CRUDE OIL

EXPANSION

COEFFICIENTS

R Third

Rhomax Engineering

SUMMARY

The need to account for the effects of temperature and pressure on the volume occupied by a mass of hydrocarbon liquid is a universal one in our industry.

The methods commonly used in the North Sea are summarised, and their inherit anomalies are listed.

The effects of applying the various different methods to the determination of liquid quantities are briefly evaluated.

Fairly gross changes in base density can be accommodated without very significant effect on meter K-factor.

Comparatively small changes in base density are likely to cause fairly meaningful changes in Standard Volume.

A method of gathering large amounts of field data directly from remote flow and quality measurement instruments is describe, and techniques for using data thus gathered for further useful analysis is described.

Tentative volume coefficients based on such field measurement data, suitable for use with various different mixes of crude/water/condensate, are described.

Note that in the following test the term "expansion" is used as meaning "change in volume", which can be in both a positive or a negative direction.

THE CURRENT REGIME

THE STANDARDS

API 2540

CONCEPT OF VCF

To predict the volume likely to be occupied by a quantity of crude at a temperature of 15 °C, the concept of a Volume Correction Factor (VCF) is invoked.

If one knows the temperature at which the volume was measured, and the density of the crude at 15 °C, one can find a unique Volume Correction Factor appropriate to those conditions listed in a set of Tables.

Multiplying the measured volume of the crude by the VCF gives the notional likely volume at 15 °C :

$$V_{15} = V_m \times VCF$$

where,

V_{15} is the volume of the crude at 15 oC, $m^3{}_{15}$
V_m is the volume of the crude at meter temperature, m^3

Equally, if one knows the *density* of the liquid at 15 °C and the measurement temperature, one can predict the density of the crude at some other temperature.

Tables which allow these calculations are in the American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 11.1, or in the separate (identical) Standard API 2540 (also adopted by other bodies and published by them, designated ANSI/ASTM D1250 or IP 200).

BASIS OF API 2540

The work upon which the Tables are based was done by the American National Bureau of Standards (now the National Institute for Standards and Technology) in 1976. The research included only two samples from the North Sea, one from each of the Forties and Auk fields.

One of the limitations of the research was that none of the samples was allowed to contain more than 0.38% of water.

A further limitation was that each sample was allowed to stabilise in an open container prior to its being tested. It is unclear from the original research paper just what proportion of the 'light ends' would thus have remained in solution for each sample.

What is explicit is that the original paper states that "tests would be discontinued when vapour pressure exceeded atmospheric pressure or when the sample under test approached a non-liquid state".

These limitations are further discussed below.

Cautionary Note : The term C_{tl} - Correction for the effect of Temperature on the Liquid - is used interchangeably with VCF. There is, however, is a common alternative usage for VCF. In this alternative usage $VCF = C_{tl} \times C_{pl}$

where C_{pl} is the Correction for the effect of Pressure on the Liquid.

THE STANDARD - COMPUTER ROUTINES

The Standard resides not in the Tables, but in the specific implementation of the computer routine described in Volume X of API 2540. This routine is for the solution of an equation, and specifies the rounding or truncation of the numbers used, and the precision of exponentials, etc.

The equation is

$$VCF = \exp[\alpha_{15}\Delta t (1 + 0.8\ \alpha_{15}\Delta t)]$$

where

α_{15} is the tangential thermal expansion coefficient of the crude at 15 °C, and

Δt is the difference between measurement temperature and 15 °C

The α_{15} value depends upon the density of the crude oil at 15 °C, as follows:

$$\alpha_{15} = K0 / \rho_{15}^2 + K1 / \rho_{15}$$

where K0 and K1 are constants applicable to the type of fluid, given in the Standard. For crude oils, $K0 = 613.97226$, and $K1 = 0$

ρ_{15} is the density of the crude oil at 15 °C, kg/m^3.

The Tables which occupy the majority of API 2540 were derived using these routines.

UNCERTAINTY

The uncertainty of the VCF calculation is stated in API 2540 Volume X as follows:

Temperature of the crude (°F)	Uncertainty
100 (approx. 37.8 °C)	± 0.05 %
150 (approx. 65.6 °C)	± 0.15 %
200 (approx. 93.3 °C)	± 0.25 %
250 (approx. 121.1 °C)	± 0.35 %

API 11.2.1M

This is a further part of the American Petroleum Institute Manual of Petroleum Measurement Standards, and is concerned with the effect of pressure on hydrocarbon liquids.

For our crudes, the liquids involved are those whose density at 15 °C is in the range from 638 - 1074 kg/m^3.

The Standard contains Tables of Liquid compressibility factors.

Unlike API 2540, the standard is the printed Tables, not the calculation routine which is also included in the document.

COMPRESSIBILITY FACTOR, F

Central to the Tables is the compressibility factor, F, which participates in the equation

$$V_e = V_m / [1 - F \times (P_m - P_e)]$$

where

V_e is the volume at equilibrium pressure (P_e), m^3
V_m is the volume at the meter pressure (P_m).

The Standard uses density in kg/l, volume in m^3, temperature in °C, and pressure in kPa.

The compressibility factor, F, is calculated from

$$F = exp (A + BT + C/\rho + DT/\rho^2)$$

where

A, B, C, and D are constants, given in the Standard thus:

A = -1.62080
B = 0.00021592
C = 0.87096
D = 0.0042092

T is the meter temperature, °C,
ρ is the density of the liquid at 15°C, kg/l

BASIS OF THE API 11.2.1 TABLES

The Standard was derived from three separate research papers which describe work done on seven different crude oils, five gasolines and seven middle-distillate oils. All of these were lumped together in the calculation of the constants.

