

MEASUREMENT ERRORS IN NORTH SEA EXPLORATION
AND PRODUCTION SYSTEMS RESULTING FROM
IGNORING THE PROPERTIES OF WATER

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**MEASUREMENT ERRORS IN NORTH SEA EXPLORATION AND PRODUCTION SYSTEMS
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INTRODUCTION

Most of the recognised standards which govern metering and analysis of crude oil and water mixtures fail to deal adequately with the presence of water. When water forms a very small part of the total flowing fluid, these omissions will not produce significant errors. The standards have grown up in an environment dominated by the need to measure relatively dry crude from ships and overland pipelines. In the North Sea, situations can exist where circumstances give rise to the need to measure substantially wetter flows than previously encountered in the shipment and transportation of export grade crudes. It is probable that the future may see more North Sea locations where there will be a need to measure high water content streams. This paper attempts to quantify some of the errors and suggest ways of minimising their effect.

1. METERING WET CRUDE

Reporting metered quantities in terms of standard volumes at 15°C is still the practice in some North Sea production areas, even though, in many instances, density at line conditions is being continuously monitored by sophisticated instrumentation. It has long been recognised that this approach is subject to a small error introduced by the need to derive a volume correction factor to convert from volume at measured conditions to standard reference conditions. The question which must have been asked by many people is - "do I only consider the physical properties of the crude oil or should I also recognise the properties of the water present?"

Let us first consider a dry crude oil stream being metered at 60°C and 25 barg having a density at these conditions of 797.8 Kg/m³ (measured by densitometer).

Using the standard formulae provided in the relevant Standards (see attachment) the following properties can be calculated:-

Compressibility factor b	=	12.10 x 10 ⁻⁵ /bar
Thermal expansion coefficient	=	0.0008919/deg C
Density at 15°C and 1.01325 bar	=	829.67 Kg/m ³
Volume correction factor	=	0.959420

The following sections consider the effect of the presence of water on the calculation of standard volumes.

1.1 COMPRESSIBILITY

Pure water is less compressible than crude oil having a compressibility coefficient of 4.4 x 10⁻⁵/bar at 60°C. The presence of salts will further decrease the compressibility of water. The degree of this effect will depend on the properties of the salts present and the degree of saturation. If we restrict our attention to NaCl, then over the range of concentrations normally found in the North Sea the compressibility will only vary by approx. ± 10% about a mean of around 4 x 10⁻⁵/bar.

If we calculate the compressibilities of crude/water mixtures assuming no effect of mixing we get:-

1% vol water b	=	12.02 x 10 ⁻⁵ /bar
10% vol water b	=	11.29 x 10 ⁻⁵ /bar

This gives pressure correction factors:-

Cpl (dry)	=	1.00303418
Cpl (1% water)	=	1.00301406
Cpl (10% water)	=	1.00283049

Even at 10% vol water the effect is very small and hence negligible as the error would only be around -0.02%. A negligible error can be shown for other salts commonly found in production water, at the pressures being considered here.

1.2 Thermal Expansion

Pure Water has a much lower thermal expansion coefficient than crude oil; ignoring this fact can lead to underestimating metered volumes at standard conditions. To demonstrate this, Volume Correction Factors (VCF's) have been calculated on three different bases and are shown in Table 1. The three different bases are:-

- VCF calculated from the thermal expansion coefficient derived from the dry crude oil density.
- VCF calculated from the thermal expansion coefficient derived from the wet crude oil density.
- VCF calculated from a total fluid thermal expansion coefficient derived from the individual thermal expansion coefficients of dry crude oil and production water. (It is assumed that this procedure generates the most accurate VCF.)

It is worth pointing out that the calculations used to derive "dry" crude thermal expansion coefficients are those specified in IP200/API2540. Strictly speaking this will not give absolutely accurate dry crude oil thermal expansion coefficients as the base data used to generate the equations (and Tables 53A and 54A) came from samples of "typical export quality" crudes i.e. they probably did contain small amounts of water. As the amount of water present is not reported, and probably varied from crude to crude, no estimate of the error involved in calculating dry thermal expansion coefficients can be made. In this paper it is assumed that this error is negligible when considering crudes containing more than 1% wt water.

