PD ISO/TR 12748:2015

BSI Standards Publication

Natural Gas — Wet gas flow measurement in natural gas operations

bsi.

...making excellence a habit.™

National foreword

This Published Document is the UK implementation of ISO/TR 12748:2015.

The UK committee, advises users to reference to ISO/TR 11583:2012 when applying this PD, in particular to the equations for wet-gas measurement using Venturi tubes found in Clause 6 of ISO/TR 11583:2012, since their use reduces the bias found at low liquid levels using other commonly used correction factors.

The UK participation in its preparation was entrusted by Technical Committee CPI/30, Measurement of fluid flow in closed conduits, to Subcommittee CPI/30/2, Differential pressure methods.

A list of organizations represented on this committee can be obtained on request to its secretary.

This publication does not purport to include all the necessary provisions of a contract. Users are responsible for its correct application.

Published by BSI Standards Limited 2016

ISBN 978 0 580 87568 7
ICS 75.060; 75.180.30

Compliance with a British Standard cannot confer immunity from legal obligations.

This Published Document was published under the authority of the Standards Policy and Strategy Committee on 31 January 2016.

Amendments/corrigenda issued since publication

Date	Text affected

PD ISO/TR 12748:2015

TECHNICAL REPORT

ISO/TR 12748

First edition
2015-10-15

Natural Gas — Wet gas flow measurement in natural gas operations

Gaz naturel — Mesurage du débit de gaz humide dans les opérations de gaz naturel

Reference number
ISO/TR 12748:2015(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 on the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the WTO principles in the Technical Barriers to Trade (TBT), see the following URL: Foreword — Supplementary information.

The committee responsible for this document is ISO/TC 193, *Natural Gas*, Subcommitte SC 3, *Upstream Area*.

Introduction

Oil and gas companies started developing Wet Gas Flow Meters (WGFMs) and Multiphase Flow Meters (MPFMs) through extensive R&D activities in the late 1980s. During this period, WGFMs and MPFMs were typically perceived as two distinct technologies for different applications: MPFMs were designed for liquid continuous flow conditions and WGFMs were designed for gas continuous flow conditions. In recent years, however, the operating range of these two technologies has increasingly overlapped, blurring the distinction between a WGFM and MPFM. As wet gas flow is presently considered a subset of multiphase flow, a WGFM is an MPFM that specializes in gas-dominant multiphase flow conditions. In this Technical Report, such technologies will be referred to as WGFMs.

There are many factors that contributed in the decision to replace a separator with a WGFM, with each application warranting careful consideration. A well-designed and maintained separator working within an appropriate flow condition range should produce accurate flow measurements. A primary concern for oil and gas companies was to reduce costs by replacing complex and bulky test separators, as well as to further simplify the upstream infrastructure, in particular for offshore and subsea projects. WGFMs typically require lower capital[1)] and operational[2)] expenditures than fully equipped test separators. More savings in CapEx may be achieved by omitting dedicated test lines in satellite developments. In addition, there is a significant benefit for offshore developments, in terms of weight and space conservation, by using the much smaller footprint of WGFMs.

Due to various operational problems, a conventional test separator does not continuously provide accurate and reliable well test data, giving only relevant information when the well is switched to the test separator. With the use of WGFMs testing well production more frequently or even continuously becomes possible. WGFM developments and extensive testing over the last two decades have resulted in WGFM technology that is a viable alternative to a test separator. Modern WGFMs now offer continuous well monitoring (per installation on individual wells).

WGFM technology is an attractive option for multiphase wet gas flow measurement. Over the last two decades, some WGFMs have been developed from prototypes into very mature, robust, advanced, and field-proven measurement devices, increasing their application scope. Although originally intended for use mainly in reservoir and well production allocations, WGFMs have evolved into a technology that spans even fiscal product allocation. In the latter case, the output of a WGFM is used to determine money transactions between operating companies or between an operating company and a host government.

This Technical Report focuses on the measurement of wet gas flow, i.e. terminology, models, and principles, and the design, implementation, testing, and operation of WGFMs.

1) Capital expenditure (CapEx) or costs for purchasing and installing a WGFM/MPFM includes all hardware to operate the WGFM (data transmission, verification facilities, sampling arrangements, etc.)

2) Operating expenditure (OpEx) or costs to operate a WGFM/MPFM (maintenance, verification processes, sampling for fluid properties, etc.)

Natural Gas — Wet gas flow measurement in natural gas operations

1 Scope

This Technical Report describes production flow measurement of wet natural gas streams with WGFMs in surface and subsea facilities. Wet natural gas streams are gas-dominated flows with liquids like water and/or hydrocarbon liquids[3)] (see 2.67 for a detailed definition). This Technical Report defines terms/symbols, explains the various concepts, and describes best practices of wet gas flow meter design and operation. It addresses metering techniques, testing, installation, commissioning, and operation practices such as maintenance, calibration, and verification. It also provides a theoretical background of this comprehensive, challenging and still evolving measurement technology.

There are four general methods in measuring wet natural gas flow. Each approach is detailed below.

— Single-phase gas flow meter with correction factor: Uses a single-phase gas flow meter (often a conventional gas flow metering device) with a correction factor for the effect of liquid on the metering system. In these cases, the liquid flow rate required to determine the correction factor, should be estimated from an external source.

— Two-phase WGFM: The gas and liquid (both water and hydrocarbon liquid combined) flow rates are predicted with no additional external information regarding the liquid flow rate required. This is generally known as a two-phase WGFM and will be referred to in this Technical Report simply as WGFM.

— WGFM: A flow meter that measures the gas and liquid flow rates, and also the gas, water and hydrocarbon liquid ratios (or “phase fractions”) with no external information required regarding the liquid flow rate.

— Phase separation/Measurement after phase separation: This traditional and conventional method of wet gas flow metering uses a two- or three-phase separator with single-phase flow meters measuring the outgoing single-phase flows.

The first three of these methods, which emerged in the last two decades, may be described as in-line wet gas flow metering, i.e. wet gas flow measurement is executed with WGFMs without separating the gas and liquid phases. This Technical Report discusses in detail these first three methods. Several best practice documents have already been issued to describe, among other topics, wet gas flow measurement[9][10][11][12].

The last method is more conventional and describes wet gas flow measurement after the gas and liquid phases have been separated. Wet gas meters can be used in multiphase flow metering systems that utilize partial separation technologies. This method is only briefly discussed in this Technical Report.

2 Terms and Definitions

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

2.1
adjustment
act of altering an instrument’s performance in any way, e.g. software, mechanical or electrical modifications, in order for the instrument’s indication to match the reference values indicated by a test stand

3) In this Technical Report, the term hydrocarbon liquid includes both oil and condensed hydrocarbons.

2.2
calibration
set procedure under specified conditions where the output/performance of an instrument is checked against a reference, usually a test stand

Note 1 to entry: The result of calibration determines the deviation between the instrument indication and the references. This deviation can assign an uncertainty value to the measurand and could indicate a requirement for an adjustment.

2.3
capacitance
the ability of a body to store an electrical charge

Note 1 to entry: Any object that can be electrically charged exhibits capacitance (e.g. a parallel-plate capacitor).

2.4
composition map
map with *water liquid ratio* or *WLR* (2.63) along the horizontal axis (0 % ≤ WLR ≤ 100 %) and *gas volume fraction* or *GVF* (2.22) along the vertical axis (0 % ≤ GVF ≤ 100 %); used to show WGFM operating envelopes and/or *well trajectories* (2.65)

Note 1 to entry: The combination of a *two-phase flow rate map* (2.59) and a composition map is beneficial to evaluate WGFM applications. See 8.1.3.

2.5
conductivity
ability of a material to conduct electrical current

Note 1 to entry: In isotropic material, conductivity is also the reciprocal of resistivity, sometimes called specific conductance.

2.6
density ratio
DR
ratio of gas density to liquid density at line conditions, or

$$\mathrm{DR} = \rho_g / \rho_l$$

Note 1 to entry: In multiphase wet gas flows, the liquid density is typically considered to be the density of a homogenous mix of liquid components. See Formula (6).

2.7
dry gas
fluid that is solely in a gaseous phase

Note 1 to entry: The mix of fluid components flowing may cause the gas to have a finite relative humidity but the flow at the flow meter is only in a gaseous phase.

2.8
emulsion
colloid substance consisting of water and hydrocarbon liquid mixes

Note 1 to entry: Emulsions can be water continuous or hydrocarbon liquid continuous, as these have different characteristics.

2.9
equation of state
EoS
equations that relate the properties of a given substance to its thermodynamic condition

2.10
film thickness
thickness of the liquid film in annular flow

2.11
flow regime
flow pattern
physical dispersion of phases of a two-phase flow (either wet gas or multiphase) in a conduit

Note 1 to entry: For a particular case of wet gas flow, the flow regime descriptions usually discuss gas and liquid interaction only, with no individual mention of water and hydrocarbon liquid.

2.12
flow quality
dryness fraction
gas mass fraction
GMF
x
ratio of the gas mass flow rate to the total mass flow rate, or

$$x = \mathrm{GMF} = \frac{\dot{m}_g}{\dot{m}_g + \dot{m}_l}$$

Note 1 to entry: In multiphase wet gas flows, the liquid flow rate is typically considered to be the sum of the liquid components (for example, hydrocarbon liquids, water and liquid chemical inhibitors).

2.13
flow regime (pattern) map
graph describing the wet gas flow regime across a range of flow conditions

Note 1 to entry: There is no agreed form for flow regime maps, and different maps can use different parameters on the graph axes. Gas and liquid superficial velocities are common choices. Flow regime maps are almost always created from experimental observation, and sometimes include theoretical considerations.

Note 2 to entry: to entry : Flow regime transitional boundaries/regions should be taken as approximations.

2.14
fluid
any substance that continuously deforms under a continuous infinitesimal sheer force.

2.15
foams
mixture of gas and liquids, where the gas is held in a liquid structure

Note 1 to entry: With wet gas, this tends to be more prevalent with gas/water flows than gas/liquid hydrocarbon flows due to the higher interfacial tension of water compared with that of liquid hydrocarbons.

2.16
free liquid
liquid components in a wet gas flow that are in a liquid form, not including evaporated liquid held as vapour state with the gaseous component of flow.

2.17
gamma rays
electromagnetic radiation of a kind arising from the radioactive decay of an atomic nucleus

2.18
gas
gaseous component of a wet gas flow, which includes any liquid vapour with relative humid gases

2.19
gas densiometric Froude number
square root of the ratio of the gas flow inertia (if it were to flow alone) to the liquid's weight, or

$$Fr_g = \sqrt{\frac{\text{Superficial Gas Inertia Force}}{\text{Liquid Gravity Force}}} = \frac{\bar{U}_{sg}}{\sqrt{gD}}\sqrt{\frac{\rho_g}{\rho_l - \rho_g}} = \frac{m_g}{A\sqrt{gD}}\sqrt{\frac{1}{\rho_g(\rho_l - \rho_g)}}$$

2.20
gas expansion factor
term used to indicate the volume change in gas between two different conditions, which may include standard conditions

2.21
gas to oil ratio
GOR
ratio of gas to hydrocarbon liquid volume flow rate

Note 1 to entry: GORs are stated at standard conditions, but may commonly use different units (e.g. sm^3/sm^3 or MMscf/bbls) resulting in different numerical values.

2.22
gas volume fraction
GVF
ratio of gas to total fluid volume flow rate at actual flow conditions, or

$$\text{GVF} = \frac{\dot{Q}_g}{\dot{Q}_g + \dot{Q}_l}$$

Note 1 to entry: The GVF is a dynamic measurement of volume flow rates that inherently accounts for slip (2.52) between the gas ($\dot{Q}_g$) and liquid ($\dot{Q}_l$) phases. The liquid volume flow rate consists of the sum of the liquid flow rates, e.g. hydrocarbon liquids, water, and liquid chemical inhibitors. This is **not** to be confused with *gas void fraction* (2.23). GVF may be expressed as a ratio or a percentage.

2.23
gas void fraction
α_g
ratio of gas cross sectional area to total pipe cross sectional area, or

$$\alpha_g = \frac{A_g}{A}$$

Note 1 to entry: Gas void fraction is a static measurement at a moment in time and it does **not** account for slip (2.52) between the gas and liquid phases. The existence of slip between the phases differentiates GVF from gas void fraction.

Note 2 to entry: Phase fraction devices in WGFM designs tend to measure the gas void fraction in the system's line-of-sight, not the GVF. The WGFM slip model then derives the GVF from inputs including the gas void fraction and other subsystem measurements.

2.24
homogeneous hydrocarbon liquid/water flow
flow of water and hydrocarbon liquid where the phases are evenly distributed throughout the fluid mix and there is no slip between the water and the hydrocarbon liquid

Note 1 to entry: The composition of a homogeneous water and hydrocarbon liquid mix is constant throughout the conduit. However, homogeneous distribution of the phases is rare.

2.25
infrared
electromagnetic radiation with longer wavelengths than visible light

2.26
intermittent flow
unsteady flow, where the GVF varies with time, e.g. slug flow

2.27
line conditions (actual, process, or operating conditions)
thermodynamic conditions of the fluid passing through the meter, i.e. the fluid conditions at line (metering device) pressure and temperature

2.28
liquid densiometric Froude number
square root of the ratio of the liquid flow inertia (if it were to flow alone) to the liquid's weight, or

$$Fr_l = \sqrt{\frac{\text{Superficial Liquid Inertia Force}}{\text{Liquid Gravity Force}}} = \frac{\bar{U}_{sl}}{\sqrt{gD}}\sqrt{\frac{\rho_l}{\rho_l - \rho_g}} = \frac{m_l}{A\sqrt{gD}}\sqrt{\frac{1}{\rho_l(\rho_l - \rho_g)}}$$

2.29
liquid hold up
α_l
ratio of liquid cross sectional area to total pipe cross sectional area, or

$$\alpha_l = 1 - \alpha_g = \frac{A_l}{A}$$

Note 1 to entry: The liquid hold up gives effectively the same information as the *gas void fraction* (2.23).

Note 2 to entry: The liquid hold up is a static measurement at a moment in time and it does **not** account for slip between the gas and liquid phases. That is the liquid hold-up gas and *liquid volume fraction* (2.31) differ due to the existence of slip between the phases.

Note 3 to entry: With multiphase wet gas flow the liquid hold up can be split into its constituent liquid components. For example, with a gas, condensate and water flow where hydrocarbon liquid hold-up (α_{hcl}) and water hold up (α_{water}) are:

$$\alpha_{hcl} = \frac{A_{hcl}}{A}$$

$$\alpha_{water} = \frac{A_{water}}{A}$$

$$\sum \alpha = \alpha_g + \alpha_{water} + \alpha_{hcl} = 1$$

2.30
liquid loading
qualitative description of the relative amount of liquid in a wet gas flow

2.31
liquid volume fraction
LVF
ratio of liquid to total fluid volume flow rate at actual flow conditions, or

$$\text{LVF} = 1 - \text{GVF} = \frac{\dot{Q}_l}{\dot{Q}_l + \dot{Q}_g}$$

Note 1 to entry: The LVF is a dynamic measurement of volume flow rates that inherently accounts for slip between the gas ($\dot{Q}_g$) and liquid ($\dot{Q}_l$) phases. The liquid volume flow rate consists of the sum of the liquid flow rates (for example, hydrocarbon liquids, water, and liquid chemical inhibitors). This is **not** to be confused with *liquid hold up* (2.29). LVF may be expressed as a ratio or a percentage.

2.32
Lockhart-Martinelli parameter
square root of the ratio of the liquid inertia to gas inertia if the phases flowed alone at line conditions, or

$$X_{LM} = \sqrt{\frac{\text{Inertia of Liquid Flowing Alone}}{\text{Inertia of Gas Flowing Alone}}}$$

that is:

$$X_{LM} = \frac{Fr_l}{Fr_g} = \frac{\dot{m}_l}{\dot{m}_g}\sqrt{\frac{\rho_g}{\rho_l}} = \frac{\dot{Q}_l}{\dot{Q}_g}\sqrt{\frac{\rho_l}{\rho_g}} = \frac{1 - GVF}{GVF}\sqrt{\frac{\rho_l}{\rho_g}}$$

Note 1 to entry: The Lockhart-Martinelli Parameter has a long 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 stated definition here. The definition supplied in this Technical Report 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[12] and.[13]

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

2.33
mass flow rate
mass of fluid flowing through a conduit per unit time

2.34
measurand
particular quantities subject to measurement

2.35
meter operating envelope
areas in the *two-phase flow rate map* (2.59) and/or *composition map* (2.4) in which a WGFM is to perform/or stated to be capable of performing

Note 1 to entry: This envelope may vary with changing operating condition and fluid properties.

2.36
microwave
electromagnetic radiation, typically in the frequency range 0,3 GHz to 300 GHz

2.37
multiphase flow
flow of gas, water, and hydrocarbon liquid phases

Note 1 to entry: Each of these three components is designated as a separate “phase”. Multiphase flows may also have other “phases” such as salinity of water or chemical injection phases. A multiphase flow is a subset of a two-phase flow where the liquid consists of two or more components, typically water and hydrocarbon liquid. There is no limit to the relative quantity of liquids in a multiphase flow, i.e. the GVF range is 0 % < GVF < 100 %.

2.38
multiphase flow meter
MPFM
device that measures the oil, water and gas flow rates in a multiphase flow

2.39
multiphase/phase fraction device
device that measures the phase area fractions of the individual phases of a multiphase flow

Note 1 to entry: These devices tend to measure the area occupied by a particular phase across a given cross-sectional area. This is not the same information as the phase volume flow rate ratios due to the existence of a *slip* (2.52).

2.40
oil continuous liquid
oil external emulsion
liquid flow consisting of the two “phases”, hydrocarbon liquid and water, where the hydrocarbon liquid phase encases the water phase suspended in water droplets in the hydrocarbon liquid phase

2.41
operating envelope
see 2.35

2.42
over-reading
ratio of a single-phase gas flow meter’s erroneous gas mass flow rate prediction (i.e. the “apparent gas mass flow rate”) to the actual dry gas mass flow rate

Note 1 to entry: In the case of DP devices, this is often approximated to the square root of the wet gas to dry gas DP ratio.

2.43
permittivity
measure of the ability of a dielectric medium to be electrically polarized when exposed to an electric field

2.44
phase
used in WGFM applications to describe each of the three components gas, water and hydrocarbon liquid. Other components such as glycol and methanol can also be referred to as “phases”

2.45
phase flow rate
amount (in mass or volume) of a specific phase passing a referenced point in the conduit per unit time

2.46
phase mass fraction
ratio of the mass flow rate of one phase to the total mass flow rate

2.47
production envelope
collection of possible well production trajectories (gas flow rates and liquid flow rates) over time in the *two-phase flow rate map* (2.59), see Figure 23

2.48
relative humidity
ratio of water liquid vapour present in a gaseous fluid relative to the maximum (or saturated) amount of water liquid vapour possible for that given gaseous fluid to hold at a given thermodynamic condition

2.49
Reynolds number
Re
ratio of the inertial to viscous forces, or

$$Re = \frac{\rho U.D}{\mu} = \frac{4\dot{m}}{\pi\mu.D}$$

Note 1 to entry: The Reynolds number is important in many single-phase meter calibrations or characterizations. In the common event of dry gas meters being used for wet gas flow measurement the Reynolds number term can be important. Note that there is no consensus on how to define Reynolds number for a multiphase flow

2.50
salinity
quantification of any dissolved salts in water, expressed as either a percentage or a concentration

2.51
shrinkage
volume change in liquids between two different thermodynamic operating conditions (may include standard conditions); comprises shrinkage due to pressure, temperature, and mass transfer between phases (e.g. gas coming out of solution)

2.52
slip
qualitative term used to describe differences in velocity between different phases in a wet gas or multiphase flow

Note 1 to entry: Typically, gas and liquid phases do not travel at the same velocity. The existence of slip significantly complicates wet gas and multiphase flow metering techniques.

2.53
slip ratio
S_R
ratio of average velocities of any two phases in a wet gas or multiphase flow, or

$$S_R = \frac{\bar{U}_g}{\bar{U}_l}$$

Note 1 to entry: For example, the slip ratio between gases and liquids, hence making the GVF and gas void fraction different parameters.

Note 2 to entry: Similarly, slip between water and gas, hydrocarbon liquids and gas, and water and hydrocarbon liquids exist. However, many manufacturers claim that the slip between water and hydrocarbon liquids in multiphase wet gas flows is negligible.

2.54
slip velocity
S
average velocity difference between two phases in a wet gas or multiphase flow, or

$$S_R = \bar{U}_g - \bar{U}_l$$

Note 1 to entry : For example, the difference in velocity between gas and liquid phases.

2.55
standard conditions
user-defined pressure and temperature, usually (but not always) a pressure of 101,325 kPa and a temperature of either 15 °C or 60 °F (15,55 °C)

Note 1 to entry : Further references are found in ISO 13443[46].

2.56
superficial gas velocity
average gas velocity that would exist if the gas of a wet gas flow was to flow alone in the pipe, or

$$\bar{U}_{sg} = \frac{\dot{m}_g}{\rho_g A}$$

2.57
superficial liquid velocity
average liquid velocity that would exist if the liquid of a wet gas flow was to flow alone in the pipe, or

$$\bar{U}_{sl} = \frac{\dot{m}_l}{\rho_l A}$$

2.58
two-phase flow
flow of a gas phase with a liquid phase

Note 1 to entry: In the definition of two phase flow the liquid is considered a single phase regardless of its composition. In the definition of multiphase flow the different liquid components (e.g. hydrocarbon liquid, water, chemical inhibitor etc.) are considered different phases.

2.59
two-phase flow rate map
used to show two-phase flow regimes, WGFM operating envelopes, and/or well trajectories

Note 1 to entry: A two-phase flow rate map has the gas flow rate as horizontal axis and the liquid flow rate as vertical axis, see 8.13. The combination of two-phase flow rate map and composition map are beneficial to evaluate WGFM applications.

2.60
x-rays
electromagnetic radiation of a kind arising from the electrons outside the nucleus

2.61
water continuous liquid
water external emulsion
liquid flow consisting of the two "phases", hydrocarbon liquid and water, where the water phase encases the hydrocarbon liquid phase suspended in hydrocarbon liquid droplets in the water phase

2.62
water cut
water to total liquid volume flow rate (for example, hydrocarbon liquids, water and liquid chemical inhibitors) at standard conditions, usually expressed as a percentage, or

$$Watercut = \left(\frac{\dot{Q}_w}{\dot{Q}_l} \right)_{standard\ \ conditions}$$

2.63
water liquid ratio
WLR
water to total liquid volume flow rate (for example, hydrocarbon liquids, water and liquid chemical inhibitors) at line conditions, may be expressed as a ratio or a percentage, or

$$WLR = \left(\frac{\dot{Q}_w}{\dot{Q}_l} \right)_{actual\ \ conditions}$$

2.64
water liquid mass ratio
WLMR
water to total liquid mass flow rate (for example, hydrocarbon liquids, water and liquid chemical inhibitors), usually expressed as a percentage or

$$WLMR = \left(\frac{\dot{m}_w}{\dot{m}_l} \right)$$

2.65
water volume fraction
WVF
water volume flow rate to the total mixture volume flow rate at operating conditions, or

$$WVF = \left(\frac{\dot{Q}_w}{\dot{Q}_g + \dot{Q}_l} \right)_{actual\ \ conditions}$$

2.66
well trajectory
trajectory over lifetime in the *two-phase flow rate map* (2.59) and *composition map* (2.4) of a well based on production forecast

Note 1 to entry: A collection of well trajectories for a gas field is called the production envelope of the gas field.

2.67
wet gas flow
subset of two-phase flow where the flow is gas dominant by volume

Note 1 to entry: The wet gas flow can have a gas flow with one or more liquid components, i.e. water only, hydrocarbon liquid only, a mix of water and hydrocarbon liquid flows, or a mix of water, hydrocarbon liquids and other liquids such as liquid chemical inhibitors, etc.

2.68
wet gas flow meter
WGFM
device that measures the gas, or gas and liquid flow rates of a wet gas flow, and may or may not meter the hydrocarbon liquid and water flow rates of the wet gas flow's liquid phase

3 Symbols

Symbol	Description	Dimension	SI unit (common field unit)
A	Meter inlet area	L^2	m^2 (in^2)
A_g	Gas cross sectional area	L^2	m^2 (in^2)
A_l	Liquid cross sectional area	L^2	m^2 (in^2)
A_t	Minimum (or throat) area of a DP meter	L^2	m^2 (in^2)
C_d	DP meter discharge coefficient	Dimensionless	Dimensionless
C_{ch}	Chisholm parameter	Dimensionless	Dimensionless
D	Meter inlet pipe diameter	L	mm (in)
DP or ΔP	Differential Pressure	M/LT^2	Pa (psi)
NOTE Dimensions: L = Length, M = Mass, T = Time, Θ = Temperature			

Symbol	Description	Dimension	SI unit (common field unit)
DR	Gas to liquid Density Ratio at operating conditions	Dimensionless	Dimensionless
E	DP meter's velocity of approach factor	Dimensionless	Dimensionless
$f_n\left(a,b,\ldots\right)$	Unspecified function with variables a, b, …	N/A	N/A
Fr_g	Gas densiometric Froude Number	Dimensionless	Dimensionless
$Fr_{g,strat}$	Gas densiometric Froude Number at the stratified/annular mist flow regime border	Dimensionless	Dimensionless
Fr_l	Liquid densiometric Froude Number	Dimensionless	Dimensionless
g	Gravitational constant	L/T^2	m/s^2 (ft/s^2)
GMF or x	Gas Mass Fraction at operating conditions	Dimensionless	Dimensionless
GOR	Gas Oil Ratio at Standard Condition	Dimensionless	sm^3/sm^3 (MMscf/bbls)
GVF	Gas Volume Fraction at operating conditions	Dimensionless	Dimensionless
K_o	Concentration of injected tracer liquid	Various	Various
K_s	Concentration of tracer in liquid sample	Various	Various
LMF	Liquid Mass Fraction	Dimensionless	Dimensionless
LVF	Liquid Volume Fraction at operating condition	Dimensionless	Dimensionless
M	Murdock coefficient	Dimensionless	Dimensionless
$\dot{m}_g$	Gas mass flow rate at the point of measurement	M/T	kg/s (lbm/s)
$\dot{m}_{g,apparent}$	Uncorrected gas mass flow rate predicted by gas meter with wet gas flow	M/T	kg/s (lbm/s)
$\dot{m}_{hcl}$	Hydrocarbon liquid mass flow rate	M/T	kg/s (lbm/s)
$\dot{m}_l$	Liquid mass flow rate	M/T	kg/s (lbm/s)
$\dot{m}_w$	Water mass flow rate	M/T	kg/s (lbm/s)
n	Chisholm exponent	Dimensionless	Dimensionless
n_{strat}	Chisholm exponent for stratified flow regime	Dimensionless	Dimensionless
OR	Over-Reading	Dimensionless	Dimensionless
P	Operating pressure	M/LT^2	Pa (psi)
PLR	Ratio of a DP meter's traditional PPL to DP	Dimensionless	Dimensionless
PPL	Permanent Pressure Loss across a pipe line component, such as a DP meter	M/LT^2	Pa (psi)
PVT	Pressure, Volume and Temperature Equation of State Calculations	Not Applicable	Not Applicable
$\dot{q}$	Tracer fluid injection volume flow rate	L^3/T	m^3/hr (ft^3/hr)
NOTE Dimensions: L = Length, M = Mass, T = Time, Θ = Temperature			

Symbol	Description	Dimension	SI unit (common field unit)
$\dot{Q}$	Volume flow rate	L^3/T	m^3/hr (ft^3/hr)
$\dot{Q}_g$	Gas volume flow rate at operating conditions	L^3/T	m^3/hr (ft^3/hr)
$\dot{Q}_{hcl}$	Actual hydrocarbon liquid volume flow rate	L^3/T	m^3/hr (ft^3/hr)
$\dot{Q}_l$	Actual liquid volume flow rate	L^3/T	m^3/hr (ft^3/hr)
$\dot{Q}_w$	Actual water volume flow rate	L^3/T	m^3/hr (ft^3/hr)
Re	Reynolds number	Dimensionless	Dimensionless
S	Slip velocity	L/T	m/s (ft/s)
S_R	Slip Ratio	Dimensionless	Dimensionless
T	Temperature	Θ	°C, K (°F, R)
U	Velocity of a fluid	L/T	m/s (ft/s)
$\bar{U}_g$	Average actual gas velocity in two-phase flow	L/T	m/s (ft/s)
$\bar{U}_l$	Average liquid velocity in two-phase flow	L/T	m/s (ft/s)
$\bar{U}_{sg}$	Superficial gas velocity	L/T	m/s (ft/s)
$\bar{U}_{sl}$	Superficial liquid velocity	L/T	m/s (ft/s)
V_g	Volume of gas in a unit length of pipe	L^3	m^3 (ft^3)
V_l	Volume of liquid in a unit length of pipe	L^3	m^3 (ft^3)
Water Cut	Water Volume flow rate to Total Liquid Volume flow rate at Standard Conditions	Dimensionless	Dimensionless
WLR	Water Volume flow rate to Total Liquid Volume flow rate	Dimensionless	Dimensionless
WLMR	Water Mass flow rate to Total Liquid Mass flow rate at operating conditions	Dimensionless	Dimensionless
WVF	Water Volume Fraction, i.e. Water Volume flow rate to Total Fluid Volume flow rate at operating conditions	Dimensionless	Dimensionless
x or GMF	Gas Mass Fraction, equivalent to Steam quality (dryness fraction), i.e. Gas Mass flow rate to Total Fluid Mass Flow rate	Dimensionless	Dimensionless
X_{LM}	Lockhart-Martinelli Parameter	Dimensionless	Dimensionless
NOTE Dimensions: L = Length, M = Mass, T = Time, Θ = Temperature			

Symbol	Description	Dimension	SI unit (common field unit)
Y or Y_g or ε	Expansibility coefficient for a DP Meter	Dimensionless	Dimensionless
Y_{tp} or Y_{gtp}	Expansibility coefficient for a DP Meter Calculated with Use of ΔP_{tp}	Dimensionless	Dimensionless
ΔP_g or ΔP_g	Single Phase Gas Differential Pressure	M/LT^2	Pa (psi)
ΔP_{tp} or ΔP_{tp}	Actual wet gas/two phase DP	M/LT^2	Pa (psi)
ΔP_{PPL} or ΔP_{PPL}	Head Loss/Permanent Pressure Loss	M/LT^2	Pa (psi)
$DP_{PPL,tp}$ or $\Delta P_{PPL,tp}$	Head Loss / Permanent Pressure Loss with two-phase flow	M/LT^2	Pa (psi)
α_g	Gas Void fraction	Dimensionless	Dimensionless
α_{liquid}	Liquid hold up	Dimensionless	Dimensionless
α_{hcl}	Hydrocarbon liquid hold up	Dimensionless	Dimensionless
α_{water}	Water hold up	Dimensionless	Dimensionless
β	Square root of a throat to meter inlet area ratio of a DP meter	Dimensionless	Dimensionless
δ	Fluctuation	Various	Various
κ	Isentropic exponent	Dimensionless	Dimensionless
ρ	Density of a fluid	M/L^3	kg/m^3 (lbm/ft^3)
ρ_g	Density of gas	M/L^3	kg/m^3 (lbm/ft^3)
ρ_l	Density of liquid	M/L^3	kg/m^3 (lbm/ft^3)
ρ_w	Density of water	M/L^3	kg/m^3 (lbm/ft^3)
ρ_{hcl}	Density of hydrocarbon liquid	M/L^3	kg/m^3 (lbm/ft^3)
μ	Dynamic viscosity of fluid	M/LT	Pa.s
ω	Frequency of a parameter measurement	1/T	Hz
NOTE Dimensions: L = Length, M = Mass, T = Time, Θ = Temperature			

4 Objectives of wet gas flow measurement

There are varying objectives that all come under the generic term wet gas flow measurement. The specific objectives will often dictate the wet gas measurement techniques applied. These techniques range from the simple and inexpensive, e.g. orifice, Venturi arrangements, to the highly complex and more expensive three-phase WGFMs[4]. The economic justification should include CapEx and OpEx considerations as well as the value of the information that is delivered by the meter. For the latter, the user should also understand the measurement objectives, i.e. the purpose of the measurements, the

4) The term WGFM means both two-phase and multiphase WGFMs. This distinction is made between two-phase WGFMs and multiphase WGFMs, where necessary.

sensitivities of the measurements, as well as the boundary conditions and limitations. As an example, the costs caused by a hydrate-plugged subsea gas line (production deferment and remedial activities) are many times more than the installation of a WGFM that is able to measure the water content and facilitate proper hydrate management.

The following are some common measurement objectives:

— reservoir and well management;

— production optimisation;

— production (gas, condensate and water) allocation (see 4.2);

— formation water breakthrough detection;

— flow assurance, e.g. hydrates, scale, salt deposition (see 4.3);

— optimization of chemical injection.

The following are limitation and boundary conditions that should also be considered:

— economic justification,

— total lifecycle cost, e.g. capital, operational, decommissioning (see 4.4);

— intended location (onshore, offshore, subsea, remote, accessible);

— size/physical/power limitations;

— impact of changing fluid properties on the meter performance (hydrocarbon compositional changes, density, H_2S, salinity, etc.), particularly for co-mingled flows;

— impact of wax, salts and scale.

A more comprehensive check list can be found in Annex A.

