JISKOOT™ QUALITY SYSTEMS

TECHNICAL PAPER TS013-1107-3

Crude oil and condensate sampling, water in oil and density measurement

What is the uncertainty of your quality measurement system?

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Custody Transfer Measurement Symposium 2002 (Saudi Aramco), Dharan, Saudi Arabia

Summary

The various standards applicable to sampling, density and on-line water content measurement have been developed and updated over many years but the most significant advances have happened over the last 20 years. While sampling systems have always been a feature of the metering process, many metering systems installed have been modified to incorporate density compensation (to yield total mass) water-in-oil monitors (**OWD** or **O**n-line **W**ater in petroleum **D**evices) or both. Integrated systems are now titled **QMS** or "**Q**uality **M**easurement **S**ystems".

Unfortunately, and to their cost (at least that of their company), many loss controllers pay the price for poor measurement by way of claims so there is a strong commercial reason to get measurement "right". Since most of the oil produced in the Kingdom of Saudi Arabia is exported via ship, buyers are bound to compare their received and loaded cargos, many using (and for good reason) accurate and proven sampling systems to minimise the chances of in-transit losses. Where there is a significant difference between the received cargo volume and that on the Bill of Lading, the buyers agent will protest first to the shipper and unless the shipper accepts liability for the claim; their first recourse is a challenge to the loading port (sellers agent).

The IP PML-4 group has tracked transit "losses" for many years and it is evident that the claim will fall to the facility whose measurement is most easily challenged. If both the load and receipt port can show that they have proven and traceable sampling operations to the highest possible standards (including sample handling and laboratory analysis) then suspicion will fall to the vessel. Without a high quality sampling system, the load port is likely to be subject to claims. This paper will outline some of the key requirements and frequently discovered deficiencies in the application of samplers, densitometers and On-line Water in petroleum Devices. (OWD).

Introduction

The fundamental issue to good measurement of quality is REPRESENTIVITY, this must exist for density, water or composition. Frequently more focus is placed on the physical (micro) capability of the measurement device rather than the representivity of the oil entering it.

Typically densitometers and water monitors are mounted in external "loops", but many of these "loops" have not been correctly configured to ensure representivity. For example a density loop taken directly from the sidewall of the pipe can never be correct, unless there is NO water in the oil.

Where total quality is required there is now a trend to integrate the sampling function with densitometers and OWD systems to form "quality" loops. Loops are preferred in the North Sea because of the premium on space (difficulties in locating in-line systems), the ability to simply isolate them for maintenance and their improved accuracy. To ensure that they are correctly designed it is important to understand the effects of water content and density to the measurement audit process.

Measurement standards and references

- Sampling (IP 6.2 July 1987)
- Density (IP 7.2 September 1997)
- OWD (API 10.11 draft standard November 2000 - now withdrawn)
- API 8.2 1995
- ISO 3171 1988
- Roxar/MFI handbook version 1.5
- Phase Dynamics literature
- Solartron advanced liquid density transducers (technical manual issue B)

Common ground

There are several issues that are equally important to good sampling, on-line water and density measurement. As flowrates fall and water contents increase (as is typical in a loading system) these become more significant.

The whole purpose of metrology is to provide a uniform measurement method and to record the useable mass of oil. To calculate mass a correct density **and** water content are required.

➢ The only density that can actually ever be measured on-line must be a "wet oil density" because the process is intrinsically "wet".

➢ The only way to measure the correct wet oil density and the correct water content from which dry oil density could be derived is to ensure accurate sampling **and** density measurement.

Therefore the only way to ensure the process ties together is to apply sampling knowledge to density measurement and to ensure that the fluids presented to the sampler and the densitometer are of the same physical composition. i.e. *REPRESENTATIVE*. *This can best be achieved by locating the sampler and the densitometer in the same process stream or loop.*

Traditional sampling and metering systems were often installed with the sampler upstream of the meter bank. Densitometers have later been added in loops taken off downstream of the meter bank. There is clearly scope for the water content and therefore the density at each point to be different.

