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Issues and Challenges with Pipeline Sampling

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1 INTRODUCTION

Sampling product from flowing fluid in pipelines is essential in the petroleum industry to obtain information on the composition of the fluids. The sample will allow measurement and quantification of the chemical composition of the fluids and the relative quantities of different fluids flowing through the pipeline. Traditionally, the primary reason for sampling in liquid hydrocarbon transportation has been to establish the relative quantities of water and sediment to ensure the quantity of hydrocarbon can be accounted for. In gas transportation traditionally the gas is sampled to determine the composition and hence derive the energy value of the gas. Sampling is crucial in all stages of hydrocarbon distribution from the extraction, and transportation of produced fluids through to the separation, refining and transportation of crude oils, liquid and gas products. Many sampling systems at crude oil unloading terminals and pipelines are water injection proven; most of these are on large pipelines (12" - 52") and on stabilised crudes at low pressure. Proving a sampling system requires a stable baseline and the ability to inject 0.5 - 1% water, both of which present challenges to offshore environments. Unlike flow meters, sampling systems off-shore are rarely proved regularly to assess if a representative sample is obtained and a reliance is placed on compliance with standards, good practice and experience. Industry is now becoming more aware of the issues involved and the large uncertainties potentially introduced by errors in sampling. This is driven by a requirement to improve the accountancy of the products, and moves to measure characteristics of the hydrocarbons produced from more difficult fluid streams and locations. It should be noted that many sampling systems are subject to systematic bias.

Within the UK, a government project funded by the National Measurement Office (NMO) within the Engineering and Flow Programme has been researching pipeline sampling of complex flows. This project has focused on water-in-oil sampling, oil-in-water sampling, LNG sampling, and the sampling of wet-gas and multiphase flows.

This paper reviews the sampling of water-in-oil flows, sampling of wet-gases and sampling of multiphase flows. These three areas were identified as the most challenging areas for future development. Sampling of LNG flows is currently being researched as part of a collaborative research programme with other European national metrology institutes within a European Metrology Research Programme (EMRP) [www.emrponline.eu].

When discussing sampling two main purposes have to be examined:

1) Is sampling to be performed for chemical analysis of one or more of the components? or
2) Is sampling to derive the relative quantities of each separate component of the fluid stream?

The fluid stream may consist of a single-phase mixture of liquid (e.g. oil and water stream) or a gas with different components, or it may be a two-phase mixture of gas and liquid.

A sampling system has to be considered as three separate functional parts:

1) The sampler (and pipeline conditioning) which is used to extract a representative sample of the flowing fluid.
2) The sample handling which involves transportation of the extracted sample without changing the composition of the sample.
3) The analysis system which takes the transported sample and performs the required analysis procedures.

2 WATER-IN-OIL SAMPLING

Obtaining representative samples to accurately determine the quantity of water present in crude oil within a pipeline has always been identified as a challenge to industry due to inadequate mixing of the fluids before sampling. Significant research was carried out some 30 years ago into the behaviour of water-oil mixtures in flowing fluids, much of this was performed in joint industry funded projects at NEL. The results of this work culminated in the current ISO 3171 standards, which were published in 1988. Not surprisingly, although still retaining the best guidance available to industry, the limitations and inaccuracies of measurements based on the standard practices are becoming more evident particularly in production environments where water content is increasing and the fluids are becoming more complex.

Sampling of crude oils in the North Sea has been identified as a major issue by the UK oil and gas regulator (DECC) due to the increasing production of water with the increasing age of North Sea fields.[1] Condensate fields represent an even greater challenge for representative sampling due to the rapid separation of the water within the pipeline and the sampling systems. Issues can occur for sampling at the outlet of a primary or secondary stage separator as the flowline can be operating at low velocity and at close to RVP (Reid Vapour Pressure) breakout, and any additional back pressure is unacceptable to the process balance. Increasingly, production fluids from multiple well platforms and fields, with different owners and tax regimes, are comingled for transportation. Defining the composition of the different inputs and water mixtures is vital for maintaining pipeline balance. Pipeline imbalances on shared pipeline systems have been correlated to platform shutdowns, which in turn have been noticed to produce large quantities of water being introduced into the pipeline system. Hence it has been suspected that the cause of the pipeline imbalance has been the lack of detection of the quantity of water entering the pipeline. The cost of the imbalance is distributed to the fields on the basis of their production, which can be inequitable. Newer fields which tend to be drier and have a higher production are therefore allocated with a higher share of the pipeline imbalance or loss even though the source may be from an older and ‘wetter’ field.

The majority of pipeline networks have automatic sampling systems installed but in addition manual samples are obtained to provide a backup measurement and to obtain spot samples to assess fluid composition closer to real time.

It is estimated that all water-in-oil sampling in production systems tend to underestimate the amount of water within the pipeline.

Until recently the issues and importance of pipeline sampling has largely been neglected. However, sampling has been receiving much greater attention in areas such as the North Sea in recent years. As fields have aged the production conditions have changed, the overall flowrates have declined, and water production and particulate content have increased. This combination makes obtaining a representative sample extremely challenging. The fluids must be completely mixed to form a homogenous fluid with a uniform distribution of water across the pipeline to enable the extraction of a representative sample from a single probe inserted into the pipeline. Sampling systems that were installed quite some time ago when flowrates were high and water content much lower then currently being experienced may now be inadequate to collect a representative sample. The lower velocities reduce mixing and additional fluid mixing elements, (e.g. static or jet-mixers) to homogenise the fluids before sampling are being required. Also the velocities at sample probes are significantly lower which will require modifications to the extraction flowrates.

Some operators have overcome this mixing problem by retrofitting jet-mixers into pipelines before sampling systems to ensure fluid homogeneity. The cost of installing a small jet-mixer would be under £400k and doesn’t include the cost of the well down-time. This expensive modification has been employed by several North Sea operators to meet the mixing criteria specified in the standard ISO 3171, which covers the requirements for the automatic pipeline sampling of petroleum liquids.

2.1 Sampling Standards

There are four main standards that cover the sampling of liquid hydrocarbons in pipelines in use in the oil industry:

- ISO standard - ISO 3171 “Petroleum liquids – automatic pipeline sampling”
- American Petroleum Institute (API), MPMS Section 8.2 (API 8.2)
- ASTM D4177 (this is a ballot to ASTM of API 8.2 and they are identical)
- Energy Institute (formally Institute of Petroleum) IP 476 (formally PMM Part VI, Section 2)

The ISO standard, ISO 3171, is generally regarded as the most stringent of the documents and if equipment complies with ISO 3171 it will mainly comply with the other standards. One noted exception is that API 8.2 requires two sequential proving results to be within specification (the proving limits have been widened). However, it used to be common that people would test as many times as it took until they got a result they liked and then called it ‘good’!

Currently the American Petroleum Institute (API) is reviewing its standard on sampling and this should feed into a review of the ISO standard. The API committee is hoping to get a new variant of the standard out to ballot by January 2013.

Current standards for water-in-oil sampling have been deemed inadequate for today’s installations, in particular for the correct prediction of mixing and dispersion conditions at potential sampling points. The lack of adequate mixing is exacerbated by ageing fields with an increasing amount of water being produced and declining production rates. In the UK, the Department of Energy and Climate Change (DECC) has the view that it does not believe that a sampling system should stand or fall on its performance relative to the ISO 3171 standard alone.[1] DECC support the uncertainties defined in the standards which should be proven physically. Problems can occur when using the ISO 3171 calculations outside of their stated ranges.

The calculation methodology for mixing in ISO 3171 uses the assumption that the water concentration is at all times below 5%, that the flow is in steady state, that the pipeline is essentially a long horizontal pipe (this contradicts the steady state at low velocities) with no transients and that viscosity and density are within reasonable ranges. Hence there are significant limitations on the range of applications for using the calculation.

Many operators have expressed strong concerns over compliance with ISO 3171 alone providing accurate measurement particularly the criteria for determining adequate mixing. One issue highlighted has been the failure to account for the mixing difference between vertical or horizontal pipe geometries. ISO 3171 in Annex A (section A.2.2) clarifies that dispersion in vertical pipes can be determined from the droplet settling rate using the defined equation or from a graph, versus the crude oil flow velocity. It is acknowledged that some “very well designed” sampling systems are known to have failed to meet the criteria for adequate mixing as defined by the standard. Ideally a designer should be able to justify or correlate the differences between their design and the standard.

As experimentation into the behaviour of all possible mixtures, velocities, pipe sizes, mixing criteria and the derivation of standard criteria for design, Computational Fluid Dynamics (CFD) modelling which simulates pipeline systems and fluid mixing is increasingly being used to provide evidence of adequate mixing. This is becoming an accepted method by the UK regulator to complement compliance with ISO 3171.

2.2 Sampling Procedure

Two recent papers by a leading supplier of sampling equipment and systems have provided a general overview of recommended sampling procedures and field experience.[2, 3] One of these papers summarised that sampling can be reduced to five main steps as follows:

Ensure fluids are completely mixed/homogenise before sampling

↓

Extract a sample

↓

Ensure sampled fluid handled correctly

↓

Ensure fluid is analysed in accordance with good laboratory practice

↓

Ensure sampling system is adequate and proved

Ensuring that the fluid within a pipeline is completely mixed or homogeneous is a crucial step to ensure collecting a representative sample. If the fluid is not homogeneous then any subsequent sampling and analysis will provide incorrect results.

2.3 Water Dispersion

Water can be present within the oil phase as free water, entrained water and/or dissolved water. In general free water, which is completely separated from oil, will tend to stratify and flow along the bottom of a horizontal pipeline at low velocities due to the higher density compared with oil. As the velocity increases, the shearing layer between the oil and water pickups water droplets and as the shear rate/energy dissipation increases the droplets sizes start to reduce and the distribution and dispersion into the oil phase both improve. Entrained water is dispersed as small droplets through the oil phase and dissolved water-in-oil can be present in very small quantities typically around 0.01% to 0.1%. Water concentration might typically run at sub-percentage values but in upset process conditions there can be up to 70% water phase.

To obtain a representative sample the fluid must be homogeneous in that all the free water must be sufficiently mixed with the oil to become entrained and dispersed as droplets that are evenly distributed across the pipe cross-section so that the concentration of water at any point in the pipeline is the same. A concentration gradient will occur in horizontal pipes and will establish as a function of the oil and water density difference and the velocity within the pipe. A ± 5% deviation from the mean concentration is considered to be homogeneous according to ISO 3171. Figure 1 clearly illustrates the consequences of inadequate mixing; this shows five samples collected from various positions within a horizontal pipeline with varying water content.