4.1 Common production scenarios

The following is a list of various production scenarios.

a) The asset is primarily for natural gas production. The fluid flow is wet gas but the main focus is on the measurement of the gas flow. The liquid flow is only an inconvenience affecting the accuracy of the gas measurement.

b) The asset is primarily for hydrocarbon liquid production. The flow is wet gas but the objective is the measurement of the hydrocarbon liquid flow. The gas flow is only providing the liquid hydrocarbon carrying mechanism. After phase separation the gas may be re-injected back into the reservoir as part of the production cycle.

c) The asset contains both valuable natural gas and hydrocarbon liquid flow. There is minimal water content in the wet gas flow. The operator is required to accurately measure the gas and liquid hydrocarbon flows. This situation is relatively common at many gas fields from early life through end of life production flows.

d) The production flow contains natural gas, hydrocarbon liquid and water flow. There is significant water content in the wet gas flow. The operator is required to accurately measure both the natural gas flow and the hydrocarbon liquid flow for production. The operator also requires to accurately measure the water flow for water treatment and disposal costs. The water flow rate may also be required to judge the level of hydrate and scale chemical inhibitors to be injected.

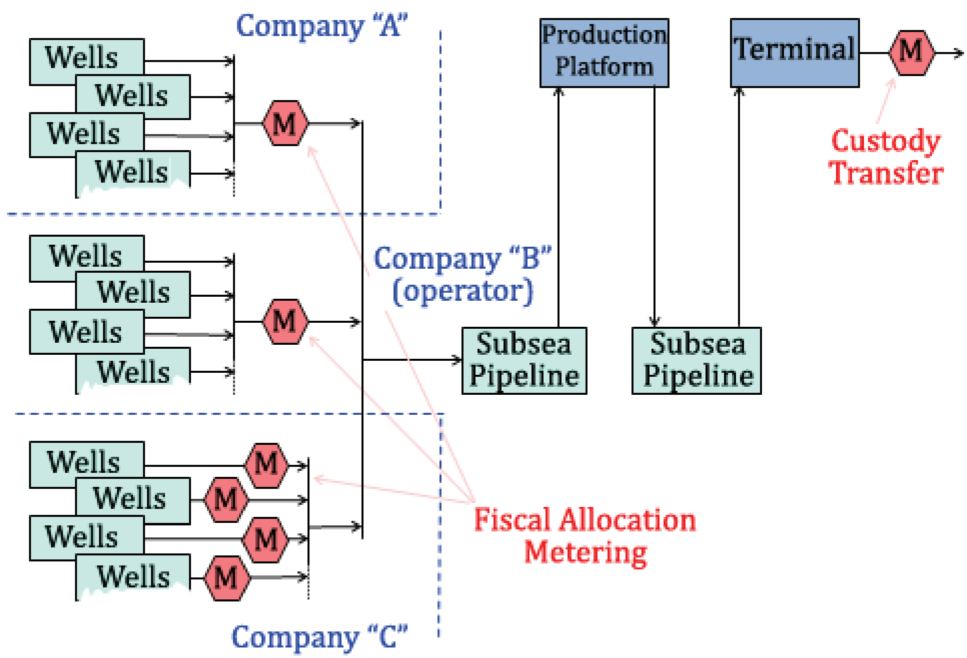
e) The production flow contains natural gas and hydrocarbon liquid flow and initially no condensed or formation/produced water flow. However, as the well ages water may appear. This phenomenon is commonly termed water breakthrough. The presence of water can adversely affect the operation of the pipeline due to hydrate formation, scale, or salt deposition. For these reasons WGFMs or (indirect) water fraction sensors may be utilized primarily as water breakthrough monitors or for determining chemical inhibitor injection rates. In these applications the water monitoring capability of the meter is the primarily requirement for flow assurance purposes.

4.2 Production allocation

In recent years, WGFMs are increasingly used for fiscal applications where the output of the meter determines money flow between oil companies or between companies and host governments (e.g. sales allocation, transportation fees, custody transfer, and royalty payments). The move of WGFMs into this application is due to the upstream oil and gas business becoming increasingly complex in terms of infrastructure, i.e. facilities are being shared between various producing companies and commingling is done much further upstream in the process.

The modern trend of subsea co-mingling the wet gas production streams (see Figure 1) calls for a new measurement approach and different philosophies for allocating the condensate, gas, and water to the respective sources. In those complex subsea infrastructures, the use of WGFMs is very beneficial, but the use of these meters creates operational challenges. As an example, in subsea applications, it is expected that these WGFMs will continue to operate for a long time without the ability to retrieve the meter or to access the meter for maintenance, verification, sampling or calibrations.

There exists a large diversity in applied physical concepts, which makes it difficult to select an adequate WGFM for a particular development. It is often difficult to judge all the future operational effects on the WGFM in a remote and inaccessible location. One issue that is not well documented and still creates uncertainty in the long term operation is the effect of changing fluid parameters on the oil/condensate, water and gas flow rate readings. Mismanagement of these fluid properties can have a significant impact on the money flows between operating companies or operating companies and host government or may jeopardize flow assurance.



NOTE "M" denotes meter location

Figure 1 — WGFMs installed at the seabed at the entry of a commingled subsea pipeline will ultimately determine the money flow between companies A, B and C

4.3 Flow assurance aspects

In order to ensure a continuous production of hydrocarbons, flow assurance is a critical aspect of flow metering system design. For instance, the management of water production is essential; water in the production lines can cause scale, salt and hydrate formation, which can ultimately block flow lines. The subsequent financial loss from such a production interruption or facility damage can be substantial. In order to optimize the scale and hydrate deposit inhibition, it is important that water production rates are measured. For many fields it is also important to know the salt content of the produced water, not only as a fluid property input to the flow rate calculation, but also in order to prevent corrosion in the pipelines and production facilities. Next to the above flow assurance aspect, knowledge about salt content is also important from a reservoir management perspective. Discrimination between salt and fresh water can be used to identify the origin of produced water, as either condensed water vapour or produced formation water.

Flow assurance is a critical task during deep water oil and gas production because of the high pressures and low temperature (approximately 4 °C) involved.

4.4 WGFM considerations

Once the decision has been made to use WGFMs in a project, either for well and reservoir management, for sales allocation, for legal requirements or for operational control or flow assurance, the WGFM selection process is started. Given the diversity in commercial WGFM concepts this is not an easy task. Each metering concept has its benefits and challenges regarding measurement performance, engineering requirements and cost.

The cost of purchasing, installing and operating the WGFMs is an important aspect that needs upfront consideration. There is a relatively large spread in purchasing costs (dependent on pressure rating and meter size) and subsea flow meters can be often multiple times more expensive than the equivalent for a topside application. However, the total life cycle cost of a WGFM should include the purchasing, engineering and installation costs (all considered CapEx) and the costs to operate the WGFMs, i.e. maintenance, verification processes, sampling for fluid properties, etc. (all considered OpEx). Hence, in the WGFM selection process it is recommended to consider these life cycle costs next to the performance driver (i.e. uncertainty, repeatability and availability).

The WGFM performance over the entire operating range and the practicality of the maintenance requirements are important considerations to be weighed against the total life cycle of the WGFM.

4.5 Reliability in remote WGFM installations

An important aspect in remote or subsea metering WGFM is reliability. Subsea WGFMs are installed for a long service life, 25 years up to 30 years in some cases. The mean time between failure (MTBF)[5] specified by vendors are also within that time span, but with subsea WGFM technology having been around less than 25 years, these theoretical MTBF numbers are unreliable.

A WGFM often contains a number of measurement systems (subsystems or building blocks) and if one system fails it would be very beneficial if its functionality could be taken over by another measurement system or a combination of other measurement systems. Having this redundancy (duplication and/or over-determined systems) allows the operator to execute verification checks on the meter as a particular measurement can be done twice with the benefit of being able to compare the two readings. For those applications with no or limited access, it is strongly recommended to apply systems that have as much redundancy as practically possible.

In addition, evaluation of the use of a virtual metering system (VMS) as fall-back is an option (see 6.8). Virtual metering systems are relatively low cost and easy to install. However, their ongoing maintenance often requires specialist involvement which can be costly, and also their uncertainty is often more difficult to assess. Note that a virtual metering system is not a replacement for conventional measurements or WGFM systems, and also is difficult to qualify.

5) MTBF is the predicted elapsed time between inherent failures of a system during operation.

5 Flow regimes

WGFMs may be influenced by flow regimes.

Brief descriptions for two-phase flow, multiphase flow and wet gas flow have already been provided in 2.58, 2.37 and 2.67 respectively. Both multiphase flow and wet gas flow are subsets of a two-phase flow (see Figure 2). For multiphase flows, there should be a minimum of three phases present (oil, water, and gas) and the GVF should range from 0 % to 100 %. For wet gas flows, gas flow — in terms of volume flow — should be dominant; thus, resulting in high GVF and the relatively small liquid volume flow can either be one-phase (two-phase wet gas flow) or more (multiphase wet gas flow). However, the differentiation between a two-phase wet gas flow and a multiphase wet gas flow is not always made in practice and generally just the term wet gas flow is used. This approach is also used in this Technical Report and, only where essential, the terms two-phase or multiphase are added to wet gas flow or wet gas flow measurement.

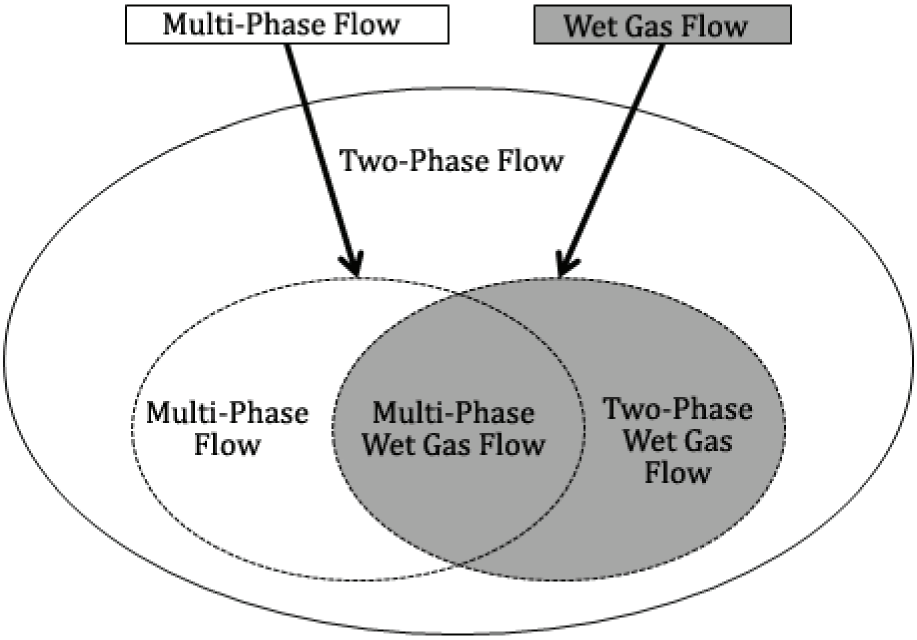


Figure 2 — Multiphase and wet gas flow shown as both a subset of a two-phase flow

The flow regime is a physical description of the way the liquid phase is dispersed in the gas flow. The flow regime is important in wet gas flow metering, as the dispersion of the liquid can influence the performance of flow meters. Many WGFM designs perform better in a particular flow regime or attempt to induce a preferred flow regime.

Flow regimes are dictated by complex phenomena and are difficult to describe precisely. Fluid properties, phase flow rates, meter orientation, pipe geometry, and the line pressure and temperature all affect the flow regime. The transitions between different flow regimes are gradual with varying influencing parameters.

Flow regimes are presented depending on flow orientation. Given these complexities, these presentations are approximations and only representative of flow in long straight pipes. Figure 3 shows typical horizontal and vertical flows. Most WGFMs are installed in one of these two orientations.

5.1 Horizontal wet gas flow regimes

For all horizontal wet gas flow regimes, the gas velocity is higher than the liquid velocity, i.e. there is slip between the phases.

5.1.1 Stratified flow

For a given gas to liquid flow rate ratio at relatively low pressure and gas velocity, i.e. a low gas dynamic pressure, the liquid weight is the dominant force on the liquid phase. In this case, the fluid phases are stratified. This is commonly termed “stratified flow” (or “separated flow”). The interface between the two phases can be smooth, but commonly has a disturbed (i.e. wavy) interface.

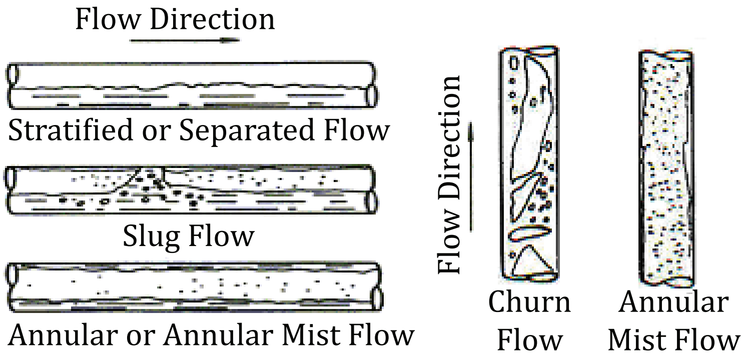


Figure 3 — Horizontal and vertical upward flow regimes

5.1.2 Slug flow

Excessive waves that nearly or completely fill the pipe cross section are termed slug flow. This is unstable flow and it is therefore generally not desirable to attempt to meter wet gas flow with a slug flow regime. Slug flow is one example of what is often called “intermittent flow”.

Slug flow should not be confused with “severe slugging”. Severe slugging is the irregular surge of a plug of collected trapped liquids in the upstream piping. This volume of liquid travels at relatively high speed and is potentially damaging to downstream equipment. The subsea riser or pipeline over rugged terrain are locations where severe slugging can occur. Slug catchers are common components in hydrocarbon production pipe lines. Severe slugging can have adverse performance effects on WGFMs.

5.1.3 Annular mist flow

At high dynamic gas pressures, i.e. high gas velocity and/or density, and higher gas-to-liquid ratio (higher GVF), the prevalent flow regime is annular mist flow.

The horizontal flow can have an asymmetrical ring of liquid around the periphery of the pipe with the gas flowing in a central core laden with entrained liquid droplets. As the gas dynamic pressure increases the entrainment increases, the annular ring depth reduces and the average drop size decreases.

At the extreme condition of the liquid being fully entrained, droplets are well dispersed in the gas phase. This mixture can be approximated as a pseudo-single-phase flow of averaged fluid properties as the slip ratio tends to unity. This condition is termed either mist flow, fully dispersed flow, or homogenous flow.

5.2 Vertical up wet gas flow regimes

Vertical and horizontal wet gas flows can have different flow regimes due to the influence of gravity.

5.2.1 Churn flow

For a given gas-to-liquid flow rate ratio at relatively low gas dynamic pressure, the wet gas flow is highly unstable. This flow regime is called “churn flow” and is generally undesirable for wet gas flow metering. It can exhibit the particular characteristic of having fluid structures that are momentarily moving against the bulk flow direction, or with a strong radial velocity component. Churn flow is another example of what is often called “intermittent flow”.

5.2.2 Annular mist flow

For a given gas-to-liquid flow rate ratio at higher gas dynamic pressure, the liquid's weight can be overcome and the flow becomes a symmetrical annular mist flow. As the gas dynamic pressure increases, annular mist flow behaves in the same way as it does in horizontal flow. The flow regime can be described as alternatively mist flow, dispersed flow or homogenous flow.

5.3 Vertical down wet gas flow regimes

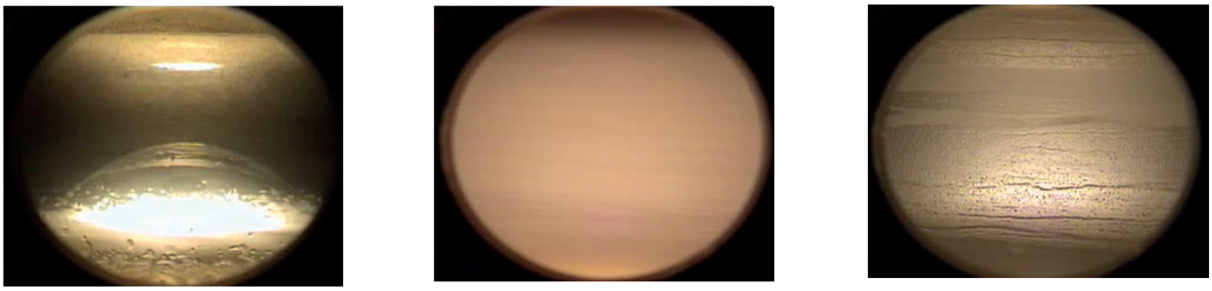
There are no diagrams presented for vertical down flow. All vertical down flow is considered to be annular mist flow as gravity acts in the same direction as the gas flow. For vertical down annular mist flow, the slip between the phases can be considerably different than with vertical up annular mist flow. This can cause the meter performance to be different.

5.4 Inclined flow

Knowledge of inclined pipe flow regimes is not well documented relative to that of horizontal and vertical flow regimes. It is known that even a few degrees positive or negative deviation from the horizontal can significantly affect a flow regime.

5.5 Examples of wet gas flow regimes

These pictures are photographs taken through a view port in the side wall of the pipe with the light source located at –120° from the camera angle.

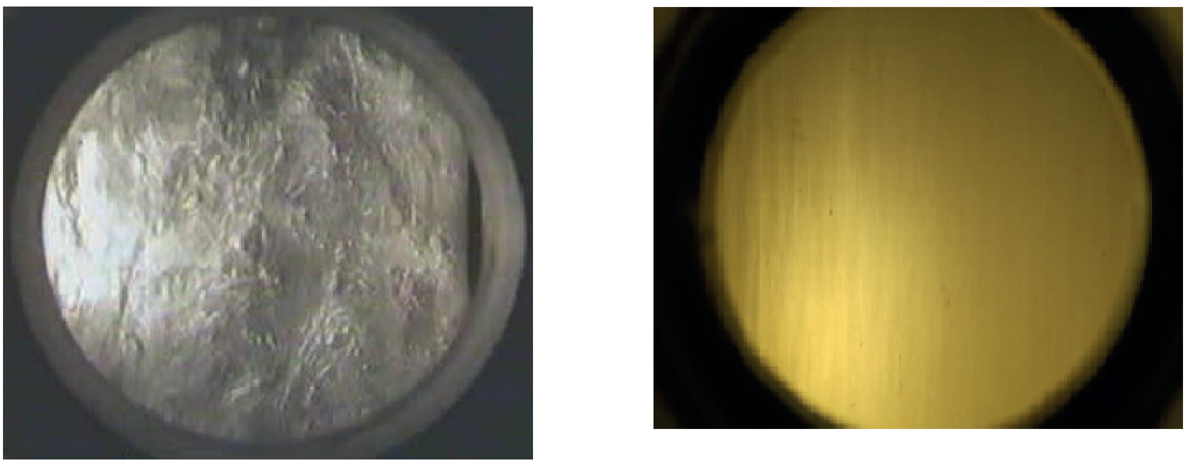


a) Nominally stratified flow

b) Annular mist

c) Transition between stratified and annular mist

Figure 4 — Examples of horizontal wet gas flow regimes



a) **Vertical up churn flow** b) **Annular mist vertical up flow**

Figure 5 — Examples of vertical up wet gas flow regimes

Figure 4 and Figure 5 show a small set of examples of horizontal and vertical up wet gas flows. Real flow regimes generally behave in a more complex and unsteady way than suggested in the idealised diagrams of Figure 3. Often, the actual flow regime is some hybrid regime in transition between two flow regimes.

It addition, most wet gas flow regime descriptions only discuss a gas and a liquid component. Most wet natural gas flow metering applications have liquid phase mixtures of both water and hydrocarbon. This can further alter wet gas flow regimes, both complicating the wet gas flow regime description and affecting the WGFM response.

— Figure 4 a) shows nominally stratified flow. The fluids are natural gas and water. However, the water phase has gas bubbles entrained within it. At the same flow conditions natural gas and hydrocarbon liquid flow does not have gas bubbles in the liquid.

— Figure 4 b) shows natural gas with a hydrocarbon liquid. The flow regime is annular mist.

— Figure 4 c) shows natural gas with both hydrocarbon liquid and water. The flow regime is in transition between stratified and annular mist. Streaks of water, or “rivulets”, can be seen on the wall. Such behaviour is not known to occur if the gas flows with water alone or hydrocarbon liquid alone. That is, the mixture of water and hydrocarbon liquid causes a shift in flow regime compared to if the gas flows with only a single liquid component.

— Figure 5 a) shows natural gas and water vertical up churn flow.

— Figure 5 b) shows a natural gas and hydrocarbon liquid annular mist vertical up flow.

This complexity of flow regimes is one of the reasons why WGFM designs largely rely on semi-empirical correlations (sometimes called “slip models”). However, the slip models correlations are often confidential and considered Intellectual Property of the vendors.

5.6 Flow regime maps

Wet gas flow regime maps present qualitative illustrations of the different flow regimes at various conditions in a graphical format. Many such maps are for general two-phase flow where the wet gas region is a section of the overall flow condition range considered. Flow regime maps may be used to educate about wet gas flow behaviour and to predict the expected flow regime. Flow regime maps are typically not used as part of the metering process.

Figure 6 shows a typical example of a horizontal flow map in the wet gas region for a nominally 4-inch line size, with natural gas and hydrocarbon liquid. Like many flow regime maps it is created from physical observation. There are no guidelines on how to create a flow regime map. For this reason flow regime maps can have different parameters on the axes. In this particular example these are the gas and liquid densiometric Froude numbers. It should be noted that flow regimes change gradually when the relevant parameters vary. The borders between the flow regimes do not represent step changes but rather the centre of transition regions.

The flow regime may change as the flow progresses through the WGFM. For example for DP meters the reduction of cross sectional area causes further local flow regime change. The acceleration of the flow causes the local flow regime to tend towards annular mist flow.

Although Figure 6 may infer that slug flow will not occur with wet gas, it should be noted that this figure is only applicable across a specific range of flow conditions. When considering other wet gas flow conditions, the boundaries shown in this map change position, and there are wet gas flow conditions where slug flow does occur.

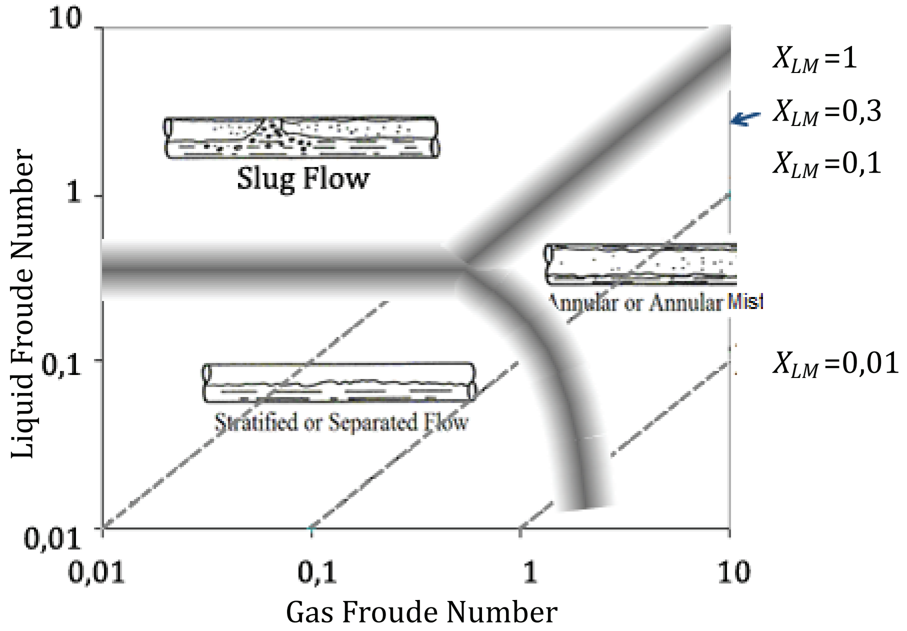


Figure 6 — An example of a natural gas and light liquid hydrocarbon horizontal flow regime map for a 4-inch line

5.7 Different wet gas flow parameters

It is common for different operators and WGFM manufacturers to use different parameters to describe liquid loading terminology. Hence, conversion between liquid loading terms is required.

Common parameters describing the "wetness" of a wet gas flow are the Lockhart-Martinelli parameter (X_{LM}), the Gas Volume Fraction (GVF), the Liquid Volume Fraction (LVF), the quality (x), the liquid to gas mass flow rate ratio or the liquid to gas volume flow rate ratio. These parameters are not all directly interchangeable. Some are related through the gas and liquid densities, and conversion equations for various wet gas flow parameters are given in Annex B.

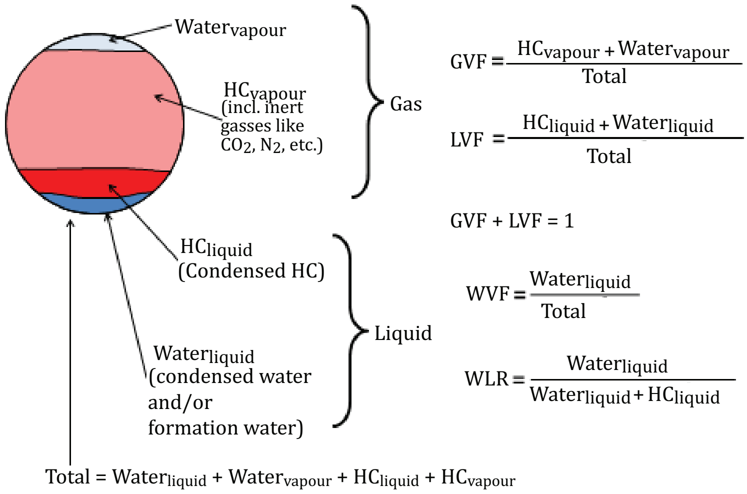
Defining the maximum value for liquid content of a wet gas flow has proved contentious. Academia, WGFM manufacturers and operators often have different ways of describing the wetness of gas flows. Furthermore, when one named parameter is chosen, there may still be debates on the precise definition of that parameter and what maximum value of that parameter constitutes the limit of wet gas flow.

However, the Lockhart-Martinelli (X_{LM}) parameter (as defined in 2.32) has become the most prominent parameter to be used to describe the liquid loading of a wet gas flow. A common definition for wet gas flow is a Lockhart-Martinelli parameter value less than approximately 0,3. This boundary value is intended to represent the approximate lower flow regime boundary from non-intermittent to intermittent flow regimes (see Figure 6). It should be noted that intermittent flow is an adverse flow condition for WGFMs. Both the operator and the WGFM vendor should mutually understand the liquid loading and the WGFM operating range in terms of gas and liquid flow rates and flow regimes.

5.8 Water in wet gas flow

Water molecules can be present in either the liquid phase or the gas phase. Water in the gas phase is generally called water vapour and originally present in the reservoir gas. The water in the liquid phase can be a mixture of condensed water (condensed from the reservoir gas in the production process) and water from the reservoir aquifer (formation water). The latter is often saline water and should in principle not be produced; however, that cannot always be avoided. In particular at a later stage in the production process this water is breaking through in the well bore. In Figure 7 a schematic cross sectional area is given of a wet gas flow with an indication of where water molecules can be found.

WGFMs are in principle able to measure the water content in the well production stream but it is not always straight forward what vendors actually mean by measuring water flow rate or WVF and this needs further clarification with the vendors.



NOTE Water in gaseous form tends to be called “water vapour”.

Figure 7 — A schematic figure showing where water molecules are present

6 Wet gas flow metering principles

6.1 General

In-line WGFMs measure a wet gas flow without the requirement for phase separation. In-line measurement of a wet gas flow is usually approached via three general methods.

a) Single-phase gas flow meter with correction factor — Use a single-phase gas flow meter (often a conventional gas flow metering device) with a correction factor for the effect of liquid on the metering system. In these cases the liquid flow rate, required to determine the correction factor, must be estimated from an external source (see 6.2.1).

b) Two-phase WGFM — The gas and liquid (both water and hydrocarbon combined) flow rates are predicted with no additional external information regards the liquid flow rate required. This is generally known as a two-phase WGFM and will be referred to in this report as just WGFM (see 6.2.2).

c) Multiphase WGFM — A method that is characterized by the WGFM measuring the gas and liquid flow rates and also the gas, water and hydrocarbon liquid phase fractions. No external information is required regarding the liquid flow rate. In order to determine the correction factor, two methods can be used. In the first case, this correction factor is deduced from fully empirical or semi-empirical correlations deduced from tests. In the second approach a physical model is used taking into account the different interactions between the phases in the WGFM (see 6.2.3). The physical model produces a semi-empirical correlation.

All three methods require the application of empirical or semi-empirical correlations, deduced from experimental data sets.

— Empirical correlations (i.e. mathematical data fit) apply a mathematical expression that is found to best represent a stated data set. There is no physical meaning to the chosen mathematical expression.

— Semi-empirical correlations apply a mathematical expression formed around a physical model. There is physical meaning to the chosen mathematical expression and only constants within the expression are fitted to a data set.

— The complexity of physical modelling, and hence the complexity of semi-empirical correlations, can vary widely between metering systems. Increasing the complexity and robustness of physical modelling, and the associated semi-empirical correlations, is at the fore-front of WGFM research and development.

This Technical Report addresses all three of these generic in-line WGFM technologies mentioned above.

The fourth approach to wet gas metering is phase separation. This traditional method uses a two- or three-phase separator to separate the natural gas, liquid hydrocarbon and water phases. Single-phase flow meters are used at the separator single-phase flow outlets. This wet gas metering system concept is simple, technically transparent and common. There are many applications where this is a successful technology. There are other applications where the use of a separator is not ideal as production conditions, and common financially driven operator practices, can adversely affect this multiphase wet gas metering methodology. This Technical Report briefly discusses these issues but concentrates on the in-line WGFM technologies.

There are examples of technologies that are hybrids of these different general methodologies.

6.2 In-Line wet gas flow meters

6.2.1 Single-phase gas flow meter with correction factor

Single-phase gas flow meters are often operated with wet gas flow. A single-phase gas meter will have a gas flow rate prediction error induced by the presence of liquid with the gas flow. For Differential Pressure (DP) meters these errors tend to be reproducible. For known fluid properties and liquid flow rate information (obtained from an external source) the gas flow rate prediction error tends to be correctable. This “wet gas correction factor” can be called a “wet gas correlation”. A wet gas correlation can be empirical or semi-empirical. Most commercial products using wet gas correlations have a heavy reliance on data fitting.

The liquid flow rate measurement is usually a spot measurement technique, including, but not exclusively using

— test separator historical data,

— tracer dilution methods, and

— PVT predictions.

The gas flow rate prediction uncertainty is influenced by the wet gas correlation, fluid property and liquid flow rate assumption uncertainties. Extrapolation of any wet gas correlation beyond the set laboratory flow conditions on which it was based can lead to gas flow rate prediction biases.

A DP meter with a wet gas flow correlation is a widely understood metering technology and is the most common way of measuring wet gas flow.

6.2.2 Two-phase wet gas flow meter

A two-phase WGFM measures the bulk gas and liquid flows without distinguishing between water and liquid hydrocarbon phases. A two-phase WGFMs require that the fluid properties be supplied by an external source, but they do not require the bulk liquid flow rate supplied from an external source.

Traditionally, two phases WGFMs are designed for gas with one liquid component flow although some designs have been successfully used with gas, water and liquid hydrocarbon wet gas flows. Two-phase WGFMs do not predict the ratio of water to liquid hydrocarbon flow rates.

Two-phase WGFMs are more complex and expensive than a standalone single-phase gas meter with a wet gas correlation. However, unlike a standalone single-phase gas meter with a wet gas correlation, two-phase WGFMs can indicate live liquid and gas flow rates.

A two-phase WGFM design combined with a “water-liquid ratio (WLR) device” can produce a multiphase WGFM system.

6.2.3 Multiphase wet gas flow meter

Multiphase WGFMs measure the natural gas, water and hydrocarbon liquid flow rates of a multiphase wet gas flow. Multiphase WGFMs are flow meters where the metering system can also measure the ratio of hydrocarbon liquid and water.

Multiphase WGFMs require that fluid properties be supplied by an external source, but they do not require the hydrocarbon liquid or water flow rates be supplied from an external source.

A multiphase WGFM offers more detailed flow information than a two-phase WGFM or a single-phase gas meter with wet gas correlation, but these advantages come with considerably more complexity, subsystems and expense.

It should be noted that such is the variety of WGFM designs available that some meter designs may not fit neatly into these general descriptions.

6.3 Single-phase gas differential pressure meters with wet gas flow

Differential Pressure (DP) meters are popular flow meters for single-phase gas flow applications. Often operators do not know a natural gas production flow will be wet before production starts, and a single-phase DP meter is chosen for the application. Gas DP meters are therefore the most common WGFMs by default.

When operators know a natural gas flow will be wet from the outset, DP meters are still a common meter choice. In many cases, it is not economically justifiable to use a WGFM. It is often considered better to have some flow information rather than none. Therefore, a DP meter will be used to measure the wet gas flow. A wet gas correlation may or may not be applied. Furthermore, in some applications the WGFM is not expected to perform with low uncertainty.

There is substantial public data showing DP meter wet gas flow trends. Although there are many single-phase DP meter designs[6)], they operate using the same physical principles and the same generic flow formula.

