North Sea FLOW Measurement Workshop

Paper 4.2

In-Situ Measurement of Fluid Properties and Integrity Verification for Multiphase and Wet Gas Metering Applications

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1 INTRODUCT ION

Accurate flow measurement of all three components in multiphase and wet gas applications can be extremely challenging. For a multiphase meter to manage it, it must be capable to operate and provide reliable results for all combinations of oil, water and gas rates. In most field applications, the fluid properties may vary over time and the meter must be able to provide accurate results even if the PVT properties change. Frequent sampling and associated lab analysis are preferably to be avoided, especially in remote sites, to reduce OPEX and HSE risks.

The dominating PVT configuration parameter for measurement of small volume fractions of a well stream component is the properties of the fluid occupying the largest volume, which is a fundamental property for any multiphase or wet gas meter. As an example, in order to achieve reliable measurements of the tiny water amounts in a wet gas, it is very important to know the real gas PVT properties. Similarly, it is important to have good control of the PVT properties of water for wells with high watercuts, to correctly measure the correspondingly small oil flow rates. This is in particular the case for water flooded reservoirs where the salinity and density may change significantly over time.

There is currently an installed base of multiphase and wet gas meters of more than 2000 units [23]. It is also well known that the measurement integrity of multiphase and wet gas meters is influenced by uncertainty and changes in PVT configuration data. As a consequence, frequent sampling and analysis of the PVT configuration data could be required in order to maintain the measurement integrity of the meters [2], [24] and some vendor recommends fluid sampling on a regular basis and in-line sampling systems even for remote subsea installations [24] .

In this paper a combined multiphase and three-phase wet gas flow meter is described. It is based on electromagnetic broadband technology and utilizing tomographic reconstruction techniques, in combination with high energy gamma mass attenuation measurements and a Venturi. The meter has proven to be very tolerant to errors and variations in the PVT configuration data. An additional and unique feature of this meter is its capability of measuring “in-situ” the fluid properties of gas and water of the wells, which enable automatic configuration with respect to water density, water conductivity, water viscosity, gas density and gas permittivity of the produced wells. This feature minimizes and in many cases completely eliminates the need for fluid sampling of the wells.

Many field applications contain significant amounts of H_2S and CO_2 which constitutes another challenge for a multiphase meter, particularly if the content changes over time. This paper also describes the metering challenges in such an environment including the theoretical basis for how CO_2 and $H2_S$ impact the field calibration parameters of a multiphase and wet gas meter and how variation in CO_2 and H_2S content can be handled without compromising on the measurement performance.

2 MPM 3D BROADBAND™ TECHNOLOGY

The MPM meter uses a combination of a Venturi flow meter, a gamma-ray detector, a multi-dimensional, multi-frequency dielectric measurement system [5] and advanced flow models [1], [4], which are combined to a multi-modal parametric tomographic measurement system.

The Venturi is used to create a radial symmetrical flow condition in the 3D Broadband™ section downstream the Venturi, which would be the natural flow condition if the pipe were infinitely long. These flow conditions are ideal when using tomographic inversion techniques.

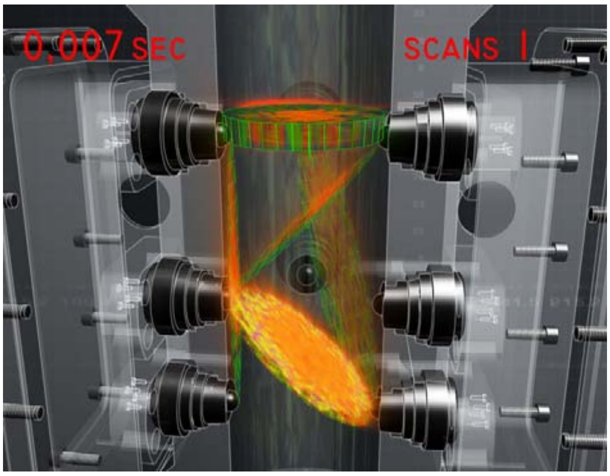


Figure 1: 3D Broadband™ tomography based meter

The 3D Broadband™ system is a high-speed electro-magnetic (EM) wave based technique for measuring the water liquid ratio (WLR), the water salinity and the liquid/gas distribution within the pipe cross section. By combining this information with the measurements from the Venturi, accurate flow rates of oil, water and gas can be calculated. The measurement is based on permittivity measurements performed at many simultaneous measurement frequencies at many planes within the sensor. The measurement frequencies cover a range of 20-3700 Mhz.

The MPM meter has a dual mode functionality, which means that the meter it is a combined multiphase and a wet gas meter. In wet gas mode, the MPM meter can either operate in three-phase mode or in two-phase mode. In three-phase mode, the meter measures all the fractions of the flow (oil, water and gas). Two-phase mode is used for verification purposes, and requires the GOR as an additional configuration parameter. The GOR is typically calculated based on the well composition.

At ultra-high GVF, when the liquid volume is extremely small compared to the gas volume, the Droplet Count® functionality significantly improves the measurement resolution of the liquid fraction. By using Droplet Count® , the MPM meter can make precise measurements of minuscule liquid volumes in a GVF range where no conventional technology is capable to make true three-phase measurements. The method is even highly tolerant towards changes in fluid PVT properties, such as the oil and gas density and water properties. This is achieved through a patented (pending) methodology with a significantly higher resolution on mixture density as compared to gamma based density measurements, and for which the liquid metering accuracy actually increases with increasing GVF.

More information about the MPM meter can be found in reference [5]-[11].

3 FIELD CONFIGURATION OF MULIPHASE AND WETGAS METERS

3.1 Multiphase meter technologies

Some of the most widely used multiphase meter technologies for fraction measurement are dual gamma systems and permittivity in combination with high energy single gamma density. The most common permittivity measurement is based using capacitive and inductive sensors [23].

Permittivity measurement based on capacitance and inductive sensor technology typical use a low frequency signals in order to measure the permittivity of the multiphase mixture (typical below 20 kHz [25]). Other multiphase and wet gas meters based on microwave technology perform permittivity measurements at higher measurement frequencies, which may be in the Mhz or Ghz region of the frequency spectrum.

Momentum rate meters, such as Venturi, V-Cone or special dP devices, are the most common velocity measurement devices. Some meters also deploy PD meters or cross-correlation techniques.

More detailed description of the available multiphase and wet gas metering technologies can be found in the Norwegian Handbook of MultiPhase Metering.

3.2 General configuration requirements

All multiphase meters require a set of configuration or PVT data describing the properties of the different flow constituents (oil, water and gas).

The PVT data is normally used for two purposes namely:

1) Calculation of fluid properties at actual temperature and temperature conditions (temperature and pressure at the location of the multiphase meter) which is used as input parameter to configure the measurements of the multiphase meter
2) Conversion of the measured flow rates at actual temperature and pressure conditions to a standard reference conditions such as 15 ºC and 1 bara.

The second purpose is common to all meters and is a general requirement when converting flow rates of hydrocarbons and water from one temperature and pressure conditions to another one.

For the first purpose, the amount and type of PVT data varies with the different metering technologies applied, as do the different technologies sensitivity to variations (errors) in the PVT configuration parameters. Therefore, some technologies may require more detailed and more accurate PVT configuration data whereas other technologies are more tolerant to variations in the PVT properties [2], [24], [7], [6].

As a consequence, the field experience gained with one type of metering technology may not be relevant for meters using other measurement principles. Until recently there has been little guidance in the industry related to the required precision in PVT data for the various metering technologies and there has been a perception that all multiphase and wet gas meters are equally highly influenced by errors in the PVT. One solution to this “problem” have been to do frequent (and expensive) sampling of the wells or to install a sampling unit as a part of the multiphase meter [24]. However, this “solution” may not be a needed for all metering technologies.

3.3 Obtaining reliable PVT data

The oil and gas PVT properties are typically calculated in a PVT simulation program based on the total hydrocarbon composition and downloaded as a temperature and pressure dependent look-up table.

Reliable PVT data is often hard to obtain, and therefore errors should be expected in such configuration data. There are two issues which then must be addressed. The first issue is the real uncertainty in the PVT data originating from the sampling, characterization process and EoS calculations. The second issue is the variations in the PVT data that might occur at a later stage due to changes in the reservoir, wellbores effects, or variations in the instantaneous contributions from individuals sections of a multi-reservoir completion.

In a real field application there can be significant errors in the PVT data, which may originate from several sources. Some of the error sources may be due to lack of representative samples of the fluids and errors in the characterization process. Commonly used Equation of State (EoS) models are also known to contain uncertainties, which typical give a bias in the calculation of the PVT data. Tests based on gas densities, calculated based on Equations of State, have shown that a positive bias is quite common at higher pressures and may typical be in the range 1-3% for the gas density.

All PVT models for calculating single phase properties at actual conditions rely on input of temperature and pressure. Temperature and pressure inputs may also contain a bias, which introduces shift in the configuration data for the meter. Finally, the fluids of the well may change during the period of the test or installation, further introducing errors in the PVT configuration data.

In a real field application, a 2-5% uncertainty in the PVT data would be considered normal. Even a 10% change (error) in the gas density and gas permittivity can be expected for comingled well applications, where the gas composition can change significantly over time. In order to provide reliable measurement of water production of a wet gas well, the measurement system needs to be able to handle uncertainties of 5-10% in the configuration fluid properties, like gas density and gas permittivity, and still maintain an accurate and repeatable water measurement.

For water flooded wells, the water properties may also vary significant over relatively short intervals. For reservoirs with high salinity formation water which is flooded with sea water or fresh water injection, the change in water properties such as density, conductivity and mass attenuation at low energies can be quite significant. A salinity change in the water salinity from 10% by weight to 5% by weight is not uncommon, and a multiphase meter must be able to cope with these variations without any intervention, and without compromising on the measurement performance.

