National Measurement System

## GOOD PRACTICE GUIDE

# AN INTRODUCTION TO MULTIPHASE FLOW MEASUREMENT

www.tuvnel.com

nel technology for life

This guide provides an introduction to multiphase flow measurement. Firstly, the document covers key definitions associated with multiphase flow before moving onto multiphase flow patterns and properties. Multiphase flow measurement technologies are introduced, along with installation and flow assurance issues.

## Contents

# 1 What is Multiphase Flow?

Before you can attempt to measure multiphase flow it is important to understand what is actually meant by multiphase flow. You may not realise it but we encounter multiphase flow just about every single day. It could be rain (liquid) falling down through the air (gas), or the bubbles (gas) in your lemonade (liquid). However, there is not much requirement to meter each individual phase in these examples. When we talk about multiphase metering, more likely than not, we mean hydrocarbon multiphase flow measurement i.e. oil, water and gas. Multiphase flow is actually a misnomer in that the oil and water are both liquid so what we really mean is multi-component flow. An everyday example of a multi-component mixture would be gin (liquid) and tonic water (liquid and gas).

Multiphase (or multi-component) flow occurs in many industries including food and drink, and pharmaceutical. There has never been any real demand to meter the individual phases or components in these industries. However, in the oil & gas industry, especially as fields become more economically marginal there is growing demand to meter the individual components of oil, water and gas stream. This good practice guide will therefore focus on hydrocarbon multiphase flow measurement although multiphase (or multi-component) flows also exist in other industries.

# 2 Key Definitions

Multiphase flow is different to single phase flow and has its own terminology.

### Phase Mass Fraction

The phase mass fraction is the mass flow rate of one component in relation to the total mass flow rate of the multiphase mixture. That is:

Gas Mass Fraction = Gas Mass Flow Rate / Total Mass Flow Rate

### Phase Volume Fraction

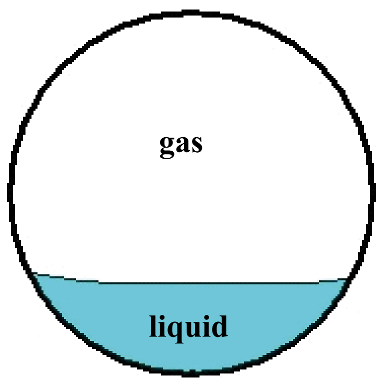
The phase volume fraction is the volumetric flow rate of one component in relation to the total volumetric flow rate. That is:

Gas Volume Fraction = Gas Volumetric Flow Rate / Total Volumetric Flow Rate

### Phase Area Fraction

The phase area fraction is the cross-sectional area occupied by one phase relative to the total cross-sectional area of the pipe at that point.

- The void fraction is the cross-sectional area of the pipe occupied with gas.
- The hold-up is the cross-sectional area of the pipe occupied with liquid.



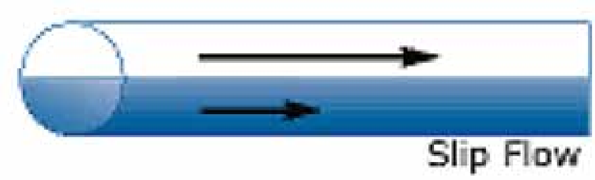

<ins>It is important to distinguish gas void fraction from gas volume fraction.</ins> Unfortunately they both have the same acronym, GVF, which makes it easy to confuse them. The gas volume fraction is usually larger than the gas void fraction.

## 2 Key Definitions cont.

### Phase Slip

The components of a multiphase mixture travel at different velocities. Generally speaking, the velocity of the gas is much greater than the velocity of the liquid. In some production wells it takes the gas a few hours to reach the well head but it can take the liquid days to travel the same distance. This difference in velocities is known as phase slip.