The generic differential pressure (DP) meter mass flow rate formula is:

$$\dot{m}_g = EA_t \varepsilon C_d \sqrt{2\rho_g \Delta P_g} \qquad (1)$$

When a generic DP meter is used with wet gas flow, the presence of the liquid with the gas causes the differential pressure produced (ΔP_{tp}) to be different than if the gas flowed alone (ΔP_g). When applying

6) This discussion excludes the laminar flow element and averaging pitot tube meter designs which operate on different physical principles to the main group of DP meter designs and are not commonly used in wet gas flow applications.

the standard gas mass flow rate Formula (1), the use of this wet gas differential pressure (ΔP_{tp}) produces an "apparent" gas mass flow rate prediction, as shown by Formula (2)

$$\dot{m}_{g,apparent} = EA_t \varepsilon_{tp} C_{d,tp} \sqrt{2\rho_g \Delta P_{tp}} \tag{2}$$

The expansibility () is dependent on the differential pressure and hence wet gas causes a different expansibility () than when the gas is dry. If the discharge coefficient is a function of the Reynolds number, then the resulting iterative solution results in a different discharge coefficient ($C_{d,tp}$) to that when the gas is dry.

The over-reading (OR) is defined as the ratio of the flow meter's apparent gas flow rate to the actual gas mass flow rate. Formula (3) expresses a DP meter's over-reading

$$OR = \frac{\dot{m}_{g,apparent}}{\dot{m}_g} = \frac{EA_t \varepsilon_{tp} C_{d,tp} \sqrt{2\rho_g \Delta P_{tp}}}{EA_t \varepsilon C_d \sqrt{2\rho_g \Delta P_g}} = \frac{\varepsilon_{tp} C_{d,tp}}{\varepsilon C_d} \sqrt{\frac{\Delta P_{tp}}{\Delta P_g}} \tag{3}$$

In many industrial flow conditions the general simplification $\varepsilon_{tp} C_{d,tp} \approx \varepsilon C_d$ is reasonable. Therefore, a DP meters over-reading is sometimes denoted as the ratio of the two-phase/wet gas DP (ΔP_{tp}) to the DP that would be produced if the gas component of the wet gas flow flowed alone (ΔP_g), i.e. Formula (4).

$$OR \approx \sqrt{\frac{\Delta P_{tp}}{\Delta P_g}} \tag{4}$$

6.3.1 DP Meter design influence on wet gas over-reading

Different DP meter designs, and different geometries of any one generic DP meter design, can have different wet gas flow over-readings for any given wet gas flow condition. However, all DP meters have the same generic wet gas flow trends. This characteristic means one DP meter design can be used to describe the generic DP meter wet gas flow response. Data for a Venturi meter is shown in Figure 8 through Figure 13, although the general trends are true of all DP meters.

6.3.2 Lockhart-Martinelli parameter influence on DP meter wet gas flow over-reading

Single-phase gas flow DP meters tend to indicate a positive bias, or "over-reading", induced by the presence of liquids. The scale of the DP meter's wet gas over-reading is influenced by the Lockhart-Martinelli parameter. As the Lockhart-Martinelli parameter increases, the over-reading increases[14]. Figure 8 shows sample DP meter data indicating this phenomenon. This type of graph is called a "Murdock plot".

For the particular case of the orifice meter with very low Lockhart-Martinelli parameter values (X_{LM} < 0,02), it is known that a slight negative bias may be induced on the gas flow rate prediction by the presence of liquids[12]. At higher Lockhart-Martinelli parameters, orifice meters will over-read the gas flow rate.

6.3.3 Gas to liquid density ratio influence on DP meter wet gas flow over-reading

The scale of a DP meter's wet gas over-reading is influenced by the gas to liquid density ratio. For a given DP meter, and all other wet gas flow parameters held constant, as the gas to liquid density ratio increases the over-reading reduces[15][16][17]. Figure 9 shows sample DP meter data indicating this phenomenon.

Also, when water and hydrocarbon liquid are the only liquids present, the average liquid density is used in wet gas flow calculations, as is calculated in Formulae (5) and (6)

$$WLMR = \frac{\dot{m}_w}{\dot{m}_w + \dot{m}_{hcl}} \tag{5}$$

$$\rho_{l,\text{homogenous}} = \frac{\rho_{hcl}\rho_w}{\rho_w\left(1-WLMR\right)+WLMR\rho_{hcl}} \tag{6}$$

6.3.4 Gas densiometric Froude number influence on DP meter wet gas flow over-reading

The scale of the DP meter's wet gas over-reading is influenced by the gas densiometric Froude number. For a given DP meter, and all other wet gas flow parameters held constant, as the gas densiometric Froude number increases the over-reading increases[18]. Figure 10 shows sample DP meter data indicating this phenomenon.

6.3.5 DP meter orientation influence on DP meter wet gas flow over-reading

The DP meter's wet gas over-reading is influenced by the installation orientation, due to the influence of orientation on flow regime. For a given DP meter and set wet gas flow conditions, different orientations therefore cause different over-reading values[19]. Figure 11 shows sample DP meter data indicating this phenomenon.

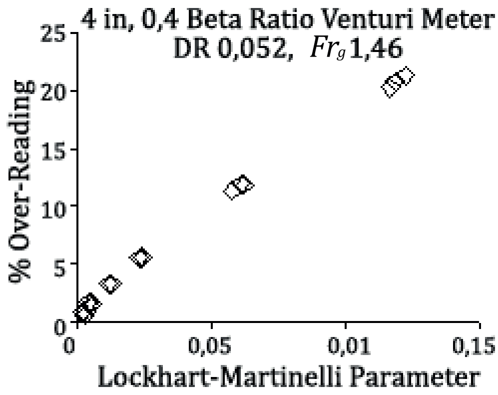


Figure 8 — The liquid loading effect

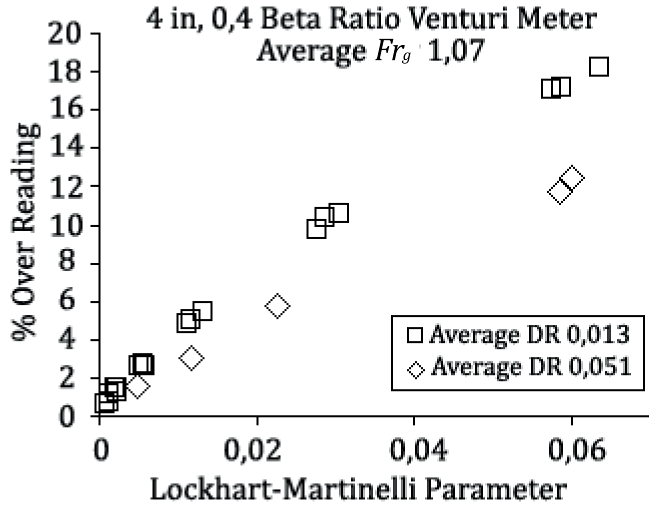


Figure 9 — Gas to liquid density ratio effect

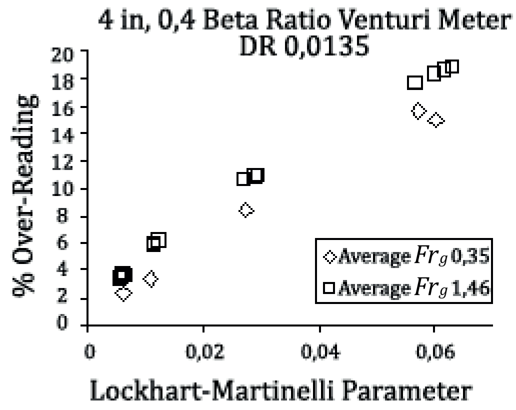


Figure 10 — Gas densiometric Froude Number effect

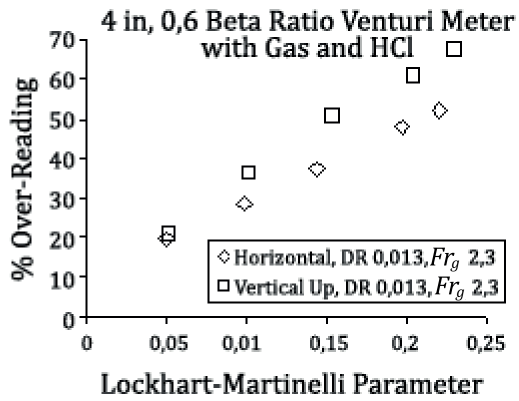


Figure 11 — Orientation of meter effect

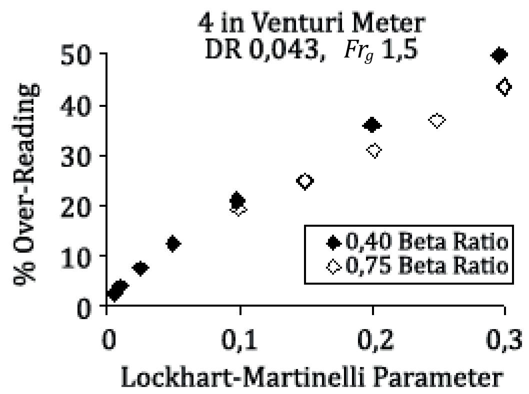


Figure 12 — Beta ratio effect

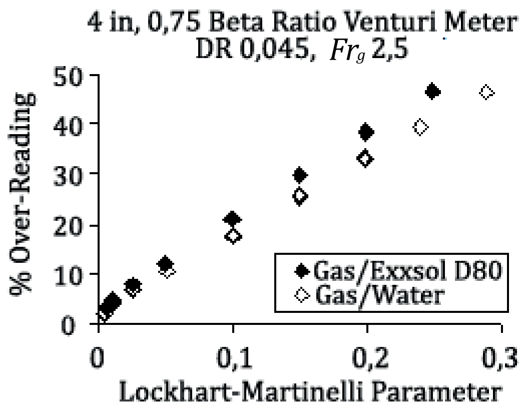


Figure 13 — Fluid properties effect

6.3.6 Influence of β on DP meter wet gas flow over-reading

The scale of the DP meters wet gas flow over-reading may be affected by the beta (β) of the DP meter. For any given DP meter design, larger values of beta tend to produce slightly smaller over-readings[20][21]. Figure 12 shows sample DP meter data indicating this phenomenon. The effects of different values of beta are typically minor, apart from meters with significant beta differences and/or at higher Lockhart-Martinelli numbers.

6.3.7 Fluid property influence on DP meter wet gas flow over-reading

Gas composition has no known effect on DP meter over-readings, other than via the gas density which is independently accounted for with the gas-to-liquid density ratio and gas densiometric Froude number[23].

Liquid composition can have a significant effect on DP meter over-reading. For a given DP meter, and all other wet gas flow parameters held constant, a wet gas over-reading is influenced by the water liquid ratio. A gas with water wet gas flow can produce a smaller over-reading than a gas with light hydrocarbon liquid wet gas flow[22][23]. Figure 13 shows sample DP meter data indicating this phenomenon.

Salque, et al.[24] modelled a multiphase wet gas flow through a Venturi meter. The scale of the DP meter's wet gas over-reading is influenced by the Water Liquid Ratio (WLR).

6.3.8 Meter size/diameter influence on DP meter wet gas flow over-reading

The scale of the DP meter's wet gas over-reading may, or may not, be influenced by the DP meter's size, i.e. inlet diameter. For a given DP meter, and all other wet gas flow parameters held constant, it is not yet certain if diameter has an influence on a DP meter's wet gas over-reading[19].

6.3.9 Applying DP meter wet gas flow correlations

Consideration should be given to the validity of extrapolating any DP meter wet gas correlation's empirical or semi-empirical equation, as such extrapolation could potentially result in flow rate prediction biases. This includes extrapolation in the following parameters:

— DP meter type design;

— Lockhart-Martinelli parameter;

— gas to liquid density ratio;

— gas densiometric Froude number;

— meter orientation;

— beta (diameter ratio);

— liquid properties;

— meter diameter.

If a given geometry DP meter is to be used installed in an orientation with given wet gas flow conditions, where no suitable wet gas correlation exists, it is best practice to characterize that DP meter's wet gas flow performance. Characterization consists of a wet gas flow test across the application's wet gas flow conditions, and a data fit to an empirical, or semi-empirical wet gas correlation. It is not good practice to use an existing DP meter wet gas correlation for a

— different DP meter design,

— same DP meter design but different diameter and /or beta ratio,

— different installation orientation, and

— different wet gas flow conditions (of any sort).

Sample DP meter wet gas correlations used for three popular DP meters are described in 6.4.2, 6.4.3 and 6.4.4.

6.4 General discussion on DP meter wet gas correlations

Across the hydrocarbon production industry there are many different DP meter types and geometries, and many wet gas flow conditions encountered. Wet gas flow DP meter correlations do not exist for many of these applications.

Each of the DP meter wet gas flow correlations that do exist are for a specific DP meter type, a specific geometry range, a specific meter installation orientation and a specific wet gas flow range. Use of any correlation outside its stated range can cause gas flow rate prediction biases.

The following information shows examples of DP meter wet gas flow correlations in the public domain. There are other wet gas flow correlations for these and other DP meter designs. These wet gas correlations discussed here are a limited set of what is publicly available, and are given here for educational purposes. The inclusion or omission of any published wet gas correlation in no way signifies ISO approval or disapproval of any wet gas correlation.

ISO is not liable for the validity of any wet gas correlation uncertainty statement claimed by the correlation developers.

6.4.1 Wet gas flow performance characterization vs. published wet gas correlations

It is technically beneficial to conduct a dedicated wet gas flow test on each individual DP flow meter. However, if for economic reasons an operator cannot wet gas characterize a particular DP meter, the operator can enquire from the meter manufacturer if any suitable in-house wet gas flow data sets and correlations are available. If not, the operator can use a published correlation as default. As with all correlations, the effect of extrapolating any parameter is unknown and likely to have an adverse effect.

Most DP meter wet gas correlations are formed from a data set obtained from a given DP meter in a given installation orientation, across some wet gas flow condition test range. It is common practice to assume that such DP meter wet gas flow correlations are transferrable to nominally identical DP meters in the same installation orientation and wet gas flow conditions.

6.4.2 Horizontally-installed orifice plate meter

Orifice meters have a reproducible wet gas flow performance[25].

The Murdock[14] wet gas flow correlation for orifice meters is reproduced here as Formula (7). The Chisholm[17] wet gas flow correlation for orifice meters was a development of Murdock's work. Later DP meter wet gas correlations tend to be based on the Chisholm mathematical form, which is reproduced here as Formula (8).

Murdock

$$\dot{m}_g = \frac{\dot{m}_{g,apparent}}{1 + MX_{LM}} \text{ with } M\text{=1,26} \tag{7}$$

Chisholm

$$\dot{m}_g = \frac{\dot{m}_{g,apparent}}{\sqrt{1 + C_{Ch} X_{LM} + X_{LM}^2}} \text{ with}$$

$$C_{Ch} = \left(\frac{\rho_g}{\rho_l}\right)^n + \left(\frac{\rho_l}{\rho_g}\right)^n \text{, where Chisholm set n to 1/4.} \tag{8}$$

Although well known, the Murdock and Chisholm orifice meter correlations have been superseded. A more advanced horizontally installed orifice meter wet gas correlation was released by Hall, et al.[25]. The correlation is shown as Formulae (8) and (9) to (13). The limits of the correlation are given in Table 1. Within the correlation limits, for known fluid properties and liquid flow rates, the gas flow rate can be predicted to ±2 % at 95 % confidence level. As with all correlations, the effect of extrapolating any parameter is unknown and likely to have an adverse effect. Users extrapolate at their own judgement.

Table 1 — Orifice Meter wet gas correlation parameter range

Parameter	Range
Pressure	100 kPa < P ≤ 7 890 kPa
Gas to liquid density ratio	0,007 < DR < 0,110
Fr_g range	0,2 < Fr_g < 7,25
X_{LM}	≤ 0,3
Inside full bore diameter	0,049 3 m < D < 0,102 3 m
WLR	0 ≤ WLR ≤ 1
Beta	0,24 < β < 0,74
Gas phase	Nitrogen or Natural Gas
Liquid phase	Light Hydrocarbon Liquid and/or water

$$Fr_{g,strat} = 1{,}5 + \left(0{,}2 \ \ WLMR\right) \tag{9}$$

$$A = 0{,}4 - 0{,}1e^{-WLMR} \tag{10}$$

$$n_{strat} = \left(\frac{1}{\sqrt{2}} - \frac{A}{\sqrt{Fr_{g,strat}}}\right)^2 \tag{11}$$

$$n = n_{strat} \ \text{ for } Fr_g \text{ "} Fr_{g,strat} \tag{12}$$

$$n = \left(\frac{1}{\sqrt{2}} - \frac{A}{\sqrt{Fr_g}}\right)^2 \text{ for } Fr_g > Fr_{g,strat} \tag{13}$$

The correlation is relatively complex. Due to this complexity it would be preferable that users apply tried and tested software. However, at the time of writing the correlation is new and such software is not yet available in flow computers.

6.4.3 Horizontally-installed Venturi meter

A horizontally-installed Venturi meter correlation was released by de Leeuw[18]. This correlation is specifically for a 4-inch, 0,4 beta ratio Venturi meter with gas and light liquid hydrocarbons only. These correlations are presented here as Formulae (8), (14) and (15). The limits of the data sets used to create these correlations are given in Table 2.

$$\text{for } 0{,}5 \le Fr_g \le 1{,}5,\ n = 0{,}41 \tag{14}$$

$$\text{and for } Fr_g > 1{,}5,\ n = 0.606\left(1 - e^{-0.746 Fr_g}\right) \tag{15}$$

Within the correlation limits, for a known liquid flow rate, the gas flow rate is reported to be predicted within ±2 % at 95 % confidence level.

The “de Leeuw” correlation is widely known as “the Venturi meter wet gas correlation”. It is used extensively throughout industry with many Venturi meters of various diameters, beta ratios, fluid types and wet gas flow conditions. However, as with all correlations, the effect of extrapolating the semi-empirical correlation is unknown and likely to have an adverse effect.

Table 2 — Venturi meter wet gas correlation parameter range

Parameter	Range
Pressure	1 500 kPa ≤ P ≤ 9 000 kPa
Gas to liquid density ratio	0,014 ≤ DR ≤ 0,080
Fr_g range	1,5 ≤ Fr_g ≤ 4,8
X_{LM}	≤ 0,3
Inside full bore diameter	0,097 18 m
Beta	0,4 only
WLR	0
Gas phase	Nitrogen
Liquid phase	Light Hydrocarbon Liquid

There are a few other publicly available Venturi meter wet gas flow correlations. The Venturi meter is a popular choice for wet gas flow applications. Various WGFM manufacturers who use the Venturi meter in their design have undisclosed wet gas flow Venturi meter data sets and associated confidential correlations.

Significant modelling of wet gas flow through Venturi meters has been undertaken by Van Werven, et al.[26] and Lupeau[27]. Such models tend to predict the liquid film thickness and droplet size of annular mist flow as well as the gas and liquid flow rates. Such modelling-based wet gas Venturi meter techniques are gaining support amongst operators. However, at the time of writing they are still confidential, not openly available in the market, and tend to be applied only in-house by the operators who developed them.

6.4.4 Horizontally-installed cone meter

Horizontally-installed cone meter wet gas correlations were released by Steven, et al.[28]. These correlations are solely for a 0,75 beta ratio cone meter. One correlation was developed for gas with light liquid hydrocarbons only. Another correlation was developed for multiphase wet gas flow. The gas/hydrocarbon liquid wet gas correlation is presented as Formulae (8), (16) and (17). The "multiphase" wet gas correlation is presented here as Formulae (8), (18) and (19). The limits of these correlations are given in Table 3.

For hydrocarbon liquid only:

$$\text{for } Fr_g \leq 0{,}5,\ n = 0{,}19 \tag{16}$$

$$\text{for } Fr_g > 0{,}5,\ n = \frac{1}{2}\left(1 - \left\{\frac{0{,}7281}{e^{0{,}31 Fr_g}}\right\}\right) \tag{17}$$

For the case of light liquid hydrocarbons only, within the correlation limits for a known liquid flow rate, the gas flow rate is reported to be predicted to ±2 % at 95 % confidence level.

For a water liquid ratio between 0 % and 100 %:

$$\text{for } Fr_g \leq 0{,}5,\ n = 0{,}143 \tag{18}$$

$$\text{for } Fr_g > 0{,}5,\ n = \frac{1}{2}\left(1 - \left\{\frac{0{,}83}{e^{0{,}3 Fr_g}}\right\}\right) \tag{19}$$

For the case of multiphase wet gas flow within the correlation limits for a known liquid flow rate, the gas flow rate is reported to be predicted to ±2,6 % at 95 % confidence level. No water liquid ratio (WLR) effect was quantified. This correlation treats the WLR effect as scatter.

Table 3 — Cone meter wet gas correlation parameter range

Parameter	Range
Pressure	1 360 kPa to 7 750 kPa
Gas to liquid density ratio	0,012 < DR < 0,090
Fr_g range	0,53 < Fr_g < 8,80
X_{LM}	< 0,305
Inside full bore diameter	0,096 9 m < D < 0,147 0 m
Beta	0,75 only
WLR	0 ≤ WLR ≤ 1
Gas phase	Nitrogen or Natural Gas
Liquid phase	Light Hydrocarbon Liquid and Water

As with all correlations, the effect of extrapolating any parameter is unknown and likely to have an adverse effect. Users extrapolate at their own judgement.

It should be noted that a cone is an obstruction in the centre of the pipeline, where velocities are highest, and adequate structural engineering considerations need to be made. In addition the effects of the erosional impact on the pipe wall should be evaluated.

6.5 Generic two-phase wet gas meter designs

Two–Phase WGFM technology is continually developing. However, most WGFM technologies are based on well-established generic concepts. These generic concepts are described below.

6.5.1 Multiple single-phase meters in series

A common approach to wet gas flow metering is to use at least two dissimilar gas flow meters in series. This is a wet gas/two-phase flow measurement by difference technique. With a measurement by difference technique, the method works better the larger the difference in the two parameters being measured. Figure 14[29] and Figure 15[30][31] are examples.

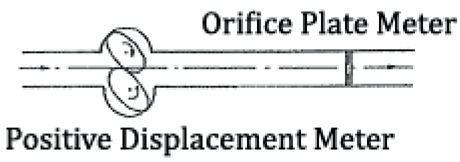


Figure 14 — Medvejev Wet Gas Flow Meter

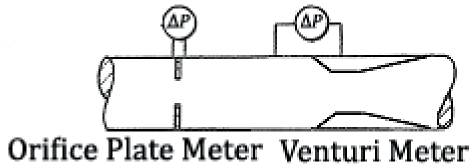


Figure 15 — Nguyen Wet Gas Flow Meter

The two meters in series must each have low single-phase gas flow rate measurement uncertainties and have reproducible and predictable reactions to wet gas flow. The two meters must also have distinctly different reactions to wet gas flow. With dry gas flow the two meters predict the same gas flow rate within their combined uncertainties, thereby indicating correctly metered dry gas flow. With wet gas flow, the meters have different erroneous gas flow rate predictions (indicating wet gas flow). A simplified graph of this scenario is shown on the left side of Figure 16.

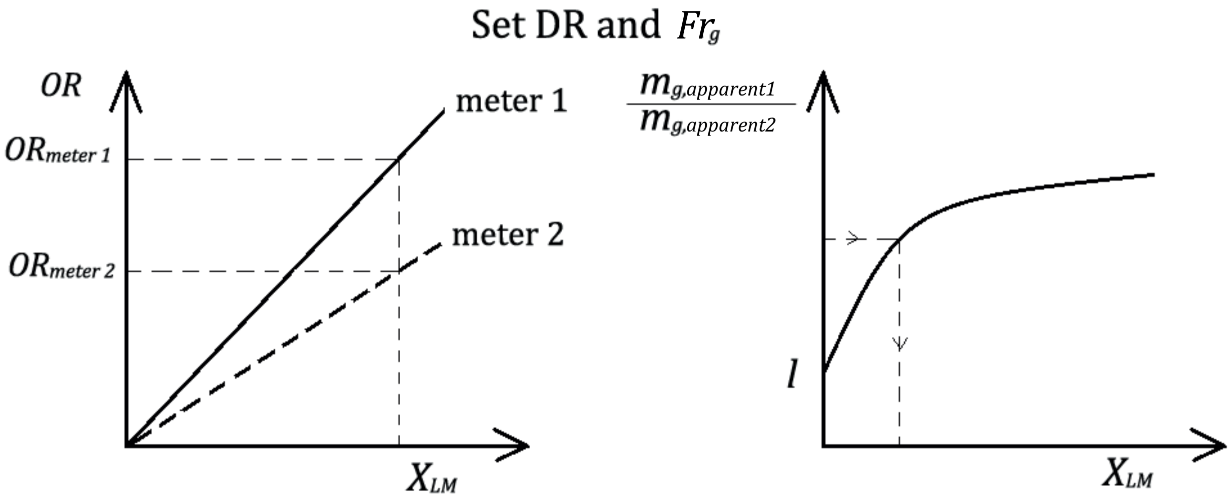


Figure 16 — Simplified sketches (not to scale) showing relationship between two dissimilar gas flow meters in series used with wet gas flow

The difference between the erroneous gas flow rate predictions can be related to the liquid loading (i.e. Lockhart-Martinelli parameter value). Once the liquid loading is known, wet gas correlations can be used to infer the gas and liquid flow rates. The mathematical procedure for this is vendor specific. A simple example is now given.

At least one meter must have a wet gas correlation [e.g. Formula (20)]. The ratio of the two meters' over-readings is the ratio of the two meters erroneous gas mass flow rate predictions, i.e. Formula (21). This ratio is related to the Lockhart-Martinelli parameter, gas-to-liquid density ratio and gas densiometric Froude number, see Formula (22). In operation, Formula (21) is obtained. The Lockhart-Martinelli parameter is then expressed as a function of the gas densiometric Froude number only, see Formula (22). And this expression is substituted into the wet gas correlation, see Formula (20). The resulting expression has one unknown parameter, i.e. the gas densiometric Froude number, or by substituting in 2.19, the gas mass flow rate

$$\mathrm{OR}_{meter2} = \frac{\dot{m}_{g,apparent2}}{\dot{m}_{g,actual}} = f\left(X_{LM}, \rho_g / \rho_g, Fr_g\right) \tag{20}$$

$$\frac{\mathrm{OR}_{meter1}}{\mathrm{OR}_{meter2}} = \frac{\dot{m}_{g,apparent1} / \dot{m}_{g,actual}}{\dot{m}_{g,apparent2} / \dot{m}_{g,actual}} = \frac{\dot{m}_{g,apparent1}}{\dot{m}_{g,apparent2}} \tag{21}$$

$$X_{LM} = f\left(\frac{\dot{m}_{g2,apparent}}{\dot{m}_{g1,aparent}}, \frac{\rho_g}{\rho_l}, Fr_g\right) \tag{22}$$

This approach is fundamentally simple and has been developed independently by various researchers. However, the actual implementation of the concept is far more complex. Figure 16 is an idealized example. In practice there are complex inter-connected relationships between relevant parameters, and the commercial mathematical methods are usually proprietary. The choice of mathematical procedure can influence the gas and liquid flow rate prediction uncertainties. An iterative solution requirement is common. Reference [32] discusses an operator's field test of such a system.

Such system can have a relatively large footprint and may have greater instrumentation requirements. However, advantages include that it tends to be relatively robust, simpler and maybe cheaper than more complex technology.

The uncertainty of any measurement by difference technique increases as the measured difference reduces. At very low liquid loadings both gas meters have correspondingly low liquid induced gas flow rate prediction errors, and hence the difference in the two meters' output is small relative to the individual meter uncertainties. Therefore a disadvantage in this measurement by difference technique is a relatively high uncertainty at very low liquid loadings.

6.5.2 Differential pressure meter classical DP/permanent pressure loss wet gas meters

The DP meter's PLR relationship with liquid loading, as described in 7.1.4, can be utilized to make a single DP meter a WGFM system[18]. A Venturi meter (as shown in Figure 21) is usually, but not exclusively, used to produce such a system.

Figure 17 shows a Venturi meter Murdock plot at one pressure (or gas to liquid density ratio). Figure 18 shows the corresponding PLR vs. Lockhart-Martinelli parameter data. The relationship between both the over-reading and the PLR vs the Lockhart-Martinelli parameter can be influenced by various parameters such as the gas to liquid density and gas densiometric Froude number etc.

The DP meter has a standard wet gas correlation data fitted from wet gas flow tests, as shown in Formula (23). It may be possible to also data fit the PLR vs. Lockhart-Martinelli parameter relationship, as shown in Formula (24). In this example, three parameters are considered to influence the over-reading and PLR, i.e. the Lockhart-Martinelli parameter, gas to liquid density and gas densiometric Froude number. In practice other parameters such as WLR may also be found to affect the over-reading and PLR. Combining Formulae (23) and (24) produces one formula with one unknown, the gas mass flow rate. The gas flow rate can then be calculated, usually by an iterative calculation.

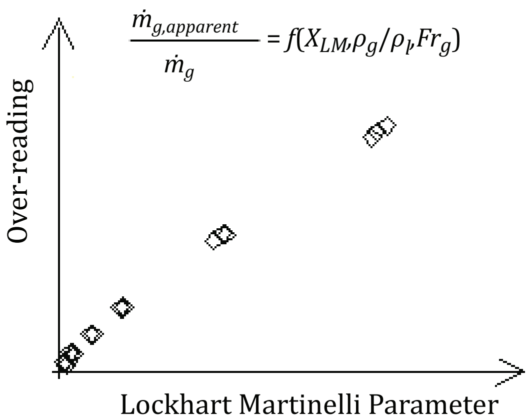


Figure 17 — A meter wet gas correlation

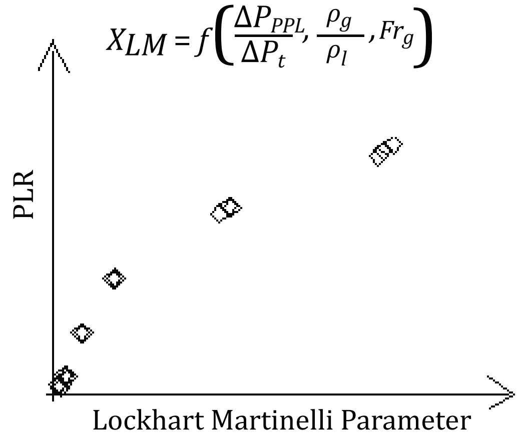


Figure 18 — PLR vs. X_{LM}

$$\mathrm{OR} = \frac{\dot{m}_{g,apparent}}{\dot{m}_g} = f\left(X_{LM}, \rho_g / \rho_l, Fr_g\right) \quad (23)$$

$$X_{LM} = f\left(\frac{\Delta P_{PPL,tp}}{\Delta P_{tp}}, \frac{\rho_g}{\rho_l}, Fr_g\right) \quad (24)$$

The technique is wholly dependent on the sensitivity of the DP meter's PLR to Lockhart-Martinelli parameter. This is influenced by various factors, including

— sensitivity increases with the choice of a DP meter with a lower dry gas PLR,

— sensitivity increases as the Lockhart-Martinelli parameter reduces,

— sensitivity increases as the gas to liquid density ratio reduces, and

— sensitivity increases as the gas densiometric Froude number reduces.

This technique therefore has limitations, but nevertheless the method is a valuable addition to industry, as many wet natural gas flow production conditions are within a flow range where this method is applicable as a wet natural gas flow metering technique. This generic two-phase WGFM method has several variants available in industry.

6.5.3 Fast response sensor system

Fast response sensor systems (usually, but not exclusively, on DP meters) can be part of a two-phase or multiphase WGFM system. Such technology has been researched for more than 20 years.

Industrial flows are rarely truly steady. Some flow condition fluctuations always exist due to the turbulence that exists in most real fluid pipe flows. Instruments therefore read parameters that have these naturally occurring fluctuations. These random turbulence signals are considerably enhanced by wet gas flows.

The frequency and magnitude of the fluctuations of any measured parameter can potentially be related to the wet gas flow to predict the flow regime and phase flow rates of wet gas flows. For example:

— the average pressure, temperature and differential pressure (P, T, ΔP)

— the magnitude of these parameters' fluctuations (δ_P, δ_t, $\delta_{\Delta P}$ respectively) and,

— the frequency of these parameters' fluctuations (ω_P, ω_t, $\omega_{\Delta P}$ respectively)

can be related through a neural network to give the flow regime and the gas and liquid flow rates.

That is:

$$\dot{m}_g = f_1\left(P, T, DP, \delta_p, \delta_T, \delta_{\Delta P}, \omega_P, \omega_T, \omega_{\Delta P}\right) \tag{25}$$

and

$$\dot{m}_l = f_2\left(P, T, DP, \delta_p, \delta_T, \delta_{\Delta P}, \omega_P, \omega_T, \omega_{\Delta P}\right) \tag{26}$$

where "f_1" and "f_2" denote complex neural network functions which are continually being improved with each additional data set. Note that there are alternative statistical data analysis methods which could work equally well.

Under the correct circumstances, a fast response sensor WGFM system can be a viable tool for operators. However, creating an appropriate neural network/statistical analysis method is not a simple task. Based on experience, fast-response sensor WGFM has the following features:

— installation-specific performance,

— must be characterised in its installation only, using separator system phase flow references (and not at a test facility), and

— only applicable within the flow data range used to produce the calculation method.

Hence, this technology is generally applicable only when an application initially has a dedicated test separator capable of giving the system flow rate information for long enough and at varied enough conditions for the appropriate system to be derived.

6.6 Multiphase wet gas flow meters

Multiphase WGFMs measure multiphase wet gas flows inclusive of separate water and liquid hydrocarbon phase flows.

