Index

Paper 5.1

Critical Review of Wet Gas Definitions

Gioia Falcone
Texas A & M University

Claudio Alimonti
University "La Sapienza" of Rome

24th International North Sea Flow Measurement Workshop
24th – 27th October 2006

Critical Review of Wet Gas Definitions

Gioia Falcone, Texas A&M University
Claudio Alimonti, University "La Sapienza" of Rome

1 INTRODUCTION

Several definitions of wet gas have been proposed within the Oil and Gas industry. However, in order to choose the best strategy to meter one's wet gas production, one must have a clear understanding of what wet gas is. So far, efforts appear to have gone awry, with companies deciding how to meter wet gas before defining what it is. This has led to companies employing existing metering solutions and strategies and characterising wet gas as a stream that can be measured with available techniques.

The concept of "wet gas metering" can apply to gas condensate fields, high gas-oil ratio (GOR) fields and wet gases. Produced streams of wet gas are metered for a variety of reasons: field economics, reservoir management, allocation issues and metering the produced gas only or metering the liquid and the gas, depending on whether one is selling one phase or both. Depending on the specific requirements, different metering accuracies may be required and different wet gas metering solutions sought.

At present, a single definition of wet gas for Oil and Gas applications does not exist (and it may never exist), so a unique metering solution for all types of wet gas may be impossible to achieve. Therefore, a critical approach must be taken to select a wet gas meter for each specific application.

2 ORIGINS AND LIMITATIONS OF CURRENT WET GAS DEFINITIONS

According to the definition given in the SPE monograph vol.20 [1], a reservoir fluid is classified as:

- dry gas when the reservoir temperature is greater than the cricondentherm and surface/transport conditions are outside the two-phase envelope;
- wet gas when the reservoir temperature is greater than the cricondentherm, but the surface/transport conditions are in the two-phase region;
- gas condensate when the reservoir temperature is less than the cricondentherm and greater than the critical temperature;
- oil (volatile or black oil) when the reservoir temperature is less than the mixture critical temperature.

This classification is illustrated in **Fig.1**.

Path A-A2 is typical of a wet gas. The fluid is single-phase gas at the initial reservoir conditions. As the fluid pressure and temperature decrease from reservoir to surface, the dewpoint is encountered and liquid starts forming from the gas. Within the two-phase region of the envelope, iso-quality lines of increasing liquid percentage are traveresed by the path.

Path B-B2 seems to be similar in principle to path A-A2, the only difference being that the temperature remains equal to the initial reservoir temperature. However, as the pressure is further decreased from B2 to B3, the so-called retrograde condensation occurs, where the liquid components show a tendency of going back into the gas phase (the path traverses iso-quality line of decreasing liquid percentage).

It must be noted that the classification illustrated in **Fig.1** only allows for hydrocarbons to be present in the liquid phase, neglecting any possible occurrence of free water or condensed vapour. Nor does not provide information on the flow patterns and phase velocities that may be encountered in the well. However, it does contain information on the fluid composition and pressure-temperature behaviour.

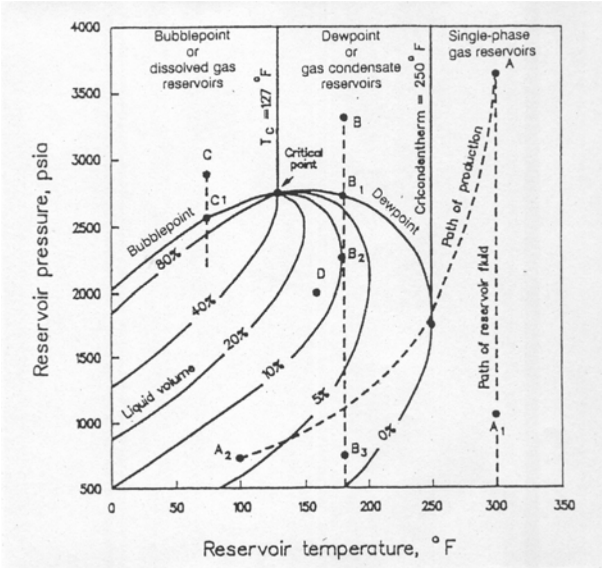


Fig. 1: Classification of reservoir fluids (Whitson & Brule', 2000 [1]).

