DO WE NEED TO USE GAS DENSITY METERS IN NORTH SEA METERING STATIONS?

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SUMMARY

A review is made of the practical problems being experienced when trying to measure gas density accurately. The advantages and disadvantages of using calculated density based on the American Standard AGA 8 for computing compressibility are discussed. A comparison is also made of the reduction in the uncertainty of calculated density to be gained from using improvements in basic metering instrumentation. The conclusion of the paper is that measuring density is probably no longer necessary.

NOTATION

A	-	Location of inlet of gas sampling system
B	-	Location of outlet of gas sampling system
p	-	Upstream pressure
Δp	-	Differential pressure across the orifice plate
ρ	-	Density
$\rho corr$	-	Density at the plane of the upstream pressure tapping on the orifice carrier.
$\rho meas$	-	Density measured by the transducer
$\rho calc$	-	Calculated density using AGA 8
K	-	A contractual number (could be the isentropic exponent)
MW	-	Molecular weight of gas
Z	-	Compressibility factor
T	-	Temperature
R	-	Universal gas component

1   INTRODUCTION

This short paper has been written to promote discussion on the topic of the necessity for gas density measurement. As part of the author's working brief over the past 10 years, numerous audits have been made on orifice plate gas metering systems in the North Sea, and world-wide. A recurring common problem that has been seen on these audits is the problem of obtaining a representative density measurement. Over almost the same 10 year time span the possibility to accurately calculate gas density has arrived with the publication of the American Standard AGA 8 for calculating natural gas compressibility factors. This standard has brought the uncertainty in calculating density to the same order of magnitude as the uncertainty on measuring density over a wide range of operating conditions.

The typical problems at present being experienced when measuring density are reviewed, and then the advantages and disadvantages of calculating density rather than measuring density are discussed. A comparison is also made of the reduction in the uncertainty of calculated density to be gained when better instrumentation is used in place of the normally accepted standard of instrumentation used in the North Sea.

2   DENSITY MEASUREMENT

Figure 1 shows a sketch of a typical layout for performing density measurement in a metering station. The method shown is the downstream recovery method which is used to overcome the upstream straight lengths restriction of the gas metering standard ISO 5167 (reference 3). The measured density from the density transducer is corrected to conditions at the plane of the upstream orifice plate tapping by the equation :-

$$\rho corr = \rho meas * \left(\frac{p}{p - \Delta p}\right)^{1/K} \tag{1}$$

where:-

ρ_{corr}	=	density at the plane of the upstream orifice plate pressure tapping
ρ_{meas}	=	density measured by the transducer
p	=	upstream pressure
Δp	=	differential pressure measured across the orifice plate
K	=	a contractual number (could be the isentropic exponent)

Referring to the sketch, the obvious possible sources of errors in the measurement of density are :-

1. Temperature difference between the gas sample in the density transducer and stream conditions.
2. Pressure difference between the gas sample in the density transducer and the pressure at location B, the return point for the gas sample in the plane of the downstream orifice plate pressure tapping.
3. The flow rate of the gas sample through the density transducer.
4. The gas sample taken is not a representative sample.
5. Filtration in the gas sample line to keep the density transducer clean.
6. Effects of velocity of sound, ie. calibration.
7. Gas condensation effects.

Each of these problems will now be discussed.

2.1 Temperature Difference

Let us consider a typical offshore gas metering system operating under the following conditions :-

Stream temperature	50°C to 60°C
Ambient temperature	10°C (Summer)
Stream pressure	100 bara

What is found by experience, even with substantial lagging around the pipework, is that, unless steps are taken to remedy the situation, the gas sample in the density transducer is only at a temperature of approximately 20°C due to the combined effects of :

* the heat sink effect of the density transducer, the pocket, and surrounding pipework.
* the heat sink effect of the isolation valves.
* the wind chill factor.

The accepted method of overcoming this temperature difference between the gas sample in the density transducer and the stream condition is to enclose the density transducer in a box and heat the air inside the box to line conditions, with a thermostat set within the box to stream temperature.

An alternative method used to over come the problem is to measure the temperature of the gas leaving the density transducer, and to heat up the incoming gas sample to the density transducer until the exit gas temperature corresponds to the stream temperature.

