Using Subsea Multiphase Flow Metering Data for Remote Characterization of Fracking Fluid-Containing Liquid Phase

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Abstract

This paper describes a method for remotely detecting impurity in the liquid phase from a subsea producing reservoir in the Gulf of Mexico using multiphase flow metering data. The data was studied, and the outcome of the analysis was a modification of the meter fluid attributes. The new configuration parameters were successfully implemented as an update to the subsea meter. Later experimental analysis of the water phase confirmed the presence of frac fluid and almost identical fluid properties as remotely predicted via multiphase flow metering data.

The technique described here demonstrates novelty in accurate characterization of frac fluid-containing liquid phase that can be performed remotely with a robust troubleshooting method for multiphase flow meters. This is specifically of interest for subsea production where minimal intervention is desired due to costly installation access.

Key words: *Reservoir fluid properties, remote monitoring, fracking fluid, multiphase flow meter*

1 Introduction

Knowledge of the reservoir fluid and particularly liquid phase is key to reservoir management and production analysis leading to operational optimization. (Nagarajan, Nonarpour, Sampath 2006). Possibilities are limited for characterization of liquid phase specially in case of deepwater reservoirs. One of the possibilities is the pressure-volume-temperature (PVT) analysis at the starting point of reservoir development, the other one is intermittent downhole or flowline sampling. The former is a once in a lifetime for the field, and the latter is quite cumbersome and thus very infrequent. This is then of great importance to use the opportunities of acquisition of PVT information in the most efficient manner.

Multiphase flow metering is a crucial technology for the oil and gas industry. It improves our understanding of production fluids. This enables production optimization, flow assurance, reservoir management, fiscal allocation and reconciliation for both onshore and offshore (Hatton 1997) (Atkinson, Berard, et al. 1999).

Having a multiphase meter installed in the production pipeline, in addition to flow metering capabilities, it is possible to gain instant insight into the flowing fluid nature and its properties. Thus, multiphase-flow metering can also lend a helping hand to provide valid PVT properties for the hydrocarbon stream produced. One of the important properties is density and accurate estimation that provides input for several prediction and decision-making processes.

In the conventional reservoirs, natural change in PVT properties of the reservoir fluids is a gradual process that takes years to show significance. An exception here is the injection of gas, water, or carbon dioxide that can temporarily alter the PVT properties of the hydrocarbon stream. Also, a change in the zonal production can make a difference in the PVT properties that are originally incorporated in the models and configuration of the production facilities. In all these cases, however, the reservoir engineer has a relatively clear picture of how the new stream contributes to the PVT properties of the reservoir fluids. The formation and production of solid materials such as scales (Bertrand, Ségéral, and Moksnes 2001) or sands (Pinguet, Hopman, et al. 2013) (Bifout, Pinguet and Rojas 2014) do not affect the PVT properties of the reservoir fluids but can significantly affect the multiphase flow meter (MPFM) measurement, and that is a lead to use MPFM to detect and address flow assurance concerns.

In unconventional reservoirs, there are additional factors that can play a role in the change of the reservoir fluids properties and behavior such as stimulation techniques including the introduction of fracking fluids. Fracking fluids made the enhanced oil recovery (EOR) operations smoother in several fields especially in the shale formations and increased the financial viability of such reservoirs (Liew, Danyaro, and Zawawi 2020). Even though such materials are normally used in the early stage of the reservoir lifetime and the related fraction is assumed negligible shortly after the introduction, the presence of fracking fluid can significantly change the properties of the produced stream from the reservoir (Zhang, Di et al. 2019). This might significantly affect flow measurements as the production progresses.

In this work, we report on a process where multiphase metering data together with top side separator readings were used in a project in Gulf of Mexico to remotely characterize the flow content and detect the presence of fracking fluid in the liquid phase based on the apparent density. This way, the change in PVT properties, because of the introduction of fracking fluid, was detected and the production actions were accordingly orchestrated.