According to McCain [2], a produced hydrocarbon stream that has a GOR higher than 50,000 scf/STB can be classified as a wet gas. For a retrograde gas, the lower limit for the initial producing GOR is approximately 3,300 scf/STB, while the upper limit can be over 150,000 scf/STB.

The difference between a wet gas and a retrograde gas can be seen from the properties of the stock-tank liquid produced. These tend to change over time for a retrograde gas, while remain basically constant for a wet gas.

Table 1 below gives a summary of typical oil field molar compositions for wet gas and retrograde gas.

Component *(mol %)*	**WET GAS**	**GAS CONDENSATE**
CO2	1.41	2.37
N2	0.25	0.31
C1	92.46	73.19
C2	3.18	7.8
C3	1.01	3.55
i-C4	0.28	0.71
n-C4	0.24	1.45
i-C5	0.13	0.64
n-C5	0.08	0.68
C6(s)	0.14	1.09
C7+	0.82	8.21

Table 1: Typical compositions of wet gas and retrograde gas (Whitson & Brule', 2000 [1])

It is usually recommended that the PVT characterisation of a wet or retrograde gas be carried out based on a molar composition down to the C_{20}. This is particularly important for a retrograde gas near the critical point, where the properties of the gas phase and the liquid phase become less distinct.

The collection of representative fluid samples for the PVT characterisation of a wet or retrograde gas remains an issue for the Oil and Gas industry. If the sample is taken downhole, paying attention to avoid contamination by mud filtrate, the fluid will be representative of *in-situ* conditions. However, along its path to surface during production, the fluid is subject to flashes with continuous exchange of components from the gas phase to the liquid phase (and vice versa). As the gas and the liquid are unlikely to be travelling at the same velocity, the overall composition arriving at surface is likely to be quite different from the original *in-situ* composition. This problem is particularly relevant when dealing with retrograde gas, as liquid drop out may occur in the formation, with the result that the heavier components are left behind and the fluids produced from the reservoir are leaner.

PVT characterisation based on the recombination of gas and liquid samples from the separator is more likely to capture the actual fluid composition at surface. However, recombination techniques are not simple, due to the problems of carry-over and carry-under in the separator and having to know the exact proportions with which the single-phase samples must be recombined.

For the purpose of wet gas metering, the accuracy of the PVT characterisation at the operating pressure and temperature of the meter is vital. As illustrated in **Fig.2**, PVT accuracy is also required at other conditions, should the measurements from the meter be reported at stock-tank conditions or at the pressure and temperature of a reference measurement point.

