FOCUS DISCUSSION GROUP C

The British Gas Metering Systems Group has Considerable Experience of Fiscal Gas Metering Systems throughout the North Sea and Overseas.

D Irvine, British Gas plc

'96 - 6.

A GAS BUYER'S GUIDE TO GAS METERING SYSTEMS

David Irvine

British Gas plc

Summary

This short discussion document is based on the experience of fiscal gas metering systems gained by the British Gas Metering Systems Group throughout the North Sea and overseas.

The paper looks at the ubiquitous orifice meter and discusses the important topics of alternative methods of density determination and energy measurement and considers the calibration and installation of differential pressure transducers.

There is a brief look at alternative meters, such as multi-path ultrasonic, turbine and energy meters, and their possible impact on the use of orifice meters.

The conclusion reached is that although much research has been carried out on primary devices and the effect of installation it is equally important for all components of a fiscal gas metering system to be installed, operated and maintained to the highest standards to ensure that the meter is unbiased with the minimum random uncertainty.

1.0 INTRODUCTION

The British Gas, Metering Systems Group was originally set up with two main objectives:

1 to provide technical support to the group negotiating Gas Purchase and Allocation Agreements and

2 to review and agree the proposals from gas suppliers for the fiscal metering systems associated with the Agreements.

The work of the Group developed to include preparation of the measurement provisions of the contracts, technical support during disputes, witnessing factory acceptance and commissioning tests, acceptance of the systems as being suitable for payment purposes and witnessing routine calibrations for British Gas and for outside companies.

This has given the Group over the past 13 years unprecedented access to well over 50 offshore and 15 onshore gas metering systems - all different from each other!

The daily average volume of gas put into the British Gas National Transmission System (NTS) is 300 - 325 million cubic metres with a maximum volume of gas on one day of over 388 million cubic metres (in February 1996).

At the time of writing all of this gas entering the NTS is measured by orifice plate meter and offshore most of the gas is exported and allocated through orifice meters.

Although all of this gas is measured through the same type of meter, using the same international standard for the primary device (the orifice fitting, tappings, orifice plate and a certain amount of the pipework) there are many differences between the meters.

It is with the secondary instrumentation that there is the most room for variation in equipment and design.

2.0 THE ORIFICE PLATE METERING SYSTEM

When installed strictly in accordance with the standard and using secondary instrumentation with known uncertainty the overall metering system uncertainty can be estimated.

Individual components may have or develop a bias and most gas contracts specify that all components of a metering system shall be checked regularly and where necessary shall be adjusted centrally and as accurately as possible. It is also essential to use staff who understand the importance of operating and maintaining the equipment at the highest possible level.

Three different measurement parameters are considered in detail.

2.1 Density

Line density is required for most fiscal gas metering systems either as a part of the flow equation (orifice meters) or when the primary output of the meter is in actual volume units (turbine and ultrasonic meters).

Density may be determined by measurement or by calculation.

2.1.1 Measured density

The traditional instrument used for measuring density is the densitometer with the vibrating spool type being the most commonly used type in the UK.

Most densitometers are fitted into pockets inserted into the gas line. The instrument should be as close to the primary device as possible without affecting the measurement process. For orifice meters the distance should be 8 pipe diameters downstream of the orifice.

Although it is easy to calculate it is often not realised by the maintenance staff how critical it is for the gas in the densitometer to be at the same temperature as the gas in the flowing stream. For a typical terminal flowing at a pressure of 70 bar a one degree difference between the flowing stream temperature and that in the densitometer causes an error in density of approximately 0.6%. This equates to an error of 0.3% of flow.

The pressure in the densitometer should also be the same as that in the pipeline at the point to which the density is referenced. (The downstream tapping pressure in the case of an orifice meter using the pressure recovery method.)

Using the same example an error of 100 mbar produces an error in density of 0.17% or nearly 0.08% in flow.

What are the possible causes of these errors and how can they be avoided?

To ensure that the gas and densitometer are at the correct temperature the densitometer must be inserted in the line in a pocket which should contain a heat transfer medium such as paste or oil. All fittings and pipes must be thoroughly insulated or lagged ensuring that the lagging material is protected against the weather. Wet lagging does not insulate!

To ensure that the pressure of the gas in the densitometer is the same as at the reference point it is essential that only full bore valves are used (fully open) between the densitometer and reference point. Flow control and fine filtration must be on the other side of the densitometer .

Although it is another obvious point, vibrating cylinder densitometers do not function accurately if there is any deposit - liquid or solid - on the cylinder so care must be taken to ensure that the sample gas is dry and clean using suitable filtration if necessary.

