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SAMPLING AND ANALYSIS FOR THE DETERMINATION OF THE WATER CONTENT  
OF CRUDE OIL - AN OVERVIEW

by

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Paper 1.1

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National Engineering Laboratory  
East Kilbride, Glasgow

SAMPLING AND ANALYSIS FOR THE DETERMINATION OF  
THE WATER CONTENT OF CRUDE OIL - AN OVERVIEW

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Chairman of IP Panel PMB-2.

I) INTRODUCTION

Sampling for water in oil is not an exact science. Over the last few years there have been some major improvements in both the theory and practice of automatic sampling, but we still do not know all the answers. Any sampling operation has to be judged on a statistical basis and eventually has to be expressed as a percentage confidence that the result obtained is within a defined tolerance of the truth. Since by ISO 5168 definition, error is always unknown, it is usually best to work in terms of 'uncertainty' although other terms are often used.

This paper is a review of recent and current attempts to reduce the uncertainty of water-in-oil measurement. It deals with the recently approved draft of an International Standard and describes some practical and theoretical work that has been done or is near to completion. All of the currently available work is being collected together into a proposed new publication from the Institute of Petroleum, which will be called a 'Guide to Automatic Sampling'. Recent developments in the measurement of water in oil are also described with a brief glance at what might happen in the future.

## II) INTERNATIONAL STANDARDS - ISO 3171

### HISTORY

In December, 1975 the first edition of ISO 3171, an International Standard document dealing with Automatic Pipeline Sampling, was published by ISO in Geneva. It was known that this early edition was not complete, and in the UK it was decided that this edition would not be published by BSI as an identical, dual-numbered British Standard. It was considered that the methods described in it were not generally applicable to crude oil. Other countries were also doing work to improve the performance of automatic sampling equipment, and hence at the meeting of the ISO Technical Committee 28 Sub-Committee 3 in Mexico City, 1979, it was decided to set up a Working Group to prepare a new edition. The Secretariat of the Working Group was allocated to the UK, and was delegated via BSI to the Institute of Petroleum where most of the detailed work was done by the Panel PM-B-2, which is part of the Petroleum Measurement Committee PM. During the compilation of the new edition, major contributions were made from the UK, USA, France and Italy. After a lot of national and international discussion and many meetings, agreement was reached at the ISO TC28/SC3 meeting held in Rome, November, 1985 about what should be included in the new ISO 3171 (Ref 1). All the technical work has now been done; we now await formal publication.

As with almost all international documents the final result was an acceptable compromise. Not all of the contents were agreed unanimously (even within the UK delegation), but the recommendations made within the document were agreed to be the best available at that time and were agreed to be conservative rather than misleadingly optimistic. All the delegations recognised the need for early publication, even though new and better information was still emerging. Our understanding of the principles and practice of automatic sampling is still improving, and yet another edition of ISO 3171 is to be expected at some time in the future, maybe 10-12 years.

## CONTENTS of ISO 3171

Some of the highlights of the new ISO 3171 are as follows:-

1) Definitions and Terminology

Some of the terms used in sampling (such as sample point, grab, profile testing, worst case conditions) have been defined more precisely than before and definitions of different types of water (ie., dissolved, suspended, free and total) have been brought into line with other international documents. Throughout ISO 3171, care has been taken to make sure that it does not conflict with other Standards, and in particular, some parts are identical to ISO 3170, a sister document dealing with Manual Sampling, which has recently been revised and which was also approved for publication at the Rome meeting.

2) Location of Sample Point

Recommendations are made about where to put the sample point. The preferred position is in the middle of a downward flowing pipe soon after the best available mixing device. Recognising that this ideal is not always practicable to achieve, other possible positions for the sampling point are discussed (Figure 1). A great deal of the Standard deals with the problems of sampling from a horizontal line.

3) Representative Sample

The definition of representative sample is the idealised case of the sample being identical to the pipeline average, but a practical limit is set of  $\pm 5\%$  of reading (ie., 1 part in 20 of the water concentration) for the uncertainty that is likely to be achieved in a good sampling system. At water concentrations below 1% this limit is replaced by a fixed limit of .05% of water, so that impossibly fine limits are not called for at low levels of water concentration.

4) Sampler System

The Standard does emphasise the need for flow-proportional sampling and is also quite strongly in favour of iso-kinetic sampling (within a factor of two up or down).

5) Sampler Performance

ISO 3171 offers two methods by which the performance of an automatic sampler can be assessed. The first is by carrying out a practical test in which a known quantity of water is injected into the pipeline at some location upstream of the automatic sampler. Details are given of the procedure to be followed in order to check if the sampler 'sees' this extra water within acceptable limits of accuracy. The second method shows how to calculate the overall uncertainty from a knowledge of the uncertainties of all the component parts or operations. In practice these component uncertainties are seldom known, but the method is useful to compare different options and to identify the most likely sources of major errors. Typical values are given.

6) Profile Testing

Before a sampler is installed (and afterwards if its performance is at all suspect) it is recommended that a profile of the water concentration across the vertical diameter where the sampler probe is to be installed, should be obtained by testing. The profile testing procedure (adapted from API) is described in detail and some typical results are shown.

7) Profile Calculation

Sometimes it is not possible to do a profile test, in which case ISO 3171 offers a method (developed in France) by means of which the shape of the profile can be predicted by calculation. This should be a major step forward in sampling system design and was welcomed by all the Working Group members. It was reckoned that the method is by no means perfect, but that it does provide some useful information and does allow valid comparisons to be made. It is believed that the method will not predict a better profile than that which will actually occur in practice.

## DEFICIENCIES of ISO 3171

Even when the present ISO 3171 was agreed at the meeting in Rome, it was known that new and better information was still being published. Automatic sampling is still a matter for innovation and development. However, it was decided that there was sufficient new information in the agreed document to justify publication and to meet a recognised demand for international standardisation. To wait for the last word on the subject would be to wait forever.

Some ways in which ISO 3171 could be improved are as follows:

1) Definitions

The terminology to differentiate between the different types of automatic sampler (in-the-line, by-pass loop, cell) is not well defined and the term 'grab sampler' could mean different things to different people.

2) Accuracy

The "5% of actual concentration" criteria is used rather indiscriminantly throughout the document and in some parts an even poorer performance seems to be condoned. This ought to be put on to a more rational basis.

3) Minimum Sampling Frequency

The Standard does not give any really useful advice on this controversial matter.

4) Profile Testing

The method described for profile testing is labour intensive and not very practicable, although it can be done. The use of multiple continuous monitors to do this job should be advocated more strongly.

5) Profile Calculation

The method described in the Standard for predicting the profile is already quite complicated. Better methods involving more refined theory and a deeper understanding of

5) Cont'd

the physical principles involved are available. How much of this can be put into the Standard without making it too complicated for a design engineer to use, will be difficult to decide. There is however, a worldwide recognition that some improvements are needed which must be based on practical experience and feedback from users of these tentative proposals.

### III) CURRENT INVESTIGATIONS

Concurrent with the preparation of ISO 3171 (and in some cases prompted by it) a number of research and development programmes concerned with automatic sampling have been set in progress. The results of some of these programmes are restricted by the need for commercial confidence, but in others the need for the conclusions to be widely understood and commonly accepted in all the oil industry (as a basis for fair trade between two parties) has been recognised. In most cases, all the important conclusions have been published for general use. In all cases at least one member of the Institute of Petroleum Panel on Automatic Sampling is aware of the results so that conflicting recommendations ought not to appear.

Three major programmes are worthy of note:-

1) BP at ROTTERDAM (Ref 2)

BP (Central Engineering Dept), who have always been pioneers in the design and construction of automatic sampling equipment, set out to test and compare the performance of some new designs of sampler. Facilities were set up at the BP Rotterdam refinery so that crude oil being unloaded from tankers and also being transferred between shore tanks could be sampled for water under realistic, but controlled, conditions. Tests were done with both in-the-line and cell samplers, which were checked both against each other and by means of the water injection test as described in ISO 3171. They also carried out profile testing as described in the standard. Additionally the opportunity was taken to test a new design of insertion flowmeter and the performance of a continuous water-in-oil monitor based on the large difference between the dielectric constants of the two components.

The initial results from the tests indicated that the cell sampler in a 1" NB pumped bypass system did give good results under almost all test conditions, but that the in-the-

1) Cont'd

line sampler was not so consistent and usually gave low results. Further testing is being carried out under the supervision of NEL.

2) NEL JOINT INDUSTRY PROJECT (Ref 3)

For a number of years, NEL have organised a joint research programme to study and improve the use of automatic samplers in the petroleum industry. Phase 3 of this programme which was supported by 17 different organisations is now virtually complete. Phase 4 is about to start.

A lot of the work done by NEL for the consortium has been done on a laboratory test rig specially designed to check the performance of samplers and sampling probes. One of the conclusions drawn from recent work is to highlight the need to take care to minimise the effect of the 'dead volume' after the grab mechanism of in-the-line samplers. The shape of the inlet orifice to sampling probes has also been studied and the design with an internal taper is recommended. This confirms the shape shown in ISO 3171.

Another aspect of the NEL work has been concerned with the number of grabs required to give a representative sample. This has been done by computer simulation, and is described in another paper at this NEL Metering Workshop. (Ref 4)

An ongoing investigation by NEL on behalf of the joint project has been made possible by the generous co-operation of BP. The test facilities at the Rotterdam Refinery (mentioned earlier) have been made available for independently controlled tests, the results from which will be of use throughout the industry. The main objective of the current programme of tests is to find out how close to

2) Cont'd

iso-kinetic operation it is necessary to be, in order to get a representative sample of water in crude oil. The present recommendation within ISO 3171 for iso-kinetic sampling (within a factor of two either up or down) is based mainly on intuition and some qualitative test work. Better information is needed to clarify the position and to allow more positive guidance to be given.

3) CRAFIELD FLUID ENGINEERING RESEARCH (Ref 5)

Prompted and assisted by close collaboration with BP, the members of the Department of Fluid Engineering and Instrumentation at the Cranfield Institute of Technology have studied two aspects of automatic sampling.

A) Profile Calculation

The procedure described in ISO 3171 to calculate the water concentration profile in a horizontal pipe has been examined in detail. The validity of the formulae used and the basic assumptions and simplifications made, have all been challenged. Recently published work by Karabelas and Segev has been compared with the ISO method, and a computer programme has been developed so that all three methods can easily be applied to a given problem. The general conclusion is that none of the methods is strong enough to stand on its own as the sole judge as to whether representative sampling is or is not possible. The methods are useful for making comparisons and for identifying where improvements can be made.

All the methods should be backed up by practical tests. It has been confirmed that the ISO 3171 method is conservative and should not predict good sampling where it is impossible. The major source

A) Cont'd

of uncertainty in all these calculations is concerned with the water droplet size, which is difficult to calculate and almost impossible to measure. Further work is proceeding on this problem.

B) Number of Samples

As a supplement to and in some ways as a duplication of the work done at NEL, Cranfield have investigated the problem of deciding what is the minimum acceptable number of grabs required to get a representative sample. They have investigated both the influence of discontinuities in time (ie., slugs of water travelling down the pipe) and also discontinuities in space (ie., large drops evenly distributed). Broad agreement has been reached with the NEL work about which factors are most significant to this decision, but further reconciliation is still required.

#### IV) IP GUIDE TO AUTOMATIC SAMPLING

When the Institute of Petroleum Panel PM-B-2 had finished its work in helping to draft the ISO 3171 document, it considered what else was most required. It decided to produce a new document to be included in the IP Petroleum Measurement Manual series of publications, but which would be more of a guide or textbook rather than a standard. The Guide is intended to amplify and explain the recommendations in ISO 3171 and also to give more background information about the equipment available and the methods to be used. It also tries to deal with some of the problems left unsolved by ISO 3171.

Some interesting features of the Guide are as follows:-

##### A) Sampler Types

The Guide describes many of the different types of sampler that are in use. It divides them up into three (3) main categories:-

##### i) In-the-line Samplers

where the grab isolation point is inside the pipeline itself, usually on the end of a long probe.

##### ii) External-Loop Samplers

where the grab isolation point is outside the pipe and is taken from a subsidiary system (often known as the fast loop).

##### iii) Cell Samplers

which are a combination of the other two, so that an in-the-line sampler in a moderately sized by-pass loop takes samples from a manageable sub-division of the main pipeline flow.

The Guide does not recommend any one type above the others.

B) **Mixing**

The Guide describes some of the various mixing devices that are available to help provide suitable conditions in a pipeline, so that a representative sample can be obtained. It describes the jet mixer and how it can conveniently be combined with a cell sampler to form an integrated system. However for design details of all such systems, it is necessary to refer to the manufacturers. In the future, it is expected that there will be a growing emphasis on the need for more deliberate mixing prior to sampling. The need for mixing after sampling (ie., homogenisation before analysis) continues to be emphasised.

C) **Sampler Location**

The recommendations in ISO 3171 about sampler location have been expanded and explained in more detail in the Guide. A vertical section of pipe with downward flow is still the ideal location, but other locations can still produce acceptable results. The ISO method of calculating the concentration profile in a horizontal pipe is explained in detail and the other methods are introduced with references. It is hoped that some clear-cut advice about iso-kinetic sampling will be available in time for publication.

D) **Minimum Acceptable Number of Grabs**

The Guide attempts to bring together all the recommendations currently available to give advice on the number of grabs that need to be taken to ensure that the total sample is representative of the whole. By combining a basic theoretical approach to the problem with the statistical and computer modelling work done by Exxon, NEL and CIT a simple formula has been proposed by means of which the minimum acceptable number of grabs can be calculated. (Fig 2) A lot of discussion will be required before we have a widely accepted solution to this contentious problem.

E) **Practical Testing**

Based on practical experience in using the two test procedures described in ISO 3171 (ie., profile testing and water injection testing), the Guide gives more detailed advice about the difficulties to be overcome. It also gives more information about how to interpret the results once they have been obtained. It emphasises that an overall accuracy of one part in twenty is not really very good and that we ought to be able to do better.

V) AUTOMATIC KARL FISCHER ANALYSIS

HISTORY

For many years the only recognised method for measuring water in crude oil was by means of centrifuge tests. The terminology 'BS + W', which is still very widely used, implies that the result is obtained by centrifuging. It takes the oil industry a very long time to change its terminology and to accept logical precision in its use of words, but it has not taken very long for the centrifuge to fall out of favour and to be replaced by an analytical procedure based on the Karl Fischer reaction.

The first method to be approved by the Institute of Petroleum IP 356/82 was designated for use with North Sea Crude Oil. The revision in 1984 (IP 356/84) removed the specific reference to 'North Sea' and implied a much wider field of use. However, the method described in those documents is to use a titration apparatus with the end point determined by an electrical potential difference method. The reagents used include pyridine which is not a very nice chemical to deal with, and moreover the reagents are not very stable and they need to be made up fresh and to be standardised daily. This is not the sort of job normally given to offshore operators more traditionally accustomed to the use of centrifuges.

COULOMETRIC ANALYSIS

A new version of the Karl Fischer method is now available that is much easier to use. It has become so popular that it is now in widespread use by North Sea operators, even before an official IP method has been published. In the new method the important reagent (iodine) that reacts with the water is produced electro-chemically by electrolysis of the anode solution. Only enough iodine is produced to react with all the water present, and by measuring the quantity of d.c. electricity (coulombs) required to liberate that iodine, a direct measurement of the quantity of water present is obtained. The end-point is still detected electrically, but in this case it is usually an a.c. potential measurement.

These new instruments are usually micro-processor controlled and apart from weighing the sample and injecting it from the syringe into the stirred measuring cell, the analysis is fully automatic. The cell is kept in operation for 24 hours per day so that any moisture that seeps into it is eliminated before the next set of samples are injected. Each refill of reagents can last several days depending on how much water is in the sample that is injected and how much seepage of water into the cell takes place.

On an offshore platform weighing the sample syringe (before and after injection) could be a problem, but modern electronically controlled weighing machines can average a large number of instantaneous readings to get an accurate result even if the platform is moving. This is often known as the 'animal weighing program'.

## OPERATION

There are a number of features of the new Karl Fischer method that need to be watched:

1) Homogenisation

To get a water-in-oil mixture into a sufficiently finely-divided homogeneous state so that a representative sample can be drawn into syringe through a small bore needle requires vigorous agitation. The best high speed homogenisers must be used and the mixing time required must be determined by a rigorous series of tests. Homogenisation for Karl Fischer needs to be much better than for centrifuges.

2) Calibration

The calibration of an automatic coulometric Karl Fischer method is usually checked when first installed by testing it with made up samples. Thereafter the electrical-to-chemical conversion is assumed to remain constant. This will only be true if the fundamental design is right and there is rigid quality control of the reagents used. An IP standard method of test is currently being prepared.

3) Salt Correction Factor (Ref 6)

The Karl Fischer method measures the mass of pure water in a weighed sample that usually consists of salt water in crude oil. If it is required to use the Karl Fischer analysis result to calculate how much salt water was in the original bulk transfer then a Salt Correction Factor must be applied. In order to avoid the possible error of applying the SCF twice, it is recommended that it is never applied to Karl Fischer percentage figures, but is only used when calculating an absolute mass of salt water.

4) Interference Reactions

Hydrogen sulphide will react with the Karl Fischer reagents in the same way as water and will appear in the result. This is the only interfering material that is likely to occur in crude oil and will usually only be present in concentrations much less than the known uncertainty of water measurement, and hence can be ignored.

Care must be taken not to introduce any other interfering agents, particularly with any solvents used for cleaning. Acetone should not be used.

5) Sediment

The old centrifuge method included any sediment in with the water measurement. The Karl Fischer method ignores any sediment. If sediment is present, it can be measured by the IP 53/70 method, but this is very much a laboratory procedure. Samples taken specifically for water measurement may not be truly representative of sediment concentration.

VI) FUTURE TRENDS

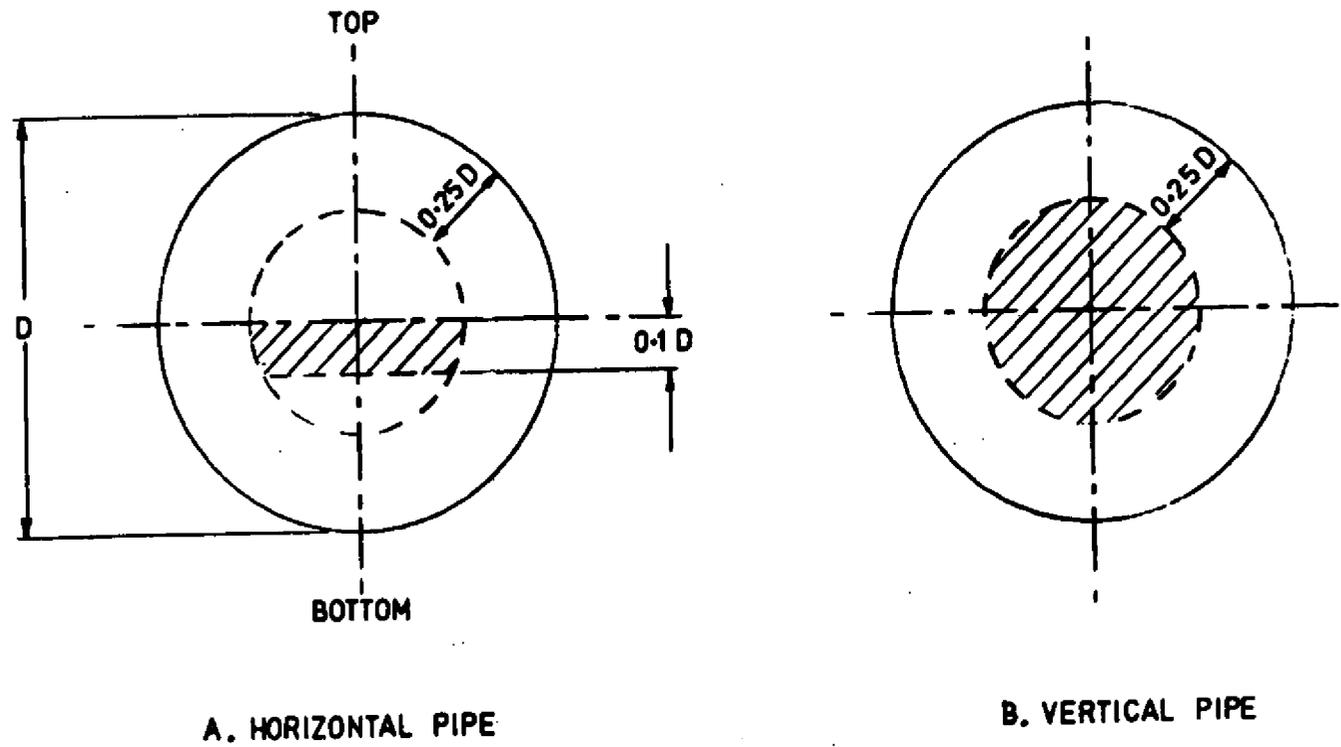
As we begin to understand the problems of automatic sampling, it becomes more and more obvious that proper mixing is vital before it is possible to obtain an accurate result. Emphasis will concentrate on the theory and practice of mixing non-homogeneous liquids in pipelines so that sampling devices can have some chance of grabbing good samples. The cell sampler with a moderately - large pumped by-pass flow loop may be the answer to this problem.

An alternative device that has been around for a long time, but looks to be making some progress, is the dielectric constant type water monitor. Potentially this can solve both the sampling and the analysis problems all in one unit. It has not yet made the same dramatic impact that the coulometric Karl Fischer method has achieved, but it may do so one day.

The author wishes to thank Chevron Petroleum (UK) Limited and the Institute of Petroleum for permission to present this paper, but the opinions expressed are solely his own.

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A. HORIZONTAL PIPE

B. VERTICAL PIPE

THE INLET ORIFICE SHOULD BE LOCATED WITHIN THE SHADED AREA

FIGURE 1 LOCATION OF WITHDRAWAL POINT ( INLET ORIFICE ).

$$\begin{array}{l} \text{MINIMUM ACCEPTABLE} \\ \text{NUMBER OF GRABS} \\ \text{(MANG)} \end{array} = \frac{300 \times P}{E \times A}$$

Where P is the Peak concentration (percentage) that is expected during the transfer. This can be obtained from experience with similar operations and systems elsewhere.

Where A is the Average concentration (percentage) of the whole transfer. This can be estimated in advance, but should not be set too low without some consideration of the appropriate associated values of E and P.

Where E is the Error limit (as a percentage of A) that is being aimed at with 95% confidence. E is usually 5%, but may need to be more if A is less than 1%.

**FIG 2      PROPOSED FORMULA FOR SAMPLING FREQUENCY**

COMPUTER SIMULATIONS TO DETERMINE THE OPTIMUM SAMPLING FREQUENCY  
DURING CUSTODY TRANSFERS

by

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Paper 1.2

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COMPUTER SIMULATIONS TO DETERMINE THE OPTIMUM SAMPLING  
FREQUENCY DURING CUSTODY TRANSFERS

by

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SUMMARY

A method using computer simulations and analysis to determine the optimum number of samples to be taken during the course of crude oil custody transfer is described. Firstly, a computer simulation 'GRAB' was used to study the effect the form of the water concentration transients had on sampling accuracy and this showed there was a linear relationship between sampling accuracy and each of transient duration, interval, peak water concentration and sampling frequency. Secondly an analytical program 'DATACAL' and its associated data-logging program 'DATALOG' were used to analyse simulated tanker discharges based on chart recordings of actual tanker discharges. This showed that to produce acceptable sampling uncertainties, 1000 samples per discharge were borderline, 2000 were adequate, and 10 000 were excessive.

## N O T A T I O N

a,b,c,d	Regression constants	-
D	Duration of water transients	s
E	Sampling measurement error = $W_s - W_a$	%
F	Frequency of sampling, time between samples	s
H	Hiatus or interval between water transients	s
P	Peak water concentration in a water transient	%
R	Correlation coefficient of interpolation or line fit	-
T	Total time of sampling period	s
$W_a$	Actual water in flow as per cent of flow	%
$W_s$	Sampled water in flow as per cent of flow	%
X	Constant defining water transient form	-

Note that  $W_a$ ,  $W_s$  and  $E$  are all expressed as percentages of the total mainflow, ie on a volume to volume basis.

## 1 INTRODUCTION

The water content of a crude oil cargo is normally determined by analysis of a sample collected automatically during the transfer of the cargo through a pipeline, be it a platform export cargo or a ship-to-shore transfer. The size of the sample taken is very small, perhaps less than a millionth of the cargo volume, so it is important that every effort be taken to ensure that the sample taken is truly representative of the entire cargo.

Towards this end the accuracy of the instruments and procedures used to obtain the samples have been greatly improved in recent years by the findings of a research project at NEL (1,2,3,4) sponsored by a consortium of the oil companies given in Table 1. Most of the laboratory and field work devoted to this project has studied the sampling errors resulting from physical sources, eg concentration profiles, sampler characteristics etc. Little effort, however, has been devoted to studying the statistical errors that occur in taking small intermittent samples from a much larger volume flowing in a pipeline.

In theory we could obviate the need for intermittent sampling (assuming only temporal water variations and a uniform concentration profile in the pipe) by taking a sample flow proportionally and continuously whereupon the results should give a good statistical representation of the characteristics of the flow at large. However, since this would involve an inordinate volume of sample being collected or a hyperdermic sized sampling probe being used, we have to accept that some form of intermittent sampling is necessary. If this is so, what sampling frequency should we adopt? Too fast and we collect too much sample incurring the errors of sub-sampling, too little and our statistical errors become too large. The question is exemplified in the current 1000 or 10 000 grab per tanker discharge debate which has focused attention on the need to resolve the issue.

To shed some light on the subject NEL has constructed two computer simulations of pipeline flow in which a perfect sampler could operate in a perfect pipeline and enable an analysis of the statistical uncertainties to be conducted in isolation from the physical uncertainties. This paper describes the use of the computer simulations and some of their results. The first simulation, GRAB, was designed to investigate the effect that transient frequency, duration and waveform had on sampling accuracy and the second, DATACAL, linked to a data acquisition program, DATALOG, to study actual or simulated transfers of crude. Together the programs occupied 70 Kbytes of memory and were written in standard Microsoft Basic. At the NEL they were run on Superbrain QD and Epson PX-8 micro-computers both running under CP/M operating systems.

## 2 TRANSIENT STUDY PROGRAM

This program was designed to study the effect that transient frequency, duration and waveform had on sampling accuracy. As such it was concerned only with individual transient types and not with an entire pipeline transfer or tanker discharge.

The program generated water transients whose duration  $D$ , interval  $H$ , and peak height  $P$  could be defined. A random number routine was used to vary these variables in a pseudo-Gaussian distribution from 75 to 125 per cent of the defined values to avoid any harmonics with the sampling frequency. A constant flowrate was assumed though the simulations would be equally valid for a varying flowrate if flow proportional sampling was used. Also homogeneously mixed water in each transient was assumed as was the ability of the sampler to

extract a perfectly representative sample of the flow passing during the instant the sample was taken. The total sampling time  $T$ , the total water content  $W$  of the flow over the sampling time and the sampling grab frequency  $F$ , could also be defined. A choice of three transient forms could be generated as given in Fig. 1, namely square, shaped and sawtooth forms defined by the parameter 'X' together with  $P$  and  $H$ . Care should be taken not to visualise these transients as physical 'waves' but as they really were, variations in concentration of homogeneously mixed water.

The program generated successive transients and intervals and monitored the flow second by second, accumulating the water sampled during the passage of each transient. The program then compared the water collected by the sampler  $W_s$ , with that actually flowing in the pipeline over the specified sampling time  $W_a$  and evaluated the difference. The process was repeated a specified number of times, usually 30 or more, to give an estimate of the standard deviation or the scatter of the difference about its mean. It was this estimate of the standard deviation which gave  $E$ , the 95 per cent confidence limits to which the correct value of the water content could be quoted.

