WET GAS MEASUREMENT
Class # **1320.1**

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Introduction

Demand for wet gas flow measurement technologies has been increasing steadily for many years. As natural gas wells age the once dry natural gas production flow becomes wet natural gas as the dynamics of the reservoir change. Furthermore, with the value of hydrocarbon products rising steadily, reservoirs that were once considered not profitable, or marginal, are being produced. These marginal fields often produce wet gas flows from the outset. It is essential that these wet gas flows are metered as accurately as possible.

The traditional method of metering wet gas or multiphase flows is to separate the fluids in a dedicated separator vessel. The inlet of these vessels receives the unprocessed flow of natural gas and liquids (which may be both hydrocarbon liquids and water). The vessel is designed to separate the component fluids and allow the flow to exit separately as natural gas and single component liquid flows where single phase flow measurement technologies can be utilized. This is the original wet gas and multiphase meter technology.

However, as will be discussed, there are operational issues with the use of separators for wet gas measurement and there is a strong desire to replace them with wet gas flow meter technologies. The development of such technology, which started with the power industries interest in the 1960's and 1970's and then advanced by the hydrocarbon production industry from the mid 1990's, has been extensive but troublesome. The idealized goal of an economically viable universally applicable wet gas flow meter has not been realized. The simply stated task of wet gas flow measurement – i.e. the measurement in real time of the gas and liquid mass flow rates – has proven to be extremely difficult and many theoretical concepts have failed to be developed into useable products. However, today there are wet gas flow measurement solutions available to natural gas production engineers.

Single phase flow measurement techniques have been developed for more than a century. A variety of single phase gas flow meters exist on the market because they all have advantages and disadvantages compared to each other. For each unique application one gas meter technology will fit the situation best. No engineer could seriously claim that there is such a thing as a universal gas meter perfect for all applications. The same is true of wet gas flow metering. There has been a tendency by many to see wet gas metering as a single issue needing a single solution. In truth the subject is as wide and varied as gas metering, and just like gas metering, there is no one technology that fits all applications best. With a variety of designs now on the market as a result of years of development, the situation is the same as with gas meter commercial competition. That is, there are advantages and disadvantages when comparing wet gas meter marketed products for any particular application.

This paper will address the definition of wet gas flow, the limitations of separator technology, the reaction of popular gas meters when exposed to wet gas flows and the popular correction methods for gas meters exposed to wet gas flows. There will also be a review of the popular wet gas meter design concepts. The aim of this paper is to help the wet gas meter user understand the principles of popular wet gas metering technology and help them ask the correct questions when choosing a wet gas meter for a particular application.

Defining Wet Gas and Wet Gas Flow Parameters

The subject of liquid and gas flowing together in a pipeline covers a huge spectrum of flow conditions. With in the natural gas production industry all combinations of natural gas, hydrocarbon liquid and water flows can be found. A common way of categorizing flows is to split the flows into two general types. That is, a gas dominant flow (with a relatively small amount of liquid) and a liquid dominant flow (with a relatively small amount of gas). The former is viewed as a wet gas, the latter is viewed as general "two-phase flow" or a "multiphase flow".

Wet gas flow is not yet quantitatively defined by any codes and standards body. However many, such as the American Society of Mechanical Engineering [1], agree that wet gas flow could be defined as a Lockhart-Martinelli parameter, X_{LM}, less than 0.3, $X_{LM} \leq 0.3$. The Lockhart-Martinelli parameter is defined by equation 1, where m_g and m_l are the gas and liquid mass flow rates and ρ_g and ρ_l are the gas and liquid densities respectively. This term is rather abstract and is used mainly by wet gas meter designers and academics. It is more common for personnel involved with the front end of production to use the term "GVF". This stands for "**G**as **V**olume Flowrate **F**raction"

$$X_{LM} = \sqrt{\frac{Superficial\ Liquid\ Inertia}{Superficial\ Gas\ Inertia}} = \frac{m_\ell}{m_g}\sqrt{\frac{\rho_g}{\rho_\ell}} \quad \text{--- (1)}$$

and it means the ratio of the gas to total volume flow rate ratio. This is shown in equation 2, where note that $\dot{Q}_g$ and $\dot{Q}_l$ are the gas and liquid volume flow rates at actual flow conditions respectively. The Lockhart Martinelli parameter and GVF are related through the gas to liquid density ratio. The conversion is shown as equation 3. Note that as these parameters are related through the gas to liquid density ratio, "DR" (see equation 4) there is no direct GVF equivalent to the Lockhart-Martinelli parameter. The precise equivalent of any Lockhart Martinelli parameter value in terms of GVF is gas to liquid density ratio dependent.

$$GVF = \frac{\dot{Q}_g}{\dot{Q}_g + \dot{Q}_l} \quad \text{---(2)} \qquad GVF = \sqrt{\frac{\rho_l}{\rho_g}} \Big/ \left\{ X_{LM} + \sqrt{\frac{\rho_l}{\rho_g}} \right\} \quad \text{--- (3)} \qquad DR = \frac{\rho_g}{\rho_l} \quad \text{--- (4)}$$

Note that as these parameters are related through the gas to liquid density ratio, "DR" (see equation 4) there is no direct GVF equivalent to the Lockhart-Martinelli parameter. The precise equivalent of any Lockhart Martinelli parameter value in terms of GVF is density dependent. The term "liquid loading" is a non-quantitative way of describing relative liquid flow with a gas flow.

