Uncertainty analysis of multiphase flow meters used for allocation measurements: Field experiences and future challenges

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1   INTRODUCTION

Multiphase flow meters (MPFMs) in combination with reference measurements in test separators are increasingly used for fiscal allocation purposes. This development is typically seen in fields which are developed as subsea production systems where unprocessed multiphase flows are transported to process platforms through pipelines. Statoil has experience from ownership allocation using multiphase meters from a number of different fields. CMR has performed uncertainty analyses for several Statoil operated fields; Alve, Morvin, Tyrihans, Visund Sør, Hyme and Skuld.

When MPFMs are used for allocation purposes, the hydrocarbon mass output by the MPFMs is corrected using correction factors (also denoted K-factors) in order improve the accuracy. The correction factors are calculated by comparing MPFM measurements to reference measurements in a test separator (TSP) – usually during planned calibration campaigns. Correction factors are calculated either for total hydrocarbon mass or separately for oil/gas mass. The uncertainty in the corrected hydrocarbon mass is influenced by differences in the measurement systems and measurement philosophy. Factors influencing the uncertainty include the measurement instrumentation used in MPFMs and test separator, the representativeness of the reference measurements, and the approach used to calculate correction factors. Even though single phase and multiphase measurement instrumentation improves and becomes more reliable, failure and error measurement will still occur. It is therefore of great importance that calibrations of multiphase meters are traceable such that systematic errors can be corrected.

As an example, the allocation metering system installed on Åsgard B in connection with tie-in of the Morvin field is shown in Figure 1. The ownership allocation between Morvin and Åsgard is based on multiphase metering of the Morvin flow line production, with two parallel topside multiphase meters installed at the Åsgard B platform. Subsea multiphase meters are installed for the 4 producing wells. The subsea multiphase meters are a part of the overall measurement system for Morvin, and are used both as back-up for the topside multiphase meters and for production optimization. Each topside multiphase meter can be directed to Åsgard B test separator in order to be individually calibrated. Correction factors are applied to the topside multiphase meters after each calibration. Calibrations are performed at regular intervals. The Åsgard B test separator was upgraded with traceable flow instruments prior to start-up of Morvin. Also, densitometers were installed at the oil and gas leg and water cut meters at the oil leg.

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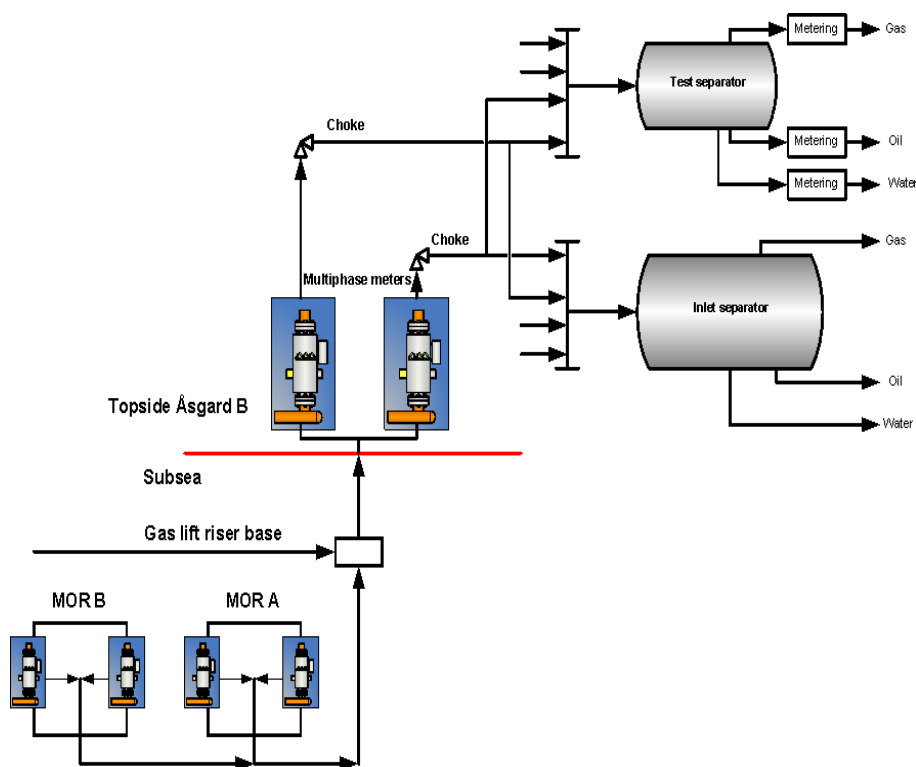
Figure 1   Morvin measurement system combining multiphase flow meters with test separator measurements as reference measurement.

The aim of the present paper is to present ongoing work and future challenges with regard to understanding and quantifying measurement uncertainties when utilizing multiphase metering systems for allocation measurements. This is done by exemplifying how differences in measurement system (e.g. measurement instrumentation and technology) may influence the uncertainty in hydrocarbon mass measured by the multiphase flow meters. In particular, the following issues are discussed:

- Influence of uncertainty in PVT compositions on the overall uncertainty,
- Use of separate correction factors for oil and gas versus a single correction factor for total hydrocarbon mass,
- Influence of flow rates and phase fractions,
- The representativeness of calibration measurements

The representativeness of the calibration measurements has significant impact on the uncertainty, and therefore special focus is put on methodology for estimating the uncertainty related to the representativeness of calibration measurements.

2   THEORY AND BACKGROUND

A sketch of a typical measurement system for fiscal allocation using MPFMs in combination with reference measurements in a test separator is shown in Figure 2. The figure shows a case with two topside MPFMs and four subsea MPFMs, but the following discussion applies to the general case with arbitrary number of topside/subsea MPFMs.

The topside multiphase flow meters (denoted MPFM 1 and MPFM 2 in Figure 2) are used for fiscal allocation purposes. In a typical setup these meters are calibrated periodically – one at a time - against the test separator. During ordinary operations the multiphase flow from the topside MPFMs is led directly to the production separator, whereas during calibration the flow from the MPFM under test is led to the test separator while the flow from other MPFM is lead to the production separator.

Gas lift in wells and riser base are measured by the topside MPFMs, and will influence the hydrocarbon mass uncertainty through changed uncertainty in the hydrocarbon composition.
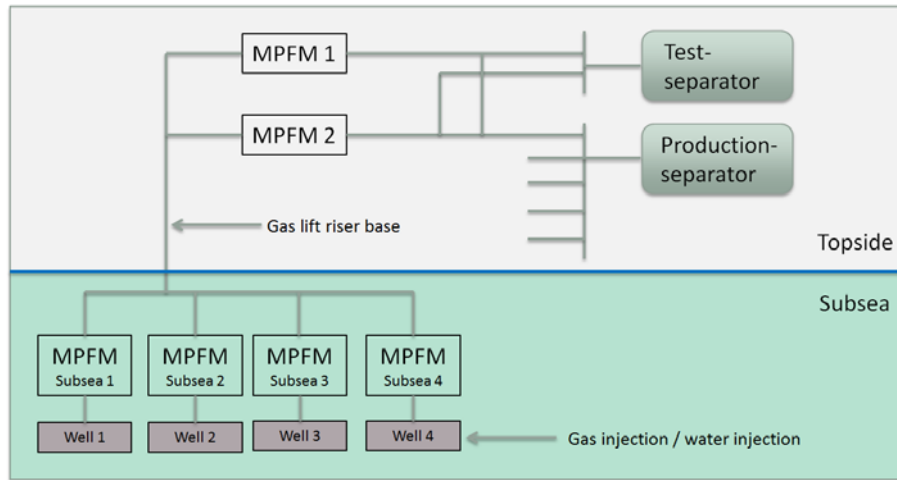

Figure 2 ***Sketch of measurement system combining multiphase flow meter measurements with test separator measurements as reference measurement.***

Two different approaches can be used for correction of MPFM measurements by test separator measurements; (1) correction based on total accumulated hydrocarbon mass or (2) correction based on oil and gas mass separately. In the first approach calibration campaigns are made in which the total accumulated hydrocarbon mass measured by the MPFM under calibration (M_{HC}^{MPFM}) is compared to the total accumulated hydrocarbon mass measured by the test separator (M_{HC}^{TSP}). A hydrocarbon mass correction factor for the MPFM under test is then calculated as

$$K_{HC} = \frac{M_{HC}^{TSP}}{M_{HC}^{MPFM}} \tag{1}$$

This correction factor (K_{HC}) is then applied to correct the MPFM measurements for the given MPFM until the next calibration campaign. The alternative approach is to use separate oil and gas correction factors where the oil mass measured by the MPFM is compared to the oil mass measured by the test separator giving a correction factor K_o, and correspondingly a correction factor K_g for gas mass.

