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# REAL LIFE EXPERIENCE WITH MULTIPATH ULTRASONIC GAS FLOW METERS

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## ABSTRACT

Multipath ultrasonic gas flow meters are to be considered as newcomers among flow meters for large, high pressure gas flows. Although the advantages of this type of meters are many and obvious, the metering community is still hesitating to go for it mainly because of lack of experience.

The objective of this paper is to present the experience of Statoil after more than six years experience with multipath ultrasonic gas flow meters. Our experience includes laboratory testing and operation in the field for a variety of designs and dimensions.
This paper presents the accuracy achieved by such meters including comparison between ultrasonic meters and orifice metering systems in operation, the unique possibilities that this type of meter offers for on-line verification of performance and installation effects.

Of particular interest should be noted that in the vicinity of low-noise control valves, such meters could stop functioning completely if no precautions are taken.

## INTRODUCTION

Statoil is the main operator of offshore gas transportation pipelines in the Norwegian Sector of the North Sea. Figure 1 shows the main pipelines in the North Sea operated by Statoil. In 1998 the total length of pipeline will be approximately 5000 km.

To be able to control which field is transporting gas in the various pipelines, allocation metering on the riser platforms where pipelines meet and split is necessary. Normal capacity of the metering systems is between 20 $MSm^3$/day to 50 $MSm^3$/day (700 MMSCFD to 1750 MMSCFD).

Since 1988 Statoil has investigated the possibility of introducing simpler fiscal metering equipment than the bulky conventional multirun orifice systems. This is of high interest offshore on riser platforms where saving of space and weight have high impact on investment cost.

For bi-directional applications metering systems the cost savings of using "natural" bi-directional meters could be enormous.

Ultrasonic flow meters turned up to be the solution with the best potential for the future.
To support this conclusion, Statoil has performed, taken part in and supported product development work and test work over the past seven years.

Currently eight ultrasonic meters accumulating to 6 years of operation are installed and running offshore. They are all accepted by Norwegian Petroleum Directorate (NPD) as fiscal meters.

A number of papers have been presented describing experiences and how different meters perform. Examples of such papers are given in the reference list (1, 2, 3, 4, 5, 6, 7).

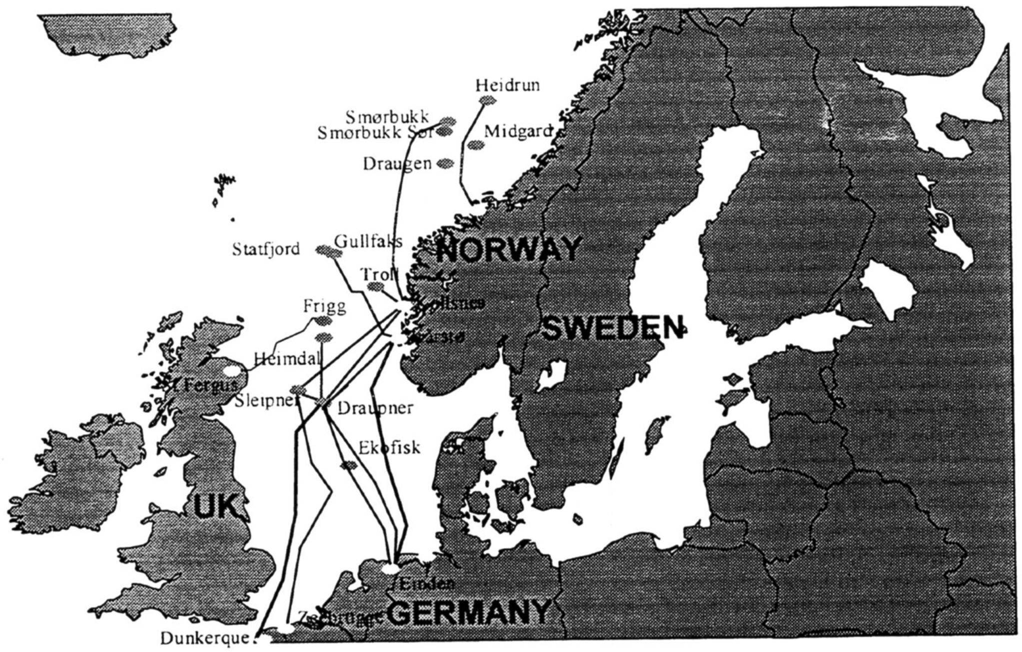


Fig. 1 Existing and planned gas pipelines operated by Statoil in the North Sea

## BASIC THEORY FOR MULTIPATH ULTRASONIC METERS

The basic equations which relate the transit times measurement to the average gas flow velocity along an acoustic path, v, and the velocity of sound, c, for an acoustic path formed as a chord in the pipe cross section are:

$$v = \frac{L^2}{2 \cdot X} \cdot \frac{(t_2 - t_1)}{t_2 \cdot t_1} \qquad (1)$$

$$c = \frac{L^2 \cdot (t_1 + t_2)}{2 \cdot t_1 \cdot t_2} \qquad (2)$$

where

L is the length of the acoustic path between the transducers in a pair
X is the axial distance between a pair of transducers
$t_1$ and $t_2$ is the transit time in downstream and upstream direction respectively between the transducer fronts

$t_1$ and $t_2$ are determined from measured times between electronically transmission of the acoustic signal till electronically detecting received signal. Delay times in the transducers and electronics and delays caused by detection method must be taken into account.

