TECHNICAL SPECIFICATION

ISO/TS 21354

First edition
2020-11

Measurement of multiphase fluid flow

Reference number
ISO/TS 21354:2020(E)

Contents

Page

Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular, the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights. Details of any patent rights identified during the development of the document will be in the Introduction and/or on the ISO list of patent declarations received (see www.iso.org/patents).

Any trade name used in this document is information given for the convenience of users and does not constitute an endorsement.

For an explanation of the voluntary nature of standards, the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT), see www.iso.org/iso/foreword.html.

This document was prepared by Technical Committee ISO/TC 28, *Petroleum and related products, fuels and lubricants from natural or synthetic sources*, Subcommittee SC 2, *Measurement of petroleum and related products*.

Any feedback or questions on this document should be directed to the user’s national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

Introduction

The need for multiphase flow measurement in the oil and gas production industry has been evident for many years. Multiphase 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. Some technologies have been abandoned, whereas other meters have become commercially available: the number of applications and users is increasing.

The first Norwegian Society for Oil and Gas Measurement (NFOGM) handbook of multiphase metering (hereafter simply called the Handbook) was published in 1995 (see Reference [16]). Since then, multiphase flow measurement has matured. New applications of multiphase flow meters (MPFMs) have emerged, from simply being a replacement for 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 on shore, topside and subsea.

Since multiphase flow metering technologies and applications had developed significantly since 1995, NFOGM updated the Handbook in 2003-5 to reflect these improvements and to make it the main guide for state-of-the-art multiphase flow measurement. That work was financed by NFOGM and The Norwegian Society of Chartered Technical and Scientific Professionals (Tekna).

Following calls from industry to produce an ISO document, NFOGM very generously allowed ISO to use the Handbook as the basis for this document.

This document is intended to serve as guidance for users, designers and manufacturers of multiphase metering systems.

The document can 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.

Even if the individual flow rates of each constituent are of primary interest, often their ratios (e.g. water liquid ratio, gas oil ratio) are useful as operational parameters. Total hydrocarbon mass flow rate can be required in particular applications. Constituents other than oil, gas and water flow rates or ratios of these are not dealt with in this document.

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

Testing and qualification of MPFMs are required to verify performance. Guidance is provided to help optimize the outcome of such activities. Since MPFMs measure at line conditions, the primary output is individual flow rates and fractions at actual conditions (i.e. 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, which can require sampling.

The clauses logically proceed from an introduction to multiphase flow measurement, via selection of technology, design considerations and performance specifications, to field installation and commissioning, and finally the operation of MPFMs.

The definitions in Clause 3 have been extended and split into definitions relating to multiphase flows in a closed conduit (see 3.1) and definitions relating to metrology that can be useful in characterizing the performance of a multiphase flow meter.

Clause 5 provides a general introduction to multiphase flows. This clause includes extended descriptions of flow regimes and slip effects in multiphase flows.

Clause 6 covers the aims of multiphase flow measurement, giving the reasoning for selection, installation and operation of multiphase flow metering systems in various applications.

Clause 7 presents guidelines for designing MPFM installations using the two-phase flow map and the composition map.

Standardized performance specification of MPFMs is essential, both for comparison of measuring ranges and measurement uncertainties, but also for more efficient selection of technology (Clause 8).

Clause 9 covers all aspects of testing, calibration and adjustment of MPFMs.

Clause 10 provides recommended procedures and practices for field installation and commissioning of MPFMs. Although MPFMs cannot easily be sent to a test facility for recalibration, there is a need for regular testing to verify the meter performance.

The purpose of Clause 11 is to provide guidelines on how to verify meter performance in the field during operation, assuming no test separator is readily available.

Annex A includes brief descriptions of the most commonly used measurement principles in MPFMs currently available on the market. Guidance on selection of technology and maintenance requirements is also provided. Annex B gives relevant information on hydrocarbon phase behaviour.

Aspects of safety are not dealt with in this document. It is the responsibility of the user to ensure that the system meets applicable safety regulations.

Measurement of multiphase fluid flow

1 Scope

This document establishes a common basis for, and assistance in, the classification of applications and multiphase meters, as well as guidance and recommendations for the implementation and use of such meters.

The so-called in-line multiphase flow meters (MPFMs) that directly measure the oil, water and gas flow rates, as well as the partial- and full-separation MPFMs are the main focus of this document. Conventional two- or three-phase separators are not included in this document. Only limited reference is made to wet-gas meters, since although wet-gas flow is a subset of multiphase flow, wet-gas measurement is covered by ISO/TR 11583 and ISO/TR 12748.

2 Normative references

There are no normative references in this document.

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at http://www.electropedia.org/

3.1 Terms related to multiphase flow metering

3.1.1
actual conditions
meter *in-situ* process operating conditions of pressure and temperature, at which measured flow rates are reported, without conversion to a standard or reference fluid state

3.1.2
composition map
graph with *gas volume fraction* (3.1.9) and *water liquid ratio* (3.1.42) along the x- and y-axis, respectively

Note 1 to entry: Both the GVF and WLR are at *actual conditions* (3.1.1).

3.1.3
dispersed flow
flow where a particular *phase* (3.1.23) is broken up into multiple small bubbles or droplets carried within the body of another phase

Note 1 to entry: Examples of such flows are bubble flow and mist flow.

3.1.4
emulsion
colloidal mixture of two immiscible fluids, one being dispersed in the other in the form of fine droplets

Note 1 to entry: In multiphase fluids, discrimination should be made between oil-in-water emulsion and water-in-*oil* (3.1.21) emulsion; they respond differently to permittivity measurements.

3.1.5
flow regime
dynamic spatial and velocity distribution of flowing fluid *phases* (3.1.23) within a conduit

Note 1 to entry: This is also known as flow pattern.

Note 2 to entry: For example, in two-phase oil/water stratified flow in horizontal pipes free water occupies the bottom of the conduit with *oil* (3.1.21) or oil/water mixture flowing above.

3.1.6
gas
hydrocarbons in the gaseous state at the prevailing temperature and pressure

3.1.7
gas oil ratio
GOR
ratio of *gas* (3.1.6) *volume flow rate* (3.1.38) and *oil* (3.1.21) volume flow rate

Note 1 to entry: Both volume flow rates should be converted to the same pressure and temperature [generally at *standard conditions* (3.1.35)]. GOR is expressed in volume per volume, F_{GOR}, e.g. scft/bbl or m^3/m^3.

3.1.8
gas void fraction
ratio of the cross-sectional area in a conduit occupied by the *gas* (3.1.6) *phase* (3.1.23) and the cross-sectional area of the conduit

Note 1 to entry: This is also known as gas hold-up.

3.1.9
gas volume fraction
GVF
gas (3.1.6) *volume flow rate* (3.1.38), relative to the multiphase volume flow rate, at *actual conditions* (3.1.1)

Note 1 to entry: The GVF is normally expressed as a fraction or percentage.

3.1.10
homogeneous multiphase flow
multiphase flow in which all *phases* (3.1.23) are evenly distributed over the cross section of a closed conduit

Note 1 to entry: A homogeneous multiphase flow is, therefore, one in which the composition is the same at all points in the cross section and where the liquid and *gas* (3.1.6) velocities are the same (no-slip). Note that bubbly multiphase *flow regimes* (3.1.5) are probably the best approximation to homogeneous multiphase flow.

3.1.11
intermittent flow
flow characterized by being non-continuous in the axial direction, that is, exhibiting unsteady *phase* (3.1.23) hold-up locally

Note 1 to entry: Examples of such flows are plug, churn and slug flow (see Figures 1 and 2): the *flow regimes* (3.1.5) are all hydrodynamic (see 5.1) two-phase gas-liquid flow regimes.

3.1.12
liquid hold-up
ratio of the cross-sectional area in a conduit occupied by the liquid *phase* (3.1.23) and the cross-sectional area of the conduit

3.1.13
liquid volume fraction
LVF
liquid *volume flow rate* (3.1.38), relative to the multiphase volume flow rate, at *actual conditions* (3.1.1)

Note 1 to entry: The LVF is normally expressed as a fraction or percentage.

3.1.14
Lockhart-Martinelli parameter
X
square root of the ratio of the liquid inertia to the *gas* (3.1.6) inertia if the *phases* (3.1.23) flowed alone at *actual conditions* (3.1.1), that is

$$X = \frac{q_{V,\text{liquid}}}{q_{V,\text{gas}}} \sqrt{\frac{\rho_{\text{liquid}}}{\rho_{\text{gas}}}} = \frac{1 - F_{\text{GVF}}}{F_{\text{GVF}}} \sqrt{\frac{\rho_{\text{liquid}}}{\rho_{\text{gas}}}}$$

where

$q_{V,\text{liquid}}$ is the volume flow rate of the liquid;

$q_{V,\text{gas}}$ is the volume flow rate of the gas;

ρ_{liquid} is the density of the liquid;

ρ_{gas} is the density of the gas;

F_{GVF} is the GVF.

Note 1 to entry: The Lockhart-Martinelli parameter has a long and complicated history. There are several different definitions for this parameter, and they are not equivalent. This includes the original definition by Lockhart-Martinelli which is different from the definition stated above. The definition supplied in this document is now commonly used. Nevertheless, this issue continues to cause confusion in the industry. The different definitions are described in detail with historical context in References [30] and [13].

Note 2 to entry: In the second formula above, the relationship of the Lockhart-Martinelli number and the *GVF* (3.1.9) is a function of the density ratio.

Note 3 to entry: An increasing value of *X* means an increasing liquid content or wetness of the flow.

3.1.15
mass flow rate
mass of fluid flowing through the cross section of a conduit in unit time

3.1.16
measuring envelope
areas in the *two-phase flow map* (3.1.37) and the *composition map* (3.1.2) in which the *MPFM* (3.1.18) performs according to its specifications

3.1.17
multiphase flow
flow consisting of two or more *phases* (3.1.23) flowing simultaneously in a closed conduit

Note 1 to entry: This document deals in particular with multiphase flows of *oil* (3.1.21), water and *gas* (3.1.6) in the entire region of 0 % – 100 % of the GVF (3.1.9) and 0 % – 100 % of the WLR (3.1.42).

3.1.18
multiphase flow meter
MPFM
device for measuring the individual *oil* (3.1.21), water and *gas* (3.1.6) flow rates in a *multiphase flow* (3.1.17)

Note 1 to entry: The total package of measurement devices for composition and velocity, including possible conditioning unit, should be considered as an integral part of the meter.

3.1.19
multiphase mixture velocity
ratio of the *multiphase volume flow rate* (3.1.20) and the cross-sectional area of the conduit

Note 1 to entry: This is a fictitious velocity: only in *homogeneous multiphase flow* (3.1.10) does this velocity have a meaningful value. Multiphase mixture velocity is the sum of *gas* (3.1.6) superficial velocity and liquid superficial velocity.

3.1.20
total volume flow rate
multiphase volume flow rate
total volume flowing through the cross-sectional area of a conduit per unit time

3.1.21
oil
hydrocarbons in the liquid state at the prevailing temperature and pressure conditions

3.1.22
oil-continuous flow
flow in which water is distributed as droplets surrounded by *oil* (3.1.21)

Note 1 to entry: Electrically, the mixture acts as an insulator.

3.1.23
phase
one constituent in a mixture of several

Note 1 to entry: In particular, the term refers to *oil* (3.1.21), *gas* (3.1.6) or water in a mixture of any number of the three. It is recognized that the terminology of the multiphase industry is different from that in much of science.

3.1.24
phase area fraction
cross-sectional area locally occupied by one of the *phases* (3.1.23) of a *multiphase flow* (3.1.17), relative to the cross-sectional area of the conduit at the same local position

3.1.25
phase flow rate
amount of one *phase* (3.1.23) of a *multiphase flow* (3.1.17) flowing through the cross section of a conduit in unit time

Note 1 to entry: The phase flow rate may be specified as phase *volume flow rate* (3.1.38) or as phase *mass flow rate* (3.1.15).

3.1.26
phase volume fraction
phase (3.1.23) *volume flow rate* (3.1.38) of one of the phases of a *multiphase flow* (3.1.17), relative to the *multiphase volume flow rate* (3.1.20), at *actual conditions* (3.1.1)

3.1.27
production envelope
areas in the *two-phase flow map* (3.1.37) and the *composition map* (3.1.2) that are determined by a number of well trajectories or specified as possible flow rates and compositions that occur in a certain application

3.1.28
proving
set of operations that establish, under specified conditions, the relationship between the values of quantities indicated by a device and the corresponding values as determined by a traceable reference device (proving system)

3.1.29
reconciliation
process whereby pieces of information that include some redundancy are matched together to satisfy constraint formulae

Note 1 to entry: In *oil* (3.1.21) and *gas* (3.1.6) production, reconciliation is the process in which oil, water and *gas* (3.1.6) production figures that have not been measured with high *accuracy* (3.2.1) are recalculated to match production figures that have been measured with high accuracy (e.g. custody transfer measurements).

3.1.30
reference conditions
conditions, in terms of pressure and temperature, at which fluid properties or *volume flow rates* (3.1.38) are expressed

3.1.31
salinity
amount of dissolved salts that are present in water

Note 1 to entry: Salinity is normally expressed in units g/kg.

Note 2 to entry: Sodium and chloride are the predominant ions in seawater, and the concentrations of magnesium, calcium, and sulfate ions are also substantial.

3.1.32
slip
flow condition that exists when the *phases* (3.1.23) have different average velocities

Note 1 to entry: The slip may be quantitatively expressed by the average phase velocity difference between the phases. See 5.3.

3.1.33
slip ratio
ratio between two phase-average velocities

Note 1 to entry: See 5.3.

3.1.34
slip velocity
phase (3.1.23) velocity difference between two phases

Note 1 to entry: See 5.3.

3.1.35
standard conditions
conditions, in terms of pressure and temperature, at which fluid properties or *volume flow rates* (3.1.38) are expressed

EXAMPLE 101,325 kPa and 15 °C.

3.1.36
superficial phase velocity
quotient of the *phase* (3.1.23) *volume flow rate* (3.1.38) and the pipe cross-sectional area

3.1.37
two-phase flow map
graph with superficial velocities of *gas* (3.1.6) and liquid along the x- and y-axes, respectively

Note 1 to entry: An example is the Mandhane flow map (see Reference [37]) for horizontal *multiphase flow* (3.1.17).

Note 2 to entry: Alternatively, the actual *gas* (3.1.6) and actual liquid *volume flow rates* (3.1.38) can be used.

3.1.38
volume flow rate
volume of fluid flowing through the cross section of a conduit in unit time

3.1.39
water-continuous flow
flow in which *oil* (3.1.21) is distributed as droplets surrounded by water

Note 1 to entry: Electrically, the mixture acts as a conductor.

3.1.40
water cut
WC
water *volume flow rate* (3.1.38), relative to the total liquid volume flow rate [*oil* (3.1.21) and water], both converted to volumes at standard pressure and temperature

Note 1 to entry: The WC is normally expressed as a percentage.

3.1.41
water fraction meter
WFM
device for measuring the *phase* (3.1.23) area fraction of water of a *multiphase flow* (3.1.17) through a cross section of a conduit

Note 1 to entry: The *phase area fraction* (3.1.24) is expressed as a percentage of the total pipe area.

3.1.42
water liquid ratio
WLR
water *volume flow rate* (3.1.38), relative to the total liquid volume flow rate [*oil* (3.1.21) and water], at *actual conditions* (3.1.1)

3.1.43
water volume fraction
WVF
water *volume flow rate* (3.1.38), relative to the multiphase volume flow rate, at *actual conditions* (3.1.1)

Note 1 to entry: The WVF is normally expressed as a fraction or percentage.

Note 2 to entry: A small absolute *error* (3.2.4) in the value of the WVF may be a large relative error, e.g. where the measured and reference values of the WVF are 1 % and 0,5 % respectively, the absolute error is only 0,5 %, but the relative error is 100 %; in this example the measured water volume flow rate is twice the reference value although the absolute error is only 0,5 %.

Note 3 to entry: $F_{\mathrm{WVF}} = F_{\mathrm{WLR}} \times F_{\mathrm{LVF}} = F_{\mathrm{WLR}} \times (1 - F_{\mathrm{GVF}})$

Note 4 to entry: where

F_{WVF} is the WVF;

F_{LVF} is the LVF;

F_{WLR} is the WLR.

3.1.44
well trajectory
production profile of a well over time in a *two-phase flow map* (3.1.37) and *composition map* (3.1.2)

3.1.45
wet gas
gas (3.1.6) containing free liquids

Note 1 to entry: Generally wet gases are defined as gas/liquid systems with a *Lockhart-Martinelli parameter* (3.1.14) lower than approximately 0,3.

Note 2 to entry: Hydrocarbon gas that contains heavy components that condense during further processing (but at a particular pressure and temperature, behaving as a pure gas) is not considered to be a wet gas from a measurement point of view.

3.2 Terms related to metrology

3.2.1
accuracy
closeness of agreement between a measured quantity value and a true quantity value of a *measurand* (3.2.6)

Note 1 to entry: The concept 'measurement accuracy' is not a quantity and is not given a numerical quantity value. A measurement is said to be more accurate when it offers a smaller measurement *error* (3.2.4).

[SOURCE: JCGM-VIM:2012, 2.13]

3.2.2
adjustment
set of operations carried out on a measuring system so that it provides prescribed indications corresponding to given values of a quantity to be measured

Note 1 to entry: Types of adjustment of a measuring system include zero adjustment of a measuring system, offset adjustment, and span adjustment (sometimes called gain adjustment).

Note 2 to entry: Adjustment of a measuring system should not be confused with calibration, which is a prerequisite for adjustment.

Note 3 to entry: After an adjustment of a measuring system, the measuring system must usually be recalibrated.

[SOURCE: JCGM-VIM:2012, 3.11]

3.2.3
calibration
operation that, under specified conditions, in a first step, establishes a relation between the quantity values with measurement uncertainties provided by measurement standards and corresponding indications with associated measurement uncertainties and, in a second step, uses this information to establish a relation for obtaining a *measurement result* (3.2.11) from an indication

Note 1 to entry: A calibration may be expressed by a statement, calibration function, calibration diagram, calibration curve, or calibration table. In some cases, it may consist of an additive or multiplicative correction of the indication with an associated measurement *uncertainty* (3.2.13).

Note 2 to entry: Calibration should not be confused with *adjustment* (3.2.2) of a measuring system, often mistakenly called "self-calibration", nor with verification of calibration.

Note 3 to entry: Often, the first step alone in the above definition is perceived as being calibration.

[SOURCE: JCGM-VIM:2012, 2.39]

3.2.4
error
measured quantity value minus a reference quantity value

[SOURCE: JCGM-VIM:2012, 2.16]

3.2.5
limiting condition
extreme operating condition that a measuring instrument or measuring system is required to withstand without damage, and without degradation of specified metrological properties, when it is subsequently operated under its *rated operating conditions* (3.2.8)

[SOURCE: JCGM-VIM:2012, 4.10, modified — the term has been modified from 'limiting operating condition' to "limiting condition".]

3.2.6
measurand
quantity intended to be measured

[SOURCE: JCGM-VIM:2012, 2.3]

3.2.7
measuring range
set of values of quantities of the same kind that can be measured by a given measuring instrument or measuring system with specified instrumental measurement *uncertainty* (3.2.13), under defined conditions

[SOURCE: JCGM-VIM: 2012, 4.7]

3.2.8
rated operating condition
operating condition whose fulfilment during measurement enables the measuring instrument or measuring system to perform as designed

Note 1 to entry: Rated operating conditions generally specify intervals of values for a quantity being measured and for any influence quantity.

Note 2 to entry: An influence quantity is a quantity that, in a direct measurement, does not affect the quantity that is actually measured but affects the relation between the indication and the *measurement result* (3.2.11).

[SOURCE: JCGM-VIM:2012, 4.9, modified — the term and the definition have been combined with JCGM -VIM:2012, 2.52 and, thus, Note 2 to entry has been added.]

3.2.9
repeatability
measurement precision under a set of repeatability conditions of measurement

Note 1 to entry: A repeatability condition of measurement is a condition of measurement, out of a set of conditions that includes the same measurement procedure, same operators, same measuring system, same operating conditions and same location, and replicate measurements on the same or similar objects over a short period of time.

Note 2 to entry: A condition of measurement is a repeatability condition only with respect to a specified set of repeatability conditions.

[SOURCE: JCGM-VIM:2012, 2.21 — Notes 1 and 2 to entry have been added.]

3.2.10
reproducibility
measurement precision under reproducibility conditions of measurement

Note 1 to entry: A reproducibility condition of measurement is a condition of measurement, out of a set of conditions that includes different locations, operators, measuring systems, and replicate measurements on the same or similar objects.