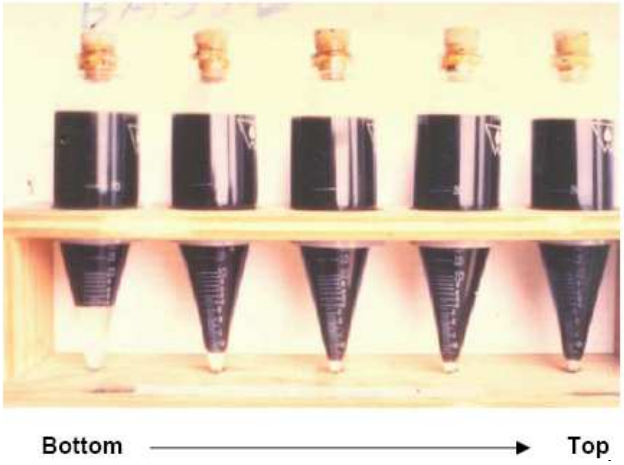


Figure 1: Pipeline samples collected from different positions (bottom of pipe to top of pipe) within a poorly mixed horizontal pipeline. [2]

2.4 Isokinetic Sampling

It has been known since the formulation of ISO 3171, that water droplets can preferentially be directed into or around a sampler inlet hence over or under estimating the water content. Larger sampling probe openings may minimise this issue. It has been generally accepted therefore that the sampler intake should be shaped to minimise this effect and that fluid should be withdrawn with the same velocity at the sampler intake as that of the fluid velocity at the sampler location. This condition is called isokinetic sampling. When the probe inlet velocity is different from the pipe velocity, water droplet flow behaviour is not well understood and is related to probe inlet diameter, density differences, droplet size and the velocities.

It should be noted that if the fluid velocity in fast sampling loops falls below that of pipeline then water separation can occur in the off-take pipework, potentially resulting in non-representative sampling. Although iso-kinetic conditions should be established in the probe, the velocity should be increased in the sampling loop.

It has been claimed that using large probe inlet areas can reduce the sensitivity to achieving precise isokinetic conditions. Field tests have been performed using water injection tests that support this claim.[2] Many systems now use much larger probe inlet diameters significantly larger than the recommended minimum value of 6 mm in ISO 3171.

Initial tests recently performed by NEL have not been conclusive as to the importance of isokinetic conditions or to quantify the effect of super- and sub-isokinetic sampling conditions. Hence, further research on isokinetic sampling is planned. From previous published documents it is recommended to internally bevel the probe, if a 6 mm probe inlet size is used this requires 50-200% of the isokinetic value and if a 2-inch probe inlet size is used then this can work over a range of 10-300 % of the isokinetic value.

2.5 Water Droplet Size

The flow regime in the pipework (and hence the accuracy of the sampling method) depends heavily on the size of water droplets in the flow. Water droplet size is determined by a number of factors including the water-oil interfacial tension and the degree of energy dissipation in the system. In particular the former is influenced by subtle factors such as fluid chemistry. Methods do exist that will predict water droplet size in oil flows, but these methods are generally validated against small-scale laboratory test data. Consequently their accuracy in larger-scale pipeline flows is not known. Different calculation methods can be used to estimate either the mean droplet size or the maximum droplet size. In addition, the distribution of droplet sizes must be considered.

If water carried in the oil is in the form of very small droplets then turbulence will keep these droplets suspended, the water concentration will be constant throughout the cross-section of the pipe and the sampled oil will have the same water concentration as the oil in the pipe. If the water is in the form of larger droplets, then these droplets will tend to drop to the bottom of the pipe and form a stratified layer. This layer may be partly or totally broken up, into droplets when the flow passes through pipeline fittings such as valves. It should be noted that if the droplet settling velocity (dependent on viscosity, density and droplet size (this is affected by interfacial tension)) exceeds the pipeline velocity, for example in a vertical riser, then the pipe geometry will act as a slug generator creating a concentration of free water that will increase until it blocks the pipe and is swept through as a slug.

The relationship between the droplet size and sample probe inlet size to the ability to perform "isokinetic" sampling is an interesting topic. It is fairly understandable that small droplets will not be as gravitationally or streamline effected as larger droplets. There is also a relationship to the droplet size and the probe opening size versus isokinetic sampling because there is a limitation as to how far, for example, a droplet on the centreline of a large opening would move away from that position. In reality very few sampling systems take a practical approach to isokinetic sampling. For example, in-line inserted probes (for example with pitots) have some bluff body effects and resistive drag that could prevent a true isokinetic sample. Fast loop systems could be operated with a variable speed pump but this is generally not done for a variety of good reasons (for example, if the fast loop was pumped isokinetically, then at low flowrates the inlet pipework would promote water settling which is something necessary to avoid).

NEL has been testing and evaluating different commercial technologies available for determining the size of water droplets in oil flows. One of the devices will be selected for further trials in a Joint Industry Project on water-in-oil sampling.

Figure 2 is a sampling probe developed for sampling research and Figure 3 shows the probe, along with a mixer to generate homogeneous flow and a droplet sizing equipment under evaluation in NEL's multiphase flow facility.

Figure 2: Sampling probe for water-in-oil research

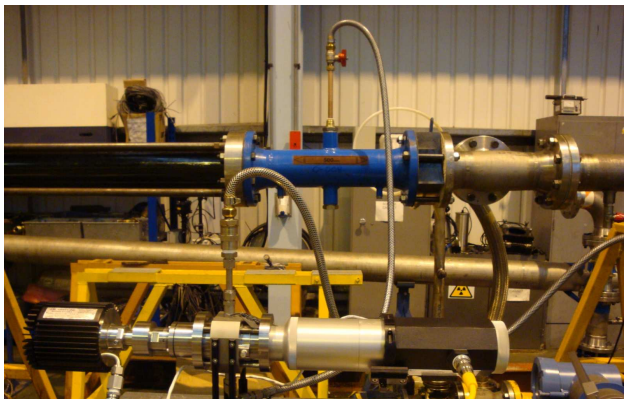


Figure 3: Photograph of the probe and mixer assembly in the NEL multiphase flow facility. The flow from the sampling probe is passed through the droplet sizing equipment shown in the bottom of the photograph.

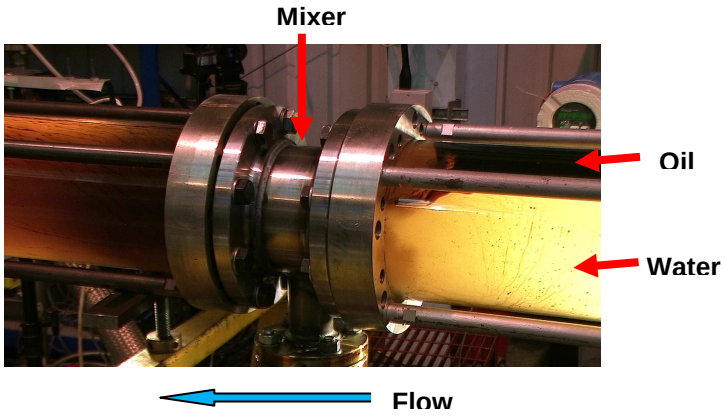


Figure 4: Photograph of the effect of the mixer used in the multiphase flow facility on oil-in-water flows to visualise the dispersion of the oil phase. In this case an oil-in-water flow was used purely for visualisation as it was impossible using water-in-oil flows due to the dark colour of the oil phase.

2.6 ISO 3171 Calculations to Determine Dispersion of Water

ISO 3171 provides details within Annex A of a comprehensive calculation procedure to determine if the fluids are adequately mixed. This 16-page appendix entitled 'Estimating water-in-oil dispersion' provides a method for calculating whether adequate mixing occurs upstream of a sampling system to ensure an accurate measurement of the water concentration. The method accounts for a range of effects such as droplet break-up in pipe fittings, interfacial tension effects and droplet settling. It should be noted that the calculation procedure has known limits and issues may occur when applied outside the working range.

The calculation method in ISO 3171 determines the water-in-oil dispersion by calculating a ratio value (C_1/C_2), where C_1 is the water concentration at the top of a pipe and C_2 is water concentration at the bottom of a pipe. For adequate mixing the value of C_1/C_2 should be between 0.9 and 1.0 indicating a uniform dispersion of water droplets. Values below 0.9 indicate that the sampled oil is unlikely to contain a representative concentration of water. Values below 0.4 indicate that water is likely to flow in a stratified layer along the pipe floor in any horizontal pipe section.

It should be noted that the equations contained in Annex A in ISO 3171 have been shown to be valid for a large number of field data. The range of the field data covered the following correlating parameters:

Relative density	**0.8927–0.8550 (27°–34° API)**
Pipe diameter	**40 cm–130 cm (16 in.–52 in.)**
Viscosity	**6–25 cSt at 40°C**
Flowing velocity	**>0–3.7 m/s (>0–12 ft/s)**
Water concentration	**<5 %**

It should be noted that many North Sea applications are often outside this range. This could be the potential reason that there have been so many issues with compliance with ISO 3171.

It has been commented on that the method can over-estimate the chances of droplet settling in vertical systems as it assumes that all pipework is horizontal. Therefore it may predict inadequate mixing in a vertical system that may well be homogeneous. It is suggested that in vertical pipelines the criteria used should be the basis of settling velocity versus the main pipe crude oil flow velocity instead of C_1/C_2 as C_1/C_2 is irrelevant for vertical pipes. It is noted however that long lengths of vertical pipe don't often exist beyond the riser from the seabed, in general piping geometries tend to be very contorted with short lengths on vertical pipes.

In horizontal pipes stratification will occur due to the effect of gravity on fluids of different densities, while in vertical pipes dispersion is normally improved. In inclined pipes the effect of gravity on promoting stratification/dispersion depends on the angle. Clearly in a vertical pipe, vertical stratification will occur at low velocities, while at higher velocities this can provide a homogeneous fluid across the pipe but it may give rise to water slugging or even unpredictable mixtures and dispersions within the pipe. A model has been developed by Flores [4] to determine the critical minimum angle to maintain homogeneous flow for inclined and vertical pipes. This is explained in the Handbook of Water Fraction Metering.[5] At high flow rates obtaining homogeneous flows are independent of the inclination angle if the angle is in the range of 45° to 90° from the horizontal.[5]

The ISO standard provides a simple guide in Annex C on the suggested minimum flowrates to achieve an adequately dispersed fluid but it should be noted that this is only a rough guide and does not take into account the physical properties of the fluids, pipe size and water concentration. The full calculation procedure as outlined in Annex A should be performed.

2.7 Mixing in a Vertical Flow Regime

Although the ISO 3171 calculation assumes horizontal pipework upstream, in reality it is likely that some vertical pipework will be present upstream of a sampling system. As stratified flow tends to break up into droplets in vertical sections (as illustrated in Figure 5) it is possible that vertical sections upstream of sampling systems could produce adequate mixing.

Caution is advised here as even within vertical pipeline sections the flowrate may be insufficient to force water droplets up through the pipe and depending on the size of droplets, the droplets may sink and settle into a stratified layer in upstream sumps due to the higher density. Slugs of water could be formed from vertical pipe sections causing more issues.

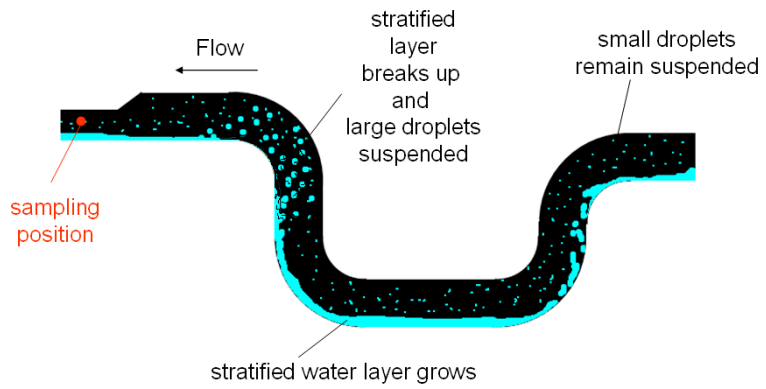


Figure 5: Illustration of a possible flow regime within horizontal and vertical pipe sections. Note that the features shown may be larger or smaller than in reality, e.g. the stratified water layer could almost fill the lower horizontal section or it may be not exist in the pipework and

the flow regime could be effectively homogenous.
Calculation methods, such as that developed by Flores [4] as outlined in [5] have been used to predict the critical velocity at which vertical oil-water mixtures flow in a "very fine dispersion of water and oil" regime (i.e. a homogenous mixture). However, as with the ISO 3171 calculation, care must be taken in interpreting this prediction. In particular, if the vertical section is not long enough it is likely that the stratified layer will not be fully homogenised.