In fields operated by Statoil the production allocation and correction of MPFM measurements is typically based on hydrocarbon mass rate rather than separate oil and gas mass. Correction based on hydrocarbon mass rate is done in order to minimize the uncertainties in the allocations, as the hydrocarbon mass is independent of the different operating temperature and pressure (T&P) conditions of the topside multiphase meters and the test separator. Thus, there is no need to convert measured data to standard (or other equal conditions) before calculating the correction factor. As will be discussed later, the uncertainty associated with such convertion can be significant.

The primary purpose of the subsea multiphase flow meters (denoted MPFM Subsea 1 to 4 in Figure 2) is production optimisation, but in addition the subsea meters function as back-up for the topside multiphase meters (Åbro 2009). While the topside meters are in normal operation, and the measured hydrocarbon mass is corrected against the test separator using the correction factors, the subsea meters are continuously compared to the topside meters. The total hydrocarbon mass rate measured by the topside meters is compared to the sum of the hydrocarbon mass rate measured by the individual subsea multiphase meters and the mass rate from the gas lift.

By comparing continuous hydrocarbon mass and water rates measured by topside meters and subsea meters, including gas lift, any deviations between the topside measurements and

subsea measurements are revealed. To map the source of such deviations, more extensive testing by using the test separator may be required.

The primary output parameters from the MPFM are component fractions and volume rates. Hydrocarbon, oil and gas masses are calculated by multiplying measured volumes with corresponding densities. Hence, the composition (PVT data) of the fluid must be known such that the densities at the operating conditions can be calculated. Any errors/uncertainties in the applied fluid composition can lead to large errors/uncertainties in measured and calculated rates. It is therefore of great importance to have accurate and updated PVT-data. The preferred approach by Statoil is to do all PVT calculations in a dedicated measurement computer, and update the MPFMs and test separator equipment with densities at their actual operating conditions. Statoil utilizes a multistage PVT model that describes the actual process. This ensures that the same PVT model is used for all calculations, such as subsea multiphase meters, topside multiphase meters, test separator and inlet separator.

The densities and flow rates of oil and gas are measured at the output of the test separator during the calibration campaigns tests, and the composition can be updated iteratively by comparing these data with calculations from the PVT model. In addition, samples of the oil and gas phases are taken during the calibration campaigns tests and subsequently analyzed in a laboratory.

Note that the MPFM also relies on knowing some fluid characteristics in order to calculate corrected volume rates and component fractions. Hence, frequent update of fluid compositions to the MPFM is still required even if component densities are calculated outside the meters.

The description above summarises the present approach used by Statoil, and is based on practical experience from a large number of field implementations as well as theoretically based considerations. In the following chapters the influence the metering philosophy has on the uncertainty in measured quantities will be described in more detail, and example cases will be presented. Before this analysis is presented, a short summary of the methodology applied for uncertainty calculations is given in next chapter

3 UNCERTAINTY MODEL FOR HYDROCARBON MASS

The uncertainty estimations made in the current work follow the method outlined in "Guide to the expression of uncertainties in measurements" (ISO-GUM, 2008). The approach used is described in Appendix A.

The uncertainty of the measured hydrocarbon mass using the approach described in Chapter 2 can be divided into the following uncertainty sources:

- Uncertainty in the primary output parameters from the MPFMs, e.g. gas volume rate, liquid volume rate and water liquid rate (WLR)
- Uncertainty in the output parameters from the reference system (test separator), e.g. densities and volume flow rates
- Uncertainty in fluid composition and uncertainties related to the PVT calculations
- The representativeness of the correction factors, based on e.g. change in process parameters since last calibration.

There are also other factors influencing the uncertainty indirectly, e.g. changes in flow rates, flow regime and temperature/pressure lead to a change in the uncertainty for the primary output parameters in both MPFMs and test separator.

The total hydrocarbon mass is typically calculated using a scheme as described below and illustrated in Figure 3,

1. During ordinary operations, hydrocarbon mass is measured by each of the topside MPFMs.

2. Corrected hydrocarbon mass from each topside MPFM is calculated by multiplying the hydrocarbon mass from each topside MPFM with correction factors.
3. Total corrected hydrocarbon mass is calculated by adding the corrected hydrocarbon mass from each MPFM.

The hydrocarbon mass produced from the field can be calculated by subtracting gas lift (if present) from the total corrected hydrocarbon mass.

In the following subsections the uncertainty related to each of these steps are discussed in more detail.
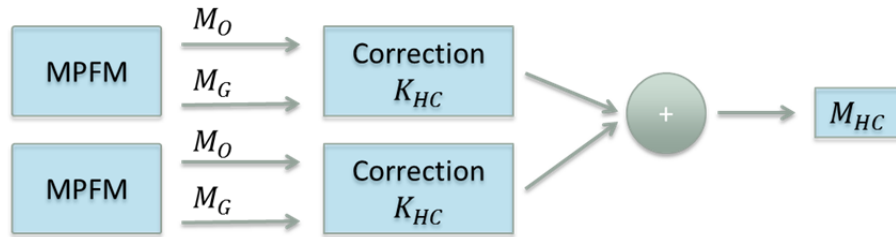

Figure 3 ***Schematic showing the approach for calculation of total hydrocarbon mass.***

3.1 Hydrocarbon mass measured by one MPFM

The uncertainty in the uncorrected hydrocarbon mass measured by a topside MPFM is dependent on the measurement technology used in the MPFM. Typically MPFM manufacturers state measurement uncertainties for liquid volume rate, gas volume rate and water-liquid ratio (WLR) – although some MPFM manufacturers use other parameters. For the example case of liquid/gas volume rate and WLR as primary parameters, the hydrocarbon mass flow rate (q_{mHC}) can be calculated as

$$q_{mHC} = q_{mo} + q_{mg} = q_{vl}(1 - \text{WLR})\rho_o + q_{vg}\rho_g, \tag{2}$$

where q_{mHC} is the hydrocarbon mass flow rate, q_{mo} is the oil mass flow rate, q_{mg} is the gas mass flow rate, q_{vg} is gas volume mass flow rate, q_{vl} is the liquid volume flow rate, WLR is the water-liquid ratio, ρ_o is the oil density and ρ_g is the gas density.

This leads to the following uncertainty model,

$$
\begin{aligned}
\left(\frac{u(q_{mHC})}{q_{mHC}}\right)^2 &= \left[\frac{q_{mo}}{q_{mHC}}\right]^2 \cdot \left(\frac{u(\rho_o)}{\rho_o}\right)^2 + \left[\frac{q_{mg}}{q_{mHC}}\right]^2 \left(\frac{u(\rho_g)}{\rho_g}\right)^2 + \left[\frac{q_{mo}}{q_{mHC}}\right]^2 \left(\frac{u(q_{vl})}{q_{vl}}\right)^2 \\
&+ \left[\frac{q_{mg}}{q_{mHC}}\right]^2 \cdot \left(\frac{u(q_{vg})}{q_{vg}}\right)^2 + \left[-\frac{\rho_o q_{mw}}{\rho_w q_{mHC}}\right]^2 \cdot \left(\frac{u(\text{WLR})}{\text{WLR}}\right)^2.
\end{aligned}
\tag{3}
$$

where q_{mw} is the water mass flow rate and ρ_w is the water density.

If water volume fraction (WVF) is used for calculation of the hydrocarbon mass instead of WLR, the uncertainty model has to be modified. This will not be discussed here.
Note that some multiphase meter vendors also report hydrocarbon mass and accompanying measurement uncertainties for hydrocarbon mass. Here the hydrocarbon mass is calculated in the MPFM based on oil and gas densities as input to the MPFM.