- Slip $v_R = v_g - v_l$
- Slip ratio $K = \frac{v_g}{v_l}$




How is the phase slip determined? That is the $64 million question and at this time no empirical formula exists but a couple of ways you could try are:

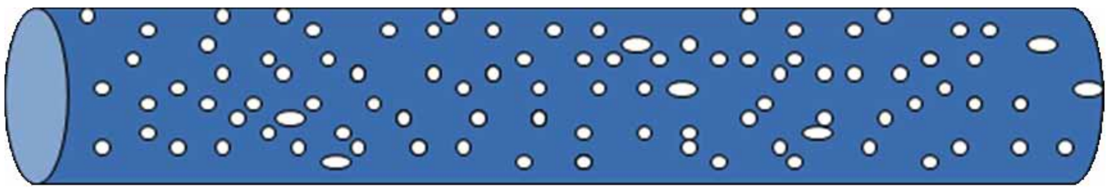
- A semi-empirical formula for a particular flow pattern[1] .
- Perform laboratory or test facility experiments with known gas volume fractions, and develop a correlation for K using appropriate physical variables. It should be noted that using this method strictly only applies to the range of conditions for that particular set of experiments and should not be extrapolated outside that range.

Gas volume fraction (GVF), gas void fraction ($\varepsilon g$) and slip (K) are all related to each other.

$$GVF = \left( \frac{\varepsilon_g K}{1 - \varepsilon_g + \varepsilon_g K} \right)$$

### Homogeneous Flow

A multiphase mixture is considered to be a homogeneous flow when the liquid and gas are travelling at the same velocity i.e. K = 1. Homogeneous flow can be desirable, depending on the design of a multiphase flow meter, as it eliminates the need for slip models.



### Water Cut

Water cut is also sometimes referred to as the water to liquid ratio (WLR). It is simply, the water volume fraction of the liquid phase:

Water Cut = Water Volumetric Flow Rate / Total Liquid Volumetric Flow Rate



[1] Flow patterns will be covered later.

## 2 Key Definitions cont.

### Inversion Region

An oil/water mixture can be described as being oil-continuous or water-continuous. Oil-continuous flow is characterised by water droplets being surrounded by oil. Water-continuous flow is oil droplets surrounded by water. The inversion region lies between oil-continuous and water-continuous flow and is unpredictable as it can show characteristics of either oil-continuous or water-continuous flow, changing from one moment to the next. Operating in the oil/water inversion region can create difficulties for certain multiphase measurement technologies.

### Superficial Phase Velocity

The superficial phase velocity is the velocity the individual phase would have if it flowed alone in the pipe. By way of illustration:

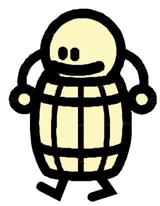
- You have a pipe with an inside diameter of 150 mm
- The cross-sectional area of the pipe would be 0.018 $m^2$
- The gas and liquid volumetric flow rates are 950 $m^3$/hr and 50 $m^3$/hr respectively
- This means the superficial velocities of the gas and liquid are 14.66 m/s and 0.77 m/s respectively

### Wet Gas

Wet gas is a multi-component mixture that mostly consists of gas with a small amount of liquid present. When does multiphase flow become wet gas? That question is not as straightforward as it seems. There have been numerous debates as to the exact definition of wet gas, the Good Practice Guide; "An Introduction to Wet-Gas Flow Metering" goes into the various definitions of wet gas in more detail. Some classify wet gas as being a multi-component flow with a gas volume fraction greater than 90%, for others it is when the gas volume fraction is greater than 95%, another classification involves calculating the Lockhart-Martinelli parameter, which defines the wetness of the gas.

### Units of Measurement

In the oil and gas industry liquids flow rates are often given in barrels per day (bbl/d) and gas flow rates are commonly measured in mmscfd (million standard cubic feet per day). As these units are different from each other it can make it difficult to get a feel for the gas volume fraction and water cut as you are not comparing like with like. To enable direct comparison it might be beneficial to convert them into metric units.



- There are numerous different sizes of barrel and they range from 100 to 200 litres. The standard oil barrel volume is equivalent to 158.98 litres.
- The "standard" part of mmscfd refers to standard pressure and temperature. This can vary depending on where in the world you are and what industry you are dealing with. The most common standard used with mmscfd in the oil & gas industry is the US standard for natural gas at 60°F (15.5°C) and 1.01325 bar.