The minimum or critical oil velocity for maintaining a good degree of water dispersion can be calculated using equations from ISO 3171. The critical liquid velocity to maintain a homogenous flow increases with the interfacial tension and pipe diameter and decreases with the oil density and viscosity.[5] It is recommended to determine the homogeneity by any calculations using the worst case conditions expected, for example, the highest fluid interfacial tension, lowest oil viscosity, lowest oil density and lowest liquid velocity.

For the mixing calculations the mixing element (e.g. a pump, turbine meter, straight pipe, valve etc.) with the highest energy is used to determine the dispersion of water. Even if multiple mixing elements are within a pipeline the mixing effect or energies of these elements cannot be combined. The element with the highest energy is used to determine the dispersion and select a suitable sampling position.

Even if the flow conditions are within the turbulent region, i.e. a Reynolds number over 4000, this does not imply that the water will be evenly dispersed within the oil phase. The calculations described in ISO 3171 should be performed to assess the degree of dispersion for a specific application.

2.8 Representative Sampling

Various assessments of mixing efficiency have been preformed to assess the ability of ISO 3171 to correctly predict the degree of mixing required for representative sampling. Recently Computational Fluid Dynamics (CFD) flow simulations have been used to assess whether the degree of flow mixing upstream of a sampling system is sufficient to ensure the water concentration at the sampler intake is representative of the water concentration in the pipeline. In some cases the CFD results have contradicted calculations from ISO 3171. ISO 3171 calculations indicated poor mixing while the CFD modelling predicted that the fluids would be homogenous. The CFD model was supported by the results from analysis of the sampling data.

Some pipeline installations in the North Sea have been known to fail the requirements in ISO 3171 even though evidence or experience suggests the fluid is adequately mixed. These examples as are mostly drawn from vertical pipe sections. There are also documented examples of "well designed" sampling systems indicating that the homogeneity requirements specified in ISO 3171 are not achieved by several orders of magnitude.[1] Until recently ISO 3171 was used by the UK regulator to determine acceptance criteria for adequate mixing before sampling in North Sea installations. Due to some discrepancies between the standard (ISO 3171) and field experience, CFD flow simulations have been deemed acceptable to assess if adequate mixing is achieved for sampling as this ought to take account of the specific characteristics of the upstream pipe installations, fluid properties and the sampling system.

Some of these issues could result from the misapplication of the calculation procedures and use outside the allowable ranges; maybe a more suitable calculation method would help to resolve some of the issues.

2.9 Computational Fluid Dynamics (CFD) Modelling of Mixing

The flow of oil and water through various pipework configurations can be simulated using a range of commercial CFD software packages. There are a range of different models available to simulate multiphase flow and to predict the dispersion of water within the oil phase.

However, most practical CFD methods suffer from a limitation in that a representative water droplet size must be defined in the model. In certain applications this is not an issue. In others the choice of droplet size will determine the result of the simulation and hence this parameter is very important.

There is no well-established approach to setting the droplet size. It can be done based on observations in field or laboratory–based trials or by using empirical or theoretical methods. A combination of these approaches could be used. Also sensitivity studies may be used to show a coherent behaviour in the sampling systems being modelled. Whichever approach is used, there is little good experimental data to confirm that the droplet size defined in a CFD simulation is realistic. If it is unclear how realistic the CFD predictions are, then the results of any study may be less valuable and reliable.

In the future tomography systems may enable the validation of CFD models to successfully predict mixing, droplet size and dispersion.

It is recommended that CFD modelling should be validated to provide confidence in the results as this could have a large financial impact on operators. Future research to improve the understanding of mixing is essential to improve the calculation procedures in ISO 3171 and develop a more sophisticated method for assessing mixing. It is also recommended to use different approaches to define the droplet size distribution for CFD analysis and assess the results.

Figures 6 to 8 illustrate some results from using CFD to model and predict the water-in-oil dispersion.

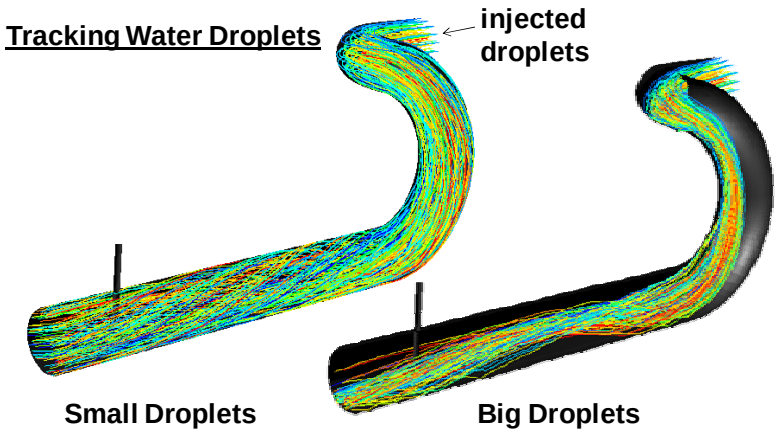


Figure 6: CFD modelling of tracking water droplets. Small injected water droplets are evenly dispersed throughout the pipe cross-section. Larger water droplets form concentration zones or stratified layers which are influenced by the pipe geometry.

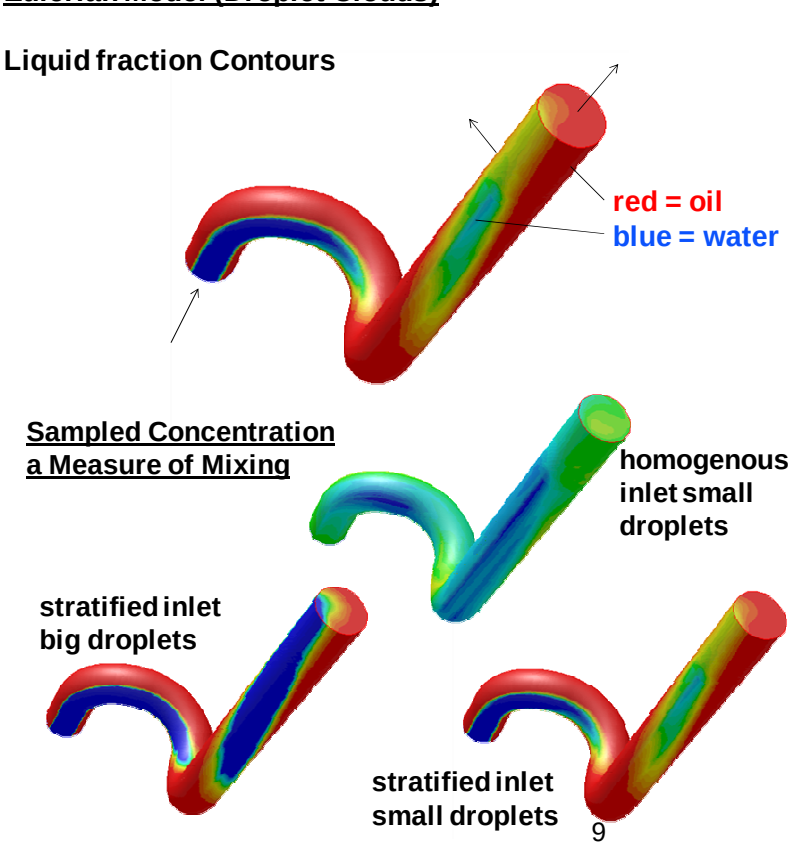


Figure 7: Eulerian CFD simulation which models the water as clouds of droplets. The colour indicates the fraction of water droplets. The stratified inlet is not completely mixed by flowing through the pipe geometry.

Figure 8: Eulerian CFD simulation which models the water as clouds of droplets. The colour indicates the fraction of water droplets.

Figure 8 shows that when the geometry is modelled as a stratified inlet with large droplets the flow is not completely mixed and shows a large deviation in water concentration across the pipe cross-section – it should be noted that any pipeline profile tests preformed from the top of the pipe to the bottom may not highlight this deviation as the water layer is forced to the side of the pipe. The stratified inlet modelled with small droplets shows almost complete mixing. The homogenous inlet with small droplets shows that the pipeline geometry can affect the distribution of water and shows that the location of the sampling point downstream of a bend is important.

As well as determining the droplet size for modelling, other parameters must be considered. These include the boundary conditions such as:

- Stratified or homogenous flow at the inlet
- Water/oil slip at inlet
- Assume isokinetic sampling
- Worst case or realistic assumptions

The general physics behind the model must also be considered, including the:

- Droplet coalescence and breakup
- Turbulence effects
- Mesh effects
- Stratification of fluids

The interfacial tension between the water and oil can also have significant influence. It should be noted in these models that the droplet size does not change during the stimulation therefore no effect of coalescence has been modelled. CFD can be useful for evaluating the effect of changing flow conditions, other parameters and sensitivity studies.

One of the concerns with using CFD is the lack of validation both for the results ensuring they match reality and for the methodology used. This is especially important if CFD has been used to provide evidence of adequate mixing for fiscal sampling.

Even if CFD results look realistic, it has been observed from experience that even a minor change to an input parameter can make a significant change to the output results. CFD can certainly be used to assess the sensitivity of input parameters but cannot provide an absolute estimate of the result unless it is calibrated against suitable experimental data. An extensive data set to cover a wide range of pipeline sizes, oil types and flow ranges is necessary to calibrate or validate CFD for practical field applications.

Table 1 shows one example of where CFD simulations fails to match (within expected tolerance) to real field data (profile data from Annex B in ISO 3171). This highlights the issue with un-validated CFD simulations.

Table 1
Comparison of CFD Simulations with Real Field Data
(Water concentration profile data from a crude oil terminal - Annex B in ISO 3171) [3]

	ISO 3171 - Page 52	CFD Simulation-1	ISO 3171 - Page 52	CFD Simulation-2	ISO 3171 - Page 52	CFD Simulation-3	ISO 3171 - Page 53	CFD Simulation-4	ISO 3171 - Page 53	CFD Simulation-5
Velocity (m/s)	1.84		1.84		1.84		2.38		2.38	
Water Injection %	3.1		5.17		7.24		3.2		5.11	
Point A	3.6	2.9	4.6	4.654	5.3	6.2	3.4	3	5	4.73
Point-B	3.4	3.09	5	5.166	5.7	7.22	2.9	3.19	5.3	5.107
Point-C	3.8	3.1	5.4	5.17	6.1	7.24	3.4	3.2	5.4	5.11
Point-D	3.2	3.1	5.3	5.17	6.6	7.24	3	3.2	5.4	5.11
Point-E	3.8	3.09	5.9	5.169	6.7	7.24	3.4	3.19	5.5	5.109
Point-F	3.4	3.09	5.7	5.169	7	7.23	3.2	3.19	5.8	5.109
Point-G	3.8	3.09	5.9	5.169	6.8	7.23	3.6	3.19	5.6	5.109
Point-H	4.4	3.37	6.4	6.275	7.2	7.9	3.6	3.48	6.2	5.8

Extensive CFD analysis has been performed on horizontal pipes to extend the CFD calculations beyond the stated limits of Annex A in ISO 3171 and to provide correlation to Annex A to assess deviations. This has been performed for a range of different pipe sizes to enable an envelope to be developed to allow understanding as to where Annex A can be correlated or to identify where certain conditions provide results that are completely out of an acceptable tolerance. This will allow enhanced understanding of the limitations of Annex A. The CFD simulations are being validated against a large set of real field data. Some examples of the CFD profiles over a range of conditions are shown in Appendix A.

