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High pressure flow loop testing of the Multiphase Fluid Analyzer (MuFA) concept

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ABSTRACT

MuFA (MultiFluid Analyser) has been further developed over some years in cooperation between NORCE, TechnipFMC and Equinor since the basic concept was presented in 2019 [1]. This paper will present recent updates and results from high-pressure flow loop (K-lab) testing of the MuFA concept with real crude oil, natural gas and saline water.

For subsea fields, multiphase flow meters are installed on individual wells to measure the produced rates from each well. Multiphase meters need fluid properties as input, dependent on their measurement principles. During start-up of a field or well, the fluid properties are known, and the multiphase flow meters use these initial fluid properties as input data (PVT input).

With production from different zones or reservoirs, water injection and gas injection, the fluid properties of oil, gas and water will change over time. Measurement errors occur if the input data to the multiphase flow meter are not updated accordingly. By backward calculation, it is possible to quantify the effect such changes in fluid properties have on the multiphase meter performance. Based on the production profile, the development of this error over the lifetime of a well can thereby be estimated.

The MuFA concept is developed to capture the primary input data based on fluid properties from individual wells and used to update input data to the multiphase meters. MuFA is installed in parallel to the multiphase meter, so primary input data are determined on the same condition as the multiphase meter is operating. Primary input data are determined by use of MuFA without deferred or lost production.

In principle, MuFA consist of the following units:
- Fluid property measurements based on the same measurement principles as the fraction measurements of the accompanying multiphase flow meter. For the TechnipFMC MPM meter those are gamma-ray densitometry (662 keV Cesium) and microwave 3D broad band section systems.
- Actuated valves
- Control algorithms

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[1] Now with Equinor

The principle of MuFA is to capture each single phase from multiphase flow and measure the primary fluid properties and input data directly at operating conditions and online without need for transportation of pressurized samples for further analysis in a laboratory.

Recent flow testing at K-lab has used real crude (Troll Blend), natural gas, and water of different salinities to demonstrate the performance of MuFA. Details of the MuFA concept and test results will be presented.

1 INTRODUCTION

For many subsea fields, multiphase flow meters are installed on individual wells to measure the produced rates from each well. Multiphase meters need fluid properties as input, dependent on their measurement principles. During start-up of a field or well, the fluid properties are known, and the multiphase flow meters use these initial fluid properties as input data (PVT input).

The fluid properties of oil, gas and water will change over time. Especially, when production from different zones or reservoirs, use of water injection and gas injection, the change in fluid properties can be significant.

Measurement errors occur if the input data to the multiphase flow meter is not updated accordingly. Note that errors in the input parameters will result in systematic errors in the flow rates, and thereby errors that accumulate with time. It is possible to quantify the effect such changes in fluid properties have on the multiphase meter performance. Based on the production profile and expected change in fluid properties, the development of this error over the lifetime of a well can be estimated.

The traditional way to provide fluid properties is to collect samples when the well is routed to the test separator. For a larger subsea field development, it is in most cases, not possible to route one and one well to a test separator without significant production loss. Therefore, samples from individual wells will not be available, and it becomes challenging to track and monitor changes in fluid properties.

The purpose of MuFA is to capture the primary input data based on fluid properties from individual wells and used to update input data to the multiphase meter. MuFA is installed in parallel to the multiphase meter, so primary input data are determined on the same condition as the multiphase meter is operating. Primary input data are determined by use of MuFA without deferred or lost production.

MuFA has been developed over some years in cooperation between NORCE, TechnipFMC and Equinor since the basic concept was presented in 2019 [1]. This paper will present recent updates and results from high-pressure flow loop (K-lab) testing of the MuFA concept with real crude oil, natural gas and saline water.

2 TYPICAL METERING CONCEPT FOR A SUBSEA TIE-IN FIELD

In the figure below, typical layout of subsea tie-ins to a process plant are shown. Often the ownerships between subsea fields can be different, and the host can also be of different ownership than the subsea fields, thus the measurements are used for ownership allocation where the NPD metering regulation applies.

The typical metering concept for a subsea tie-in field, includes single phase meters to measure gas injection, water injection and gas lift, while multiphase meters are to measure produced rates. Multiphase meters are installed on each subsea well and on the inlet flowline to measure the total production from each subsea tie-in field.

For larger subsea fields, incl subsea-subsea tie-ins, it is not possible to route one and one well to test separator for capturing samples. Thus, other alternatives or concepts are needed. Over the last decades, different concepts of subsea sampling to capture multiphase samples have been presented. Despite the complexity of presented subsea sampling concepts, lack of capturing representative samples over a wide range of multiphase flows and properties has been an obstacle for further developments.

Some production scenarios that can result in changes in fluid properties are:
- Commingled production from several zones or reservoirs
- Gas lift
- Gas injectors
- Water injectors

While water injection of sea water will have an impact on the salinity of the produced water, gas injection will have an impact on the composition of the hydrocarbons that are produced. Even though it is easier to compensate and correct for gas lift, gas lift rates will also have an impact on the composition of the produced hydrocarbons. Gas lift rates are measured, adjustments of gas rates from the measured multiphase flow and correction of fluid compositions are performed in the metering control system, called LivePVT.

Production from different zones with different composition will have a flow weighted mixed composition, where the PVT compositions at the well head at the location of the multiphase meter will vary dependent on fluid characteristics from each zone. Gas production can be dominated from one zone, while oil can be dominated from other zones. At the well head, the overall fluid characteristics of the flow through the multiphase meter will be a mixture of the production from the zones. Without updating fluid parameters in the multiphase meter, significant impact in the measurement performance can be the result.

Figure 1 and 2 show typical subsea fields with different ownerships tied-in to a FPSO, with corresponding metering concepts. Typically, marginal subsea fields utilize existing infrastructures, with different fluid properties from different reservoirs. The drainage and production strategies can also be different for the reservoirs, for example use of water injection, gas injection and gas lift.

Typical for marginal subsea fields it is limited or no access to the test separator in order to route individual wells for sampling, thus it is a risk that multiphase meters will drift off, since it will not be detected if fluid properties have changed.

This makes the performance of the metering solutions for subsea tie-in fields more challenging, and thus new ideas and concepts are needed be implemented to maintain the measurement performance for multiphase metering systems over the life-time of the fields.