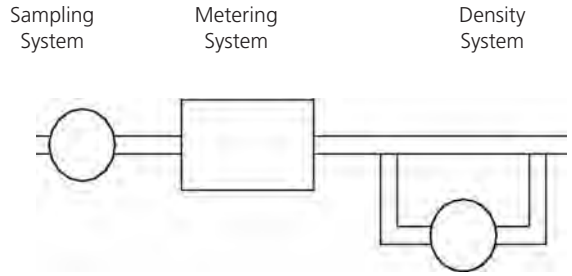

Figure 1 - Traditional sampling, metering and density locations

It should be remembered that the IP (and equivalent other) density standards require that all considerations of the Sampling Standards (IP 6.2, ISO 3171) be taken into account (for oil service).

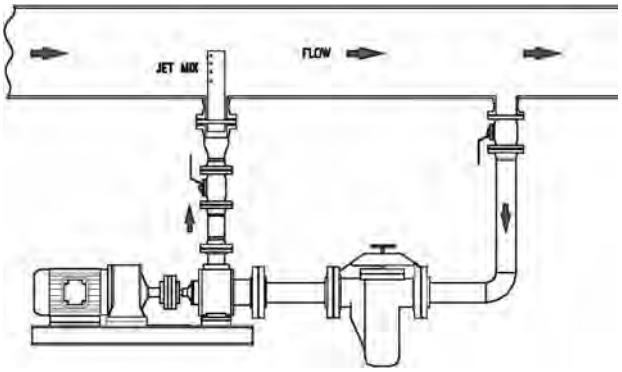

Figure 2 - In-line sampling system with JetMix

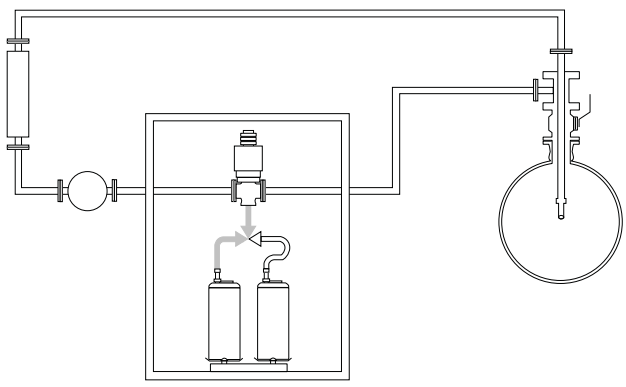

Figure 3 - Fast loop system with densitometer & OWD

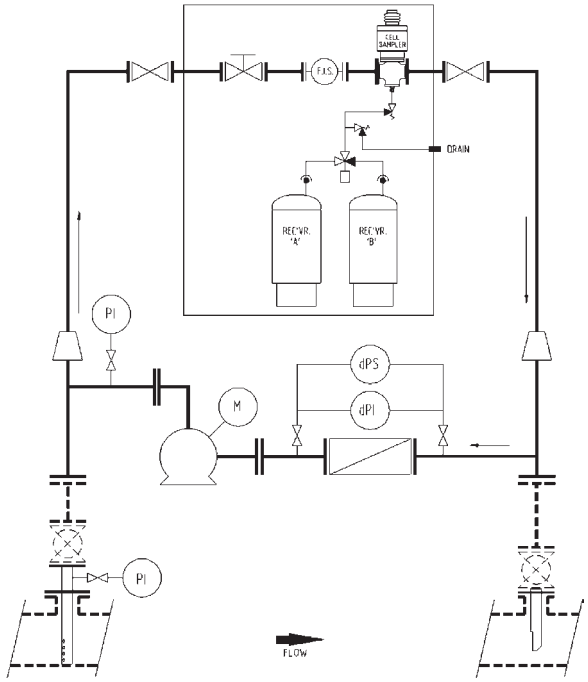

Figure 4 - A Co-Jetix system

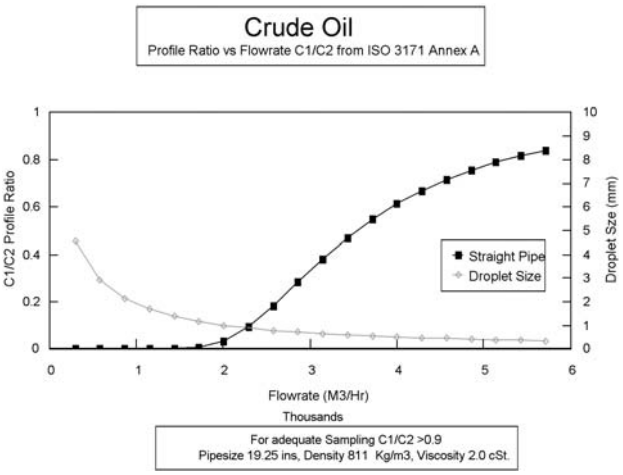

Figure 5 - C1/C2 mixing profile

This means that the sampling process and the measurement of density must be considered simultaneously.

The three steps to ensure compliance are:

1. Pipeline mixing
2. Representative off-take and maintaining representivity in the off-take system through the measurement devices
3. Sample handling and analysis (for the sampling function only) or the performance of the on-line analyser

Before consideration can be given to the overall uncertainty of mass measurement derived from the metering and quality systems, the main pipeline must be adequately mixed to prevent the densitometer, sampler or OWD under-measuring the water content or the density because these "samples" are taken from a single point on the cross section. The uncertainty in this area is always negative (i.e. results in a loss of product).

1. Pipeline mixing

For all measurements, even those employing a full-bore sensor (i.e. a spool) a well-mixed pipeline is a pre-requisite. The majority of densitometers, OWD's and samplers are located in loops extracted from the main pipeline. The quality of the dispersion required is directly related to the measurement methodology, for example ISO 3171 requires that the diameter of the inlet to a sampling/quality loop be 10 times the size of the expected water droplets. The graph above is a method of estimating the dispersion quality and droplet sizes and forms part of all the internationally accepted standards, where the C1/C2 ratio is the water concentration in the top of a horizontal pipe divided by that at the