TESTED PERFORMANCE OF THE HITEC/MULTI-FLUID WATER FRACTION METER

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Paper 6.1

NORTH SEA FLOW MEASUREMENT WORKSHOP 1990
23-25 October 1990

National Engineering Laboratory
East Kilbride, Glasgow

MULTIPHASE FRACTION METERING SOLVED? A REPORT OF THE LATEST RESULTS ACHIEVED WITH A NEW TECHNOLOGY

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SUMMARY

This paper reports results achieved with a new multiphase fraction metering technology that is being developed by Multi-Fluid Inc. of the U.S.A and Hitec of Norway in cooperation with a number of North Sea oil companies. Results will be reported for three different applications of the technology:

1) Water cut monitoring to fiscal and/or custody transfer specifications for crude oil streams having low water contents,

2) Water cut metering (or Net Oil Metering) of crude oil streams where the water content can vary from 0 - 100%, and

3) True multiphase fraction metering of oil, water, and gas streams.

In all cases, the results are competitive with or superior to all known techniques used for such measurements.

1 INTRODUCTION

For many years, the oil industry has been trying to develop instrumentation to continuously measure the composition of multi-component crude oil streams. That is to measure the water content of oil streams and the water and gas content of multiphase streams. Despite the effort, the industry has achieved only modest success. It has been particularly difficult developing an oil, water and gas fraction meter. The problems that the oil industry face with respect to accurate, continuous composition metering are not unique. They reflect a more fundamental difficulty in measuring process chemical variables as opposed to physical variables. For example, it is much easier to measure pressure and temperature than it is to measure the methane content of natural gas.

Consequently, the oil industry still depends on separation and sampling to measure what is being produced. For onshore production, this is cumbersome, but workable. For offshore production, is is most often prohibitively expensive for marginal field developments.

As the results reported in this paper will indicate, a new technology has emerged which can significantly improve the industry's ability to measure the production process - from downhole, to the well head, to the platform, to the pipeline, and to the refinery. The new technology makes possible continuous, full bore volumetric component ratio measurements of oil/water and oil/water/gas mixtures. The units have no moving parts and they can be made to fit any pipe size from one inch up to 54 inches as necessary.

From 1987, Statoil funded a development project for a new multiphase metering concept developed at SRI International, a non-profit research and development company in California. From the beginning this concept was tailored to solve the oil, water, and gas fraction measurement problem, in particular that of water continuous flows. Later, the principle also proved ideal for custody transfer measurements of water cut in pipeline quality crude oil. After early prototypes were successfully demonstrated at the end of 1988, a new company, Multi-Fluid Inc. was started to commercialize the technology. In 1989, Hitec in Norway was asked to join in the effort and the development program was moved to the North Sea to more properly address the needs of the offshore oil production industry. To date, four other companies besides Statoil have joined in the product development efforts. They are BP Norway Ltd., Total Marine Norsk, Elf Aquitaine Norge, and Phillips Petroleum Company Norway. Without the support of these companies, this technology would not have progressed as it has and might well have died.

In this paper, some of the latest test results are reported. They pertain to three distinct measurement needs in the oil industry.

1) Water cut monitoring to fiscal and/or custody transfer standards for crude oil streams having low water contents,

2) Water cut metering (or Net Oil Metering) of crude oil streams where the water content can vary from 0 - 100%, and

3) True multiphase fraction metering of streams containing oil, water, and gas.

In all cases, the technology is competitive with or superior to all other measurement techniques used for these applications. The multiphase fraction meter has so far exhibited an accuracy of better than 1% for all components.

2 BRIEF DESCRIPTION OF THE MEASUREMENT TECHNIQUE

The technique is based upon very accurate measurement of the complex dielectric constant of crude oil mixture at microwave frequencies. The complex dielectric constant is denoted as follows:

$$e^* = e' - je'' \qquad \text{(Eq. 1)}$$

$$= e' - j\kappa/\omega e_o \qquad \text{(Eq. 2)}$$

e^* = complex dielectric constant.
e' = dielectric constant;
e'' = loss factor;
$j = \sqrt{-1}$
κ = conductivity
ω = frequency in radians
e_o = permittivity of vacuum.