None of the crude oils was of North Sea origin. Those included had base density values form 825.2 to 890.9 kg/m^3, and were investigated over a temperature range of 4.44 to 76.7 °C and 0 to 3503 kPa pressure for five of the samples, over a temperature range of 37.78 to 76.67 °C for the sixth and over a temperature range of 15.56 to 76.67 °C for the seventh . The experimental work included five measurement points for each of six of the crude oil samples, and four data points for the seventh sample.

From this very limited database, data was obtained by extrapolation for a temperature range of -30 to 90 over a temperature range of 37.78 to 76.67 °C, a density range of 600 - 1074 kg/m^3, and a pressure range from 0 to 10300 kiloPascals.

The API Committee generating API 11.2.2 were aware of this shortcoming. To quote from the Standard "The data base is...........not large enough to cover the range of current commercial operations. When new data are available, they will be incorporated into an expanded standard". That was the case when the Standard was first published, and was still the case when the BS / ISO versions were published in 1991 / 1989.

HISTORIC USE OF 'DOWNER' EQUATION

Use of the API 11.2.1M tables (or equation) is comparatively new in the UK. A similar *(not identical)* function was previously performed by use of the "Downer" equation. This calculated a compressibility value for the crude, but took no account of the vapour pressure of the liquid.

The Downer equation was used to calculate a value, β, as follows:

$$\beta = \exp ([a + bT - (c+dT) \ln (\rho_{15} /1000)] \times 10^{-5}$$

where
β is the secant compressibility of the liquid, bar^{-1}

a, b, c, and d are constants as follows

$a = 1.38315$
$b = 0.00343804$
$c = 3.02909$
$d = 0.0161654$
T is the measured temperature, $^{\circ}C$
ρ_{15} is the density of the crude oil at 15 $^{\circ}C$ and 1.01325 bar a, kg/l.

β is, to all extents and purposes, the same as F.

This β value was then used to calculate the Correction for the effect of Pressure on the Liquid as follows

$$C_{pl} = 1/(1 - \beta P)$$

where

P is measured pressure, bar g

This correction was used to predict the notional volume the liquid would occupy at 15 $^{\circ}C$ and 0 bar g.

Calculation routines based upon use of the Downer equation (see IP Measurement Paper No 2 below) are incorporated into a great many flow computers in use in the UK, and are written into several pipeline agreements.

UNCERTAINTY IN COMPRESSIBILITY

Assessment of the uncertainty associated with the use of the API 11.2.1M Tables (and the equation) is not straightforward.

The maximum uncertainty of the compressibility factor, F, as predicted by the Tables, when compared with the actual compressibility factor for the same liquid, is stated as $\pm$ 6.5%.

The resulting uncertainty in *volume* is related to the measurement pressure, but may also be compounded by an extra uncertainty related to the effect of pressure on the compressibility. The point at which this pressure effect becomes significant is not clear. However, there is a hint that the 4902 kPa limit of the experimental data may be taken as the break point.

In considering the values for any installation metering at approximately 7000 kPa this extra uncertainty should be considered.

On the basis of a ρ_{15} value of 840 kg/m^3, temperature of 46 °C, and pressure of 70 bar, API 11.2.1M gives a compressibility factor value of 0.903E-6.

The uncertainty is then estimated in line with the method suggested in API 11.2.1M as follows:

Basis A Uncertainty (no pressure effect)

$$0.903E\text{-}6 \times 6.5 \times 7000$$

i.e., $\approx$ 0.04 %

The Standard states that this value may be *doubled* for pressures over the break point, giving a possible value of approximately 0.08%.

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IP PAPER NO 2

This is primarily a guide for users of the API 2540 Standard, but its valuable contribution to the industry is a detailed routine for the calculation of C_{tl}, C_{pl} and base density.

Using these combined conversion factors, the Paper No 2 routine allowed the calculation of the notional volume the crude would occupy at 15 °C and 0 bar g, approximately Metric Standard Conditions (stated in ISO 5024 as 15 °C temperature and 1.01325 bar a pressure), the "Standard Volume"

The overall calculation made possible by the Paper is as follows:

$$Q_{vs} = Q_{vg} \times C_{tl} \times C_{pl}$$

where

Q_{vs} is the Standard Volume, Sm^3,
Q_{vg} is the Gross Volume, m^3, the measured volume.

The routine is based upon a series of nested iterations, which take as entry data the measured density, temperature and pressure.

The calculations use the API 2540 algorithms for the determination of C_{tl}, along with the "Downer" equation (currently being replaced by the API 11.2.1M routine), for the determination of C_{pl}.

It incorporates specific methods for the rounding and truncation of input data values, and specifies the precision of the polynomial series used for the exponential values within the calculation. In one form or another, the routine is built into many of the current flow computers in use in the UK, and is written into pipeline operating agreements.

BASIS OF MEASURED DENSITY

The attraction of the approach is that the calculation is firmly based upon current measurements, and closely follows changing process conditions. Any change in the water content, for example, will make some change in the measured density, and may be reflected in the calculated expansion factors. The inclusion of NGL spike into the crude oil stream will also be accounted for in this way.