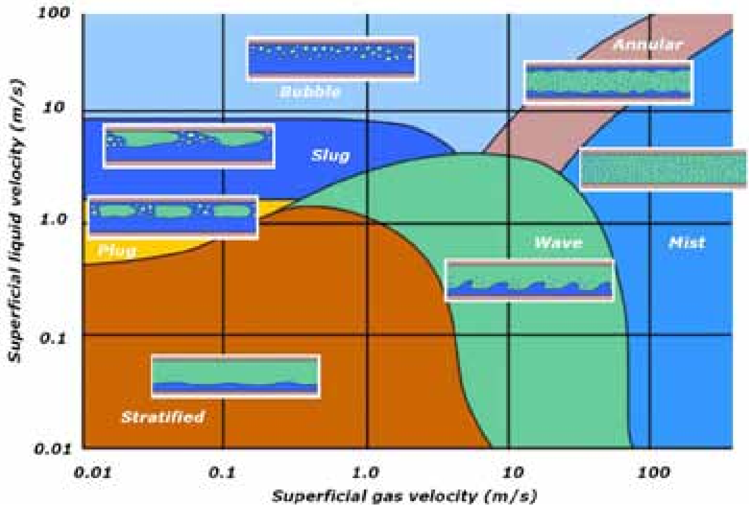
## 3 Flow Patterns

In single phase flow you either have laminar or turbulent flow but in multiphase flow it is a little more complicated. How the liquid and gas is distributed within a pipe varies depending on the superficial velocities of the phases and the orientation of the pipe.

### Two-Phase Horizontal Flow Patterns

There are seven horizontal flow patterns:

- Stratified
- Stratified wavy
- Plug
- Slug
- Bubble
- Annular
- Mist




Stratified and stratified wavy flow patterns occur at fairly low liquid and gas velocities. As the gas velocity increases, or if the pipe inclines, then the interface becomes wavy.

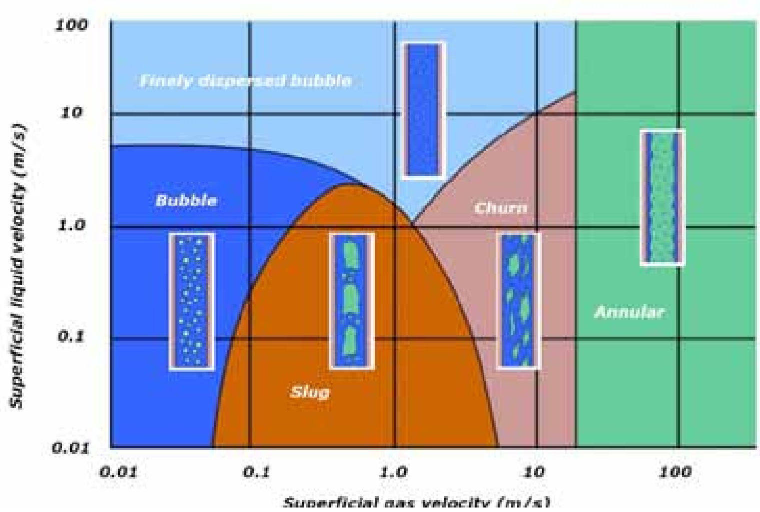
Plug and slug are intermittent flow patterns as they have alternating regions of high and low liquid hold-up. As the liquid flow rate increases, the liquid becomes the dominant phase and the flow changes from plug into slug.
Then there are the distributed flow patterns, bubble, annular and mist. Bubble flow occurs at high liquid velocities where the gas bubbles are suspended in the liquid phase.

Annular flow occurs at high gas velocities where the gas flow along the central core of the pipe and the liquid forms a film on the pipe wall. When the gas flow increases it will start to pick up the liquid from the pipe wall and incorporate it into the gas flow: this is called mist flow.

### Two-Phase Vertical Flow Patterns

There are five vertical multiphase flow patterns:

- Bubble
- Finely dispersed bubble
- Slug
- Churn
- Annular




 Note: Flow maps of the type presented here will be dependent upon the fluid, temperature and pressure; they are not generic.

## 3 Flow Patterns cont.

Similar to horizontal bubble flow, vertical bubble flow has a continuous liquid phase with dispersed gas bubbles. As the gas velocity increases, the dispersed bubbles start to coalesce and form Taylor bubbles also known as slugs. Increasing gas velocity will cause irregular gas slugs and the liquid will start to rise and fall, or in other words, churn. A further increase in gas velocity will form a gas core in the pipe with the liquid forming an annulus at the pipe wall.