Figure 19, suggested in Reference [33] shows all multiphase flow phase fraction possibilities including the phase inversion region between oil and water at the lower GVF values. WGFM operate in the high GVF region.

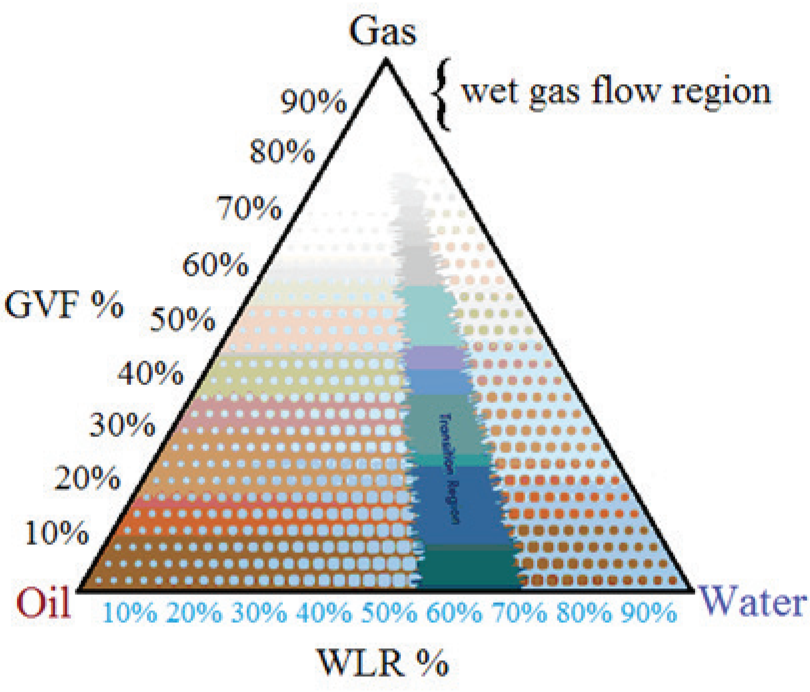


Figure 19 — An example of a multiphase composition triangle

The nominal WGFM measurement range is $0 \leq X_{LM} \leq 0{,}3$ with a water to liquid ratio range of 0 % ≤ WLR ≤ 100 %. However, it is unreasonable to expect any WGFM to accurately measure water flow down to ever reducing trace quantities. Direct measurement methods are usually more capable at measuring trace water flows than measurement-by-difference techniques.

6.6.1 Trace water metering with multiphase wet gas flow meters

At low liquid loading where light liquid hydrocarbon is the predominant liquid phase, the water flow will be a small fraction of the total fluid flow. However, the operator may still need to know if water is present. Even trace amounts of water can potentially threaten production due to, for example:

— hydrate formation;

— ice formation;

— scale deposits;

— salt deposits.

Real time identification of trace water content is important in order that timely appropriate flow assurance actions can be taken. Consequently, with multiphase WGFMs having multiple outputs, e.g. various phase flow rates and phase fractions outputs, some multiphase WGFMs are designed to be optimized, and used primarily, to see trace fractions of formation water that may exist in a wet natural gas flow.

6.6.2 Multiphase wet gas flow meter subsystems

In-line WGFMs tend to comprise a DP meter component with various other sensor components. As standalone systems each component gives valuable information regarding some aspect of the multiphase flow. However, combining these components into a single overall system produces a system with a whole greater than the sum of its parts. By cross referencing the individual component outputs a fuller understanding of the flow can be developed.

Most WGFM manufacturers consider the mechanical design and calculation procedure details of their commercial product to be intellectual property and confidential. It is therefore not possible for ISO to give a detailed discussion on these proprietary meter operations; instead, only a generic overview can be given.

Although commercial WGFM designs vary in both mechanical design and data processing techniques, most are variations on generic themes. Hence, it is possible for ISO to give a multiphase WGFM generic over-view.

Most in-line WGFMs consist of a DP meter installed in the vertical orientation. Flow is usually vertical up although other installation orientations do exist. The DP meter gives information related to the total bulk flow. Sensor types collectively called “phase fraction devices” are embedded within, or in close proximity to, the DP meter body.

Phase fraction devices use various physical principles to measure various properties of flowing fluids, by looking at either the bulk flow or a representative sample of the flow, depending on the technique employed.

The choice of which phase fraction device/s to utilize is manufacturer-dependent, but includes:

— capacitance sensors;

— microwave sensors;

— single energy gamma source and receiver;

— multi energy gamma sources and receivers;

— infrared source and sensor;

— cross-correlation system.

The core DP meter or any one standalone subsystem does not independently provide the phase flow rates. Multiphase WGFMs combine the output from their particular combination of such subsystems, and then process this data by manufacturer-specific confidential calculation routines to produce phase flow rate estimations. This calculation routine is often called a “slip model”. Slip models are exclusively semi-empirical and many are proprietary.

6.6.3 Phase fraction device choices

The phase fraction devices of a multiphase WGFM are critical to the system’s ability to distinguish between the liquid component flow rates. Some generic phase fraction devices are outlined below.

6.6.3.1 Gamma ray attenuation systems

A gamma ray attenuation system measures the scintillation count which is inversely proportional to the attenuation of radiation between a source and receiver positioned across the diameter of the multiphase wet gas flow pipe.

A single gamma densitometer typically with a source in the Compton energy range, i.e. greater than 100 keV, can determine the bulk density of the fluids in the path traversed by the radiation. Whereas the attenuation of this Compton energy range radiation is very dependent on the bulk fluid density it is rather insensitive to other medium properties. Hence, use of a Compton energy range radiation source can determine overall multiphase flow bulk density, but cannot be used to determine the phase ratios.

A multi energy system uses at least two energy levels and these are selected sufficiently different, e.g. high (100 keV or higher) and a low (10 keV to 40 keV) energy level to use the different absorption characteristics in an oil, water and gas mixture. The phase fractions can be determined by combining the absorption from the different energies.

6.6.3.2 Electromagnetic measurements

Fluids respond to electromagnetic radiation according to their dielectric properties. Fluid dielectric properties are determined by the fluid's capacitance (charge storage) and conductance (or resistance to moving charge). For the various components in a multiphase wet gas flow, the differences between the relative dielectric constants help enable the fractions of each fluid to be found.

Table 4 — Permittivity values for gas, hydrocarbon liquid and water

Fluid	Capacitance, ε_r	Conductance, σ (S/m)
Gas	$1 \le \varepsilon_r \le 1{,}5$	0
Light Hydrocarbon Liquid	$2 \le \varepsilon_r \le 2{,}5$	$10^{-9} \le \sigma \le 10^{-7}$
Water	$40 \le \varepsilon_r \le 80$	$10^{-1} \le \sigma \le 10^{2}$

Capacitance and Conductance

WGFM capacitance sensors detect water by measuring the fluid's ability to store charge between two plates in contact with the fluid. Conductance sensors measure the conductivity of the fluid between two plates to determine the phase fractions. However, there are multiphase flow condition range limits on both capacitance and conductivity systems.

Capacitance sensors cannot operate in water continuous conditions (where the water electrically connects and earths the two plates thereby preventing measurement). Water continuous flow can be seen on the right hand side of the triangle from Figure 19. Capacitance sensors are therefore an option for WGFM.

Conductivity sensors cannot operate in multiphase flows where there is insufficient water. This tends to be a problem with multiphase wet gas flows as the flow often has relatively low water phase fractions. Conductivity sensors are therefore an option for high liquid loading and relatively high WLR multiphase flows, but are not seen as a valid option for a multiphase wet gas flow option.

Note that when utilizing electromagnetic measurements, it is necessary to also accurately know the gas fraction, as this also affects the electromagnetic properties of the mixture. This inter-relationship will require the meter manufacturer's semi-empirical slip model to relate these parameters.

Microwave Systems

At the higher frequency of microwaves, measurements such as frequency shift, phase shift, or attenuation of the transmitted or reflected electromagnetic signals can be directly related to the fluid permittivity and conductivity. The complexity of these methods can be somewhat simplified by utilizing resonance structures, which directly relate the fluid mixture permittivity to the frequency shift of a resonance peak. These methods are sensitive to the water fraction, and also to water salinity. Increasing salinity causes a reducing water dielectric constant. Hence, it is important to enter the correct salinity/dielectric constant input to the WGFM system, as a salinity/dielectric constant input bias will cause a bias in the meters outputs.

A multiphase wet gas flow's water vapour content is dependent on pressure, temperature and fluid composition. Water vapour affects the gas phase permittivity value. The water vapour content and its effect on gas permittivity needs to be taken into account when predicting the water volume fraction value using the read mixture permittivity.

6.6.3.3 Light scattering and attenuation

Other electromagnetic spectrum frequencies can also be used at one or more wavelengths. For instance, water absorbs near infrared radiation; therefore, this effect can be used to determine the water fraction in the fluids within the sensor path.

6.6.3.4 Cross-correlation

Cross-correlation can be implemented using a number of different physical techniques. In general, two or more fast sampling sensors placed a fixed axial distance apart in a pipe should detect fluctuations with a delay related to the velocity of the fluid. The resulting velocity should be relatable to the flow rate of one or more of the phases. The accuracy of this calculated velocity is dependent on the clarity of the cross correlation function which in turn depends on the “fluctuation” at the upstream location resembling the “fluctuation” at the downstream location. Thus, development of the flow pattern between the sensors must be minimal and the sample rate of data must be sufficient to capture such fluctuation movements.

6.6.3.5 Imaging techniques

The determination of the flow regime may be possible via imaging techniques. A camera viewing through a port looking towards a light source, as utilized at certain test facilities, can see the liquid flowing (e.g. see Figure 4 and Figure 5). However, such view ports are not used with production flows because:

— view ports do not offer flow measurement capability

— production flows contain particulate which scours the viewing lens.

6.6.3.6 Advanced imaging techniques

Multiple fast response sensors positioned in a suitable array through a meter body, coupled with high computational processing speeds, can provide a running “image” of a multiphase wet gas flow that can significantly aid the metering process. The higher the image resolution, and the faster the image update, the more useful to multiphase wet gas flow metering this technique is.

The image resolution is dependent on the number of sensors, sensor reading frequency and the computational speed. Such a technique has been called “tomography”. However, present WGFM systems have neither the required number of sensors, nor high enough sensor reading frequencies, to create sequential images with the resolution that could be called tomography in the true sense of the word (as used by other science disciplines on stationary objects).

Nevertheless, the information gathered by these advanced imaging techniques can be, and is, helpful in conjunction with the other meter readings in metering multiphase wet gas flow. Furthermore, it is likely that as the technology develops such techniques will become increasingly powerful and useful.

6.6.4 Gas volume fraction vs. gas void fraction measurement

Dual (or multiple) gamma ray energy systems, electromagnetic measurements and light scattering techniques etc., measure the fraction of phases in the system’s line of sight at the time of that reading. Each reading is a “snap-shot” of the phase ratio at that instant the reading was taken. Therefore, these phase fraction devices do not measure the actual phase flow rate fractions but rather the “Gas Void Fraction” (see 2.23) or “Liquid Hold Up” (see 2.29).

The phase flow rate fractions (such as the Gas Volume Fraction) are calculated by cross-referencing the phase fraction device output with the DP meter output, by use of the semi-empirical slip model. It is the model’s resulting prediction of the phase flow rates, and hence the slip between the phases, that give the name “slip model”.

6.6.5 Semi-empirical multiphase flow calculation — Slip model

Commercial multiphase WGFM manufacturers require “slip models” to make sense of the combined WGFM subsystem readings. A slip model allows the estimate of slip to be based on some physical understanding, with only certain parameters within the calculation derived empirically. The preference of slip models over fully empirical data fits diminishes the chance of metering errors on interpolation or extrapolation of the underlying data sets. However, slip models are still semi-empirical correlations.

As with all correlations, the effect of extrapolating any parameter is unknown and likely to have an adverse effect. Users extrapolate at their own judgement.

A multiphase WGFM system depends on the integrity, robustness and quality of the slip model used. WGFM manufacturers' slip models represent the intellectual property attained through long term investment in time, effort and funding, in both complex theoretical flow modelling and massed laboratory and field data set procurement, compressed into a mathematical equation set. As such, slip models tend to be proprietary and held in confidence by the meter manufacturers. Extrapolations within this "black box" are less visible.

6.6.6 PVT (pressure volume temperature) models

PVT models for wet gas metering often make use of Equations of State (EoS) or correlations relating the fluid composition and state variables (usually pressure, temperature, overall composition) to thermodynamic properties (usually volume, density, energy, phase-composition) of the fluids and/or mixture.

Both EoS and correlations need some sort of calibration to experimental data in order to be effective. Note that other physical properties (e.g. viscosity) have separate correlations; those correlations usually require the state variables and thermodynamic properties as input data.

6.6.7 Multiphase wet gas flow meter required fluid property inputs

As with single-phase gas flow meters, multiphase wet gas flow meters require all relevant fluid property values to be supplied to the flow calculation from an external source, i.e. an equation of state. The equation of state fluid property prediction requires the multiphase wet gas flow fluid composition be supplied independently.

A significant uncertainty factor in the output of WGFM is often the uncertainty associated with the fluid composition predictions supplied to the Equations of State. A multiphase wet gas flow fluid composition prediction may rely on

— reservoir engineer estimates, and

— wet gas flow samples.

Both reservoir engineer fluid composition estimates and wet gas sampling techniques can have significant uncertainties. Fluid composition estimates can be one of the largest source of uncertainty in a wet gas flow meters output.

6.6.8 Multiphase wet gas flow meter phase fraction measurement

A multiphase WGFM requires physical measurements to measure the cross sectional area fraction of each phase, i.e. water, liquid hydrocarbon and gas. At least two physical measurement principles are required, and combining these measurement principles with the knowledge that the sum of the cross sectional area fractions in a closed conduit is 1, will give three equations with three unknowns. Thus this can be solved and an example of this set of equations can graphically represented by a triangle with the physical measurements along the horizontal and vertical axis. An example is given in Figure 20. However, the effect of slip still needs to be taken into account through the slip model.

Examples of combination of physical measurements often used are (but not limited to):

— Dual Energy Gamma Ray Absorption, measuring the absorption at a low energy level and a high energy level (coming from the same radioactive source) results in two absorption equations,

— Single Energy Gamma Ray Absorption (generally higher energy level) and a form of permittivity measurements.

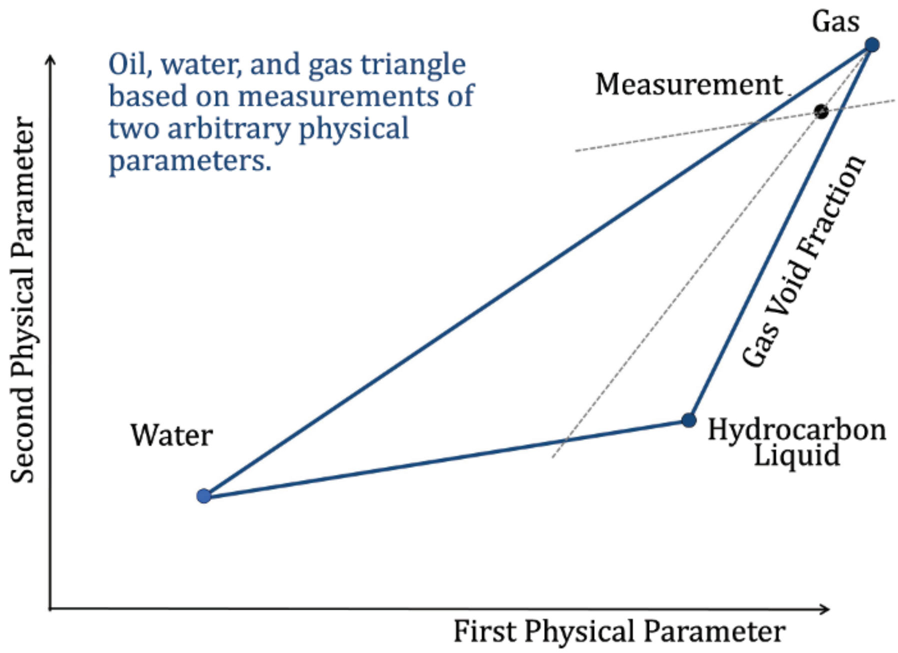


Figure 20 — A water, light liquid hydrocarbon and gas triangle plotted for measurements of two arbitrary physical parameters

6.6.9 Measurement of water salinity

Some WGFM have subsystems that can measure salinity, for example via water conductivity or permittivity sensors, and therefore do not require the salinity as an external input. Such a salinity measurement may be used to distinguish between condensed and formation water, aiding the detection of water breakthrough. Some WGFMs are designed to optimize their water sensing capability, such that small water fractions may be detected.

6.6.10 Multiphase wet gas flow meter redundant subsystems and diagnostics

WGFMs are relatively recent additions to the equipment used in the hydrocarbon production industry. As with most new technologies, redundancy of subsystems and diagnostic capabilities are developed after the primary system development.

Recent WGFM designs now exhibit some level of subsystem redundancy, although detailed descriptions of diagnostic analysis techniques are as yet sparse. Subsystem redundancy may consist of duplicate backup instruments and/or measuring some parameter via a secondary but independent method.

Multiphase wet gas flow components such as salts, hydrate inhibitor chemicals, H_2S, CO_2, etc. can potentially induce a bias on the WGFM flow predictions. Meters with redundancy in measurement have some basis for diagnostics, and could potentially identify if interfering components are present, or determine if a component of the meter is beginning to fail.

Meters with redundancy in measurement are more successful in continuing to provide flow measurements if one or more sensors fail, enabling the meter to have a managed malfunction rather than an unexpected sudden total system failure.

6.6.11 Selection of multiphase wet gas flow meter technologies

When compared with single-phase flow meter technologies, there are relatively few manufacturers of commercially available WGFMs. Meters from different manufacturers utilizing different combinations of techniques have different performance specifications such as:

— capacity and turn-down;

— sensitivity to liquid at different liquid loading;

— sensitivity to discriminate between hydrocarbon liquid and water;

— sensitivity to water and formation water (irrespective of hydrocarbon liquid fraction);

— sensitivity to salts;

— tolerance against minerals, H_2S, CO_2 and injected chemicals;

— sensitivity to errors in input parameters such as phase densities, viscosities, interfacial tension, water conductivity, etc.

Different WGFM designs are optimized for different prime outputs. For example, one manufacturer may have optimized the water detection ability, but at the expense of the phase flow rate prediction uncertainties. Another manufacturer may have optimised the phase flow rate prediction uncertainties but at the expense of the water detection ability.

Before comparing WGFM designs that are not always designed to be in direct competition, an operator needs to establish the predicted flow condition range and the prime reason for requiring a multiphase wet gas flow meter.

Operators of multiphase wet gas flow meters often require manufacturer aid

— to select a meter suitable for the application,

— to select the optimum size,

— to understand precisely what fluid properties they are required to supply, and

— to make an evaluation of predicted performance.

It is recommended that the user carries out an acceptance test to verify that specifications are met before accepting the delivery.

6.7 Wet gas flow meter performance testing

Many wet natural gas flow metering applications are economically important and a relatively low metering uncertainty is required. However, for the foreseeable future wet gas meter systems are not “off the shelf” commodities. There is a very wide range of flow conditions throughout the production industry. The WGFM systems on the market are typically only tested and proven in a relatively small range of wet gas flow conditions.

When applying a standalone gas flow meter with a wet gas correction, it is the operator’s responsibility both to predict the liquid flow rate and to check that the correlation to be used is suitable. If the operator is uncertain of the correlation’s suitability, or if no suitable correlation exists, then the operator should carry out a wet gas flow test of the meter, either to check a correlation’s performance or to create a suitable correlation.

When utilizing a WGFM, it is the operators’ responsibility to check that the chosen system will operate successfully in the particular application’s wet gas flow conditions. The meters may not been developed or tested in a particular application’s wet gas flow conditions.

Test data that does exist for a given WGFM may originate from the meter's development programme. These tests are usually not independently witnessed and the data are held as proprietary by the vendor or may be covered under a non-disclosure agreement. Furthermore, as these metering systems are "black box" technologies and the slip models are not disclosed it is not feasible for the meter operator to predict the meter's response outside its tested flow range.

Operators are faced with the choice of either applying selected WGFM technology untested or conducting verification tests. "Verification tests" are common at the industrial wet gas flow test facilities as operators check a WGFM performance. WGFM test procedures are relatively complicated. Such testing requires detailed planning, and experienced professional staff operating reputable test facilities. Clause 9 discusses the discipline of WGFM testing.

6.8 Virtual metering system (VMS)

Based on various existing measurements in a production facility, like measurement of temperature, pressure, and other information like choke and valve settings, etc., a virtual metering system can be used to estimate flow rates. In addition to these measurements, either physical models (e.g. using PVT models, pressure drop models, etc.) or mathematical process (just using meter signals irrespective of their physical meaning) are used. Such a VMS is relatively inexpensive because it requires no extra sensors or field equipment. Whatever sensors and transmitters are available are used. The more input data available to the models the better the VMS will predict the oil, water and gas flow rates. Sometimes physical properties of the fluids will be used as inputs and thus these need to be monitored. The applicability of such a VMS may vary considerably from field to field. The uncertainty of the estimated flow rates is not generally well known.

A VMS should not be considered as a replacement of a WGFM but rather as a complementary tool to provide backup and redundancy. Physical measurements are required to tune a VMS. The more comprehensive the information supplied to the VMS during this tuning phase, the more capable the system will be. If the tuning includes possible drift or systematic errors of the input devices, the effects will be included in the flow rate estimates. Tuning is only for the current conditions and should be an ongoing process.

There is a significant probability that a WGFM will have an increased output uncertainty or shows systematic errors over time. The best WGFM performance should be expected in the early stage of the system's life, hence the VMS should be operational as soon as production commences. If at a later stage of the production phase the (subsea) WGFM should fail to operate, a properly tuned VMS might be able to take over the measurements and estimate the oil, water and gas flow rates for a certain period of time.

Uncertainty in oil, water and gas flow rates from a VMS is difficult to assess as it depends on so many factors; often the vendors quote uncertainties that have been achieved in the most optimal situation and may not be applicable in other field situations. A direct measurement with a WGFM, that is properly implemented and frequently verified, should be considered to have a lower uncertainty.

7 DP Meter Wet Gas Correlation Practical Issues

A DP meter's wet gas correlation uncertainty statement assumes all required fluid properties and liquid flow rate predictions are accurate. Any bias in either input has an associated bias on the correlation's output.

Establishing the liquid properties in a wet gas flow is a challenge. There are issues with wet gas flow sampling, and subsequent sample analysis techniques that are still debated by industry. Although such issues are important, and have a direct influence on wet gas meter output uncertainties, they tend to be seen as out of the scope of wet gas flow metering. Further discussion of this topic is out of the scope of this Technical Report.

In many applications the liquid flow rate prediction may have significant uncertainty. This causes an associated increase in the DP meter's wet gas correlation's gas flow rate prediction uncertainty. However, this gas flow rate prediction uncertainty's sensitivity to liquid flow rate input uncertainty is typically relatively low. A liquid flow rate prediction error produces a smaller gas flow rate error. For example, for an orifice meter, a liquid flow rate estimation bias of +10 % was shown by Hall et al[25] to have a follow on associated gas flow rate prediction bias in the order of +2,5 %. For further details on this issue, see Reference [25].

7.1 DP meter wet gas flow installation issues

Throughout the hydrocarbon production industry, there is more horizontally installed pipe than vertically installed pipe. The majority of DP meter wet gas correlations are for horizontal orientations. They are not applicable to vertical up, vertical down or inclined pipe orientations. Figure 11 shows the significant effect orientation can have on a DP meter's wet gas over-reading.

Industry's understanding of flow regime influences, and distances required to change flow regimes is incomplete and somewhat contradictory. The upstream piping can influence a wet gas flow regime. Distances required to obtain flow regime equilibrium condition after a disturbance are discussed in Reference [34]. They predicted up to 100 pipe diameters are required to settle a wet gas flow regime. In most applications this is not practical. However, it has been shown in test facilities that it is not possible to force any given flow regime to another desired flow regime. For example, it is not practical to use a mixer to convert a stratified flow to an annular mist flow in front of a wet gas meter that has better performance with annular mist flow. Any change of flow regime through the mixer reverts back to the initial flow regime dictated by the balance of forces downstream of the mixer. Also, it has been found by various wet gas flow facilities that different liquid flow into gas flow injection methods always create the flow regime dictated by the balance of forces a few diameters downstream of the injection point, regardless of the different flow regimes created at the point of injection. With most DP meters wet gas flow tested in long straight pipe runs, there is little in the literature describing upstream/inlet requirements for DP meters with wet gas flow.

It has been postulated that the flow regime in the DP meter's throat is more critical to the meter's wet gas flow performance than the inlet flow regime. For most industrial wet gas flow conditions the DP meter throat tends to have an annular mist flow regime regardless of the inlet flow regime.

Some DP meters are installed vertical up after a blind tee, as this arrangement is often thought to produce a repeatable flow regime into the meter regardless of the flow regime upstream of the blind tee bend.

For whatever reason, there is little in the literature about this subject, and many wet gas meter systems have no specified upstream piping requirements.

7.1.1 Liquid flow rate estimation techniques

Many natural gas production flows are relatively steady for extended periods of time. It is often assumed that a "spot" measurement of a wet gas flow's liquid flow rate at a given place and time will remain valid. There are two common methods of obtaining such a liquid flow rate spot measurement.

— Test separator method - A test separator is temporarily connected to separate the phases and meter the single-phase outlet flows. Each liquid component outlet single-phase flow meter gives a liquid flow rate spot check.

— Tracer dilution method - Tracer fluids, usually inert dyes of known fluorescent intensity, are injected into the wet gas flow at a precise low flow rate. There are tracer fluids that are absorbed by water only, and tracer fluids that are absorbed by hydrocarbon liquid only. The tracers mix with the liquid phase. Combining tracer concentration measurements from downstream liquid samples and tracer injection rates allow a liquid phase flow rate prediction.

Both these liquid flow rate measurement techniques make the assumption that the wet gas flows liquid flow rate remains constant between periodic checks. In applications where the liquid flow rate is stable, where low uncertainty is not required, these methods may be sufficient. Each has challenges when trying to ensure a low uncertainty liquid flow rate prediction.

7.1.1.1 Liquid phase flow rate metering with a test separator

Separator gas- and liquid-phase flow measurement uncertainties are influenced by the efficiency of the separator, and by the performance of each of the single-phase flow meters.

If the wet gas flow rates are too high for a given separator, full separation of the phases may not occur. In such cases wet gas flows through the gas outlet and the single-phase gas meter, causing a bias in the gas flow rate prediction. In such cases liquid with gas flows through the liquid outlet and the single-phase liquid meter, causing a bias in the liquid flow rate prediction.

For optimal performance, a separator must be large enough to fully separate the phases, and the single-phase meters at the outlet to a separator must be well maintained, have the appropriate upstream pipe length, be appropriately sized and have the meter body and secondary instrumentation correctly calibrated to minimize single-phase flow prediction uncertainty.

The test separator liquid flow rate measurement uncertainty can change significantly from case to case. With good design and good oilfield practice it is often assumed to have an uncertainty < 10 %.

7.1.1.2 Liquid phase flow rate metering with a tracer dilution method

In field applications, it is challenging to meter tracer injection flow rates to a low uncertainty. Tracer concentrations are kept low to avoid introducing significant quantities of foreign chemicals to the process flow. Very low flow rates are difficult to meter accurately. Furthermore, in production flows the line pressure is not truly constant but has small variations. These slight pressure fluctuations at the tracer injection port make steady low flow tracer injection and tracer flow metering challenging.

After the tracer injection point a suitable mixing distance is required. There are no stated distance requirements for this process. The mixing distance is usually decided per application by engineering judgment. It is beneficial to place the tracer injection point upstream and the sample point downstream of pipe components, such as a flow meter (see Figure 21), to aid mixing in a shorter distance.

Analysis of the liquid samples is typically done on site with portable equipment. It takes several hours to allow the sample to settle. The analysis of liquid samples is usually sophisticated and must account for the sample analysis being conducted at ambient conditions instead of line conditions.

With the tracer fluorescent intensity (K_0) and sample fluorescent intensity (K_S) measured along with the tracer injection flow rate ($\dot{q}$), Formula (27) gives the liquid flow rate ($\dot{Q}_l$).

$$\dot{Q}_l = \frac{K_0}{K_S}\dot{q} \tag{27}$$

Due to practical difficulties, the tracer dilution technique should only be conducted by trained and experienced personnel.

7.1.2 Monitoring wet gas liquid loading with a DP meter downstream port

Figure 21 shows a Venturi meter with a downstream pressure port and a tracer dilution system. The schematic diagram is not to scale. The downstream pressure port position is preferably located at 5D downstream or at a different position dependent on manufacturer's choice.

The traditional gas flow DP (ΔP_g) is the difference in pressure between the inlet and "throat" pressure ports. The gas flow permanent pressure loss (ΔP_{PPL}) is the difference in pressure between the inlet and downstream pressure ports. The Pressure Loss Ratio, or "PLR', is the ratio of the permanent pressure loss to the traditional DP. With single-phase flow, across large flow and line pressure ranges, the PLR is effectively a constant value, a characteristic of the DP meter ($\mathrm{PLR}_{\mathrm{dry\ gas}}$), i.e. Formula (28).

$$PLR_{dry\ \ gas} = \frac{\Delta P_{PPL}}{\Delta P_g} \tag{28}$$

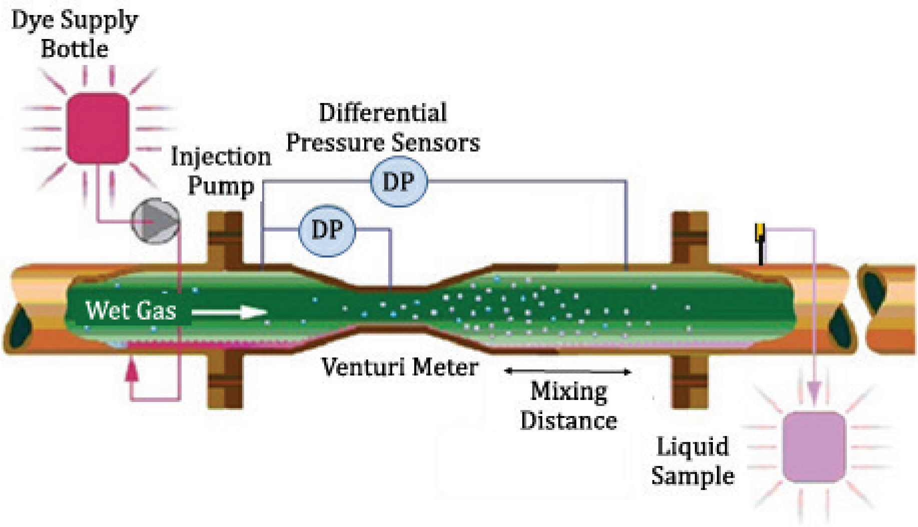


Figure 21 — Tracer Dilution Method Being Applied Across a Venturi Meter

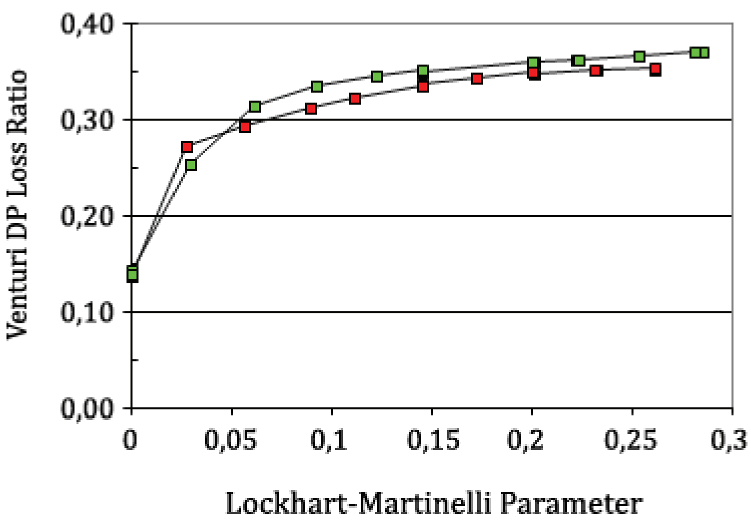


Figure 22 — Results from a DP Meter with Downstream Pressure Port in Wet Gas Service, PLR vs. X_{LM}

De Leeuw[18] showed that the wet gas liquid loading affects a DP meter's PLR value. The wet gas PLR ($PLR_{wet\ gas}$) is greater than the DP meters dry gas PLR ($PLR_{dry\ gas}$). The wet gas Pressure Loss Ratio, or '$PLR_{wet\ gas}$', is the ratio of the wet gas permanent pressure loss ($\Delta P_{PPL,tp}$) to the wet gas DP (ΔP_{tp}), i.e. Formula (29).

$$PLR_{wet\ \ gas} = \frac{\Delta P_{PPL,tp}}{\Delta P_{tp}} \tag{29}$$

Therefore, a DP meter's PLR could be potentially used to monitor a wet gas flow's liquid loading. Figure 22 shows sample wet gas flow data from a Venturi meter where the dry gas PLR is 0,14. As liquid loading (e.g. Lockhart-Martinelli parameter) increases so does the PLR. Monitoring the PLR can indicate liquid loading changes. A PLR change can therefore indicate when a liquid flow rate spot check must be used to update a wet gas correlation.