At the end of each simulation the program output:

Average sampling time  $T$ , per iteration (seconds)  
Average number of grabs taken during each iteration  
Average grabs/minute during each iteration  
Average number of transients per iteration  
Average peak height  $P$ , of the transients  
Mean transient duration,  $D$  (seconds)  
Sigma value of the variation of the transient duration  
Mean interval duration,  $H$  (seconds)  
Sigma value of the variation of the transient interval  
Percentage of water in the flow,  $W_a$   
Percentage of the baseline water  
Percentage of water sampled,  $W_s$   
Mean difference flowing and sampled water content  
Sigma value of the mean difference  
Mean percentage sampling error,  $E$   
Sigma value of the mean percentage sampling error.

The input values for  $D$ ,  $H$ ,  $P$ ,  $T$ ,  $W$  and  $F$ , as well as the number of iterations per simulation, the time of start and completion of the simulation were also output so that a permanent printed copy was available.

To expedite its operation, the program had the facility to cover a range of  $D$ ,  $H$ ,  $P$ ,  $T$ ,  $W$  and  $F$  values in any one run and allow the simulation to run unattended overnight if required. This was very useful as several hours of computer time could be required per simulation.

## 2.1 Application of the Computer Simulation to Sampling Frequency

The first task to which the computer program was applied was that of ascertaining the relative merits of taking 10 000 as opposed to 1000 grabs per tanker discharge. The problem was not as simple as might be thought in that the shape or form of the water transients was not well defined. The limited data supplied by sponsor companies suggested a wide range of transient durations, peaks and intervals were possible between different installations and even within the same installation. Rather than predict what sampling errors could be incurred at a particular installation therefore, it was decided to quantify the characteristics of flows that would give unacceptable sampling errors.

The problem still remained, however, in the number of variables in operation, namely transient duration, peak, form and interval, water content, sampling period and grab frequency - seven in all. Fig. 2 illustrates just some of the possible combinations when only three of these variables are considered. In order to reduce the variables to manageable limits it was therefore decided that:

- a Only 1000 and 10 000 grabs per tanker discharge would be investigated.
- b The sampling period would be held constant at 24 hours.
- c The water content would be held constant at 1, 5, 10, 20 and 50 per cent and would not include any background water, ie the total water content was contained within the water transients no matter what form they took.
- d The transient interval would be varied from 10 to 10 000 seconds.
- e The transient peak or water content would be varied from 0-100 per cent of full flow.
- f The transient duration would be varied from 1-1000 seconds.
- g Only square waveforms would be studied as these were expected to give the worst case.

Effectively, therefore, there were only three variables H, P and D, and these defined the form of each water transient. These three variables could be plotted along three dimensions as in Figs 3 and 4 where the transient interval H lies along the x-axis, the transient peak P along the y-axis, and the transient duration D along the z-axis; each axis being logarithmic in order to cover the wide range of values required for these variables.

Fixing the water content defined a surface in the three dimensions such that -

$$W_a = \frac{DP}{H + D}$$

A uniform grid of 34 evenly spaced locations were taken across this surface and the 95 per cent confidence limits of the sampling error E evaluated by taking 30 iterations at each location at each water content for 1000 and 10 000 grabs per discharge. The exercise showed in passing that the sampling errors from this source were entirely random and no significant systematic element could be detected. Graphical interpolations were then performed across the grid points to give the +0.01, 0.02, 0.05, 0.10, 0.20 and 0.50 per cent uncertainty contours of the 95 per cent confidence limits as seen on the graphical representation for the 1 per cent water case in Figs 3 and 4.

The data was also used to calculate by multiple linear regression using Gauss's method with partial pivoting the relationship and the coefficients of the three independent variables P, H and D for both 1000 and 10 000 grabs per sampling period. The relationship was of the form -

$$E = a + bP - cH + \frac{d}{D}$$

which shows that if a given amount of water has to be transferred then to reduce sampling errors to a minimum transients should:

- i Have as long a duration as possible as E is inversely proportional to D.
- ii Have as long an interval as possible as E is linearly proportional to -H.
- iii Have as small a peak as possible as E is directly proportional to P.

These three conclusions are basically stating that the water should ideally come over as one long uniform transient. However, examination of the coefficients of the relationships given in Table 2 give less obvious but equally important conclusions. At first glance there seem to be no trends between the values of the coefficients and water content, except for a steady increase in the value of c as water content increases. The reason for the lack of any other trend is a combination of the statistical uncertainty in the determination of the coefficients themselves in that each were derived from only 30 measurements, and also to the complex interactions between the variables.

Two distinct trends, however, become apparent when individual cases are taken and displayed graphically as in Figs 5a, 5b and 5c. These figures take three cases, keeping any two of the variables P, H and D constant at a time and varying the third. Two conclusions can be drawn:

I The sampling error is usually about ten times as large when only 1000 grabs as opposed to 10 000 grabs/discharge are taken.

II The sampling error increases only fractionally in proportion to the increase in water content, ie the sampling error at 20 per cent water content is far from being 20 times the sampling error at 1 per cent water content.

It must be remembered that though the relationships between variables given above will in general hold true, the magnitude of the errors in the field would be expected to be much less because the computer simulation models the worst case of a square wave transient. The next use of the program was therefore to investigate the effect transient form had on the sampling accuracy.

## 2.2 Application of the Computer Simulation to Transient Form

On first glance an obvious refinement to a square wave transient was seen to be the use of a sine wave. On reflection, however, it was thought doubtful that sine wave transients would actually occur in real life - again it must be remembered that the problem is not concerned with gravity or physical waves but with a variation in the concentration of water suspended in a flowing crude oil. Examination of the limited production platform and tanker discharge traces available suggested that transients usually had a steady state between their shaped leading and trailing edges. For this reason the sine wave transients were abandoned in favour of the shaped and sawtooth waveforms shown in Fig. 1 together with a square wave for comparison.

The simulation program was run using each of the three waveforms with again no background water and the duration of each transient form chosen in such a way as to give the same water concentration at each given peak value.

Tables 3 and 4 give the results of the simulations for each waveform as a function of peak height for grab rates of 1000 and 10 000 grabs/tanker discharge respectively with a total water content of 5 per cent. P is the peak of the transient ranging from water contents of 100 per cent maximum to 5 per cent

minimum at which point the transients became level and continuous. H is the interval between each transient, and X the value that defines the transient form as given in Fig. 1. The column 'Diff' is the average difference between the water sampled and the actual water present as a percentage of the total flow and column 'E' is the 95 per cent confidence limits to which any one sampling period could be quoted again as a percentage of the total flow. For instance, the first row of Table 3 for the square waveform at 100 per cent P measured on average 0.002 per cent above the actual 5 per cent water but any one tanker measurement could only be quoted to  $\pm 0.814$  per cent. Examination of Tables 3 and 4 produce the following conclusions:

a Maximum sampling errors are incurred with transients of square waveform, less so with shaped waveform and least with sawtooth waveform. In the case of the 1000 grabs/discharge simulations the relative ratios in sampling error between the waveforms were 4:2:1 respectively.

b For the square waveform the sampling error at 10 000 grabs/discharge is about 10 times less than the sampling error at 1000 grabs/discharge - confirming Section 2.1 above.

c For the shaped and sawtooth waveform the sampling error is substantially less than the square waveform sampling error at 10 000 than at 1000 grabs/discharge and increasingly so as transient peak increases.

d At 10 000 grabs/discharge the sampling error is almost insignificant for both shaped and sawtooth waveforms and also for the square waveform except when the peak rises above about 30 per cent.

e At 1000 grabs/discharge the sampling error is very significant except for shaped and sawtooth waveforms with peak values less than about 30 per cent.

It must again be emphasised that the errors given in the tables refer only to the statistical errors of intermittent sampling, and do not include the physical errors incurred in obtaining and analysing the samples.

The values of sampling error given in Tables 3 and 4 can be used to obtain approximate values for errors in shaped and sawtooth waveforms for other durations and intervals by comparison of the square waveform values given in Table 2.

### 3 TRANSFER STUDY PROGRAM

The foregoing simulation determined the effects transient waveform had on sampling accuracy but was an academic exercise in many ways because it is very difficult to establish the waveforms in real life. The second program was therefore written to examine a pipeline transfer or tanker discharge in its entirety and as such was written in two parts, a data acquisition program DATALOG, and a data analysis program, DATACAL, each of which is described below:

#### 3.1 Data Acquisition Program

This program was written specifically for an Epson PX-8 micro-computer to utilise its portability, internal timers and 6 byte resolution analogue to digital converter. Input was in the form of a 0-2 V d.c. signal either from a manual control or from a water in oil capacitance cell. As such the computer and program could be used to manually simulate a pipeline transfer from chart recordings etc, or be carried and linked to a capacitance cell off-shore or at a jetty to record 'real time' transfers.

During data acquisition the program displayed variables such as control status, actual time, elapsed time, storage capacity, and analogue input signal level on the LCD screen of the computer. Either averaged or instantaneous digital recordings could be taken at specified intervals from one second or longer and stored in the internal memory of the computer or on an external micro floppy disc. If stored internally, 60 000 or stored on micro disc, 140 000 two byte recordings could be taken per transfer or tanker discharge.

### 3.2 Data Analysis Program

Analysis of the data was in three parts:

#### 3.2.1 Evaluating sampling error relative to sampling frequency

The actual water content in the transfer was calculated by accumulating the water content at every point recorded during the transfer. Sampling errors were then evaluated for a particular sampling frequency by accumulating the water content at points separated by that frequency and evaluating the difference between that and the actual water content. This was repeated for 30 different statistical populations at each sampling frequency from which the 95 per cent confidence levels of quoting water content for any one population could be calculated. These confidence levels were taken as being the sampling error for sampling at that particular frequency. This was repeated for a series of sampling frequencies, the results of which were output in numerical form.

#### 3.2.2 Evaluating the sampling error/frequency function

The sampling errors evaluated at each sampling frequency were entered into a curve fitting routine to calculate a mathematical relationship between sampling error and sampling frequency. From this relationship, the minimum sampling frequency required to give a specified confidence level for water content measurement could be derived.

#### 3.2.3 Evaluating the probability density function

All the data points were 'filtered' into 64 different water content ranges and the number of points falling in each range accumulated for the total transfer or discharge. The number of points falling in each range was then evaluated as a percentage of the total number of points and output both numerically and graphically to give the probability density function of the water contents recorded during the transfer or discharge.

### 3.3 Application of the Program

No opportunity was available to use the data acquisition system on a field transfer or tanker discharge during the course of this work. In the absence of any field data, therefore, several simulated tanker discharges were created from a manual input. The simulated discharges were modelled on several chart recordings of actual tanker discharges and endeavoured to give a high water content during the initial and final stages of the discharge and to insert random transients during the entire discharge period. The simulated discharges were deliberately made much more severe in terms of transient character to give a 'worst case' simulation.

The results of this exercise can be seen in the computer printouts for a typical simulated discharge logging and analysis given in Tables 5 and 6. Table 5 shows the analysis covered  $3400 \times 24 = 81600$  points at one second intervals, ie a total of 22 hours and 40 minutes. The maximum water content during that time was 2 per cent, and the mean water content 0.5 per cent. Table 5 also shows the

regression relationship between sampling error and sampling interval. Table 6 shows the probability density function of the discharge where the top S63 represents the 2 per cent water level, and S0 the 0 per cent water level. Densities at each intervening water level are given as percentages of the whole and plotted horizontally across the page as a graphical representation of the function.

Three simulated discharges were created and analysed over different sections of the recordings to give a total of 25 different simulated discharges, the results of which are summarised in Table 7. Several relationships, power, logarithmic and exponential between sampling uncertainty and sampling frequency were tried on the analysis of several simulated discharges and the linear relationship returned the highest correlation coefficient in every case. Examination of the results in Table 7 show this linear relationship between sampling error and sampling frequency, ie sampling error is inversely proportional to sampling frequency.

Before using the results of Table 7 to estimate an optimum sampling frequency a measure of the sampling accuracy required must be decided. Wilson and Richards (5) estimated that the best obtainable accuracy for the overall sampling/transfer/handling/sub-sampling/lab-testing procedure was  $\pm 0.05$  per cent. This estimate included the repeatability/reproducibility for the Karl Fischer titration water analysis method which was quoted as 0.02/0.06 per cent up to the 1.5 per cent water content. If this is the case then it would be pointless trying to reduce the uncertainty attributable to sampling frequency to better than  $\pm 0.01$  per cent as it would be lost in the other components contributing to the overall sampling uncertainty. Table 7 shows that for the assumed 'worst case' simulated discharges analysed that a sampling frequency of 1000 samples per discharge would be borderline, 2000 samples per discharge would be more than adequate and that 10 000 samples per discharge would really be unnecessary. This conclusion is based on the worst case of tanker discharges but in cases where minimal water transients would be expected, in a continuous production well export line for example, it is possible that the sampling frequency could be substantially less without impairing sampling accuracy.

#### REFERENCES

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- 2 KING, N. W. The NEL Sampling Project. North Sea Flow Metering Workshop, NEL, East Kilbride, October 1984.
- 3 KING, N. W., PURFIT, G. L., PURSLEY, W. C. Improving the performance of automatic grab samplers using a unique laboratory test facility. Spring National AIChE, Houston, Texas, USA, March 1985.
- 4 KING, N. W., PURFIT, G. L., PURSLEY, W. C. Studies and improvements in the design and operation of fast loop water in oil samplers. BHRA Conf. Multi-phase Flow, London, June 1985.
- 5 WILSON, M. B., RICHARDS, B. O. Continuous measurement of the water content of crude oil using electrical capacitance techniques - development and applications IP Conf. Oil Loss Control in the Petroleum Industry, London, Oct 1984.

TABLE 1

MEMBERS OF PHASE THREE OF THE NEL AUTOMATIC SAMPLING PROJECT

Organisation	Representative
AMOCO (UK) Exploration Co.	B Henderson
BRITISH PETROLEUM Int. Ltd.	R Gold, J S S Miller, A Thorogood
BRITOIL Plc.	K F L Withams
CHEVRON Petroleum (UK) Ltd.	D Clark
CONOCO (UK) Ltd.	G Payne
DEPARTMENT OF ENERGY	C F Sayer
DEPARTMENT OF TRADE AND INDUSTRY	P R Lalleem
ELF (UK) Ltd.	E Garland
ESSO Engineering (Europe) Ltd.	Dr. L P Golan, G W Watts
MARATHON Oil (UK) Ltd.	E Tolladay
MOBIL Services Co. Ltd.	L W Farey, J Beeftink
NORWEGIAN PETROLEUM DIRECTORATE	F Paulsen, S Solbakken
OCCIDENTAL Pet.(Caledonia) Ltd.	M. D H Bayliss, B Lawson
PHILLIPS Pet. Co. (Norway)	W G Grant, R T Liddle
SHELL UK Exploration	G R Watson, G Cromarty, Miss K Paterson, E G McGirr
STATOIL	N Monsen, T Ingebrigtsen
UNION OIL of Great Britain Ltd.	P Clegg

TABLE 2

INTERPOLALATION COEFFICIENTS FOR THE COMPUTER SIMULATIONS

Regression fits were of the form :-

$$E = a + bP - cH + \frac{d}{D}$$

where P, H and D are dependent variables given by

$$W_a = \frac{DP}{H+D}$$

G	% Water	R	a	b	c	d
1000	1	0.93	0.092437	0.004516	0.000025	0.090338
1000	5	0.93	0.059429	0.008836	0.000068	0.971822
1000	10	0.94	-0.019357	0.013786	0.000254	2.441642
1000	20	0.88	0.296827	0.010450	0.000491	0.248190
1000	50	0.69	1.561355	0.001545	0.001455	0.119280
10,000	1	0.92	0.005638	0.000747	0.000003	0.085879
10,000	5	0.90	0.004825	0.001011	0.000008	0.338854
10,000	10	0.93	0.023533	0.001122	0.000025	0.075399
10,000	20	0.97	0.080174	0.000138	0.000030	1.749248
10,000	50	0.94	0.015115	0.000910	0.000020	6.843370

TABLE 3

STUDY OF EFFECT OF TRANSIENT WAVEFORM ON INTERMITTENT SAMPLERS  
AT A GRAB RATE OF 1,000 GRABS/TANKER DISCHARGE, 5% WATER

P %	H sec	X sec	Diff.	95% C.L.
<b>SQUARE WAVEFORM H+D=1200, G=86</b>				
100	1140	60	0.002	0.814
90	1133.3	66.66	0.005	0.534
80	1125	75	0.035	0.306
70	1114.3	85.71	0.001	0.272
60	1100	100	-0.008	0.350
50	1080	120	-0.004	0.418
40	1050	150	-0.026	0.328
30	1000	200	-0.030	0.194
20	900	300	0.002	0.138
10	600	600	0.005	0.074
7.5	400	800	0.003	0.052
5	flat	flat	0.000	0.000
<b>SHAPED WAVEFORM H+D=1200, G=86</b>				
100	1110	90	-0.004	0.434
90	1100	100	-0.009	0.378
80	1087.5	112.5	-0.019	0.200
70	1071.4	128.6	-0.001	0.048
60	1050	150	0.004	0.130
50	1020	180	0.025	0.130
40	975	225	0.004	0.046
30	900	300	0.003	0.024
20	750	450	0.001	0.018
10	300	900	0.002	0.004
7.5	0	1200	0.002	0.004
5	flat	flat	0.000	0.000
<b>SAWTOOTH WAVEFORM H+D=1200, G=86</b>				
100	1080	120	0.010	0.208
90	1066.7	133.3	0.071	0.142
80	1050	150	-0.000	0.046
70	1028.6	171.4	0.002	0.014
60	1000	200	0.007	0.050
50	960	240	0.008	0.074
40	900	300	0.000	0.034
30	800	400	0.002	0.022
20	600	600	0.002	0.016
10	0	1200	0.003	0.002
7.5	over	lap		
5	flat	flat	0.000	0.000

TABLE 4

STUDY OF EFFECT OF TRANSIENT WAVEFORM ON INTERMITTENT SAMPLERS  
AT A GRAB RATE OF 10,000 GRABS/TANKER DISCHARGE, 5% WATER

P %	H sec	X sec	Diff.	95% C.L.
<b>SQUARE WAVEFORM H+D=1200, G=8.6</b>				
100	1140	60	-0.001	0.076
90	1133.3	66.66	0.003	0.064
80	1125	75	-0.002	0.044
70	1114.3	85.71	-0.002	0.046
60	1100	100	-0.001	0.030
50	1080	120	-0.001	0.034
40	1050	150	-0.003	0.022
30	1000	200	0.001	0.020
20	900	300	0.001	0.016
10	600	600	0.001	0.008
7.5	400	800	0.001	0.004
5	flat	flat	0.000	0.000
<b>SHAPED WAVEFORM H+D=1200, G=8.6</b>				
100	1110	90	0.000	0.006
90	1100	100	0.000	0.002
80	1087.5	112.5	0.001	0.004
70	1071.4	128.6	0.001	0.000
60	1050	150	0.000	0.002
50	1020	180	0.001	0.000
40	975	225	0.000	0.002
30	900	300	0.001	0.002
20	750	450	0.001	0.002
10	300	900	0.001	0.000
7.5	0	1200	0.001	0.000
5	flat	flat	0.000	0.000
<b>SAWTOOTH WAVEFORM H+D=1200, G=8.6</b>				
100	1080	120	0.001	0.002
90	1066.7	133.3	0.001	0.002
80	1050	150	0.001	0.002
70	1028.6	171.4	0.000	0.002
60	1000	200	0.001	0.002
50	960	240	0.001	0.002
40	900	300	0.001	0.002
30	800	400	0.001	0.002
20	600	600	0.001	0.002
10	0	1200	0.001	0.000
7.5	over	lap		
5	flat	flat	0.001	0.000

TABLE 5

PRINTOUT OF 'DATACAL' PROGRAM SHOWING STATISTICAL RESULTS

-----  
ANALYSIS OF SAMPLING RECORDING TEST4

\*\*\* NATIONAL ENGINEERING LABORATORY \*\*\*  
 \*\*\* program DATACAL by N W King \*\*\*

Comments:- DATALOGS program used for logging  
 Artificial tanker discharge

Test start 08:43:29 on 11/02/86 and end 10:10:42 on 11/02/86  
 File has 3401 records each with 24 single loggings every 1 sec.  
 This analysis covered records from 1 to 3400  
 Maximum voltage was 2.0 representing 2.0 % water content.

<<< MEANS AND STANDARD DEVIATIONS >>>

	MEAN	DIFFERENCE	SIGMA	'T'SIGMA
Every 1536 points =	0.5314	-0.0030	0.0533	0.1045
768 =	0.5319	-0.0024	0.0310	0.0608
384 =	0.5334	-0.0010	0.0238	0.0466
192 =	0.5339	-0.0005	0.0145	0.0285
96 =	0.5342	-0.0002	0.0076	0.0148
48 =	0.5342	-0.0001	0.0022	0.0043
24 =	0.5344	-0.0000	0.0018	0.0038
12 =	0.5344	0.0000	0.0006	0.0012
8 =	0.5344	0.0000	0.0007	0.0016
4 =	0.5344	0.0000	0.0003	0.0008
2 =	0.5344	0.0000	0.0000	0.0000
1 =	0.5344	0.0000	0.0000	0.0000

<<< REGRESSION >>>

SAMPLING ERROR = 0.00006951 \* SAMPLING INTERVAL(S) + 0.00442706

Correlation coefficient = 0.97805

Interval to obtain +/- 0.1 % water confidence limits = 1375 sec.

Interval to obtain +/- 5% of mean water content c.l. = 321 sec.

TABLE 6

PRINTOUT OF 'DATACAL' PROGRAM SHOWING PROBABILITY FUNCTION

S63 = 0.42 *	S31 = 0.98 *
S62 = 0.13 *	S30 = 0.92 *
S61 = 0.15 *	S29 = 0.98 *
S60 = 0.07 *	S28 = 0.98 *
S59 = 0.25 *	S27 = 1.34 *
S58 = 0.40 *	S26 = 1.48 *
S57 = 0.32 *	S25 = 2.26 *
S56 = 0.47 *	S24 = 1.69 *
S55 = 0.31 *	S23 = 2.87 *
S54 = 0.21 *	S22 = 1.62 *
S53 = 0.47 *	S21 = 1.73 *
S52 = 0.47 *	S20 = 1.62 *
S51 = 0.26 *	S19 = 2.07 *
S50 = 0.50 *	S18 = 1.61 *
S49 = 0.47 *	S17 = 1.13 *
S48 = 0.43 *	S16 = 2.21 *
S47 = 0.74 *	S15 = 1.91 *
S46 = 0.38 *	S14 = 1.23 *
S45 = 0.54 *	S13 = 1.91 *
S44 = 0.54 *	S12 = 1.33 *
S43 = 0.68 *	S11 = 3.87 *
S42 = 0.64 *	S10 = 2.47 *
S41 = 0.33 *	S09 = 6.39 *
S40 = 0.60 *	S08 = 5.29 *
S39 = 2.07 *	S07 = 2.95 *
S38 = 1.01 *	S06 = 3.78 *
S37 = 0.47 *	S05 = 3.78 *
S36 = 0.76 *	S04 = 17.93 *
S35 = 0.28 *	S03 = 4.39 *
S34 = 0.56 *	S02 = 0.42 *
S33 = 0.34 *	S01 = 0.49 *
S32 = 0.82 *	S00 = 0.54 *

TABLE 7

## RESULTS OF 25 'DATA CAL' COMPUTER SIMULATIONS

TEST NO	REC START	REC END	NO PTS	MAX WATER	MEAN WATER	NOM* PEAK	UNCERTAINTY AT GIVEN SAMPLES/DISCHARGE						
							100	200	500	1000	2000	5000	10000
4	1	3400	81600	2	0.53	1.86	0.114	0.061	0.030	0.019	0.007	0.004	0.003
4	1	1700	40800	2	0.54	1.86	0.149	0.098	0.046	0.020	0.015	0.004	0.003
4	1700	3400	40800	2	0.53	1.88	0.059	0.031	0.015	0.009	0.007	0.005	0.004
10	1	2400	57600	2	0.38	2.63	0.121	0.060	0.035	0.023	0.017	0.006	0.004
10	1	1200	28800	2	0.39	2.56	0.095	0.052	0.017	0.009	0.004	0.002	0.001
10	1200	2400	28800	2	0.36	2.74	0.086	0.050	0.040	0.033	0.016	0.003	0.003
10	1	600	14400	2	0.36	2.76	0.091	0.050	0.015	0.013	0.006	0.003	0.003
10	600	1200	14400	2	0.42	2.38	0.071	0.043	0.018	0.013	0.007	0.003	0.003
10	1200	1800	14400	2	0.40	2.47	0.074	0.065	0.044	0.012	0.007	0.003	0.003
10	1800	2400	14400	2	0.33	3.07	0.110	0.086	0.054	0.025	0.010	0.003	0.003
10	1	300	7200	2	0.43	2.3	0.065	0.035	0.016	0.007	0.003	0.003	0.003
10	600	900	7200	2	0.41	2.42	0.097	0.059	0.036	0.014	0.006	0.004	0.004
10	1200	1500	7200	2	0.34	2.91	0.058	0.048	0.017	0.013	0.003	0.002	0.002
10	1800	2100	7200	2	0.33	3.07	0.055	0.046	0.018	0.003	0.002	0.002	0.002
11	1	2400	57600	32	1.64	19.53	0.322	0.213	0.086	0.056	0.015	0.005	0.003
11	1	1200	28800	32	2.00	16.00	0.219	0.126	0.071	0.052	0.020	0.003	0.001
11	1200	2400	28800	32	1.27	25.20	0.289	0.179	0.113	0.070	0.011	0.004	0.002
11	1	600	14400	32	2.63	12.16	0.166	0.093	0.049	0.010	0.007	0.003	0.002
11	600	1200	14400	32	1.37	23.25	0.206	0.082	0.051	0.010	0.004	0.003	0.002
11	1200	1800	14400	32	0.64	50.00	0.342	0.218	0.125	0.060	0.020	0.010	0.005
11	1800	2400	14400	32	1.91	16.74	0.183	0.131	0.060	0.016	0.007	0.005	0.004
11	1	300	7200	32	3.70	8.64	0.136	0.081	0.030	0.011	0.006	0.004	0.003
11	600	900	7200	32	1.54	20.78	0.188	0.050	0.020	0.010	0.005	0.004	0.003
11	1200	1500	7200	32	0.78	40.76	0.198	0.099	0.040	0.013	0.009	0.005	0.003
11	1800	2100	7200	32	1.44	22.29	0.174	0.084	0.035	0.014	0.007	0.005	0.003

means = 0.147 0.086 0.043 0.021 0.008 0.004 0.003

(\* Nominal Peak = maximum peak water content if mean water were 1 percent)