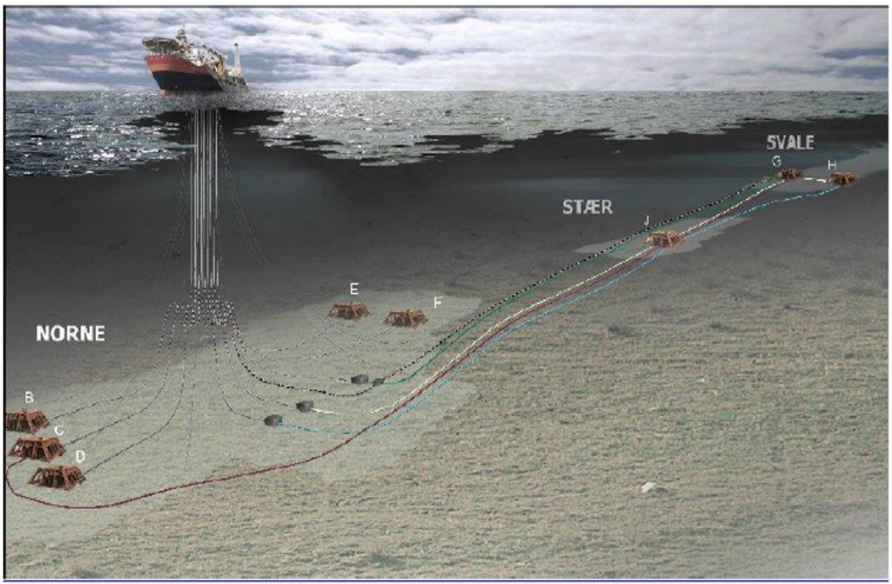

Figure 1 Typical field layout with several subsea tie-ins

The combination of topside and subsea multiphase meters ensures robust metering solution incl backup in case of failures in one or several multiphase meters, as seen in Figure 2. Beyond ownership allocation between licenses, multiphase meters are beneficial for accurate and reliable measurements also for other purposes such as:

- Daily production optimization
- Well allocation
- Input to automatic production optimization tools
- Detection of water and/or gas breakthrough
- Reservoir historic matching

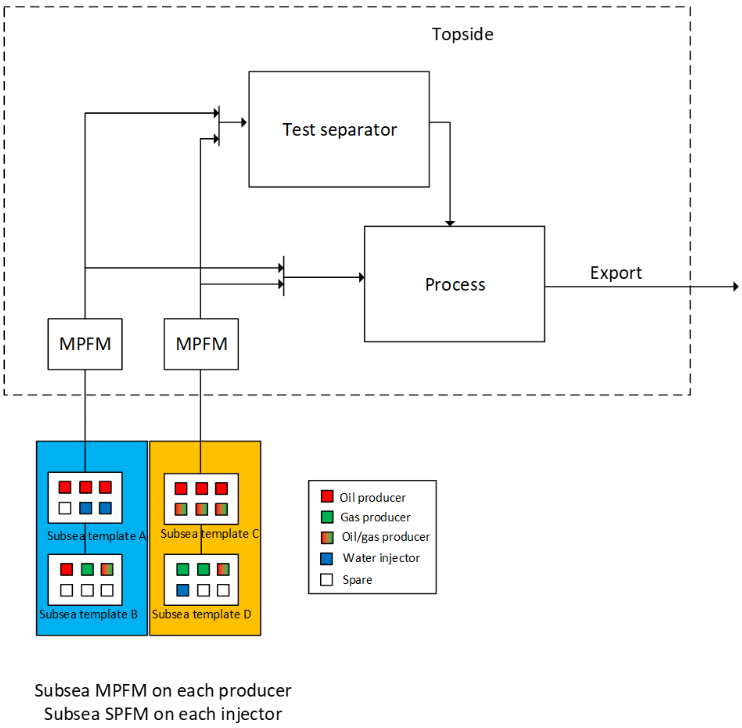

Figure 2 Typical metering concept for subsea tie-ins to a FPSO

3 CHANGES IN FLUID PROPERTIES

Assessments have been performed to map the effect of measurement errors to lack of updated PVT data. With reference to Figure 3, the assessments are based on the following method:

1. The true flow rates of a multiphase flow are used as input, i.e oil, gas and water flow rates.
2. The single phase fluid parameters at MPFM operating conditions are initial input data. For the TechnipFMC MPM meter this will be permittivity/conductivity (microwave) and attenuation coefficient/density (gamma densitometry) for oil, gas and water.
3. The flow mixture parameters are calculated from the true multiphase flow rates and fluid parameters using an inverse model of the MPFM. Thus, the true (model) mixture permittivity/conductivity and mix attenuation coefficient/density are found.
4. An error (or uncertainty) is added to the input fluid parameters, providing the *erroneous fluid parameters*.
5. The flow rates are then calculated from the true mixture parameters and the erroneous fluid parameters using a forward MPFM model. These rates are referred to as the *erroneous flow rates.*

The relative changes between the erroneous and true flow rates represent measurement errors due to changes in fluid properties.

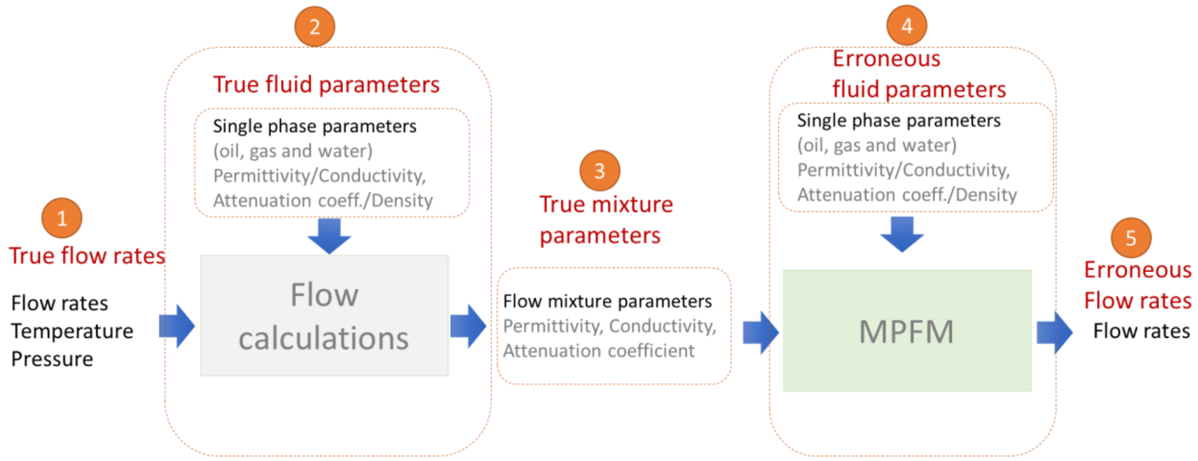

Figure 3. Process to determine potential measurement errors due to changes in fluid properties

This method will not give the overall measurement uncertainties of a multiphase meter but is used to map the contribution from potential changes in the fluid properties. This PVT sensitivity will be different for various multiphase meter technologies, as the sensitivity will depend on measurement principles that are implemented in specific multiphase meters.

Figure 4 shows an example of a sensitivity mapping for a given production well. Figure 4(a) shows the GVF and WLR vs production year. Figure 4(b) shows the resulting relative uncertainty in oil flow rate for two cases:

- The *compositional error* case shows the oil volume flow rate uncertainty of the multiphase meter when the fluid input parameters are calculated from pvt-calculations that provides 5% uncertainty in oil and gas density and 0.5 wt% (abs) uncertainty in water salinity.
- The *MuFA uncertainty* case shows the oil volume flow rate uncertainty of the multiphase meter when the fluid parameters are measured directly using MuFA. This estimate is based on the results from this K-lab tests (see Table 4).

By comparing the two cases, it is clearly illustrated that a significant improvement in performance can be expected by applying the MuFA concept.