4 EFFECT ON PVT DATA FROM FLUID VARIATIONS

4.1 Changes in H_2S and CO_2 content

An increasing number of oil and gas wells contain H_2S and CO_2. H_2S and CO_2 levels may vary from very small to large fractions (ppm to percentage levels) and poses specific challenges for multiphase meters in two areas:

1. Mechanical integrity
2. Measurement integrity

In a particular well or production zone, the H_2S and CO_2 content in the gas and oil phases may change over time, either as a result of

- Variations in temperature and pressure causing transfer of the H_2S and CO_2 from the oil to gas phase or vice versa whereas the mol fraction of H_2S remains constant in the total hydrocarbon fraction.
- Variation in H_2S and CO_2 mol fraction, due to changes in the reservoir, reinjection of H_2S and CO_2 rich (or lean) gas, changes in reservoir composition etc. This also changes the mole fraction of H_2S in the total hydrocarbon fraction

H_2S and CO_2 variations will impact the mass attenuation factors as well as the permittivity as outlined further below.

4.1.1 Mass Attenuation Coefficient

In the figure to the right is plotted the mass attenuation coefficients for various hydrocarbons, water solutions in addition to H_2S and CO_2. As can be seen, certain energy levels (like Barium in the lower range) are very much influenced by the various fluids, fluid solutions and their mass attenuation properties. At low energy, in particularly H_2S have a significantly higher mass attenuation coefficient compared to the hydrocarbon fractions. CO_2 also have a considerable higher mass attenuation coefficient compared to hydrocarbons at low energy.

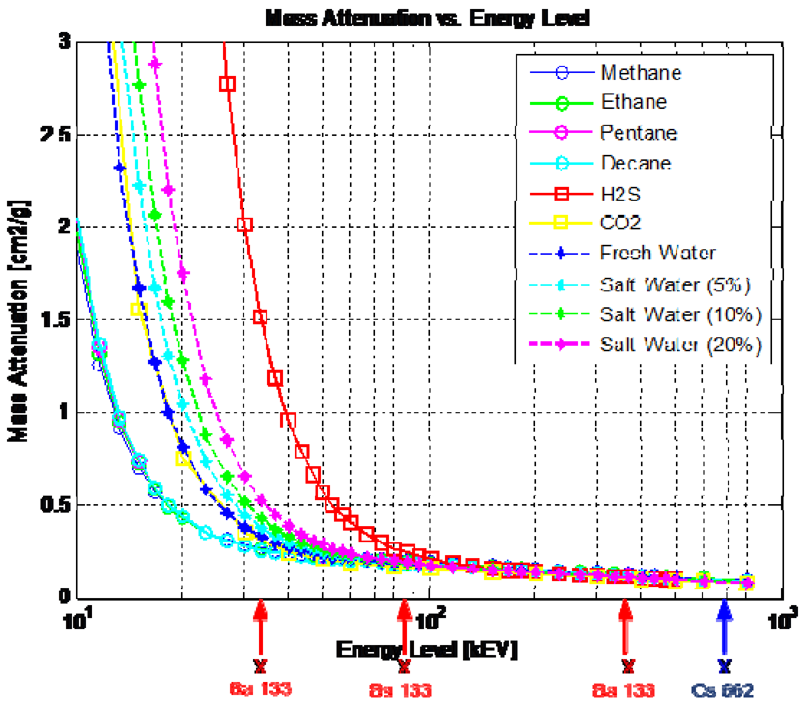


Figure 2: Mass attenuation coefficient vs Energy Level (Source: NIST)

The count rate at the gamma detector, density and mass attenuation coefficient of the fluid within the pipe relates according to the following equation:

$$N = No * e^{-\gamma \rho x}$$

N : Gamma Photon Count Rate
No : Empty Pipe Calibration Value
μ : Mass attenuation coefficient
ρ : Density
x : Pipe diameter

The Caesium high energy gamma technology (single energy at 662 keV) has a significant higher energy compared to traditional dual gamma system. At this energy level the mass attenuation coefficient is almost constant and does not change much as a function of the composition. Hence the measurement is virtually a true density measurement which makes a system based on this energy level less dependent on fluid sampling. This is also illustrated in the graph in figure 2 which shows that the mass attenuation coefficient is almost constant for all the stated materials at the 662 kEV energy. Hence, when using high energy (662 keV) gamma technology, the GVF and density measurement of the Caesium meter is virtually unaffected by changes in the H_2S and CO_2 content compared to low energy systems.

4.1.2 Permittiv ity

It is well known that permittivity measurements at high frequency (typically above 1 Ghz - microwave and RF based techniques) are much more tolerant towards variation in the composition of the oil compared to permittivity measurements at low frequency (kHz region - capacitance based techniques) [14].

Below are two graphs (figure 3 and 4) illustrating the frequency dependency of the permittivity for different oil compositions, published by Friisø et al [14].

Figure 3 and 4 below shows the real part of the permittivity of an oil example with different asphaltene fractions (the concentration dipolar fractions like N, S, and O are highest in heavier fractions like asphatlenes) [14]. The lower end of the scale is at 1 kHz which is a frequency region often used by capacitance based meters (typical 2-50 kHz). The right corner of the scale is at 1 Ghz.

The MPM meter uses frequencies up to 3.7 Ghz as illustrated by the arrow on the chart. As seen from the graph, the variation in permittivity as a function of asphaltenes is far less at high frequency compared to the permittivity at low frequency (H_2S has a similar impact as asphaltenes). Hence using a high measurement frequency is essential in order to obtain a permittivity measurement which is tolerant towards variations in the composition of the oil.

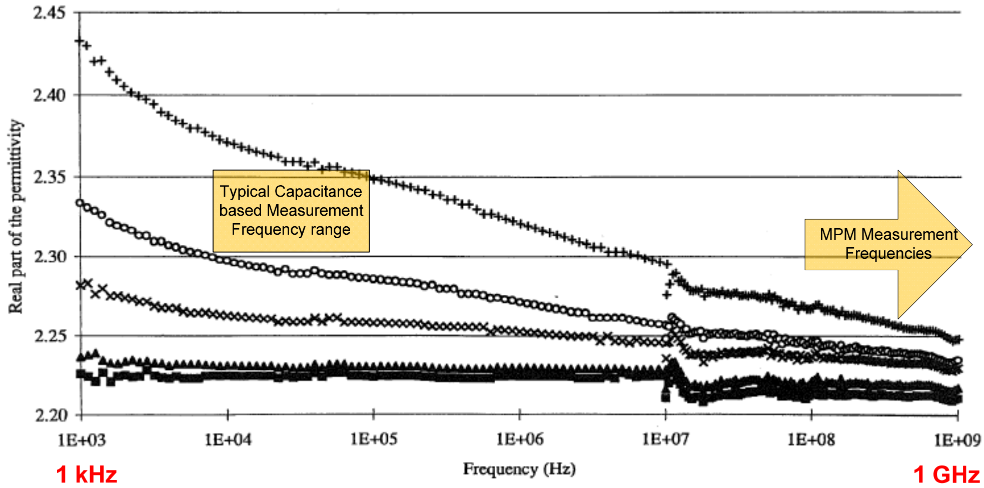


FIG. 1. The real part of the permittivity spectra for n-decane/toluene 1:1 by volume (■), 1% (▲), 5% (X), 10% (o) and 17% (+) n-pentane asphaltenes in n-decane/toluene.

Figure 3: Oil Permittivity (real part) vs. measurement frequency [14]

Below is the corresponding figure for the imaginary part of the permittivity.

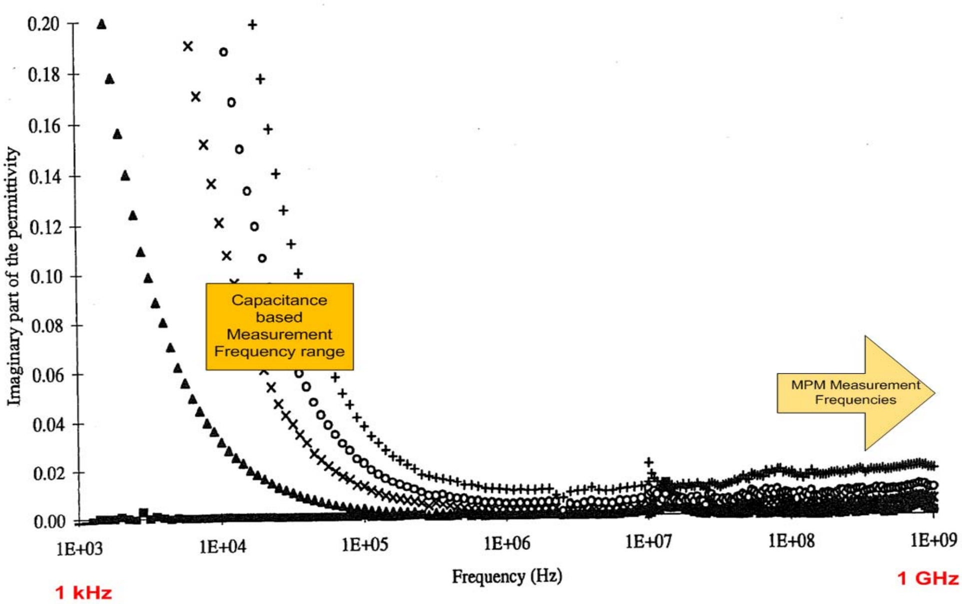


FIG. 4. The imaginary part of the permittivity spectra for n-decane/toluene 1:1 by volume (■), 1% (▲), 5% (x), 10% (o) and 17% (+) n-pentane TIAF in n-decane/toluene.