The results, in Table 1, show that use of dry oil density to calculate VCF will cause significant errors at levels of water in excess of about 3% wt. (in this context it is assumed that a bias of -0.06% is significant in a modern turbine metering system designed to measure gross volumes to an accuracy of $\pm 0.1\%$). The errors will lead to an underestimate of the standard volume at 15°C.

It should be stressed that the errors being discussed are in addition to the potential errors already implicit in the VCF's derived by Standard IP200/API2540. The VCF precision (at the 95% confidence level) quoted in this Standard is:-

Temperature °C	40	65	90	120
Precision %	0.05	0.15	0.25	0.35

This arises because of the generalised correlation on which this Standard is based. The inherent precision of the VCF can be improved by using actual measured data for the thermal expansion coefficient of the substance being measured.

From the data in Table 1 it can be seen that the use of wet oil density, in the VCF calculation, produces much more acceptable results. At very high water concentrations (say > 30% wt) the accuracy provided by this route may be judged to be inadequate, for the example chosen. If the production water is purer than the one used in the example (which was 2.68 molal NaCl) errors will increase because the thermal expansion

coefficient of pure water is less than that for salt water, at temperatures less than 60°C. Errors will obviously increase with operating temperature.

1.3 CONCLUSIONS

1. The relevant standards do not allow for use of the properties of water in metering calculations.
2. Ignoring the lower compressibility of production water, compared to crude, is unlikely to produce significant metering errors unless water concentrations are extremely high (e.g. 30% wt).
3. Use of dry oil density to calculate total wet fluid thermal expansion coefficients and hence Volume Correction Factors can generate significant underestimates of metered volumes at standard conditions if water contents are 3% wt.
4. Use of wet oil density to calculate total wet fluid thermal expansion coefficients, and hence Volume Correction Factors, does produce sufficiently accurate results over the range of water contents examined in Table 1 (1-10% wt)

1.4 RECOMMENDATION

1. Up to 10% wt water wet oil densities should be used to calculate metered volumes at standard conditions.
2. Above 10% wt water the need to include the thermal expansion coefficient of the produced water in the calculation of metered volumes at standard conditions, should be examined before a decision to use wet oil density alone is made.

The need for all of these calculations can of course be obviated by measuring and reporting platform dispatches in mass, calculated at line conditions. If this is done, a water measurement in terms of % mass is required to avoid the need to again introduce the uncertainties discussed above. The effect of salt content on the measurement of water concentrations is considered in the following section.

2. CALCULATING WATER QUANTITIES EXPORTED FROM NORTH SEA PLATFORMS

The most accurate method, available to the oil industry, of analysing for water is the Karl Fischer method. (IP 356/84). Unfortunately the chemists have provided an excellent way of determining pure water whereas the oil industry needs to know the level of produced water exported with the oil. A correction for water salinity therefore needs to be applied.

It can be shown that the mass of produced water exported in a given period can be calculated:-

$$\text{Mass of produced water} = \text{Total mass} \times \% \text{ wt pure water} \times \left(\frac{D_w}{D_w - \text{TDS}} \right)$$

where - % wt pure water is the Karl Fischer result

D_w = Density of produced water at 15°C in g/l

TDS = Total dissolved solids in produced water in g/l @ 15°C

$$\text{Salt correction factor} = \frac{D_w}{(D_w - \text{TDS})}$$

This salt correction factor is plotted against water density in figure 1. This is only an approximate relationship, as the relationship between TDS concentration and water density obviously depends on the actual compounds present.

If gross quantities are measured to an accuracy of $\pm 0.1\%$ one can see that the salt correction factor becomes significant at production water densities 1070 g/l at the 1% wt water level and at densities 1010 g/l at the 10% wt water level.

Hence, ignoring the salt correction factor can result in serious overestimates of the quantities of dry hydrocarbon exported from North Sea platforms.

It has already been suggested that measuring mass at line conditions eliminates several calculational uncertainties which would be reintroduced if water is measured as %volume. But what if the analytical technique used does give a volume answer, do corrections still need to be applied?