3.2 Hydrocarbon mass measured by one MPFM and corrected using test separator measurements

The correction factors are calculated based on planned calibration tests where MPFM measurements are compared to corresponding hydrocarbon mass measurements from a reference system, typically a test separator (see Figure 4 for illustration). For the example case of a common hydrocarbon mass correction factor K$_{HC}$, the correction-factor is given in equation (1). The calibration typically takes from 12 to 24 hours, and in this period the PVT composition is iteratively updated based on test separator measurements. Typically oil/gas densities and/or PVT composition in the MPFM are also updated iteratively during the calibration cycle.

Generally the corrected hydrocarbon mass rate $q_{mHC,corr}$ can be expressed by

$$q_{mHC,corr} = K_{HC}\, q_{mHC} \tag{4}$$

leading to the following uncertainty model

$$
\begin{aligned}
\left(\frac{u\big(q_{mHC,korr}\big)}{q_{mHC,korr}}\right)^2 = \\
\frac{1}{(q_{mHC})^2}\Bigg[q_{mo}^2 \left(\frac{u(q_{mo})}{q_{mo}}\right)^2 + q_{mg}^2 \left(\frac{u\big(q_{mg}\big)}{q_{mg}}\right)^2 \Bigg] \\
+ \frac{1}{(q_{mHC}^{TSP})^2}\Bigg[q_{mo}^{TSP^2} \left(\frac{u(q_{mo}^{TSP})}{q_{mo}^{TSP}}\right)^2 + q_{mg}^{TSP^2} \left(\frac{u\big(q_{mg}^{TSP}\big)}{q_{mg}^{TSP}}\right)^2 \Bigg] \\
+ \frac{1}{q_{mHC,cal}^2}\Bigg[q_{mo,cal}^2 \left(\frac{u(q_{mo,cal})}{q_{mo,cal}}\right)^2 + q_{mg,cal}^2 \frac{u\big(q_{mg,cal}\big)}{\big(q_{mg,cal}\big)^2} \Bigg] \\
- 2\, r_o \left(\frac{q_{mo}\, q_{mo,cal}}{(q_{mHC})(q_{mHC,cal})}\right)\left(\frac{u(q_{mo})u(q_{mo,cal})}{(q_{mo})(q_{mo,cal})}\right) \\
- 2\, r_g \left(\frac{q_{mg}\, q_{mg,cal}}{(q_{mHC})(q_{mHC,cal})}\right)\left(\frac{u(q_{mg})u(q_{mg,cal})}{(q_{mo})(q_{mg,cal})}\right)
\end{aligned}
\tag{5}
$$

where q_{mHC}^{TSP}, q_{mo}^{TSP} and q_{mg}^{TSP} are the hydrocarbon mass flow rate, oil mass flow rate and gas flow mass rate measured by the test separator, respectively. Further on, $q_{mHC,cal}$, $q_{mo,cal}$ and $q_{mg,cal}$ are the hydrocarbon mass flow rate, oil mass flow rate and gas mass flow rate measured by the MPFM during the calibration and q_{mHC}, q_{mo} and q_{mg} are corresponding mass rates measured at ordinary operations. It is notable that there is a correlation between the hydrocarbon mass measured by the MPFM during ordinary operations and during the calibration which must be taken into account in the uncertainty model. This is done through correlation coefficients as introduced in equation (20) in Appendix A – one correlation coefficient for oil mass flow rate (r_o) and a corresponding correlation coefficient for gas mass flow rate (r_g). This correlation influences strongly on the uncertainty – this will be exemplified further below in Chapter 4.

For the case with separate correction factors for oil and gas, the corrected hydrocarbon mass is

$$q_{mHC,corr} = K_o\, q_{mo} + K_g\, q_{mg} \tag{6}$$

The uncertainty model for this case has many similarities with the uncertainty model for the case with common hydrocarbon mass correction factor, but an extra uncertainty contribution must be included due to the need for converting the oil and gas masses from test separator

and MPFM to the same pressure/temperature. The detailed calculations for this uncertainty model are not included here.
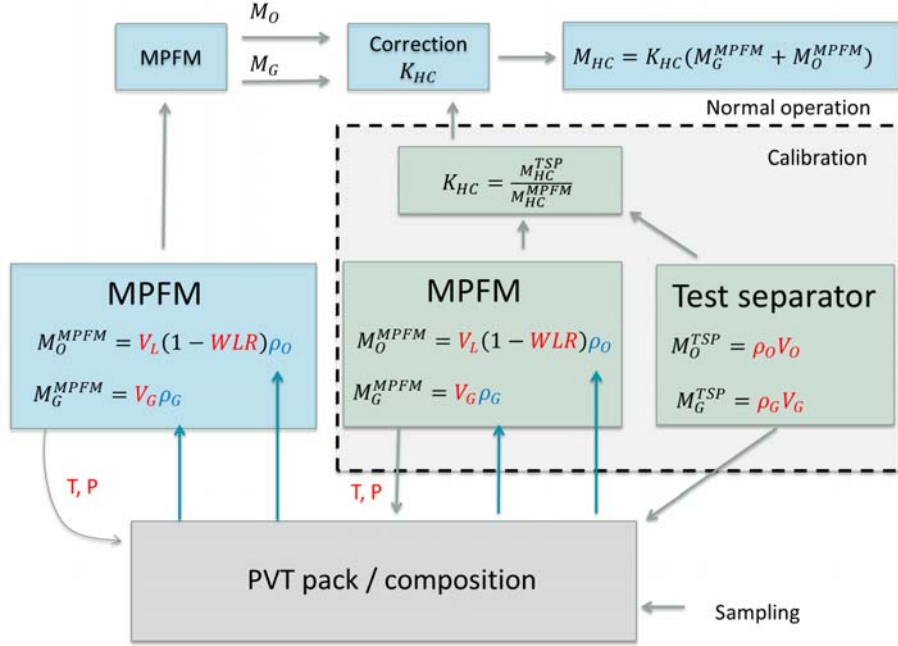

Figure 4   Schematic showing how the correction factor is calculated during the correction process and is later used under normal operations.

3.3   Calculation of total corrected hydrocarbon mass

The total corrected hydrocarbon mass for *N* MPFMs in parallel is calculated by adding the hydrocarbon mass from each MPFM (see Figure 3), giving

$$q_{mHC,corr_{tot}} = \sum_{i=1}^{N} K_{HC_i} q_{mHC_{i.}} \tag{7}$$

In the uncertainty model this gives correlation terms due to the correlation between the test separator measurements for each MPFM and due to the densities used in the different MPFMs.

3.4   Calculation of hydrocarbon mass produced from field
The actual hydrocarbon mass produced from the field is also a quantity of interest. This quantity is calculated by subtracting the gas introduced by the gas lift from the total corrected hydrocarbon mass (see Figure 3),

$$q_{mHC,corr_{tot,Field}} = q_{mHC,corr_{tot}} - q_{mHC,gaslift} \tag{8}$$

This gives the following uncertainty model,

$$\left(\frac{u\left(q_{mHC,corr_{tot,Field}}\right)}{q_{mHC,corr_{tot,Field}}}\right)^2$$

$$= \left[\left(\frac{q_{mHC,corr_{tot}}}{q_{mHC,corr_{tot,Field}}}\right)\left(\frac{u\left(q_{mHC,corr_{tot}}\right)}{q_{mHC,corr_{tot}}}\right)\right]^2 \tag{9}$$

$$+ \left[\left(\frac{q_{mHC,gaslift}}{q_{mHC,corr_{tot,Field}}}\right)\left(\frac{u\left(q_{mHC,gaslift}\right)}{q_{mHC,gaslift}}\right)\right]^2$$

4   APPLICATION EXAMPLES

In the following the developed uncertainty model is applied to some example cases in order to illustrate how different parts of the measurement system influence the uncertainty.

4.1   Example 1: Correction factor for hydrocarbon mass versus separate oil/gas correction factors

As discussed in Chapter 2, the correction factors can either be calculated as separate gas- and oil correction-factors or as a common hydrocarbon factor. One advantage of using two separate factors for oil and gas is that any *proportional* systematic errors in the primary output of the MPFM ($q_{vl}, q_{vg}, WLR, \rho_g$ or ρ_o) will be cancelled out in the calculated hydrocarbon mass when separate K-factors for oil and gas are used. This is not the case when using a common hydrocarbon K-factor.