Basically, the measurement of the complex dielectric constant is equivalent to measuring the permittivity and conductivity of the mixture.

For two component mixtures such as oil and water, a measurement of the complex dielectric constant suffices for determining the component ratios in the mixture. This is accomplished by making use of "mixing law" that relates the dielectric constant of a mixture and the dielectric constants of its components to the volume fractions of those components in the mixture. Mixing laws of this type have been derived by Maxwell, Bruggeman, and Looyenga. The simplest is Maxwell's :

$$\frac{e - e_o}{3e_o} = \Phi_w \frac{(e_w - e_o)}{(2e_o + e_w)} \qquad \text{(Eq. 3)}$$

e = dielectric constant of the mixture;
e_o = dielectric constant of the oil;
e_w = dielectric constant of the water;
Φ_w = the volume fraction of the water in the mixture.

The volume fraction of the oil would be determined trivially from the following equation:

$$1 = \Phi_w + \Phi_o \qquad \text{(Eq. 4)}$$

Φ_o = the volume fraction of oil in the mixture.

This is the technique with which the Multi-Fluid technology measures the water content of oil and water streams that contain no gas.

The addition of gas to the mixture complicates the problem at a fundamental level - it adds a third unknown to the problem. In theory, it would be possible to measure the dielectric constant and the conductivity alone to determine the three component ratios. The third variable is eliminated using the equation:

$$1 = \Phi_w + \Phi_o + \Phi_g \qquad \text{(Eq. 5)}$$

Φ_g = the volume fraction of gas.

Our measurements have shown that in practice this method will not work. A practical example is illustrated by a saltwater continuous mixture containing oil and gas. Differentiating the dielectric constant and conductivity of the oil versus that of the gas is impossible. Given this dilemma, it is necessary to add another measurement device to the dielectric instrument if it is to measure oil, water and gas mixtures. We have chosen to use gamma ray densitometers for this purpose because it is non-invasive and particularly sensitive to the gas content of the mixture. Gamma ray densitometers function by measuring gamma ray absorption in matter. The degree of absorption is closely related to the density of the absorbing material. The density is determined from the following relationship:

$$\alpha\rho = \ln(I_o/I_m) \qquad \text{(Eq. 6)}$$

α = gamma ray absorption constant for the material
ρ = the density of the material
I_o = gamma ray intensity for material of density 0
I = measured gamma ray intensity of the material.

For a multicomponent mixture, Equation 6 generalizes as follows:

$$\Sigma\alpha_i\rho_i\Phi_i = \ln(I_o/I_m) \qquad \text{(Eq. 7)}$$

i is the subscript for component i
Φ_i = the volume fraction of component i.

The Multi-Fluid oil, water and gas meter functions by measuring the complex dielectric constant as is it shown in equation 1 and the mixture density using a gamma ray densitometer. With this information about the mixture it is possible to determine the component rations by using Equations 5 and 7 and one similar to Equation 3 that is suitably generalized to three components.

3 TEST METHODS AND APPARATUS

An important question regarding composition meter test results is, "What is the measurement referenced to?" Reference measurements are difficult, particularly for multiphase flow where no direct referencing techniques exist. In order to overcome these problems, we developed a unique, but simple test rig with which precise volumetric (and/or mass control) of the constituent components can be attained.

The test rig is a closed loop system where the total volume of the loop is known at all times. Moreover, the rig volume is continuously expandable so it can accept injections of new material without the need to simultaneously remove material from the loop. Thus, when water or gas is injected into the loop, the loop volume expands to incorporate the new material. This eliminates errors associated with removing unevenly mixed material at the same time as new material is being injected. The total volume of the loop varies between 130 and 160 l depending on the configuration and it can be expanded by just over 19 liters. The rig contains a separate heater and cooler to regulate the temperature. The pump is a centrifugal pump capable of generating velocities ranging from about 0.5 m/sec up to 5 m/sec.

The metering section is oriented vertically with the flow rising upwards through the meters. A static mixer made by Sulzer is installed just prior to the metering section in order to maintain even mixing during the liquid/gas runs.