Note 2 to entry: The different measuring systems may use different measurement procedures.

Note 3 to entry: A specification should give the conditions changed and unchanged, to the extent practical.

Note 4 to entry: Relevant statistical terms are given in ISO 5725-1:1994 and ISO 5725-2:1994.

[SOURCE: JCGM-VIM:2012, 2.25, modified — Notes 1, 2 and 3 to entry have been added.]

3.2.11
measurement result
set of quantity values being attributed to a *measurand* (3.2.6) together with any other available relevant information

Note 1 to entry: A measurement result is generally expressed as a single measured quantity value and a measurement *uncertainty* (3.2.13).

[SOURCE: JCGM-VIM:2012, 2.9]

3.2.12
systematic error
component of measurement *error* (3.2.4) that in replicate measurements remains constant or varies in a predictable manner

[SOURCE: JCGM-VIM:2012, 2.17]

3.2.13
uncertainty
non-negative parameter characterizing the dispersion of the quantity values being attributed to a *measurand* (3.2.6), based on the information used

Note 1 to entry: Measurement uncertainty includes components arising from systematic effects, such as components associated with corrections and the assigned quantity values of measurement standards, as well as the definitional uncertainty. Sometimes estimated systematic effects are not corrected for but, instead, associated measurement uncertainty components are incorporated.

Note 2 to entry: The parameter may be, for example, a standard deviation called standard measurement uncertainty (or a specified multiple of it), or the half-width of an interval, having a stated coverage probability.

Note 3 to entry: Measurement uncertainty comprises, in general, many components. Some of these may be evaluated by Type A evaluation of measurement uncertainty from the statistical distribution of the quantity values from series of measurements and can be characterized by standard deviations. The other components, which may be evaluated by Type B evaluation of measurement uncertainty, can also be characterized by standard deviations, evaluated from probability density functions based on experience or other information.

Note 4 to entry: In general, for a given set of information, it is understood that the measurement uncertainty is associated with a stated quantity value attributed to the *measurand* (3.2.6). A modification of this value results in a modification of the associated uncertainty.

[SOURCE: JCGM-VIM:2012, 2.26]

4 Symbols and subscripts

4.1 Symbols

For the purposes of this document, the symbols given in Table 1 apply.

Table 1 — Symbols

Symbol	Quantity	Dimension	SI unit
A	area (to denote the cross-sectional area of the pipe the subscript 'pipe' may be used)	L^2	m^2
C	capacitance	$M^{-1}L^{-2}T^4I^2$	F/m
D	internal pipe diameter	L	m
F	reconciliation factor	—	—
F_{GVF}	gas volume fraction	—	—
F_{LVF}	liquid volume fraction	—	—
F_{WLR}	water liquid ratio	—	—
F_{WVF}	water volume fraction	—	—
g	acceleration due to gravity	LT^{-2}	m/s^2
I_A	current (electric)	I	A
q_c	count rate	—	—
q_V	volumetric flow rate	L^3T^{-1}	m^3/s
R	resistance	$ML^2T^{-3}I^{-2}$	Ω
t	time	T	s
U	percentage uncertainty	—	—
V	volume	L^3	m^3
v	velocity	LT^{-1}	m/s
v_m	multiphase mixture velocity ($v_m = v_{s,gas} + v_{s,liquid}$)	LT^{-1}	m/s
v_s	superficial velocity	LT^{-1}	m/s
X	Lockhart-Martinelli parameter	—	—
ε_r	relative permittivity (or dielectric constant)	—	—
λ_{gas}	gas void fraction	—	—
λ_{liquid}	liquid hold-up	—	—
ρ	density	ML^{-3}	kg/m^3
σ	conductivity	$M^{-1}L^{-3}T^3I^2$	S/m

NOTE The phase to which density or other quantity relates is shown by the subscript 'gas' or 'liquid'.

4.2 Colours and symbols used in schematic drawings

 gas

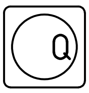
 wet gas

 water

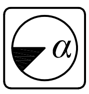
 water/oil mixture

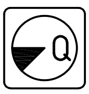
 oil

Ratio **Rate**



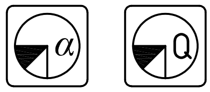
single-phase meter

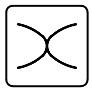




dual-phase meter

 multiphase flow

 multiphase meter

 mixer

5 Multiphase flow

5.1 General

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 not sufficient 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 long straight pipes and are referred to as “hydrodynamic” flow regimes.

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

— Dispersed flow, is characterized by liquid droplets throughout a continuous gas phase or gas bubbles throughout a continuous liquid phase. Examples of such flows are mist flow and bubble flow (Figure 2).

— Segregated-phase flow, is characterized 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 2).

— Intermittent flow, is characterized by being non-continuous in the radial and axial directions, and therefore exhibits locally unsteady behaviour. Examples of such flows are churn and slug flow (Figure 1).

5.2 Multiphase flow regime maps

5.2.1 General

Figures 1 and 2 are general illustrations of the flow regimes and indicate where the various flow regimes occur. Physical parameters like density of gas and liquid, viscosity and surface tension 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 in (100 mm) to 3 in (75 mm), both the superficial phase velocities (gas and liquid) increase by a factor 16/9. Hence, in the two-phase flow map the operational flow point moves 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 do not have sharp boundaries but instead change smoothly from one regime to another.

The flow pattern maps shown in Figures 1 and 2 are not accurate tools for flow pattern prediction: Figures 1 and 2 provide an illustration of the general trends only.

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 diagram in Figure 1 is a qualitative illustration of how flow regime transitions are dependent on superficial gas and liquid velocities in vertical multiphase flow.

The parameter 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 ($q_{v,gas}$ 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 Formula (1):

$$v_{s,gas} = \frac{q_{v,gas}}{A}; v_{s,liquid} = \frac{q_{v,liquid}}{A} \quad (1)$$

The sum of $v_{s,gas}$ and $v_{s,liquid}$ is the multiphase mixture velocity, and the expression is given in Formula (2):

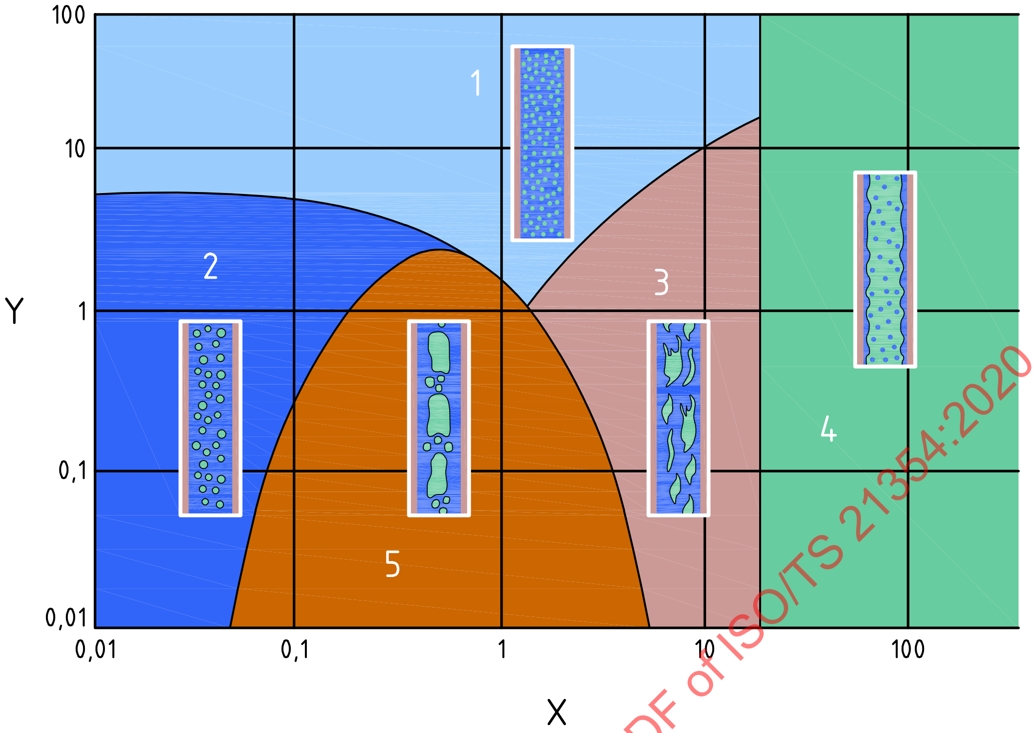
$$v_m = v_{s,gas} + v_{s,liquid} \quad (2)$$

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

5.2.2 Vertical flows

The transitions in Figure 1 are functions of factors such as pipe diameter, interfacial tension and density of the phases. Figure 1 is a qualitative illustration of how flow regime transitions are dependent on superficial gas and liquid velocities in vertical multiphase flow. A map like this is only valid for a specific pipe and pressure and a specific multiphase fluid.

In vertical upward flows, the superficial gas velocity increases and the multiphase flow can change between regimes. Note that for some superficial gas velocities, the multiphase flow is annular for all superficial liquid velocities.



Key

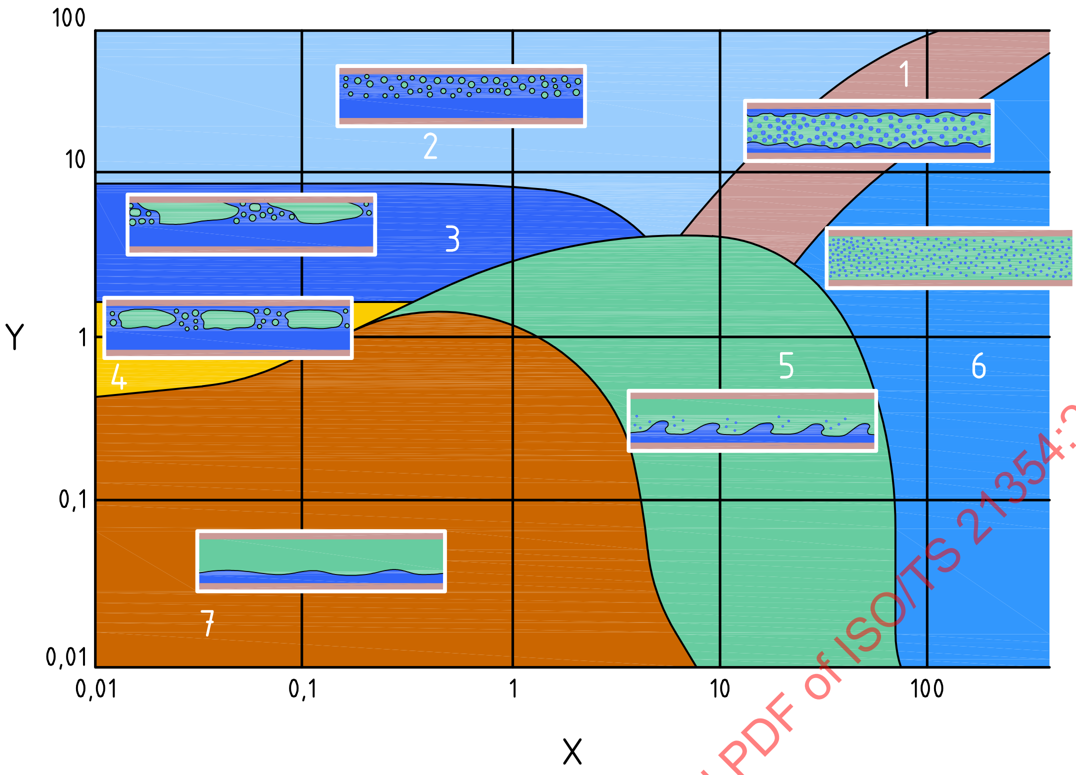
X superficial gas velocity (m/s)
Y superficial liquid velocity (m/s)
1 finely dispersed bubble
2 bubble
3 churn
4 annular
5 slug

NOTE Superficial velocities are used along the axis.

Figure 1 — Generic two-phase vertical flow map

5.2.3 Horizontal flows

In horizontal flows too, the transitions are functions of factors such as pipe diameter, interfacial tension and density of the phases. Figure 2 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 is only valid for a specific pipe and pressure and a specific multiphase fluid.



Key

X superficial gas velocity (m/s)

Y superficial liquid velocity (m/s)

1 annular

2 bubble

3 slug

4 plug

5 wave

6 mist

7 stratified

NOTE Superficial velocities are used along the axis.

Figure 2 — Generic two-phase horizontal flow map

5.3 Slip effects

When gas and liquid flow simultaneously in a pipe, the cross-sectional area covered by liquid generally is greater than it would be if the liquid and gas were moving at the same velocity, particularly in horizontal and upwardly inclined flows; this is due to bulk slippage between liquid and gas. The lighter gas phase normally moves faster than the liquid phase; the liquid has the tendency to accumulate in horizontal and inclined pipe segments. The liquid and gas fractions of the pipe cross-sectional area (A) as measured under two-phase flow conditions are known as liquid hold-up (λ_{liquid}) and gas void fraction (λ_{gas}): see Formulae (3) to (6).

$$\lambda_{liquid} = \frac{A_{liquid}}{A_{pipe}} \quad (3)$$

$$\lambda_{\text{gas}} = \frac{A_{\text{gas}}}{A_{\text{pipe}}} \quad (4)$$

$$\lambda_{\text{liquid}} + \lambda_{\text{gas}} = 1 \quad (5)$$

Similarly

$$F_{\text{LVF}} + F_{\text{GVF}} = 1 \quad (6)$$

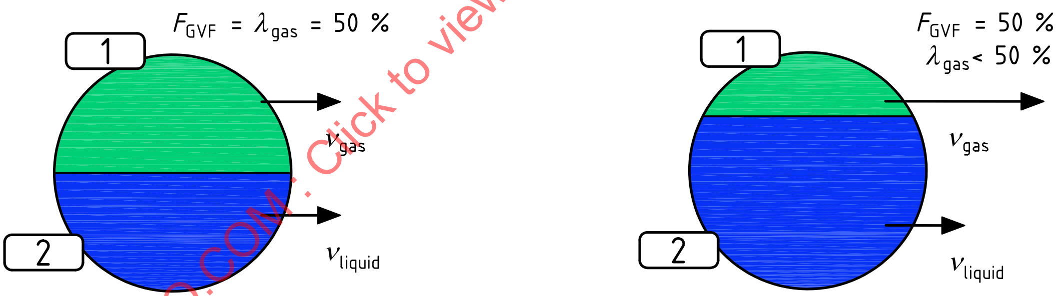
In the majority of flow regimes, the liquid hold-up is larger than the liquid volume fraction and the gas void fraction is smaller than the gas volume fraction (see Figure 3). These differences are due to slip and are particularly significant in horizontal and upwardly inclined flows. Liquid hold-up is equal to the liquid volume fraction (and gas void fraction equal to the gas volume fraction) only under conditions of no slip, when the flow is homogeneous and the two phases travel at equal velocities.

From the liquid hold-up and the actual phase velocities the superficial gas and liquid velocities can be calculated according to Formulae (7) to (9) (note that $v_{\text{gas}} \geq v_{\text{s,gas}}$).

$$\lambda_{\text{liquid}} \geq F_{LVF} \text{ and } \lambda_{\text{gas}} \leq F_{GVF} \quad (7)$$

$$v_{\text{s,gas}} = \frac{q_{\text{v,gas}}}{A_{\text{pipe}}} = \frac{q_{\text{v,gas}}}{A_{\text{gas}}} \cdot \frac{A_{\text{gas}}}{A_{\text{pipe}}} = v_{\text{gas}} \lambda_{\text{gas}} \quad (8)$$

$$v_{\text{s,liquid}} = \frac{q_{\text{v,liquid}}}{A_{\text{pipe}}} = \frac{q_{\text{v,liquid}}}{A_{\text{liquid}}} \cdot \frac{A_{\text{liquid}}}{A_{\text{pipe}}} = v_{\text{liquid}} \lambda_{\text{liquid}} \quad (9)$$



a) No-slip conditions **b) Slip conditions**

Key

1 gas

2 liquid

Figure 3 — Difference between gas void fraction and gas volume fraction

The slip ratio and slip velocity are also used in the field of multiphase flow fluid dynamics to quantify the phase slip.

5.4 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 2.

Table 2 — Classification of multiphase flows

Class	Indicative GVF range	Comment
Low GVF	0–25 %	This low GVF range of multiphase flow can also be termed 'gassy liquid'. In the lower end of this range, traditional single-phase meters can in many cases provide sufficient measurement performance. Increasing measurement uncertainty, and also the risk of damage or malfunction, should 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 traditional single-phase meters are not a viable option.
High GVF	85 %–95 %	Entering this high GVF range the uncertainty of multiphase meters starts to increase, with a rapid increase towards the upper end of the range, particularly for the liquid phases. This increase in uncertainty is not only linked to complex flow patterns but also occurs because the liquid measurement uncertainty increases as the liquid fraction, including the component of highest value (in this case the oil), decreases. In some cases, partial separation (see A.2.3.3) is used to move the GVF back into the moderate GVF range.
Very high GVF	95 %–100 %	This upper end of the multiphase range is 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 optimization 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 (see ISO/TR 11583 and ISO/TR 12748) is the preferred option. This corresponds to a Lockhart-Martinelli parameter (X) value in the range from 0 to approximately 0,3.

6 Aims of multiphase flow measurement

6.1 General

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, owing 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 should be exercised when planning installations that include one or more MPFMs. One of the limitations of multiphase measurement technology is the uncertainty of the measurement. The main source for these higher measurement uncertainties of MPFMs in comparison with single-phase metering systems 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 should 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 (see Annex A and Clause 8). Outputs vary between MPFM designs, e.g. there can be gas, oil, and water mass or volume flow rates, total hydrocarbon mass flow, GVF, WLR, WVF. As there are different designs, calculation routines (slip models) and different outputs, it is not always straightforward to compare MPFMs directly. Different MPFMs are optimized to give minimum uncertainty to different outputs. One MPFM may be optimized to see water breakthrough (for flow assurance requirements) with a relatively poor flow rate prediction. Another may be optimized to predict total hydrocarbon flow to minimum uncertainty (for allocation requirements) with a relatively poor water breakthrough indicator performance. Thus, some MPFMs perform better in certain applications than others. Hence, a careful comparison and selection process is required to determine the optimal MPFM procurement and installation option for each specific application.

In selecting the optimal multiphase flow metering technology for a specific application, it is necessary first to investigate and describe the expected flow regime(s) from the wells to be measured and determine the production envelope (see Clause 7 for more information about production envelopes). Subsequently it should be assessed whether there exist 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 is to use the two-phase flow and composition maps described in this document (see Clause 7).

The next step is to select an MPFM that is capable of continuously measuring the representative phases and volumes within the required uncertainties. The well stream flow rates vary over the lifetime of the well, and it is important to ensure that the MPFM measures within the required uncertainty at all times. Alternatively, the MPFM may be required to be exchanged at some later stage in the production life. This is 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 should 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 (see Clauses 9, 10 and 11). If such periodic verification of the MPFM is not carried out, increased measurement uncertainty should 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 (e.g. tracer methods). The extent of such regular testing depends on the criticality of the application and operation.

There are many possible applications for MPFMs. Owing 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 clauses:

— individual-well surveillance or monitoring;

— production optimization;

— 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.

6.2 Individual-well surveillance or monitoring

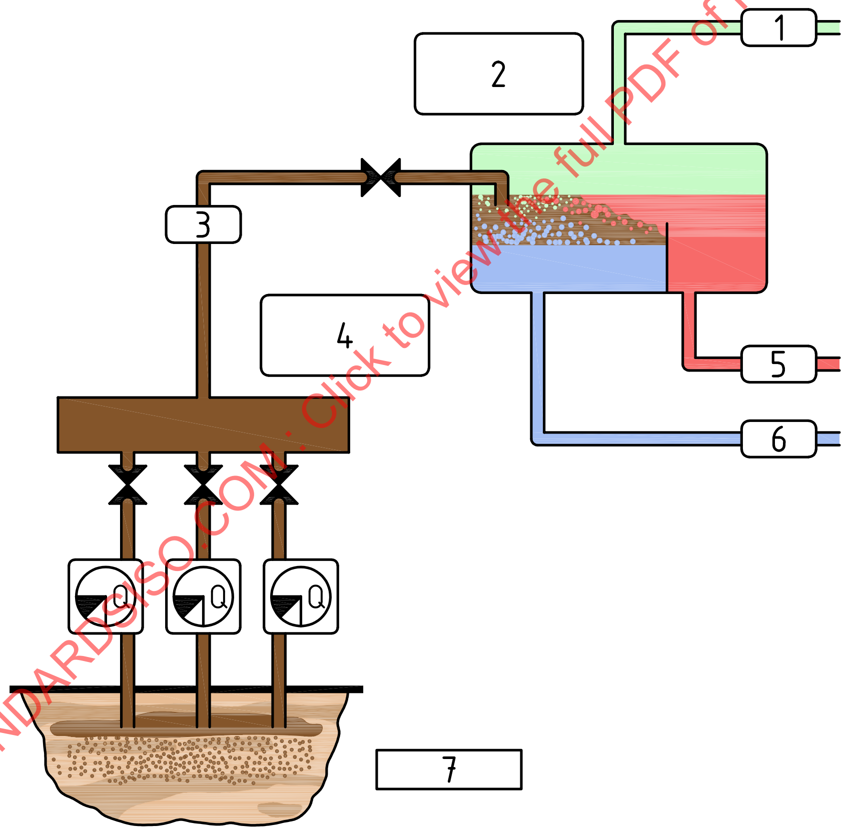
6.2.1 General

Using continuous monitoring with an MPFM, the time resolution of the information is higher than using 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 an 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 with the installation of a new test separator, and it can reduce the time occupation of existing test separators.

