# Composition Measurement of Multiphase Flow

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## 1    INTRODUCTION

The successful operation of most types of multiphase meters hinges among other things on accurate PVT properties at the operating conditions [1, 2].  As pressure and temperature change, the gas and oil properties also change according to the total wellstream composition.  Over the lifetime of a reservoir the wellstream composition will gradually change and thus the composition or stored PVT tables used in the MPFM flow-computer needs to be updated.

Traditionally the total wellstream composition found by sampling gas and oil from a test separator.  Bottom hole sampling (BHS) can also be used as long as the reservoir conditions allow this.  Otherwise gas and oil or condensate must be sampled from a multiphase wellstream, usually close to the MPFM or WGM location.

This creates two challenges:

1. Obtaining high quality PVT gas and oil samples from multiphase flows is considerably more error prone than sampling from a separator.
2. The recombination factor for the gas and oil compositions needed to find the wellstream composition are derived from the measured gas and oil flow rates (or GOR) measured by the MPFM.

Regarding point 2 one will easily realise that if the MPFM measurements are very inaccurate for some reason, the updated wellstream composition could be worse than the old one.

To address these issues Expro has for many years employed miniaturised PVT sampling equipment suitable for wet-gas and multiphase flows.  This eliminate the need to divert the flow though test separators or other equipment and also the need to break into the flow line to install temporary sampling devices or reference flow meter devices.

This equipment can sample from a multiphase flow lines, separate the gas and oil at flow line conditions and transfer sufficient sample volumes to standard PVT oil and gas sample bottles with compositions that are the same as the flowline fluids.

The same sampling equipment is used with the MultiTrace technique. MultiTrace gives independent measurements of the flow rates and can be used to check the MPFM or WGM.

This is further described in the following. However, in this paper the main focus is on a more novel and experimental technique. This involves the direct determination of the gas/oil recombination factor and GOR directly from PVT samples, thus sidestepping any type of flow measurement.

## 2      MULTPHASE METERING AND PVT-SAMPLING

Expro has provided PVT sampling from multiphase flow lines for more than 20 years. The MultiTrace technique for flow measurement also involves multiphase sampling. Thus Expro has developed sampling equipment to serve both needs.

 One common mode of operation is the following:

Permanently installed venturi-type wet-gas meters are regularly updated (once a year or so) with new liquid flow rates for the over-reading correction to the gas rate [3]. This is done by using tracer measurements of the condensate and water flow rates. At the same time PVT gas- and condensate samples are collected.

The procedure for a typical WGM installation is briefly described as follows [4], [5]:

1. MultiTrace is used to measure the condensate and water flow rates
2. PVT gas and condensate samples are collected from the flow-line.
3. The WGM gas rate over-reading is found using the liquid rates obtained by MultiTrace.
4. The WGM gas rate and the MultiTrace condensate rate are used to find the GOR and recombination ratio for the gas and condensate compositions.
5. The WGM flow computer is updated with new PVT tables based on the updated wellstream composition.

When the need arises the gas flow rate can be measured using the MultiTrace gas tracer instead.

A more recent development is the Expro Sonar clamp-on meter used together with the MultiTrace technique. This is used for periodic production testing on gas-condensate production wells. The tracer technique provides the minor water and condensate flows while the Sonar meter provides the gas rate after a small correction due to the liquids. All that is required is suitable tracer injection and sampling points. The clamp-on Sonar only needs a short stretch of straight pipe for the installation. This is being used on wet-gas production wells that are operated without any permanent flow metering instrumentation.

Figure 1. Bank of WGMs for wellstream monitoring

## 2.1 PVT Sampling In Multiphase Flow

Compared to separator sampling it is more challenging to obtain high quality PVT samples from multiphase flow lines. The available sample point(s), pressure and temperature conditions and the sampling equipment needs to be evaluated together before the job to ensure good results.

The issues that must be addressed when sampling from multiphase flow lines:

- Nature of the sample points
- Accurate pressure and temperature control during sampling
- Gas/oil/water separation during sampling

Often both gas and liquid will be drained together from a sample point on a multiphase flow line. In horizontal flows the flow regime will often be such that even if not stratified, there is accumulation of gas towards the top of the pipe and mostly liquid near the bottom. For a sample-point the at the 12 o'clock position one may reasonably expect to sample gas, but often also some oil or condensate, depending on the flow regime. But at high gas volume fractions (GVF) and stratified flow it may be impossible to sample any oil out of such points.

Sample points in the 6 o'clock position on the other hand will often make it impossible to sample gas. If there is significant amounts of water it can even be difficult to sample oil or condensate from valves at the bottom of the pipe.