Figure 4: Oil Permittivity (imaginary part) vs. measurement frequency [14]

As seen from the graphs in figure 3 and 4 above, the spread in the imaginary part of the oil permittivity is significant at low measurement frequencies whereas the permittivity is almost constant at the high measurement frequencies used by the MPM meter. Hence, a high frequency permittivity measurement is much more tolerant towards changes in the compositions of the oil. The permittivity used in the mixing formulas (like Bruggerman) is based on the effective permittivity of the oil. Effective permittivity is defined by the following equation:

$$\varepsilon_{eff} = \frac{\varepsilon^{'}}{2} * \{1 + \sqrt{1 + (\frac{\varepsilon^{''}}{\varepsilon^{'}})^2}\}$$

where ε' is the real part of the permittivity and ε'' is the imaginary part of permittivity.

Based on the above equation for the effective permittivity for oil it is seen that the variation in the oil permittivity at high frequency is typical ± 0.5 - 1% due to asphaltenes whereas the variation at low frequency permittivity measurements typical is 4 times higher (or more) when adding up the impact from the real and imaginary part. The density dependence of the permittivity of any dielectric substance is fundamentally governed by Clausius-Mosotti type relations ref, W. Greiner – "Classical Electrodynamics" [5], as shown in equation 1 below.

$$N\,\gamma = \frac{3}{4\pi}\,\frac{\varepsilon_r - 1}{\varepsilon_r + 2} \quad \text{(c.g.s units)} \quad (1)$$

where ε_r is the relative permittivity, γ is the molecular polarizability which depends on the type of material, and N is the number of molecules per unit volume which is proportional to density. The density dependence of any substance is hence given by an expression of the type:

$$C\,\gamma\,\rho = \frac{\varepsilon_r - 1}{\varepsilon_r + 2} \qquad (2)$$

where C is a constant and ρ is the density. There is no fundamental difference between hydrocarbons, H_2S and CO_2 in this respect. The MPM meter is calculating the permittivity of the oil and the gas utilising the Clausius-Mosotti relationship and empirical measurements of oil and gas permittivity. The permittivity models are based on CO_2 and H_2S free oil and gas and is corrected for presence of H_2S and CO_2 using the Clausius-Mosotti relationship and physical properties of H_2S and CO_2 found in [15].

4.2 Changes in H_2S, CO_2 and Water Salinity

4.2.1 Calibration triangle

For dual gamma systems, it is common to illustrate the effect of changes in PVT properties using the calibration triangle. A typical calibration triangle for a dual gamma system with a 30 keV low energy and 100 keV high energy is shown in figure 5.

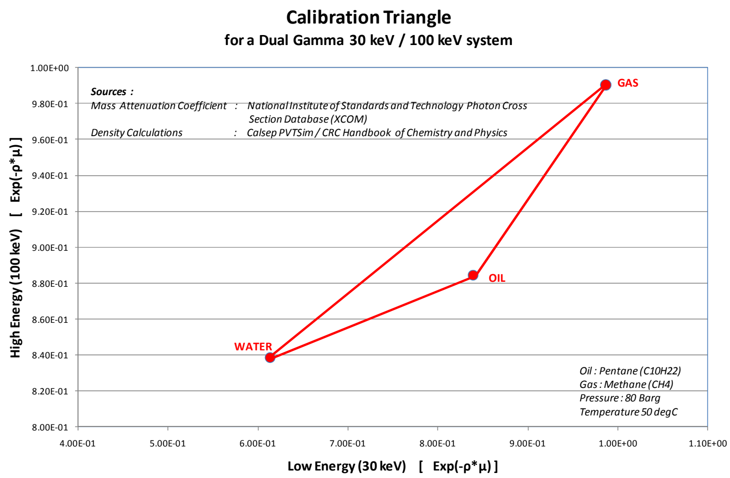


Figure 5: Calibration triangle for a 30/100 keV Dual Gamma System

For this example, the mass attenuation coefficient for oil water and gas is calculated using the National Institute of Standards and Technology (NIST) XCOM photon cross section database which is found at http://physics.nist.gov/PhysRefData/Xcom/Text/XCOM.html . Pentane $C_{10}H_{22}$ is used for oil and Methane CH_4 is used as gas and the water is saline water containing 10 % NaCl by weight. Based on the measured low and high energy level, which should fall within the calibration triangle, it is possible to calculate the fractions of oil, gas and water.

A similar calibration triangle can also be used for a system like the MPM meter, as shown in the next figure. The Y-axis is the product of the density and mass attenuation for the 662 keV single energy gamma measurement and the X-axis is the permittivity. The oil and gas point will be located at a fixed position. The water permittivity will change as a function of the measurement frequency as described by the Debye Relaxation Law for calculation of the effective permittivity of water [10].

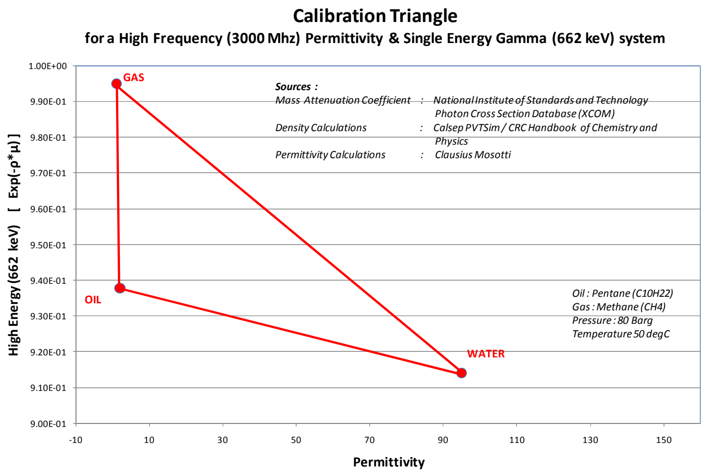


Figure 6: Calibration triangle for a High Frequency Permittivity and 662 keV single Gamma System

Since the MPM meter is using many simultaneous measurement frequencies, there will be many simultaneous calibration triangles. In the example above, a measurement frequency of 3000 Mhz has been used. It is also worth mentioning that the fractions are not a linear function of the value of the X and Y axis and it will also be different in oil and water continuous flow. However, the calibration triangle is a useful tool to illustrate how the measurements are influenced by changes in the oil, water and gas PVT properties which is used to configure the meter.

4.2.2 Sensitivity to changes

Changes in the PVT properties for oil, water and gas will have the effect of moving the calibration points in the phase triangle. Hence, if the change in PVT properties is not accounted for by updating the position of the calibration point, it will introduce a measurement error in the calculation of the phase fractions of oil, water and gas.

In this section the effect of such errors will be analysed by some case examples. All the cases have been calculated at an operating temperature of 50 ° and operating pressure of 80 barg. Calsep PVTSim is used for calculation of the oil and gas density based on the composition of Methane and Pentane with H_2S and CO_2.

Calculations have been performed for the following cases:

1) Oil and Gas with 0-30% (weight) dissolved H_2S
2) Oil and Gas with 0-30% (weight) dissolved CO_2
3) Water salinity change from 0 – 25% NaCl by weight

Figure 7 shows the effect on the calibration triangle for a 30/100 keV Dual Gamma system and figure 8 shows the effect for a 662 keV gamma, high frequency permittivity system.

From figure 7 and 8 it is seen that the water point is influenced similarly by changes in water salinity changes in both cases, which illustrates the importance of in-line measurement of the water salinity at high watercuts. However, the impact of H_2S and CO_2 is very different for the two systems.

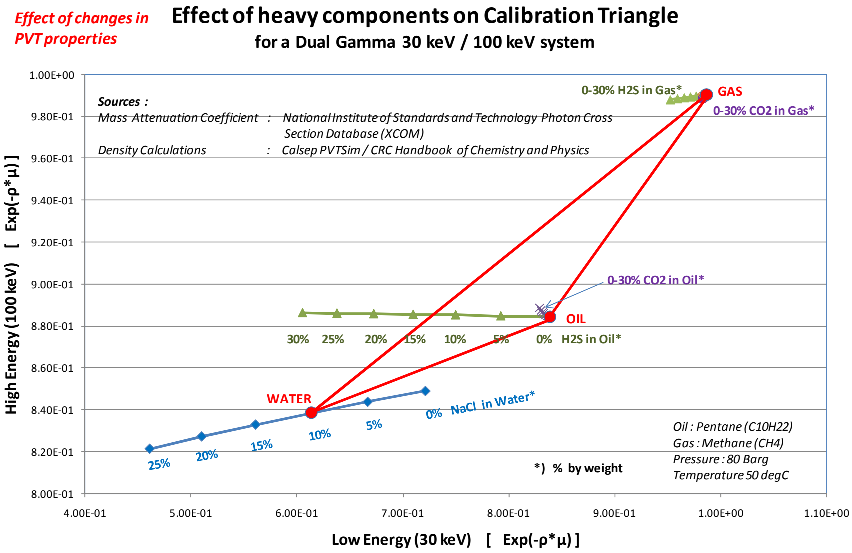


Figure 7: Effect on the calibration triangle for a Dual Gamma 30/100 keV system for changes in H_2S, CO_2 and NaCl content

For the Dual Gamma system, H_2S dissolved in the oil have a large impact on the low energy calibration point for oil which in particular has a large influence on the measured watercut. For the Dual Gamma system, the "triangle" becomes a straight line when the H_2S content is approximately 12 % and hence the meter would be unable to perform any measurements of the WLR. For H_2S content above 12%, the triangle "flips".