A typical oil continuous (or water continuous) run consists of the following steps. The test rig is filled with crude oil (or water). The liquid is mixed in the rig, then samples are taken. The oil/water content of these samples is determined using Karl Fisher analysis. This calibrates the initial conditions of the loop. In a stepwise fashion, water (or oil) is injected into the loop in known quantities to increase the volume fraction of the water (or oil). The injection procedure is metered in one of two ways.

For measurements simulating fiscal or custody transfer conditions where the water content is typically between 0 - 5%, the water is injected in controlled volumetric shots of up to 200 ml using a piston pump calibrated to an accuracy of ±100µl. In this fashion injections of 0.005% to 0.1% can be made. The volume injections are adjusted for thermal volume expansion in the loop. The accuracy of this procedure was tested using sampling and Karl Fisher analysis to verify the accuracy of the water content after each injection. To the degree possible with sampling and Karl Fisher analysis, no errors have been detected with this procedure. In particular, no water holdup has been detected.

For larger increases in the water (or oil) content, the water (or oil) injection is controlled on a weight basis using a scale accurate to ±2 gm. The injected weight is converted to an equivalent volume using the appropriate density for the injected liquid in the rig during the measurements. Using the weight control technique, we can simulate the conditions necessary for net oil measurements where the water content can be from 0 to 100%.

The injection of gas makes precise material accounting virtually impossible because of gas holdup and slip flow. We have sidestepped these problems in the following manner. First, all liquid injections are performed with no gas in the loop so precise component volume ratios can be maintained. Water or oil are injected to attain the desired volume fractions in the liquid components. Then gas is injected while maintaining constant liquid fraction quantities. After completing the gas measurements for a given set of liquid volume fractions, the gas is removed and the initial liquid composition is reestablished. Then more water or oil is added and the gas process is repeated.

How much gas is present in the test section at each test point? Given that we know the component fractions in the liquid and therefore the liquid density to a fairly high precision, we can independently determine the gas content in the test section using the measured density of the gamma ray densitometer using the following simple relation;

$$\Phi_g = \rho(\text{meas})/\rho(\text{liq}) \qquad \text{(Eq. 8)}$$

ρ(meas) = measured density
ρ(liq) = density of the liquid alone.

This gives us the reference point to which we compare the measured values from the oil, water, and gas meter.

4 RESULTS

The results reported for the various meters are always expressed in volume percentages rather than weight percentages.

4.1 WATER CUT METER for Fiscal / Custody Transfer

The Multi-Fluid water cut meter, or Fiscal Meter, is specially designed for fiscal metering standards where measurement accuracy, sensitivity, and stability are paramount. This meter achieves outstanding performance in all three areas. However, the meter will only function if the loss factor of the crude oil mixture as defined in Equation 2 is below a certain level. Because salt water is the major source of loss in crude oil mixtures, the upper measurement limit for crude oils containing brine is about 30 - 60% water in oil depending on the crude oil and the salinity. Fortunately for most fiscal or custody transfer applications, the water content is less than 5%.

Most of our measurements are concentrated in the 0 - 5% water content range. ISO Standard 3171 defines the necessary level of accuracy for a fiscal sampling systems to be ±5% of reading from 1 - 5% water content. No solid guidelines exist for assessing the meter performance above 5%, but we can be certain that the inaccuracy of the meter which can be tolerated will increase for water contents above 5%.

Figure 1 shows a typical measurement result for 0 to 5% water in crude oil. In this case the water was fresh water. Figure 1 also shows the error bounds stipulated by ISO 3171. Clearly the meter is capable of performing well within existing fiscal metering standards. For 0 - 3% water, the meter readings are consistently within 0.05% of the correct value water and within 0.1% for water contents ranging from 3 - 5% and above. The meter has been tested at velocities ranging from 0.5 - 5 m/sec and no flow rate dependency has been detected. The meter has been tested using waters with conductivities ranging from 0 to 20 S/m (conductivity values for water at 20°C) in order to check the effect of the loss factor on the results. For all cases, the meter is consistently much more accurate than stipulated by ISO 3171.

