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NORSK FORENING FOR OLJE OG GASSMÅLING

Tekna

HANDBOOK OF MULTIPHASE FLOW METERING

Revision 2, March 2005

Handbook
of
Multiphase Flow Metering

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Revision 2, March 2005

Produced for
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Preface

Multiphase metering, and a handbook for providing the users, manufacturers and others some form of guidelines for handling multiphase flow measurement has been wanted by the industry from the start. The Norwegian Society for Oil and Gas Measurement (NFOGM) first developed a handbook to serve as a guideline and provide a common basis for the in-line multiphase measurement system. With help from the manufacturers and the users the first revision of the handbook was published in 1995.

The development and use of the meters has increased since then, and NFOGM contacted Christian Michelsen Research (CMR) to investigate the need for an updated handbook.

In 2003 it was decided to start the work, and a revision to include comments from users and get a more detailed and up to date handbook was initiated by NFOGM. The work was financed by NFOGM and The Norwegian Society of Chartered Technical and Scientific Professionals (Tekna).

A project was established at Christian Michelsen Research in order to coordinate an international workgroup to carry out this task. The workgroup consisted of ten participants who contributed on a voluntary basis with a broad and varied skills and experience from oil and gas flow measurement. The participants were each assigned main responsibility for the revision of one or more chapters, and they have contributed by writing of texts and in discussions at a total of 8 workgroup meetings in the period from October 2003 until March 2005.

We wish to express our thanks to all the workgroup participants (listed on the previous page) and the project leader at CMR, Eivind Dahl, for their contributions to this Handbook.

March 2005

Norwegian Society for Oil and Gas Measurement
Chairman
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1. INTRODUCTION

The need for multiphase flow measurement in the oil and gas production industry has been evident for many years. A number of such meters have been developed since the early eighties by research organizations, meter manufacturers, oil and gas production companies and others. Different technologies and various combinations of technologies have been employed, and prototypes have been quite dissimilar in design and function. Some lines of development have been abandoned, whereas a number of meters have become commercially available, and the number of applications and users is rapidly increasing.

Since the first Handbook of multiphase metering (hereafter simply called the Handbook) was published in 1995, multiphase flow measurement has further matured and is now being considered a separate discipline in the oil and gas flow measurement society. New applications of multiphase flow meters (MPFMs) have emerged, from simply being a replacement of the conventional test separator shared by a number of wells, towards more compact and low cost meters with application on a one-per-well basis and installations both topside and subsea.

Meters from different manufacturers will always differ in their design, function and capabilities. In order to promote mutual understanding of MPFMs and their applications among users, manufacturers and others, some form of guidelines or user manual seemed appropriate and was the reason for publishing the first Handbook in 1995 (Dykesteen, 1995). The Handbook was written to serve that purpose and to help provide a common basis for the field of in-line multiphase flow measurement systems. It was not the intention at that stage that this document should be regarded as a final report. Rather, it was hoped that it would initiate more international work in which the issues and topics raised here can be further developed.

Since the multiphase flow metering technologies and applications have developed significantly since 1995, the Norwegian Society for Oil and Gas Measurement (NFOGM) therefore in 2003 decided to update the Handbook to reflect these improvements and to make it the main guide for state-of-the-art multiphase flow measurement.

1.1 About the new revision

The revision of this Handbook has been carried out over the years 2003 – 2005. In this Section the major updates of the present version of the Handbook are briefly described as well as other work of particular relevance. The chapters logically follow the course from an introduction to multiphase flow measurement philosophy and multiphase flows in general, via selection of technology, performance specifications, design considerations to field installation and commissioning and finally the operation of MPFMs.

Chapter 3 is new and includes informative references to provide the reader with some references to relevant standards and literature regarding multiphase flow measurement. The definitions in Chapter 4 have been extended and split into definitions relating to multiphase flows and definitions relating to metrology in general.

The chapter previously called “Applications of multiphase metering” has been renamed to “Multiphase flow metering philosophy” (Chapter 5). As the change in heading indicates, the chapter has been extended to include more of the general and overall reasoning for selection, installation and operation of multiphase flow metering systems in various applications.

Chapter 6 provides the reader with a general introduction to multiphase flows. This chapter has been updated and includes extended descriptions of flow regimes and slip effects in multiphase flows. A new classification of multiphase flows linked to the gas volume fraction has also been introduced, and it is emphasised that wet gas meters and their applications have now been included in the Handbook, since wet gas is considered as a subset of multiphase flows.

MPFMs are still classified into categories in terms of technology (Chapter 7), and brief descriptions of the most commonly used measurement principles in MPFMs currently available on the market have also been included. Guidance on selection of technology and maintenance requirements is also provided.

There is a need for more standardised performance specification of MPFMs, both for comparison of measuring ranges and measurement uncertainties but also for more efficient selection of technology. This chapter has therefore been updated and extended to serve this purpose (Chapter 8).

Chapter 9 presents new guidelines for designing MPFM installations. As an aid in designing MPFM installations we introduce the “two-phase flow map” and the "composition map". These two maps provide convenient ways of first plotting the predicted well production which is due to be measured in a specific application. The measuring range of a MPFM may then be plotted in the same maps, overlying the estimated well trajectories (estimated production over the field life time). This method for design of MPFM installations is described in more detail in this chapter. In addition a Microsoft Excel program has been developed to provide the users with a software tool for generating these plots.

The last chapters of the Handbook have been reorganised significantly compared to the previous version, where Chapter 10 now covers all aspects concerning testing, calibration and adjustment of MPFMs. Testing, calibration and adjustment can take place at different locations and for different purposes in the course from manufacturing to commissioning on site. This chapter covers some of the alternatives and highlights particular issues for each alternative.

Chapter 11 covers field installation and commissioning, and provides recommended procedures and practices for field installation and commissioning of MPFMs. Although MPFMs cannot easily be sent to a calibration facility for recalibration, there is a need for regular calibration to verify the meter performance. The purpose of Chapter 12 is to provide some guidelines on how to verify meter performance in the field during operation, assuming no test separator is readily available.

The appendices include a short introduction to important aspects concerning nuclear gauge employment and also a brief user manual for the Excel program for generation of the flow maps described in Chapter 9.

1.2 Other relevant work

Parallel to the work by the NFOGM workgroup, an API Upstream Allocation Task Group has been at work to develop an API Recommended Practise RP 86 Measurement of Multiphase Flow. Their remit has been to consider and evaluate all methods which are used today to estimate flow rates in a multiphase environment. A close cooperation was established between the two groups in order to harmonise the documents in terms of terminology, methodology and content and to make them consistent. The API RP 86 Measurement of Multiphase Flow is due for ballot in mid 2005. Other relevant publications are the Guidance Notes for Petroleum Measurement published by the UK Department of Trade and Industry (DTI).

2. SCOPE

This document is intended to serve as a guide for users and manufacturers of MPFMs. Its purpose is to provide a common basis for, and assistance in, the classification of applications and meters, as well as guidance and recommendations for the implementation and use of such meters.

The document may also serve as an introduction to newcomers in the field of multiphase flow measurement, with definition of terms and a description of multiphase flow in closed conduits being included.

The so-called in-line MPFMs that directly measure the oil, water and gas flow rates without any conditioning, as well as the partial- and full separation MPFMs are the main focus of the Handbook. Conventional two- or three-phase separators are not included here. It should be emphasized however that in contrast to the previous Handbook, this version also covers wet gas meters and their applications, since wet gas is considered as a subset of multiphase flows.

Even if the individual flow rates of each constituent are of primary interest, often their ratios (Water-in-Liquid Ratio, Gas/Oil Ratio, etc) are useful as operational parameters. Constituents other than oil, gas and water flow rates or ratios of these are not dealt with here.

The performance of a multiphase flow meter in terms of uncertainty, repeatability, range, etc. is of great importance, as this enables the user to compare different meters and evaluate their suitability for use in specific applications. Section 8 covers this issue in detail and proposes standard methods to describe performance .

The testing and qualification of the meters is also related to performance. Guidance is provided to help optimise the outcome of such activities. Since MPFMs measure at line conditions, the primary output is individual flow rates and fractions at actual conditions (e.g. at the operating pressure and temperature). Conversion of these actual flow rates to flow rates at standard conditions, requires knowledge of composition and mass transfer between the liquid and the gas phases and may involve multiphase sampling. The conversion from actual conditions to standard conditions is not included here.

3. INFORMATIVE REFERENCES

In single-phase flow measurement there exists normative standards; this is not the case for multiphase flow metering. The following literature is recommended as informative references for multiphase flow metering.

ISO-Guide (The abbreviation "GUM" is often used)	International Organization for Standardization (1995): *Guide to the expression of uncertainty in measurement, ISBN-92-67-10188-9.* When reporting the result of a measurement of a physical quantity, some quantitative indication of the result has to be given to assess its reliability and to allow comparisons to be made. The Guide to the expression of uncertainty in measurement establishes general rules for evaluating and expressing uncertainty in measurement that can be followed at many levels of accuracy and across many fields.
ISO-11631:1998	International Organization for Standardization (1998): *Measuring of fluid flow*. Methods of specifying flow meter performances.
API TP 2566	American Petroleum Institute (2004): *State of the art Multiphase Flow Metering.*
API RP-85	American Petroleum Institute (2005): *Use of Subsea Wet gas Flow meters in Allocation Measurement Systems.* Recommended Practice 85 discusses how liquid hydrocarbon measurement is accomplished by using available sampling information to determine the well's water volume fraction and gas-oil ratio (GOR). This RP presents a recommended allocation methodology that is technically defensible and mathematically optimised to best fit the application, and that equitably accommodates variances in the uncertainty level between meters within the system.
ISO/TR 7066-1:1997	International Organization for Standardization (1997): *Measurement of fluid flows in general.* Assessment of uncertainty in calibration and use of flow measurement devices - Part 1: Linear calibration relationships.
DTI, Issue 7, December 2003	UK Department of Trade and Industry (DTI) (2003): *Guidance Notes for Petroleum Measurement, Issue 7.*
	State of Alaska, Alaska Oil and Gas Conservation Commission (2004): *Guidelines for qualification of multiphase metering systems for well testing.*

4. DEFINITIONS

Two categories of terms are defined below. The first section defines terms that are commonly used to characterise multiphase fluid flow in a closed conduit. The second section defines metrological terms that may be useful in characterising the performance of a multiphase flow meter.

4.1 Terms related to multiphase flow metering

Actual conditions	The actual or operating conditions (pressure and temperature) at which fluid properties or volume flow rates are expressed.
Adjustment (See important notice at the end of this Section)	Operation of bringing a measuring instrument into a state of performance suitable for its use (*ISO-VIM*, 1993). NOTE: A tuning of the measuring instrument or measuring system in order to operate according to a reference or standard. The tuning may include software, mechanical and/or electrical modifications.
Calibration (See important notice at the end of this Section)	Set of operations that establish, under specified conditions, the relationship between values of quantities indicated by a measuring instrument or measuring system, or values represented by a material measure or certified reference material, and the corresponding values realised by standards (*ISO-VIM*, 1993). *NOTE 1*: The result of the calibration may indicate a need for **adjustment** of the measuring instrument or measuring system in order to operate according to a reference or standard. *NOTE 2*: The result of a calibration permits either the assignment of values of measurands to the indications or the determination of corrections with respect to indications. *NOTE 3*: A calibration may also determine other metrological properties such as the effect of influence quantities. *NOTE 4*: The result of a calibration may be recorded in a document, sometimes called a calibration certificate or a calibration report.
Capacitance	In a capacitor or system of conductors and dielectrics, the property that permits the storage of electrically separated charges when potential differences exist between the conductors. Capacitance is related to charge and voltage as follows: $C = Q/V$, where C is the capacitance in farads, Q is the charge in coulombs, and V is the voltage in volts.
Certified Reference Material (CRM)	Reference material, accompanied by a certificate, one or more of whose property values are certified by a procedure which establishes traceability to an accurate realization of the unit in which the property values are expressed, and for which each certified values is accompanied by an uncertainty at a stated level of confidence (*ISO-VIM*, 1993).
Compression factor Z and Z_0	The compression factor Z is the quotient of the actual (real) volume of an arbitrary mass of gas, at a specified pressure and temperature, and the volume of the same gas, under the same conditions, as calculated from the ideal gas law. The compression factor at standard conditions is Z_0.
Conductivity	The ability of a material to conduct electrical current. In isotropic material the reciprocal of resistivity. Sometimes called specific conductance. Units are Siemens/m or S/m.

Dielectric constant	See the definition of permittivity.
Dispersed flow	Dispersed flow is characterised by a uniform phase distribution in both the radial and axial directions. Examples of such flows are bubble flow and mist flow.
Dissolved water	Water in solution in petroleum and petroleum products.
Dry Gas	Gas flows not containing any liquids under the actual operating conditions, however with further processing e.g. temperature and pressure changes liquids again might fall out
Emulsion	Colloidal mixture of two immiscible fluids, one being dispersed in the other in the form of fine droplets, in multiphase fluids discrimination should be made between oil-in-water emulsion and water-in-oil emulsion. Both respond differently to permittivity measurements.
Entrained water	Water suspended in oil. Entrained water includes emulsions but does not include dissolved and free water.
Equation of State	Equations that relate the composition of a hydrocarbon mixture, pressure and temperature of gases and liquids to one another.
Fiscal	Fiscal refers to a meter's service and does not imply any standard of performance. A "fiscal" measurement (or custody transfer measurement) is basis for money transfer, either between company and government or between companies.
Flow regime	The physical geometry exhibited by a multiphase flow in a conduit; for example, in two-phase oil/water, free water occupying the bottom of the conduit with oil or oil/water mixture flowing above.
Fluid	A substance readily assuming the shape of the container in which it is placed; e.g. oil, gas, water or mixtures of these.
Froude numbers	Froude number (F_r) is the ratio of inertial force and gravitational force for a particular phase; in other words, the ratio of kinetic to potential energy of the gas or the liquid.
Gamma rays	Electromagnetic waves of the highest frequencies known, originally discovered as an emission of radioactive substances and created by transition of a nucleus to lower energy states.
Gas	Hydrocarbons in the gaseous state at the prevailing temperature and pressure.
Gas-Liquid-Ratio (GLR)	The ratio of gas volume flow rate and the total liquid (oil and water) volume flow rate, both volume flow rates should be converted to the same pressure and temperature (generally at the standard conditions). Expressed in volume per volume, e.g. m3/m3.
Gas-Oil-Ratio (GOR)	The ratio of gas volume flow rate and the oil volume flow rate; both volume flow rates should be converted to the same pressure and temperature (generally at standard conditions). Expressed in a volume per volume, e.g. scft/bbl or m3/m3.
Gas Volume Fraction (GVF)	The gas volume flow rate, relative to the multiphase volume flow rate, at the pressure and temperature prevailing in that section. The GVF is normally expressed as a fraction or percentage.
Homogeneous Multiphase Flow	A multiphase flow in which all phases are evenly distributed over the cross-section of a closed conduit; i.e. the composition is the same at all points in the cross section and there the liquid and gas velocities are the same (no-slip). Note that bubbly multiphase flow regimes are probably the best approximation for homogeneous multiphase flow ($v_{\mathrm{Mixture}} = vs_{\mathrm{Gas}} + vs_{\mathrm{Liquid}}$).
Homogeneous oil/water flow	A two-phase oil/water flow in which both phases are evenly distributed over the cross-section of a closed conduit; i.e. the composition is the same at all points.

Intermittent flow	Intermittent flow is characterised by being non-continuous in the axial direction, and therefore exhibits locally unsteady behaviour. Examples of such flows are elongated bubble, churn and slug flow (Figure 5.4). The flow regimes are all hydrodynamic two-phase gas-liquid flow regimes.
Liquid-Gas-Ratio (LGR)	The ratio of liquid volume flow rate and the total gas volume flow rate. Both rates should be converted to the same pressure and temperature (generally at the standard conditions). Expressed in volume per volume, e.g. m3/m3.
Liquid Hold-up	The ratio of the cross-sectional area in a conduit occupied by the liquid phase and the cross-sectional area of the conduit, expressed as a percentage.
Liquid Volume Fraction (LVF)	The ratio of liquid volume flow rate and the total fluid (oil, water and gas) flow rate, both volume flow rates should be converted to the same pressure and temperature. Expressed as a fraction or percentage.
Lockhart-Martinelli parameter	Lockhart-Martinelli parameter (LM or X) is defined as the ratio of the liquid Froude number and the gas Froude number or in other words the ratio of the pressure gradient for the liquid to the pressure gradient for the gas in a pipe under equilibrium flow conditions (an increasing LM parameter means an increasing liquid content or wetness of the flow).
Mass flow rate	The mass of fluid flowing through the cross-section of a conduit in unit time.
Measuring envelope	The area's in the two-phase flow map and the composition map in which the MPFM performs according to its specifications.
Microwave	Electromagnetic radiation having a wavelength from 300 mm to 10 mm (1 GHz to 30 GHz).
Multiphase flow	Two or more phases flowing simultaneously in a closed conduit; this document deals in particular with multiphase flows of oil, water and gas in the entire region of 0-100% GVF and 0-100% Water Cut.
Multiphase flow meter (MPFM)	A device for measuring the individual oil, water and gas flow rates in a multiphase flow. The total package of measurement devices for composition and velocity, including possible conditioning unit, should be considered as an integral part of the meter. Note that under this definition also a conventional two- or three-phase test separator is a multiphase meter.
Multiphase flow velocity	The ratio of the multiphase volume flow rate and the cross sectional area of the conduit. Note that this is fictive velocity, only in homogeneous and slip free multiphase flow this velocity has be meaningful value. Multiphase flow velocity is the sum of gas superficial and liquid superficial velocity.
Multiphase fraction meter	A device for measuring the phase area fractions of oil, gas and water of a multiphase flow through a cross-section of a conduit.
Multiphase volume flow rate	The total (oil, water and gas) volume flowing through the cross-sectional area of a conduit per unit time.
Oil	Hydrocarbons in the liquid state at the prevailing temperature and pressure conditions.
Oil (water or gas) volume fraction	The ratio of oil (water or gas) volume flow rate and the total fluid (oil, water and gas) flow rate, both volume flow rates should be converted to the same pressure and temperature (generally at the standard conditions). Expressed in a fraction or percentage.
Oil-continuous two-phase flow	A two-phase flow of oil/water characterised in that the water is distributed as water droplets surrounded by oil. Electrically, the mixture acts as an insulator.

Permittivity	The permittivity of a dielectric medium is a measure of its ability to be electrical polarised when exposed to an electric field. A dielectric medium in a condenser will, due to the polarisation, decrease the original electric field and increase the capacitance of the condenser. The capacitance *C* of an electrical condenser is proportional to the permittivity of the dielectric medium, i.e. $$C = \frac{\varepsilon}{\varepsilon_0} C_0$$ where C_0 is the vacuum capacitance of the condenser. ε and ε_0 is the absolute permittivity of the dielectric medium and free space, respectively ($\varepsilon_0 = 8.854 \cdot 10^{-12}$ F/m). The ratio $\varepsilon_{0\,/}\,\varepsilon$ is defined as the relative permittivity (previously the term dielectric constant was used), which is ≥ 1. In practice, however, when the term permittivity is used, it is usually referred to as the *relative* permittivity, which is also the case for this report. See reference [Haus & Melcher, 1989] for more details about permittivity and electromagnetic field theory. NOTE: The permittivity is a complex quantity, which depends on the frequency. The imaginary part of the permittivity is due to dielectric losses at high frequencies.
Phase	In this document, “phase” is used in the sense of one constituent in a mixture of several. In particular, the term refers to oil, gas or water in a mixture of any number of the three.
Phase area fraction	The cross-sectional area locally occupied by one of the phases of a multiphase flow, relative to the cross-sectional area of the conduit at the same local position.
Phase flow rate	The amount of one phase of a multiphase flow flowing through the cross-section of a conduit in unit time. The phase flow rate may be specified as phase volume flow rate or as phase mass flow rate.
Phase mass fraction	The phase mass flow rate of one of the phases of a multiphase flow, relative to the multiphase mass flow rates.
Phase volume fraction	The phase volume flow rate of one of the phases of a multiphase flow, relative to the multiphase volume flow rates.
Production envelope	The areas in the two-phase flow map and the composition map that are determined by a number of well trajectories or specified as possible flow rates and compositions that will occur in a certain development.
Reconciliation	A process whereby oil, water and gas production figures that have not been measured with fiscal accuracy are “re-calculated” to match the production figures that have been measured with a fiscal accuracy.
Salinity	The term "salinity" refers to the amount of dissolved salts that are present in water (kg/m3). Sodium and chloride are the predominant ions in seawater, and the concentrations of magnesium, calcium, and sulphate ions are also substantial.
Separated flow	Separated flow is characterised by a non-continuous phase distribution in the radial direction and a continuous phase distribution in the axial direction. Examples of such flows are stratified and annular (with low droplet entrained fraction.
Slip	Term used to describe the flow conditions that exist when the phases have different velocities at a cross-section of a conduit. The slip may be quantitatively expressed by the phase velocity difference between the phases. See Section 6.2.
Slip ratio	The ratio between two-phase velocities. See Section 6.2.

Slip velocity	The phase velocity difference between two phases. See Section 6.2.
Standard or Reference conditions	A set of standard (or reference) conditions, in terms of pressure and temperature, at which fluid properties or volume flow rates are expressed, e.g. 101.325 kPa and 15 °C.
Superficial phase velocity	The flow velocity of one phase of a multiphase flow, assuming that the phase occupies the whole conduit by itself. It may also be defined by the relationship (Phase volume flow rate) / (Pipe cross-section).
Composition map	Graph with Gas Volume Fraction (GVF) and Water Cut (WC) or Water in Liquid ratio (WLR) along the x- and y-axis, respectively. Both the GVF and Water Cut or WLR should be at actual conditions.
Two-phase flow map	Graph with superficial velocity of gas and liquid along the x- and y-axis, respectively e.g. the Mandhane (1974) flow map for horizontal multiphase flow. Alternatively the actual gas volume and actual liquid volume flow rates can be used.
Void fraction	The ratio of the cross-sectional area in a conduit occupied by the gas phase and the cross-sectional area of the conduit, expressed as a percentage.
Volume flow rate	The volume of fluid flowing through the cross-section of a conduit in unit time at the pressure and temperature prevailing in that section.
Water-continuous two-phase flow	A two-phase flow of oil/water characterised in that the oil is distributed as oil droplets surrounded by water. Electrically, the mixture acts as a conductor.
Water Cut (WC):	The water volume flow rate, relative to the total liquid volume flow rate (oil and water), both converted to volumes at standard pressure and temperature. The WC is normally expressed as a percentage.
Water Fraction Meter (WFM)	A device for measuring the phase area fractions of oil and water of a two-phase oil/water flow through a cross-section of a conduit expressed as a percentage.
Water-in-liquid ratio (WLR)	The water volume flow rate, relative to the total liquid volume flow rate (oil and water), at the pressure and temperature prevailing in that section.
Well trajectory	The trajectory of a well over time in a two-phase flow map and composition map.
Wet gas	Gas that contains liquids, generally wet gas is defined as gas/liquid systems with a Lockhart-Martinelli parameter smaller than approximately 0.3. Hydrocarbon gasses that contain heavy components that will condensate during further processing (but at a particular p and T behaves as a pure gas) are not considered to be a wet gas from a measurement point of view.
X-rays	X-rays are electromagnetic radiation of a similar nature to light, but with an extremely short wavelength. It is produced by bombarding a metallic target with fast electrons in vacuum or by transition of atoms to lower energy states. Its properties include ionising a gas upon passage through it, penetrating certain thickness of all solids and causing fluorescence.

IMPORTANT NOTICE

It is important to note that the ISO definitions (*ISO-VIM*, 2003) of the terms "Calibration" and "Adjustment", which are used in this Handbook, are fundamentally different from the definitions of these terms in the API RP 86 Measurement of Multiphase Flow. The API RP 86 uses definitions consistent with the API Manual of Petroleum Measurement Standards (MPMS).

According to the MPMS, the term "Calibration" prescribes an adjustment to the meter should it be found out of range, whereas the ISO definition does not permit such an adjustment. ISO identifies "Adjustment" as a separate activity and not part of a "Calibration".

The ISO definition of "Calibration" is similar to that defined in the API RP 86 as "Verification".

4.2 Terms related to metrology

The uncertainty of MPFMs should be specified by terms that are in conformance with "The international vocabulary of basic and general terms in metrology" (VIM) issued by ISO (1993). Other standards based on the above document may also be used, e.g. BS 5233 (1986): "Glossary of terms used in metrology". Some of the definitions of BS 5233, which may be particularly relevant to multiphase flow measurement, are quoted below (or form part of the definitions).

Accuracy of measurement	Closeness of the agreement between the result of a measurement and the value of the measurand (*ISO-VIM*, 2003). *NOTE 1:* The value of the measurand may refer to an accepted reference value [1]. *NOTE 2:* "Accuracy" is a qualitative concept, and it should not be used quantitatively. The expression of this concept by numbers should be associated with (standard) uncertainty.
Corrected results	Result of a measurement after correction for systematic error (*ISO-VIM*, 2003).
Error of measurement	Error of measurement is the result of a measurement minus the value of the measurand (*ISO-VIM*, 2003). In general, the error is unknown because the value of the measurand is unknown. Therefore, the uncertainty of the measurement results should be evaluated and used in specification and documentation of test results.
Influence quantity	Quantity that is not the measurand, but that affects the result of the measurement (*ISO-VIM*, 2003).
Limiting conditions	Extreme conditions that a measuring instrument is required to withstand without damage, and without degradation of specified metrological characteristics when is subsequently operated under its rated operating conditions (*ISO-VIM*, 2003).
Measurand	Particular quantities subject to measurement (*ISO-VIM*, 2003).
Measuring range	Set of values of measurands for which the error of a measuring instrument is intended to lie within specified limits (*ISO-VIM*, 2003).
Random error	The result of a measurement minus the mean that would result from an infinite number of measurements of the same measurand carried out under repeatable conditions. *NOTE:* Because only a finite number of measurements can be made, it is possible to determine only an estimate of the random error. Since it generally arises from stochastic variations of influence quantities, the effect of such variations is referred to as random effects in the *ISO-Guide* (1995).
Rated operating conditions	Conditions of use for which specified metrological characteristics of a measuring instrument are intended to lie within given limits (*ISO-VIM*, 2003).

[1] In some documents it also points to the "true value" or "conventional true value". However, according to the ISO *Guide* this definition should be avoided since the word "true" is viewed as redundant; a unique "true" value is only an idealised concept and "a true value of a measurand" is simply the value of the measurand.

Reference conditions	Conditions of use prescribed for testing the performance of a measuring instrument or for intercomparison of results of measurements (*ISO-VIM*, 2003). *NOTE:* The reference conditions generally include **reference values** or **reference ranges** for the influence quantities affecting the measuring instrument.
Repeatability	Closeness of the agreement between the results of successive measurements of the same measurand carried out under the same conditions of measurement (*ISO-VIM*, 2003). *NOTE 1:* These conditions are called repeatability conditions *NOTE 2:* Repeatability conditions include: - the same measurement procedure - the same observer - the same measuring instrument, used under the same conditions - repetition over a short period of time *NOTE 3:* Repeatability may be expressed quantitatively in terms of the dispersion characteristics of the results.
Reproducibility	Closeness of the agreement between the results of measurements of the same measurand carried out under changed conditions of measurement (*ISO-VIM*, 2003). *NOTE 1:* A valid statement of reproducibility requires specification of the conditions changed *NOTE 2:* The changed conditions may include: - principle of measurement - method of measurement - observer - measuring instrument - reference standard - location - conditions of use - time *NOTE 3:* Reproducibility may be expressed quantitatively in terms of the dispersion characteristics of the results. *NOTE 4:* Results are here usually understood to be corrected results.
Result of a measurement	Value attributed to a measurand, obtained by measurement. It is an estimated value of the measurand (*ISO-VIM*, 2003).
Span	The algebraic difference between the upper and lower values specified as limiting the range of operation of a measuring instrument, i.e. it corresponds to the maximum variation in the measured quantity of interest[2]. Example: A thermometer intended to measure over the range -40 ^{0}C + 60 ^{0}C has a span of 100 ^{0}C.
Systematic error	The mean value that would result from an infinite number of measurements of the same measurand carried out under repeatability conditions minus a true value of the measurand (*ISO-VIM*, 2003).