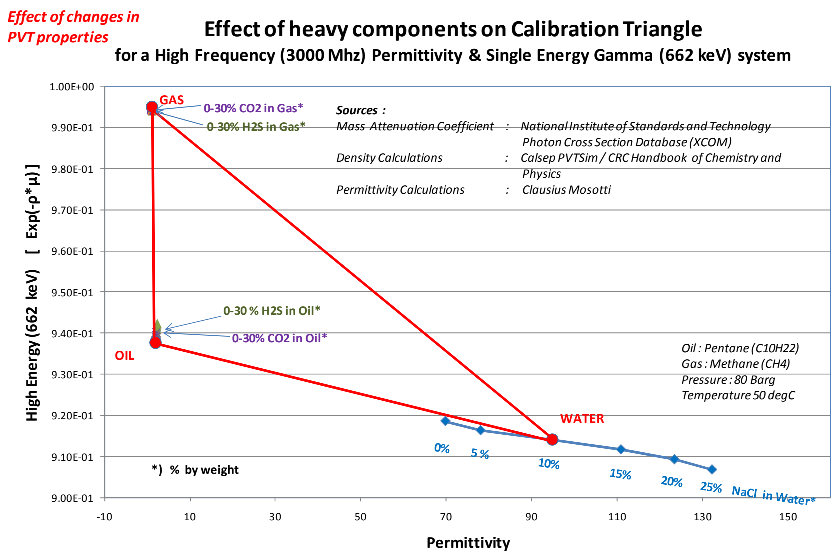


Figure 8: Effect on the calibration triangle for a High Frequency Permittivity and 662 keV single energy system for changes in H_2S, CO_2 and NaCl content

For the HF permittivity/660 keV gamma system, a 0-30% change in the H_2S content has a marginal impact on the triangle. H_2S in the oil influences the oil/gas ratio and introduces a small zero shift of the watercut measurement.

For the Dual Energy system, dissolved H_2S in the gas also have a quite large impact on the low energy calibration point for the gas, whereas dissolved H_2S have a small impact on the gas point for the HF permittivity/662 keV gamma system. In both cases, dissolved CO_2 in the gas have a small impact.

The example above illustrates the need for fluid sampling when using a 30/100 keV Dual Gamma system, particularly for applications containing H_2S and CO_2. The example also demonstrates that the field experience gained with one type of multiphase meters may not be directly transferred to meters based other metering principles. It is also worth noting that a dual gamma system which uses higher energy levels will be less influenced by H_2S and CO_2, whereas a dual gamma system that uses lower energy levels will be even more influenced which further complicates the issue of comparing different metering technologies.

The PVT robustness of the MPM meter, being a HF permittivity/662 keV gamma tomgraphic based meter, is an important enabling factor for simplified field configuration and In-Situ measurement of fluid properties. It also make it possible to use a more generalised fluid compositions for calculation of oil and gas properties, particularly when this is combined with automatic configuration of water and gas PVT properties using the salinity and in-situ gas measurement functionality of the meter.

5 MPM WITH IN-SITU MEASUREMENT OF FLUID PROPERTIES

5.1 Unique methodology

The MPM meter has three methods for In-Situ measurement of fluid properties that represent further increased robustness against uncertainties of the PVT properties for the MPM technology.

1) Measurement of water salinity of the water phase. This is an in-line continuous measurement which is performed while the well is flowing. Separate methods are used for water continuous conditions multiphase flow conditions and wetgas flow conditions.
2) Measurement of gas density and permittivity by utilising the DropletCount method to detect periods with pure gas within the pipe. During these periods, the permittivity and density measurement is used to measure, verify and correct the PVT calculated values for permittivity and density. The method can also be used to measure the permittivity and density of oil
3) In wetgas, the MPM meter incorporates three different methods for measurement of the fractions and flow rates of the wetgas which can be used to determine PVT properties. This is also an in-line continuous measurement which is performed while the well is flowing based on recalculation of the following measurement modes;
    a) two-phase mode with GOR Input
    b) three-phase mode
    c) three-phase mode with Droplet Count®

    These three methods behave differently when errors are introduced in the PVT configuration data which can be used to calculate an estimate of the PVT configuration data.

5.2 Measurement of Water Properties

The MPM meter can measure the conductivity of the produced water. The measured conductivity is converted to salinity, and the water density is calculated assuming a certain composition of the salt (e.g. NaCl). Based on the measured temperature and salinity of the water, the viscosity of the water can also be calculated by the meter. The measurement method is based on RF measurements and MPM's patented 3D Broadband™ technology.

The MPM meter can automatically measure the water conductivity and density in water-continuous emulsions.

For low watercut, the water conductivity has little effect on the measurement uncertainty, provided the specified value is within reasonable limits of the true value. If, however, the Water Liquid Ratio (WLR) is expected to increase during the life of the field and the flow changes to water continuous, then configuring a multiphase meter with the correct water conductivity is important.

With MPM's automatic configuration, the water conductivity and water density are automatically and continuously measured by the meter. This eliminates the risk of getting wrong measurement as a consequence of incorrect configuration data. It also eliminates the need to take the produced water/liquids samples, in order to update the configuration constants when the watercut is increasing, and when the salinity of the produced water is changing. This is very valuable for unmanned and remote operations, as well as for subsea installations.

The watercut for which the flow turns into water-continuous depends on the application, but normally it occurs when the watercut gets in the 30-60% range – although water-continuous conditions have been seen at the lower end and the upper end depending on the general flow regime and fluid properties. If slugging is expected, measurement of the water conductivity could be important even for lower watercuts. The reason is that if the water comes in slugs, then the watercut during the slug can be well above the water-continuous threshold. If so, and if the water conductivity is incorrectly specified, the oil and water flow rates will be heavily distorted.

Another benefit of the method is that the water conductivity is measured at actual temperature conditions, avoiding discrepancies in the models which convert the conductivity from one temperature to another. As an example, it is common to use the conductivity at 25ºC as a configuration parameter, since the water conductivity in most cases is measured in a laboratory at room temperature and converted to 25ºC. The multiphase meter requires the water conductivity at actual conditions, and hence the water conductivity needs to be converted from 25ºC to the actual line temperature, which may differ significantly. This conversion model may be quite inaccurate, introducing a secondary source of error for meters which rely on the water conductivity as a configuration parameter. This is avoided when the water conductivity is measured at line conditions.

The water conductivity/salinity measurement is based on a patented method using dielectric measurements carried out locally at the pipe wall, using a differential principle with one transmitting and two receiving antennas. Electromagnetic phase measurements are performed over a broad frequency range, and each measurement frequency provides a separate independent equation. All the measurements are combined in such a way that the measured water conductivity represents a "best fit" of the measured water fraction for all the measurement frequencies, assuming that the ratio between the real and imaginary part of the dielectric constant of the multiphase mixture is related to the ratio between the real and imaginary part of the dielectric constant for pure water.

In wetgas applications, the salinity measurement method implemented in the MPM meter is split into two stages:

- First, it is determined whether salt is present in the stream or not (by a so-called salt water index)
- Second, if salt is present, then the salinity is measured quantitatively

The reason for this two-step approach is that some measurement plans of the 3D Broadband™ are very sensitive to presence of salt, whereas others are useful to determine quantitatively the degree of saltiness. This feature is also used as a type of quality assurance.

Another reason for splitting the salinity measurement into two stages is to make the formation water break-through measurement robust with respect to discrepancies in the configuration data, such as the dielectric properties of the gas phase. The water salinity measurement is related to the water fraction measurement, such that any error in the water fraction measurement will relate to an error in the measured water salinity. As an example, the dielectric properties of the gas is a configuration parameter for the meter, and a discrepancy in the dielectric constant for gas may cause a measurement error on the water fraction and hence the water salinity. The salt water index on the other hand, is virtually independent of the gas properties and, as a consequence, reliable detection of salt (or formation water) can be achieved irrespective of significant discrepancies in the dielectric constant of gas.

The salinity measurement is further described in reference [7]-[9].

5.3 Measurement of Gas Properties

A patented (pending) method for in-situ measurement of gas properties has been developed and implemented in the MPM meter [17]. The method uses the Droplet Count® function [26] to detect short periods of time where pure gas flows through the measurement section of the meter. Alternatively the meter can be bypassed, and gas filled during a scheduled shut-in of the well or during the passage of long gas slugs.

Figure 9 below shows the measured GVF and the liquid detection signal, called the Liquid Index, for a gas filled period in the measurement section. The yellow line is the threshold value for gas detection.