The meter is capable of measuring water cut with equal precision at water contents much higher than 5%. Figure 2 shows the results for a run where the content goes up to 20%. In this case, the injected water is not fresh water but brine containing 7.5% by weight salt and with a conductivity of over 10 S/m at 20°C. Over the entire range the meter reads within 0.1% of the actual water content.

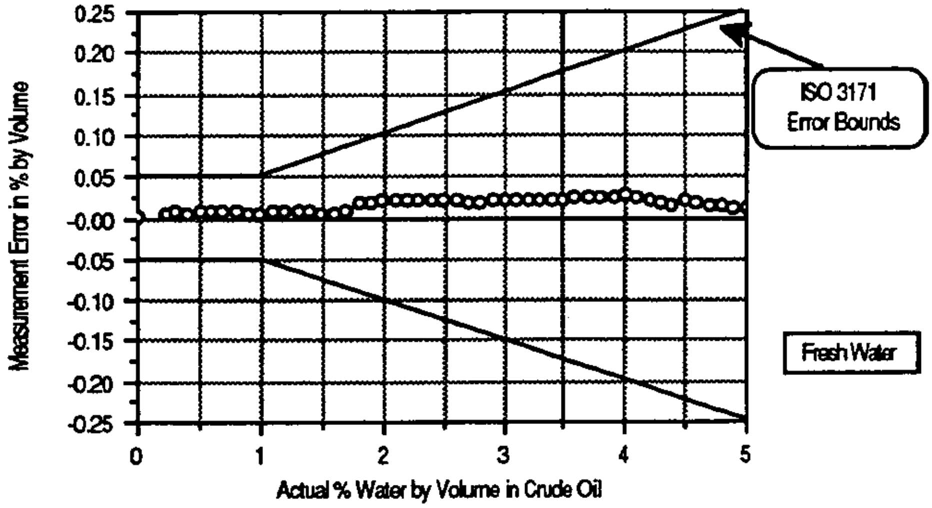

Figure 1 Fiscal Meter Results - 0 - 5% Fresh Water in Crude Oil

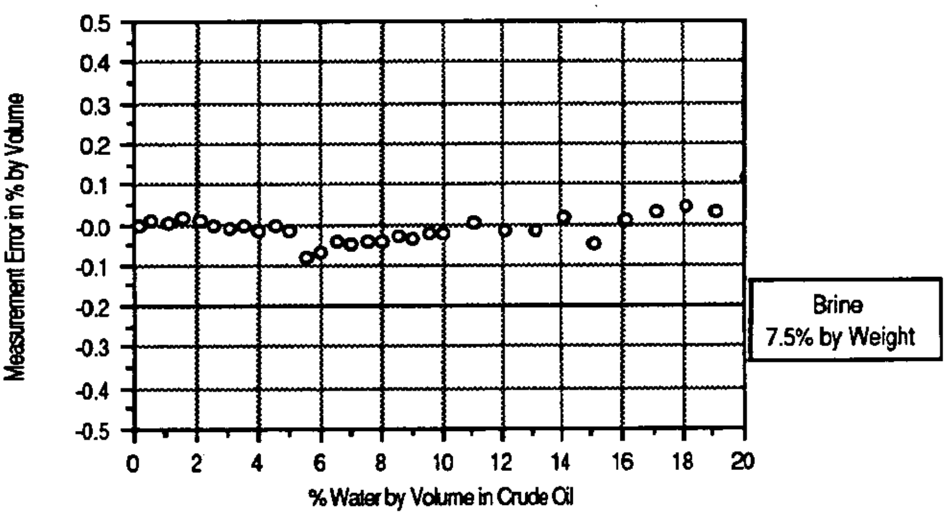

Figure 2 Fiscal Meter Results -0 - 20% water in Crude Oil

In addition to the accuracy, the sensitivity and stability of the meters have also been tested. From a measurement standpoint, the electronics as currently configured have a detection sensitivity of as little as 0.002% water. These levels of sensitivity were demonstrated by repeated water injections of 0.01%. Not only did the meter detect the change quite easily but it measured the changes accurately.

The long term stability of the meter itself has not been tested for long times owing to the inherent stability of the measurement apparatus. Notably, over a six month period, the dielectric constant of air as measured by a given sensor drifted by less than the equivalent change caused by 0.01% water.