If the water concentration is determined by the centrifuge technique (IP 359/82) one does get an answer which relates in some way to the volume of produced water present. However, as the centrifuge technique uses equipment calibrated at 20°C and is actually done at 60°C the answer is not %volume water at 15°C as most people assume. The errors involved due to the confusing mixture of temperatures involved are not significant given the overall accuracy claimed for the test. It is the authors view that this method is not sufficiently accurate for modern mass metering installations.

If the water content is determined by the Dean and Stark Distillation technique (IP 358) the answer generated again relates to a concentration of pure water and therefore a salt correction factor must be applied.

In modern offshore metering installations volume temperature, pressure and density can be continuously monitored. Water measurement, however, still relies on collecting representative samples to be analysed off-line by laboratory techniques. It is not surprising, therefore that much

effort has been expended in recent years in attempts to develop instruments which will continuously monitor water concentrations in a flowing pipeline. From the comments made above it is apparent that the ideal continuous water measurement should generate a concentration in mass terms and allow for the salts present in the water.

2.1 CONCLUSIONS

1. To provide the best accuracy water should be analysed by the Karl Fischer technique which provides a concentration in mass terms.
2. Significant errors can be introduced in calculated dry oil quantities if the salt content of the produced water is ignored when the analytical test method is designed to measure pure water.
3. Any device developed to measure water content continuously would ideally need to allow for water salinity.

Aknowledgnaent

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TABLE 1

	dry	wet 1% wt water	wet 10% water	Using α for water = 0.00035 deg/C	
				1% wt water	10% wt water
Density at 60°C, 25 bar g. Kg/m ³	797.8	800.00	820.34	800.00	820.34
Density at 15°C, 1.01325 bar Kg m ³	829.67	831.59	851.30	-	-
α	0.0008919	0.0008878	0.0008472	0.0008879	0.0008508
VCF	0.959420	0.959609	0.961475	0.959606	0.961310

$$VCF = \exp [-\alpha \Delta t (1 + 0.8 \alpha \Delta T)]$$

$$\Delta T = 45^\circ C$$

$$\text{Density of Water} = 1100 \text{ kg/m}^3 \text{ (at } 60^\circ C, 25 \text{ bar g)}$$

$$\text{Assume thermal expansion coefficient of water} = 0.00035/\text{deg C}$$

$$\begin{aligned} 1\% \text{ wt water} &= 0.74\% \text{ volume @ } 15^\circ C \\ 10\% \text{ wt water} &= 7.62\% \text{ volume @ } 15^\circ C \end{aligned}$$

Water Concentration	Error in VCF caused by using	
	dry oil density	wet oil density
1% wt	-0.019%	0.001%
10% wt	-0.197%	+0.017%

FORMULAE USED

Thermal expansion

$$VCF = \exp [-\alpha \Delta T (1 + 0.8 \alpha \Delta T)]$$

VCF = Volume correction factor

α = Thermal expansion coefficient = $\frac{613.9723}{215^2}$

ΔT = Operating temperature - 15°C

ρ_{15} = density at 15°C, 1.01325 bar g in kg/m³

Compressibility

$$b = \exp [1.38315 + 0.00343804T - (3.02909 + 0.0161654T) \ln \rho_{15}]$$

T = Operating temperatures °C

ρ_{15} = density at 15°C, 1.01325 bar g in kg/l

b = compressibility factor

$$Cp1 = 1/(1 - Pb \times 10^{-5})$$

Cp1 = Correction for pressure

p = Operating pressure - bar gauge

b = Compressibility factor

Conversion of wet to dry oil density

$$D_{dry} = \frac{D_{wet} \times D_{water} \times (100 - x)}{100 D_{water} - x D_{wet}}$$