The job was performed remotely based on MPFM data, and the characterization of the liquid properties was later proven accurate by performing experimental analysis on the liquid phase. The outcome of the study was to reconfigure the multiphase meter for the transitional conditions with high confidence.

2 Measurement Principles and Detecting Impurity

The multiphase meter used in this work has two main parts: A venturi to measure the total flowrate and a nuclear system to measure individual phase fractions in real time.

If the inlet diameter is A_1 and the throat of venturi has a diameter of A_2, and there are pressure transmitters before the venturi (P_1) and at the throat of the venturi (P_2) to measure the differential pressure ($P_1 - P_2$), one can use a simplified form of Bernoulli equation-driven formula such as **Equation 1** to estimate the total volumetric flowrate (Q) of the passing stream through the venturi.

$$Q = A_1 \sqrt{\frac{2(P_1 - P_2)}{\rho\left(\frac{A_1^2}{A_2^2} - 1\right)}} \qquad (1)$$

where ρ is the mixture density of the fluid.

Here no-slip condition assumption between the different phases in the stream is applied. It should be noted that the configuration of the multiphase meter used in this work is vertically oriented. There the additional exerted forces on the flow including the gravitational force must be considered. However, the effect of the important factors such as the density, the diameters, and the pressure values on the total volumetric flow rate can be perceived from **Equation 1**.

The nuclear system comprising a dual-energy spectral gamma ray detector combined with a ^{133}Ba radioactive source is used to measure oil, water, and gas fractions in real time. The way it works is that the detector measures the number of photons that pass through the flow stream in venturi throat. Then that measurement is compared against the theoretical number of photons emitted by the source. This is based on a reference measurement performed sometime before the multiphase meter was installed at the field. **Equation 2** then can be used to develop two equations for high and low energy levels of the source:

$$N^{energy} = N_{vac}^{energy} e^{-d.\rho.\mu} \qquad (2)$$

Here the attenuation of the nuclear beam strength for a given fluid content is expressed by the number of photons in vacuum (N_{vac}^{energy}) and the effect of beam travel distance or d (here the meter's throat diameter), fluid density ρ and the mass attenuation coefficient (μ).

Write the nuclear equation for both low and high energy levels of the Ba source. Then expand the fluid density as 'mixture density' containing all the summation of oil, water, and gas densities weighted for their fraction (α_o, α_w and α_g). Assume that the sum of fractions is equal to unity ($\alpha_o + \alpha_w + \alpha_o = 1$). Then one obtains three equations with three unknowns which are the individual phase fractions. Solving the three equations simultaneously, it is straightforward to calculate the phase fractions. More details on the calculations are described in (Darab, Nygaard, et al. 2018).

In industry, a visual representation of these three equations and three unknowns is popular through a Solution Triangle in conjunction with an Operating Point as shown in **Figure 1**.