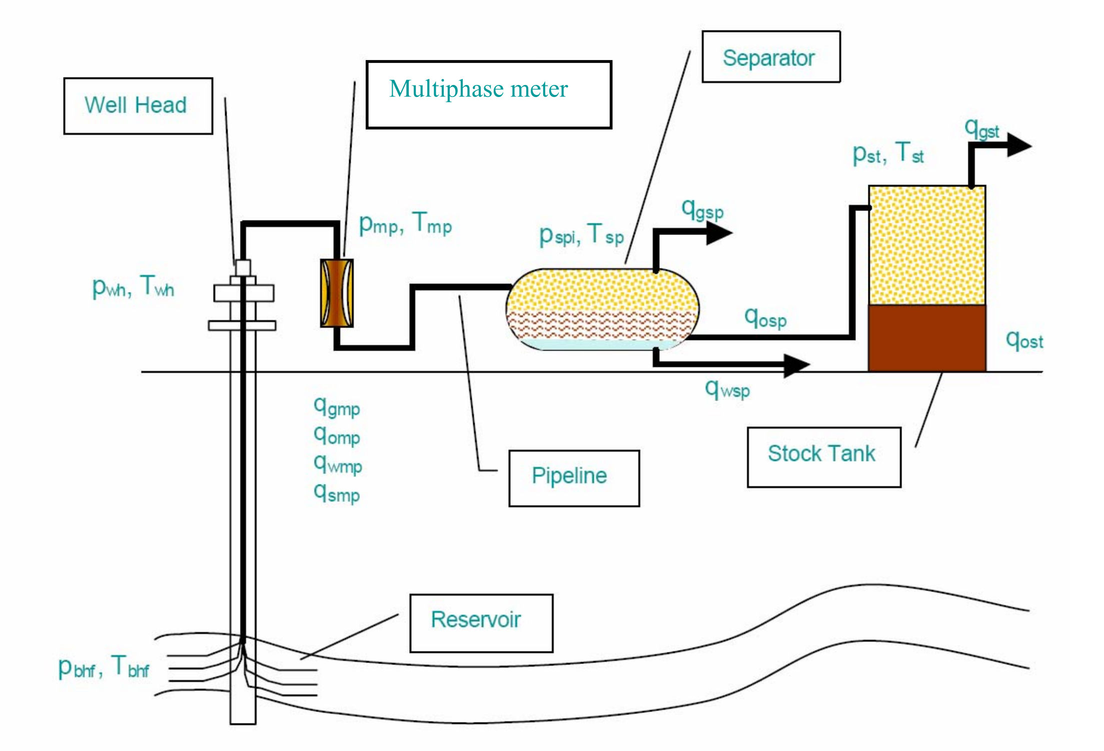


Fig.2: Schematic of a typical multiphase flow meter installation, showing the different pressures and temperatures in the reservoir, at bottomhole, at the wellhead, at the meter, at the separator and at stock-tank conditions (Pinguet *et al.*, 2005 [3]).

In 2003, the UK Department of Trade and Industry (DTI) issued guidelines [4] where wet gas was defined as a stream with liquid volume fractions (LVF's) between 0 and 10% at metering conditions. Following this definition, wet gas metering can be regarded as the upper limit of multiphase flow metering [oils with high gas volume fractions (GVF's)] and the bottom boundary of gas metering [gases with high liquid volume fractions (LVF's)]. This implies that, in theory, by pushing either multiphase flow metering or gas metering to their extremes, wet gas metering solutions can be found.

Another way of expressing the wetness of the gas by volume is to use volume triangles [5], with gas, oil and water at the three vertices. The area around the gas vertex is that of wet gas.

Definitions based on volume are pressure dependant and do not give any indication of the molar composition of the fluid. In particular, they do not help to differentiate between a volatile oil, a wet gas and a retrograde gas, for the same operating GVF. On the other hand, definitions based on volume can be made more specific if the operating pressure and temperature are specified and/or the densities of the liquid and gas phases are provided.

The importance of working in mass fractions, rather than volume fractions, when characterising wet gas fields has been highlighted in the literature [5], [6]. Multiphase mass fraction triangles have been produced for different fluid densities, showing the possible percentages of gas, oil and water in a wet gas stream. They are shown in **Fig.3**.