In this work, the simulations and assessments are based on TechnipFMC MPM multiphase meters. The methodology is applicable for all type of multiphase meters, but the results may differ according to measurement principles. Note that for the studied case, the oil production is decreasing steadily towards the end of the lifetime as the water production increases. Thus, the relative uncertainty in oil flow rate becomes high due to reduced oil rate. This will also be the case for other multiphase meters.

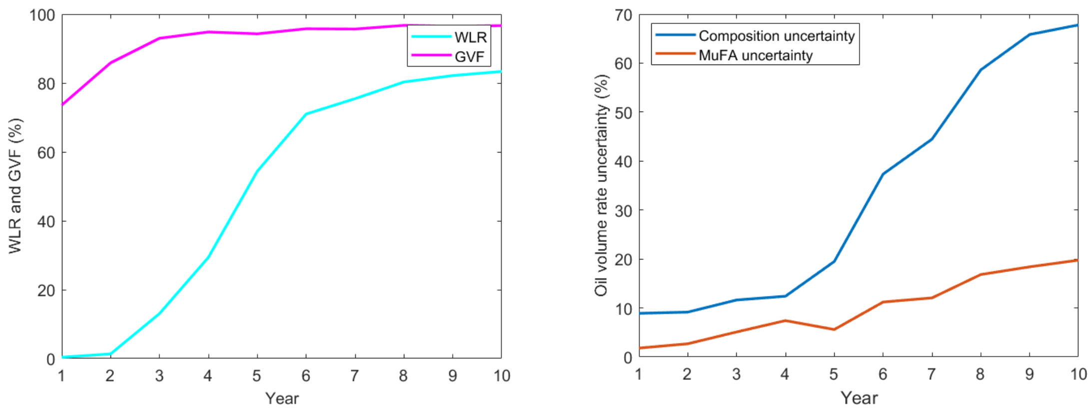

Figure 4. Illustration of improvements in performance by using input parameters measured by MuFA instead of estimated from composition. (a) GVF and WLR for an example production profile (b) uncertainty in oil volume rate.

In Figure 4, the uncertainty in oil volume rate is estimated from PVT-data and MuFA measurements. 5% uncertainty in densities and 0.5wt% uncertainty in salinity is assumed for the PVT-data, and uncertainties in the MuFA measurements are according to Table 4.

4 MUFA CONCEPT

The idea behind the MuFA is to measure the primary single phase fluid properties directly at operating conditions inside the closed piping system, without any need for sampling through ports and external laboratory analysis. The in-situ measured properties can then be automatically provided as input data directly to a multiphase meter.

In the current proposed realization, the MuFA is placed vertically in parallel with the MPFM and is comprised of two *sampling units* and an *analysis chamber* (Figure 5). The sampling units each consists of a valve with electrical actuator and a T-junction, while the analysis chamber contains of sensors to measure fluid properties. The sensor technologies used should preferably be the same as in the MPFM. In the currently tested implementation this was a gamma densitometer and a microwave permittivity sensor. Temperature and pressure sensors are also necessary to account for T&P effects on the measured properties, and to verify conditions during the analysis period are stable and close to operating conditions of the MPFM.

When the MuFA is not in operation both valves are closed, and all the flow is routed through the MPFM. When a new characterization of the fluids is initiated, the valves are operated according to a pre-defined algorithm to capture a pure single phase in the analysis chamber:

Gas capture and analysis:

- Both valves are opened for some time to ensure the analysis chamber is filled with representative process fluids to achieve process temperature.
- The upper valve is then closed, letting the liquid drain out and leaving pure gas (at process conditions) in the chamber.
- The lower valve is then closed, and gas properties are measured by the sensors.

Oil capture and analysis:

- As for gas, both valves are opened to flush the module with the process fluids.
- The lower valve is then closed, and liquid is accumulated due to gravity and gradually fills the module.
- The upper valve is then closed, and liquid is separated into oil and water. Oil is characterized by the sensors, which are placed in the upper part of the analysis chamber.
- If (in the previous step) the water level reaches the sensors, the lower valve is opened for a short time to drain out some water, and the upper valve is opened again until the chamber is filled with liquid, whereby the upper valve is closed to let the oil and water settle and separate. This is repeated until the sensors only see oil (the oil-water interface is sufficiently far below the sensors)

Water capture and analysis:

- Both valves are opened to flush the module with the process fluids.
- The lower valve is then closed, and liquid will accumulate and gradually fill the module from the top.
- The upper valve is left open and due to the higher density, the water level will gradually increase and cover the sensors. The oil will gradually be replaced by the heavier water.
- The upper valve is then closed, and water is characterized when measurements have stabilized.

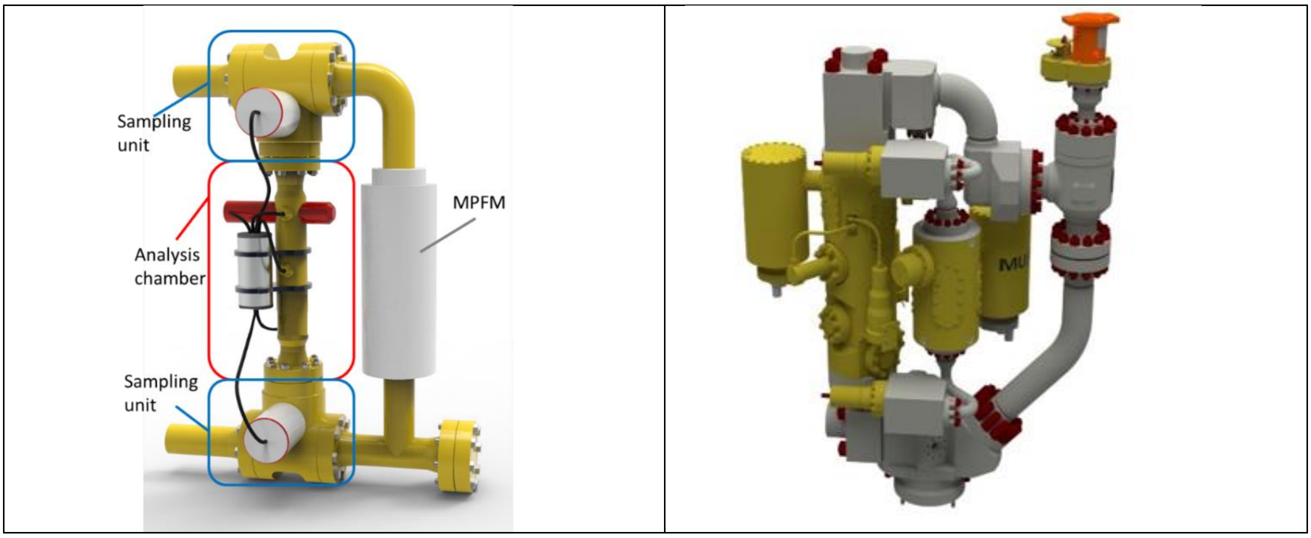

Figure 5. Illustration of sampling and analysis module for the multiphase fluid analyzer concept MuFA concept (left) and MuFA mounted in a flow control module parallel with a MPFM (right).