In a multipath ultrasonic meter, the velocity is measured along a multiple number of acoustic paths as indicated in fig. 2. An estimate for the mean axial fluid velocity in the pipe cross section, $v_A$, is calculated as follows:

$$v_A = \sum_i w_i \cdot v_i \qquad (3)$$

where

$w_i$ is weighing factor for acoustic path no. i

$v_i$ is the average velocity measured along acoustic path i

The weighing factor may be fixed numbers different for the different acoustic paths or more complex expression which which results in numbers which varies with the ratios between the gas flow velocities from the individual acoustic paths.

A measurement cycle consists of transit time measurements in both directions for all acoustic paths. Most meters average the transit time measurements over a number of cycles before presenting figures for flow rate and velocity of sound. The number of cycles can be selected by the user. The number of measurement cycles is often refered to as the "batch number". For a 12" meter a cycle takes approximately 50 - 100 ms. A batch number of 20 means an updating time of 1-2 seconds.

As this type of meter is bidirectional when the flow direction changes, the sign of $t_2 - t_1$ changes. Hence the meter will also indicate direction of flow.

## WHY ULTRASONIC FLOW METERS

### Size and money

The main driving force behind our search for simpler metering system was saving of investment cost.
There is potential for an enormous reduction in size and weight when using ultrasonic meters instead of conventional orifice plate systems.
The reason is that for our operational conditions, the measuring range for a single meter run with ultrasonic meters was three times that of the orifice meter run of the same diameter and the requirement for the length of straight upstream pipe is less than half.

Fig. 2 shows the main parts of a meter run and the function of the meter.

The cost saving on offshore platforms by reduced weight is estimated to 300 - 800 kNOK pr. ton depending on the type of platform. Where bi-directional meters are required savings of more than 100 MNOK have been realised.

### Accuracy

From the meter specification the accuracy appears to fulfil the formal requirement for accuracy for fiscal gas flow meters in Norway which is 1 % on mass basis.
We have concluded through our tests that this is confirmed for the meters that we have put in operation provided the meters are flow calibrated, eventually corrected and installed properly.

### Information and diagnostics

The ultrasonic meters can offer valuable additional information about the flow velocity and the velocity of sound. This information can partly be used for diagnosis of the "health condition" of the meter and partly as valuable information about what is going on inside the pipe.
In addition to the self diagnostics, the ultrasonic meters offer in most cases information which allows the user to perform verification checks and recording of the meter's condition and performance during operation. See fig. 3.

Gas flow velocity and velocity of sound from the individual acoustic paths give useful information for monitoring, check and verification of the stability and condition of the meter.
We believe that once the meter is flow calibrated and a calibration factor is determined, the verification of the transit times and transit time difference is all that is required to verify the accuracy at any time.
Velocity of sound can also give information about gas properties.

In addition, the meters themselves have built-in diagnostics which can tell the operators when and why the condition of the meter is deteriorated.
Such diagnostics allow considerable checking of basic acoustic signals, both on individual acoustic pulses as well as on batches. The meter itself determines whether the acoustic signals used for transit time measurements are accepted or rejected. In a batch, the percentage number of accepted pulses are indicated in the information report.

### Redundancy in one meter

The multipath design of the ultrasonic meter can, in addition to improve accuracy, also be regarded as a redundant meter. This becomes possible if the meters are so designed that it continues to meter with one or more pair of transducers (up to maximum all except one pair) failing. There should also be a possibility to replace a malfunctioning pair of transducers during normal flow conditions.

### Low pressure drop

Ultrasonic meters have no pressure drop but the one for the straight, pipe unlike orifice meters or turbine meters. This is not of major importance in our cases since we have pressure drop across control valves anyway. However, under other circumstances this is an important aspect. (8)