bottom. A C1/C2 ratio above 0.9 is considered adequate for sampling. The water droplet size has a direct relationship to the rate of energy dissipation and the rate of gravitational fallout (segregation). There is clearly a relationship between pipeline mixing and the (diameter) size of the inlet to a sampling device or quality loop.

Larger offtake sizes produce lower uncertainties in measurement systems for any given quality of pipeline mixing. This is also borne out in the IP 6.2 standard where the definition of isokinetic sampling is widely extended as the size of the off-take loop is increased.

Previously at the Aramco Measurement Symposium I have proposed that there is a hierarchy of sampling methods that can be used to minimise uncertainty starting with the highest uncertainty/lowest accuracy :

In-tank sampling

Shipboard sampling

Inline sample probes

Large bore fast loop samplers

Co-Jetix sampling systems

It is imperative to minimising uncertainty that the pipeline mixing and the sampling system design are considered *simultaneously*.

Assessment of the mixing should be conducted for every application using the calculations in the standards. Mixing should be conducted at the worse case conditions of minimum velocity, density and viscosity. In general the lighter and less viscous the oil the more mixing is required to meet the C1/C2 requirement of >0.9 at all flow rates

With inadequate pipeline mixing it becomes irrelevant to consider the uncertainties of a sampling device or quality loop because the sample taken cannot be representative.

2. Representative off-take loop (for a sampler or densitometer)

While not all systems use loops, it is apparent that a correctly designed quality loop will consistently outperform an in-line device. The collated results of over 100 water injection tests (including "failures") of sampling systems in a variety of configurations yielded the following results:

Type of system	Average proving error	Number of tests
In line probe	-0.118 %	80
Fast Loop (33mm or bigger inlet)	-0.035%	23
Co-Jetix	-0.025%	10

When you consider the fluid mechanics, this is a fairly obvious but overlooked result :