2.10 Proving of Sampling Systems

The sampling system can be proved by testing the individual steps in the procedure, e.g. mixing, extraction device, sample receiver and lab analysis technique or by testing the entire sampling procedure with a water injection test. In reality it is quite difficult to prove the individual steps such as validating the mixing efficiency and the uniform dispersion of the water. The laboratory analysis and handling procedures can be tested by providing a spiked or known water-content sample to the lab and evaluating the results.

The only technique that has been recommended by industry experts to fully validate an entire sampling system is a water injection test. This is the recommended way to prove a new sampling system or an existing system in which the fluid conditions have changed.

The water injection test is described in ISO 3171 and API 8.2. It should be noted that the acceptance criteria for water injection testing is more stringent in ISO 3171. The method involves injecting a volume of water and confirming that the extracted sample obtained represents the total volume of water injected plus the baseline water. The water injection method tests the whole sampling system and not just the mixing efficiency. This includes the sample grab location, sample grab volume, flow proportionality and the integrity of the relief valve, tubing and receivers.[2] Although water injection testing is recommended, in reality this is rarely done to prove a sampling system particularly off-shore. Only a few companies require that water injection is used to prove a sampling system and hence consideration is given to ensure the procedure can be performed, e.g. by ensuring a suitable location and equipment for the water injection. Water injection tests have been successfully performed on some of the North Sea installations.

It should be recognised that even using this test the results can be influenced by the position of the injection point and the design of the sampling system, for example, pipe configurations can cause the formation of slugs of the water passing the sampling point rather than forming a stable flow regime. In this case the uncertainty of measurements will be increased and testing periods may need to be extended to obtain reasonable values. A stable baseline water value is required which may be problematic to achieve in some installations. The water injection test ideally should be performed at the worst case conditions of lowest expected flowrate, lowest density and viscosity.

Performing water injection testing offshore may be challenging due to the environment and accessing the pipe to be able to inject water at a suitable position upstream of the sampler to establish a stable flow regime. The injection of water itself should not promote mixing. The mixing should be a result of the configuration and components within the pipework upstream of the sampler.

It has been observed that when proving a sampling system with ISO 3171 the uncertainty will tend to be a negative value which means that in general sampling systems will understate the actual water content even when under the best operating conditions.[2]

Before committing the time and resources to performing a proving test on a sample system it may be beneficial to first assess other criteria and do some basic checks on the system. For example, assess the quality of mixing from the mixing calculations, inquire if the fluid composition or flowrates have changed, review the sampler performance factors etc. A proving test can demonstrate that the sampling system is operating well and complying with the appropriate standards.

Independent auditing of sampling systems is recommended and any proving of a sampling system should be traceable to provide confidence in the testing and evaluation.

2.11 Recommendations

If the fluid compositions and flowrates have changed (e.g. water cut, density and viscosity) since the installation was designed and validated then the system should be reassessed. These changes may well result in an understatement of the water content. The mixing calculations outlined in ISO 3171 should be checked and the system proved. Proving by water injection is recommended. If the system fails the mixing calculations but evidence or experience suggest the fluid should be completely mixed, e.g. sampling from a vertical pipe section, then CFD could be used to provide some indication of the mixing performance observed. If using CFD then attention should be paid to the limitations of CFD, lack of validation of the modelling and uncertainties introduced from estimating the droplet size and other assumptions used with the modelling. Ideally benchmark data should be used to validate the CFD methodology and results before extrapolating it to other conditions. CFD can only predict if the fluid will be completely mixed, it will not predict if the entire sampling system is operating correctly and if the sampling results will be truly representative of the actual fluids in the pipeline.

Sampler performance checks should always be carried out to assess the performance of the sample collection process. There should be a log of the performance factors.

The reliability of the system should be regularly checked to ensure the equipment is functioning and the sample volume is as expected. If the sampling system is flow proportional then other considerations to check and confirm are the flow measurement signal and its accuracy, the volume and repeatability of each sample grab, volume in sample receiver compared to the number of grabs taken. The sampling frequency should be assessed as the sampler may miss collecting samples when water slugs are present and underestimate the amount of water.

The laboratory analysis and handling procedures can be tested by providing a spiked or known sample and evaluating the results. Staff competence, training and an awareness of the importance of good sampling practice is critical as even small errors can lead to a large financial exposure.

3 WET-GAS SAMPLING

The sampling of wet-gas flows is extremely challenging to perform and obtain reliable results. NEL carried out a review of wet gas sampling to obtain the opinions and experiences from industry in 2010 [6]. This review identified some of the issues associated with the sampling of wet gas flows and was used as the basis to develop further research into wet gas sampling and to perform some testing [7].
Wet gas sampling can be divided into two types:

1. Representative (which collects representative fractions of the gas and liquid stream).
2. Non-representative (which extracts quantities of either the gas or the liquid stream for analysis of composition).

The information required from the sample may dictate the type of sampling equipment required.

Wet gas sampling may be performed for a variety of reasons including providing information to:

- use wet gas correlations for single phase meters
- use specific wet gas/multiphase meters
- validate wet gas meters
- determine composition of fluids
- determine fluid properties
- perform PVT (Pressure Volume Temperature) analysis on fluids
- determine if liquid is present within a gas flow
- determine if water is present in liquid for flow assurance supposes, e.g. hydrate and corrosion control
- well testing and performance monitoring

For wet gas flows the liquid can be condensate and / or water. The liquid can be distributed in a variety of ways depending on the flow regimes, for example, it can be flowing along the bottom of the pipe or distributed as liquid droplets entrained in the gas. Sampling is extremely challenging due to the variety of flow patterns and the uneven distribution of the liquid.

A key difficulty of achieving representative sampling is the problem of how to ensure an even distribution of the liquid phase within the gas stream. In mist flow this is not too problematic, but in annular flow some form of mixing device is generally required to strip the liquid from the walls of the pipe and disperse it within the gas phase. Sample probes must also be carefully designed (and positioned) to average out any remaining distribution variances within the flow.

If a non-representative sample is adequate then the choice and selection of sampling system can be significantly easier. In some cases it may be suitable to sample the fluids after the test separator and recombine the fluids to the appropriate conditions of temperature and pressure although this may increase the uncertainty of the analysis of results.

To avoid phase changes, the samples themselves should be maintained at the same pressure and temperature as the wet gas stream during off-take, accumulation and analysis. If a representative sample was taken at the meter location but analysed at a different temperature and pressure this would cause the relative volumes to change.

Although there are commercial wet gas sampling systems available, operators and contractors lack confidence in their ability to obtain and analyse a representative sample. Operators have had variable and inconsistent results from using wet gas sampling systems. However, there may be no other viable options but to use available equipment offered by manufacturers.

In general operators will have to assess:

- the application of sampling
- information required from sampling
- cost
- frequency of sampling
- investment in the validation / testing of the sampling system (if any)
- associated uncertainty in the measurements
- risk of mis-measurement and the financial impact

3.1 Industry View on Wet Gas Sampling

Sampling technologies have been considered by many to be insufficiently developed to provide accurate sampling in the case of wet gases. In fact, for a long time, the sampling of wet gas has been actively avoided by the natural gas industry, particularly in the USA [8]. This is due to a belief that wet gas sampling technologies are incapable of obtaining a representative sample, based on information from the API Manual of Petroleum Measurement Standards, Chapter 14 [9]. In the USA it is common practise to physically separate the liquid and gas phases before or after a sample is drawn from a pipeline [9]. Single phase sampling technology is then applied. Recently the US regulator commissioned a review of wet gas sampling [9].

The UK is considerably more receptive to using wet gas sampling systems and there are some commercial systems installed in the UK. There has been a trend towards using wet gas meters without having to first separate the fluid streams as this is considered more cost effective; the same principle has been applied for representative sampling. Operators have invested resources in the field testing of wet gas sampling systems to assess their capability. This has been with mixed results and identified various issues. More recently within the UK there has been some avoidance of sampling of wet gas flows due to the complexity of obtaining a representative sample and reliability of the results. Some members of industry are of the opinion that it is impossible to collect a fully representative sample and there has been a shift to sampling the gas and liquid separately.

Despite these challenges, there are some systems available that claim to produce accurate samples of a wet gas stream, even though few independent evaluations of their performance currently exist.

3.2 Standards / Guidelines

Currently there is no standard procedure or guidelines for the sampling of wet gases. Some operators are using information from the ISO Standard 10715 "Natural Gas – Sampling Guidelines". This covers sampling dry gases to obtain samples for gas composition analysis and only briefly mentions two-phase flows. It states that the technology for natural gas sampling is not advanced enough to handle wet-gases with a reasonable accuracy and recommends avoiding the sampling of two-phase flows [10]. The standard highlights the following issues:

- Changes in temperature or pressure, for example after a separator, may cause the gas to be very close to the dew point and further changes may result in condensation occurring.
- Temperature changes between sampling in daytime and night-time have been noticed to affect the sample composition and hence calorific value, where cooler night time temperatures have resulted in heavier hydrocarbons condensing.

The standard ISO 10715 recommends to sample at a minimum of 20 pipe diameters downstream of any flow disturbance (e.g. a valve). This is beneficial for dry gas sampling to ensure minimum turbulence, as turbulence is thought to increase the entrainment of liquids and solid particles into the gas phase (generation of aerosols), and hence collect condensate [10]. However, for wet gas flows it may be beneficial to collect a sample directly after a flow disturbing element, such as a mixer that will produce well mixed fluids. The flow may quickly stratify after any flow disturbance making any sample withdrawn unrepresentative. ISO 10715 also recommends withdrawing a sample from the centre one-third of the pipeline diameter.

Some of these recommendations were investigated in the experimental test programme to assess their relevance to wet gas sampling.

Overall industry would appreciate more extensive testing to be performed and some form of guidelines and recommendations to be produced. A small amount of research has been performed by industry in the form of field trials, however due to the costs involved, including the disruption to operations, the field trials were only conducted for a short period of time.

Within the UK, the DTI Guidance Notes for Petroleum Measurement are used as the guidelines on the sampling of the gas and condensate separately [11].

3.3 Predicting Wet Gas Flow Regimes

Wet gases can flow in a variety of flow regimes or patterns. The variety of flow regimes encountered in industry makes wet gas sampling a complex and difficult issue. One wet gas sampling system may work reasonably well in a particular pipe system but could fail in another or if the flow conditions change. In addition, how do we know if a wet gas sampling system is collecting a representative sample?