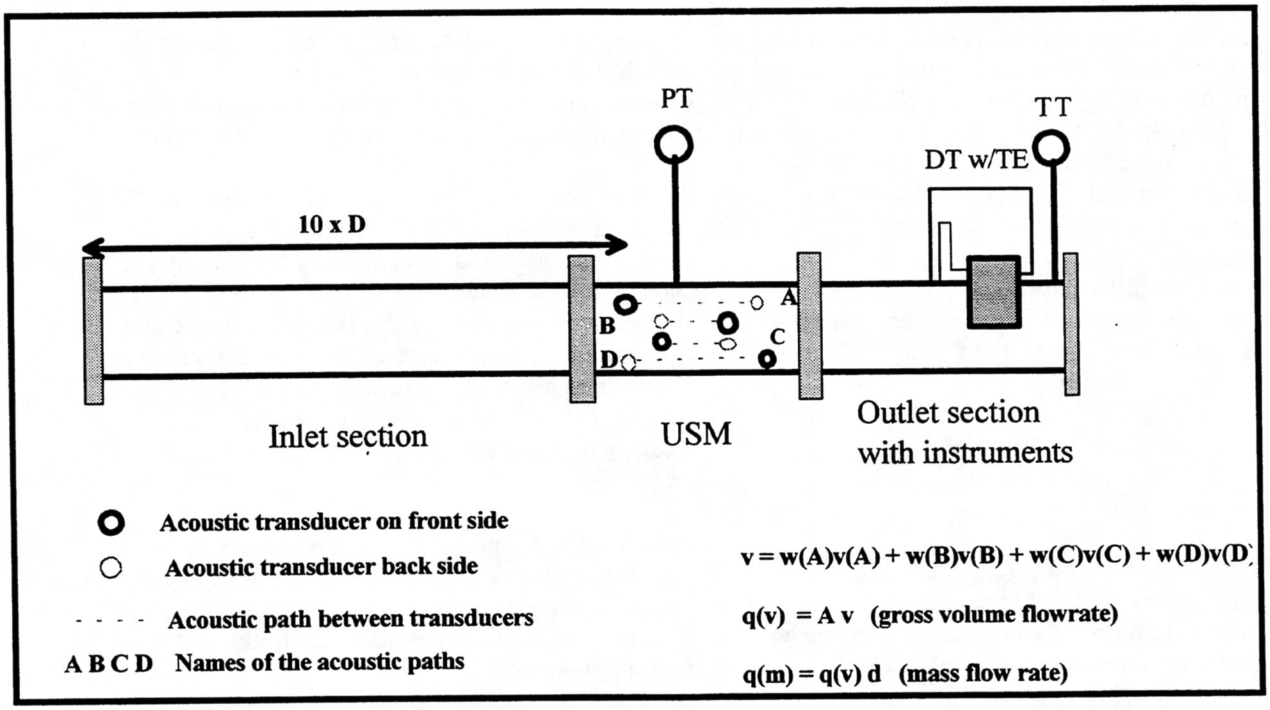


**Fig. 2 Layout and principles for a meter run with a four paths USM**

| Volume flow: | 470.7 $m^3/h$ |
|---|---|
| Tot. forwards: | 2781 $m^3$ |
| Tot. backwards | 2 $m^3$ |

| Transducer no. | Measurements % used | Path. no. | FLOW VELOCITIES (m/s) Measured | FLOW VELOCITIES (m/s) St. dev. | SOUND VELOCITIES (m/s) Measured | SOUND VELOCITIES (m/s) Calculated |
|---|---|---|---|---|---|---|
| 0 | 100 | | | | | |
| 1 | 100 | | | | | |
| 2 | 100 | | | | | |
| 3 | 100 | | | | | |
| 4 | 100 | | | | | |
| 5 | 100 | Tot. | 7.7839 | 0.0139 | | 417.111 |
| 6 | 99 | 0 - 11 | 7.1178 | 0.0188 | 416.576 | |
| 7 | 100 | 1 - 10 | 7.3468 | 0.0201 | 416.550 | |
| 8 | 100 | 2 - 9 | 8.1592 | 0.0117 | 417.053 | |
| 9 | 100 | 3 - 8 | 8.1736 | 0.0150 | 416.730 | |
| 10 | 100 | 4 - 7 | 8.0758 | 0.0116 | 416.491 | |
| 11 | 100 | 5 - 6 | 7.2234 | 0.0211 | 416.356 | |

**Fig. 3 Example of an information report from a six path ultrasonic report**

## EXPERIENCE

### Calibration accuracy

All meters installed until now have been individually calibrated in flow laboratory.
Examples of results from such flow calibrations are shown in fig. 4 for a number of 20" meters.
They all show deviations of less than 0.5 % against the reference meters which in this case were turbine meters traceable to Dutch National Standards.

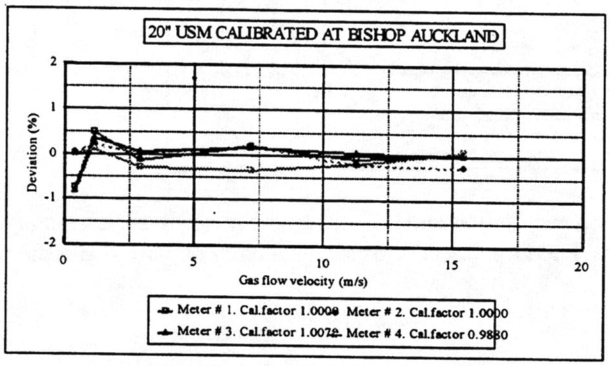


Fig. 4 Results from calibration of four 20" ultrasonic flow meters at 60 bar and 10 °C.
Turbine meters used as reference meters.

Additional tests have been performed to study the accuracy under varying conditions like pressure and temperature.

Figure 5 shows example of calibration results obtained at pressures of 20 bar to 100 bar for a 12" meter. There is no significant difference between the two calibrations.