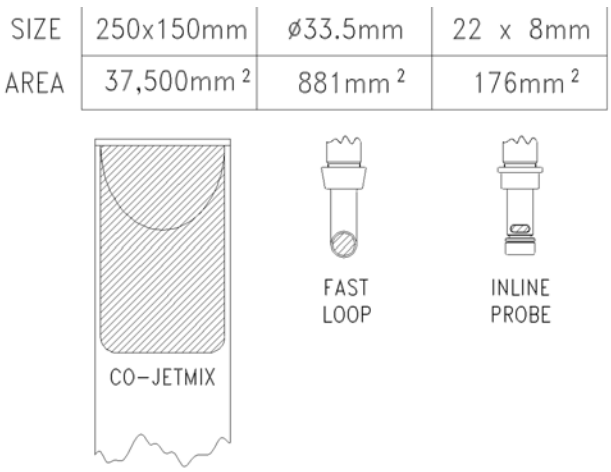

Figure 6 - Take-off loop inlet sizes

Once a representative stream has been created it is imperative that the quality loop maintains representivity; this requirement can produce two problems. The first to ensure the flowrate in the loop maintains the stream in an adequately "dispersed" state and the second to ensure that the stream properties are not changed due for example to pressure or temperature effects which can include RVP issues and cavitation.

3. Physical sampling, handling, mixing and laboratory analysis

These issues apply of course only to "physical sampling" methodology and the requirements for collection, retention, sub-sampling and analysis. Breaking these into the three parts of the sequence:

- Collection
- Sub-sampling
- Analysis

Collection

The sample needs to be collected into a receiver capable of retaining the sample in a state where there is no depletion of the quality of interest. What this means in practice is to provide clean receivers without water traps and with the ability to ensure no loss of light-ends. Light-end loss can be wildly affected by temperatures so in a desert environment where samples can be "cooked"; as soon as an attempt is made to sub-sample the receiver contents, even if held under pressure, a significant volume of light-ends can be blown off rendering a lower API result than the bulk volume and with that water vapour.

Sample mixing and sub-sampling

Due care must be taken in the mixing and sub-sampling process, because the mixing itself tends to render change in density to such an extent that some companies take density samples from hand agitated receivers only, returning the density sample to receiver before mixing for water content.

In a test on Middle East crude a sample container and mixer were circulated continuously and density samples drawn every 5 minutes over a one hour period and this rendered a 40 point shift in density result.

IP/API and ISO all point out that the number of sub-sampling processes should be minimised, because each step in the process must ADD uncertainty, therefore by nature fixed receiver systems are not ideal. From a practical point the use of field mounted fixed receivers takes a key measurement process from a (hopefully

controlled) laboratory to a field environment which is never a good thing.

Sample analysis

What can I say ? The de facto standard is Karl Fischer for water and either a wet bob or an Anton Parr densitometer for the laboratory. The wet bob method requires diligence to correct to normalised conditions.

All of the steps must be given equal attention because uncertainty generated by any of the steps will yield uncertainty on the overall result.

Uncertainties

There are several sources of uncertainty in the mass calculation outside of those created by the metering (volumetric) element itself. These relate to the correct measurement of density and the correct measurement of the water content in the batch.

Poor pipeline mixing results in both poor sample water content measurement and poor measurement of density. In addition poor measurement of density through changes in the physical characteristics of the fluid compared to those metered volumetrically will cause further uncertainty.

Uncertainty created by poor pipeline mixing

The uncertainty in the overall mass will be reduced if the sampling and density measurements are taken from identical process stream.

If the recorded density relates correctly to the recorded water content a correct balance can be achieved, however if the recorded density is lower, for example because the density loop has a lower water content than that produced by the sampling system then the total mass of oil will be understated.