Figure 22 shows that the PLR vs. Lockhart-Martinelli parameter relationship is not linear. The PLR is very sensitive to the Lockhart-Martinelli parameter at low Lockhart-Martinelli parameter values, but has reducing sensitivity as the Lockhart-Martinelli parameter increases. Hence, this simple liquid loading monitoring system is more effective at lower Lockhart-Martinelli parameters.

The DP meter PLR liquid loading monitoring system is a generic concept potentially applicable to all DP meters. The theoretical DP meter PLR range is $0 \leq PLR \leq 1$. Increasing liquid loading increases the PLR. As the PLR cannot exceed unity, the lower a DP meter's single-phase flow PLR value, the larger the potential wet gas flow PLR range and the more sensitive the meter is to liquid loading changes. Hence, a rule of thumb is the lower a DP meter's single-phase PLR value, the more capable that DP meter's PLR wet gas flow liquid loading monitoring system.

8 Design and Installation Considerations

Design and installation considerations should be done as early as possible in the conceptual design stage. Many factors should be considered by an operator when determining the requirements for the design and installation of a WGFM. The predominant reasons and justification for measuring wet gas flow, or the liquids, should be given in a Measurement and Allocation Philosophy document. For example, the WGFM may be for

— well and reservoir surveillance and/or allocation,

— indication of formation water breakthrough in the reservoir,

— flow assurance (e.g. hydrate management), and

— fiscal allocation between production streams — this is required to determine financial transactions between operators or between operators and host governments.

Knowing the main objectives for metering can guide the operator as they select the appropriate technology and determine the requirements that will be placed on the WGFM selection. The operator should also consider aspects including the piping system design (and therefore the meter's location and orientation), the environmental conditions the meter must operate in, the maintenance and service plan and many other factors. These need to be evaluated for the full lifecycle of the meter's operation and with regards to the desired uncertainties in the flow measurement (i.e. uncertainty per phase).

8.1 Design considerations

This subclause addresses various issues that should be considered in a WGFM design. However, it will not address the mechanical integrity of a WGFM (e.g. mechanical aspects, pressure containment, etc.).The latter is part of the total facility integrity and should comply with good engineering practices.

8.1.1 Meter orientation and fluid flow

Some manufacturers claim their design and measurement uncertainty is not impacted by the piping layout. Other manufacturers' designs require a vertical or horizontal piping installation. The operator may clarify some of these issues by reviewing the manufacturer's test data, but preferably should consider testing the WGFM at an independent testing facility. However, a test in one meter orientation should not be considered an acceptable test for a different meter orientation.

It is technically possible to measure a wet gas flow in inclined pipe; however, such installations are very rare. Unless a dedicated test program is instigated to characterize a particular WGFMs performance in an inclined pipe as per the expected installation (which can and has been done) it is advisable that WGFMs should be installed in horizontal or vertical flow only.

In the design review, the operator should also include the fluid types the WGFM will be exposed to over its operating envelope in the design review. At the onset of production, completion fluids[7] may be

7) Liquids circulated in the well after drilling to "complete" an oil or gas well.

introduced through the meter, which may alter its measurement performance. As production volumes and fluid velocities increase, the operator should also consider other possible contaminants, such as sand production from the reservoir or other particulate matter that may cause erosion or fouling of the wetted parts of the flow meter. Erosion will create measurement uncertainties that cannot be easily replicated in a wet gas flow test facility.

8.1.2 Meter location relative to other piping components

Good engineering practice for the installation of single-phase flow meter technologies generally holds true for the installation of wet gas flow WGFMs. However, this rule of thumb has exceptions, as there are subtle differences between dry and wet gas flow metering.

One example is the installation of a flow conditioner upstream of a meter. In single-phase flow such flow conditioners are beneficial as they condition any disturbed flow as close as possible to fully developed flow profile at the meter inlet. However, with wet gas flow when water is present the pressure drop across the flow conditioner can cause hydrate formation that can partially or wholly block the flow conditioner. That is, if a flow conditioner is used with a wet gas flow, any hydrate formation induced by the pressure drop through the flow conditioner can cause the flow conditioner to become partially blocked, thereby making the flow profile more asymmetrical rather than more symmetrical. The potential of a complete hydrate block is a significant flow assurance issue.

A second example of where a WGFM system may be installed differently from a single-phase meter is in the case of horizontally installed meters. With single-phase gas flow a horizontally installed meter will usually have pressure ports at 90° or 270° to top dead centre. However, due to the potential for liquid being trapped in the impulse lines it is common practice for a horizontally installed WGFM to have the pressure ports at the top of the pipe only to reduce the likelihood of impulse line flooding and to increase the ability of any trapped liquids to drain away. Pressure tappings with remote seals and capillary impulse lines may also be beneficial where impulse line blockage by solids such as salt, scale, or hydrate deposits is a concern.

WGFM installation near the wellhead choke or other pressure reduction devices could have an impact on the measurement uncertainty. Other internal restriction devices, like sand monitors/probes, thermocouples, sampling devices, etc. can induce unwanted pressure drops, which may impact the measurement uncertainty.

Often, the need for a compact piping system design is a requirement for cost and installation considerations. An example is the installation of a subsea module that contains the WGFM. The operator should consider these issues at the design stage. At present the final design decision is based on engineering judgment.

8.1.3 Use of two-phase flow rate and composition maps

The sample two-phase flow map presented before (Figure 6) is a general example. A useful alternative presentation is a two-phase flow rate map with the actual gas and liquid volumetric flow rates (Am^3/d) plotted along the axis[35]. Note that this two-phase flow rate map is only valid for a given flow line diameter and for the given temperature and pressure.

In Figure 23, a two-phase flow rate map is presented in terms of Am^3/d. The X- and Y- axis are a log-log plot. Well production can be plotted as a function of time, i.e. both the liquid and gas volumetric flow rates will change over time. Thus the well will follow a certain trajectory. A single well trajectory or a collection of well trajectories can be defined as the production envelope of a gas field. This production envelope can also be presented as an area between minimum and maximum liquid and gas flow rates. As an example, in Figure 23, a well trajectory is plotted in the two-phase flow rate map. These trajectories are often based on preliminary information from reservoir engineers and consequently there is considerable uncertainty attached to them. It is strongly recommended to also include these uncertainty ranges in the two-phase flow rate maps. Well trajectories can also be plotted with 10 % or 25 % uncertainty bars.

Similar to single-phase flow meters, WGFMs also have operating envelopes which should be specified by the vendors. The production envelope (a collection of well trajectories) and the WGFM operating envelope should coincide. This is the first step in the selection of a suitable WGFM for a particular application. In Figure 23, an example of a two-phase flow rate map with a well trajectory together with the WGFM operating envelope is presented.

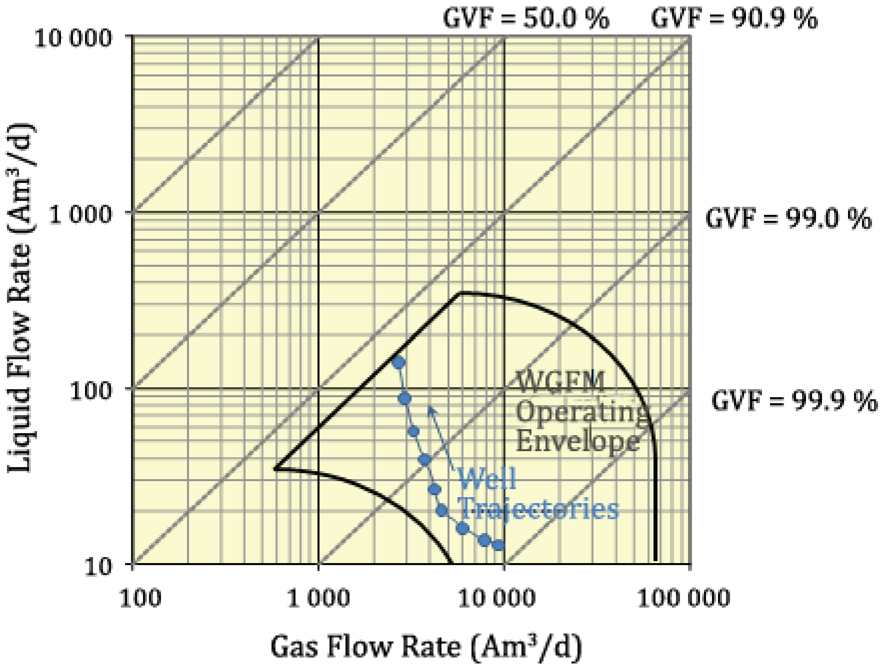


Figure 23 — Two-phase flow rate map with a well trajectory and a WGFM operating range, for a specific temperature, pressure and fluid composition

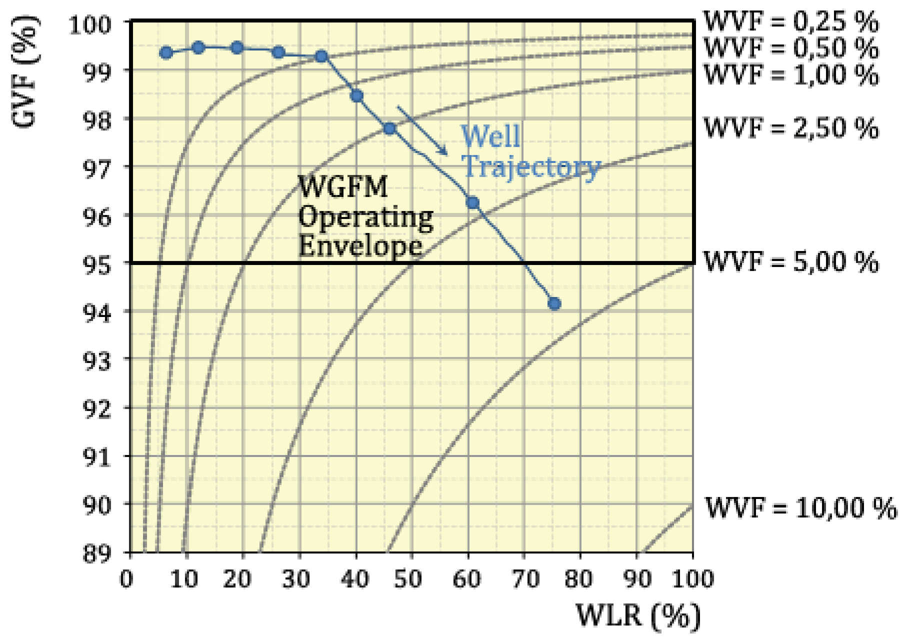


Figure 24 — Composition map with a well trajectory and a WGFM operating range, for a specific temperature, pressure and fluid composition

As a multiphase WGFM is only fully described with three parameters, e.g. oil flow rate, water flow rate and gas flow rate, a two-dimensional two-phase flow rate map is not sufficient. The three parameters can be described in different ways, e.g. oil/condensate flow rate, water flow rate and gas flow rates, or liquid flow rate, gas flow rate and WLR. Regarding the latter, the two-phase flow rate maps describe the total liquid and gas flow rates (and thus GVF), hence another map is required with information on the composition. This second map is the composition map which can have the WLR along the horizontal axis and GVF along the vertical axis. If necessary, the scale of both the X- and Y-axes can be adjusted to increase the visibility in a certain region, e.g. for a high GVF application the GVF could range from 89 % to 100 % (see Figure 24). As WLR and GVF generally change over time, a well trajectory can also be constructed, similar to the well trajectories in the two-phase flow rate map. One or more of these well trajectories are the production envelope in the composition map.

Multiphase WGFMs can also have their operation envelopes presented in the composition map. This operating envelope is not necessary always from 0 % to 100 % GVF. For example, electrical impedance methods have different responses in an oil-continuous (WLR is low) than a water-continuous (WLR is high) flow. Gamma ray based measurement is less dependent on the physical appearance of the oil-water mixture. Moreover, the uncertainty in measured WLR also depends on the technology used. In Figure 24 an example is given of the composition map with a well trajectory (production envelope) and the operating envelope of a multiphase WGFM. The production envelope and the WGFM operating envelope in the composition map should coincide for a particular application.

8.1.4 Fluid sampling

Fluid sampling is an important topic that should be discussed between the engineers, the WGFM end users (i.e. operations, petroleum or reservoir engineering) and the selected meter vendor at the start of the design stage. The meter end users and the design team should understand any specific contractual requirements that would require fluid sampling (and the subsequent sampling frequency) with the Joint Venture partners, government regulators or for internal data requirements used for reservoir surveillance and maintenance activities. These requirements, once identified, need to be documented.

Obtaining representative fluid samples from a wet gas flow is significantly more difficult than obtaining representative fluid samples from a single-phase flow. A representative sample means that the property or parameter to be determined in the sample is representative for that same property or parameter in the main flow line. For example, if the “property or parameter to be determined in the sample” is the phase flow rate ratios then the sample is “representative” only if the static sample’s phase volume ratios are the same as the flow rate ratios. In such a scenario there is by definition, a sample of each fluid available for physical property analysis. Alternatively, if the “property or parameter to be determined in the sample” is only each phase’s properties then a “representative” sample only means a sample that collects a sample of each and every component in the flow for physical property analysis. In this scenario the “representative” sample does not necessarily have a static sample with phase volumes representative of the phase flow rate ratios. Due to limitations in wet gas sample technology, most samples in the field are not representative of the phase flow rate ratios.

As a wet gas flow mainly contains gas by volume with smaller volumes of water and hydrocarbon liquids, there is a significant challenge to ensure that a given sample contains all the phases. Wet gas flow sampling is a specialist undertaking; at the present time there is no agreed wet gas flow sampling method that is the accepted practice in the hydrocarbon production industry. However, it is key not to allow phase change or a change of the individual phase properties during sampling which means the sampling system needs to be kept under line pressure and temperature.

8.1.5 Redundancy and external environmental considerations

The WGFM operator should consider the external environment where the meter will be installed.

The physical location and installation design of the WGFM are often different in a subsea system from those on land, and require different designs. For subsea applications, the retrieval and replacement of a meter will be an order of magnitude more expensive than in a surface installed metering system. The operator should therefore consider if redundant (duplicate) measurement devices are required to ensure acceptable measured data.

For example:

— redundant pressure and temperature transmitters;

— redundant phase fraction device sensors;

— redundant Differential Pressure (DP) transmitters;

— different DP readings across the meter to calculate flow rate (e.g. permanent pressure loss or recovered DP as well as traditional DP readings);

— the sum of the permanent pressure loss and recovered DP allows a secondary inferred traditional DP measurement and therefore redundancy on any one of the three DP readings;

— redundant power supply and communication wiring;

— redundancy for other critical devices necessary for capturing and transmitting the information that will be used for the flow calculation (e.g. digital communications networks).

Duplicate systems are not only important as back-up systems but they allow a level of diagnostics on the primary readings to give correct meter operation assurance. WGFMs that have more than one method of calculating a meter output also offer ultimately greater flow assurance.

Onshore installations can be affected by the operating environment, such as in extreme operating temperatures of the arctic cold, humid tropical conditions or very hot desert environments. When selecting a WGFM, there may be different installation requirements depending which environment it will be exposed to. This may include weather protection equipment (e.g. an enclosed containment to protect the instruments from extreme high or low temperatures). These external effects need to be incorporated into the design and installation of the metering system. In addition these issues must be addressed in the meter's maintenance philosophy and its maintainability with respect to the measurement uncertainty. Operations may require the piping system to include a bypass that will allow removal of the meter during operation without shutting in the flow. In an onshore application the complexity of providing this bypass may be minor, but for a subsea meter installation including a bypass system can be complicated and expensive.

The functional duration of the measurement system is another important design criterion that the operator should evaluate when considering WGFM designs. The system design may differ if the WGFM is required for an operational life cycle of 5 years vs. 25 years. The operator needs to consider the measurement device recovery and re-installation after repairs or re-validation; for instance, the measurement subsea module may have a special design for its removal, or require special tooling for a Remotely Operated Vehicle (ROV) to perform the removal and installation task. Again, this may be more critical for subsea designs, while for an onshore installation they will probably not be as important.

8.1.6 Security

Security issues may need to be addressed when considering the use of WGFMs. Theft of the flow meter, or part of the device, or tampering with the data for measurement and allocation purposes are issues that should be considered.

For land applications, the operator should consider the geographic location; remote areas may require data telemetry for monitoring and periodic data gathering. Some WGFM designs incorporate the use of radioactive sources. The security of the radioactive source should be considered. It may prove necessary to select a meter that does not utilize radioactive sources, even if this results in higher flow measurement uncertainties.

Data security is an important subject for partnerships with joint venture energy companies and for governments. The flow meter design and data storage also may be important for auditing purposes, and should be appropriately considered.

8.1.7 Cost and project schedule implications

WGFM selection may present a "challenge" to the project team as they aim to minimize cost and schedule. The meter operators may want a system design that will "never fail" while continuously providing very low measurement uncertainty. In contrast, the project team has stewardship to deliver the project within reasonable economics to their stakeholders and in a timely manner. The stakeholders should be realistic and pragmatic about the available meter technologies' specifications. The meter operator must therefore use sound engineering judgment to evaluate the relative risks of a chosen WGFM design.

The requirements of the Factory Acceptance Testing (FAT) should also be considered. Generally a FAT may consist of a comparison of delivered hardware and documents with the specifications. However, it may also include a test of WGFM performance in a test facility, particularly if needed for other reasons, such as regulatory or contractual requirements. It is also good practice to schedule the test with as much time between the FAT and installation dates as possible, and to consider what happens in case a wet gas meter system fails the FAT.

8.2 Performance specifications

During the design stage of project development, the design team should compare different WGFM technologies in order to decide which technology is best for that particular application. As discussed in Clause 1, each project might have different WGFM requirements and as indicated in Clause 6, different WGFMs will operate on different physical principles and therefore have different advantages and disadvantages. Partly due to the fact that no two WGFM technologies are identical and partly due to the lack of standards for WGFMs, each vendor presents their WGFM specifications in their own preferred way. This creates a significant problem to the engineer attempting to decide upon the best technology for a given application.

Also, as WGFM technology is generally more complex than single-phase flow meter technology, the performance specifications for WGFMs are also more complex. This makes it more difficult to make a true comparison between the various WGFMs. It would therefore be beneficial to have a standardized method of presenting WGFM performance specifications.

The performance specifications for WGFMs are complex and often not constant over the operating envelope. Most WGFMs outputs are sensitive to an extensive list of parameters. For example, a WGFM may find it relatively easy to meter higher liquid flow rates in high liquid loading wet gas flows. However, as the liquid loading and liquid flow rate decrease to trace levels, the normal instrumentation rules still apply in that there is an increasing percentage uncertainty in the measurement of the smaller measurand fraction.

A potential meter operator may want each vendor to supply the appropriate performance specifications for a particular application. However, in order for the vendor to supply the appropriate information it is a requirement that the potential operator gives details of the application's wet gas flow condition range. It is also necessary that the potential meter operator states the primary objective of the WGFM system.

Due to the diversity of the world's wet gas production flow conditions, there may be a portion of this wet gas flow condition range out of the experience of WGFM vendors, and/or out of the testing capability of the available wet gas flow test facilities. In such a case there is no practical way for any WGFM vendor to prove or guarantee any expected meter performance claims. In this situation, due to lack of any practical alternatives, it is common for the operator to be pragmatic and on checking for realistic claims, accept the vendors best guess uncertainties.

When comparing different WGFM technologies, the different physical principles will typically result in one being stronger in one measurement parameter but weaker in another. For example, a WGFM may have a lower uncertainty in hydrocarbon flow rate prediction than another meter, but yet it is less able to predict water break-through than the other meter. The operator then has to decide which output is the most critical while also considering the other important issues of cost, required maintenance, redundancy levels, safety, etc.

8.3 Wet gas flow measurement uncertainty

Whereas, the Guide to the Expression of Uncertainty in Measurement (ISO/IEC 98-3:2008)[45] and its supplements were written to "establish general rules for evaluating and expressing uncertainty in measurement", and as such provides a general methodology, ISO 5168[3] exists to provide methods of computation of uncertainty more specific to flow measurement. However, additional considerations should also be made for the complications associated with wet gas flow measurement beyond that detailed in these referenced documents.

8.3.1 Uncertainty evaluation methodologies

To calculate the overall uncertainty of a measurand generally requires the evaluation of the uncertainties associated with all relevant parameters and the calculation algorithm used to determine the chosen result.

ISO 5168, 10.2 defines the Uncertainty Budget methodology, which allows the determination of the overall uncertainty by individually evaluating the uncertainty of each input parameter and the sensitivity of the measurand calculation to that parameter. This technique is suitable for systems where the calculations are known and simple. With more complex systems, such as WGFM calculations, the Uncertainty Budget method may therefore be cumbersome.

An alternative is to use the Monte Carlo methodology (see for instance Supplement 1 to ISO GUM, "Propagation of distributions using a Monte Carlo method"). This treats the algorithm as a "black box" where the inputs are entered and outputs are obtained. By altering the inputs parameters in a manner determined by their respective uncertainties, the end result (or results) can be recorded.

8.3.2 Additional factors affecting wet gas flow measurement uncertainty

The methodologies discussed above give a sensible process for calculating the uncertainty in the required output parameters, where the major complications would be providing the input parameters and uncertainties, and fully detailing the required algorithms. Certainly for standard single-phase flow meters, or for simple wet gas corrections, these techniques provide reliable solutions.

For the more complicated (multiphase) wet gas systems, other factors beyond the evaluation of the sensor measurement uncertainty associated with each parameter may lead to additional uncertainty in the measurement. For example:

a) Although the uncertainties of individual phase parameters (such as density, viscosity, permittivity, etc.) may be known, the uncertainty associated with the combined phase mixture may not be determined.

b) The number and variety of metering sensors may be significantly more than those used for a single-phase flow meter. Additional care should be taken to ensure that the relevant parameters and their respective uncertainties are evaluated for all sensors, including sensors that switch based on the current range of operation. Also, if a fall-back case is provided where a secondary sensor or sub-system replaces a failed sensor or sub-system, the uncertainty associated with this system should also be appropriately evaluated.

c) Calibration of sensors should also be considered, particularly for subsea WGFMs where recalibration may not be feasible.

d) The associated uncertainties in the measurements of a meter technology may be affected by the wet gas flow regime, which may not be determined for given input parameters. For example, a gamma densitometer "sees" what occurs in a beam, and therefore this measurement would be altered depending on the local flow regime.

e) It may be impractical to fully detail the flow measurement algorithms with all associated meter parameters and their individual uncertainties in a spreadsheet. The uncertainties in some calibration parameters may be difficult to know if they are determined experimentally.

Furthermore, the flow measurement algorithms may not be available to the end users due to the vendor keeping them confidential.

f) The uncertainty associated with the change of fluids between that used at a wet gas test laboratory and those the meter will see over its lifetime in the field may not be known. For instance, a wet gas test laboratory may use air or nitrogen as the gas phase and a condensate substitute and fresh water, whereas the meter will see live hydrocarbon fluids and saline water. This may result in a lower uncertainty at the flow facility than would be seen with the live conditions.

g) The uncertainties associated with fitting a model to real life data may not be accurately known, given the relatively few points of a typical wet gas test matrix. Also, if a theoretical model is used for any aspect of the flow metering algorithm, this will also have an uncertainty as to how well it represents the real world (for instance, PVT Equations of State).

h) Real world wet gas flow can be relatively unstable, so the uncertainty of an instantaneous measurement (from a single sensor or the meter as a whole system of sensors) will fluctuate. Some systems may incorporate averaging functionality, which may require additional consideration, as this time effect will not be appropriately evaluated for a static system.

i) Determination of some parameters may not be so readily possible in the field as at a wet gas test laboratory. For instance, the difficulty associated with representatively sampling the fluids passing through the meter may lead to an additional error in the total hydrocarbon composition and other parameters, which would increase the overall uncertainty in the flow measurement.

8.3.3 Expressing uncertainty of wet gas flow rates

As far as possible, the uncertainties of the flow rate measurements from a WGFM should be clearly expressed in a manner that does not hide calculation parameter details within the “black box”. An appropriate uncertainty evaluation should take place, and should consider both

— the input parameters to the algorithm (with their associated uncertainties and sensitivities), and

— other factors that may affect the flow measurement that otherwise would not be evaluated by considering only the input parameters.

The methodology should be consistent with those detailed in the relevant standards (such as the uncertainty budget as per ISO 5168, or Monte Carlo from ISO GUM). The uncertainties should also be computed for each relevant output variable that the meter claims to measure.

It should also be noted that not every flow meter manufacturer supplies the uncertainties associated with their meter with the industry standard coverage factor $k = 2$ (i.e. 2 standard deviations, representing a confidence interval of approximately 95 %). It is important, therefore, when comparing the uncertainty specification of two meters that the uncertainty specifications are corrected back to a common coverage factor. Only when two WGFMs uncertainty specifications for the same output parameter are stated at the same confidence interval are they directly comparable.

9 Testing, Verification and Calibration

In this clause, the testing and verification of WGFMs are discussed. Before WGFMs are installed and operated in the field; it is recommended to execute a number of tests/evaluations. This can include a Factory Acceptance Test (FAT), a flow facility evaluation and/or a Site Acceptance Test (SAT). The FAT and the SAT are often considered essential by operators. Whether a flow facility test is required depends on factors including the existing experience, the confidence of the operator, budget, availability of test facility, etc.

9.1 Meter orientation

Good operating practice for single-phase flow meter testing and calibration is generally also good for WGFM testing. The addition of liquids to the gas flow makes the test more complicated. Multiphase wet gas flow in a test facility is more difficult to control than single phase flow and it can take longer to stabilize and log test points.

Wet gas flow orientation (e.g. vertical up, horizontal) can influence the flow regime and the flow regime can influence the response of most WGFMs (e.g. see Figure 11). It is critical that a WGFM should be installed in the wet gas flow test facility such that the wet gas flow regime through the meter is representative of the wet gas flow regime it will encounter in the field. A WGFM designed for, and destined to be operated with vertically up flow must be tested in this particular orientation. If such a WGFM was tested in another orientation (e.g. horizontal flow) then the resulting flow regime and therefore the resulting data may not be representative of the meter's performance in the field.

9.2 Comments on flow regimes and mixers

It is not advisable to attempt to artificially manipulate a wet gas flow regime by use of a mixing device. Wet gas flow regimes are dictated by the balance of forces on the gas and liquid fluids. The addition of a mixer to modify the naturally occurring flow regime at any given flow conditions has only a transient effect on the wet gas flow regime. On exiting the mixer, the fluids will immediately start transition back to the flow regime dictated by the local flow conditions. There is significant evidence from wet gas flow facilities that this transition occurs over a few diameters of pipe.

For a similar reason, it is also not possible to artificially induce a mist/homogenous flow in a wet gas test facility by using a mixer.

Wet gas flows with low gas dynamic pressure (i.e. low gas density and/or low gas velocity) are inherently unstable. If there is not enough energy in the gas to drive the liquid flow steadily, the liquid tends to enter a cycle of slowing and collecting, and then accelerating before slowing again. Such flow is called "intermittent flow". In horizontal flow this is "slug flow" and in vertical upward flow this is "churn flow" (see Figure 3). Wet gas flows with intermittent flow regimes are difficult to meter. During wet gas flow tests at wet gas flow facilities, such flow instability is not a limitation of the test facility but rather due to the natural behaviour of wet gas flows at these conditions.

WGFMs, which are to be installed vertically with upward flow, often have a stated minimum operational gas dynamic pressure in order to avoid intermittent flow. Some WGFM manufacturers claim that with higher sensor reading frequencies, appropriate data averaging and proprietary software their WGFMs can cope with intermittent flow. However, testing is recommended.

9.3 Installation requirements

Most WGFM systems (whether a standalone DP meter with a wet gas correlation, a two-phase WGFM or a multiphase WGFM) utilize a Venturi meter or cone configuration as a subsystem of the overall metering system. In single-phase flow measurement, Venturi and cone meters have a requirement for upstream pipe straight run lengths to ensure fully developed flow and correct meter operation. With WGFMs, upstream pipe straight run lengths are not stated by most WGFM manufacturers. Alternatively, a blind-T configuration may be used to provide a level of flow conditioning.

WGFM manufacturers tend to dictate piping requirements based on wet gas flow regime factors, rather than the traditional single-phase flow considerations of velocity profile. Venturi meters in WGFM systems may not be compliant with the installation requirements of ISO 5167-4. Dry and wet gas flow testing of the meter resolves any effects of these specific deviations.

9.4 Wet gas flow characterization tests — Single-phase DP meter baselines

Most WGFMs are required in horizontal piping. As some WGFM designs require (or are optimized by) installation in vertical up flow conditions (see 9.1) these meters are commonly installed in an inverted U-bend. These meters are often located in the piping immediately downstream of a blind tee entrance. Figure 25 below shows such an installation.

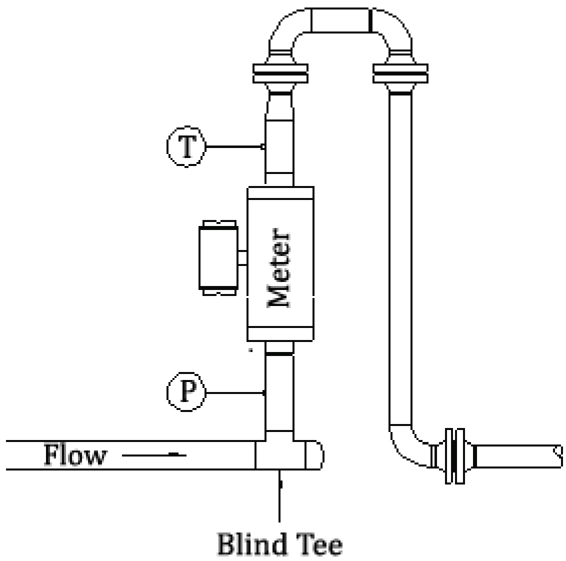


Figure 25 — Common WGFM installation with a blind tee upstream

Cone meter manufacturers state that for low uncertainty single-phase gas flow metering cone meters require to be individually calibrated across the application's Reynolds number range. For Venturi meters, ISO 5167-4 states that that for low uncertainty single-phase gas flow metering Venturi meters require individual calibration if the meter geometry and flow conditions fall outside the following ranges:

Pressure ≤ 10 Bar

20,000 ≤ Inlet Reynolds Number (D) ≤ 10^6

50 mm (2 in) ≤ D ≤ 250 mm (10 in)

0,4 ≤ β ≤ 0,75

The majority of wet natural gas production flows are at pressures and Reynolds numbers significantly above these thresholds. It is therefore recommended that WGFM technologies that utilize Venturi or cone meters should be dry gas flow calibrated to characterize the meter's dry gas flow baseline performance across the application's flow range.

9.5 Wet gas flow facility operational considerations

The integrity of a wet gas flow test facility is heavily dependent on the integrity of the test facility reference meters. When flow testing a WGFM, it is necessary to

— Verify that the flow in the test facility is steady during the time of measurement so as to ensure that the flow rate reading and composition (each phase) at the reference meter is representative of the flow at the meter.

— Know the local thermodynamic conditions at the reference measurement and at the WGFM. If pressure and temperature are different, make the necessary PVT corrections. Either compare at the same operating conditions or convert to standard conditions.

9.5.1 Test facility operational issues — Achieving thermodynamic equilibrium

The temperature of the injected liquid phases should match the temperature of the gas flow. Single-phase gas, hydrocarbon liquid and water flow meters, upstream of the multiphase mixing point provide the gas, hydrocarbon liquid and water reference measurement. If the system is not in thermodynamic equilibrium, i.e. the phases are mixed at different temperatures, phase change may occur as heat transfer occurs. Both the hydrocarbon gas and liquid phases are mixtures of various compounds. Depending on the hydrocarbon gas and liquid phase composition, a temperature gradient between the phases can cause

— compounds in the hydrocarbon liquid phase to be absorbed into the gas phase,

— compounds in the gas phase to be absorbed by the liquid phase.

Without thermodynamic equilibrium the integrity of the upstream phase flow rate references can be compromised.

A wet gas flow test facility reaches thermodynamic equilibrium by flowing the system for a period of time that allows the phases to be well mixed and heat transfer to be complete. Some phase change will inevitably occur during the warm up but will stop as the fluids reach thermodynamic equilibrium with each other. The larger the liquid holding tanks, the greater the liquid mass, and the longer the required heating period.

It is important that phase properties are logged live at the test condition and not the static sample condition. For the case of natural gas flow, a gas chromatograph should be in continuous operation to monitor the gas composition during the test. Often the actual liquid densities are measured along with the flow rate by reference liquid Coriolis meters. Also, if required, a pycnometer can be used to measure the liquid density at line pressure.

It is necessary to account for any change in thermodynamic conditions between the reference measurement points and the WGFM under test as minor changes in fluid properties can occur. The less permanent pressure loss between the reference instrumentation and the test meter inlet, the less likely these changes will be problematic.

9.5.1.1 Test facility operational issues — Fluid choice

The industry is still debating the advantages and disadvantages of various fluids used to mimic the real world fluids in wet gas flow facilities. It is often considered ideal to use the application's actual production fluids. However, there are two practical factors that make this significantly less attractive:

— delivering to, and filling, a wet gas test facility with specific fluids for each and every wet gas flow test makes wet gas flow facility operation significantly more expensive and time consuming than if one set of fluids are accepted for that wet gas flow facility, and

— even if thermodynamic equilibrium exists between the phases at the test meter inlet, many production hydrocarbon liquids are so light that they can change phase due to the small changes in thermodynamic conditions (e.g. pressure loss) between the injection liquid meter location and the test meter location.