Vibrating cylinder densitometers are usually calibrated with nitrogen and if the operating temperature and gas composition are specified a "user gas" certificate can be produced. The further away from the ideal conditions that the densitometer is operated then the higher the uncertainty. The manufacturer quotes an accuracy for a vibrating cylinder densitometer of $\pm$ 0.2% of reading but this may not be achievable with some gas compositions.

2.1.2 Calculated density

It is becoming more common to calculate density for offshore applications from gas composition, determined by an on-line gas chromatograph, using an equation of state. My colleague, Malcolm Emms, presented a paper at the Workshop two years ago on the subject and he concluded that uncertainties of 0.38% and 0.55% are achievable using AGA8 1992 and GERG TM2 respectively when the gas composition is determined from a gas chromatograph and the gas contains water and methanol. He raised questions about the uncertainty in calculated density using an equation of state when the gas is near to a phase boundary.

Most gas chromatographs are set up to analyse the gas to C_{6+} . The proportion of these components vary with the separator conditions as well as longer term changes to the wellstream composition. It is possible with most modern flow computers to apportion the C_{6+} fraction of the gas reported by the gas chromatograph to the higher hydrocarbons. The proportions are determined from an off-line analysis of the process gas.

With 0.4% of C_{6+} in a typical natural gas stream, there can be variations in density of 0.3% depending on the proportions of the components set into the computer.

The installation of the gas chromatograph is critical to its correct operation. The gas entering the chromatograph, which should ideally be installed higher than the sample take-off point, must again be clean and dry. Sample lines should be as short as possible, lagged and heat traced and care must be taken with the pressure let-down system to ensure that liquid drop-out cannot occur.

2.2 Energy

Under sales gas Principal Agreements gas is bought and sold in energy units so the calorific value of the gas being metered is required to be measured. (Under an Allocation Agreement gas is usually allocated initially by component mass which is then converted to energy.)

Energy used to be measured by burning the gas in a calorimeter which was calibrated with methane and had a claimed uncertainty of $\pm$ 0.1%.

Heating value transmitters operating on the principle of stoichiometric combustion took over from calorimeters - the DTI approved one model for Gas Act applications - but they have been largely superseded and the majority of terminals now use on-line gas chromatographs.

The most common arrangement is for the gas chromatograph to determine gas composition up C_{6+} or, in some cases, C_{7+} and the comments in the previous section are applicable.

The modem gas chromatograph is a very effective and reliable piece of equipment provided that it has been set up correctly and is operated in accordance with the manufacturer's instructions. However, it is a comparator which compares the composition of two gases - the process gas and the calibration gas. If the composition of the calibration gas has not been accurately determined or is not appropriate for the process gas then errors can occur which will usually be in the form of a bias.

Calibration gas may be made up to a formula, approximating the process gas as closely as possible, or a sample of process gas which has been analysed in a laboratory and the laboratory should be accredited.

An evaluation of the suitability of the calibration gas for a particular application can be made and a range of process gas compositions for which it is suitable determined. However, if there are major changes to the processing of the gas then the process gas may fall outside the applicable range of the calibration gas and errors in the calculated calorific value (and calculated density) may occur.

As with calculated density, changes to the proportion of the components in C_{6+} or C_{7+} can cause errors in the calculated calorific value. These changes can also be caused by variations in the processing of the gas.

2.3 Differential pressure measurement

Two topics are covered on the subject of differential pressure (DP) transmitters.

2.3.1 Calibration

DP transmitters are now available with claimed uncertainties of better than 0.1% of span and they should be selected wherever possible.

The use of high and a low range DP transmitters is the most common arrangement . By way of illustration a turn-down of about 3.6:1 can be achieved using high and low DP transmitters with an uncertainty of ± 5%. The turn-down increases to just over 4:1 for a system using high and low transmitters with uncertainties of 0.25% and 0.35% respectively and to over 9:1 when 0.075% and 0.1% transmitters are used.

These high accuracy DP transmitters are still affected by pressure and temperature and like all DP transmitters they need recalibrating at regular interval. For optimum accuracy they should be calibrated in situ and at the line pressure at which they will be used. Most DP transmitters are affected by the way they are installed and it is impossible to be sure that calibrating a DP transmitter in a laboratory - even one on the same site as the metering station - and then installing it on the system does not introduce some additional uncertainty.

The question is, how should they be calibrated? The claimed uncertainty of the transmitters is now similar to most of the high static pressure calibration equipment available and even the National standard. One clue is given in the manufacturer's literature where the claimed accuracy includes "hysteresis, linearity and repeatability". This implies a transmitter with very good and stable metrological characteristics. For calibration onshore a high static calibrator should be used and for offshore the foot-print method is generally used.

Some work has been carried out on producing a transfer standard for calibrating DP transmitters offshore but this method is not currently available.