Smaller meter like 6" meters turns out be less linear than bigger meters. Example of calibration result of a 6" meter is shown in fig. 6.

Calibration results are used to determine correction factors for the individual meter.

It is a goal for the manufacturer and the user to rely on dry calibration. Our experience is that individual flow calibration before installation still remains necessary in order to obtain an uncertainty of less than 1 % on mass flow.

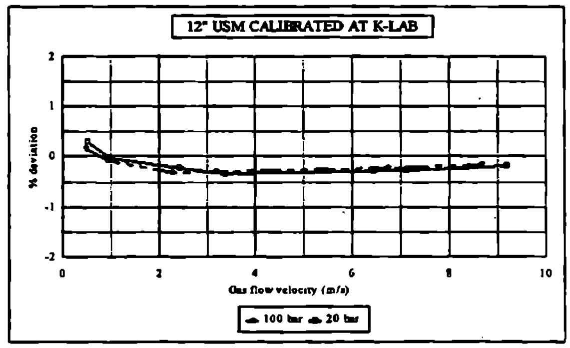


Fig. 5 Result from calibration of one 12" ultrasonic meter at various pressure and 37 °C.
Sonic nozzles used as reference meters.

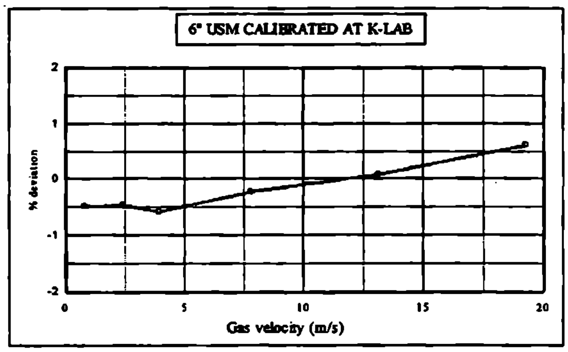


Fig. 6 Result from calibration of one 6" ultrasonic flow meter at 37 bar and 55 oC.
Correction factor 0.988. Sonic nozzles used as reference meters

### Accuracy in operation

In some of our applications it is possible to compare metered result from the ultrasonic meters with conventional fiscal metering station on daily and monthly basis.

Figure 7 shows an example of such comparison on daily basis for a monthduration. The difference between the orifice metering system and the ultrasonic meter in this case less than 0.5 % in average.
Over a period of 4 months, the average deviation between three assumed properly working orifice metering stations consisting of 16" meter runs and six 20" ultrasonic meters are 0.06 %.

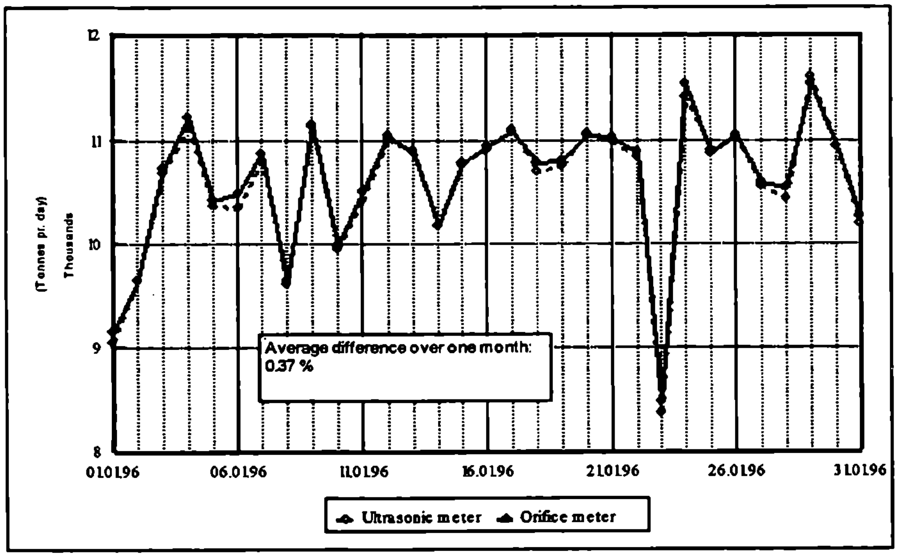


Fig. 7 Daily comparison of figures from a 16" orifice meter station and 20" ultrasonic meter in series. In between are 200 km pipeline (between Heimdal and Draupner). Variations in daily deviation are due to uncertain inventory determination.

This comparison does not tell anything about the absolute accuracy, but it tells that there is consistency between properly working orifice meters and ultrasonic meters.

## Monitoring of gas flow velocity

In a multipath meter more flow velocities are measured as previously mentioned.
For a meter installed in a fixed geometry, the relation between the individual velocities is normally constant over time for a given flow rate. The relation may depend on flow rate.

Under this assumption, monitoring the individual velocities chronologically and also plotted as function of flow velocity will indicate the stability of factors affecting the time measurement and time difference measurements. Error in the most sensitive term, $\Delta t$, will result in a zero error for the actual chord.