The compensation for changing process conditions happens automatically, to all intents and purposes 'in real time' (independent of operator or technical action, independent of sampling or analysis error), and is incorporated immediately into the on-line determination of quantities.

Clearly, its efficacy depends upon good density measurement.

FLOW COMPUTER ROUTINES

The earlier generation of flow computers tended to have a straight implementation of IP Paper No 2 built into the software. Models currently being offered may include a variant of the Paper No.2, in that the Downer equation for compressibility has been replaced with the API 11.2.1M equation instead.

RESOLUTION OF CALCULATION

An integral part of the API 2540 calculation implementation is a specific approach to the rounding or truncation of values. These are carried through in Paper No 2, and some new rounding is added. The value of K0 given in API 2540 for crude oil, for example, is 613.97226 ; Paper No 2 rounds this to 613.9723. This rounding and truncation was specified to ensure that identical results, within the uncertainty of the Standard, would be obtained regardless of the variety of the computer used to perform the calculations: current flow computers tend to use the values at their full resolution.

METER K-FACTOR CALCULATION ANOMALIES

The meter K-Factor calculation is defined in IP Part X, as follows:

$$K = [(n/V_b) \times (C_{tlm}/ C_{tlp}) \times (C_{plm}/ C_{plp})]$$

where
K is the meter K-factor, pulses/m^3
n is the number of pulses from the turbine meter during the proving run
V_b is the volume of the prover during the proving run, m^3
C_{tlm} and C_{tlp} are corrections for the effect of temperature on the
liquid, at meter and prover conditions respectively
C_{plm} and C_{plp} are corrections for the effect of pressure on the liquid, at
meter and prover conditions respectively.

Some systems use a variation of this equation

$$K = [(V_b/n) \times (C_{tlm}/ C_{tlp}) \times (C_{plm}/ C_{plp})]$$

This has the effect of having the K-factor in units of m^3 per pulse, the "one pulse volume".

The implementation of the full equation depends upon the calculation of the liquid expansion factors at the various locations: density transducer to turbine meter in the first case, meter to prover conditions in the second.

The first of these is not shown explicitly in the equation above, but may participate nevertheless in that the value of "density at meter conditions" depends upon the notional expansion of the liquid from density transducer to turbine meter conditions of temperature and pressure.

It follows, therefore, that any error in the calculation of the liquid expansion factors will contribute to an error in the value of any meter K-factor based upon them. The nature of the calculation of, say, C_{pld} will be included also in the calculation of C_{plm} and C_{plp}.

Since the meter K-Factor calculation is central to all the subsequent determination of quantities, it is clearly vital that the expansion calculations be as accurate as possible.

THE EFFECT OF WATER

It is not clear *from the Standards* if the crudes which formed the database studied had any appreciable water content. Water content is not even mentioned, suggesting that it was not a significant consideration in respect of their samples tested. In addition, the only North Sea crudes included in the study are samples form Shell's Auk and BP's Forties fields. Whether these crudes were at all 'wet' at the time of the study (late 1970s) is irrelevant in so far as the Standard is concerned.

In fact, one has to go behind the Standard to the paper published by NBS describing the original research to find that water content was very much a factor in the selection of the crudes investigated.

No sample of crude which contained more that 0.38% of water was investigated, so there is real doubt as to the applicability to (typically wet) North Sea fluids.

In addition, the research samples were of 'stable' crude : the typical North Sea crude contains some proportion of components which are naturally gaseous at Standard Temperature and Pressure. The 'natural drip gasolines' are specifically treated in the Guidelines (see below).

A typical expansion factor for *fresh water* may be calculated from IP Part X Section 3 (which refers to either ISO 3838 or ISO 8222). At 46 °C and 70 bar g, a combined expansion coefficient for fresh water is 0.9937.

At the same temperature and pressure, a typical value for crude oil is 0.9790. This represents a difference of approximately 1.5%.

Even if the values had been similar to those for crude, we would be left with the problem that the values given by the IP are for fresh water.

The water content of our crudes is very different from fresh water, containing as they do a variety of mineral salts, and frequently contain amounts of process chemicals.

This being so, it is pointless to suppose that there could be some way of applying these values for pure water into any calculation involving the water content of the metered liquids.

THE EFFECT OF SPIKED NGL

We know that NGLs behave differently from crude oil in terms of temperature and pressure.

IP Measurement Paper No 2, in its section giving guidance on the use of API 2540, specifically excludes NGLs from the applicability of the Standard, if the NGLs are *pure components*, e.g., pure butane or pure propane. It allows their inclusion if they are "drip gasolines......the paraffinic condensate from gas well production". The liquids spiked into the crude in the North Sea fall into this latter category, in which case API 2540 states that they should be treated as if they were crude oil.

In addition, Paper No 2 states explicitly that its calculation routine is for crude oil or condensate.

The effect of adding NGLs into the crude stream will be to decrease the value of the measured and the base density. This is the sort of change which is accounted for automatically if one uses the Paper No 2 method, based upon measured density.

A recent revision of the API Manual of Petroleum Measurement Standards Chapter 12.2 suggests the use of the Historical 1952 Edition of API 2540 for condensates. It is interesting to note that while IP Paper No 2 stated explicitly that API 2540 constants should not be applied to pure NGLs, the 1952 Standard was based upon laboratory investigation of the characteristics of pure NGLs. Either way, this is of no help in the treatment of crude / condensate mixes.

