Improved Measurement Accuracy of Net Oil Rate Using SONAR-Based Gas Volume Fraction Meter

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ABSTRACT

Accurate measurement of net oil rate from individual wells is a critical component in effective oil field management influencing production optimization strategies and financial allocation issues. Most net oil measurement approaches involve some type of gas/liquid separation, with the accuracy of the measurement dependent on the effectiveness of this separation.

In two phase, gas/liquid separator-based net oil measurement approaches, the presence of small, but unknown and variable, level of gas carry-under in the liquid leg of the separator can result in significant over-reporting of net oil. Due in part to demanding design constraints on separators for reduced foot prints, lower residence times, and higher turn-down ratio, it is not uncommon for gas carry-under to reach levels such that it is responsible for the majority of net oil measurement error in some applications.

An approach is presented which enables accurate net oil measurement of oil/water mixtures with entrained gases. The approach employs a SONAR-based gas volume fraction measurement installed on the liquid leg of a gas/liquid separator. The real-time, entrained gas measurement is then used in conjunction with the measured density of the aerated oil/water mixture to provide an accurate measure of the oil fraction, independent of the level of gas carry-under. Although this paper focuses on density-based net oil measurements, similar improvements can be obtained in microwave-based net oil measurement approaches as well.

Laboratory results are presented which demonstrate the ability of the combination U-tube coriolis meter and a SONAR-based gas volume fraction meter to accurately report the density of the liquid phase of gas/liquid mixture with varying levels of gas volume fraction.

Data from a field trial of this approach on a producing oil well is also presented. The data show the presence of small, but varying, levels of entrained gases in the liquid leg of a Gas Liquid Cylindrical Cyclone separator in the range of 0% to 5% by volume, which, if not appropriately considered in the net oil measurement, would result in ~100% over reporting of net oil over a 9-1/2 hour well test.

Introduction

Oil wells produce widely varying amounts of oil, water and gas and exhibit a wide range of multiphase flow patterns. As a result, economical, accurate, real-time measurement of individual well production has remained a long-standing challenge for the industry. Current methods typically involve some form of separation of the produced fluid prior to measurement. Historically, producers have relied on three phase separators to divide the production streams into single-phase oil, water and gas stream for measurement using conventional, single-phase flow meters. Although generally effective, three phase separators have several properties including size, cost and limited turndown ratios that have driven the industry to seek alternative solutions. Recently, the maturing of online watercut and gas/liquid separation technology has enabled the industry to consider compact approaches based on two-phase separation. In these systems, the produced stream is separated into a gas and a liquid stream for measurement. Net oil is determined by measuring the liquid rate and watercut of the liquid leg.

Although the accuracy of all separation-based measurement approaches is, to some degree, dependent on separator effectiveness, the accuracy of a net oil measurement from two-phase separation approach can be particularly sensitive to the presence of a small, but unknown, amount of gas in the liquid leg due to its effect on the determination of the watercut of the liquid. From a volumetric flow perspective, the presence of entrained gases in the liquid stream will typically result in an over reporting of the volumetric flow of the liquid that is proportional to the amount of entrained (free) gas in the mixture. However, for most watercut devices, a small amount of gas can result in a significant over reporting of oil content, and, in turn, a significant over reporting of net oil production. The sensitivity of the net oil measurement to gas carry-under is a function of the type of watercut monitoring device, as well as the properties of the produced fluids. This paper specifically addresses density-based water cut measurement.

For a density-based water cut determination, the presence of entrained gas in an oil / water mixture serves to decreases mixture density; similar to a decrease in mixture density associated with a decrease of watercut in a liquid-only mixture. Therefore, without appropriately considering that presence of the gas, the water cut is under-reported and net oil rate overstated. Similar inaccuracies will exist in all methods of microwave and nuclear density water cut measurement as well. However, if, the amount of gas in the liquid stream is accurately determined, the liquid density can be calculated from the measured mixture density, resulting in an accurate determination of water cut. Similar calculations can be made with microwave-based measurements as well.