### Multiphase Flow

The horizontal and vertical flow patterns discussed in the previous two sections cover two-phase or two-component flow with only one liquid and one gas present. In multiphase flow you will have three-phases or, three-components. Having two components in the liquid phase (oil and water) can throw up further complications, particularly in horizontal flow. In stratified flow and in slug flow it is possible for the oil and water to separate meaning that there will be slip between the two liquid phases. This will make it more difficult to calculate the water cut and so flow measurement of all three phases will be more complicated. The separation between oil and water is more likely to happen in horizontal flow as gravity will be lending a hand since the oil and the water will have different densities. Whereas separation due to gravity is not such an issue for vertical flow, and the oil and water are usually well mixed eliminating slip between the two liquid phases.

## 4 Fluid Properties

In single phase flow measurement it is relatively simple to determine the fluid properties. Compressible fluids (gases) can sometimes be a little trickier than incompressible fluids (solids and liquids) but on the whole single phase fluid properties should be reasonably simple.

With multiphase flow, fluid properties can be very difficult to estimate. To start with, there is a combination of compressible and incompressible fluids in the same pipe at the same time. Furthermore, the fluid properties of a multiphase mixture cannot simply be found by combining the fluid properties of the individual components. It is also quite possible to have mass transfer between the phases of a multiphase mixture.

Multiphase fluid properties really start to get interesting when emulsions form. There is a saying that “oil and water don’t mix”, but they can.

Salad dressing is an everyday example of an oil and water mixture. You add oil, vinegar, perhaps some lemon juice and a pinch of salt, then shake vigorously. Voila, an oil and water mixture but leave it sitting in the jar and the oil, vinegar and lemon juice will soon start to separate out into different layers because it is an unstable emulsion.

Take the same ingredients but this time add an emulsifier, lecithin, which is found in egg yolks. Mixing the oil, vinegar, lemon juice, salt and egg[2] , will form mayonnaise which is an emulsion. The fluid properties of mayonnaise are completely different to the fluid properties of the individual ingredients that made it. There is no empirical formula to calculate the viscosity of mayonnaise using the viscosities of the oil, vinegar, lemon juice and egg.

[2] Some people like to add mustard which also acts as an emulsifier.

## 4 Fluid Properties cont.

Furthermore, unlike the salad dressing that will quickly separate out into its original components, mayonnaise will not because it is a stable emulsion. These are the same issue faced when oil/water emulsions form in pipelines and why it can be difficult to measure the flow rate and composition of your multiphase mixture.

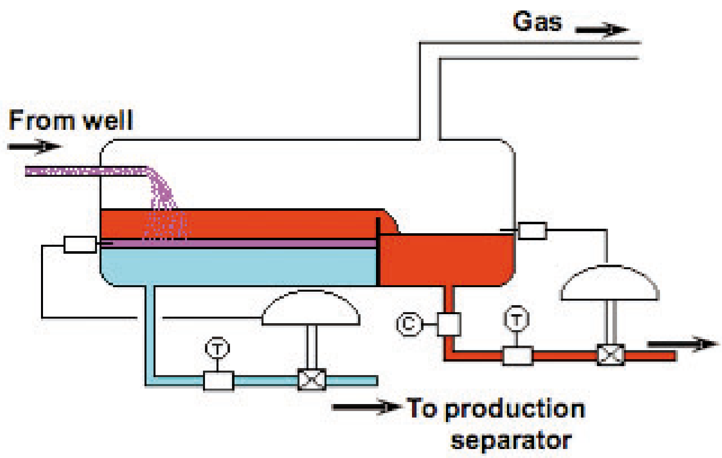
## 5 How to Measure Multiphase Flow

There are three ways to measure multiphase flows.

### 5.1 Separation

The traditional approach to measuring multiphase flow is separation. In the North Sea, three-phase gravity separators are common but elsewhere in the world two-phase separators are more likely to be used. Separators work by exploiting the differences in fluid properties of the multiphase components. In a two-phase separator, the liquid and gas will separate given enough time (known as the residence time) because the gas has a much lower density than the liquid. The gas and liquid are separated in a similar way in the three-phase separator. The oil and water will separate due to their immiscibility and the difference in densities and viscosities of the two fluids.

The outlet streams from the separator can then be measured using single phase meters. Usually this is an orifice plate on the gas stream and a turbine in the liquid stream(s) although Coriolis and ultrasonic meters are also now being considered. In the case of a two-phase separator a water cut monitor will also be required.