CHOICES AVAILABLE

It is clear that the current regime of using the API / IP / ASTM / ISO methods described have several shortcomings when applied to our North Sea crudes. To summarise these:

API 2540 makes no provision for the presence of water
API 2540 is not applicable to lively crudes

There are several methods available to calculate for crude oil expansion. There are three factors to be considered:

> The Operator's commercial interest
> The Department of Trade and Industry's requirements
> Pipeline operating agreements.

The first of these could sometimes be at variance with the other two.

The choices available are:

Ignore β (F)
Use IP Paper No 2
Use a modified version of IP Paper No 2
Use pre-set correction factors
Use a modified version of IP Paper No 2, with custom values for K0 and K1

IGNORE β (F)

The Department of Trade and Industry standards state that they may allow UKCS operators to ignore the effects of pressure of the crude, presumably on the basis that crude itself is not very compressible.

This may be true at fairly low pressures. At higher levels, pressure is likely to have an increasing effect upon the volume of the crude. At higher pressures, and certainly for crude/condensate mixtures, it would not be considered wise to ignore the effects of pressure.

In any event, pipeline agreements frequently require that the compressibility be taken into account.

IP PAPER NO 2

It is a requirement of the Department of Trade and Industry that "good oilfield practise" be followed in one's metering effort. This probably involves some form of implementation of IP Measurement Paper No 2, in the general sense that it may be the most common approach in the industry. In addition, the DTI Standards specifically mention API 2540 and IP Paper No 2.

All the rounding and truncation is designed to achieve results within the uncertainty of the original, which is the best that any user of the API standard can claim for any implementation.

The fact that the original standard was generated to be used with the computers commonly-available in the late 1970s and early 1980s may make the provisions unnecessarily restrictive today : they are being widely ignored.

I P PAPER NO 2 MODIFIED

A major part of the IP Paper No 2 routine, the use of the "Downer" equation for the calculation of the compressibility of the crude oil, has been superseded, however. The equation and constants from API Chapter 11.2.2M are being used instead.

Its use has been sanctioned by the Department of Trade and Industry and by the Institute of Petroleum. (It is, in fact, included in its recently published revisions of parts of the Petroleum Measurement Manual, e.g. Part X. (It is also, I am told, included in a revised version of Part VII Section 2, due to be published 1992!)). Its use has been approved by Mr Lionel Downer himself, and it has been incorporated in BS 7340 / ISO9770.

PRESET α AND β (F)

It is possible have the major inputs to the expansion calculations, α_{15} and β (or F), input into the flow computers as pre-set constants.

In this method, α_{15}, and β (or F), can be established by laboratory analysis on the basis of a periodic flow-proportional sample. The values can be set into the flow computers as soon as possible after the results of the analysis have been obtained and checked, and up-dated as required.

It may be considered that this approach contributes no more uncertainty to the overall determination of quantities than any other method. If conditions vary randomly, within very small limits, this could be the case. However, the uncertainty of the laboratory evaluation of compressibility is estimated as ±5%.

In a situation where any single input parameter may vary by an order of magnitude for an appreciable period (e.g. water or NGL content going from 1% to, say, 10% for several hours, or even days) this assumption is not tenable. This would require the pre-set values to be updated to match the new circumstances.

Technicians or operators may be unable, for whatever reason, to input updated values at the prescribed time, or even forget to have the values updated for long periods, regardless of the results of analysis. In these situations, the potential for mis-measurement is greatly increased.

This can give rise to the use of inappropriate meter K-Factors. While the magnitude of the error in meter K-Factor is generally small, it is systematic, and should not be lightly ignored.

METER K-FACTOR CALCULATIONS

A set of calculations has been done to assess the implications of using pre-set expansion constants, as opposed to allowing the (effectively "real time") updated calculation of these using the IP Paper No 2 method.

a   A baseline calculation where the assumption is that the constants are entirely appropriate for the conditions, is done for typical conditions.

Thus for example, with 30000 pulses, a prover certified volume of $1.625m^3$, meter temperature of 44 °C, meter pressure of 70 bar, prover temperature of 44.5 °C, prover pressure of 69.5 bar, base density of 825 kg/m^3, a likely meter K-Factor is approximately 5.424941E-5 m^3 per turbine meter pulse (the "baseline" K-factor).

b   Calculations are repeated where the base density changes by 1% steps (both above and below the nominal 825 kg/m^3 value). The resulting meter K-Factor is compared with the baseline meter K-Factor in each case.

These changes in base density are an attempt to replicate the situation where, for example, water cut or NGL content changes, a situation in which the expansion constants should be changed in the flow computer system.

c   The % error in meter K-Factor per change % in base density is then assessed.

d.   Results are as follows:

% Change in Base Density	Base Density (kg/m³)	K-Factor	% Change in KF
-10	742.50	5.4279575e-5	-0.012
-9	750.75	5.4278845e-5	-0.010
-8	759.00	5.4278140e-5	-0.009
-7	767.25	5.4277459e-5	-0.008
-6	775.50	5.4276802e-5	-0.007
-5	783.75	5.4276166e-5	-0.005
-4	792.00	5.4275551e-1	-0.004
-3	800.25	5.4274956e-5	-0.003
-2	808.25	5.4274379e-5	-0.002
-1	816.75	5.4273822e-5	-9.95e-4
+1	833.25	5.4272758e-5	9.64e-4
+2	841.50	5.4272251e-5	1.89e-3
+3	849.75	5.4271759e-5	0.003
+4	858.00	5.4271282e-5	0.004
+5	866.26	5.4270820e-5	0.005
+6	874.50	5.4270371e-5	0.005
+7	882.75	5.4269935e-5	0.006
+8	891.00	5.4269511e-5	0.007
+9	899.25	5.4269099e-5	0.008
+10	907.50	5.4268700e-5	0.008

It is clear that the greater the 'error' in density, the greater will be the error in the meter K-Factor. (NB : This is only true if temperature and pressure at the turbine meter are different from those at the prover, or if density is measured at a different temperature and pressure from those obtaining at the meter, and density is "referred" from one set of conditions to another).