Wet gas flow facilities tend to operate with one set of gas, liquid and water fluids with known properties. The fluids chosen usually represent the lightest hydrocarbon liquids that can be run in that wet gas flow facilities thermodynamic condition range without causing significant phase change uncertainty. It is only with specialized high-cost and time-consuming testing that particular fluids are introduced instead of a wet gas flow facility's default fluids.

9.5.1.2 Test facility operational issues — Gas breakout

Many WGFM systems are to be used over long periods of time where the production flow conditions change as the well ages. WGFMs are therefore often tested over a range of thermodynamic conditions — in particular, a range of pressures.

The thermodynamic condition dictates the amount of gas absorbed in the liquid phase. At higher pressures liquid can typically absorb more gas than at lower pressures. Hence, when conducting a wet gas flow test, where more than one pressure is required, it is good practice to test at low pressures first and then test at increasing pressures. Testing a WGFM with reducing pressure, and not waiting an extended period of time to allow the liquid to de-gas, can and does result in significant gas release from the liquid phase during the test, thereby compromising the integrity of the lower pressure reference data.

9.5.2 Test facility operational issues — Phase flow rate stability

Wet gas flow test facilities can take longer to change flow conditions than a single-phase flow facility. When changing either the gas or the liquid phase flow rates it takes some time for the new wet gas flow condition to stabilize and settle to give a constant flow through the test meter. For example, when injecting more liquid at a constant gas flow rate it takes some time for the extra liquid to be moved down the pipe by the gas flow. A test point can only be logged once the operator is sure that the new wet gas flow condition is stable at the WGFM inlet. The stability check usually consists of

— monitoring the single-phase reference meters for stability at the new required flow rates, and

— monitoring the test meter output signals between the previous and new wet gas flow conditions, until test meter sensor averaged data repeatedly produces the same new averaged values.

The shorter a test facility's wet gas flow test section, the less of an issue stabilizing the system at a new wet gas flow condition is. Most wet gas flow test facilities have less than 150 m of wet gas flow test section between injection point and separator inlet (with varying nominal pipe diameter). This means that the test meter inlet flow reaches wet gas flow equilibrium reasonably quickly. For example, at 150 m of length, even at an unusually low superficial gas velocity of 2 m/s, and an unusually high slip ratio (S_R) of 4, the gas flow passes from inlet to exit in approximately 75 s, and the liquid in four times that time, i.e. 300 s, or 5 min. That is, most industrial wet gas flow facilities can achieve a new wet gas flow test condition within 5 min.

The term "stable" wet gas flow is subjective, and needs to be defined between the parties involved in the test. By nature wet gas flow is inherently a transient flow. Hence, the term "steady wet gas flow" is usually verbally agreed, or inherently understood between parties without discussion, to mean "pseudo-steady wet gas flow". Here, repeated sensor readings vary reading to reading, but when grouped with a large enough data set they always average to a reproducible value. With such pseudo-steady wet gas flow the average sensor outputs of the WGFM under test (with relatively large standard deviations) are deemed to be relatively constant over time.

Figure 26 shows sample wet gas flow DP meter data, in the form of the meter's read DP per scan vs time. The data starts with dry gas flow and then various liquid loadings of wet gas flow.

— The first data point (circled left) is a dry gas flow. The standard deviation of the DP is very low.

— The second point (circled right) shows wet gas flow (at X_{LM} of 0,25). The liquid has induced a significant rise in DP for the set gas flow rate and also a significant rise in the DP's standard deviation.

— As the liquid loading is reduced in steps, the subsequent DP value and standard deviation reduce towards the original dry gas values.

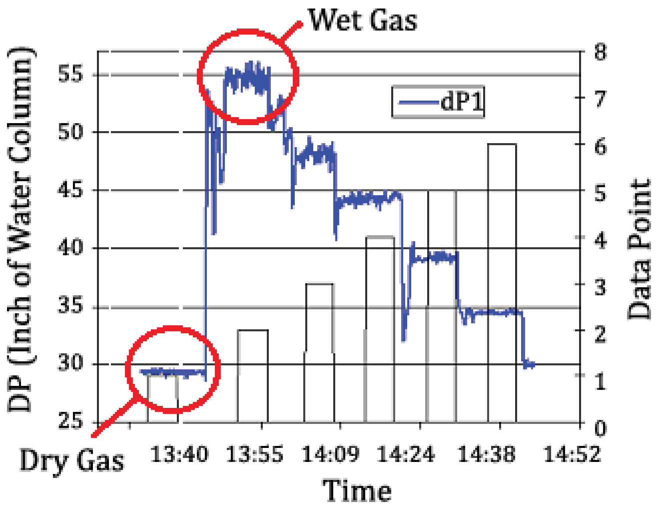


Figure 26 — DP vs. time data of a DP meter under dry and wet gas flow conditions

It is this phenomenon that is exploited in the fast-response-sensor wet gas systems discussed in 6.5.3.

Pseudo-steady wet gas flow causes meter sensors (of various physical basis) to have higher standard deviations than if that gas flow was dry. Some technologies may require more data sweeps, i.e. a larger data set to be averaged to achieve a representative data sample, than other technologies. The meter manufacturer will suggest to the test facility and operator the amount of data to be gathered, i.e. at what frequency and over what time frame, and averaged to obtain a representative data point.

9.5.3 Test facility operational issues — Witnessing of tests

A meter's wet gas flow test matrix is decided amongst the relevant parties before the test commences. The test matrix usually incorporates the field application's predicted wet gas flow conditions. Hence, there is usually no secrecy amongst participants regarding the test matrix.

— If the test is research and development based this is not an issue.

— If the test is conducted without the meter manufacturer's participation this is not an issue.

— If the test is a verification test to assure correct meter operation, and the operator invites the meter manufacturer to help operate the meter during the test, this can be an issue.

In the third scenario, the meter manufacturer's knowledge of the test matrix means that the test is not truly blinded. A partial solution to this issue is

— give the attending meter manufacturer staff a range of conditions that the test will be within (i.e. a range of pressures, gas and liquid flow rates etc.),

— do not give the attending meter manufacturer staff the actual wet gas flow conditions of each test point their meter is to predict.

It is also beneficial to the blinding process to randomly select test points in the matrix rather than moving through the test points in sequence. However, this method of making the test more realistic has time and financial consequences.

— It is impractical to randomly switch pressures. This is not only impractical from a time perspective, but failing to only maintain or increase pressure as the test matrix proceeds, can cause gas break out compromising the integrity of the test (see 9.5.1.2).

— It takes longer to substantially change the gas and liquid flow rates between subsequent tests, than to hold one phase (or more phases) constant and change a single-phase flow rate. Whereas this increase in time is relatively modest per test point, it accumulates to a significant increase in time, and therefore cost, if the practice is repeated over a whole test matrix.

Therefore, due to practical limitations the operator is limited to how blind a WGFM manufacturer attended test can be. It is possible to truly blind a test, but it takes significant time and effort.

9.6 Meter testing in a wet gas flow facility

It is advantageous for the operator and WGFM manufacturer to discuss what is to be achieved by a WGFM test before the test commences and it is preferable that the entire test shall be documented in a test program. The latter should include the following information:

— description of the test facility in terms of available flow rates, GVF, and WLR:

o type of fluids to be used, and if possible, the variations in fluid properties, e.g. salinity;

o available reference measurements with the uncertainties (calibration sheets);

— description on how the test will be conducted in terms of vendor, test facility operator, and oil/gas company operator interaction:

  o type of external inputs, e.g. fluid properties, required for the WGFM;

  o test matrix in terms of flow rates, GVF, and WLR, as well as the sequence of test points.

As with all instrumentation, it is ideal for the end user to independently test the equipment for their own verification. However, with the state of the art of wet gas flow meters, due to their relative complexity and the manufacturer’s confidentiality requirements, operators may opt to include the manufacturer in the test procedure. In such circumstances it is the operator’s prerogative to decide upon the level of manufacturer access to the flow meter under test.

It is common for a verification tests to take place either before or after final purchase. Testing WGFMs should be conducted at the earliest possible time. This maximizes the operator’s options if test results are problematic.

In plotting results from a WGFM test, use can be made of the two-phase flow rate map and the composition map that were discussed earlier in 8.1.3. The WGFM operating envelope is plotted and the test points are represented by two points. One is the reference measurement and one is the WGFM output (squares and circles in Figure 27). The length of the line between the reference measurement and the WGFM output represents the deviation between the reference measurement and the WGFM output. An advantage of a log-log plot is that throughout the plot a certain relative error in flow rate is represented by the same length. The reference measurement and the WGFM output can also be presented in the composition plot with the same connecting line between reference measurement and WGFM output (see Figure 28).

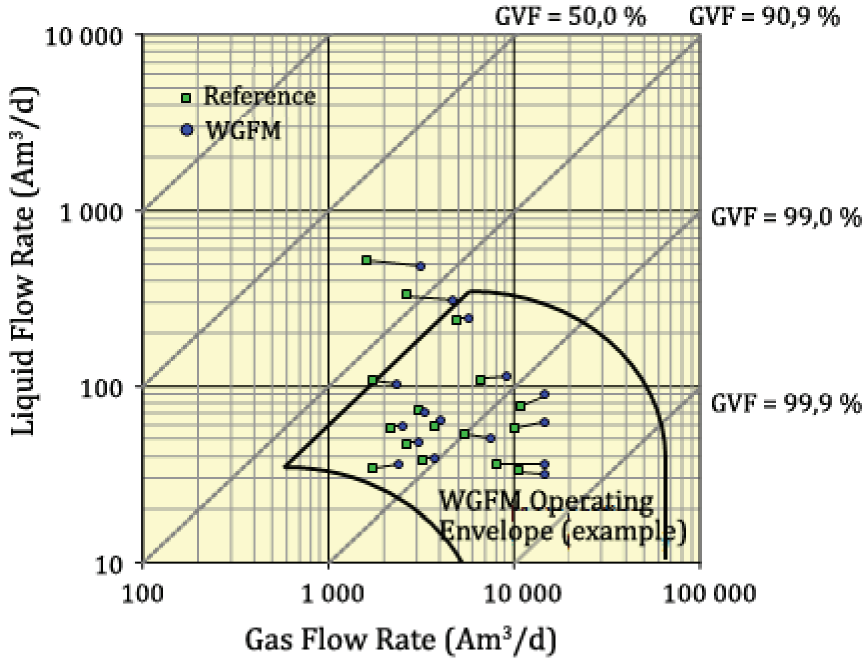


Figure 27 — Two-phase flow rate map showing the test points from a flow facility evaluation and the WGFM operating envelope

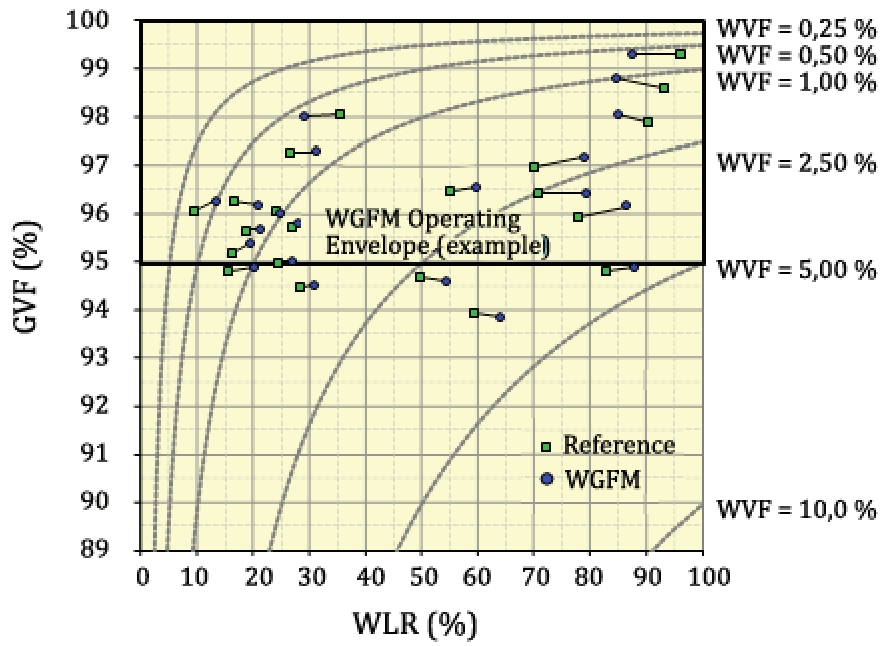


Figure 28 — Composition map showing the test points from a flow facility evaluation and the WGFM operating envelope

In addition to the above two-phase flow rate map and the composition map, it is also convenient to plot the deviations between reference measurement and WGFM output reading as a function of GVF. This can be done for gas flow rate, liquid flow rate, WLR and WVF. An example for liquid flow rate vs. GVF is presented in Figure 29.

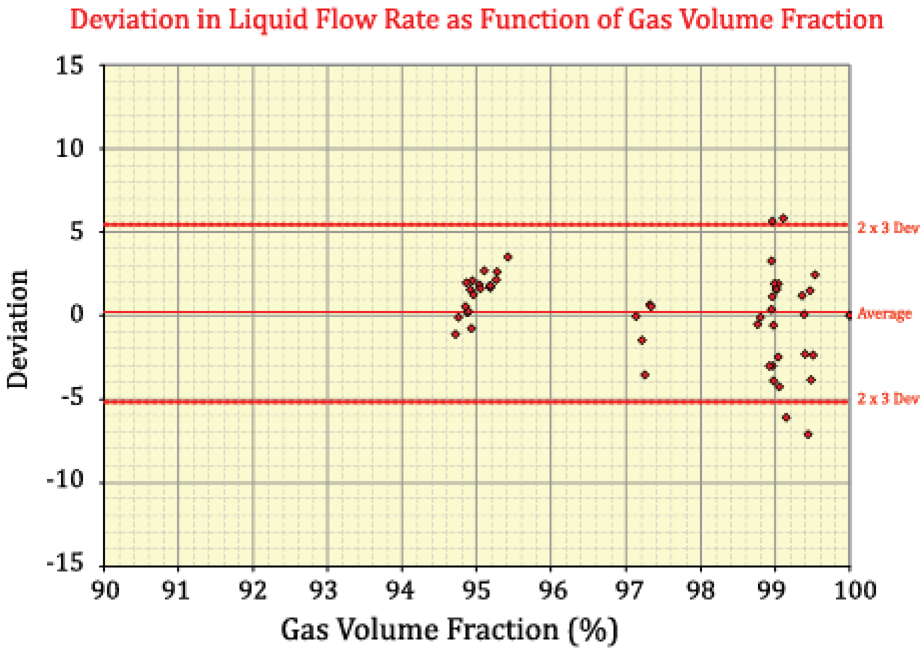


Figure 29 — Deviation of liquid flow rate prediction from reference plotted vs. GVF%

Cumulative deviation plots are a convenient way to compare the performance of different WGFMs. In Figure 30 and Figure 31 the cumulative deviation between the reference measurement and the WGFM measurement is plotted along the X-axis and the Y-axis represents the percentage of test points that fulfil a certain deviation criteria. This example shows that 90 % of all the test points show relative deviations in liquid flow rate that are smaller than 4 %. Similar conclusions can be made for the gas flow rate, the WLR and the WVF.

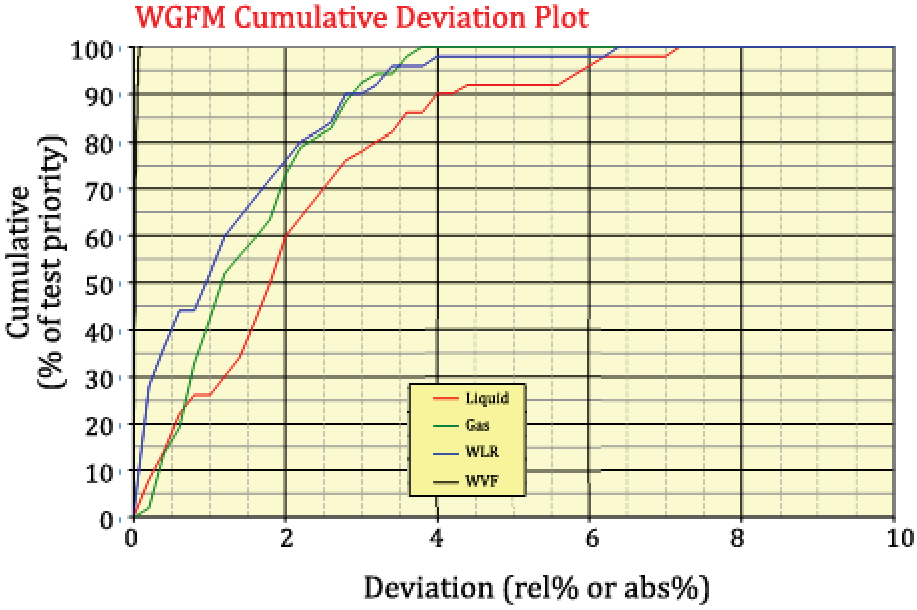


Figure 30 — Cumulative deviation plots indicating the percentage of test points as function of the deviation

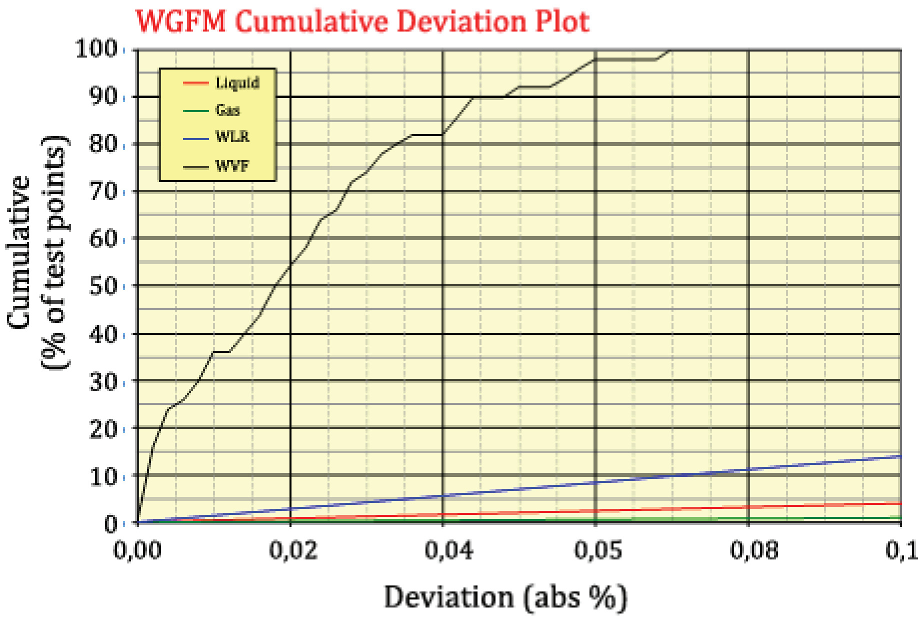


Figure 31 — As per Figure 30, but scaled to make the cumulative deviation for WVF more visible

10 Operational and Field Verification Issues

Depending on the WGFM technology, various levels of fluid property information are required. However, these fluid properties are not always easy to obtain in a real field installation.

10.1 Laboratory reference vs. field hydrocarbon flow composition estimates

In the field, reservoir or petroleum engineering generally provides the initial fluid composition estimate in terms of mole fraction. During the operations phase, if it is possible, samples are taken to update this fluid composition. Note that either fluid composition (mole fraction) or fluid parameters (e.g. density, gamma ray absorption coefficient, etc.) are often inputs for the WGFMs.

At a multiphase wet gas flow facility, the wet gas flow is artificially created by injecting water and hydrocarbon liquids into a single-phase natural gas flow. Here also the WGFM under test requires the fluid composition or fluid parameters.

A multiphase wet gas flow created in a test facility has a varying total hydrocarbon flow mole fraction as the flow conditions are deliberately changed during the test procedure. For each selected wet gas flow condition, the total hydrocarbon mole fraction is set by the natural gas and hydrocarbon liquid phase flow rates and the compositions of the natural gas and hydrocarbon liquid, i.e.

— gas flow rate from gas reference meters,

— gas composition from gas chromatograph,

— liquid hydrocarbon flow rate reference meter, and

— hydrocarbon liquid composition from sample analysis.

10.2 Laboratory reference vs. field calibration of phase fractions

Multiphase WGFMs contain “phase fraction devices”. These devices are discussed in 6.6.3.

In order to reduce phase fraction device output uncertainty, it is desirable to characterize these devices with the fluids to be seen during the operation. Ideally, this can be done by filling the meter chamber with each of the individual phases in turn, and calibrating the phase fraction device for each individual “phase”. This practice is possible in a wet gas flow test facility but often not possible in field applications such as subsea installations. If filling the meter body with each of the live fluids cannot be achieved in the field then the phase fraction devices have to be set to recognize each phase by another method. This may be done by using the reservoir engineer’s fluid property predictions. This practice has higher uncertainty than calibrating the device/s to the live individual phases.

Multiphase WGFM output sensitivities to biases in the total hydrocarbon flow mole fraction input values and/or the phase fraction device’s characterization of the individual phase properties are largely undisclosed by the WGFM manufacturers.

10.3 Comparisons of multiphase wet gas flow meter and single-phase meter requirements

Most flow meters require some fluid property inputs. For example, single-phase DP, turbine and ultrasonic meters require fluid density and viscosity be supplied from an external source. A WGFM such as two meters in series (see 6.5.1) may require the gas and liquid densities be supplied from an external source. Therefore, a WGFM’s requirement for fluid property inputs to be supplied from an external source is fundamentally analogous with other flow meter’s requirements. However, there are two crucial differences between WGFMs and other flow meters regarding fluid property information requirements that an operator should be aware of.

10.3.1 The challenge of supplying multiphase wet gas flow fluid properties

Finding the required fluid properties of a single-phase flow in field conditions is relatively simple compared with doing the same in multiphase wet gas flows. For example, a single-phase natural gas flow can have its composition determined by an in-line gas chromatograph, or from a sample and subsequent laboratory analysis. There are equations of state available for single-phase natural gas that are known to predict gas flow properties with very low uncertainty.

Finding the required fluid properties of a multiphase wet gas phase flow is a difficult task under field conditions. A gas chromatograph cannot be directly used with multiphase wet gas phase flow (due to the likelihood of flooding the gas chromatograph columns). There are no standard documents on, and no agreed method of, sampling multiphase wet gas flows. Sampling of multiphase wet gas flows is a contentious issue.

The dispersion of different liquid components in the gas flow (i.e. the flow regime) makes it challenging to take a "representative" sample of a multiphase wet gas flow. This statement holds true regardless of whether the operator wishes to obtain a sample that has phase fractions representative of the phase flow rate ratios or just a sample that contains all the flow components for fluid property determination.

Multiphase wet gas flow samples are usually taken to determine one of two different sets of information.

a) Capture all components present in the flow so as each component can be analysed and fluid properties found, i.e. collecting all liquid components and all gas components to subsequently determine liquid and gas fluid properties. The components do not need to be captured such that the ratio of components present in the sample represents the phase ratios of the multiphase wet gas flow.

b) Capture all components present in the flow in the correct ratio (e.g. WLR and GVF) that they flow together. Note this is very challenging and it is an on-going debate in industry as to whether such a task is practically achievable with the present state of the art sampling technology. However, if successful, each component can then be analysed and fluid properties found.

There is as yet no industry agreed method or standard document for conducting multiphase wet gas flow sampling. Consequently, it is a challenge for operators to give uncertainty statements regarding the sampling process. Other difficulties with determining multiphase wet gas flow fluid properties include:

— the significantly higher likelihood of a multiphase wet gas flow sample undergoing phase change between line and laboratory conditions than most single-phase flows, i.e. phase change will add to the fluid property uncertainty;

— the probability that the operator may fall back on reservoir engineering fluid property estimates when samples are not available (e.g. for subsea WGFMs), as estimates for both original data and the historical nature of the data may have relatively high uncertainty;

— the difficulty in compiling multiphase wet gas flow fluid property information, as WGFMs require more fluid property information than traditional single-phase flow meters, i.e. WGFMs require various combinations of fluid properties, from a substantial list including for example, each phase's density and viscosity, dielectric constant/permittivity, various absorption coefficients, interfacial tension, the water's salinity, the flow's H_2S content etc.

In summary, obtaining WGFMs required fluid properties in the field, to a low uncertainty, is a complicated task.

10.3.2 Confidential slip models

Due to intellectual property issues, WGFM manufacturers hold in confidence most of the underlying flow calculations, including the "slip model', i.e. the calculation procedure (as discussed in 6.6.5), and in some cases the details of the systems hardware. Therefore, operators do not have a comprehensive understanding of both the hardware and the software of most WGFM technologies. Another example with Venturi meters used in WGFMs is the calculation of the baseline single-phase discharge coefficient *C*, this also is often proprietary information. This is why WGFMs are often called "Black Boxes", i.e. the calculations to determine the flow rates are not transparent and are unknown to the meter operator. A consequence of this is an operator cannot calculate the sensitivity of the flow rate predictions to any fluid property input bias.

10.4 The importance of correct fluid property predictions

Apart from the fact that fluid properties are difficult to obtain in the field, a further issue is that the fluid properties most likely will change over time, particularly for comingled flows. Therefore, for optimum WGFM performance the correct fluid composition and/or fluid properties have to be kept up to date as the reservoir conditions change over time. Unfortunately, sometimes a relatively small input fluid property bias can potentially create a relatively large phase flow rate prediction bias.

Consider an example of a hypothetical mass flow meter with the ability to measure the fluid density, used to measure two-phase hydrocarbon liquid and water flows. In this idealised example, assume that this hypothetical mass flow meter reacts to the hydrocarbon liquid and water mixture flow as if the mixture flows as a homogenous fluid of average density. With known base densities of the hydrocarbon liquid and water the measured density results in the fractions of the hydrocarbon liquid and water, i.e. the WLMR, or by conversion, the WLR. Hence, base densities are important and the flow computer needs the density of hydrocarbon liquid and water as inputs to calculate the WLR. However, if the actual fluid densities deviate from the values in the flow computer the meter output will start to show systematic errors.

Let us say that the flow computer contains values of 850 kg/m^3 and 1 050 kg/m^3 for hydrocarbon liquid and water respectively. However, say the actual water density is only 1 020 kg/m^3. Figure 32 shows this scenario. If the density of the mixture is read by the meter as 1 010 kg/m^3 than the flow computer calculates the WLR as 80 %. However, the actual WLR is seen to be 94 %. That is, the relatively small positive bias in water density of +3 % cause the water liquid ratio estimation to be under predicted by 14 %. Alternatively, if the density of the mixture is read by the meter as 880 kg/m^3 than the flow computer calculates the WLR as 15 %. However, the actual WLR is seen to be 18 %.

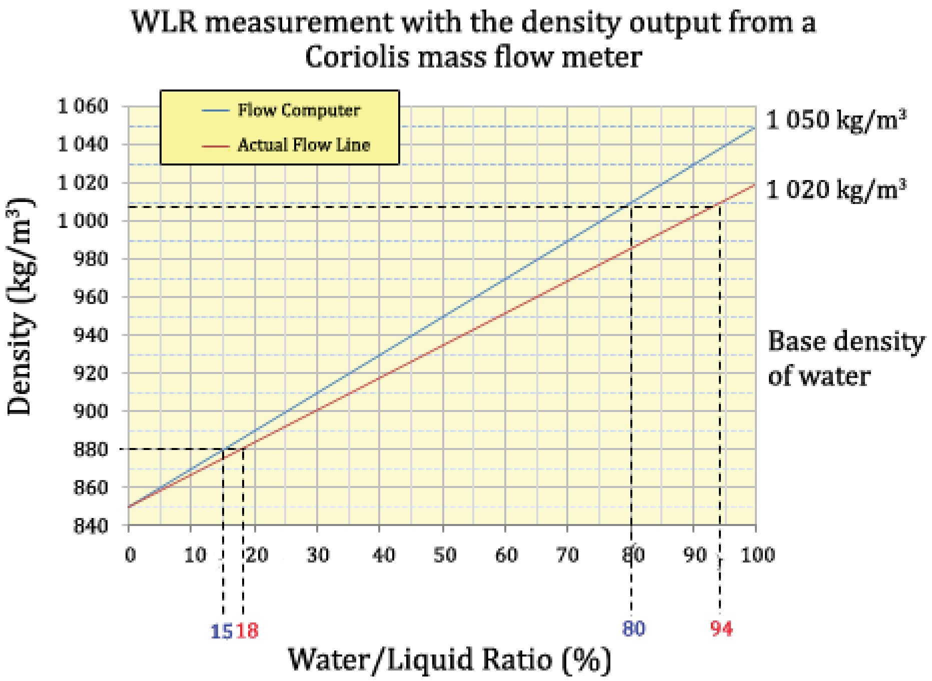


Figure 32 — Hypothetical Water-Liquid Ratio (WLR) calculations with the density output from a hypothetical mass and density flow meter

Biases in water or hydrocarbon liquid density inputs produce biases in the WLR prediction, and in turn in the water and hydrocarbon liquid flow rate predictions. The scale of the biases is dependent on which liquid properties are incorrect and the actual water liquid ratio.

The above example is simple and straight forward. It can be easily simulated and understood by all interested parties. However, with WGFMs this phenomenon is not so straight forward. Due to black box calculation methods the sensitivity of WGFMs cannot be simulated by anybody but the meter manufacturers. Even if these calculation routines were available, due to the considerable greater level of complexity, analysing the sensitivity of the meter to any fluid property input is difficult. In some cases, due to the complexity of the calculations, the relationship between any given input and the meter's output can be nonlinear.

Figure 33 shows another example but now for a hypothetical WGFM metering three phase flow. Again if a fluid physical property input to the WGFM is not equal to the actual physical property in the fluid flow, this will immediately lead to systematic errors in the measured water, hydrocarbon liquid and gas flow rates.

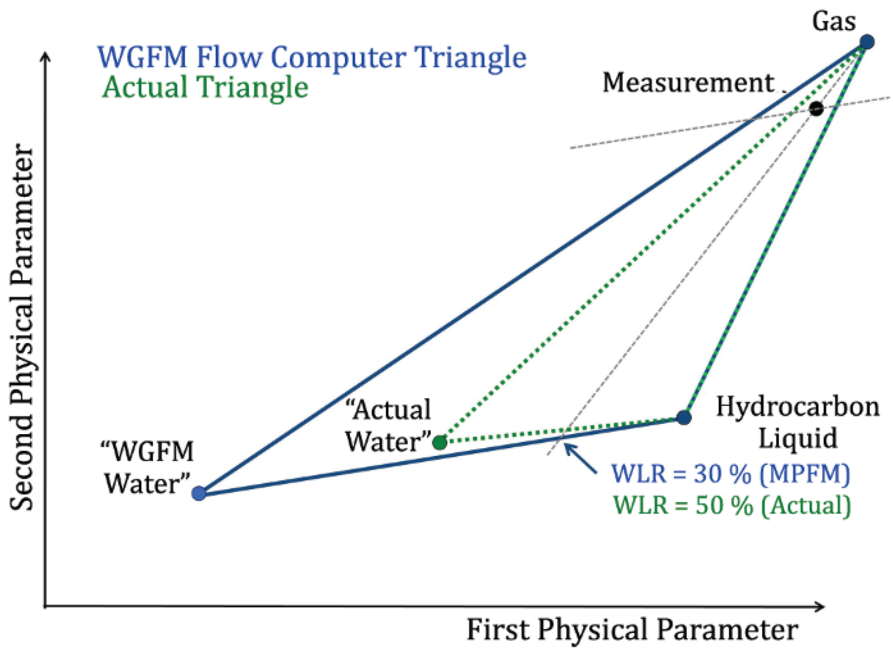


Figure 33 — Potential impact of water salinity on the WLR measurement

In Figure 34, a similar composition triangle is plotted, again for a hypothetical meter and indicating the effects of changing salinity, H_2S and CO_2 concentrations.

These are examples, but it is of vital importance that the user of WGFMs discusses these sensitivity issues with the vendor. An alternative is to investigate these fluid property sensitivities, see 10.4.3.

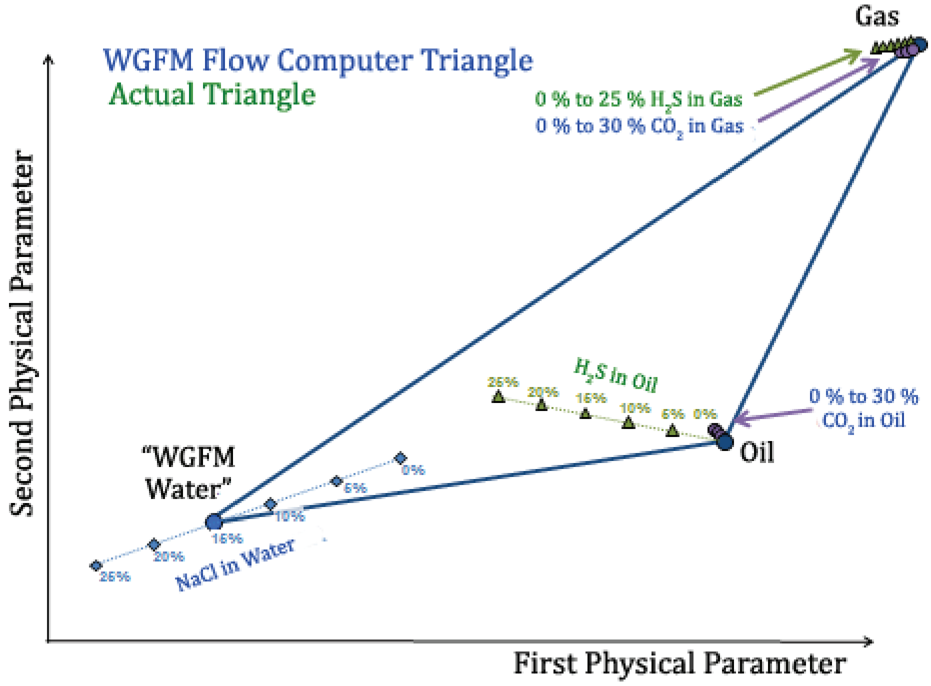


Figure 34 — Impact of H_2S and CO_2 on the composition triangle

10.4.1 The importance of gas properties when metering small liquid flow rates

If small amounts of one phase need to be measured, e.g. water in a multiphase wet gas flow, it may be important to know the fluid property of the dominant gas phase well. Reference [36] discusses the theoretical effects errors in gas properties have on the water flow rate measurement. Data to practically demonstrate this sensitivity for a particular meter design are presented in Reference [37].