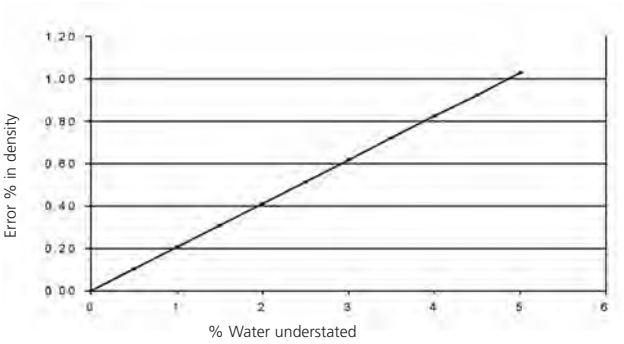

Figure 7 - Uncertainty vs water content

Uncertainty caused by poor density measurement

Density measurement errors can be caused by a variety of sources; in the example above the density measurement system was separate from the sampling system and therefore subject to potential error. It is also possible to reduce the likelihood of a correct density reading by poor conditioning within the quality loop. For a metering system to totalise mass, the IP density standard requires that the density measurement be made at conditions close to the metering process. The uncertainty in density measurement is not only affected by the pipeline condition but also by physical changes that can occur in the quality loop which are often simply overlooked.

If the correct fluid enters the quality loop, the physical properties can be altered by changes in temperature and pressure. Section 7.3.4 states that for an overall density uncertainty of 0.1 % errors arising from pressure and temperature should not be greater than 0.03%.

For crude oil with a nominal density of 850 Kg/M3

These figures can be adjusted if the density is correctly adjusted to process conditions (i.e. at the flowmeter) from local pressure and temperature measurements.

Parameter	Units	For 0.03 % uncertainty
Temperature Sensitivity	-0.7 Kg M3 per K	0.4 K
Pressure Sensitivity	0.06 Kg/M3 per bar	4.2 bar

These uncertainties can be influenced by further changes in the physical properties for which no compensation can be made. These would include a significant change in temperature or alternatively pressure or suction losses that may cause “gassing” of the oil.

The affects of density errors on OWD systems

As there is an increasing tendency to use OWD systems, it is important to note that any water in oil monitor using dielectric constant upon which to base the water content will need compensation for the "dry oil" dielectric – this includes microwave-based techniques.

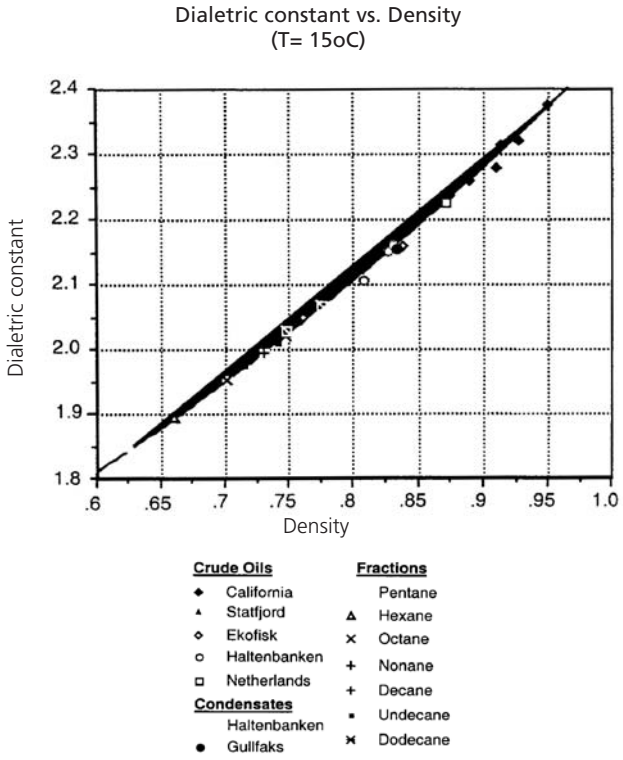

Figure 8 - OWD dielectric v density

Several vendors suggest that the dry oil dielectric constant can be ascertained by measuring the density of the process stream, but this a wet oil stream so the meter is actually compensated using the wrong density!