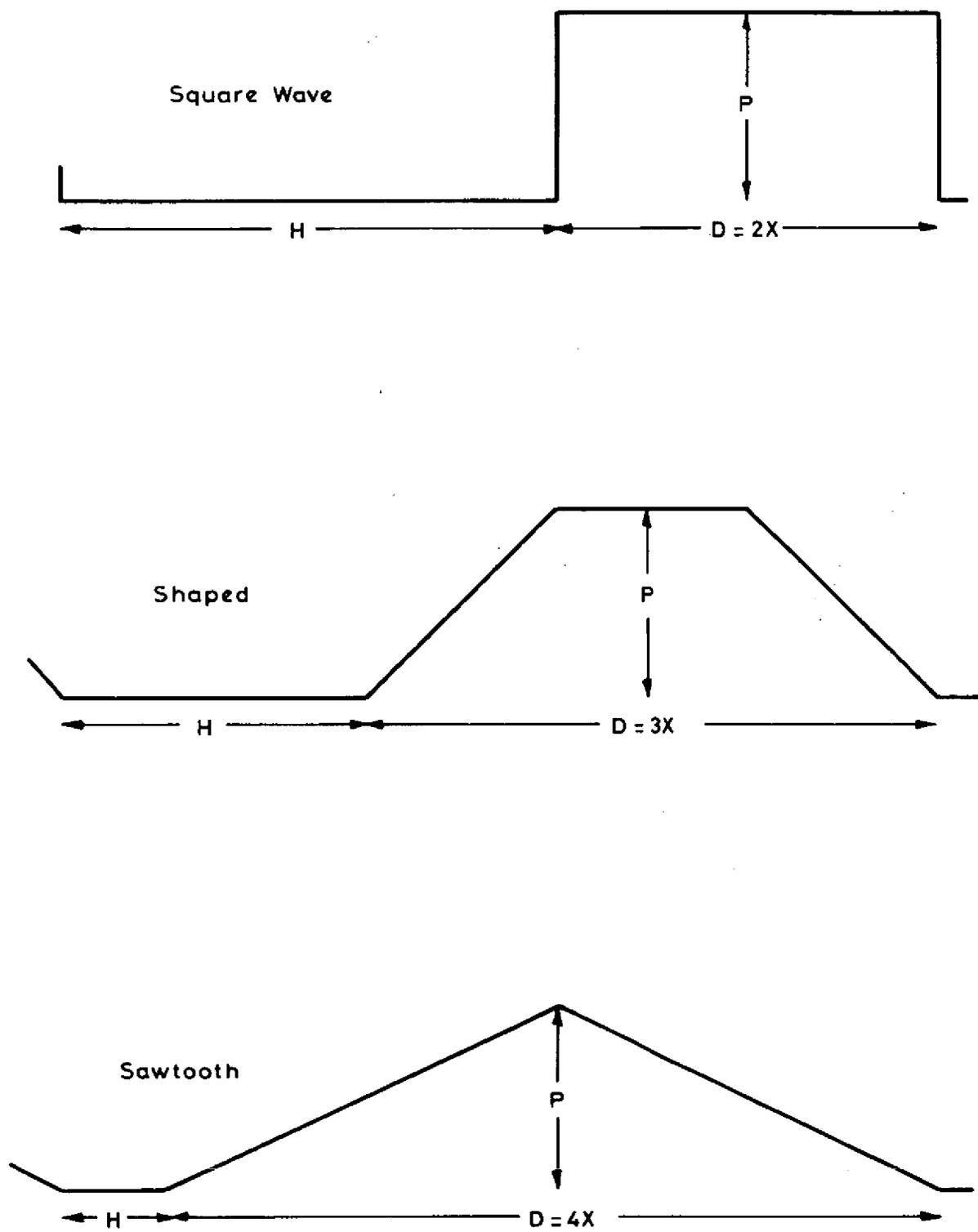


Fig 1 Transient Waveforms used in Computer Simulations

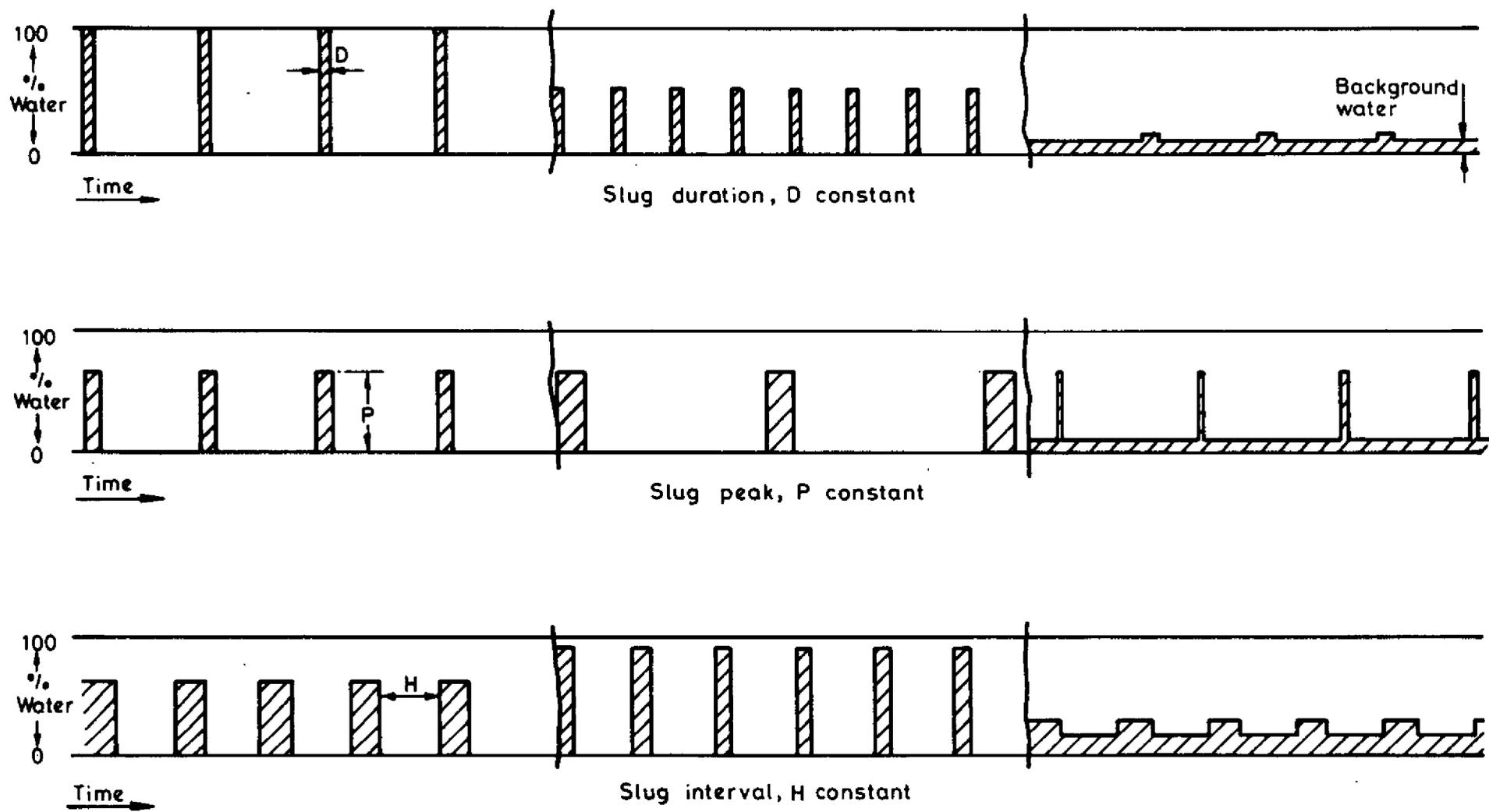


Fig 2 Examples of Some Types of Water Transients

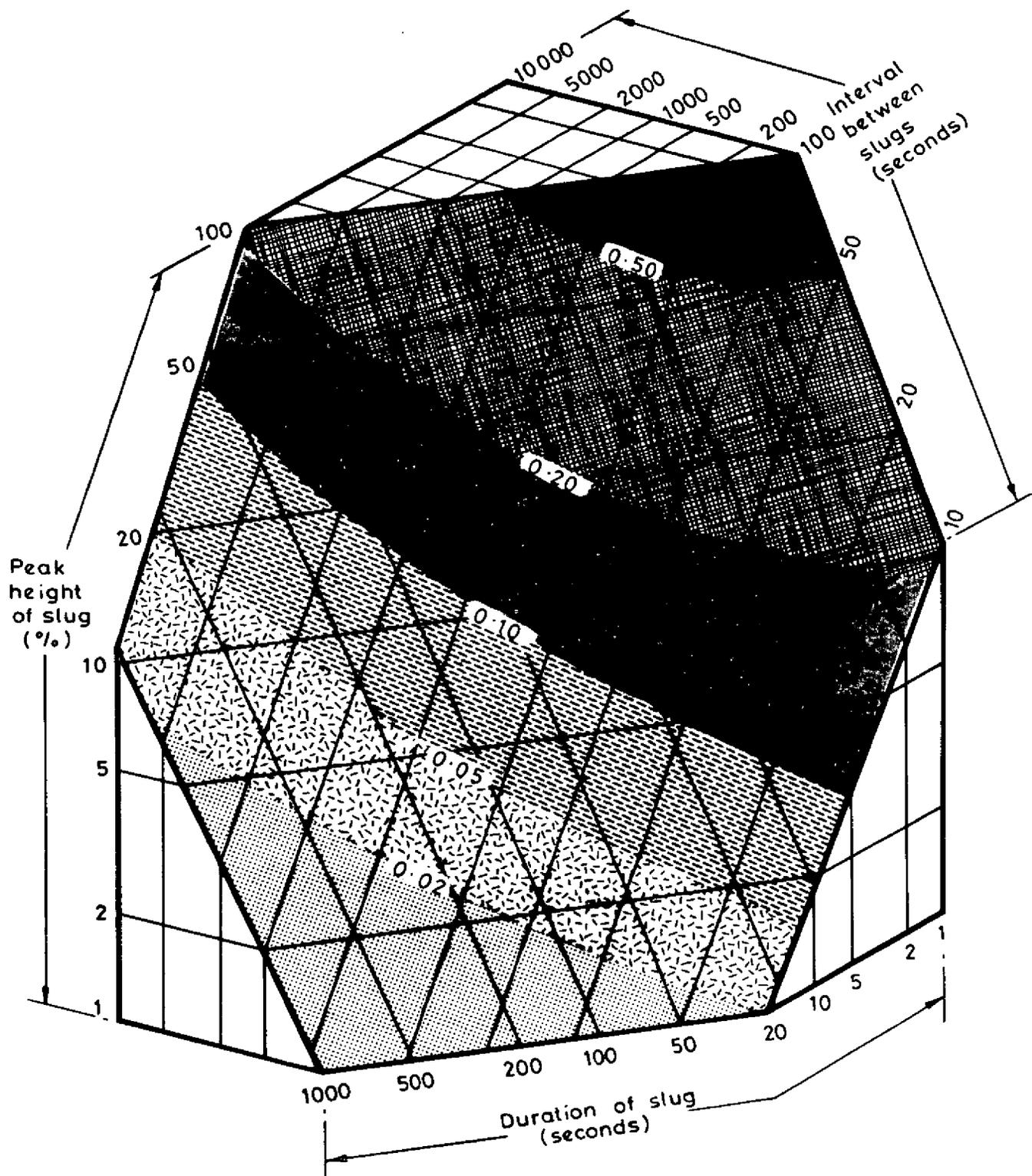


Fig 3 Three-Dimensional Representation of Magnitude of Sampling Error E as Transient Duration, Peak and Interval are Varied with 1 per cent Water Content, 24 Hour Sampling Period and 1000 Sample Grabs

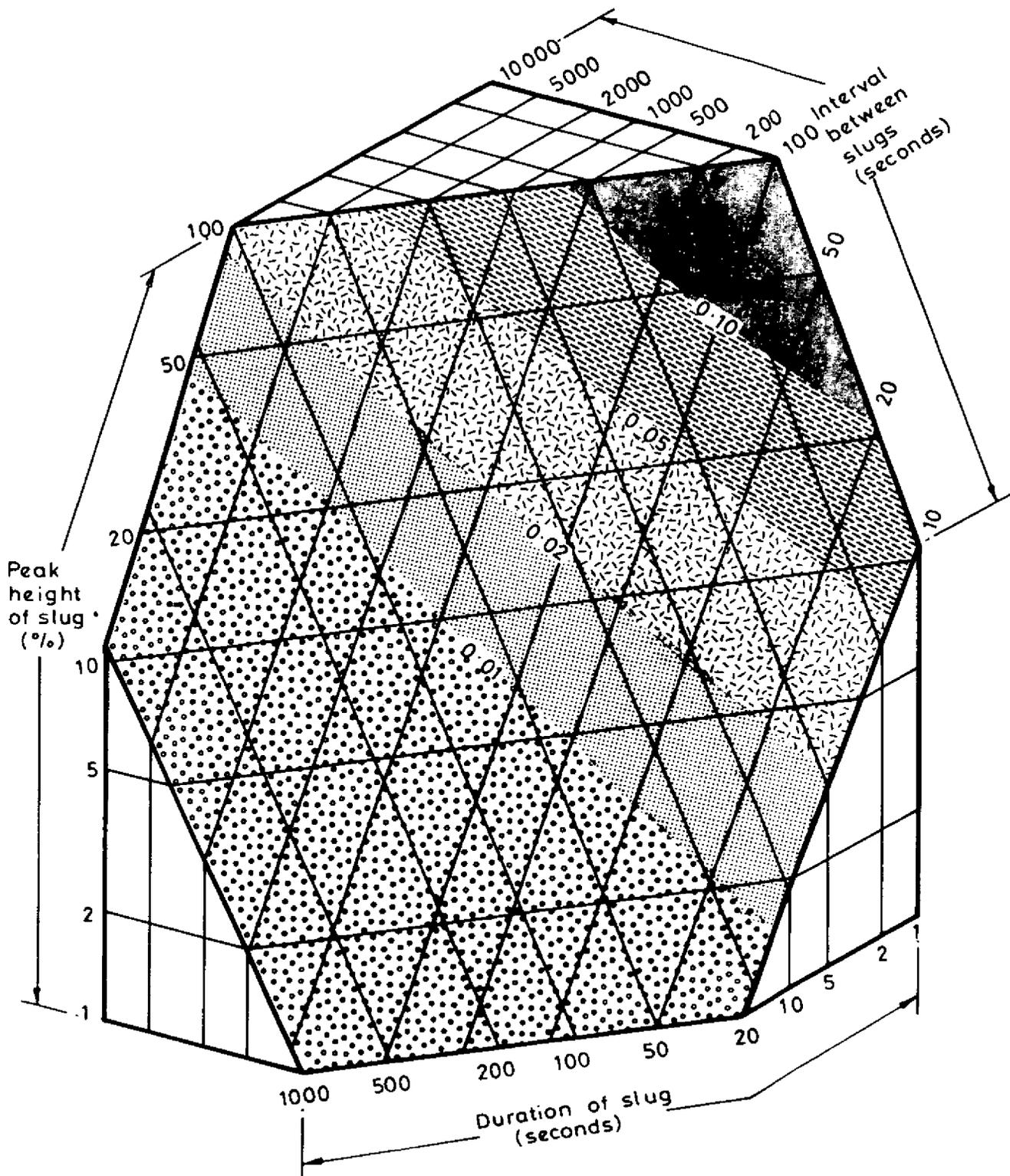
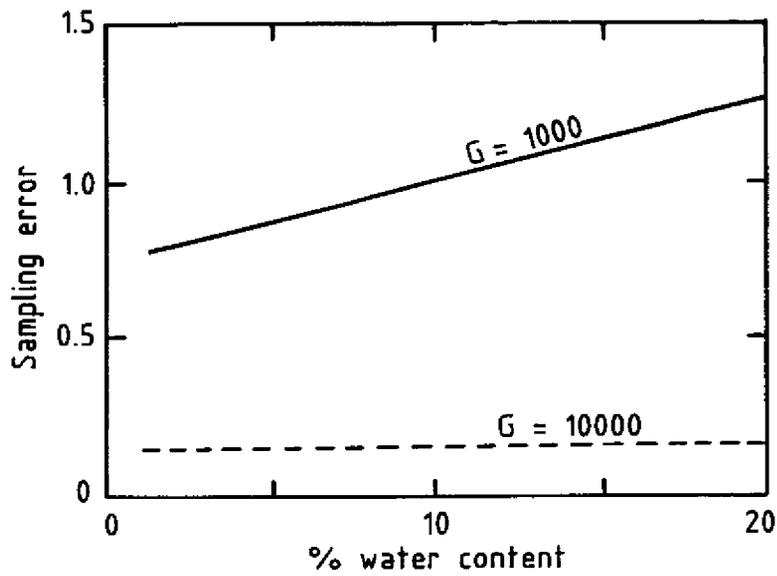
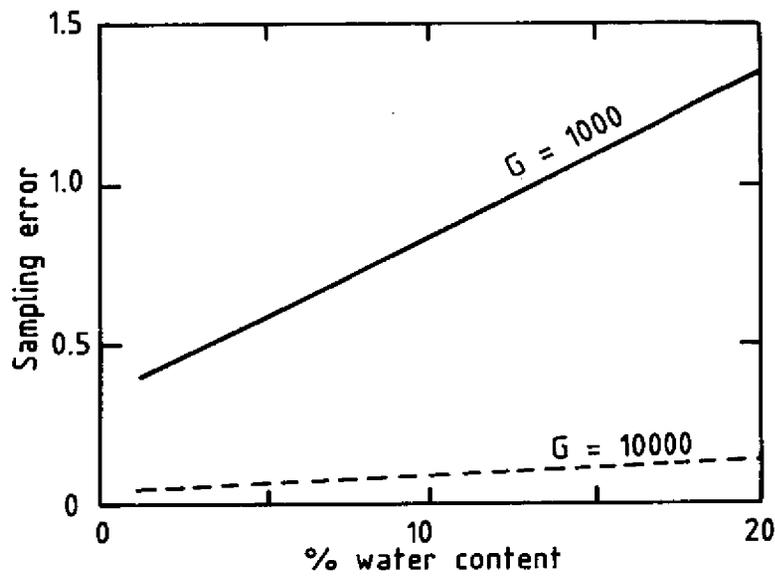


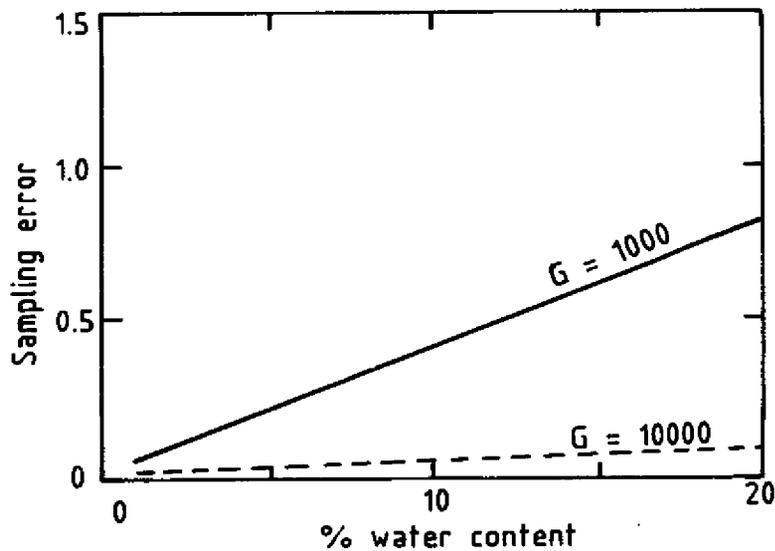
Fig 4 Three-Dimensional Representation of Magnitude of Sampling Error E as Transient Duration, Peak and Interval are Varied with 1 per cent Water Content, 24 Hour Sampling Period and 10000 Sample Grabs



(a)  
 $p = 100\%$   
 $H = 500 \text{ sec}$



(b)  
 $p = 100\%$   
 $D = 100 \text{ sec}$



(c)  
 $H = 1000 \text{ sec}$   
 $D = 500 \text{ sec}$

Fig 5 Graphical Representation of Selected Variable Relationships from the Computer Simulation

OFFSHORE EXPERIENCE WITH THE ENDRESS AND HAUSER WATER IN  
HYDROCARBONS MONITOR

by

G SHIRAN  
SHELL UK EXPLORATION AND PRODUCTION LTD

---

Paper 1.3

NORTH SEA FLOW METERING WORKSHOP 1986

7-9 October 1986

National Engineering Laboratory  
East Kilbride, Glasgow

## INTRODUCTION

In order to reduce the considerable expense involved in transporting oil from offshore production platforms to onshore terminals, it is now common practice for several different platforms to use the same pipeline. For accounting purposes, each contributor to the pipeline must obviously monitor both the quantity and the quality of the fluid which it exports. This information is of great interest (mainly financial !) to the contributor, its pipeline partners, and to the Department of Energy.

In this context, Shell U.K. Exploration and Production Ltd has mandatory and contractual obligations to measure and record the water content of the oil it produces in the Northern Sector of the North Sea. This measurement, commonly referred to as "B.S. & W." within the industry, has proved a difficult one to make using continuous means. The intention of this paper is to briefly describe the problems encountered, and to show how these have led to our present programme of installing and evaluating the "Aquasyst" sensor manufactured by Endress & Hauser (U.K.) Ltd.

## BACKGROUND

The most obvious means of determining the water content of oil in a pipeline is to draw off a sample for analysis in a laboratory. However this technique is beset by two major problems.

Firstly, it is not continuous, allowing short peaks of high water levels to pass undetected between samples. This applies during process upsets or when the wells in use are being changed over.

Secondly, it is cumbersome and is acknowledged to need improvement. Recent work indicates that the geometry of the sampling point and the method of analysis can have a dramatic effect on accuracy.

In an attempt to overcome these problems, many platforms have been fitted with sensors which provide continuous measurement. These take the form of a cylinder within the oil pipework which acts as a fixed geometry capacitor. The different dielectric constants for oil and water allow the water content to be inferred from the capacitance measured.

Most sensors of this type are without formal certification of their suitability for use in hazardous areas. Only one unit is covered in this way, and it has therefore been used widely in the North Sea.

Some problems have been experienced with this unit. In a few instances, the cylindrical section within the oil pipe has broken off, probably due to turbulent flow. This has been caused, or accompanied, by a failure of the main connecting stud joining the cylinder and the electronics housing, allowing oil at pressure to flood the instrument electronics. In some cases, the oil actually made its way up the signal cable. With this in mind, we continued to make the measurements required of us, but looked for some improvement on the methods available.

## ONSHORE EXPERIENCE

Our search for a replacement led to the Endress & Hauser "Aquasyst" instrument. This device had been developed in conjunction with B.P. and carried a suitable specification, deriving its capacitance measurement from change transfer characteristics of the fluid instead of the impedance method of earlier instruments. Early trial reports seemed encouraging. It was not covered by formal certification of its suitability for use in hazardous areas, although it has been submitted to BASEEFA for approval. It has, however, been given a Letter of Conformity for the appropriate CENELEC standards by SIRA Ltd. It can therefore be regarded as meeting the engineering requirements for an Intrinsically Safe system, and we have chosen to accept this pending full certification cover.

We therefore purchased one unit - the dual cell model with Class 900 piping specification and 5% range. To gain some experience quickly, without the obvious disadvantages of working on a "live" offshore platform, we pursued a brief programme of onshore testing.

A small pumped test rig as used (see Figure 1) with gas oil as the fluid, since this has a dielectric constant similar to that of our crude oil. Measured quantities of water were added, and the resulting mixture analysed by the Karl Fischer titration method. The results obtained (Appendix A) indicated three main characteristics for the instrument.

1. Linear response.
2. Good repeatability.
3. Rapid and stable response to "step" changes in water level.

Our instrument gave sensible readings up to 5.5% water in oil, then simply continued to display this figure at all higher water levels. These results were deemed satisfactory, and the instrument was taken offshore.

## OFFSHORE INSTALLATION

The first unit purchased was installed on the North Cormorant platform. For operational reasons, the instrument had to be installed without shutting down the platform, resulting in the sensor being mounted in a densitometer bypass loop, with the sample flowing vertically downwards (see Figure 2). Although the manufacturers recommend that the sample should flow upwards ideally, this option was not available at the time.

Two points regarding the installation are worthy of note. Firstly the weight of the sensor itself demands attention. At 98 kg, it cannot simply be mounted at the side of a pipe - proper structural supports are essential, especially since the inlet and outlet connections are made via one inch pipework.

Secondly, we chose to use a manual bypass valve in parallel with the sensor. No figures were available for the flow resistance presented by this sensor, so we needed a means of controlling both the flow rate through the sensor (to exceed recommended minimum velocity) and the flow resistance in the main sample loop (to avoid overloading the pumps and prevent gas break-out within the instrument).

Using this arrangement, we then carried out several series of comparisons between the readings generated by the instrument and the corresponding sample analyses using laboratory techniques. The results of these tests are discussed in the next section.

In view of the importance of the measurement, a further two instruments were installed - one on the Fulmar Alpha platform and one on the Fulmar Floating Storage Unit (F.S.U.). In both cases, the sensor was again mounted in a pumped densitometer loop, but with the sample flowing vertically upwards as recommended. Both instruments were monitored as above. By this stage, Endress & Hauser had replaced the original electronics module with a microprocessor based unit, but the sensor remained unchanged.

Further installations are planned on three more platforms at present, with some improvements. Additional isolation valves with dedicated calibration and drainage connections should help both commissioning and maintenance. A local flow indicator will ensure that the minimum recommended flow velocity through the sensor is consistently exceeded. (See Figure 3).

#### TEST RESULTS

After initial commissioning of the North Cormorant instrument, its readings were recorded and compared with a sample taken some way downstream and analysed by the centrifuge technique.

While the upper cell followed the trend in water levels indicated by sample results, the lower cell drifted steadily to a high reading. The discrepancy between cells exceeded 1% water in oil within 24 hours. Closing in the bypass valve to increase the sample flow rate through the instrument cleared the discrepancy in some ten minutes. This "flushing" technique confirmed the manufacturer's warning that low flow rates can lead to water droplets settling out on the lower sensor. It has also proved useful when similar problems were encountered as a result of water slugs.

These early results (Appendix B) showed an encouraging ability of the instrument to follow changes in the water content of the oil being analysed. In fact the recorder trace became a convenient tool for the platform operators to monitor short peaks of water during process upsets or well changes (Appendix C).

The absolute accuracy of the instrument readings still required further investigation however. By this stage, three instruments were installed. The testing programme was continued on all three locations, but with two distinct improvements.

Firstly, the samples were taken close to the instrument, within the sample loop, to provide a more representative sample. Secondly, the laboratory analysis was based on the Karl Fischer titration technique, which has been demonstrated to be more accurate than the centrifuge technique, especially at low water levels.

Each series of tests covered one month, with samples taken every 12 hours (one per operating shift). Some of the results are displayed in Appendix D, and be summarised as follows:-

1. The instrument follows trends in water levels closely.
2. Occasional sudden divergences appear to be unrelated.
3. In the majority of cases, the instrument readings and the results of sample analysis differ in the second decimal place of percentage water in oil.

Throughout our work, the equipment has appeared robust, with failures limited to the safe area electronics, namely an opto-isolator and a power supply card.

#### FURTHER WORK

At the time of writing, our series of tests are still continuing. The major question marks lie in the areas of sample removal and analysis. Getting a representative sample of the fluid passing through a pipe is now recognised to be fraught with difficulties. In an ideal world several samples would be taken for independent analysis and comparison by dedicated laboratory personnel, but such luxury is not available on a busy offshore platform.

The relationship between pressure loss across the cell and flowrate has still to be determined if the instrument is to form part of a pumped analysis loop. We have attempted to calculate theoretical figures, but the assumptions made to cope with the internal geometry of the cell simply confirm that some practical testing is essential.

Full BASEEFA approval would clearly be desirable. The instrument range is now 40% water in oil, compared with the original 5%, so that it is now being looked at for other uses outside fiscal oil metering stations. In such applications (for example, within the separation process of an offshore platform) any increase in range beyond 40% water would be particularly attractive as the water levels encountered in our existing fields increase through time.