The gas densimetric Froude number (5) is defined as the square root of the ratio of the gas inertia if it flowed alone to the gravitational force on the liquid phase. The liquid densimetric Froude number (7) is defined as the square root of the ratio of the liquid inertia if it flowed alone to the gravitational force on the liquid phase. In these equations, g is the gravitational constant (9.81m/s^2 or 32.2 ft/s^2), D is the pipe internal diameter, A is the pipe cross sectional area and U_{sg} & U_{sl} are the superficial gas and liquid velocities calculated by equations (6) and (8).

$$Fr_g = \frac{U_{sg}}{\sqrt{gD}}\sqrt{\frac{\rho_g}{\rho_\ell - \rho_g}} \quad \text{-- (5)} \qquad U_{sg} = \frac{m_g}{\rho_g A} \quad \text{-- (6)} \qquad Fr_\ell = \frac{U_{s\ell}}{\sqrt{gD}}\sqrt{\frac{\rho_\ell}{\rho_\ell - \rho_g}} \quad \text{-- (7)} \qquad U_{s\ell} = \frac{m_\ell}{\rho_\ell A} \quad \text{-- (8)}$$

Finally, as will be seen, differential pressure (DP) meters in wet gas flows tend to have a positive bias or *over-reading* on their gas flow rate prediction. The uncorrected gas mass flow rate prediction is often called the *apparent* gas mass flow, $m_{g,apparent}$. The over-reading is the ratio of the apparent to actual gas flow rate. Equations (9) and (10) show the over-reading and percentage over-reading (where ΔP_{tp} and ΔP_g are the actual two-phase differential pressure and the differential pressure if the gas flowed alone respectively.)

$$OR = \frac{m_{g,apparent}}{m_g} \cong \sqrt{\frac{\Delta P_{tp}}{\Delta P_g}} \quad \text{--(9)} \qquad OR\ (\%) = \left(\frac{m_{g,apparent}}{m_g} - 1\right) * 100\% \cong \left(\sqrt{\frac{\Delta P_{tp}}{\Delta P_g}} - 1\right) * 100\% \quad \text{--(10)}$$

Wet Gas Flow Patterns

The way that a liquid phase is dispersed in a gas pipe flow is called the "flow pattern". Figures 1 and 2 show well known sketches of typical wet gas flow patterns in horizontal and vertical up flow pipes. Vertical down flow patterns, where gravity and flow do not appose each other, are usually considered to be mist flows although little research is published on the matter. Information on inclined pipe flow patterns is very rare in the literature.

The majority of the wet gas flow pattern map literature is for horizontal flow and vertical up flow. Even here, there is not a great deal of literature available. The different flow patterns for any pipe orientation correspond to different flow conditions (e.g. gas and liquid flow rates, pressures, pipe diameter, liquid properties etc.) The flow pattern entering any wet gas metering device has a significant effect on the performance of most wet gas meters. Usually, the wet gas meter correlations in flow computer software are designed to account for these effects so,

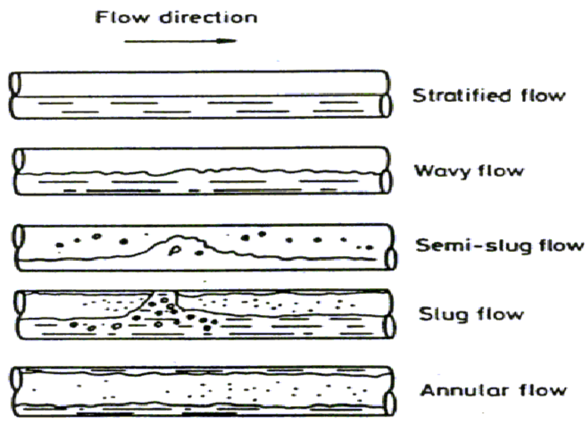


Fig 1. Horizontal Wet Gas Flow Pattern Maps.

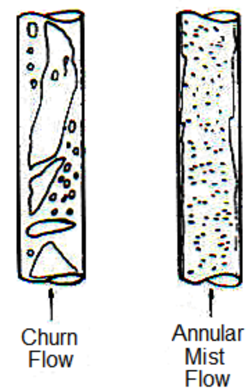


Fig 2. Vertical Up Wet Gas Flow Pattern Maps.

although flow patterns are important in wet gas metering, a meter end user should not have to be directly concerned about them. The exceptions are when the flow conditions are out with the conditions of the data set that was used to create the correlations in the software and when wet gas conditions in the pipe are extremely adverse. If the conditions are out with the data set range that created the correlations in use then the correlation is being extrapolated by the software calculation and the uncertainty statement of the manufacturer can no longer be considered valid. If the wet gas flow conditions are adverse the meter could suffer damage. An example of this is low lying pipe work collecting liquid from a wet gas flow until such time as it has built up into a significant blockage. The gas being blocked will build up pressure and then push the liquid forward in a column called a "slug". This phenomenon is called "severe slugging" and is particularly common on start up of production flows. These slugs can travel at high velocity and damage meters on impact. An example is buckled orifice plates.

The Limitations of Using Separators

Theoretically, separators are an ideal way to meter wet natural gas flows. They split multiphase or wet gas flows into single phase flows and therefore allow single phase low uncertainty metering techniques to be utilized. Unfortunately, in practice there are several problems with the use of separators. They are large, heavy and expensive to manufacture and install (especially offshore). They can be expensive to maintain. It is difficult to know if they are 100% efficient (i.e. the exit flows have no other phase entrained with them) especially if the flow conditions change from the original design specifications of the system. Figure 3a shows how a separator is meant to work with a wet gas flow. Three clean single phase flows of natural gas, water and hydrocarbon liquid (or "oil") can be seen in the outlet pipes. Figure 3b shows what often happens in reality. The separator is not 100% efficient and the outlets do not have single phase flows.

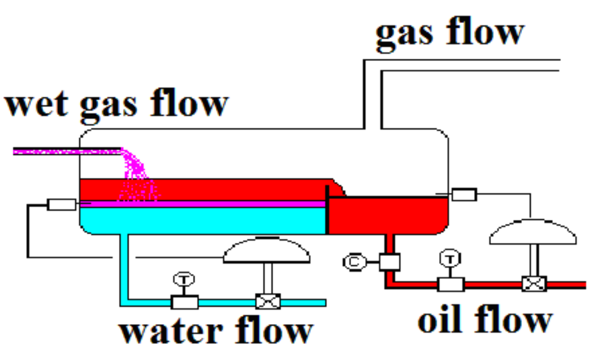


Fig 3a. Ideal Separator Vessel Operation.