Figure 4 shows the use of MPFMs on the flow line of each of a group of wells replacing a test separator and its instrumentation.



Key

1 gas
2 first stage separator
3 multiphase
4 production manifold
5 oil
6 water
7 oil wells

Figure 4 — 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 unstable wells (gas-lifted wells for instance) using conventional separators, and in such situations MPFMs become 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 to monitor flow rate from individual wells or flow lines. It should be noted, however, that retrieval of an MPFM for maintenance or repair may be expensive, difficult or impossible. *In situ* calibration is normally not available, and other, less direct, verification methods may be required to be devised. Reliability and stability of subsea meters are of paramount importance and need to be addressed by the manufacturer of the MPFM, the subsea system integrator and the operator.

6.2.2 Production optimization

Production from oil wells may be assisted by gas lift for several reasons. Once gas lifting has been implemented it is required to optimize 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 a 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 of handling this high GVF operation. Alternatively, a wet-gas meter could be used.

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

6.2.3 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, reproducibility, for a flow assurance type of application, is often more important than absolute accuracy.

6.3 Well testing

6.3.1 General

There is a need to monitor the performance of each individual well in order to optimize well production and the lifetime of the field. For many fields important decisions (e.g. shutting down of wells, drilling of new wells and reducing production rate from the reservoir) are based on well-test results.

Well testing is widely carried out by use of a test separator. An MPFM may be applied as a replacement for, or a supplement to, a test separator if:

— it is decided not to install a test separator in the processing plant;

— there is a need to increase the capacity for well testing, or

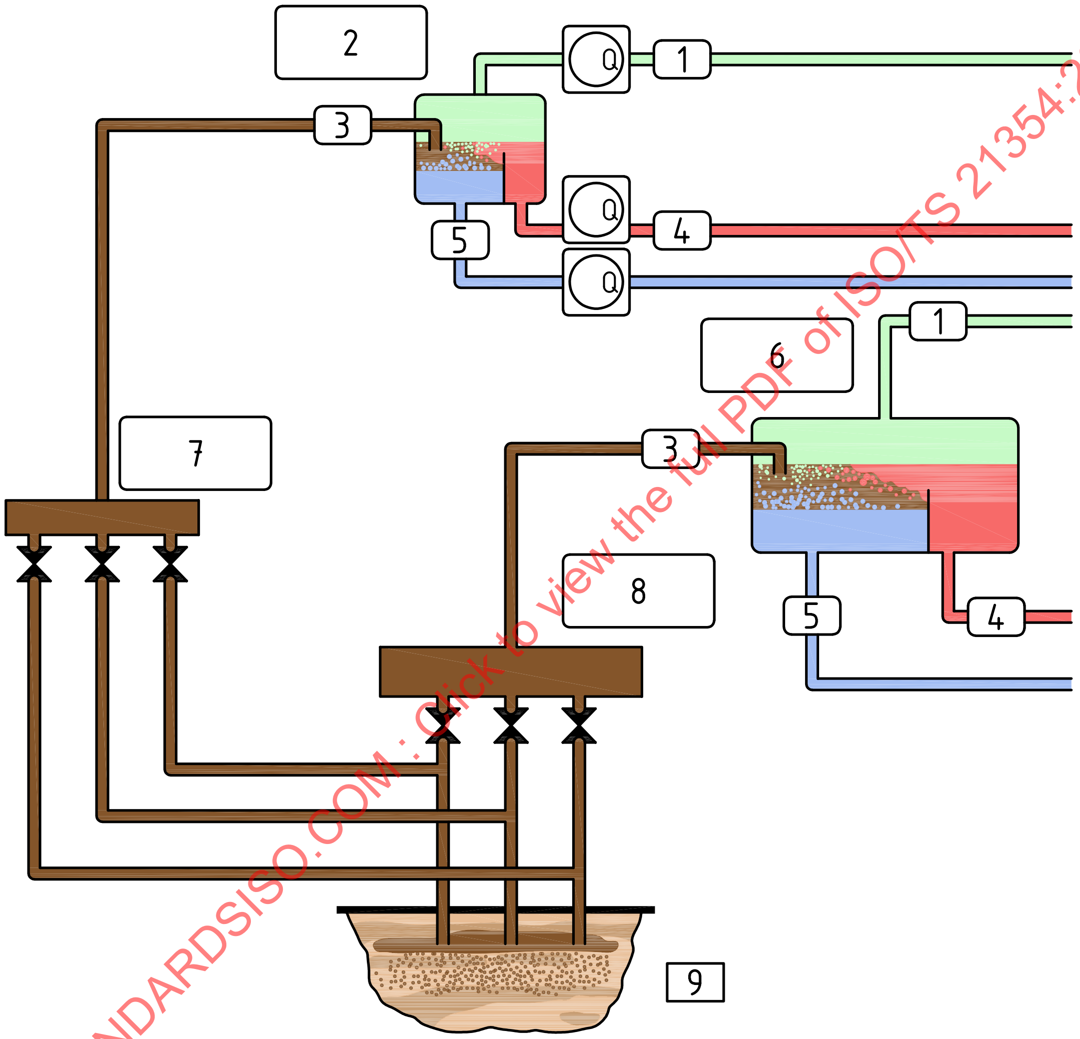
— the test separator is left to other use, e.g. as an ordinary production separator (low pressure).

NOTE A test separator can also be used for purposes other than well testing and hence can be installed in any case.

An MPFM may give a higher or lower uncertainty of the phase flow rates than a test separator system, depending on the application considered. The response time of an MPFM, however, is significantly less (minutes) than that of a separator (hours), and more well tests may be carried out using the MPFM.

6.3.2 Conventional well testing

Conventional well testing is usually performed by means of a test separator. The well streams are measured by directing one well stream at a time through the test separator (see Figure 5). 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.



Key

1 gas
2 test separator
3 multiphase
4 oil
5 water
6 first stage separator
7 test manifold
8 production manifold
9 oil wells

Figure 5 — First-stage production separator and test separator

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

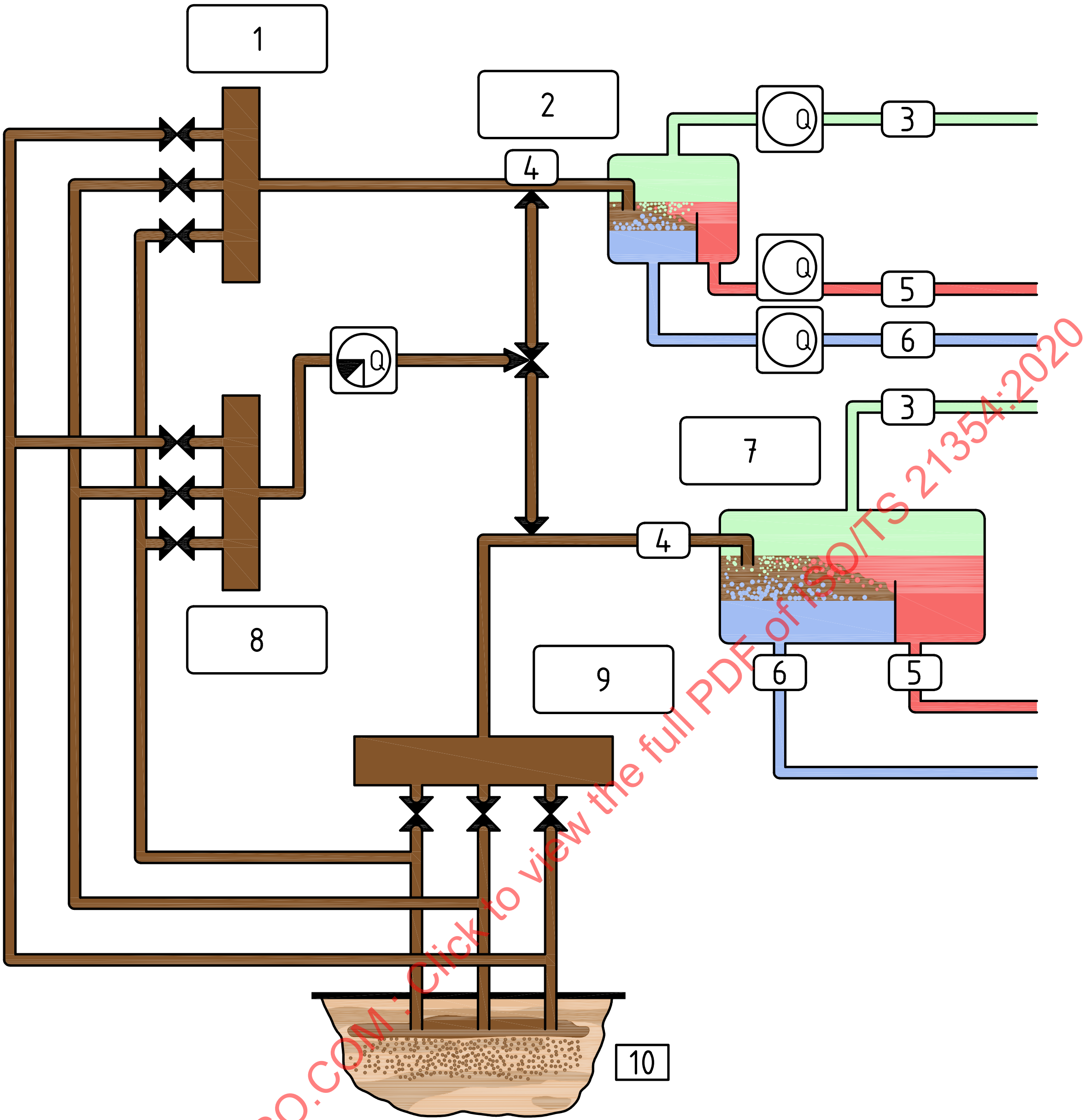
For wells where daily control is needed, for example to keep wells stable or to produce at optimum flow rates in order to utilize the full capacity of the production facilities, this conventional system may not be satisfactory.

6.3.3 Well testing by MPFMs

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

There are two options: either both the test separator and the MPFM are used for well testing to increase the overall testing capacity, or only the MPFM is used for well testing and hence the test separator can be used as a normal production separator and thereby the total production capacity of the processing facility is increased (see Figure 6).

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



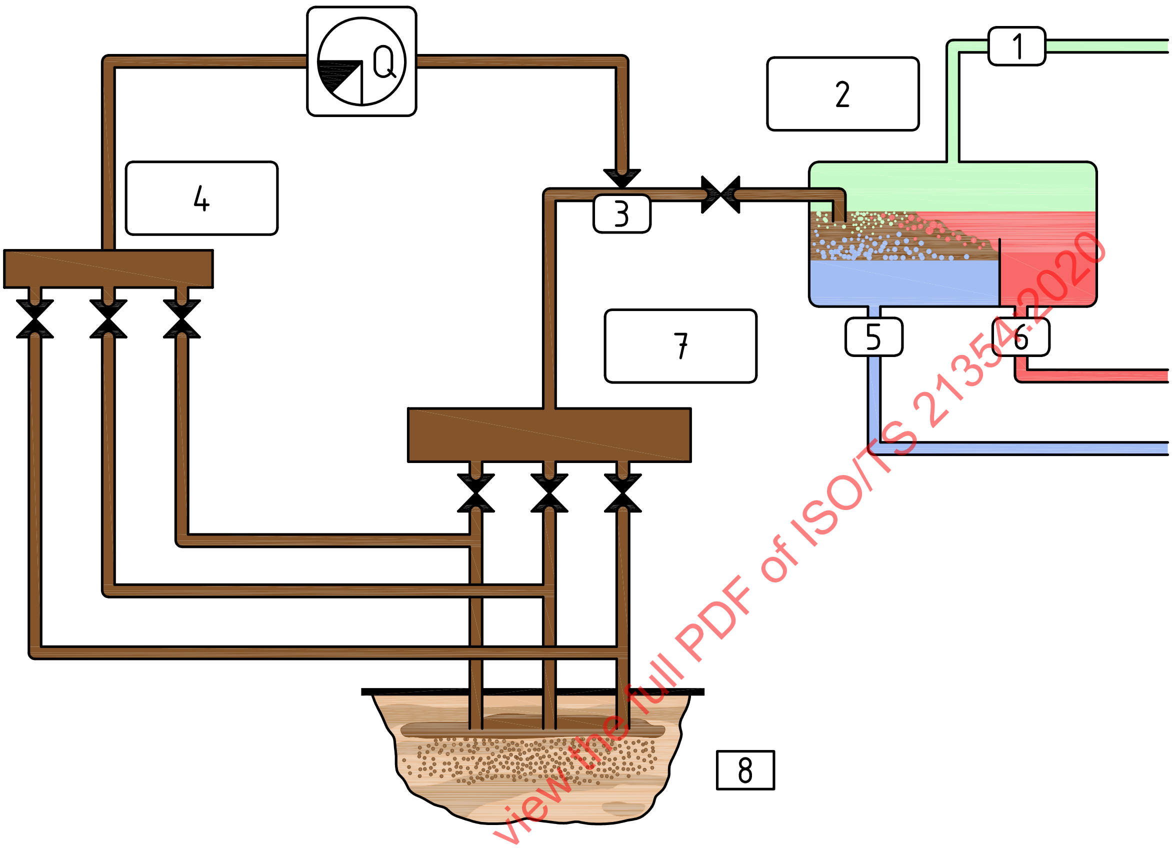
Key

1 test manifold 1
2 test separator
3 gas
4 multiphase
5 oil
6 water
7 first stage separator
8 test manifold 2
9 production manifold
10 oil wells

Figure 6 — Multiphase metering used to increase overall testing capacity

The MPFM might also replace the test separator completely (see Figure 7). 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 Clause 7, it is possible to 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.



Key

1 gas
2 first stage separator
3 multiphase
4 test manifold
5 water
6 oil
7 production manifold
8 oil wells

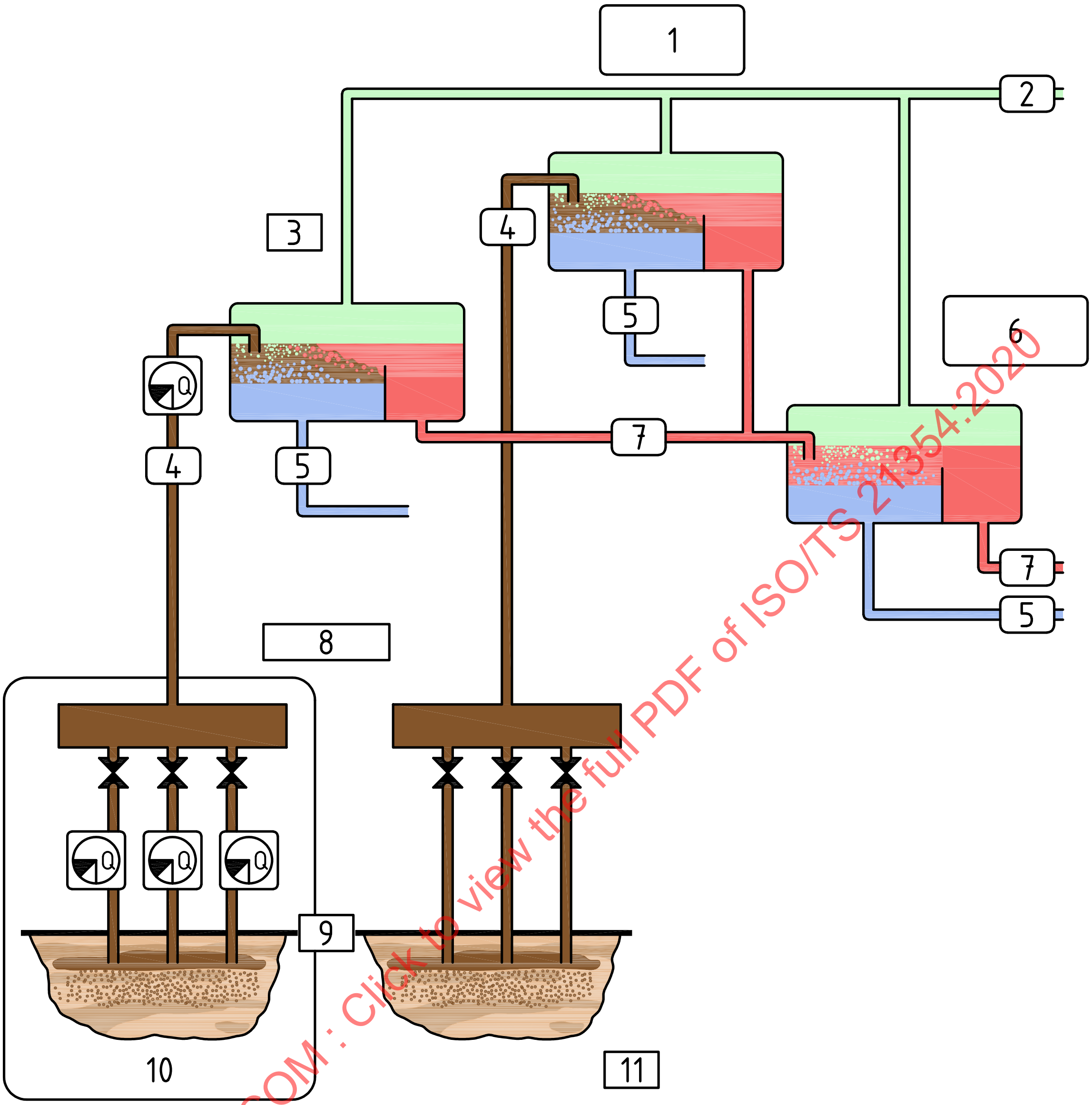
Figure 7 — Multiphase metering replacing test separator and its meters

6.4 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 those required for well testing.

A possible marginal-field solution for an unmanned wellhead platform is to have MPFMs on each individual well for well surveillance and to measure the main tie-in stream (into a manned installation) using 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 minimize uncertainties due to, e.g. slugging, when accumulated oil, water and gas flow rates measured by the MPFM are compared with 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 is replacing the conventional well testing. Moreover, 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 is still needed on the production platform, a typical multiphase production metering concept can be as shown in Figure 8. An example of a guidance note for such an application can be found in Reference [46].



Key

1 first stage separator
2 gas
3 inlet separator
4 multiphase
5 water
6 second stage separator
7 oil
8 production manifolds
9 oil wells
10 satellite field B
11 field A

Figure 8 — Satellite field B with MPFMs for well testing and production metering

6.5 Fiscal or custody transfer measurement

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

The metering of production from each licence area is used to allocate the total commingled production, metered from the outlet of the common processing facility, back to each licence area. Consequently national regulations or guidance notes for petroleum measurements govern this production metering. Other optimization considerations can be made for chemical injection (e.g. methanol, demulsifier), gas-lift optimization, gas-coning detection and water-breakthrough detection.

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 results in a systematic error in the money flow. Hence, it is of paramount importance that sufficient verification processes are included (see Clause 11). Note that the classification 'fiscal or custody transfer' does not specify any uncertainty requirement; it just describes the purpose of the meter. The uncertainty requirements should be further negotiated.

NOTE For fiscal MPFMs, the government authorities give regulations and guidelines.

6.6 Summary of advantages and disadvantages of MPFMs

A multiphase flow measurement system for well testing and production metering has the main capabilities and limitations shown in Table 3.

Table 3 — Main capabilities and limitations of MPFMs

Capabilities of MPFMs	Limitations of MPFMs
Continuous metering is possible.	MPFMs are relatively new instruments and sometimes complex systems that require, like any advanced metering system, specific training to be operated according to specifications.
Installation and operating costs are low compared with those of a conventional system.	MPFMs are sensitive to fluid property inputs.
The footprint is reduced.	Verification is recommended. For allocation metering systems periodic verification is normally required.
Given the possibility of continuous metering, the total uncertainty may be lower than in a conventional system.	
Increased safety of the installation as an MPFM is a flow-through device (no pressure or energy can be stored) and has a much reduced number of leak paths.	

