WHAT IS THE UNCERTAINTY OF YOUR QUALITY MEASUREMENT SYSTEM?

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Summary

The various standards applicable to sampling, density and on-line water content measurement have been developed concurrently with, and in some cases as a result of, the development of the North Sea. While sampling systems have always been a feature of the metering process, many metering systems installed on older platforms have been modified to incorporate density or water-in-oil monitors (OWD or **O**n-line **W**ater in petroleum **D**evices) or both. Integrated systems are now also titled **QMS** or "**Q**uality **M**easurement **S**ystems". The designs used often fall outside the accuracy they are supposed to attain and shortcomings are generally overlooked because in some cases it is hard to confirm compliance. This paper will outline some of the key requirements and frequently discovered deficiencies.

Introduction

North Sea fields are maturing and although there are restrictions in the quality (i.e. water content) of oil entering pipeline systems, production is getting "wetter". Where production has been relatively dry, both sampling and density errors have been relatively easy to overlook because the errors in mis-measuring fractional percentages of water still allow on-line densitometers to remain within the uncertainties allowed by the standards. As production gets wetter the already prevalent errors in sampling and density measurement will become more obvious.

There is also a move to produce "wetter" fields at lower production rates and with less separation. In these conditions the produced fluids tend to be at elevated vapour phase conditions (higher RVP's). These conditions will also render higher errors in both density and water content measurement.

Many sampling systems are now integrated with densitometers and OWD systems to form "quality" loops. Loops are preferred 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 current 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)
- Additional references
    - API 8.2 1995
    - ISO 3171 1988
    - Roxar/MFI handbook version 1.5
    - Phase Dynamics literature
    - Solartron Advanced Liquid Density Tranducers (technical manual issue B)

Common ground

There are several issues that are equally crucial to good sampling, on line water content and density measurement and as flowrates fall and water contents increase these become more significant.

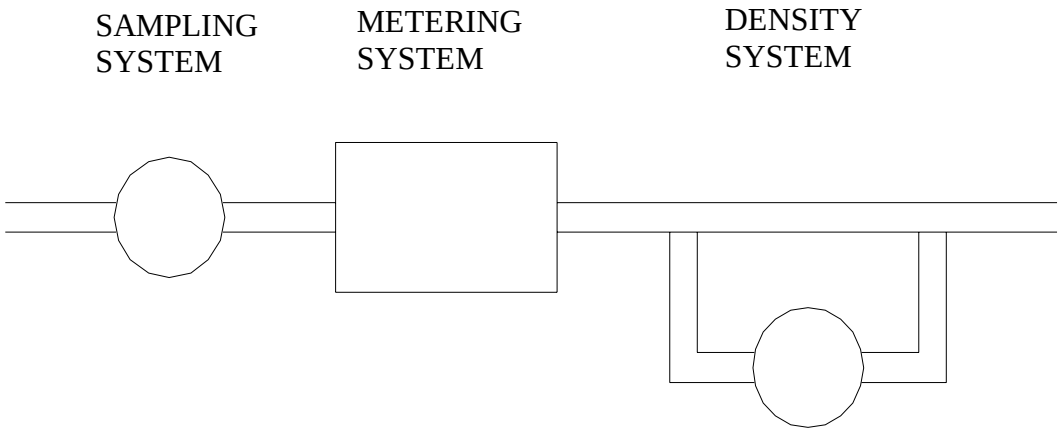
The whole purpose of metrology is to provide a uniform measurement method and in general the measurement standard is to record the useable mass of oil. To calculate mass a correct density ***and*** water content are required.

- 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 installed with the sampler upstream of the meter bank. Densitometers have later been added as loops taken off downstream of the meter bank. There is clearly scope for the water content at each point to be different.