[2] E.g. a flow metering system which covers the <u>range</u> 50-200 m^3/h, has a <u>span</u> of 150 m^3/h.

Uncertainty of measurement	Parameter associated with the result of a measurement, characterising the dispersion of the values that could reasonably be attributed to the measurand (*ISO-VIM*, 2003). *NOTE 1:* The parameter may be, for example, a standard deviation (or a given multiple of it), or the half-width of an interval having a stated level of confidence. *NOTE 2:* Uncertainty of measurement comprises, in general, many components. Some of these components may be evaluated from statistical distribution of the results of series of measurements and can be characterised by experimental standard deviations. The other components, which can also be characterised by standard deviations, are evaluated from assumed probability distributions based on experience or other information. *NOTE 3:* It is understood that the result of the measurement is the best estimate of the value of the measurand, and that all components of uncertainty, including those arising from systematic effects, such as components associated with corrections and reference standards, contribute to the dispersion.

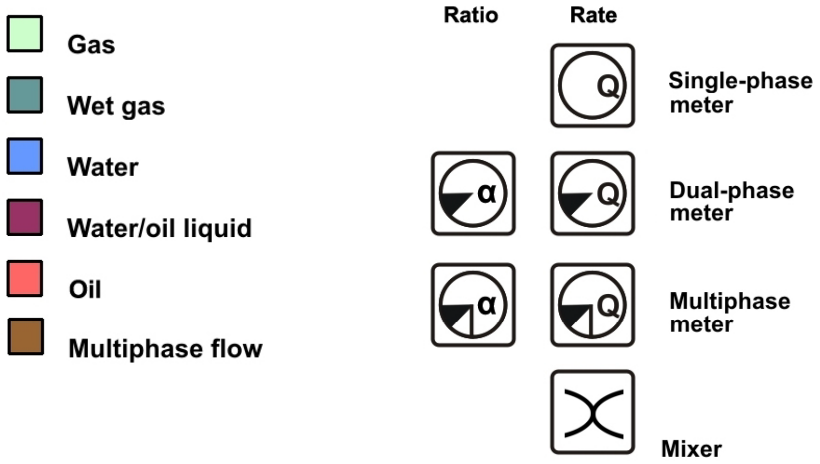
4.3 Subscripts and symbols

Table 4.1 includes a list of the main subscripts used in the equations in the Handbook, while colours and symbols used in the schematic drawings are included below.

Table 4.1 Subscripts used in the equations in the Handbook.

Symbol	Quantity	Value / SI Units
C	Capacitance	F
ε_o	Permittivity of free space	$8.854 \cdot 10^{-12}$ F/m
$v_{s,gas}$	Superficial gas velocity	m/s
$v_{s,liquid}$	Superficial liquid velocity	m/s
v_m	Multiphase mixture velocity ($v_m = v_{gas} + v_{liquid}$)	m/s
q_{gas}	Gas volume flow rate	m^3/s
A	Area (e.g. cross-sectional area of pipe)	m^2
λ_{liquid}	Liquid hold-up	
λ_{gas}	Gas void fraction	
α_{liquid}	Liquid volume fraction	
α_{gas}	Gas volume fraction	
t	Time	s
μ	Linear attenuation coefficient	1/m
I	Count rate	
X	Lockhart-Martinelli parameter (see Section 7.1.3.2)	
ρ_g	Gas density	kg/m^3
ρ_l	Liquid density	kg/m^3
D	Internal pipe diameter	m
g	Gravitational constant	~9.81 m/s^2
F_r	Froude number (see Section 7.1.3.2)	

Key to colours and symbols:



5. MULTIPHASE FLOW METERING PHILOSOPHY

Conventional single-phase metering systems require the constituents or "phases" of the well streams to be fully separated upstream of the point of measurement. For production metering this requirement is usually met automatically at the outlet of a conventional process plant, since the main purpose of such a plant is to receive the sum of well streams in one end and to deliver (stabilized) single phases ready for transport (and hence also measurement) in the other end. Single-phase metering systems normally provide high-performance measurements of hydrocarbon production.

The need for multiphase flow metering arises when it is necessary or desirable to meter well stream(s) upstream of inlet separation and/or commingling. Multiphase flow measurement technology may be an attractive alternative since it enables measurement of unprocessed well streams very close to the well. The use of MPFMs may lead to cost savings in the initial installation. However, due to increased measurement uncertainty, a cost-benefit analysis should be performed over the life cycle of the project to justify its application.

MPFMs can provide continuous monitoring of well performance and thereby better reservoir exploitation/drainage. However this technology is complex and has its limitations; therefore care must be exercised when planning installations that include one or more MPFMs. One of the limitations of the multiphase measurement technology is the uncertainty of the measurement. The main source for these higher measurement uncertainties of MPFMs in comparison to single-phase metering systems (for example) is the fact that they measure unprocessed and far more complex flows than what is measured by single-phase measurement systems.

A second limitation in a multiphase application is the possibility to extract representative samples. Whereas samples of the different fluids are readily captured from, for example, the single-phase outlets of a test separator, no standard or simple method for multiphase fluid sampling is yet available. Since most MPFMs on the market need some kind of *a priori* information about the properties being measured (like densities, oil permittivity and/or water conductivity/salinity), this information must be made available and be updated on a regular basis.

A number of different MPFMs are available on the market, employing a great diversity of measurement principles and solutions (Cf. chapter 7 and 8). Some MPFMs work better in certain applications than others. Hence a careful comparison and selection process is required to work out the optimal MPFM installation for each specific application.

In selecting the optimal multiphase flow metering technology for a specific application, one must first investigate and describe the expected flow regime(s) from the wells to be measured and determine the production envelope (Cf. Chapter 9 for more information about production envelopes). Subsequently one must assess if there exists MPFMs with a corresponding measuring envelope making them suitable for the purpose of measuring the well streams in the specific application. Exploration/ reservoir samples or well production forecasts can be used in these considerations, and a useful aid in selection of MPFMs will be to use the two-phase flow and composition maps described in this Handbook (Cf. Chapter 9).

The next step is to select a MPFM that is capable of continuously measuring the representative phases and volumes within the required uncertainties. The well stream flow rates will vary over the lifetime of the well, and it is important to ensure that the MPFM will measure with the required uncertainty at all times. Alternatively, the MPFM may have to be exchanged at some later stage in the production life. This will be an important issue to consider when deciding upon the sizing of the MPFM.

Careful selection of the type of MPFM is not the only important factor. In addition the installation must include adequate auxiliary test facilities to allow calibration (and if needed adjustment) and verification during operation to ensure confidence in the measurements over the well lifetime (Cf. chapter 10, 11 and 12). If such periodic verification of the MPFM is not carried out, increased measurement uncertainty must be expected. Simple testing may be performed with a static measurement. More extended testing may be carried out by comparing the MPFM flow rate and WLR/GVF measurements against a test separator (static or transportable) or by other means (tracer methods, etc.). The extent of such regular testing will depend on the criticality of the application and operation.

There are many possible applications offered by MPFMs that might not be considered prohibitive. Due to the higher measurement uncertainties, it is generally not recommended to use a multiphase flow meter to replace a high accuracy fiscal measurement; however MPFMs are now being used in some cases of marginal field developments where the cost of processing facilities and metering downstream of separation cannot be justified.

Some general types of applications are briefly described in the next Sections:

- Single well surveillance or monitoring
  - Production optimisation
  - Flow assurance
- Well testing
- Production allocation metering
- Fiscal or custody transfer measurements

Since this document is intended to be a guide for users, or potential users of MPFMs, in the oil and gas production industry, application areas in other industries are not included.

5.1 Single well surveillance or monitoring

By continuous monitoring using a MPFM, the time resolution of the information is higher compared with random well testing with a test separator. Using an MPFM instead of a separator may therefore reduce the total uncertainty in well data, even if instantaneous phase flow rates are measured with increased uncertainty, while changes in performance between tests are not recorded by separators.

Access to continuous high-resolution data from a MPFM may be a valuable resource in various decision processes, for example in connection with well overhauls.

Installing a new MPFM can save space, weight and cost compared to the installation of a new test separator, and it can reduce the time occupation of existing test separators.

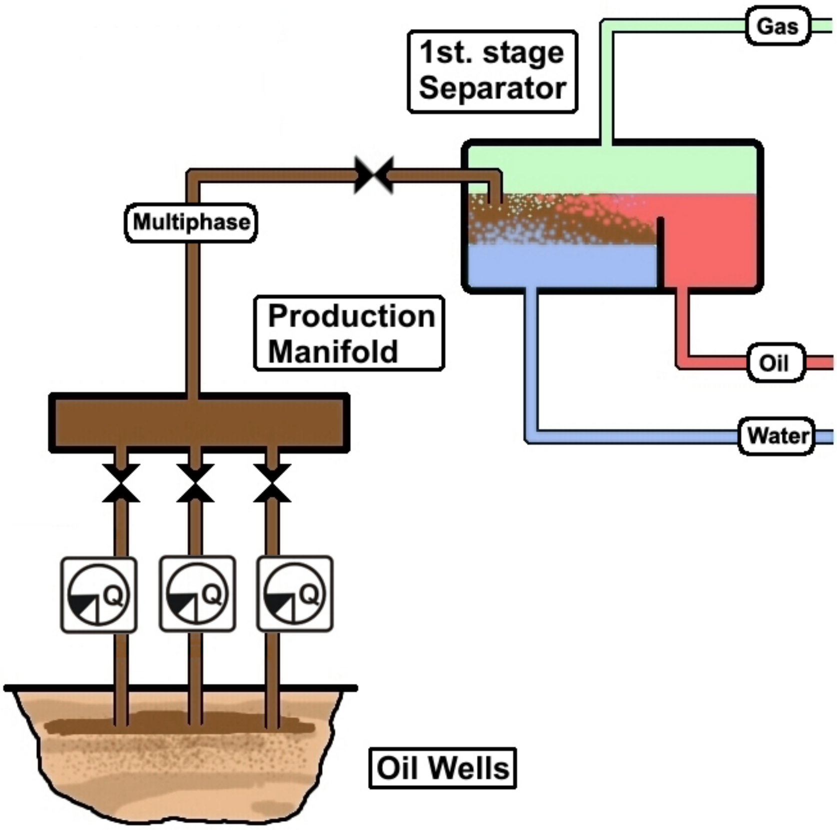


Figure 5.1 MPFMs on the flow line of each well replacing test separator and its instrumentation.

Well instability is a well-known problem during decline of production, and in many cases it is not acceptable that the well is connected to the production installation before some degree of control has been achieved. It may be difficult to detect variations in flow rates from instable wells (gas lifted wells for instance) using conventional separators, and in such situations MPFMs becomes a useful tool for the production engineer.

MPFMs may be considered useful for - or even an integral part of - subsea installations. In cases of subsea commingling and/or long flow lines (several kilometres) MPFMs may be used for monitoring of flow rate from individual wells or flow lines. It must be noted, however, that retrieval of a MPFM for maintenance or repair, may be expensive, difficult or impossible. In-situ calibration is normally not available, and other, less direct verification methods would have to be devised. Reliability and stability of subsea meters is of paramount importance and needs to be addressed by the manufacturer of the MPFM, the subsea system integrator and the operator.

5.1.1 Production optimisation

Production from oil wells may be assisted by gas lift for several reasons. Once gas lifting has been implemented it is required to optimise the gas lift process (neither too much nor too little gas for lifting is economical, and there is a clear optimum for the amount of lift gas to be used to maximize the oil production). MPFMs can be of help in finding the optimum gas lift injection rate as they are capable of instantaneously showing the oil flow rate as function of injection gas flow rate. Conventional test separators would need more time to provide the same information. However, most gas lift operations are relatively high GVF applications (adding even more gas to the system) and care should be taken that the MPFM is capable to handle this high GVF operation. Alternatively a wet gas meter could be used.

Other similar optimisation considerations can be made for chemical injection, gas coning detection, water breakthrough detection, etc.

5.1.2 Flow assurance

Flow assurance includes all aspects that are relevant to guarantee the flow of oil and gas from reservoir to the sales or custody transfer point. It often involves facility engineers, production technologists and operations staff, and they evaluate and study the hydraulic, chemical and thermal behaviour of multiphase fluids. By more frequent (or continuous) measurement with MPFMs it may be possible to identify potential blockages in the production system (e.g. hydrates, asphaltenes, wax, sand, scale). Often the trending here is more important than providing numbers with absolute accuracy. In other words repeatability, for a flow assurance type of application, is often more important than absolute accuracy.

5.2 Well testing

There is a need to monitor the performance of each single well in order to optimise well production and the lifetime of the field. For most large fields in the North Sea, important decisions are based on well-test results using conventional test separators, like shutting down of wells, drilling of new wells, reducing production rate from the reservoir, etc.

Standard well testing is by use of a test separator. A MPFM may be applied as a replacement for, or a supplement to, a test separator if:

1. it is decided to not install a test separator in the processing plant,
2. there is a need to increase the capacity for well testing, or
3. the test separator is left to other use, eg. as an ordinary production separator (low pressure).

It should be noted that a test separator may be used also for purposes other than well testing and hence may be installed in any case.

A MPFM cannot be expected to return phase flow rates with an uncertainty equivalent to what is obtained from test separator measurements, for all flow rates, from all wells producing to the process plant. This is certainly the case if in-situ calibration of the MPFM is not available. The response time of a MPFM, however, is significantly less (minutes) than that of a separator (hours), and more well tests may be carried out using the MPFM.

5.2.1 Conventional well testing

Conventional well testing is usually performed by means of an extra separator dedicated for well test or special purposes. The well streams are measured by directing one well stream at the time through the test separator (see Figure 5.2). The well stream being tested is then separated into three "phases": high vapour-pressure oil, gas and water, which are then measured by means of single-phase instrumentation at the outlets of the separator.

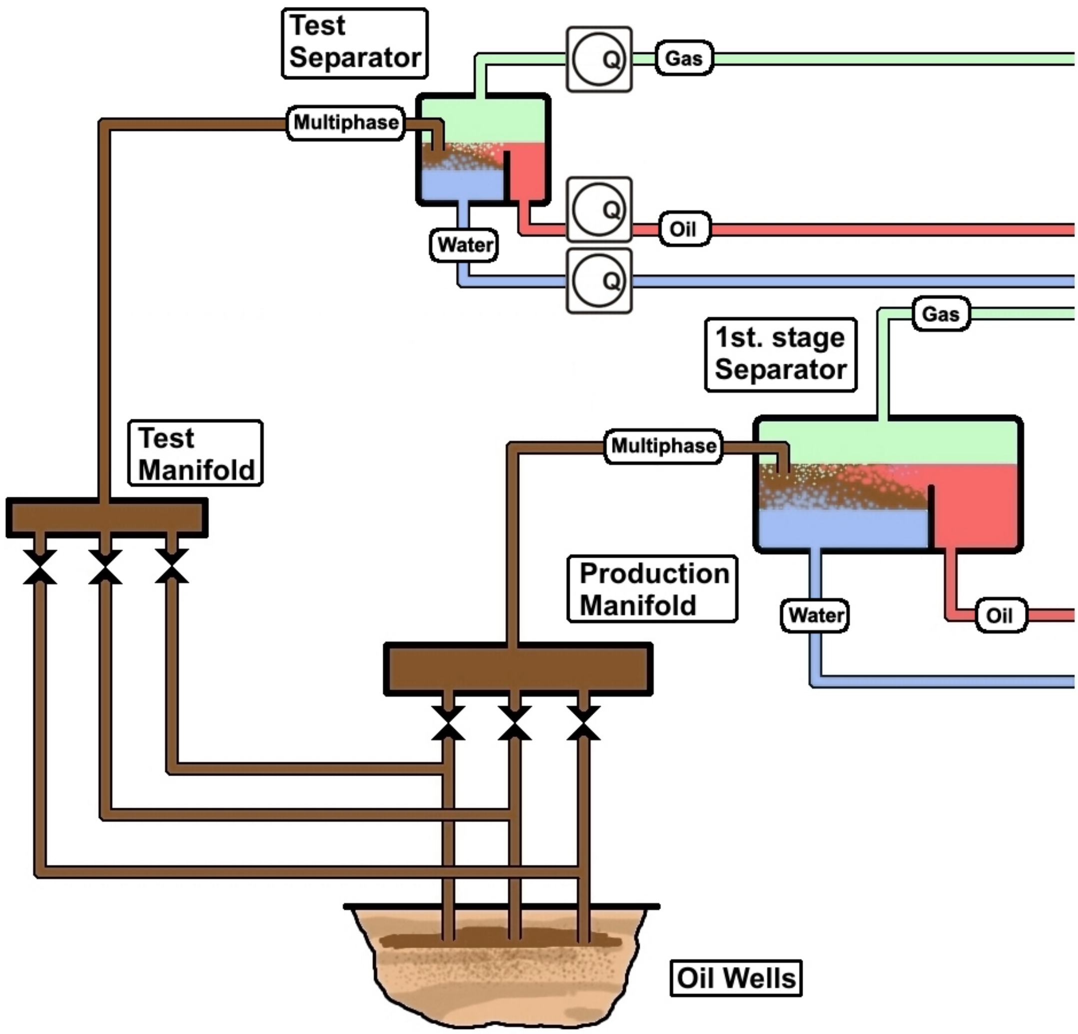


Figure 5.2 1st-stage production separator and test separator.

Today, a test separator can be designed with meters and instrumentation that will be capable of measuring the gas phase with an estimated uncertainty better than 5%, potentially as low as 2% and 1% for the gas and oil phases respectively, if effort is made to optimise the instrumentation and the separation is ideal.

During a well test, certain parameters such as choke opening, wellhead flow pressure, and separator pressure and temperature are recorded. Fluid samples are normally also captured at the test separator during these tests. Each well may be tested at one or more settings of the well's choke. For each choke setting, all the corresponding measurements are recorded.

The recorded information will be used until the next well test is performed to calculate the theoretical contribution made by the well to the commingled output stream of the entire processing facility.

For wells where daily control is needed, for example to keep wells stable or to produce at optimum flow rates in order to utilize the full capacity of the production facilities, this conventional system may not be satisfactory.

5.2.2 Well testing by MPFMs

MPFMs may be installed and used in the same way as the test separator. If a MPFM is installed in addition to an existing test separator, this arrangement provides an increased flexibility.

One can either use both the test separator and the MPFM for well testing to increase the overall testing capacity. Or one can use only the MPFM for well testing and hence use the test separator as a normal production separator and thereby increase the total production capacity of the processing facility (see Figure 5.3).

The main advantage of the MPFM over the test separator will be the reduction in time to perform a measurement. While the separator must be allowed to fill and stabilise when changing wells for test, the MPFM responds more quickly to changes in the well fluids and needs less time to stabilise.

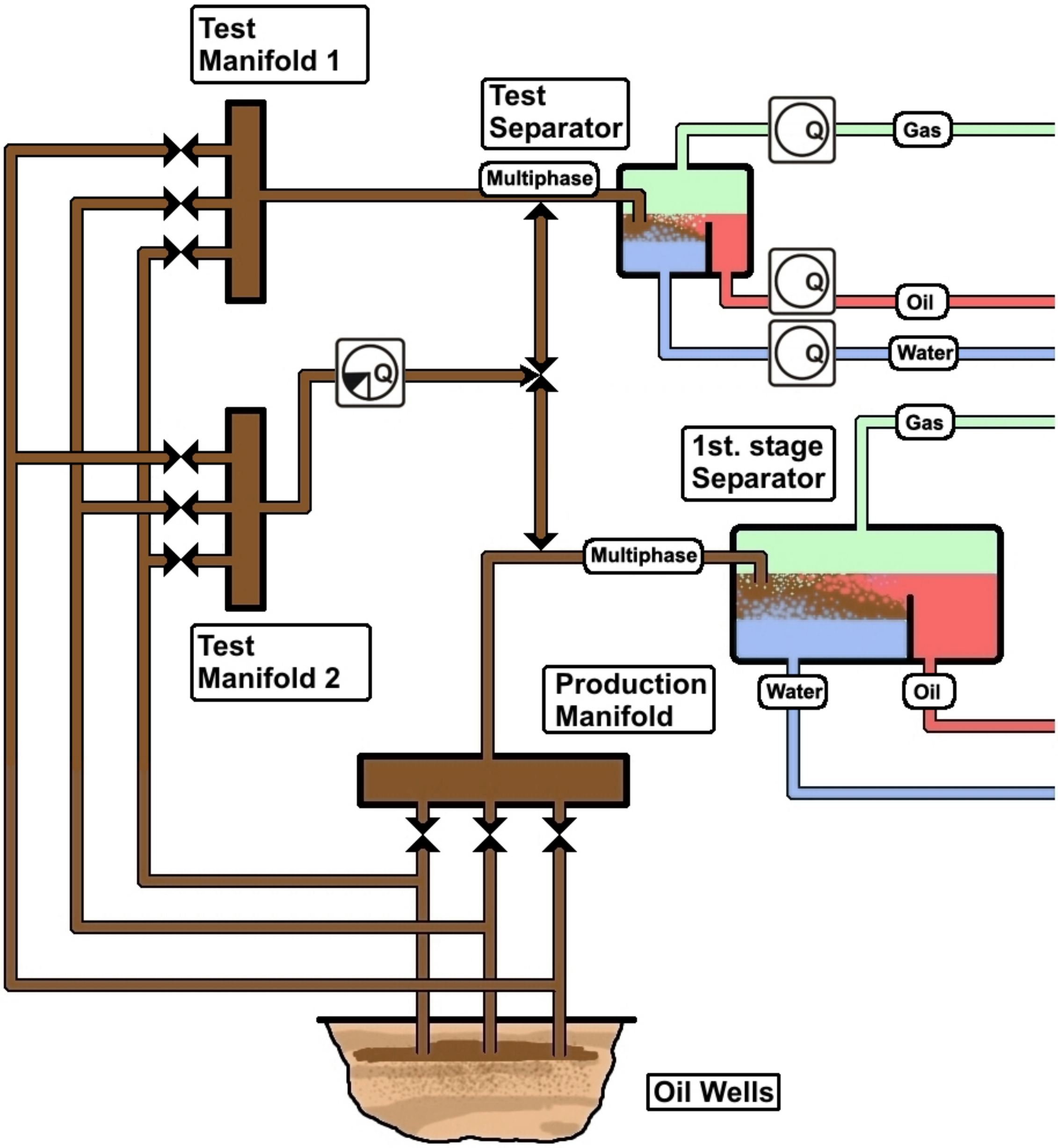


Figure 5.3 Multiphase metering can be used to increase overall testing capacity.

The MPFM might also replace the test separator completely (see Figure 5.4). This may be a solution for fields in the decline phase where the production from the well does not match the size of the test separator any more.

By using the two-phase flow map and the composition map, described in Chapter 9, one can evaluate whether there is a need for more than one MPFM to test all wells, i.e. whether several MPFMs with different sizes and measurement ranges are required to cover all wells to be tested.

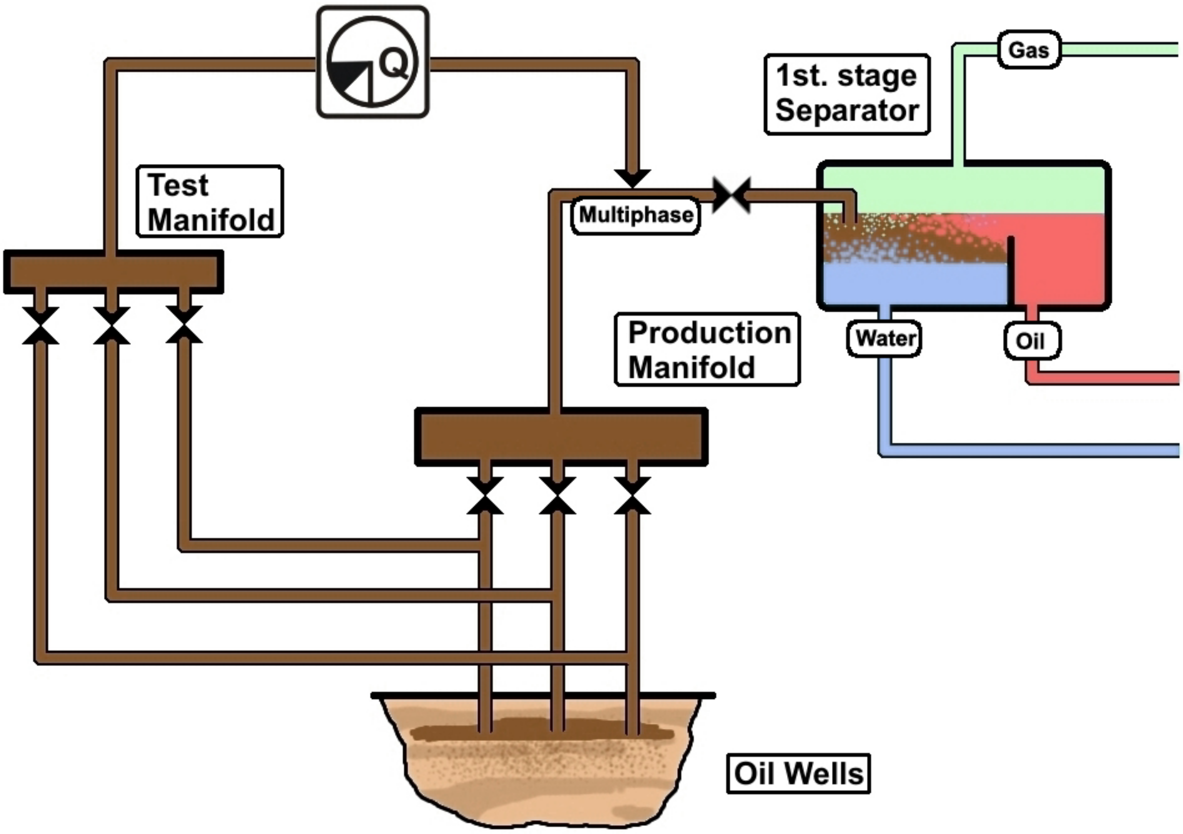


Figure 5.4 Multiphase metering replacing test separator and its meters.

5.3 Production allocation metering

For production allocation measurements, stronger requirements in terms of measurement uncertainty, calibration of instruments and representative fluid sampling are usually imposed than what is required for well testing.

A marginal field solution can be to let an unmanned wellhead platform have MPFMs on each individual well for well surveillance and the main tie-in stream (into a manned installation) be measured by a multiphase meter that is frequently "proved" to provide k-factors by a test separator equipped with measurement equipment to a fiscal standard. Long proving periods should be used to minimise uncertainties due to e.g. slugging, when accumulated oil, water and gas flow rates measured by the MPFM are compared to the separator measurements, and in some cases proving should last for days. In this application the measurement of each well stream by means of MPFMs are replacing the conventional well testing. And when the test separator is not used as a "prover" it can be used for other purposes or to "prove" other tie-in streams.