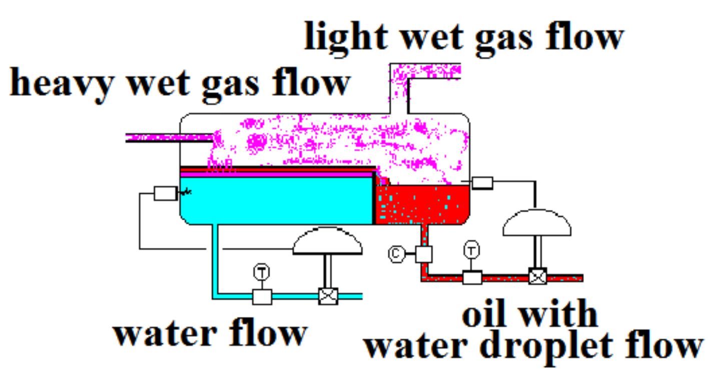


Fig 3b. Many Real Separator Vessel Operations.

Furthermore, there can be practical issues with the single phase measurement. Take the gas outlet for example. Even if the gas flow is dry it is common for separators to be located in areas of limited space. Often the single phase meters are installed with shorter upstream pipe runs than the standards say are required. Often the separator is in a remote location and the single phase meters are in an awkward location for maintenance. Is the meter maintained? For example, if it is an orifice plate, when was the last time the plate was checked for damage and if it was checked was it re-installed correctly? Has the flow rate changed since the last maintenance meaning the beta ratio and the DP transmitter are incorrectly sized? Does the DP transmitter have a lapsed calibration certificate?

In general terms it would be expected that the best measurement uncertainty that could be expected on the gas leg of a separator would be in the region of ± 2% to ±3%. However, it is more likely to be the case that an average uncertainty might be in the region of ± 3% to ±6% with uncertainty contributions from the some of the above sources. In extreme cases where most or all of the above sources contribute to uncertainties it has been suggested by some industry sources that it is possible to encounter uncertainties up to ±15%. For these reasons, as well as for the cost of separators, industry is trying to move away from separator technology and meter wet gas (and multiphase flows) directly.

Single Phase Gas Meter Reaction to Wet Gas Flows

The initial research into wet gas flow metering was the investigation into the reaction to wet gas flow of DP meters. However, since the 1990's most common gas meters have been tested to ascertain their wet gas performance. By coincidence it has been found that DP meters have by far the most stable and repeatable wet gas performance. The other traditional gas meter designs have varying performances and limited use with wet gas flows. Taking a look at these designs in turn:

Differential Pressure Meters

The various DP meter designs all have the same general wet gas meter trends. These trends were discovered over many years of research, by different researchers working with many different DP meters. However, regardless of what DP meter design was tested to first find the phenomenon, it is most straight forward here to state the known response of the generic DP meter and then show the different wet gas correlations in the next section. These correlations indicate the different size of the liquid induced gas flow rate prediction errors between DP meter designs.

In 1962 Murdock [2] effectively showed that as the Lockhart Martinelli parameter increases the positive bias, or "over-reading" (see equations 9 and 10), of a DP meter increases. In 1967 Chisholm [3] showed that while Murdock's statement was generally true the size of the over-reading was also dependent on the gas to liquid density ratio, as sketched in Figure 4. As the gas to liquid density increased for all other parameter held constant the over-reading reduced. In 1997 de Leeuw [4] furthered Chisholm's work when he found that the over-reading was not just dependent on the Lockhart Martinelli parameter and gas to liquid density ratio but also the gas densiometric Froude number (see equation 5). As the gas densiometric Froude number increased for all other parameter held constant the over-reading increased.

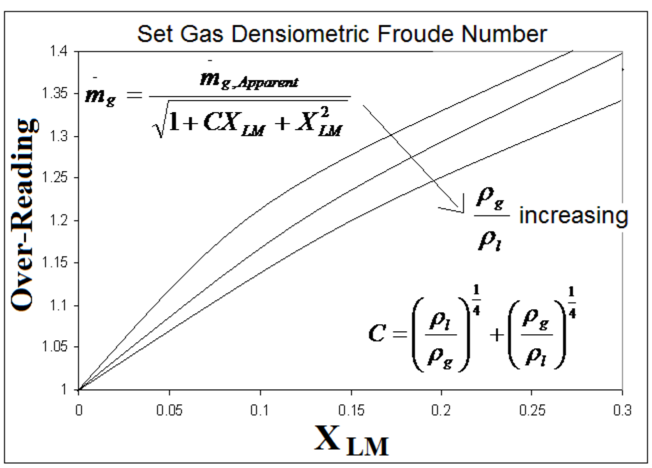


Fig 4. DP Meter OR relationship with X_{LM} and DR.

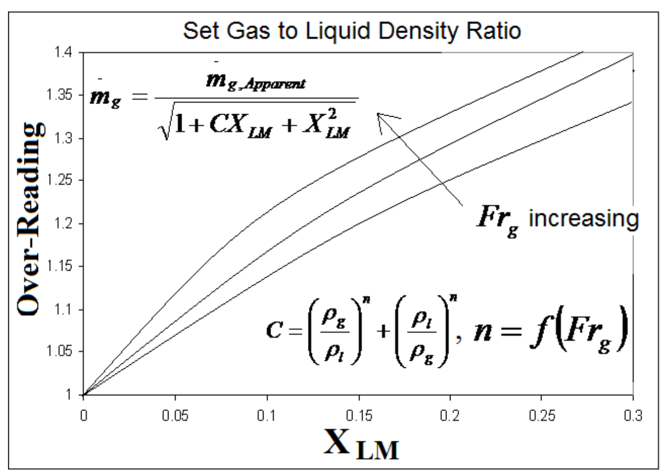


Fig 5. DP Meter OR relationship with X_{LM} and Frg.

Stewart et al [5,6] showed that the over-reading of DP meters are dependent on the beta ratio. Reader-Harris [7] showed that the over-reading of DP meters is insensitive to gas properties but sensitive to liquid properties. Steven [8] offered a theory which accounted for all these phenomena through flow pattern considerations. Steven [9] also discussed the strong possibility that there is a diameter effect on the wet gas response of DP meters.