This error in K-Factor is small, and the direction of the error matches the direction of the departure from the accurate density. Under normal operating conditions, variations would be random and could cancel out. A change in base density due to an increased water cut or to a period of NGL spike is not a randomly varying change. Such a change in operating conditions will, instead, be a significant bias in one direction, and liable to be in place for extended periods.

This bias would have the effect of making the metered volumes appear to be different from what they should be otherwise. Whether indicated volumes appear larger or smaller will depend upon the direction of the shift in the base density. If actual base density is larger than that used (e.g. because of a higher water content), calculated volumes will be smaller than actual volumes. If on the other hand actual base density is smaller than the value in use (say because of NGL spiking), calculated volumes will be larger than actual volumes.

STANDARD VOLUME CALCULATIONS

Different considerations apply when one wants to establish the effect of inaccurate expansion constants on calculated Standard Volumes, on which pipeline tariff payments are frequently based.

A set of test calculations was done to determine the likely effect of inappropriate expansion constants on Standard Volumes. The basis of the calculations was the same as used above, i.e., the input of 1% changes in base density followed by a comparison between the resulting Standard Volume and a "correct" baseline value.

Calculated values are based upon a typical situation with 2 meter streams on line, each flowing 280 m^3/h for a period of 365 days, i.e. a notional Gross Observed Volume of

$2 \times 280 \times 24 \times 365 = 4905600$ m^3 per annum

With a temperature of 46 °C, a pressure of 70 bar g, base density of 825 kg/m^3, this gives a Gross Standard Volume of 4799397 Sm^3 for the year.

% Change in Base Density	Base Density (kg/m^3)	Standard Volume	% Change in Standard Volume
-10	742.50	4780706	0.389
-9	750.75	4782588	0.350
-8	759.00	4784482	0.311
-7	767.25	4786380	0.271
-6	775.50	4788278	0.232
-5	783.75	4790169	0.192
-4	792.00	4792049	0.153
-3	800.25	4793914	0.114
-2	808.25	4795763	0.076
-1	816.75	4797591	0.038
+1	833.25	4801180	-0.037
+2	841.50	4802937	-0.074
+3	849.75	4804668	-0.120
+4	858.00	4806372	-0.145
+5	866.26	4808049	-0.180
+6	874.50	4809697	-0.215
+7	882.75	4811317	-0.248
+8	891.00	4812908	-0.281
+9	899.25	4814470	-0.341
+10	907.50	4816003	-0.346

These values are based upon a nominal total for a whole year's flow at the maximum flow rate for each of two meter streams. A situation where a systematic discrepancy remained in place for such an extended period is clearly not likely.

In addition, the likelihood of this level of flow rate for sustained periods is fairly small.

However, the calculated % change is perfectly applicable for the time for which the discrepancy is in place, and is independent of flow rate.

AN ALTERNATIVE

CUSTOM COEFFICIENTS FOR SPIKED OR WET CRUDE

The approach which would offer the optimum in terms of reflecting real operating conditions is to use

A different set of coefficients for each typical fluid mix

Means of placing the appropriate values in use depending upon the actual flowing conditions.

This is not as straightforward as it might appear.

Apart from the problem of acquiring a truly representative sample of each type of mix, there would be a problem in establishing, and agreeing with interested third parties, the specific coefficients for each mix, whose delimiting characteristics would also have to be agreed. There would be the matter, also, of establishing the means of triggering the use of one set of coefficients or the other in the flow computer. Not least, there would be large expense involved. There would be need for a major and complicated research project, including the cost of designing and building the necessary test equipment.

The author's musing on the nature of the test equipment required for such tests prompted the realisation that most North Sea oil platforms already have installed fairly sophisticated, certainly expensive, skid-mounted equipment for the reliable and accurate measurement of the density, and automatic sampling of the quality, of their exported products. Not only that, but the uncertainty of measurement of such equipment is fairly broadly accepted. The equipment is generally maintained to agreed procedeures, with the major items being calibrated annually against traceable standards.

This musing prompted the notion of analysing the output of such equipment to see if useful conclusions could be derived.

To be of use, any conclusion would have to be based upon a very large number of samples; ignoring the fact that API 11.2.2 is based upon only 5 tests on each of 6 samples plus 4 tests on the seventh sample, i.e., 34 data points in all! - API 2540 is based upon approximately six hundred data points, gained from a total of over 100 samples.

To use the outputs from offshore metering equipment would necessitate a major data-gathering effort, which might mean many man-hours of technician time taking periodic sets of readings from flow computers or transposing data from periodic printed reports into, say, spreadsheet form - undoubtedly a time-consuming and expensive exercise.

THE DATABASE

The Amerada Hess Ltd (AHL) AMADAES system provided the easy answer to the task of data-gathering.