In vertical flows it is more unpredictable what phases will be sampled from a sample point but often the sample will be dominated by liquid. This can make gas sampling difficult in some cases. The gas/liquid ratio can also show large variations with the rate the sample is drawn from the sample point.

The use of injectable sampling probes can significantly reduce these problems.  With these the point of sampling can be placed anywhere over the pipe cross-section. Thus when sampling for oil or condensate the probe can be placed so that a minimum of gas and water is sampled along with the oil. However, this requires that the sample point is fitted with a DBB valve assembly of minimum 16 mm bore for the Expro type probes. Sufficient spacing around the sample point is also necessary in order to install the probe. DBB valve assemblies are often found to be more than a meter in length.  This necessitates the use of quite long injectable probes in many cases.   Shorter, telescopic type probes have now been developed and are presently being tested.
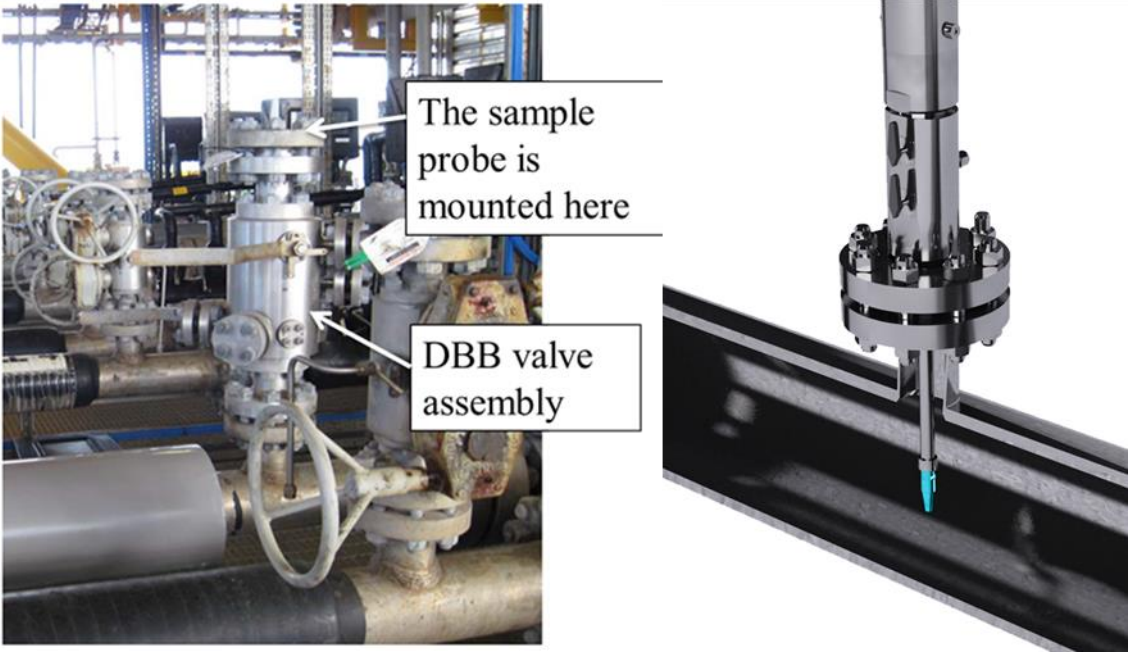


Figure 2. Sample point with Double-Block-Bleed valve and drawing of the probe.

In general gas, oil and water will be sampled together. These must be separated at the wellstream pressure and temperature before transfer to PVT bottles. For PVT sampling accurate control of the pressure and temperature is important while this is less critical for the tracer flow measurements. The Expro Mini-separator is used for multiphase PVT sampling, MultiTrace sampling as well as onsite FVF and GOR2 measurement



The mini-separator is operated at full flow line pressure, up to 250 bar, 130 $^o$C. An internal electrical heater (Exd) is used to reheat and keep the incoming sample stream at the flow temperature.

Fig 3. Mini-separator

The operator of the mini-separator ensure that the sampling rate is sufficiently low so that only negligible pressure drop occurs from the sample point and that the retention time in the separator is long enough for full separation. If there is a large amount of water, this can be drained while oil or condensate is accumulated inside the mini-separator.

A heat traced or thermally insulated, flexible high pressure sampling line connects the mini-separator to the sample point.

It is important that the samples are as pure as possible. Typically the gas is collected in fixed volume sample bottles. In the PVT lab these are heated above the temperature at the sample point to evaporate any liquids that that have condensed out of the gas. This procedure will fail if also oil or condensate has been sampled into the cylinder. Partial evaporation of the oil or condensate will occur and this will alter the gas composition. Since the bottles are fixed volume it is also impossible to heat them so that both the pressure and temperature of the flow is matched. Thus it is impossible to make adjustments in order to fully match the gas composition of the flow.