DP meters are significantly affected by the presence of liquid in the gas flow. However, repeated experiments have shown that the positive bias is repeatable and therefore correctible. Various correlations exist for dedicated

DP meter types with set geometries (i.e. diameter and beta ratio) that are all of the form shown as equation 11. It is suspected that a truly universal DP meter wet gas correlation for a dedicated DP meter type would have to also take account of meter diameter, beta ratio and liquid properties. As this is too complicated to be practical, the current research aim seems to be to create a correlation for set meter geometries but have the Lockhart Martinelli parameter, the gas to liquid density ratio, the gas densiometric Froude number and the liquid properties as variables. That is, the variables are the factors not controlled in meter design and choice but by the applications flow conditions. Currently no such universal correlation has been created for any DP meter.

$$OR = \dot{m}_{Apparent} \Big/ \dot{m}_g = f\left(X_{LM}, \rho_g / \rho_l, Fr_g\right) \quad \text{-- (11)}$$

The latest DP meter wet gas correlations are modifications of the early Chisholm [3] orifice plate meter correlation. Chisholm's equation set was equations 12 and 13, where Chisholm stated n=1/4.

$$\dot{m}_g = \frac{\dot{m}_{g,apparent}}{\sqrt{1 + CX_{LM} + X_{LM}^2}} \quad \text{-- (12)} \qquad \text{where} \qquad C = \left(\frac{\rho_g}{\rho_\ell}\right)^n + \left(\frac{\rho_\ell}{\rho_g}\right)^n \quad \text{-- (13)}$$

The latest orifice plate meter wet gas correlation [10] uses equation set 12 and 13 in combination with equation set 14 and 15:

for $Fr_g \leq 1.5$: $$n = 0.214 \quad \text{-- (14)}$$

and for $Fr_g > 1.5$: $$n = \left\{\left(\frac{1}{\sqrt{2}}\right) - \left(\frac{0.3}{\sqrt{Fr_g}}\right)\right\}^2 \quad \text{--- (15)}$$

This data set is for 2" through 4" orifice plate meters with beta ratios 0.2433 to 0.7298, pressures below 80 bara (1160 psia). Most data was for gas and hydrocarbon liquid. Limited data sets had air and hydrocarbon liquid and natural gas with water and hydrocarbon liquid. The equation is said to have corrected all gas flow rate predictions for a known liquid mass flow rate to ±2% (to 95% confidence).

The latest Venturi meter wet gas correlation [4] uses equation set 12 and 13 in combination with equation set 16 and 17:

for $0.5 \leq Fr_g < 1.5$: $$n = 0.41 \quad \text{-- (16)}$$

and for $Fr_g > 1.5$: $$n = 0.606\left(1 - \exp\left(-0.746 Fr_g\right)\right) \quad \text{-- (17)}$$

This data set is for a 4", 0.4 beta ratio Venturi meter with gas and hydrocarbon liquid only. The data has pressure up to 100 bara (1450 psia). The equation is said to have corrected all gas flow rate predictions for a known liquid mass flow rate to ±2% with a few outliers. No confidence level was stated.

The latest cone DP meter wet gas correlation [10] uses equation set 12 and 13 in combination with equation set 18 and 19:

for $Frg \leq 0.5$: $$n = 0.19 \quad \text{--- (20)}$$

for $Frg > 0.5$: $$n = \frac{1}{2}\left(1 - \left(\frac{0.83}{1.14 * \exp\left(0.31 * Fr_g\right)}\right)\right) \quad \text{--- (21)}$$

This data set is for 4" through 6" cone DP meters with a beta ratio of 0.75, pressures below 75 bara (1087 psia). All data was for gas and hydrocarbon liquid. The equation is said to have corrected all gas flow rate predictions for a known liquid mass flow rate to ±2.5% (to 95% confidence).

Note that all equations require that the liquid mass flow rate be found by an external source and then all the parameters in the equation sets can be reduced to known parameters and the unknown gas flow rate. The gas flow rate can then be found by iteration. A good starting point for the iteration is the apparent gas mass flow rate.

(Note that it is assumed that the gas and liquid densities are known from sampling and PVT calculations. Wet gas sampling is an extremely difficult procedure and the issues involved in this process are out with the scope of this paper.) The *Achilles heel* with regards to all DP meter designs with wet gas correlations of the form of equation 11 is clearly that in order the calculate the gas flow rate the liquid flow rate needs to be initially known. In natural gas production flows this information is not usually known. Furthermore, it is not a simple task to meter it from any independent source. Methods on how this issue can be over come will be discussed later.

Turbine Meters

While excellent gas meters it is generally accepted that turbine meters are not gas meter designs that can be exposed to wet natural gas flows. The blades of a turbine meter are susceptible to damage from impact with the liquid phase. Furthermore, wet natural gas production flows are not usually clean and the particulate in the flow can wear the meters bearings. Limited testing has been reported by Ting [11] and Stewart [12]. All tests were for very low liquid loadings. Ting concluded that "… a Turbine meter should not be used in continuous unprocessed (i.e. wet) gas operations".

Coriolis Meters

Originally known for being an excellent liquid meter the Coriolis type has become an accepted gas meter. However, it is generally accepted that the standard gas Coriolis meter has a very poor response to wet gas flow. After extremely small quantities of liquid loading the gas meter prediction is reported by both Stewart [12] and Britton et al. [13] to become extremely erratic and not repeatable. There are research projects that are developing the use of the Coriolis meters diagnostics to allow the meter to be useable with wet gas flows. Also note that Coriolis meters have been used in series with orifice plate meters to produce a wet gas meter system but these systems are understood to be prototypes and out with the scope of this paper.