4.2 NET OIL METER for Measuring 0 - 100% Water in Crude Oil

The Net Oil Meter is capable of measuring high water contents. In fact it can measure 0 - 100% water. The MFI meter functions equally well whether water or oil is the continuous phase. Capacitance meters only operate as long as oil is the continuous phase. The ability to measure water continuous mixtures becomes increasingly important as more and more water is produced by older fields around the world. In the United States most wells produce much more water than oil. Figures 3 and 4 below show the results of two different measurement runs performed with the net oil meter. Figure 3 shows the results of a run where fresh water was injected into crude oil. For this run, up to 57% water in oil was measured. In other similar runs, up to 78% water in oil was measured.

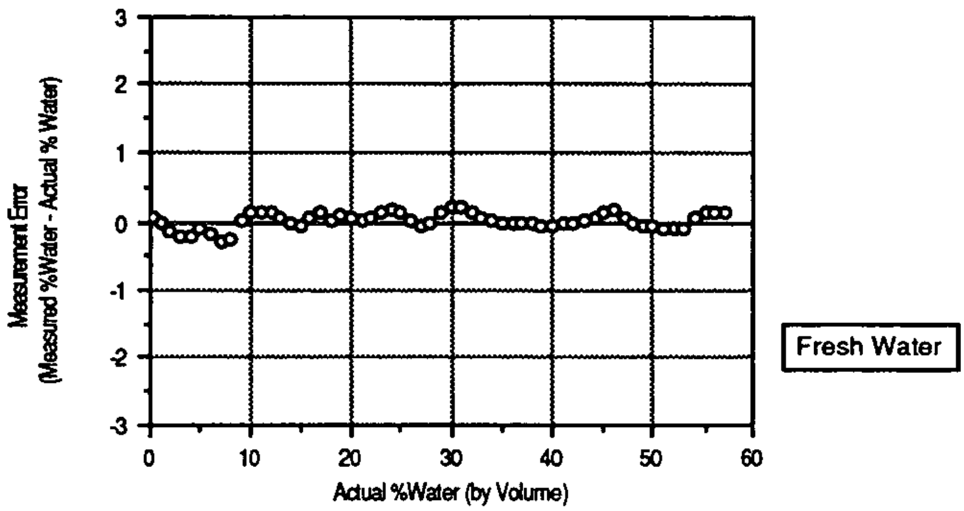

Figure 3 Net Oil Meter Results - Oil continuous mixture containing Fresh Water.

Similar results can be achieved with a capacitance meter, though perhaps not similar accuracies. Figure 4 shows the result of a water continuous run where the water was salty. It is here that the advantages of the new meter become apparent.

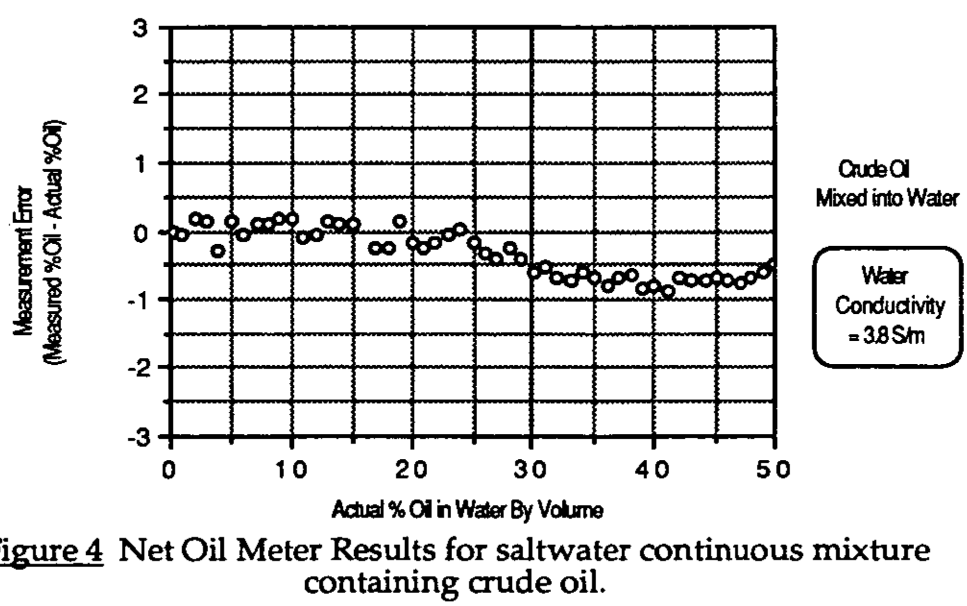

Figure 4 Net Oil Meter Results for saltwater continuous mixture containing crude oil.