Oil and condensate are collected on piston bottles where the volume can be adjusted somewhat. With these one can adjust the volume and pressure to some degree after re-heating so that the pressure and temperature of the flow can be matched. But high purity oil samples are preferred since this makes the procedure is less prone to errors.


## 3      MEASURING THE WELLSTREAM COMPOSITION

Measuring the wellstream composition using single phase samples (BHS) is relatively straight forward. The single-phase sample is flashed to atmospheric conditions is the lab, and the amounts of "dead" oil or condensate and of the evolved gas are carefully measured.  Tiny samples of the gas and oil are introduced into gas chromatographs (GC) which measure the gas and liquid compositions (the detailed molecular make-up of the fluids).  Also the densities and average molecular weights of the fluids are measured or directly calculated form the compositions.  The molar volumes are found by the dividing the average molecular mass by the density.  This information allows one to determine the molar gas and oil fractions, and the reservoir composition is determined by mathematically recombine the flashed gas and dead oil compositions.

PVT samples from separators or multiphase flows are analysed in a similar way.  The pressurised oil sample is analysed essentially like a single-phase sample described above. This gives the live oil composition in the multiphase flow.  The PVT-sample of the gas phase is also analysed.  The final crucial step is to recombine this gas composition with the live oil composition to obtain the total composition of the flow.  This last step requires the input of gas and oil flow rates or GOR from separators, MPFMs/WGMs, tracer measurements or some combination of the above.

Of course, any uncertainty or errors associated with these flow metering technologies will cause errors in the total flow and reservoir composition.

When using a MPFM or WGM there is a higher risk for the measured gas/oil ratio to be poor compared to a test separator. Thus there is a higher risk that the well compositions

will be in error, and indeed the new, updated composition could be worse than the old composition for the wellstream.


## 3.1    Obtaining the wellstream composition without flow metering


A new method for finding the total composition of multiphase flows described in the following. The new method exploits the partitioning changes that take place between the gas and oil when the pressure or temperature of the flow changes.

By utilizing the fact that different hydrocarbon molecules partition differently between the gas and oil (or condensate) phases, and also taking advantage of the fact that this partitioning is pressure and temperature dependent, it is in fact possible to calculate the wellstream composition from gas and oil samples taken at two different pressure and/or temperature conditions [6].

When the flow goes through a change in pressure and/or temperature the oil and gas compositions will change but the overall wellstream composition will remain the same since we can safely assume that no chemical reactions occurs within the flow because of the change in pressure or temperature.  Significant changes to the oil and gas compositions can occur between the upstream and downstream conditions of a choke, heat exchanger or between the inlet and outlet of a long pipeline.  Of course, not only do the compositions change but also the gas and oil fractions.

Often a significant change in pressure can be induced at the same location by choke adjustment.  Thus the gas and oil can be sampled at the same location before and after the choke change as long as the well feed composition remains the same.

From the gas and oil compositions sampled at (at least ) two different thermodynamic conditions the gas and oil gas and oil molar fractions are calculated, and thus also the volume fractions since also the molar volumes of the samples are known from the lab analysis.

The method thus requires multiphase PVT sampling at two different pressures and/or temperatures.  The gas and oil (or condensate) samples are then analysed as usual and the resulting 4 compositions (2 gas and 2 oil) are processed according to the new technique.  The end result is the total well-stream hydrocarbon composition as well as the gas and oil molar fractions and GOR at both sampling locations.

Note that this does not involve any isokinetic or other types of sampling where gas and oil are collected in proportions that correspond to well flow.  All that is needed is samples of gas and oil in sufficient amounts necessary to perform the usual PVT lab analysis.

Since the method hinges on compositional changes, naturally the accuracy of the GC analysis becomes more important. Not only is the GC analysis used to obtain the gas and oil compositions, but also the gas and oil recombination factor (the gas and oil molar fractions) to get the well-stream composition.

If pressures and/or temperatures at the two conditions are close, only small changes will occur to the gas and oil compositions and the method can break down due to the

unavoidable uncertainties in the GC analysis.  Fortunately the method will itself inform the user when this happens.


## 3.2    Mathematical Proof


Consider a hydrocarbon molecule and label it "j". The concentration of this molecule in the total flow is given by

$$z(j) = \alpha y(j) + (1 - \alpha)x(j) \qquad (1)$$

The index j will range over all components (molecular species) that were found in the analysis of the gas and oil samples.

$z(j)$ : Concentration of molecule "j" in the total flow,  $\Sigma z(j) = 100\%$

$y(j)$ : Concentration of molecule "j" in the gas phase,  $\Sigma y(j) = 100\%$

$x(j)$:  Concentration of molecule "j" in the (live) oil phase, $\Sigma x(j) = 100\%$

$\alpha$: Gas molar fraction, a number between 0 and 1.