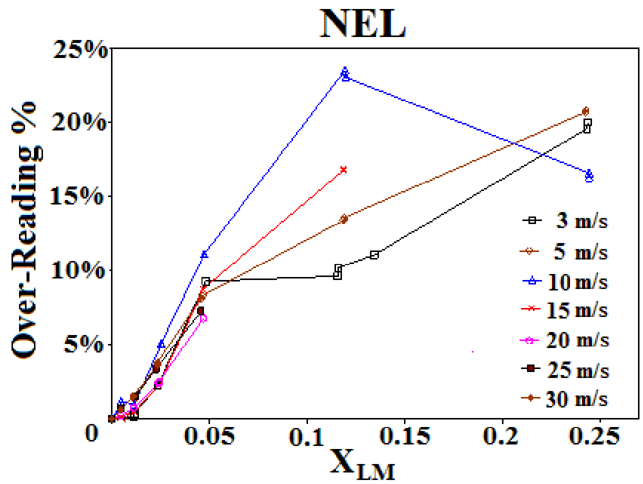
Ultrasonic Meters

While excellent gas meters it is generally accepted that standard Ultrasonic meters are not gas meter designs that should be exposed to wet natural gas flows. Substantial research was conducted in the late 1990's into the early 2000's on the possibility of turning a standard Ultrasonic meter into a wet gas meter by utilizing the meters potentially diverse diagnostic capabilities. Without any corrective software the ultrasonic meter gave large random unrepeatable gas flow rate errors from low liquid loadings. However, for the particular flow patterns of stratified flow in horizontally mounted meters and mist flow in any meter orientation some success was achieved in developing the meter into a wet gas meter (see Zanker et al. [14,15]). Unfortunately, in real flow applications meter users can not usually guarantee a particular flow pattern and many real natural gas production flows are in transition between stratified and mist flow patterns. The author knows of no further stand alone ultrasonic meter wet gas flow developments in the public domain.

Vortex Meters

Vortex meters are known as sturdy gas meters with an exceptionally high turn down (i.e. flow range). They have periodically been tested with wet gas flow with mixed results.

Washington et al [16,17], Stewart [18], CEESI [19] and Hall et al [20] have all released research into the performance of vortex meters with wet gas flows. Unfortunately, the research does not all agree. Washington did not state the vortex meter design or the orientation of the bluff body. Stewart, CEESI and Hall stated the tests were for horizontal pipe work. Stewart tested with the bluff body installed vertically (i.e. perpendicular to the ground) while CEESI & Hall tested with the bluff body horizontally installed (i.e. parallel to the ground). Different designs were tested by CEESI and results were similar. There is a general agreement amongst the different researchers that liquid presence with the gas adversely affects the vortex meter. The liquid induced error is positive, i.e. an "over-reading". However, the research disagrees in two aspects. The magnitude of the over-reading reported by Stewart was reported to be quite different than that reported by Washington. Stewart reported that testing at TUVNEL showed the over-reading having a linear relationship with the Lockhart Martinelli parameter up to some critical value (dependant on pressure) above which the over-reading was erratic and unrepeatable. Figure 6 shows an example from Stewart [18] for tests at 30 barg / 450 psia. CEESI and Hall reported that testing at CEESI showed the over-reading having a near linear relationship with the Lockhart Martinelli parameter across the tested range ($X_{LM} \leq 0.13$) for all pressures tested (200 psia to 1100 psia). Figure 7 shows a sample of CEESI vortex meter wet gas data. It is not at all typical for the CEESI and TUVNEL wet gas test facilities to not agree. All other meter designs tested in both facilities have given the same response. Therefore, it is likely that the bluff body orientation causes these significant differences in the vortex meters wet gas flow performance.



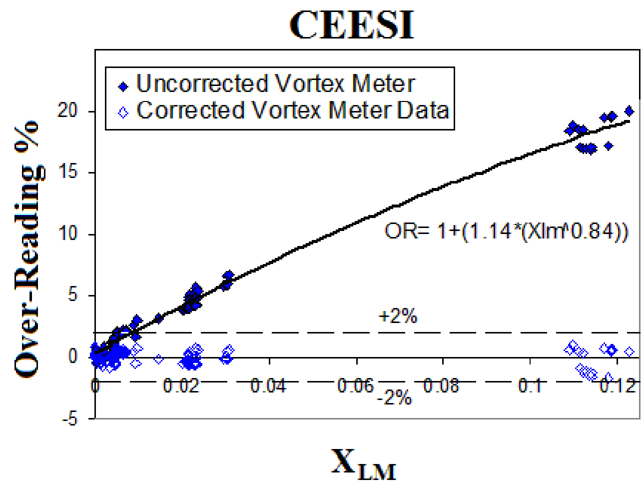


Fig 7. N_2 / Kerosene, 4" Vortex Data at 30 Barg. Fig 8. NG / Kerosene, 4" Vortex Data multiple pressures.

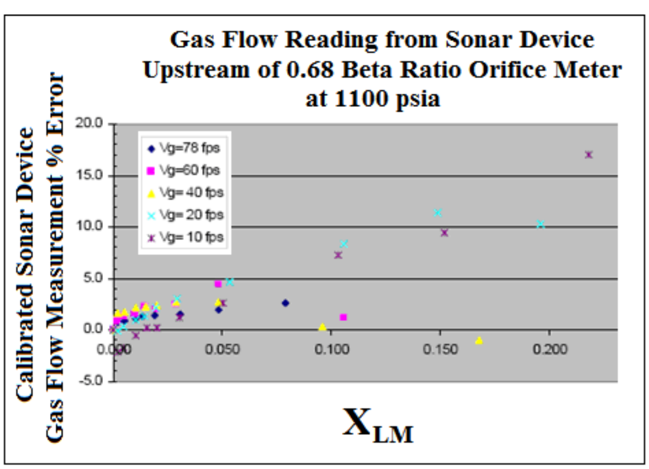
Note that in Figure 7 a data fit is shown for the CEESI tests. That is a vortex meter wet gas correlation. However, unlike DP meters who's over-readings are extremely repeatable and reproducible this is not the case with the vortex meter. It would not therefore be advisable to use any wet gas vortex meter correlation currently listed in the literature. These correlations are for that meter only. Whereas there is some promise that vortex meters could be developed for use with wet gas flows at the time of writing the metering community simply does not know enough about the vortex meter wet gas response to have any confidence in this issue.