Figure 8 shows an example of such a monitoring for a 20" meter installed offshore over a period of 3 months.
Figure 9 shows the same data as in fig. 8 but plotted as function of flow velocity.
This kind of monitoring will reveal drift in the meter caused by for example drift in the transducers' "delta delay times". No other flow meters offer similar possibility to reveal small drifts in the primary element.

The information of flow velocity distribution can also give valuable information about the fluid dynamic effects from certain pipe elements.

An example of such a case is the results from one of our installations:

One of the streams is split in a tee-connection. The flow rates in the two branches are controlled separately by flow control valves in each branch.
When plotting the flow velocity distribution between the acoustic paths which in this case are chordial as a function of the ratio of flow in the two branches, the trend became quite clear as shown in fig. 10.
Given this velocity distribution relationship, it is possible to continue the monitoring for revealing zero offsets in the future.

This example indicates the possibilities that multipath ultrasonic flow meters offer with respect to study of flow velocity pattern in the pipes.

## Monitoring of velocity of sound distribution

The monitoring of the velocity of sound (VOS) is in essence a monitoring and verification of the absolute transit times measurements. There are two kinds of monitoring: Verification of the closeness between the individual measured VOS and a comparison between measured VOS and a calculated VOS.

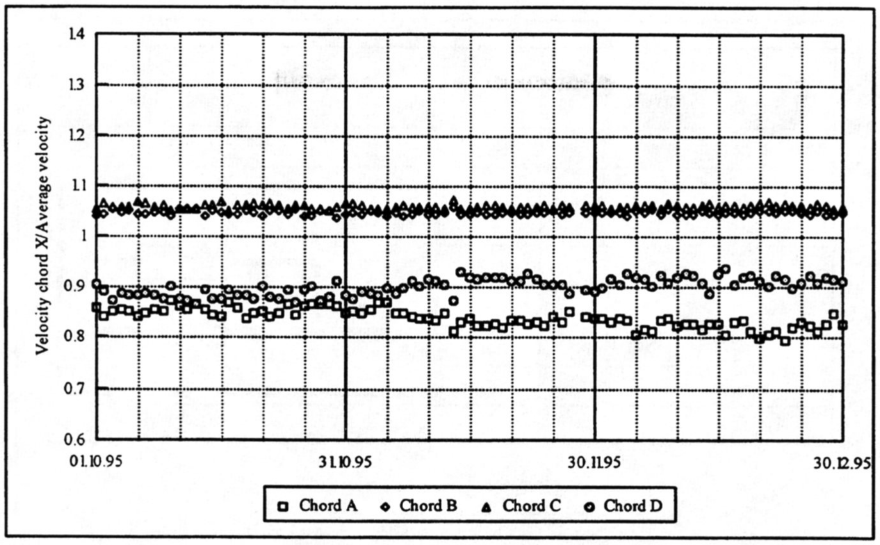


**Fig. 8. Chronological record of the velocity distribution in a 20" ultrasonic meter in continuos operation. For chord layout see fig. 2.**