$(1-\alpha)=\beta$: Oil molar fraction, $\alpha+\beta =1$.

The molecular concentrations are given in mol% usually.

Suppose we are able to sample the gas and oil at the two different conditions and analyse their compositions. This will result in gas and oil compositions for the upstream condition and likewise for the downstream condition.

Thus we have the molar balance equation for any molecule:


$$\alpha_1 y_1(j) + (1 - \alpha_1)x_1(j) = \alpha_2 y_2(j) + (1 - \alpha_2)x_2(j) \qquad 2$$


Here subscripts 1 and 2 refer to the two different pressure/temperature conditions.  Both sides of equation (2) represent the total concentration $z(j)$ of molecule "j" in the well-stream.

It does not matter which pressure, temperature condition is labelled 1 or 2 as long as one stick to the same convention throughout.

We now consider a different molecule denoted by k.  For example j could refer to Methane (C1) and k could refer to n-Butane (nC4).

For component k we have the same relation:


$$\alpha_1 y_1(k) + (1 - \alpha_1)x_1(k) = \alpha_2 y_2(k) + (1 - \alpha_2)x_2(k) \qquad 3$$

Thus the GC analysis of gas sample at condition 1 provides the values for $y_1(j)$ and $y_1(k)$, the analysis of oil sample at condition 1 provides the values for $x_1(j)$ and $x_1(k)$ and the same for the samples collected at condition 2.

In equations 2 and 3 all values are known from the sample analysis except the values for the molar fractions, $a_1$ and $a_2$.

The reader will now probably recognise that equations 2 and 3 constitute two equations with two unknowns, $a_1$ and $a_2$, so this can be solved. It only takes a little bit of algebra to solve this. In order to simplify somewhat we can define the quantities:

$$A_1(j) = y_1(j) - x_1(j) \qquad (4)$$

$$A_2(j) = y_2(j) - x_2(j) \qquad (5)$$

$$A_1(k) = y_1(k) - x_1(k) \qquad (6)$$

$$A_2(k) = y_2(k) - x_2(k) \qquad (7)$$

If we choose to first eliminate $a_2$, we find for $a_1$:

$$\alpha_1 = \frac{[x_1(j) - x_2(j)]A_2(k) + [x_2(k) - x_1(k)]A_2(j)}{[A_2(j)A_1(k) - A_1(j)A_2(k)]} \qquad (8)$$

And then also for $a_2$:

$$\alpha_2 = \frac{[\alpha_1 A_1(j) + x_1(j) - x_2(j)]}{A_2(j)} \qquad (9)$$

Thus the molar fractions at both P,T conditions have been found. Working backwards using the measured molar volumes we can now also find the GOR at standard and line conditions. If a multiphase meter is installed at a location that is close to one of the pressure and temperature conditions, we could check the GOR or water-free GVF of the meter with this technique.

## 3.3    Redundancy and alternative calculations

Suppose we have N different molecules at disposal we can repeat the above calculations in M = N*(N-1)/2 different ways.

For example, using the common components C1, C2, C3, iC4, nC4, iC5, nC5, pairwise combinations among these may be inserted in to the equations above and used to calculate the molar fractions. Using these 7 molecules the calculations can be performed

in 7*6/2 = 21 different ways. All should give the same result in a perfect world (or with perfect GCs). With non-perfect GCs there will be scatter among the results. One can calculate the average and RMS deviations as well from the results and evaluate the overall uncertainty. However, experience shows that in order for this type of calculations to succeed a very large pressure change is needed (70 - 80 bar or more) in order to have acceptable uncertainty in most cases.

However, there are other, more robust ways to find the molar fractions. Involving more than two molecules at the same time will reduce the sensitivity to errors in the GC analysis.

One can for example use error minimisation techniques where one seeks to find the molar fractions $a_1$ and $a_2$ that minimize some error expression (= finds maximum consistency). Some examples are given below.

Define functions of $a_1$ and $a_2$ for each component molecule as:

$$z(\alpha_1, j) = \alpha_1 y_1(j) + (1 - \alpha_1)x_1(j) \qquad (10)$$

$$z(\alpha_2, j) = \alpha_2 y_2(j) + (1 - \alpha_2)x_2(j) \qquad (11)$$

We let the index j range over the molecules we choose to include in the analysis. A straight forward error minimisation is shown in equation (12):

$$E_0(\alpha_1, \alpha_2) = \sum_{i=1}^{n} [z(\alpha_1, j) - z(\alpha_2, j)]^2 \qquad (12)$$

In computer software using the above equation one would let the molar gas fractions $a_1$ and $a_2$ vary independently between 0 and 1 to find the values that minimize $E_0$.