5 TEST SET-UP AND TEST SCOPE

To mature the MuFA concept, extensive testing has been performed. The MuFA concept was tested at Norce flow loop (low pressure) in 2017 and 2019. The results of these tests were presented in 2019 [1]. The first initial and simplified K-lab test was conducted at K-lab in 2021, with a limited scope using condensate and manual operated valves.

The scope for this K-lab test was extended compared to previous tests:

- Use crude (Troll Blend) rather than condensate
- Use of natural gas
- High pressure and temperature
- Use of electric actuated gate valves
- 3'' MPM used as MuFA chamber
- Installation of thermowell and temperature transmitter in the analysis chamber
- Updated test spool lay out incl pipe support
- Large test matrix, with large range of WLR, GVF and flow rates
- Use of two water salinities
- Venturi to generate a representative pressure drop around the MuFA chamber

Production profiles of oil producers can cover a wide range in gas fraction and water cut. It is therefore important that the test scope cover a broad range in WLR, GVF, different flow rates, different water salinity. Pressure and temperature have been the same during the test, i.e about 90 barg and 60°C.

The size of a subsea multiphase meter is typical 5-inch, while the MuFA chamber is 3-inch. To replicate a standard multiphase meter, a venturi spool (5-inch venturi with beta 0.7 incl dP transmitter) in parallel to the MuFA unit was installed, see Figure 6. This gives realistic pressure conditions around the MuFA unit.

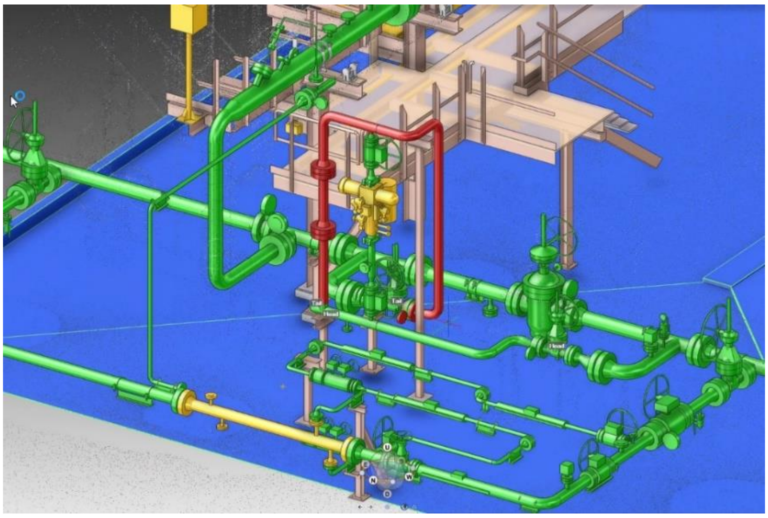

Figure 6. 3D model for the test set up. Red pipes represent the piping layout including venturi, while yellow is the MuFA. Green represent the fix piping installation at K-lab.

The K-lab loop is a closed flow loop, meaning the total composition in the loop is constant. For the first part of the test, the water salinity was 2.8wt% NaCl. For the last part of the test, the water salinity was 5.2wt% NaCl.

5.1 K-lab references

K-lab is a closed flow loop, where the single phase flow rates are measured separately downstream the separators, before the flow rates are mixed to a multiphase flow. The flow rate of each phase can be controlled, thus a wide span and combination in multiphase flow can be generated and used for testing.

The media used in the loop are live, thus phase transfer from one condition to another need to be taken into account. The reference measurement at single phase is measured upstream the mixing point and PVT compensated for, and the overall uncertainty of the references at the test objective, is given by K-lab:

Table 1. Relative total expanded uncertainty (95% confidence level) at the test objective of the reference measurements at K-lab

Fluid phase	**Mass flow [%]**	**Density [%]**	**Volume flow [%]**
Oil	1.0	0.8	1.3
Water	1.0	0.8	1.3
Gas (Coriolis as reference)	0.7	1.5	1.7
Gas (USM as reference)	1.6	1.5	0.4

The water salinities used during the test is shown in Table 2.

Table 2. Laboratory analysis of water samples

	Laboratory analysis	
Sample	Salinity [%weight]	Density @ 15C [kg/m3]
#1	2.8	1021
#2	5.2	1039

The laboratory analysis of water samples based on titration and measured conductivity, where the average values are presented. Only minor deviations between the methods are observed.

5.2 Control algorithm

The purpose of the test was to verify the operation of the valves to fill and empty the analysis chamber automatically and to ensure the software and algorithms worked as intended.

Since the properties of the dominate phase have the largest impact to the multiphase meter performance, test matrix has been prioritized accordingly. Only a limited number of sample points with low impact have therefore been run, since sampling of the small liquid fractions can take several hours.

The control algorithms for the valves were installed and integrated in the ABB control system at K-lab and measurement readouts from the MuFA were used as input to the control algorithms.

The control of the valves is fully automated based on measured data from the densitometer and the microwave module. Measured permittivities/conductivity/densities for oil, gas and water are compared to predefined criteria for the respective phases to determine the fluid phase. Depending on the conditions, the relative permittivity for gas is typically between 1.0 to 1.5, while the relative permittivity for oil is typically 1.9 – 2.6. Such ranges can also be defined for the densities and conductivities of the pure phases and liquid mixtures. This knowledge is applied to detect when the chamber is filled by gas or liquid, and thereby control the opening and closing of the valves. The sensor readings are also used to monitor the separation of liquid into oil and water and determine if resampling is needed. To determine if the fluids have stabilized before starting the analyzes process, the time variation of the sensor data must be below certain limits. The microwave module has several permittivity sensors, and it is also required that the readings of these are equal. The sensor readings must also stay within the defined limits during the complete analyzes period in order to be accepted.

5.3 Test matrix

The purpose is to demonstrate capturing single-phase samples in the MuFA analysis chamber from multiphase flow with a range of different flow rates, GVF and WLR.

The actual number of test points that has been run is shown in Table 3. For most of the test points, one gas analysis, one oil analysis and one water analysis are performed.

Table 3. Number of test points

	Number of test points	**Range WLR [%]**	**Range GVF [%]**	**Total rate [m3/h]**
Gas analysis	47	0 - 100	40 - 100	80 - 780
Oil analysis	43	0 - 70	40 - 80	120 - 780
Water analysis	35	20 - 100	40 - 80	250 - 900

Each test point is logged for 10 minutes (600 measurement points - 1 s resolution), and the results are presented as averaged values over the logging period.

6 TEST RESULTS

In the following, test results are presented. In addition to the measured fluid properties, the sampling time needed to collect samples for different phases are presented.

For each test point, after pure phases have been captured and stabilized, the analysis phase provides average value and standard deviation calculation over the logging time. The sampling time is the time needed before MuFA can start analyzing, i.e the time to capture and stabilize pure single-phase samples from a multiphase flow, see details in Figure 7.

The figure show, as an example, one sequence of a sampling point for. The water cut in this example is 50%. The plot shows the different periods, such as flushing, sampling, stabilization and analysis.