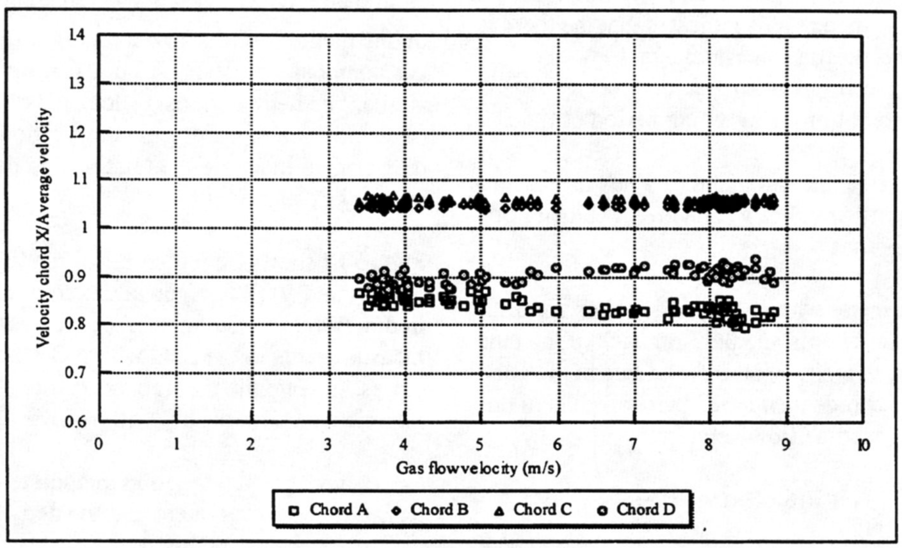


**Fig. 9 . Same data as in fig. 8 sorted as a function of gas flow velocity.**

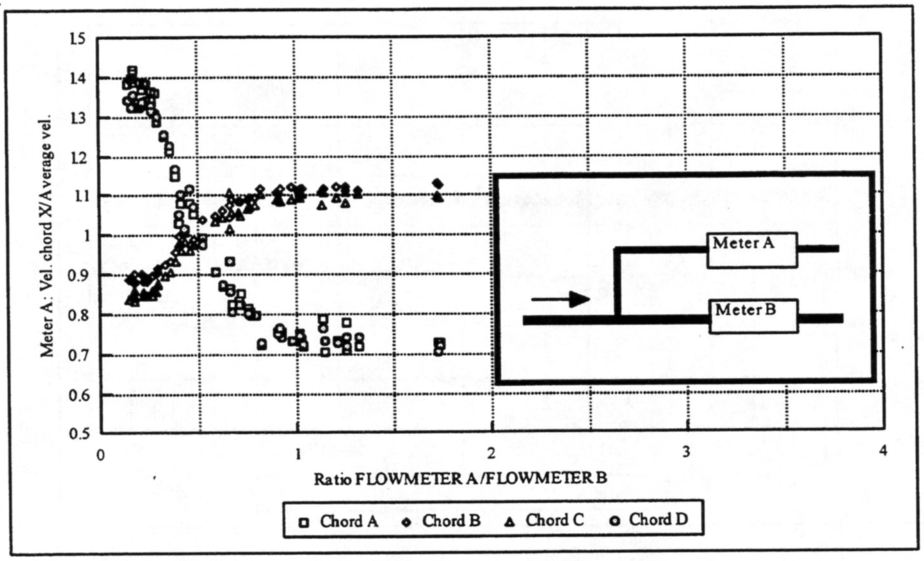


Fig. 10 Velocity distribution in a 20" ultrasonic meter downstream a tee-connection and 90° single bend as function of flow distribution between the two branches.

VOS from each chord is close to each other when gas is flowing through the meter. This indicates that the there is no large error in transit time measurement.
Figure 11 gives an example of such a monitoring indicating stable conditions over a long period of time.

An error in transit time measurement of 1 m/s means an error in flow velocity of 0.5 % when correct velocity of sound is 400 m/s.

Given a four path meter where weighing factors are 0.13 for each of the outer chords and 0.37 for each of the inner chords, an error in velocity of sound of 1 m/s in the chords or combination of chords mentioned below results in the following error in average flow velocity:

| Error in chord | Effect on $v_A$ (%) |
|---|---|
| A or D | 0.065 |
| B or C | 0.185 |
| A and B | 0.25 |

Verification of the accuracy of measured VOS is a bit more "tricky". We have based our calculated VOS, $c_g$, on the general thermodynamic relation:

$$c_g = \sqrt{\gamma\left(\frac{\delta p}{\delta \rho}\right)_T} \qquad (4)$$

Both ρ and the expression $(\frac{\delta p}{\delta \rho})_T$ can be calculated based on the method for density/compressibility calculation from gas composition described in AGA Report No.8 or other similar verified methods. Calculated density and velocity of sound for a range of gas composition can be plotted in diagrams to illustrate the relationship between density and velocity of sound.

Figure 12 shows both theoretical relationship between density and VOS for typical gas composition range used in our system based on AGA Report no. 8 as well how our measurements in the field where gas the composition varies, fits into the theoretical relationship. This experienced relationship will be investigated further.

We believe this a very good method to verify both the transit time measurement and the density measurement.

## INSTALLATION EFFECTS

Below are the two major concerns with ultrasonic meters discussed: Installation downstream bends and installation in the proximity of a control valve.

### Downstream of bends

The velocity distribution downstream bends could be both swirly and asymmetric. Because of this situation, it can be difficult to determine the real average flow velocity in the

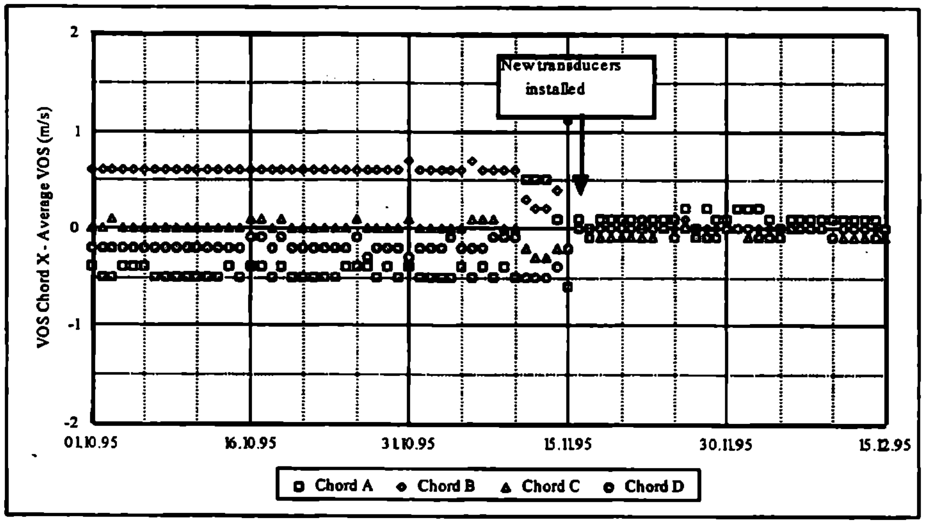


Fig. 11 VOS record for a 20" ultrasonic meter. Note the improvement in spread of VOS after replacement of the transducers.