7 Production envelope and installation design guidelines

7.1 General

This clause presents 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 (oil flow rate plus water flow rate) is plotted against gas flow rate, whereas in the composition map GVF is plotted against WLR.

These two maps provide convenient ways of plotting the predicted well production over the field lifetime, the production envelope, which is due to be measured in a specific application. The measuring range of an MPFM, the measuring envelope, can then be plotted on the same maps, overlying the production envelope. This method for design of MPFM installations is described in more detail in 7.2 and 7.3.

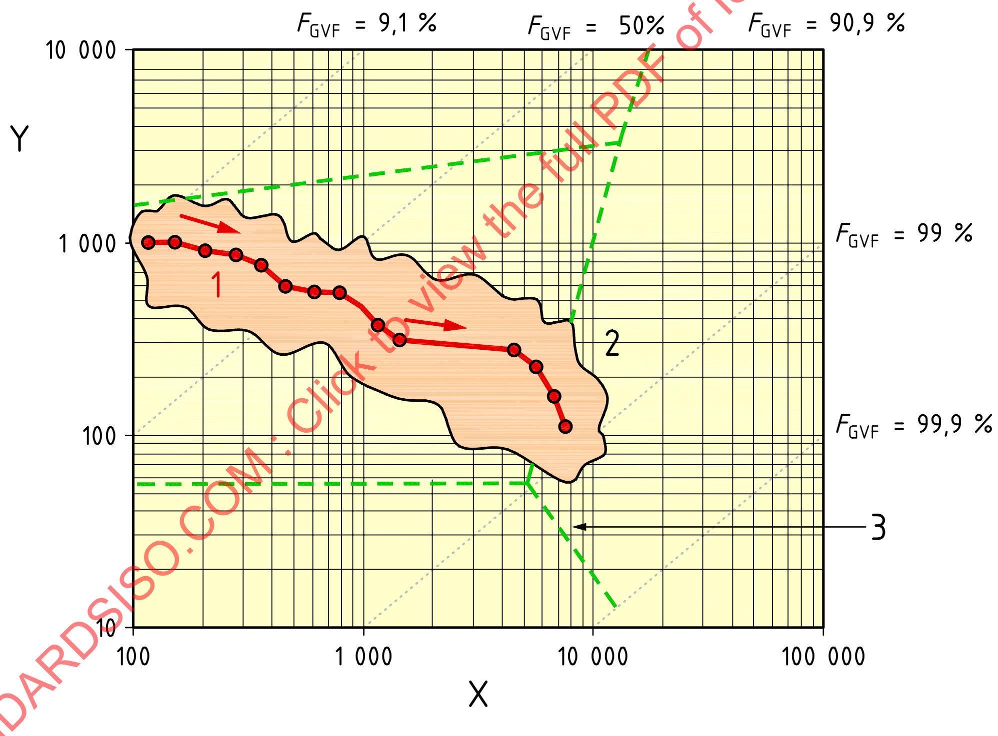
7.2 Production envelope

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

The two-phase flow regime maps, as presented in Clause 5, are very general ones and use the superficial gas velocity along the x-axis and superficial liquid velocity along the y-axis. The superficial velocities are dependent on the actual flow rate of either phase and the cross-sectional area of the pipe. A more practical and convenient presentation is where the superficial velocities are converted to actual flow rates, i.e. along the x- and y-axes the actual gas and liquid flow rates, respectively, in m^3/d are now plotted.

Further convenience can be achieved if logarithmic scales are used. Compared with linear scales this has the advantage that the measuring envelopes of MPFMs of different sizes have equal cross-sectional areas in the two-phase flow map and that uncertainty bands (or deviations in test programmes) 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 for an example). The actual boundaries between flow regimes are not as sharp as is indicated in Figure 9. Apart from the pipe diameter used, these boundaries also depend on density, viscosity, surface tension, pressure and geometry.



Key

X gas flow rate (m^3/d) at actual conditions

Y liquid flow rate (m^3/d)

1 uncertainty in prediction

2 wet-gas area

3 approximate boundaries between flow regimes

Figure 9 — Two-phase flow map that can be used to plot the trajectory of wells (production envelope) and the measurement envelope of an MPFM

Gas and liquid flow rates of wells can be plotted on this flow map, and over time the wells follow a certain trajectory, i.e. both the liquid and gas flow rates 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. These minimum and maximum flow rates are indicators of the time history of the well production where, for example, new oil wells are characterized by lower gas flow rates and higher liquid flow rates probably with a lower WLR. Note that the unit used is actual m^3/d, i.e. the volumetric flow rate at the pressure and temperature at which the meter operates.

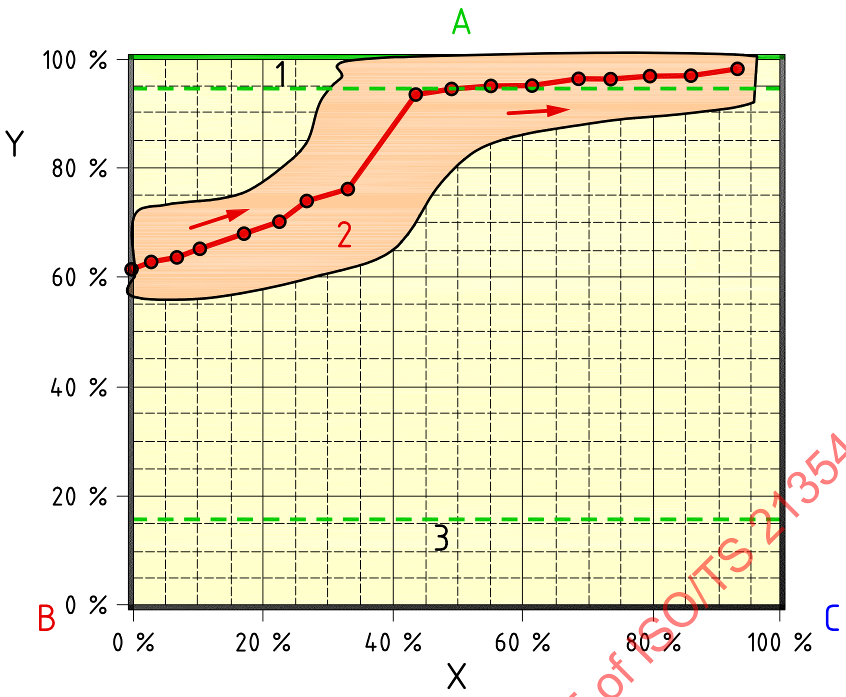
As these trajectories are often based on very preliminary information from reservoir engineers, there is uncertainty attached to these trajectories and it is recommended that these uncertainty ranges are also shown in the two-phase flow maps. Either this uncertainty can be plotted as an area or uncertainty crosses can be used for each point. As explained in 7.3, multiphase flow meters have measuring envelopes and it is obvious that the production envelope and the measuring envelopes should have reasonably good overlaps. This is the first step in the selection of a suitable multiphase meter for a particular application.

7.2.2 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 (F_{GVF} = 100 %) represents the gas phase, the left bottom corner (F_{GVF} = 0 %, F_{WLR} = 0 %) and the right bottom corner (F_{GVF} = 0 %, F_{WLR} = 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 a well trajectory in the composition map can also 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 7.3.2) and obviously the two envelopes should overlap. An example of a well trajectory in the composition map is given in Figure 10.



Key

X F_{WLR} (%)

Y F_{GVF} (%) at actual conditions

1 wet-gas area

2 uncertainty in prediction

3 gassy liquid

A gas

B oil

C water

NOTE The largest uncertainties in liquid and oil flow rate occur at the high GVF applications. Here often (partial) separation results in improved performance.

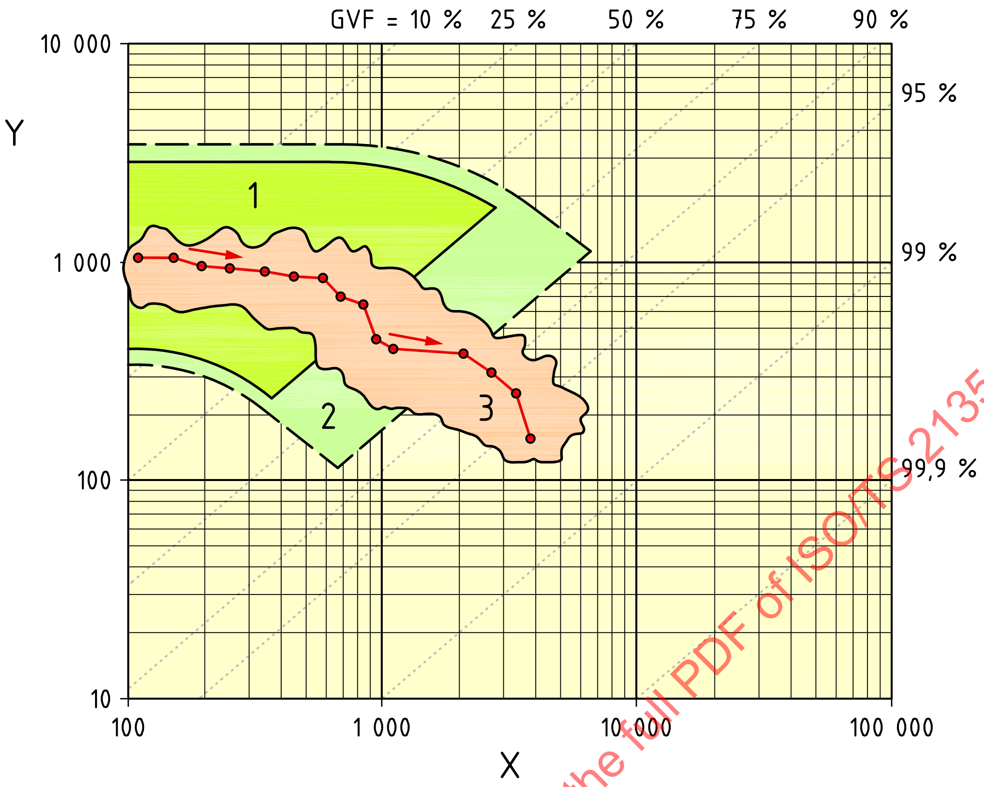
Figure 10 — Well trajectory in the composition map

In this example, a large increase in GVF (from 75 % to 95 %) is noticed which is due to the introduction of gas lift during later field life. Again, the uncertainty in the reservoir engineering data should also 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.

7.3 MPFM measuring envelope

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

In general, MPFMs have measuring envelopes that are specified by the vendor. However, in some cases, the vendors also provide measuring envelopes that best suit the end user's requirements. Often the minimum and maximum gas and liquid flow rates are given, and uncertainties in liquid flow rate, gas flow rate and WLR are specified as a function of GVF. Like the production envelopes, the MPFM measuring envelopes can be plotted on the two-phase flow map, and, if various uncertainties are quoted, it is possible to plot various measuring envelopes, one for each set of uncertainty statements. In Figure 11 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 should be used over the field lifetime (with different measurement uncertainties).



Key

X gas flow rate (m^3/d) at actual conditions

Y liquid flow rate (m^3/d)

1 uncertainty: 5 % liquid (total oil and water), 10 % gas

2 uncertainty: 10 % liquid (total oil and water), 10 % gas

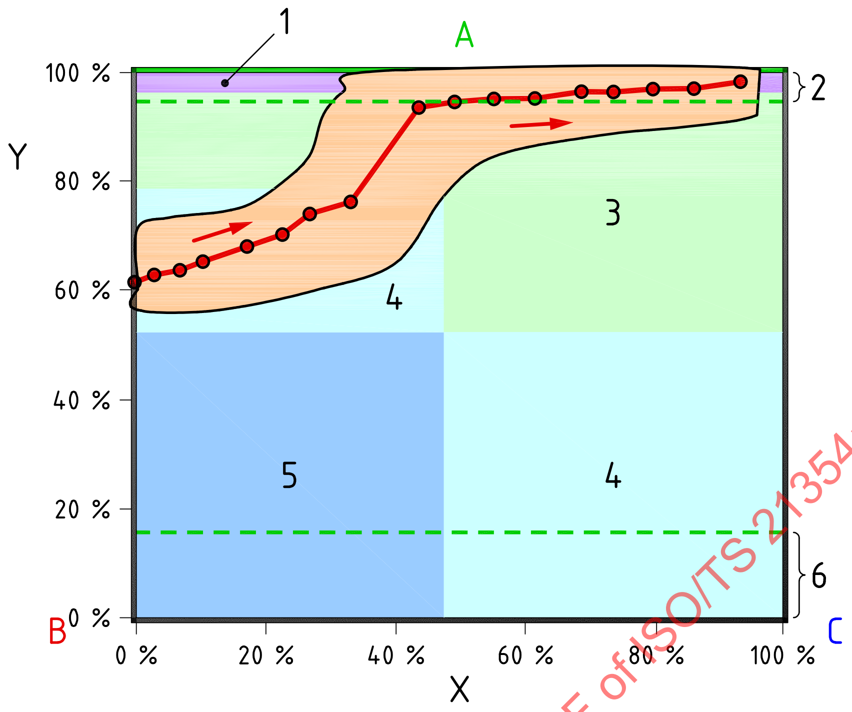
3 uncertainty in production stream profile

Figure 11 — Example of an MPFM measuring envelope plotted together with a production stream profile 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). Gas field operations are generally situated on the bottom right side of the flow map, i.e. the wet-gas region.

7.3.2 Plotting the MPFM measuring envelope in the composition map

In a similar manner to plotting the measuring envelope in the two-phase flow map, a measuring envelope in the composition map may be plotted as well (an example is given in Figure 12). Generally, MPFMs cover the entire range of 0 % – 100 % of WLR and 0 % – 100 % of GVF, but the uncertainty specifications are often given as a function of the WLR and GVF. In particular, at high GVF the uncertainties in the liquid flow rates will deteriorate.



Key

X F_{WLR} (%)
Y F_{GVF} (%) at actual conditions
1 F_{WLR} uncertainty >10 % absolute
2 wet-gas area
3 F_{WLR} uncertainty: 7,5 % absolute
4 F_{WLR} uncertainty: 5 % absolute
5 F_{WLR} uncertainty: 2,5 % absolute
6 gassy liquid
A gas
B oil
C water

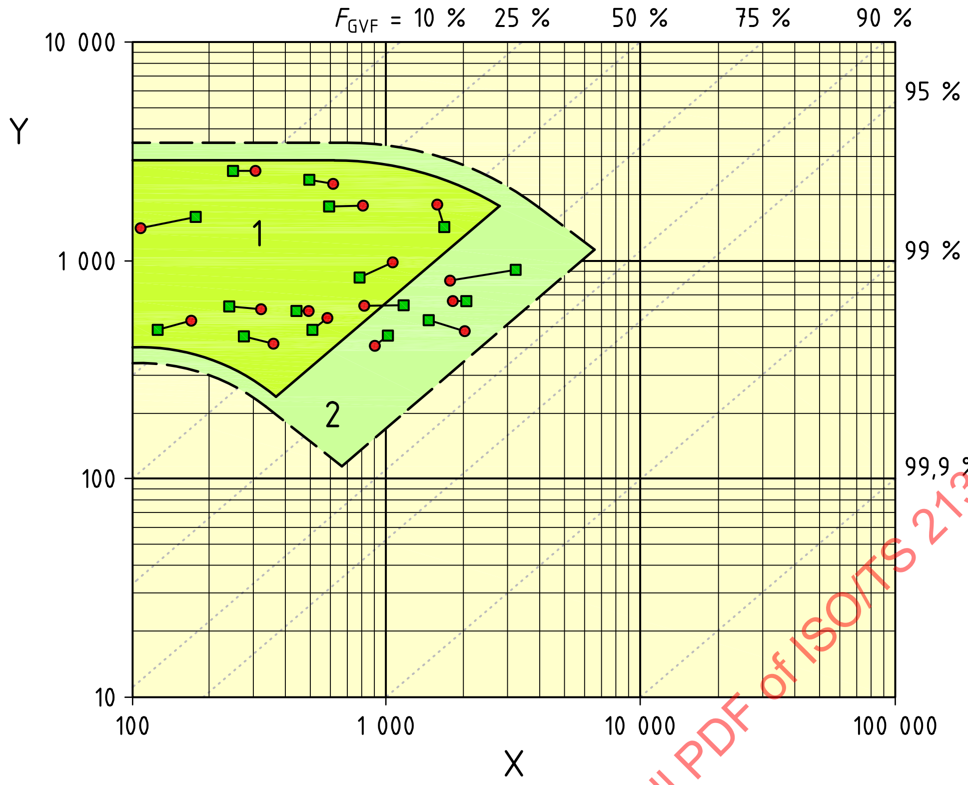
NOTE The uncertainties shown in this step-wise manner are a guide, and a more detailed and complicated statement of uncertainty can be given.

Figure 12 — Example of an MPFM measuring envelope plotted together with the production envelope in the two-phase composition map

7.4 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 convenient. Both the reference measurements and the MPFM measurements can be plotted on the two-phase flow map (see Figure 13 for an example) and the composition map (see Figure 14), and by connecting these two points with a single line the test point is represented.

In Figure 13 the directions of the lines indicate whether deviations from the reference 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 the same length for a certain relative deviation in the entire map). Since the reference measurements are key in quantifying the performance of the MPFMs, the data must be traceable.



Key

X gas flow rate (m^3/d) at actual conditions

Y liquid flow rate (m^3/d)

■ reference

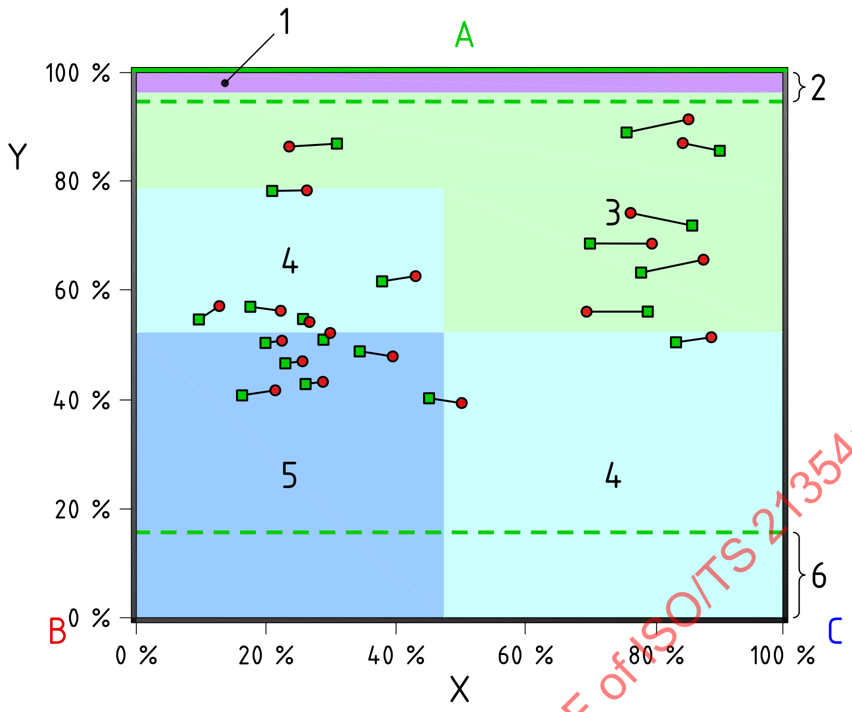
● MPFM

1 uncertainty: 5 % liquid (total oil and water), 10 % gas

2 uncertainty: 10 % liquid (total oil and water), 10 % gas

Figure 13 — Test results for an MPFM plotted in the two-phase flow map

Measurement deviations in MPFMs are often systematic because of partially correct/optimized 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 points now indicates an absolute deviation between the reference and MPFM (see Figure 14 for an example).