The main drawback of using two K-factors is that the measurements from the MPFM and the test separator must be converted to the same pressure/temperature conditions All PVT calculations have uncertainties, which depend on different process conditions (e.g. pressures, temperatures, fluids). According to Statoil's PVT tool supplier the general uncertainty of PVT calculation has been estimated to 3% for oil and gas densities. This is here interpreted to be relative expanded uncertainty. Thus, this additional uncertainty must be included in the overall uncertainty analysis. This conversion is not needed if a correction factor for hydrocarbon mass is used, as the hydrocarbon mass is conserved at different conditions.

PVT calculation uncertainties in oil and gas densities must be included as part of the calculations of the hydrocarbon mass measured by the MPFM as the densities are input parameters used when calculating the hydrocarbon mass from the primary output parameters. It should be noted that there is a need for more accurate knowledge about the uncertainty associated with the PVT calculations. It is for example very unlikely that the relative expanded uncertainties in oil and gas densities are as large as 3 % if changes in temperature or pressure are small. Hence, more work should be done on mapping the uncertainty of the PVT calculation.

An example illustrating how the additional PVT calculation uncertainty affects the combined uncertainty is shown in Figure 5, which is taken from an uncertainty analysis for a Statoil operated field. In the case considered here the measurements from the test separator are converted to MPFM T&P conditions before the oil and gas correction factors are calculated. In Figure 5 the relative expanded uncertainty for oil-, gas- and hydrocarbon mass rate measured by the test separator are shown at test separator T&P conditions (upper three uncertainty bars) and converted to MPFM T&P conditions (next three uncertainty bars). It may be noted that the conversion from TSP T&P conditions to MPFM T&P conditions gives a significant contribution in the relative expanded uncertainty for gas and oil mass rate, whereas the relative expanded uncertainty for hydrocarbon mass rate is not influenced.

The uncertainty budget for the corrected hydrocarbon mass when using separate oil/gas correction factors and a common hydrocarbon correction factor is shown in Figure 6 using the data from Figure 5 as input. For the case where separate correction factors for oil and gas mass rates are used, test separator oil and gas mass rates must be converted separately to MPFM T&P conditions, leading to a large uncertainty contribution (blue uncertainty bars). For the case where a common correction factor is used, the relative expanded uncertainty in hydrocarbon mass rate is invariant to T&P conversion, leading to a significantly smaller uncertainty contribution (red uncertainty bars). The relative expanded uncertainty (95 % confidence interval) is estimated to 3.6 % when using separate correction factors and 2.8 % when using a common correction factor.

It may also be noted that if densitometers are not present at the test-separator's oil and gas-legs, the oil and gas densities must be calculated from PVT-data, and thus the 3% uncertainty

in density will give a large influence on the calculated hydrocarbon mass from the test separator. This example thus also illustrates the importance of having densitometers at the test separator.
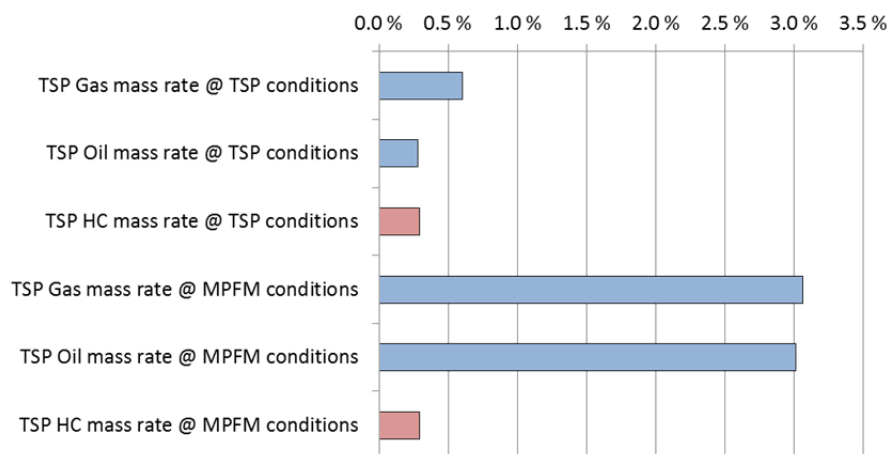

Figure 5 ***Relative expanded uncertainty for TSP oil, gas and hydrocarbon mass rates at different operating conditions – including PVT contribution due to P&T conversion.***
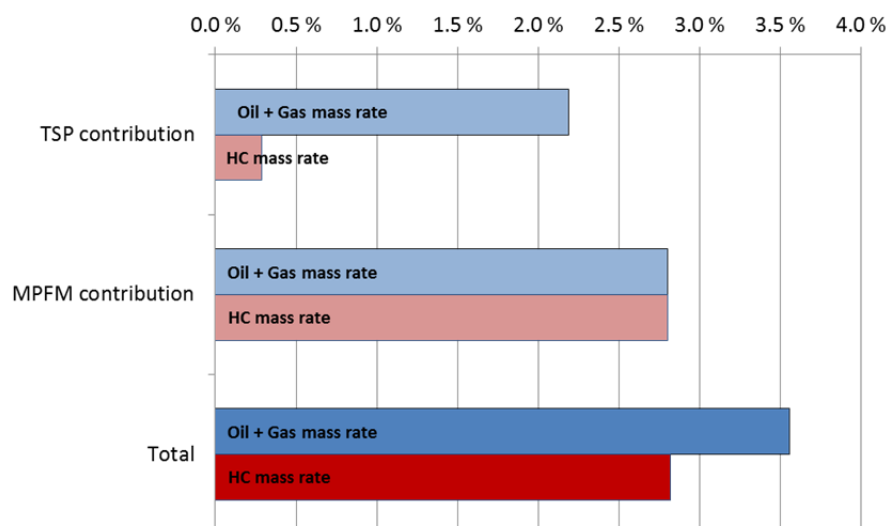

Figure 6 ***Example of the contributions to the relative expanded uncertainty in corrected hydrocarbon mass comparing the use of separate oil and gas correction factors (blue bars) and common hydrocarbon mass correction factor (red bars). The relative expanded uncertainty in corrected hydrocarbon mass is divided into contributions from TSP (based on data from Figure 5) and MPFM.***

4.2   Example 2: Representativeness of calibration

Calibrations are usually performed at regular intervals, In addition calibrations are initiated if there are significant changes in operating conditions. As illustrated in the following example, it is important to keep the operating conditions and process parameters during calibration as close to the normal operating conditions as possible as this will reduce the uncertainty in corrected hydrocarbon mass. Examples of process parameters that may change with time are temperature, pressure, fluid composition, densities, flow rates and flow regimes.

Shortly after a calibration, the correlation between MPFM measurements under normal operations and MPFM measurements during the recent calibration will be very high, and the uncertainty of the corrected data will be close to the uncertainty of the test separator measurements. As time goes, this correlation will be reduced due to changes in the process parameters and due to changes (e.g. drift) in the measurement instrumentation. Thus, the uncertainty of the measurements will increase as the representativeness of the calibration is reduced with the changes in process parameters. This is illustrated in Figure 7.

According to ISO GUM (2008) this representativeness can be described by a correlation coefficient (see Appendix A). This coefficient is equal to *one* when there is a full correlation between measurements under calibration and normal operation, and is equal to *zero* if there is no correlation between the measurements. Figure 8 compares the relative expanded uncertainty in the corrected hydrocarbon mass measured with one MPFM (solid blue line) with the corresponding uncertainty in the uncorrected hydrocarbon mass for one MPFM (dashed blue line) as a function of the correlation coefficient. Corresponding lines are also shown for two MPFMs in parallel (red lines). In this example separate correction factors for oil and gas are used. It may be observed that the influence of the correlation coefficient is significant. The uncertainty of the corrected hydrocarbon mass is equal to the uncertainty of the test separator for fully correlated measurements, whereas the uncertainty of the corrected hydrocarbon mass is larger than the uncertainty for the uncorrected hydrocarbon mass for the extreme case of fully uncorrelated measurements.

Significant amounts of statistical data are needed in order to quantify the actual value of the correlation coefficient accurately. The approach suggested and applied in this work is to do an analysis of data available from subsequent calibrations. As described above, any process variations between two calibration measurements will be accounted for by a change in correction factors K (assuming that the drift and uncertainty in the MPFM between calibrations are small). For the time interval between two calibrations, both the pre-interval and post-interval correction values should give adequate correction. Thus, the changes in subsequent K-factors will be a measure of the representativeness of the calibrations for the given time interval.