Passive Sonar Sensors

Passive sonar technology has been proven to be an acceptable industrial gas meter. The clamp on device (which consists of an array of sensors outside the pipe) gives a low uncertainty gas flow rate prediction (after in situ calibration).

Like all gas meters the sonar device is adversely affected by the presence of liquid with a gas flow. However, it has been found that the liquid induced error is significantly smaller for any given wet gas flow condition than for DP meters. Figure 9 shows a sample of data presented by Ting et al [21]. However, from other graphs shown by Ting et al there does appear to be a very significant velocity effect as well as a significant effect due to the location of the sonar device to various pipe components. This is not necessarily a problem as the velocity issue could be accounted for in a wet gas correlation for a dedicated installation set up. As yet the author knows of no sonar device wet gas correlation so the uncertainty of any stand alone sonar device with wet gas flow can not be stated here. The sonar device is a patented technology and it is therefore assumed that the manufacturers can give uncertainty esti

mates if requested. Figure 10 shows how the sonar device is said to relate to the commonly used DP meters with the correlation uncertainties shown.



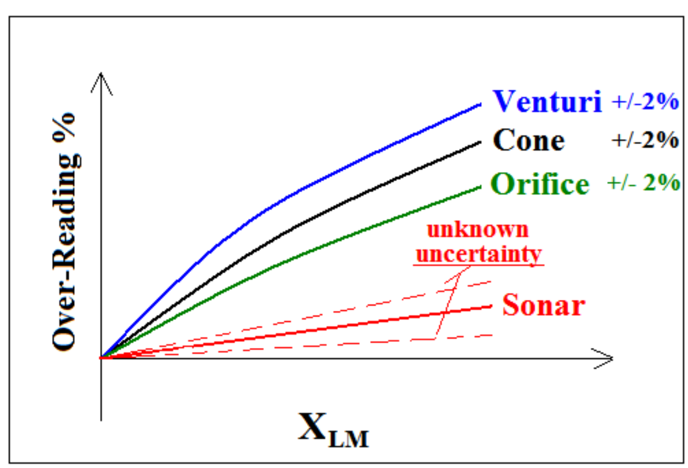


Fig 9. Sample Sonar Device Data. Fig 10. DP and Sonar Meter Wet Gas Responses.

Figure 10 shows a sketch comparing four different meter responses to wet gas flow. This is not simply to compare which meter is best for an application. Two dissimilar gas meters with different wet gas responses in series with each other has been an established wet gas meter system design for many years. The various wet gas meter system concepts on the market will now be discussed.

Wet Gas Flow Metering Concepts

Of the marketed wet gas meters there are four recurring themes that encompass virtually all the available designs. These are:

1. Using single phase gas meter wet gas correlations by obtaining the liquid flow rate from an external source.

2. Reading the permanent pressure loss as well as the traditional DP taken on a DP meter.

3. The use of two (or multiple) gas meters in series.

4. Using a DP meter with imbedded phase fraction devices.

An overview of the generic concepts is now discussed.

Liquid Flow Rate Estimations and Wet Gas Correlations

There are two methods commonly used for estimating liquid flow rates in a wet gas flow. These are test separator historical data and tracer dilution methods.

For wet natural gas production flows many pipelines periodically have well maintained test separators attached to check the flow rates. If it can be reasonably assumed for that production site that the flow rate is relatively constant over a period of time it can be assumed that the liquid flow rate has not changed significantly between separator tests. Hence the last test separator liquid flow rate reading is used in wet gas correlations.

During the 1990's Shell developed a tracer dilution method. This consisted of injecting an inert dye of a known florescent intensity at a known precise injection rate. Florescent dyes have been developed that will only be absorbed by one liquid component and no other component in the wet gas flow. Therefore, separate estimations of the water and oil flow rates can be made. After injection a mixing distance is required to allow full mixing of the tracer and the produced liquids. Samples of each liquid component are then drawn and analysed. The magnitude of the tracer injection is extremely small compared to the liquid flow rates and hence it does not have any significant effect on the production flows properties. As long as the tracer liquids are fully mixed with the production liquids the flow rate equation for each liquid component is given by equation 22. Note that $\dot{m}_{liquid}$ is the produced liquid mass flow rate, $\dot{m}_{tracer}$ is the tracer liquid mass flow rate, K_o is the florescent value of the tracer liquid and K_s is the florescent value of the sample.

$$\dot{m}_{liquid} = \frac{K_o}{K_s} . \dot{m}_{tracer} \quad \text{--- (22)}$$

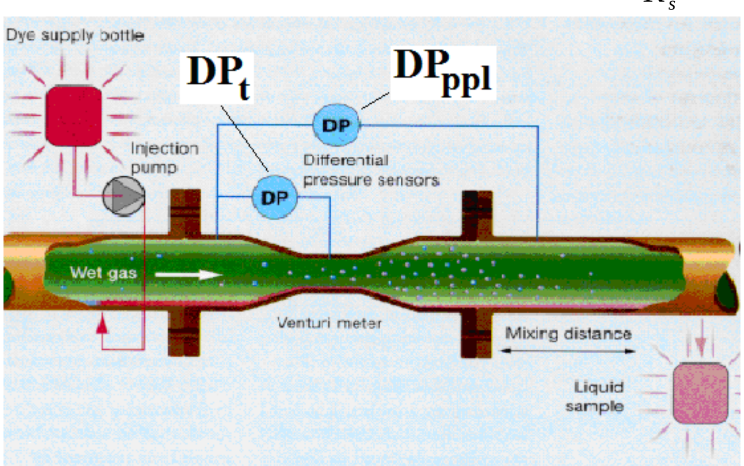


Fig 11. Sketch of Tracer System with Venturi [11].