Key

X F_{WLR} (%)
Y F_{GVF} (%) at actual conditions
reference
MPFM
1 F_{WLR} uncertainty: >10 % absolute
2 wet-gas area
3 F_{WLR} uncertainty: 7,5 % absolute
4 F_{WLR} uncertainty: 5 % absolute
5 F_{WLR} uncertainty: 2,5 % absolute
6 gassy liquid
A gas
B oil
C water

Figure 14 — Test results for an MPFM plotted in the composition map

7.5 Cumulative performance plot

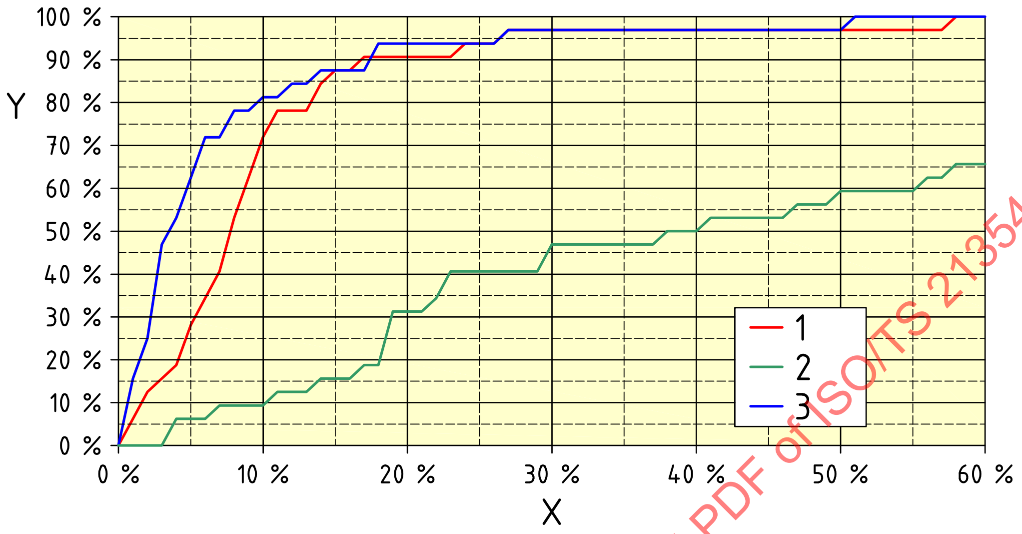
With sufficient test points in an evaluation program, it is possible to make cumulative performance plots. These plots can be conveniently used to compare the performance of various MPFMs.

An example is given in Figure 15, 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 criterion: approximately 70 % of all test points show deviations of 10 % or less in liquid flow rate, approximately 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, e.g. one plot for GVF between

0 % and 30 %, one for GVF between 30 % and 90 %, one for GVF between 90 % and 96 % and one for GVF above 96 %.

Cumulative plots for MPFM performance deviations can also be made in the same manner for deviations in oil flow rate and water flow rate. These flow rates and the gas flow rate are the main quantities of interest to the end users of the measurement data. Net oil and water flow rate performance test deviation data may show a larger proportion of higher deviations from reference than for bulk liquid.



Key

X deviation (%)

Y cumulative (% of test points)

1 liquid flow rate

2 gas flow rate

3 water liquid ratio

Figure 15 — Example of a cumulative performance plot

7.6 Other considerations

A number of other considerations should also be included when designing an MPFM installation; see Table 4.

Table 4 — Check-list for some other important considerations to keep in mind when designing MPFM installations

Subject	What to consider
High or low ambient temperatures?	Notice that operation of an MPFM in very 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 instruments resistant to H_2S and chemicals used for hydrate prevention and scale inhibition? Are the 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, which could cause significant excursions out of range. Users should estimate and allow an appropriate margin in terms of possible flow rates.

Table 4 *(continued)*

Subject	What to consider
Changes in fluid properties	Changes in fluid properties require sampling of the fluids for laboratory analysis and a subsequent update of the fluid data in the MPFM flow computer. Hence, sensitivity to expected fluid property changes at the specific installation should be considered, and facilities and routine for measuring and tracking fluid properties with time should be included in the design. The multiphase fluid properties measured by the MPFM system can change over the years either because it is not always used with the same wells or because some injection techniques are put in place at a later production stage to enhance the oil recovery, thus modifying the fluids composition in each well (water produced or oil/gas produced). These changes could increase the MPFM measurement uncertainties depending on which measurement technology is selected. If the impact of these changes is large then some means to decrease this risk should be implemented (additional sensors, calibration or configuration update frequency...).
Fluid properties and flow regimes	As described in the previous parts of this document, the multiphase flow can be complex and different flow regimes can be observed (slug flow/mist flow...). In addition, the fluid mixture can result in complex forms (like foam or emulsion) that can have some properties that are not well characterized and may affect the performance of the MPFM measuring system. Information on the fluid mixture and flow regime, if available, should be considered in the design of the MPFM installation to ensure the selection of the most appropriate measurement technique and set-up. Viscosity may be difficult to predict accurately for foams and emulsions. For emulsions, the bulk liquid viscosity can peak sharply as a function of WLR, in some cases by orders of magnitude.
Space and mechanical installation	Space can be a strong constraint, particularly on offshore platforms. Inline meters are generally easier to integrate into the fluid processing facility; however, the following points can influence the space required: — MPFM system orientation (vertical or horizontal assembly and also the position of the sensors versus the flow direction); — the dimensions of the MPFM system (height, length and width); — installation guidelines from vendor for optimum performance (upstream or downstream straight length, specific flow conditioning, upstream or downstream height, sampling, injection and bleed-off ports); — installation recommendations from vendor for the commissioning and the maintenance of the equipment; — some space may also be required for the periodic verification of the MPFM system with another flow measurement device. The verification strategy should be established to define the space required. The MPFM may be mounted with a by-pass to allow maintenance without production shutdown.
Pressure drop	The pressure drops created by the MPFM installation depend on the technology selected, the complexity of the piping lay-out, the viscosity of the fluids, the operating pressure and the flow rates. Pressure drops can be minimized by a proper sizing of the equipment. A sizing study is generally required based on estimated production of the well(s) flowing through the MPFM system.
Hydrate, scale or wax deposits	The MPFM's ability to tolerate hydrate, scale or wax should be evaluated, and also its susceptibility to the chemicals that might be used to prevent the formation of these on a regular basis, or as part of a programme to clean the pipelines and meter internals for such deposits. Scaling, wax or asphaltene deposits can occur in some applications depending on the produced fluids' composition and flow characteristics. A prevention/mitigation plan may be put in place (heat tracing, maintenance plan...). Some deposits or particles can also plug the sampling valves or the pressure impulse tubing. The risk and its consequences should be assessed and some solutions evaluated (port location, remote seals, maintenance frequency...).

Table 4 *(continued)*

Subject	What to consider
Method of verification during operation	The method of verification of the multiphase meter during operation should already be considered at the design stage. This ensures that any special facilities, e.g. bypass, isolation valves, sampling points, or other, required for the selected method of verification are in place (see also Clause 11).
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 manufacturer’s assistance at remote or offshore sites may be expensive and disrupt MPFM operation.
Nucleonic instrumentation requirements	Installation and use of nucleonic devices in industrial plants is subject to rigorous regulations, from authorities and operator, requiring careful and consistent handling, formally and physically.
Spare parts	Does the vendor have spare parts on the shelf, or are spare parts 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 an MPFM and credibility of meter readings depends on calibration/verification methods. See 9.3.
Corrosion and erosion	Can the MPFM take some wear and tear from abrasive particles and chemical attack in the flow? Are there aspects of technical safety? How is MPFM performance affected? Do flow regimes (e.g. mist, stratified or slug flows) affect the erosion and corrosion risk?
Remote access	Can the MPFM be accessed remotely? Are there sufficient communication ports available to serve communication to plant control system, information system, intelligent device management system, metering control system, local PC 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 the company network?
Fluids	What test fluids are required during factory set-up and laboratory testing and calibration, and are they available and acceptable to the laboratory? In the installation can methanol or other service fluid be used safely and easily for flushing?
Impulse lines	Can MPFM pressure impulse lines become filled with multiphase fluid and can this cause error in differential transmitter lines? Can hydrates form in impulse lines? Is routine purging required or can remote transmitter seals and lines filled with suitable hydraulic fluid be installed?
Accessibility	During installation and commissioning or during a maintenance event some space is required around the system and should be planned during the design of the installation. Specific attention should be paid to: — lifting of heavy parts (such as valves); — opening of the cabinet’s doors; — access to sampling, injection or bleed-off ports; — clearance for tools. In a vertical multiphase flow measurement configuration (which is very common), a blind T on top of the system may be used as an access port to test the system or make some reference measurements possible. Depending on the height of the location of this port, a specific platform could be required.

Table 4 *(continued)*

Subject	What to consider
Environmental constraints	Extreme ambient temperature conditions may require specific considerations in the design of the installations. Additional features could be implemented to protect the equipment from these effects such as thermal insulation, heat tracing and shelters. Harsh weather conditions such as sand storms or marine atmosphere could affect the ageing of the equipment and should be considered when designing the protection of the MPFM installations (shelter), specific ingress protection or components' material selection.
Communication and wiring lay-out	An MPFM can be operated in stand-alone mode (memory) or connected to a communication network (typically SCADA). The number of communication ports and which communication protocol is used should be considered in the design of the communication infrastructure including the distance between the communication modules and the cable selection. Another element to focus on during the cabling and wiring installation is grounding and earthing of electrical equipment as well as the shielding of the communication cables to prevent electromagnetic noise from disturbing the signal.
Vendor's specific requirements	Installation requirements may be specific to some equipment (e.g. some systems may be using pneumatic actuators and need an air supply, or some equipment requires straight length upstream of the metering system). The vendor's requirements should be taken into consideration in the installation design.
Power requirements	Is sufficient power available?
Over-determination	Is there sufficient redundancy to make allowance for the possibility of failure of components?
Physical properties	What fluid properties are required?
Inputs	What metering system inputs are required and how can they be obtained?

The list of requirements to comply with (described above) is not exhaustive and can be extended to include additional requirements from local regulations or from client-specific standards or guidelines for piping and instrumentation installations.

8 Performance specification

8.1 General

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 standardized 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 standardized performance specifications will help users compare MPFMs proposed from different manufacturers for specific applications.

Clause 8 does not provide specific numerical targets for performance, as they may vary significantly between applications and depend on the importance of the measurements, but a guideline is provided 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 parameters such as: rated operating conditions, limiting conditions, component performances (performance of primary measurement devices such as pressure and temperature transmitters), sensitivities, influence factors, stability and repeatability. These parameters should 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 ISO 11631:1998, which describes methods of specifying flow meter performances in general terms. ISO 11631:1998 includes some general definitions and key principles which should also be applied to MPFMs.

In addition to measurement performance considerations there are other important factors such as mechanical design, functional reliability and system compatibility which should be accounted for in meter design and selection. These considerations are outside the scope of this document.

8.2 Technical description

Because of the complexity of multiphase flow metering systems, manufacturers should provide clear technical descriptions of their MPFMs as part of the performance specification. This is an important 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 and primary measurement devices such as sensors, transmitters, software and 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 bulk or total flow element employed, phase fraction or compositional sensors, flow stream conditioning and flow regime computational modelling approaches);

— description of configuration parameters and required input data (such as fluid properties).

8.3 Specification of individual sensors and primary devices

A multiphase flow metering system relies on a number of individual sensors and transmitters that each directly influences the overall quality of the measurements. Detailed descriptions of the individual sensors and primary devices and their measurands, measuring ranges, limiting conditions of use, diagnostic output parameters, repeatability, hysteresis and drift characteristics 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 or other nucleonic and electromagnetic instrumentation;

— electrical sensors such as capacitance, conductance and microwave systems;

— densitometers;

— analysers.

These descriptions should be accompanied by a full description of the calibration process and requirements for each type of instrument.

8.4 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 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 as a minimum:

— oil, water and gas flow rates (volume and/or mass);

— phase volume fractions (WLR, GVF);

— pressure and temperature.

These outputs are typically available as time-series signals and as averages over user-selectable periods. Some MPFMs may also provide other operational information, for example, indication of:

— the presence of formation or injection water;

— deposits affecting readings;

— inhibitor chemical.

Raw data from MPFM sensors such as permittivity, capacitance, conductance, conductivity, gamma attenuation, optical absorbance and differential pressure should be made available to users for verification and operation of multiphase metering systems.

8.5 Measuring range, rated operating conditions and limiting conditions

The performance specification should include information about measuring range, rated operating conditions and limiting conditions (for definitions see 3.2).

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 shown in Table 8. In addition, a list of compatible or non-compatible chemicals such as those used for scale, wax, hydrate and corrosion inhibition, and clean-up, and service fluids, such as those typically used for pressure leakage tests and flushing, should also be included as part of the ″rated operating conditions″. Compatibility should also be ensured with substances like H_2S, Hg and naturally occurring radioactive material (NORM) or tracers and any others that can influence sensor response if these are present in the production streams.

The measuring range and limiting conditions of an MPFM can also be described as measuring and limiting envelopes which can be plotted in two-phase flow and phase fraction or composition maps, as presented in Clause 7. This enables ready comparison with predicted production flow rate envelopes.

8.6 Measurement uncertainty

8.6.1 General

In order to use an MPFM in a specific application, the meter should be evaluated with respect to combined expanded measurement uncertainty for the various measurements it will perform.

Such an uncertainty evaluation should include the uncertainties of the parameters configured as input to the MPFM and of the functional relationships used as well as the uncertainties of the component instrumentation. 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/IEC Guide 98-3:2008.

The uncertainty of MPFMs should be specified using terms that are in conformance with “International Vocabulary of Metrology — Basic and General Concepts and Associated Terms (VIM)” issued by JCGM (2012)[12]. Other standards based on the above document may also be used. Some definitions that may be particularly relevant to multiphase flow measurement are given (or form part of the definitions) in 3.2.

The credibility of, and degree of effort to be applied to, such uncertainty evaluation should be assessed and judged on the basis of scientifically sound and transparently acquired, realistic flow test evidence to back assertions regarding measurement performance for a particular meter technology design, system implementation and size. See Clause 9 for guidance on flow testing.

8.6.2 Measurement uncertainty evaluation of MPFMs

Since MPFMs are complex, sophisticated systems consisting of a number of subsystems and primary devices that are closely integrated, a full and complete quantitative theoretical uncertainty evaluation may not be practical or credible.

Fundamentally, any flow models and assumptions on which an MPFM technology relies to translate the component instrument readings to phase flow rates are susceptible to the variability of the flow regime behaviour in and between different production streams, which can be difficult to predict. Fluid behaviour in service is not fully reproduced in laboratory flow testing nor necessarily in prior field testing: these testing methods are typically the basis for the empirical models. Sole reliance on a complete quantitative uncertainty evaluation is insufficient.

The uncertainty evaluation should also take account of measurement results from independent flow tests. These should be conducted using facilities meeting the requirements of ISO/IEC 17025 (or equivalent) and operated by a non-conflicted third party, to a transparent, controlled protocol. Independent flow tests should replicate relevant deployment conditions and field set-up as closely as possible. No special adjustment or additional testing is allowed before, during or after the performance test that would not occur in tests specified when a meter is purchased and operated in the field. This should enable the estimation, documentation and acceptance of the meter measurement uncertainties for various relevant flow conditions and regimes; see Reference [15].

Clause 7 describes graphical tools, including the two-phase flow and composition map representations, which provide alternative ways of presenting measuring ranges and measurement uncertainties. These graphs may be helpful in addition to 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.

8.6.3 Influence quantities and sensitivity coefficients

In support of quantitative uncertainty estimates, it is recommended that analysis of influence quantities is undertaken. Influence quantities are quantities that are not measurands, but affect the result of the measurement. Examples of factors that can influence MPFMs are:

— flow regimes;

— additives, e.g. emulsifiers, wax inhibitors, corrosion inhibitors;

— MEG (mono-ethylene glycol)/ DEG (di-ethylene glycol)/ TEG (tri-ethylene glycol);

— methanol;

— scaling / wax / hydrates;

— pressure loss and gas evolution;

— vibrations;

— fluid properties (e.g. water salinity and conductivity, oil permittivity, phase densities and viscosities, elemental composition);

— H_2S;

— ambient temperature and pressure variations;

— sand;

— installation effects, upstream straight lengths, bends;

— EMC noise.

To determine how the main influence quantities affect the measurements, sensitivity coefficients should be estimated.

A specific sensitivity study can be performed (within defined input parameters) to describe how the measurement output varies with changes in the values of critical influence quantities, and should be undertaken 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 percentage variation of the indicated WLR per percentage change in salt content in various defined operating conditions.

8.6.4 Repeatability

The repeatability of a meter 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.

8.6.5 Stability and frequency response

Since MPFMs can be exposed to, and used to follow, continuously rapid variations in flow conditions, flow rates and flow regimes or for unattended applications, including remote installations and subsea, time-series flow measurement outputs can be useful operationally and specified as well as averaged production rate reporting.

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

— the response time and signal sampling interval to track variations in flow regimes and conditions;

— the response time to track variations in fluid properties;

— the measurement duration, i.e. averaging period to determine phase flow rates;

— the drift in readings with time.

8.7 Guideline on MPFM performance specification

8.7.1 General

Subclause 8.7 provides a brief guideline on MPFM performance specification. It provides a suggested format for specifying the performance of MPFMs that vendors may use when quoting for specific applications.

An MPFM performance specification should include the following items:

— technical descriptions;

— specification of required input data;

— specification of output data;

— rated operating conditions;

— measurement uncertainty;

— two-phase flow map: measuring and limiting envelopes;

— composition map: measuring and limiting envelopes.

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

8.7.2 Technical descriptions

Reference is made to 8.2 and Table 5. The technical descriptions may also include references to relevant documentation containing the detail of the specifications.

Table 5 — 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 and primary measurement devices		
4	Description of configuration parameters and required input data		

8.7.3 Specification of input data

MPFMs typically require some a priori information on fluid properties. Some example input parameters are listed in Table 6. The actual configuration parameters required are technology-specific.

Table 6 — 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	mPa·s

8.7.4 Specification of output data

Reference is made to 8.4. Table 7 illustrates a simple sample format for specifying typical outputs from an MPFM at actual conditions.

Table 7 — Specification of typical output data

Output parameters	Unit
Volume flow rate per phase	am^3/h
Accumulated volume per phase	am^3
Phase density	kg/m^3
WLR	%
GVF	%
Temperature	°C
Pressure	bar

MPFMs provide phase quantity outputs at actual conditions, but most MPFMs can also give outputs at standard conditions. In that case, the methodology and PVT or equation-of-state (EOS) models used as inputs to configure the meter to convert phase flow rate outputs from actual to standard conditions should be specified and agreed between the user and the vendor.

8.7.5 Rated operating conditions and limiting conditions

As an example, in reference to 8.5, Table 8 shows typical parameters for the 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 might not be applicable to all meters and that other parameters not listed here might be relevant to some meter types.

Table 8 — 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
WLR	%	%	%	%
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

Table 8 *(continued)*

Substances	Compatible (yes/no)	Maximum concentration		Maximum concentration
H_2S		ppm		ppm
Hg		ppm		ppm
MEG		ppm		ppm
DEG		ppm		ppm
TEG		ppm		ppm
Demulsifier		ppm		ppm
Sand		kg per m^3 fluid		kg per m^3 fluid
Corrosion inhibitor		ppm		ppm
Scale inhibitor		ppm		ppm

8.7.6 Measurement uncertainty

Reference is made to 8.6, where parameters to be specified, such as shown in Tables 9 and 10, are described in more detail. No numbers are given here except possible ranges of GVF and WLR because the uncertainties depend on the technology and the application. The uncertainties should be given at particular line conditions.

Table 9 — Specification of measurement uncertainty

Confidence level:	**95 % (k = 2)**		**Combined expanded uncertainties**		
Summary specification					
	F_{GVF} **range [%]**	**Total volume flow rate turndown**	**Average gas (% relative)**	**Average liquid[a] (% relative)**	**Average F_{WLR} (% absolute)**
10 % F_{WLR}	0 to 15	x: 1	y_{gas}	y_{liquid}	w
	15 to 85	x: 1	y_{gas}	y_{liquid}	w
	85 to 95	x: 1	y_{gas}	y_{liquid}	w
	95 to 98	x: 1	y_{gas}	y_{liquid}	w
	98 to 100	x: 1	y_{gas}	y_{liquid}	w
50 % F_{WLR}	0 to 15	x: 1	y_{gas}	y_{liquid}	w
	15 to 85	x: 1	y_{gas}	y_{liquid}	w
	85 to 95	x: 1	y_{gas}	y_{liquid}	w
	95 to 98	x: 1	y_{gas}	y_{liquid}	w
	98 to 100	x: 1	y_{gas}	y_{liquid}	w
90 % F_{WLR}	0 to 15	x: 1	y_{gas}	y_{liquid}	w
	15 to 85	x: 1	y_{gas}	y_{liquid}	w
	85 to 95	x: 1	y_{gas}	y_{liquid}	w
	95 to 98	x: 1	y_{gas}	y_{liquid}	w
	98 to 100	x: 1	y_{gas}	y_{liquid}	w

Table 9 *(continued)*

[a] The liquid flow rate uncertainty can be split into oil and water flow rate uncertainties as follows:

$$U_{\text{oil}} = \sqrt{U_{\text{liquid}}^2 + \left(\frac{U_{\text{WLR}}}{1 - F_{\text{WLR}}}\right)^2} \quad \text{and}$$

$$U_{\text{water}} = \sqrt{U_{\text{liquid}}^2 + \left(\frac{U_{\text{WLR}}}{F_{\text{WLR}}}\right)^2}$$

where

U_{oil} is the relative uncertainty percentage in the oil volume flow rate;

U_{water} is the relative uncertainty percentage in the water volume flow rate;

U_{liquid} is the relative uncertainty percentage in the liquid volume flow rate;

U_{WLR} is the absolute uncertainty percentage in the water liquid ratio.