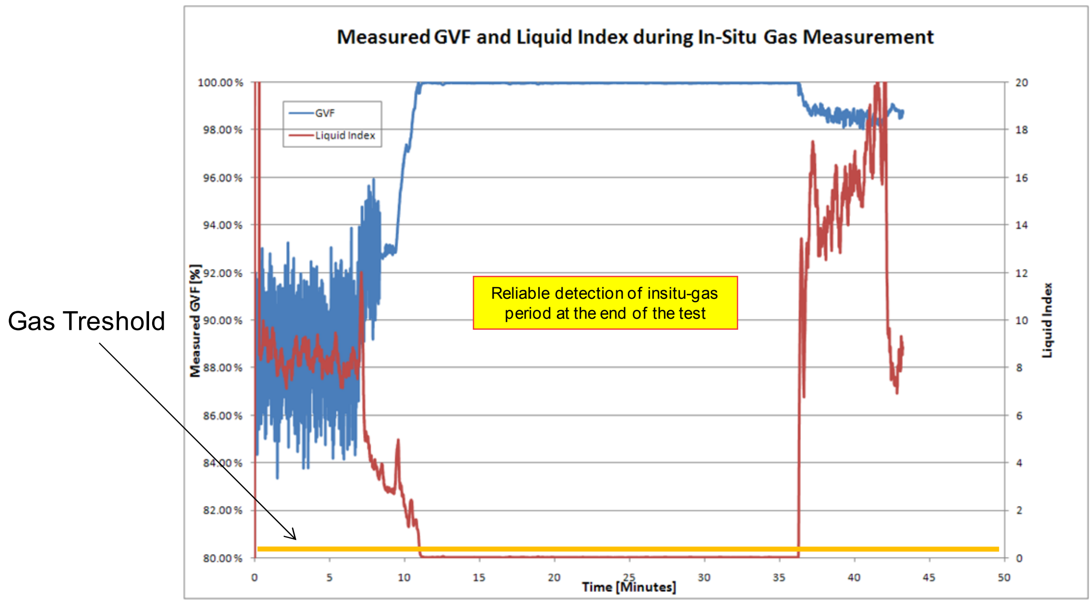


Figure 9: Example of detection of gas in the meter

When pure gas is present, the permittivity and the density of the gas are measured using the 3D Broadband™ section and the gamma densitometer. The Droplet Count® is so sensitive to droplets that it immediately detects when condensation of liquid starts to occur, due to falling temperature, such that the in-situ gas measurement can be halted in due time.

Since the 3D Broadband™ section performs measurement of permittivity at multiple frequencies and on multiple measurement planes, many different measurements of the gas permittivity and density can be made. These all should give the same result, and thus the gas in-situ gas measurement has a built-in quality verification function of the 3D BroadBand™ measurements. Such measurements can also be used to verify the integrity of the 3D Broadband™ sensors during flow.

The in-situ measurement can either be used to calculate correction factors to the input configuration gas density and gas permittivity, or to adjust the composition of the well fluid and generate new look-up tables using a sub-service based on the Calsep PVTSim routines.

Two methods for use of the in-situ gas measurement have so far been implemented; a manual procedure and a method based on automatic update. The automatic method is well suited for applications where frequent variations in the gas properties are expected. In the manual version, an in-situ report is generated, where the in-situ measurements are documented together with a calculation of the effect any changes in the gas configuration data may have on historical measurements. A recommendation for potential corrective action is also added to the report before it is issued to the operator for final approval. If the operator approves the corrective actions, the in-situ measured corrections to the gas density and permittivity are implemented in the MPM meter, and the date and time of the implementation is noted in the in-situ report.

This manual procedure ensures full traceability of any changes performed on the gas configuration data, and the procedure is particularly suited for applications where the MPM meter is used for fiscal applications. This procedure is typically used as a part of the commissioning of the meter. Most MPM meters are pre-configured with the field PVT data prior to delivery, as a part of the FAT procedure. The MPM meter is then fit for service immediately at start up of the wells. Following successful commissioning of the field and the individual wells, any in-situ measurements made can then be inspected to validate the pre-configured PVT data in the meter.

Evaluation of the in-situ gas measurements may also be performed on a regular basis as part of the metering quality assurance plan. Using pre-agreed acceptance limits for the in-situ gas measurements, allows the operator to efficiently process the in-situ reports. This procedure also ensures that the operator has full documentation of the validity of the configuration data for the meter. Documentation of the integrity of the measurements from the meter is also obtained by inspecting the historical trend of the multi-frequency and multi-directional measurements from the 3D Broadband™ sensor in gas.

5.4 Comparrison between measurement modes

As mentioned above, the MPM meter incorporates three different methods for measurement of the fractions and flow rates (2-Phase mode, 3-Phase mode, 3-Phase mode with DropletCount) which all are influenced differently by errors in the PVT configuration data.

Error in the PVT configuration data is one potential source for the discrepancy between the two measurement modes. In [7] the influence of PVT configuration parameters in wetgas mode was analyzed in 2-Phase mode and 3-Phase mode without DropletCount. As shown in the contour plots in section 3 of [7] , the gas and hydrocarbon mass rates are very little influenced by error in the gas PVT data for both measurement modes.

In 2-Phase mode operation, the gas density and GOR input mode have the largest impact on the measurement result. The contour plots in section 3 of [7] also show that 3-Phase mode and 2-Phase mode are influenced differently by error in the configuration data. The water fraction is little influenced by error in the gas density in 3-phase mode operation, whereas it has a significant impact on the water fraction in 2-phase mode. Similarly, the gas density have a large relative impact on the liquid flow rate in 3-Phase mode without droplet count, but as little influence on the measured liquid flow rate when the DropletCount function is used in 3-Phase mode or when the meter is operating in 2-phase mode.

This difference in behavior can be used to investigate the most likely source for the discrepancy and provide an estimate of corrections to the PVT configuration data used by the meter. This is done by using logged raw data within the meter which is then used to reprocess the measurements in 2-Phase mode, 3-Phase mode and 3-Phase mode with Droplet Count for a range of Gas Densities and GOR inputs. The density and GOR range is typical selected such that it spans around the PVT calculated values.

The measured water fraction and liquid flow rate is plotted vs. the Density and GOR range for all measurement modes, and by inspecting the interception points between the modes, it is possible to obtain an estimate of the gas density and GOR input which minimizes the discrepancy between the different measurement modes. These data can be used together with in-situ gas measurement to validate the PVT data and even trend changes in the PVT data.

6 SIMPLIFIED FIELD CONFIGURATION

The robustness of the MPM meter towards errors in the PVT data and the ability to perform in-line measurement of the water and gas properties have enabled MPM to implement a simplified procedure for field configuration of multiphase and wetgas meters.

Simplified field configuration means that the meters are delivered ready field configured from the MPM factory and are therefore fit for field service upon delivery from the factory. For subsea applications the operator can install and commission the meters and start producing wells without any assistance from MPM. For topside meters, some assistance may be needed in connection with installation and calibration of the gamma source, but apart from that, the operator can do all the needed work to put the meters in operation.

In order to use the simplified configuration scheme, it is required that the PVT configuration of the meter is handled during the production phase of the meters. During this period, the operator should provide MPM with the most recent (or relevant) PVT data for the reservoirs or wells where the meter is going to be used. In order to do the evaluation, the total hydrocarbon composition is needed for the various reservoirs, preferable as a fully characterised fluid to avoid errors in the characterisation process. Alternatively, a characterised oil and gas fluids can be used which MPM can recombine to generate a relevant total composition.

Based on the available data, MPM will evaluate the expected range in PVT data. This analysis will reveal if a generalised PVT composition can be used for all the flow cases or if several different PVT setups are needed.

If the water salinity measurement option and in-situ gas measurement option is enabled, the meter will be configured to use the measured water salinity to calculate the water conductivity, water density and water viscosity based on the measured water conductivity. Similarly, the meter can also be configured to use the In-Situ measured gas PVT to correct the PVT calculated values for gas. Alternatively, the PVT calculated and in-situ measured values will be logged in the database and use to manually correct the PVT configuration data when the meter has been in operation for a while.

MPM will then issue a configuration report which describes the recommended configuration of the meter with respect to PVT data for oil, gas and water and use of the water salinity measurement and in-situ gas PVT measurement. At the end of the FAT test in the MPM factory, the MPM meter will be configured according to the configuration report, witnessed by the operator, and the meter is fit for field service.

After the meter has been in operation for a while, it is recommended to perform a verification of the PVT data in the meter using the in-situ verification functionality. If the installation is equipped with a remote connection to MPM, the in-situ verification can easily be done remotely by MPM. At present, approximately 50% of the MPM meters in operation can be accessed remotely. Several field commissions have also been done remotely from MPM.

7 CASE EXAMPLES

7.1 Multiphase and WetGas

Most MPM meters in operation are using the simplified configuration scheme as described in section 6 above.

In [6] (2009), the operational experience with a MPM meter, configured with one common PVT configuration for all the wells at the Ekofisk field in Norway, is described. The Meter was configured in October 2007. Even though there was some scatter in the PVT properties for the different wells, one common (average) PVT configuration was used for all the wells. In addition, the meter was delivered with automatic configuration of water properties, based on the measured conductivity. The operating conditions at Ekofisk are typical *multiphase flow,* represented by high watercuts, GVF over a large span and severe slugging.

Based on the operational experience, ConocoPhillips concluded that:

> *"One common PVT configuration has been used for all the 15 wells at the test header, and the measurements from the MPM meter have proved to be robust with respect to variation in the PVT configuration data with no need for sampling of the wells."*

and

> *"The meter handles extreme salinity changes without recalibration."*

Similar experiences have been gained at many other locations and presented in various papers and conferences [5], [7], [8], [9], [10], [11], [18], [19], [20], [21], [22].

7.2 We tgas

7.2.1 Measurement mode comparrison

In this section is given an example where the in-situ gas PVT measurement functionality is used in a high pressure wetgas application.

As outlined in section 5.4, the MPM meter incorporates three different methods for measurement of the fractions and flow rates of the wetgas which can be used to determine PVT properties. The three methods behave differently when errors are introduced in the PVT configuration data, which is a feature that can be used to calculate an estimate of the PVT configuration data.

The four charts in figure 10 and 11 below show the measured gas volume rate, hydrocarbon mass rate, liquid volume rate and water fraction for three wetgas conditions (GVF, 93%, 97% and 99.5%). The measurements are performed at an operating pressure of approximately 100 barg. In the charts, results are shown for measurements in 3-phase and 2-phase mode.

