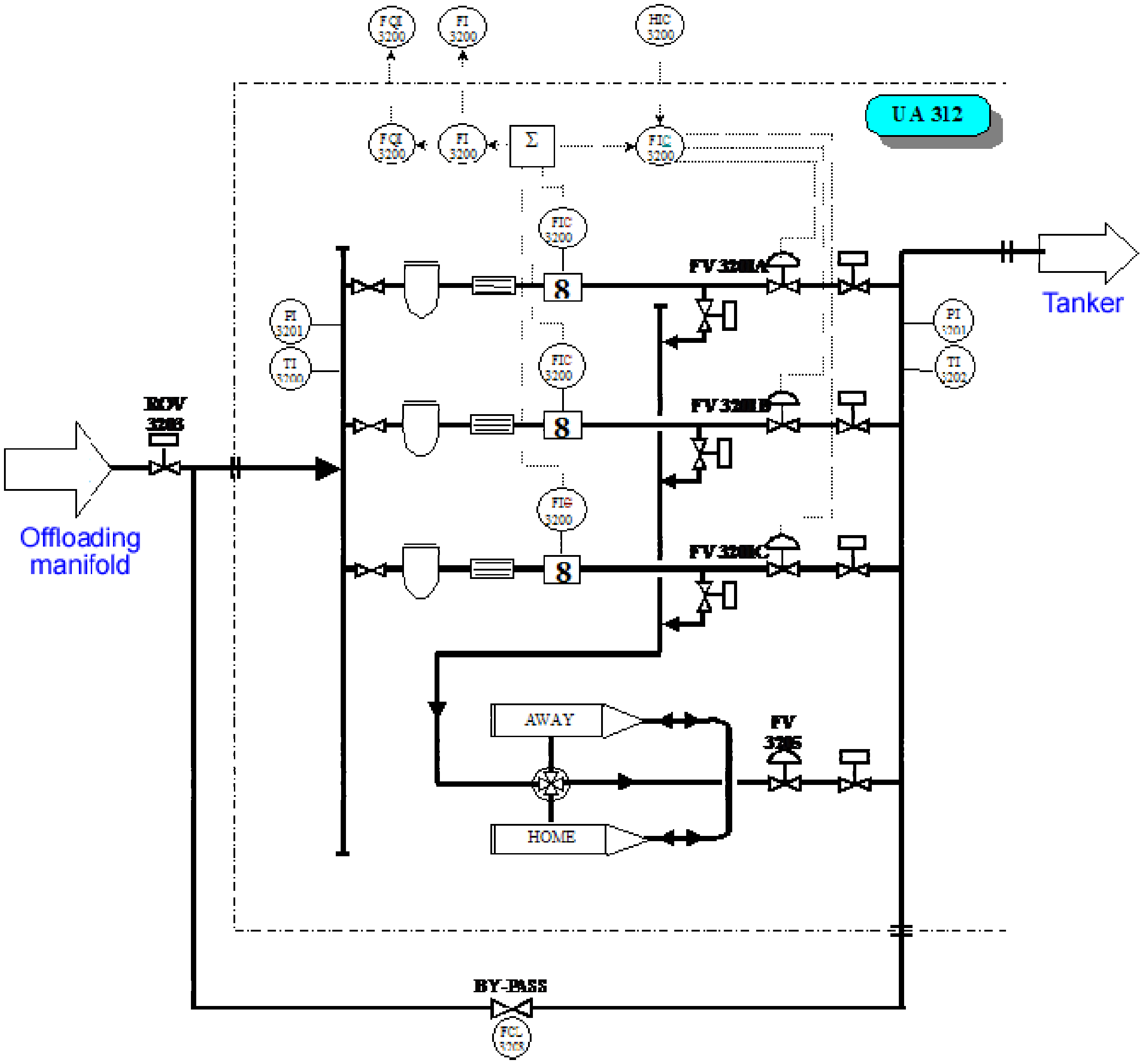


Figure 77: Girassol metering station

A minimum export flow rate of 1,500 m3/h must be reached for the sampling run to operate.

Each meter run mainly comprises a filter, a flow conditioner, a turbine to measure the stabilised oil passing through the branch, a flow control valve and a motorised ROV. Each meter run also has a connection equipped with a motorised ROV for connection to the automatic calibration line.

The metering station is fed by the export manifold (upstream line). Downstream, at the meter station outlet, the oil is sent into a manifold common to the export booster pumps (suction side).

The metering station pressure drop is 1.4 bar @ 6 000 m3/h.

For offloading in tandem, the oil is sent via this manifold directly to the offloading tanker without passing through export booster pumps.

A bypass line has been provided so that the export operation can still go ahead if the metering station is unavailable. The exported stabilised oil is then measured by the difference in level in the storage tanks. This line is equipped with a fiscal manual block valve with leak detection. This line's takeoff is located upstream of the metering station on the export manifold and uses the common outlet line of the metering station's meter runs as downstream line (inside the station).

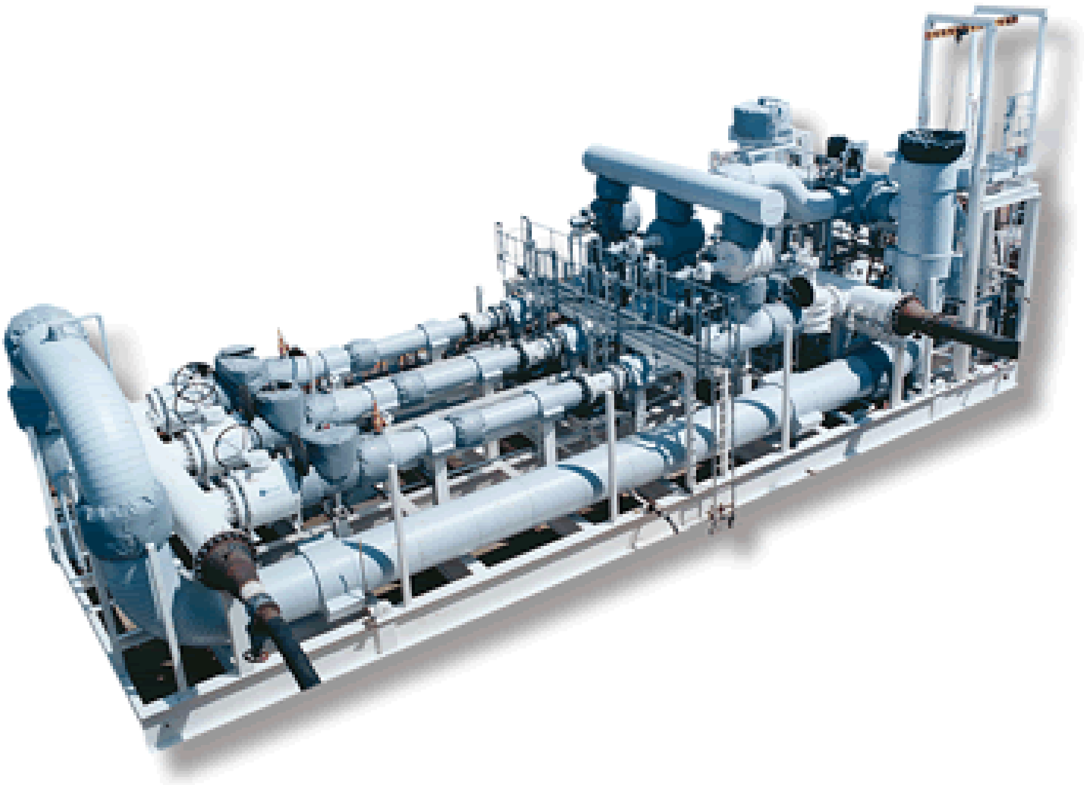


Figure 78: Metering station

5.3.3. Description of a calibration loop

5.3.3.1. Provers

Principles

There are two types of prover:

- **Uni-directional prover**
  There are two types of uni-directional provers: manual return pipes (basic shape) or automatic return pipes (endless loop).