Example oil and water flow rate uncertainty specifications are provided below:

	F_{GVF} **range [%]**	**Total volume flow rate turndown**	**Average gas (% relative)**	**Average oil (% relative)**	**Average water (% relative)**
10 % F_{WLR}	0 to 15	x: 1	y_{gas}	y_{oil}	y_{water}
	15 to 85	x: 1	y_{gas}	y_{oil}	y_{water}
	85 to 95	x: 1	y_{gas}	y_{oil}	y_{water}
	95 to 98	x: 1	y_{gas}	y_{oil}	y_{water}
	98 to 100	x: 1	y_{gas}	y_{oil}	y_{water}
50 % F_{WLR}	0 to 15	x: 1	y_{gas}	y_{oil}	y_{water}
	15 to 85	x: 1	y_{gas}	y_{oil}	y_{water}
	85 to 95	x: 1	y_{gas}	y_{oil}	y_{water}
	95 to 98	x: 1	y_{gas}	y_{oil}	y_{water}
	98 to 100	x: 1	y_{gas}	y_{oil}	y_{water}
90 % F_{WLR}	0 to 15	x: 1	y_{gas}	y_{oil}	y_{water}
	15 to 85	x: 1	y_{gas}	y_{oil}	y_{water}
	85 to 95	x: 1	y_{gas}	y_{oil}	y_{water}
	95 to 98	x: 1	y_{gas}	y_{oil}	y_{water}
	98 to 100	x: 1	y_{gas}	y_{oil}	y_{water}

Some other factors that should be considered are listed below:

Table 10 — Additional factors for consideration in the specification of the measurement uncertainty

Repeatability		**Gas flow rate**	**Oil flow rate**	**Water flow rate**	F_{WLR}
		%	**%**	**%**	**% absolute**
Response time:	**ms**	**Measurement update frequency:**			**Hz**
Influence quantities		**Effect**			
Salinity					
Flow regime					
Sand					
Additives					

Table 10 *(continued)*

Scale			
Wax			
Hydrates			
Fluid properties			
	References (documentation)		
1			
2			
3			
4			
5			
6			
7			

8.7.7 Two-phase flow map

The performance specification should include one or more two-phase flow maps as described in 7.3.1. Both the measuring and limiting envelopes should be plotted. The production envelope should also be shown on this plot to gauge meter fitness-for-purpose limits.

8.7.8 Composition map

The performance specification should include one or more composition maps as described in 7.3.2. Both the measuring and limiting envelopes should be plotted. The production envelope should also be shown on this plot to gauge meter fitness-for-purpose limits.

9 Testing, calibration and adjustment

9.1 General

Testing, calibration and adjustment can take place at different locations and for different purposes in the course of manufacture through to commissioning and operation on site. This subclause covers some of the options and highlights particular issues for each option. Table 11 shows a matrix of options for locations and activities that should be addressed.

Table 11 — Testing, calibration and adjustment options

Location	Activity	
	FAT / testing	**Calibration/testing**
Factory	Visual inspection Functional testing Instrument testing Dimension control Documentation/certificates verification	Static / dynamic — Model fluid — Purpose-built flow loop — Static instrument calibrations and tests

Table 11 *(continued)*

Location	Activity	
	FAT / testing	Calibration/testing
Test Facility	Instrument check Communication checks	Static / dynamic — Non-conflicted third-party test operator — Extended test matrix — Reference instruments traceable to standards (preferably in facilities meeting the requirements of ISO/IEC 17025) — Representative or model fluids
***In situ* (i.e. once installed in the field application)**	Instrument check Communication check Commissioning	Static / dynamic — Baseline recording — Performance test (e.g. against test-separator metering as reference)

Each of the rows “factory”, “test facility” and “*in situ*” denote a location for testing of an MPFM. Factory testing is the least expensive option. By “*in situ*” is meant the final destination of the MPFM where it is going to be put into service. The row “test facility” refers to various possibilities for where the MPFM can be tested (9.3.5). Details for different test locations are provided in separate sub clauses. There might be various reasons for selecting these locations. There are at least two routes to putting the MPFM into service:

— factory → test facility → *in situ*,

— factory → *in situ*.

9.2 Factory acceptance testing (FAT)

Prior to shipping the MPFM to site, a comprehensive test should be completed by the vendor. The purpose of the FAT 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 check;

— alarms check;

— integrity testing (hydro + leak tests).

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

The FAT procedure is 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 12.

Table 12 — Example FAT inspection table

Item	Inspection description	Design requirement	Accepted (yes/no)
x.x	Check that all cables and 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, i.e. 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 has also signed for each dimension checked.

9.3 Calibration and test of MPFMs

9.3.1 General

Some MPFMs are subjected to static calibration and adjustment at the factory. Flow-loop testing for performance verification of the meter in dynamic conditions is usually optional.

For example, although some MPFMs are set up solely on the basis of 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 measurement results from a calibration are assessed, the significant difference between MPFMs and single-phase meters should be borne in mind. That is, the major part of the uncertainty of an MPFM is associated with changes and variability in fluid dynamic process conditions and fluid properties, rather than with the intrinsic uncertainty of the primary sensor elements.

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

Therefore, flow rate calibration procedures, where an MPFM is calibrated against reference flow rate measurements, as can be done for single-phase metering, cannot necessarily be relied upon as transferrable from the calibration scenario to operation *in situ*.

In the case of MPFMs which use differential pressure elements specifically, if the claimed uncertainty in single phase flow is less than that stated for an uncalibrated single-phase meter in the appropriate part of the ISO 5167 series, it is recommended that MPFM technologies that utilize Venturi tube or cone meters should be flow calibrated to characterize the meter's single-phase flow baseline performance (discharge coefficient) across the application flow range.

The following subclauses provide details regarding performance verification of MPFMs in static and dynamic conditions.

9.3.2 Performance verification in static conditions

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

The factory calibration performed by the manufacturer may consist of, for example, measurements of geometric dimensions and sensor measurements in calibration fluids, 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 is used. However, it should indicate or read out the expected values at zero flow conditions.

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 can provide a health check of the MPFM. Such tests are usually performed when the installation has a scheduled shutdown.

9.3.3 Performance verification in dynamic conditions

9.3.3.1 General

Performance verification in dynamic conditions 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 to compare them against reference flow rates. The reference measurement systems used for performance verification in dynamic conditions may vary in size and thus flow rate capabilities. Therefore, prior to a performance verification in dynamic conditions, it should be ensured that the measuring envelopes for the MPFM and reference measurement system overlap. If they do not overlap sufficiently, only performance verification of a part of the measuring envelope of the MPFM may be possible.

There are at least three different methods for performance verification in dynamic conditions:

— factory;

— test facility;

— *in situ*.

Each method has its advantages and disadvantages, but before addressing each method, a few important issues concerning performance verification in dynamic conditions are highlighted.

Specific requirements for blind tests in flow loops are given in 9.5.

9.3.3.2 Fluids

The ideal situation would be that the test facility could reproduce the expected field conditions. 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 in many cases specific for each particular facility for performance verification in dynamic conditions.

The test 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.

Some facilities for performance verification in dynamic conditions use a model fluid, for reasons of cost and working environment. 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 of using model test fluids is that they are normally well-behaved and their PVT properties are well-known; so uncertainties regarding PVT properties are reduced to a minimum. It is important to convert flow rates recorded by the reference measurement system in the test 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, salt content, mass transfer between the phases, phase surface active components, and generation of flow regime."

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

Another problem with using produced hydrocarbons as a test fluid is the lack of wide 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 hydrocarbon fluid used as test fluid may not be representative of any other produced oil or gas production stream.

It is possible to synthesize a produced-hydrocarbon-type test fluid from stabilized crude oil, water with salts added and gas synthesized from methane, ethane and other gases.

9.3.3.3 Operational constraints

The fluids in a test 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 should be calculated for the conditions of the multiphase flow meter. This would include calculation of mass transfer between the phases. When testing in a facility with different conditions (e.g. pressure) from those in the field, the results may not be fully indicative of performance in service and should be interpreted with caution.

9.3.3.4 Test matrix

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

A test matrix should be defined for each meter to be calibrated. In principle, this is no different from other test situations, but with MPFMs the test matrix can have a large number of points, owing to the many combinations of flow rates and phase fractions. For example, with four flow rates per phase, a minimum of 64 points is necessary. To cover every possible combination of pressure, temperature and water salinity, the test matrix can run 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 owing to the very large number of possible variations. The test points which can be omitted with the smallest loss of information on meter performance should be identified. It is possible that the “most redundant” points are different for different types of meters, owing to their different working principles.

9.3.3.5 Reference measurement uncertainties

Test results are only as accurate as the reference measurements provided by the test facility. When the results of MPFM tests are evaluated, the measurement uncertainty of the reference measurements should also be taken into consideration.

In some facilities one or more phases may not be measured directly, and in such cases, it should be expected that these reference measurement uncertainties are higher than those being directly measured.

Additional measurements or calculations may also be required, such as water-in-oil and/or oil-in-water in the “single-phase” oil and water flowlines to estimate water/oil carry-over/under, owing to limitations of fluid processing efficiency.

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

Given the criteria and considerations regarding performance verification in dynamic conditions, the different alternatives as provided in the next subclauses can be reviewed.

9.3.4 Factory test

A factory test is a test performed by the manufacturer of the instrument: the test is usually carried out using facilities owned or controlled by the manufacturer.

A factory test may be carried out for several reasons:

— investigation of the performance of a new type of meter during a development phase;

— calibration or functional verification of meter before delivery to customer/user.

Factory tests have advantages, as well as limitations, and the most important have been listed in Table 13:

Table 13 — Advantages and limitations of factory tests

Advantages of factory tests	Limitations of factory tests
Easy access to test facilities and relatively fewer limitations on test time, making larger test matrices possible.	The test fluid is normally unlike that of an oil/gas well stream.
Relatively inexpensive.	Flow conditions/regimes are likely to be different from the real-life application.
Test facility may be purpose-built for a specific make/type of meter.	Tests cannot be regarded as fully independent.
The range of phase flow rates may be wide.	Normally low pressure.

9.3.5 Test facility

9.3.5.1 General

Some vendors have their own test facility; however, third-party independent laboratory facilities are also available. Some operating companies have even 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 the field test loop are treated separately in 9.3.5.

9.3.5.2 Independent laboratory test

An independent laboratory test is an impartial third-party test. An independent test facility should be expected to have a quality assurance programme with formalized procedures and reference instrumentation traceable to national or international standards. It is recommended that the test should be performed in a laboratory meeting the requirements of ISO/IEC 17025.

The aim of an independent laboratory test is to verify the MPFM performance in a third-party facility and thereby to increase the confidence in the MPFM performance from that in a factory test. Such tests may be regarded as unbiased; moreover, tests may be standardized, which allows for comparison between the performance of different meters. A good facility also offers extensive test matrices covering, at least, major parts of most MPFM measuring envelopes.

If the variation in performance of the MPFM under changing process and flow conditions is not known, or is not regarded as adequate, the laboratory should 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, flow rate ranges and water liquid ratio, WLR, should resemble their values in the field.

It is recommended that independent laboratory testing is used with care, with all the information available on MPFM performance, i.e. in previous tests and field applications, being carefully evaluated before a test programme is carried out.

Independent laboratory test facilities vary significantly in terms of test capabilities and cost levels. Various test fluids and flow conditions are available, e.g. model systems and real hydrocarbon fluids. Flow rates, flow regimes and temperature and pressure ranges differ between the different test facilities.

One way of providing additional confidence in a multiphase test facility is for the facility to participate in an intercomparison with other multiphase test facilities. A best practice guide on intercomparisons between multiphase test facilities has been published (Reference [34]).

Compared with a factory test, some of the main features of an independent laboratory test have been listed in Table 14.

Table 14 — Main advantages and disadvantages of an independent laboratory test

Advantages of an independent laboratory test	Disadvantages of an independent laboratory test
Test is independent and results are largely reproducible and verifiable.	Test is more expensive.
A larger test matrix in terms of flow rates, pressure and temperature is normally possible, as is a test with different fluids.	

9.3.5.3 Field test

From a test point of view, the main difference between an independent laboratory test and a field test 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 test facilities in their production plants and offer field tests with live well fluids at real process operating conditions.

Various options are available for setting up the test 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 test points. Only changing the well being tested can change fluid properties and phase fractions. Hence, although the flow rates are selectable in theory, in practice the wells or flow rates available for testing rely on the general plant operation, which should not be hampered. Operational process and economics could dictate the extent to which process set-up variations are undertaken to accommodate different test conditions.

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 though such tests are very useful and necessary, these facilities are not considered to be measurement performance test facilities.

Further information on performance testing is provided in 9.3.7.

9.3.6 *In situ* test

9.3.6.1 General

In situ testing is a test performed after the MPFM has been installed at its final location in the field. The aim of *in situ* testing is to verify the measurement performance of the MPFM in operation, as compared with the results from a factory test, an independent laboratory test or a field trial.

Some meters first require an initial static calibration *in situ* using actual well or other fluids before a performance verification in dynamic conditions can be performed. Some meters also require corrections on both the fluid data analysis and the fluid thermophysical properties such as PVT data, as the embedded algorithms usually employ related empirical factors. Whenever possible, implementation and periodic verification of this type of static calibration are recommended. The results establish an important track record, and a change in performance can be spotted. It is necessary that reliable reference measurements and 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 limit the accuracy of the test. The quality of *in situ* testing is further limited by the accuracy of the reference measurements made on site. Nevertheless, a test is important to build a track record and to monitor changes in performance.

Unstabilized hydrocarbons contain molecular components that are transferred from the liquid phase to the gas phase or vice versa when the pressure and temperature are varied. Thus, the mass flow rates of hydrocarbons in the liquid and gas phases change when the pressure is reduced. For this reason, the reference flow rates should 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. The uncertainty of such a simulation should be considered. On the other hand, if the uncertainty can be considered to be the same for each test, a useful track record can still be established and monitored.

Further information on performance testing is provided in 9.3.7.

There are various installation scenarios which accommodate *in situ* MPFM testing to varying degrees. Three possible configurations are addressed in more detail in the following:

— test separator used as reference;

— start-up of a satellite field;

— tracer techniques.

9.3.6.2 Testing 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 as a reference to adjust, check or verify the MPFM.

The results obtained from the test separator or MPFM should usually 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. The flow rates are usually converted to a common basis, which can be either the test-separator, the MPFM or standard conditions.

With good instrument repeatability for both the test separator and the MPFM, the conditions for establishing a track record should be good. The phase transition uncertainties are less pronounced for installations where the distance between the MPFM and the test separator is short. When the test results are assessed, the flow stability should also be considered, i.e. that the flow is not dominated by transient conditions. If transient conditions prevail and cannot be avoided, it should be verified that the reference instruments and the 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 with the flow rates measured by reference instruments topside, i.e. using a topside separator if possible. Provided that the PVT properties do not change significantly, the performance can routinely be verified, and any anomalies are easily spotted. If any discrepancies are spotted a start should be made on investigating PVT properties, reference instruments or MPFM instruments. This includes investigation into possible incorrect set-up and instrument failure. If flow conditions vary significantly in time, and there is a long distance between the MPFM and the separator, comparing accumulated quantity values for a longer time period may be of more value than comparing flow rate measurements.

9.3.6.3 Testing at start-up of a satellite field

A potential use of MPFMs is to place one MPFM on each individual wellhead in a satellite field. In this way, a test line, a test manifold and a number of valves are avoided. If individual wells are put into production one by one, each meter can be checked and its response adjusted 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 a calibration adjustment for each meter, provided that 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.

Checks and meter response adjustments can also be done using a deduction technique. When testing by deduction, the first well is opened and measured using the separator and an MPFM. When the first meter test is complete, the second well is opened. The increase in flow rate at the separator is now 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. Test by deduction is more accurate with MPFMs placed on each well, since the wells that have not been tested can be measured using previously tested MPFMs. This method should be used with great caution since several factors influence the quality of any test result and MPFM calibration adjustment, for example:

— spread in well performances;

— flow instability, i.e. slugging;

— differences in fluid PVT properties;

— flow-range limits of test or production separator;

— high uncertainty in the difference between two total stream reference production numbers relative to the individual-well stream rate under test by deduction (further exacerbated since the two total production stream production rates are sequentially measured at different times and often in different conditions).

9.3.6.4 Tracer techniques

The technique of tracer dilution flow measurement has also been applied for measuring liquid hydrocarbon and water flow rates on a manual spot sampling basis to verify or calibrate meter response, particularly in wet-gas flows. This is dependent on the availability of suitable tracer injection and downstream sample extraction tapping points and adequate mixing length between the tapping points.

9.3.7 Further information on performance testing

9.3.7.1 General

This subclause gives more details of how to assess the operational performance of an MPFM confronted with real field operating conditions. The main objective is to evaluate the flow measurement performance of the MPFM against a reliable and fully auditable reference measurement: first, to ensure clear conclusions are reached; and, second, to determine the MPFM adequacy for deployment in a certain field application under a comprehensive range of flow conditions.

Annex C provides one example of how this work might be done.

9.3.7.2 Field test description

By definition, field testing is performed in an operational oil or gas field where the MPFM is installed permanently or in a temporary production test section. In either case, the MPFM is installed in series with a reference measurement device, which is typically a conventional test separator equipped with single-phase metering devices. The flow is diverted to the meter under test then through the reference measurement device for a duration long enough to achieve stabilized conditions. Once stabilized conditions are achieved, measurements are taken, oil, gas and water production figures, water cut, GOR and any other relevant measurement that is used for data validation [e.g. Base Sediment and Water (BS&W), shrinkage measurement]. Then, there remains the task of comparing flow rates predicted by the meter under test with those taken as a reference measurement for each flow condition test point. Thus, the performance of the meter is determined and assessed according to predefined criteria for certain flow conditions.

9.3.7.3 Field test matrix

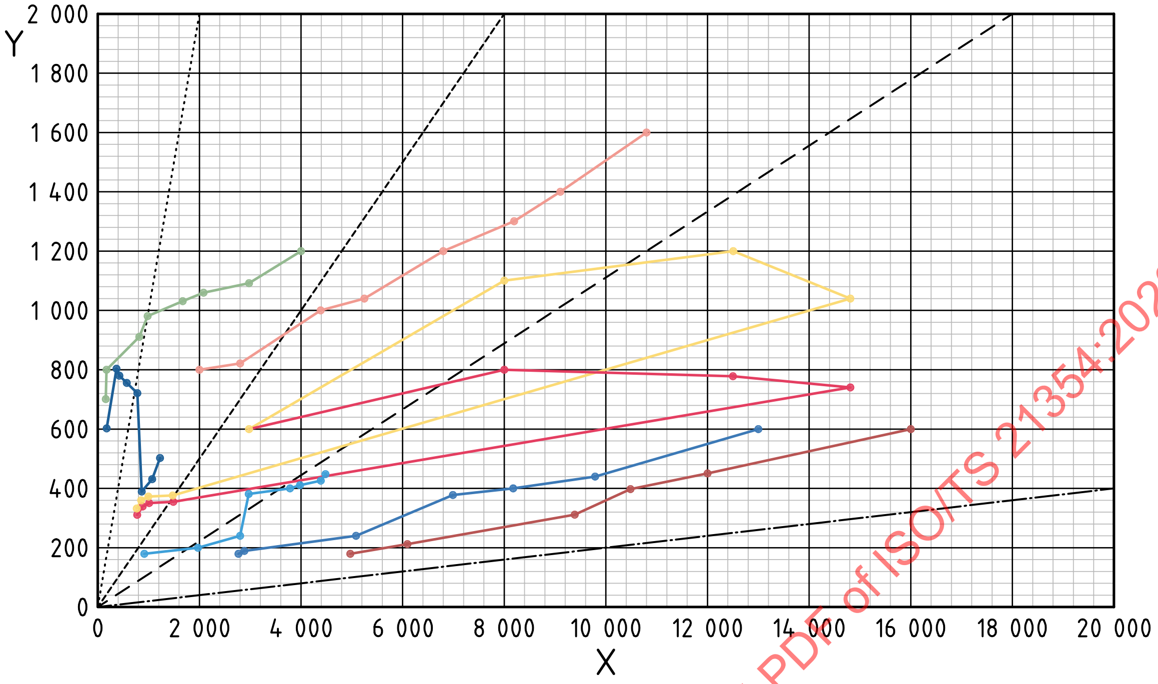
The main objective of the field-testing is to assess the suitability of the MPFM technology for application. The test matrix is defined based on current and expected future production for a given application. This may be assessed on the basis of projected production trajectories, of which examples are given in Figures 16 and 17. In order to cover those conditions, well candidates associated with production scenarios are selected for evaluation purposes. Each well is tested at one or more different choke settings to ensure proper coverage of flow rate, GVF and WLR conditions. The ranges of expected test conditions are summarized in Table 15.