However, it is easy to set up alternatives to the above simplistic error minimisation. A few examples other valid but non-equivalent ways to do the error minimization are shown below:

$$E_1(\alpha_1, \alpha_2) = \sum_{i=1}^{n} [1/z(\alpha_1, i) - 1/z(\alpha_2, i)]^2 \qquad (13)$$

$$E_2(\alpha_1, \alpha_2) = \sum_{k=1}^{i-1} \sum_{i=2}^{n} [z(\alpha_1, k)z(\alpha_2, i) - z(\alpha_2, k)z(\alpha_1, i)]^2 \qquad (14)$$

$$E_3(\alpha_1, \alpha_2) = \sum_{k=1}^{i-1} \sum_{i=2}^{n} [z(\alpha_1, k)/z(\alpha_1, i) - z(\alpha_2, k)/z(\alpha_2, i)]^2 \qquad (15)$$

One can set up equations also involving 3 (or more) different molecules at the same time:

$$E_4(\alpha_1, \alpha_2) = \sum_{k=1}^{n-2}\sum_{m=2}^{n-1}\sum_{p=3}^{n}\left[\frac{\{z(\alpha_1,k) - z(\alpha_2,m)\}}{z(\alpha_1,p)} - \frac{\{z(\alpha_2,k) - z(\alpha_1,m)\}}{z(\alpha_2,p)}\right]^2 \quad (16)$$

Note that by permuting the roles of components k, m and p in (16), one obtains other independent minimization criteria. The point with all this is that one obtains minimisation criteria which have different and often contradictory sensitivity to unavoidable errors in the GC analysis of the molecular concentrations. By averaging over many such minimisation criteria one can improve the accuracy greatly. This allows one to use this technique at much smaller pressure and temperature differences than what more straight forward mathematical techniques allows.

Only ones own imagination and patience will limit how many different ways on can set up such error minimisation equations or other mathematical techniques. The above gives only a small taste.

Further improvements can be reached in many cases by noting that for heavy molecules from ca C9 or C10 and heavier, the concentration in the gas phase of these molecules is usually zero or negligible. Thus equation 2 becomes:

$$(1 - \alpha_1)x_1(j) = (1 - \alpha_2)x_2(j) \quad\quad\quad (17)$$

Thus for the heavy components we can define a proportionality factor P:

$$P(j) = \frac{\beta_2}{\beta_1} = \frac{1 - \alpha_2}{1 - \alpha_1} = \frac{x_1(j)}{x_2(j)} \quad\quad\quad (18)$$

When the analytical results of the liquids are accurate the various P(j) for heavy molecules (or pseudo-components), C10, C11 etc should all be very similar. If there is some scatter among them one should calculate an average P and use this.

Thus instead of letting both $\alpha_1$ and $\alpha_2$ vary freely in the error minimization shown above one can let for example only $\alpha_1$ vary and let $\alpha_2$ be calculated by the factor P and $\alpha_1$. In terms of P and $\alpha_1$, equation (18) gives for $\alpha_2$:

$$\alpha_2 = 1 - P(1 - \alpha_1) \quad\quad\quad (19)$$

Substituting this for $\alpha_2$ in error minimization expressions above will in most cases give more accurate results, since the factor P can be determined with low uncertainty, usually.

To improve further, one is free to exclude any molecule that is suspected to be poorly measured. Components that are only present in amounts that cannot be accurately measured should be excluded or lumped together with similar molecules (similar partitioning behaviour or molecular weights). Components which usually have very small concentrations like cyclo-C5, Benzene, Toluene, xylenes etc. are lumped together with

components like C5, C6, C7, C8 because of this. This also tends to increase the accuracy for these major components. $CO_2$ must be excluded if there is significant amounts water in the flow. This is due to partitioning into the water phase. $N_2$ is often measured poorly and is usually left out unless the N2 is fairly high in the sampled gases.

The component C2 (Ethane) is often found to partition in quite similar ways between the gas and liquid phases, and is thus not very responsive to thermodynamic changes. Therefore it is sometimes beneficial to also exclude C2 from the calculations. In some conditions this may also apply to C3 (Propane) but in those cases one can use often use C2 instead.

Naturally, the gas and oil compositions at both conditions must be treated in exactly the same way when lumping together or excluding components.

## 3.4    Application on Field Data

The easiest way to demonstrate the method is on gas and liquid compositions obtained from test separator samples. Usually the test separator flow rates are quite accurate and will thus provide an accurate gas/oil recombination ratio to use as reference.