The relative variation in accumulated hydrocarbon mass between two calibrations calculated with subsequent K-factors for a sample case from a Statoil operated field is shown in Figure 9. The variation is calculated as

$$\frac{\Delta M_{HC}}{M_{HC}} = \frac{\left(K_{o,i+1}M_{o,i} + K_{g,i+1}M_{g,i}\right) - \left(K_{o,i}M_{o,i} + K_{o,i}M_{g,i}\right)}{\left(K_{o,i}M_{o,i} + K_{g,i}M_{g,i}\right)} \tag{10}$$

For the case shown in Figure 9 it is observed that the variations using subsequent K-factors change with time, but are typically within 3 – 3.5 %. Comparing this with the uncertainty analysis in Figure 8 this corresponds to a correlation coefficient of 0.8-0.9. At day 171 it is observed that the deviation is above 6 % for MPFM1, corresponding to a correlation coefficient below 0.3. A closer examination of the process data for this period shows that there are significant changes in process parameters: A new well was put in production in this period, and there had been a change in hydrocarbon mass flow rate of approximately 70 % between the two calibrations of MPFM1. Thus, this illustrates that the uncertainty associated with the present correction method is very dependent on the stability of the process. It is therefore recommended to perform new calibration measurements and update the correction factors when significant changes in the process occur.

For the case using common hydrocarbon correction factors, the variation is calculated directly as

$$\frac{\Delta M_{HC}}{M_{HC}} = \frac{K_{HC,i+1}M_{HC,i} - K_{HC,i}M_{HC,1}}{K_{HC,i}M_{HC,i}} = \frac{K_{HC,i+1} - K_{HC,i}}{K_{HC,i}} \tag{11}$$

The capacity of a test separator is limited, and may be lower than the actual operating flow rate through the multiphase flow meter to be calibrated. In order to operate the test separator within its operation range, it is tempting to reduce the flow through the multiphase meter during calibration. However, this will reduce the representativeness of the calibration (i.e. the correlation coefficient) significantly, and thereby increase the uncertainty of the measured hydrocarbon mass. Note that in this case the method outlined above for estimating the correlation coefficient is not applicable due to the lack of adequate reference data. With limited test separator capacity it is recommended to install two multiphase meters in parallel, where each multiphase meter can be calibrated separately at full operating range. If this is not possible, it is worth considering operating the test separator somewhat outside its operating range. This will reduce the separation process and increase the uncertainty of the test separator measurements. However, the MPFM measurements during calibration will be representative for the MPFM measurements during normal operation. By including water-in-oil monitoring equipment on the oil leg, the uncertainty of the oil and gas mass measurements out of the test separator may also be reduced.
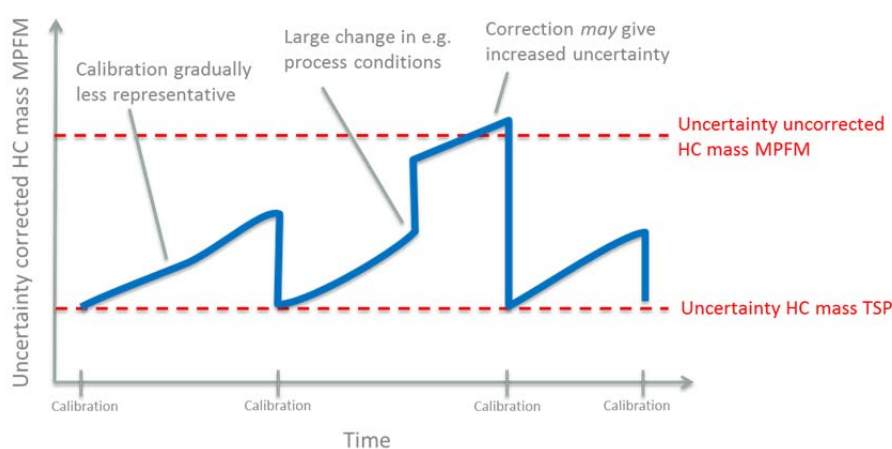

Figure 7 **Illustration of how the uncertainty in corrected hydrocarbon mass may vary with time.**
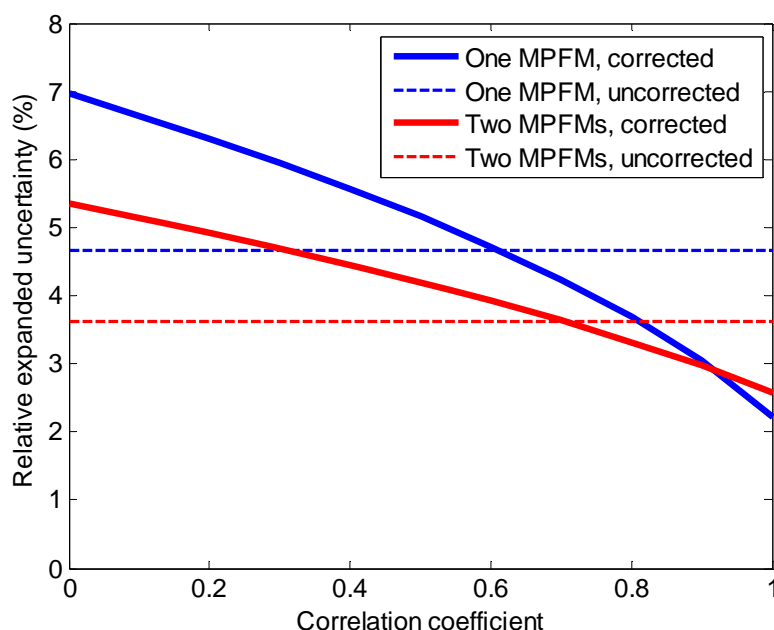

Figure 8 **Relative expanded uncertainty (95 % confidence level) in corrected hydrocarbon mass as a function of correlation coefficient.**
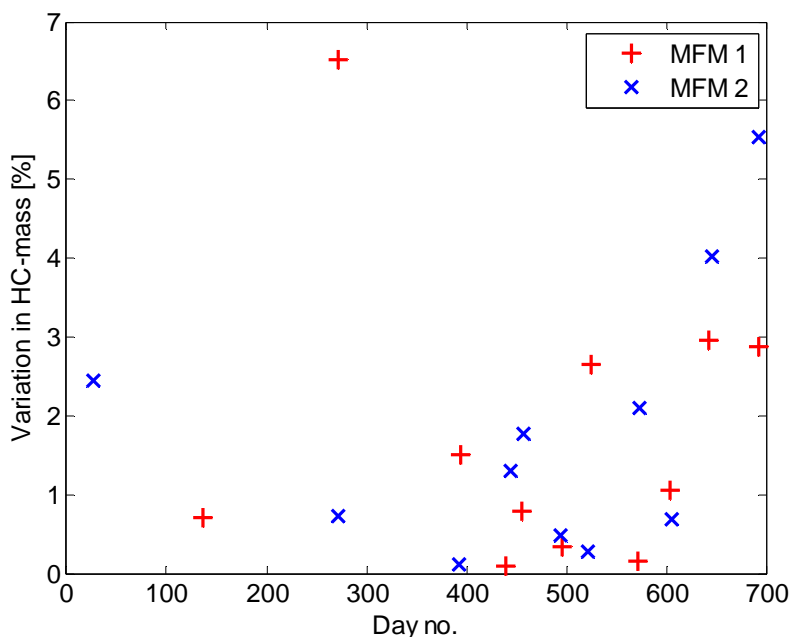
Figure 9   ***Relative variation in hydrocarbon mass using two subsequent correction coefficients***

4.3 Example 3: Flow and process conditions

In this example some aspects related to how flow and process conditions influence the measurement uncertainty are discussed, and it is illustrated how the main contributions to the total uncertainty can be identified. The example is based on data for a Statoil operated field where estimated flow rates for a span of 17 years is used as input. Figure 10 shows the mass rates over the lifetime of the field, and Figure 11 shows the GVF and WLR. The field has a production profile which is typical for many oil fields in which the majority of the hydrocarbon mass is produced the first 5-6 years (see Figure 10). Produced water is increasing with time, with the WLR rising steeply to 80% after 5 years, and from there slowly increasing further to around 95% in the last years of operation. GVF is above 70 % over the lifetime of the field.