FIGURE 1 - ONSHORE TEST RIG

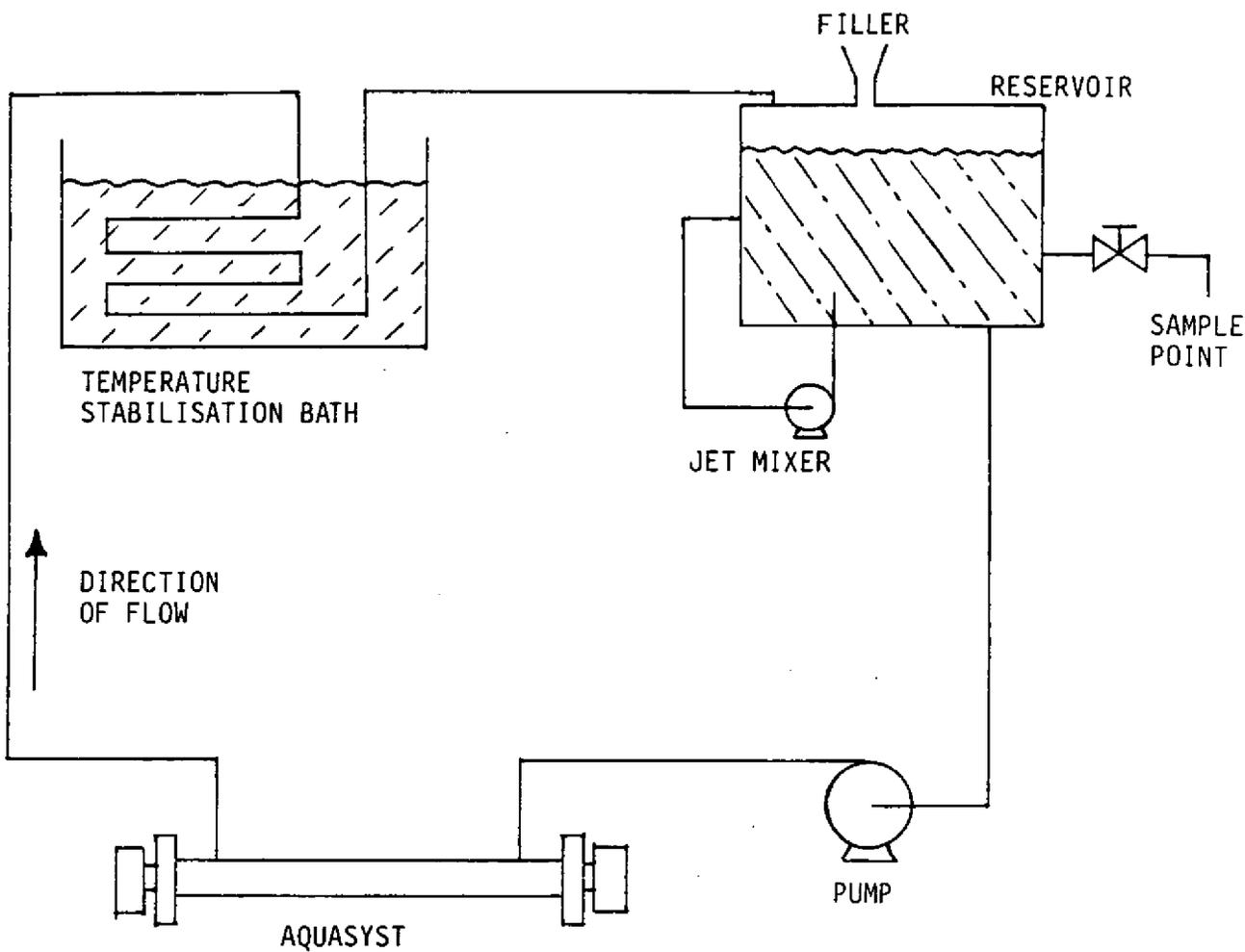


FIGURE 2 - INSTRUMENT INSTALLATION (NORTH CORMORANT)

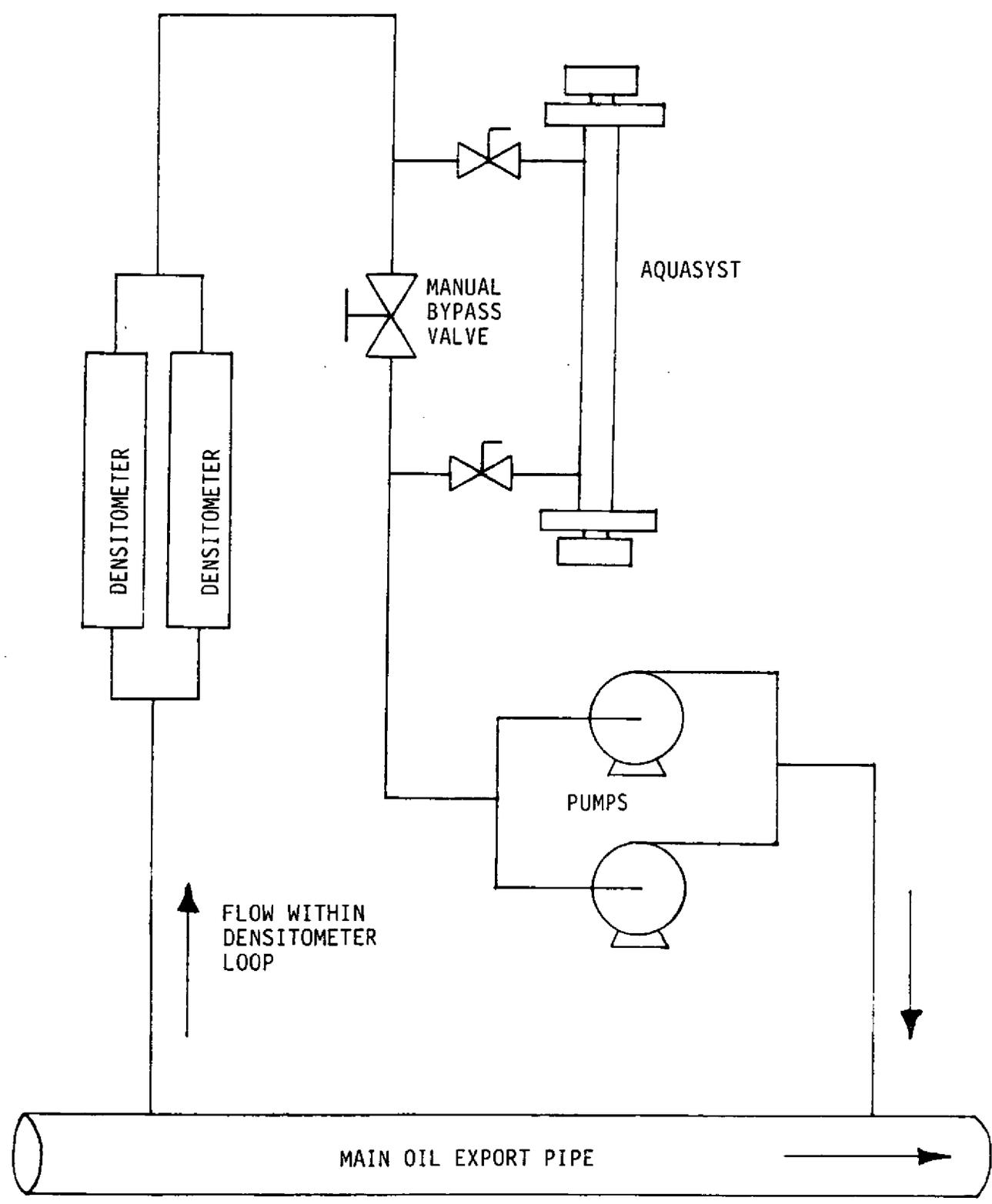
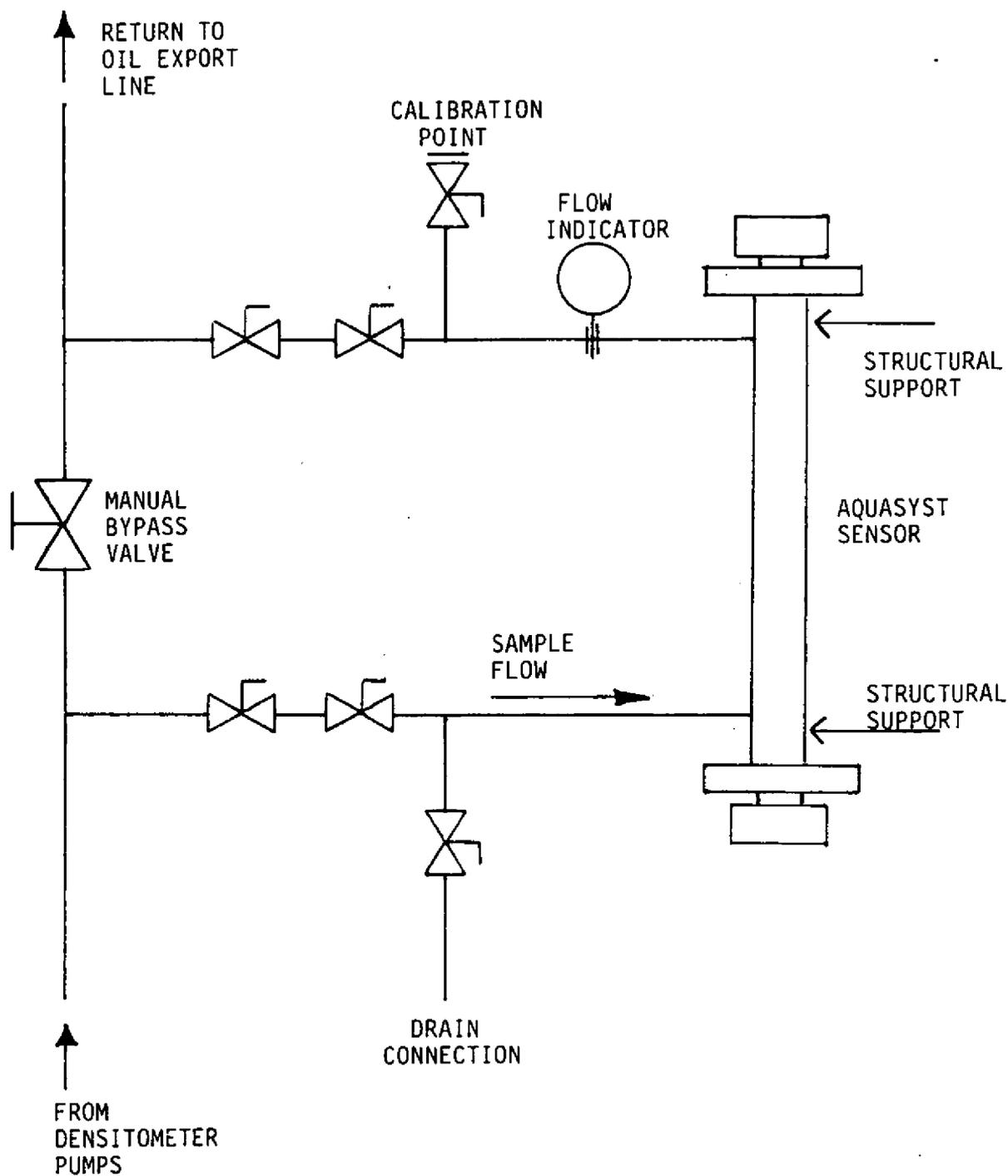
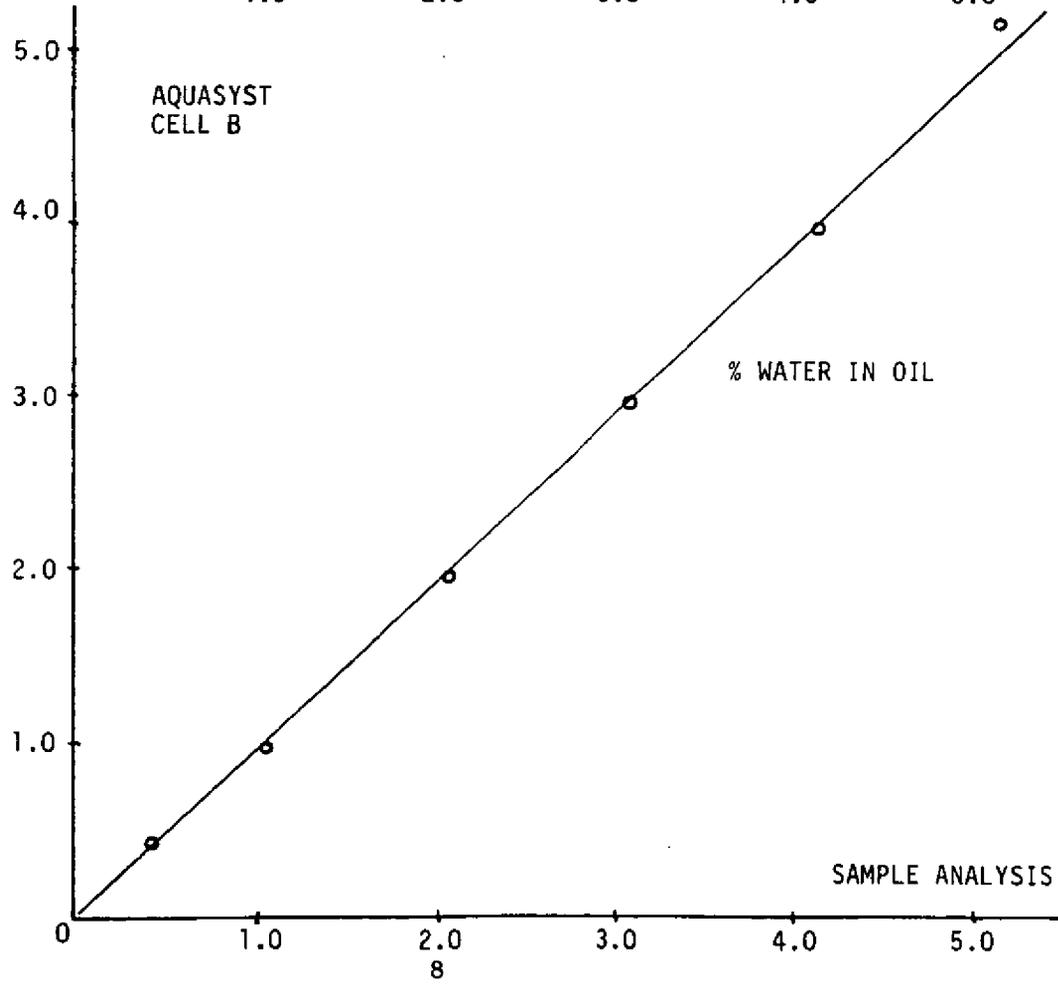
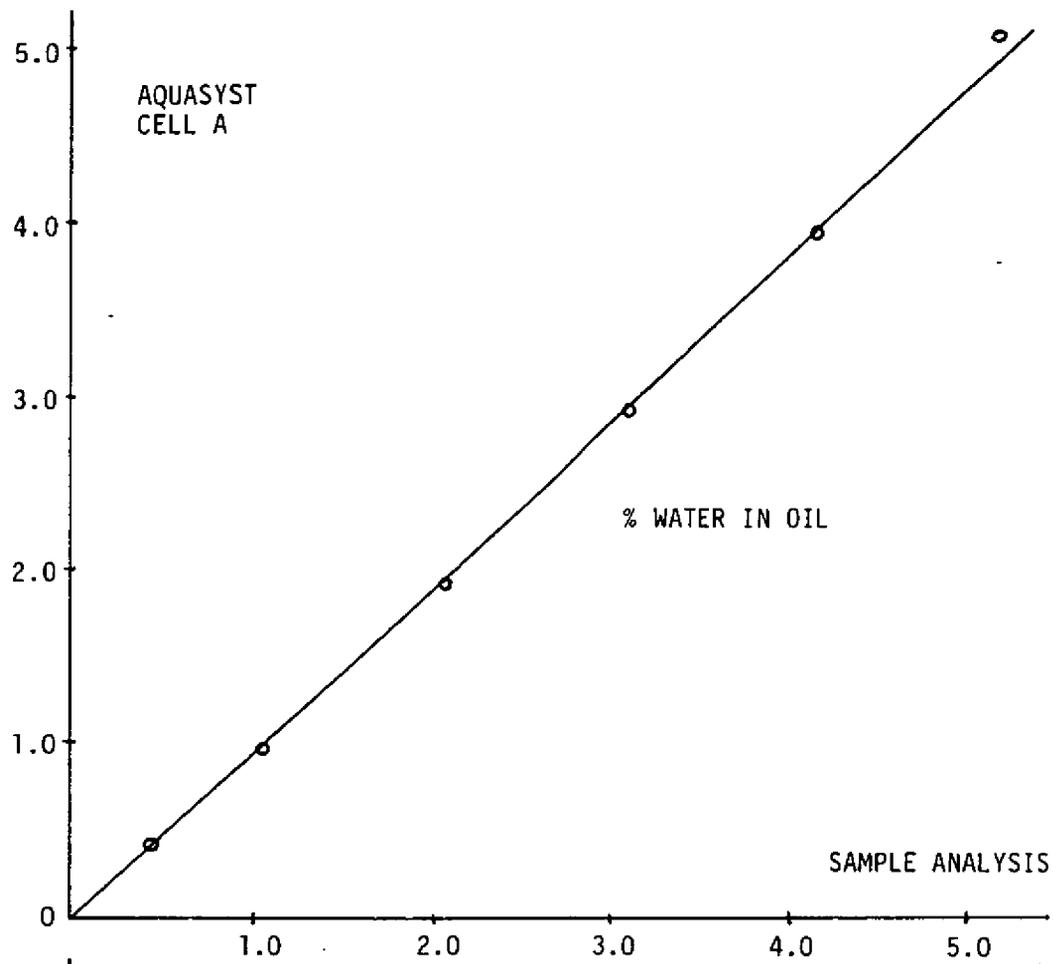


FIGURE 3 - PROPOSED INSTALLATIONS



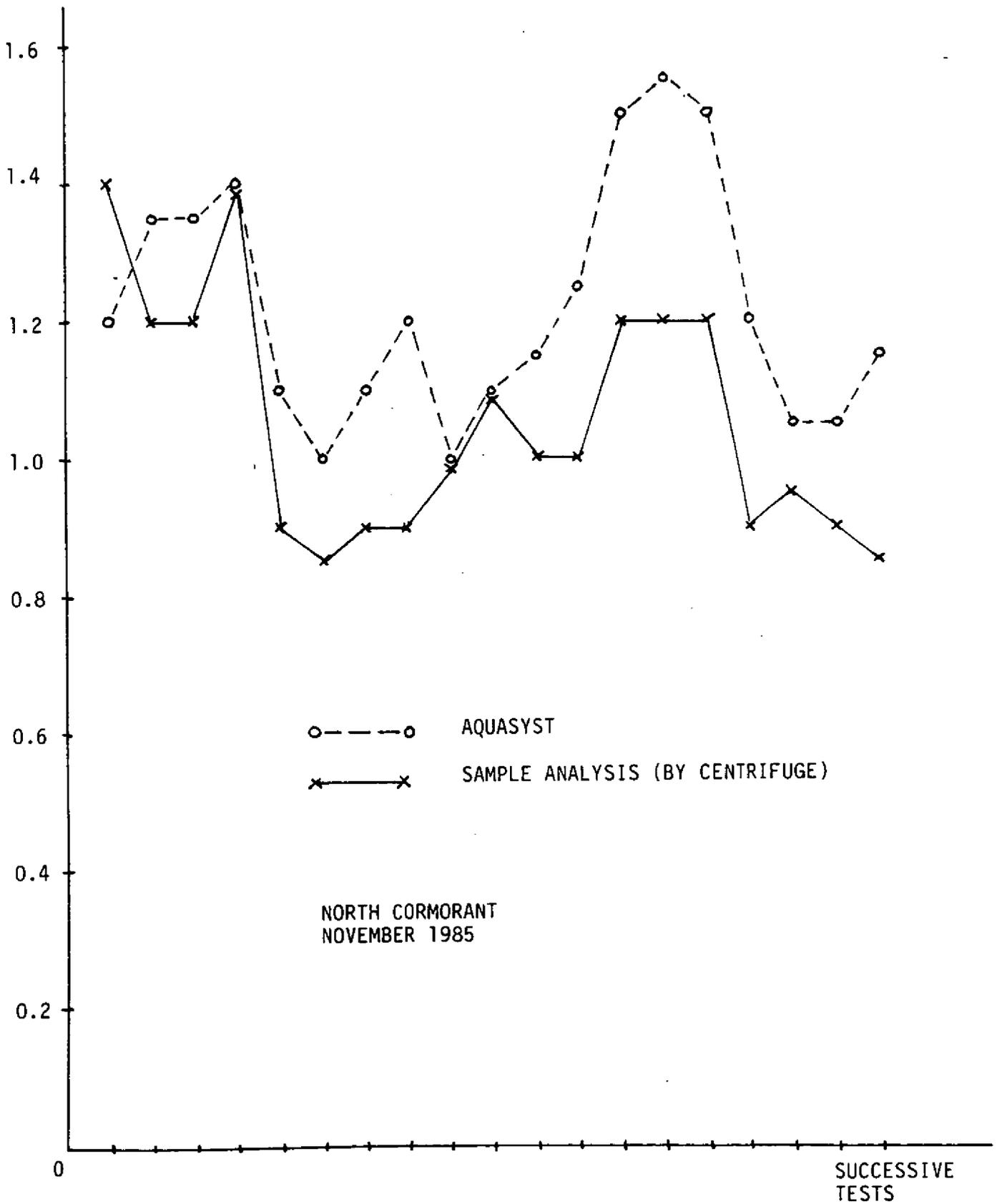
APPENDIX A - ONSHORE TEST RESULTS

X  
5  
0



APPENDIX B - OFFSHORE RESULTS

% WATER IN OIL

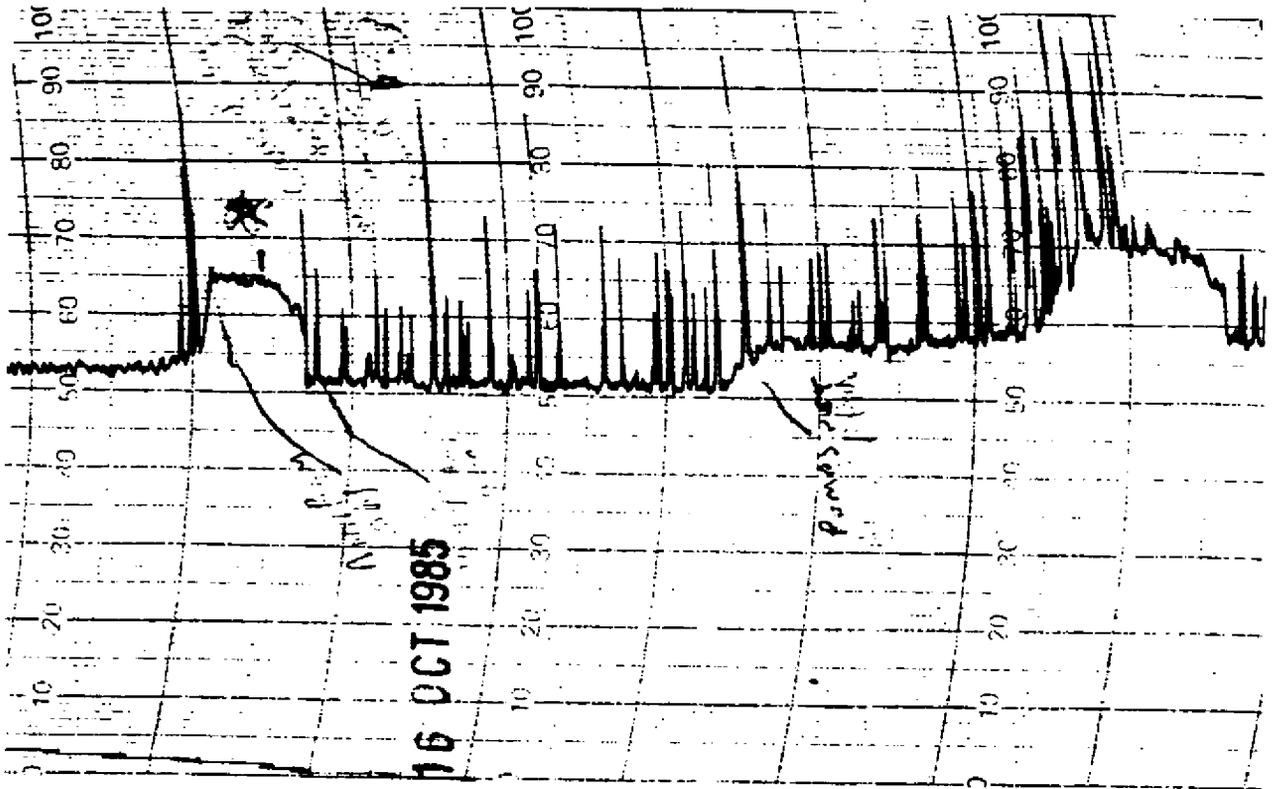


NORTH CORMORANT  
NOVEMBER 1985

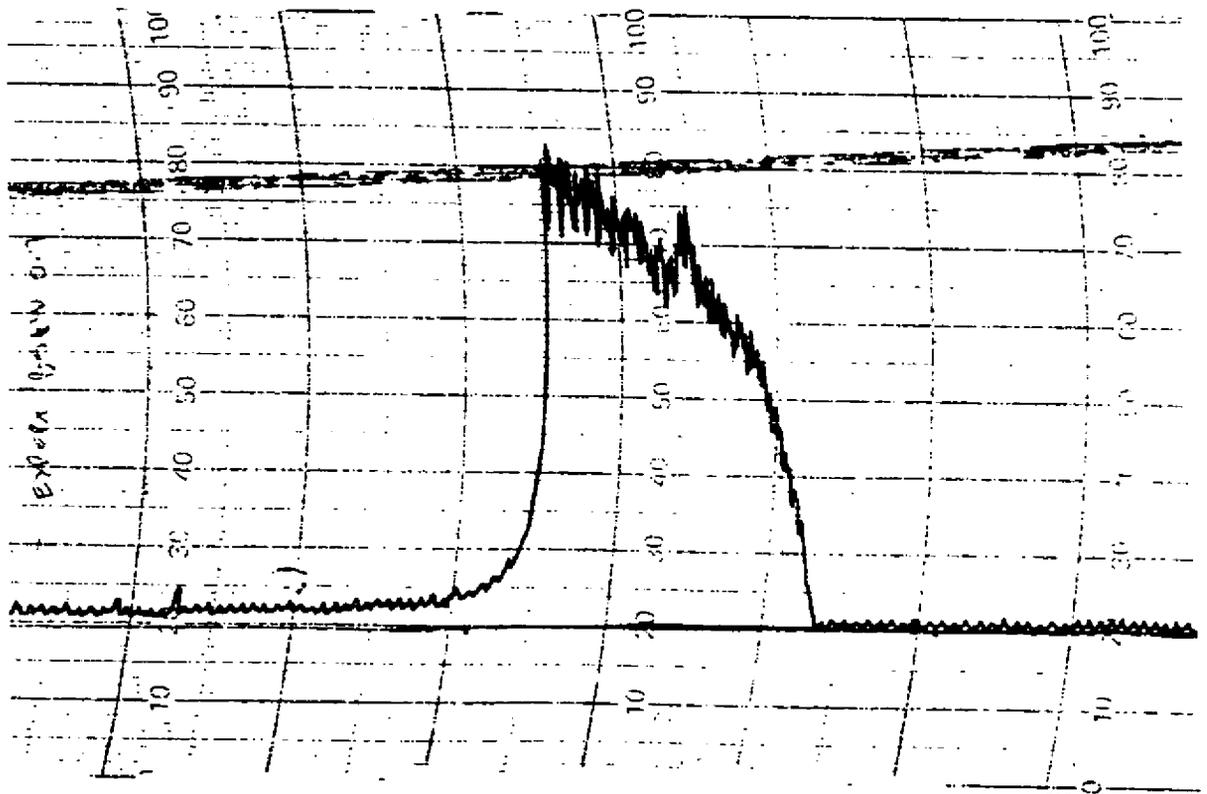
APPENDIX C - EXTRACTS FROM RECORDER TRACES