Often during well-tests oil and gas PVT sets are sampled at different chokes. A change of choke size tends to cause changes to the operating pressure and temperature of the test separator. Thus oil and gas samples that have been sampled at different chokes will have different compositions due to the P, T changes.

The data used is this section is from a well test performed for a major oil company a few years back.

The gas and condensate compositions are from two PVT sample sets from a test separator. The sets were sampled during two different flow periods with different chokes. In main flow period 1 (MF-1) the test separator P, T was 34.3 Bara, 43.9 °C, while in flow period 2 (MF-2) the separator P, T was 45.4 Bara, 37.2 °C. The separator measured GORs were ca. 2900 Sm3/Sm3 with ca 11% variation in the measured GOR between MF1 and MF2.

The condensate volume fractions (LVF) at the two different PT conditions were ca. 1.5% and 2.10%. Thus it would probably be difficult for most types of multiphase metering technology to measure these volume fractions (and liquid flow rates) accurately and thus provide an accurate recombination ratio for the well-stream composition.  This fact is the main motivation for using this particular dataset. However, the temperatures are similar and the pressure difference is only 11 bar, which make this a border-line case for what is possible to use with this method.  Earlier work has shown that typically 20 to 30 bar pressure difference is needed for acceptable results.  Also the quality of the GC analysis in each case will weigh heavily on what can be achieved with this method.

 Table 1 shows the separator gas and live condensate compositions at the two different test separator sampling conditions.

**Table 1. Gas and condensate compositions at the two conditions**

| Component | Main Flow 1 P1= 34.3 bara, T1 = 43.9 degC | | Main Flow 2 P2 = 45.4 bara, T2 = 37.2 degC | |
|---|---|---|---|---|
| | Gas | Condensate | Gas | Condensate |
| N2 | 0.15 | 0.006 | 0.155 | 0.013 |
| CO2 | 0.224 | 0.061 | 0.219 | 0.08 |
| C1 | 93.407 | 13.001 | 93.607 | 17.002 |
| C2 | 3.539 | 2.323 | 3.497 | 2.937 |
| C3 | 1.338 | 2.33 | 1.303 | 2.841 |
| iC4 | 0.292 | 0.994 | 0.277 | 1.147 |
| nC4 | 0.431 | 2.068 | 0.403 | 2.313 |
| iC5 | 0.168 | 1.696 | 0.15 | 1.763 |
| nC5 | 0.16 | 2.275 | 0.141 | 2.299 |
| C6 | 0.163 | 6.064 | 0.138 | 5.787 |
| C7 | 0.099 | 11.203 | 0.084 | 10.348 |
| C8 | 0.022 | 8.911 | 0.0198 | 8.179 |
| C9 | 0.005 | 5.201 | 0.005 | 4.763 |
| C10 | 0.002 | 6.164 | 0.002 | 5.656 |
| C11 | 0.001 | 4.528 | 0.000 | 4.168 |
| C12+ | 0.000 | 33.175 | 0.000 | 30.704 |

The concentrations are given in mol%. Minor components like Benzene, Toluene etc. have been lumped into neighbouring components.

This is a case where the PVT samples at the two different conditions have been sampled at the same physical location (test separator). The change in choke has generated the two different thermodynamic conditions that are needed for this method.

Using test separator compositions like this is a bit risky since there could be a change in the total well-stream composition as the choke is changed. This method is sensitive to changes in the total composition. However, the recombined separator compositions at the two flow periods are quite similar and they also match quite well the compositions of BHS single phase samples taken before and after the well test.

The reservoir compositions for the two BHS samples and the recombined test separator gas and condensate compositions are given below for a few of the components.

**Table 2. BHS and recombined separator compositions**

| Component | BHS 1 | Recom Sep MF1 | Recom Sep MF2 | BHS 2 |
|---|---|---|---|---|
| C1 | 89.614 | 89.825 | 89.763 | 89.591 |
| C3 | 1.376 | 1.382 | 1.380 | 1.401 |
| nC5 | 0.269 | 0.254 | 0.249 | 0.268 |
| C7 | 0.445 | 0.411 | 0.412 | 0.445 |
| C10 | 0.293 | 0.276 | 0.285 | 0.286 |
| C12 + | 1.536 | 1.478 | 1.541 | 1.514 |

Only a few of the components are shown in table 2, but this nevertheless shows that the overall wellstream composition probably remained constant during the well-test. The

deviations seem to be in line with the unescapable uncertainties both in separator flow rates and in the laboratory analysis. Also the bottom-hole samples show that the reservoir remained in single phase conditions during the flow tests.