Based on the uncertainty model given in Chapter 3, the relative expanded uncertainties (95% confidence interval) for corrected and uncorrected hydrocarbon mass are calculated and shown in Figure 12. The calculations are based on the MPFM specifications given in Table 1. The uncertainty curves for both corrected and uncorrected hydrocarbon mass show some interesting characteristics,

- A local maximum at year 6
- A steady increase in relative expanded uncertainty for hydrocarbon mass towards the end of the operating time of the field

In the following these characteristics will be explained by investigating the contributions from different parts of the measurement system.

Table 1 Specifications for the MPFM analysed in example 3

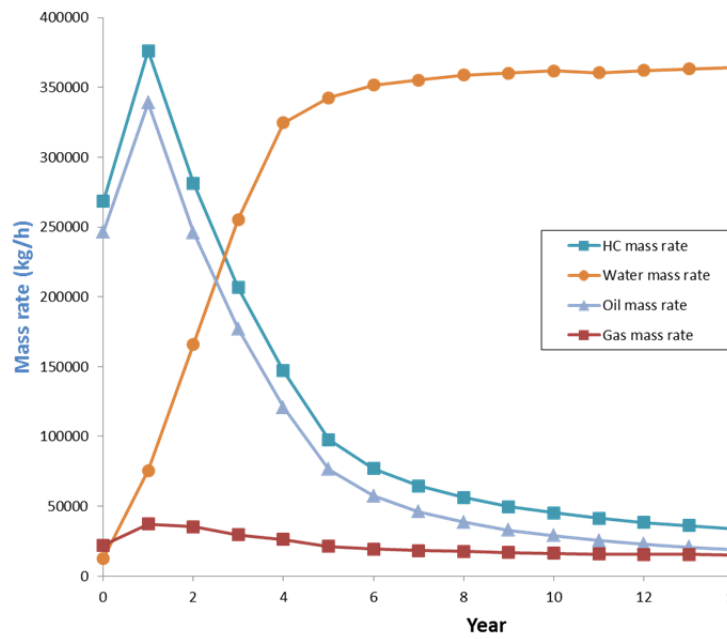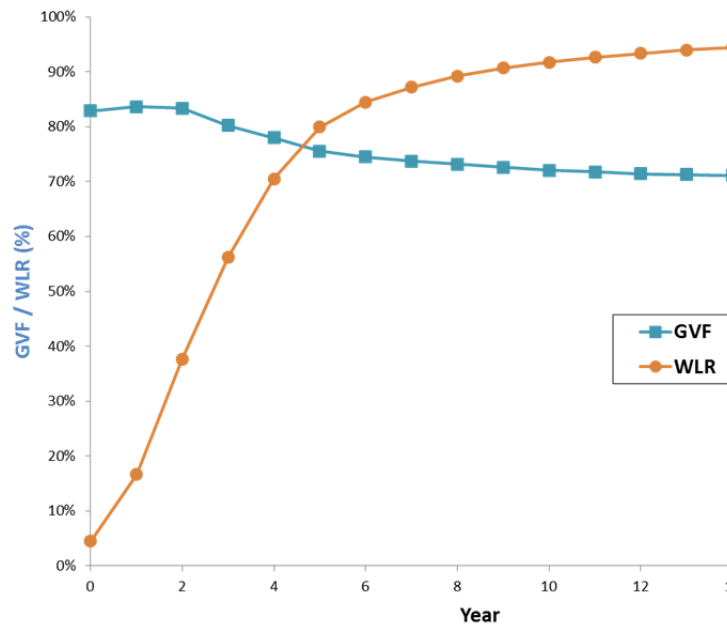|	***Uncertainties (95% conf. int.)***
Liquid Volume Flow	2.5 % for GVF< 80%
	5 % for GVF>80%
Gas Volume Flow	5 %
Water Liquid Ratio	2 % absolute for WLR< 85 %
	1 % absolute for WLR>85%
Densities (oil and gas)	3 %

Figure 10   ***Mass rates for the Statoil-operated field considered in example 3.***

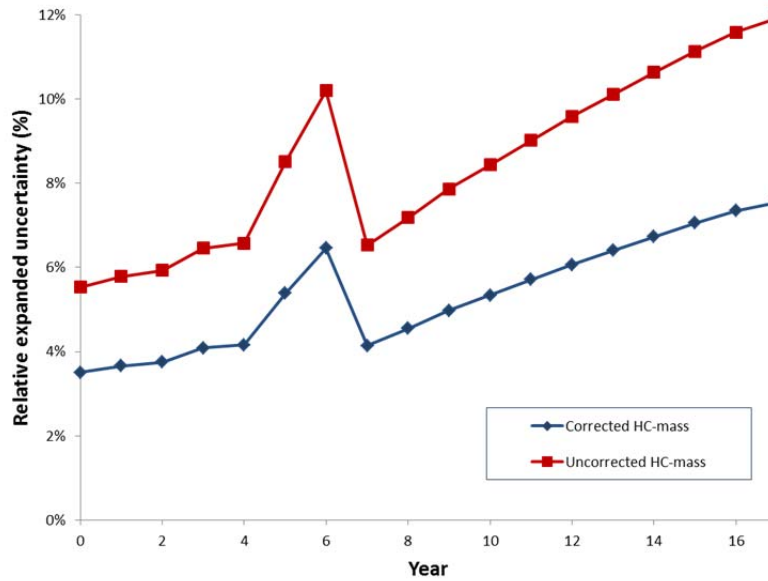***Figure 11***   ***GVF and WLR for the Statoil-operated field considered in example 3.***

Figure 12 ***Relative expanded uncertainty (95 % confidence level) in corrected and uncorrected hydrocarbon mass for the Statoil-operated field considered in example 3.***

Break-down of uncertainty for uncorrected hydrocarbon mass
The relative expanded uncertainty in uncorrected hydrocarbon mass is given in Equation (3) as a sum of contributions which can be related to uncertainty contributions from WLR, gas density, oil density, gas volume rate and liquid volume rate. Thus, equation (3) can be written as

$$\left(\frac{u(q_{mHC})}{q_{mHC}}\right)^2 = \left(\frac{u_{\rho_o}}{q_{mHC}}\right)^2 + \left(\frac{u_{\rho_g}}{q_{mHC}}\right)^2 + \left(\frac{u_{qvl}}{q_{mHC}}\right)^2 + \left(\frac{u_{qvg}}{q_{mHC}}\right)^2 + \left(\frac{u_{WLR}}{q_{mHC}}\right)^2 \tag{12}$$

where the uncertainty contributions are:

Gas density contribution:
$$\left(\frac{u_{\rho_o}}{q_{mHC}}\right) = \left[\frac{q_{mo}}{q_{mHC}}\right] \cdot \left(\frac{u(\rho_o)}{\rho_o}\right) \tag{13}$$

Oil density contribution:
$$\left(\frac{u_{\rho_o}}{q_{mHC}}\right) = \left[\frac{q_{mo}}{q_{mHC}}\right] \cdot \left(\frac{u(\rho_o)}{\rho_o}\right) \tag{14}$$

Liquid rate contribution:
$$\left(\frac{u_{qvl}}{q_{mHC}}\right) = \left[\frac{q_{mo}}{q_{mHC}}\right] \left(\frac{u(q_{vl})}{q_{vl}}\right) \tag{15}$$

Gas rate contribution:
$$\left(\frac{u_{qvg}}{q_{mHC}}\right) = \left[\frac{q_{mg}}{q_{mHC}}\right] \cdot \left(\frac{u(q_{vg})}{q_{vg}}\right) \tag{16}$$

WLR contribution:
$$\left(\frac{u_{WLR}}{q_{mHC}}\right) = \left[\frac{\rho_o q_{mw}}{\rho_w q_{mHC}}\right] \cdot \left(\frac{u(\text{WLR})}{\text{WLR}}\right) \cdot \tag{17}$$

In Figure 13 the relative expanded uncertainty in uncorrected hydrocarbon mass (red curve from Figure 12) is compared to each of the contributions. From the comparison it can be observed that there are two main contributions to the uncertainty in uncorrected hydrocarbon mass; the uncertainty related to liquid volume rate in the first 3 years until the shift downwards in year 4, and the uncertainty related to WLR in the remainder of the operating time of the field. The reduction in contribution from the liquid volume rate in year 4 is due to the GVF being reduced below 80 %, in which case the relative expanded uncertainty in liquid volume

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rate measured by the MPFM is reduced by a factor 2 according to the MPFM specifications (see Table 1).