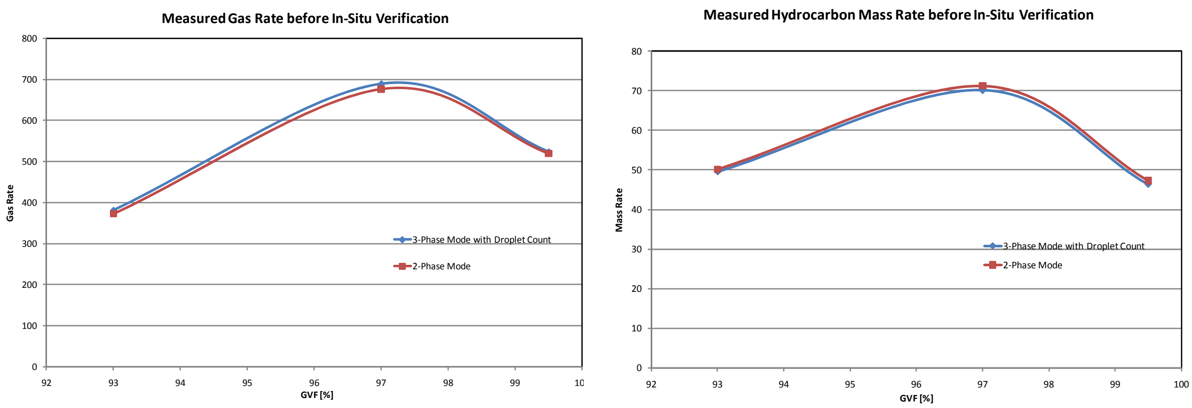


Figure 10: Measured Gas and Hydrocarbon flow rate for 3 GVF cases in 2-Phase and 3-Phase mode operation

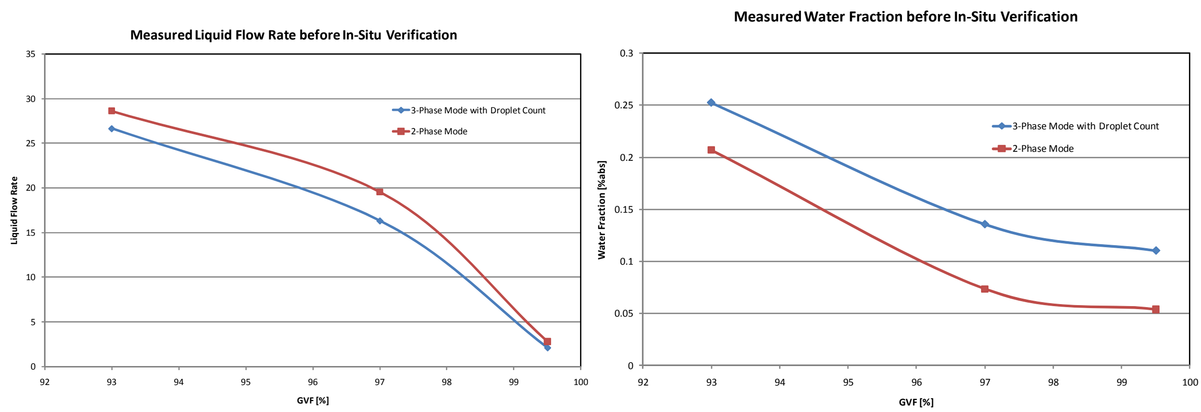


Figure 11: Measured Liquid and water fraction for 3 GVF cases in 2-Phase and 3-Phase mode operation

From the charts above it is seen that the measured gas volume rate and hydrocarbon mass rate agree well between 2-Phase and 3-Phase mode, whereas a bias is seen between the measured liquid and water fraction in the two measurement modes. Droplet Count is used for GVF of 99.5%, but not for the 97% and 93% GVF case. At high GVF, the dominating PVT configuration parameters are the PVT calculated density for gas and the PVT calculated GOR input in 2-phase mode [7].

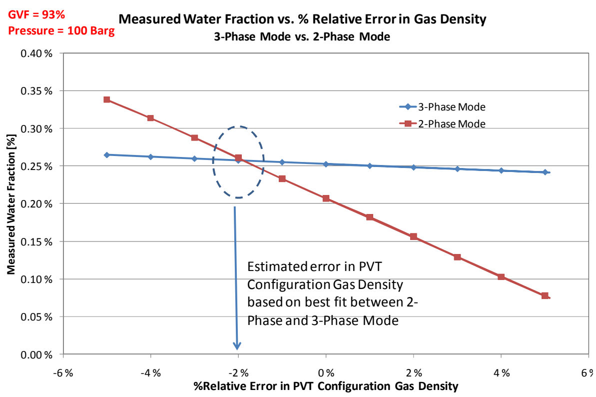
7.2.2 In-Situ Measurement of Gas density

From theory and experience, we know that the water fraction measurement in 3-Phase mode is little influenced by an error in the gas density whereas the water fraction measurement in 2-Phase is highly influenced by an error in the gas density. Since the two methods have different sensitivity to error in the gas density, this can be used to determine the most likely value of the gas density based on identifying the gas density which gives the best match in both measurement modes. This is done by varying the gas density and identifying the crossover point on the water fraction between 2-Phase and 3-Phase mode. The cross over point defines the value of the gas density which gives the best fit.

Similarly, the liquid flow rate in 2-Phase and 3-Phase mode with DropletCount is very little influenced by the gas density whereas the liquid flow rate can be highly influenced by the gas density in 3-Phase mode without DropletCount. By varying the gas density and identifying the crossover point on the liquid flow rate between 2-Phase and 3-Phase mode it is possible to find an estimate of the gas density.

Figure 12 below shows the recalculated water fraction (denoted measured water fraction) and the recalculated liquid flow rates (denoted measured liquid flow rates), when an error span of ± 5% is introduced in the PVT calculated gas density for 3-Phase and 2-Phase mode. This is done for the tests at a GVF of 93 %. Recalculated results mean that the raw sensor data from the original test are used, only with a different set of configuration parameters.

As seen in figure 12, the water fractions calculated in the two measurement modes change as a function of the relative change in the gas density and intercepts at a gas density error of -2%. Similarly, the calculated liquid flow rate changes as a function of the error in the %relative change in the gas density, and the liquid flow rates in the two measurement modes intercept at a gas density error of -3.8% indicating a negative density error in the range 2-4% in the PVT calculated gas density.



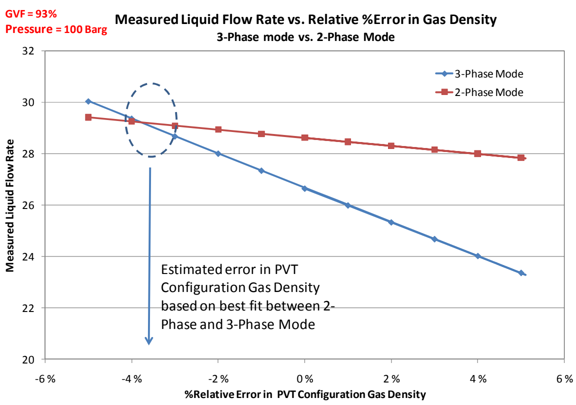
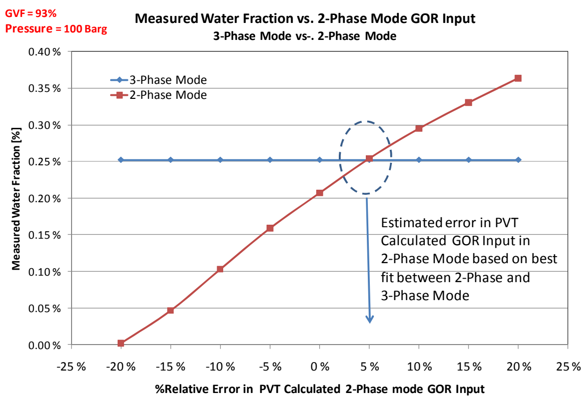


Figure 12: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the gas density for 3-Phase and 2-Phase mode operation at GVF of 93%

7.2.3 Verification of GOR input value

The above assumes that the entire discrepancy is due to an error in the gas density. The error may, however, also be in the PVT calculated GOR input in 2-Phase mode. In order to study the effect of error in the PVT calculated GOR input, a similar recalculation study can also be performed. E.g., by varying the GOR and identifying the crossover point for the water fraction and liquid flow rate between 2-Phase and 3-Phase mode, an estimate for the potential error in the GOR can be found. This procedure can again be repeated for different values of the gas density in 3-phase mode which would give rise to a set of likely errors in the gas density with corresponding errors in the GOR input.

Figure 13 below shows the recalculated water fraction and the recalculated liquid flow rate for a ± 25% error in the PVT calculated GOR input for 2-Phase mode. As seen on the graph, the water fraction and liquid flow rate in 2-Phase mode changes as a function of the relative error in the GOR input. Since the GOR input is not used in 3-Phase mode, the calculation in 3-Phase mode is unaffected by changes in the GOR input. From figure 13 below it is seen that the discrepancy in the measured water fraction and liquid flow rate between 2-Phase and 3-Phase mode may also be due to a 5-15 % error in the PVT calculated GOR input for 2-phase mode.



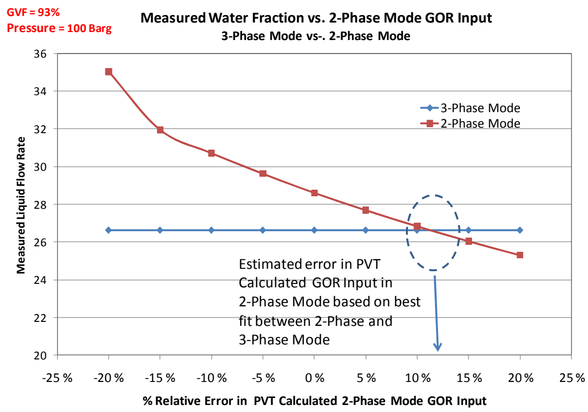


Figure 13: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated GOR input in 2-Phase mode for 3-Phase mode and 2-Phase mode operation at GVF of 93%

7.2.4 Further analysis at different GVF's

From the analysis in the sections above it is seen that the source of the discrepancies in results for 2- and 3- phase mode can be either a 2-4% negative bias in the PVT calculated gas density used by both measurement modes, or a 5-15% positive bias in the PVT calculated GOR input in 2-phase mode. In most field applications, a 2-4% error in the PVT calculated gas density may be equally realistic as a 5-15% error in PVT calculated GOR input, and hence, more measurements or evidence would be required in order to identify the source of the discrepancy. However, the tests have revealed that there is a PVT discrepancy which needs to be further investigated and monitored.