- **bi-directional prover** (see diagram in Appendix)
  The flow direction of the effluent and of sphere travel in the calibration loop is reversed by means of a 4-way diverter valve.
  For this type of tube, each meter calibration consists of a return trip (out and back) by the sphere.

Both types of prover are designed so that the totality of the liquid passing through the meter to be calibrated also passes through the prover.

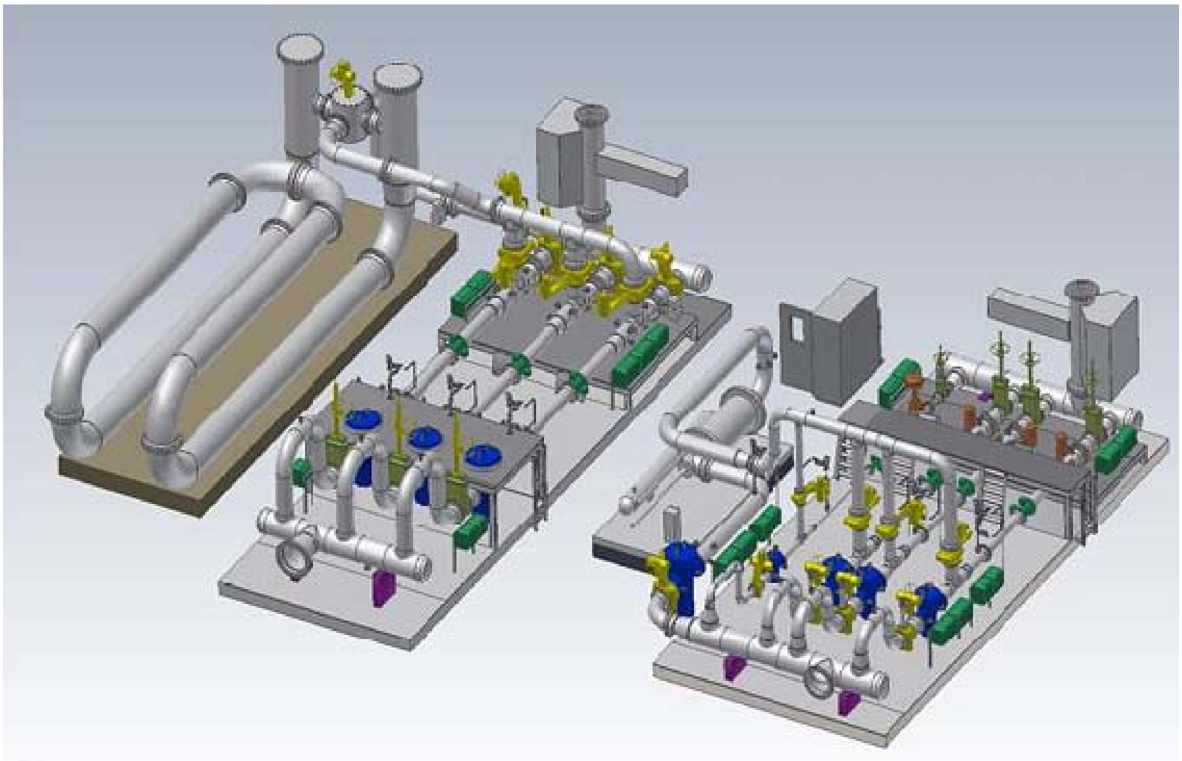


Figure 79: Different calibration tubes on metering stations

Function and requirements

The provers are used as a reference volume to calibrate the meters of the custody transfer meter stations.

The design and operating procedure of the provers must reach the accuracy levels defined by the metrological specifications for metering.

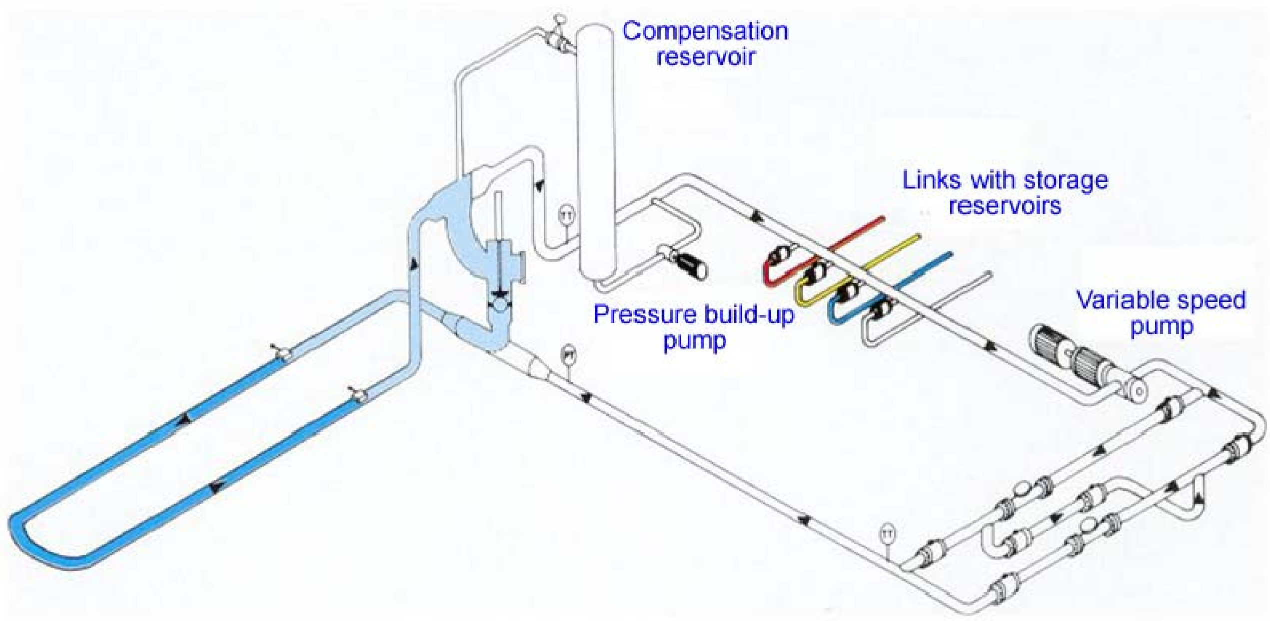


Figure 80: Example of a calibration loop diagram

<u>Description of the above diagram:</u>

The method used is direct comparison of the volumes by means of provers. This is a method standardised internationally by International Standardisation Organisation (ISO) under the reference 7278.

The operating conditions (configuration, flow rate, viscosity) are reproduced in a closed circuit and the volume indicated by the computer is compared with the known volume of the prover. This is represented by the path (shown in darker blue) of a sphere travelling between 2 passage detectors, in a section of calibrated pipe of the “calibrated volume”, traceable to the national reference measurement standards system.