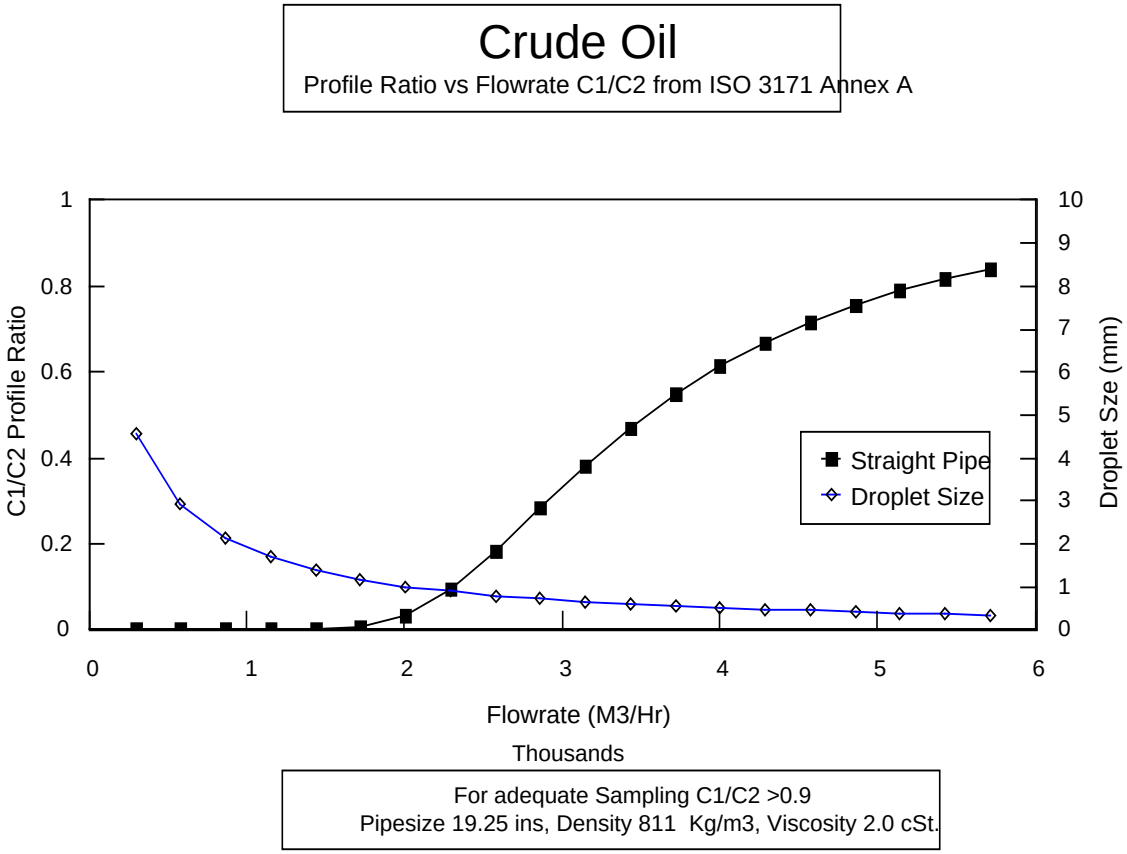
It should be remembered that the IP density standard requires that *all considerations of the IP 6.2, ISO 3171* be taken into account (for oil service). This means that the sampling process and the measurement of density must be considered simultaneously.

The three steps to ensure compliance are:

1. Pipeline Mixing
2. Representative offtake and maintaining representivity in the offtake system through the measurement devices
3. Sample handling and analysis (for the sampling function only)

Before consideration can be given to the overall uncertainty of mass measurement derived from the quality system, the main pipeline must be adequately mixed to prevent an offtake loop under-measuring the water content or the density. 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 "sample" (read quality) loop be 10 times the size of the expected water droplets. The water droplet size has a direct relationship to the rate of energy dissipation and the rate of gravitational fallout (segregation) also relates to the droplet size. Therefore there is clearly a relationship between pipeline mixing and the (diameter) size of any "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 offtake loop is increased.

It is imperative to minimising uncertainty that the pipeline mixing and the sample loop design are considered simultaneously.