Well testing and production metering from the wells in a satellite field can be done by means of MPFMs, and this removes the need for a separate test line and manifold system for the satellite field. Assuming that a dedicated inlet separator would still be needed on the production platform, a typical multiphase production metering concept could be as shown in Figure 5.5. A guidance note for such an application can be found in the document published by the Department of Trade and Industry (DTI), Uncertainty in Measurement, Chapter 8.

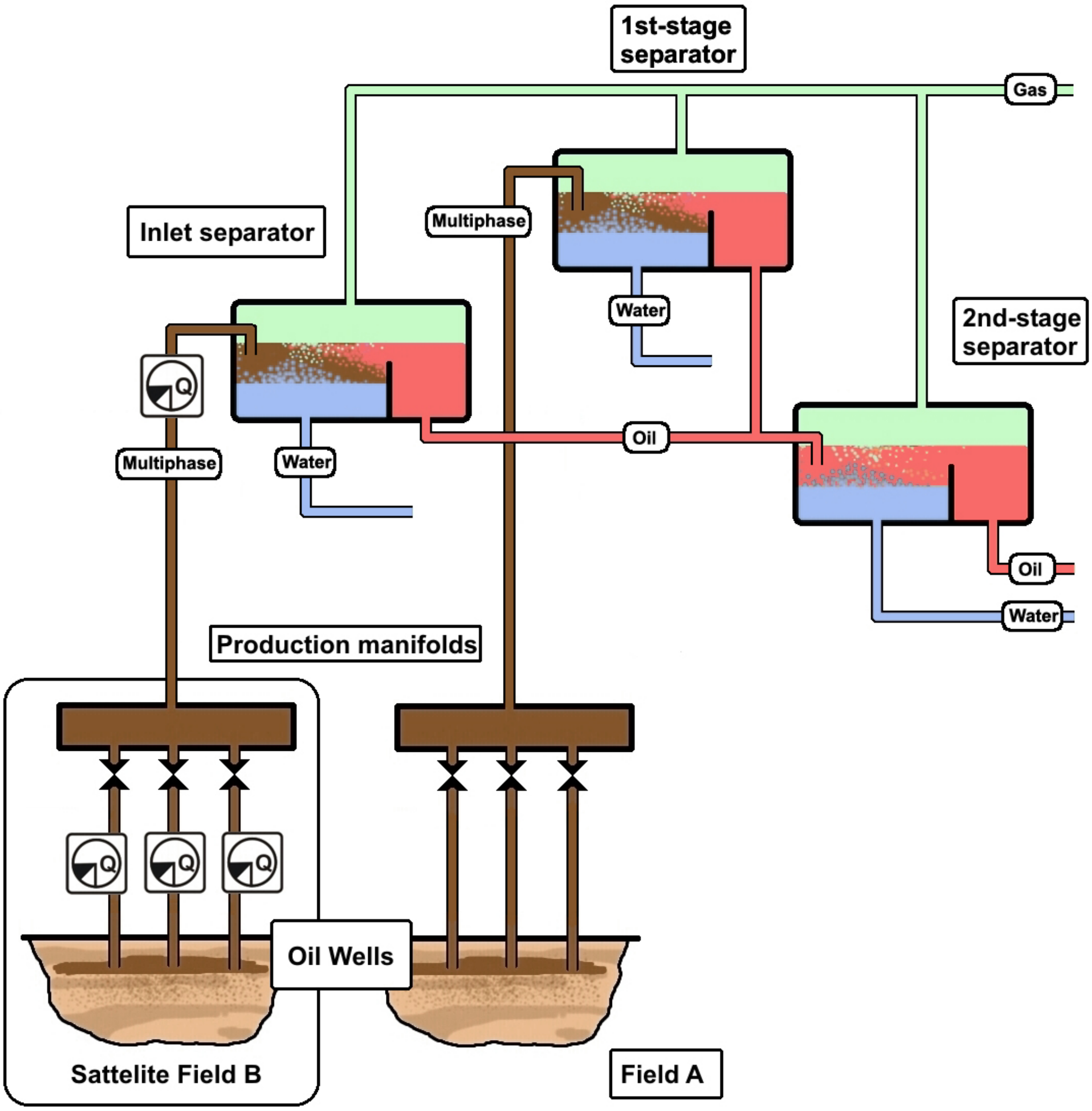


Figure 5.5 Satellite field "B" with MPFMs for well testing and production metering.

5.4 Fiscal or custody transfer measurement

When well streams from different production licenses are commingled into one single processing facility or flow line, it is normally necessary to meter the production from each license area separately before it enters the common processing facility or flow line.

The metering of the production from each license area is used to allocate each field owner's ownership to the well streams at the outlet of the common processing facility. Consequently national regulations or guidance notes for petroleum measurements govern this production metering. Other optimisation considerations can be made for chemical injection (e.g. methanol, demulsifier, etc.), gas lift optimisation, gas coning detection, water breakthrough detection, etc.

Fiscal or custody transfer measurements are the basis for money transfer, either between company and government or between two companies. Any systematic error in the measurement will result in a systematic error in the money flow. Hence, it is of paramount importance that sufficient verification processes are included (see Chapter 12). Note that the classification fiscal or custody transfer does not specify any uncertainty requirement; it just describes the purpose of the meter. The uncertainty needs to be further negotiated. For fiscal MPFMs it is required to follow the regulations and guidelines as set forward by the government authorities.

5.5 Summary of features of MPFMs

A multiphase flow measurement system for well testing and production metering has the following main features:

Table 5.1 Main features of MPFMs.

Positive
Continuous monitoring or metering is possible.
Installation and operating costs are low compared to those of a conventional system.
Test separator, test lines, manifolds and valve systems are eliminated.
Given the possibility of continuous metering, the total uncertainty will be lower than in a conventional system.
Negative
MPFMs are complex instrument systems that require awareness of the personnel operating the meters in order to operate according to specifications.
MPFMs may not be stable over time.
MPFMs are sensitive to the physical properties of the phases to be measured.
Verification is strongly recommended. For allocation metering systems periodic verification is normally required.
There is no standard for multiphase fluid sampling. It is difficult, if at all possible in practise.

6. MULTIPHASE FLOW

Multiphase flow is a complex phenomenon which is difficult to understand, predict and model. Common single-phase characteristics such as velocity profile, turbulence and boundary layer, are thus inappropriate for describing the nature of such flows.

The flow structures are classified in flow regimes, whose precise characteristics depend on a number of parameters. The distribution of the fluid phases in space and time differs for the various flow regimes, and is usually not under the control of the designer or operator.

Flow regimes vary depending on operating conditions, fluid properties, flow rates and the orientation and geometry of the pipe through which the fluids flow. The transition between different flow regimes may be a gradual process. The determination of flow regimes in pipes in operation is not easy. Analysis of fluctuations of local pressure and/or density by means of for example gamma-ray densitometry has been used in experiments and is described in the literature. In the laboratory, the flow regime may be studied by direct visual observation using a length of transparent piping. Descriptions of flow regimes are therefore to some degree arbitrary, and they depend to a large extent on the observer and his/her interpretation.

The main mechanisms involved in forming the different flow regimes are transient effects, geometry/terrain effects, hydrodynamic effects and combinations of these effects.

- Transients occur as a result of changes in system boundary conditions. This is not to be confused with the local unsteadiness associated with intermittent flow. Opening and closing of valves are examples of operations that cause transient conditions.
- Geometry and terrain effects occur as a result of changes in pipeline geometry or inclination. Such effects can be particularly important in and downstream of sea-lines, and some flow regimes generated in this way can prevail for several kilometres. Severe riser slugging is an example of this effect.
- In the absence of transient and geometry/terrain effects, the steady state flow regime is entirely determined by flow rates, fluid properties, pipe diameter and inclination. Such flow regimes are seen in horizontal straight pipes and are referred to as “hydrodynamic” flow regimes. These are typical flow regimes encountered at a wellhead location.

All flow regimes however, can be grouped into dispersed flow, separated flow, intermittent flow or a combination of these.

- Dispersed flow is characterised by a uniform phase distribution in both the radial and axial directions. Examples of such flows are bubble flow and mist flow (Figure 6.2).
- Separated flow is characterised by a non-continuous phase distribution in the radial direction and a continuous phase distribution in the axial direction. Examples of such flows are stratified and annular (Figure 6.2).
- Intermittent flow is characterised by being non-continuous in the axial direction, and therefore exhibits locally unsteady behaviour. Examples of such flows are elongated bubble, churn and slug flow (Figure 6.1). The flow regimes are all hydrodynamic two-phase gas-liquid flow regimes.

Flow regime effects caused by liquid-liquid interactions are normally significantly less pronounced than those caused by liquid-gas interactions. In this context, the liquid-liquid portion of the flow can therefore often be considered as a dispersed flow. However, some properties of the liquid-liquid mixture depend on the volumetric ratio of the two liquid components.

6.1 Multiphase flow regime maps

Figure 6.1 and Figure 6.2 provide general illustrations of the most flow regimes and indicate where the various flow regimes occur. Physical parameters like density of gas and liquid, viscosity, surface tension, etc. affect the flow regimes and are not included in this graph. A very important factor is the diameter of the flow line, if the liquid and gas flow rates are kept constant and the flow line size is decreased from 4” to 3”, both the superficial gas and liquid velocities will increase by a factor 16/9. Hence, in the two-phase flow map this point will move up and right along the diagonal to a new position. This could cause a change in flow regime, e.g. changing from stratified to slug flow or changing from slug flow to annular flow. Multiphase flow regimes also have no sharp boundaries but instead change smoothly from one regime to another.

Most oil wells have multiphase flow in part of their pipework. Although pressure at the bottom of the well may exceed the bubble point of the oil, the gradual loss of pressure as oil flows from the bottom of the well to the surface leads to an increasing amount of gas escaping from the oil. The diagrams in Figure 6.2 and Figure 6.1 are qualitative illustrations of how flow regime transitions are dependent on superficial gas and liquid velocities in vertical multiphase flow.

The term superficial velocity is often used on the axes of flow regime maps. For example, the superficial gas velocity ($v_{s,gas}$) is the gas velocity as if the gas was flowing in the pipe without liquids, in other words the total gas throughput (q_{gas} in m^3/s at operating temperature and pressure) divided by the total cross sectional area of the pipe (A). For the superficial liquid velocity the same can be derived, and the simple expressions are given in Eqn. (6.1).

$$v_{s,gas} = \frac{Q_{gas}}{A} \qquad v_{s,liquid} = \frac{Q_{liquid}}{A} \tag{6.1}$$

The sum of the $v_{s,gas}$ and $v_{s,liquid}$ is the multi-phase mixture velocity, and the expression is given in Eqn. (6.2).

$$v_m = v_{s,gas} + v_{s,liquid} \tag{6.2}$$

However, the latter is a derived velocity and only has a meaningful value if the multiphase flow is homogeneous and slip free.

6.1.1 Vertical flows

In vertical flows, the superficial gas velocity will increase in a vertical flow and the multiphase flow will change between all phases, bubble - slug - churn and annular. Note that for a particular superficial gas velocity, the multiphase flow is annular for all superficial liquid velocities.

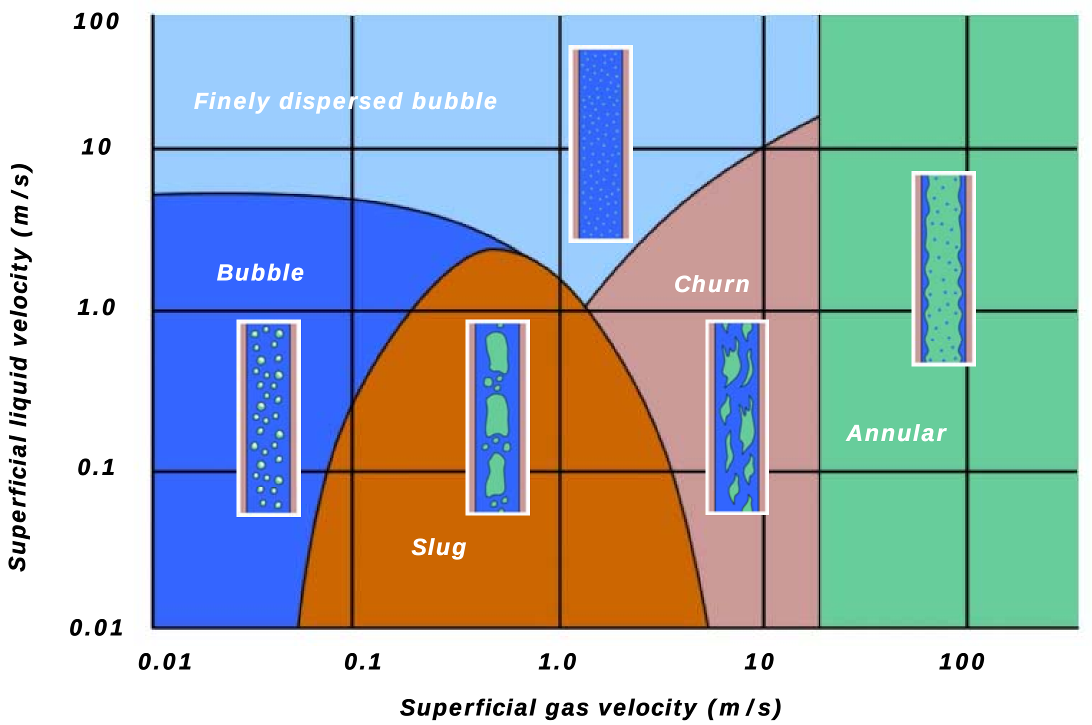


Figure 6.1 A generic two-phase vertical flow map, note that superficial velocities are used along the axis.

6.1.2 Horizontal flows

In horizontal flows too, the transitions are functions of factors such as pipe diameter, interfacial tension and density of the phases. The following map is a qualitative illustration of how flow regime transitions are dependent on superficial gas and liquid velocities in horizontal multiphase flow. A map like this will only be valid for a specific pipe, pressure and a specific multiphase fluid.

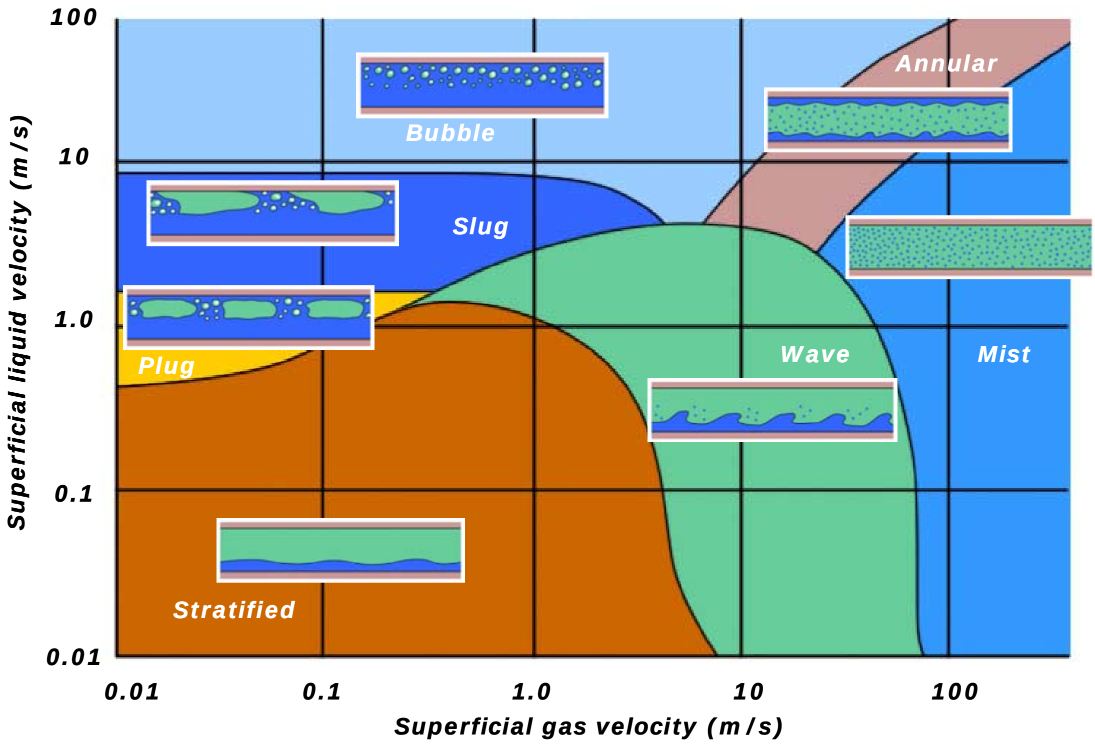


Figure 6.2 A generic two-phase horizontal flow map; note that superficial velocities are used along the axis.

6.2 Slip effects

When gas and liquid flow in a pipe, the cross sectional area covered by liquid will be greater than under non-flowing conditions, this is due to the effect of slip between liquid and gas. The lighter gas phase will normally move much faster than the liquid phase; the liquid has the tendency to accumulate in horizontal and inclined pipe segments. The liquid (α_{Liquid}) or gas fraction (α_{Gas}) of the pipe cross sectional area (A) as measured under two-phase flow conditions is known as liquid hold-up (λ_{Liquid}) and gas void fraction (λ_{Gas}). Owing to slip, the liquid hold-up will be larger than the liquid volume fraction. Liquid hold-up is equal to the liquid volume fraction only under conditions of no-slip, when the flow is homogeneous and the two phases travel at equal velocities.

$$\lambda_{Liquid} = \frac{A_{Liquid}}{A_{Pipe}}, \text{ Liquid Hold-up} \qquad (6.3)$$

$$\lambda_{Gas} = \frac{A_{Gas}}{A_{Pipe}}, \text{ Gas void fraction} \qquad (6.4)$$

$$\lambda_{Liquid} + \lambda_{Gas} = 1 \qquad (6.5)$$

$$\alpha_{Liquid} + \alpha_{Gas} = 1 \qquad (6.6)$$

Only in no-slip conditions is the gas void fraction equal to the gas volume fraction, and the Liquid Hold-up is equal to the Liquid Volume Fraction.

In the majority of flow regimes the Liquid Hold-up will be larger than the Liquid Volume Fraction and the gas void fraction will be smaller than the gas volume fraction (see Figure 6.3).

From the Liquid Hold-up and the actual velocities the superficial gas and liquid velocities can be calculated according to Eqn. (6.7) to (6.9) (note that $V_{Gas} \geq V_{s,Gas}$).

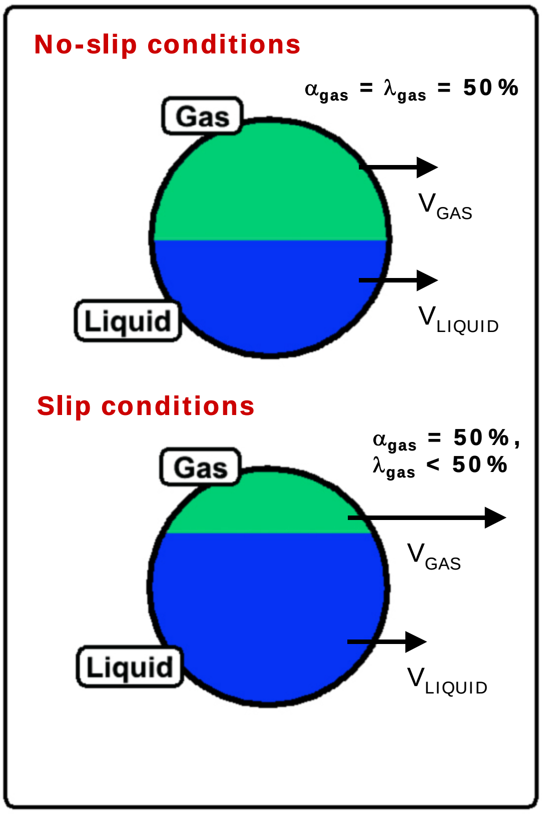


Figure 6.3 Difference between gas void fraction and gas volume fraction.

$$\lambda_{Liquid} \geq \alpha_{Liquid} \text{ and } \lambda_{Gas} \leq \alpha_{Gas} \tag{6.7}$$

$$V_{s,Gas} = \frac{q_{Gas}}{A_{Pipe}} = \frac{q_{Gas}}{A_{Gas}} \cdot \frac{A_{Gas}}{A_{Pipe}} = V_{Gas} \cdot \lambda_{Gas} \tag{6.8}$$

$$V_{s,Liquid} = \frac{q_{Liquid}}{A_{Pipe}} = \frac{q_{Liquid}}{A_{Liquid}} \cdot \frac{A_{Liquid}}{A_{Pipe}} = V_{Liquid} \cdot \lambda_{Liquid} \tag{6.9}$$

6.3 Classification of multiphase flows

Another way to classify multiphase flow, apart from the classification according to the flow pattern, is by the GVF of the flow. This method of classification is relevant to multiphase metering; one would expect that a meter measuring predominately liquid with just a few percent gas would be significantly different from one designed to operate in what is generally understood as a wet gas application. Four classes are defined in Table 6.1:

Table 6.1 Classification of multiphase flows.

Class	Indicative GVF range	Comment
Low GVF	0 - 25%	This Low GVF range of multiphase flow could also be termed 'gassy liquid'. In the lower end of this range traditional single-phase meters could in many cases provide the sufficient measurement performance. Increasing measurement uncertainty, and also risk of malfunctioning must be expected as the GVF increases.
Moderate GVF	25% - 85%	The Moderate GVF can be considered as the 'sweet spot' of multiphase meters, i.e. the range where they have their optimum performance, and where at the same time traditional single-phase meters are not a viable option.
High GVF	85% - 95%	Entering this High GVF range the uncertainty of multiphase meters will start to increase, with a rapid increase towards the upper end of the range. This increase in uncertainty is not only linked to more complex flow patterns at high gas fraction, but also because the measurement uncertainty will increase as the relative proportion of the fraction of the component of highest value (in this case the oil) decreases. In some cases partial separation (see 7.1.2.2) is used to move the GVF back into the Moderate GVF range.
Very high GVF	95% - 100%	This upper end of the multiphase range could also be termed the 'wet gas' range. In the lower end of the very high GVF range the measurement performance of in-line multiphase meters may still be sufficient for well testing, production optimisation and flow assurance. For allocation metering, in particular at the high end of this range, often gas is the main 'value' component, and a wet gas meter would be the preferred option. This corresponds to a Lockhart-Martinelli (LM) value in the range from 0 to approximately 0.3.

7. TECHNOLOGY

This chapter has been included in order to provide the reader with a general background on the different technologies and concepts in use in MPFMs available on the market. It is not our intention to cover all technologies or aspects in detail, and the reader is referred to other literature for more information on the different subjects.

In Section 7.1 we provide an overview of the main categories of MPFMs, in Section 7.2 we briefly describe the most commonly used measurement principles in MPFMs currently available on the market and in Section 7.3 we provide some guidance on selection of technology and maintenance requirements.

7.1 Meter categories

The following main categories can be applied to MPFMs and are briefly described in the following Sections:

- In-line meters
- Separation type meters
  - Full two-phase gas/liquid separation
  - Partial separation
  - Separation in sample line
- Wet gas flow meters
- Other categories of MPFMs

7.1.1 In-line meters

In-line MPFMs are characterised in that all the measurements of the individual phase fractions and total or individual phase flow rates are performed directly in the multiphase flow line, hence, no separation and/or sampling of the fluids are required.

The volume flow rate of each phase is represented by the area fraction multiplied by the velocity of each phase. This means that a minimum of six parameters has to be measured or estimated. Some MPFMs assume that either two or all three phases travel at the same velocity, thus reducing the required number of measurements. In this case either a mixer must be employed or a set of calibration factors established.

In-line MPFMs commonly employ a combination of two or more of the following measurement technologies and techniques:

- Electromagnetic measurement principles
    - Microwave technology
    - Capacitance
    - Conductance
- Gamma ray densitometry or spectroscopy
- Neutron interrogation
- Differential pressure using Venturi, V-cone or other restriction
- Positive displacement
- Ultrasonic
- Cross-correlation of electromagnetic, radioactive, ultrasound signals (to calculate flow velocities)

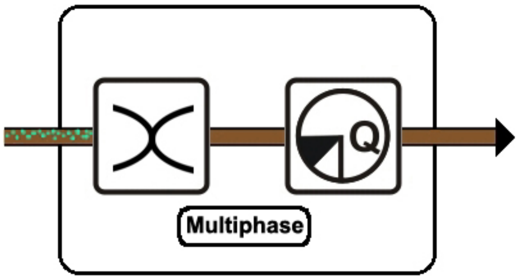


Figure 7.1 Principle design of in-line MPFM with mixer (optional).

7.1.2 Separation type meters

Separation type MPFMs are a class of MPFMs characterised by performing a complete or partial separation of the multiphase stream, followed by in-line measurement of each of the three phases. The test separator, which is found on nearly every production platform, is basically a two-phase or three-phase separation-type meter. It separates the three phases and carries out flow measurements of the oil, water and gas. Complete separation utilising three-phase separators will not be described further in this handbook and is only mentioned here to make the overview complete.

7.1.2.1 Full two-phase gas/liquid separation

This type of meter is characterised by its separation of the multiphase flow, usually a full separation to gas and liquid (see Figure 7.2). The gas flow is then measured using a single-phase gas-flow meter with good tolerance to liquid carry-over, and the liquid flow rate is measured using a liquid flow rate meter. An on-line water fraction meter may determine the water-in-liquid ratio.

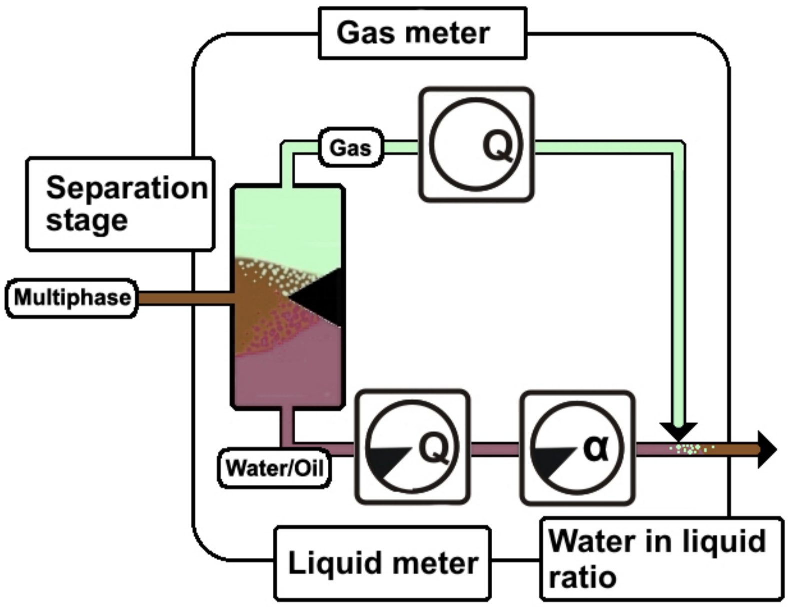


Figure 7.2 Principle design of a separation type meter.

7.1.2.2 Partial separation

This type of meter is characterised by separating only a part of the gas in the multiphase flow into a secondary measurement loop around the main loop through MPFM (see Figure 7.3). Since the separation is only partial, one must also expect some liquid to travel with the gas through the secondary measurement loop, which then calls for a "wet gas" measurement. The remaining multiphase stream will than have a reduced GVF and thereby operate within the designed envelope of the flow meter.