Figure 14 below shows the recalculated water fraction and the recalculated liquid flow rate for a ± 5% error in the PVT calculated Gas density for 3-Phase and 2-Phase mode for the same case. In this case, another set of raw data are used; those obtained at a GVF of 97%.

As seen in figure 14, the water fractions for this case intercept at a gas density error of -2.5% and the liquid flow rates intercept at a gas density error of -2.8%. Quite interestingly it is seen that, at a GVF of 97%, both the water fraction and the liquid test indicate a negative density error in the range of 2.5 - 3% in the PVT calculated gas density. This is very similar to the error range calculated at a GVF of 93%.

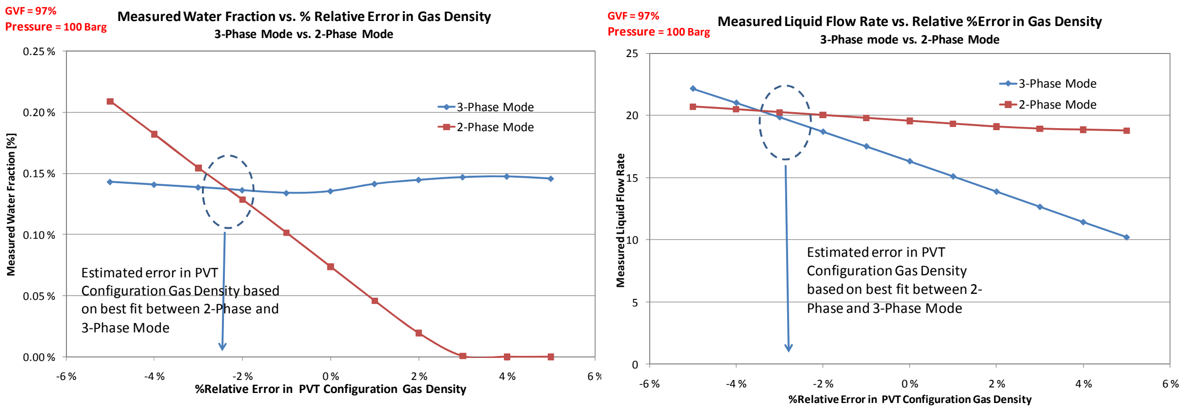


Figure 14: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated gas density for 3-Phase mode and 2-Phase mode operation at GVF of 97%

Figure 15 below shows the recalculated water fraction and the recalculated liquid flow rate for a ± 50% error in the PVT calculated GOR input for 2-Phase. From figure 15 below it is seen that the discrepancy in the measured water fraction and liquid flow rate between 2-Phase and 3-Phase mode may also be due to a 40-50 % error in the PVT calculated GOR input for 2-phase mode. A 40-50% error in the PVT calculated GOR is in most cases considered to be quite significant which indicates that the most likely source of the error is in the gas density. This is further confirmed by the fact that the error in the gas density at a GVF of 97 % is within the same range as for the calculation at 93% GVF, whereas the potential error in the GOR input have increased from a 5-15 from 93-97% GVF.

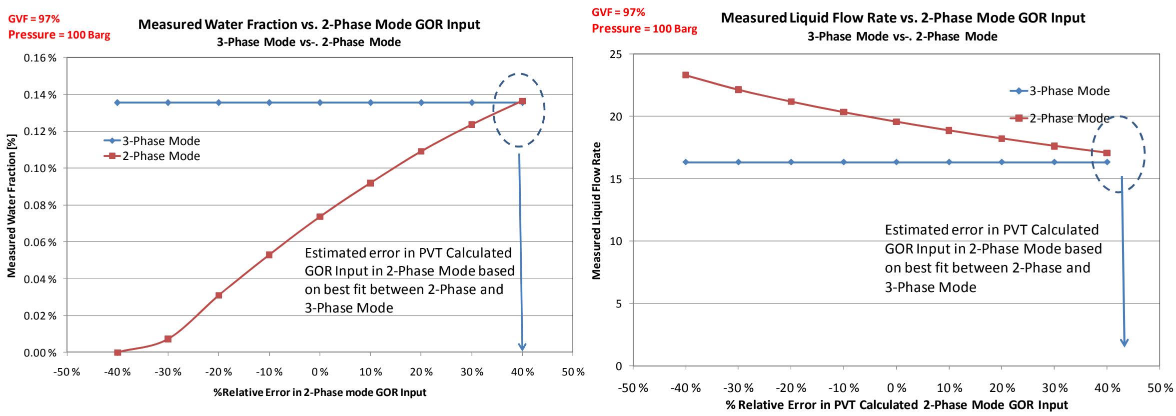


Figure 15: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated GOR input in 2-Phase mode for 3-Phase mode and 2-Phase mode operation at GVF of 97%

Figure 16 below shows the recalculated water fraction and the recalculated liquid flow rate for yet another value of GVF, this time 99.5%. Again, results are shown for a ± 5% error in the PVT calculated Gas density for 3-Phase, with and without DropletCount and 2-Phase mode.

As seen in figure 16, the water fractions intercepts at a negative gas density error in the range 2.5%- 4%. 3-Phase mode without Droplet count is indicating a density error of -4% and with DropletCount the density error is also negative in the range 2.5-3%. Now there is also a bit more variation (ripple) in the curves which is due to short logging interval (3 minutes). By using longer logging intervals, the ripple would have been significantly reduced.

The liquid flow rate of figure intercepts at a negative gas density error in the range 2%- 3%. 3-Phase mode without Droplet count is indicating a density error of -3% and with DropletCount the density error is approximately -2 %.

It is also seen that the liquid flow based on 2-Phase mode and 3-Phase mode with Droplet Count are far less influenced by density errors compared to 3-Phase mode without DropletCount. The 3-Phase measurement with DropletCount is in particularly stable with respect to errors in the gas density. At a GVF of 99.5%, the measurement of the density error is consistent with the 93% and 97% GVF case indicating a negative error in the range 2-4%.

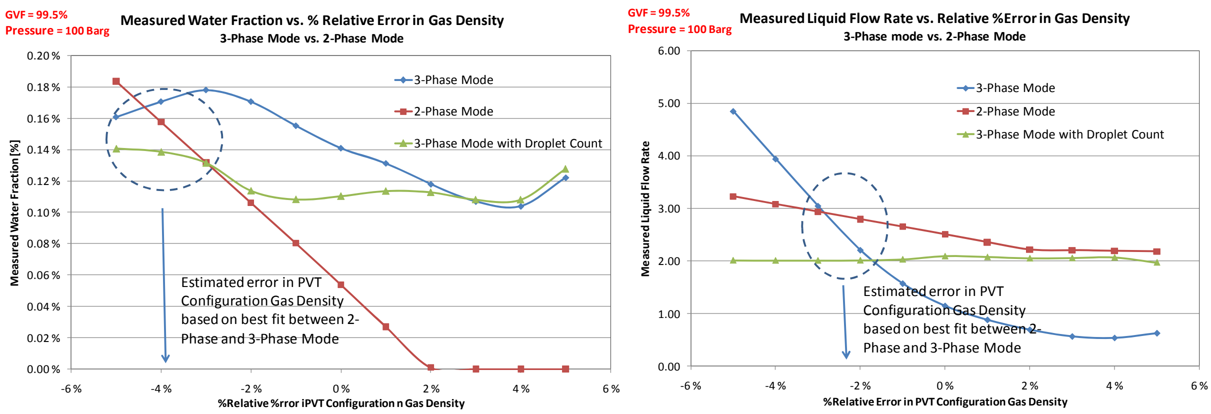


Figure 16: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated gas density for 3-Phase mode and 2-Phase mode operation at GVF of 99.5%

Figure 17 below shows the recalculated water fraction and the recalculated liquid flow rate for a ± 200% error in the PVT calculated GOR input for 2-Phase. From the recalculated water fraction, is seen that even a 200% error in the GOR is not sufficient in order to obtain an interception between the 3 different measurement modes. The liquid flow rate show an interception between 2-Phase mode and the two versions of 3-Phase mode at a GOR error of 50% and 200%. In other words, the water fraction test shows a GOR error in excess of 200% (from the slope of the curve it looks like 500%) whereas the liquid test shows a GOR error of 50-200%.

The test at 99.5% GVF indicate that the observed discrepancy in the measured liquid and gas flow rate observed at 99.5% GVF may be caused by a negative density error in the range 2-4% or a GOR error in the range 40-500%. The density error is consistent with the previous GVF cases whereas the GOR error is different in all the cases. Moreover, the GOR error is not consistent when it is compared against the two 3-Phase modes (with and without Droplet Count), which by itself is an indication of a GOR input.