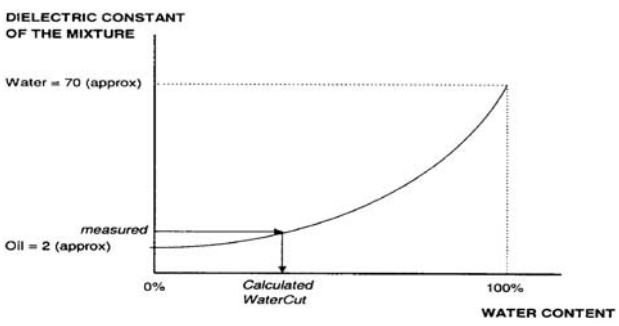

Figure 9 - dielectric curve

While the errors in using an erroneous density for compensation may not be huge, they exist and have precluded the use of this technology for import terminals subject to a wide range of oil types but they can operate successfully for export systems.

This is because the uncertainty in the overall measurement increases disproportionately to the changing water content and design failures become more evident as production rates fall.

Density loops in service

It comes as a great surprise to see many densitometer loops installed with their takeoff from the side of the pipeline (with no due consideration of the representivity of the source), densitometers installed on the suction sides of pumped loops or in loops that have insufficient velocity to maintain process equilibrium.

The manufacturers own suggestions pay no care in suggesting representivity:

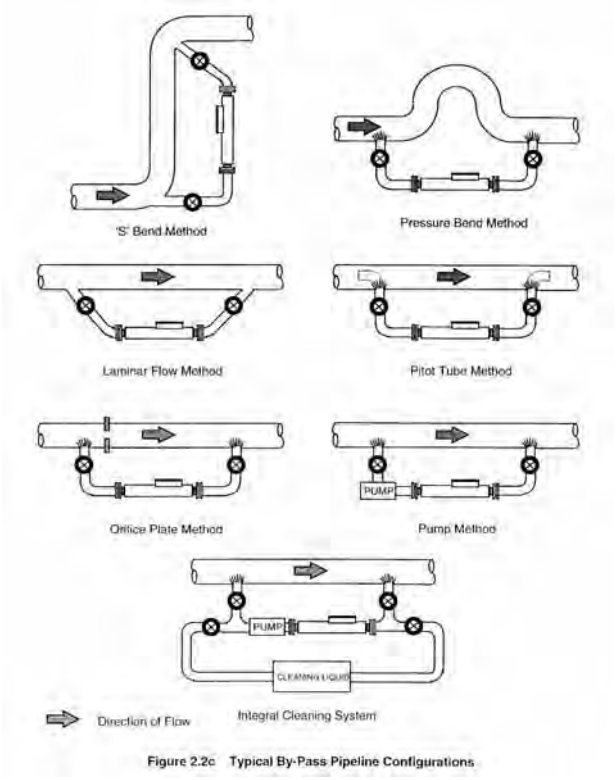

Figure 10 - Typical by-pass pipeline configurations

Quality loops are often convoluted designs, engineered into little space, often with long and undersized suction lines. Significant pressure and temperature offsets between the metering point and the densitometer would not be unusual.

Due to restricted piping and the poor consideration of temperature losses and with low NPSH pumping conditions, local hotspots within pumps, a temperature

offset of 0.2 K between the metering location and the densitometer is likely to be considered an extremely good result.

So there are key components often overlooked in density measurement quality loop design:

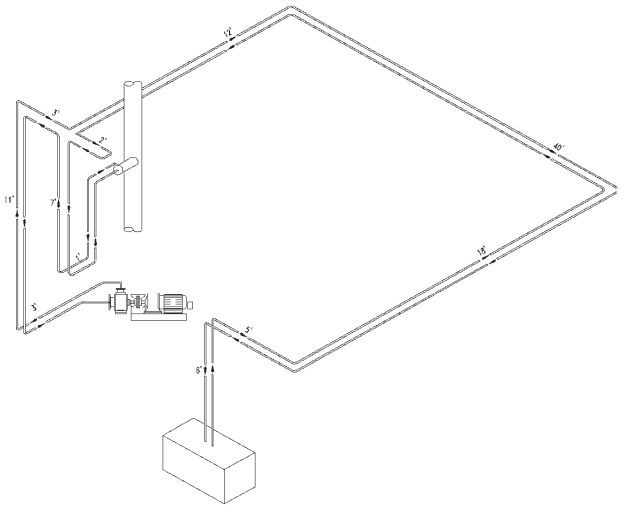

Figure 11 - Typical loop configuration

1. The representivity of the quality loop in regard to accurate water content is frequently wrong.
2. The content of the quality loop does not maintain the process conditions adequately to represent the process at the measurement point (i.e. pressures and temperatures are offset).