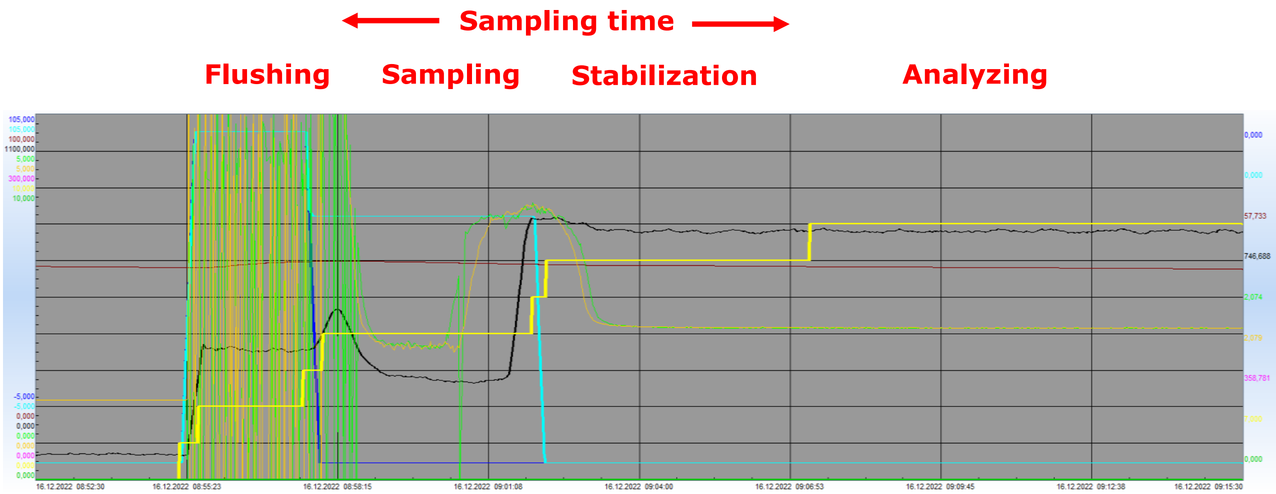

Figure 7. Example of an oil sampling sequence – liquid with 50% water cut

The yellow legend represents the step or progress in the software and is used to troubleshoot and show how the control algorithm operates. The blue and aqua legends represent the opening (in %) of the upper and lower valves, respectively. The black legend is the measured density by the gamma densitometer. The green and orange legends represent the measured permittivity.

6.1 Sampling time

The time needed to collect samples and stabilize before the analysis was logged during the test, and the time for all **gas samples** are shown in the figure below. The control algorithm that is used to collect gas samples is simple, it is simply to keep the lower valve open, until the gas has accumulated at the chamber.

After the gas is accumulated in the MuFA chamber, the lower valve is closed for stabilization before the analyzing is started, i.e. log the gas properties (permittivity and gamma attenuation) for 10 minutes.

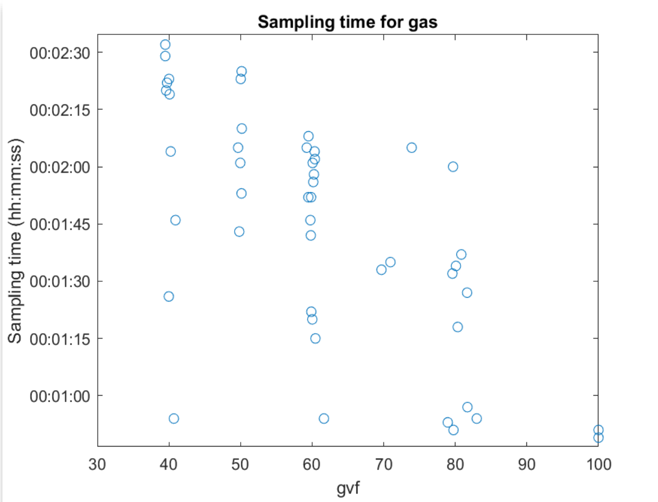

Figure 8. Sampling time of all gas sampling points vs GVF

From Figure 8 it is seen that the maximum time to collect gas in the MuFA is about 2:30 minutes, before MuFA is ready to perform the gas analysis. Minor increased time to collect gas at lower gas fraction can be observed from the test results.

Similar as for the gas points, the **sampling time for all oil points** are shown in Figure 9. For test points with water cut less than 50%, most samples are captured within 30 minutes. For higher water cuts, especially in combination with lower flow rates, the time to collect samples of pure oil, the sampling time show an increasing trend. The reason for this increase in sampling time is that the sampling process must be repeated several times (with some drainage of water between each sampling) when the liquid phase mainly consists of water.

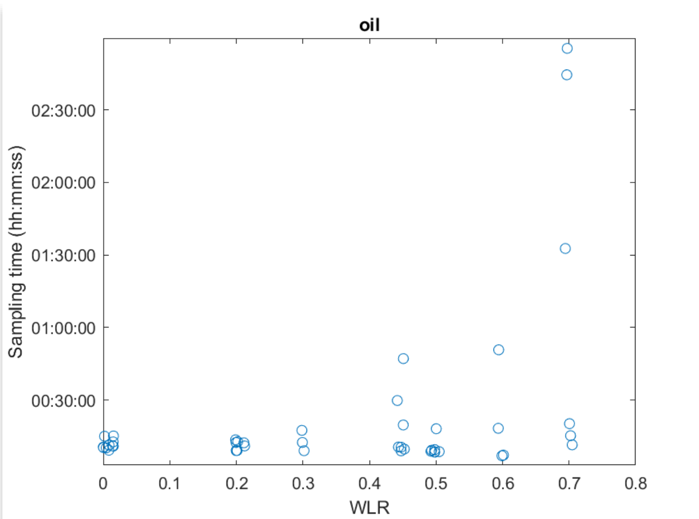

Figure 9. Sampling time of all oil sampling points

The time to capture oil and water samples was 2-3 hours for the marginal phase. Compared to the previous test at K-lab, the sampling times (with use of condensate) were in the same range.

Note that the oil properties do not affect the MFPM performance significantly when the WLR is high. Thus, it may not be required to characterize oil in all cases.

The **sampling time for all water points** is shown in Figure 10. For test points with WLR above approximately 45%, samples are captured within 30 minutes, while for liquid flows with lower WLR, especially in combination with lower flow rates, the sampling times to collect water samples increase.

Some further improvements that can be made to reduce the time, f.ex by adjusting the upper valve opening, would most likely reduce the time needed to capture water samples from liquid with lower water cut.

Note that the water properties do not affect the MFPM performance significantly when the WLR is low. Thus, it may not be required to characterize water in all cases.