Knowledge of wet gas flow regimes can be beneficial in knowing where to take a sample from and intuition as to whether the sample is likely to be representative. However, it is very difficult to predict the flow regime. Characterisation of wet gas flows has been performed at various flow laboratories, including NEL, using Perspex pipes and various imaging systems. These flow maps are only considered accurate for the exact flow conditions and pipe geometries used in the testing. If conditions change or the pipe set-up differs, it is likely the flow regimes may also change. However, there is considerable uncertainty about how the flow regime changes. The main flow map used throughout industry for predicting the flow regime of wet gas flows was devised by Shell.

More recent research suggests that the flow regimes and boundaries between them can shift significantly depending on the fluid properties, for example, the surface tension of the liquid [12-15].

The flow regime of a wet gas can depend on:

- Flow composition (relative fractions of gas and liquid – perhaps even water and oil)
- Liquid and gas velocities
- Liquid and gas densities (pressure dependent)

- Viscosity
- Surface tension

Ideally, a homogeneous flow (e.g. a mist flow) would be available for obtaining a representative sample. However, it is the opinion of some wet gas experts that a mist flow is never fully achieved and there will always be a film of the liquid on the pipe wall. Therefore it may be impossible to collect a 'true' representative sample.

Making a wet gas flow into a mist flow or more homogeneous flow before sampling has many advantages in obtaining a representative sample. Some providers of wet gas sampling systems use a mixing device before sampling.

Some manufacturers have tested and successfully used particular pipe geometries to ensure the collection of a wet gas sample. However, in this case the pipe geometries were specifically used for collecting the liquid fraction to analyse the liquid properties for a wet gas / multiphase meter which was sensitive to the fluid properties. This was a subsea wet gas sampling system.

3.4 Industry Requirements

Some of the issues identified by industry are:

- Compliance with standard ISO 10715:2001
- Location of probe downstream of a flow disturbance
- Orientation of probe, towards or away from flow
- Type of sample cylinder to use
- Selection of commercial wet gas sampling system for Normally Unmanned Installations (NUIs)
- System design to limit heavier components condensing or preferential collection of sample.

One of the main concerns of the industry is the possibility of heavier hydrocarbons condensing in the sample piping or preferentially being collected in the cylinder. Temperature and pressure changes in addition to the design and geometry of the sampling system will significantly influence the ability to collect a representative sample and biases may be introduced.

3.5 Experimental Tests at NEL

A series of tests were performed at NEL's flow facilities to identify and highlight any problems that could potentially occur in industry. For these tests nitrogen was used as the gas and water as the liquid giving a good stable fluid mixture unaffected by potential phase changes, hence allowing investigation of the fundamental interactions.

Issues investigated included:

- Isokinetic sampling
- Distance of sample probe from a mixing element
- Design of sample probes – beveled or multi-hole probe (averaging pitot tube)
- Location of sample probe within pipe, i.e. top, middle or bottom of pipe
- Orientation of probe

The samples were collected from locations downstream of a 4-inch static mixer. The distance from the static mixer to the sample probe varied from 2, 10 to 34 inches. A 4-inch Perspex section of pipe (approximately 1 m in length) was adapted to hold the probes and to visualise the flow.

Wet gas samples were collected in a customised NEL-designed cyclone separator that was constructed from a vertically mounted 6-inch Perspex pipe, a 6-inch Perspex mixer/separator block, and various fittings. A picture of the cyclone separator can be seen in Figure 9. Wet gas samples flowed into the separator block which forced the fluids against the pipe wall. The water spiralled down the 6-inch pipe to collect at the bottom, while the gas vented through a valve at the top of the separator unit.

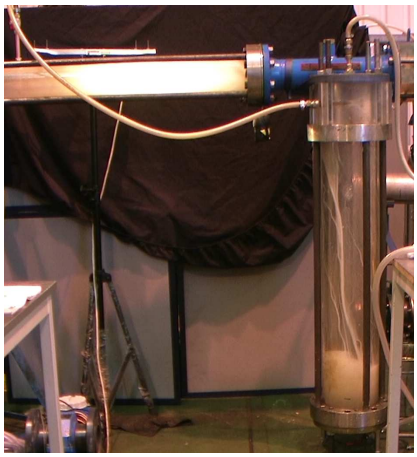


Figure 9: Cyclone Separator

3.6 Test Set-Up

To evaluate the effects of sample probe location, orientation and probe type, representative samples were taken from positions across the pipe cross section and analysed in terms of the gas volume fraction and expected liquid content. The probes were manufactured in such a way that they could be moved to adjust the sampling location within the pipe cross section. Figure 10 shows photographs of the sample probe at 2 and 34 inches downstream of the mixer.

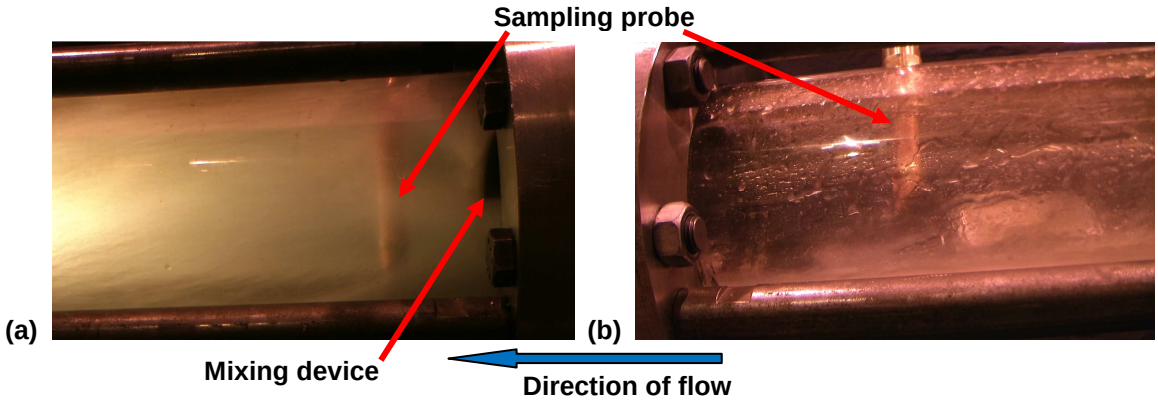


Figure 10: Sampling probe located (a) 2 inches downstream of the mixer (b) 34 inches downstream of the mixer

The sample line was connected to the cyclone separator which enabled the separation of the liquid and gas phases for measurement. In the gas outlet line from the top of the cyclone separator, a micro-motion Coriolis meter was installed. The flow through the meter was controlled by a valve. This allowed the gas velocity to be monitored for isokinetic sampling. From the measurements recorded the sampled gas volume fraction could then be calculated. Tests were performed at conditions with gas volume fraction (GVF) > 99.6%, 100% water cut, line pressure ~5 bar, water flowrate 0.5 l/s and gas flowrate > 138 l/s.

3.7 Summary of Test Results

- The experimental set-up evaluated various sampling parameters including:
    - Sample probe design
    - Velocity ratio (effect of isokinetic sampling)
    - Gas velocity
    - Probe location downstream of mixer
    - Probe entrance position in pipe (top, centre, bottom)
    - Orientation of probe entrance
- Tests have demonstrated that it is extremely difficult to obtain a representative wet gas sample even using a mixing element. Due to the liquid jets forming from the mixer this could

introduce bias in the sample collected depending on the location of the sample probe entrance.

- The probe location and position can have a significant effect on the amount of liquid collected and calculated GVF values. After the mixer the flow quickly formed an annular flow before collapsing to a stratified flow regime. Increasing the gas velocity, increased the distance downstream from the mixer before the flow became stratified.

- The velocity ratio can have a significant effect on the amount of liquid collected and the calculated GVF value depending on the probe type. Differences of over 50% in the collected liquid content from non-isokinetic sampling conditions were observed. Isokinetic sampling requires precise knowledge of both the main test line conditions and the sample probe line process conditions. The velocity and pressure are two of the most important parameters and it is vital that the correct velocity ratios are calculated using 'live' conditions.

- The orientation of probe entrance can affect the representivity of the samples and amount of liquid collected. There was an 82% reduction in the collection of the liquid sample when the entrance of the probe was facing away from the flow.

- The gas velocity appears to have an effect on the amount of liquid collected when the probe is positioned directly after the mixer. In this case increasing gas velocity decreased the amount of liquid collected. It is acknowledged that this will very much depend on the mixer design which can form liquid jets or concentration zones and the position of the probe entrance.

- From comparison of the test results for both the bevelled and the averaging pitot sample probes, it appears that probe type selection has no distinguishable difference on the sampling performance. There were similar deviations in GVF and amount of liquid collected for the two probe designs.

3.8 Factors for Future Consideration in Wet Gas Sampling

- Changing conditions of the flowrate / velocity of the gas can change the flow regime and will affect the distribution and flowrate of the liquid.
- The liquid distribution changes along the pipeline downstream of the mixer and quickly formed an annular-stratified flow regime.
- Position, orientation and location of sampling probe
- Probe design

3.9 Modelling and Simulation of Wet Gas Sampling

The use of Computational Fluid Dynamics (CFD) to predict wet gas flow regimes was assessed and validated with experimental data. Different approaches were assessed to simulating wet gas sampling with mixed success.

Figure 11 gives an indication of the flow behaviour seen in the Perspex pipe downstream of the mixer. Flow entering the mixer was clearly stratified. The mixer threw much of the liquid onto the walls, producing a wall film. Gravity caused the wall film to drain, downwards from the walls into a stratified layer running along the bottom of the pipe downstream of the mixer. The stratified layer grew downstream as more of the wall film drained into it. For high gas flow rates most of the liquid stayed on the walls for the length of the 1 metre long Perspex section. At low gas rates the wall film fully collapsed into the stratified layer after a few pipe diameters.

Two types of multiphase CFD models were tested; the Volume of Fluid (VOF) model represents liquid and gas as being separated in each cell; the Eulerian model represents clouds of droplets in a continuous gas phase. Different issues were experienced with each model.