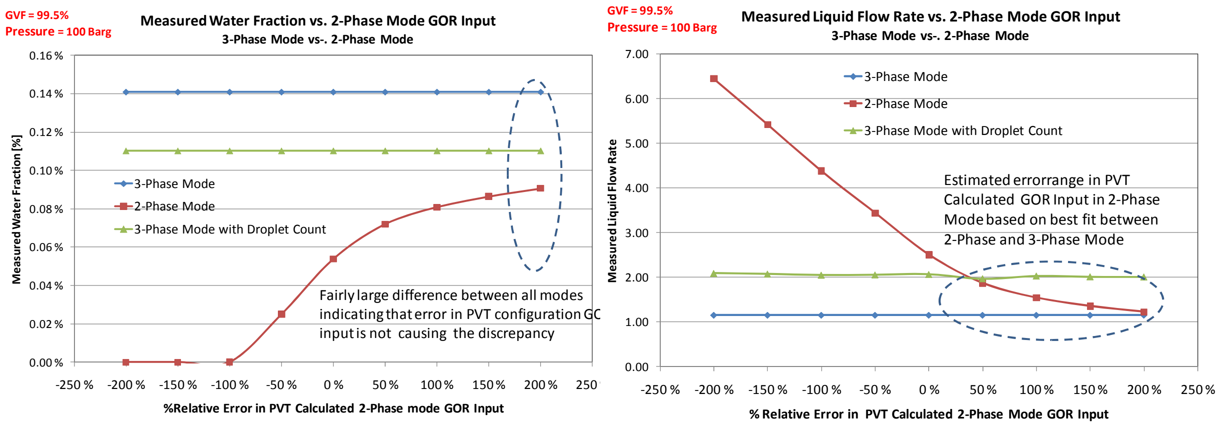


Figure 17: Measured Water Fraction and Liquid Flow Rate vs. % relative error in the PVT calculated GOR input in 2-Phase mode for 3-Phase mode and 2-Phase mode operation at GVF of 99.5%

7.2.5 Summarizing the In-Situ evaluations

Based on the cases above a negative bias in the gas density in the range 2-4% would explain the observed discrepancy between the measurement modes. There also appears to be a small error in the GOR input, but this is marginal compared to the density effect.

The uncertainty of the PVT calculated density was discussed with the vendor of the PVT software. Based on the gas and condensate composition for this for this application, the vendor expected a positive bias in the PVT calculated density in the range 1-3% due to the cubic nature of the EoS models which does not give sufficient precision at this range introducing a bias in the calculation. The expectation from the vendor was also confirmed by an in-situ measurement of the gas phase as shown in figure 18 below.

The graph to the left shows the liquid index goes below the gas threshold followed by an in-situ gas period of approximately 15 minutes before the flow starts again. The graph to the right shows the measured gas density and permittivity vs. the PVT calculated values for the same period. As seen from the graph, the in-situ measurement of the gas properties shows that there is a negative bias of 2.8% of the PVT calculated gas density vs. the measured one, and a negative bias of 0.2% on the PVT calculated gas permittivity. This is consistent with the calculations performed during the water fraction and GOR test for the three cases at GVF of 93%, 97% and 99.5%.

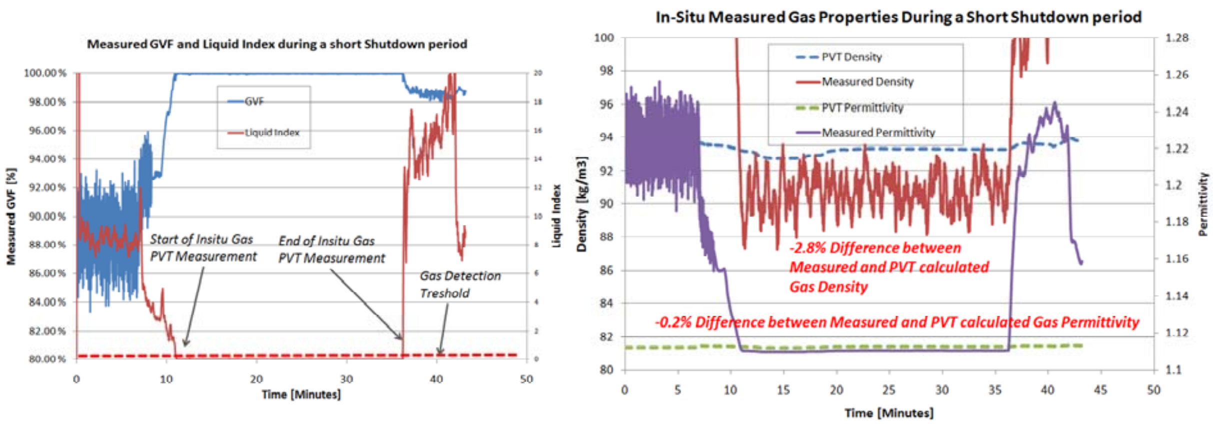


Figure 18: Measured Liquid Index, GVF, Gas Density, Gas Permittivity, PVT calculated gas density and PVT calculated Permittivity during the In-Situ Gas Measurement

Figure 19 below shows the recalculated measurement in 2-Phase and 3-Phase mode using the in-situ measured gas PVT data. The measurements performed with the original PVT configuration data is denoted as ("Before In-Situ") and the recalculated measurement where the error in the gas density and permittivity have been corrected is denoted ("After In-Situ").

From the graph it is seen that there is a good fit between 2-Phase and 3-Phase mode in the entire GVF range for both the water fraction measurement and liquid measurement when the in-situ measured gas PVT properties are used. The recalculated measurements, based on the in-situ measured PVT data, also agree well with the red stipulated reference value.

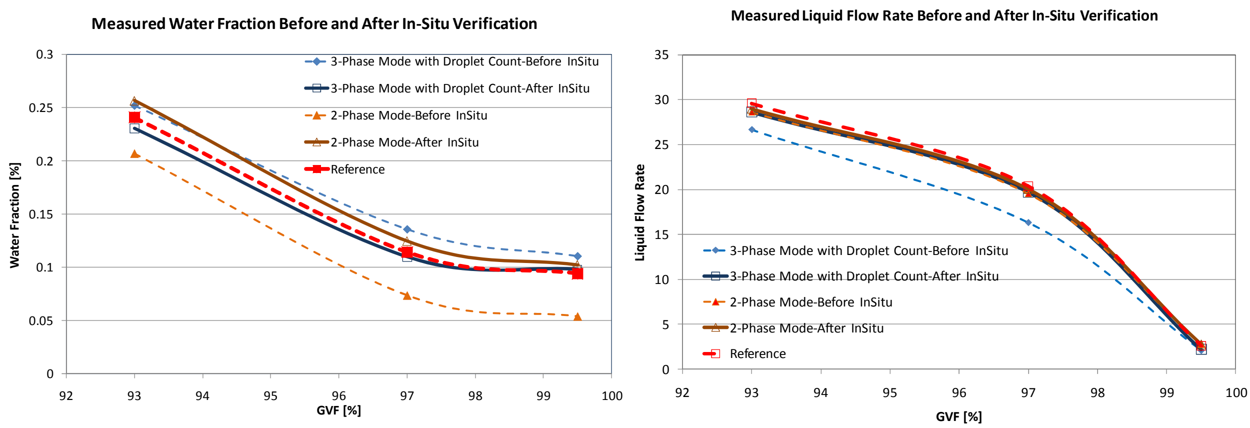


Figure 19: Measured Water Fraction and Liquid Flow Rate vs. when using the In-Situ Measured Gas Density

The example above illustrates how the different measurement modes together with in-situ gas measurements can be used to identify and correct potential errors in the PVT calculated data without performing any sampling of the well and while the well is flowing. In-Situ measurement of gas, using the DropletCount function to detect pure gas in the meter, can together with the above measurements be used to correct the PVT configuration data used by the meter. The correction can either be implemented based on a manual procedure or performed fully automatic by the meter. Both cases are used by MPM meters in operation.

8 CO NCLUSIONS

This paper shows that all types of multiphase and wetgas meters, independently of what technologies they are based on, are depending on a set of configuration data in order to provide accurate and reliable flow rates.

It is well known that the dominating PVT configuration parameters for measurement of small volume fractions of a well stream component are those of the fluid occupying the largest volume. The paper demonstrates that different technologies applied for multiphase and wetgas metering have very different requirements and sensitivities with respect to what configuration data is required. More important, the different technologies have different sensitivity to errors and variations in the PVT configuration data. This is particularly the case for H_2S and CO_2 rich applications, wetgas fields which require accurate water measurements and water flooded fields with high watercuts.

As a consequence, the field experience gained with one type of metering technology may not be relevant for meters using another measurement principle and the operational procedures (including frequent sampling) deemed necessary for one type of meters may not be needed for meters based on other measurement principles.

The MPM meter is based on a technology which is very tolerant towards potential errors in the PVT configuration data. The meter has in-built functionality for in-situ measurement of water and gas PVT properties which is used to measure and compensate for changes in the PVT properties. This unique combination eliminates the need for fluid samples or installation of in-line sampling systems, which otherwise would be important particularly for subsea and H_2S rich applications.

The PVT robustness of the MPM meter makes it also possible to use a generalised fluid composition for calculation of oil and gas properties. The generalised fluid composition can be verified in-situ and further enhanced by using the automatic configuration option based on the in-built functionality for measurement of water and gas PVT properties.

The robustness of the MPM meter towards errors in the PVT data and the ability to perform in-line measurement of the water and gas properties have enabled MPM to implement a simplified procedure for field configuration of multiphase and wetgas meters. Simplified field configuration means that the meters are delivered ready field configured from the MPM factory and are therefore fit for field service upon delivery from the factory. For subsea applications the operator can install and commission the meters and start producing the wells without any assistance from MPM. For topside meters, some assistance may be needed in connection with installation and calibration of the gamma source, but apart from that, the operator can do all the needed work to put the meters in operation.

ACKNOWLEGDEMENTS

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