However, if the stream temperature is constantly fluctuating, it requires a very sophisticated temperature compensation system to keep up with changes. So sophisticated, I believe no system exists today!

2.2 Pressure Difference

For the system of density measurement to operate correctly, there must be a flow through the transducer from the pipeline offtake at location A in the sketch, to the pipeline return at location B. This changing flow brings to the density transducer information on changes in stream gas composition and stream gas temperature, but it must be recognised that these changes will not be instantaneous. To have a flow through the gas sample line it is obvious that the pressure at location A must be higher than the pressure at location B. In addition, because the density transducer lies in between locations A and B, we must have :-

$$P_A > P_{transducer\ location} > P_B \qquad (2)$$

What is normally assumed is that the pressure at the transducer location is the same as that at location B, which is at the downstream pressure tapping location of the orifice plate. This of course is not true, and few studies have been made to determine the actual pressure at the density meter location. A quick test is to close off the inlet sample valve whilst leaving the outlet valves open. This will provide information on the effect of the magnitude of the pressure difference between gas transducer and sample outlet on the measured density.

As with the temperature difference effect, the pressure difference effect will tend to give higher density values, and hence over-metering of the flow will occur through the metering station.

2.3 Gas Sample Flow Rate

As stated previously, a flow of sample gas is required through the density transducer to bring information on changes in gas composition and stream temperature to the transducer. If the flow rate is too low, in the absence of any additional external temperature correction, there can be a considerable heat loss from the sample gas. On the other hand, of the flow rate is too high, there can be a considerable pressure loss through the sample line. Again, there appears to be few studies made on what the optimum sample flow rate should be.

2.4 Taking A Relevant Gas Sample

The most commonly used gas sample take off method is simply a wall tapping, unlike the sample probes commonly used in conjunction with liquid density meters which take samples from the middle portion of the main stream flow.

It is debatable whether a wall tapping does take a representative sample of the main stream flow.

2.5　Filtration

Filters in the sample line are necessary to keep dirt or condensate off the sensitive innards of the density transducer. However, filters will cause a pressure drop through the sample line - particularly when they become clogged with debris. This will cause a change in density measurement.

2.6　Velocity of Sound Effects

This is one area in gas density measurement where there has been considerable progress. The problem was originally caused by calibrating transducers on a different gas (Argon or Nitrogen) to that in which it was be going to be used (Natural gas). With calibration services now being able to calibrate at high pressure using Nitrogen and able to provide User Gas Certificates at temperatures close to that at which a density transducer will operate in the field, it is felt that velocity of sound effects are no longer a problem.

2.7　Gas Condensation Effects

Operating conditions sometimes occur where the gas is completely gaseous at the metering system operating conditions, (say at 100 barg and 50°C), but undergoes partial condensation at atmospheric pressure and ambient temperature. Thus it has been known to occur on some metering systems that condensates are deposited within the density transducer every time the metering tube is depressurised, or the density transducer is depressurised, to enable the regular monthly calibration to be performed.

In some instances, the condensates will evaporate when a vacuum is pulled on the transducer. On other metering stations, the vibrating tube within the density transducer has been affected and must be cleaned before again re-calibrating.

3　CALCULATING GAS DENSITY

The upsurge in calculating density occurred with the arrival of the American Standard AGA 8 for calculating compressibility factors of natural gas and other hydrocarbon gas mixtures, reference (1). Prior to the arrival of this standard, gas calculation routines were only used as back-up routines to give a comparison with the measured density.

The second edition of AGA 8 produced in 1992, reference (2), extended the data bank used to compile the first edition of AGA 8. This together with additional velocity of sound data and more GRI and GERG compressibility factor data resulted in two new equations of state. However, it has modified inwards the boundaries for which an uncertainty in calculated compressibility can be expected to be 0.1%.

The required starting point for the AGA 8 calculations is a gas composition, which would normally be obtained from a periodic flow proportioned gas sample analysis if the gas constant is fairly constant with time. Alternatively, the gas composition can

be obtained from an on-line chromatograph analysis. The gas composition, together with AGA 8 and measured values of stream pressure and stream temperature, enables the gas density to be calculated.

4 COMPARING MEASURED AND CALCULATED DENSITY

Figure 2 gives a comparison table of the advantages and disadvantages between measured and calculated density. Although it should be clear from the comparison that calculating density has more advantages than disadvantages compared with measuring density, what the table does not bring out is the simplicity and time and cost saving in calculating density.