Break-down of uncertainty related to WLR
The uncertainty contribution related to the WLR is further investigated in Figure 14. Here the contribution in uncertainty related to the WLR given in equation (17) is broken down into the relative expanded uncertainty in WLR (from the MPFM specifications) and the relative sensitivity coefficient[3],

From Figure 14 it can be observed that the downshift in relative expanded uncertainty in uncorrected hydrocarbon mass is caused by a shift in the uncertainty in the WLR (from the MPFM specifications) occurring between year 6 and year 7. This shift is due to the fact that the WLR increases above 85 % in year 7, for which the uncertainty in WLR is reduced by a factor 2 according to the MPFM specifications (see Table 1).

Figure 14 shows that the steady increase in relative expanded uncertainty in uncorrected hydrocarbon mass is due to a steady increase in the sensitivity coefficient. By analyzing the sensitivity coefficient in more detail (see equation (17)), it can be observed that the hydrocarbon mass is the main contributor to the steady increase in sensitivity coefficient. This is evident from Figure 15 in which the inverse of the hydrocarbon mass is compared to the relative sensitivity coefficient.

Absolute versus relative uncertainty
In Figure 16 the relative expanded uncertainty for corrected hydrocarbon mass (blue curve from Figure 12) is compared to the corresponding absolute expanded uncertainty curve. Note how the absolute measurement uncertainty is constant during the last production years even though there is a steady increase in the relative expanded uncertainty. The reason for this increase in relative uncertainty is that the hydrocarbon mass decreases with time. This confirms the observation from Stockton and Wilson (2012) that a high relative uncertainty may be a small absolute quantity in a multiphase flow metering station.
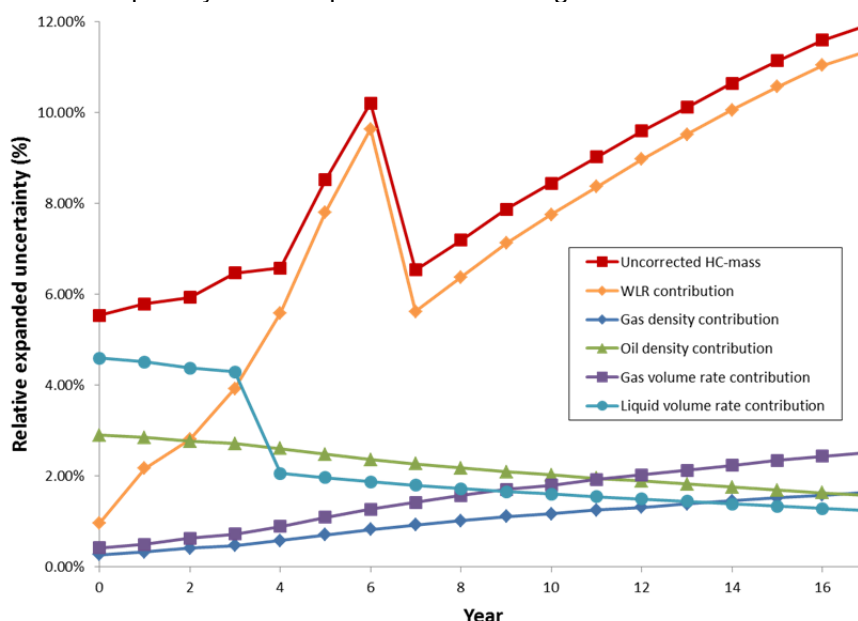

Figure 13   Relative expanded uncertainty (95 % confidence level) in uncorrected hydrocarbon mass compared to the uncertainty contributions. For the Statoil-operated field considered in example 3.

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[3] See Appendix A for definition of *sensitivity coefficient.*

$$\frac{u_{WLR}}{q_{mHC}} = \left[\frac{\rho_o\, q_{mw}}{\rho_w\, q_{mHC}}\right] \cdot \left(\frac{u(\text{WLR})}{\text{WLR}}\right)$$
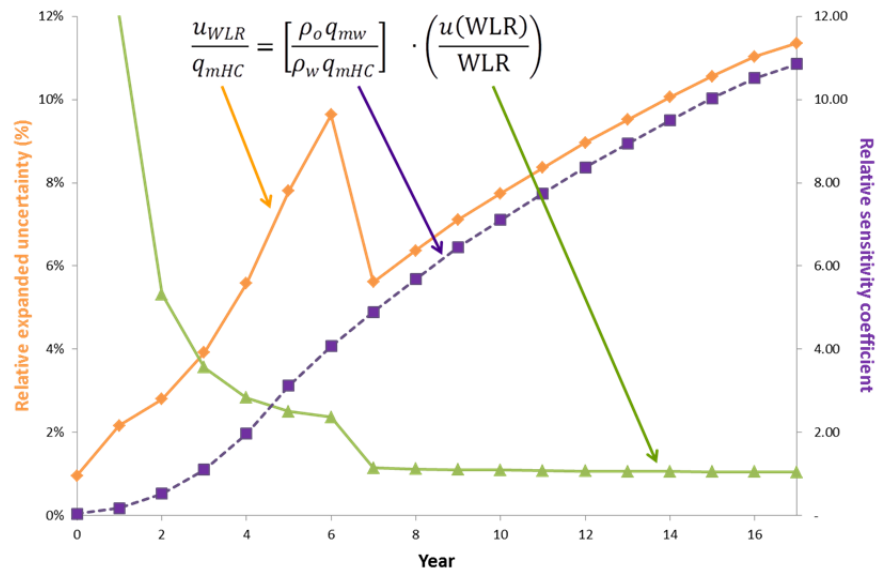
Figure 14   Relative expanded uncertainty contribution (95 % confidence level) from WLR compared to sensitivity coefficient for WLR and relative expanded uncertainty for WLR calculated from the MPFM specifications (see equation (17)). For the Statoil-operated field considered in example 3.
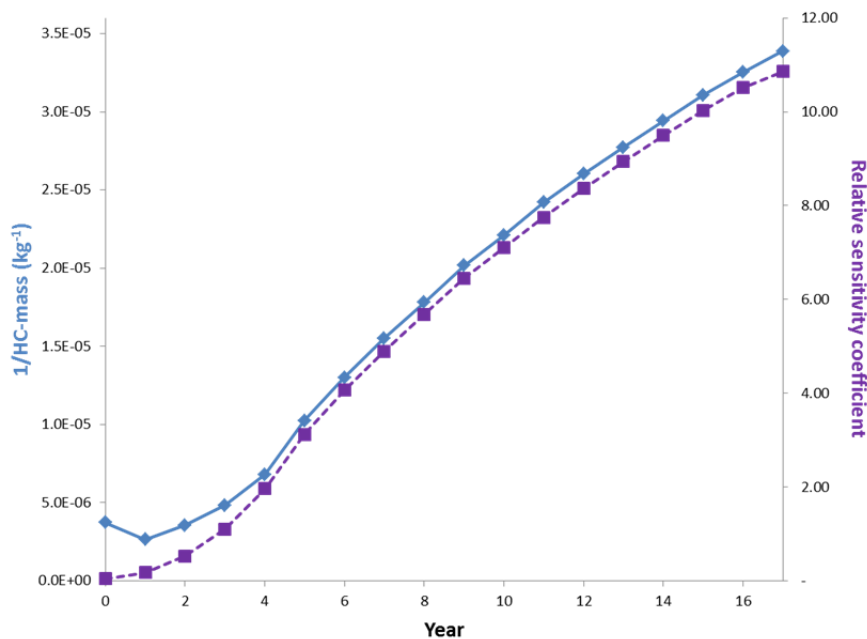