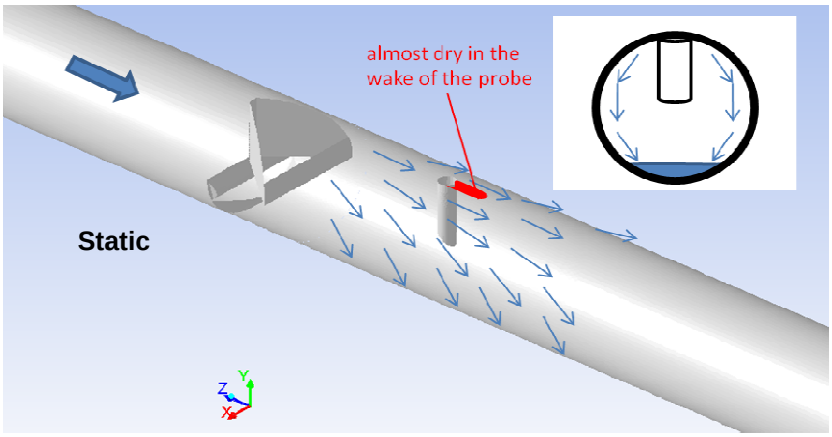
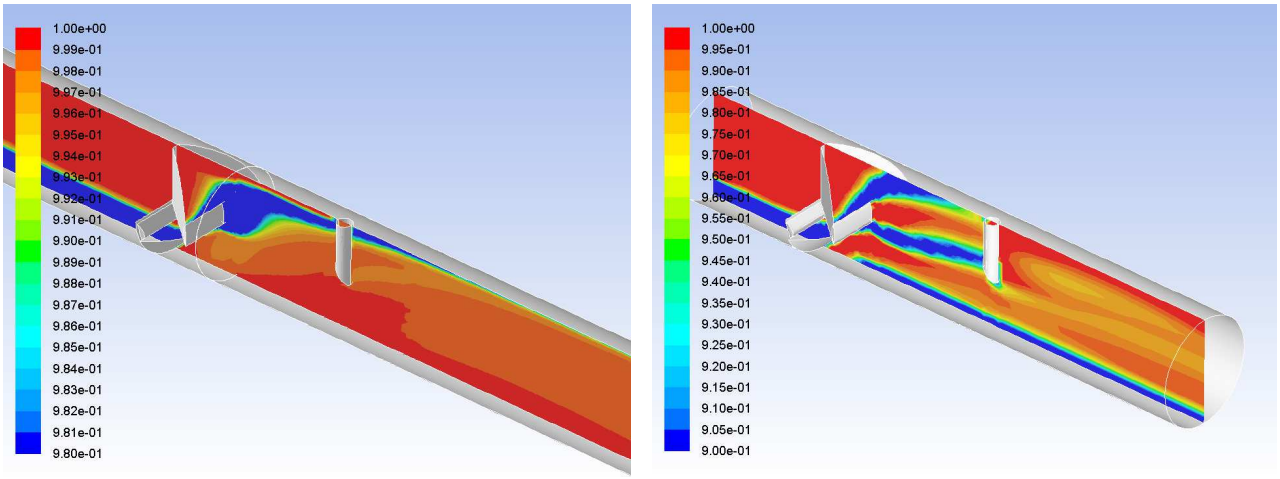


Figure 11:
Wall Film Flow Behaviour

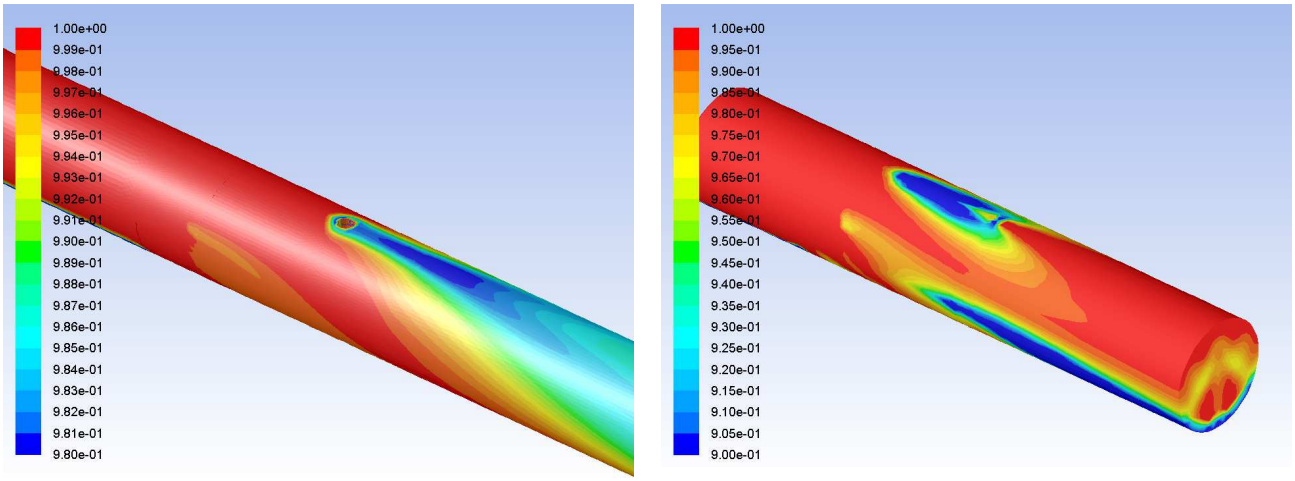
Figures 12 and 13 show the CFD results. In these figures red represents gas and blue represents regions of high liquid fraction and flow is from left to right.

It was concluded that CFD does show the potential for modelling wet gas sampling systems provided the correct multiphase models are chosen. However, to do this sufficiently well to be of use, further work is required to optimise various solution parameters including the mesh and droplet size.



(a) VOF **(b) Eulerian**

Figure 12: Predicted Gas Fraction on the Centre Plane in the Pipe



a) VOF (b) Eulerian

Figure 13: Predicted Gas Fraction at the Walls of the Pipe

3.10 Wet Gas Sampling Conclusions

The results obtained have demonstrated that many factors can influence the ability to obtain a representative wet gas sample and have assisted in determining the magnitude of these parameters. The knowledge gained will enable a more comprehensive and detailed test programme to be carried out in the future.

As the test matrix was limited in relation to what is expected in real field conditions, it would be advisable to simulate the actual conditions in a laboratory or perform field testing to evaluate the performance and reliability of a wet gas sampling system. Hence, why modelling is considered important if it can reliably be used and reduce the need for experimental tests and field trials, although substantial further research is required in this area.

Modelling of wet gas flows is achievable with CFD simulations but is considerably more complex than single-phase flows. The ability to simulate fluid distributions in a pipe would be beneficial for improving the ability to collect a representative sample and assess the effect of changes in flow conditions to determine the most appropriate location for collecting a sample. However, based on this study substantially more evaluation of CFD for wet gas flows is necessary to improve the confidence in the results.

4 MULTIPHASE SAMPLING

It has become increasingly common for the handling and management of complex multiphase fluids due to changes in field conditions, exploitation of new resources, and the drive to reduce capital and operational expenditure. New technologies, such as multiphase flow meters (MPFM), have, and are being, developed to meet this demand to handle and meter these fluids. However, to achieve this accurately there is a corresponding demand for sampling techniques for multiphase flows to enable adequate information on the fluid components to be obtained.

Multiphase sampling is similar to wet gas sampling as it can be performed to collect representative or non-representative fluid samples in terms of the phase fractions. The information required from the sample may dictate the type of sampling equipment required.

Many of the challenges with sampling multiphase fluids are similar as those defined for wet gas flows. Hence any considerations for wet gas sampling may be applied to multiphase sampling if appropriate.

Multiphase fluids are more likely to contain higher molecular weight hydrocarbons than wet gases and hence wax formation within pipelines can be an issue. For flow assurance purposes sampling and analysis of multiphase flows can provide information on the likelihood of wax formation and deposit as this can have a major effect on metering technology and efficient transportation of fluids. Also waxes can cause blockages or restrictions in sampling equipment and result in a failure to collect samples.

Information from sampling can be used to enable fine tuning of reservoir, well and production models for enhanced prediction of the system over the production life.[22]

4.1 ‘Representative’ Sampling

Industry is aware that it can be extremely difficult to obtain a truly representative sample of multiphase flows, if not impossible. The fluids must be completely mixed to form a homogeneous fluid before obtaining a sample. For collecting fluids samples to determine fluid properties as inputs to multiphase meters or for flow assurance assessments or to detect tracers then non-representative sampling may be adequate.

The term ‘representative’ is often used to mean two very different types of sampling within the industry. This is most notable in multiphase metering and sampling. In water-in-oil sampling representative is generally accepted to mean that the sample is representative in terms of the relative fluid fractions or water-cut. This assumes the chemical composition in the sample is also representative of the production fluid. In multiphase terminology ‘representative’ is generally used by vendors in terms of the sample containing fluids that are the same chemical composition, hence same

physical properties as the production fluid and not representative in terms of the relative phase fractions of the production fluid, i.e. the sample can have a different water cut and different gas volume fraction (GVF) to the production fluid.

Most multiphase sampling technologies collect a sample that is representative in terms of the chemical composition and not the phase fractions. Some sampling designs preferentially collect liquid or gas and liquid enriched samples. Recent published data have shown good results for determining the water liquid ratio from collected samples.

4.2 Flow Assurance

Flow assurance is one of the main drivers for multiphase sampling. Downhole samples are usually collected during the exploration phase however, reservoir fluid compositions can change over the field lifetime and the downhole samples can be contaminated. Early identification of flow assurance risks is hugely beneficial to allow mitigation.

4.3 Reservoir Management

Subsea multiphase sampling has been used to obtain information on the reservoir production by collecting hydrocarbon samples containing chemical tracers that have been injected into the reservoir. The samples collected can be used to determine which part of the reservoir is producing. In this application only collection of the hydrocarbon fluid is necessary. Systems that have been developed for this application can be integrated into the subsea manifold and collect samples from separate wells feeding into the manifold without shutting in any of the other wells. Pumps and other components of the sampling system can be made retrievable.

4.4 Multiphase Metering

The majority of multiphase flow meters currently available use fluid property characteristics such as density, permittivity and radiation absorption, to determine the nature of the flow in terms of phase fraction. For tie-backs and shared pipelines, the properties of the oil, water and gas will usually vary, and so it is important to ensure correct fluid property data is entered into the multiphase meter for each well stream.

The main methods for determining oil, water, and gas phase fractions are:

- Gamma-ray absorption methods
- Bulk electrical property measurements, e.g. capacitance and/or conductivity
- Microwave resonance or attenuation

All these method are sensitive to the fluid properties, in particular the water salinity. Information on the fluid densities is also usually required for multiphase metering. For microwave measurement techniques the permittivity of the water phase often requires a calibration on the actual produced fluid, while the permittivity of hydrocarbons is fairly well characterised.

The principle measurement techniques used in the multiphase meter may directly determine the type of sampling necessary.

The salt content of the water can vary significantly between wells, with some water densities reaching over 1200 kg/m^3. Careful thought should be given to potential changes in the physical properties of the water in terms of their effect on meter calibration; this is especially important in multiple tie-back situations, or the manifolding of a number of subsea wells into one common flowmeter and riser.

Sampling is usually essential to obtain information on the fluid properties to enable more accurate metering of multiphase fluids. Information on the fluid properties is normally manually entered by the user.

Fluid property information should ideally be updated regularly but this is seldom done in practice. There have been examples where the fluid properties entered into the meter were not changed after

the meter was tested in a laboratory with substitute fluids. Understandably the meter was providing inaccurate measurements when installed in real conditions and in one case was providing negative oil readings. The operators had falsely blamed the mis-measurements on the meter performance rather than inaccurate fluid property information.

Infrequent sampling could lead to large errors in flow metering if the fluid properties have changed and this is not updated in the flow calculations. This could be a significant issue for allocation purposes.

A system capable of providing representative samples from a wet gas or multiphase flow stream would be of significant benefit to the oil and gas industry; in particular by removing the need for traditional phase separators. It is likely that such a combination (i.e. of multiphase meter and multiphase sampler) would be attractive for many custody transfer and cost-reduction applications, such as the metering of multiple flow streams prior to their commingling and processing in common facilities. In reality the challenge and uncertainty in obtaining a representative sample in terms of relative phase fraction and chemical composition may limit the technique for this application. The "Holy Grail" of flow metering would be a technique that could perform *in-situ* validation of multiphase and wet-gas flowmeters.