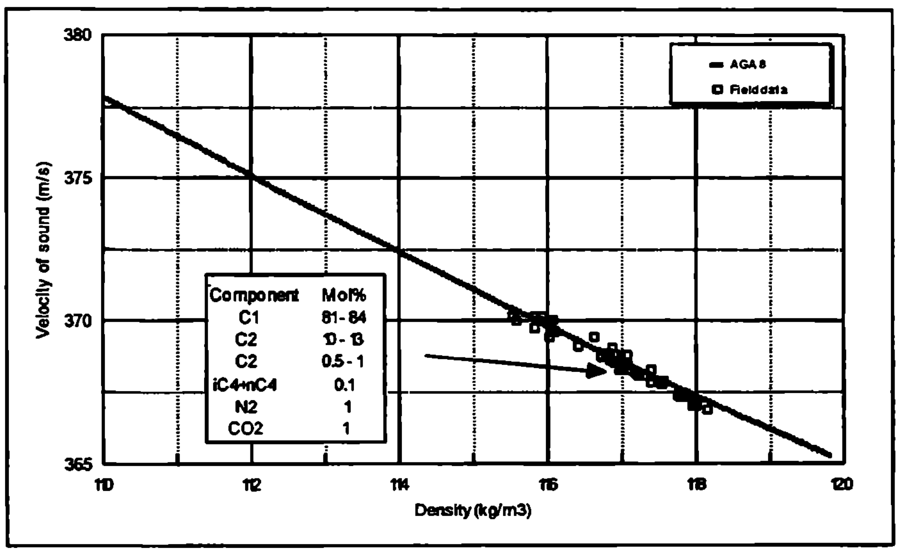


Fig. 12 Relationship between density and velocity of sound. All data reduced to 100 bar and 7°C. Theoretical according to AGA 8 and field data from 20" system where both density and VOS are measured.

pipe cross section when measuring the average fluid velocity along a finite number of acoustic paths. The ability of the meter to determine the mean axial fluid velocity depends also on the orientation of the acoustic paths relative to the flow pattern. Some investigations have been done and reported. (9).

Fig. 13 shows how meter error for a certain 6 path USM depends on the orientation of the acoustic path relative to the plane of a single bend for a meter with chordial acoustic paths. Even as close to a single bend as 5 D, the meter error is below 1%.

Most of the ultrasonic meters on the market seem to be less sensitive to solid body swirl which occurs typically downstream double bend out of plane than to cross flow typical downstream single 90° bends.

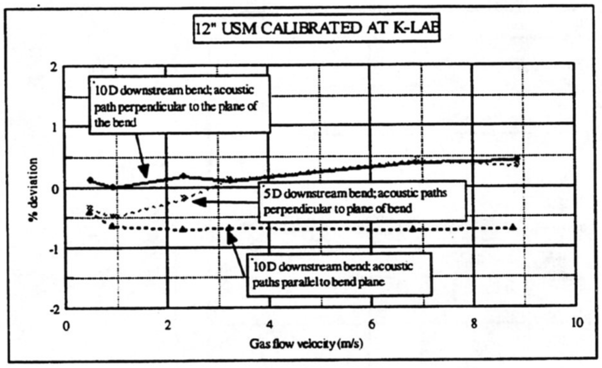


Fig. 13 Example of installation effect.
Results from calibration of a 12" USM installed downstream a single bend and rotated at different angles relative to the plane of the bend. Calibrated at K-Lab at 60 bar.

## Effect of control valves

Flow control valves create acoustic noise. The noise level increases with differential pressure and with flow rate. Normally, it is the audible noise which is of concern.

The frequency of the noise radiated from a valve is however much wider. The problem from an ultrasonic meter's point of view is the frequencies between 80 kHz and 180 kHz which are radiated inside the pipe. This is the sensible range for most acoustic transducers used in ultrasonic gas flow meters.
The high frequency distribution of radiated acoustic noise from valves is normally not well known and understood. Our experience with control valves and ultrasonic meters have told us the following:

- valves equipped with silencer moves the noise towards higher, non-audible frequencies
- the more effective silencer the more energy is radiated at higher frequencies
- the noise level at any frequency increases with differential pressure and flow rate
- more noise is radiated in downstream direction than in upstream direction
- high frequency acoustic noise from the valves can interfere with the acoustic signals in the flow meter resulting in ruined measurement signals.

One way to observe this effect is that the number of accepted pulses in a batch will decrease, meter reading will become unstable and the meter error will increase. At the end, none pulses will be accepted and the meter will stop functioning completely.

Figure 14 shows how the meter reading becomes more and more unstable with increasing differential pressure across a control valve downstream of the USM before finally the function of the meter more or less collapses.

Fig. 15 shows how the number of accepted pulses for a given flow velocity and pressure decreases with increasing differential pressure across a control valve downstream the meter and how the meter error increases. Those results are from tests at K-Lab.