Figure 15   Relative sensitivity coefficient for WLR compared to the inverse of the hydrocarbon mass. For the Statoil-operated field considered in example 3.
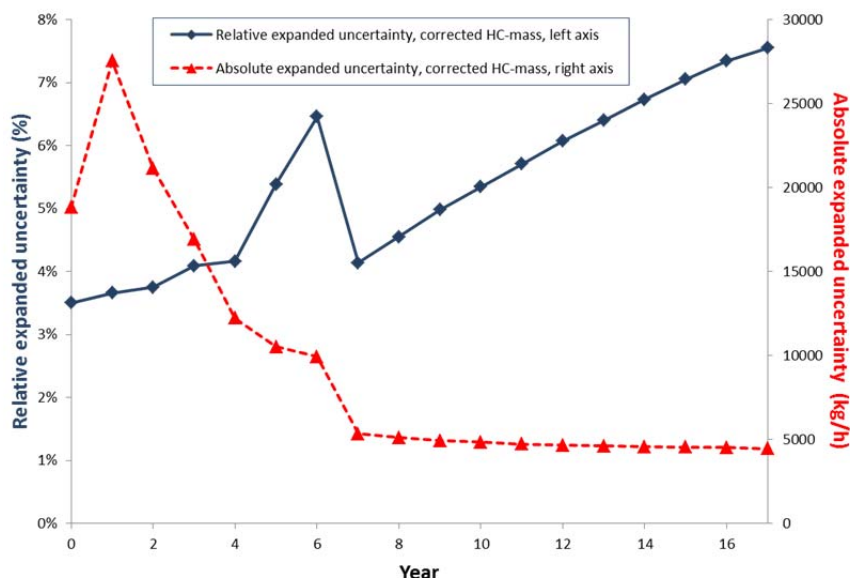
Figure 16 *Expanded relative and absolute uncertainty in produced hydrocarbon mass during the lifetime of a field. For the Statoil-operated field considered in example 3.*

5   CONCLUSIONS AND FUTURE CHALLENGES

In this paper a measurement approach has been described in which the MPFM measurements are corrected by calibration towards test separator, and a methodology for analyzing the uncertainty in the calculated hydrocarbon mass has been outlined. Different issues affecting the uncertainty in hydrocarbon mass have been discussed, and in particular it was found that the following factors affected the uncertainty strongly:

- Representativeness of reference measurements
- Uncertainty in fluid densities due to PVT calculation
- Production profiles

To ensure a high representativeness of the calibration measurements it is important to calibrate at actual flow rates and operating conditions. A new calibration should be performed if the process conditions changes significantly. In this paper we have suggested a method for estimating the representativeness (i.e. the correlation coefficient) through comparing the corrected hydrocarbon mass using adjacent correction factors.

The added uncertainties of the fluid densities when converted to other temperature and pressure conditions are significant. The studied example illustrates that the use of a common correction factor for hydrocarbon mass is preferable. This conclusion is based on the assumption that the uncertainties in PVT conversions are 3 %. More knowledge on the uncertainty associated with the PVT conversion process is needed in order to give more accurate estimates of the uncertainty in hydrocarbon mass.

Even though single phase and multiphase measurement instrumentation improves and becomes more reliable, failure and error measurement will still occur. It is therefore of great importance that calibrations of multiphase meters are traceable such that systematic errors can be corrected. Trending and analysis of measured and derived data (e.g. correction factors) gives a lot of information about the quality and performance of the measurement system, but it is also challenging to analyse all this information due to multiphase measurements at one process condition compared to single phase measurements at different

process conditions. It is therefore of importance to plan for and implement adequate methods and tools for this purpose.

The specifications of a MPFM are typically given for primary output parameters such as liquid volume flow, gas volume flow and water-liquid ratio, whereas the primary measurements are done by techniques such as electrical impedance, microwave transmission, gamma densitometry and differential pressure (Thorn et al., 2013). In order to calculate the correct output parameters, it is important to know the physical properties that affect the primary measurements of the particular MPFM (e.g. permittivity, salinity, density and linear attenuation coefficients) as accurately as possible. These physical properties are dependent on the fluid composition, temperature and pressure, and an uncertainty in composition will therefore affect the uncertainty in the output parameters. The influence of a composition uncertainty will affect the various measurement technologies differently.

In order to reduce the sensitivity for input parameters, some multiphase meter vendors perform in-situ measurements of fluid parameters such as water salinity and fluid densities . These new features integrated in the multiphase meters are important to reduce measurement uncertainties. More work should be performed to examine how these features can be integrated in the overall measurement system.

REFERENCES

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APPENDIX A   Calculation of uncertainties

The uncertainty estimations are following the method outlined in "Guide to the expression of uncertainties in measurements" (ISO-GUM, 2008). The definition of some basic terms from the guide is given in Table 2. For a more detailed discussion of uncertainty calculations, the reader is referred to ISO-GUM (2008)

Table 2   Definition of terms related to uncertainty calculations (ISO-GUM, 2008).

Factor		Comment
Measurand	Y	Particular quantity subject to measurement
Standard uncertainty	$u(x_i)$	Uncertainty of the result of a measurement expressed as a standard deviation
Combined standard uncertainty	$u_c(x_i)$	Standard uncertainty of the result of a measurement when that result is obtained from the values of a number of other quantities. See equations (18) and(21).
Expanded uncertainty	$U(y)$	Quantity defining an interval about the result of a measurement that may be expected to encompass a large fraction of the distribution of values that could reasonably be attributed to the measurand. See equation (22).
Coverage factor	k	Numerical factor used as a multiplier of the combined standard uncertainty in order to obtain an expanded uncertainty. See equation (22).
Sensitiviy coefficient	c_i	Quantity describing how the output estimate y varies with changes in the values of an input estimate x_i. See equation (19).

The uncertainty in the estimated output quantity is calculated by the following 4 steps:

1. Modelling the measurement
   - Identify the input quantities that may influence the measurand. The uncertainty contribution for a given input quantity typically depends on the operating conditions, and for completeness even input quantities that may have insignificant contribution on the output quantity should also be included in the uncertainty budget. In this manner, the uncertainty budget is easily recalculated for other operating conditions where the input quantity may have a more significant contribution.
   - Determine the functional relationship relating the measurand and the input quantities, i.e. $Y = f(X_1, X_2, …, X_N)$. The functional relationship should be interpreted in a broad context as a function that contains every quantity that contributes to the measurement uncertainty. This function may be very complex and, and may have to be determined experimentally or numerically.
2. Determine the *standard uncertainty* of input quantities
   - The uncertainty is evaluated by statistical analysis (Type A) or by scientific judgment based on available information on the possible variability of the input quantity (Type B) . Examples of information that can be used in Type B evaluation are manufacturer's specifications, previous measurement data, calibration certificates and relevant experience.
   - The input quantities may themselves be considered as measurands of other input quantities, and estimated using the ISO-GUM method.
   - The uncertainties given in e.g. datasheets or found elsewhere are typically expanded uncertainties, and the standard uncertainty must therefore be calculated by dividing the expanded uncertainty by the coverage factor k. The coverage factor k depends on the probability distribution and level of confidence given in the datasheet (a typical 95 % normal distribution corresponds to a coverage factor $k = 2$).
3. Determine combined standard uncertainty
   - For the general case of correlated input quantities, the combined standard uncertainty is

$$u_c(y) = \sqrt{\sum_{i=1}^{N} c_i^2 u^2(x_i) + 2 \sum_{i=1}^{N-1} \sum_{j=i+1}^{N} c_i c_j u(x_i) u(x_j) r(x_i, x_j)} \qquad (18)$$

The sensitivity coefficient is defined as

$$c_i = \frac{\partial f}{\partial x_i} \qquad (19)$$

The correlation coefficient is defined as

$$r(x_i, x_j) = \frac{u(x_i, y_j)}{u(x_i) u(x_j)} \qquad (20)$$

where $u(x_i, x_j)$ is the estimated covariance associated with x_i and x_j.

- For uncorrelated input quantities, the combined standard uncertainty is simplified to

$$u_c(y) = \sqrt{\sum_{i=1}^{N} c_i^2 u^2(x_i)} \qquad (21)$$

4. Determine the expanded uncertainty.
- The expanded uncertainty is obtained by multiplying the combined standard uncertainty, u_c, by the coverage factor, k

$$U(y) = k u(y) \qquad (22)$$

- The coverage factor is chosen on the basis of the level of confidence required, and in general k is in the range 2 to 3. When the probability distribution of y is approximately normal, a coverage factor $k=2$ produces a level of confidence of approximately 95 %.