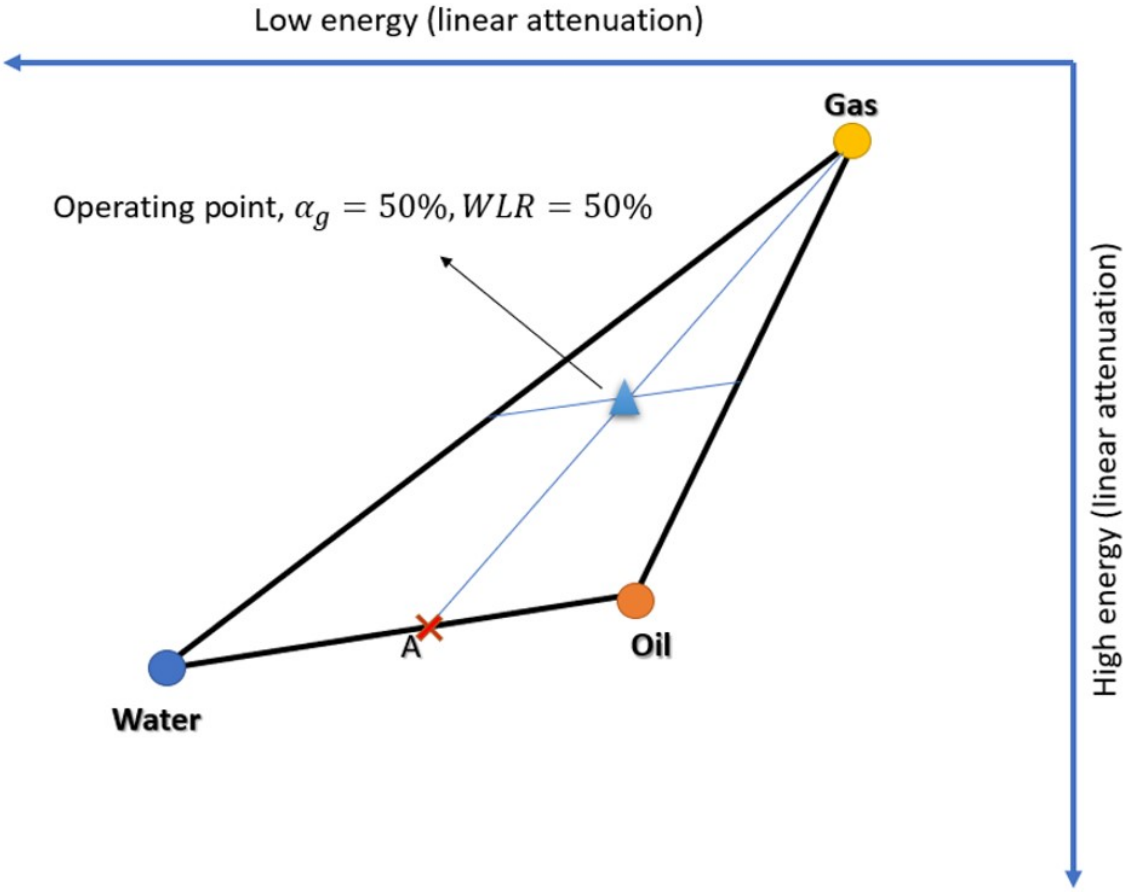

Figure 1. Example Solution Triangle and Operating Point

The mentioned presentation of the Solution Triangle and the Operating Point is for the typical cases of the operation where the passing stream through the MPFM only contains hydrocarbons and formation water. When there are additional non-hydrocarbon substances in the liquid phase of the stream, the PVT properties such as phase densities and mass attenuation coefficients are likely to change. A practical example here is the unconventional reservoirs where different chemical substances in a so-called fracking fluid is used as a well stimulation technique to enhance hydrocarbon recovery. The fracking fluid possesses higher density than the pure liquid hydrocarbon phase. Thus, the calculation of the flowrates based on **Equation 1** will be erroneous if the density and mass attenuation coefficients used in the equation is not updated for the representative new stream.