X  
5  
0

RESPONSE TO VESSEL LEVEL CONTROL PROBLEM  
WITHIN SEPARATION PROCESS

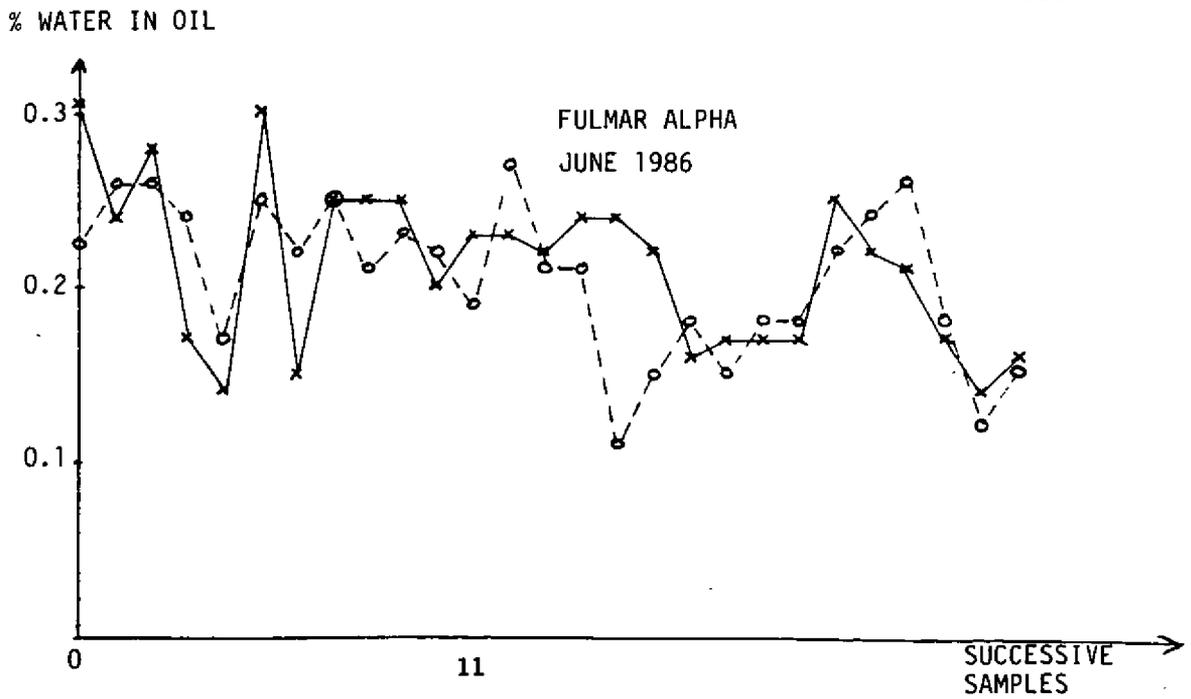
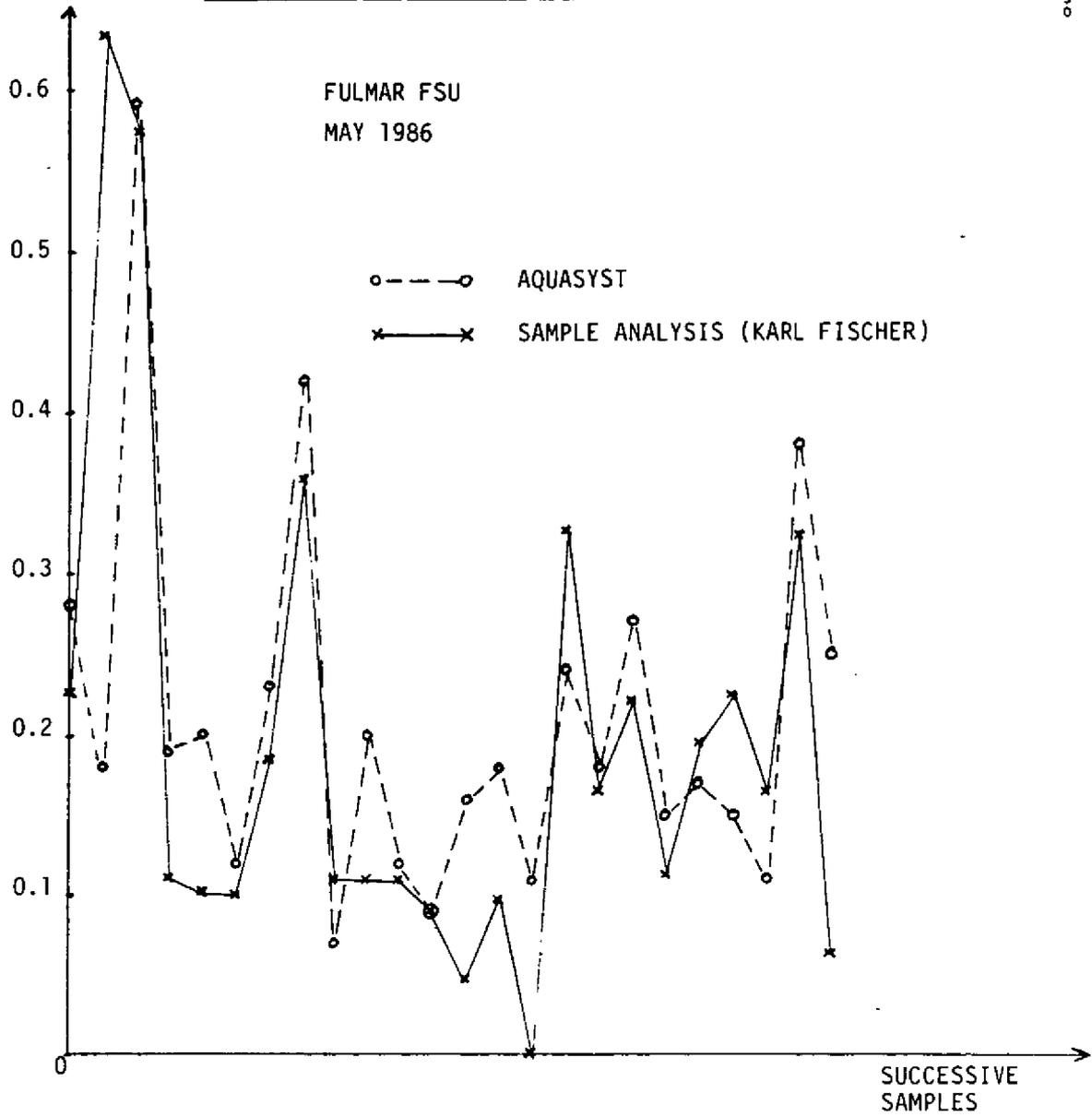


RESPONSE TO WELL CHANGE



APPENDIX D - OFFSHORE RESULTS

x  
5  
0



USE OF THE INLINE GAS CHROMATOGRAPH FOR GAS SALES FROM AN OFFSHORE PLATFORM

by

G BROWN  
MOBIL EXPLORATION NORWAY INC

---

Paper 1.4

NORTH SEA FLOW METERING WORKSHOP 1986

7-9 October 1986

National Engineering Laboratory  
East Kilbride, Glasgow

USE OF THE INLINE GAS CHROMATOGRAPH  
FOR GAS SALES FROM AN OFFSHORE PLATFORM

by

GAREY BROWN  
MOBIL EXPLORATION NORWAY INC.

OCTOBER 1986

USE OF THE INLINE GAS CHROMATOGRAPH  
FOR GAS SALES FROM AN OFFSHORE PLATFORM

1.0 Introduction

This paper is intended to give an overview of our limited experience in the operation and maintenance of inline gas chromatographs in the Statfjord Field.

While inline gas chromatographs are not new devices, they are however new in the offshore oil and gas industry, and like other new devices in this industry it takes time before they become truly accepted. I therefore intend as part of this paper to outline how far we have come in having these devices accepted, and to describe the lessons that we have learned which could benefit others considering the installation of similar devices. As my own experience is specifically operational, I do not intend to address problems from an engineering view point.

Before proceeding with our experiences I would first like to describe the systems which we currently have on our offshore platforms.

2.0 Background

Installed on each of the Statfjord platforms there are individual meter stations for measuring the quantity of gas produced by each platform. In addition there is a further meter station installed on "B" platform for measuring the quantity of gas being exported to the UK. All of these meter stations are of orifice plate design and are supplied by Daniel Industries.

During the design of our gas meter stations it was decided that an inline gas chromatographs should be installed on each meter run to provide real time analysis of export gas. The reason for this decision was fourfold, namely:

- to furnish data which could be used for calculating the volume and energy of exported gas (i.e. calculate the heating value in MJ and the relative density)
- to ensure that gas quality specifications were met (i.e. Nitrogen and CO<sub>2</sub> content)
- to provide the pipeline operator (Statpipe) with input for their leak detection system and pipeline optimisation model
- to provide a means for allocation accounting after a period of testing

### 3.0 System Requirements

In order to meet the above requirements it was decided to install a fully automatic system which could meet the following parameters:

- Remove a representative sample of the gas from the sales line, prepare the sample and inject a measured amount of sample into the GC Columns.
- Separate the sample into desired component parts for analysis.
- Identify the components.
- Measure and calculate the physical values of the components.
- Examine the physical values for validity by
  - a) Comparing them with preset high/low values.
  - b) Totaling and normalizing them.
- Examine the correct functioning of the analyzer
- Calibrate at a predetermined frequency.
- Produce an Analysis Report every analysis cycle.
- Produce a System Status Report daily.
- Produce a Sensor Status Report every time a change of status is detected.
- Carry out all the necessary switching actions.
- Output data to the Metering Station Master Computer as required.

### 4.0 System Description

In order to perform these functions and to meet our design and operations criteria stated above our system was installed with the following hardware configuration.

#### 4.1 Gas Chromatograph (Bendix 022)

Each of the Bendix gas chromatographs are divided into three compartments, i.e. electronic housing, uninsulated control housing and the insulated oven housing.

The electronic housing contains the data converter, the bridge amplifier, the oven controls, the solenoid controls and the electrical terminations.

The uninsulated control housing contains the column pressure gauge and regulator.

The oven housing is an insulated, air tight enclosure which provides a temperature control environment for the switching valves, flow adjusting valves, columns and thermal conductivity detector. The heater is a 1000 watt heater with a cylindrical heater barrel which extends into the oven.

The oven contains three columns for separating the components to be analyzed. Each column is made of 1/8" SS tubing with internal packing conforming to the following specifications:

- Column 1 which analyses the C6 plus components lump is a 2 ft. column filled with OPN/Porasil "C" 80/100.
- Column 2 which analyses IC4, NC4, IC5 and NC5 is a 20 ft. column filled with DC200 20% chromosorb 60/80.
- Column 3 which analyses N2, C1, CO2, C2 and C3 is a 10 ft. column filled with Poropak "T" 50/80.

By use of these three columns a cycle time of 15 minutes between each analysis can be achieved.

The inert carrier gas used is high purity Helium and the calibration gas for the chromatograph complies with the analysis shown in Table I, which is near our export gas composition.

#### 4.2 Analyzer Control (Bendix Model 500 - 2)

The analyzer control system is run by a Data General MP-100 Micro Computer composed of a CPU board, a 32 K memory board, power supply, battery pack and battery backup power supply. In addition it has a disc subassembly, a Perkin Elmer model 550 VDU, a keyboard, and a Texas Instrument Omni 800/model 840 teleprinter terminal.

The computer insures that the sample is introduced into the proper columns, controls column switching, and monitors the output of the detector system. It then converts the raw data from the detector system into the gas analysis and checks to see that the individual components are within certain pre-set limits. The limits used by our system are shown in Table II. These are based on our experience with our gas analysis variation.

The computer also calculates the Relative Density and Heating Value for the analysed gas. These values are then transmitted along with the analysis through an RS 232 C output port to the station Master Computer. These values are used for flow and energy calculation until new updated values are available. The computer also controls the calibration of the gas chromatograph using the calibration gas.

This computer system requires a minimum of operator input. The Control Room Operator chooses the automatic calibration frequency and number of consecutive cycles for each calibration. The frequency can be in hours or days. If days are chosen, the calibration will be done at 08.00 hrs. each day.

When a new standard gas is connected to the system, the operator must enter the new concentrations of each individual component into the computer system using a set procedure. The computer will then use these values in the automatic calibrations of the gas chromatograph.

#### 4.3 Pressure and Purge System (Expo Safety Systems Ltd.)

This system purges and pressurizes the data converter and the electronic unit. The initial action on start-up is to purge the enclosure by pressurising to a higher pressure than normal. This high pressure is maintained for a preset time, after which the pressure is lowered to the normal operating pressure and then electrical power is allowed to be supplied to the chromatograph.

#### 4.4 Sampling System

##### 4.4.1 General

The sample systems used for conditioning the gas sample supply from the pipe to the Bendix Gas Chromatographs on the Statpipe and UK gas offtake metering systems are essentially identical.

The sample systems are configured in 3 distinct parts:

- a. Cosasco probe sample take off.
- b. High pressure sample conditioning system.
- c. Low pressure sample conditioning system.

##### 4.4.2 Cosasco Probe

The Cosasco probes on all skids are located on the gas export metering system inlet headers. The probes are fitted into a 2 inch Weldolet flange located in a common flow point of the inlet headers.

##### 4.4.3 High Pressure Sample System

The high pressure sample conditioning system is located adjacent to the Cosasco probe as shown in Sketch I. The tube run between the probe and HP system is 1/4 inch OD thick wall tubing. The total length of the tubing between the Cosasco probe and the HP cabinet is in all installations less than 2 meters.

The pressure reduction for the gas is performed in two stages. Stage one reduces the pressure from the operating line pressure (approx. 170 barg) to 70 barg. The second stage reduces the sample from 70 barg to approx. 7 barg.

The sample system enclosure is heated to maintain the enclosure temperature above 25 degrees celcius to prevent liquid condensation, and all pipework is heat traced and insulated to prevent the cooling of the gas which would result in liquid dropout causing bad analysis. Particular attention has been placed with regard to heat tracing the "Tescom" pressure regulators. These pressure regulation stages have been duplicated to allow maintenance and replacement of a faulty regulator without loss of sample to the HP skid outlet.

#### 4.4.4 Low Pressure Sample System

The low pressure sample system is located immediately outside the chromatograph housing. The layout of the LP skid is shown in Sketch II. It is connected to the HP sample system by a sloping run of 1/4 inch thick wall stainless steel tubing.

The low pressure sample systems are identical on the Statpipe skids. The UK offtake low pressure sample system is slightly different in that it is equipped with sampling conditioning equipment to provide a sample for the Relative Density Analyzers on the meter skid.

The low pressure sample system is constructed in much the same way as the HP sample system. A space heater maintains the enclosure temperature above 25 degrees celcius. The sample response time is kept to a minimum by using a fast bleed to vent via a variable area flowmeter. The typical response time from the Cosasco probe to the Bendix chromatograph is approx. 3 minutes. (This could be improved to approx. 30 seconds). To find the best response time for our installation, we have experimented with this response time and have found that the various pressure regulators give a more stable performance at the response time of 3 minutes selected. This performance is most apparent during start-up where it is possible to contaminate and freeze up the regulators with liquid dropout particularly after a shutdown when the gas is below the cricondenbar and is allowed to cool.

The gas sample is further reduced to 3 barg before it is supplied to the gas chromatograph itself. The Bendix chromatograph calibration gas is piped to the LP sample system and is automatically supplied on a periodic basis via a 3 way pneumatically actuated valve. This valve is controlled by the Bendix controller using a solenoid valve.

## 5.0 Experiences during Design and Installation

In my opinion the failure or success of a GC System is decided during the design and installation stages. In selection of the system we sometimes simply buy the most expensive GC on the market, and then do not install it properly or design a good and maintainable sample system, and expect it to function perfectly in an offshore environment. This is a common misconception and one which can result in disillusionment and mistrust of offshore GC systems or even failure of the system to perform at all.

This section therefore endeavours to highlight from our experience those areas where attention should be paid during the design and installation of such systems.

### 5.1 Positioning of Sample Probe

The sample point must have a proper sample probe to ensure that gas is sampled from the center 1/3 of the pipe. Probes should also be located such that gas is well mixed but not too turbulent. The probe location should be about 8 - 12 pipe diameters downstream of the last restriction or elbow. Also be sure that you specify a probe type that can be withdrawn under pressure.

In our system the probe was designed to take a large pressure drop and use flowing gas to keep the gas warm. Since we did not continuously flow through each meter run, the device was sometimes left with stagnant gas which resulted in freezing problems. Our solution was to build both the HP and LP sampling systems.

### 5.2 Sample Lines

The sample line from the probe in the gas flow line to the sample conditioning system should be as short as possible. Care must be taken to ensure the gas in this line does not reach conditions where liquids can form, or if liquid do form, where they can be trapped.

In a fast loop system the velocity through the probe and system must be high enough to ensure that the gas in the fast loop is representative of the gas in the main line at the point where the sample is taken.

Care must be taken to ensure that no foreign material, dirt, scale, free liquids etc. gets into the GC. I suggest that a small inline filter be installed to remove these impurities. Care again should be exercised to ensure that no liquids are formed due to pressure drop in these filters.

### 5.3 Conditioning System

The sample conditioning system should be designed such that it has adequate rotometers to ensure proper flows and sufficient valving to allow proper maintenance of the system.

The entire sample system should be inside some type of building which is near the sample probe, and the building should be large enough to allow the technician to perform work on the system within the enclosure.

#### 5.4 Vent System

Be sure that the gas vented from the GC sample system is properly installed so as not to create a safety problem or cause operations problems by its location.

#### 5.5 Vendor Interface

Be sure testing is done on the GC system at the vendor's factory a sample of the actual calibration gas to be used, prior to shipment.

Involve someone in your own organization in the programming of the computer so that if you want to make some changes later you don't always have to go back to the vendor. Only in this way can you control your own destiny.

Be sure the standards for calculating values meet with approved standards for allocation. By this I mean don't use GPA standards or ASTM standards where ISO is required.

Be sure reports generated by GC meet operations and accounting needs. It is best to have report layouts approved by Operations before the programming begins.

Be sure that the system has a proper security system so that the data is adequately protected. This is requirement of all governmental bodies.

Be sure that the vendor furnishes complete documentation. This must include flow charts for all computer programs and back-up disks.

#### 5.6 Spare Parts

Be sure to get plenty of spare parts especially detectors and columns. The columns can be poisoned by impurities in the gas and the detectors can be ruined easily during start-up. The spare columns should be capped and kept in the GC oven so they will be ready when needed.

#### 5.7 General Tips

Use Helium as carrier gas not Hydrogen because of the danger of fire. This is very important on enclosed offshore installations.

Check on where you can locally obtain calibration gas, you can use a lot. When specifying this gas it should be as near as possible to the gas to be analyzed. In addition a minimum pressure should be determined for each bottle above which the analysis is valid. Long storage of these gases can be a problem through stratification.

A thermal conductivity detector does not detect low concentrations of H<sub>2</sub>S. If you want to do this it will probably require a flame ionization detector which will increase the cost.

Check on the impurities in the gas. Some impurities can poison the GC columns or cause other problems.

Be sure and pick a reasonable analysis time. Too fast a time can increase maintenance cost while too slow could lose accuracy.

## 6.0 Experiences During Operation and Maintenance

Our operation and maintenance experience is to say the least somewhat limited, since it is only in recent months that all of our system have been finally commissioned. None the less there are a number of factors which we consider to be important, and would draw to your attention.

### 6.1 Education of Personnel

Probably the one most important factor effecting the operability and maintenance of the GC system is the quality and experience of staff dedicated to these tasks. It is therefore vital (especially in the early months of the systems operation) that good communications exist between personnel on each shift, to enable experiences and problems to be shared. This level of communication is hard enough to achieve at the best of times without the extra complications of offshore shift work, where one works two weeks offshore and then has three weeks free.

We would therefore recommend that as much training and experience gathering is carried out at the beginning of the project thus consolidating the learning period and preventing the generation of doubts regarding the reliability of the system. When people have a clear understanding of the operation of a system they tend to believe in its success and work harder towards that goal.

### 6.2 Pressure and Temperature Instability

During the first 6 months of operation the most frequent problem encountered was one of pressure and temperature instability of the chromatograph columns. This problem was due primarily to sever environmental conditions (around the sampling system and GC cabinet) which resulted in the need to regularly reset the response factors and gating timing after adjustment of the pressure regulators inside the chromatographs. This problem was eventually cured by a redesign of the temperature control system and the use of heat tracing and cabinet heaters. Since that time very little adjustment has been necessary.

### 6.3 Back Pressure Problems

During the early period of operation we experienced back pressure problems on the vent system. This problem was caused by high winds and was cured by a redesign of the system.

### 6.4 Daily Maintenance

Many times we blame a system's failure on its design when possibly we have not given it the proper daily care required to keep it operating properly. A GC system is a device which needs TLC (Tender Loving Care). This does not mean that the system needs to have someone working on it continually, but it does mean that daily checks need to be made by a competent person. Some of these checks needed are adequate carrier gas, standard sample pressure, sample system cleanness, and other items. By doing this on a daily basis the system will run smoothly and will keep its high degree of accuracy. It is recommended that a check list be developed for ensuring that proper checks are made.

### 6.5 Care during Downtime

If the gas is below its cricondenbar in the sample conditioning system when the system is shut down, it is very important that proper precautions are taken to safeguard against liquid buildup. This is especially important when the system is down for prolonged periods of time such as yearly shutdowns.

## 7.0 Proving the Inline GC for Allocation Accounting

As was mentioned earlier, one of the reasons for installing the gas chromatograph offshore was to provide a means for allocation accounting. While this concept is by no means new, it has not received general acceptance in the offshore industry. A conversion to the use of gas chromatograph for allocation accounting would of course mean a change from the existing accepted use of flow proportional or spot gas samples for allocation purposes.

This change we have tried to justify on both economic and commercial grounds.

Our economic justification is based principally on problems with sample cylinders for the existing flow proportional sample systems, namely:

- logistics, transport and handling problems.
- high cost of maintaining/replacing sample cylinders
- statutory requirements regarding the six monthly maintenance and annual recertification of sample cylinders.

A breakdown of some of the costs (which we believe to be conservative) associated with the above are presented in Table III.

In addition to basic economic considerations, the use of inline gas chromatograph would enable us (via our offshore data transmission system) to meet contract deadlines for volume and allocation data transmissions without the need for analysing sample at an onshore laboratory.

## 7.1 Approach

Before our inline gas chromatograph can be accepted for allocation accounting, they must however be approved by all unit owners (i.e. all partners). As none of the Statfjord partners or for that matter other operators in the Norwegian sector, use inline gas chromatographs for allocation purposes, we have been breaking virgin ground. We have therefore developed a test procedure in discussion with all interested parties that comprises three distinctly separate stages, namely:

- collect maintenance and reliability data about the inline GC.
- prove the capabilities/accuracy of the inline GC.
- test inline GC against flow proportional system.

The purpose of this three stage approach is to enable the program to be halted at any time should any of the three stages fail to meet agreed acceptance criteria.

### 7.1.1 Stage I

This first stage is intended to prove the mechanical reliability of the entire system and will last approximately six months. During this period daily records will be kept on reliability, downtime, mechanical problems, and computer problems. A report on these matters will be sent to all interested parties every two months. At the end of this period the results will be evaluated and should show that the inline Gas Chromatograph is mechanically sound and operates reliably. In this first stage no extra manpower requirements are envisioned above those presently used for keeping the system running.

### 7.1.2 Stage II

In this stage we intend to prove the inline Gas Chromatograph against a certified onshore GC system at an approved laboratory. This will be done by preparing two certified gas samples. These samples will be numbered and sent onshore for analysis on an approved Gas Chromatograph. Thereafter the samples will be returned offshore for analysis by the inline Gas Chromatograph.

The analysis will be run on each GC until two analysis are within the following repeatability limits from ASTM 1945. (This standard which was chosen as the new ISO standard was not approved when field procedures for sampling were approved.)

Component, Mol %	Repeatability
0.01 to 1.0	0.03
1.0 to 5.0	0.05
5.0 to 25.0	0.15
Over 25.0	0.30
C <sub>6</sub> and heavier fraction	5% of amount

The analysis from both the offshore and onshore tests will be compared, to establish if they are within the reproducibility limits given below.

Component, Mol %	Reproducibility
0.01 to 1.0	0.06
1.0 to 5.0	0.10
5.0 to 25.0	0.20
Over 25.0	0.60
C <sub>6</sub> and heavier fraction	10% of amount

Each of the inline gas chromatographs will have this comparison analysis carried out on at least two occasions separated by a period of two months. On completion of this portion of the test we hope to have proven the GC portion of the system.

### 7.1.3 Stage III

The intention of the final stage will be to prove the entire GC system, (including the sample preparation system), and will be possibly the most difficult stage. In this stage we will compare the results of the inline GC with the analysis from the existing flow proportional sampler for the same period. This comparison will be done by the following method which will be preformed by our offshore computer system:

- The Mol % calculated by the Inline Gas Chromatograph Computer will be converted to Wt % for each component.
- The computer will calculate the tonnes of gas (MF) measured from the time the sample is taken into the GC until the next sample is taken into the GC.

- The following algorithm will be used to calculate the average wt% for each component analysis:

a)  $Wt(x) = 0$  for  $x = 1$  to  $10$

b)  $Wt(x) = Wt(x) + \left( MF * \frac{WtP(x)}{100.0} \right)$

$Wt(x)$  for each component will be zeroed at the end of each period (i.e. two weeks)

The "B" calculation will be done for each component after each analysis is completed.

The MF will be the tonnes determined in item 2 above.

$WtP(x)$  is the Wt % of component  $x$  as determined for the latest analysis.

c) At the end of the period the Wt % for each component will be determined in the following manner:

$Wt(x)$  - This is total tonnes for each component delivered for the period as determined by last value in b) above.

$tWt =$  Total tonnes of gas delivered during period or MF for the entire period

$$Wt(x) \% = \frac{Wt(x)}{tWt} \times 100$$

This  $Wt(x) \%$  is then the weighted wt % for each component  $x$ .

This  $Wt(x) \%$  will then be normalized as required and will be the value for each component needed for allocation. After this value is stored the component  $Wt(x)$  for each component will be zeroed and the process begun again.

The Wt % determined in this manner will be compared to the Wt % determined from the analysis of the composite sample analyzed at the onshore laboratory.

The allowable deviation that can be tolerated between these two analysis has not been found in any published standards. Because of this we propose to gather statistical data during a 6 month period. At the end of this period we will use this data to evaluate the acceptance of the deviation by comparison within agreed limits which will be

agreed prior to Stage III (if none has been found in the literature by start of this stage). At the end of this final test period we hope to have proved that the inline GC can be used for allocation within the Statfjord Unit.

## 7.2 Additional Operational Checks once inline GC is approved

We have developed a Maintenance and an Operations Manual for the inline GC. Both of these manuals will be used during the test and after approval. In order to ensure the continued proper operations of the system after the test the following procedure will also be followed.

### 7.2.1 Weekly Checks

Each Monday (or more often if required), a spot sample would be taken and analyzed in the offshore Lab. and compared to the inline GC results. If these results are over the agreed limits used for acceptance in Stage III the back up procedure for spot sampling in Section 3,1,3 of "Sampling and Analysis Procedures for Gas Sales from the Statfjord Unit" will be followed. This procedure shall be continued as long as the GC is unavailable or giving bad results. If this period persists for a long time the proportional sampler will be put back into service to avoid taking a large number of spot samples.