SONAR-based gas volume fraction meters provide an independent and accurate measurement of gas volume fraction in a flowing liquid stream. Thus, the combination of coriolis-based or microwave-based compositional measurements with SONAR-based gas volume fraction meters provides the means to accurately measure the water cut in liquid streams, independent of gas carry-under.

Background

The coriolis meter is widely used for net oil measurement and fundamentally measures two quantities: the mass flow rate and the density. The net oil rate is determined by first calculating the gross volumetric rate from the measured mass flow rate and density:

$$Q = \frac{\dot{m}}{\rho} \quad (1)$$

Where m = measured mass flow rate
ρ = measured density

The oil volume fraction is calculated using the measured density with knowledge of the pure phase water and oil densities giving the net oil as:

$$Q_{NO} = Q \cdot \phi_O \quad (2)$$

Where Q_{NO} = net oil volumetric flow rate
ϕ_O = oil volume fraction

This methodology is accurate only if there is no gas phase present in the liquid stream flowing through the coriolis meter. A closer analysis shows that in the presence of gas in the liquid stream the oil fraction result will be significantly over-stated if the gas content is not accounted for.

The density of any N-component mixture equals the sum of the individual component densities times the volumetric fraction:

$$\rho = \sum_{i=1}^{N} \phi_i \rho_i \text{ with the constraint } \sum_{i=1}^{N} \phi_i = 1 \quad (3)$$

Where ρ = mixture density
ϕ_i = component volume fraction
ρ_i = component density

For oil, water and gas mixtures the density equation (3) is equal to:

$$\rho = \phi_O \rho_O + \phi_W \rho_W + \phi_G \rho_G \text{ with the constraint}$$
$$\phi_O + \phi_W + \phi_G = 1 \quad (4)$$

Where O, W and G subscripts refer to oil, water and gas, respectively.

Combining, assuming $\phi_G\rho_G$ is small and solving for the volume fraction of the oil yields:

$$\phi_O = \frac{\rho - \rho_W (1 - \phi_G)}{\rho_O - \rho_W} \quad (5)$$

Again starting with equation (3) but this time assuming the mixture contains only oil and water the oil fraction (ϕ') is calculated as:

$$\phi_O' = \frac{\rho - \rho_W}{\rho_O - \rho_W} \quad (6)$$

Note that these equations differ only by the 1-ϕ_G term. Figure 1 shows the error in the oil volume fraction (and thus net oil rate) if this term is ignored when free gas is indeed present. It is noted that the errors in the net oil measurement are significant and will result in a gross overstatement of the net oil rate. For example with only 1% gas volume fraction the error in the oil fraction is between 30 and >100% depending on the oil gravity.

This error is removed if the free gas is known and accounted for when calculating the oil fraction. The remaining sections describe a SONAR-based method of measuring the free gas and present some experimental and field data demonstrating the measurement concept.