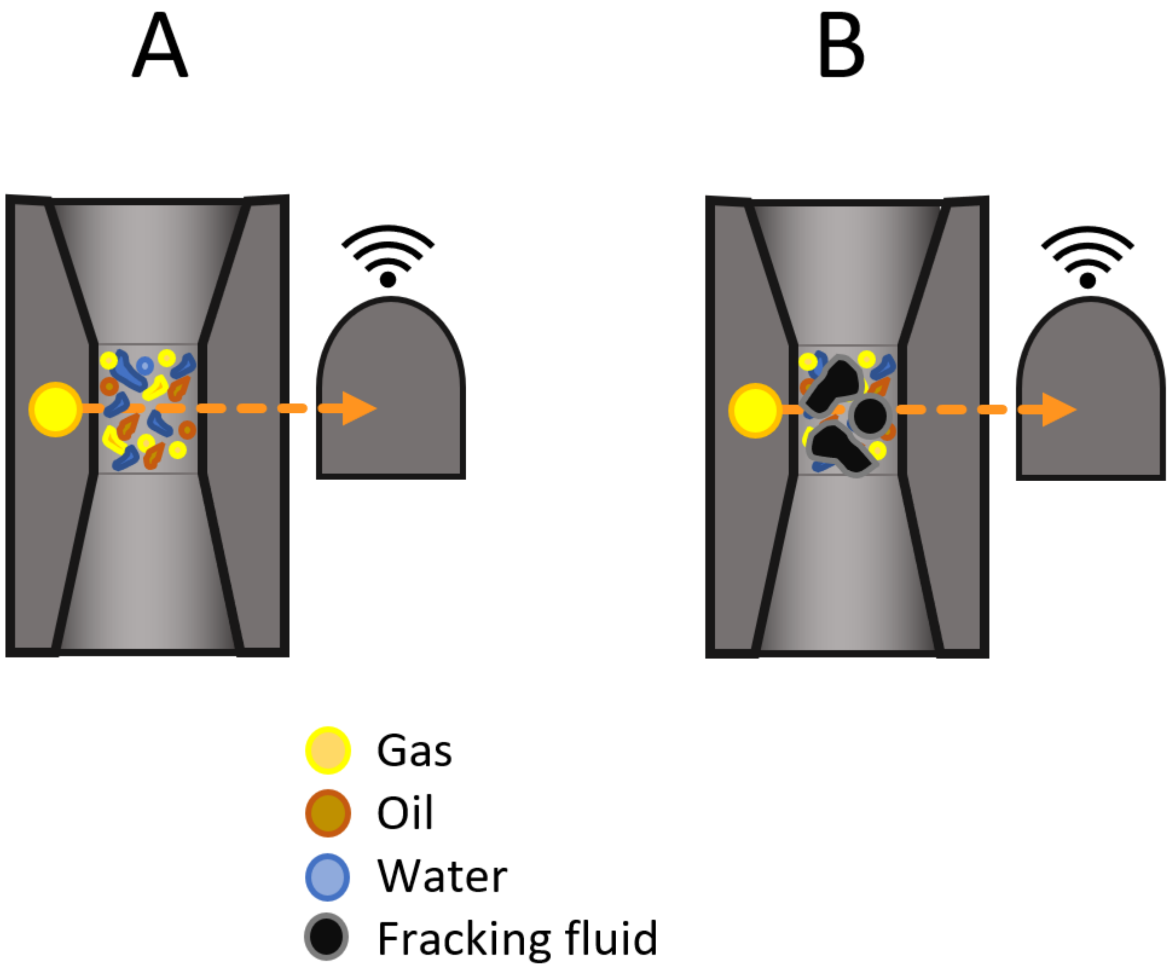

Figure 2. Schematic representation of streams passing through the venturi; A: only hydrocarbon B: hydrocarbon and additional fracking fluid

Figure 2 schematically shows the gamma ray passing through the streams for a MPFM in a hydrocarbon-only case versus a fracking fluid-containing sample. **Figure 2-A** shows the conventional situation where only gas, oil and formation water produced through the MPFM. The relevant Solution Triangle for this case is the same as the one presented in **Figure 1.**

The gamma ray obviously experiences a higher barrier when fracking fluid is in the stream compared to only hydrocarbon in the piping. The outcome of the situation shown in **Figure 2-B** is a change in water phase properties, including water density. That is accordingly reflected in the Solution Triangle for the multiphase flow measurement in question.

The new water density, or apparent water density, results in a new location for the water point and consequently a new Solution Triangle. Such change in water point due to changed density is shown in **Figure 3.** So in brief, the flow shown in **Figure 2-A** possesses a Solution Triangle similar to **Figure 1** (only gas, oil and water) and the flow shown in **Figure 2-B** possesses a Solution Triangle similar to Figure 3 (gas, oil and water + fracking fluid).