Problems encountered with test separators include but are not limited to:

- Undersized separators lead to a reduction in residence time which leads to poorer separation. This can lead to liquid being carried over into the gas stream and/or gas being carried under to the liquid stream.
- Foams and emulsions are difficult to separate.
- In very viscous liquids, micro-bubbles can be held in solution and may not be separated out.
- Poor maintenance and calibration of reference flow meters and secondary instrumentation.

## 5.1 Separation cont.

In addition to these issues, it is rare that test separators are solely used for the purpose of monitoring well production, also known as well testing.  A number of other production requirements can take them away from their intended use leading to long periods of time between well tests.

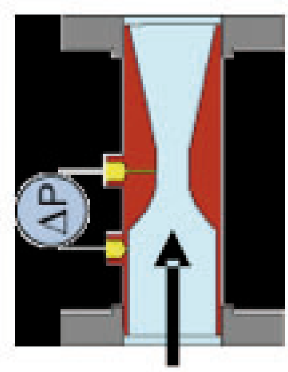
## 5.2 Multiphase Flow Meters

Compared to test separators, multiphase flow meters (MPFM) are a relatively new technology.  There are a number of different designs on the market but they all follow the principle of measuring the bulk flow rate of the multiphase mixture, calculating the individual phase fractions, and then using these to give the flow rates of the individual streams.

Although each manufacturer has its own design of MPFM there are a number of commonly used measurement techniques.  One technique on its own is not enough to determine the individual flow rates of the oil, water and gas and so a suitable combination must be used.

### Differential Pressure (DP) Meters

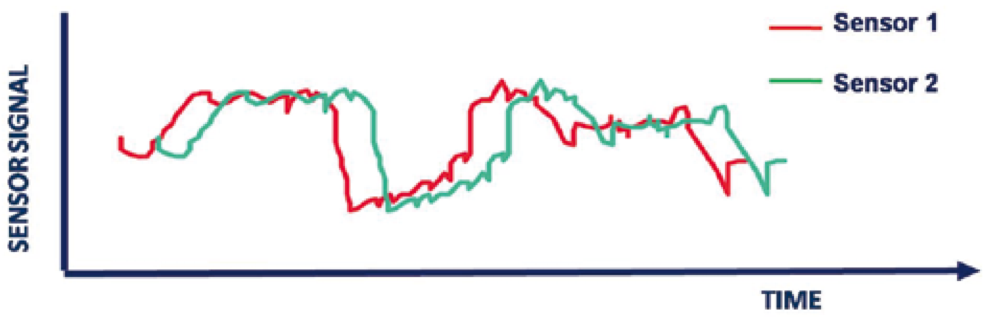
Differential pressure meters are one of the most commonly used groups of flow meter.  There are several different types of DP meter but more often than not a MPFM will have a Venturi although one particular manufacturer actually uses a proprietary mixer as a DP device.




The DP meter can be used in one of two ways.  It can either be used to calculate the flow rate of multiphase mixture or, if you already know the flow rate, you can use the DP device to derive the mixture density.

### Cross-correlation

Cross-correlation is another method to measure the flow rate of the multiphase mixture.  Two sets of sensors are placed a known distance apart.  A number of sensor types can be used such as densitometers, pressure gauges, but more commonly are electrical sensors (capacitance and/or inductance).  The signal processing looks for correlated signals due to flow disturbances such as slugs and bubbles.  This means cross-correlation does not work particularly well in homogenous flow or when there is an emulsion as there is nothing to cross-correlate.



## 5.2 Multiphase Flow Meters cont.

### Electrical Properties

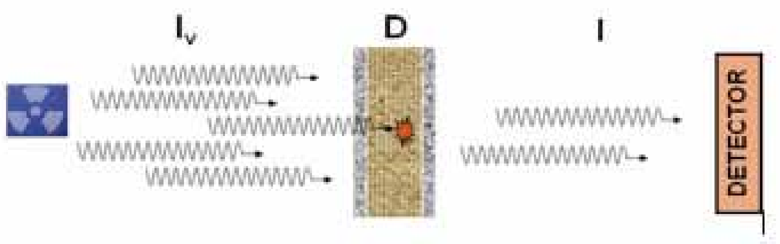
Measuring the electrical impedance across the pipe using electrodes can determine electrical properties of the multiphase mixture such as capacitance and conductance. The measured electrical quantity of the mixture is dependent on the permittivity and conductivity of the individual phases. Permittivity can be measured using electrical capacitance sensors and will change depending on the phase fractions of the multiphase mixture. Capacitance sensors work best in oil-continuous flow. Conductivity is measured by injecting an electrical current into the flow, and measuring the voltage drop between the electrodes. Conductivity sensors work best in water-continuous flow. Electrical property measurements can be used to determine the phase fractions of the multiphase mixture.