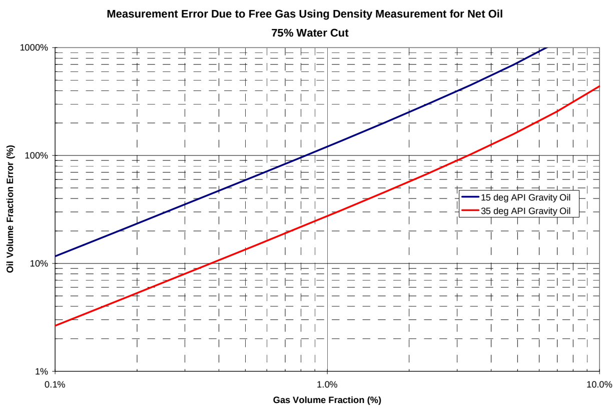

FIG. 1

Speed of Sound Measurement

A SONAR-based entrained air measurement system consists of an array of strain-based sensors clamped to the outside of standard process piping. The array output is interpreted using array-processing algorithms to determine the speed at which naturally occurring, one-dimensional acoustic waves propagate through the process fluid. The measured sound speed is then used, in conjunction with knowledge of the liquid density and line pressure, to determine entrained gas content of the process fluid. The relationship between mixture sound speed and entrained gas in bubbly liquids is well established. These relationships, however, are typically only applicable for the propagation of relatively low frequency, long wavelength sound. While this restriction does not present any significant obstacles for the sonar meter, it does present significant challenges to ultrasonic sound speed measurement devices. SONAR-based flow meters use an approach developed and commercialized specifically for multiphase flow measurement in the oil and gas industry [1] in which multiphase challenges associated with bubbly flows described above are routinely encountered. SONAR-based meters measure the propagation velocity of operationally generated sound in the low, audible frequency range. In this frequency range, sound typically propagates as a one-dimensional wave, using the process pipe as a waveguide. The wavelength of sound in this frequency range (>1 m) is typically several orders of magnitude larger than the length scale of any bubbles or flow non-uniformities. The long wavelength acoustics propagate through multiphase mixtures unimpeded, providing a robust and representative measure of the volumetrically averaged properties of the flow. The temporal and spatial frequency content of sound propagating within the process piping is related through a dispersion relationship.

$$k = \frac{\omega}{c} = \frac{2\pi}{\lambda} \qquad (7)$$

Where k = wave number or spatial frequency, rad/m
ω = the temporal frequency, rad/sec
c = the speed at which sound propagates through the fluid mixture within the process piping, m/s
λ = the wavelength, m

Utilizing SONAR-processing techniques, data from an array of sensors can be processed to decompose the sound field into specific temporal and spatial frequency components. The result of this two-dimensional, Fourier-based composition can be represented with a k-ω plot, in which the power of the sound field is plotted as a function of both temporal and spatial frequencies. Under this transformation, all the acoustic energy is distributed in regions of the k-ω plot where the wave number and temporal frequency are related through the propagation velocity as described above. The result is that the acoustic energy forms what is often termed, the “acoustic ridge”. Since sound typically propagates both with and against the flow, k-ω plots of the acoustic field often appear as a “v”- like structure in the k-ω plane. Determining the slope of the acoustic ridges provides a measure of the speed of sound [2], [3].

Entrained Air Determination

The connection between speed of sound of a two-phase mixture and phase fraction is well established for mixtures in which the wave length of the sound is significantly larger than flow inhomogenieities, i.e. bubbles, in the flow [4], [5]. Thus, for long wavelength sound propagation, the sound speed of a mixture can be related to volumetric phase fraction of the components and the sound speed and densities of the components through these well established mixing rules. One simple mixing rule given by Wood is as follows:

$$\frac{1}{\rho c^2} = \sum_{i=1}^{N} \frac{\phi_i}{\rho_i c_i^2} \qquad (8)$$

Where ρ = mixture density
c = mixture speed of sound
ϕ_i = component volumetric phase fraction
ρ_i = component density
c_i = component speed of sound

The mixing rule essentially states that the compressibility of a mixture ($1/(\rho c^2)$) is the volumetrically weighted average of the individual component compressibilities. For gas/liquid mixtures at pressure and temperatures typical of separator outlet conditions, the compressibility of gas phase is orders of magnitude greater than that of the liquid. Thus, the compressibility of the gas phase, given by the inverse of the pressure, and the density of the liquid phase primarily determine mixture sound speed and as such, it is necessary to have a good estimate of process pressure to interpret mixture sound speed in terms of volumetric fraction of entrained gas.

SONAR-based entrained gas measurements have been performed for numerous applications within many industries and have demonstrated the ability to track small variations in entrained gas levels on a real time basis. It is this real time entrained gas measurement that is employed to significantly reduce the errors in the net oil rate measurement due to the presence of gas carry-under.