In terms of accuracy, sensitivity, and stability, the net oil meter is not as good as is the Fiscal Meter. But, it doesn't need to be. The accuracy of the meter is better than ±2% from 0 - 100% water. The sensitivity limit of the net oil meter for oil continuous mixtures is about 0.01 to 0.02% water, or 5 - 10 times worse than the Fiscal Meter. For water continuous mixtures the sensitivity is is probably no better than 0.05% water. The long term stability of the meter for both water and oil continuous mixtures is about 0.1% water.

4.3 OIL, WATER, AND GAS FRACTION METER

Of all the multiphase (read multicomponent) fraction meters needed by the oil industry, perhaps the need is most acute for the oil, water, and gas fraction meter. This need is also least satisfied for this meter. In the last 6 months, one company introduced a creditable oil, water and gas fraction meter based on the measurement of capacitance. The drawback of this systems is that it only works with oil continuous mixtures. As the results below illustrate, the Multi-Fluid meter does not have this limitation.

Figures 5 and 6 show typical results for oil continuous mixtures.

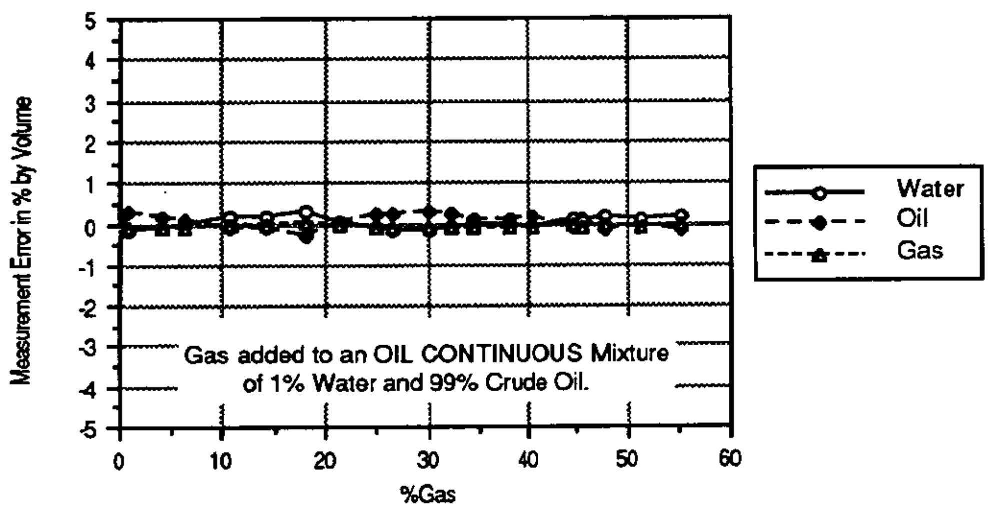

Figure 5 Measurement results for gas injected into a liquid mixture containing 1% fresh water in crude oil.

The figures simultaneously displays the measurement errors for oil, water, and gas fractions respectively. On the x axis is shown the actual gas content for each measurement. The actual oil or water content can be calculated from the gas content using the following formula.

$$\Phi_i = \Phi_{i(init.)} (1 - \Phi g) \qquad \text{(Eq. 8)}$$

Φ_i = volume fraction of oil or water respectively in the oil, water, gas mixture

$\Phi_{i\ (init.)}$ = the volume fraction of oil or water respectively in the liquid phase prior to gas injection.

Φg = the volume fraction of gas at the point of interest.