### 7.2.2 Six Monthly Checks

In addition, for a period of two years after the GC is approved, or longer if required, the proportional sampler will be used for two weeks every six months and these results compared in the same manner as the results from the inline GC. These results must be within the limits agreed to in Stage III. If the GC should fail to remain within these limits during those tests and no reasonable explanation can be found, the proportional sampler would continue to be used until the error is corrected.

## 8.0 Conclusion

If you are considering the use of offshore inline gas chromatographs for allocation accounting pay very close attention to the design and installation of your sampling system.

Of equal importance is the quality and experiences of the staff you will use to operate and maintain the systems.

If both of the above are properly addressed you will stand a good chance of having a reliable system which could be used for allocation accounting.

Attachments

TABLE I  
CALIBRATION GAS MIX. FOR STATFJORD CHROMATOGRAPHS

	<u>Mol%</u>
Nitrogen	0.5
Carbon Dioxide	0.5
Methane	79.0
Ethane	10.0
Propane	6.0
Iso Butane	0.5
Normal Butane	2.0
Iso Pentane	0.5
Normal Pentane	0.5
Normal Hexane	0.5
<hr/>	
Total	100.0

Methane within 2.0% of 79.0%.

Remainder within 5.0% of stated figure.

Gas contains no impurities.

Cylinder volume - 10 litres.

The above analysis is certified by an approved third party laboratory.

TABLE III

COST OF GAS SAMPLING BY CYLINDERS

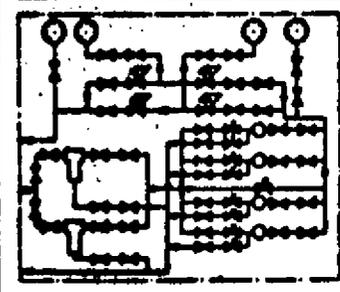
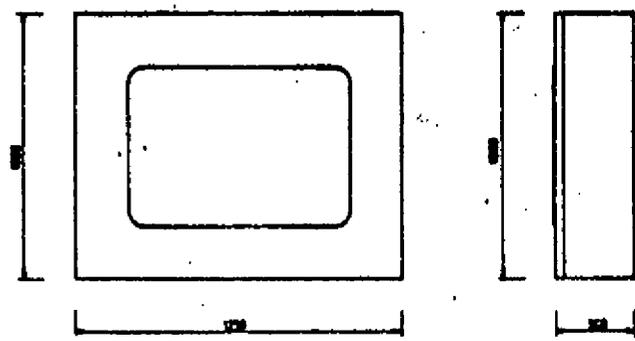
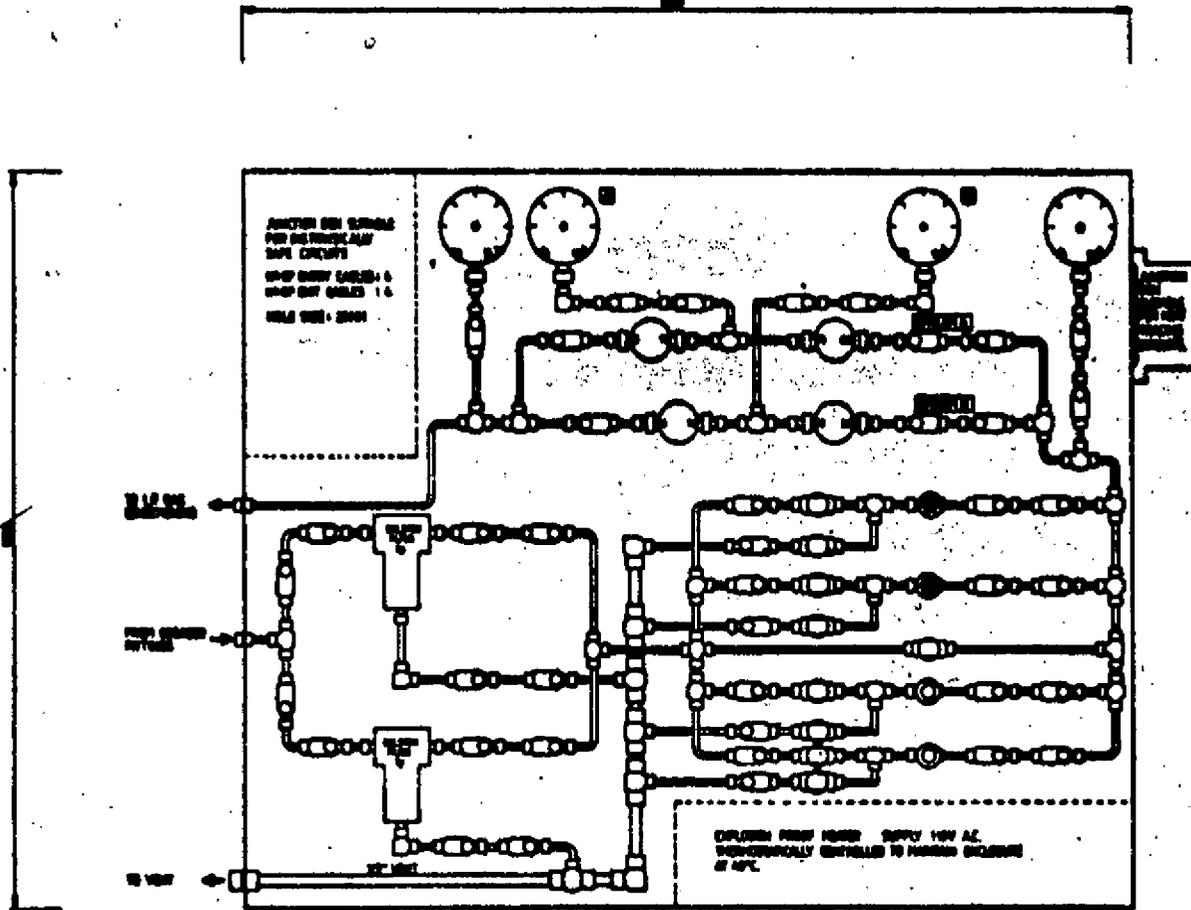
Cost of transportation of cylinders from platform to Kårstø and return	228,000 NOK/yr
Cost of 6 month and yearly inspection of cylinders	300,000 NOK/yr
Cost of running analysis	240,000 NOK/yr
Cylinder replacement 8 cylinders/yr (Based on past experience)	280,000 NOK/yr -----
Total	1,048,000 NOK/yr

TABLE II

CHROMATOGRAPH ANALYSIS LIMITS

<u>Component</u>	<u>Mol % Low Limit</u>	<u>Mol % Upper Limit</u>
C1	72.00	77.00
C2	10.50	13.00
C3	7.00	9.50
IC4	0.60	1.10
NC4	1.75	2.75
IC5	0.25	0.65
NC5	0.25	0.65
C6+	0.20	0.70
C02	0.30	0.80
N2	0.30	0.80

Sketch I



- LEGEND**
- ALL INSTRUMENTS ARE SHOWN IN PLACE
  - INSTRUMENTS:
    - TEMPERATURE GAUGE
    - PRESSURE GAUGE
    - FLOW GAUGE
    - LEVEL GAUGE
    - PH GAUGE
    - PHOTOCELL
    - RELAY
    - SOLENOID
    - VALVE
    - PIPE
    - CONNECTOR
  - ALL INSTRUMENTS ARE SHOWN IN PLACE
  - ALL PIPES TO BE 1/2" O.D. GALV. STEEL PIPE
  - ALL FITTINGS TO BE 1/2" O.D. GALV. STEEL
  - ALL PIPES SHALL BE 1/2" O.D. GALV. STEEL PIPE AND SHALL BE INSULATED TO MAINTAIN DISCHARGE AT 40°C.
  - EXPLORER PUMP MOTOR SUPPLY 120V AC, INDIVIDUALLY CONTROLLED TO MAINTAIN DISCHARGE AT 40°C.

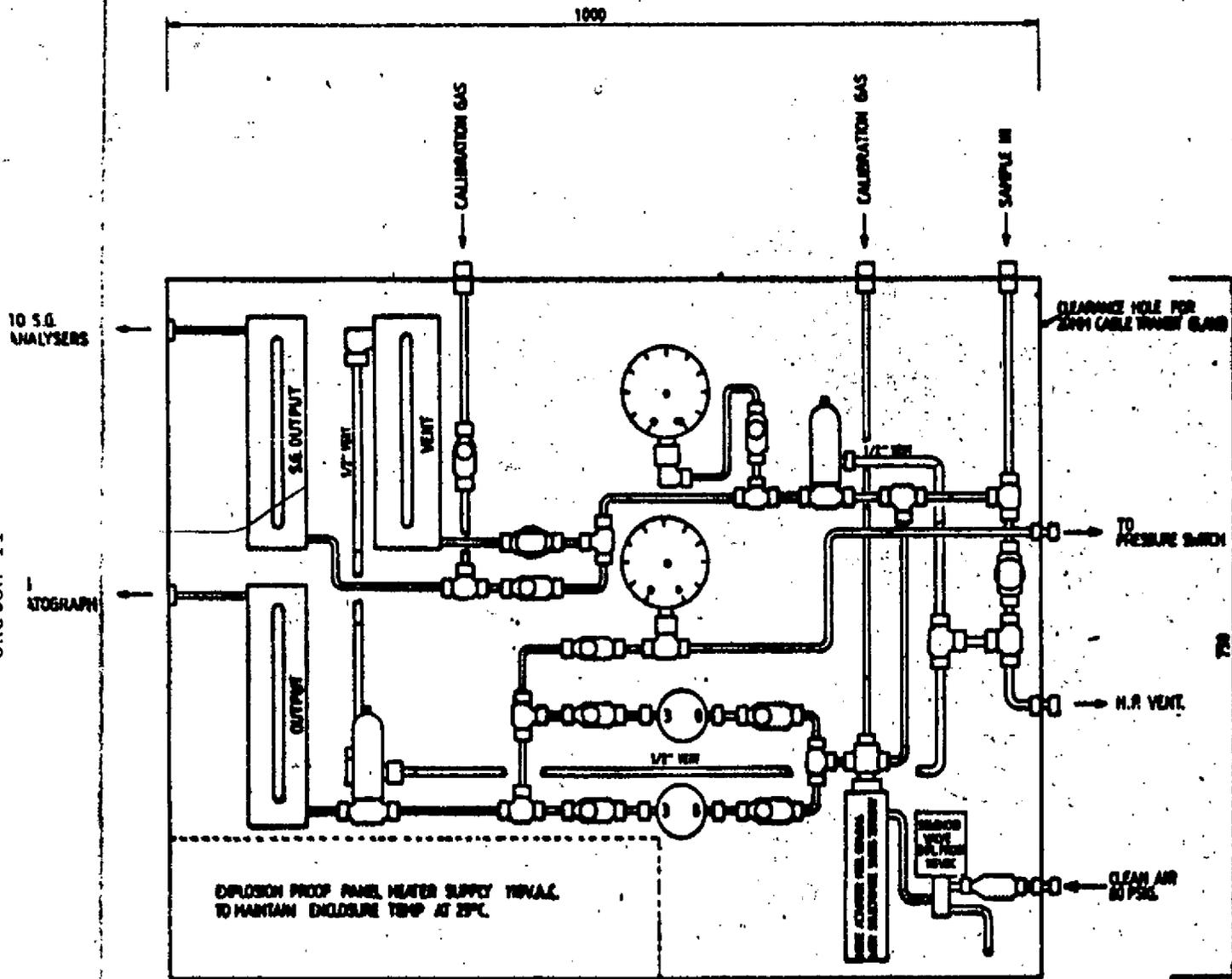
NO.	DESCRIPTION	QTY.
1	TEMPERATURE GAUGE	1
2	PRESSURE GAUGE	1
3	FLOW GAUGE	1
4	LEVEL GAUGE	1
5	PH GAUGE	1
6	PHOTOCELL	1
7	RELAY	1
8	SOLENOID	1
9	VALVE	1
10	PIPE	1
11	CONNECTOR	1

**Mobil** OIL COMPANY  
 EXPLORATION COMPANY

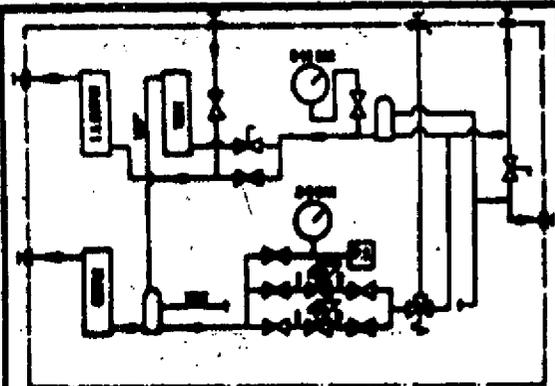
**STATION 2**  
 PUMP MOTOR SUPPLY

PL. 100.11648

Sketch II

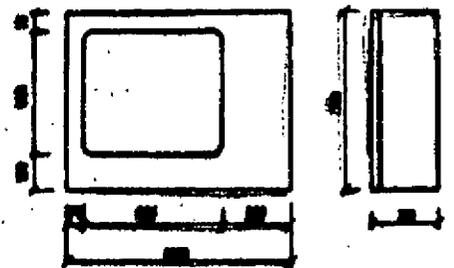


LP GAS CONDITIONING SKID - GAS EXPORT



**NOTES**

1. ALL DIMENSIONS ARE GIVEN IN INCH.
2. SPECIFICATIONS:  
 FABRICATION SP/12/100  
 WELDING SP/10/100  
 INSULATION SP/10/100  
 PRESSURE TEST SP/10/100  
 SURFACING SP/10/100  
 COATING SP/10/100  
 TRACE HEATING SP/10/100
3. THE ENCLOSURE TO BE UNICELL MODEL N-46000-04 WITH INSULATION WINDOW AS SHOWN.



4. ALL PIPING TO BE 1/2" O.D. UNLESS OTHERWISE NOTED.
5. ALL PIPING FITTINGS TO BE STAINLESS STEEL TO BE COMPATIBLE WITH THE PROCESSING FLUIDS.
6. V.A. FITTINGS TO BE PROVIDED WITH OXYGEN SERVICE.
7. ALL FITTINGS TO BE NPT OR ORIFICE.
8. PRESSURE REDUCTION STATIONS TO BE PROVIDED.

MOORE ENGINEERING CORP.

6045 JONES BLVD  
 OK GAS OPTIMIZE METERING  
 SYSTEM  
 LP GAS CONDITIONING SKID

DATE: 11/18/78  
 DRAWN BY: J. L. B. / 11/18/78  
 CHECKED BY: J. L. B. / 11/18/78

THE CERTIFICATION OF TEST GASES

by

T NILSEN  
NORSK HYDRO

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Paper 1.5  
(Part I)

NORTH SEA FLOW METERING WORKSHOP 1986

7-9 October 1986

National Engineering Laboratory  
East Kilbride, Glasgow

## THE CERTIFICATION OF TEST GASES

T Nilsen, Norsk Hydro, Norway

### INTRODUCTION

The marked for calibration gases have increased considerably during the last years, partly because of better instrumental analysis methods.

The new methods:

- Have replaced manual methods of chemical analysis.
- Are used for control of the ambient air within and outside the chemical works.
- Will detect components which were not detectable some years ago (for instance sulfur containing components).
- Are more precise and selective.

The limit of uncertainty has been lowered, due to economic demands. It is thus of importance to:

- Obtain maximum production.
- Obtain the optimal efficiency.
- Calculate heat values.

A calibration gas is a homogeneous mixture, consisting of one or more components, qualitatively and quantitatively determined. The accuracy of concentration is given for each component.

A calibration gas mixture may contain as many as 20-25 components, depending on the necessity of accurate analysis.

All information concerning the actual mixture is given in the certificate of analysis. The certificate contains:

- The method of mixture preparation.
- Concentration (mole %, volume % or weight %).
- Relative uncertainty of the value of concentration, for each component  $\Delta C/C$ .
- The original pressure of the gas in the cylinder.
- Dew point temperature, which means at what temperature liquid is formed.
- Lowest utilization pressure.
- The period of time the mixture is guaranteed.

#### PRODUCTION OF CALIBRATION GASES

A stable calibration gas mixture in one selected type of cylinder, can be highly unstable if the mixture is filled into another cylinder with different type of material. By choosing unsuitable cylinder-material chemical reactions can occur between a single gas component and the cylinder-material, or the cylinder-material may act as a catalyst and the gas components may react.

Therefore the certification of a calibration gas is started by choosing the correct cylinder and cylinder valve. The cylinder material shall not react with any component, or the reaction shall be so slow that the concentration of the components shall be within the limits  $\pm \Delta C$  in the period of guarantee. To achieve good results, it is necessary to passivate or treat the inner surface of the cylinder in special ways, - most important for corrosive components in the low ppm-range.

Note: The stability of a calibration gas mixture must be confirmed through time related stability tests of the calibration gas mixture in question.

## CALCULATION OF PRODUCTION PARAMETRES

For mixtures containing condensable components, it is necessary to perform a dew point calculation.

Based on the calculated pressure with for instance dew point + 10 °C, 0 °C and other temperatures a filling procedure can be established.

Depending on requirement to accuracy in concentration, and the composition of the mixture, the filling method has to be defined and selected.

The filling methods are as described in the following ISO-documents.

ISO 6146 Gas Analysis-Calibration gas mixtures- Preparation by manometric methods

ISO 6144 Gas analysis - Preparation of calibration gas mixtures - static volumetric methods.

ISO 6142 Gas analysis - Preparation of calibration gas mixtures - weighing methods.

The weighing-method gives the possibility of preparation of calibration gas-mixtures for which the accuracy of the concentration of each component is better than 1%. The method is applicable only to gaseous components which do not react between themselves or with the cylinder-walls, and to totally vaporized components if they are condensable.

To produce low-concentration mixtures is it possible to make a single or multidilution.

Calibration gas mixtures can be produced by using NBS traceable "S" serie weights.

Gravimetric prepared calibration gas-mixtures are so-called primary calibration gas-mixtures, since it is directly related to the measurement of basic standards (such as mass, length, etc.)

Mixtures prepared by manometric method must be analyzed against a primary standard, and can be certified as a secondary calibration mixtures.

When producing calibration gas mixtures, it is only allowed to use high purity, preanalyzed starting components.

#### **HOMOGENISATION OF A MIXTURE**

Prior to use of a calibration gas-mixture, we have to be sure that the mixture is homogeneous. If a gas-cylinder after filling is allowed to be kept stationary and undisturbed, many weeks may expire before the calibration-gas is completely mixed.

The homogenization procedure is accelerated by the use of a mechanical cylinder roller.

Laboratory tests have shown when the gas-mixture is homogeneous, it will remain in the state, unless liquid is formed due to low temperature.

#### **ERROR CALCULATION**

The accuracy of the weighing-system is estimated, to calculate the error involved in the weighing operation.

The purity of liquids and gases, and their content of other components is taken into consideration (Example 1).

For the mixture previous shown, it should be possible to prepare accurate concentration better than 0,5% relative for all components (the result is based on use of the weighing system

previous shown:

1. Volland weight and s-series weights.
2. One skilled operator.
3. Preanalysed high purity gases and liquids.
4. Use of clean and polished gas cylinders.

#### CERTIFICATION

All calibration gas-mixtures are analyzed before certification. For the gravimetric prepared (not reactive) calibration gas mixture, this is done to make valid that the weighing system functions correctly.

For manometric or volumetric prepared blends, or calibration gas containing reactive components, the certificate has to be based on the results of analyses.

THE USE OF TEST GASES

by

E BJARNOV  
DANTEST

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Paper 1.5  
(Part II)

NORTH SEA FLOW METERING WORKSHOP 1986

7-9 October 1986

National Engineering Laboratory  
East Kilbride, Glasgow

**T H E   U S E   O F   T E S T   G A S E S**

Erik Bjarnov

DANTEST

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Gas chromatography .....	4
Natural gas analysis .....	6
Can test gases be trusted? .....	7
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## Introduction

I have been asked to talk about the certification and use of test gases. With Torbjørn Nilsen talking about production and certification of test gases, I shall try to talk about test gases from the viewpoint of the user, as well as my experience as an analyst with test gases.

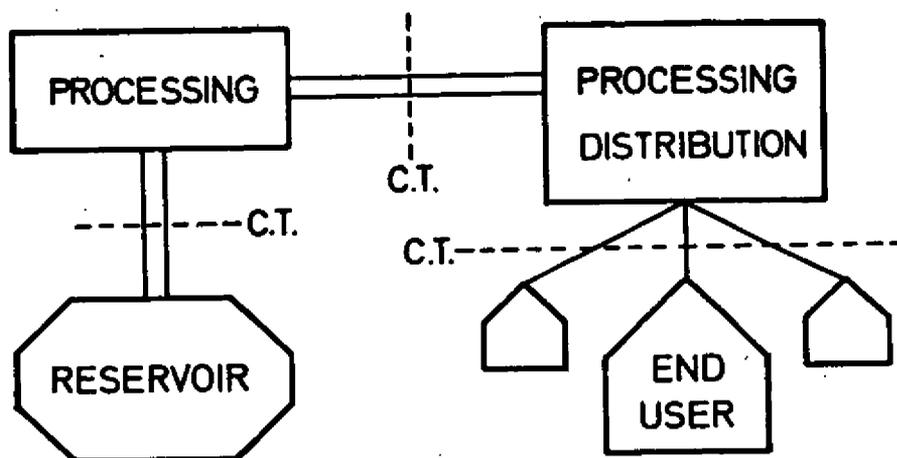
I shall not talk very much about certification, because the most accurate test gas that can be produced is a gas that has been prepared by the gravimetric method. There is no way to add accuracy to such a gas by analysis, the only thing that can be added is confidence. Of course it is possible to certify a gas by analysis, but the use of this gas will be limited to places where less than the best accuracy is acceptable.

I have relied rather heavily on the Gas Quality conference (1) that was held in April this year in Groningen because test gases and gas quality are closely connected. Actually whenever a quality parameter is measured, test gases have been used at some stage or another in the measuring process. A quality parameter is a parameter that depends on the composition of natural gas.

By test gases is here meant synthetic natural gas mixtures that could be used for gas chromatographic analysis of the main constituents in natural gas. Trace components like water and sulphur compounds are important in gas quality specification, but their analysis is very specialised. Besides there are several independent methods for the analysis of most of the trace components and some of these methods do not need test gases for calibration.

Why is it we use test gases? Well, it is primarily because some measurements can only give quantitative results by calibration with gases of known composition. Furthermore test gases are needed as part of the quality assurance program as a convenient way of convincing oneself and others that the measurements are as accurate as they can possibly be.

In order to get some perspective I have made this simplified picture of the natural gas world. There is a gas reservoir with a pipeline to a processing unit, that removes unwanted components, like water and condensate. Another pipeline brings the gas to the distribution system, where it again may be processed, odorised for instance. Finally the distribution system brings the gas to the end user, who will typically burn it.



The natural gas world. C.T.: possible custody transfer points.

At several points in the system there may be custody transfer. Whenever there is custody transfer two questions must be answered: How much gas is there? and How good is it?.

The answer to "how much" is generally expressed in cubic meters at some reference pressure and temperature. The answer to "how good" is primarily a statement of calorific value, but may also refer to the absence or low level of for instance sulphur compounds.

#### Measurements on natural gas.

There is a desire from all parties involved that the properties are measured precisely and with a negligible bias.

The measurements may be absolute or relative. An absolute measurement is a measurement with an unbroken line of traceability to the fundamental units of mass, length, current or time. A relative measurement lacks one or more links in the traceability train (2).

The gaps in the traceability train for relative measurements may conveniently be overcome through the use of calibration standards which for our purposes means test gases.

While absolute measurements are more simple to understand, the relative measurements may be much more feasible, faster and even more accurate. Let me illustrate this postulate by two ways of measuring the density of natural gas. Density is by definition the mass of a unit volume of a substance. Thus the density may be found by weighing a known volume of natural gas at a given pressure and temperature in a suitable container. This is an absolute measurement, but it is not feasible outside a laboratory. Instead the choice can be to use a density transducer, which has to be calibrated with test gases.

## Gas chromatography

A gas chromatographic analysis is a relative measurement, so the analysis will have an uncertainty that is a combination of the uncertainty in the reference gas used and the precision of the equipment. Error in the composition of the reference gas will be a major source of bias in the measurement.

In view of its importance I have allowed myself to repeat for you some of the properties of gas chromatography.

### Elements of a gas chromatograph

Carrier gas  
Sample size  
Column  
Column oven  
Detector

The carrier gas brings a portion of the sample to be analysed to the separating column, where the different compounds are delayed more or less so that groups of compounds will reach the detector at different times. With gas chromatography of complex mixtures like natural gas it is important to know before an analysis is made, which compounds the sample should be analysed for and what the expected concentrations are.

Each choice of element in the system optimises analysis of some compounds while others may not at all be detected. The carrier gas most often used is helium, and it is excellent for the purpose except for analysis of helium or hydrogen contents. The sample size is chosen with respect to the expected concentration of the compounds of interest: small samples are used for compounds in the percentage level larger samples for compounds in ppm level, with a compromise when the ppm compound elutes close to a percentage compound.

The heart of the system is the separating column. The separation depends on the temperature, the length of the column and type and amount of adsorbent or coating. In general low boiling compounds need long columns and low temperatures to be separated while high boiling compounds need shorter columns and high temperatures to pass the column in a reasonable time. By use of column switching with different columns and eventually temperature programming it is possible to overcome some of the conflicts. Column switching causes pressure pulses and may influence the quantification of peaks eluting shortly after.

There are two detectors commonly used for natural gas analysis: the thermal conductivity detector, the TCD, and the flame ionisation detector, the FID. The TCD is a robust generally useful detector, that responds to anything with

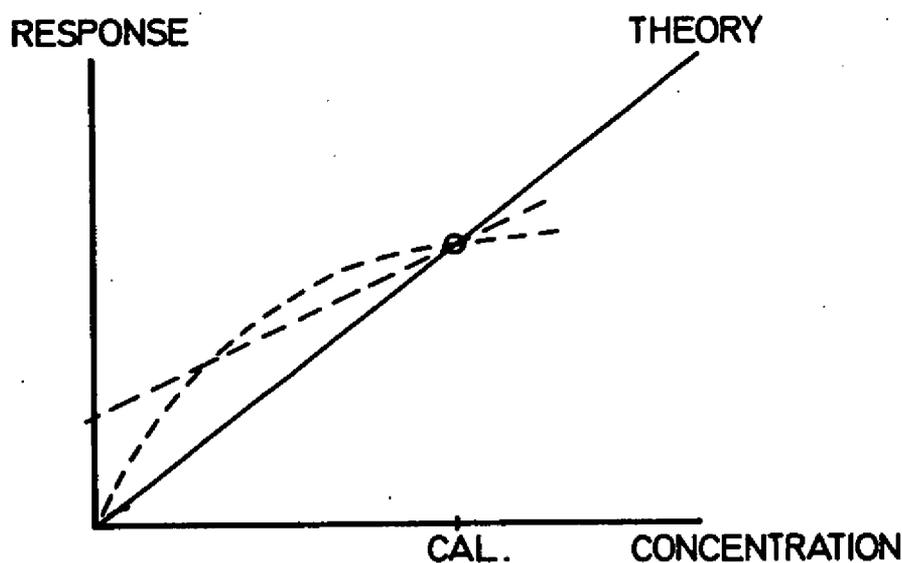
thermal conductivity different from the carrier gas. Except hydrogen everything else has significantly lower thermal conductivity than helium, which makes helium an ideal carrier to use with a TCD, unless helium or hydrogen should be analysed.