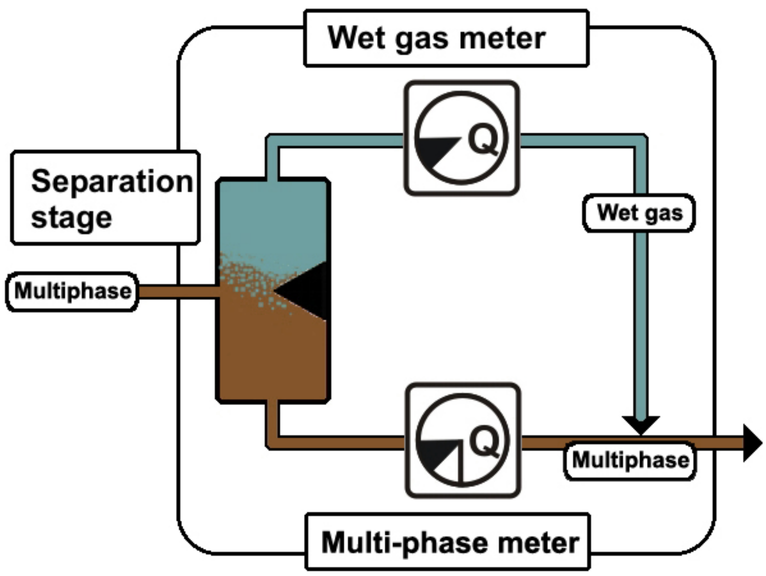


Figure 7.3 Principle design of a partial separation with a secondary measurement loop

7.1.2.3 *Separation in sample line*

This type of meter is characterised by the fact that separation is not performed on the total multiphase flow, but on a bypassed sample flow (see Figure 7.4). The sample flow is typically separated into a gas and liquid flow, where after the water-in-liquid ratio of the liquid sample stream can be determined using an on-line water fraction meter. Total gas/liquid flow rate and ratio must be measured in the main flow line, and assuming the bypassed sample flow is representative of the main flow, the water in liquid ratio is based on the by-pass measurement of this parameter.

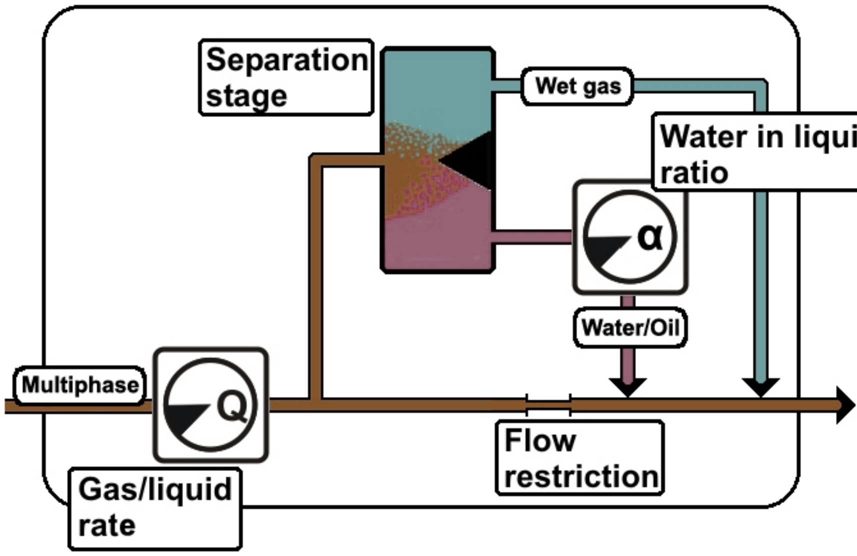


Figure 7.4 Principle of a MPFM with separation in sample line

In this configuration three measurements are required to determine the mass and volume of the three phases, and the common alternative technologies can be used:
Gas / liquid ratio (GLR):

- Gamma attenuation
- Vibrating tube
- Neutron interrogation
- Weighing

Multiphase flow rate:

- Cross-correlation using radioactive, acoustic or electrical signals
- Differential pressure using Venturi, V-cone or Dall tube
- Mechanical, e.g. positive displacement or turbine

Water-in-liquid ratio (WLR):

- Electrical impedance
- Vibrating tube

7.1.3 Wet gas flow meters

7.1.3.1 Applications

There are several types of applications for wet gas meters, some of which are distinctly different:

1. Measurement of gas with some entrained liquid. The liquid is of no value and only represents a problem for the gas measurement. The objective is to make correction to achieve a correct gas measurement. A single-phase meter is normally used, corrected for liquid fraction.
2. Measurement of hydrocarbon gas and liquid (hydrocarbon + water). Also the liquid needs to be measured. WLR is unknown or of no importance.
3. Measurement of hydrocarbon gas, hydrocarbon liquid and water.
   The need is to measure hydrocarbons.
4. Measurement of water and small changes of water fraction. The application may be flow assurance, for the purpose of hydrate mitigation, corrosion inhabitation etc. This is a difficult task because the water fraction may be very low and the changes in water fraction even lower. Water is of primary interest, but is normally available only as a fraction. Hence, gas flow must be measured accurately in order to determine water flow rate.
5. Measurement of water salinity or changes in water salinity. The purpose is to be able to monitor wells for water breakthrough.

A wet gas flow meter can be installed as a stand-alone system in typical wet gas applications, or it can be installed in conjunction with a partial separation system like the one described in Section 7.2.1.2.

A wet gas meter can be a combination of various measurement techniques as outlined in Section 7.1.1. Wet gas can, for example, be measured by single-phase flow meters like a venturi or a V-cone meter. However, when single-phase meters like these are used for wet gas flow measurements, one must correct the standard single-phase measurement models using various models and correction factors to compensate for the presence of liquid in the gas (orifice meters: Murdoch (1962), venturi meters: De Leeuw (1997a)). The liquid fraction is normally input as a manual data entry.

Other wet gas flow meters measure two phases (hydrocarbon and condensate plus water). Also there exist in-line three-phase wet gas flow meters capable of measuring oil, water and gas. Some wet gas meters can even discriminate between produced water/condensate water and formation water by measuring the salinity of the water. Nucleonic density meters are normally not used because the liquid contributes very little to the mixture density. Gas density may be calculated by means of PVT from gas composition, pressure and temperature. Water content may be calculated from the assumption that the gas is saturated in the reservoir.

The expected liquid and gas flow rates, flow profiles and eventually requirements for formation water detection will together with the required uncertainty form basis for selection of the wet gas meters for given applications.

7.1.3.2 Algorithms

The Liquid/Gas Ratio (LGR) strongly influences the apparent reading of a differential pressure meter. During the calculation of the gas flow rate the flow computer shall take account of the deviation introduced by the LGR. This deviation shall be corrected for with an approved correction algorithm, preferably in the flow computer based on the raw data from the installation. This correction procedure may be implemented in the Hydrocarbon Accounting computer system.

Wet gas tests performed on venturis have been reported on in the open literature, for example by Stewart et. al. (2003). These tests showed that the deviation as determined by Chisholm (1967) or Murdock (1962) on orifice plates are also applicable for venturi meters with some limitations (range, flow regime, uncertainty).

The formulae for the determination of the dry gas flow rate from the wet gas measurements are as follows:

$$\text{Murdock} \qquad q_g = \frac{q_{tp}}{1 + 1.26X} \tag{7.1}$$

$$\text{Chisholm} \qquad q_g = \frac{q_{tp}}{\sqrt{1 + CX + CX^2}} \tag{7.2}$$

Where:

$$C = \left(\frac{\rho_l}{\rho_g}\right)^{0.25} + \left(\frac{\rho_g}{\rho_l}\right)^{0.25} \qquad (for\ X < 1) \tag{7.3}$$

$$X = \frac{q_l}{q_g} . \sqrt{\frac{\rho_l}{\rho_g}} \text{ is the Lockhart Martinelli parameter} \tag{7.4}$$

Where:

q_g is the (dry) gas flow rate

q_{tp} is the gas flow rate calculated using the two-phase pressure drop

ρ_g is the density of the gas

ρ_l is the density of the liquid

However, the Murdock formula does not incorporate a pressure dependence term, and at larger liquid/gas ratios the pressure dependence of the Chisholm formula does not match experimental data.

A more recent formula for the determination of the dry gas volume has been developed by De Leeuw (1997a). The formula has been verified against an extensive database of experimental data to establish its validity.

The formula was presented at the North Sea Flow Measurement Workshop in 1997 and was published at the Multiphase '97 Conference in Cannes by De Leeuw (1997b). Further work carried out at NEL (Steven, 2002)) has shown a dependence on the β-ratio of the Venturi.

De Leeuw $$q_g = \frac{q_{tp}}{\sqrt{1 + CX + CX^2}} \tag{7.5}$$

Where:

$$C = \left(\frac{\rho_l}{\rho_g}\right)^n + \left(\frac{\rho_g}{\rho_l}\right)^n \tag{7.6}$$

$$n = 0.606(1 - e^{-0.746 \cdot Fr_g}) \qquad (for \quad Fr_g \geq 1.5) \tag{7.7}$$

$$Fr_g = \frac{v_{sg}}{\sqrt{gD}} . \sqrt{\frac{\rho_g}{\rho_l - \rho_g}} \tag{7.8}$$

F_r is the Froude number

g is the gravitational constant

D is the internal pipe diameter

V_{sg} is the superficial gas velocity

A V-cone meter manufacturer has established a similar correction formulae, which were published at the North Sea Flow Measurement Workshop in 2004 (Peters et. al., 2004)

It is recommended that the rangeability of the measurement installation in terms of dry gas be determined as for dry gas flow measurement. Preferably a smart digital differential pressure sensor should be applied, allowing a turn down of 10:1 in gas measurement, or a maximum of two differential pressure transmitters ranged high and low.

The maximum value for the LGR corresponds to a Lockhart-Martinelli parameter of 0.3, or approximately 10% free liquid by volume. The uncertainty of the LGR value shall be less than 10%.

For the collection of gas samples a sample point including a probe shall be installed outside the straight lengths of the wet gas meter.

Where the LGR is determined by means of a tracer technique, sample injection and collection points shall be made available. The injection point shall be located in the bottom of the flow line at a sufficient distance upstream of the primary element to allow adequate mixing of the tracer with the liquid phase. The collection point shall be located in the bottom of the flow line downstream of the primary element.

Where the wet gas meter can be put in series with a test separator, gas and liquid flow rates and samples may be taken at the test separator. Gas and liquid properties may be derived by means of a flash calculation, and from the data gathered it will be possible to check whether the wet gas meter is functioning correctly.

7.1.4 Other categories of MPFMs

Other categories of MPFMs include advanced signal processing systems ("virtual" measurement systems), estimating phase fractions and flow rates from analysis of the time-variant signals from whatever sensors are available in the multiphase flow line. Such sensors may be acoustic, pressure or other types. The signal processing may be a neural network or other pattern-recognition or statistical signal-processing system, for example.

There are also multiphase metering systems that have been developed on the basis of process simulation programs combined with techniques for parameter estimation. Instead of predicting the state of the flow in a pipeline at the point of arrival, its pressure and temperature can be measured at the arrival point and put into the simulation program. In addition, the pressure and temperature of an upstream or downstream location must also be measured. When the pipeline configuration is known along with properties of the fluids, it is then possible to make estimates of phase fractions and flow rates.

7.2 Measurement principles

A multiphase flow consists of the three phases: oil, gas and water. To work out the individual volumetric flow rate of these phases, the fractions and velocities of each of the phases have to be found as in Eqn. (7.9). In Section 7.1.1 we stated that a minimum of six parameters must be measured or estimated.

$$q_V = \alpha \cdot v \tag{7.9}$$

An ideal flow meter would have three measurements; phase fraction, phase velocity and phase density. By means of these measurements the oil, gas and water mass flow rate can be calculated as in (7.10).

$$q_m = q_V \cdot \rho \tag{7.10}$$

In practise, the density of the oil, water and gas is calculated by means of PVT-data.

The MPFM is then set up to measure component velocities and two of the component fractions, since the fractional sum should equal 1. The phase mass flow rates of oil, gas and water are found by combining the fractional measurement, velocity measurement and density measurement.

The most common principles used for measurement of phase velocities and phase fractions are described in the next Sections.

7.2.1 Phase velocities and volume flow

7.2.1.1 Venturi meter

A venturi is often used to determine the velocity of the multiphase flow. In a venturi meter the differential pressure across the upstream section and the throat section of the device is measured and can be related to the mass flow rate through the Venturi.

The venturi technology for single-phase flow is described in ISO 5167:2003. The equations outlined in the ISO standard cannot be applied directly to multiphase flows, and are thus modified for use in MPFMs. Most manufacturers apply their own corrections or compensations to the standard venturi equations.

7.2.1.2 *Cross correlation*

Velocity measurements by cross-correlation is a standard signal processing method to determine the velocity of flows. Some property of the flow is measured by two identical sensors at two different locations in the meter, separated by a known distance. As the flow passes the two sensors, the signal pattern measured by the first sensor will be repeated at the downstream sensor after a short period of time (dt) corresponding to the time it takes the flow to travel from the first to the second sensor. The signals from the two sensors can be input to a cross-correlation routine, which moves the signal trace of the second sensor over the signal trace of the first sensor in time. The time-shift that gives the best match between the two signals corresponds to the time it takes the flow to travel between the sensors. Knowing the distance between the sensors, it is therefore possible to calculate the flow velocity.

If the *x(t)* and *y(t)* are the two signals, the cross-correlation function can be expressed as:

$$\phi_{xy}(t) = \int_{\div\infty}^{+\infty} x(t+\tau)\, y(\tau)\, d\tau \qquad (7.11)$$

Examples of technologies where cross-correlation techniques are often used are:

- Microwave
- Gamma-ray (density)
- Differential pressure measurements
- Electrical impedance principles

7.2.1.3 *Positive displacement meter*

Positive Displacement (PD) flow meters measure the volumetric flow rate of a liquid or gas by separating the flow stream into known volumes and counting them over time. Vanes, gears, pistons, or diaphragms may be used to separate the fluid.

As part of a MPFM, a PD meter will usually measure the total volumetric multiphase flow rate (gas and liquid).

7.2.1.4 Examples of applications of these technologies and techniques

Some examples of applications of these technologies and techniques include:

- Venturi measurements on multiphase flows can be corrected for gas fraction and a number of algorithms have been published in international literature describing how to correct the standard formulae given in e.g. ISO-5167:2003 to calculate the total multiphase flow rate from the venturi differential pressure measurements and gas fraction.

- Several meters using electromagnetic measurement principles apply cross-correlation techniques to calculate a characteristic velocity of the multiphase mixture. By careful selection of electrode designs one may also (by means of cross-correlation of these signals) identify velocities of the different phases in the multiphase flow.

- Some MPFMs use positive displacement meters to determine the total volumetric flow rate of gas and liquid.

7.2.2 Phase fractions

A number of technologies are used in MPFMs for measurement of phase fractions and some of the most common are briefly described in the following Sections.

7.2.2.1 Gamma ray methods

A number of different gamma ray methods exist and that are applied in flow metering, and here we will only discuss briefly the more common single-, dual- or multiple energy gamma ray attenuation methods. In principle a gamma ray attenuation measurement is applicable to all possible combinations of two-and three-phase flows. There are few measurement limitations and the measurement works in the whole range from 0 - 100% water cut and 0-100% GVF applications.

Single energy gamma ray attenuation measurement is based on the attenuation of a narrow beam of gamma- or X-rays of energy E. Note that the single energy gamma ray attenuation concept as a stand-alone measurement can only be applied in a two-phase mixture. In a pipe, with inner diameter d, containing two phases the attenuation is described with:

$$I_m(e) = I_v(e).\exp[-\sum_{i=1}^{2} \alpha_i.\mu_i(e).\mathrm{d}] \qquad (7.12)$$

I_m (e) is the measured count rate, I_v (e) is the count rate when the pipe is evacuated and μ_i represent the linear attenuation coefficients for the two phases. Apart from the fractions (α_i), the attenuation coefficients (μ_i) are also initially unknown. However, the latter can be found in a calibration where the meter is subsequently filled with the individual fluids or they can be entered in the software after they have been determined offline.

In both cases the following two equations, Eqn. (7.13) and (7.14), can be used:

$$I_{Water} = I_v.\exp\left[-\alpha_{Water}.\mu_{Water}.d\right] \tag{7.13}$$

$$I_{Oil} = I_v.\exp\left[-\alpha_{Oil}.\mu_{Oil}.d\right] \tag{7.14}$$

These two calibration points together with the obvious relation that $\alpha_{Water} + \alpha_{Oil} = 1$ can be rewritten as an expression for the water fraction in a two phase liquid/liquid mixture (or the water cut) as shown in Eqn. (7.15):

$$\alpha_{Water} = \frac{\ln(I_{Oil}) - \ln(I_m)}{\ln(I_{Oil}) - \ln(I_{Water})} \tag{7.15}$$

Single energy gamma ray attenuation can be used conveniently in liquid/liquid system (oil/water) or liquid/gas system. If Single energy gamma ray attenuation meters are used in multiphase meters where three phases are present, often algorithms or correlations based on the output from the other measurements in the multiphase flow meter are implemented in the software to correct the expression in Eqn. (7.15) (e.g. variations in the linear attenuation coefficient of the liquid, consisting of water and oil, due to variations of the water fraction).

The basics of the Dual Energy Gamma Ray Absorption (DEGRA) measurement are similar to the single energy gamma ray attenuation concept, but now two gamma- or X-rays of energies e_1 and e_2 are used. In a pipe, with inner diameter d, containing a water, oil and gas mixture with fractions α_{Oil}, α_{Water} and α_{Gas} measured count rate I_m (e) is:

$$I_m(e) = I_v(e).\exp[-\sum_{i=1}^{3}\alpha_i.\mu_i(e).\mathrm{d}] \tag{7.16}$$

$I_v(e)$ is the count rate when the pipe is evacuated and $\mu_{i\,w/o/g}$ represents the linear attenuation coefficients for the water, oil and gas phases. For two energy levels, e_1 and e_2, provided the linear attenuation coefficients between water, oil and gas are sufficiently different, two independent equations are obtained. The third equation is simply the fact that the sum of the three fractions in a closed conduit should equal 1. A full set of linear equations is given below. R_o, R_w, R_g and R_m now represents the logarithm of the count rates for water, oil, gas and the mixture, respectively, at energies e_1 and e_2.

The elements in the matrix are determined in a calibration process by filling the instrument with 100% water, 100% oil and 100% gas (air) or alternatively by calculations based on the fluid properties. Together with the measured count rates at the two energy levels from a multiphase mixture it is then possible to calculate the unknown phase fractions.

$$\begin{bmatrix} R_w(e_1) & R_o(e_1) & R_g(e_1) \\ R_w(e_2) & R_o(e_2) & R_g(e_2) \\ 1 & 1 & 1 \end{bmatrix} . \begin{bmatrix} \alpha_w \\ \alpha_o \\ \alpha_g \end{bmatrix} = \begin{bmatrix} R_m(e_1) \\ R_m(e_2) \\ 1 \end{bmatrix} \tag{7.17}$$

In Figure 7.5 this is graphically presented with the logarithm of the count rates of the two energy levels plotted along the axis. The corners of the triangle are the water, oil and gas calibrations, and any point inside this triangle represents a particular composition of water, oil and gas, e.g. a point half way on the water-gas line represents a 50% water and 50% gas mixture.

As for the single energy gamma ray attenuation concept, the contrast between the phases should be high, i.e. a large cross-sectional area of the triangle in Figure 7.5. The shape of the triangle depends mainly on the energy levels used (thus the specific radioactive source), pipe diameter and detector characteristics; however, fluid properties may also influence the triangular shape. If the energy levels are too close the triangle will transform into a line and obviously cannot be used for a three-phase composition measurement.

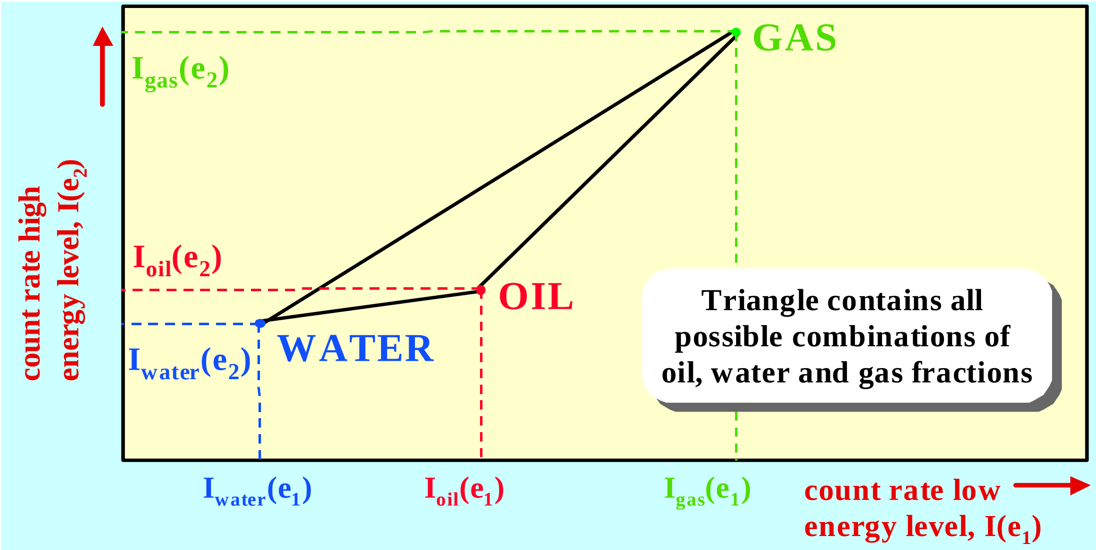


Figure 7.5 If oil, water and gas calibration points are plotted on a log-log scale a composition triangle can be constructed.

A dual gamma ray system is required to solve the Eqn. (7.17) for 3 components, whereas single gamma ray densitometers are typically used with Eqn. (7.15) to determine the gas fraction and/or water cut.

7.2.2.2 Electrical impedance methods (capacitance and conductance)

The main principle of electrical impedance methods for component fraction measurements is that the fluid flowing in the measurement section of the pipe is characterised as an electrical conductor. By measuring the electrical impedance across the pipe diameter (using e.g. contact or non-contact electrodes), properties of the fluid mixture like conductance and capacitance can be determined. The measured electrical quantity of the mixture then depends on the conductivity and permittivity of the oil, gas and water components, respectively. Permittivity is an electrical property that will be different for each of the three components in an oil/gas/water mixture, and the permittivity of the mixture is therefore a measure of the fractions of the different components (permittivity is also sometimes called the dielectric constant).

The permittivity can be measured using a capacitance sensor, typically by placing one electrode on each side of the flowing medium, inside of the spool, but separated from the steel pipe by an electrical insulator. The electrodes will act as a capacitance detector and the resulting capacitance can be measured between the electrodes. This capacitance will therefore vary when the permittivity changes, i.e. according to the amount of oil, gas and water in the mixture.

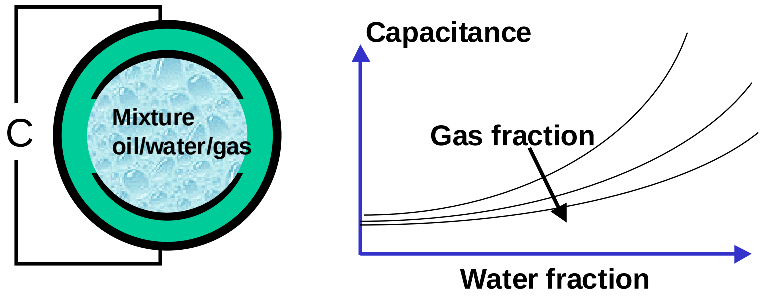


Figure 7.6 A typical capacitance measurement principle

This capacitance measurement works as long as the flow is oil continuous, i.e. as long as water is dispersed in the oil and does not form a continuous path of water between the electrodes. Normally, the flow is oil continuous as long as the water cut is below approximately 60 – 70%. For higher water cuts the flow will normally become water continuous. For these situations the capacitance measurement must be replaced by a conductivity measurement.

The conductivity will typically be measured by injecting a known or controlled electrical current into the flow, and then measure the voltage drop between to electrodes along an insulated section of the pipe. The current can be injected by contact electrodes, or in a non-contacting mode by coils (inductive mode). Knowing both the current and the voltage drop, the resistance (or conductance) can be calculated using Ohm's law. Since also the distance between the detector electrodes is known, the measured resistance can be converted into a conductivity measurement.

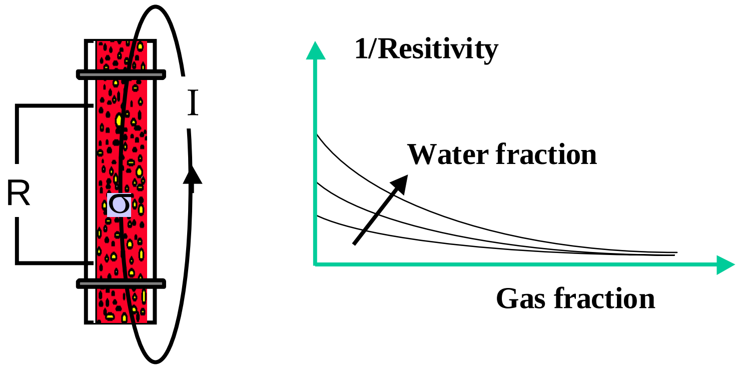


Figure 7.7 A typical conductance measurement principle.

7.2.2.3 Microwave technology

Microwave measurements are also dielectric measurements, but are significantly different from the capacitive measurement techniques as both the frequencies are higher and the operation principles of the sensor devices are different. Several operation principles have been described by Nyfors, E. & P. Vainikainen (1989):

- Transmission sensor, measurement on a single frequency. Two probes (i.e. antennas) are used, one for transmitting a signal and one for receiving the same after transmission through the medium. Care must be taken to avoid reflections in the pipe/sensor. Alternatively some kind of guided wave transmission sensor can be used. The sensor may be based on the measurement of the attenuation or the change of phase.

- Transmission sensor, measurement on a varying frequency. Because the attenuation in water-continuous fluids is high on high frequencies, it is an advantage to change the measurement frequency with the permittivity of the fluid. A particularly useful concept is to measure the change of phase such that the meter detects the frequency, where the change of phase is constant, i.e. the meter looks for the frequency, where the change of phase is equal to a fixed value.

- Resonator sensor. The resonant frequency changes with the permittivity (ε) of the medium according to a simple equation:

$$\varepsilon = \left(\frac{f_0}{f_r} \right)^2 \tag{7.18}$$

where f_0 is the resonant frequency of the sensor filled with air, and f_r is the measured resonant frequency when the sensor is filled with the fluid. An advantage is that the relation expressed in Eq. (7.16) is a physical relation that is independent of the shape of the individual resonator, and therefore needs no other calibration than the measurement of f_0. Hence the primary measurement is a measurement of frequency, which can be performed very accurately with practically no drift. Because also f_0 only depends on the physical size and shape of the resonator, the resonator measurement method is accurate with virtually no drift in measurements. The main limitation of the resonator method is that it can only be used with low-loss media, i.e. with oil-continuous fluids in this application. Water-continuous fluids absorb the microwave energy too fast for resonance to occur. Nyfors, E (2000) gives an account on principles for design of resonator sensors in pipes.

A practical microwave MPFM uses the resonator principle for oil-continuous fluids, and the varying frequency transmission principle in water-continuous fluids, utilizing the same probes. When the attenuation is low, the pipe acts as a resonator and, when the attenuation is high, the phase difference between two receiving probes is detected. By using two sets of probes axially separated by a fixed distance, cross correlation can be used to measure the velocity of the flow.

A microwave MPFM would typically also contain a gamma densitometer to obtain enough measurements to solve the system of equations. The densitometer “sees” a high contrast between liquid and gas, while the microwave sensor “sees” a high contrast between water and hydrocarbons due to the fact that the permittivity of water is high compared to that of both oil and gas.

7.2.2.4 Venturi meter

The standard venturi equations as given in ISO-5167:2003 can be solved in several ways. Not only can mass flow rates be calculated based on measurement of the differential pressure over the venturi and knowledge of parameters like the density of the fluid. When used in multiphase flows one must also apply corrections to the single-phase venturi equation, e.g. based on knowledge of the gas fraction.