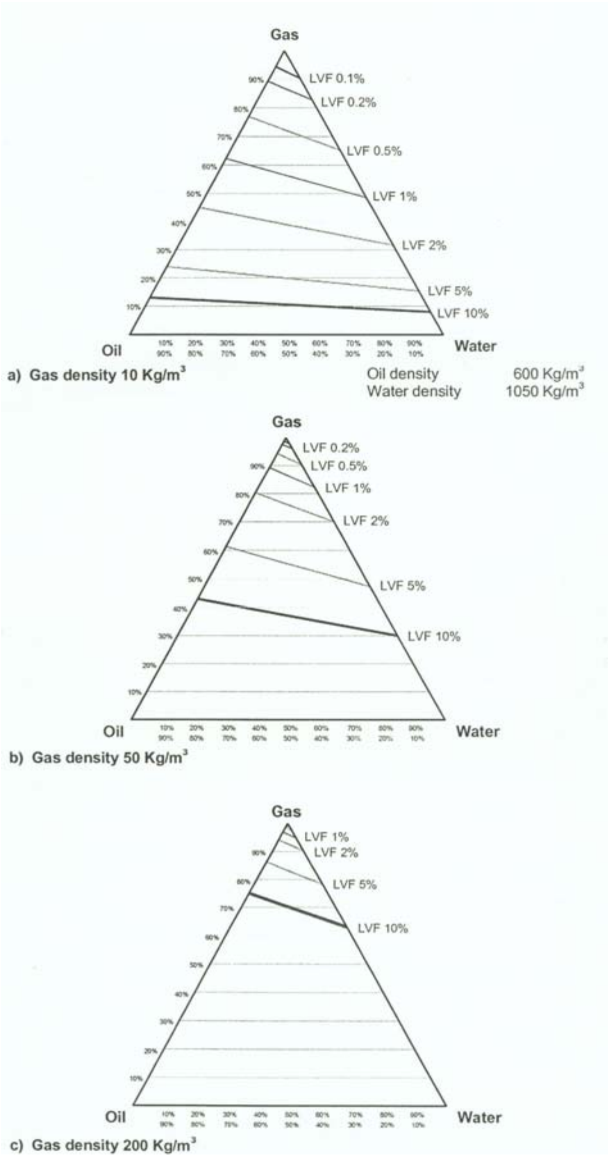
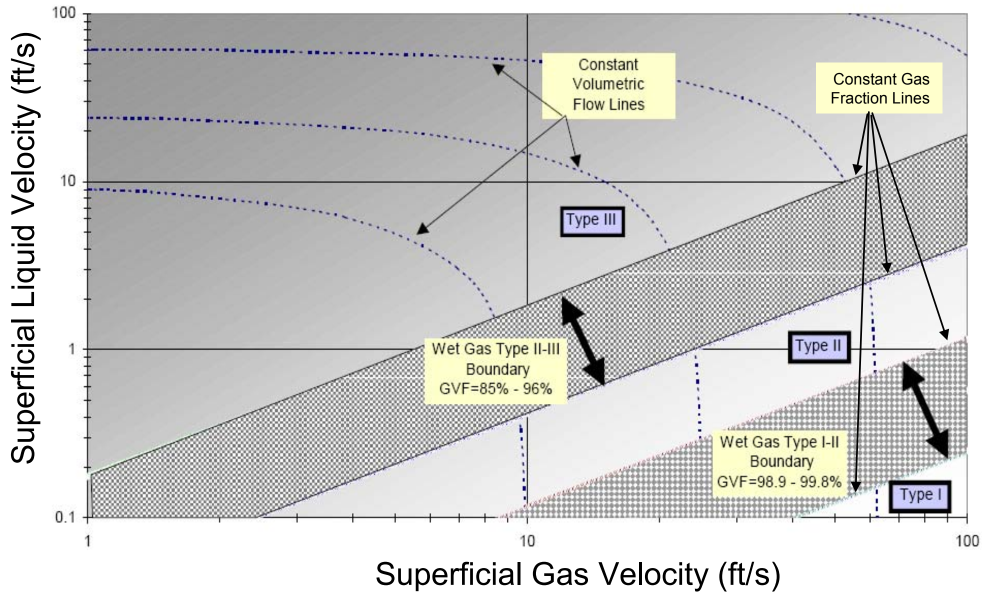


Fig.3: Multiphase mass fraction triangles showing liquid volume fraction lines at three gas densities (Jamieson, 2001 [5]).

The mass triangles show that, depending on the value of the gas density at the metering location (i.e. depending on the pressure and the composition), the same LVF can correspond to different liquid mass fractions.