5.3.3.2. Loop calibration principle

Aim

The aim of the calibration is to determine the volume(s) located between two sphere detector switches. The calibration is performed by precisely measuring the displacement of a volume of liquid in a calibrated section of pipe by using a slightly over-inflated sphere (diameter increased by 2 to 4%).

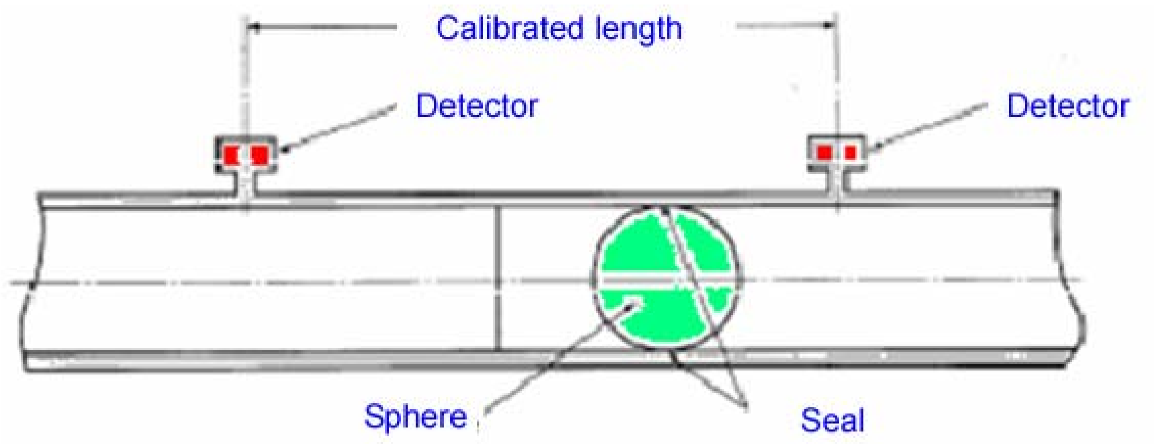


Figure 81: Displacement of the sphere

Initial calibration

The standard volume is originally determined at the reference pressure and temperature conditions. It receives a certificate which must be accompanied by the metrological characteristics of the reference elements (gauges, etc.).

On-site calibration

The purpose of this is to measure the reference volume on site to make sure that the volume remains constant, to compensate any drift and to detect the causes of variations. This operation must also allow any faulty elements to be replaced (e.g. passage detectors).

The value of the measured volume must be associated with an uncertainty;

It is essential to establish meter calibration reports for these operations so as to keep a clear historical record of their reliability.

5.3.3.3. Repeatability versus accuracy

The various standards give repeatability as a calibration acceptance criterion.

Bear in mind that good repeatability is not enough to guarantee the calibration "accuracy"; systematic errors must be eliminated (bias errors) (e.g. reference gauge volume error).

5.3.3.4. Usable methods

Two calibration methods are mainly used:

- **Master meter method**

  When the sphere moves, a high accuracy master meter (good linearity and proven repeatability) acts as an intermediate transfer means between the pipe to be calibrated and a reference gauge.

  The use of a standard volume calibrated by Compact Prover gravimetry eliminates the need for intermediate standard tanks. The reference Compact Prover is factory-calibrated before and after the operation and not on site.

- **Water draw method**

  This method consists of filling a precise reference gauge as many times as necessary to obtain the volume of the loop to be calibrated. It is used less on site as it may involve extensive handling constraints for the gauges (number of fills) for high volume pipes. It is the method often used for the initial factory calibrations.

5.3.3.5. Critical points during calibration

- **Leaks**

  The sphere launch traps, the flow reversal systems and each valve must be perfectly positioned and sealed when the sphere passes between the detectors.

  During calibration, it is essential the totality of the effluent passing through the meter also passes through the metering loop. Therefore the isolating valves, four-way valves and bleed valves must be perfectly sealed since each leak is a source of errors.

  The spaces between the valve seal seats must be connected to pressure detectors and small bleed valves to check their integrity (to be checked each time a valve is closed).

- **Impacts**

At the nominal flow rate, the sphere must stop smoothly (without impacts) at the end of its travel.

- **Integrity, deposits and internal condition of the prover**
The prover internals must be verified to ensure they are perfectly uniform.

They must be checked to see if any deposits are present. An internal inspection may be necessary.

- **Cavitation and degassing**.

In the normal flow rate, pressure and temperature conditions, there must be no risk of cavitation in the pipe or through the valves with the effluent used.

Drawing fluid from a tank in which the level is low can generate a vortex effect causing carry-over of air or gas in the measured liquid. A vortex breaker must be installed in the tanks and a gas eliminator upstream of the meter.

- **Flow rate stability**

The effect of flow rate variation on the metering accuracy can be ± 0.1% for a variation of 10% in the flow rate.

The measurement performances depend on the stability of the flow rate during calibration and on maintaining the nominal flow rate.

The flow conditions must be stable upstream and downstream of a turbine. For example, there must be no valves or restrictions.

- **Effluent quality**

The correction factors depend on the density of the effluent used.
An error of 0.1% when determining the density produces an error of 0.001% when determining the correction factors.

The liquid's vapour pressure must be less than the pressure in the meter or in the calibration loop (downstream pressure must be checked).

- **Temperature stability**

The order of magnitude of the volume corrections to be made for the temperature variations is ± 0.1% per degree.

For better results, the calibration and metering temperatures must be stabilised. It must be possible to detect and record the temperature variations during calibration if precise results are to be obtained. This should be carried out at night in countries with a high daily temperature variation.

The thermometers used must be "master" class i.e. ± 0.1°C.

- **Pressure stability**

The order of magnitude of the volume corrections to be made for the pressure variations must be +/- 0.01% per bar.

The pressure measurement apparatus must be able to measure pressures with an uncertainty of ± 0.5 bar up to 25 bars and of ± 1% for the higher pressures.

- **Effect of wear, damage and deposits in the meter or straight sections.**

In use, the meter correction factors gradually change. The meters must be regularly cleaned and calibrated.

Turbine meters are particularly sensitive to organic deposits.

Similarly, the fouling of the internals modifies the velocity of the liquid in the meter and generates measurement error. The solid deposits must be removed from the effluent by filtration upstream of the meter.

The temperature variations have an effect on a volumetric meter's mechanical clearances (just as much as the fluid viscosity).

- **Integrity of instrumentation and electronic equipment**

All the loop equipment, such as sphere detectors, contactors, transmitters and recorders must have been tested and adjusted.

- **Master meter condition**

The master meters must also have been checked.
A meter can miss counting pulses generated. In all cases, the reading will be low. Metering which is too low is often caused by a sensitivity setting which is too low or an electrical fault that develops.

A meter can also pick up signals from an outside source and treat them as pulses. The metering will be high (electric power source, welding equipment, radio transmitter, etc.). These signals are intermittent and difficult to detect.

- **Sphere/prover sealing**

The longer the sphere travel time between the detectors the greater will be the effect of a leak around the circumference of the sphere when determining the volume of the loop.

For example, it may be 40 min. during calibration instead of 30 seconds during loading, i.e. a ratio of 100.

These leaks can be reduced by increasing the nominal inflation of the sphere. In principle, the sphere must be inflated so that its minimum diameter is slightly greater than the internal diameter of the prover.

The purpose is to create a seal without excessive friction. This is generally achieved by inflating the sphere to a diameter 2% greater than that of the prover.