For Main Flow 1 the test separator gas and condensate compositions were recombined with gas and liquid molar fractions $\alpha_1$ = 0.95529 (and thus $\beta_1$=0.04471) in order to find the reservoir composition. The molar fractions were determined from the separator gas and condensate flow rates and the fluid properties in the usual manner. Likewise for Main Flow 2 the molar fractions were determined to be $\alpha_2$= 0.94983, $\beta_2$ =0.05017.

At this stage it is possible to quickly check the consistency between the condensate compositions and the molar fractions used for the recombinations for MF1 and MF2. For the C12+ concentrations in Table 1 we see that P = $x_1/x_2$ = 33.175/30.704 = 1.0805. For C11 we find likewise P = 4.528/4.168 = 1.086. However, the recombination data from the test separator gives

$P_{sep}$ = $\beta_2/\beta_1$ = 0.05017/0.04471 = 1.122.

This shows that there is some inconsistency in the recombined test separator compositions. This is likely caused by uncertainties in the test separator data and/or in the PVT laboratory data (like molecular weight measurements for example). The inconsistency is not very visible in the recombined compositions since these are heavily dominated by the gas compositions; the gas molar fractions are close to 1.

By using the new method we now proceed to calculate the gas and condensate molar fractions purely from the gas and condensate compositions in Table 1. Since the difference between the two conditions are small (ca. 11 bar pressure difference, and small temperature difference), simplistic calculations of the gas and condensate fractions will be very inaccurate. Also describing hundreds of different, independent calculations and showing their results is not feasible in this paper.

Instead another useful method is that is easier to implement is described in the following. This method also tends to be among the better ones when the pressure difference is small.

The above defined proportionality factor P (=$\beta_2/\beta_1$) can also be calculated for any component as:

$$P = \frac{y_1 - x_1}{y_2 - x_2} - \frac{1}{1 - \alpha_1}(y_1 - y_2)/(y_2 - x_2) \qquad (20)$$

This collapses back to P= $x_1/x_2$ for molecules that are not present in the gas phase ($y_1$ = $y_2$= 0), see also equation (18). The index indicating the different molecules is dropped from now on.

It can be easily shown that using P, the oil or condensate molar fraction at PT condition 1 is given by:

$$\beta_1 = \frac{y_2 - y_1}{[x_1 - y_1 + P(y_2 - x_2)]} \qquad (21)$$

This is valid for all molecules that have non-zero gas concentrations.

The procedure now proceeds as follows:

1. Use equation (20) to calculate P-factor from C1 as function of $\alpha_1$ which is used as free tuning parameter.
2. Use this P and equation (21) for calculating the liquid molar fractions $\beta_1$ for the other molecules up to the C8 component.
3. Calculate the average molar $\beta_1$ for the 5 "light" components C2, C3, iC4, nC4, iC5.
4. Calculate the average molar $\beta_1$ for the 4 "heavier" components nC5, C6, C7, C8.
5. Vary $\alpha_1$ and (thus also P) until the best match is found.

For finding the best match one can use the following quantities:

$$\Delta_l = (1 - \beta_{1l} - \alpha_1)^2 \qquad (17)$$

And:

$$\Delta_h = (1 - \beta_{1h} - \alpha_1)^2 \qquad (18)$$

The subscripts l and h refers to the average of the light and heavy components respectively. These quantities should go to zero approximately simultaneously as both $(\beta_{1l} + \alpha_1)$ and $(\beta_{1h} + \alpha_1)$ should add up to 1 at a value of $\alpha_1$ that should be close to the true $\alpha_1$. In the Fig. 4 below the sum of $\Delta_l$ and $\Delta_h$ are plotted as function of the tuning parameter $\alpha_1$:
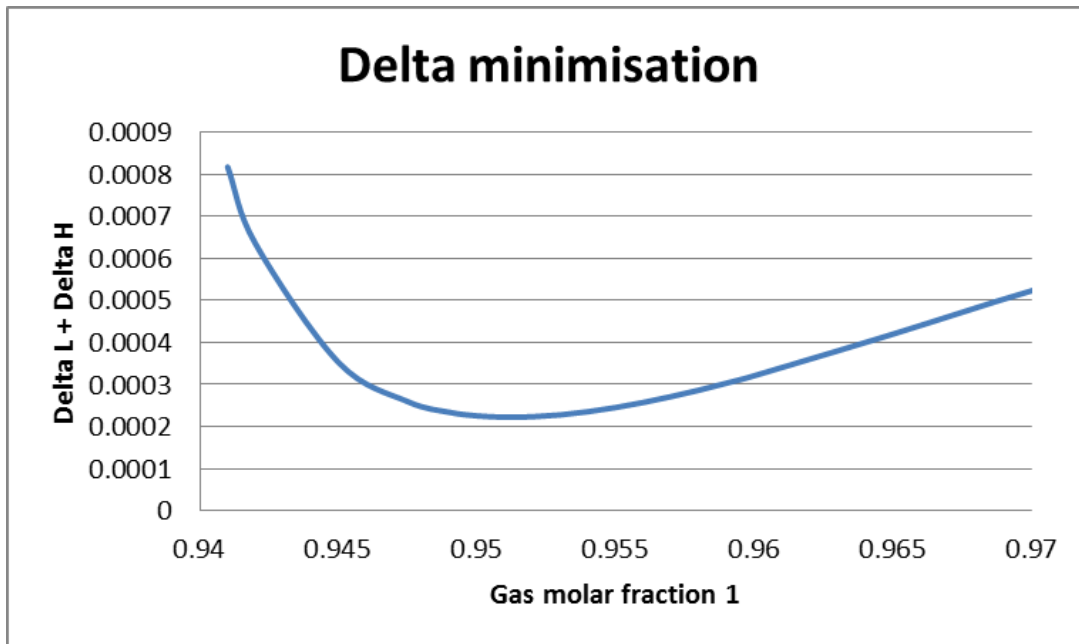
Fig. 4. Finding the minimum of Δl + Δh.