Experimental Data

To verify the ability to accurately measure the liquid density using the combined coriolis density and SONAR-based gas fraction measurement an experimental test was conducted. The test consisted of a water flow loop with a 2-inch Micro Motion CMF200 coriolis meter installed in a vertical upward flowing orientation (“flag” mount) with a CiDRA *SONARtrac*™ gas volume fraction meter and pressure sensor installed just downstream of the coriolis outlet. A provision to inject air upstream of the test section was included (see figure 2).

Varying amounts of air were injected while flowing water and recording the coriolis measured density and the sonar gas volume fraction. Using equation (3) for a two-component water/air mixture the density is given as:

$$\rho = \phi_W \rho_W + \phi_A \rho_A \text{ with the constraint}$$
$$\phi_W + \phi_A = 1 \qquad (9)$$

Where W and A subscripts refer to the water and air, respectively. Combining, assuming $\phi_G \rho_G << \phi_W \rho_W$ and rearranging gives an equation for the water density as:

$$\rho_W = \frac{\rho}{1-\phi_G} \qquad (10)$$

It has been shown analytically that in the limit of well-mixed flow with low tube frequency (as is the case for the CMF200) the coriolis meter will properly measure the mixture density [6]. This indicates that in this experiment the density measured by the coriolis meter divided by 1-ϕ_G would give the correct water. The results of this test confirm this as shown in figure 3.

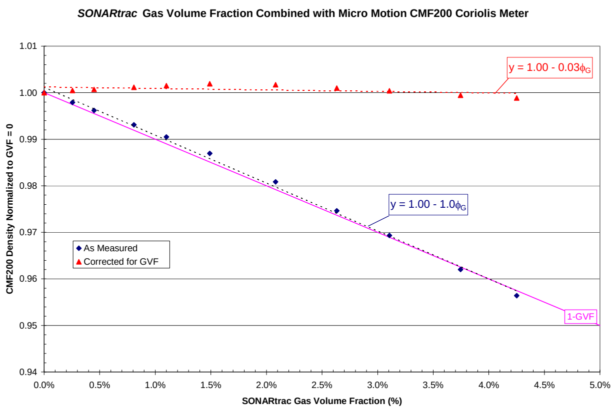

FIG. 3

Oil Field Test Data

A SONAR-based gas volume fraction meter was installed on the outlet of a coriolis meter on the liquid leg of a gas/liquid cylindrical cyclone (GLCC) two-phase separator. Both meters were mounted on a vertical orientation with upward flowing liquid similar to the experimental test section as described above. The mass rate, density and drive gain from the coriolis meter and the gas volume fraction from the SONAR-based meter were output to a programmable logic controller (PLC) where the data could be stored and later retrieved. The pressure at the outlet of the coriolis meter was also output to the PLC (Fig. 4).

The data for a 9-1/2 hour well test were retrieved from the PLC and analyzed. Figure 5 shows the gross flow rate and coriolis measured density. The gross rate was calculated by dividing the mass flow rate by the density, both directly measured by the coriolis meter. Figure 6 shows the measured gas volume fraction and coriolis measured density. Note the gas volume fraction is not constant, but varies between 0 and nearly 4%. This variation eliminates the ability to perform any fixed gas correction to the coriolis density measurement. A cross plot of the measured density and the gas volume fraction (Fig. 7) shows good correlation and a decrease in the measured density as the gas volume fraction increases. Note that as the gas volume fraction increases the measured density is decreasing.