Bear in mind that the greater the diameter of the sphere the higher the inflation needed. The inflation limit corresponds to a repeatability with less than 0.02% difference between the volume measurements of the different calibration passes.

5.4. SIZING

5.4.1. Pressure differential systems

These systems are sized taking into account:

- maximum and minimum flow rate,
- fluid viscosity,
- pipe diameter,
- density,
- max. residual Δp,
- acceptable straight lengths.

Sizing consists in defining the primary component (orifice) and the secondary instrumentation (Δp transmitter) for the fluid.

5.4.2. Turbines

The parameters to be taken into account when sizing the turbines are:

- minimum and maximum viscosities,
- admissible pressure drop,
- upstream and downstream pipe diameters,
- space available for the necessary straight lengths,
- flow rate ranges to be covered,
- liquid bubble point and (where applicable) the presence of gas or solid particles,
- excess flow rates, where applicable (which may deteriorate the turbine mechanical parts).

Sizing must allow the following to be defined:

- the type of turbine to be used and the number of runs,
- the necessity to install filters or backpressure devices,

- the flow conditioners or flow conditioners,
- the associated measurements to be planned (temperature, pressure, viscosity, etc.) and their frequency.

5.4.3. Electromagnetic flowmeters

- The suitable nominal diameter is determined by choosing a flow velocity of between 0.3-0.5 m/s and 10 m/s. A high velocity (> 2 m/s) must be used for fluids that tend to form deposits.
- We must check that the materials are chosen for the pressure and temperature conditions and that the conductivity is greater than 5 μs/cm.

5.4.4. Vortex flowmeters

The following information must be supplied for liquid metering:

- maximum and minimum flow rates,
- meter run pressure and temperature,
- density and viscosity for the application

for use in selecting the inside diameter of the flowmeter to be used.

It will be chosen to have high flow rate and velocity range values.

The following data will also be needed:

- operating dynamics in the design conditions (max. and min. flow rates),
- operating domain according to the viscosity,
- K-factor (number of pulses per unit of flow rate),
- maximum and minimum velocities,
- pressure drop.

The following information must be supplied for gas metering:

- the maximum flow rate,
- the meter run pressure and temperature (min., normal, max.),
- the density in the reference conditions,
- the compressibility factor,
- the viscosity (for liquids).

These data re used to select:

- the meter diameter,

and to calculate:

- the minimum flow rates measurable,
- the dynamics in the design conditions,
- the pressure drop,
- the K factor (number of pulses per unit of flow rate),
- the maximum and minimum velocities.

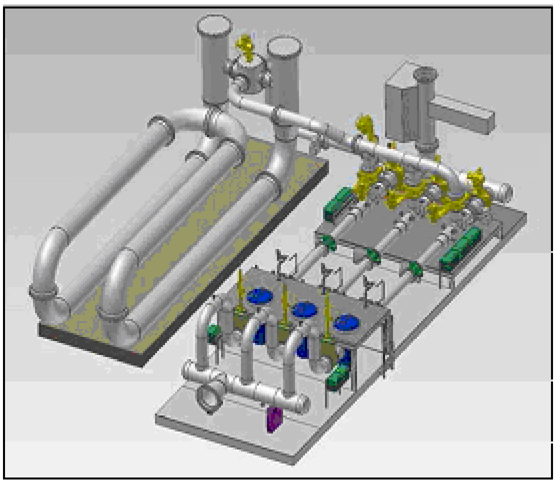
Coriolis flowmeters

For technical metering, the dimensions of the Coriolis flowmeters will be chosen based on:

- the range of flow rates to be measured,
- the admissible pressure drop,
- the upstream and downstream pipe diameters,
- the desired accuracy,
- the bubble point of the fluid to be metered.

5.5. EXERCISES

41. The figure shows:



- ❑ A uni-directional prover
- ❑ A bi-directional prover

42. The purpose of calibration is to determine the volume(s) located between the sphere passage detector switches.

- ❑ True
- ❑ False

43. Volume = ………………………………………… * Length

44. Velocity = Length * ………………………………………….

45. Flow rate = Velocity * ……………………………………………….

6. LOCATION AND CRITICALITY

The use of a metering station is not a short-term criticality. Metering stations often comprise several meter runs and the exported fluid is distributed over them.

So, if one line of a metering station is out of action, the export time will be longer but the operation will not be halted.

For technical metering, if the metering system is out of action, the installation will not necessarily be shut down but the efficiency of the fluid recovery will be seriously affected.

7. AUXILIARIES

In this chapter we shall discuss auxiliary equipment located on a metering station. A measuring package is not limited to just a meter…

In the Legal Metrology sense, a measurement package comprises, at the minimum:

- A meter
- A transfer point
- A hydraulic system transporting the product to be measured to the transfer point, taking into account the supply conditions (hydraulic).

For the system to operate correctly, it is often necessary to include called "additional equipment" to it:

- An air and gas elimination system
- A filtering system
- A pumping system
- Systems for correcting temperature, viscosity, pressure, etc.

Finally, the measuring package can be equipped with "supplementary" devices:

- A printing system
- A data storage system
- A conversion system
- A predetermination system

Note: The additional and supplementary systems may or may not be subject to legal metrology inspections depending on their role in the measuring package, and national regulations.

As mentioned above, a measuring package is not limited to a just meter but is a set of elements adapted to the context of the measurement to be carried out.

The equipment ensuring the main functions in a measuring package can be divided into 6 categories:

- Protection equipment
- Conditioning equipment
- Primary measuring equipment
- Associated measuring and product quality equipment
- Acquisition and calculation equipment
- Surveillance and supervision equipment

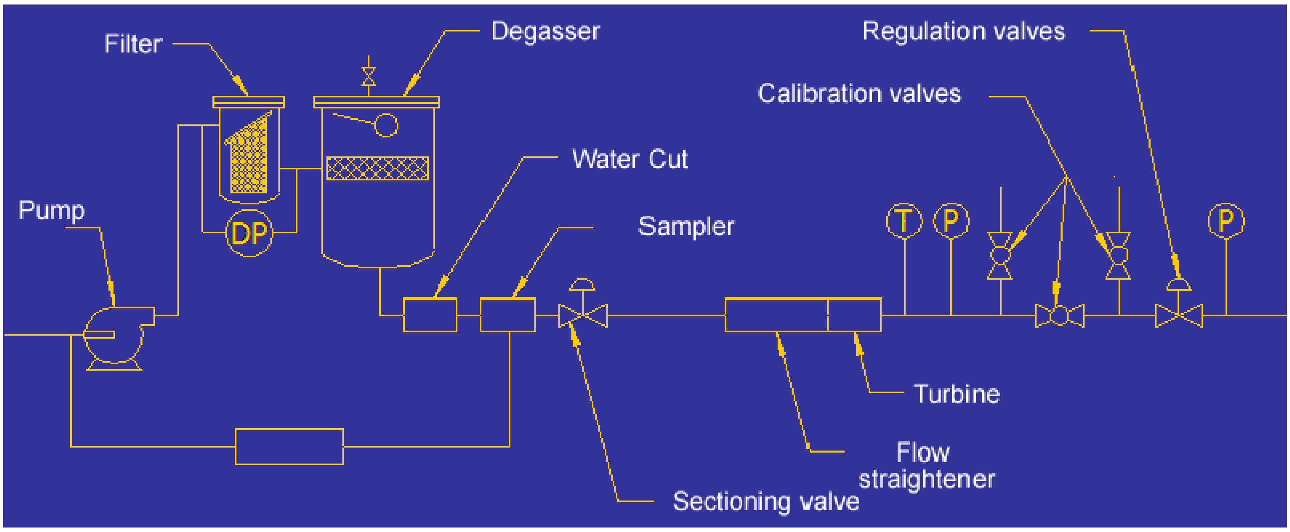


Figure 82: Metering station auxiliaries

7.1. PROTECTION EQUIPMENT

7.1.1. Filters

As the name indicates, this equipment is designed to protect the measuring equipment and the installation in general from any damage arising from the process and the operating conditions:

- Product contamination
- Lack of product homogeneity
- Capacity overshoot (pressure, temperature, flow rate, etc.)
- etc.