Every metering supervisory computer in each of the fields operated by AHL sends a minute-by-minute 'snapshot' of its measurement data into a database computer located in Scott House in Aberdeen. The data comprises raw signal data from field equipment (e.g., density transducer periodic time, flow transmitter milliamps, etc.), temperature, pressure, density, base density, flow rates for each meter stream and for the station, calculation constants held in the flow computers, chromatograph analysis and configuration data, accumulated and periodic flow totals, meter proving reports, etc.

Each minute's data is stored for some 40 days, during which time it is available for monitoring and evaluation on the local PC-based network. Thus it is possible to monitor some 10,000 data points every minute. At the end of this 40 day period, it is archived. Even when the bulk of the data has been placed in the archive, a picture of the data is still available on line for ten-minute intervals.

The system arose from the perceived need to be able to offer onshore support to platform technicians who might not have in-depth measurement experience, on the one hand, and to allow readily-accessible data for the verification of daily allocation totals and calculation of mis-measurements. Since its

inception some three years ago, it has proved an invaluable tool for these purposes. It has proved useful, in addition, for the monitoring of quality data (export gas density versus composition, etc.) and of turbine meter performance (each successful proving event is automatically assimilated into trended data, for example).

Thus it is a fairly easy matter to acquire into a desktop personal computer all the data necessary for the evaluation of custom expansion coefficients.

FIELD MEASUREMENTS OF DENSITY AND WATER CONTENT

The combined density measurement / sampling systems, whose data is used in the calculations below, comprise a flow-proportional sampler and two Solartron 7830 or 7835 density transducers mounted in a pumped fast loop drawing its contents from, and returning them to, the inlet header of the metering system. A manual valve and a flow indicator, which are fitted downstream of the sampler, are used to adjust the flow, the ideal rate being that which is isokinetic with the flow through the inlet header.

In the case of one of the platforms, an Endress and Hauser Aquasyst Water-in-oil monitor, whose output is sent into the platform's metering supervisory computer, is also fitted in the fast loop. This monitor is calibrated daily with reference to the water content of a sample taken manually from the location.

On the other installation, a manual sample is taken every 4 hours, and the water content of the sample determined in the platform laboratory. This water content value is manually entered into the platform's metering supervisory computer.

A 4-wire PRT (to BS 1904 Class A) and a high good-quality pressure transmitter are typically installed at the densitometer location, feeding their signals into the flow computer.

A pitot-style probe is installed in the metering inlet header in such a location as to ensure that a representative sample of the crude being exported is introduced to the fast loop system. The loop is insulated to prevent wax build up inside the pipe work.

Density Transducers

The density transducers are Solartron 7830 or 7835 vibrating-tube units with an operating range of 0 - 3000 kg/m^3. Each transducer has a single tube through which the pumped fast loop flow passes.

The tube is driven by a pair of electromagnetic coils to vibrate at its resonant frequency. This vibration is detected by a second set of coils, and converted into a pulse train by the instrument's electronics. These pulses are sent to the flow computers, which measure the periodic time of the pulses.

The periodic time is a function of the mass of the vibrating element, which, in turn, is a function of the mass, and therefore the density, of the fluid with which it is filled. The stream flow computers calculate a density value based upon this periodic time, and correct it for the effects of transducer temperature and pressure.

In the calculation, the flow computers use a set of constants which are unique to the transducer, and which have been established at its latest calibration.

Twin Transducers

One of the transducers is designated 'master' or 'fiscal', as the density value derived from its output is the one used in all the flow computers' subsequent calculations. The other is designated the 'tracking' transducer, and its density value is used to check on the health of the other. The output from the 'tracking' transducer may also be used should the 'master' instrument fail.

The density values produced by both transducers are continuously monitored by the stream flow computers. Should a discrepancy, which is greater than a preset value, arise between the two values, an alarm is raised by the flow computer.

Regular re-calibration

Each month an alternate density transducer is removed and air checked in accordance with maintenance procedures.

A regular replacement programme ensures that the density transducers are routinely calibrated.

Every 6 months one of the density transducers is removed from service and replaced by a unit which has recently been calibrated.

The density transducer that has just been fitted after re-calibration, is designated the fiscal transducer and the unit which has been in service is demoted to tracking duty.

This routine ensures that each transducer is changed out every 6 months. When a unit is changed, the one which has been removed is sent to a laboratory for re-calibration.

The Sampler

The sampler is supplied with product from a pumped fast loop system.

The sampler is a pneumatically-operated positive displacement unit which traps a sample in a cup type chamber from the fast loop flow line without interruption to the flow, and discharges it to the pressurised sample receiver.

7-day sample

The requirement is for one representative sample to be gathered over a seven day period.

The metering supervisory computer provides the sampler with a flow proportional pulse rate, to ensure that the acquired sample in the container is representative of the exported fluids.

The sample receiver is pre-charged with nitrogen or argon, to a pressure higher than that in the fast loop, prior to being fitted. This ensures that any sample acquired will be held well above its vapour pressure.

The sample is assayed at an onshore laboratory, the assay results going into the allocation system. The water content is determined as part of the assay.

NGL / CONDENSATE MASS FLOW

In one of the platforms, NGLs / condensates recovered from the gas processing system are 'spiked' (i.e., injected) into the crude oil stream just upstream of the crude oil export metering system. The term 'NGLs' is used in the following text to describe this fluid stream, as that is the common AHL usage. In other companies' installations the fluids may frequently be referred to as 'condensates'.