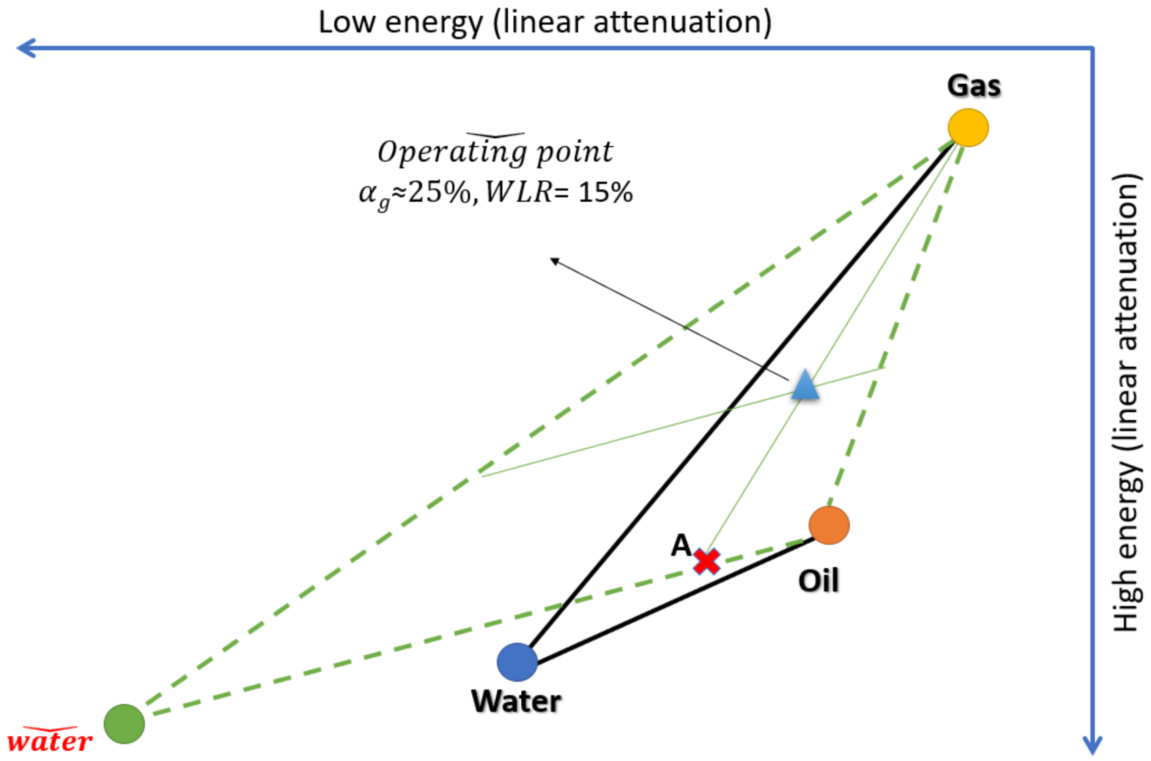

Figure 3. Modified Solution Triangle and shifted location of water point and new relative location of Operating Point due to the presence of fracking fluid

In **Figure 3** the solid Solution Triangle in black is related the original configuration of the meter. The dashed Solution Triangle in green is related to the updated configuration of the meter. The dashed Solution Triangle has a new water point where the new density for the additional fracking fluid are taken into consideration. The gas-oil line is common between the solid and dashed Solution Triangles.

In the dashed Solution Triangle, the water point moves to the left and down in this case compared to the original situation. Even though the actual location of the Operating Point is unchanged, the relative location toward the new water point ($\widetilde{water}$) is now different. This results in significantly reduced water liquid ratio (WLR) since the corresponding line is now crossing the oil-water line in a position much closer to the oil point than the water point. The gas volume fraction (GVF) is also lower in the new case (dashed Solution Triangle). For the calculation of GVF in the figure, we need to draw a parallel line to water-oil line crossing the Operating Point. When performing this, the oil-gas line is closer to oil point compared to the original configuration (solid black Solution Triangle) and then less gas content is perceived by the metering system in the original configuration of the MPFM (solid black Solution Triangle). Here the oil fraction is obviously underestimated before changing the water point. These issues are addressed when the MPFM is configured with the water points ($\widetilde{water}$) in the dashed Solution Triangle.