Figure 83: Filters: Protection equipment

For measuring gases, just as for measuring liquids, the filters are designed to protect the whole installation from the effects of solid particles that might be introduced into the measuring package. Solids may:

- Damage the measuring or control equipment
- Affect the measurements
- Modify pipe geometry
- Give rise to corrosion (coupling of materials)
- Etc.

The dimensions of the filters are matched to the application thanks to different technologies, different sizes and different mesh sizes.

When choosing the filter dimensions, consideration must be given to the fluid flow velocity (flow rate/cross sectional area), the required filtration level and the admissible pressure drop. As is often the case, the product chosen is generally the result of a compromise which includes, in particular, the expected maintenance costs.

The level of filter fouling is generally monitored using a clogging indicator or a system measuring the pressure drop between the upstream and downstream sides of the filter element. The maximum admissible relative pressure drop value is chosen to determine the limit after which a cleaning operation is required. Self-cleaning technologies are available which limit the intervention time.

7.1.2. Deaerator / Gas separator

"The measuring assemblies must be constructed and installed in a way designed to ensure that there is no air ingress or gas release in the liquid upstream of the meter during normal operation. If there is a risk that this condition will not be met, the measuring assemblies must include deaerators to correctly remove any undissolved air and gases in the liquid before it enters the meter".

In other words, when there is a risk of air or gas being present in the pipe at the measuring point (whatever the measurement technology used), it is recommended or even essential that a system to remove this gas phase be installed upstream.

A gas separator must guarantee that the air or gas present in the liquid flow does not affect the measuring result by more than 0.5 to 1.0% of the quantity measured. This level of performance must be checked for levels of up to 30% gas, for a total flow rate greater than or equal to 20 m3/h.

The conventional operating principle consists of “bursting” the flow to help liberate the gas phase and to release the volume of liquid at the bottom of the tank. There are also systems available which use centrifugal force to remove the gas concentrated at the centre of the tank.

Simple gas removal devices are used to evacuate the gases through a mechanical float system while other systems incorporate level detectors and a pilot-operated electrovalve which manages the liquid level and ensures the homogeneity of the product measured. In addition, these systems can also be used to interrupt the current delivery by acting on the flow control valve.

7.1.3. Gas purge

Unlike the gas separator which is basically designed to remove dissolved gases, the gas purge is mainly designed to eliminate "pockets" of air or gas present in the flow.

A gas purge must therefore remove a volume corresponding to the minimum delivery volume of a measuring package, at the maximum service flow rate, without introducing an error greater than 1.0% of that minimum measured quantity.

7.1.4. Flow and pressure control valves

To guarantee that the operating conditions are maintained within acceptable limits by the equipment used (particularly in terms of flow rate and pressure), valves usually located downstream of the primary measuring instrument ensure that the previously defined threshold values are respected, via the PID loops.

Respecting the flow rate thresholds guarantees that the measuring system functions in its optimum operating range and protects it from possible overspeeds.

Respecting the pressure thresholds prevents cavitation phenomena that may deteriorate the measurement, and protects the installation against any accidental overpressures.

7.2. CONDITIONING EQUIPMENT

The measurement of fluid quantities is based on a certain number of hypotheses, among them:

- Product homogeneity
- Flow stability (for certain measuring technologies)
- Stability of the pressure and temperature variables

Specific equipment may be integrated in the measuring packages, where necessary, to approximate these hypotheses by theoretical definitions.

7.2.1. Static mixer

This type of equipment is basically used on crude oil measuring packages. Whether the package is located downstream of a separator or at the wellhead, the fluid is only very rarely homogenous enough for satisfactory measurements to be performed.

The effects due to the stratifications resulting from density variations and the presence of water are attenuated by installing one of these devices upstream of the measurement point.

The static mixer consists of flow disturbance mechanisms (inclined plates, tubes, etc.) that very significantly increase the flow turbulence level, thus creating a homogenous flow upstream of the measurement.

Figure 84: Static mixer - Conditioning equipment

7.2.2. Flow conditioners

Most fluid quantity measuring equipment is sensitive to the upstream flow conditions. Apart from the volumetric meters and, with reservations, the Coriolis flowmeters, all volume measurement systems are more or less sensitive to flow profile dissymmetry and to swirl in the fluid stream.

Therefore the standards define the specific installation conditions for each technology (turbine, ultrasonic, orifice plate, etc.) and specify, in particular, the lengths of the straight pipes upstream of the measurement system and the position, or even the type, of the conditioning system to be used.

The various pipe and accessory configurations upstream of the measurement create different levels of flow disturbance.

Two parameters must be considered when defining a flow profile

- Axial symmetry
- Swirl

The first disturbance (bend outlet, butterfly valve, etc.) generates displacement velocities which vary according to the position in the pipe.

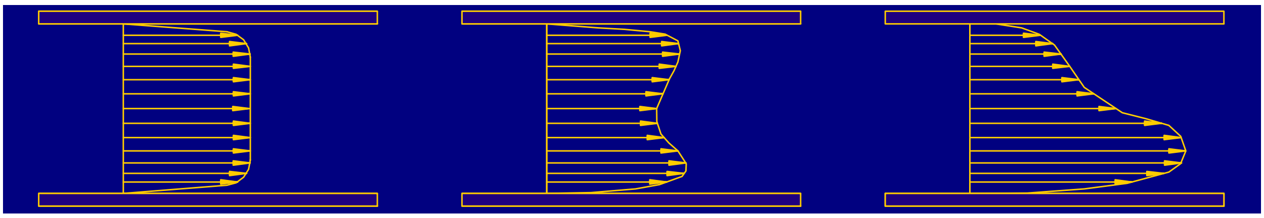


Figure 85: First flow disturbance (axial symmetry)

The first disturbance (outlet of two non-coplanar bends, manifold, non-concentric reducer, etc.) generates displacement velocities (radial) thus generating one or more swirls in the fluid stream.

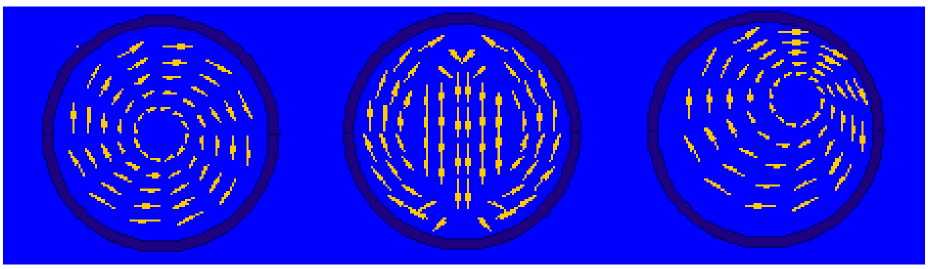


Figure 86: Second flow disturbance (swirl)

In the case of a single centred swirl it is obvious that the direction of rotation will not affect, for example, two turbines with rotors rotating in opposite directions in the same way.