In order to account for the joint effects of gas and liquid superficial velocity, GVF and Lockhart-Martinelli parameter (X), the classification illustrated in **Fig.4** was presented [7], [8]. Using this characterisation, wet gas is defined as a gas stream with a Lockhart-Martinelli parameter of 0.3 or less.



Type of Wet Gas	Lockhart-Martinelli Number	Typical Applications
Type 1	Equal or less than 0.025	Type 1 wet gas measurement represents measurement systems at production wellheads, unprocessed gas pipelines, separators, allocation points, and well test facilities. Liquid measurement is necessary to make correction for improved gas measurements.
Type 2	0.025 to 0.30	Type 2 wet gas-metering systems cover higher liquid flow ranges so that the users often require more accurate gas and liquid flow rates. Applications include the flow stream at the production wellhead, commingled flow line, or well test applications.
Type 3	Above 0.30	Type 3 meter must make an oil, gas and water rate determination at relatively high GVF > 80% or X≥0.3. Typical application is gas condensate wells and gas lift wells.

Fig.4: A proposed map for classifying a wet gas stream, based on gas and liquid superficial velocity (Mehdizadeh & Marelli, 2002 [7]). Three types of wet gas have been defined using superficial velocities, GVF & Lockhart-Martinelli parameter (Mehdizadeh & Williamson, 2004 [8]).

The classification reported in **Fig.4** above is pressure dependant. Also, it does not fully account for the effects of composition of the liquid phase, gas velocity, venturi beta ratio (if a venturi is used to meter the wet gas stream) and flow regime. It has been shown [9] that, when X>0.13, the effects of flow regime on measured signals for wet gas metering become important and cannot be neglected.

It is important to remember that the Lockhart-Martinelli parameter was originally introduced for the interpretation of separated flow in horizontal pipes [10]. Data for the simultaneous flow of air and liquid in horizontal pipes varying in diameter from 0.0586 in. to 1.1017 in were used to derive an experimental expression of the pressure drop for iso-thermal two-phase, two-component flows in pipes.

In its original formulation, the Lockhart-Martinelli parameter was defined through the following expression:

$$X^2 = \frac{(\mathrm{Re}_{GP})^m}{(\mathrm{Re}_{LP})^n}\frac{\rho_G}{\rho_L}\left(\frac{W_L}{W_G}\right)^2 = \frac{\left(\frac{\Delta P_f}{\Delta L}\right)_L}{\left(\frac{\Delta P_f}{\Delta L}\right)_G} \qquad \textbf{Eq. 1}$$

where $\left(\frac{\Delta P}{\Delta L}\right)_L$ and $\left(\frac{\Delta P}{\Delta L}\right)_G$ are the frictional pressure drops per unit length of pipe that would exist if the liquid phase or the gas phase were assumed to flow alone. W_L and W_G are the liquid and gas mass flow rates. ρ_L and ρ_G are the liquid and gas densities. Re_{LP} and Re_{GP} are the Reynolds moduli for liquid and gas, based on the inside pipe diameter. Values for the exponents m and n, for the constants C_L and C_G and for the Reynolds moduli were proposed in [8] for four different flow types: turbulent liquid, turbulent gas flow; viscous liquid, turbulent gas flow; turbulent liquid, viscous gas flow; viscous liquid, viscous gas flow (Note: “viscous” means laminar in this context).

For turbulent liquid, turbulent gas flow, **Eq.1** can be written as:

$$X^2 = \left(\frac{\mu_G}{\mu_L}\right)\frac{\rho_G}{\rho_L}\left(\frac{W_L}{W_G}\right)^{1.8} \qquad \textbf{Eq.2}$$

Since its introduction, the Lockhart-Martinelli parameter has been simplified for specific use with differential pressure meters correlations. Unfortunately, this has meant that its origins have been partly forgotten and further assumptions have been made in addition to those already intrinsic in the initial definition. The Lockhart-Martinelli parameter was introduced for the interpretation of the frictional pressure drop in separated two-phase flows in horizontal pipes, based on experimental data. It neglected the effects of surface tension and flow development [11].