But instead of calculating the mass flow rate, the equation may also be solved for one of the other parameters, and hence when a corrected venturi equation is applied, for instance, the gas fraction may be determined, given that information about the total mass flow rate or the total fluid density is made available by other means.

7.2.2.5 Examples of applications of these technologies

Some examples of applications of these technologies include:

- A single gamma densitometer can be used to measure the total multiphase mixture density, which then can be used to calculate the gas fraction when electric impedance methods are used for measurement of WLR.
- A dual gamma densitometer with different energy levels can be used to calculate the gas fraction and water cut of the multiphase mixture.
- Utilise the differential pressure over the venturi meter in conjunction with other instruments to determine the mixture density and thereby the gas fraction. To determine the WLR, microwave technology electric impedance methods can be used.

7.3 Selection of technology and maintenance requirements

This Section briefly covers some important factors to keep in mind when selecting and specifying a MPFM for a specific application (well) to help ensure that important issues concerning the technology and maintenance requirements are highlighted and dealt with at an early stage.

7.3.1 Pressure measurements

All pressure tappings and pressure transmitters require some degree of maintenance in terms of for example inspection and cleaning. Maintenance requirements should therefore be considered at an early stage when installations involving pressure measurements are planned.

7.3.2 Positive displacement meters

Positive displacement meters contain moving parts, and if exposed to impurities in the flow, the sensors may be damaged.

7.3.3 Electrical impedance and microwave sensors

Electrical impedance methods utilising capacitance measurement principles work only for oil continuous fluids. For water continuous fluids, conductivity measurement principles must be used. The switching between the different methods occurs whenever the fluid is changing between oil and water continuous flows, this can introduce a higher uncertainty if the sensor operates for a long time in the transition region (where the flow is more or less rapidly changing between oil and water continuous flow inside the measurement volume of the meter).

Sensors for electrical impedance must be robust to withstand erosion, as erosion may change the characteristics of the sensor and cause drift in measurements. If non-contact electrodes are used the insulating material (often Peek-materials are used) must withstand the erosion. If contact-electrodes are used the electrodes themselves must withstand erosion.

Systems or routines should also exist to detect and handle deposits on the insulating material or directly on contact electrodes as deposits may influence measurements of some electrical impedance sensors.

Microwave technology based meters are often equipped with special microwave cables, and typically the transceivers can be changed without removing the entire flow meter from the installation.

7.3.4 Gamma ray technologies

Single energy gamma ray attenuation systems may need recalibration whenever fluid properties change. If, for example, either the oil density or the water density changes, the new linear attenuation coefficients (or mass attenuation coefficients) should be entered in the flow computer and if possible a new calibration should be performed to verify that the instrument measures according to specification. Linear attenuation coefficients can be updated based on compositional analysis of oil and gas. The linear attenuation coefficients for water may be determined from a water analysis.

It is strongly recommended that the influences of changes in fluid properties and their effect on the overall measurement uncertainty are determined at an early stage. If the range of fluid properties is known, the manufacturer should be consulted to determine the influence on the primary and derived measurements. For example, a change in oil density from ρ_1 to ρ_2 kg/m^3 will result in a systematic error of x% in water cut.

In both single and multiple energy gamma ray attenuation concepts, the attenuation measurement involves a certain counting time. For a given period of time, the counts from the gamma ray detector are registered and the total counts over that period are used in the calculations. However, as the attenuation of gamma rays is an exponential phenomenon, this is only correct if the composition is constant during the counting period.

The 100% water reference count rate in a single, dual or multiple energy gamma ray attenuation concept is also strongly dependent on the salinity of the production water, since salt has a high attenuation coefficient compared to water. Systematic errors in the measured water, oil and gas fractions will occur if the salinity of the production water changes and the 100% water reference count rate is not reflecting the actual water salinity anymore. In many potential multiphase metering applications, the salinity of the production water will indeed vary in time, or could be different for each well drilled in the same reservoir. In water injection reservoirs, for example, the salinity will vary between that of formation water and that of injection water.

Finally, the type of radioactive source is an important aspect and needs proper consideration with respect to the end user (company policy), national and international regulations (for more details, see Appendix A).

In general, whenever a major modification on a multiphase flow meter has been performed the flow meter's primary variables should be verified. A static calibration and an update of the PVT data should be performed on a regular interval (preventive maintenance) to build confidence. If the results do not change the interval between these tests could be extended.

7.3.5 Limitations of technologies – use of partial separation meters

Slug and annular flows are often the hardest flow regimes to measure. When the GVF increases to the upper limit of the measuring range of the meter, this will normally cause an increased measurement uncertainty. If the measurement uncertainties obtained with a in-line MPFM (without separation of the flow) are not within acceptable limits for use in these high gas volume applications, a partial separation design may resolve this limitation in technology, see Section 7.1.2.2.

7.3.6 Calibration and fluid properties

Issues concerning testing, calibration and adjustment of MPFMs and operation of MPFMs once they have been installed are covered in more detail in Chapter 10 and 11. Often the flow meter must to be removed from the installation or the skid in order to carry out the required maintenance tasks and field calibration of meters, and the infrastructure at the point of installation should therefore be carefully planned and prepared for these operations.

It should be noted, however, that the type of calibration and process data/ fluid properties that are required prior to start-up varies between the different makes. This also calls for slightly different piping arrangements and infrastructure in the field to allow for field calibrations (and if necessary adjustment) and other tests of meter performance in the field.

Some MPFMs will be more robust to changes in process conditions and fluid properties than others in some applications due to the applied technologies and designs, while in other situations alternative MPFMs with different designs may be preferred. It is therefore important to closely investigate each solution to find the best for the specific application.

8. PERFORMANCE SPECIFICATION

The performance of MPFMs is a key element in the assessment of whether multiphase flow measurement technologies can be applied in a specific application, and it is also a basis for selecting the most suitable technology.

There is a need however for more standardised performance specification of MPFMs, both for comparison of measuring ranges and measurement uncertainties but also for more efficient selection of technology and operation of the systems. More standardised performance specifications will help users compare MPFMs proposed from different manufacturers for specific applications.

This chapter does not provide specific numerical targets for performance, as this may vary significantly between applications and the importance of the measurements, but we provide a guideline for specifying the main performance parameters for multiphase flow metering systems.

It should also be noted that a performance specification is not limited to measuring ranges and measurement uncertainties, but also includes other equally important features/properties like: rated operating conditions, limiting conditions, measuring ranges, component performances (performance of primary measurement devices like pressure and temperature transmitters, etc), sensitivities, influence factors, stability and repeatability. These must also be described and specified to ensure correct overall performance and use of the systems.

Even though MPFMs are complex systems, often comprising a number of integrated subsystems and advanced software, reference is made to the ISO 16131:1998 standard describing methods of specifying flow meter performances in general terms. The standard includes some general definitions and key principles which should also be applied to MPFMs.

8.1 Technical description

Due to the complexity of multiphase flow metering systems it is required that manufacturers provide clear technical descriptions of their MPFMs as part of the performance specification. This will be an essential prerequisite for users in their evaluation of the suitability and expected performance of an MPFM for a specific application. The technical description should include:

- general overview of the MPFM and its basic principle of operation (e.g. block-schematic)
- descriptions and specifications for all sub-systems/ primary measurement devices like sensors, transmitters, software, computers, that can affect the meter performance
- general outline of the basic measurement principles and models that can help the user in assessing and predicting the meter behaviour (for instance, the type of correction model used for liquid correction in a wet gas meter should be specified with its uncertainty and validity domain if available)
- description of configuration parameters and required input data (like fluid properties, etc.)

8.2 Specification of individual sensors and primary devices

A multiphase flow metering system relies on a number of individual sensors and transmitters that will each directly influence the overall quality of the measurements. Detailed descriptions of the individual sensors and primary devices and their measuring ranges, limiting conditions of use and measurement uncertainties should therefore be included in the performance specification.

This applies to for example:

- Pressure and temperature measurement devices
- Differential pressure measurement devices
- Gamma-ray instruments
- Electrical sensors such as capacitance, conductance and microwave systems
- Densitometers

8.3 Specification of output data and formats

All measurements output from the MPFM to the user should be clearly described and documented with corresponding output formats and units. It should be clearly stated whether data are reported at actual or reference conditions (which should then be specified). If data are converted to reference conditions, the method and models used in these calculations should be specified, including specification of uncertainties and validity ranges.

A three-phase MPFM normally provides the following outputs:

- Oil, water and gas flow rates (volume and/or mass)
- Phase volume fractions (WLR, GVF)
- Pressure and temperature

Instruments that have been developed specially for measurement in wet gas (very high GVF applications, see Section 6.3) typically provide the following outputs:

- Gas and liquid flow rates, or
- Gas and water flow rates, or
- Gas, oil and water flow rates
- Pressure and temperature

Some also provide information on the presence of formation water.

8.4 Measuring range, rated operating conditions and limiting conditions

The performance specification should include information about:

- <u>measuring range</u>, i.e. the range within which the MPFM operates according to its specification,
- <u>rated operating conditions</u>, i.e. the range within which specified metrological characteristics of a measuring instrument are intended to lie within given limits, and
- <u>limiting conditions</u> for which the MPFM and its components can be used without failure or irreversible change in performance.

A typical specification of the measuring range, rated operating conditions and limiting conditions for a particular meter should include environmental, process and fluid conditions, as are shown in Table 8.4 in Section 8.6.4. In addition, one should also include a list of compatible or non-compatible chemicals and gases typically used for pressure leakage tests, scale-, wax- and corrosion inhibition, etc. as part of the rated operating conditions. One must also ensure compatibility with substances like H_2S, Hg and similar if these will be present in the well streams.

The measuring range and limiting conditions of a MPFM can also be interpreted as measuring and limiting envelopes and be plotted intwo-phase flow and composition maps which are presented in more detail in Chapter 9. This allows easy comparison with predicted production envelopes.

8.5 Measurement uncertainty

In order to use a MPFM in a specific application it is required that the meter has been evaluated with respect to combined expanded measurement uncertainty for the various measurements it will perform.

Such an uncertainty evaluation must include the uncertainties of the quantities input to the MPFM and the functional relationships used. This evaluation should also include the implementation of the models and measurement procedures in the MPFM, in order to consider the meter as it really operates. Uncertainty calculations should be performed according to the principles of the ISO Guide to the expression of uncertainty in measurement (1995).

For more details on how to carry out uncertainty calculations in practise and documentation of such evaluations, we recommend the reader to consult the NFOGM Handbook of Uncertainty Calculations – Fiscal metering stations (2003). The NFOGM Handbook of Uncertainty Calculations provides a simple introduction to the issue of uncertainty calculations and contains an introduction to the terminology, step-by-step procedures for uncertainty calculation and a number of practical examples.

8.5.1 Measurement uncertainty evaluation of MPFMs

Since MPFMs are very complex and extensive systems consisting of a number of subsystems and primary devices that are closely integrated, a full and complete quantitative uncertainty evaluation may not be possible.

Furthermore, a complete quantitative uncertainty evaluation is most certainly not sufficient, since the major sources of uncertainty in these meters are related to less quantifiable multiphase flow conditions and regimes.

The uncertainty evaluation should therefore also include results from independent laboratory tests and field tests to document the meter measurement uncertainty for various relevant flow conditions and regimes.

In Chapter 9 we also introduce some very useful graphical tools, the two-phase flow map, the composition map, and the cumulative performance plot, which provide alternative ways of presenting measuring ranges and measurement uncertainties. These graphs should be included in addition to normal tabular presentation of measurement uncertainties.

The uncertainty evaluation should be properly documented and all information necessary for a re-evaluation of the work should be available to others who may need it. This requires references to sources and background material, and detailed outlining of the evaluations where engineering judgement has been used.

The confidence level of the specified measurement uncertainties of MPFMs should be clearly stated, and 95% (k=2) should be the default confidence level.

Measurement uncertainties can be specified both as absolute or relative uncertainties, and for MPFMs:

- flow rates are normally specified with *relative* uncertainties, and
- phase fractions are normally specified with *absolute* uncertainties.

8.5.2 Influence quantities and sensitivity coefficients

In addition to the above-described quantitative evaluations, it is strongly recommended that a qualitative evaluation (quantitative if possible) is performed to consider influence quantities. Influence quantities are quantities that are not the measurand, but that still affect the result of measurement. Examples of influence quantities to MPFMs are:

- flow regimes
- salinity variations
- additives, e.g. emulsifiers, wax inhibitors, corrosion inhibitors
- MEG / DEG / TEG
- Methanol
- scaling / wax / hydrates
- pressure loss
- vibrations
- viscosity variations
- fluid properties (for example water salinity and conductivity, oil permittivity, densities, etc.)
- if intrusive parts: cavitation
- ambient temperature and pressure variations
- sand
- installation effects, upstream straight lengths, bends, etc.
- EMC noise

To determine how influence quantities affect the measurements, sensitivity coefficients must be calculated/estimated. Sensitivity coefficients describe how the output estimate varies with changes in the value of an input estimate or quantity, and should be given to quantify the effect of these factors on the combined expanded uncertainty of the MPFM measurements.

For example, the sensitivity coefficient for salinity influences on the WLR measurement can be given as a % variation of WLR per % change in salt content.

8.5.3 Reproducibility and repeatability

The reproducibility of a meter is a quantitative expression of the closeness of the agreement between the results of measurements of the same value of the same quantity, where the individual measurements are made under *different* conditions.

One significant difference between MPFMs and single-phase meters is that most of the uncertainty of a multiphase meter is caused by variations in process conditions and fluid properties, rather than the uncertainty of the primary measurement devices. Therefore, the meter's ability to reproduce its performance under different process conditions, installation set-ups and flow regimes becomes a very important factor.

The reproducibility of a MPFM for a set of flow rates may be established by recording the deviation between values measured by the meter and reference values obtained from different test facilities. Particular emphasis should be placed on the establishment of the reproducibility from independent laboratory tests to field test conditions.

The repeatability of a MPFM should also be specified. It is a quantitative expression of the closeness of the agreement between the results of successive measurements of the same measurand carried out under the *same* measurement conditions, i.e. by the same measurement procedure, by the same observer, with the same measuring instrument, at the same location at appropriately short intervals.

8.5.4 Stability and time response

Since MPFMs can be used to continuously follow rapid variations in flow conditions and flow regimes or for unattended applications (subsea), it can be helpful if time related performances are specified.

Examples of such performance specifications can be (if applicable):

- response time for variations in flow regimes and conditions,
- response time for variations in fluid properties,
- measurement duration
- drift in readings with time

8.6 Guideline on MPFM performance specification

This section provides a brief guideline on MPFM performance specification, and the purpose of this section is to propose a format for specifying the performance of MPFMs that vendors may use when quoting for specific applications.

A MPFM performance specification should include the following items:

1. Technical descriptions
2. Specification of required input data
3. Specification of output data
4. Rated operating conditions
5. Measurement uncertainty
6. Two-phase flow map: measuring and limiting envelopes
7. Composition map: measuring and limiting envelopes

Sample formats for specifying these individual items have been included in the following sections.

8.6.1 Technical descriptions

Reference is made to Section 8.1. The technical descriptions may also include references to relevant documentation supporting the other specification statements.

Table 8.1 List of attached documentation with technical descriptions

No	Documentation	Reference(s): (to attached documents)	Included (yes/no)
1	General overview and basic principle of operation (e.g. block schematic)		
2	General outline of basic measurement principles and models		
3	Description and specifications of sub-systems / primary measurement devices		
4	Description of configuration parameters and required input data		
5			
6			

8.6.2 Specification of input data

MPFMs typically require some *a priori* information of fluid properties like the typical parameters listed in Table 8.2.

Table 8.2 Specification of typical input data.

Input parameters	**Unit**
Density per phase	kg/m^3
Water conductivity	mS/cm
Oil Permittivity	F/m
Linear attenuation coefficients per phase or Mass attenuation coefficients per phase	1/m m^2/kg
Viscosity per phase	m·Pa

8.6.3 Specification of output data

Reference is made to Section 8.3. Table 8.3 show a sample format for specifying typical outputs from a MPFM at actual conditions.

Table 8.3 Specification of typical output data.

Output parameters	**Unit**
Volume flow rate per phase	Am^3/h
Accumulated volume per phase	Am^3
Density per phase	kg/m^3
WLR	%
GVF	%
Temperature	°C
Pressure	Bar

MPFMs provide primarily outputs at actual conditions, but most MPFMs can also give outputs at standard conditions. In that case, the methodology and PVT models used to convert from actual to standard conditions must be agreed between the user and the vendor.

8.6.4 Rated operating conditions and limiting conditions

Reference is made to Section 8.4. Table 8.4 includes specification of rated operating conditions and limiting conditions. These parameters are meter specific, and it should be noted that the parameters listed in Table 8.4 might not be applicable to all meters and that other parameters not listed here might be relevant for others.

Table 8.4 Specification of typical rated operating conditions and limiting conditions.

	Rated operating conditions		**Limiting conditions**	
	Minimum	**Maximum**	**Minimum**	**Maximum**
Liquid velocity	m/s	m/s	m/s	m/s
Gas velocity	m/s	m/s	m/s	m/s
Oil density	kg/m^3	kg/m^3	kg/m^3	kg/m^3
Gas density	kg/m^3	kg/m^3	kg/m^3	kg/m^3
Water density	kg/m^3	kg/m^3	kg/m^3	kg/m^3
Water conductivity range	mS/cm	mS/cm	mS/cm	mS/cm
Line pressure	Bar	Bar	Bar	Bar
Line temperature	°C	°C	°C	°C
Ambient pressure	Bar	Bar	Bar	Bar
Ambient temperature	°C	°C	°C	°C
Substances	**Compatible (yes/no)**	**Maximum**		**Maximum**
H_2S				
Hg				
MEG				
DEG				
TEG				
Demulsifier				
Sand				

8.6.5 Measurement uncertainty

Reference is made to Section 8.5, where the various parameters to be specified in Table 8.5 are described in more detail.

Table 8.5 Specification of measurement uncertainty.

Confidence level:	**95% (*k*=2)**	**Combined expanded uncertainties**		
Sub range	**GVF range**	**Gas**	**Liquid**	**WLR**
A	$x_1 - x_2$%	%	%	%abs
B	$x_2 - x_3$%	%	%	%abs
C	$x_3 - x_4$%	%	%	%abs
D	$x_4 - x_5$%	%	%	%abs
E	$x_5 - x_6$%	%	%	%abs
Repeatability:		%	%	%abs
Reproducibility:		%	%	%abs
Response time:	s	**Update frequency:**		Hz
Influence quantities	**Effect**			
Salinity				
Sand				
Flow regime				
Sand				
Additives				
Scaling				
Wax				
Hydrates				
Fluid properties				
References (documentation)				
1				
2				
3				
4				
5				
6				
7				

For dedicated wet gas meters, a similar table can be provided, but the WGR (Water Gas Ratio) uncertainty may be specified rather than the WLR uncertainty.

8.6.6 Two-phase flow map

The performance specification should include one or more two-phase flow maps as described in Section 9.2.1. Both the measuring and limiting envelopes should be plotted, and preferably overlaid the production envelope in this plot.

8.6.7 Composition map

The performance specification should include one or more composition maps as described in Section 9.2.2. Both the measuring and limiting envelopes should be plotted, and preferably overlaid the production envelope in this plot.

9. DESIGN GUIDELINES

This Chapter presents new guidelines for designing MPFM installations. As an aid in designing MPFM installations, the two-phase flow map and the composition map are introduced. In the two-phase flow map, liquid flow rate is plotted against gas flow rate, whereas in the composition map the GVF is plotted against WLR.

These two maps provide convenient ways of first plotting the predicted well production, the "production envelope", which is due to be measured in a specific application. The measuring range of a MPFM, the "measuring envelope", may then be plotted on the same maps, overlying the production envelope (estimated production over the field life time). This method for design of MPFM installations is described in more detail in the following sections.

9.1 Production envelope

9.1.1 Plotting the production envelope in the two-phase flow map

The two-phase flow regime maps, as presented in Chapter 6, are very general ones and use the diameter dependent superficial gas velocity along the X-axis and the superficial liquid velocity along the Y-axis. A more practical and convenient presentation is where the superficial velocity together with the pipe diameter is converted in to actual flow rates, i.e. along the X and Y-axis now the actual gas and liquid flow rates in m^3/day are plotted, respectively.

Further convenience can be achieved if logarithmic scales are used. Compared to linear scales this has the advantage that measuring envelopes of different size MPFMs have equal cross sectional areas in the two-phase flow map and that uncertainty bands (or deviations in test programs) in the low flow rates are equal in size throughout the two-phase flow map.

For most applications it is often sufficient to cover three decades along each axis (see Figure 9.1 for an example). The actual boundaries between flow regimes are not as sharp as is indicated in Figure 9.1. Apart from the pipe diameter used, these boundaries also depend on density, viscosity, surface tension, pressure, geometry, etc.

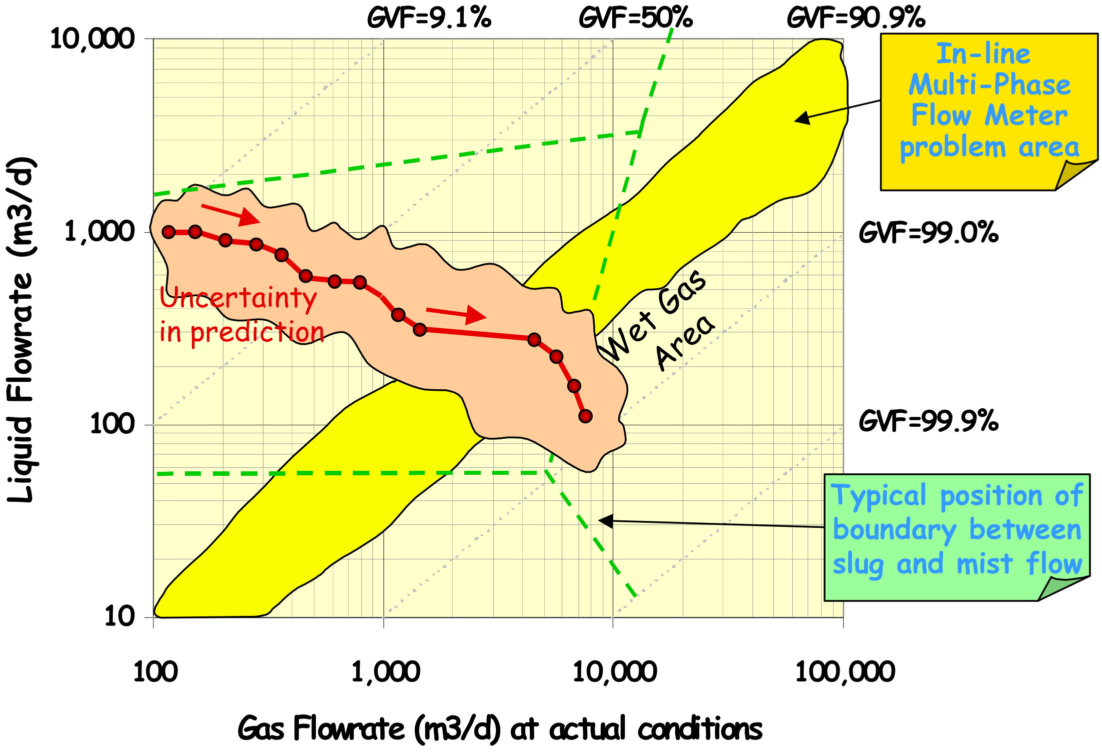


Figure 9.1 Two-phase flow map that can be used to plot the trajectory of wells (production envelope) and the measurement envelope of a MPFM.

Gas and liquid flow rates of wells can be plotted in this flow map and over time the wells will follow a certain trajectory, i.e. both the liquid and gas flow rates will change over time. One or more of these trajectories can be defined as the production envelope of an oil field. Often this production envelope is also indicated as an area between minimum and maximum liquid and gas flow rates. Note that the units used along the X- and Y-axis is Am^3, i.e. the volumetric flowrate at the pressure and temperature of which the meter will operate.

As these trajectories are often based on very preliminary information from reservoir engineers, there is uncertainty attached to these trajectories and it is recommended that these uncertainty ranges are also shown in the two-phase flow maps. As an example a 10% and 25% uncertainty production envelope can be used. This uncertainty can either be plotted as an area or uncertainty crosses can be used for each point. As will be explained in the following section, multiphase flow meters have measuring envelopes and it is obvious that the production envelope and the measuring envelopes should overlap. This is the first step in the selection of a suitable multiphase meter for a particular application.

9.1.2 Plotting the production envelope in the composition map

An additional useful tool in the selection process of MPFMs is the composition map, with WLR (in % or fraction) on the X-axis and GVF (in % or fraction) on the Y-axis. Note that the top line (GVF=100%) represents the gas phase, the left bottom corner (GVF=0%, WC=0%) and the right bottom corner (GVF=0%, WC=100%) represent the oil and water phase, respectively. If necessary, the scale can be adjusted to increase visibility in a certain region, e.g. GVF axis from 80% to 100% for a high GVF application.

As WLR and GVF generally increase over time also a well trajectory in the composition map can be plotted, similar to the well trajectory in the two-phase flow map. One or more of these well trajectories will represent the production envelope in the composition map.

MPFMs can also have their measuring envelope plotted in the composition map (more in Section 9.2.2) and obviously the two envelopes should overlap. An example of a well trajectory in the composition map is given in Figure 9.2.

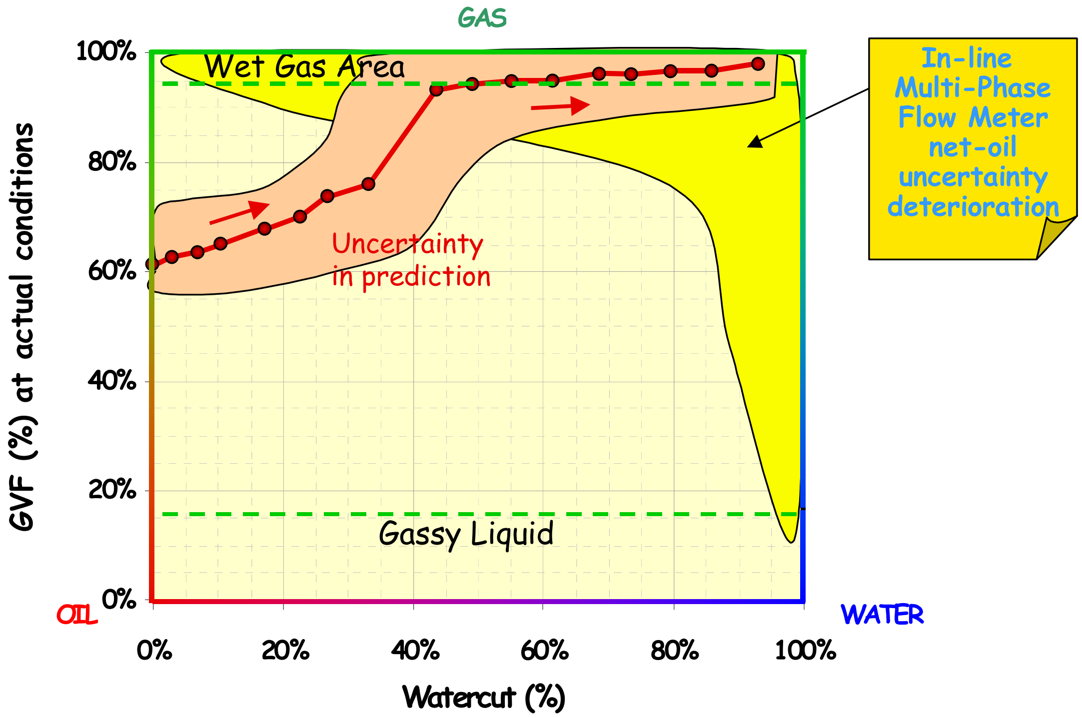


Figure 9.2 Well trajectory in the composition map. The largest uncertainties in liquid and oil flow rate occur at the high GVF applications. Here often (partial) separation results in improved performance.