This type of disturbance can be dealt with more or less effectively by different technologies.

The most frequently used flow conditioner consists of a bundle of 19 tubes uniformly distributed in the upstream pipe section. This technology generally reduces the swirl in the stream very effectively, but does not attenuate the dissymmetry.

Conversely, the plate flow conditioners developed in particular by K-Lab (NOVA), or SMITH create a symmetrical flow stream by increasing the flow turbulence level, but only very partially reduce any swirl which may be present.

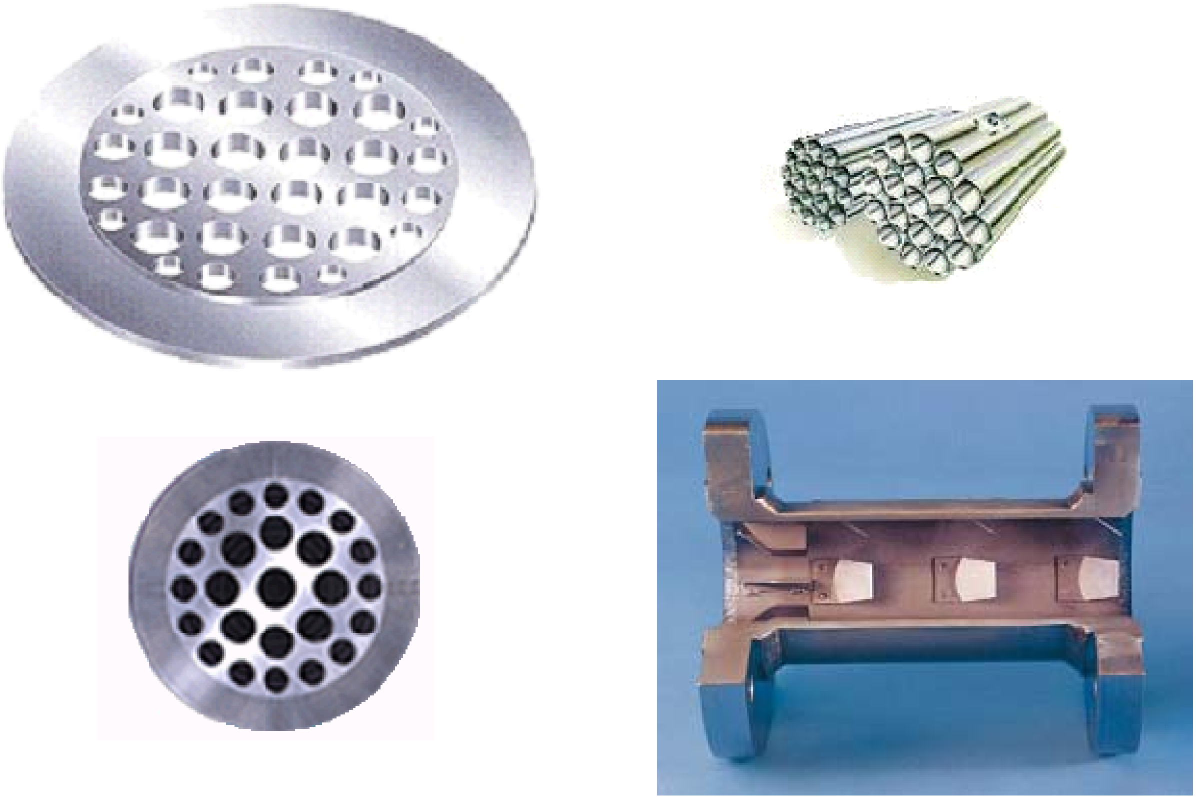


Figure 87: Different types of flow conditioners

The Gallagher Flow Conditioner (GFC) associates both the previous principles by combining a tube bundle (or a straight vane section) and a plate in series, upstream of the measurement.

It is available as separate elements or as a fully integrated version according to the diameters and the applications.

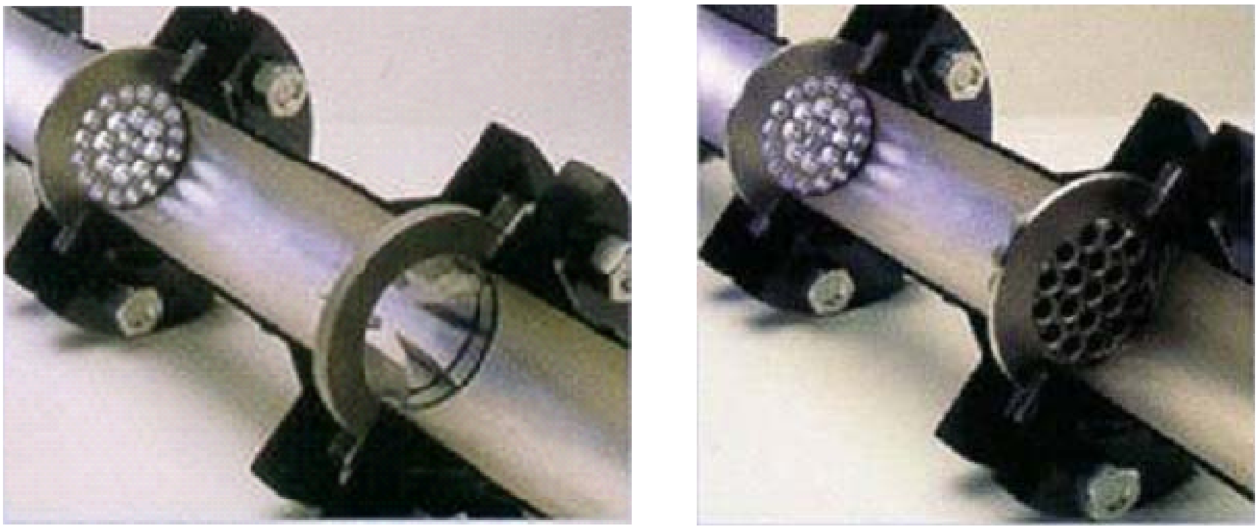


Figure 88: GFC flow conditioners

Pressure control systems have already been mentioned as protection equipment and are used to maintain a pressure level compatible with the measurement. The product equilibrium depends on the pressure (vapour pressure), and the pressure drops inherent in the installation can produce cavitation phenomena (phase change) incompatible with reliable measurements.

When there may be large variations in the product temperature according to the process, or when, for example, a gas has to be expanded before it can be measured, conditioning systems must be installed to control the fluid temperature:

- Reheating system (e.g. upstream of an expander)
- Thermal insulation of the pipes
- Heat exchangers
- Etc.