Their mass, density and temperature are measured by Rosemount Micro Motion coriolis meter, whose data are sent into the metering supervisory computer, prior to their being mixed with the crude oil.

The flow of combined crude oil / spiked NGLs is measured by the platform's three stream and prover turbine meter system, combined with the density measurement system described above. Thus it is simple to derive the percentage of the combined fluids which is from the NGL spike.

The other platform studied has no NGL spike.

THE EXPERIMENTAL CALCULATIONS

The object was to establish the relationships between crude oil density, temperature, pressure, NGL content and water content for the first platform's exported crude oil, and between crude oil density, temperature, pressure, water content for the second platform's exported crude oil.

Coefficients derived from one exporting period would be used to predict the density of crude oil for each of the platforms for other exporting periods.

The experimental procedure was as follows.

A   For Platform 1 (NGL Spike and Water Content)

NB: It has not yet been possible to make a satisfactory evaluation of the effects of water content for this platform, as the water content of its exported crude oil is typically below the uncertainty of the method of its determination and therefore taken as zero. However, there is a data set in hand for a period when water content was measurable. This data set has not yet been evaluated.

A1   Using AMADAES, acquire minute-by-minute values for :

Combined crude oil / NGL mass flow rate
NGL mass flow rate
Measured NGL density
Measured crude oil density
Measured crude oil export temperature
Measured crude oil export pressure.

This data is output by AMADAES as a 'Comma Separated Variable' (CSV) file.

A2   Convert the CSV file into a Microsoft 'EXCEL' file.

A3   Remove all data where the minute's set was incomplete or anomalous, or where there was any sign that fixed values (as opposed to measured ones) were in use at the time, or where there was no flow in the system.

Interruptions to the offshore to onshore communications links mean that there are some gaps in the data. These appear to be infrequent, although no attempt has been made to assess the actual frequency, as the information is not relevant to the present study.

Fixed values may appear in the data for two reasons :

They may be used by technicians as part of their routine checks of the flow computers.
They may be adopted automatically by the flow computers in the event of instrument failures.

A4   Using Microsoft 'EXCEL' derive coefficients relating measured crude oil density to :

NGL % of combined exported fluids
Measured NGL density
Measured crude oil export temperature
Measured crude oil export pressure.

The 'LOGEST' function was used for this. This function generates the coefficients a and b for an equation of the form :

$$d = a \times b^P$$

where

> d is the density, kg/m^3
> a and b are coefficients for the parameter being investigated
> P is the magnitude of the parameter being investigated
> (bar for pressure, % for NGL content, °C for temperature, kg/m^3 for NGL density).

The 'LOGEST' function generates these values to fit the data as closely as possible to a non-linear curve.

A5   Use the coefficients thus derived for pressure, NGL% and temperature to calculate the density from the equation :

$$d_{calc} = average((C_1 \times (a_1 \times b_1^{bar})),(C_2 \times (a_2 \times b_2^{NGL\%})),(C_3 \times (a_3 \times b_3^{degC})))$$

> where

> d_{calc} is the calculated density for the pressure, NGL%, and temperature combination of a minute's data set, kg/m^3
> C_1 is a constant reflecting the weighting of the pressure effect in the equation
> C_2 is a constant reflecting the weighting of the NGL% effect in the equation
> C_3 is a constant reflecting the weighting of the temperature effect in the equation.
> (The derivation of C_1 C_2, and C_3 is described below)
> a_1 and b_1 are the coefficients for the pressure effect on density
> a_2 and b_2 are the coefficients for the NGL% effect on density
> a_3 and b_3 are the coefficients for the temperature effect on density
> bar is the minute set's pressure, bar
> NGL% is the minute set's NGL mass flow rate as a percentage of the total combined NGLs and crude oil mass flow rate, %
> degC is the minute set's temperature, °C

A6   Setting C_1, C_2, C_3, and C_4 each to unity , a d_{calc} value was generated for each minute set's combination of pressure, NGL%, NGL density, and temperature.

A7   The percentage difference between the measured (d_{meas})and calculated density values for each minute's data set was calculated as follows :

$$Error\% = 100 \times \frac{|d_{meas} - d_{calc}|}{d_{meas}}$$

A8   The average of all the Error% values for all the minute data sets was calculated.

A9   The Microsoft EXCEL 'Solver' function was used to vary the C_1, C_2, C_3 , and C_4 values to achieve the lowest possible average Error% value. The function automatically re-calculates each of the d_{calc}, Error%, and average Error% values.

A10   Investigations into the combinations giving large Error% values led to the awareness that the density of the NGL was a significant factor. A second equation, of the form

$$d_{calc} = \text{average}((C_1 \times (a_1 \times b_1{}^{bar})),(C_2 \times (a_2 \times b_2{}^{NGL\%})),(C_3 \times (a_3 \times b_3{}^{degC})), (C_4 \times (a_4 \times b_4{}^{NGLdens})))$$

where

> C_4 is a constant reflecting the weighting of the NGL density effect in the equation
> a_4 and b_4 are the coefficients for the NGL density effect on crude oil density
> NGLdens is the minute set's NGL density, kg/m^3

is also being investigated. Results from this calculation are not yet complete.

B   For Platform 1 (Water)

B1   Using AMADAES, acquire minute-by-minute values for :

Measured crude oil density
Measured crude oil export temperature
Measured crude oil export pressure.
Measured crude oil export water content

B2   Convert the file into an 'EXCEL' file, and remove any sets where data was incomplete, anomalous or appeared fixed, or where there was no flow in the system.