Currently multiphase sampling is regarded as one of the highest uncertainty contributions for multiphase metering. The overall uncertainty from a MPFM includes two main sources of errors of the metering technology itself and the fluid properties. Meter manufacturers are constantly trying to reduce the metering uncertainty and lead the way for multiphase meters to be used for fiscal allocation which requires much lower uncertainties than for using a meter for monitoring production. The next step would be for fiscal metering, which required even lower uncertainties. The sensitivity of multiphase meters to fluid properties such as water salinity is an issue due to the cost and frequency with which sampling may need to be performed to provide information on the fluids. Industry would prefer multiphase meters which are less reliant on fluid properties but are cheap and have a low measurement uncertainty.

The outputs from MPFMs are usually converted to standard condition using a model based on PVT properties. This adds an additional uncertainty to the results. It has been recommended to use an Equation-of-State (EOS) model tuned to data from a PVT report to reduce the errors rather than a Black Oil model, which were developed for separator operating a much lower pressures and temperature. An overview of the errors from different models is provided in [22].

4.5 Sample Analysis Techniques

It is preferable to avoid distortion of the phase samples even after separation, since changes in temperature or pressure can lead to mass transfer between the phases e.g. the condensation of gas into liquid or the vaporisation of liquid into gas.

Whether collecting a sample into a receiver, or extracting and analysing the flowstream continuously, a suitable sample analyser must be selected (or developed) in order to detect the fluid components of interest. The parameters to be measured will depend on the application and may include the liquid / gas ratio, liquid water-cut, hydrocarbon composition and water salinity.

The sample should first be equilibrated at the flowline pressure and temperature in the laboratory. The first stage in the analysis of any multiphase fluid is normally to separate the liquid from the gas. This can be achieved by conventional means, such as gravity separation or centrifuging. However, the phases should be separated isothermally and isobarically.[18] Techniques such as liquid absorption or adsorption have been used for the collection of liquids in wet gas applications due to the small amount of liquid present compared to gas.

The composition, density and volume (or the mass) of the oil, water and gas should be measured at the sampling conditions. For wet gases the key challenge is how to deal with the very high gas fractions present in a wet gas mixture and analysis of the small amount of the liquid phase to obtain information such as water-cut or composition evaluation.

The samples may also be used to conduct in-situ meter calibrations, e.g. for gamma energy attenuation to determine the phase fractions.

Inhibitor chemicals such as methanol may have been injected subsea for flow assurance mitigation (i.e. to prevent hydrate formation). As some of these chemicals are soluble in oil or water they cannot be easily separated and may affect the analysis results of the fluids.

For flow metering considerations, if the flow meter is subsea and a sample is collected at the surface then information on where the inhibitors were injected is useful, i.e. upstream or downstream of the flowmeter. If upstream then the sample analysis results are appropriate to the meter. If the injection was downstream of the meter then the results may not be appropriate and may affect the metering accuracy. Additional chemicals such as defoamers can be injected into separators and may affect the fluid property measurements.[18] Defoamers aid the quick separation of the oil and gas by minimising foaming. If a sample is collected after separation then this sample will not be representative of the fluid passing through the meter.

4.6 Thermodynamics Modelling of Multiphase Sampling Systems

Research and modelling of the thermodynamics and fluid dynamics of multiphase and wet gas mixtures is advisable to assess how the mixture will affect the collection of a representative or non-representative sample using a particular sampling system design.

- Components in the sampling system could present constrictions and therefore generate pressure and temperature differences leading to possible changes in phase and associated sampling difficulties.

- Changes in temperature during a sample collection will also occur due to heat transfer between the hot fluid and the pipe work which is at the temperature of the surrounding atmosphere.

- The precipitation of waxes and the formation of hydrates could easily form obstructions within the sampling system and result in the failure to collect a sample.

- Hydrates and waxes could form if a warm sample was flowing into a cold sample bottle. Hydrates and waxes could be expected to precipitate out of the fluid within the sample bottles unless the bottles are kept at a suitable temperature and pressure above the precipitation and formation point.

- It is recommended that samples should be kept at the pipeline pressure and temperature changes should be limited.

4.7 Additional Multiphase Sampling Considerations

It is recommended that the sampling should be in a vertical section of the pipe preferably downstream of a component that could provide fluid mixing, e.g. a multiphase meter or valve. The design of sampling systems can take advantage of certain piping geometries or mixing elements to preferentially collect a sample enriched in one component, though there will always likely be a mixture. Ideally a sample should be taken when the water-cut is stable but this is not always possible. Several samples can be taken and the average of the values used. The difference in the highest and lowest fluid values from multiple samples should be lower than the uncertainty required for the evaluation.[16] If the fluid properties change over time then the sampling frequency may need to increase to provide information for flow assurance assessments and for updating multiphase meter inputs.

To obtain reliable fluid property data for flow assurance and multiphase meters it has been demonstrated that it is more important to ensure the temperature and pressure of the sample is stable rather than collect a representative sample.[16,22] This should ensure no mass transfer between the phases and no molecular change in the phases.

The sampling system should be designed to minimise pressure and temperature changes from the pipeline to the sample container. Systems that used a differential pressure, for example across a choke value or flow meter, to drive a sample into the container will affect the representivity of the

sample.[22] Fluids may need to be actively pumped into the sample container to reduce this issue. Heating can be incorporated into the sampler design.

Sampling should ideally be performed at the same location (or in very close proximity) for collecting a sampling of each multiphase component to ensure collection at the same conditions of temperature and pressure to ensure thermodynamic equilibrium.

Initial well sampling fluids may contain contamination from drilling fluids and mud which could affect the accuracy of PVT data derived from these samples.[17] Ideally new samples should be taken after the field start-up.

4.8 Subsea Sampling

Subsea sampling can offer many advantages including:

- Eliminates sample contamination from other wells if using shared pipeline systems especially if shared flowlines are not sufficiently flushed through.
- Eliminates need for well shut-ins for sampling of individual wells if several wells are commingled and sampled topside.
- Eliminates problem of liquid holdup in long tiebacks for topside sampling. Sampling at the surface may be less representative as it may take some time for the liquid to be swept to the surface hence the fluid does not contain all the liquid components.
- Eliminate issues with some organic components such as paraffins and asphaltenes that can deposit in the flowline and not be collected in topside samples.
- Sampling at same conditions as subsea flowmeter otherwise if sampling topside the fluid properties may have to be estimated due to the different conditions.
- Fluids collected are ‘representative’ of what passes through the meter
    - Addition of inhibitor chemicals after the flow meter may affect the samples if collected topside.

Subsea sampling systems for wet gas and multiphase fluid streams have been successfully implemented (and some not so successful) and are in operation by several companies. This is an area which is currently seeing major developments. Subsea sampling is considered a very challenging task due to the environment and accessibility issues for retrieving samples and general maintenance. The requirement to sample subsea and the very high costs of retrieving samples has to be balanced against the consequences of not knowing the composition of the produced fluids. Currently, it is samples to predict well performance, flow assurance mitigation and information for multiphase flow meters that drives subsea sampling rather than the value of the product.

It is essential that any subsea sampling system is robust and reliable to cope with the conditions and other complexities that accompany subsea engineering including the reliable collection of the sample and reinstallation of the sample equipment. The system may be installed at a substantial depth below the surface where the pressure is high and consideration must be given to the corrosive effect of sea water. In addition to these engineering challenges the sampling system may need to be equipped to collect fluid samples at high temperatures and pressures. For example, systems may have to operate in conditions with temperatures up to 200 ^{o}C, pressures up to 15 000 psi and water depths down to 3 000 m.[22]

Subsea sampling systems are designed to be operated by a remote submersible vehicle (ROV) which can plug the sampler unit into the live crude pipe manifold on the ocean floor. The sampler is expected to collect reservoir fluids at live reservoir conditions of temperature and pressure. Once a sample has been captured, the sampler unit is isolated from the live pipeline and brought back to the surface for analysis. The difficulty of retrieving a representative sample from subsea conditions is exacerbated by the high temperature and pressures of the fluid as it emerges from the oil reservoir together with any associated produced water and gas.

Due to the complexities and costs of subsea sampling considerable resources are being invested by companies in the development of sampling system designs and testing to mitigate the risk of failure when installed subsea. The supply of an ROV for just one day can greatly exceed £250k and the cost increases substantially for deep water retrieval of samples. Hence operators want to be certain the sample is going to be useful.

The RPSEA project in the US has completed some research into the design and testing of a subsea sampling system. Further work is currently being initiated to extend this programme of work. NEL conducted fluid modelling to assess the design for flow assurance issues such as waxes and hydrates forming at the production conditions.

For reservoir management, sampling of the multiphase fluids subsea can provide more accurate and representative results as the recombination of samples after separation can increase the uncertainties and may depend on the separator design, efficiency, sampling technique and flowrate measurement.[17] Sampling close to the wellhead can be beneficial as the fluid will be closest to reservoir conditions and less affected by phase changes.

It may actually be beneficial to sample gas-condensate systems subsea as the fluid may be a single phase liquid at reservoir conditions and hence easier to obtain a representative sample. The fluid could change phase to a wet gas at topside conditions where it is more difficult to obtain a representative sample.

Customised subsea sampling systems have been specifically developed and implemented in partnership with operating companies. The most recent systems to be developed involve a flow-through system to continuously flush the multiphase/wet gas fluids through the sample bottle.[19] This ensures the collection of a sufficient amount of liquids for laboratory analysis, whilst limiting contamination from barrier fluids and ensure the sampling bottle is in thermal equilibrium with the flowline.

Several recent papers by Shell have highlighted the issues of subsea sampling for multiphase flow metering and the effect of errors in the fluid properties.[18-20]

Reference [22] highlights the benefits of subsea sampling for flow assurance, fluid property information and multiphase metering.

On-line multiphase fluid sampling and analysis systems are being developed which aim to avoid the need to transport samples to the surface by remote operated vehicles for subsequent analysis at a laboratory.[21]

Even with subsea sampling some components of the flow could be deposited in the wellbore or properties could change due to temperature and pressure changes, e.g. increased viscosity from cooling or emulsions forming. [22]

4.9 Guidelines

Currently there is no standard or guidelines or simple method for multiphase fluid sampling, most of the techniques used have been adapted from previous sampling technology, standards and experience. Developers of multiphase (and wet-gas) sampling technology would appreciate some form of guidance on how to perform sampling. Companies have spent extensive resources on design and testing the performance of sampling systems. It has been noted that changes in fluid conditions (e.g. temperature, pressure, hydrocarbon compositions, water-cut, velocity etc) can affect the collection of a sample depending on the sampler design. The changes in fluid conditions can change the multiphase flow regime which can make collecting a sample more challenging. Some sampler designs are specified for particular pipe geometries and flow conditions and are redesign by trial-and-error to accommodate changes. Testing the equipment in the conditions in which the sampler will be used is essential but challenging due to the limited range of test conditions offered by available multiphase test facilities. The prediction of multiphase flows is not always intuitive. CFD modelling has been used with some success for simulating multiphase flows. The formation of guidelines would be aided by companies willing to share their knowledge and experience. However, due to the resources spent on the development of systems by companies they would probably be unwilling to share proprietary information. The technology may need to mature and develop substantially first.