7.3. ASSOCIATED MEASURING EQUIPMENT

- Pressure
- Temperature
- Density
- Viscosity
- Composition (Chromatography)
- Water and Sediment content (BSW)
- Sampling systems

Transmitters / indicators

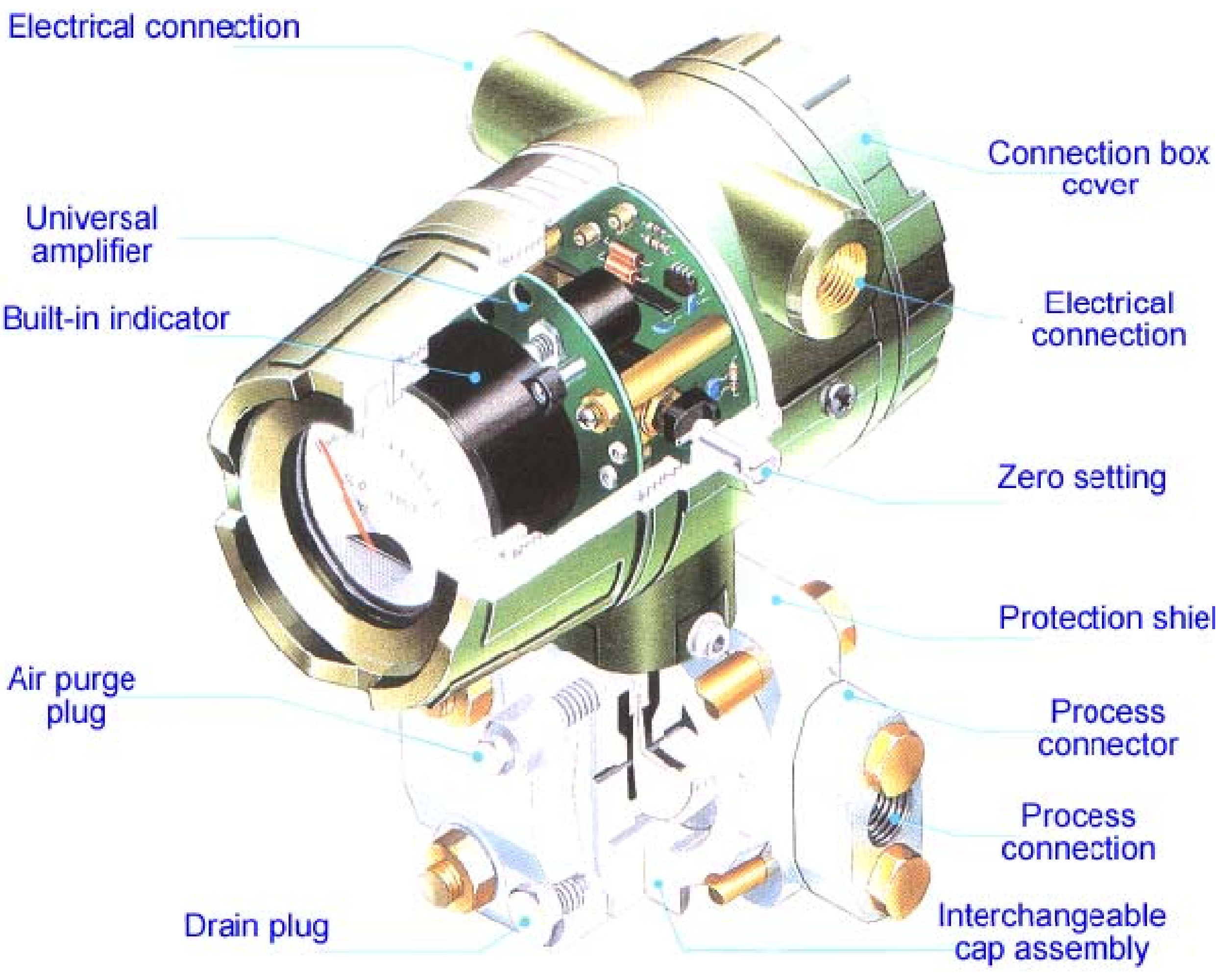


Figure 89: Differential pressure transmitter

These are differential pressure transmitters with the following types of measuring elements: strain gauges, capacitance gauges, etc.

The standard scale used for liquids is the 250 mbar scale.

The most recent models, called Smart Transducers, have the following features:

- correction of the measurement for pressure and temperature,
- automatic scale change (e.g. from 0-25 mbar to 0-250 mbar) to cover a wider flow range: 1 to 10 instead of 1 to 3,
- they are also more stable (see typical data sheet).

The data delivered is a pressure difference in mbar, Pa or mm H_2O.

7.4.

7.5. ACQUISITION AND CALCULATION EQUIPMENT

Main functions:

- MEASUREMENT/CORRECTION: Acquisition and processing of the signals generated by the measuring systems (pulses, periods, 4-20 mA, etc.)
- CONTROL: Control of the PID loops to regulate the operating parameters (flow rate, pressure, etc.), regulation of the start-up and end-of-load (batch) gradient functions, management of the calibration system, whatever the technology used, management of the sampling systems, etc.
- COMMUNICATION: Whatever the level of integration, communication with the whole operating environment is essential, SCADA, DCS, Top Level Supervisor or even with the maintenance technician's laptop computer, etc.

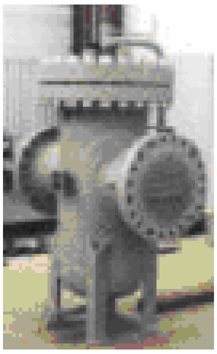
Whatever the integration level envisaged, the computer's main function must always be the RELIABLE generation of PRECISE SECURE data COMPLIANT with the applicable standards and regulations.

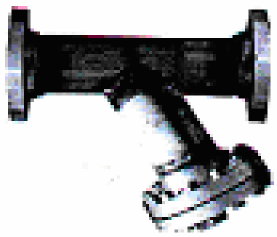
This basic function makes the flow computer the metering point's "cash register" and, whenever necessary, it must be possible to demonstrate the pertinence of the results displayed, printed or transmitted.

In addition, the computer's integrity must be protected to prohibit all interventions which might temporarily or permanently disrupt any of the measuring system elements (connection of the associated measuring instruments, variables and internal parameters, calculation algorithms, etc.).

7.6. EXERCICES

45. What is this equipment called?

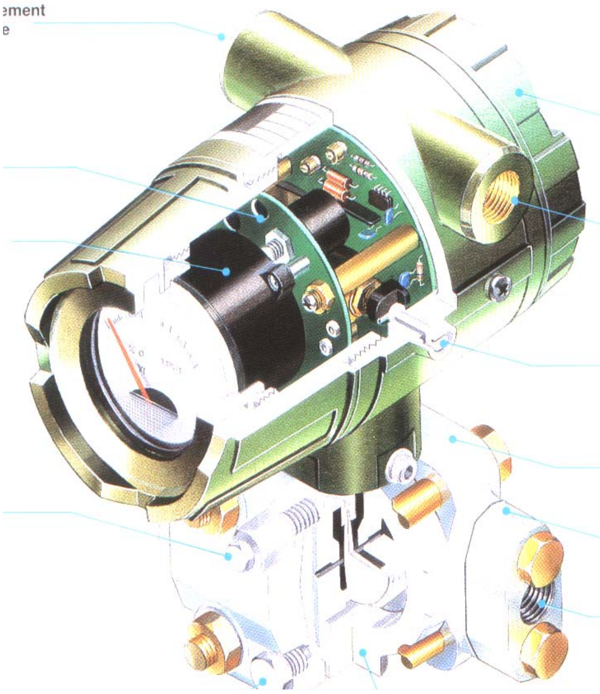




46. What is this equipment called?

47. What is this equipment called?

48. What is this equipment called?



8. OPERATING PARAMETERS

8.1. NORMAL OPERATION

The first requirement for the metering station is to comply with the instructions in force on the site.

In addition to these instructions, there are actions that will help ensure that the metering installations are operating correctly.