### Microwaves

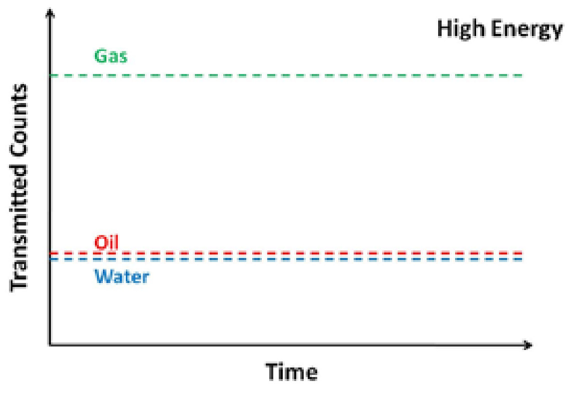
There are two ways microwaves can be used to measure multiphase mixtures; resonance and absorption. Like electrical capacitance measurements, microwaves exploit the difference in permittivity of the multiphase components to determine the individual phase fractions of the mixture.

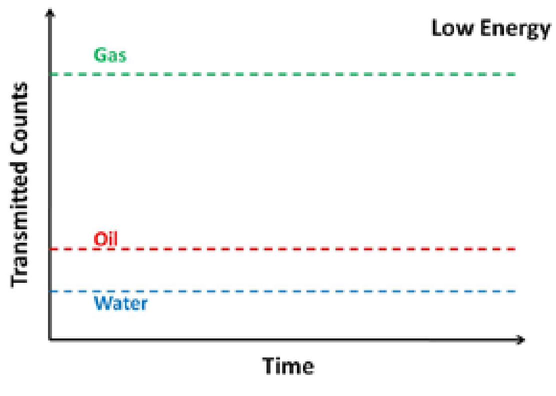
### Gamma Ray Attenuation

A number of different nuclear sources are used in multiphase flow measurement but the most common ones are Barium 133, Caesium 137 and Americium 241. The nuclear source is placed at one side of the pipe with a detector on the opposite side. The number of gamma rays that are able to pass through the pipe is dependent on the composition of the multiphase mixture. Gas is a weak absorber of gamma rays whereas water is a stronger absorber.




There are two main types of gamma ray attenuation used in multiphase flow meters; single energy and dual energy sometimes referred to as DEGRA (dual-energy gamma ray attenuation). Single energy attenuation uses the high energy gamma ray emitted by a nuclear source to distinguish the gas from the liquid. DEGRA uses both the high and low energy gamma ray emitted to firstly distinguish the gas from the liquid, and then the oil from the water.



## 5.2 Multiphase Flow Meters cont.

Research has been carried out into multiple energy gamma attenuation where manufactures are looking at a third gamma ray energy to help determine another property of the multiphase mixture.

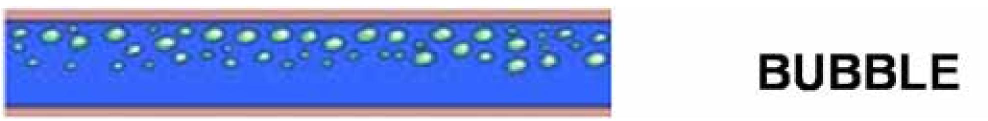
Gamma sources can also be used as a gamma densitometer to measure the density of the mixture to use in the Venturi momentum equation.