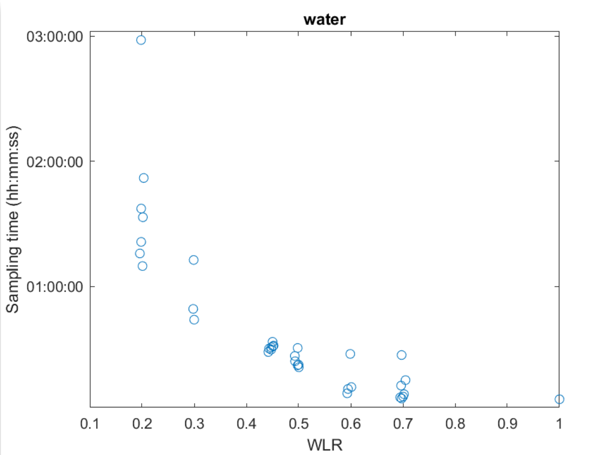

Figure 10. Sampling time of all water sampling points

6.2 Fluid properties

The fluid properties permittivity and density are measured during the analysis period for the single-phase samples. Due to some instabilities experienced in the MPFM conductivity measurements during the test, the water conductivities were not measured but instead estimated from the measured water density. The conductivity measurement issue will be investigated further.

As described earlier, all data to K-lab control system is logged with 1 second resolution. Within the 3D microwave broadband section, the permittivity is measured in several directions, while the densities are measured using the gamma densitometer. For the fluid samples, average values of the measured data and corresponding standard deviations from the test are calculated. The averaged values and standard deviations based on 10 minutes logging periods.

Figure 11 shows the measured **oil permittivity** for all test points as a function of reference oil density. The precision in each test point is calculated as *2 times std dev* and showed as error bars in following figures. In general, oil permittivity is a function of the oil density

[2]. However, no systematic variation in oil permittivity between the different test points is observed from the test results. This is because the densities of all test points are quite similar (variation below 1%), Similarly, no systematic variation with temperature is observed from the test results. Thus, the spread in measured average permittivity between the different test points can be analyzed directly to determine the repeatability of the measurements. By also considering the precision for each test point, the overall uncertainty (95 confidence interval) of the oil permittivity measurements is estimated to be within 0.6 %.

Only one permittivity measurement direction (D7) is shown in Figure 11. The other measurement direction (D9) that has been analyzed is more or less overlapping and follows the same trend from point to point. This gives a clear indication that the oil is homogenous within the microwave module, i.e., that there is a limited amount of water droplets or gas bubbles at the chamber wall or in the sample that have disturbed the measurements of the samples.

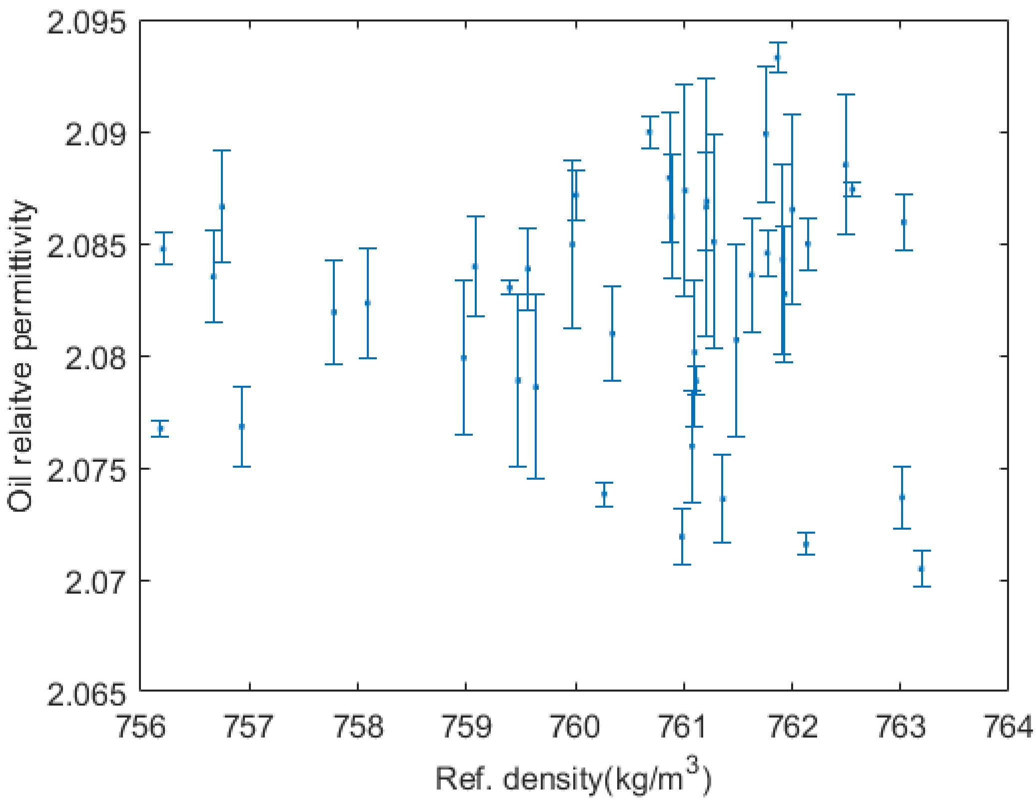

Figure 11. Measured oil permittivity (D7) versus reference oil density

The **gas permittivity** is a function of gas density [3], [4]. The pressure in the MuFA module varied between 88 and 95 bar for the different test points, and thereby the gas density varied significantly. Hence, the measured permittivity also varied between different test points and can therefore not be compared directly. The measured permittivity is shown as a function of reference gas density in Figure 12. The fluids applied in the tests are well characterized, and the reference density is therefore estimated with reasonable low uncertainty using PVT-calculations (see Table 1). The measurement precision (95%

confidence interval) for each test point is shown as an error bar for each test point. The permittivity is known to vary with density according to Clausius-Mossotti's relation [4], and the solid line shows the best fit to this model.

Based on the measurements, the combined measurement uncertainty (95% conf.int.) in gas permittivity is estimated to be approximately 0.3 %. This estimation includes both the measurement precision of the individual test points and the variation in measured permittivity between the different test points.

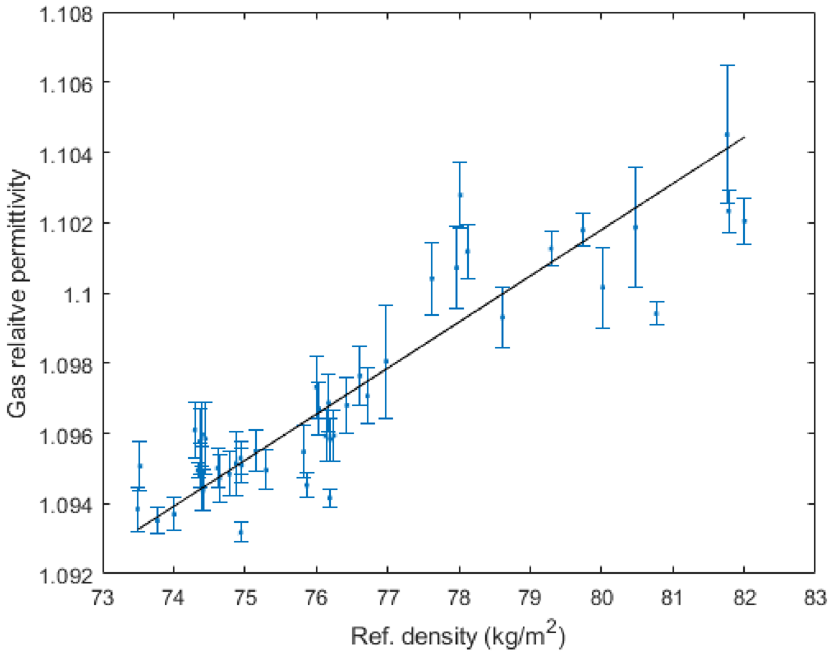

Figure 12. Measured gas permittivity (D7) versus reference gas density

The measured **gas density** for each test point versus the reference gas density is shown in Figure 13. A systematic deviation of around 1.9 kg/m3 (or about 2.5%) is observed. This is considered to be a bit high even when taking the uncertainty in reference measurements into account. Further analysis showed that this was caused by a cool down of the analysis chamber during the sampling and analysis period. This can be improved by minor changes in the measurement configuration, for instance by reducing the logging time, using longer flushing times to stabilize the MuFA module temperature, and improved thermo coupling between MPFM and MuFA.