Densitometer loop design

The original intention in designing densitometer loops was to use a pressurised pyknometer as the proving method with two densitometers. One installed as the recording instrument and the second **in parallel** as a standby.

Industry practice changed so that the preferred method was to use the substitution method i.e. the densitometer signals (one being the reference and the other comparator) are continuously compared and at a regular interval a unit is replaced with a "transfer standard" calibrated instrument. The problem with the change of operating methodology is that for this to be operated correctly the densitometers in question should be **in series.**

No account has generally been taken in system design for the loop to be split and therefore inadequate flow may exist to maintain good temperature stability or to assure that the parallel streams are subject to the same water content.

Practicality and theory, as always have a gulf to bridge, this gulf is to ensure that the density/sampling water in oil monitor loops are consistently referenced. If the density measurement is separated from the sampling function, then there must be some doubt as to whether the figures will tie up.

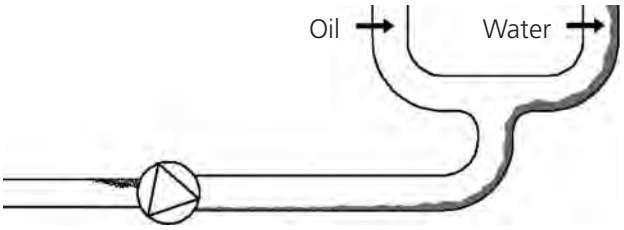

Figure 12 - Bias in parellel densitometers

Conclusion

There are significant uncertainties in the overall net oil results for measurement systems caused by disparities in the measurement of water content and density, these result from poorly mixed pipelines, poor density measurement loops and poor application of sampling technology. These errors may not lead to real physical losses, but if the potential exists within the trans-shipment for real physical losses then it is imperative that the defined ends of the measurement chain both apply technology with the minimum possible uncertainty to eliminate their process from the dispute. Until due care and attention is paid to improving and integrating the quality process, piecemeal improvement is unlikely to yield much improvement in uncertainty. Finally all systems installed should be subject to a proving test of preference meeting the highest possible standard i.e. ISO 3171.

References

IP 7.2 highlights

Avoid hydraulic shock

6.7.2 …….density transducer should be installed at a position where a representative sample of the main flow is presented to it. To enable accurate conversion to reference conditions, line temperature and pressure should be measured at a point which most closely represents the conditions at the density sensor.

6.11.1 a) …..the uncertainty of density measurement should be better than 0.15% of the true density at the point of volume measurement…….

6.11.2.2 b) all density meters in the system should be kept in continuous operation.

6.12.1 …….it is required to measure the density of oil that contains water in order to derive the density of the dry oil or to calculate the percentage water. ……special care is required to ensure that the fluid at the measurement transducer is truly representative of the total quantity of fluid of interest.

7.3 b) temperature or pressure differences between the liquid in the flow element and the liquid at the density transducer should be minimal and within specified limits (see table 1)

7.3.4 …for an overall density measurement uncertainty of 0.1% of reading, the errors arising from this source should not be greater than 0.03% of reading.

For crude oil

Temperature effect is –0.7 kg/m3 /K that INDIVIDUALLY relates to a maximum temperature difference of 0.4 K and a pressure effect 0.06 Kg/m3 /bar which would INDIVIDUALLY allow a maximum pressure difference of 4.2 bar.

8.4/8.5 Transfer Standard procedure and Substitution method.

Densitometer Installation Guidelines

The liquid must always be at a pressure substantially above its vapour pressure.

Cavitation, caused by pumping, should not generate bubbles from dissolved gases.

If a pump is used it should "push" rather than "pull" the product through the transducer.

A fast flowrate e.g. 3000 litres/hour, will help to achieve good temperature equilibrium and have a self-cleaning action.

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