In this example a strong increase in GVF (from 75% to 95%) is noticed which is due to the introduction of gas lift during later field life. Again also the uncertainty in the reservoir engineering data should be taken into account and if possible also plotted in the composition map. This can be done either as an uncertainty area or with uncertainty crosses per year.

9.2 MPFM measuring envelope

9.2.1 Plotting the MPFM measuring envelope in the two-phase flow map

MPFMs have measuring envelopes that are specified by the vendor. Often the minimum and maximum gas and liquid flow rates are given and uncertainties in liquid flow rate, gas flowrate and WLR are specified as a function of GVF. Like the production envelopes, the MPFM measuring envelopes can be plotted in the two-phase flow map and if various uncertainties are quoted it is possible to plot various measuring envelopes, one for each set of uncertainties. In Figure 9.3 an example is presented where the 5% and 10% uncertainty measuring envelopes are plotted. This allows the user to assess what the consequences in the measurement uncertainty are over the field lifetime, and whether different measurement ranges need to be used over the field lifetime (with different measurement uncertainties).

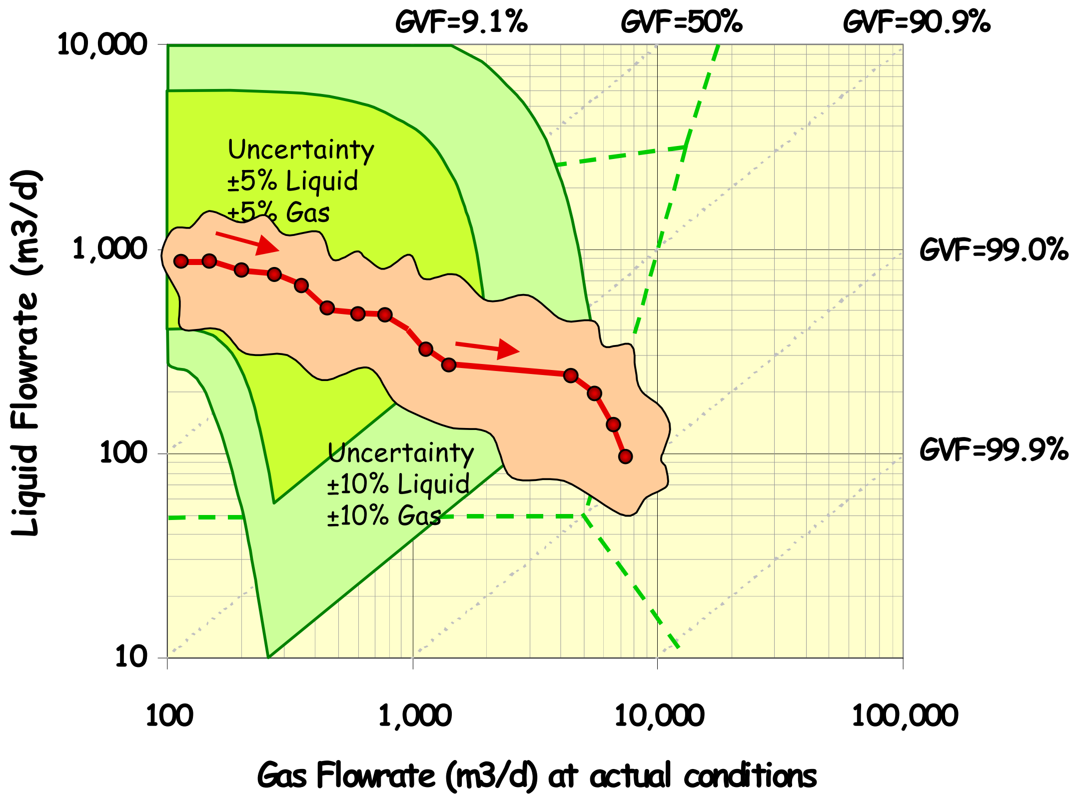


Figure 9.3 Example of a MPFM measuring envelope plotted together with a well trajectory or a production envelope in the two-phase flow map.

The diagonal lines in this two-phase flow map are lines of constant GVF. Generally oil fields operate in a GVF region between 40% (high pressure operations) and 90-95% (low pressure and/or gas lifted operations). Oil field operations at the high flow rates, top right corner of the flow map, means high productivity wells but also calls for high maintenance costs due to the mechanical vibrations and erosion of production facilities. This is a mechanical and not a fluid flow issue. Operating at the lower flow rates, the lower left corner of the two-phase flow map means less than expected production rates and thus oversized flow lines. Both these corners of the flow map should be avoided. The most commonly encountered flow regime in oil field operations is the slug flow regime in the middle of the flow map. Gas field operations generally are situated on the right bottom side of the flow map, i.e. the wet gas region.

9.2.2 Plotting the MPFM measuring envelope in the composition map

In a similar manner to plotting the measuring envelope in the two-phase flow map, one can plot a measuring envelope in the composition map as well. Generally MPFMs cover the entire range of 0-100% WLR and 0-100% GVF, but the uncertainty specifications are often given as a function of the WLR and GVF. In particular at the high GVF the uncertainties in the liquid flow rates will deteriorate.

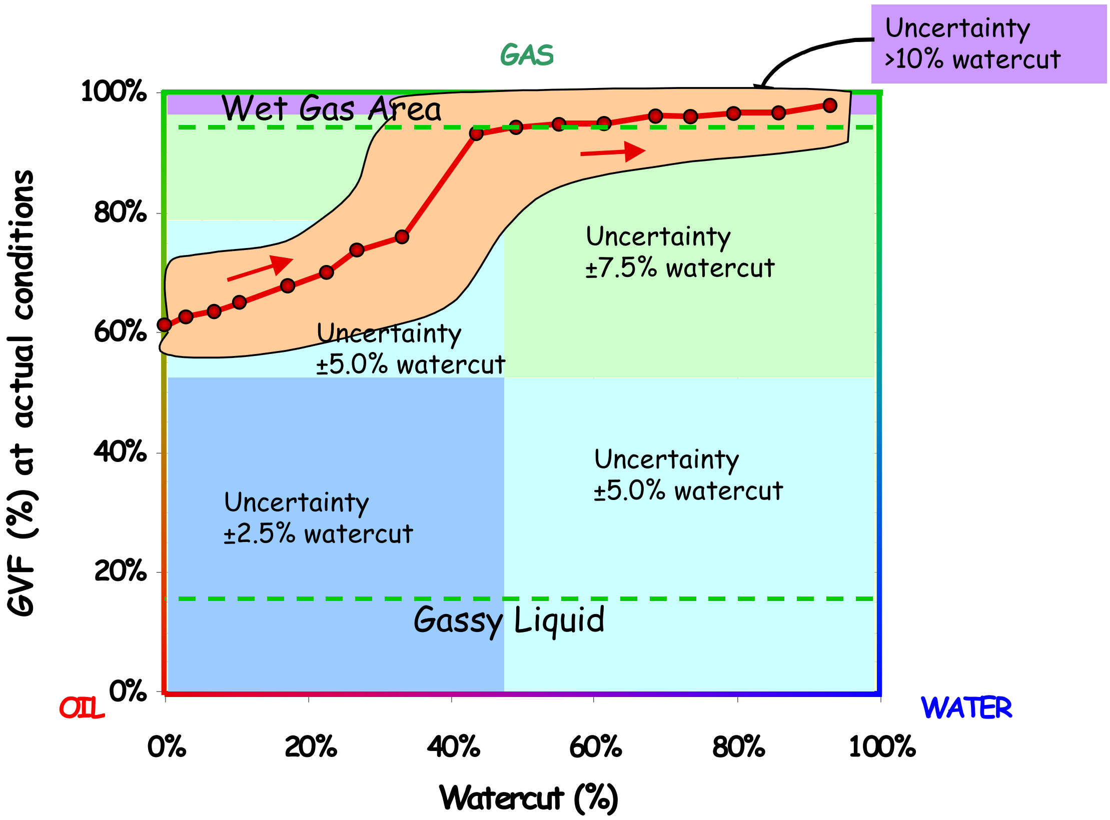


Figure 9.4 Example of a MPFM measuring envelope plotted together with the production envelope in the two-phase flow map.

9.3 Using the flow maps during testing

When running test programs to verify the performance of MPFMs, the above-mentioned two-phase flow map and the composition map also prove to be very convenient. Both the reference measurements and the MPFM measurements can be plotted in the two-phase flow map and the composition map, and by connecting these two points with a single line the test point is represented (see Figure 9.5 for an example).

The directions of the lines indicate whether deviations are in the liquid flow rates (mostly vertical lines) or whether they are in the gas flow rates (mostly horizontal lines). The length of the line indicates the magnitude of the deviation (again a logarithmic flow map gives same length for a certain relative deviation in the entire map).

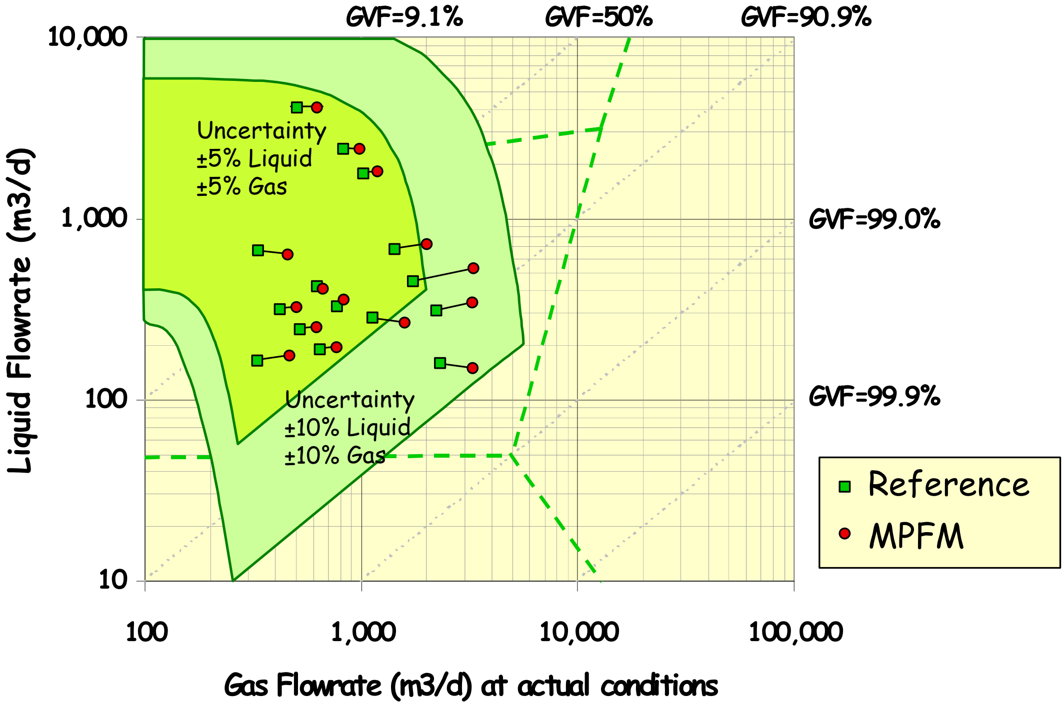


Figure 9.5 Test results for a MPFM plotted in the two-phase flow map, here the MPFM shows some systematic errors in the gas flow rates (overreading) whereas the liquid flow rates are ok.

Measurement deviations in MPFMs are often systematic due to partially correct/optimised flow models or differences between the used and actual basic fluid properties. The same test points can also be plotted in the composition map. Again deviation in WLR and GVF can be presented and it is often easy to spot where the largest deviations occur. The length of the lines between the reference measurement and MPFM measurement point now indicates an absolute deviation between the reference and MPFM (see Figure 9.6 for an example).

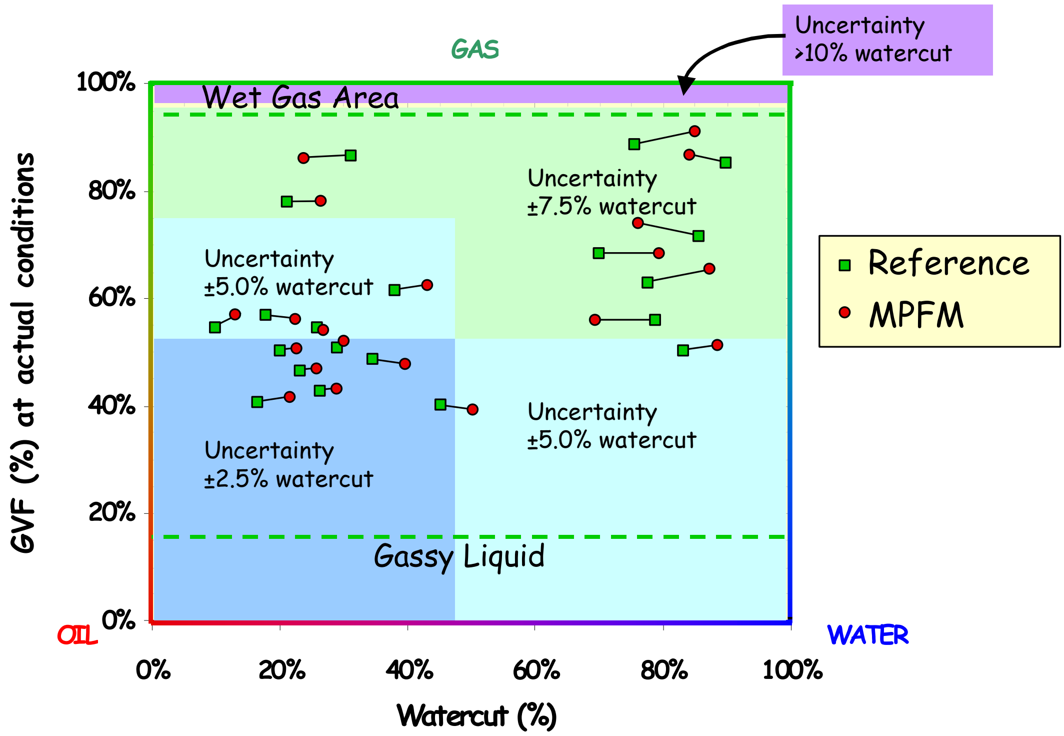


Figure 9.6 Test results for a MPFM plotted in the composition map, here the MPFM shows larger deviations in the water continuous emulsions than in the oil continuous emulsions.

9.4 The cumulative performance plot

With sufficient test points in an evaluation program it is possible to make cumulative performance plots. These plots can be conveniently used to compare performance of various MPFMs.

An example is given in Figure 9.7, where the X-axis represents the deviation between reference and MPFM measurement and the Y-axis indicates the percentage of test points that fulfil a certain deviation criteria. As an example the meter used in Figure 9.7 shows that approximately 70% of all test points show deviations of 10% or less in liquid flow rate, approx. 80% of the test points show deviations of 10% (absolute) or less in WLR and only 10% of all test points show a deviation of less than 10% in gas flow rate.

The test points to be used in the cumulative plots are obviously only test points that fall within the measuring envelope of the MPFM. If the measuring envelope is specified with various GVF ranges, it is recommended to construct cumulative deviation plots for each GVF range, i.e. one plot for 0 < GVF < 30%, one for 30% < GVF < 90%, one for 90% < GVF < 96% and one for GVF > 96%.

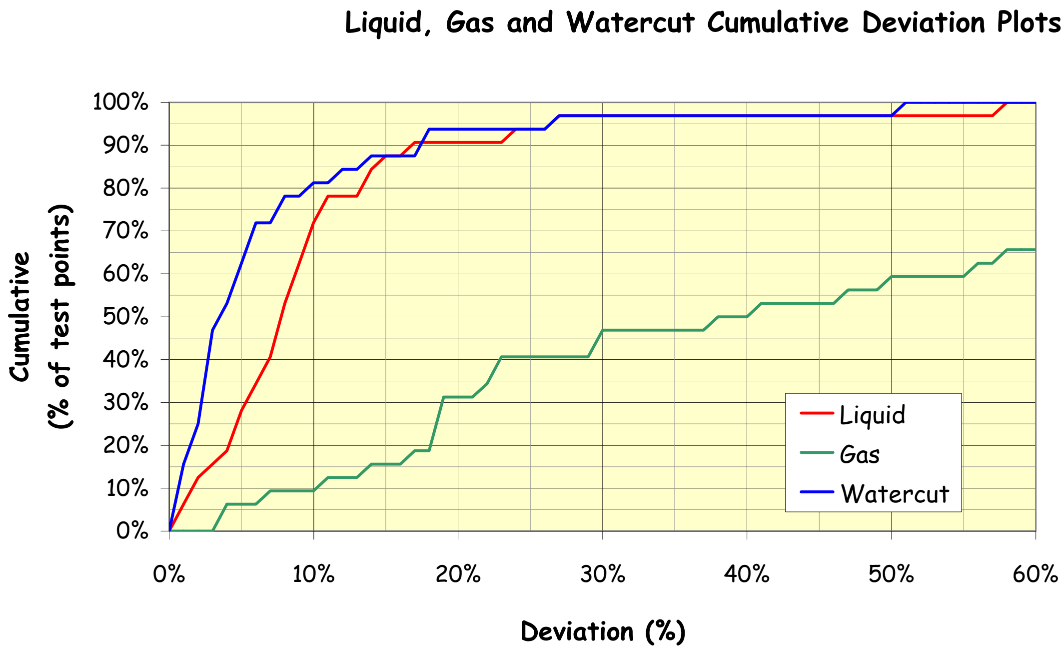


Figure 9.7 Example of a cumulative performance plot.

9.5 Other considerations

A number of other considerations should also be included in when designing a MPFM installation, and a short check list has been included (Table 9.1) to help identify important issues:

Table 9.1 Check-list for some other important considerations to keep in mind when designing MPFM installations.

Subject	**What to consider**	**Ok ? (Yes/No)**
High or low ambient temperatures?	Notice that operation of a MPFM in ery high or low ambient temperatures may require extra shielding of the pressure lines and temperature transmitters and sometimes the whole meter needs to be insulated and/or heat traced.	
H_2S / Chemicals	Are the instrument resistant to H_2S and chemicals used for hydrate prevention, scale inhibition, etc? Are concentration and physical properties of chemicals such that measurement of phase fractions is affected?	
Instantaneous vs. average flow rates	Depending on the flow conditions at the installation, there may be significant differences between instantaneous flow rates and average flow rates.	
Changes in fluid properties	Changes in fluid properties will call for sampling of the fluids for laboratory analysis and a subsequent update of the fluid data in the MPFM flow computer. Hence, sensitivity for expected fluid property changes at the specific installation must be considered, and facilities and routine for measuring and tracking fluid properties with time must be included in the design.	

Table 9.1 contd.

Subject	What to consider	Ok ? (Yes/No)
Pressure drop	Some MPFMs introduce pressure drops that can be significant in some installations.	
Hydrate, scale or wax deposits	The MPFMs' ability to tolerate forming of hydrate, scale or wax should be evaluated, and also susceptibility to the chemicals that might be used to prevent forming of these on a regular basis, or as part of a programme to clean the pipelines and meter internals for such deposits.	
Method of verification during operation	The method of verification of the multiphase meter during operation should be considered already in the design stage. This will ensure that any special facilities, e.g. bypass, isolation valves, sampling points, or other, required for the selected method of verification will be in place (see also Ch. 13)	
Test or acceptance programme /	If a new type of MPFM is to be used, the user may decide that tests are carried out to establish or verify performance/suitability of the meter	
Maintenance requirements	Maintenance requirements should be clarified. Frequent maintenance requiring manufacturers assistance at remote or offshore sites may be expensive and disrupt MPFM operation	
Nucleonic gauge requirements	Installation and use of nucleonic devices in industrial plants is subject to rigorous regulations, from Authorities and Operator, requiring conscious and consistent handling, formally and physically.	
Spare parts	Does the vendor have spare parts on the shelf, or must spare parts be purpose made?	
Support / service on site / remote service	Is service/support locally available?	
Verification and calibration options	Options for verification or calibration of MPFMs may vary considerably from one installation to another. It may not be a free choice. Reference measurements may be expensive or unavailable. The usefulness of a MPFM and credibility of absolute numbers will depend on calibration/verification methods. Ref. Section 10.2	
Solids impact	Can the MPFM take some wear and tear from abrasive particles in the flow? Are there aspects of technical safety? How is MPFM performance affected?	
Remote access	Can the MPFM be accessed remotely? Are there sufficient communication ports available to serve communication to plant control system (SAS), information system (IMS), metering control system, local PC etc. simultaneously? Is remote access through a fire wall? Is communication software running on remote PC? Or on local server (fire wall option)? How can the manufacturer access the MPFM from outside company network?	
Test media	Test media before delivery, prior to start-up and in regular operation must be considered for representativity, suitability and availability.	

10. TESTING, CALIBRATION AND ADJUSTMENT

Testing, calibration and adjustment can take place at different locations and for different purposes in the course of manufacture through to commissioning on site. This chapter covers some of the alternatives and highlights particular issues for each alternative. In Table 10.1 is shown a matrix of alternatives for locations and activities that will be addressed.

Table 10.1 Testing, calibration and adjustment alternatives.

LOCATION	ACTIVITY	
	FAT / TESTING	CALIBRATION
FACTORY	Functional testing Instrument testing	Static / Dynamic • Model fluid • Least expensive • Purpose built loop
TEST FACILITY	Instrument check Communication checks	Static / Dynamic • Non-biased • Extended test matrix • Reference instruments traceable to standards • Representative fluids • Live process fluids
IN-SITU	Instruments check Communication checks Commissioning	Static / Dynamic • Baseline recording • Phase transition issues may arise • Performance test • Satellite field start-up

Each of the rows “Factory”, “Test facility” and “In-situ” denote a location for calibration of a MPFM. With “In-situ” is meant the final destination of the MPFM where it is going to be put into service. The row “Test facility” includes several options for where the MPFM can be tested. Details for different test locations are provided in separate sub sections. There might be various reasons for selecting these locations. However, the aim is to end up at the in-situ location where the MPFM will be put into service. The alternative routes are then:

Factory → Test facility → in-situ,
Factory → in-situ.

That is, calibration at a test facility is usually an option.

10.1 Factory Acceptance Testing (FAT)

Prior to shipping the MPFM to site, a comprehensive test should be completed by the vendor. The purpose of the test is to ensure that the system performs all functions satisfactorily. The test should be performed with the MPFM fully assembled. These function tests do not necessarily require process flow.

The FAT should include a full functionality testing of all instrumentation, any flow computer and communication to a service computer. This includes testing of software as well as hardware. The FAT should include, but not be limited to, the following activities:

- Equipment visual inspection
- Power-up test of the whole system
- Instrumentation tests
- User interface / parameter check
- Final result / result files
- Alarms

Prior to the FAT the vendor should produce a report containing results from an instrumentation setup and inspection.

The FAT procedure will be vendor specific, however it is recommended to use a form with a format that indicates what to inspect and what the expected observation should be. Finally, a tick box should be available where the client can tick off or sign whether or not the item passed the check. An example format is provided in Table 10.2.

Table 10.2 Example FAT inspection table.

Item	Inspection Description	Design Requirement	Accepted (Yes/No)
x.x	Check that all cables glands installed are of the correct type, and fully tightened.	MPFM interconnection diagram	
...			

During the FAT, documentation of checked mechanical dimensions should be available for the client. That is, some sort of measurement certification or a document where it is shown that vital mechanical dimensions are checked and that the person who did the check also has signed for each dimension checked.

10.2 Calibration of MPFMs

Most MPFMs are subjected to *static* calibration and adjustment at the factory. Flow loop testing for *dynamic* calibration of the meter is usually optional. It is important to note that a calibration of a measuring instrument is simply a verification of the meter performance versus (traceable) reference instrumentation (cf. the definition of Calibration in Section 4.1). Hence no adjustments are made during a calibration.

Although most MPFMs are solely based on static calibrations and subsequent adjustments at the factory, some MPFMs do in fact require a dynamic flow loop calibration that can form a necessary basis for adjusting the meter. In these cases the flow loop test for calibration is not simply used for verification of meter performance, but as a basis for adjustment of the meter.

When the results from a calibration are assessed, one should bear in mind the significant difference between MPFMs and single-phase meters. That is, the uncertainty of a MPFM is mainly caused by changes in process conditions and fluid properties, rather than by the uncertainty of the primary measurement elements.

The primary measurement elements that make up a MPFM can usually be calibrated according to standard procedures, similar to those used for single-phase flow measurements. However, the output of the primary measurements of a MPFM is used as the input to the advanced signal-processing stage, giving individual phase flow rates as the end result.

Flow rate calibration procedures, as we know them from single-phase metering, can therefore not be directly transferred to MPFMs.

The following subsections will provide details regarding static and dynamic calibrations of MPFMs.

10.2.1 Static calibration

A static test does not require flowing conditions and is usually done during FAT and commissioning on site. Although the static tests will differ for each MPFM make, they will have in common that the purpose is to establish a reference based on a known fluid inside the measurement section of the MPFM.

The factory calibration performed by the manufacturer may consist of measurements of geometric dimensions, gamma-meter count rates and static impedance measurements in calibration fluids, etc., depending on the working principle of the primary measurement elements. Calibration of the primary elements is usually independent of the process conditions for which the instrument will be used.

The results from these static tests are usually stored and used as part of a maintenance plan. The static tests can be repeated at regular intervals and compared. This is a very convenient and simple health check of the MPFM. Such tests are usually performed when the installation has a scheduled shutdown.

10.2.2 Dynamic calibration

Dynamic calibrations can be done in different ways and at different locations. Regardless of the method, the purpose is to measure the oil, water and gas flow-rates from the MPFM and compare against reference flow rates. The reference measurement systems used for dynamic calibrations may vary in size and thus flow-rate capabilities. Therefore, prior to a dynamic calibration one must ensure that the measuring envelopes for the MPFM and reference measurement system overlap. If they do not overlap sufficiently, only calibration of a part of the measuring envelope of the MPFM may be possible (such tests are often considered to be dynamic functionality tests).

One can distinguish between at least three different methods for dynamic calibration:

- Factory calibration
- Test facility
- In-situ calibration

Each method has its pros and cons, but before addressing each method a few important issues concerning dynamic calibrations are highlighted.

10.2.2.1 Fluids

The ideal situation would be that the calibration facility could reproduce the expected field conditions. This is rarely possible. For example the fluid constituents of oil, water and gas should preferably be similar to those of the application fluid. This might not be an open choice, as the fluids are usually specific for each particular facility for dynamic calibrations.

The calibration fluid is either:

- a model system, using some sort of model oil, water and air or nitrogen, or
- a system with live crude, formation water and hydrocarbon gas, with mass transfer between the oil phase and the gas phase.

Most dynamic calibration facilities use a model fluid, for reasons of cost, working environment, etc. In many cases a model system is the only option available. Even operating a model system may be subject to stringent conditions of use, and the model oil may not have been selected for meter-testing purposes only.

One advantage with model calibration fluids is that they are normally well behaved and their PVT properties are well known. That is, uncertainties regarding PVT properties are reduced to a minimum. It is important to convert flow rates recorded by the reference measurement system in the calibration loop to a common basis (e.g. standard conditions or actual conditions at the MPFM) before the loop reference measurements and the MPFM measurements are compared. The use of live crude introduces the uncertainties of PVT conversions. One argument often used against model fluid is: *The fluid is not representative of the fluid to be measured, in terms of density, viscosity (and thus generation of flow regime), dielectric constants, salinity, mass transfer between the phases, phase surface active components, etc.*

On the other hand, each oil field is different from the other and no flow loop fluid will be representative unless those particular field fluids are brought into the loop and operated at field pressure and temperature.