3 Fracking Fluid Detection in Water Phase

In the current work, the engineer of a subsea field in the Gulf of Mexico detected a discrepancy between the top side separator and the subsea multiphase flow meter measurements. This initiated an investigation of the deviation which showed the possibility for a suboptimal compatibility between the actual reservoir fluid properties and the PVT setup used in the meter.

The remote analysis of the multiphase flow metering data showed that there possibly was a non-hydrocarbon substance present in the liquid phase contributing to the deviation. Some of the production testing parameters from the field were considered as benchmarks when compared with the multiphase meter reports with the same parameters. The behavior of the Solution Triangle for the multiphase meter was identical to Figure 2 indicating the possibility that fracking fluid was present in the water phase.

Phase densities were then predicted based on the MPFM data and top side separator data. To perform this, data for a specific flow period from MPFM was compared with analyzed top side separator readings. The possibility for the contamination of the stream with fracking fluid was then accounted for and the new water point location based on the updated fluid properties was predicted. The configuration was updated to adopt to the contamination of the stream passing through the meter.

Reconfiguration of the meter and experimental verification

Based on the findings for the presence of fracking fluid in the water phase, the multiphase meter was reconfigured to address the apparent density for the transition period. The transition period concluded when the fracking fluid was all produced out of the reservoir.

The operator reconfigured the meter using the updated phase properties and the resultant configuration was delivered to the field for deployment.

Later a few milliliters of the breakout fluid were examined in the lab, and the density of the water phase was precisely measured. The density value agreed with the fracking fluid used in the completion phase and with slight deviation (less than 1% absolute) with that predicted based on MPFM-data. It was found that the well stream contained stimulating fluid used in drilling and completion operations. This extended the fractures increasing the number of extractable hydrocarbons from the reservoir.

By using multiphase flow metering data and top side separator data it became possible to detect the presence of additional non-hydrocarbon substances, in this case fracking fluid.

4 Conclusion

In this work, using subsea multiphase flow metering data, it was shown that remote characterization of fracking fluid-containing liquid phase is possible. In general, the presence of additional non-hydrocarbon substance can be remotely detected using multiphase flow metering data.

In this case, by experimental analysis of breakout fluid, the density of the water phase agreed with the fracking fluid used in the completion phase, and agreed, with slight error (less than 1% absolute), with that predicted based on MPFM data.

The technique described here demonstrates novelty in accurate characterization of frac fluid-containing liquid phase that can be performed remotely with a robust troubleshooting method for multiphase flow meters. This is specifically of interest for subsea fields where minimal intervention is desired because of the cost associated with installation access.

With obtained results and validated approach, it is possible to not only detect the presence of fracking fluid in the production flow, but potentially quantify it. Having access to necessary MPFM data it is also possible to evaluate the development of the fracking fluid content in the flow and conclude on the transition period timeline. Furthermore, having continuous data stream from the MPFM, the presented technique enables calculation of the reliable flowrates for oil, water and gas during the transition period.

5 Notation

Symbols and abbreviations:

N_{vac}^{energy} = Number of photos in vacuum
ρ = Mixture density
μ = Mass attenuation coefficient
Q = Volumetric flowrate of the passing stream
α = Fluid phase fraction (holdup)
D = Venturi throat diameter
DP = Differential pressure (bar)
EOR = Enhanced oil recovery
GVF = Gas volume fraction
MPFM = Multiphase flow meter
N = Count rate
PVT = Pressure, volume, and temperature
WLR = Water liquid ratio

Subscripts:

g = gas
he = high energy
le = low energy
m = mixture
o = oil
vac = vacuum
w = water

Superscripts:

32 = 32 keV energy level
81 = 81 keV energy level
356 = 356 keV energy level

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