To put some numbers to this; North Sea pipelines are unlikely to be adequately mixed (without the use of static or power (jet) mixers) at velocities less than about 4 m/s and for condensates significantly higher velocities than these are required. There are significant

problems with older production systems, in one recent example the daily flowrate related to a pipeline velocity of under 0.08 m/s!

With inadequate pipeline mixing it becomes irrelevant to consider the uncertainties within a quality loop because the loop itself can at no point be representative.

2. Representative Offtake 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 (9 x 25mm inlet)	-0.118 %	80
Fast Loop (33mm or bigger inlet)	-0.035%	23

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.

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.

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 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/M^3

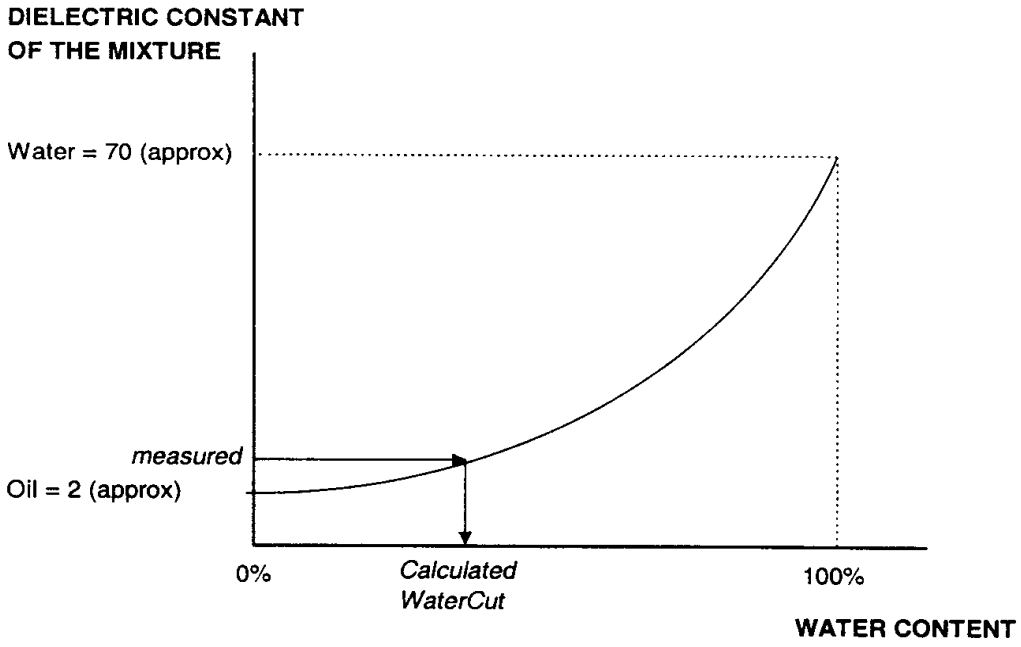
Parameter	Units	For 0.03 % uncertainty
Temperature Sensitivity	-0.7 Kg M^3 per K	0.4 K
Pressure Sensitivity	0.06 Kg/M^3 per bar	4.2 bar

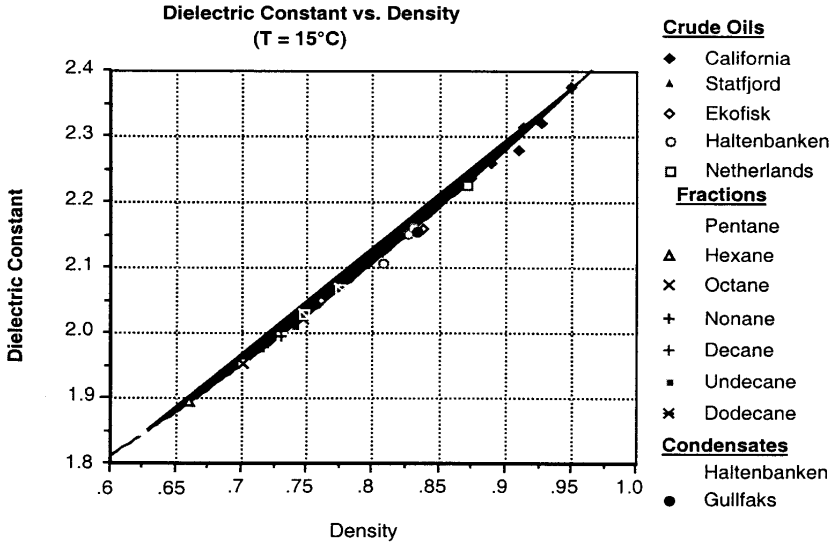
These figures can be adjusted if the density is correctly adjusted to process conditions (i.e. at the flowmeter) from local pressure and temperature measurements.