Table 15 — Expected test conditions

Well/formation	Liquid rates [sm^3/d]	F_{GOR} [sm^3/sm^3]	Operating conditions [bara/°C]	F_{WLR} [%]	F_{GVF} [%]
Well 1/formation 1	min-mid-max	min-max	range	value 1 - value 2 - value 3	value 1 - value 2 - value 3
Well 2/formation 2					
Well 3/formation 3					
Well 4/formation 4					

Trials should include reproducibility tests, whereby a given well is tested at least twice at the same choke setting at some time interval, to verify the ability of the meter to reproduce the results under similar conditions. It is also advisable to vary water flow rates to check the ability of the meter to detect small changes in water content. Resolution tests to determine the ability to detect small changes in flow conditions should also be undertaken.

Actual candidate well data should be shared with the MPFM vendor before the start of the field test and relevant information such as related PVT data, as the vendor may advise the details of the equipment that it is offering for the field tests. This allows a sizing study to ensure the proper coverage of target conditions. Multiple sizes may be used during trials in circumstances where it is required to cover a range of conditions extending beyond the capability of a single unit.



Key

X gas flow rate (m^3/d) at actual conditions

Y liquid flow rate (m^3/d) at actual conditions

natural flow 1

natural flow 2

gas lift well 1

gas lift well 2

ESP1

ESP2

high $F_{GOR,1}$

high $F_{GOR,2}$

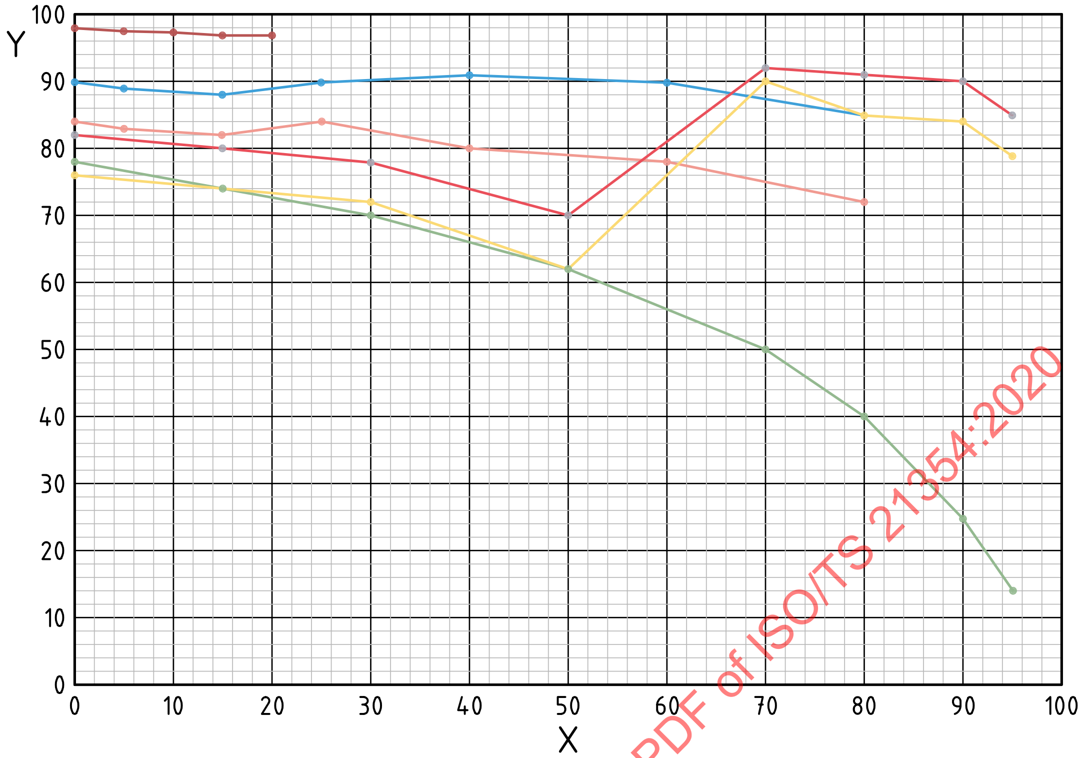
F_{GVF} = 50 %

F_{GVF} = 80 %

F_{GVF} = 90 %

F_{GVF} = 98 %

Figure 16 — Example of target well trajectories for target conditions: Flow map



Key

X F_{WLR}, in %

Y F_{GVF}, in %

natural flow 1

natural flow 2

gas lift well 1

gas lift well 2

ESP1

ESP2

High $F_{GOR,1}$

high $F_{GOR,2}$

Figure 17 — Example of target well trajectories for target conditions: Composition map

9.3.7.4 Comparison between MPFM under test and reference measurements

It is not a trivial task to compare MPFM readings with reference system readings. The two reading sets are usually measured at different locations and thus at different pressures and temperatures. Therefore, to compare flow rates on a volumetric basis, quantities should be converted to a common process condition basis. It should be ensured that the PVT and other fluid data used by the MPFM, by the reference system and in the conversion are consistent. To ensure a proper comparison, the following guideline is recommended.

— Verify that the MPFM and the reference system use the same basis for PVT data.

— Compare total stream mass flow rate readings. To do this, no fluid state conversion is necessary, and thus the comparison reveals any deviations before introducing the uncertainty of PVT conversions. If there is an unacceptable difference, this should be investigated, as it provides a fundamental basis for assessing the validity of the reference measurement system and the MPFM performance. The uncertainty of the reference measurement systems should be checked and confirmed in this instance. If the reference measurements are found to be acceptable, then this total mass flow basis of assessment provides definitive evidence about the performance capability of the MPFM in question.

— Compare total hydrocarbon mass flow rate indicated by the MPFM with the reference system value. If water is present, also compare the indicated water mass flow rates. Although there is a mass transfer between the hydrocarbon liquid and gas phase, the sum of the two should remain constant with changes of pressure and temperature, as should the mass flow rate of the water present. As above, this can provide further fundamental insight into the performance of the reference and MPFM meter systems.

— Compare phase volumetric flow rates converted to a common fluid state basis.

— If possible, take physical gas and liquid samples during the test and analyse them. The purpose is to verify the PVT and water property data currently used by the MPFM and the reference system.

— Finally, compare and present the flow rate results, including representation of the specified uncertainties of both the MPFM and the reference system.

9.3.8 Test report

Regardless of how the test is performed, it needs to be reported in some format. A standardized format is desirable, and a suggestion for a test report table is shown in Table 16.

The test report should give the results in terms of both tables and graphs. Table 16 shows an example. The format in the Table 16 example accommodates an MPFM where the uncertainty is specified in terms of total 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 16 — Example of a test report sheet

Test report																
Test date:									**Test location:**							
MPFM S/N:																
Key calibration data relevant for MPFM make:																
Test matrix signal data recording basis[a]:																
	Reference average phase flow rates[b]						**MPFM average phase flow rate measurements**									
Test no	q_{oil} m^3/h	q_{water} m^3/h	q_{gas} m^3/h		t_{ref} °C	p_{ref} bar	q_{oil} m^3/h	**Dev.** **%**	q_{water} m^3/h	**Dev.** **%**	q_{gas} m^3/h	**Dev.** **%**			t **°C**	p **bar**
1																
2																
3																
4																
5																
6																
7																
8																
9																
10																
	Reference average phase flow data[2]						**MPFM average phase flow measurements**									
Test no	q_{liq} m^3/h	q_{gas} m^3/h	F_{WLR} **%**	F_{GVF} %	t_{ref} °C	p_{ref} bar	q_{liq} m^3/h	Dev. %	q_{gas} m^3/h	Dev. %	F_{WLR} %	Dev. %abs	F_{GVF} %	Dev. %abs	t °C	p bar
1																
2																
3																
4																
5																
6																
7																
8																
9																
10																
[a] Description of signal data time series recording procedure, such as signal sample rates, well test or averaging period, stabilization determination and timing, MPFM versus reference comparison timing basis.																
[b] Deviations are calculated at reference conditions, standard conditions or MPFM conditions, as agreed.																
Dev.: Deviations calculated between reference and measurement.																
Test technician:									Approved by:							
									Date:							

As well as tabulated data, the test report should also include the results illustrated in the graphical formats described in Figures 13 to 15.

In addition to the tabulated and graphical comparison results, the test report can also include:

1) a sketch and pictures showing important details of the test installation:

- — whether the MPFM was mounted for horizontal, vertical upwards or vertical downwards flow;
- — straight upstream/downstream pipe length requirements;
- — phase commingling point and distance to meter under test;

— position of reference measurements;

2) process conditions:

— pressures, pressure drop across MPFM and temperatures recorded for each test point;

— oil-in-water and water-in-oil measurements in the reference system liquid lines taken during the test;

— oil and water density measurements performed during the test;

— gas quality measurements taken during the test;

3) reference measurements:

— type and standard of reference measurements;

— reference measurement calibration record references;

— diagram of piping and process between reference metering and MPFM installation point;

4) operational procedures: a reference should be provided for the documented facility operation procedures as these relate to measurement management and integrity;

5) MPFM set-up prior to test: a full description of the set-up performed by meter manufacturer (including meter serial number and software version), or by test institution, prior to the test, including details of any special set-up and preparation procedures requested by the manufacturer or undertaken, and the time taken;

6) summary of test results:

— A representative number of test points should be obtained. This is governed by the buyer's requirements for flow rate, WLR, GVF, pressure, temperature and fluid property test ranges.

— Any PVT conversion or other issues should be noted and explained.

— Any particular observations during test should be recorded.

9.4 Adjustment of MPFMs

9.4.1 General

Most MPFMs require adjustment based on static configuration. Some MPFMs also require adjustment based on a performance verification in dynamic conditions.

9.4.2 Adjustment based on static configuration

The usual purpose of a static configuration is to generate input parameters to set up the MPFM and to establish a baseline. For example, it might be required to record transmitter data on a model fluid or a representative well fluid to set up the transmitters correctly based on the recorded data. Examples are mass attenuation coefficients for a nucleonic system and dielectric constants for a capacitive system.

9.4.3 Adjustment based on performance verification in dynamic conditions

9.4.3.1 General

For the type of MPFMs that require adjustments based on performance verification in dynamic, i.e. fluid flow, conditions, the adjustment can be implemented using one of the following methods or combinations of these methods. This method generally has a narrow application range, and outside of the test matrix conditions measurement behaviour is unknown.

9.4.3.2 Matrix calibration

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

9.4.3.3 Curve-fit calibration

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

9.4.3.4 Factor calibration

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

9.5 Blind tests

9.5.1 Scope and objective of MPFM blind test

Blind testing can be used to evaluate measurement performance. The user only provides the meter vendor(s) with flow and process range information to enable test unit sizing and configuration. The individual flow condition test points and the sequence and degree of their adjustment and variation through the test and the associated reference flow measurements are not disclosed. Further, no party is permitted to make adjustments of the test meter configuration and software during testing, beyond the normal vendor-specified and -documented factory and site installation preparation, commissioning and operation as would apply in an actual procurement and field application scenario.

Such tests are expected to represent real situations in which the MPFM systems face real conditions which are not controlled.

Blind tests are designed in order to verify performance but also in order to evaluate and understand flow meter technologies and to understand how to use and install systems and to assess their performance.

The effects of installation configurations and flow conditioning systems may also be investigated.

9.5.2 Organization and implementation

Blind tests are generally carried out in a third-party multiphase flow loop by individual MPFM users or by a group of MPFM users through a joint testing programme established and agreed between users to evaluate flow meter technologies.

A blind flow test should reflect as much as possible a real installation. If several meters are tested together, efforts should be made to test different technologies in similar flow conditions. No 'tuning' of MPFM output data to fit reference values is allowed during the test.

Tests are "blind" and do not necessarily stay exactly within the vendor operating envelope.

9.5.3 Multiphase flow loop

The selected flow loop should have traceable reference flow data for gas, oil and water. The uncertainty of the reference flow data at the metering point should not exceed one third (and preferably not exceed one fifth) of the expected uncertainty of the meters to be tested.

Ideally the flow-loop operator should also be able to characterize the flow regime upstream of the meter under test as well as to measure or calculate fluid properties (such as the density of oil, water and gas) at the metering point. Other characteristics such as viscosity and water salinity may be required.

9.5.4 Test matrix

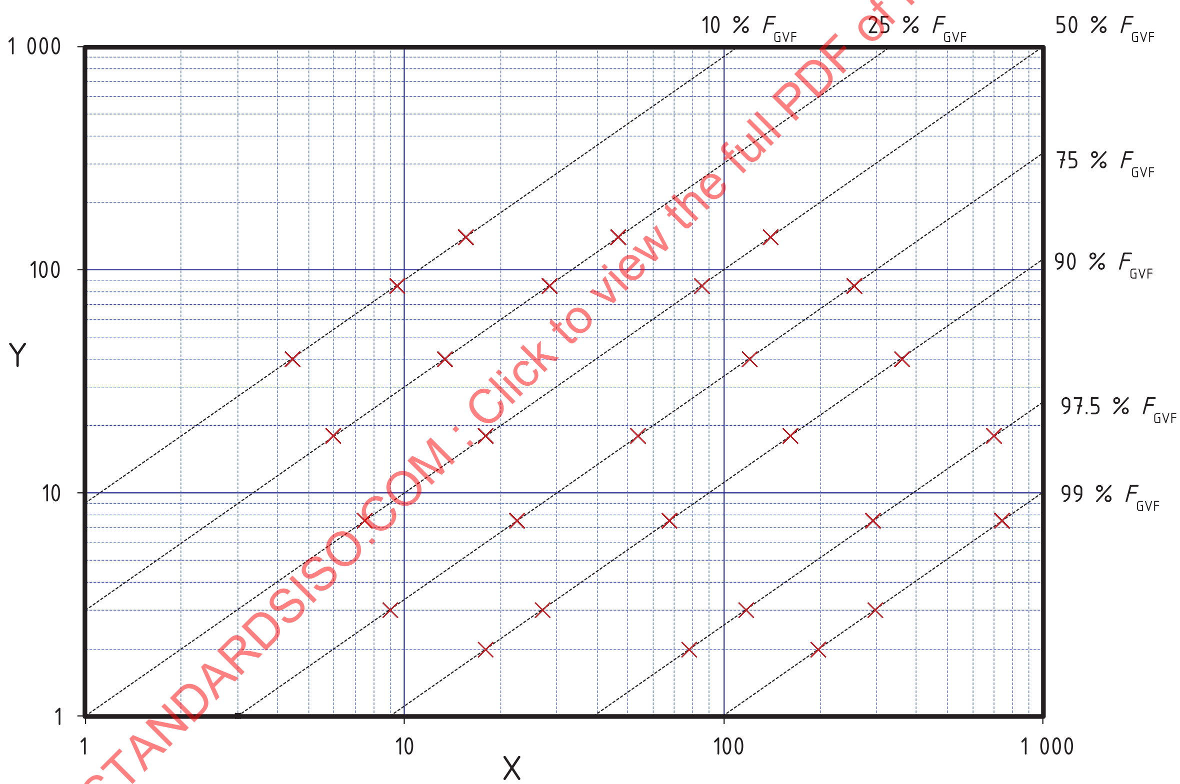
For a blind test, the detailed test matrix is defined by the users (and, as stated in 9.5.2, tests do not necessarily stay entirely within the vendor operating envelope).

The test matrix consists of a significant number of operating points characterized by pressure, temperature, gas and liquid flow rates, water liquid ratio or water volume fraction, density, viscosity, and water salinity.

Each test point is logged for a certain period and one test result represented in terms of the average flow rates over the logging period.

In the case of testing conducted in collaboration with MPFM vendors, the only information provided to manufacturers prior to the test may be minimum and maximum flow rates and, in some cases, minimum and maximum GVF and WLR in order to make good sizing of meters possible.

Figure 18 represents a typical test matrix.



Key

X gas flow rate (m^3/hr) at actual conditions

Y liquid flow rate (m^3/hr) at actual conditions

Each point shown on the graph may correspond to multiple (fixed bulk liquid and gas flow rate) test points representing a range of selected WLRs. For example, these may be selected to cover a water content range specific to an application; or with more detailed increments within the oil/water inversion water cut region in order to assess susceptibility of a particular metering technology to complex emulsions.

Figure 18 — Example of a test matrix

9.5.5 Information to be provided by MPFM vendors

For any test of a commercial version of an MPFM, all relevant documentation (e.g. specification, installation manual, operating manual, Modbus data) should be delivered to the flow-loop operator and the test customers. It is generally required from MPFM vendors that they provide available resources to deliver, install, set up and configure the system. Installation requirements and drawings should also be handed over to the flow-loop operator.

A list of available meter raw output data should be provided in order to set up the data acquisition system.

A copy of the meter set-up file as configured in the meter system immediately before and after the test should also be provided.

9.5.6 Information provided to MPFM vendors

9.5.6.1 General

Table 17 indicates the minimum information that may be provided to MPFM vendors before a blind test.

Table 17 — Minimum information that may be provided to MPFM vendors before a blind test

1	Information regarding the test matrix ranges in order to verify MPFM sizing	Maximum and minimum flow rates
2	Oil, water and gas properties or oil, water and gas samples in order to incorporate required information in the MPFM configuration: PVT / fluid densities / other parameter inputs	
3	Installation set-up schematic	

9.5.6.2 PVT data

Reservoir-engineering analysis allows the supply of mole-fraction composition estimates for production flows from wells. This information is required as an input to some MPFM designs.

For MPFM testing at laboratory multiphase / wet-gas flow test facilities, there may be no well-production mole-fraction composition estimate, depending on the design and operation of the test facility. Therefore, in order to test MPFMs in such circumstances, the 'production' mole-fraction composition, when required in order to configure the MPFM, is determined from the known reference gas, oil, and water flow rates and their associated phase compositions for each flow condition test point.

It should be noted that such multiphase-flow test-facility mole-fraction composition estimates can be more accurate than field-reservoir engineer estimates. A consequence of this is that test-facility MPFM performance results can be correspondingly better than in the field.

Furthermore, for known individual gas, oil, and water phase compositions, the created total multiphase-flow mole-fraction composition calculation for each test point condition inherently includes accurate reference GOR information being supplied to the MPFM under test. That is, whereas the GOR is an intended output of the MPFM in the field, it is effectively an input to any MPFM that relies on hydrocarbon fluid compositional configuration in the multiphase test facility. Again, this results in the test facility MPFM performance results appearing correspondingly and artificially better than would be representative of field operation.

9.5.7 Test completion

9.5.7.1 General

After test execution, the meter vendor should provide a diagnostic status for the test data points.

Sampling of water and hydrocarbons should be carried out at suitable intervals sufficient to measure and capture any variation or change in fluid chemistry or compositions and phase properties through the course of the test programme.

The following parameters should be obtained for each piece of equipment under test as a minimum:

— gas, oil and water flow rates;

— test facility reference metering uncertainties;

— pressure and temperature measurements for meter inlet and outlet conditions.

The stability of each test point should be logged.

9.5.7.2 Comparison

Information on comparison is given in 9.3.7.4.

9.5.8 Test results and deliverables

After the tests, the following information should be made available by a flow-loop operator:

1	Description and drawing of the test set-up
2	Observations during the testing
3	Information on flow regimes
4	Methodology for the reference flow rate calculation at test section metering point
5	All measured flow rates at meter location and pressure and temperature measurements
6	Reference flow rate uncertainties at meter location
7	Relevant fluid properties at meter location
8	Electronic data file with the fluid-composition and property data, and the logged signal and flow data
9	Any recommendations for installation / operation

10 Field installation and commissioning

10.1 General

Clause 10 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 is a vast number of ongoing activities and bed space is usually a limiting factor.