FID's are sensitive to essentially all organic compounds and it is orders of magnitude more sensitive to the higher hydrocarbons than the TCD.

Besides these two general purpose detectors there are selective detectors of which the flame photometric sulphur detector is the more common in natural gas analysis.

No matter which detector its response is compound dependent and to get quantitative results it is necessary to use a calibration gas mixture to establish the response factors that shall be used to convert the peak areas to concentrations. Moreover it is essential to treat the calibration gas exactly as the samples are treated, so that the peak shape of each component is the same in both cases.

It is common to use a single calibration gas mixture and assume linearity. Some possible errors in this assumption are illustrated here.



Instrument response as function of concentration of a single component. Dotted lines represent possible deviations from preferred behaviour.

The curved line demonstrates the effects of a saturation phenomenon of the detector. This will primarily happen at high concentrations of the component. The other line has a nonzero intercept due to interference from another component. Such interferences can happen when there is not complete separation of the components. It was mentioned at the Gas Quality conference that one should always determine the full linearity curve for all components. This is a very idealistic approach, and besides being very time consuming, it is not necessary, when one deals with natural gas of pipeline quality. However it will always be wise to have at least two checkpoints to cover the gas compositions that are likely to occur.

### **Natural gas analysis.**

There are several standards (for instance ref. 3,4) for the analysis of natural gas by gas chromatography. They mainly focus on the analysis of compounds of influence on the calorific value. These are the compounds normally found in calibration gases, and the methods of the standards may therefore be used for certification and verification of gas mixtures.

Certification means here that the resulting certificate will contain the "true" concentrations of the constituents. Verification similarly means that the "true" values from a supplier are confirmed by the analysis.

Verification may be performed on a typical natural gas analyser, that can analyse for all the compounds in the certificate, or all except one. The verification should always be done as part of the reception procedure for a new test gas.

There have been two schools for calibration one preferring binary mixtures the other multicomponent mixtures. At the Gas Quality conference Rhoderick and Hughes from NBS presented a lecture on the subject and concluded that there was no difference in accuracy between the two methods (5). Further when there is column switching the multicomponent mixture is a must besides being much more convenient.

Natural gas analysis is probably the only analysis, where one tries to quantify the main component directly as well as all the "impurities". The result is, of course, that the analysis does not sum up to 100 %. To help this one can normalise the results - ISO 6974 allows normalisation when the sum is between 99 and 101 %. Another way is to quantify the methane by difference. In either case the difference to 100 % ends in the methane concentration. Normally this difference is caused by the repeatability of the instrument, but it may also hide the existence of some component not analysed for.

### Can test gases be trusted?

In general the answer is yes, no matter who is the supplier, be it a commercial company or some official authority. The latter by definition must be trusted, but anyway, humans are involved in the preparation of the gas and the writing of the certificate. Thus there is always a finite risk that the gas at hand is the one that is off specification. This is the reason a test gas always should be verified before it is taken into use. Bearing in mind that the test gas essentially controls the bias of the measurement, the efforts of verifying it are small compared to the inconveniences an erroneous test gas will cause.

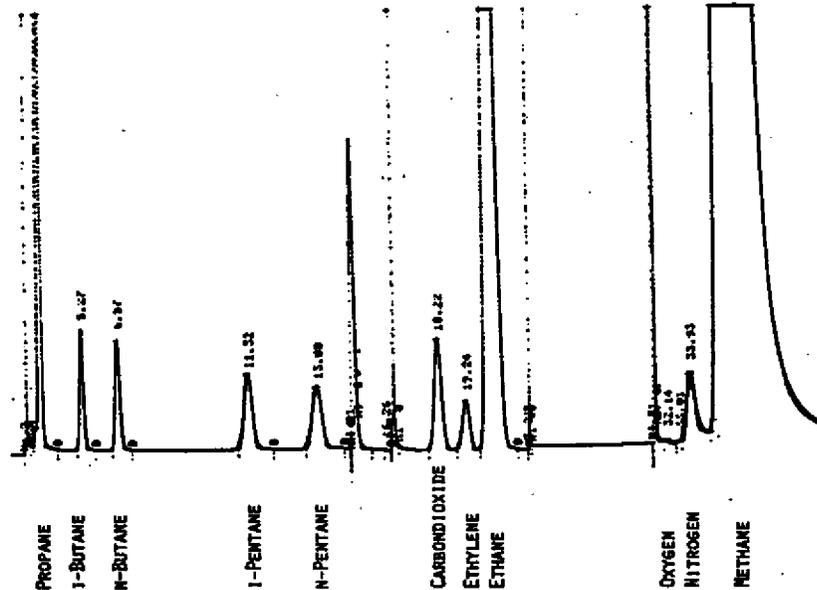
A few years ago the BCR arranged an intercomparison of reference gas mixtures for natural gas (6). Some 16 participants each prepared up to three different gas mixtures of three nominal compositions. Each group of mixture was then analysed by 3 to 4 laboratories. The conclusions from this exercise were that :

- (i) The gravimetric methods for preparing gas mixtures, if they are carefully applied, allow to prepare mixtures of sufficient accuracy.
- (ii) The major source of error seems to be impurities in the primary gases used for the mixture.
- (iii) The main source of error in analysis was the differences in accuracy of the analytical procedure of the laboratories.

Among the impurities found were hydrogen and ethylene. Both are impurities commonly found in gases prepared from refinery gases.

Roughly half of the participants were compressed gas producers, three were independent or governmental laboratories and the remainder were natural gas companies.

My own experience with test gases is limited to around 20 different primary mixtures, and as I mentioned, generally the test gases are as good as they claim to be. This does not mean that I have not seen gases with impurities, on the contrary I can show you this chromatogram which shows traces of ethylene. However, even with the impurities the concentrations of most components have been within the experimental error from the certified values, with discrepancies mainly for the pentanes, that were present in the 0.1 mole % level. Further I have had the pleasure to find that one company, which previously had delivered test gases containing ethylene, now is aware of the problem and uses clean primary gases.



Example of chromatogram of a test gas with ethylene at a level of 0.1 mole %.

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p-V-T PROPERTIES OF NATURAL GAS AT TEMPERATURES BETWEEN 270 K AND  
300 K AND PRESSURES OF UP TO 6 MPa

by

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PHYSIKALISCH-TECHNISCHE BUNDESANSTALT

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Paper 2.1

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p-V-T Properties of Natural Gas at Temperatures  
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### Introduction

There are two reasons why the knowledge of reliable values of the thermal variables of state of natural gas, i.e. pressure, density and temperature, is of significance. On the one hand, these data are required to judge the quality of methods applied for the computation of variables of state as they are, for instance, used in the charging of thermal gases. On the other hand, they are necessary to check methods for the measurement of the gas density which are often based on the calibration with pure gases of known density. Owing to the different thermodynamic properties of the gas to be measured and the gas used for calibration, the density values read may be affected by errors.

A thermodynamic state in the single-phase region of a fluid is defined by the related values of pressure  $p$ , temperature  $T$  and density  $\rho$ . In experiments, two variables of state are therefore given and the third variable, which is established in the state of equilibrium, is measured. Various experimental methods result from this. A given gas quantity is filled into a measuring vessel and its temperature or volume is changed so that different states of the gas are obtained. The method applied at the Physikalisch-Technische Bundesanstalt for measuring the thermal variables of state of gas mixtures combines the gravimetric density determination with the isothermal determination of the compressibility factor by the Burnett method. States in the vicinity of the two-phase region are obtained by quasi-isothermal cooling, starting from a temperature of 50 °C. During the test series, the density of the gas remains almost constant, the temperature is given and the resulting pressure measured.

### Experimental procedure

The experimental apparatus is schematically shown in Fig.1. It essentially consists of three pressure vessels connected in series, the thermostat, and devices for measuring pressure and temperature. The pressure is measured by means of a piston gauge. The diaphragm of a differential manometer, which is located in an agitated water bath, serves as null indicator of the constant volume pressure tap. As pressure

transmission medium between diaphragm and piston gauge, nitrogen is used whose pressure can be controlled with the aid of an oil injector and acts on an oil column connected with the piston gauge. The sensitivity of the differential manometer is higher than of the piston gauge so that the uncertainty of the pressure measurement is not influenced by the pressure being tapped via the diaphragm. From the force due to gravity, the effective cross section of the piston and the barometer reading - taking the difference of altitude into account - the pressure is determined with a relative uncertainty of less than  $1 \cdot 10^{-4}$ .

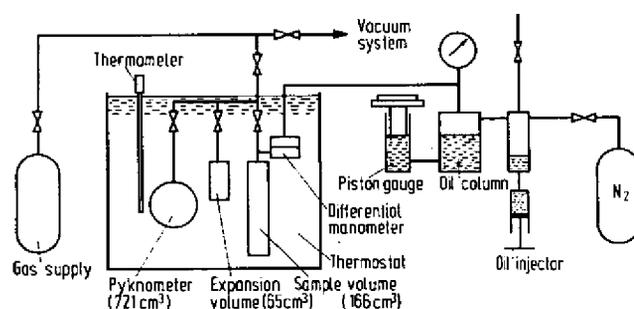


Fig.1: Apparatus for p-V-T measurements

The temperature of the controlled thermostat, which houses the pressure vessels and the diaphragm, is measured with two platinum resistance thermometers ( $R_0 = 25$  ohms) and a resistance bridge. Prior to each measurements, the  $^0$  temperature is kept constant to 10 mK for at least one hour so that thermal equilibrium is established between the fluid under study and the thermostat bath.

The sample volume and the volume of the pyknometer were determined several times using distilled water which had been carefully degassed. At zero pressure and at  $t_0 = 20$  °C, the pyknometer volume  $V_{0,k}(20$  °C) = 720,72 cm<sup>3</sup> and the cylindrical sample volume  $V_{0,z,k}(20$  °C) = 166,44 cm<sup>3</sup>. The pressure and temperature dependence of  $V_{0,z}$  the volumes is allowed for by the linear equation

$$V(t,p) = V_0(t_0) \cdot (1 + \alpha(t - t_0) + \beta(p - p_0)) \quad (1)$$

where  $V_0(t_0)$  is the volume at zero pressure at the temperature  $t_0$  and  $p_0$  the atmospheric pressure. For the pyknometer, the coefficient of thermal expansion  $\alpha$  and the pressure coefficient  $\beta$  have the values  $\alpha_k = 47 \cdot 10^{-6} \text{ K}^{-1}$  and  $\beta_k = 2.31 \cdot 10^{-4} \text{ MPa}^{-1}$ , respectively, whereas the values are  $\alpha_z = 49.5 \cdot 10^{-6} \text{ K}^{-1}$  and  $\beta_z = 1.6 \cdot 10^{-5} \text{ MPa}^{-1}$ , respectively,

for the sample volume. The relative uncertainty of the volume values amounts to  $5 \cdot 10^{-4}$  at most.

For isothermal expansion measurements, the gas from the sample volume is expanded into the expansion volume. The zero pressure cell constant

$$N_{\infty} = \frac{V_1^{\circ} + V_2^{\circ}}{V_1^{\circ}}$$

was determined at temperatures of 20 °C, 30 °C and 50 °C from expansion runs with helium, whose volumetric behaviour is very exactly known. The mean value  $N_{\infty} = 1.39000$ .

Prior to filling the pressure vessels, the apparatus is evacuated down to a final pressure  $p < 10^{-4}$  Pa using the turbomolecular pump connected with them. When gas mixtures are investigated, the temperature of the pressure vessels and of the gas supply are regulated to about 50 °C in order to achieve sufficient homogeneity. Heating of the connecting line is to prevent individual mixture components from accumulating at the surface of the filling line. After the pressure vessels have been rinsed several times, the main valve is closed and the thermostat temperature decreased to 20 °C.

During pressure measurement, the valves between pyknometer and sample volume are almost closed so that the pressure change due to the final closing of the connecting valves is negligibly small.

The mass of the gas confined in the sample volume results from the difference in mass of the filled and the evacuated pyknometer divided by the volume ratio of the pressure vessels at the temperature at which the valves were closed.

First a quasi-isochoric run is carried out. For this purpose, the thermostat temperature is usually varied in steps of 5 °C and the respective values of temperature and pressure are measured.

The uncertainty of the variables of state found results from the uncertainties by which the measurements of the temperature, the pressure, the volumes and the mass of the gas contained in them is affected. The relative uncertainty of the temperature measurement is  $3 \cdot 10^{-5}$ , that of the pressure measurement  $1 \cdot 10^{-4}$  at most. The volume values and the values of the masses of confined gas are affected by an uncertainty of  $5 \cdot 10^{-4}$  and less than  $1 \cdot 10^{-3}$ , respectively.

Following the quasi-isochoric test run, an expansion run can be carried out. The compressibility factor  $Z_j$ , after the  $j$ -th expansion, results from eq.(2).

$$Z_j = \frac{p_j}{p_0} \cdot \frac{N_{\infty}^j}{\prod_{i=1}^j \frac{1 + a_1 p_{j-1} + a_2 p_{j-1}^2}{1 + b_1 p_{j-1} + b_2 p_{j-1}^2}} \quad (2)$$

$p_j$  is the pressure prevailing after the  $j$ -th expansion. The constants  $a_1$  and  $b_1$  result from the pressure distortion coefficients of the sample volumes and the pyknometer; the constants  $a_2$  and  $b_2$  were obtained from the non-linear regression of the measurements executed with helium to determine the constant of the apparatus. With this method, the so-called "run constant" of the expansion run  $Z_0/p = \frac{1}{\rho_0 RT}$  can be obtained

by regression. When the density is measured with the pyknometer, the constant results directly from the gravimetrically determined density. On the one hand, the combination of the measurement methods makes use of the advantage offered by the method of constant volume which lies in the fact that the sensitivity is the same over the whole pressure range. The quantity of gas required becomes the greater, the higher the pressure becomes. A disadvantage of this method is the high expenditure of time which is due to the fact that for each filling, the mass of the filled-in gas must be determined.

By the expansion method according to Burnett, a larger number of  $p$ - $V$ - $T$  data are obtained in the same period of time, as this method basically requires neither the determination of the volume nor that of the mass, but only pressure measurements along an isotherm. This method is, however, only suitable for measurements in the gaseous region.

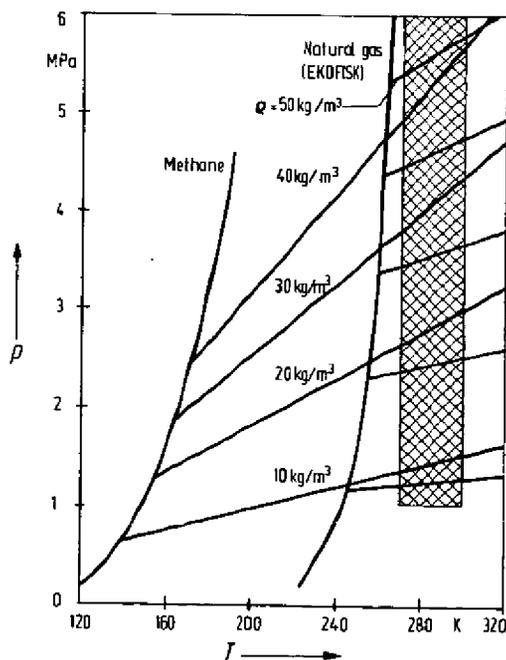


Fig.2:  $p, T$  diagram for methane and natural gas with isochores in the gaseous region

Attention must be paid to the fact that the distance between the isotherm and the two-phase region is sufficiently large so that condensation phenomena during expansion are definitely excluded. Whereas in the case of methane - the main component of natural gases - the region which is of interest here is situated at a clear distance from the two-phase region, with Ekofisk natural gas samples the condensation limit is almost reached for densities of more than  $30 \text{ kg/m}^3$  and at temperatures below  $270 \text{ K}$ . Fig.2 shows a comparison of the  $p,T$  diagrams for methane and for a natural gas sample from the Ekofisk field situated in the North Sea. The isochores in the gaseous region for densities from  $10 \text{ kg/m}^3$  to  $50 \text{ kg/m}^3$  have been entered. The plotted dew line of natural gas was experimentally determined by means of a dew point measuring instrument.

When the results of the expansion measurements are evaluated it should be borne in mind that for the computation of the compressibility factors  $Z_j$ , the uncertainty of the compressibility factors increases with rising pressures because the uncertainties of all compressibility factors at the lower pressures enter into the computation.

#### Experimental results

In order to check the experimental apparatus, initial measurements were carried out with a pure gas whose variables of state in the envisaged pressure and temperature range were well known. In view of the fact that tests with natural gas were to be carried out, methane, the main component of natural gases, was chosen for these preliminary tests. The mole fraction of the impurities of the methane used for the experiments was less than  $5 \cdot 10^{-6}$ .

In Fig.3, the variables of state measured are compared with values computed with the aid of three equations of state for methane / 1, 2, 3 /. In the figure, the relative deviations between measured and computed pressures have been plotted against the temperature for densities from  $10 \text{ kg/m}^3$  to  $40 \text{ kg/m}^3$ . With the exception of the IUPAC values at the highest density measured, the equations of state represent the measured values within the uncertainty of measurement. Here the deviations of the IUPAC tables from the measured values are by about 0.1 % higher than those of the equations of state of Sievers et al. and Kleinrahm et al.

The two natural gas samples investigated stem from the Ekofisk field in the North Sea. They were taken from the natural gas pipeline at an interval of three years and differ above all in the mole fractions of methane and ethane. The results of the analyses are given in Table 1.

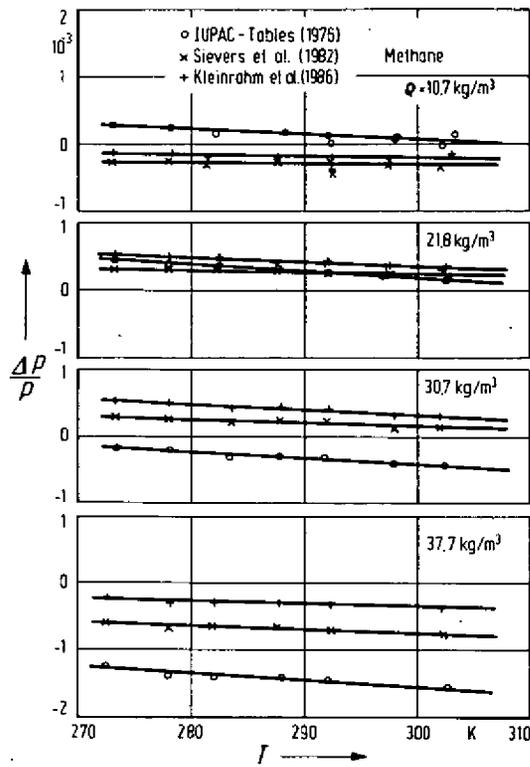


Fig.3: Comparison of 3 equations of state with experimental results of methane

Table 1: Composition of the investigated natural gas samples from the Ekofisk field

Component	Mole fraction in %	
	Sample 1	Sample 2
CH <sub>4</sub>	84.47	83.48
C <sub>2</sub> H <sub>6</sub>	8.86	9.47
C <sub>3</sub> H <sub>8</sub>	3.18	3.62
CO <sub>2</sub>	1.85	1.80
N <sub>2</sub>	0.43	0.53
C <sub>4</sub>	1.21	1.10

The volumetric behaviour of the Ekofisk natural gas sample 1 was also investigated by Achtermann et al. / 4, 5 / at the Institute of Thermodynamics of the Hannover University. Two different methods were applied - on the one hand the refractive index measurement and on the other hand, the measurement of the expansion behaviour (Burnett method). The variables of state determined by the two methods agree to 0.5 %/oo. The authors state the relative uncertainty of the measurements to be 1 %/oo.

In order to allow the p-p-T values measured with the isochore apparatus to be compared with the variables of state determined by Achtermann et al., the measured values must be represented by a correlation equation.

#### Representation of the measured values by a virial equation

A virial equation terminated after the third coefficient has proved to be suitable for representing our measurement results / 6 /:

$$\rho = \frac{p \cdot R \cdot T}{M} \left( 1 + \frac{B \cdot p}{M} + \frac{C \cdot p^2}{M^2} \right) \quad (3)$$

$$B = \sum_{i=1}^6 \sum_{j=1}^6 B_{ij}(T) \cdot x_i \cdot x_j \quad (4)$$

$$C = \sum_{k=1}^6 C_k(T) \cdot x_k \quad (5)$$

with R = general gas constant, M = molar mass, B = second and C = third virial coefficient of the mixture,  $x_i$  = mole fraction of the i-th component.

To limit the number of constants in the equation, only six components of the mixture were allowed for, i.e. methane, ethane, propane, carbon dioxide and nitrogen; the higher hydrocarbons were combined and treated like n-butane. The virial coefficients of methane were computed according to the equations stated by Sievers and Schulz / 2 /, those of ethane which, with a mole fraction of almost 10 %, is the most important sub-component of the Ekofisk natural gas, according to the equations given by Goodwin et al. / 7 /. The remaining virial coefficients of the other components and the mixed coefficients were taken from the book by Dymond and Smith / 8 / and approximated by a parabolic fit in the temperature range from 270 K to 300 K if sufficient data had been indicated.

If on the basis of two given variables of state the third variable is to be computed by means of the virial equation, in addition to the virial coefficients of the mixture, the molar mass  $M$  must be known.  $M$  can, for example, be computed from the complete analysis or from the density and the compressibility factor in standard state.

In order to achieve optimum adaptation to the measured values,  $M$  was varied for both natural gas samples until the standard deviation between measured and computed pressure values was minimum. For sample 1 with the lower ethane content, the relative deviation between the measured and computed values is on an average  $-5 \cdot 10^{-6}$  with an empiric standard deviation of  $6.7 \cdot 10^{-4}$ . As can be seen in Fig.4, all values are within the 1/100 limit, i.e. the measured values are represented by the set-up equation of state within the scope of the uncertainty of measurement.

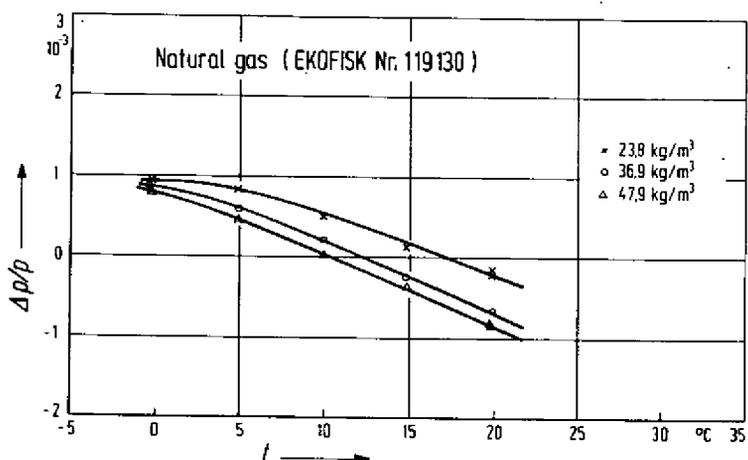


Fig.4: Comparison of the virial equation of state with experimental results on natural gas

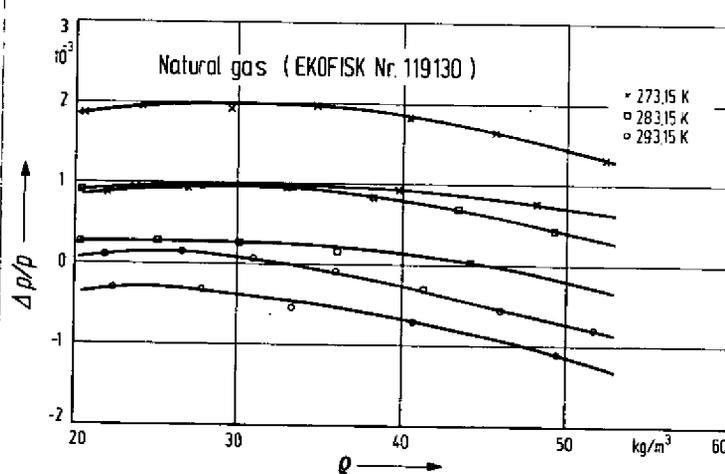


Fig.5: Comparison of the virial equation of state with experimental results from Achtermann et al. / 4, 5 /

After a suitable and simple equation of state had been formed which represents the measured values within the scope of the uncertainty of measurement, a direct comparison with the results obtained by the Burnett method and the optical method could be made. In Fig.5, the relative deviations of the pressures measured by Achtermann et al. / 4, 5 /, from the pressures computed by means of the virial equation have been plotted against the density. For 36 values from the density region between  $20 \text{ kg/m}^3$  and  $50 \text{ kg/m}^3$  and at the temperatures  $0^\circ\text{C}$ ,  $10^\circ\text{C}$  and  $20^\circ\text{C}$ , the mean relative deviation is  $5.2 \cdot 10^{-4}$  with an empiric standard deviation of  $8.5 \cdot 10^{-4}$ . The deviations are greatest with respect to the variables of state determined at  $0^\circ\text{C}$  by the optical

method; however, these values, too, do not exceed 2 ‰. The other values agree to 1 ‰, i.e. within the scope of their relative uncertainty of measurement. The results prove that with the experimental method applied by us, reliable variables of state can also be determined for multi-component natural gases in a region which almost extends up to the dew line.

Application of the virial equation to other results

The simple equation of state set up by us in the form of a virial statement terminated after the third coefficient has proved its worth for the description of the volumetric behaviour of the Ekofisk natural gas samples investigated. It therefore seemed appropriate to check, whether this equation also furnishes comparably good results for other gas mixtures of similar composition.

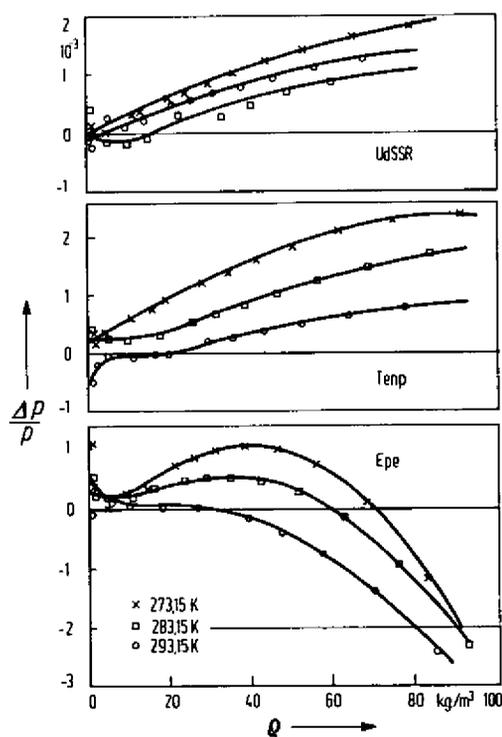


Fig.6: Comparison of the virial equation of state with experimental results on natural gas

In Fig.6, the relative deviations of the pressures computed with the virial equation, from measurement values taken from the literature / 4, 5 / are plotted against the density for the temperatures 0 °C, 10 °C and 20 °C. The composition of the natural gas samples are given in Table 2.