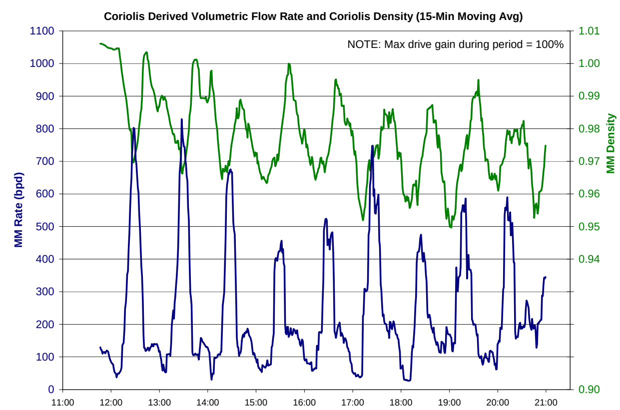

FIG. 5

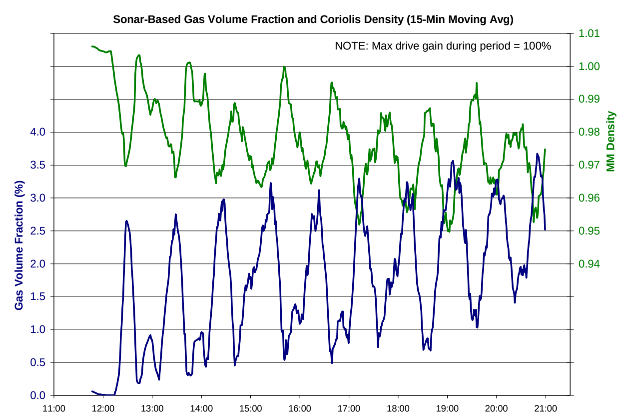

FIG. 6

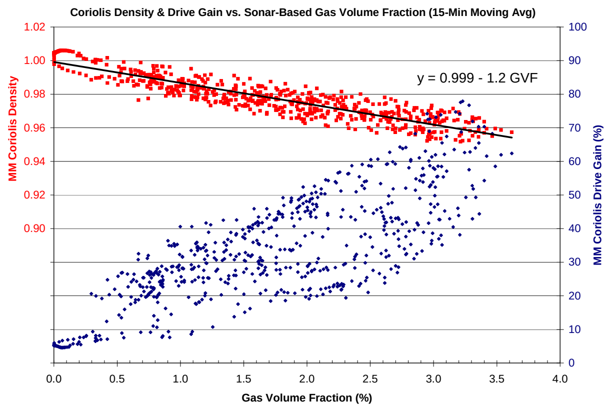

FIG. 7

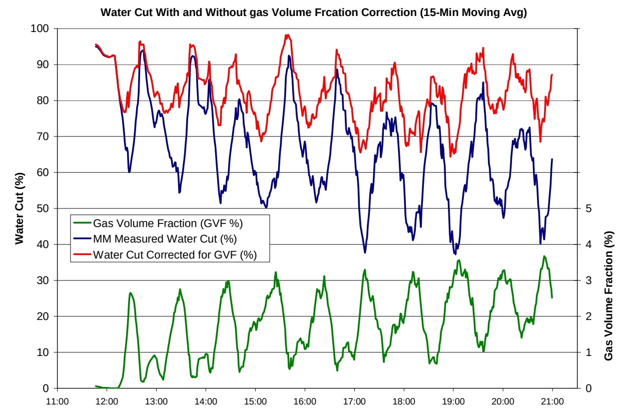

FIG. 8

As described for the experimental test above, a plot of the measured density versus gas volume fraction should yield line equal to $\rho_L(1-\phi_G)$. In the case of field data the liquid density is not exactly constant because the oil/water ratio is changing over time and it is postulated that the gas volume fraction would tend to increase as the oil fraction increases since the gas is associated with the oil, not the water. However assuming the mixture density is on average close to one, note that the best straight line fit is very close to the theoretical $1-\phi_G$ for liquid / gas mixture.

The water cut with and without the knowledge of the gas volume fraction is shown in Fig. 8. Using knowledge of the gas volume fraction when calculating the oil fraction (equation 5) yields a total oil of 19.2 barrels for this 9-1/2 hour well test. If the gas fraction information is ignored and therefore it is assumed all free gas has been removed by the separator the total oil for this test is given as 39.9 barrels. This is an overstatement of the total oil by 20.7 barrels or 108% (Fig. 9).