Figure 35 illustrates graphically the systematic effect of a change in fluid property. The uncertainty of the measurement fluid property x_0 produces an input to the WGFM with uncertainty between x_1 to x_2 and this coupled with the uncertainty of the WGFM, will result in the uncertainty of the WGFM output parameter (a_0) being in the range a_1 to a_2, i.e. random errors. However, this assumes that the basic fluid property (i.e. the value between x_1 and x_2) input into the flow computer will stay representative of the actual flow line fluid property over the period that the WGFM is in service. In reality, there is no guarantee that this will be the case. Moreover, sometimes the WGFM measures a commingled flow and then the fluid properties depend on the varying uncertain relative contribution of each stream. In other situations the salinity of the production water may change. Therefore, a change in fluid property to either x_3 or x_4 will result in a change in the output to a_3 or a_4; these changes in output are systematic.

In particular, at locations where there is no access to the meter, or access is difficult and expensive, it is extremely important to know what the impact is of a change in fluid property. Examples are deep subsea installations where it is very cumbersome and extremely expensive to run a sampling exercise in order to determine a new value for a fluid property. Also for remote and unmanned operations or applications where sampling cannot be tolerated from a safety point of view (e.g. operations with a high H_2S composition in the gas) it is important to make an upfront consideration regarding the actual change in fluid property and the type of WGFM concept and the WGFM sensitivity to changing fluid properties.

The uncertainty of the output of phase fraction devices, such as gamma ray absorption systems, microwave systems, capacitance/permittivity systems etc., are dependent on the appropriate fluid properties being correctly entered into the WGFM "black box".

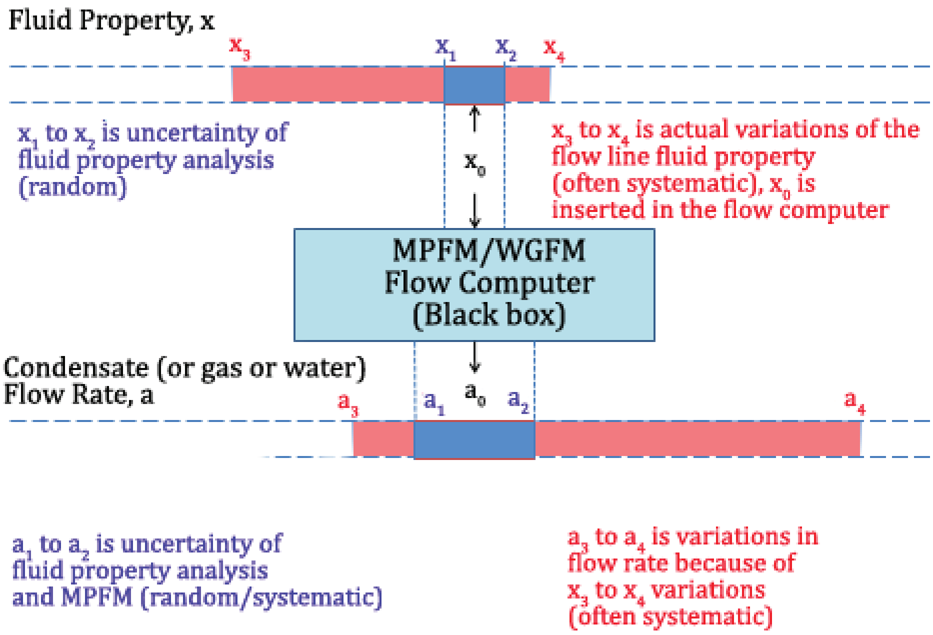


Figure 35 — Relationship between input and output uncertainties

10.4.2 Preparation for fluid property variations during meter service

Ideally, when applying WGFMs, the operator and WGFM manufacturer should act as a team and the following are key topics to be addressed.

— Operator to supply to the meter manufacturer all available information regarding the expected changes in fluid properties over the operating life of the meter.

— Manufacturer to provide what effects these fluid property variations will have on the meter's performance, with and without fluid property corrections applied to the system.

In the absence of a full disclosure of the slip model calculation it is the manufacturer's responsibility to inform the operator how these fluid property changes will affect the multiphase wet gas flow meter's output with and without corrections applied to the system.

Note that water salinity may affect some WGFM phase fraction devices. The measurement of WLR and Gas Void Fraction may therefore be dependent on the water salinity. Even if the water salinity is known and correctly entered, the WGFM's output uncertainties are not necessarily constant for a range of different salinities.

10.4.3 Fluid property sensitivity investigation

The magnitude of the phase fraction and phase flow rate prediction errors associated with fluid property biases can be difficult to determine theoretically, mainly because of the "slip models", i.e. the calculation routines, being proprietary information. Therefore, testing WGFM sensitivity to fluid property uncertainty can be a valuable operator exercise.

Physically testing a WGFM's reaction to varying fluid properties by actually changing the fluids in a multiphase wet gas flow test facility is very time consuming and cost prohibitive. Instead of keeping the meter software's fluid property inputs constant while the actual flowing fluid properties change (as would be the concern in the field), it is considerably more practical to keep the flowing fluid properties constant and change the meter's keypad fluid property input values. The subsequent misreading in the individual phase flow rates will be the fluid property induced biases.

Such a fluid property sensitivity exercise could be conducted as a desktop exercise only[38]. The WGFM has set proprietary calculation methods. While the meter is off-line, it may be possible to input some reference fluid properties and some hypothetical sensor values to the flow computer. The subsequent phase flow rate predictions can be assigned as reference values. Keeping the hypothetical sensor values constant, each individual required fluid property input can be varied by step percentage biases to investigate its corresponding percentage bias influence on each of the meters outputs. A block diagram for this exercise is shown in Figure 36.

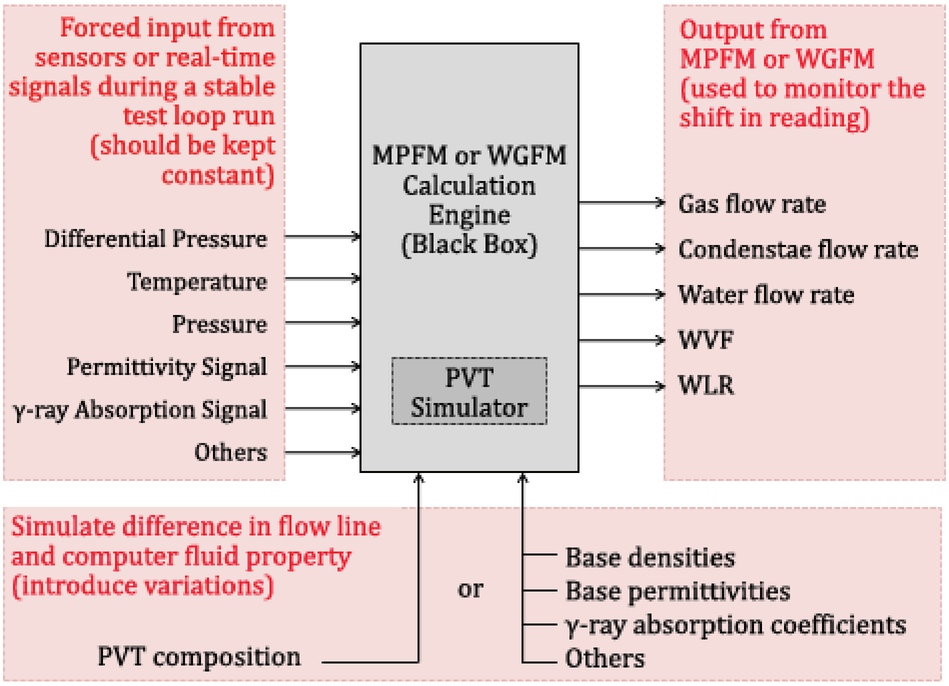


Figure 36 — Method of determining fluid property influences on WGFM outputs

For each fluid property input sensitivity investigation, the results can be plotted as shown in the hypothetical example presented in Figure 37. In this way the WGFM black box calculation sensitivity to fluid property bias could be determined. However, this potentially very useful exercise is only possible if the WGFM manufacturer's software is configured to function with artificial sensor inputs while off-line. Otherwise stable test facility flow rates need to be used.

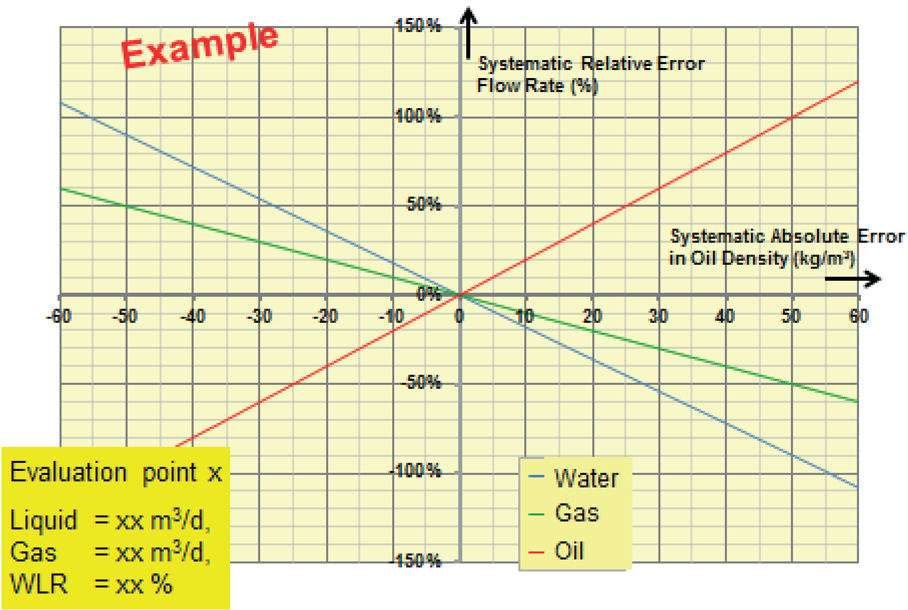


Figure 37 — Hypothetical example of fluid property input error vs. WGFM output bias

10.5 The benefit of an initial wet gas flow facility test

For remote and subsea applications, it can be beneficial to flow test a WGFM at a multiphase wet gas flow test facility to ensure it is fully operational before installation. The costs of a multiphase wet gas flow test facility evaluation are relatively small compared with the operating costs if a subsea WGFM needs to be retrieved and replaced. Moreover, running a multiphase wet gas flow facility test produces a “fingerprint” of the meter that is then available for use as a reference during later meter operations.

10.6 Line size limitations for some multiphase meters

Some phase fraction devices have size limitations. For example, gamma ray or microwave absorption techniques have maximum distances between source and receiver before the signal becomes too weak to be reliable. Permittivity based sensors have equivalent issues if the cavity is too large.

Different phase fraction devices have different maximum line sizes, or more precisely different maximum DP meter throat sizes, in which they can operate effectively. This needs to be checked with the WGFM vendor.

10.7 *In situ* wet gas flow meter verification

In situ characterization or verification of WGFMs may be difficult during operation. The following situations are some of the main issues:

— low uncertainty reference systems are often unavailable;

— meter inaccessibility (especially subsea);

— limited flow condition range during the characterization or verification procedure compared with the required long term flow condition range the meter is to cover.

The conventional meter verification procedure consists of mass flow rate balance checks. It is conducted by cross referencing the meter’s mass flow rate predictions with the mass flow rate predictions of independent systems directly or indirectly metering the same flow. Such mass flow balance checks can include comparing the meters' outputs

— by difference (e.g. knowing total mass flow of each phase and the mass flow of each phase in other pipes in the system),

— by continuous or periodic comparison with downstream flow meter measurements from either another WGFM or single-phase meter outputs downstream of a separator, and

— by continuous or periodic comparison with other WGFMs.

In addition, there are other *in situ* verification procedures developed to monitor, troubleshoot and validate WGFM performance. These include:

— injection of specific fluids in the meter (e.g. methanol);

— tests by permutation (i.e. varying flow through the meter from multiple wells);

— tests by perturbation (i.e. choke changes)[39];

— data trending;

— inter-comparison with redundant systems[40];

— static tests which allow a level of sensor integrity and fluid property verification.

10.7.1 Reconciliation factors and meter output confidence

The operator may have some level of flow metering redundancy in the production facility by balancing the various phase flow rates over the facility. As an example the sum of the flows entering (e.g. WGFM readings) the facility should in principle be equal to the output flow (e.g. fiscal metering). Reconciliation Factors are useful in trending the imbalance and are defined as the ratio of facility output over facility input. In the ideal case with no measurement and phase change errors the factor should be equal to 1. See ISO/TR 26762:2008 for further information not discussed in this Technical Report.

10.8 Operation and maintenance

WGFMs are often installed in remote and difficult-to-access locations. A consequence of this is that when comparing WGFM technologies potential maintenance issues and subsystem redundancies should be an important part of the WGFM comparison process. Depending on where the WGFMs are to be installed considerations should be given to have:

— as sturdy a design as possible,

— sensor redundancy, i.e. DP, P, T, subsystem redundancy, i.e. electronics,

— internal diagnostic capability,

— ability for in-situ maintenance.

10.8.1 System redundancy and diagnostics

WGFMs are often required at upstream production locations, e.g. at the well head, subsea, topside on unmanned platforms etc. Such upstream production locations are often remote and tend to have adverse operating and flow conditions. Routine maintenance is most beneficial in such locations where a flow meter experiences adverse operating and flow conditions. However, routine maintenance is undesirable due to the remoteness of these locations.

With WGFM systems, maintenance is potentially required most where it is usually available least. For this reason, WGFMs are often built as robust as possible, with various levels of diagnostic capabilities and redundant features if possible.

Internal meter diagnostics may offer the meter operator significant benefits, e.g.:

- a diagnostic system offers the operator the choice of a condition based maintenance scheme rather than a routine maintenance scheme, i.e.:
  - a diagnostic system showing no diagnostic warnings gives the operator assurance that the meter is serviceable, thereby alleviating requirements for routine maintenance which would be:
    - expensive
    - time consuming
    - a safety hazard through loss of containment risk;
- a diagnostic warning can indicate that a meter is unserviceable, and that a maintenance intervention is required, therefore reducing the chance of a metering bias going unidentified between routine maintenance;
- when subsystem redundancy allows, a diagnostic warning can indicate that a subsystem should be taken off line and replaced with a redundant measurement until maintenance intervention is successful.

The inclusion of diagnostic systems can mean the addition of extra instrumentation and calculations, with the associated increase in capital cost and complexity. In many WGFM applications, operators may consider the cost of diagnostics justifiable. However, having diagnostic systems does not reduce the requirement for the operator to utilize good engineering practices.

There are presently redundancy and/or diagnostic systems in operation with various WGFM technologies, where some are intellectual properties, while others are freely available.

- DP reading integrity/redundancy system: Duplication of primary instrumentation, e.g. dual DP transmitters on a wet gas meter DP meter subsystem. Duplication allows a level of redundancy and inter-comparison.
- DP reading integrity/redundancy/diagnostic system: Inter-comparison of the three DPs available when a wet gas meter DP meter subsystem has a third pressure port downstream of the meter body[41]. Multiple different but related DP readings allow a level of redundancy and diagnostics.
- Meter output integrity/redundancy/diagnostic system: Inter-comparison of a WGFM's multiple redundant subsystems. Multiphase wet gas meters with multiple systems may be capable of predicting an output in more than a single way. Dual or multiple measurement techniques can be inter-compared[42]. This diagnostic concept is strengthened if the output predictions are sourced from subsystem measurements based on different physical principles, such that common source errors can be eliminated.
- Meter output integrity/redundancy/diagnostic system: Trends in characterization parameter shifts over time can be monitored with statistical methods to identify equipment failure and long-term drift which may not be immediately obvious. This diagnostic possibility can be, but is not restricted to the internal meter software, and can be conducted by the meter internal software or externally by the operator.

10.8.2 Operating WGFM diagnostics

It is good practice for all WGFM diagnostics to be regularly displayed and monitored with the standard flow rate output of the metering system. Such good practice helps reduce required maintenance on wet gas meters and helps build confidence in the meter's outputs.

10.9 Miscellaneous operational issues

10.9.1 Wet gas flow and DP transmitters

10.9.1.1 Wet gas flow, pressure ports and remote seals

Most WGFM designs have pressure ports. Pressure ports connect the live produced fluids to the DP transmitter high and low pressure diaphragms via an impulse line. The integrity of the metering system is dependent on the impulse line being serviceable, i.e. clear with no blockages. Alternatively remote seals may be used to mitigate potential problems in the impulse lines.

The validity of the high and low pressures the DP transmitters' diaphragms are exposed to by the respective impulse lines can be compromised by blockages in the impulse lines. Impulse line blockage can be due to build-up of:

— particulate;

— hydrate;

— salt deposit;

— scale deposit;

— wax deposit;

— ice deposit.

Hydrate or ice deposits in an impulse line can originate from produced water, or water left from hydrostatic testing, see 11.3.2.

Due to the possibility of impulse line blockages, some WGFM designers choose to utilize "remote seal" DP transmitter technology. Remote seal locates the diaphragm at the pressure port on the wetted wall of the flow meter, thereby removing the need for impulse lines.

Remote seal technology has the disadvantages of suppressing the DP transmitters' response time and being more expensive than the traditional DP transmitter with impulse line system. However, in many WGFM applications impulse line blockage is a constant concern. In these cases the DP reading assurance offered by remote seals often outweighs these disadvantages.

10.9.1.2 Wet gas flow, DP transmitters and drift

Wet gas flow is inherently a more adverse flow condition to meter than single-phase flow.

An example of the standard deviation difference in DP readings between dry and wet gas flow is shown in Figure 26. Whereas this, in itself, is not a problem as the mean parameter value is correct and reproducible, the continuous increased variation about the mean can cause some instrumentation (such as DP transmitters) to drift.

Some wet gas flow conditions can cause periodic slugging flow. Slugs (i.e. columns of liquid) passing through a DP meter will cause DP spikes, where the DP can suddenly and briefly jump to several times the mean DP. Repeated slugs passing the meter, and the corresponding DP spikes, can cause a DP transmitter to drift.

WGFM DP transmitters should be checked for drift as often as is practically possible. DP transmitter redundancy and diagnostic systems (10.8.1) are beneficial for monitoring for DP reading integrity.

10.9.1.3 Wet gas flow and DP transmitter over-ranging

For a set gas flow, a DP meter will produce a higher DP the more liquid that is present. For example in Figure 26 the DP meter's dry gas DP value of 7,3 kPa (29.5 in of water column) was increased to the circled 13,6 kPa (54.5 in of water column) by wet gas flow. Hence, it is a common problem for wet gas flow service

DP transmitters to be under-sized and for the DP transmitter to become "saturated" with wet gas flow. WGFM DP transmitters should be checked for saturation as often as is practically possible. DP transmitter redundancy and diagnostic systems (10.8.1) are beneficial for monitoring DP reading integrity.

10.9.2 Software and fluid property update procedures

10.9.2.1 Software updates

WGFM technologies are continuing to be improved. As such, new edition software can become available for any given meter while it is in service. Operators should carefully consider the potential issues associated with changing software in an existing operating WGFM before deciding to proceed.

As with single-phase flow meter technologies, there are advantages and disadvantages to updating software during service. Potential issues include a step shift in meter predictions (thereby exposing the operator to potential measurement error claims) and software bugs causing a previously operating meter to malfunction.

As with all flow meter operation good practice, software updates should only be implemented by a proper procedure, i.e. with full documentation.

10.9.2.2 Fluid property updates

Reliable fluid property inputs are crucial to wet gas flow metering systems. It is therefore strongly advisable that an operator monitors the fluid properties of a wet gas flow at a regular (frequent) interval.

As with all flow meter operation good practice, fluid property updates should only be implemented by a proper procedure, i.e. with full documentation, and be fully traceable.

10.9.3 Long term trending comparisons with test facility/factory characterization

Many WGFMs are flow tested at a wet gas flow test facility in order that the meters performance can be characterized. Although not strictly technically correct these characterization tests are sometimes called "calibrations".

Trends in characterization parameter shifts over time should be monitored with statistical methods to identify equipment failure and long-term drift which may not be immediately obvious (see 10.8.1).

Wherever possible characterization checks both onsite and offsite should include an "as found" and "as left" indication, so that necessary adjustments can be identified and any drift or step shift from the previous "calibration" is not masked.

11 Common Field Issues

As with all technologies. there are practical problems that arise when implementing wet gas flow metering technology in the field. These are not always properly considered at the design stage or will not become evident during laboratory and field testing. However, there are several well-known phenomena that are known to adversely affect WGFM performance and "prevention is better than cure". These practical problems are discussed below.

11.1 Inefficient separator systems

In some areas of the world, the use of a test separator is the primary method of determining well production rates. However, there are known problems with using separator systems. For example, single-phase flow meters installed as part of separator systems will not always produce the expected performance of these same meters installed in standard single-phase applications.

The conventional wet gas meter system is the separator system, comprising a two- or three-phase separator with single-phase flow meters in the outlets. The flow metering performance of a correctly sized, well-maintained separator system is often seen as the benchmark to which all other wet gas (and multiphase) flow meter designs are compared. There is a perception amongst some in industry that a separator system predicts the gas and liquid (and perhaps the water and hydrocarbon liquid) flows to single-phase uncertainties. Whereas this is true in theory it is seldom if ever true in practice. Capital expenditures due to the weight, volume and “footprint” of the separator systems are prime motivators for their replacement with multiphase or wet gas flow meters. A secondary driving force is the potential poor performance of separators in the real production environment combined with the associated impact on the integrity of the gas and liquid flow measurements on separator outlets.

Separators are usually sized before production starts and sizing is based on the reservoir engineering production forecast. However, such forecasts typically have large uncertainties and thus actual flow rates will almost certainly be different. If flow rates were over-predicted, phase separation should be efficient; however, the outlet single-phase meters may also be correspondingly over-sized meaning the meters operate at the low end of their range, causing increased flow rate prediction uncertainties. If the flow rates were under-predicted the separator can be under-sized, and the actual flows will be too high for the separator resulting in ineffective phase separation. Thus, the single-phase flow meters may receive “gassy liquid” or “bubbly liquid flow” in the liquid outlet and “wet gas” in the gas outlet, thus causing systematic metering errors.

In many cases, flow conditions experienced by a separator system can change significantly during the life-time of the separator. Production at different layers within the well creates different flow conditions. Such changes are very difficult to accurately predict at the time of the system design. Furthermore, it is also common for satellite wells to be added to existing infrastructure long after the existing infrastructure separator is in operation. This too can significantly change the flow conditions experienced by a separator from that envisaged at the design stage. Real production flow can have quantities of unexpected substances such as mud, rock, sand etc. that can accumulate in the separator vessel, clog filters and generally adversely affect the separation and the metering. The mix of particular gas, hydrocarbon liquid and water components at particular thermodynamic conditions can create emulsions which hinder separation. A further problem with three phase separator systems is poor level control in the liquid section which might result in the oil phase containing water or the water phase containing oil. These factors also may lead to inefficient separation.

A difficulty with an inefficient separator is that there is no universally agreed way to check the efficiency of a separator. This problem is compounded by the fact that liquid carry-over and gas carry-under can be intermittent. One common method is to choose flow meter technologies for the separator gas outlet that have predictable wet gas flow performance and some wet gas flow indicating capability, such as single-phase meters with diagnostic capabilities. However, such a requirement to select metering with wet gas flow capabilities undermines the use of the separator in the first place. It is sometimes argued by wet gas meter manufacturers that as you may need a wet gas meter at the gas outlet of a separator then the separator system may as well be dispensed with altogether. A counter-argument is that WGFM technologies are not yet definitively shown to universally have lower phase flow rate uncertainties than separator systems. Furthermore, separator systems are far more extensively used than wet gas flow meters and industry currently has lots of experience with separators and relatively little experience with wet gas meter technologies.

11.2 Separator systems — An adverse environment for single-phase meters

It is not just the fact that separators are not always 100 % efficient at separating the phases that causes the single-phase meters at separator outlets to have increased flow rate prediction uncertainties or biases. The production environment can cause a separator system’s single-phase meters to face other challenges.

Single-phase gas and liquid flows from the exits of a separator system can be metered with any single-phase flow technology. There is no standard flow meter used for these separator applications. Throughout the world different single-phase flow meter technologies are employed at separator exits. For these single-phase flow meter technologies, there are both general and type-specific flow meter challenges associated with separator outlet deployment.

11.2.1 Separator Outlet deployment

The following are some general flow meter challenges with deployment at a separator outlet.

— Limited rangeability of the single-phase meters. Often the large differences between well production as well as changes over field life result in large required ranges of the single-phase outlet flow meters.

— Restricted straight length of pipe runs. Separators are often in confined space and long straight lengths of pipe are not available. Often single-phase meters are installed without the ideal pipe run lengths.

— Clogged flow conditioners. A remedy to short pipe lengths is the use of flow conditioners. However, the same contaminants that can clog the separator filters can clog the flow conditioners in the single-phase flow exit piping. Also, if there is any water carry-over with the natural gas into the gas outlet then the pressure drop across a flow conditioner can induce the creation of hydrates which plug holes in the flow conditioner. A clogged flow conditioner can make the flow disturbance worse instead of better.

— In many cases spot samples of the gas composition are used to determine gas properties. Liquid carry over into the separator's gas flow outlet can affect the accuracy of the gas composition used with the gas flow meter and adversely affect the meter's output. This is an additional uncertainty added to that due to the gas meter being subjected to wet gas flow.

— Separators are often installed in remote and/or difficult to access locations. Many separator systems therefore get infrequent maintenance. This means that the single-phase flow meters installed on the separator outlets get less maintenance than is ideal. Instrumentation may therefore drift. Flow conditions may change such that the single-phase meters installed are no longer in range.

— Often single-phase meters are not calibrated regularly once in service.

— The separator liquid outlet flow requires a WLR meter/analyser to determine the oil/water fraction. Under the adverse conditions as just described for the single-phase flow meters their uncertainty may be significant.

— Furthermore, particular single-phase meter designs have type-particular problems as single-phase flow meters at the outlet of separators. As examples the orifice plate meter for the gas outlet and the liquid turbine meter for the liquid outlets are now discussed.

11.2.2 Gas Measurement at the separator outlet

The following are some examples of the challenges with measurement at the gas outlet of a separator, using the example of an orifice plate:

— Wet gas flow is typically dirty wet gas flow. Any particulate exiting the separator with the gas flow can wear the sharp edge of an orifice plate such that it is not compliant with ISO 5167-2. The contamination that can wear the sharp edge can also stick to the inlet pipe and plate. A worn sharp edge or a contaminated orifice meter run causes the gas flow rate prediction to have a negative bias[43].

— An orifice meter's performance is optimum for a set orifice size/beta at a particular flow range and an associated DP transmitter range. If the flow conditions have changed and the operators do not change the plate beta and/or the DP transmitter range, the orifice plate meter can be operating at a higher uncertainty than previously calculated.

— If an inefficient separator creates periodic slugging it is possible that an orifice plate could be buckled. A buckled plate causes the gas flow rate prediction to have a negative bias.

— If the separator is not 100 % efficient the wet gas flow through the orifice can cause higher DPs than would be obtained with the gas flowing alone. This can result in a saturated DP transmitter (i.e. the actual DPs being higher than the maximum range of the instrument).

— If carried out, maintenance of the orifice plate consists of removing the plate (usually from a dual chamber fitting) and visually inspecting it before either replacing it or returning it to service. Although this is an established procedure it does not guarantee subsequent correct gas flow metering. There are recorded instances of inspected or replacement plates being installed backwards, not wound down fully onto the fitting's seat and even occasionally the plate being accidentally left out of the chamber altogether.

Reference [43] discusses such orifice meter performance problems and an example of an orifice meter diagnostics system. Single-phase gas flow meter diagnostics are beneficial for gas meters in such adverse operating conditions.

The potential problems described here regarding the orifice meter in separator gas outlet service should be taken in context. It is important to note that the orifice meter is discussed here as an example only. Other gas meter designs such as turbine, Coriolis, ultrasonic meters etc. have equivalent challenges in this adverse flow metering application.

11.2.3 Liquid Turbine Meter

The following are some examples of the challenges with measurement at the liquid outlet/s of a separator, using the example of liquid turbine meter:

— As wet gas flow is typically dirty the liquid outlet can contain particulates. Due to gravity the liquid phase outlets tend to have more particulates than the gas outlet. Particulates in a liquid flow adversely affect a liquid turbine meter. Larger debris can damage the turbine blades but the very small particulate can be abrasive to the turbine bearings. Damaged turbine blades and worn bearings cause flow rate prediction biases.

— An inefficient separator can have gas bubble carry-under to the liquid flow outlets. In the case of a three-phase separator the water exit can also have some hydrocarbon liquid present and vice-versa. Such two- or three-phase flows through a single-phase liquid turbine have adverse effects on the turbine meter's performance[44]. The liquid outlet flows WLR needs to be measured online. This increases the individual flow rate uncertainties.

— With some separators in remote and/or difficult to access locations regular maintenance, or ideal re-calibration intervals, can be missed thereby increasing the turbine meter's flow rate prediction uncertainty. The secondary instrumentation (i.e. pressure and temperature transmitters) may also be infrequently calibrated.

— As the flow conditions into a separator change significantly over time the flow rates through a liquid turbine meter will also change. If the liquid flow is much higher or lower than the turbine meter was designed for and/or calibrated at, there can be a significant increase in the turbine meter's flow rate prediction uncertainty.

The potential problems described here regarding turbine meters in separator liquid outlet service should be taken in context; other single-phase technologies have equivalent problems with these applications.

11.2.4 Practical limitations of wet gas flow metering with separator technology

As separator systems are the most widely used wet gas meter systems in the hydrocarbon production industry, the performance of the single-phase flow meter technologies at the outlet of the separators is of significant importance to wet gas meter technologies. Some regulatory bodies are now advocating condition based monitoring (CBM) of these single-phase flow meters. They advocate maintenance being carried out on these meters when there is evidence that the meter requires maintenance only instead of periodic scheduled maintenance. For this to be practical each single-phase flow meter chosen for use with the separators should have a comprehensive diagnostic system. Furthermore, such a diagnostic system is also potentially useful for indicating when a separator is inefficient and the single-phase meter is encountering two-phase flow.

In summary, it is not realistic to assume that the single-phase flow meters installed at separator outlets will have the standard advertised single-phase meter flow rate prediction uncertainties. The adverse flow meter conditions that are often present make higher uncertainties inevitable, in many cases between 5 % and 10 % may be more realistic. In more extreme cases when several of the above error sources combine it is possible to encounter single-phase flow meter's uncertainties up to 15 % or more.

Separator technology is often treated as the benchmark of wet gas flow metering technology. However, as indicated above, if there is deviation from ideal conditions the meter's performance can deteriorate dramatically. Hence, practical problems regularly encountered in production ensure that a wet gas separator system is not an ideal solution.

11.3 Wet gas flow meter practical problems

Reservoir engineering estimates of the expected future wet gas flow conditions are usually the only guide available when considering the specifications required of a WGFM for any new application. They are notoriously approximate due to the considerable complexity and array of parameters that can affect the flow conditions. Nevertheless, these estimates are usually the best available, and the overall wet gas flow metering strategy will be determined based on these predictions.

If the production flow is predicted to have a very low liquid loading, then the most economic and practical solution for flow measurement may be to use a single-phase meter and accept a slight bias, or higher uncertainty. If the prediction is for a significant liquid loading ($X_{LM} \leq 0{,}3$) then a wet gas meter will be required. However, depending on the WLR and the application's metering requirements, a wet gas meter (measuring bulk gas and liquid flows) or a multiphase wet gas meter (measuring gas, hydrocarbon liquid and water flows) may be required.

If reservoir engineering flow rate estimates are for very significant amounts of liquid relative to gas, then a wet gas meter may not be the appropriate metering system and a general multiphase meter system is required. Once reservoir engineering estimates are reviewed the best choice of metering system is case-by-case dependent. Hence, management has to accept the fact that the engineers are making decisions based on best practice, and due to the inherent imprecision of this best practice it is a reality that occasionally inappropriate wet gas meter systems are installed for the actual flow conditions encountered. This is an unavoidable reality of the state of the art of technology.

Wet gas meters all have stated ranges, with preferred "sweet spots" and unsuitable "sour spots". Therefore, if a reservoir engineering estimate is significantly in error, it is distinctly possible that the installed wet gas meter may not meter the actual flow to a satisfactory uncertainty.