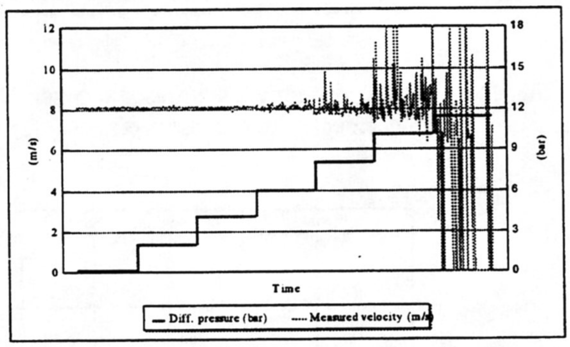


Fig. 14 Example of how the stability of velocity measurement develops with increasing differential pressure over a 6" control valve 10 D downstream a 6" ultrasonic meter. Pressure in the meter is 70 bar.

From more extended tests we have done with the meter upstream of the valve, it seems like it is a combination of differential pressure, pressure and the gas flow velocity which determines how the meter behaves under such installation conditions. This will be looked into in more detail.

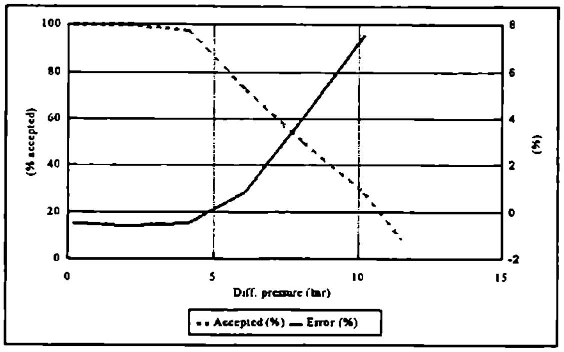


Fig. 15 Example of how number of acoustic pulses decreases and meter error increases with increasing differential pressure over a 6" control valve 10 D downstream a 6" USM. Data from the same tests illustrated in fig. 14.

Figure 16 shows an example from a field installation of how the stability of meter readings develops when differential pressure across the control valve downstream the meter goes up. In this case there is approximately 10 meter between the meter and the valve and there are two 90° bends in between.

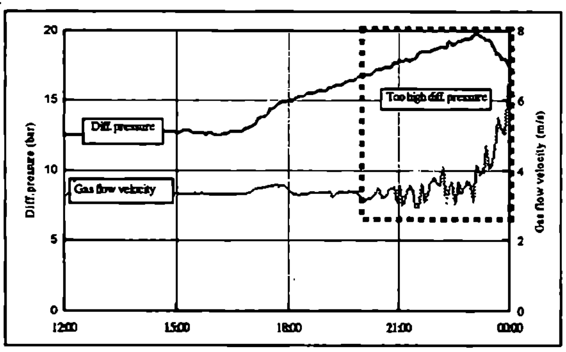


Fig. 16 Field data from a 20" USM system with a 20" control valve 10 meters downstream of the USM. Between the USM and control valve are two 90° bends. Pressure about 90 bar.
The flow measurement became unstable when the differential pressure was above 16 bar. "Stacking function" was used.

With the valve upstream of the meter, the function of the meter collapses at a much lower differential pressure.

This may look like disappointing results. It is underlined that the valves tested here are extremely low noise valves in the audible range, and that pressure drop is high, meaning that this might not be typical installation conditions.

These characteristics are similar for all meters we have tested. However, the meter manufacturers seem to take this problem seriously. Methods are developed to make the meters less sensible to external generated noise. Some methods like the "stacking" function can increase the tolerated differential pressure by a factor of two - five. Finally it should be mentioned that if the acoustic signal is decreased for instance by deposit on the transducers, the noise-to-signal (N/S) will increase and lower differential pressure may be tolerated.

## Thermal insulation

The meter spoolbody should be thermally insulated. This is especially important when gas temperature is far from ambient, and for smaller meters and meters with deep transducer cavities which increase the risk of temperature gradient in the transducer cavity. Temperature gradients in the cavities introduce meter error.

## Wet gas application

Some work has been done to see how the meters perform in wet or saturated gas. (5). So far the conclusion seems to be that with the liquid phase in a mist distribution and a liquid-to-gas ratio less than 1%, the meter will function and the meter error will be equal to the liquid-to-gas ratio.

## CONCLUSION

With the knowledge about the multipath ultrasonic gas flow meters that we have obtained over the past six years, we consider this type of meter as a meter for the future.

Papers have been recently been presented which support this conclusion and which indicate the trends towards common use of this technology. Efforts have also been done to come up with an international standard (10).

Because of the good relation we have had with different manufacturer, the technology has improved and relevant and good verification procedures have been developed.

There is however still a need for more work to be done, especially on installation effects including effects of flow control valves (11).

## ACKNOWLEDGEMENTS

This paper is based on research work being performed by Statoil, on information from development project and from operation of the meters at Draupner and Sleipner platforms.

The effort made by the personnel at those two platforms is gratefully acknowledged.

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