The combined uncertainty (95 % conf.int.) of gas density when taking both the measurement precision and repeatability into account is estimated to approximately 3.8 %. By correcting for the cool down effect assuming a linear temperature correction, the uncertainty can be reduced to approximately 2.8 %.

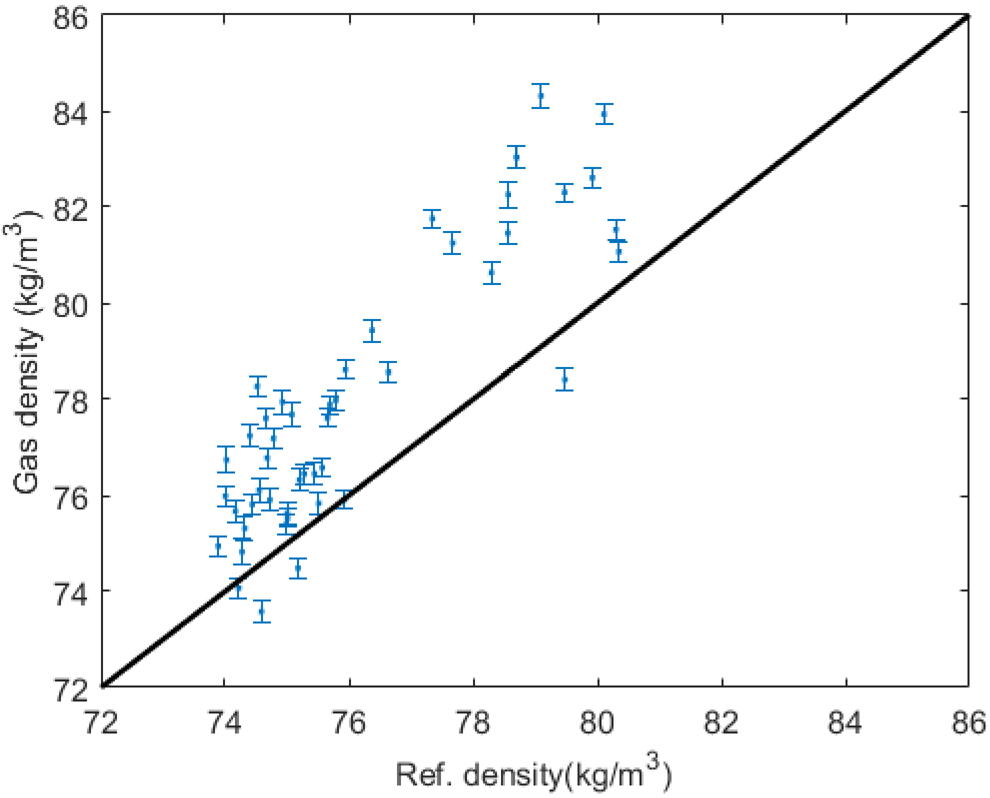

Figure 13. Measured gas density versus reference density.

The measured **oil density** versus the reference oil density is shown in Figure 14. A systematic deviation of around 7.9 kg/m3 (approximately 1%) is observed. The oil density is slightly underestimated and gas density overestimated. Thus, there might be a systematic deviation in phase split calculation in the PVT model used at K-lab reference data.

The combined uncertainty in oil density taking both the measurement precision and repeatability into account is estimated to be below 0.6 %.

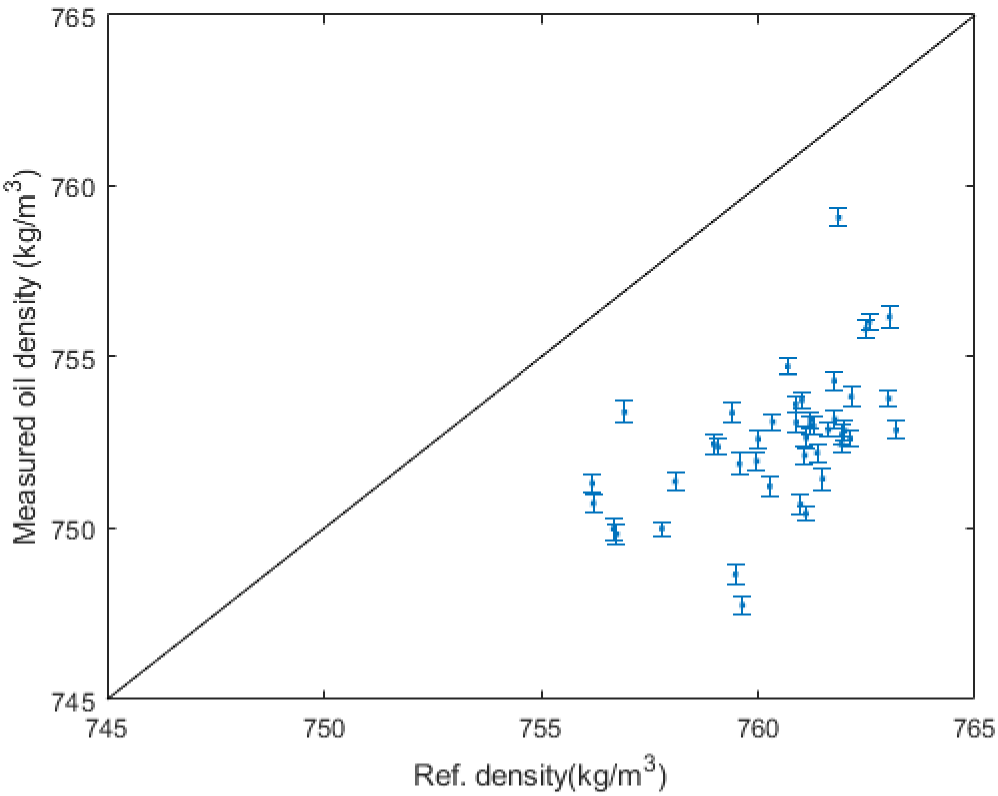

Figure 14. Measured oil density versus reference density.

In total 35 water samples were analyzed. The first 24 test points were done with water salinity of 2.8 wt% NaCl, whereas the last 11 test points were done with a water salinity of 5.2 wt% NaCl. The water density was measured by the gamma densitometer.