B3   Using the Microsoft 'EXCEL' 'LOGEST' function, derive coefficients relating measured crude oil density to :

Measured crude oil export water content
Measured crude oil export temperature
Measured crude oil export pressure.

B4   Use the coefficients thus derived for pressure, $H_2O\%$ and temperature to calculate the density from the equation :

$$d_{calc} = \text{average}((C_1 \times (a_1 \times b_1{}^{bar})),(C_2 \times (a_2 \times b_2{}^{H2O\%})),(C_3 \times (a_3 \times b_3{}^{degC})))$$

where

> d_{calc} is the calculated density for the pressure, $H_2O\%$, and temperature combination of a minute's data set, kg/m^3
> C_1 is a constant reflecting the weighting of the pressure effect in the equation
> C_2 is a constant reflecting the weighting of the $H_2O\%$ effect in the equation
> C_3 is a constant reflecting the weighting of the temperature effect in the equation. C_1, C_2, and C_3 were derived in the same manner as were those in A above.
> a_1 and b_1 are the coefficients for the pressure effect on density
> a_2 and b_2 are the coefficients for the H_2O % effect on density
> a_3 and b_3 are the coefficients for the temperature effect on density
> bar is the minute set's pressure, bar
> $H_2O\%$ is the minute set's crude oil water content
> degC is the minute set's temperature, °C

B5   A d_{calc} value was generated for each minute set's combination of pressure, $H_2O\%$, and temperature.

B6   The percentage difference between the measured (d_{meas})and calculated density values for each minute's data set was calculated as follows :

$$Error\% = 100 \times \frac{|d_{meas} - d_{calc}|}{d_{meas}}$$

B7   The average of all the Error% values for all the minute data sets was calculated.

PRELIMINARY RESULTS

For Platform A

One day's data acquired from AMADAES yielded 1425 minute sets, where

Minimum NGL% value was	1.68*
Average NGL% value was	2.65
Maximum NGL% value was	4.27

*Zero values were excluded for this preliminary test, but will be incorporated in more refined tests.

Minimum temperature value was	42.94
Average temperature value was	46.07
Maximum temperature value was	47.34

Minimum pressure value was	69.74
Average pressure value was	77.56
Maximum pressure value was	82.14

Minimum crude density value was	795.54
Average crude density value was	806.51
Maximum crude density value was	811.75

This gave the equation

d_{calc} = average((0.9998437 × (823.07745 × 0.9997378^{bar})),(0.997551 × (810.02934 × $0.9993505^{NGL\%}$))

,(1.0006256 × (806.16877 × 1.0000091^{degC})))

Applied to each of the sets of data from which the coefficients had been derived, this gave an average Error% value of 0.216, and a maximum Error% value of 1.3436.

Applied to the next day's data, the equation gave an average Error% value of 0.5585, and a maximum Error% value of 2.63.

Applied to the another day's data, the equation gave an average Error% value of 0.1566, and a maximum Error% value of 0.761.

Applied to the third day's data, the equation gave an average Error% value of 0.2337 and a maximum Error% value of 7.463.

These large variations have not yet been investigated.

For Platform B

A set of 10507 minutes' data was acquired from a period of approximately 7.5 days yielded the following data :

Minimum H$_2$O%	0.30

Average H₂O%	0.91
Maximum H₂O%	15.0
Minimum Pressure	8.10
Average Pressure	14.48
Maximum Pressure	16.90
Minimum Temperature	47.10
Average Temperature	54.92
Maximum Temperature	55.80
Minimum Density	789.50
Average Density	794.50
Maximum Density	823.10

$$d_{calc} = average((-0.032 \times (802.8595 \times 0.999274^{bar})),(0.999274 \times (792.4156 \times 1.002847^{H2O\%})),(0.023154 \times (810.309 \times 0.$$

This equation gave a Maximum Error% of 0.719, and an Average Error% of 0.052 when applied to its own data.

The Maximum Error% of 0.719 was found to be from the minute with the highest water content and highest measured density values. It may be noted that, while the *average* water content value was found to be below 1%, this *highest* water content was 15%.

DISCUSSION OF RESULTS

The results so far indicate that the method is potentially a very useful one.

The data acquired so far for each of the platforms comprises many thousands of minute sets. It has not been possible to process more that a very small part of these, so it is not wise to give firm conclusion at this time. We estimate that another month's work, which would include some test of the results on data from other installations, is required before firm conclusions and recommendations can be made.

We have made no serious attempt so far to quantify the uncertainty of our proposed system of coefficients.

The uncertainty of the measurements on which the equations are based are likely to be dominated by the uncertainty of the water-in-oil determination and of the NGL density for Platform A, and by the uncertainty of the water-in-oil monitor for Platform B. (However, if we remind ourselves that the API coefficients and equations currently in use make no allowance whatever for water or NGLs, we can retain some perspective).

It will be clear also that one of the basic tenets of API 2540, namely that the density at 15 °C is a vital measurement point, may not be achievable using our alternative method. We may retain some useful perspective, again, however, when we remind ourselves that some North Sea crudes are liable to show wax precipitation at this temperature!

There remains the basic philosophical question of the validity of using API 2540 or API 11.2M on crude oil containing substantial admixtures of water or NGLs, when they were derived from experimental work on what was effectively dry, stock tank crude.

ACKNOWLEDGEMENTS

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.