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

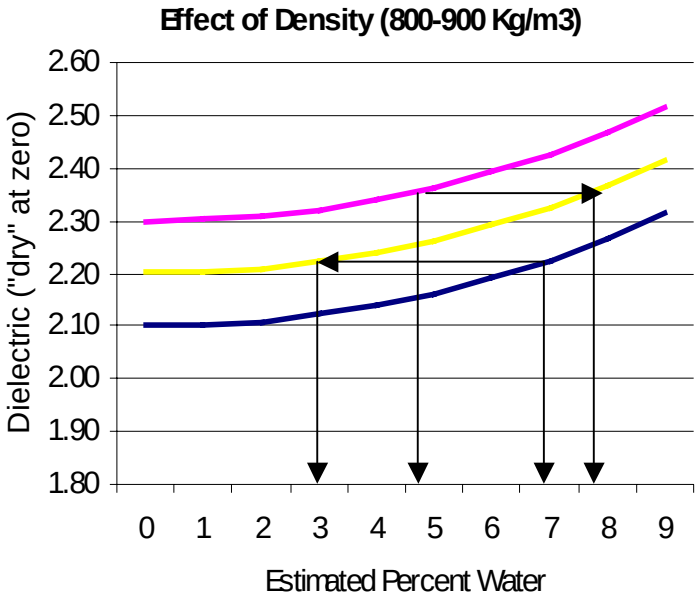
As there is an increasing tendency to use OWD systems, it is important to note that any water in oil monitor using dielectric constant upon which to base the water content will need compensation for the "dry oil" dielectric – this includes microwave-based techniques.





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 compensated using the wrong density!

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.



Are there new issues?

So why are these issues of more significance now than in the past?

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:

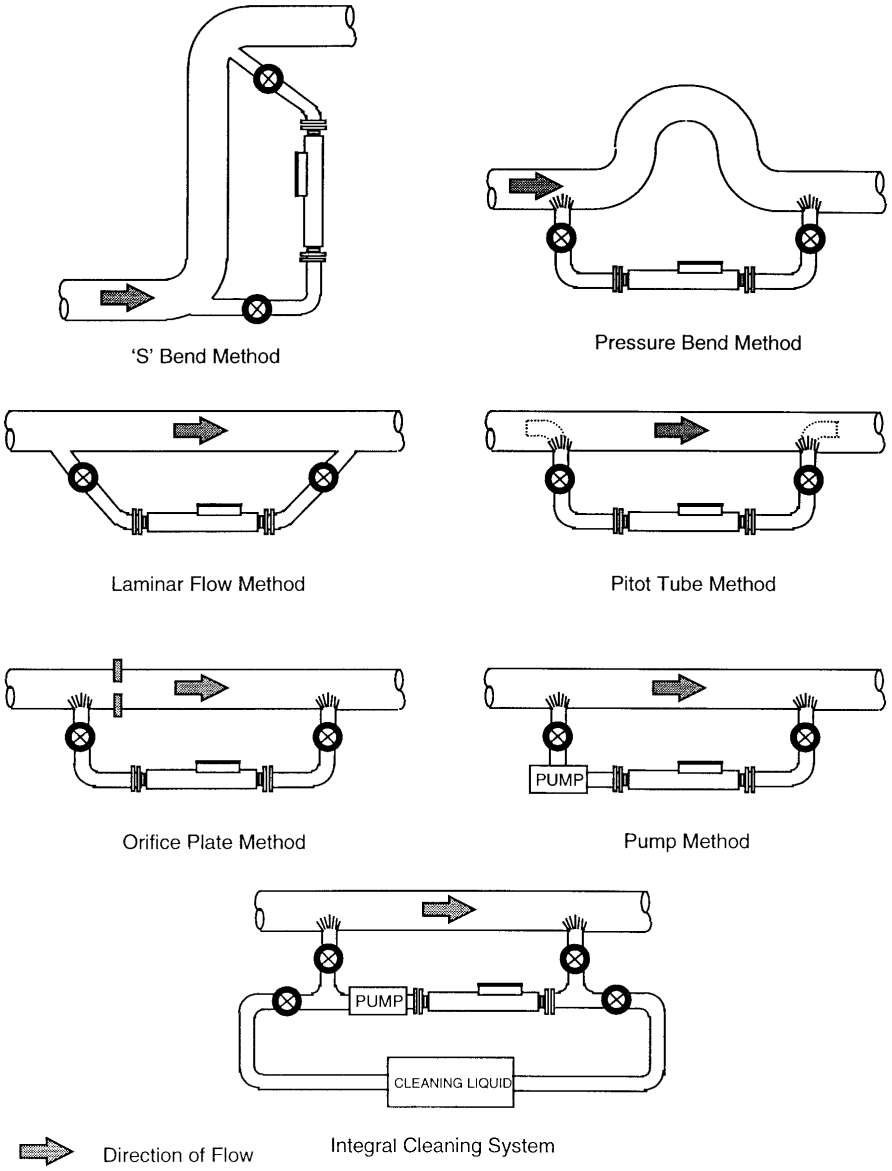


Figure 2.2c Typical By-Pass Pipeline Configurations

Given that quality loops are 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:

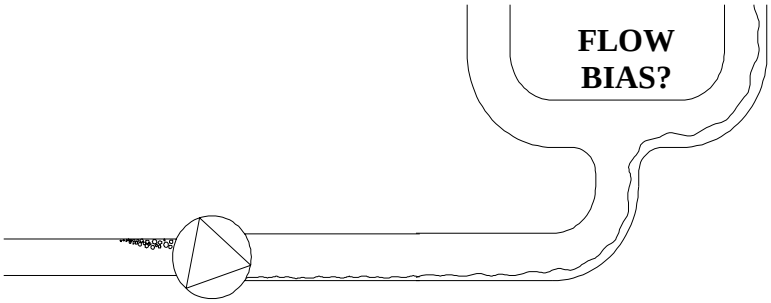
1. The representivity of the quality loop in regard to accurate water content is frequently wrong.
2. The content of the quality loop does not maintain the process conditions adequately to represent the process at the measurement point (i.e. pressures and temperatures are offset).

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.



These are the numbers, but in reality what is likely to happen? As fields are getting older and if no attention is paid to correct integration of quality measurement an uncertainty of 0.15% is probably unattainable.

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.

New production

In an effort to reduce production costs there is now a tendency to produce over existing facilities with new fields, the characteristics of which may be significantly different from those envisaged for the original process train or to create new process systems with minimal separation (often single stage). The problem with single stage separation is that the measurement system is now being asked to cope with fluids at higher pressures but also with RVP, which is extremely close to the process condition. This yields little available operating

envelope for creating adequate mixing or for pumping a loop. Extreme care is required to design quality loops and the necessary process mixing without destroying the ability to accurately measure the qualities of the process.

Conclusion

There are significant uncertainties in the overall net oil results for offshore 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. Until due care and attention is paid to improving and integrating the quality process piecemeal improvement is unlikely to yield much improvement in uncertainty.

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.