Another issue of using oil products as calibration fluids are related to the availability of a suitable plant (the cost aspect) and the fact that such plants are built and operated under a hazardous area regime. Since the properties of well streams differ, a specific product used as calibration fluid may not be representative of any other product or well stream.

It is possible to synthesise a product-type calibration fluid from stabilised crude oil, water with salts added and gas synthesised from methane, ethane etc. Using a synthesised product as calibration fluid is practical only for calibration facilities that employ closed-loop circulation.

10.2.2.2 Operational constraints

In any given calibration facility one or more of the flow parameters:

- temperature and pressure
- oil, water and gas flow-rates

may be impossible to control, limiting the calibration capabilities.

The fluids in a calibration facility are normally circulated in a closed-loop system, and there are at least two options:

- Single phases of oil, water and gas are pumped and measured before being mixed and passed through the test section. Downstream of the test section, the multiphase fluid flow is again separated into single phases. Reference measurements of each single phase are made before mixing, even if a multiphase reference flow meter downstream of the mixing point could also be used.
- Oil, gas and water are first mixed and then pumped continuously as a multiphase fluid in a closed loop. Gas and/or water fractions can be varied by injecting or withdrawing fluid into/from the circulating mix. Phase flow rates or fractions are determined by the mixing procedure and are assumed to be constant until pumping or composition is changed by adding or withdrawing fluid(s).

MPFMs measure flow rates at the operating conditions of the fluid as it passes through the meter (actual conditions). If the reference instrumentation in the facility operates at conditions different from those of the multiphase flow meter, flow rates must be calculated for the conditions of the multiphase flow meter. This would include calculation of mass transfer between the phases. Special care must be exercised when testing in low-pressure loops; small deviations in pressure will have significant impact on volumetric gas flow rates and often the low pressures may even be outside the measuring range of the pressure transmitters of the MPFMs.

10.2.2.3 Calibration matrix

Depending on the calibration facility flow-rate capabilities and degrees of freedom in choosing fluid properties, a comprehensive calibration matrix can be set up.

A calibration matrix must be defined for each meter to be calibrated. In principle, this is no different from other calibration situations, but with MPFMs the calibration matrix can have a large number of points, due to the many combinations flow rates and phase fractions. For example, with four flow rates per phase, 64 points are needed to cover every possible combination of pressure, temperature, water salinity, etc. The calibration matrix soon runs into hundreds of points.

For this reason it is usually necessary to reduce the number of points from "the full set", to one or more subsets. With MPFMs, such a reduction is more difficult and more important due to the very large number of possible variations. The calibration points, which can be omitted with the smallest loss of information of meter performance, must be identified. It is likely that the "most redundant" points are different for different types of meters, due to their different working principles.

10.2.2.4 Reference measurement uncertainties

Calibration results are only as accurate as the reference measurements provided by the calibration facility. When the results of MPFM calibrations are evaluated, the measurement uncertainty of the reference measurements must also be taken into consideration.

In some facilities one or more phases may not be measured directly, and in such cases one should expect that these reference measurement uncertainties are higher than those being directly measured. Additional measurements or calculations may also be required, such as a water-in-oil meter in the oil line to measure water carry-over.

The reference flow meters must be subject to periodic calibration, traceable to national or international standards.

Bearing the criteria and considerations regarding dynamic calibrations in mind, one can review the different alternatives as provided in the next subsections.

10.2.3 Factory calibration

"Factory calibration" is a calibration performed by the manufacturer of the instrument, and the calibration is usually carried out using facilities owned or controlled by the manufacturer.

Factory calibration may be carried out for several reasons:

- Investigation of the performance of a new type of meter during a development phase.
- Calibration (verification) of meters before delivery to customer/user.

Factory calibrations have advantages, as well as limitations, and the most important have been listed in Table 10.3

Table 10.3 Advantages and limitations of factory calibrations.

Positive
Easy access to calibration facilities and fewer limitations on calibration time, making larger calibration matrices possible
Relatively inexpensive
Calibration facility may be purpose-built for a specific make/type of meter
The range of phase flow rates may be wide
Negative
The calibration fluid is normally unlike that of an oil/gas well stream
Flow conditions/regimes are likely to be different from the real-life application
Calibrations cannot be regarded as independent, unless the facility is operated as a part of the organisation which is independent of production, and with its own quality assurance program
Normally low pressure

10.2.4 Test facility

Some vendors have their own test facility, however, third party independent laboratory facilities are also available. Some companies even have made their own test facility in conjunction with a production plant where live hydrocarbons can be measured in a dedicated test section. The independent laboratory and field test loop will be treated separately.

10.2.4.1 Independent laboratory calibration

"Independent laboratory calibration" is a calibration performed by an organisation or company which is independent of the manufacturer of the meter. An independent calibration facility must be expected to have a quality assurance programme with formalised procedures and reference instrumentation traceable to national or international standards. It is possible for a laboratory to obtain official accreditation. In principle, it is also quite possible for a manufacturer to establish independent calibration according to the description above.

The aim of independent laboratory calibration is to verify the MPFM performance in a third-party facility and thereby increase the confidence of the MPFM calibration compared to a factory calibration. Such calibrations are regarded as non-biased and in addition calibrations may be standardized which allows for comparisons of different meter performances. A good facility will also offer extensive calibration matrices covering, at least, major parts of most MPFM measuring envelopes.

The value of any independent laboratory calibration will also depend on the reproducibility of the MPFM under changing process and flow conditions. If a MPFM gives the same output for identical flow rates under different process conditions and physical properties of oil, gas and water, i.e. it displays good reproducibility and the value of independent laboratory calibration will be high.

If the reproducibility of the MPFM is not known, or is not regarded as adequate, the laboratory must be able to reproduce process conditions and physical fluid properties as close as possible to those of the actual application. At least the gas volume fraction, GVF, and water in liquid ratio, WLR, should resemble the field data.

It is thus recommend that independent laboratory calibration is used with great care, carefully evaluating all the information available on instrument reproducibility, i.e. previous tests and field applications, before a calibration test program is performed.

At the time of writing, independent laboratory calibration facilities vary significantly in terms of calibration capabilities and in cost levels. Various calibration fluids and flow conditions are available, e.g. model systems and real hydrocarbon fluids. Flow rates, flow regimes, temperature and pressure ranges will differ among the different calibration facilities.

Compared to factory calibration, some of the main features of independent laboratory calibration have been listed in Table 10.4:

Table 10.4 Main features of independent laboratory calibration.

Positive
Calibration is independent and results are non-biased.
A larger calibration test matrix in terms of flow rates, pressure and temperature is normally possible, as is calibration with different fluids.
Negative
Calibration is more expensive

10.2.4.2 Field calibration

From a calibration point of view, the main difference between an independent laboratory calibration and a Field Calibration is that representative fluid properties are more likely to be obtained in a field test facility than in a laboratory. Some oil companies have set up calibration facilities in their production plants and offers Field Calibrations with live well fluids at real process operating conditions.

Various options are available for setting up the calibration bed in the process. Reference measurements are normally carried out on single-phase outlets from a separator, e.g. the test separator.

With this set-up, the available wells or fluids that can be routed via the separator limit the selection of calibration points. Only changing the well being tested can change fluid properties and phase fractions. Hence, although the flow rates are selectable in theory, in practise the wells or flow rates available for testing relies on the general plant operation which must not be hampered.

Some live process test facilities have been modified to offer the option of injecting, withdrawing or recirculating fluids. In such facilities fluid properties, flow rates and phase fractions may be selected within a much wider range. Interference with normal plant operation is also reduced. Such test facilities may be complex, and direct reference measurements may be more difficult to obtain.

In some cases MPFMs are installed in a process for functionality test purposes where reference measurements may be limited or non-existent. Even if tests are very useful, such facilities are not really considered to be calibration facilities for the purposes of this Handbook.

10.2.5 In-situ calibration

"In-situ calibration" is a calibration performed after the MPFM has been installed at its final location in the field. The aim of in-situ Calibration is to verify the measurement performance of the MPFM compared against the results from a factory calibration, an independent laboratory calibration or a Field Calibration.

Some meters may first require an initial static calibration in-situ using actual well fluids before a dynamic calibration can be performed. Whenever possible, implementation and periodic verification of this type of static calibration is recommended. It will establish an important track record and changes in performance is easily spotted. Provision is made that reliable reference measurements and/or reference fluids are available.

Since in-situ implies measuring a live process, it is important that good PVT data for the fluids are available. Accurate PVT data are a prerequisite for any MPFM to measure flow rates accurately. Thus, inaccurate PVT data will limit the accuracy of the calibration. The quality of in-situ calibration is further limited by the accuracy of the reference measurements made on site. Nevertheless, a calibration is important to build a track record and to monitor changes in performance.

Unstabilised liquid hydrocarbons contain some light components that will be transferred from liquid phase to the gas phase when the pressure is reduced. Thus, the mass flow rate of hydrocarbons in the liquid and gas phases will change when the pressure is reduced. For this reason the reference flow rates must be compensated for this phase transition. If the pressure loss between the MPFM and the reference instruments is small, this effect may be neglected.

If the pressure loss between the MPFM and the reference meters is large, a simulation program can be used to compensate for the effect of phase transition. However, the uncertainty of such a simulation may be large. On the other hand, if the uncertainty can be considered to be the same for each calibration, a very useful track record can still be established and monitored.

There exists a multitude of in-situ configurations, and two common configurations will be addressed in more detail in the following:

- Test separator used as reference
- Start up of a satellite field

10.2.5.1 Calibration using test separator as reference

When the MPFM is used to measure a well stream which is occasionally routed through a test separator, the test separator measurements can be used to calibrate the MPFM.

The results obtained from the test separator or MPFM usually need to be compensated for phase transition due to changes in pressure and temperature in the well stream between the location of the test separator and that of the MPFM. One usually converts the flow rates either to a common basis, which can either be the test separator, MPFM or standard conditions.

With good instrument repeatability for both the test separator and MPFM, the conditions for establishing a track record should be good. The phase transition uncertainties will be less pronounced for installations where the distance between the MPFM and the test separator is short. When the calibration results are assessed one should also consider the flow stability, i.e. that the flow is not dominated by transient conditions (which can occur for example if the MPFM is installed immediately downstream of a choke valve). If transient conditions prevail and can not be avoided, one should verify that the reference instruments and MPFM are not influenced significantly by the fluctuations.

MPFMs located at a subsea wellhead can in principle be calibrated using a vessel prepared for well testing. To establish a track record the MPFM flow rates can be compared to the flow rates measured by reference instruments topside, i.e. a topside separator if possible. Provided that the PVT properties do not change significantly, the performance can be routinely verified and any anomalies are easily spotted. If any discrepancies are spotted one should start to investigate PVT properties, reference instruments or MPFM instruments. This includes investigation for incorrect setup and instrument failure. If flow conditions vary rapidly in time, and there is a long distance between the MPFM and the separator, comparing accumulated values for a longer time period may be of more value than comparing instantaneous measurements.

10.2.5.2 Calibration at start-up of a satellite field

A potential use of MPFMs is to place one MPFM on each single wellhead in a satellite field. In this way, test line, test manifold and a large number of valves are avoided. If individual wells are put into production one by one, each meter can be calibrated at the start up of each well. If a multi-rate test is done for each well at start up, it should be possible to obtain quite a good calibration for each meter, provided the production can be measured by an instrumented inlet separator or test separator.

An option can be to record a set of flow rates through a multi-rate test with the MPFM and the references, and to establish a calibration curve based on this data set.

The calibration can also be done using a deduction technique. When calibrating by deduction, the first well is opened and measured using the separator and a MPFM. When the first meter has been calibrated, the second well is opened. The increase in flow rate at the separator will now be due to the production of the second well. If the production of the first well changes, this can be measured by the first meter and compensated for. Calibration by deduction will be more accurate with MPFMs placed on each well, since the wells that have not been calibrated can be measured using previously calibrated MPFMs. This method should be used with great caution since several factors will influence the calibration quality, for example:

- Spread in well performances
- Flow instability, i.e. slugging
- Difference in fluid PVT properties

10.2.6 Calibration report

Regardless of how the calibration is performed, it needs to be reported in some format. A standardised format is desirable, and in a suggestion for a calibration report table is shown.

The calibration report should give the results both in terms of tables and graphs. The tabular form might have a form as a certificate on which the vendor has signed. The format in Table 10.5 is particularly suited to a MPFM where the uncertainty is specified in terms of liquid flow rate, gas flow rate and WLR. Other formats might be more suitable for other uncertainty specifications, however, the general idea should be clear.

Table 10.5 Calibration certificate sheet.

Test Certificate

Test date: **MPFM S/N:**	**Test location:**
Key calibration data relevant for MPFM make:	

Test matrix recorded[1]:

	Reference[2]				MPFM measurements									
No	**qliq** m^3/h	**qgas** m^3/h	**WLR** %	**GVF** %	**qliq** m^3/h	**Dev.** %	**qgas** m^3/h	**Dev.** %	**WLR** m^3/h	**Dev.** %abs	**GVF** m^3/h	**Dev.** %abs	**T** °C	**P** Bar
1														
2														
3														
4														
5														
6														
7														
8														
9														
10														

[1] Details on recording time procedure
[2] Recalculated at MPFM conditions

Dev.: Deviations calculated between reference and measurement

Test technician:	**Approved by:** **Date:**

In addition to the table in Table 10.5, the calibration report should also include the tests points illustrated in the graphical formats previously described in Chapter 9 in Figure 9.5, Figure 9.6 and Figure 9.7.

In addition to the tabulated and graphical information already mentioned, the calibration report can also include:

- A sketch/pictures showing important details of the test installation:
  - Horizontal / vertical upwards / vertical downwards flow through the MPFM.
  - Straight upstream / downstream lengths.
  - Phase commingling point / distance to meter under test.
  - Position of reference measurements.

- Process conditions:
  - Pressure and temperature recorded for each test point.
  - Oil in water and water in oil measurements during calibration.
  - Oil and water density measurements performed during calibration.

- Reference measurements:
  - Type and quality of reference measurements.
  - Reference to installation point on installation sketch should be given.

- MPFM setup prior to calibration:
  - A qualitative description of the setup performed by meter manufacturer, or by test institution, prior to the calibration.

- Summary of calibration results:
  - A representative number of calibration points should be filled in. This can often be governed by the buyer's request for WLR and GVF test ranges.
  - Test results are either converted to flow loop or MPFM conditions before comparison.
  - Any PVT conversion issues should be noted and explained
  - Any particular observations during calibration should be identified in a comments field.

10.3 Adjustment of MPFMs

Most MPFMs are adjusted based on a static calibration and do not require dynamic calibration. However, as mentioned in the introduction to Section 10.2 some also require an adjustment based on a dynamic calibration.

10.3.1 Adjustment based on static calibration

The usual purpose of a static calibration is to generate input parameters to setup the MPFM and to establish a baseline. Using the strict definition of the term calibration, some of what is called a static calibration is not a calibration because there is no reference to compare to. For example, it might be required to record transmitter data on a model fluid or a representative well fluid to setup the transmitters correctly based on the recorded data. Examples are mass attenuation coefficients for a nuclear system and dielectric constants for a capacitive system.

10.3.2 Adjustment based on dynamic calibration

For the type of MPFMs that require adjustments based on dynamic calibrations, the adjustment can be implemented using one of the following methods or combinations of these methods.

10.3.2.1 Matrix calibration

The data obtained from the calibration can be used to establish a matrix of factors relating the MPFM outputs to the reference measurements. When such a matrix is used, the instrument chooses the factors valid for the flow conditions that occur in the pipeline to correct the outputs accordingly.

10.3.2.2 Curve-fit calibration

Curve-fit adjustment is carried out by recording measured oil, gas and water flow rates and reference flow rates for many points in a matrix. Using these data, a function (equation) can be derived which relates signals in the MPFM (e.g. primary measurements or derived values) to the reference flow rates, and this equation is then used to calculate flow rates with the meter in normal operation.

10.3.2.3 Factor calibration

If the meter will be used mainly in a small range of flow conditions, and it is possible to obtain reference values for the meter when it used to measure at some point within this limited range, a single calibration factor can be established for each of the components for later use as a valid calibration within the given range.

11. FIELD INSTALLATION AND COMMISSIONING

This chapter describes recommended procedures and practices for field installation and commissioning of MPFMs.

The on-site installation includes the physical connection/installation of the MPFM to the client's production and piping system. The on-site installation procedure covers all physical aspects related to the communication and electrical hook-up of the meter to the client's systems. After the installation process, the MPFM should be subject to an on-site commissioning procedure.

For both these steps it is important to get an overview of the work involved, the staffing required and a time schedule. These parameters are especially important for offshore work as during start-up of a field or well there will be a vast number of ongoing activities and bed space is usually a limiting factor.

11.1 Installation considerations

Before the MPFM is finally selected and installation started, the following items should have been considered:

- Vendor's installation requirements (when it comes to the meter installation).
- Limits have been established for temperature, pressure and flow rates at the MPFM location, and it has been ensured that these parameters and the production envelope are within the Operating and measuring envelopes of the MPFM.
- PVT data at the MPFM location as required for optimal measurements.
- Facilities to ease the installation and removal of the meter. It might be wise to plan for the possibility to replace the MPFM with another sized MPFM to accommodate unexpected well flow-rates.
- Access for maintenance and service of instruments, single phase checking cleaning of internal deposits that may form.
- Bypass to prevent well shutdown during testing and service.
- Facilities and access for flow rate checking. Header to local test separator or connection to transportable test equipment. Injection point(s) for tracers.
- Power and communication lines to the meter computer for local and remote data collection, configuration, operation and verification of comm. line.
- Facilities to collect multiphase fluid samples. (Very difficult to get representative samples of multiphase fluids. No standard yet available.)

- Flow mixing requirements.
- Backup facilities and spare parts.

Provided the main issues as described above have been covered, one can proceed to install the MPFM according to the outcome of the considerations.

11.2 Installation and site integration

To ensure a smooth installation process, good communication and clarification of responsibilities is required between client and vendor representatives. This can be achieved after reviewing the vendor's installation and commissioning procedures. The outcome of the review should be a mutual agreement on the various tasks to be performed.

This section presents some general guidance on some of the main preparatory issues to be considered for a MPFM installation. The list is not exhaustive; however, it covers some typical aspects. Some of the issues might not be applicable for a subsea installation, although the principles will be similar.

Prior to the installation process, the actual documents and drawings should be reviewed and compared with the MPFM scope of delivery and design dossier. Any deviations should be reported and an action plan created to rectify any the deviations. This is important to prevent delays in the installation process.

One may benefit from planning a field visit well in advance. Process and Instrument Diagram (P&ID) and MPFM installation drawings should be agreed upon before the field visit. The main purpose of the field visit is to verify spacing, dimensions, electrical supplies, communication interfaces, etc. The visit might also include hook-up of a MPFM simulator to the client control system to verify communication and power supply. If a field visit has been performed and everything is in accordance with the scope of delivery, an additional meeting should be arranged to do a field visit review.

Table 11.1 Installation checklist.

ISSUE	COMMENTS	STATUS
1. Meeting, review of field visit report. Organise a meeting with the following personnel to review the additional issues presented in this check-list. - Client project representative - Client electrician/electrical engineer - Client instruments engineer and communication expert (SCADA expert) - Vendor representative involved in the field visit - Vendor project representative		
2. Is all the referenced documentation from the installation procedure ready and reviewed for installation?		
3. Have both client and vendor representatives been designated for the installation / commissioning project?		
4. Has the on-site electrician, instrument man or communication man for the SCADA system been notified for the installation job?		
5. Are P&ID and general arrangements for piping and zone classification ready and reviewed as per reference documentation?		
6. Drawing and dimensions verified against the physical components for the installation?		
7. Are the commissioning material and spares inventoried and physically counted?		
8. Check meter and piping physical dimensions / accessibility.		
9. Check piping / inlet & outlet connections, material, size, painting requirements, …		
10. Check the required mechanical support for the installation.		
11. Check grounding (weld extra pad eyes …)		
12. Are the operational procedures and JSA/Hazop already approved?		
13. Review location of nearest power supply and MPFM power requirements.		
14. Review routing to connect the MPFM to the power source (cable dimensions).		

11.2.1 Installation requirements

One should as early as possible clarify if the vendor has any special installation requirements. This might include:

- Vertical / horizontal alignment
- Requirements on straight pipe lengths before and after the MPFM
- Special requirements for accessing the MPFM
- etc.

Does the vendor require access to the MPFM prior to mounting it to the pipe work? As mentioned under Section 10 some MPFM makes may require the ability to fill the tool with reference fluids to do in-situ static calibration.

11.2.2 Electrical connections and power requirements

The MPFM power and voltage requirements should be clearly stated by the vendor and an interconnection diagram should describe the electrical hook-up. It is usually the client's responsibility to provide cabling and glands that satisfy both site hazardous area installation requirements and the requirements stated by the vendor.

Before connecting the cabling, several checks should be performed:

- Continuity checks of the cable using a multimeter, each wire and screen should be checked.
- Test the cable using a megger, each wire and screen vs. all other wire/screens in the same cable
- Check that the power supply has the correct output voltage.

11.2.3 Function test

After installation and hook-up, a physical inspection and system test should be performed. The purpose of this test is to ensure that the system performs all specified functions satisfactorily. The test should be performed with the complete system installed. Usually there is no process flow during the function test. The test could be a repetition of selected tests from the FAT usually performed at the vendor's factory. The results should be recorded for later use as reference documentation during the commissioning stage.

11.3 Commissioning

The vendor should provide a commissioning document that describes the procedures that will be carried out by the vendor when the MPFM is commissioned at the client's site. The on site commissioning scope should include the post-installation functional test and field set up of the MPFM prior to initial flow. The commissioning test will ensure that the system performs all specified functions satisfactorily. The test should be performed with the complete system installed. Power and communication should be tested during the commissioning process to ensure the reliability of the installation. Complete MPFM set up should be performed (instrumentation readings review, zero trim of required transmitters, baseline reference recordings). Normally there will be no process flow during the commissioning phase.

11.3.1 Preparation

Verify that all installation tasks have been completed. It can be beneficial if an installation handover has been completed and signed off. If any activity has not been completed one should ensure that all the additional tools/parts/procedures needed are available.

11.3.2 Documentation and equipment

The vendor should provide a list of all necessary procedures, certificates, tools and consumables so that the client can review it. Usually the vendor requires some information from the client on how to set up the MPFM. These requirements should be clearly stated in a separate document and made available to the client as early as possible. If any special tools which cannot be easily transported are needed the client should be notified so they can be included in the logistics as early as possible.

11.3.3 On site authorisation

Depending on MPFM make, different authorizations are needed:

- Mechanical / pressure system isolation and depressurisation
- Electrical system isolation
- Electrical "Hot Work" permits
- Radioactive source handling, if the MPFM contains a nuclear source

The permit(s) to work authorizing the above activities may specify certain installation specific precautions to be followed by the vendor. The installation may require additional documentation to be presented prior to authorization being granted, and this could include risk assessments, pre-job safety meetings, detailed job specific operational procedures and contingency planning, copies of equipment and operator certification.

11.3.4 Commissioning activities

The vendor usually has a list of activities to be performed as part of the commissioning. A generic sample of such a list might be:

- System checks. The vendor will usually hook-up to the MPFM using a service computer, either a laptop or a permanently installed computer to run various system checks specific for the MPFM make.
- System configuration. During commissioning the vendor will usually establish a single or multiple baseline references for the MPFM. If required, fluid properties data will be entered as a part of the system configuration.
- System test. All readings from the MPFM to the customer's supervisory system are checked. The continuity of the communication system is checked by monitoring the communication over an appropriate period.
- Pressure test. On site testing falls under the responsibility of the client and shall be performed according to client's procedure. The vendor should be consulted prior to pressure testing to reveal any limitations regarding test medium and test procedure.
- Final testing. Once all commissioning activities have been completed it is recommended that a thorough quality check of the first flowing data through the MPFM be undertaken to ensure consistency of results. This is a task typically performed by the vendor.

The outcome of the activities listed here should be part of a commissioning handover document, which outline in more detail all the activities and checks performed. Where applicable, values should be stated and signed. Finally, the handover document should be signed by both the client and vendor representative.

11.4 Start-up

The start-up should be a part of the commissioning. It is an extension of the final testing part of the commissioning activities. If possible, one task should be to compare MPFM measurements against reference instruments if such are available. This is usually a test separator / production separator. The purpose is to achieve some verification of the MPFM. In some cases a reference system is not available and one has to resort to physical WLR samples and pipeline models.

A pipeline model can together with pressure readings from the wellhead and to the production system estimate the GOR or GVF. WLR samples and GVF calculations are not considered very accurate; however, they might be the only choices. WLR and GVF are key parameters for any MPFM and will give a good indication of the MPFM performance. If the WLR and GVF are not measured correctly, one cannot anticipate that the reported volume flow rates are very accurate.

Although a reference system is available, it is not a trivial task to compare reference system readings with MPFM readings. The two readings are usually measured at different locations and thus at different pressures and temperatures. Therefore, to compare flow rates on a volumetric basis one should first convert flow-rates to a common basis. To reduce the uncertainties related to PVT data, one should convert the rates to either MPFM or reference system conditions before comparison. One should also make sure that the PVT data used by the MPFM, the reference system and in the conversion are consistent. To ensure a proper comparison, the following guideline is recommended:

- Verify that MPFM and reference system uses the same basis for PVT data.
- Compare total mass flow rate. To do this no conversion is needed and thus the comparison will reveal any deviations before introducing the uncertainty of PVT conversions. If there is a difference, then one should not proceed further until the cause of the difference is found.
- Compare hydrocarbon total mass flow rate for the MPFM and the reference system. If any water is present do the same for the water mass flow rate. Although there is a mass transfer between the hydrocarbon liquid and gas phase, the sum of the two should remain the same regardless of pressure and temperature. Again, there is no point in proceeding if the compared rates are not within expectations.
- Compare volumetric flow rates converted to a common basis. The volumetric flow rates should be converted to either MPFM or reference system conditions.
- If possible, take physical gas and liquid samples during the test and analyse them. The purpose is to verify the PVT data currently used by the MPFM and the reference system.
- Finally, compare and present the results as for a flow loop test, where uncertainties of both the MPFM and reference system are included (see Section 9.3.

As outlined above, comparing reference system and MPFM data may involve more than stacking numbers side by side. In fact, if there is any deviation, it calls for some experience and expertise to analyse and investigate the difference. Therefore, both the vendor and client should plan to have the necessary resources available during start-up.

12. VERIFICATION DURING OPERATION

MPFMs cannot easily be sent to a calibration facility for recalibration, yet there is a need for regular calibration to verify the meter performance. Calibration or verification of individual sensors is a simple and effective way to verify and validate parts of the MPFM. In many installations there will be provision for checking the performance of the MPFM using a permanently installed or portable test separator. In these cases the calibration of the MPFM can be checked at regular intervals, taking heed of the precautions and recommendations already discussed in Chapter 10. The purpose of this section is to provide some guidelines on how to verify meter performance in field during operation, assuming no test separator is readily available. The methods discussed are:

- Baseline monitoring
- Self checking / self diagnostics capabilities / redundancy
- Two meters in series
- Mobile test unit
- Tracer technology
- Injection
- Sampling
- Reconciliation factor
- Geo-chemical fingerprinting

Which one, or which combination of several, of these methods should be used will be application dependant, but it is recommended that the method of verification be considered already in the design stage. This will ensure that any special facilities, e.g. bypass, isolation valves, sampling points, or other, required for the selected verification method(s) will be in place.