An example will illustrate how this works. In Figure 5 above, the oil fraction in the mixture containing 30 % gas would be equal to the product of the initial oil fraction, 0.99, and 1 minus the gas fraction (which is equal to the liquid fraction) which is (1 - .30) = 0.7. Thus the oil content at that point is 0.99 x 0.70 = 0.693, or 69.3%. From Figure 5, we see that with 30% gas, the measured oil fraction was only about 0.4% too high.

Figure 6 shows the results of another test run in which gas was injected into an oil continuous mixture. This time the liquid contained 20% water and 80% crude oil.

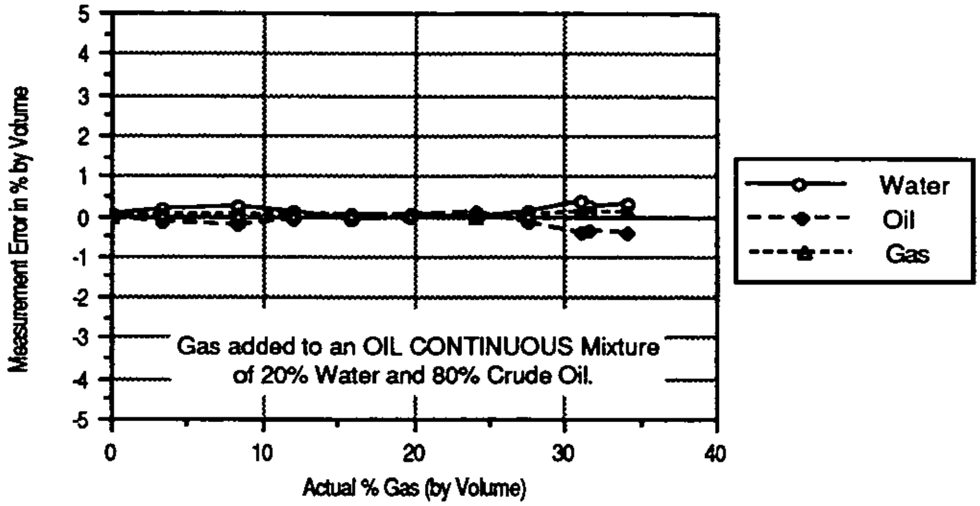

Figure 6 Measurement results for gas injected into a liquid mixture containing 20% water in crude oil.

In Figures 5 and 6, the maximum measurement for any of the component fraction measurements is less than 0.5%. Even when the water content was only 1 % as shown in Figure 5, the meter measured it quite accurately. For all the oil continuous runs performed to date the maximum error has been 0.7%. This compares well with the historically accepted accuracy level of ±3% to ±5% at which a multiphase fraction meter would be useful to the oil companies.

Figures 7 and 8 below show an even more remarkable set of results. These figures illustrate the meter's performance when measuring saltwater continuous oil, water and gas mixtures. Here too the measurement accuracies are far better than the levels deemed to be acceptable to the industry.

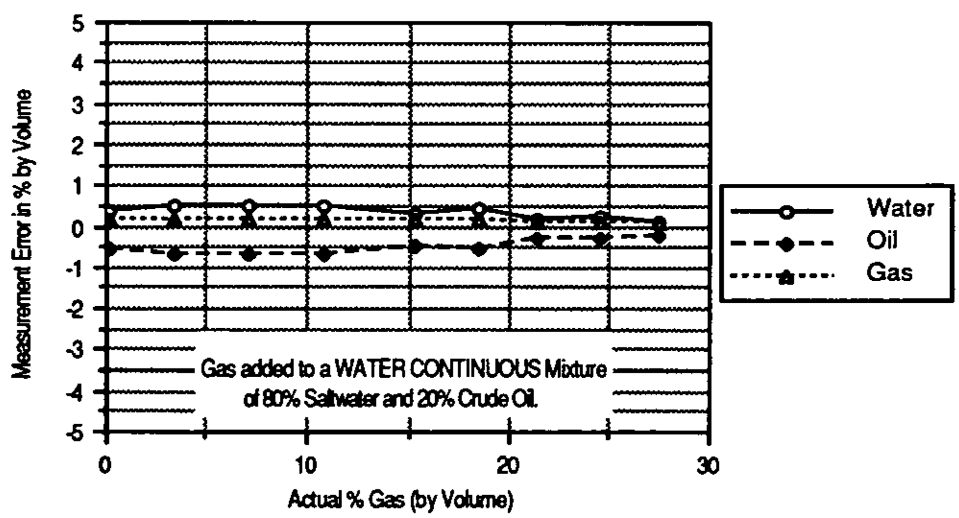

Figure 7 - Multiphase Fraction Meter performance with saltwater continuous mixture initially containing 80% water and 20% crude oil.