8.1.1. Quality assurance

All the metering system operating (calculations, maintenance, control) and control and monitoring procedures must be formally defined to:

- check their compliance with the standards and regulations,
- ensure that they are respected and monitored,
- meet the contractual requirements,
- allow audits to be conducted (both internal and external).

8.1.2. Validation by monitoring tank/metering station/ship discrepancies (tanker loading metering)

8.1.2.1. Discrepancy assessment

In the general case of a cargo metered using a metering station, the measured quantity can be checked by comparison with the quantities:

- measured in the tanks by gauges,
- measured in the tanks by gauges and corrected by the Terminal Experience Factor,
- received by the ship,
- received by the ship and corrected by the ship's experience factor, also known as the Vessel Experience Factor (VEF).

In addition, the tank measurements can also be checked using the tank's fixed instruments which often relay the measurements to the control room (non-approved equipment).

Finally, a subsequent check can be carried out for unloading measurements but the terminal rarely has access to these except for claims purposes.

The source of any excessive discrepancies with the ship must be found, if possible before the ship's departure so that it can be validated by the loadmaster.

Note: the metering station values prevail when no technical incidents have disrupted its operation. Therefore, it is not necessary to disclose the tank gauging results to the loadmaster or to make the tank strapping tables available to him.

8.1.2.2. Discrepancies

Monitoring the tank/metering station/ship discrepancies over several loads may also reveal a discrepancy in one of the metering systems.

In the case of a metering station, there is normally a difference of around 0.2% between the gauge measurement and the metering station measurement (Terminal Experience Factor). Any changes in this value, in one direction of the other, indicate a discrepancy and must be detected.

By comparing the changes in the tank/metering station differences, the metering station/ship differences (with VEF) and the tank/ship differences (with VEF), we can isolate the system at the origin of the discrepancy. It is more difficult to detect when no metering station is used.

Important: during comparisons with the tanks it is essential to clearly and correctly identify the tanks, as the whole of the error may be due to a single tank (e.g.: passing valve, incorrect tank strapping table, etc.) and it is important to know which. Thus a significant difference may appear at one loading operation and disappear at the next if the tank with the anomaly was not used for the second loading operation.

8.1.3. Checks

Depending on the configuration of the terminal lines, a full-scale test on the metering systems can be carried out:

- by directly transferring the contents of one tank to another,
- by directly transferring the contents of one tank to another via the metering station,
- while continuing the ship loading operations.

Reminder: for the gauging to be sufficiently precise, the volumes to be transferred must generate level variations of at least 3 m in the tanks.

8.2. MIN. / MAX. CAPACITIES

In this chapter we will cover the recommended types of metering according to the fluid to be measured and, to a lesser extent, the min. / max. capacities of each type of metering.

Flowmeter type	Liquid						Gas		Vapour	
	Clean	Charged	Highly charged	Viscous	Corrosive	Multi-phase	Clean	Charged	Saturated	Dry
Press. differ. device (*) - Target, Bend, V	Yes	Yes	±	Yes	Yes	±	Yes	Yes	Yes	Yes
- Orifice plate	Yes	No	No	±	Yes	No	Yes	No	Yes	Yes
- Nozzle, Venturi	Yes	±	±	±	Yes	No	Yes	±	Yes	Yes
- Pitot	Yes	Yes	No	No	Yes	No	Yes	±	Yes	Yes
Variable section	Yes	No	No	±	Yes	No	Yes	No	Yes	Yes
Turbine	Yes	No	No	±	Yes	No	Yes	±	Yes	Yes
Volumetric	Yes	Yes	No	Yes	Yes	No	Yes	No	No	No
Electromagnetic	Yes	Yes	Yes	Yes	Yes	±	No	No	No	No
Vortex	Yes	Yes	No	No	Yes	No	Yes	Yes	Yes	Yes
Ultrasonic (transit)	Yes	±	No	Yes	Yes	±	Yes	Yes	±	±
Ultrasonic (Doppler)	No	Yes	±	±	Yes	±	No	No	No	No
Coriolis	Yes	Yes	Yes	Yes	Yes	±	Yes	Yes	±	±
Thermal	Yes	No	No	Yes	Yes	No	Yes	±	No	No

This information is given as an indication only, it may vary from one supplier to another
(*) These differ widely depending on the type of pressure differential device
(**) There are no reliable methods for measuring flow rates on multiphase mixtures (liquid / gas)

Table 3: Recommendation on types of meters according to the type of fluid metered

9. THE METERING OPERATION

9.1. START-UP/SHUTDOWN

The following operating instructions must be strictly respected.

9.2. HANDOVER TO MAINTENANCE

The site operating instructions and the Permit to Work (PTW) must be strictly respected.

LEVEL 1 MAINTENANCE

The first metering quality control and monitoring level is ensured via equipment operation and servicing:

- maintenance,
- calibration,
- compliance with the operating procedures,
- spot checks.

The routine checks and checks on request must not be neglected, like for example:

- meter run inlet and outlet valve sealing tests,
- filter cleaning,
- checking the sensors and local indicators for value match,
- checking the sphere diameter and surface condition.

This means:

- precise and complete procedures must be written,
- metrological instruments must be under monitoring,
- calibration means must be checked,
- a metrology record and histories must be kept,
- life data sheets must be kept for each item of equipment.

10. TROUBLESHOOTING

10.1. IF? WHY? SO?

Summary of the main metering anomalies for each type of flowmeter

10.1.1. Coriolis flowmeter

10.1.1.1. Problems due to the instrumentation

See the manufacturer documentation to find the source of the incidents (no output signal, output signal insensitive to flow rate variations, variation unconnected to the flow rate, intermittent output signal).

10.1.1.2. Problems due to the fluid

An unstable random density signal may be due to degassing in the pipes.

A minor error in the density readings may indicate the formation of a deposit in the pipes. The pipes must be cleaned and flushed with solvent, hot water or other suitable fluid before being recalibrated using air then water.

10.1.2. Pressure differential orifices

- Flow pulses.
- Take-off points clogging problems.
- Fouling or erosion of the plates.
- Changes in the viscosity or density of the fluid metered.
- Disturbances in the flow (swirl, etc.).
- Distorted plate.
- Effect of temperature on the take-off points (pressure, vaporisation).

10.1.3. Turbines

- Metering errors due to pulses or to vortices.
- Meter over-reading due to excess speeds.
- Meters used for flow rates which are too low (example: for flow rates $< 10\% \ Q_{max}$).
- Electrical problems (preamplifier, cables).
- Mechanical problems: rotor imbalance, hub component wear.
- Errors due to viscosity changes (quality or temperature change).

10.1.4. Volumetric meters

- Damage due to overspeeds.
- Presence of cavitation.
- Mechanical deterioration due to possible solids.
- Liquid leaks or slip at low flow rates.
- Over-reading if entrained gas present.

10.1.5. Vortex flowmeter

Anomalies on liquid metering may be due to:

- pressure pulses,
- vibrations,
- max. flow rate exceeded by more than 20%,
- electrical interference,
- cavitation or presence of gas in the pipe,
- fouling of the vortex generator,

- poor flow conditions or Reynolds number,
- straight lengths too short.

10.1.6. Electromagnetic flowmeters

- Failure due to deposits on the electrodes (adherence of foreign bodies causing a finite resistance).
- Incorrect assembly or deterioration of insulating materials.
- Signal too low due to an insufficient velocity or insufficient conductivity (< 5 μs/cm).
- Flowmeter incorrectly filled, presence of bubbles.

11. GLOSSARY

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