D_{dry} = density of dry oil

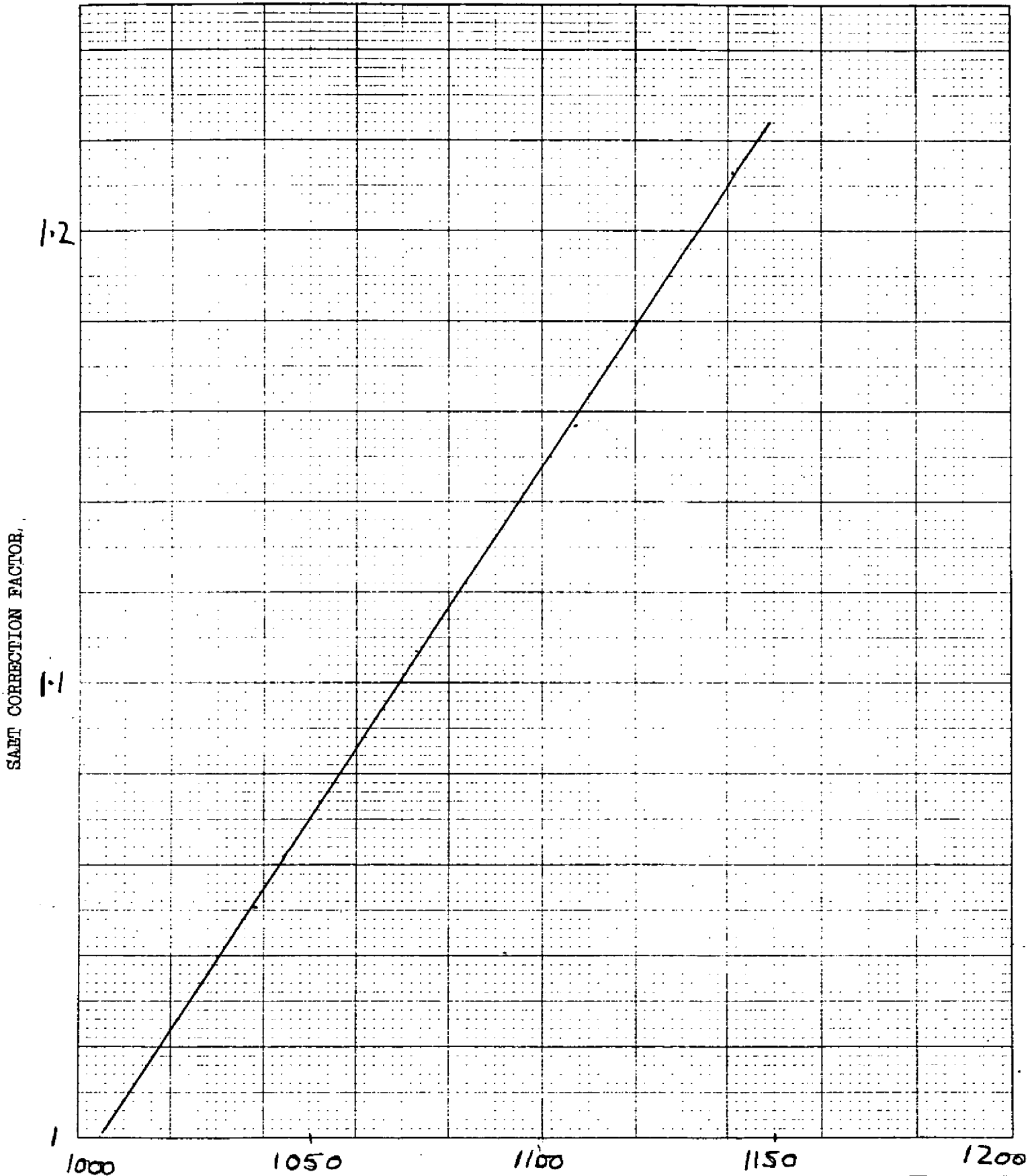
D_{wet} = density of wet oil

D_{water} = density of produced water

x = percent wt/wt of production water present in wet oil

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APPROXIMATE RELATIONSHIP BETWEEN
PRODUCTION WATER DENSITY AND SALT
CORRECTION FACTOR FOR KARL FISCHER
TEST



BP. 1. (JAN. 62) DENSITY OF PRODUCED WATER g/l @ 15°C



References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL

Note that this reference was not part of the original paper, but has been added subsequently to make the paper searchable in Google Scholar.