The measured **water density** for each test point versus the reference water density is shown in Figure 15. There is not observed any systematic deviation between the measured and reference densities, and it is found that all measurements are within 0.4% of the reference measurement. The combined uncertainty of water density taking both the measurement precision and repeatability into account is approximately 0.35 %.

The water density uncertainty achieved by the MuFA gamma densitometer is in the same range as the uncertainty of water single-phase reference measurement (Coriolis meter) at K-lab.

As described earlier, some instabilities in the MPFM conductivity measurements were experienced during the test. This is still under investigation, and direct measurement results for water conductivities are therefore not given here. However, the **water salinity and conductivity** can be estimated from the measured water density and water temperature instead of being measured directly [5], [6].

Based on the density measurements shown in Figure 21, the mean water salinities were estimated to 2.8 wt% and 5.1 wt% (cf. reference values of 2.8 and 5.2 wt%). The uncertainty estimated as 2 standard deviations of the estimated salinities were 0.4 wt% and 0.2 wt% for the low and high salinities, respectively.

This corresponds to mean water conductivities (at 25 °C) 46 mS/cm and 78 mS/cm for the two water salinities, with 2 standard deviation of 6 mS/cm and 4 mS/cm, respectively. By resampling water several times and averaging the results, it is possible to reduce the conductivity uncertainty significantly.

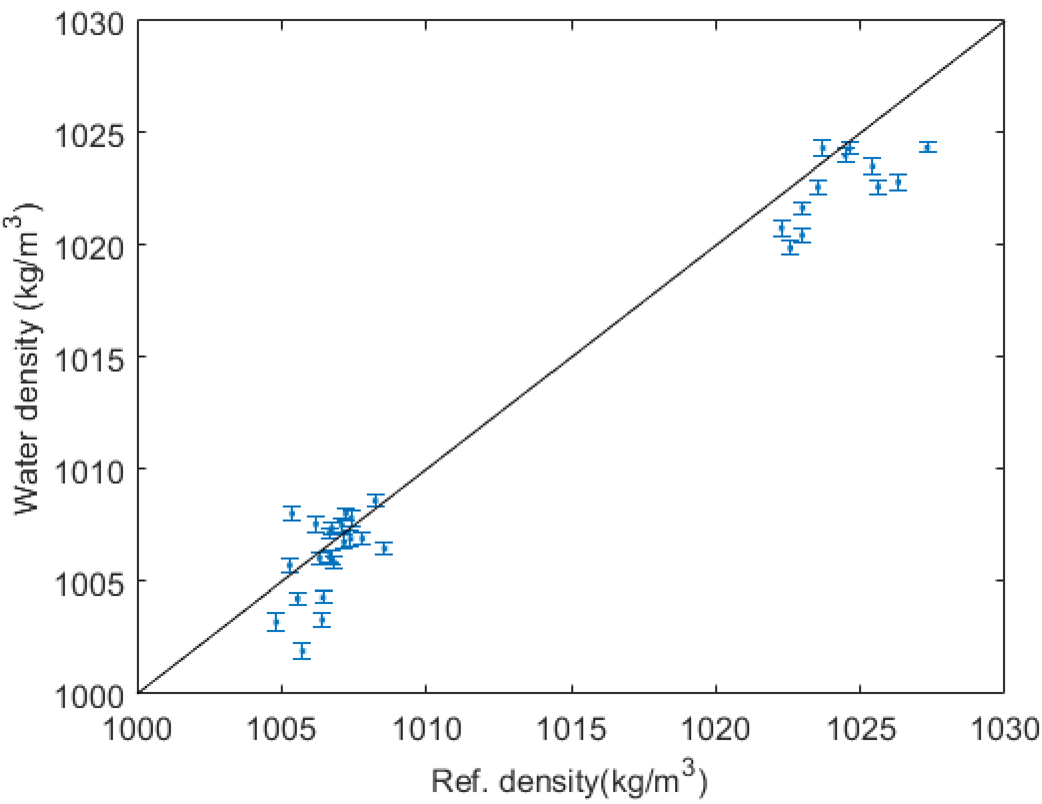

Figure 15. Measured water density versus reference density.

The overall results from the MuFA test show good measurement precision and repeatability for all parameters, which indicate that the samples have been analyzed with negligible amount of contamination of other phases during the logging.

In Figure 4 the achieved results from MuFA are compared against an expected change of fluid properties for a particular well. The level of the measurement uncertainty for oil flow rate shows a reduction of about 2/3 or more over the lifetime, which is a significant improvement. Other typical production profiles confirm similar improvements, if the fluid parameters can be determined with similar results achieved from this work. Especially in the late life of a well, where the water cut is high, it is believed that further reduction of uncertainties will be achieved.

Table 4. Summary of test results

Parameter/fluid property	**Test results**
Oil permittivity	0.6% (95% C.I)
Gas permittivity	0.3% (95% C.I)
Water conductivity	4.6% (95% C.I)
Oil linear attenuation coefficient ***Oil density***	0.6% (95% C.I)
Gas linear attenuation coefficient ***Gas density***	3.8% (95% C.I)
Water linear attenuation coefficient ***Water density***	0.35% (95% C.I)

By integrating or including other measurement principles than used in the corresponding multiphase meters, such as optical, IR, ultrasonic or others measurement principles, even more information from single phase samples can be achieved. What is practically possible to integrate in a MuFA unit will be determined by the actual application, available space, powering and signaling. Additional parameters beyond those parameters needed for the multiphase meter can provide more information about single phase samples at line condition.

During analysis of the gas sampling points, cool down effects were observed during the stabilization and analyze periods, that gave some deviations in measured gas densities. It was not observed cool down effects for water or oil sampling points. However, the cool down between operations gives a risk for hydrate formation that needs to be considered. Improvements in the control algorithms should be considered to reduce the cool down effect, such as longer flushing time and shorter analysis periods. The ambient temperature during the test was below 0°C. For the subsea design of MuFA, the combination of improved control algorithms and updated design to better ensure thermo coupling between the multiphase meter and the MuFA chamber is being worked on.

7 CONCLUSION AND OUTLOOK

All samples were correctly captured for all test points without any failure in valve operations during the test. The test was performed using electric actuators and gate valves with equal percentage characteristics and an opening time of 18 seconds over a wide range of multiphase flow in terms of GVF, WLR, and flow rates, with the control algorithms integrated at K-lab's control system.

The results from the K-lab test have demonstrated that MuFA (sensors, valves and control algorithms) can capture accurate fluid properties from each phase to be used to update the input data of multiphase meters. The level of measurement uncertainties of multiphase meters due to changes in fluid properties can be significantly reduced.

The cool down effect during gas sampling and potential dead leg when MuFA is inactive between sampling requires good thermal coupling in the final subsea version of combined

MPFM/MuFA. Some updates in the design of the subsea MPFM/MuFA assembly, compared to the layout that were tested, is currently ongoing.

Due to instabilities in the water conductivity measurements for the applied multiphase meter, it was decided to determine the water salinity from the density measured by the gamma densitometer.

The results show that this is possible with alternative methods to determine the salinity and still have good performance of MuFA, although the direct measurement of conductivity is believed to give a lower uncertainty. The most important, it is possible to verify the conductivity and salinity results by using two independent methods.

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