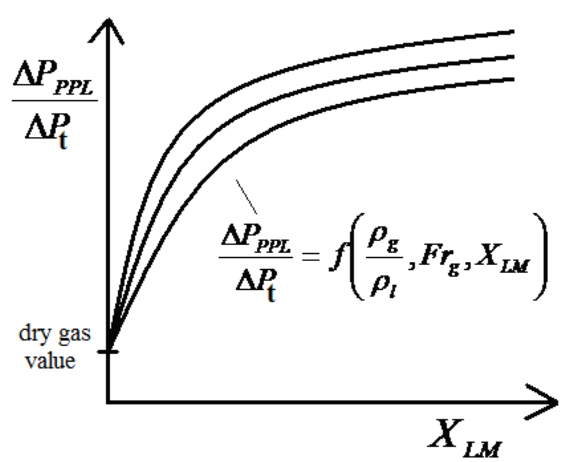


Fig 12. Sketch of the PLR vs. X_{LM} relationship.

Figure 11 shows a sketch of such a system by de Leeuw [4]. The mixing distance is compressed here to show the principle in one clear sketch. Nilsson [22] and Van Maanen [23] give a detailed overview of this technology in terms of practical application.

The main limitation of tracer dilution techniques is the same as with test separators. That is, these are spot checks and not continuous. The liquid mass flow rate can be applied to single phase gas meter wet gas correlations and estimates of the gas and liquid flow rates will be achieved. However, if the liquid flow rate changes between these spot checks such a metering system will not respond to this. Furthermore, the uncertainty in the liquid mass flow rate input to a wet gas correlation will have a knock on effect on the systems gas flow rate prediction. This is discussed in some detail by Steven [24].

<u>Differential Pressure Meters with Downstream Pressure Ports</u>

De Leeuw [4] not only discussed tracer dilution technology but also a proposed alternative method for metering the gas and liquid flow rates of a wet gas flow by using a stand alone Venturi meter. The method used both the permanent pressure loss and the traditional DP readings (as shown in Figure 11). De Leeuw showed that for his 4", 0.4 beta ratio Venturi meter wet gas data set the ratio of the permanent pressure loss and the traditional DP (which he called the "pressure loss ratio" or "PLR" and is constant for single phase gas flows) was related to the Lockhart Martinelli parameter (as sketched in Figure 12). It was therefore proposed that this could potentially allow a Lockhart Martinelli parameter prediction without prior knowledge of the liquid mass flow rate. Hence, gas meter wet gas correlations of the form shown as equation 11 would only have the gas flow rate as the unknown and would therefore be solvable.

De Leeuw [4] suggested the concept but the paper did not develop the idea into a wet gas meter. This has since been done by meter manufacturers. The concept is however generic to all DP meters. A CEESI wet gas Joint Industry Project (JIP) therefore tested the concept with various DP meter designs with some success. This research project is discussed by Steven [25, 26] in some detail. Figures 12 & 13 show sample findings for a classical 4", 0.4 beta ratio Venturi meter tested for this JIP research. Figure 12 shows the PLR vs. Lockhart Martinelli parameter and Figure 13 shows the uncorrected over-reading and the correction based on data fitting to de Leeuw's methodology.

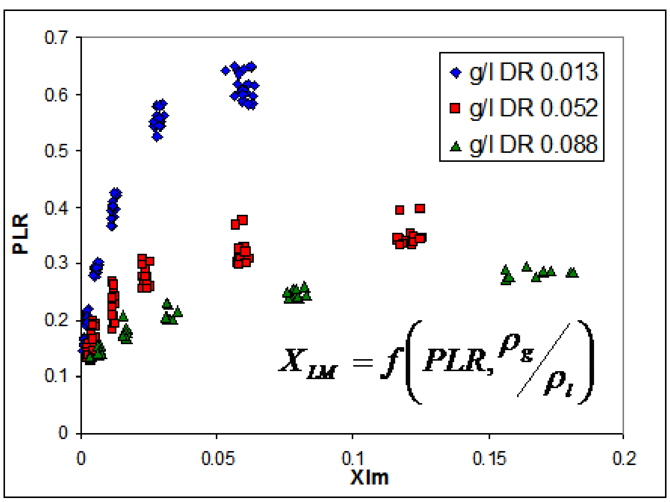


Fig 13. 4", 0.4 Beta Venturi Meter PLR vs. X_{LM} Data.

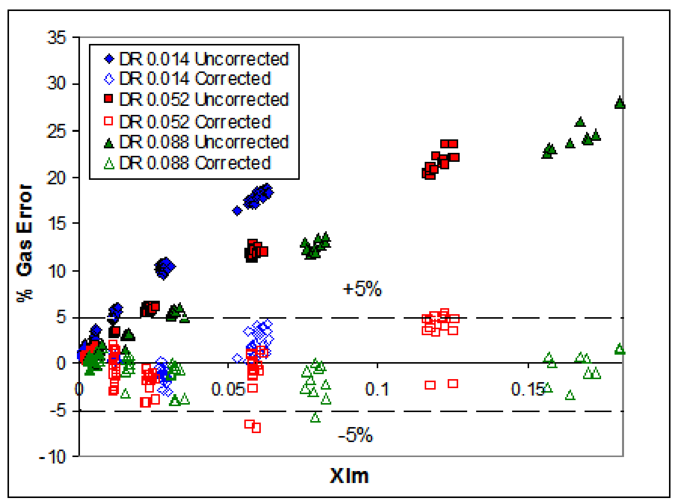


Fig 14. 4", 0.4 Beta Venturi Meter Gas Flow Data.

The results of the CEESI JIP showed that the methodology did work as a basic and inexpensive wet gas meter. However, where as the gas flow could be predicted to ±5% the liquid flow rate prediction was not at all accurate. It was also noted that the PLR vs. X_{LM} relationship, which the method relies upon was very sensitive at low Lockhart Martinelli parameters and insensitive at high Lockhart Martinelli parameters. The method also had a strong pressure and gas flow rate effect. The lower the gas dynamic pressure the more accurate the method is.