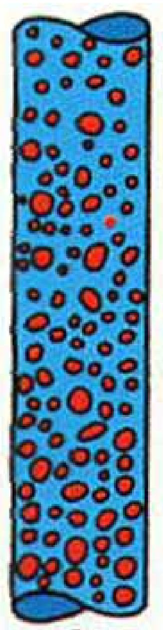
## 5.3 Partial Separation

Partial separation combines elements of separation with MPFM techniques and can be particularly useful when a multiphase mixture has a high gas volume fraction (>95%). Partial separators use a device such as a cyclone to separate the gas and liquid streams. The gas stream is then measured using a single phase meter such as a Coriolis or Venturi tube which is tolerant to small amounts of liquid in gas streams. The liquid phase (which may still contain some gas) can be measured using a MPFM. Partial separators are less compact than a MPFM but are smaller than test separators.

# 6 Installation of Multiphase Flow Meters

In Section 3 where flow patterns were covered there was a footnote stating that there being only five vertical flow patterns is important. Most, but not all MPFM are installed vertically because the flow pattern has a significant bearing on the MPFM readings. There are seven horizontal flow patterns but only five vertical flow patterns therefore installing the meter vertically automatically reduces the possibilities. In the vertical flow, bubbles and slugs are more evenly distributed across the pipe unlike horizontal flow where, due to gravity, they tend to migrate towards the top of the pipe.



Another installation feature which many (but again not all) MPFM have is a blinded tee at the meter inlet. The purpose of the blinded tee is to homogenise the flow and reduce slip. There are always exceptions to the rule so a small number of MPFM have no blinded tee upstream and are installed horizontally.

# 7 Flow Assurance Challenges

Whatever method of multiphase flow measurement is chosen there are some issues and challenges which affect both separators and MPFM.

### Hydrates

Hydrates are solid crystalline structures which form in natural gas and water mixtures under certain pressure and temperature conditions. Hydrates are problematic because they can damage equipment and even block the whole pipe line. Methanol and glycol are used as hydrate inhibitors as they prevent hydrates from forming.

### Waxes

Some oils contain wax molecules, and at sufficiently low production temperatures will form wax particles. The wax can start to deposit on the pipe wall or inside the MPFM. This can lead to blockages in the pipe, or if your MPFM has a Venturi, the wax build up can start to alter the dimensions of the Venturi leading to errors as well as blocking the impulse lines. Keeping production temperature sufficiently high using a technique such as heat tracing can prevent waxes from forming.

### Scales

Scales are formed from inorganic chemicals present. Mixing sea water and produced water from the well is a common source of scales, as is mixing water from multiple wells. Scales can be treated using inhibitors and prevention is better than cure as scales are difficult to remove. Once formed strong acids might be required to remove scale.

### Asphaltines

Asphaltines are dark solids, usually black or dark brown in colour. The operating temperature, pressure and multiphase composition determine whether asphaltines form. Unlike hydrates and waxes, asphaltines do not melt when heated.

### Sand

Sand is undesirable not just for multiphase flow but all types of flow. Sand erodes pipe work, multiphase flow meters, valves and other components. Unlike hydrates, wax and scales there is no cure for erosion. Once a component has been eroded the only thing left to do is replace it. Sand can also build up in a separator reducing the space available for the fluids and therefore reducing the residence time which leads to poorer separation of the fluids.

# 8 Summary

- Multiphase flow measurement is significantly more complicated than measuring a single phase fluid.
- Multiphase flow measurement has its own terminology.
- Multiphase flow has a number of possible flow patterns which depend on the orientation of the pipe and the velocities of the individual phases.
- There are 3 approaches to measuring multiphase flow; separation, MPFM and partial separation.
- MPFM use a combination of techniques to determine the flow rates of the individual phases.
- The gas volume fraction (GVF) is usually greater than the gas void fraction ($\varepsilon g$) because the gas is usually travelling at a greater velocity than the liquid. In homogeneous flow where K = 1; GVF = $\varepsilon g$.

# 9 Further Reading


- Norwegian Society for Oil and Gas Measurement. Handbook of Multiphase Flow Metering. Revision 2, March 2005
- Ross, A., Stobie, G. Well Testing – An Evaluation of Test Separators and Multiphase Flow Meters. In Proc. of 28th North Sea Flow Measurement Workshop, October 2010


For further information, contact:
TUV NEL, East Kilbride, GLASGOW, G75 0QF, UK
Tel: + 44 (0) 1355 220222 Email: info@tuvnel.com www.tuvnel.com

National Measurement System

*The National Measurement System delivers world-class measurement for science and technology through these organisations*

National Measurement Office

NPL National Physical Laboratory

LGC Setting standards in analytical science

nel technology for life