Whichever method is used the uncertainty of the test equipment must be combined with that of the transmitter when the system uncertainty is being calculated.

2.3.2 Installation

DP transmitters are affected by pulsations in the impulse lines so should be installed as close to the meter tapping points as possible. The impulse lines and transmitters should also be protected from the weather.

These two requirements are incompatible if a metering house is to be used in which to locate the DP transmitters (and other instruments) and where the equipment will be installed to calibrate the instruments.

One solution is to mount the transmitters directly on to the meter body and a manifold has recently been produced which makes for easy installation. The instruments can be installed in a small temperature controlled cabinet to provide weather and temperature protection. However, modem smart transmitters may be susceptible to rapid changes in temperature such as when the cabinet is opened for calibration due to the location of the temperature compensation device in the instrument. In addition protection is required for the calibration equipment (and the technician) during in situ calibration.

Another manufacturer has introduced a flow transmitter which incorporates DP, pressure and temperature in a single instrument which mounts directly on to the meter body and also includes a flow computer.

Neither of these two devices has been put into fiscal service in the UK, to my knowledge.

3.0 OTHER FISCAL GAS METERING DEVICES

With so much of the gas in the UK measured with orifice plate meters a strong financial case with demonstrable significant positive advantages needs to be made for using altemative measurement systems for new projects. An even stronger case needs to be made for changing out existing systems and replacing them with new meters such as turbine or ultrasonic meters where the costs of the change-out are considerable.

The outputs from the USM and the turbine meter are proportional to actual volume flow so secondary instrumentation is required to convert to standard volume, energy and mass flow.

There is a big advantage in using a meter that does not need calibrating on a flow rig. This is especially true offshore where the cost of transporting a meter for recalibration can be considerable.

Brief comments are made on three possible altematives to the orifice plate meter

3.1 Multi-path ultrasonic meter

The theory of the "time of flight" ultrasonic meter (USM) is well known and multi-path devices were devised in the early 1980's. These meters have self diagnostics built in to the electronic circuits and swirl and velocity profile effects are largely eliminated by the use of a number of paths.

Modem digital circuits should eliminate the acoustic noise interference to which early analogue models were prone.

USM's have the same advantage as orifice plate meters. Because they rely on the metrology of the meter (path lengths and cross sectional area of the meter) and timing circuits (for timing the transit time of the ultrasonic signals) it should be possible, in time, to calibrate a meter in the factory without using a calibration rig. At present they are still considered to be novel devices and most purchasers require the meters to be calibrated on a flow rig. It is likely that some configurations of multi-path USM will always require calibration on a flow rig.

There are now two metering stations using multi-path ultrasonic meters USM's for fiscal duties in the UK.

There is, as yet, no International standard for USM's but a draft has been prepared by an ISO working group (ISO/TC 30/WG 20).

3.2 Turbine meter

Gas turbine meters have been around for a long time and are used extensively on the continent to measure large volumes of gas at high pressure.

Calibration on a flow rig is always required for fiscal measurement but at present there are no accredited natural gas high pressure calibration facilities in the UK.

There is an international standard for gas turbine meters, ISO 9951, which deals mainly with specifying the perturbation tests that a meter is required to pass for fiscal use.

3.3 Energy meter

As already stated, gas is bought and sold in energy units. One manufacturer is advertising an instrument which measures energy directly with a claimed repeatability of energy and volume flow-rate of $\pm 0.35\%$ of reading and an overall accuracy of $\pm 0.5\%$ depending on the accuracy of the reference gas and DP transmitters.

This is an interesting concept but there no reports available yet of any practical tests in the UK.

4.0 CONCLUSIONS

Fiscal gas metering systems have been around for many years and the associated technology has become more and more sophisticated. However, there are still fundamental issues which need to be addressed by the system designer, operator and maintenance engineer.

A gas metering system should be designed to carry out the job for which it is required. It should provide unbiased measurement within the uncertainty limits prescribed by regulation, contract or agreement. Different techniques may be required when trying to apply the same limits of uncertainty to a terminal metering system, measuring clean dry specification gas, as for an offshore allocation meter measuring gas at its dew point or even containing liquid droplets.

This paper has looked at several of the factors which may make a metering system acceptable or unacceptable.

High standard fiscal gas metering depends on three qualities -

Quality of design
Quality of components
Quality of maintenance.

LATE PAPER
FOR
FOCUS DISCUSSION GROUP C

The British Gas Metering Systems Group has Considerable Experience of Fiscal Gas Metering Systems throughout the North Sea and Overseas.
D Irvine, British Gas plc

PLEASE ENSURE YOU PICK UP YOUR COPY FROM THE CONFERENCE RECEPTION DESK.

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.