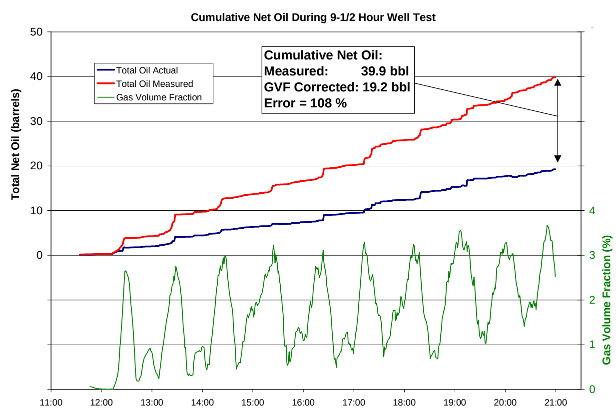

FIG. 9

Summary

Accurate measurement of net oil rate from individual wells is a critical component in effective oil field management. Using two-phase gas/liquid separators and density- or microwave-based watercut on the liquid leg is an established method for measuring net oil rate. There is the potential, however, for an unknown and varying amount of gas carry-under in the liquid leg of up to several percent resulting in a significant overstatement of the net oil rate. A method to use a SONAR-based measurement of the gas volume fraction to remove the uncertainty due to gas carry-under has been established. Results of both laboratory and field tests show the validity of this measurement and the ability to restore the accuracy of the net oil measurement even with imperfect separation.

Acknowledgements

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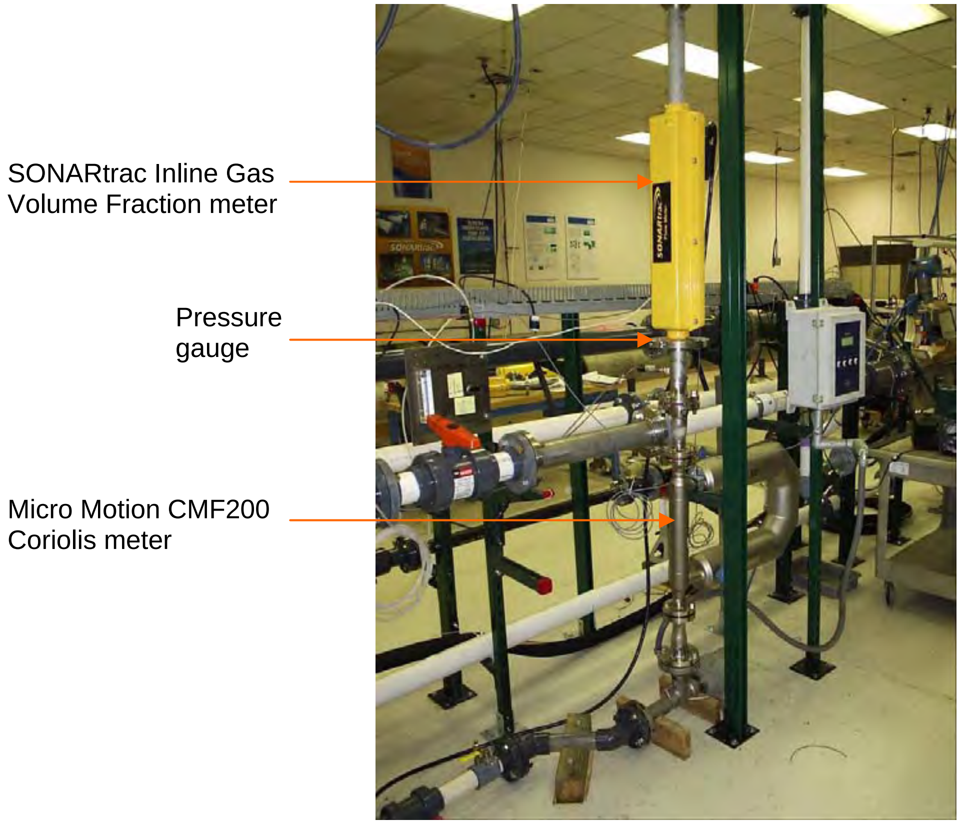
SONARtrac Inline Gas Volume Fraction meter
Pressure gauge
Micro Motion CMF200 Coriolis meter