For all the water continuous measurements performed to date, the measurement error has never exceeded 0.8% for any of the components. If and when these results are confirmed by future field trials, the oil industry will have the multiphase fraction meter it has been seeking for so long and one that exceeds all expectations.

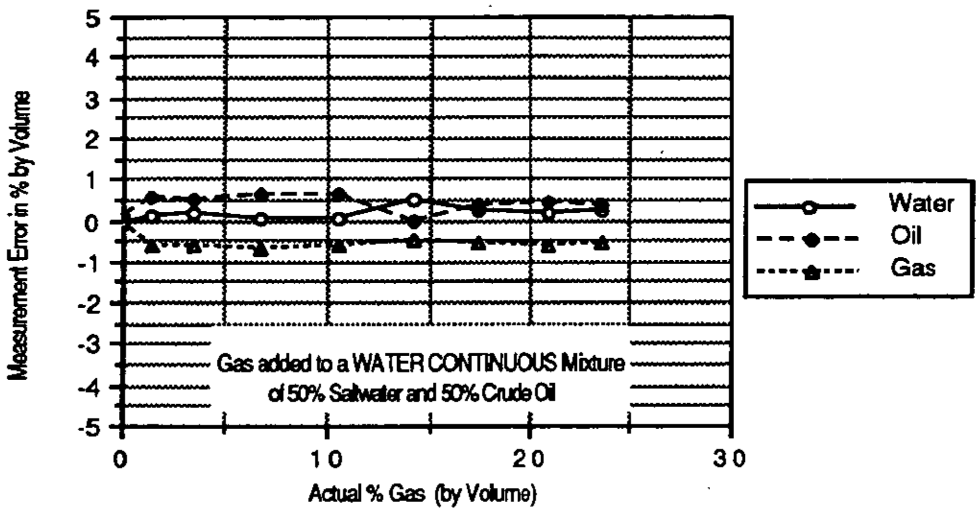

Figure 8 Multiphase Fraction Meter - More saltwater continuous results.

5 CONCLUSIONS

The remaining questions are: 1) can the Muli-Fluid meters perform in the field? and 2) can they be installed and operated easily. The answer to the first question will have to wait for actual field trial results. But all experience and results to date indicate that they will perform equally well in the field.

The answer to the second question is an unqualified yes. All three meters will be spool pieces of modest length. The fiscal meter will be no longer than 4 pipe diameters while the net oil meter and multiphase fraction meter will be about 7 pipe diameters in length.

Of the three meters, calibrating the net oil meter will be the easiest. It only requires that the operator keys into the meter the density of the production oil and the conductivity of the formation water. Conversely, the calibration can be performed remotely if desired. The oil density and the water conductivity are usually known for most production lines.

To calibrate the multiphase fraction meter, the density of the formation water will needed to be entered into the instrument in addition to the oil density and the water conductivity. Quite clearly, given these simple calibration requirements, the Multi-Fluid multiphase fraction meter will be straightforward to install subsea. They can be remotely calibrated and recalibrated as necessary. It is one of the most important advantages of these meters that they can be this easily calibrated and that the important calibration parameters are ones that do not change much over time.

The fiscal water cut meter may also prove to be as easy to calibrate as the net oil meter, that is it may be possible to calibrate the fiscal meter only with the crude oil density and the water conductivity only. However, preliminary results indicate that it may be necessary to calibrate fiscal meters more specifically to given crude oils according to the dielectric constants of those oils. If this proves to be the case, it will obviously complicate the installation and usage of the meter, but not enough to outweigh the advantages inherent in continuous, full-bore water cut metering to fiscal standards.

References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL

Note that this reference was not part of the original paper, but has been added subsequently to make the paper searchable in Google Scholar.