An MPFM or WGFM applied to a predicted multiphase wet gas flow that is actually effectively a dry natural gas flow is a pointless capital expenditure. A further difficulty is that the conditions can change considerably over the years of production meaning that over the lifetime of the well no one metering technology may be suitable for the range of flows expected. It may be necessary for the meter technology to be replaced as the well ages and flow conditions change.

11.3.1 Considerations for wet gas flow metering

It is advisable to address the technical challenges of wet gas metering at the earliest stage in the overall system design. Failure to prepare for wet gas flow metering during the conceptual design stage can cause extra problems.

Certain problems induced on wet gas flow meters by the piping layout are avoidable if the piping is designed to include a wet gas meter from the outset. It is generally good practice to install a wet gas meter at a high elevation point in piping, or at least in a location where flooding is not likely. Even with wet gas flows that only have trace liquids present, over time low points in the piping can act as a liquid trap and significant liquid hold up can occur in these regions.

It should be noted that regardless of where a WGFM is installed, the ability to cope with periodic flooding and to re-start automatically without any intervention is highly desirable. It would be unrealistic of any operator to assume that a wet gas meter would not be flooded at some time during its service. Some meters in wet gas flow service may be more susceptible to damage from liquid slugging than others (e.g. an orifice meter is more susceptible to damage than a Venturi meter). The sturdiness of a wet gas meter design should be considered relative to the potential environment it will encounter. Even if a

WGFM can survive slugging it will more likely have its performance adversely affected by slugging. When possible it is good practice to avoid installing meters in piping that tends to induce severe slugging. However, all these considerations are best made during the conceptual design. Attempting to fix existing problems after the system is designed and built is considerably more troublesome, time-consuming and expensive.

Some wet gas meters require vertical up flow. There tends to be much less vertical up piping available for wet gas flow metering than horizontal flow. Vertical up piping that can be used for meter installation is typically more difficult than horizontal piping to access for maintenance. Accounting for maintenance access to a wet gas meter is easier done at the overall system design stage than at any later stage.

It is common for wet gas meter manufacturers to build a meter skid that connects to horizontal piping, turns the flow vertical up through the meter before returning it to the horizontal piping. However, these skids can be relatively bulky. As space is often at a premium it can be difficult to fit such equipment into some existing infrastructures. Hence, again, this is an example of why it is good practice to design for the wet gas meter system at the piping design stage.

11.3.2 The adverse effects of contamination, hydrates, scale, and salts

Physical chemistry phenomena can endanger production and have an adverse influence on wet gas flow meters. Chemical components in the flow can react with each other and/or cross phase transition boundaries within the production's operational envelope. These chemical components include water, hydrocarbons, diluents, and salts, which lead to the formation of hydrates, waxes, scale and salt deposits. The presence of these compounds at particular operating conditions alters the chemistry, fluid properties, flow geometries, and fluid dynamics of the system. Some multiphase wet gas meters are designed and installed primarily to monitor for water content, and the phase flow rate outputs are considered secondary information. Water is the source of the problems that cause wet gas flow assurance issues. These WGFMs are therefore used to monitor water to allow the appropriate chemical inhibitors to be added to reduce the risk of a flow assurance problem.

Wet natural gas production flows upstream of the initial processing equipment are generally not clean. General debris and contaminates are carried with the flow. Although this contamination can adversely affect all pipe line components wet gas flow meters can be particularly susceptible to this. Contamination can cause erosion of, or build-up on, meter component wetted components. Clearly such build-up has the potential to adversely affect many wet gas meter designs (e.g. by changing meter factors, blocking pressure ports, depositing on sensors etc.) Unfortunately there is no easy remedy to dealing with contamination of pipe line components such as wet gas flow meters. If possible it is good practice to have regular cleaning of meters that are exposed to contaminated flows. For wet gas meters that are not easily accessible the operator may wish to take into account the potential for contamination. As with single-phase flow meters, it can be beneficial to include a bypass loop to facilitate easy access for maintenance.

Scale and salt deposits can cause similar problems to contamination build-up in meters. There are different types of scale. Scale is usually a mineral compound (typically calcium sulfate or calcium or magnesium carbonates). The most common scale reported is calcium carbonate. Carbon dioxide break-out from water can cause scale by triggering a chemical reaction with other minor components of the flow. The mineral compound is often impure. It often mixes with iron or sand grains. Salt deposits come from formation (i.e. produced) water. Formation water is saline and with changing thermodynamic conditions formation water can become saturated and deposit salts in the pipe and on flow meters. Scale or salt deposits on a wet gas meter can block sensors and reduce the flow area thereby causing significant errors or malfunctions or stopping the meter from operating.

With both scale and salt deposits the best solution is prevention. Scale can be difficult, if impossible to remove. There are no effective chemicals that can be injected into an in service meter run to guarantee the removal of scale and the return of the meter to pre-scale formation performance. For scale and salt issues a common approach is to inject an appropriate chemical inhibitor.

Hydrates are solid compounds formed by water and natural gas components at particular thermodynamic condition ranges. Hydrates visually look like ice. However, hydrates differ from ice in their crystal structures, phase boundaries and fluid properties. Hydrates form when the light hydrocarbon components contact liquid water at a thermodynamic condition that causes the formation of a crystalline phase — with water molecules encasing a gas molecule.

The chemistry of hydrates is reasonably well known. Pressure vs. Temperature graphs exist for set gas types that indicate the thermodynamic ranges where that gas component with water will and will not produce hydrates. However, these hydrate phase diagrams do not provide a complete picture of the physical behaviour of hydrates in a wet gas flow. They do not describe complex transport behaviour of hydrates or give any indication of hydrate formation and dissipation rates.

There has been limited research undertaken on hydrate issues with wet gas flows. Laboratory testing has shown that the creation of hydrates in a wet gas flow can be rapid when the phase boundary is crossed. A wet gas flow with even a small liquid loading of water can produce enough hydrates over a short period of time to block the pipe thereby stopping production. Flow causes hydrate crystals to deposit and agglomerate at flow obstructions into larger hydrate masses. These hydrate masses become flow line blockages. The presence of hydrocarbon liquids with the water in the wet gas flow appears to accelerate the formation and distribution of hydrates. Hydrates can form at very different thermodynamic conditions from those inexperienced operating staff often expect, e.g. much higher temperatures than water at atmospheric conditions freezes. Hence, operating staff being caught by surprise by hydrate problems is unfortunately a relatively common occurrence.

Hydrate blockage of pipes is a relatively common phenomenon throughout the hydrocarbon production industry, causing loss of production, and damage to piping. If the hydrate issue is not addressed (and the flow is not entirely blocked) then hydrates will adversely affect wet gas meter performance. The causes of hydrate induced flow meter errors include changes to the flow geometry, fluid properties, sensor performance, and a partially blocked flow conditioner, among others. Multiphase wet gas flow meters that monitor for water content can be extremely important devices for hydrate management. They monitor the wet gas flow for water content in order to regulate the appropriate hydrate chemical inhibitors.

A hydrate blockage creates significant safety issues. Once a hydrate plug is formed inside a pipe (or meter run) it is necessary for action to be taken to remedy the problem. One remedy is to heat the pipework. However, such heating tends to be local, and therefore if hydrate disassociation only occurs at a central portion of a hydrate plug (where the heating is directly applied) there is a resulting gas volume between upstream and downstream hydrate plugs. If the remaining plugs hold tight as heating continues this local gas pocket's pressure can rise to exceed the systems design pressure thereby introducing the risk of catastrophic failure, i.e. pipe rupture and loss of containment. Furthermore, in addition to heating, attempts to change the pressure or local chemical injection are options for hydrate plug disassociation. However, the hydrate plug does not suddenly disappear. It slowly dissociates. Unfortunately the blockage could have produced a very significant pressure differential across the plug. As the hydrate plug weakens its adhesion to the pipe or meter wall as it disassociates, this differential pressure can cause the remaining plug to become a high energy projectile. There are many recorded instances of such hydrate projectiles causing severe damage to pipework, including loss of containment.

On a separate note, it is the convention for meter manufacturers to use water to pressure test, i.e. "hydrotest" a flow meter. Operators of wet gas flow meters should therefore be diligent in a pre-installation inspection to make sure the meter has been properly dried. Water can be held up in cavities such as pressure ports, impulse lines and sensor sockets by its interfacial tension even after the meter appears dry with a superficial inspection. There are recorded cases of meters being installed and not operating due to a malfunction which was subsequently found to be caused by hydrates or ice forming in these cavities. Once this water is in contact with the wet or dry natural gas flow the local thermodynamic conditions can cause ice or hydrates to form thereby causing a meter malfunction. Furthermore, the ice or hydrate plug is not only often in a very sensitive position for adversely affecting the meter sensors but in a position that is particularly difficult to supply chemical inhibitor to. Prevention is therefore significantly better than cure. This means operators should make a dedicated effort to check there is no water in any cavity of the meter before installation. This is a relatively easy process once the installers know why this must be done.

11.3.3 Theoretical, laboratory and actual wet gas flow conditions

The worldwide natural gas production industry has an extremely wide range of wet natural gas flow conditions. There are relatively few industrial grade wet gas flow test facilities. These few facilities all have stated wet gas flow condition test ranges. Not all the industrial flow conditions can be met by any one test facility, and indeed the variety of the world's wet gas production flow conditions cannot be met by the combined ranges of the test facilities available. This fact means that it is not always possible for operators to conduct a test of a given flow meter's performance across the full range of expected wet gas flow conditions. It is often only possible to test a meter over part of its flow range. Furthermore, due to manufacturers having developed and tested their products at the available test facilities it is common for the operators to be testing the meter at the same test facility across the same flow conditions as the meter type has been developed and tested before by the manufacturer. Therefore the industrial reality is that sometimes a meter's wet gas flow performance cannot be truly independently checked and cannot be checked across its full operating range. This of course adds to the uncertainty of the meter's performance across the full wet gas flow range. All operators of wet gas flow meters should be aware of this industrial reality.

There can be differences between WGFM operation theories, test facility wet gas flows and real wet natural gas flows. Laboratory tests are strictly controlled and there are no unexpected extra variables. However, in wet gas production flows unexpected and/or untested phenomena can exist to make the situation more complex. One example of this is thermodynamic effects. As wet gas flows through a DP meter the local thermodynamic conditions change. However, most theoretical discussions of wet gas meter performance assume that there are no significant thermodynamic effects. The gas to liquid mass flow rate ratio is assumed to stay approximately constant and the flow through the meter is assumed to be isothermal. As such it is assumed that there is no phase change between the gas and liquid phases as thermodynamic conditions change. Most test facilities use stable gas and liquids where this is a reasonable assumption. In fact there are very practical reasons for this. Phase change causes the gas and liquid flow reference rates at the meter to be unknown which of course is not acceptable for a wet gas flow facility.

However, with natural gas and light liquid hydrocarbons (or "condensate") changes in thermodynamic conditions through a DP meter can cause phase change. This real-world phenomenon is not always accounted for in the meter theoretical calculations and not seen in the test facility data. Nevertheless, it is widely accepted that some thermodynamic effects (and phase change) must exist in some production WGFM applications. Therefore, WGFM users should be aware of the limitations of both the theory and the wet gas test laboratories when faced with these difficult real-world conditions. It is a practical reality that wet gas meter operators should understand that there will always be higher uncertainties with real wet gas metering applications than will be found when testing a meter at a wet gas flow test facility.

11.3.4 Undisclosed WGFM calculation procedures

The difficulty faced by operators in obtaining "representative" multiphase wet gas flow field samples and the corresponding accurate multiphase wet gas flow fluid properties required by WGFMs are discussed in 10.3.1. Moreover, the proprietary "black box" nature of WGFM slip models (i.e. calculation routines) is described in 10.3.2. Without knowledge of the fluid property value biases and the sensitivity of the slip models to fluid property biases operators have difficulty setting a defensible uncertainty rating on a field installed WGFM. However, it should be noted that wet gas meter manufacturers have very reasonable cause to maintain confidentiality over their meters' calculation procedures. The calculation method, often called the "slip model", is a semi-empirical calculation procedure that incorporates expensive specialist flow modelling and hugely expensive multiple laboratory and field trial data sets. In effect the slip model is a mathematical expression of a wet gas meter manufacturer's extensive intellectual effort and hugely expensive investment in research. For a wet gas meter manufacturer to publish a slip model would be tantamount to publicly and freely releasing all research and development on that meter technology. Hence, the fact that wet gas meter flow rate calculations are confidential is an unfortunate but practical reality of industry.

Solutions to this practical problem include:

— the operator asking the manufacturer to estimate uncertainties;

— the operator carrying out sensitivity tests by changing fluid property inputs to the flow computer and noting output shifts (as discussed in 10.4.3); and

— operators being realistic and pragmatic and accepting that they have state of the art metering equipment and the measurement uncertainties are as low as the state of the art can achieve.

11.3.5 Differential pressure measurement and wet gas flows

Single-phase DP meters are popular meters for wet gas flow metering. Most sophisticated and capable wet gas and multiphase flow meters contain a DP meter at their core. Hence, the effect wet gas flow has on DP transmitters and DP measurement is an important issue.

DP meters designed for single-phase flow may have evenly spaced pressure ports radially around the perimeter of the pipe cross section, sometimes with a piezometer ring to average the pressure. However, this set-up should not be used for horizontal installation wet gas flow applications. The liquid can flood the lower part pressure ports and cause DP reading errors. It is advisable that in order to minimize the likelihood of pressure port flooding, when a DP-based WGFM is installed in horizontal installations, it should not use piezometer rings and the pressure ports should ideally be orientated at the 12 o'clock position.

Another potential adverse condition for DP measurement is that wet gas flow can also cause liquid to become trapped in impulse lines. This issue is why most horizontally installed DP meters for wet gas flow service have impulse lines that are preferably vertical. It is important to have straight impulse lines with no liquid trap U-bend design. This orientation allows the maximum chance of drainage and hence minimizes the likelihood of liquid being trapped in the impulse lines. Furthermore, the length of the impulse lines should be kept as short as possible to avoid heat exchange causing phase change in the tubing. The effect of a stationary gas and liquid mix in an impulse line on a pressure or differential pressure measurement is not well documented but the situation is generally considered to be adverse to good pressure and differential pressure measurement.

Moreover, as stated in 10.9.1.2 wet gas can cause DP transmitters to prematurely drift (in comparison to regular single phase flow service). Furthermore, as stated in 10.9.1.3 wet gas can cause the produced DP to be higher than initially predicted. As such the DP can exceed the DP transmitters upper range limit. In such as case the DP transmitter is said to be saturated. A saturated DP transmitter cannot read the correct DP. Saturated DP transmitters are a significant field issue with wet gas flows. A worked example describing the problem is given in 11.3.5.1.

11.3.5.1 Saturated DP transmitter worked example

With single-phase flow the DP produced by DP meters has a parabolic relationship with the flow rate. Formula (30) shows a (simplified) single-phase DP meter mass flow rate equation linking the gas mass flow rate ($\dot{m}_g$) for a set meter geometry and fluid properties (where the parameter denoted as K is then approximately constant) to the differential pressure (ΔP_g).

$$\dot{m}_g = EA_t \varepsilon C_d \sqrt{2\rho_g \Delta P_g} = K\sqrt{\Delta P_g} \tag{30}$$

The effect of liquid entrained in a set mass of gas flow is to significantly increase the DP (ΔP_{tp}) created by a DP meter. The over-reading of a DP meter can be defined as Formula (31) (see 6.3).

$$\mathrm{OR} = \sqrt{\frac{\Delta P_{tp}}{\Delta P_g}} \tag{31}$$

If, by way of example, we consider a horizontally installed 4-inch, 0,75 beta ratio Venturi meter flowing natural gas and a light hydrocarbon wet gas flow at a Lockhart-Martinelli parameter of 0,25, a gas to liquid density ratio of 0,045 and a gas densiometric Froude number of 2,5 it can be seen from the test data in Figure 13 that the resulting over-reading is approximately 50 %, or 1,5 in ratio terms. Formulae (32) and (33) show the resulting relationship between the actual wet gas DP and the DP if the gas phase flowed alone

$$\mathrm{OR} = \sqrt{\frac{\Delta P_{tp}}{\Delta P_g}} = 1,5 \tag{32}$$

$$\Delta P_{tp} = \left(1,5\right)^2 \Delta P_g = 2,25\Delta P_g \tag{33}$$

The liquid has induced an uncorrected gas flow rate prediction 1,5 times higher than the actually gas flow rate, and a DP reading 2,25 times that which would have been created by that gas flow flowing alone. Due to wet gas flows causing any given DP meter to have a considerably larger DP than would be seen with dry gas flows designers and operators should pay particular attention to the size of the DP expected. Failure to take into account the significantly higher DPs that can be caused by the liquid's presence in the gas flow can, and often does, cause saturation of the DP transmitter and failure of the metering system. Saturated DP transmitters are a very common fault with WGFM systems.

It is good practice for operators of wet gas flow meters to check the DP transmitters regularly for drift or saturation. Of course, in some installations this is not practical. Therefore, with DP meters being at the core of many WGFM designs and the DP measurement being critical to the DP meter operation, any diagnostic systems that can aid monitoring of DP transmitter drift both internally or externally to the DP transmitter can be very beneficial to WGFM operators.

11.3.6 Problems due to lack of long time operating experience of WGFMs

Wet gas flow meter designs are under continuous development and improvement. The majority of wet natural gas flow meters are sized and built to order. As a WGFM is usually made specifically for a particular application, for best results that application should be prepared for the meter installation. Along with selecting an appropriate location where liquid flooding and slugging is unlikely it is beneficial whenever possible to include isolation valves and a by-pass to ease removal and inspection and/or re-characterization of the meter. Considering the complexity of many wet gas metering systems industry has relatively little experience operating them. Some applications may therefore require re-verification, re-characterization or regular maintenance of the WGFM system. As with all instrumentation the periods of these events will be extended as and when the operator feels more ensured of the system's correct operation. As with all instrumentation wet gas meters with some internal diagnostic capability and subsystem redundancy will tend to more capable and more likely to be allowed longer operating periods before requiring re-verification, re-characterization or regular maintenance.

Annex A
(informative)

WGFM design checklist

In this Annex a brief check list is presented that can be used during the design stage of a WGFM application. Consideration of each of these topics is recommended. Note that further discussion of the topics in the list below can be found in the main body of the report or may be checked with others (e.g. a WGFM vendor). This list is given to ensure certain topics are not overlooked in a gas field development project.

- Summary of the gas field development
  - Reservoir engineering aspects
  - Partners, Government, Regulator aspects
  - What are the measurement objectives (gas only, gas and water, gas and HC liquids, etc.)
- Infrastructure
  - Flow lines and production facilities
  - Concessions/Royalty/Fiscal allocation
  - Location of the WGFMs and accessibility
  - Power availability/limitations
  - Pressure drop limits
- Key fluid and flow rate parameters of the development
  - Flow rates (forecast with uncertainties)
  - Compositions
  - Operating pressures/temperature
  - Water breakthrough, condensed water vs. formation water
  - Salinity issues
  - Hydrate management
  - Solids/Sand/Wax/Scale/H_2S
  - Other injection flow rates (e.g. methanol)
- Metering and Allocation philosophy
  - Other metering in the development
  - Allocation algorithm
  - Fiscal and/or Sales metering
  - Virtual metering system

  - Future extensions
- WGFMs
  - Installation orientation
  - Measurement principle suitable
  - Uncertainties of measured flow rates
  - Impact of changing fluid properties
  - Operational aspects (maintenance, verification, etc.)
  - Economics of the WGFM application
  - Data acquisition and IT architecture
  - Calibration and maintenance requirements
  - Backup and redundancy for the WGFM
  - Ensure transparency and auditability of readings
  - Delivery time
  - Vendor support
- Health, Safety and Environmental (HSE) issues regarding any WGFM radioactive source
  - Licence for applying the radioactive source
  - Who is custodian?
  - Shielding and maintenance of the source
  - Abandonment aspects
- Testing
  - Factory Acceptance Test
  - Additional flow facility testing and test program (if required or desired)
  - Site Acceptance Test

Annex B
(informative)

Wet gas parameters equations

In this Annex some conversion formulae have been presented. Note that the correct units (see Clause 3) need to be used.

$$X_{LM} = \frac{\dot{m}_l}{\dot{m}_g}\sqrt{\frac{\rho_g}{\rho_l}} = \frac{\dot{Q}_l}{\dot{Q}_g}\sqrt{\frac{\rho_l}{\rho_g}} = \frac{1-\left(\mathrm{GVF}\right)}{\left(\mathrm{GVF}\right)}\sqrt{\frac{\rho_l}{\rho_g}} = \frac{1-x}{x}\sqrt{\frac{\rho_g}{\rho_l}} = \frac{\left(\mathrm{LVF}\right)}{1-\left(\mathrm{LVF}\right)}\sqrt{\frac{\rho_l}{\rho_g}}$$

$$\mathrm{GVF} = \frac{1}{1+\left(\frac{\dot{m}_l}{\dot{m}_g} * \frac{\rho_g}{\rho_l}\right)} = \frac{1}{\left(\frac{\dot{Q}_l}{\dot{Q}_g}\right)+1} = 1-\left(\mathrm{LVF}\right) = \frac{\sqrt{\frac{\rho_l}{\rho_g}}}{X_{LM}+\sqrt{\frac{\rho_l}{\rho_g}}} = \frac{\left(\frac{\rho_l}{\rho_g}\right)}{\left(\frac{\rho_l}{\rho_g}\right)+\left(\frac{1-x}{x}\right)}$$

$$x = \frac{1}{1+\left(\frac{\dot{m}_l}{\dot{m}_g}\right)} = \frac{1}{1+\left(\frac{\rho_l}{\rho_g}\frac{\dot{Q}_l}{\dot{Q}_g}\right)} = \frac{1}{1+X_{LM}\sqrt{\frac{\rho_l}{\rho_g}}} = \frac{1}{1+\left(\left(\frac{1-\left(\mathrm{GVF}\right)}{\left(\mathrm{GVF}\right)}\right) * \frac{\rho_l}{\rho_g}\right)} = \frac{1}{1+\left(\left(\frac{\left(\square\mathrm{VF}\right)}{1-\left(\square\mathrm{VF}\right)}\right) * \frac{\rho_l}{\rho_g}\right)}$$

$$\frac{\dot{m}_l}{\dot{m}_g} = X_{LM}\sqrt{\frac{\rho_l}{\rho_g}} = \frac{\rho_l}{\rho_g}\frac{\dot{Q}_l}{\dot{Q}_g} = \frac{1-\left(\mathrm{GVF}\right)}{\mathrm{GVF}}\frac{\rho_l}{\rho_g} = \frac{\mathrm{LVF}}{1-\mathrm{LVF}}\frac{\rho_l}{\rho_g} = \frac{1-x}{x}$$

$$\frac{\dot{Q}_l}{\dot{Q}_g} = X_{LM}\sqrt{\frac{\rho_g}{\rho_l}} = \frac{\rho_g}{\rho_l}\frac{\dot{m}_l}{\dot{m}_g} = \frac{1-\left(\mathrm{GVF}\right)}{\mathrm{GVF}} = \frac{\mathrm{LVF}}{1-\left(\mathrm{LVF}\right)} = \left(\frac{1-x}{x}\right)\frac{\rho_g}{\rho_l}$$

$$\mathrm{LVF} = 1-\left(\mathrm{GVF}\right) = \frac{X_{LM}\sqrt{\frac{\rho_g}{\rho_l}}}{1+X_{LM}\sqrt{\frac{\rho_g}{\rho_l}}} = \frac{\left(\frac{1-x}{x}\right)}{\left(\frac{1-x}{x}\right)+\frac{\rho_l}{\rho_g}} = \frac{\frac{\rho_g}{\rho_l}}{\frac{\rho_g}{\rho_l}+\frac{\dot{m}_g}{\dot{m}_l}} = \frac{\frac{\dot{Q}_l}{\dot{Q}_g}}{1+\frac{\dot{Q}_l}{\dot{Q}_g}}$$

Bibliography

[1] ISO 5167-1, *Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full — Part 1: General principles and requirements*

[2] ISO 5167-4, *Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full — Part 4: Venturi tubes*

[3] ISO 5168, *Measurement of fluid flow — Procedures for the evaluation of uncertainties*

[4] ISO 10715, *Natural gas — Sampling guidelines*

[5] ISO 12213 (all parts), *Natural gas — Calculation of compression factor*

[6] ISO 14532, *Natural gas — Vocabulary*

[7] ISO 15970, *Natural gas — Measurement of properties — Volumetric properties: density, pressure, temperature and compression factor*

[8] ISO/TR 26762, *Natural gas — Upstream area — Allocation of gas and condensate*

[9] NFOGM, "Norwegian Handbook for Multiphase Flow Measurement", 2005.

[10] API Manual of Petroleum Measurement Standards (MPMS), Chapter 20.3, "Measurement of multiphase flow".

[11] API Recommended Practice (RP) 87, "Use of wet gas flow metering in allocation measurement"

[12] American Society of Mechanical Engineering, MFC Report 19G, 2008.

[13] Steven R., Grifin D., Hall A. A Discussion on Wet Gas Flow Parameter Definitions", North Sea Flow Measurement Workshop, Norway, October 2007.

[14] Murdock J.W. Two-Phase Flow Measurements with Orifices. J. Basic Eng. 1962 December, **84** pp. 419–433

[15] Chisholm D. Flow of Incompressible Two-Phase Mixtures through Sharp-Edged Orifices. J. Mech. Eng. Sci. 1967, **9** (1)

[16] Chisholm D., & Leishman J.M. Metering of Wet Steam", Journal of Chemical & Process Engineering, pp103-106, July 1969.

[17] Chisholm D. Research Note: Two-Phase Flow Through Sharp-Edged Orifices. J. Mech. Eng. Sci. 1977, **19** (3)

[18] De Leeuw R. Liquid Correction of Venturi Meter Readings in Wet Gas Flow", North Sea Flow Measurement Workshop, Norway, Oct 1997.

[19] Britton C., Kinney J., Steven R. A Review of the Parameters Influencing Venturi Meters with Wet Gas Flows", North Sea Flow Measurement Workshop, Norway, Oct 2008.

[20] Stewart D., Hodges D., Steven R., Peters R.J.W. Wet Gas Metering with V-Cone Meters", North Sea Flow Measurement Workshop 2002, St Andrews, Scotland, UK. Paper No.4.2.

[21] Stewart D.G. Application of Differential Pressure Meters to Wet Gas Flow", 2nd International South East Asia Hydrocarbon Flow Measurement Workshop, 25th-28th March 2003.

[22] Steven R. Liquid Property and Diameter Effects on Venturi Meters Used with Wet Gas Flows", International Fluid Flow Measurement Symposium, Mexico, May 2006.

[23] Reader-Harris M. Venturi-Tube Performance in Wet Gas Using Different Test Fluids", North Sea Flow Measurement Workshop 2006, St Andrews, Scotland, UK.

[24] Salque G., Couput J.P., Gajan P., Strzelecki A., Fabre J.L. New correction method for wet gas flow metering based on two phase flow modelling: Validation on industrial Air/Oil/Water tests at low and high pressure", 26th North Sea Flow Measurement Workshop, 2008, St. Andrews, Scotland, UK.

[25] Hall A., Priddy B., Steven R., Stobie G. Horizontally Installed Orifice Plate Meter Response to Wet Gas Flows", North Sea Flow Measurement Workshop 2011, Tonsberg, Norway.

[26] Van Werven M., Van Maanen H.R.E., Ooms G., Azzopardi B.J. Modelling wet gas annular/dispersed flow through a Venturi. AIChE J. 2003, **49** (6) pp. 1383–1391

[27] Lupeau A., Platet B., Gajan P., Strzelecki A., Escande J., Couput J.P. Influence of the presence of an upstream annular liquid film on the wet gas flow measured by a Venturi in a downward vertical configuration". In: Flow Measurement and Instrumentation. 2006, pp. 1-11.

[28] Steven R. Horizontally Installed Cone Differential Pressure Meter Wet Gas Flow Performance", South East Asia Hydrocarbon Flow Measurement Workshop, March 2009.

[29] Medvejev V.F. Gas and Liquid Flow Rate Measurement in Gas-Liquid Mixture", Journal of Instrumentation and Control System, No. 10, pp 18-20, 1972.

[30] Nguyen T.V. Methods for Metering Two-Phase Flow", US Patent No. 4,576,043, Date of Patent, March 18th, 1986.

[31] Nguyen T.V. Methods for Metering Two-Phase Flow", US Patent No. 4,662,219, Date of Patent, May 5th, 1987.

[32] Wood I. Penguin Wet Gas Measurement", North Sea Flow Measurement Workshop 2003, Tonsberg, Norway.

[33] Jamieson A. Multiphase metering — The challenge of Implementation", 16th North Sea Flow Measurement Workshop 1998.

[34] Kataoka I., & Ishii M. Mechanism and correlation of droplet entrainment and deposition in annular two-phase flow", NUREG/CR-2885, ANL-82-44, 1982.

[35] Scheers A.M. Use of the Two-Phase Flow Map and the Composition Map in Multiphase Flow Meter Application", South East Asia Hydrocarbon Flow Measurement Workshop, March 2005.

[36] Van Maanen H. Measurement of the Liquid Water Flow Rate Using Microwave Sensors in Wet-Gas Meters: Not As Simple As You May Think", North Sea Flow Measurement Workshop 2008, St. Andrews, Scotland, UK.

[37] Collins A., Hu J.L., Tudge M., Wade C. The Development of Initial Data from a New Multiphase Wet Gas Meter", North Sea Flow Measurement Workshop 2010, St Andrews, Scotland, UK.

[38] Scheers L. Challenges in Multiphase and Wet Gas Flow Metering For Applications with Limited Accessibility", North Sea Flow Measurement Workshop 2010.

[39] Cooley C., Letton W., Hall J. Wet Gas Allocation on the Canyon Express Project", North Sea Flow Measurement Workshop 2003.

[40] Couput J.P. Subsea multiphase measurements: where we are and what's next from an oil & gas operator perspective", North Sea Flow Measurement Workshop 2011.

[41] Deverapalli V., Glover B., Ayre J., Steven R. A Diagnostic System for Venturi Meters in Single phase and Wet Gas Flow Applications", North Sea Flow Measurement Workshop October 2011, Tonsberg, Norway.

[42] Rodríguez D.J. Modular wet gas and multiphase flow meter", 6ª Jornada Internacional de Medición de Fluidos, 2011-06-28.

[43] Skelton M. Diagnostics for Large High Volume Flow Orifice Plate Meters", North Sea Flow Measurement Workshop 2010, St Andrews, Scotland, UK.

[44] Cousins T., Hodges C., Steven R., Myer D. The Emperor's New Clothes – Oil with Water Flow Metering", North Sea Flow Measurement Workshop, Tonsberg, Norway, October 2013

[45] ISO/IEC 98-3:2008, *Uncertainty of measurement — Part 3: Guide to the expression of uncertainty in measurement (GUM:1995)*

[46] ISO 13443, *Natural gas — Standard reference conditions*

This page deliberately left blank

This page deliberately left blank

British Standards Institution (BSI)

BSI is the national body responsible for preparing British Standards and other standards-related publications, information and services.

BSI is incorporated by Royal Charter. British Standards and other standardization products are published by BSI Standards Limited.

About us

We bring together business, industry, government, consumers, innovators and others to shape their combined experience and expertise into standards -based solutions.

The knowledge embodied in our standards has been carefully assembled in a dependable format and refined through our open consultation process. Organizations of all sizes and across all sectors choose standards to help them achieve their goals.

Information on standards

We can provide you with the knowledge that your organization needs to succeed. Find out more about British Standards by visiting our website at bsigroup.com/standards or contacting our Customer Services team or Knowledge Centre.

Buying standards

You can buy and download PDF versions of BSI publications, including British and adopted European and international standards, through our website at bsigroup.com/shop, where hard copies can also be purchased.

If you need international and foreign standards from other Standards Development Organizations, hard copies can be ordered from our Customer Services team.

Subscriptions

Our range of subscription services are designed to make using standards easier for you. For further information on our subscription products go to bsigroup.com/subscriptions.

With **British Standards Online (BSOL)** you'll have instant access to over 55,000 British and adopted European and international standards from your desktop. It's available 24/7 and is refreshed daily so you'll always be up to date.

You can keep in touch with standards developments and receive substantial discounts on the purchase price of standards, both in single copy and subscription format, by becoming a **BSI Subscribing Member**.

PLUS is an updating service exclusive to BSI Subscribing Members. You will automatically receive the latest hard copy of your standards when they're revised or replaced.

To find out more about becoming a BSI Subscribing Member and the benefits of membership, please visit bsigroup.com/shop.

With a **Multi-User Network Licence (MUNL)** you are able to host standards publications on your intranet. Licences can cover as few or as many users as you wish. With updates supplied as soon as they're available, you can be sure your documentation is current. For further information, email bsmusales@bsigroup.com.

Revisions

Our British Standards and other publications are updated by amendment or revision.

We continually improve the quality of our products and services to benefit your business. If you find an inaccuracy or ambiguity within a British Standard or other BSI publication please inform the Knowledge Centre.

Copyright

Useful Contacts:

Customer Services
Tel: +44 845 086 9001
Email (orders): orders@bsigroup.com
Email (enquiries): cservices@bsigroup.com

Subscriptions
Tel: +44 845 086 9001
Email: subscriptions@bsigroup.com

Knowledge Centre
Tel: +44 20 8996 7004
Email: knowledgecentre@bsigroup.com

Copyright & Licensing
Tel: +44 20 8996 7070
Email: copyright@bsigroup.com

BSI Group Headquarters

389 Chiswick High Road London W4 4AL UK

bsi.