3 CONCLUSIONS

Although each of the above attempts to classify wet gas covers a true aspect of wet gas, none of them can be considered as universal and self-sufficient.

Due to the complexity and peculiarity of wet gas flow, it is extremely difficult to capture the effects of operating pressure and temperature, composition, flow regime, mass flow rates and volume flow rates in a single definition. Among the factors that make wet gas difficult to classify are:

- the occurrence of slip between the liquid and the gas;
- the difficulties in predicting the transition between flow regimes in horizontal and in vertical currents;
- the uncertainties related to the PVT characterisation of wet and retrograde gas fields;

- the liquid phase of wet gas streams may be a combination of hydrocarbons and water, so that wet gas metering becomes a three-phase problem;
- the oil/water inversion point can have a significant impact on the multiphase flow correlations used to calculate pressure drops and boundaries between flow regimes;
- solids or chemicals may be a “fourth phase” present in the stream;
- the composition of the stream to be metered may vary with time, along with the operating pressure and temperature and, ultimately, the flow regime. Hence, a gas which is initially dry becomes a gas condensate, with the heavier components in the liquid phase and the lighter components in the gas phase.

The development of multiphase flow metering and, subsequently of wet gas metering, was originally driven by instrument engineers and therefore some definitions mirror the operational capabilities of specific metering devices, rather than capturing the actual nature of the flow being metered.

Fluid composition, operating pressure and temperature, gas velocity, flow pattern, meter geometry and orientation all need to be accounted for to properly characterise the type of wet gas towards an accurate prediction of the flow rates.

5 REFERENCES

[1] Whitson, C.H., Brule’, M.R. (2000): “Phase Behaviour”, SPE monograph Vol. 20, 13.

[2] McCain, W.D. Jr. (1990): “The properties of petroleum fluids”, 2nd edition, PennWell Books, Tulsa, Okloma.

[3] Pinguet, B., Haddad, N., Birkett, G. (2005): “Fluid Properties on the Main Path for Multiphase Meters and Wet Gas Meter Accuracy: An Analytical Approach”, paper presented at the 4th South East Asia Hydrocarbon Flow Measurement Workshop, Kuala Lumpur, Malaysia, 7-11 March 2005.

[4] DTI (2003), “Guidance Notes For Petroleum Measurement”, Issue 7, December 2003.

[5] Jamieson, A.W. (2001): “Wet Gas Metering – The Unexpected Challenge Status and Trends on Technology and Applications”, paper presented at the 19th North Sea Flow Measurement Workshop 2001.

[6] Couput, J., Gajan, P., de Laharpe, V., Strzelecki, A. (2000): “Wet Gas Metering in the upstream area: needs, applications & developments”, presented at the 18th North Sea Flow Measurement Workshop held in Scotland, 24-27 October 2000.

[7] Mehdizadeh, P., Marrelli, J. (2002): “Wet Gas Metering: Trends in Applications and Technical Developments”, SPE 77351 presented at the 2002 SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 29 September-2 October 2002.

[8] Mehdizadeh, P., Williamson, J. (2004): “Principles of Multiphase Flow Measurements”, Information Document prepared for the Alaska Oil & Gas Conservation Commission to accompany “Guidelines For Qualification of Multiphase Metering Systems for Well Testing”, November 30, 2004.

[9] Geng, Y., Zheng, J., Shi, T. (2006): “Study on the metering characteristics of a slotted orifice for wet gas flow”, Flow Measurement and Intrumentation, 17 (2006) 123-128.

[10] Lockhart, R.W., Martinelli, R.C. (1949): “Proposed correlation of data for isothermal two-phase, two-component flow in pipes”, Chem. Eng. Prog. (January 1949), 45, no.1, pp. 39-48.

[11] Hewitt, G.F. (1982): “Prediction of Pressure Drop in Annular Flow by Phenomenological Modelling”, Section 2.2.4 of Handbook of Multiphase Flow System, ed. G.Hetsroni, Hemisphere Publishing Corporation.