FIG. 2

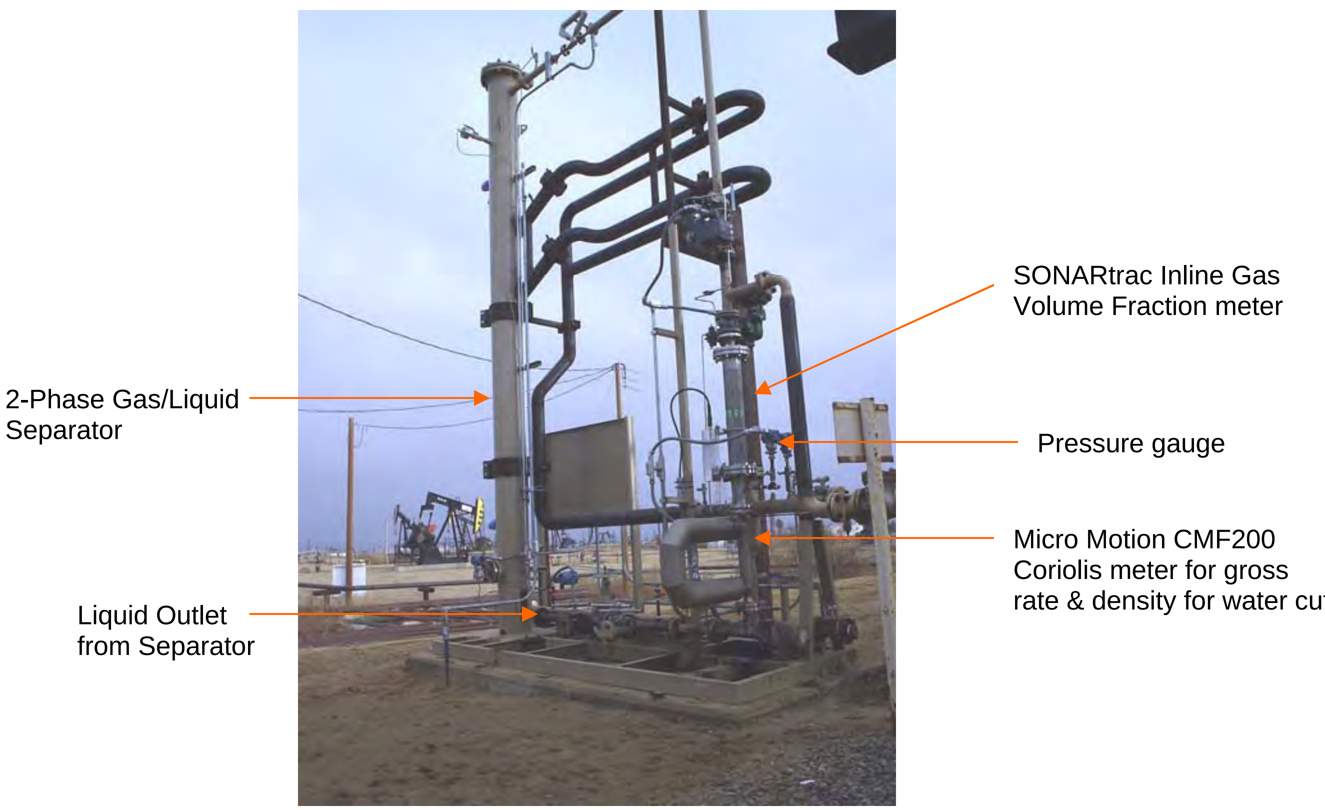
SONARtrac Inline Gas Volume Fraction meter
2-Phase Gas/Liquid Separator
Pressure gauge
Micro Motion CMF200 Coriolis meter for gross rate & density for water cut
Liquid Outlet from Separator

FIG. 4