But before explaining these different verification methods in more detail, it is should be noted that perhaps the most important factor is to verify that the meter operates within the rated operating conditions given by the supplier, and that influence parameters, e.g. fluid property data, has not drifted outside the tolerance bands for the meter.

12.1 Baseline monitoring

Baseline monitoring is the simplest method for qualifying meter performance in field, yet it is quite efficient and should constitute a minimum requirement for follow-up of any MPFM. Baseline monitoring is the concept of establishing a baseline of key parameters describing reproducible states of the MPFM. The most typical will be key measurement parameters at empty and preferably depressurised sensor, and typical parameters will be differential pressure, density parameters and electrical impedance parameters. A traceable log must be established for the parameters to be included in the baseline monitoring, together with an acceptable tolerance band for each parameter. The exact suite of baseline parameters will depend on the type of MPFM, and should be agreed with the vendor to achieve best result.

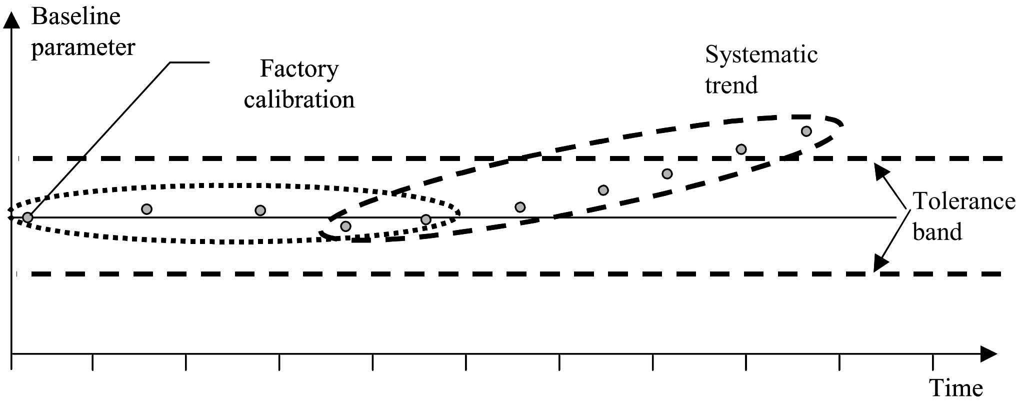


Figure 12.1 Example of baseline monitoring.

Empty sensor is a typical example of a reproducible state, and the baseline parameters for this state should be logged first at factory calibration, later at field commissioning, and at regular intervals thereafter. By plotting historical trend plots for the baseline parameters, one may distinguish between random deviations within (or outside) the tolerance band, or a systematic drift, even if this is within the tolerance band.

Other baseline parameters can be, for example, internal reference parameters in the detector electronics, e.g. control voltages, that are available by default, or could be made available on request to facilitate a more robust baseline monitoring system. In a more comprehensive version, measurement parameters when the meter is filled with a known reference fluid can also be included in the baseline parameter suite.

12.2 Self checking / self diagnostics capabilities / redundancy

The concept of self-checking can be described as an automated way of baseline monitoring, but can also be significantly more advanced. With the self diagnostic capabilities, the meter will automatically check and log single key measurement parameters and built-in references, and can also cross-check these (e.g. calculate a ratio), and verify whether the meter operate within tolerances, and also warn of a systematic drift. In some meters there is also an inherent or purposely built-in redundancy. This will make the self-diagnostic capability more robust, in particular for the on-line verification in flowing conditions.

12.3 Two meters in series

Additional redundancy, allowing diagnostic and verification possibility, can be achieved by installing two MPFMs in series. Typical applications for this method of verification are in applications where the required measurement range is outside the measurement range for one MPFM only. An example of an application using two meters in series is shown in Figure 12.2. The configuration is that a small ID MPFM is installed in a bypass, and a ball valve and a larger ID MPFM is installed in the main line. The ball valve is operated either fully closed or fully open; fully closed is the low range, and all flow then passes through the small ID meter. The full multiphase flow will in all cases pass through the large ID meter.

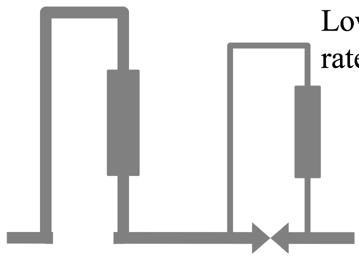


Figure 12.2 Example of an installation with two meters in series to provide an extended measurement range for the installation.

From a flow map showing the measurement ranges for these two meters, we observe that the turndown in flow rate for each phase has been increased from a typical 10:1 to close to 100:1. In addition, there is an overlapping range that can be used for verification. It is worth mentioning that while both meters are operating within their specified range in this region, one operates in the upper range and one in the lower. This further means that while flow rates are the same for the two meters, flow velocities will be different, giving an added dimension to the verification compared to a case of two identical meters in series.

Verification by two MPFMs in *parallel* can only be achieved in very stable conditions, as these tests would necessarily have to be performed in sequence.

12.4 Mobile test units

Similar possibilities for diagnostic and verification as described above can be achieved using mobile test units. The mobile test unit could e.g. be a skid- or truck-mounted MPFM (or meters), or could be a tailor made test package e.g. using partial separation and including facilities to obtain fluid samples.

12.5 Tracer technology

The tracer technology works by injecting small volumes of tracers that are selective to oil, water or gas phases. These tracers could be dye tracers, but could also be other types of material, e.g. fluorescent or radioactive tracers. By injecting these tracers at known rates, and by analysing a sample of the multiphase flow sufficiently far downstream of the injection point, the individual phase flow rates can be determined by measuring the dilution of tracer in the sample.

A specialist company would typically deliver the tracer method for verification of MPFM performance as a service. The uncertainty of the tracer technique will depend on the composition and flow regime, and the expected uncertainty should be established for each specific application. The use of this technique requires that suitable points for injection and sampling be included in the installation.

12.6 Injection

Similar to the tracer technology, this method works by injection into the flow line, but in this case the injection is of a higher volume, and the injected medium is oil, water or gas. An example is the injection of water into the flow line, which would verify if the meter responded correctly to the change in WLR and water flowrate. Care must be taken to make sure the injection does not alter the production conditions, e.g. pressure, in such a way that the production itself change, thereby invalidating this method of verification, e.g. the use of lift gas cannot be used to validate the meter. Also it is important to note that the fluid properties of the injected fluid must be similar to those of the corresponding process fluid, and definitely within a range such that the fluid properties of the combined phase are within the tolerance band specified for the MPFM.

12.7 Sampling

Representative sampling in a multiphase flow is difficult, and requires that rigorous procedures are followed. The method is not recommended for verification of the gas fraction measurement performance. On the other hand, if a well-designed procedure is followed, sampling and offline analysis of the water/liquid ratio can be a very efficient method for tracking the performance of a MPFM. Obtaining a representative liquid sample is by no means straightforward, and the complexity may vary between applications. Issues to consider are:

- The sampling point should be in a vertical leg of the flow line, best position is immediately downstream a flow line component providing a mixing effect.
- A number of subsequent samples (minimum 5) should be taken. Each sample must be allowed to completely separate before the WLR is measured. For some crude oils this will require use of de-emulsifier.
- All samples must be taken within a time frame where the WLR is stable, i.e. with variations less than the uncertainty required for the verification.
- The sampling point should be close to the MPFM, and the time frame for the samples must be selected such that the samples are representative for the liquid passing through the MPFM during the same time frame.
- If the difference between the highest and the lowest WLR of the samples obtained is greater than the uncertainty required for the evaluation, the verification test should be terminated, and a complete new set of samples must be obtained.
- The average WLR of the samples should be used for the comparison with the MPFM. The uncertainty of the average WLR will be no better than 2 times the standard deviation of the samples.

12.8 Reconciliation factor

Use of reconciliation factor as a means of monitoring the quality of the data from the MPFMs and according to Stephen (2001) can be a very efficient method. The method can be exemplified by the field layout shown in Figure 12.3:

- Three satellite fields are commingled into a common transport pipeline to a processing facility.
- Each satellite produces a number of wells; in this example 5 wells per satellite.

- Each satellite has a MPFM to continuously measuring the total production for that satellite.
- The measured production from each satellite is converted to rates at the same conditions as the measurement conditions at the processing facility.
- At the central processing facility the total production is separated and measured to a high standard.

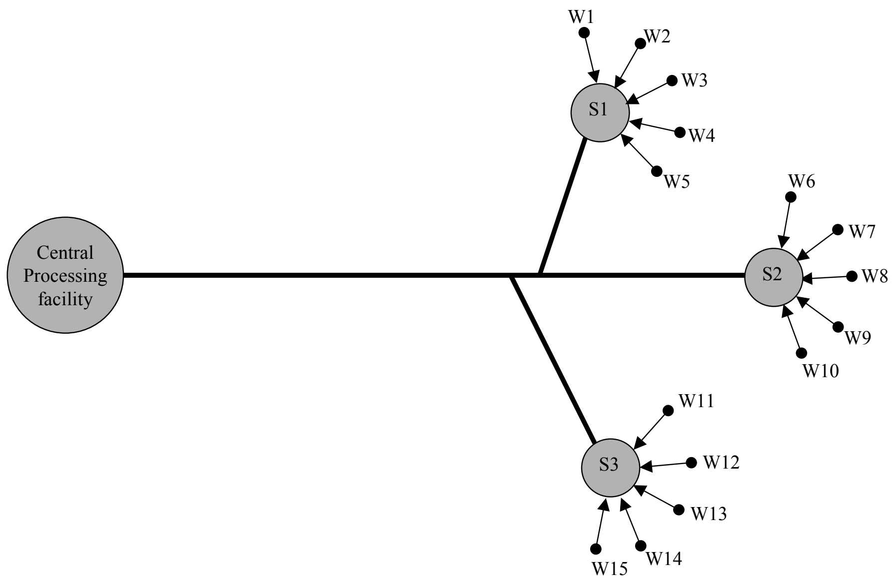


Figure 12.3 Example of a typical field layout.

The flow rates measured at the central processing facility should be directly proportional to the satellite production, and a reconciliation factor for each phase can be calculated as:

$$\text{Reconciliation Factor} = \frac{\text{Phase flow rate at central platform}}{\text{The sum of the satellite flow rates}}$$

Ideally the reconciliation factor should be equal to 1, and a reconciliation factor close to 1 gives an added confidence in the accuracy of the meters. However, in the context of monitoring and tracking the performance of the MPFMs, it is the stability of the reconciliation factor that is important rather than its absolute value. If the reconciliation factor remains constant despite variation in the relative flowrate of the metered inputs, then the system can be considered as equitable.

For the reconciliation factor system to provide an efficient method for periodic verification of the MPFMs, the uncertainty and the expected repeatability of the reconciliation factor should be established. Based on this one can establish a tolerance band. In addition to the tolerance band, monitoring the reconciliation factor is recommended for early detection of systematic drift, even if it is within the accepted tolerance band.

If all the wells of the satellite are measured by MPFMs as well, then a similar system of reconciliation factors may be established for each satellite, which in turn makes it possible to identify exactly which satellite has a measurement problem if a deviation in the reconciliation factor for the central processing facility is detected. This will enable detection of inconsistencies and may for basis for initiation of further verification procedures. Ideally this should be carried out for gas, oil and water flow rates on a volume (or preferably mass) basis.

12.9 Geo-chemical fingerprinting

According to Rowe (2001), geo-chemical fingerprinting technology used for verification of MPFMs has a limited application, but it is worthwhile mentioning as it can be an efficient method if the conditions are right. The method can typically be applied in allocation measurement, where the MPFM measures several individual wells or reservoirs, which are later combined and measured. The limiting factor for this method is that it can only be used in applications where each stream has a characteristic composition, or geo-chemical fingerprint.

Using the same example as above (Figure 12.3), the oil produced at each of the satellites S1, S2 and S3 are therefore required to have a characteristic geo-chemical fingerprint for this method to be applied.

12.10 Subsea systems verification

In subsea applications for which access to equipment is difficult, specific procedures can be implemented on a case-by-case basis. Such procedures will depend on measurement quality requirements. Some alternatives may be:

- injection of specific fluids in the meter for verification (for example Methanol),
- test / calibration "by difference",
- test by permutation (several well configurations tested in sequence), or
- by perturbation (choke changes) using topside measurements as described by Cooley et. al. (2003),

Sensor and system redundancies also offer possibilities for cross checking and validating measurements. If required, compensations for fluid properties changes must be managed through subsea sampling or direct measurement of fluid properties.

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A NUCLEAR GAUGE EMPLOYMENT

Applications of MPFMs employing radioactive sources in their measurement concept require much more attention to organisational and HSE issues. Local legal and company requirements for the use of radioactive devices should be checked and fulfilled. Next to all these formal aspects (legislation, safety plans, contracts of ownership, custodianship, disposal/recycling, security) the more psychological and emotional aspects should not be underestimated.

The International Commission on Radiological Protection (ICRP) is supported by a number of international organisations and by many governments. It issues recommendations on the principles of radiation protection for man. A number of documents have been published and the most relevant for the application of nucleonic type of multi-phase flow meters is referred to as ICRP-60.

For radiological safety the following three issues should be considered as a minimum:

1) Exposure limits.

The unit of adsorbed dose is the Gray (Gy) and the unit of effective dose is the Sievert (Sv); see the definitions in the next paragraph. The maximum effective dose limits for radiological workers is set at 20 mSv per year (averaged over a 5 year period and no single year may exceed 50 mSv). For the general public or non-radiological workers the effective dose limit is set to 1 mSv per year (approx. 0.1 μSv/hr continuous exposure). This value is excluding the average 2.5 mSv that the general public is already exposed to (see Section A.2. Multi-phase meter manufacturers should be able to indicate and demonstrate the radiation levels in the vicinity of their metering equipment.

2) Type of radioactive source

All multiphase flow meters using gamma ray attenuation technology use sealed radioactive sources, e.g. Am-241, Cs-137, Co-60, Gd-153 and Ba-133. Radioactive sources can be classified in so-called toxicity groups, group 1 is for the very high toxicity, group 2 for high toxicity, group 3 for medium toxicity and group 4 is for low toxicity. Of the above sources only the Am-241 source falls in the highest toxicity group. It is this group that requires most frequent testing on leakage (so-called “wipe tests”) For toxicity group 1 a wipe test at least every six months is required, while the other groups require leakage tests once every one or two years. How this leakage testing will be handled in sub-sea applications is not yet generally agreed in industry.

3) Organisational aspects

The responsibility for control of operations where radioactive sources are used rests with the management of the company. Advice on radiological protection can be provided through in-house resources or contract specialists. The International Atomic Energy Agency (IAEA) recently issued a Nucleonic Gauge Manual and Directory (ISSN 1011-4289, June 2004).

A.1 UNITS

Below are definitions of the most frequent used units.

Gray (Gy)

Gray (Gy) is the SI-unit of absorbed dose of ionising radiation. It describes the absorbed dose, in terms of energy, delivered per unit mass. 1 Gy is equivalent to 1 Joule per kilogram. The Gray has replaced the much older, and still often used unit of absorbed dose, the rad (radiation absorption dose). Note that 1 Gy = 1 J/kg = 100 rad.

Sievert (Sv)

Sievert (Sv) is the unit of (effective) dose equivalent; the dimension is also J/kg. The dose equivalent in Sievert is numerically equal to the absorbed dose in Grays multiplied by the quality factor. The Sievert (Sv) is the SI unit and has replaced the older unit, the rem (Rontgen Equivalent Man). The Sievert takes into account the relative biologic effectiveness of ionising radiation, since each form of such radiation, e.g. X-rays, gamma rays, neutrons, has a slightly different effect on living tissue. Accordingly, one Sievert is generally defined as the amount of radiation roughly equivalent in biologic effectiveness to one Gray (or 100 rads) of gamma radiation. The Sievert is inconveniently large for various applications, and so the milliSievert (mSv) is frequently used instead. Note that 1 Sv = 1 J/kg = 100 rem.

Rad

The pre-SI unit of absorbed dose, see also Gray

1 rad = 0.01 J/kg = 0.01 Gy

Rem

The pre-SI unit of dose equivalent, see also Sievert

1 rem = 0.01 J/kg = 0.01 Sv

Becquerel (Bq)
The SI unit of activity, one Becquerel equals one nuclear transformation per second
1 Bq = $2.7 * 10^{-11}$ Ci

Curie (Ci)
The pre-SI unit of activity (abbreviated Ci), exactly equal to $3.7 * 10^{10}$ disintegration's per second and very nearly equivalent to the activity of one gram of naturally occurring radium, see also Becquerel

Activity
The number of disintegration's per second, or the number of unstable atomic nuclei that decay per second in a given sample (unit is Becquerel).

Radiation weighting factor (Q)
The radiation weighting factor is the factor by which absorbed doses are multiplied to obtain a quantity that expresses – on a common scale for all types of ionising radiation – the biological effectiveness of the absorbed dose. For photon and electron radiation this is 1, for alpha particles this is 20 and for neutron radiation this is depended on the neutron energy

A.2 EXPOSURE EXAMPLES

The average effective dose rate of man due to natural radiation is estimated to be approximately 2 mSv per year. Including the effective dose due to artificial radiation the annual dose becomes approximately 2.5 mSv per year. In the table some typical values are given. Also note that 14-day ski vacation at an altitude of 2-3 km or a 10-hour flight at an altitude of 10 km results in an additional exposure of 0.02 mSv. Typical radiation levels at the surface of multi-phase flow meters are in the order of 0.5 μSv/h or less, i.e. at the surface of 8 hrs at day, 200 days per year this is equivalent to 0.8 mSv/year. As radiation levels decrease with the distance squared, at 1-meter distance from the meter radiation levels are often orders of magnitude smaller.

Table 13.3 Typical values for average effective dose rate.

Natural radiation	
Cosmic rays	0.36 mSv/year
Terrestrial	1.55 mSv/year
Artificial radiation	
Medical exposure	0.50 mSv/year
"Chernobyl"	<0.02 mSv/year (Western Europe)
Nuclear weapons fall out	0.01 mSv/year

B USER MANUAL FOR THE EXCEL PROGRAM FOR GENERATION OF FLOW MAPS

The Excel program consists of 6 charts containing plots, 9 worksheets containing input data for the plots, 1 worksheet for adjustments of some of the charts, and 1 information worksheet.

The 6 charts containing the plots are

- Flow rate plot
- WLR-GVF-plot
- Dev Gas-GVF plot
- Dev Liq-GVF plot
- Dev WLR-GVF plot
- Cum plot

The 9 worksheets containing input data for the plots are

- Well Data No. 1 to 5
- Meter Specs - Flow
- Meter Specs - WLR
- Uncertainty limits
- Test Data

The worksheet for adjustments of some of the graphs is

- Graph Menu

The information worksheet is

- ReadMe

The 5 well data worksheets are identical and can be used for plotting of well data from up to 5 different wells. The data that needs to be specified in the well data work sheets is the gas flow rate, liquid flow rate and the WLR. Note that different units can be specified for the gas and liquid flow rates. The GVF is not to be specified in the work sheet. This quantity is calculated based on the other input data. Therefore, the GVF data are displayed with blue text instead of black. In addition, uncertainty of each of the four quantities gas flow rate, liquid flow rate, WLR and GVF must be specified.

All these data can be specified at several time positions, to indicate the evolution of a well over time. The time unit is not used in any graph and is therefore arbitrary. The well data as specified above, will be plotted in the two charts “Flow rate plot” and

“WLR-GVF-plot”. In the “Graph Menu” sheet the user can choose the wells to be included in these two plots.

In the worksheet “Meter Specs – Flow” the specifications for a given MPFM should be given. The uncertainty limit is specified as gas flow rate uncertainty less than a given percentage and similarly for the liquid flow rate uncertainty. The table to be filled in is intended to describe a contour (map) corresponding to the given uncertainty specification. This means that the points specified as gas and liquid flow rate should together form a closed curve (meaning that the first and the last point set should be identical). The contours are plotted in the “Flow rate plot” chart. See Figure 13.1 for an illustration of the connection between the worksheet “Meter Specs – Flow” and the chart “Flow rate plot”. It should also be noted that it is possible in the “Meter Specs – Flow” worksheet to decide how many of the uncertainty contours that are to be plotted. In the “Graph menu” worksheet it is possible to turn on and off the display of these meter specifications for the “Flow rate plot”.

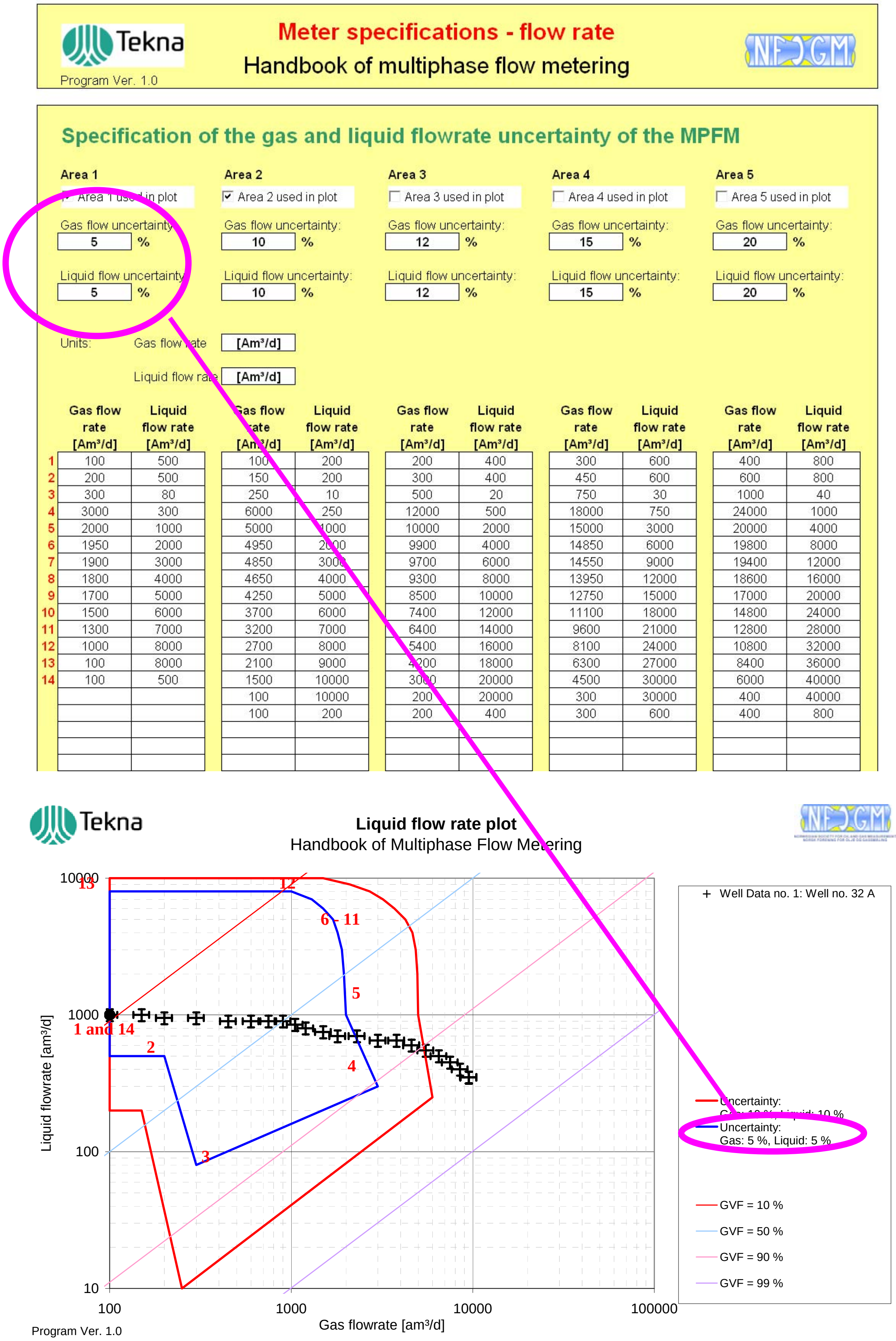
The worksheet “Meter Specs – WLR” is similar to the worksheet “Meter Specs – Flow”. The input to the “Meter Specs – WLR” worksheet is plotted in the “WLR-GVF Plot” chart. Note also that the uncertainty in the “Meter Specs – WLR” worksheet can be specified either as “Less than” or as “More than”.

In the worksheet “Uncertainty limits”, input data for the three worksheets “Dev Gas-GVF plot”, “Dev Liq-GVF plot” and “Dev WLR-GVF plot” is given. In these three plots, deviations from reference are given for gas flow rate, liquid flow rate and WLR, respectively as a function of GVF. In the worksheet “Uncertainty limits” the uncertainty limit for each of these plots is given as a curve where straight lines are used between the specified points (x-y), similar to in Figure 13.1.

The input from the worksheet “Test data” is used in all the 6 charts. Here both gas and liquid flow rate, WLR and GVF should be given both for the meter readings and for the reference data.

In the “Graph Menu” worksheet it is also possible to give the range in WLR and GVF in which the test data should be counted for in the Cumulative plot.

It should finally be noted that this program is not protected, and every user is free to access and modify all parts of the Excel workbook. However, if lines or columns are added inside the worksheets and if worksheet names or chart names are changed, some of the macro functionalities of the program may fail. This is therefore not recommended.



Meter specifications - flow rate
Handbook of multiphase flow metering
Program Ver. 1.0

Specification of the gas and liquid flowrate uncertainty of the MPFM

	Area 1	Area 2	Area 3	Area 4	Area 5
Used in plot	Area 1 used in plot	Area 2 used in plot	Area 3 used in plot	Area 4 used in plot	Area 5 used in plot
Gas flow uncertainty:	5 %	10 %	12 %	15 %	20 %
Liquid flow uncertainty:	5 %	10 %	12 %	15 %	20 %

Units: Gas flow rate [Am³/d]
Liquid flow rate [Am³/d]

	Area 1 Gas flow rate [Am³/d]	Area 1 Liquid flow rate [Am³/d]	Area 2 Gas flow rate [Am³/d]	Area 2 Liquid flow rate [Am³/d]	Area 3 Gas flow rate [Am³/d]	Area 3 Liquid flow rate [Am³/d]	Area 4 Gas flow rate [Am³/d]	Area 4 Liquid flow rate [Am³/d]	Area 5 Gas flow rate [Am³/d]	Area 5 Liquid flow rate [Am³/d]
1	100	500	100	200	200	400	300	600	400	800
2	200	500	150	200	300	400	450	600	600	800
3	300	80	250	10	500	20	750	30	1000	40
4	3000	300	6000	250	12000	500	18000	750	24000	1000
5	2000	1000	5000	1000	10000	2000	15000	3000	20000	4000
6	1950	2000	4950	2000	9900	4000	14850	6000	19800	8000
7	1900	3000	4850	3000	9700	6000	14550	9000	19400	12000
8	1800	4000	4650	4000	9300	8000	13950	12000	18600	16000
9	1700	5000	4250	5000	8500	10000	12750	15000	17000	20000
10	1500	6000	3700	6000	7400	12000	11100	18000	14800	24000
11	1300	7000	3200	7000	6400	14000	9600	21000	12800	28000
12	1000	8000	2700	8000	5400	16000	8100	24000	10800	32000
13	100	8000	2100	9000	4200	18000	6300	27000	8400	36000
14	100	500	1500	10000	3000	20000	4500	30000	6000	40000
			100	10000	200	20000	300	30000	400	40000
			100	200	200	400	300	600	400	800

Figure 13.1 The red numbers 1-14 indicate the connection between the worksheet "Meter Specs – Flow" and the chart "Flow rate plot".