<u>Two Meter in Series</u>

The most popular design of wet gas meter systems is the single phase gas meters in series method. The principle is simple although the correlations and calculations in practice can be complicated. The general principle is to place to gas meters in series. These meters would give the same gas flow reading in dry gas (within their gas flow rate uncertainty limits). This is the gas flow base line. The meters are chosen to be paired as they have different responses to the wet gas flow. It was stated earlier that for any DP meter the wet gas over-reading “OR” can be expressed as some function “f”:

$$OR_1 = \left(\dot{m}_{Apparent}\right)_1 \Big/ \dot{m}_g = f\left(X_{LM}, \rho_g/\rho_l, Fr_g\right) \quad \text{-- (11)}$$

This function ‘f’ is not defined here as it depends on the response of that particular meter. In fact equation 11 is not DP meter specific and all gas meters with predictable liquid induced gas prediction errors can have such a function ‘f’ created from data fitting. If we place another different meter design in series that also has a predictable liquid induced gas prediction error then it too can have some over-reading function created from data fitting. But, crucially, as this second meter is chosen for having a different wet gas response to the first meter the function is different, say function ‘g’:

$$OR_2 = \left(\dot{m}_{Apparent}\right)_2 \Big/ \dot{m}_g = g\left(X_{LM}, \rho_g/\rho_l, Fr_g\right) \quad \text{-- (23)}$$

Now, if we assume no significant phase change between the meters, we have two equations and two unknowns, i.e. the gas and liquid mass flow rates. (An examination of equations 1,5,6,11 & 23) will show this to be the case. We can therefore solve for both unknowns. This is graphically shown in Figures 15 & 16.

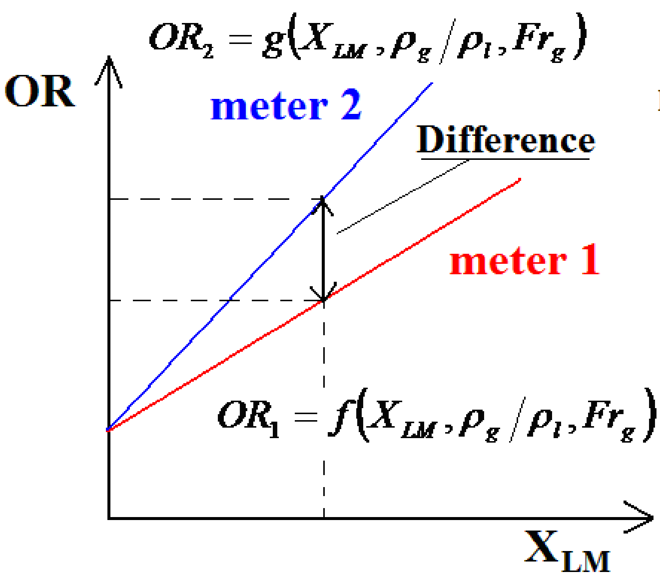


Fig 15. Two Dissimilar Gas Meters in Series, OR vs. X_{LM}

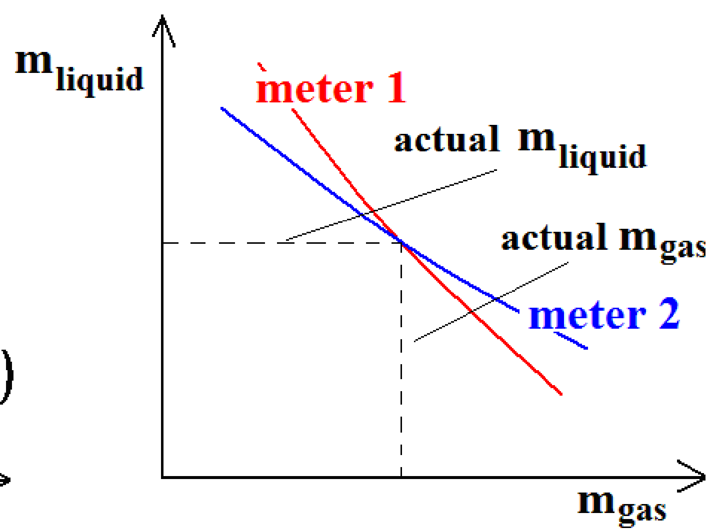


Fig 16. Two Dissimilar Gas Meters in Series, m_l vs. m_g

In reality there are several ways to approach solving these equations. Different methods have different uncertainties.

Wet gas meters that operate on the principles based on two meters in series include the Dualstream II (which consists of a Venturi and wedge type DP meters in series), the Weatherford wet gas meter (which consists of a Venturi with a sonar device imbedded in the Venturi meters throat), the Cidra wet gas metering solution (which consists of a clamp on sonar device in series with a gas DP meter), the Foxboro wet gas meter (which consists of a Coriolis meter in series with an orifice plate meter) and the Texas A&M dual slotted orifice plate wet gas meter.

<u>Multiphase meters</u>

There are a few multiphase meter designs (i.e. meters that were principally designed and developed for GVF < 80% applications) that are now stated to be capable of metering wet gas flows under certain conditions. These meters are the high end of the market and are typically aimed at off-shore subsea applications where the conditions have high pressures and high flow rates.

The manufacturers do not divulge the full technical detail of how these proprietary devices operate and as such they are widely seen as black box technologies. This is a specialist area of wet gas metering and due to lack of space these metering technologies will not be discussed here. Furthermore, at ISHM there is a separate class on multiphase flow meters and this should include operation of multiphase flow meters in the wet gas flow range.

Conclusions

Wet gas flow metering technologies have advanced considerably in the last decade. Until relatively recently there was little to no wet gas meter product choice available for a field engineer. However, while wet gas metering technology is still very much in its infancy and research and technical advances are still continuing at a considerable pace, there is now in the last few years, beginning to be a selection of technologies available on the market.

Like all products these wet gas meters all have there advantages and disadvantages when compared to each other and it is for the end user to make a judgment call on which technology suits his particular application best. However, due to the recent appearance of many of these technologies there is a considerable level of ignorance amongst the majority of the industries well trained and experienced engineers. This can make well informed decision making with regards to wet gas metering difficult. In modern business it is all too often the case that personnel find it difficult to find time for training and keeping up with the latest developments. However, most of the wet gas meter products currently on the market actually operate according to the same few basic principles and in fact in a relatively short time an engineer or technician can be trained or self educated in these principles.

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