The minimum was found to be at $a_1$ = 0.951 and thus $\beta_1$ = 0.0490. At this value for $a_1$ the P-factor obtained from the C1 component has the value of P = 1.105. Instead of performing a similar tuning for $a_2$ we bypass this and use equation (18) instead to calculate $\beta_2$ = $P\beta_1$ =1.105*0.049 = 0.05403.

In finding the minimum $a_1$ was varied in large steps first. This established that the minimum was in the vicinity of $a_1$ = 0.95. Then $a_1$ was varied in steps of 0.001 in a small range around 0.95. The results are summarised in Table 3.

**Table 3. Measured liquid molar fractions**

| Method | MF1 | MF2 |
|---|---|---|
| Test Sep | 0.0447 | 0.0502 |
| This work | 0.049 | 0.054 |

Compared to the condensate molar fractions calculated from the test separator flow rates given above, we see that using this method the condensate fractions are almost 10% larger (relative). The uncertainty of the molar fractions derived from the test separator data cannot be estimated here but typically the uncertainty would be ca 5%. There may be up to ca 2-3% additional uncertainty from the lab data for conversion from flow rates to the molar liquid fractions. As noted earlier there is some inconsistency in the recombined compositions based on the test separator results, so this can also contribute to the discrepancy.

However, given the small difference in pressure and temperature in this case very accurate results cannot be expected. The uncertainty tends to decrease rapidly with increasing difference in pressure when the two temperatures are similar.

A detailed uncertainty analysis on this technique is quite involved and cannot be explored in a short paper. But by calculating a large number of results as described earlier, one can calculate the average and the RMS variation around this to estimate the uncertainty

in the results.  In this way the technique can be said to describe its own measurement uncertainty.

As noted before the uncertainty using this technique arises from the GC uncertainties. These are partially systematic (imperfect calibration), and partly due to random variations (repeatability). The latter can be reduced somewhat by averaging over repeated the GC runs. This was not done in the present case.

But the main point being made here is that it may be difficult to achieve this sort of accuracy for an MPFM at the high GVFs corresponding to this case.  Thus this method can be useful for obtaining the recombination factor if there is doubt about the MPFM and other alternatives are difficult or impossible to use.

The reader might have noticed that with this measurement principle the molar fractions are found without using the pressure and temperature at the sampling conditions. However, the knowledge of these is of course needed in order to calculate the GOR at the flow conditions.

Possible applications for the new technique are briefly summarised below:

- Alternative to Bottom-Hole sampling (BHS) for measuring the reservoir composition
- Updating the composition or PVT data tables in multiphase meters flow computers
- Check/verify the GVF or GOR reading of multiphase meters

## 5    SUMMARY AND CONCLUSION

A new technique for multiphase composition measurement has been presented.  With this method one can find the overall well-stream (reservoir) composition as well as the gas and oil molar and volume fractions without using any flow metering equipment.

This method can be useful in situations where bottom hole sampling is not feasible or in situations where the output from multiphase meters may not give accurate gas/oil recombination ratio for finding the overall composition from the gas and oil samples.  It also provides a way to check the operation of multiphase and wet-gas meters by providing independent GVF or GOR measurement at the line condition that can be compared to the meter reading.

In order to obtain high quality PVT samples for compositional analysis, the sampling process is critical.  Usually both gas and oil enter the sampling equipment together, and accurate pressure and temperature control is needed in the sampling process.

Older techniques like the MultiTrace technique are also available for the same service.  A recent development is the combination with the Expro Sonar meter with the MultiTrace technique.  The best option(s) to use will have to be evaluated in each case.

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