10.2 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 for temperature, pressure and flow rates at the MPFM location: it should be ensured that these parameters and the production envelope are within the operating and measuring envelopes of the MPFM;

— fluid properties such as PVT data for hydrocarbon as well as conductivity/salinity for water 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 of replacing the MPFM with an MPFM of another size to accommodate unexpected well flow rates;

— access for maintenance and service of instruments, configuration and checking of readings with single-phase fluids present in meter, cleaning of internal deposits that may form;

— access to all data (measured or calculated) required to operate and maintain the MPFM: this includes raw signals from individual sensors;

— 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 communications line;

— facilities to collect multiphase fluid samples (it is difficult to get representative samples of multiphase fluids; no standard is yet available);

— flow conditioning requirements;

— backup facilities and spare parts;

— that the MPFM is often integrating a radioactive source that is shipped separately and requires specific authorization (even if it is sometimes managed by the vendor).

Provided that the main issues as described above have been covered, the MPFM should be installed according to the outcome of the considerations.

10.3 Installation and site integration

10.3.1 General

To ensure a smooth installation process, good communication and clarification of responsibilities are 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 subclause presents some general guidance on some of the main preparatory issues to be considered for an 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 are 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 deviations. This is important to prevent delays in the installation process.

There is benefit in planning a field visit well in advance. Piping and Instrumentation 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 and communication interfaces. The visit might also include hook-up of an MPFM simulator to the client control system to verify communication and power supply. A rigorous set of organizational project-engineering-discipline execution procedures and check-list close-outs should be implemented, as is good practice for oilfield instrument and metering package systems in general. If a field visit has been performed and everything is in accordance with the scope of delivery, an additional meeting should be arranged to complete a field-visit review.

10.3.2 Installation requirements

It should be clarified as early as possible if the vendor has any special installation requirements. These might include:

— vertical / horizontal alignment;

— requirements on straight pipe lengths before and after the MPFM and the fittings beyond the straight lengths;

— special requirements for accessing the MPFM.

Some vendors require access to the MPFM prior to installing it in the pipe work. As mentioned under Clause 9, it may be necessary to fill some types of MPFM with reference fluids to perform *in situ* static calibrations. Some vendors wish to perform cleaning of sensor window surfaces to ensure measurement errors due to surface deposits or contamination are minimized.

10.3.3 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;

— testing of the cable using a megohmmeter: each wire and screen vs. all other wire/screens in the same cable;

— check that the power supply has the correct output voltage.

10.3.4 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.

10.3.5 Fluid calculation checks

A verification of fluid parameters and properties downloaded and/or calculated within the MPFM system (computer) should be carried out. This is a critical item to reduce uncertainty/errors due to incorrect fluid parameter inputs/calculation.

As well as addressing actual fluid properties at line conditions, this should also consider conversion parameters used to convert actual rates to standard rates.

10.4 Commissioning

10.4.1 General

The vendor should provide a commissioning document that describes the procedures that are 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 is designed to 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 is no process flow during the commissioning phase.

10.4.2 Preparation

It should be verified 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 it should be ensured that all the additional tools/parts/procedures needed are available.

10.4.3 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 client requires some information from the vendor 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 required the client should be notified so that they can be included in the logistics as early as possible.

10.4.4 On site authorization

Depending on the make of MPFM different authorizations are required:

— mechanical / pressure system isolation and depressurization;

— 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.

10.4.5 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 can include the following.

— System checks: the vendor usually hooks up to the MPFM using a service computer, either a laptop or a permanently installed computer, to run various system checks specific for the make of MPFM. This may include static tests (no flow with MPFM filled with known fluid).

— System configuration: during commissioning, the vendor usually establishes single or multiple baseline references for the MPFM and its individual sensors; fluid properties data are entered or checked as a part of the system configuration.

— System test: all readings as well as raw data from individual sensors from the MPFM to the customer’s supervisory or acquisition systems 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 should 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 output data with flow through the MPFM be undertaken to ensure consistency of results. This is a task that may be performed by the vendor.

The outcome of the activities listed in this subclause should be part of a commissioning handover document which outlines 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 representatives.

10.5 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. Start-up verification depends on applications (topside, subsea) as well as the purpose of the measurements (fiscal or non-fiscal) and the uncertainty requirements. If possible, one task should be to compare the MPFM measurements against reference instruments if such are available (see 9.3.6). 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 it is necessary to resort to system material balance, physical WLR samples and pipeline/flow models.

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

Even if a reference system is available, comparing reference system and MPFM data can be involved (see 9.3.7.4). 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.

11 Verification during operation

11.1 General

MPFMs' verification/calibration during operation may be addressed in several ways depending on applications and facilities available.

Main items to verify are:

— the sensors themselves, such as differential pressure;

— the fluid properties and associated parameters;

— the flow calculations.

An MPFM cannot easily be sent to a test facility for sensor and flow recalibration; yet there is a need for regular surveillance and testing in the field 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 some installations, there is provision for checking the performance of the MPFM using a permanently installed or portable test separator. In these cases, the flow test of the MPFM can be checked at regular intervals, taking heed of the precautions and recommendations already discussed in Clause 9.

The purpose of Clause 11 is to provide some guidelines on how to verify meter performance in the field during operation, assuming no test separator is readily available (in which case 9.3.6 applies). The methods discussed are:

— baseline monitoring;

— self-checking / self-diagnostics capabilities / redundancy;

— MPFM data validation;

— remote MPFM monitoring;

— comparison with model-based multiphase flow calculations;

— MPFM meters in series;

— mobile test unit;

— tracer technology;

— injection;

— sampling;

— reconciliation factor;

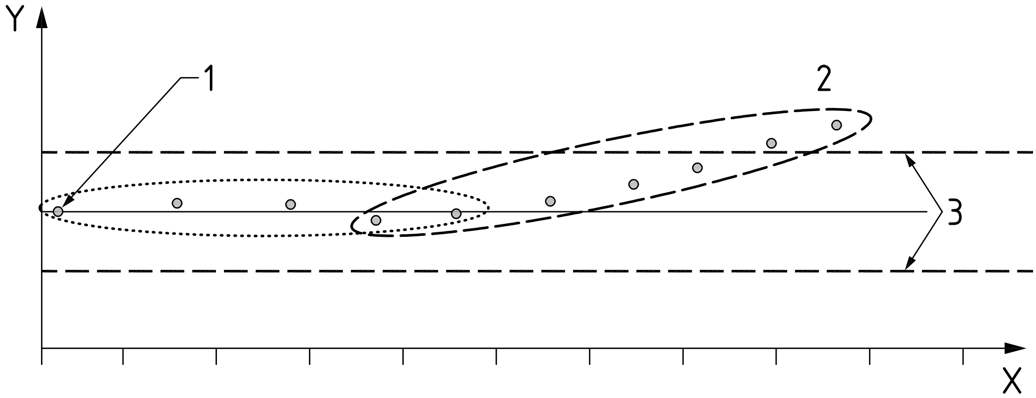
— geo-chemical fingerprinting.

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

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

11.2 Baseline monitoring

Baseline monitoring is the simplest method for assessing meter performance in the 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 are key measurement parameters in an empty and preferably depressurized sensor, and typical parameters are differential pressure, density parameters and electrical and optical parameters. A traceable log should 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 depends on the type of MPFM, and should be agreed with the vendor to achieve best results.



Key

X time

Y baseline parameter

1 factory calibration

2 systematic trend

3 tolerance band

Figure 19 — Example of baseline monitoring

An empty meter 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 (see Figure 19), it is possible to 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.

11.3 Self-checking, self-diagnostic capabilities and internal 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 automatically checks and logs key measurement parameters and built-in references, and can also cross-check these (e.g. calculate a ratio), and verify whether the meter operates within tolerances, and also warn of a systematic drift. In some meters, there is also an inherent or purposely built-in redundancy. This makes the self-diagnostic capability more robust, in particular for online verification in flowing conditions.

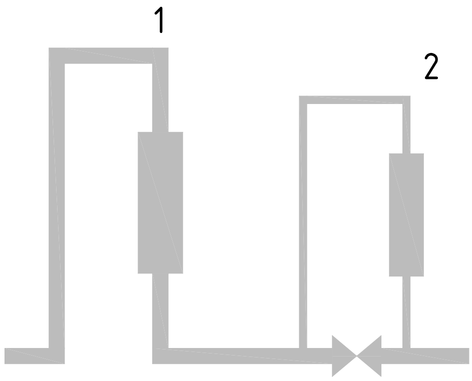
11.4 Comparison with model-based multiphase flow calculations

In some cases, such as continuous use of MPFM for well metering or flow line metering, it may be relevant to implement so-called virtual flow metering systems for MPFM verification.

Virtual flow metering systems, called VFM, are flow calculation systems using models and simple sensors like pressure and temperature. They may be used to indicate some significant drift or error in an MPFM (see References [18] and [26]).

11.5 Two meters in series

Additional redundancy, allowing the possibility of diagnostics and verification, can be achieved by installing two MPFMs in series. Typical applications for this method of verification are 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 20. The configuration is that a small ID MPFM is installed in a bypass, and a ball valve and a larger ID MPFM are 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 in all cases passes through the large ID meter.



Key

1 high flow rate meter

2 low flow rate meter

Figure 20 — 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, it may be observed that the turndown in flow rate for each phase has been increased depending on flow regime. 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 are different, giving an added dimension to the verification in comparison with the case of using two identical meters in series.

Verification by two MPFMs in parallel can only be achieved in very stable conditions, as these tests must be performed in sequence.

11.6 Mobile test units

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

11.7 Tracer technology

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 use of this technique requires that suitable points for injection and sampling be included in the installation.

11.8 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 whether the meter responded correctly to the change in WLR and water flow rate. Care should be taken to make sure the injection does not alter the production conditions, e.g. pressure, in such a way that the production itself changes, thereby invalidating this method of verification, e.g. lift gas cannot be used to validate the meter. Moreover, it is important to note that the fluid properties of the injected fluid should 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.

11.9 Sampling

11.9.1 General

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 WLR can be a method for tracking the performance of an MPFM.

11.9.2 Sampling for information about WLR

Obtaining a representative liquid sample is by no means straightforward, and the complexity may vary between applications. Issues to consider are as follows.

— The sampling point should be in a vertical leg of the flow line: the best position is immediately downstream of a flow-line component that provides a mixing effect.

— A number of successive samples (minimum 5) should be taken. Each sample should be allowed to separate completely before the WLR is measured. For some crude oils, this requires use of a de-emulsifier.

— All samples should 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 should be selected such that the samples are representative of 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 should be obtained.

— The average WLR of the samples should be used for the comparison with the MPFM.

11.10 Imbalances and reconciliation factor

Imbalance monitoring or use of reconciliation factor as a means of monitoring the quality of the data from the MPFMs can be a useful method. An example of the method is shown in the field layout in Figure 21:

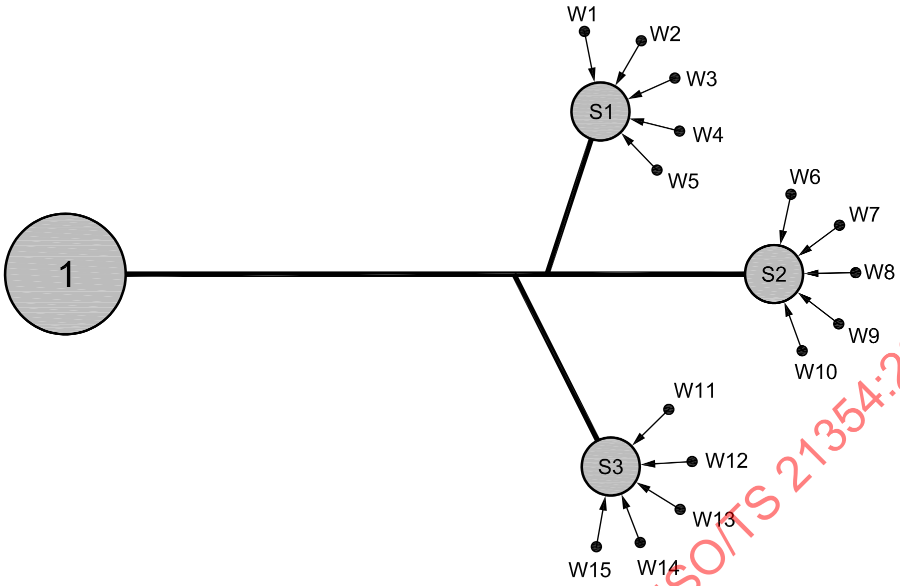
— three satellite fields are commingled into a common transport pipeline to a processing facility;

— each satellite produces a number of wells, in this example 5 wells per satellite;

— each satellite has an MPFM to measure continuously 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.



Key

1 central processing facility

Figure 21 — 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, F, for each phase can be calculated as:

$$F = \frac{q_{\text{phase,central}}}{\sum_{i=1}^{N} q_{\text{phase,satellite(converted)}i}}$$

where

$q_{\text{phase,central}}$	is the phase flow rate at the central platform;
$q_{\text{phase,satellite(converted)},i}$	is the phase flow rate at satellite i (converted to central platform conditions);
N	is the number of satellites.

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 and the corresponding PVT conversions.

For the reconciliation factor system to provide an efficient method for periodic verification of the MPFMs, the uncertainty and the expected reproducibility of the reconciliation factor should be established, from the uncertainty specifications for the central process facility metering and the satellite MPFMs. Based on this a tolerance band can be established. In addition to monitoring for adherence 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 which satellite has a measurement problem if a deviation in the reconciliation factor for the central processing facility is detected. This enables detection of inconsistencies and may form a basis for initiation of further verification procedures. Ideally, this should be carried out for gas, oil and water flow rates on a volume or mass basis, depending on the application.

11.11 Geo-chemical fingerprinting

According to Reference [47], 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 21), the oil produced at each of the satellites S1, S2 and S3 is therefore required to have a characteristic geo-chemical fingerprint for this method to be applied.

11.12 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 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

— test by perturbation (choke changes) using topside measurements as described in Reference [21];

— remote MPFM monitoring (see Reference [24]);

— in-line fluid property verification (e.g. during meter shut-in);

— data validation using redundancy (see Reference [25]);

— comparison with flow models.

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

Annex A
(informative)

Multiphase meter technologies

A.1 General

This annex 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 the 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 Clause A.2 an overview of the main categories of MPFMs is provided; in Clause A.3 the most commonly used measurement principles in MPFMs currently available on the market are briefly described; in Clause A.4 some guidance on selection of technology and maintenance requirements is provided.

A.2 Meter categories

A.2.1 General

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

— in-line meters;

— separation-type meters:

— full two-phase gas/liquid separation;

— partial separation;

— separation in sample line;

— wet-gas meters;

— other categories of MPFMs.

Wet-gas meters are a subset of MPFMs but are covered in ISO/TR 11583 and ISO/TR 12748, and are only briefly described in Clause A.2.

A.2.2 In-line meters

In-line MPFMs are ones in which all the measurements of the individual phase fractions and total or individual phase flow rates are performed directly in the multiphase flow line without separation (see Figure A.1).

The volume flow rate of each phase is represented by the phase area fraction multiplied by the velocity of each phase. This means that a minimum of six parameters must be measured or estimated, although in fact only five parameters must be measured as the sum of the phase area fractions is 1.

In-line MPFMs employ a combination of two or more measurement technologies and techniques, for example:

— electromagnetic measurement principles;

    — microwave technology;

 — capacitance;
 — conductance;
 — infrared;

— gamma ray densitometry or spectroscopy;

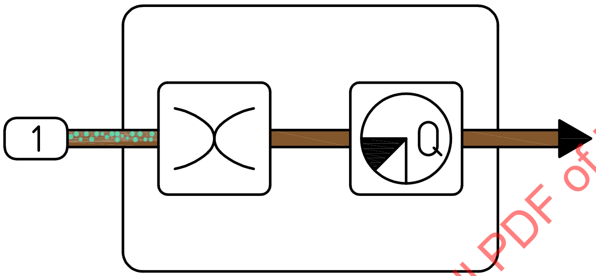
— differential pressure using Venturi tube, cone meter or other restriction;

— ultrasonic;

— cross-correlation of electromagnetic, radioactive or ultrasound signals (to calculate flow velocities);

— optical attenuation;

— magnetic resonance (no combination with another technology required).



Key

1 multiphase

Figure A.1 — Design (in principle) of in-line MPFM with mixer (optional)

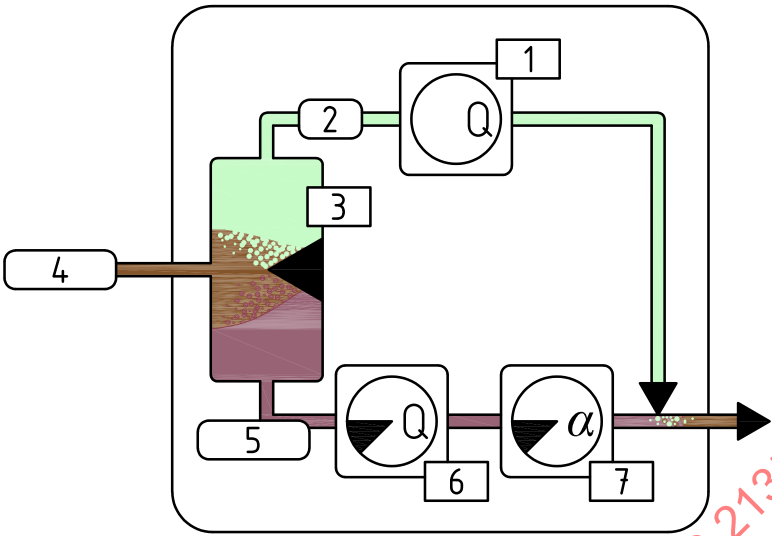
A.2.3 Separation-type meter systems

A.2.3.1 General

Separation-type MPFMs are a class of MPFMs characterized 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 metering system. It separates the three phases and carries out flow measurements of the oil, water and gas outlets. Separation utilizing three-phase separators is not described further in this document and is only mentioned in this subclause to make the overview complete.

A.2.3.2 Full two-phase gas/liquid separation

This type of meter system is characterized by its separation of the multiphase flow, usually a full separation to gas and liquid (see Figure A.2). The gas flow is then measured using a single-phase gas-flow meter with adequate tolerance to liquid carry-over, and the liquid flow rate is measured using a liquid flow meter. An online water fraction meter may determine the water liquid ratio.



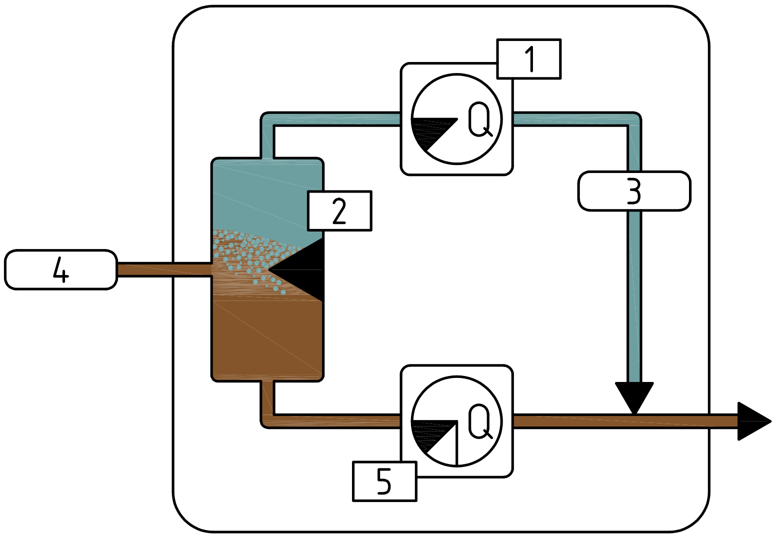
Key

1 gas meter
2 gas
3 separation stage
4 multiphase
5 water/oil
6 liquid meter
7 water liquid ratio

Figure A.2 — Design (in principle) of a separation type meter system

A.2.3.3 Partial separation

This type of meter system is characterized by separating only a part of the gas in the multiphase flow into a secondary measurement loop around the main loop through the MPFM (see Figure A.3). Since the separation is only partial, it should be expected that some liquid will travel with the gas through the secondary measurement loop, which then calls for a wet-gas measurement. The remaining multiphase stream then has a more optimal GVF range and thereby operates within the designed envelope of the flow meter.



Key

1 wet-gas meter
2 separation stage
3 wet gas
4 multiphase
5 multiphase meter

Figure A.3 — Design (in principle) of a partial separation with a secondary measurement loop

A.2.3.4 Separation in sample line

This type of meter system is characterized by the fact that separation is not performed on the total multiphase flow, but on a bypassed sample flow (see Figure A.4). The sample flow is typically separated into a gas and a liquid flow, in which the water liquid ratio of the liquid sample stream can be determined using an online water fraction meter. Total (gas and liquid) flow rate and GVF should be measured in the main flow line, and assuming the bypassed sample flow is representative of the main flow, the water liquid ratio is based on the by-pass measurement of this parameter.