5 COMPARISON OF PREDICTED UNCERTAINTIES FOR MEASURED AND CALCULATED DENSITY

5.1 Measured Density

The uncertainty value associated with measuring density of natural gases using vibrating tube transducers is accepted to be : 0.2% of reading.

Many laboratory tests performed in Denmark in the '90's, at the Institute formerly named DANTEST, have confirmed this value of uncertainty. However, it is debatable whether such an uncertainty can be directly attributed to density measured on a metering system in the field.

More realistically, in a gas metering station the uncertainty on the measured density would additionally be affected by temperature and pressure differences between the transducer and the stream as previously discussed. If we assume that the temperature difference and pressure difference is, say, 1°C and 0.1 bar respectively, then the uncertainty on measured density becomes :-

$$Unc. \ \rho_{meas} = \sqrt{(0.2)^2 + (\frac{1}{323.15} \times 100)^2 + (\frac{0.1}{100} \times 100)^2} \qquad (3)$$

$$= \underline{0.38\%}$$

5.2 Calculated Density

In this section, the uncertainty predicted for calculating density will be obtained using two sets of measuring instruments. "Standard" instruments consist of the normally accepted type of instruments used for measuring pressure and temperature, whereas the "upgraded" instruments are slightly more expensive instruments, still off-the-shelf, but which Operators do not usually purchase. The corresponding uncertainties for each package are as follows :-

PARAMETER	UNCERTAINTY	
	NORMAL	UP-GRADED
Static Pressure	0.25% of span	0.1% of span
Temperature	0.5°C of reading	0.2°C of reading
Molecular Weight	0.1% of value	0.1% of value
Compressibility Factor	0.1%*	0.1%*

* What is at present unclear to the author and many of his colleagues is : How does the uncertainty associated with the analysis of each gas component using a gas chromatograph relate to the uncertainty of calculating z from AGA 8?

Let us assume the operating conditions are 50°C and 100 bara, with the span for the pressure instruments as 200 bara.

Ignoring the uncertainty involved in computing the formula :

$$\rho = \frac{p}{ZT} \cdot \frac{MW}{R}, \qquad (4)$$

where :-

ρ =   density
p   =   pressure
MW   =   molecular weight
Z   =   compressibility factor
T   =   temperature
R   =   universal gas constant

and also the uncertainty involved in the value of the universal gas constant, it is found that the predicted uncertainty for calculated density when using "normal" and when using "up-graded instruments" is :

"Normal Instruments"

$$\text{Uncertainty for } \rho_{calc} = \sqrt{(0.5)^2 + (\frac{0.5}{323.15} \times 100)^2 + (0.1)^2 + (0.1)^2} \quad (5)$$

$$= \underline{0.54\%}$$

"Up-graded Instruments"

$$\text{Uncertainty for } \rho_{calc} = \sqrt{(0.2)^2 + (\frac{0.2 \times 100}{323.15})^2 + (0.1)^2 + (0.1)^2} \quad (6)$$

$$= \underline{0.25\%}$$

Comparing these calculated uncertainty values against the measured density uncertainty values of 0.2% and 0.38% obtained under laboratory conditions and typical metering conditions, it is felt that the calculated values are very close to the measured values of uncertainty. In particular, a metering system using "up-graded" instruments would have an extremely low value of uncertainty for calculated density which approaches that obtained under laboratory conditions for measured density.

6   CONCLUSION

The practical problems arising when attempting to measure gas density accurately in metering systems are significant. The standard AGA 8 enables density to be calculated with a comparable value of uncertainty to that obtained using density transducers, particularly if the more accurate readily available instruments for measuring pressure and temperature are used.

It is concluded that gas density measurement is probably no longer necessary.

REFERENCES

1   "Compressibility and super-compressibility for natural gas and other hydrocarbon gases", AGA Transmission Measurement Committee Report No. 8, 1985.

2   "Compressibility factors of natural gas and other related hydrocarbon gases", AGA Transmission Measurement Committee Report No. 8, Second Edition, November 1992.