5 FUTURE RESEARCH

Responding to concerns within the industry, NEL has launched a Joint Industry Project (JIP) to investigate some of the current issues that operators are facing with regard to water-in-oil sampling and to assess the standards. This will involve extensive experimental work using NEL's multiphase flow facility and CFD modelling simulations. The overall aim of the JIP is to improve water-in-oil sampling practice and provide information to augment existing standards. Several major operators have already signed up for the project. To summarise, the project aims to:

- Collect information with examples showing discrepancy between practice and theoretical prediction by ISO 3171
- Perform laboratory tests to evaluate mixing and dispersion under different flow conditions and pipeline configurations
- Establish and validate CFD modelling for predicting mixing and dispersion conditions
- Investigate effect of non-isokinetic sampling
- Provide input for future review of ISO 3171

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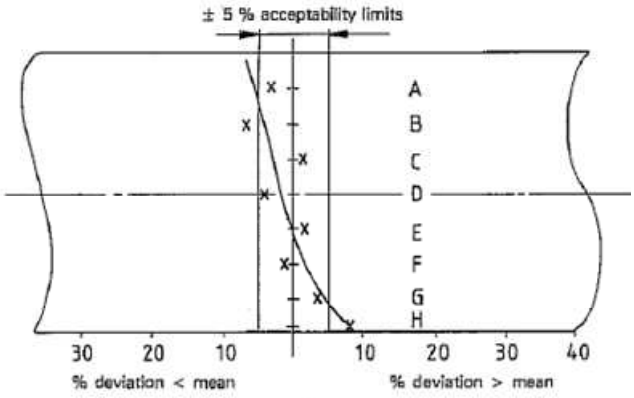
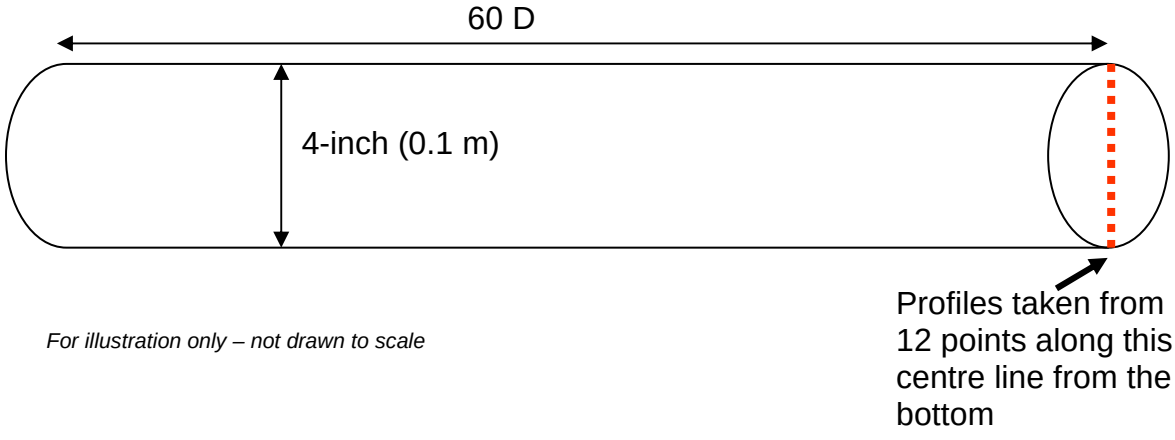
APPENDIX A
Examples of CFD Simulations Preformed by Jiskoot on Pipeline Profiles



The figure above is taken from ISO 3171 - Annex B, Page 53, Figure 13b. This is used as a reference for plotting different water concentration plots as shown in the graphs below.

For the CFD simulations:
Pipe diameter: 4-inch (0.1016 m)
Pipe length: 60 diameters
Water concentration: 2% (constant for all simulations shown)
Flow velocity: 0.1 m/s to 8 m/s
Oil density: 750 kg/m^3 or 850 kg/m^3
Oil viscosity: 1 cS to 120 cS

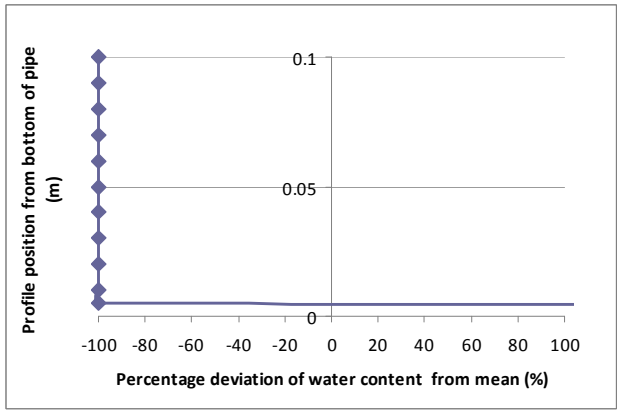
The graphs below show the percentage deviation of water concentration along the x-axis and profile position (m) on the y-axis. 12 points were assessed on the vertical axis-ordinate along the centerline at the outlet of the pipe (at 60 D). The simulations were performed with an even cross sectional distribution of water at the pipe inlet.



For illustration only – not drawn to scale

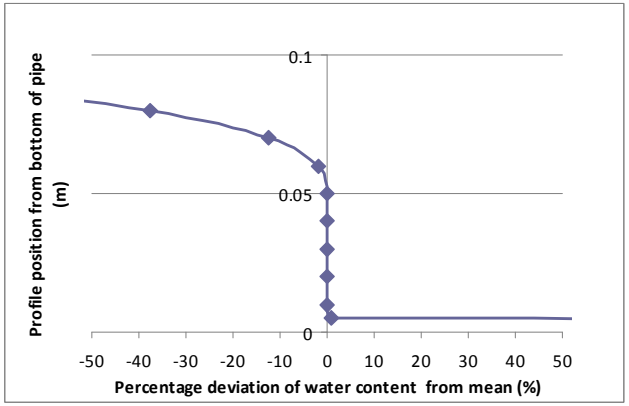
Simulation 1

Flow Velocity	0.1	m/s
Density	750	kg/m3
Viscosity	1	cS
Water Concentration	2	%



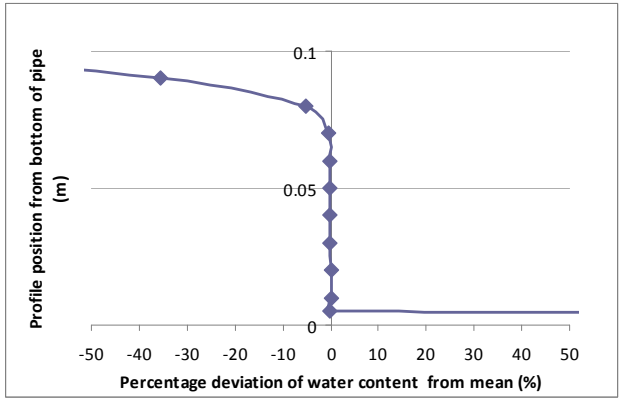
Simulation 6

Flow Velocity	0.1	m/s
Density	750	kg/m3
Viscosity	120	cS
Water Concentration	2	%



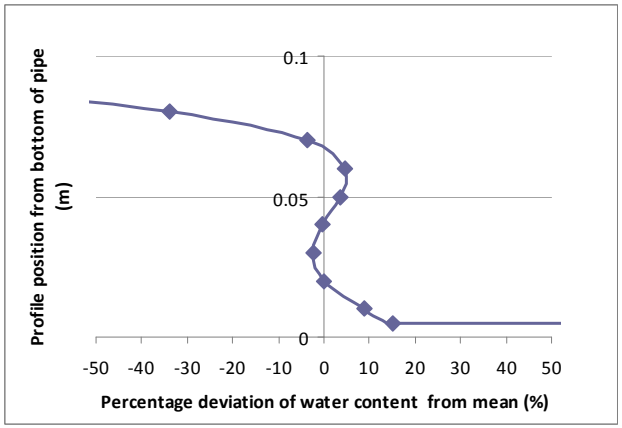
Simulation 12

Flow Velocity	0.1	m/s
Density	850	kg/m3
Viscosity	120	cS
Water Concentration	2	%



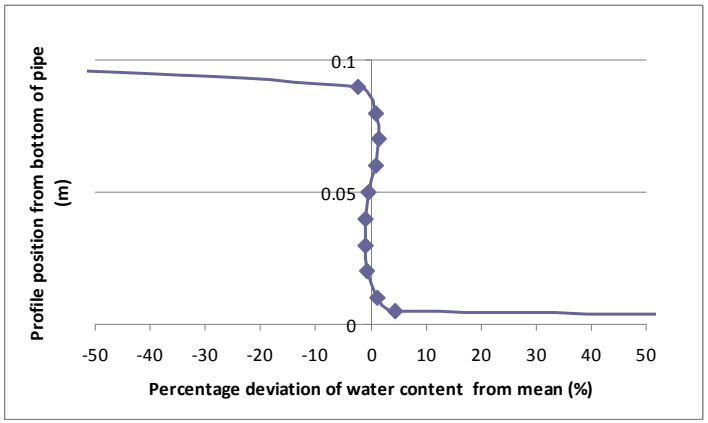
Simulation 67

Flow Velocity	4	m/s
Density	850	kg/m3
Viscosity	1	cS
Water Concentration	2	%



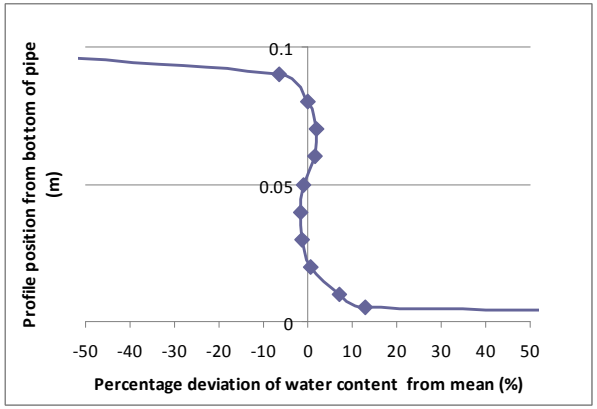
Simulation 69

Flow Velocity	4	m/s
Density	850	kg/m3
Viscosity	8	cS
Water Concentration	2	%



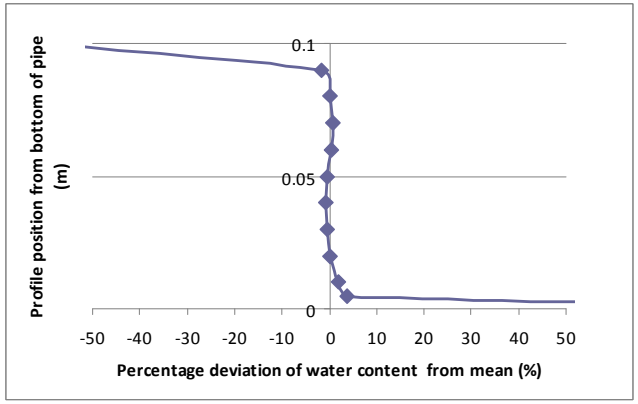
Simulation 79

Flow Velocity	8	m/s
Density	850	kg/m3
Viscosity	1	cS
Water Concentration	2	%



Simulation 81

Flow Velocity	8	m/s
Density	850	kg/m3
Viscosity	8	cS
Water Concentration	2	%



Simulation 84

Flow Velocity	8	m/s
Density	850	kg/m3
Viscosity	120	cS
Water Concentration	2	%