3   "Measurement of fluid flow by means of pressure differential devices - Part 1: Orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full", ISO 5167-1, First Edition, 15 Dec. 1991.
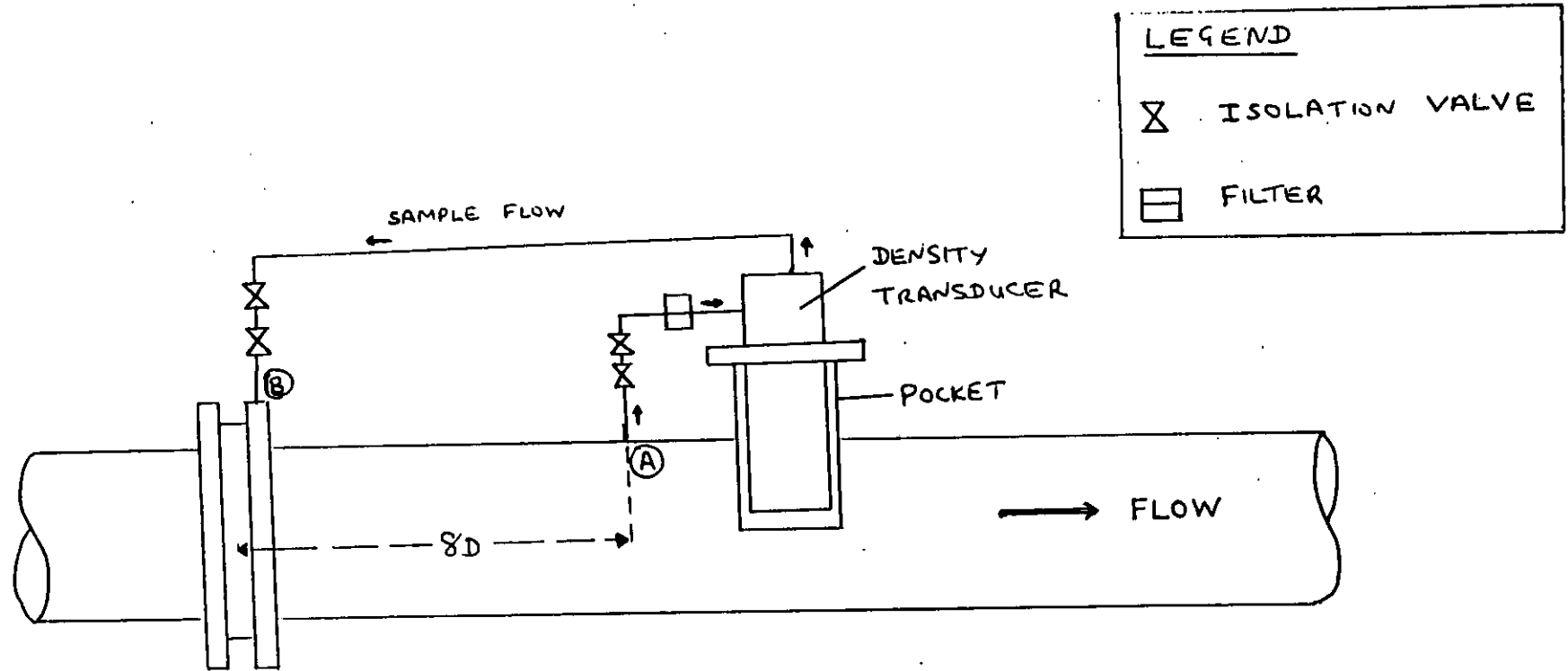
FIGURE 1 - DENSITY MEASUREMENT USING THE DOWNSTREAM RECOVERY METHOD

FIGURE 2 - COMPARISON BETWEEN MEASURED AND CALCULATED DENSITY

MEASURED DENSITY	
ADVANTAGE	DISADVANTAGE
On-line Measurement	Prone to temperature, pressure, installation, ambient surroundings effects.
Knowledge of gas composition not required.	Density transducer needs periodic re-calibration off-site.
	High maintenance and re-calibration costs.

CALCULATED DENSITY	
ADVANTAGE	DISADVANTAGE
Not prone to temperature, pressure, installation, ambient surroundings effects	Need to know gas composition.
Minimal maintenance and re-calibration costs.	(However, if using an on-line chromatograph to obtain gas composition, regular in-situ re-calibration is possible).