Table 2: Composition of natural gas samples

Component	Mole fraction in %		
	USSR	Tenp	Epe
CH <sub>4</sub>	93.53	85.27	85.50
C <sub>2</sub> H <sub>6</sub>	1.88	5.40	8.06
C <sub>3</sub> H <sub>8</sub>	0.49	1.59	2.86
CO <sub>2</sub>	0.23	1.46	1.86
N <sub>2</sub>	1.61	5.68	0.61
C <sub>4</sub>	0.26	0.70	1.11
Standard density in kg/m <sup>3</sup>	0.7541	0.8346	0.8531
Gross calorific value in MJ/m <sup>3</sup>	40.249	40.287	44.100

For the USSR natural gas, the representation quality is very good over the whole density range; the relative deviations become greater with increasing density, however, they do not exceed 2 ‰. The same trend can be observed with the Tenp natural gas; for this natural gas, too, the virial equation gives a good description of the volumetric behaviour. The relative deviations remain smaller than 2 ‰ up to a density of 60 kg/m<sup>3</sup>. In the range of low pressures, the Epe natural gas shows a behaviour similar to that of the USSR natural gas, i.e. the relative deviations slightly increase with density. At a density of about 40 kg/m<sup>3</sup>, this trend is reversed, the curves now drop with increasing density; at 80 kg/m<sup>3</sup> the relative deviations amount to up to 2 ‰.

In future, methods as the one described here for computing the gas density from analytical data and measured pressure and temperature values will gain in importance to the extent as reliable, automatic analyzers will be available.

#### Investigations into the adsorption behaviour of natural gas

The adsorption of the fluid to be measured on the walls of the pressure vessels may falsify the results of p-V-T measurements. When the gas density is determined by weighing a known volume, the adsorption of the

gas molecules at the walls leads to a decrease in pressure. When the measurement is carried out by the method of constant volume, the mass of the adsorbed gas may change as a function of temperature and pressure, i.e. the prerequisite of constant density is not guaranteed. The isothermal determination by the Burnett method can only be applied if the adsorption effects of the fluid to be measured can be neglected. As the expansion volume is evacuated after each expansion, only a small portion of the adsorbed gas molecules is left on the walls. After expansion, part of the gas "disappears" due to new adsorption. This falsification of the measured values becomes greater when the number of expansions increases. As so far no details of the adsorption behaviour of natural gas on metal surfaces are to be found in the literature, we carried out some orientating measurements which allow the influence of the adsorption effects on our p-V-T measurements to be estimated.

#### Experimental apparatus and carrying-out of the adsorption measurements

The experimental apparatus is schematically shown in Fig.7. The mass of the adsorbed gas is determined gravimetrically using a microbalance with a sensitivity of  $1 \cdot 10^{-6}$  g for a maximum mass of 20 g.

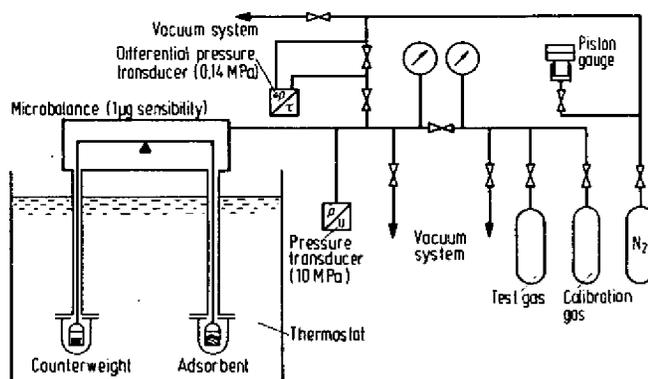


Fig.7: Apparatus for adsorption measurements up to 10 MPa

As the adsorption effects are small, it must be ensured that the sample has a highly specific surface. For this reason, only powdered samples or foils can be used for the measurements. The counterweight should consist of a sample of small surface, if possible of the same material. For reasons of expediency, the buoyancy correction should be determined with a gas whose adsorption is negligible in the range, which is of interest here, i.e. between 270 K and 300 K and at pressures up to 6 MPa, e.g. argon. For powdered samples, the surface effective during adsorption can be estimated if the distribution of the grain diameters

is known. The surface can be determined experimentally by applying the BET theory to adsorption measurements with pure gases. According to the literature, the uncertainty of the surface determined in this way is 10 % to 20 % / 9 /. The value of the surface on which our measurements are based is the mean value of the BET surfaces determined with carbon dioxide, propane and ethane. Depending on the size fraction, the surface values of the powders investigated lay between 1 m<sup>2</sup> and 3.5 m<sup>2</sup>. When foil was investigated, only 1/10 of this surface could be placed into the weighing crucible.

### Results of the adsorption measurements

To date, three metal powders and one foil have been investigated, i.e. titanium, iron and aluminium powder and ALFOL aluminium foil. With a few exceptions the measurements were carried out at 0 °C and at pressures of up to 3 MPa. Adsorbates were the natural gas components methane, ethane, propane and carbon dioxide and two natural gas samples whose composition is stated in Table 3.

Table 3: Composition of natural gas samples

Component	Mole fraction in %	
	EKOFISK	NAM + USSR
CH <sub>4</sub>	84.40	94.10
C <sub>2</sub> H <sub>6</sub>	8.87	1.49
C <sub>3</sub> H <sub>8</sub>	3.17	0.39
CO <sub>2</sub>	1.92	0.41
N <sub>2</sub>	0.42	3.42
C <sub>4</sub>	1.22	0.19

Fig.8 shows typical adsorption isotherms by the example of the propane/titanium adsorption system at the temperatures  $t = 0\text{ }^{\circ}\text{C}$  and  $t = 20\text{ }^{\circ}\text{C}$ . Initially, the mass of adsorbed gas increases strongly, then rises steadily, and finally increases strongly again when the saturation pressure is approached. The desorption branch of the isotherms slightly offset in relation to the adsorption branch, is represented by broken lines. This hysteresis phenomenon is frequently observed with adsorption effects. Dependent on the adsorption system it is more or less pronounced. This is also reflected in Fig.9, where the adsorption of methane is compared with the adsorption of the two natural gas samples investigated, titanium powder being again used as adsorbent.

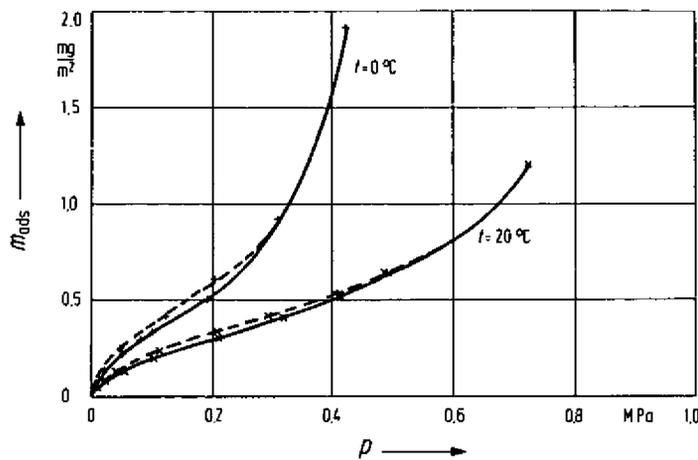


Fig.8: Adsorption isotherms of propane on titanium

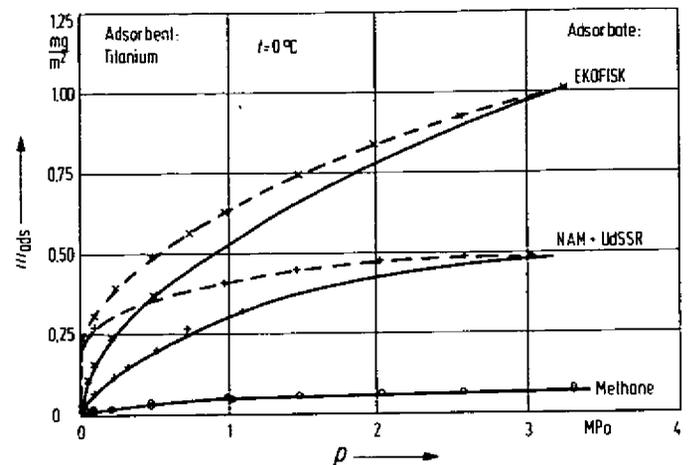


Fig.9: Adsorption isotherms of natural gas on titanium at 0 °C

While the adsorption of methane on the surface of the titanium powder is very low and practically no hysteresis phenomenon can be recognized at the scale chosen, the natural gas samples are adsorbed to a much greater extent. Although with 94.10 % of  $\text{CH}_4$  and 3.42 % of  $\text{N}_2$ , the natural gas sample contains as much as 95.52% of gases, which<sup>2</sup>- being pure gases - show only very low adsorption phenomena, 0.5 mg/m<sup>2</sup> of natural gas are adsorbed at 3 MPa. For the Ekofisk natural gas sample, even twice the amount of adsorbed gas is measured.

Fig.10 shows the influence of the adsorbent. While the adsorption of natural gas on titanium and iron powder is almost the same, the amount adsorbed on aluminium is only approximately 1/3 of the value measured for iron and titanium. This effect is less pronounced with Ekofisk natural gas, as this gas contains larger quantities of higher hydrocarbons. The adsorption behaviour of ethane and propane on iron and titanium is approximately the same, and on aluminium, adsorption is slightly lower. With methane and carbon dioxide, the differences are clearly more pronounced; for carbon dioxide, the mass of the gas adsorbed on aluminium is only about half the amount adsorbed on iron and titanium.

In order to estimate the influence which the adsorption effects exert on the p-V-T measurements, we formed the ratio of the mass of adsorbed gas to the mass confined in the vessel. The volume of the pressure vessel of  $V = 60 \text{ cm}^3$  corresponds to the volume of the expansion vessel used in the experiments. The surface of  $85 \text{ cm}^2$  follows from the cylindrical geometry of the vessel. The surface, which becomes effective

during adsorption, depends on the surface treatment of the material and may be substantially larger. Fig.11 shows the ratio for the adsorption of Ekofisk natural gas on aluminium, iron and titanium. As can be seen, in the range of lower pressures of up to 1 MPa, the mass of adsorbed gas decreases rapidly from about  $5 \cdot 10^{-5}$  to values below  $1 \cdot 10^{-5}$  of the mass of gas contained in the vessel. Provided that the behaviour of stainless steel surfaces does not differ substantially from that of the metal surfaces investigated so far, it can be assumed on the basis of the results on hand that the influence of the adsorption effects remains by a factor of 10 smaller than the uncertainty of the p-V-T measurements.

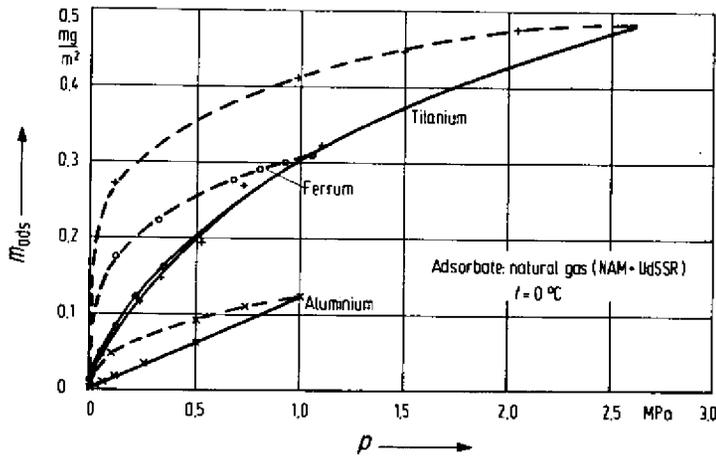


Fig.10: Adsorption isotherms of natural gas on different adsorbents

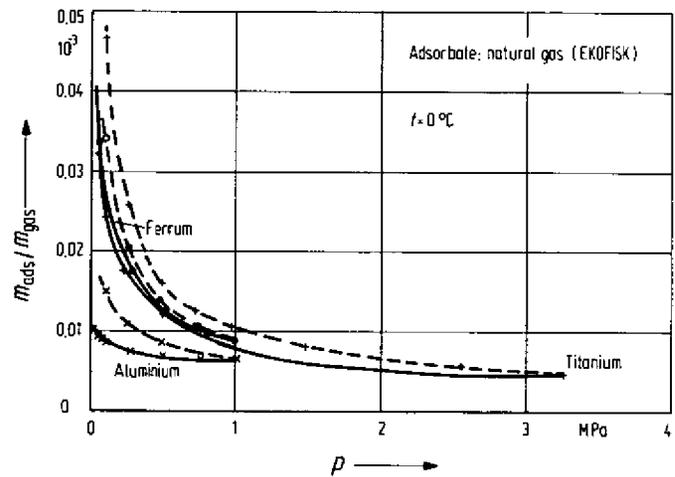


Fig.11: Effect of gas adsorption on p-V-T measurements in cylindrical pressure vessels ( $V = 60 \text{ cm}^3$ ,  $S = 85 \text{ cm}^2$ )

### Summary

The composition and thermal behaviour of natural gas may differ substantially depending on the sources from which it has been lifted. Frequently a mixing with other gases takes place. The method applied for the measurement of the thermal variables of state combines the gravimetric determination of the density with the isothermal determination of the compressibility factor by the Burnett method. States in the vicinity of the two-phase region are obtained by quasi-isochoric cooling, starting from a temperature of 50 °C. The measured p-V-T data can be represented within the uncertainty of measurement by a simple virial equation of state whose coefficients have not been adapted to the measured values. There is also a good representation of the thermal variables of state

of various natural gas samples taken from the literature. In order to allow the influence of the adsorption of the fluid to be measured on the walls of the pressure vessels to be estimated, the adsorption on metal surfaces of natural gas and its main components was gravimetrically investigated. The results obtained so far suggest that, in small vessels, the portion of the mass of adsorbed gas does not exceed  $5 \cdot 10^{-5}$  of the mass of gas contained in the vessel.

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VELOCITY OF SOUND EFFECT ON GAS DENSITY TRANSDUCERS - THE THEORY,  
MEASUREMENT RESULTS AND METHODS OF CORRECTION

by

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SOLARTRON TRANSDUCERS

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Paper 2.2

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East Kilbride, Glasgow

# VELOCITY OF SOUND EFFECT ON GAS DENSITY TRANSDUCERS – THE THEORY, MEASUREMENT RESULTS AND METHODS OF CORRECTION

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## SUMMARY

This paper describes the basic theory of the velocity of sound effect on vibrating cylinder gas density transducers. Measurement results are presented which confirm this effect. With this understanding the user is better able to select with confidence the most suitable correction method for a particular application. It is also hoped that this understanding will help to focus more emphasis on other application and installation details, thereby ensuring that the total measurement task is adequately performed.

## 1 INTRODUCTION

Differential pressure and gas density are the two prime quantities which are required in order to calculate the flow of gas through an orifice system. Gas density measurement is also of considerable importance when metering high pressure gas using turbine or vortex shedding meters.

Vibrating cylinder gas density transducers are now widely used for this service and when correctly applied offer very high accuracy. In order to achieve these high accuracies, it is important to consider a number of factors such as the performance of the prime calibration, installation details like pressure and temperature equilibrium, the representation of the sample gas and the systematic offsets due to temperature and the gas velocity of sound. Of these, the most difficult to understand has been the velocity of sound effect. A lack of understanding of this effect has, in a number of instances, led to bad practices and in consequence unnecessarily large measurement errors. This difficulty can give rise to conflict between the buyer and seller of the gas and should therefore be avoided.

The problem is clearly in two parts. The first is quantifying the velocity of sound effect on the sensor and the second is determining the actual velocity of sound of the calibration gas and the user gas so that, if necessary, suitable corrections can be applied.

## 2 HISTORY

Vibrating cylinder gas density transducers were first introduced in 1968. Early evaluations by Shell<sup>1</sup>, British Gas<sup>2</sup> and later Sira<sup>3</sup> clearly identified calibration offsets when changing from one gas type to another. Careful examination of this problem soon identified the velocity of sound effect and resulted in the publication of a paper by Solartron<sup>4</sup> on this topic.

This early work resulted in some design improvements for the vibrating cylinder and some application recommendations to correct for this effect.

Much of this early work was confused by the difficulties of carrying out accurate calibrations on gases and gas mixtures and by the manner in which the accuracy of some of these instruments were specified — for example, the use of 'percent full scale' against 'percent reading'. The velocity of sound effect is a 'percent reading' influence so becomes negligible at low densities, against an accuracy which is specified with respect to a large full scale reading.

A dramatic demonstration of the velocity of sound effect occurs when measuring gases such as ethylene through their critical region. Under these conditions there is a large change in the velocity of sound at constant density for small changes in pressure and temperature. For this reason much work has been concentrated in this area with impressive results. More recently, and with respect to very high pressure natural gas measurement, Dantest<sup>5</sup> and Ruhrgas<sup>6</sup> have carried out extensive tests, the results of which are now published.

During the past fifteen years a great deal of work has been done both theoretically and experimentally on the subject. Without exception this effort confirms the velocity of sound effect and in consequence gives strong indications on how corrections can best be achieved.

### 3 THEORY

Most vibrating element density transducers work on the principle of a simple mass spring system which is maintained in resonance by some electro-mechanical/electronic feedback system.

Part of the fluid, whose density is to be measured, is carried by or is in contact with the vibrating element and in consequence forms part of the total mass of the vibrating system. As the density changes, the total mass changes and hence the resonating frequency changes. This is simply illustrated by Figure 1 which shows the fluid within a container on the end of a spring. In this illustration it is assumed that the fluid is oscillating in complete sympathy with the container.

This assumption cannot be completely correct since the fluid is compressible and has a finite velocity of sound.

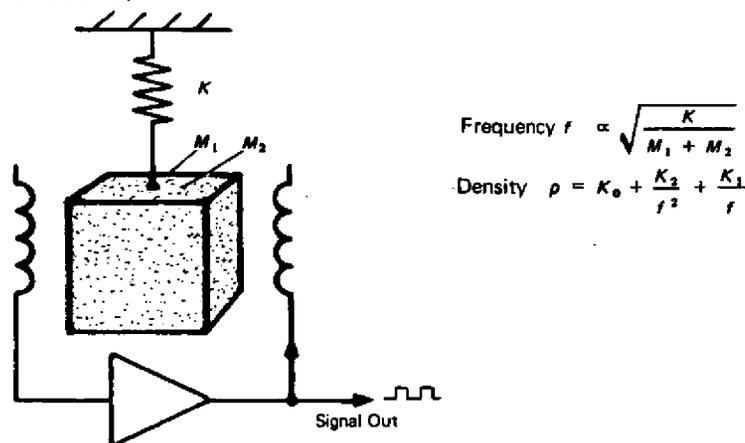


Fig. 1 Simple schematic of resonant element density transducer

A great deal of effort has gone into trying to understand and quantify the properties of a fluid, and their affect on the resonating frequency. Some of this work is still classified as confidential since its application is of significant benefit in the design optimisation of these density transducers. However, the conclusions reached after similar research by other interested parties confirm, without exception, the presence of a velocity of sound effect which causes the transducer to overread for a reduction in the fluid velocity of sound.

In general the simple approaches to solving the problem are easy to understand but will not yield accurate results. The more exact solutions are very complex but have been shown to be accurate.

One very simple model is illustrated in Figure 2. Here the resonant element is shown as having a mass of  $M_1$  and a stiffness of  $K_1$ . The fluid within the container is shown as having two components, one of mass  $M_2$  is coupled rigidly to the container while the other of mass  $M_3$  is coupled to the container by a stiffness  $K_2$ . This stiffness term  $K_2$  is a very simple representation of the properties of the fluid such as compressibility and velocity of sound.

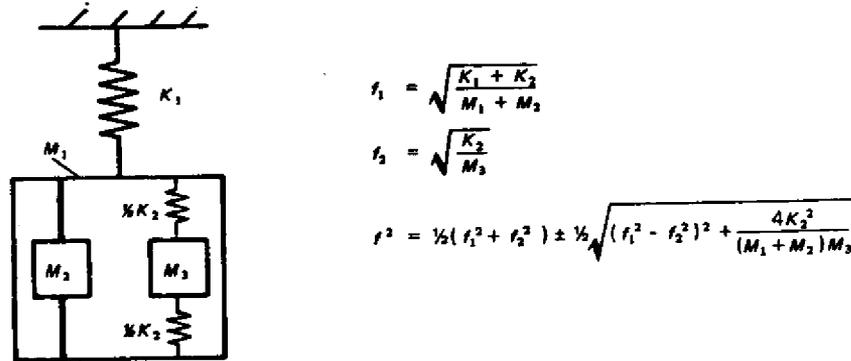


Fig. 2 Simple representation of fluid effects

This is a classical description of a resonant system with two degrees of freedom for which the solutions are illustrated in Figure 3.

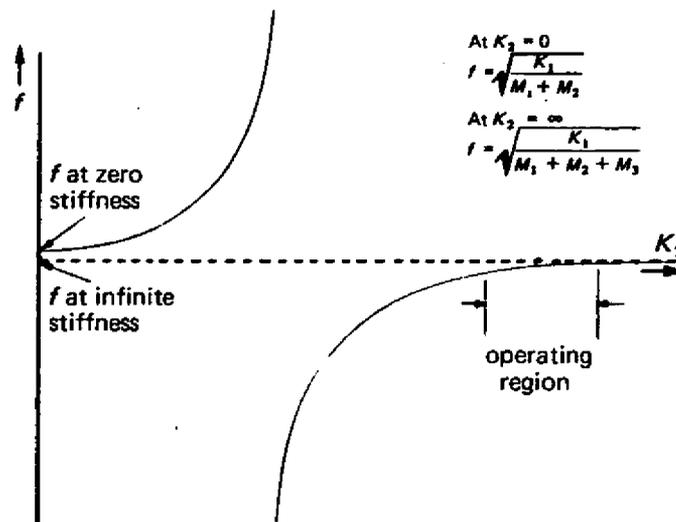


Fig. 3 Solution of system illustrated in Figure 2



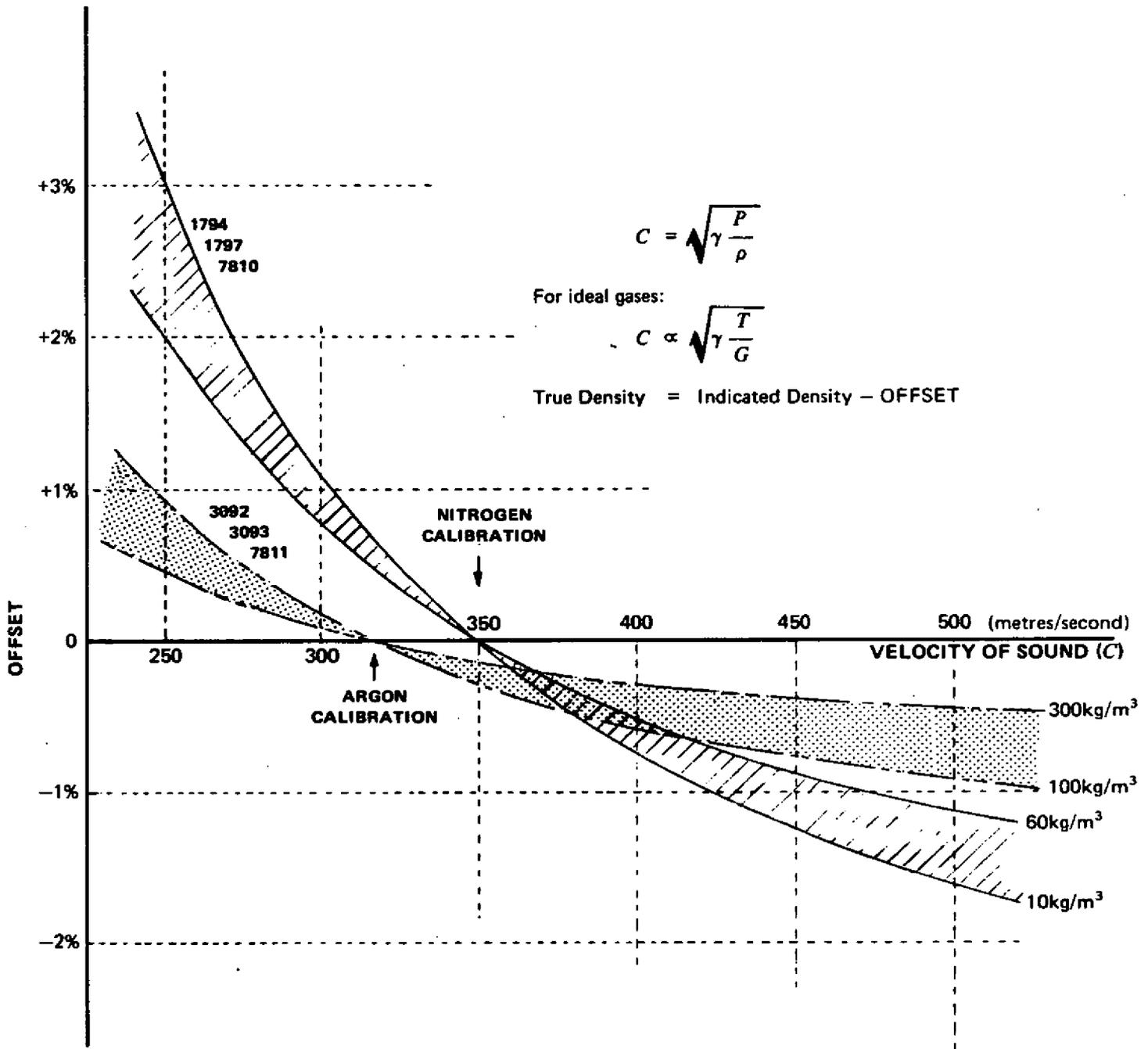


Fig. 5. Density offset due to velocity of sound effect

**Note:** For simplicity, this figure does not show the effects of changing Velocity of Sound of the calibration gas itself.

#### 4 MEASUREMENT RESULTS

Early measurements of the velocity of sound effect were based on noting the difference between calibrations performed on different gases. These calibrations used pressure and temperature measurements on certified pure gases with the density calculated from the standard gas tables. The results were good with respect to the limitations of the gas quality and the gas tables. For applications where the calibration offset is not large, such as for medium pressure natural gas measurement, these tests, supported by theory, were considered adequate.

For applications where large calibration offsets are expected, such as for ethylene in its critical region, where the velocity of sound changes dramatically and is of a low value, more comprehensive tests were considered necessary. Since accurate Pressure/Temperature/Density tables for ethylene in its critical region are not available, it was necessary to determine the density from highly accurate measurements of gas volume and mass.

Two experiments were set up, one sponsored by Shell in the Netherlands and carried out by the Dutch Weights and Measures Authority at Dordrecht<sup>7</sup>. The other was sponsored by Solartron, BP and ICI and carried out at the National Physical Laboratory (NPL)<sup>8</sup> in London. Both experiments used a pressure vessel which contained the ethylene gas and embodied the density transducer. Although the two vessels varied in their construction (Figures 6 and 7) the measurement principles applied were identical and the results were in very close agreement.

Volume was determined by weighing the vessels empty and then full of water. The pressure and temperature coefficients were also established. The vessels were then charged with gas and sealed. Gas density was determined by calculating the mass of the gas from the weighing of the vessels full and the vessels empty and then dividing the difference by the already established volume. Uncertainties of about 0.02% are claimed for this method. With the vessels charged in this manner, the temperature and hence the pressure conditions may be varied without changing the density, except as defined by the small pressure and temperature coefficients of the vessels. In this manner the performance of the density transducer can be determined at several fixed and accurately defined densities and over the required pressure and temperature ranges.

By performing these tests using argon and then ethylene, the differences can be quantified, and then examined with respect to the expected velocity of sound offsets. The benefit of this work is that some of the major systematic uncertainties of this measurement technique such as the volume determination cancel out. Tables 1 and 2 list the results from the NPL studies and they clearly show very good agreement, and that an instrument calibrated on one gas will accurately measure the density of another gas after correction for the velocity of sound effect.

In recent years much experimental work has been carried out on the effects of natural gas mixtures. Probably the most significant published work is that carried out by Ruhrgas<sup>9</sup> and Dantest<sup>5</sup>. Both of these reports clearly confirm the velocity of sound explanation for the calibration offsets.

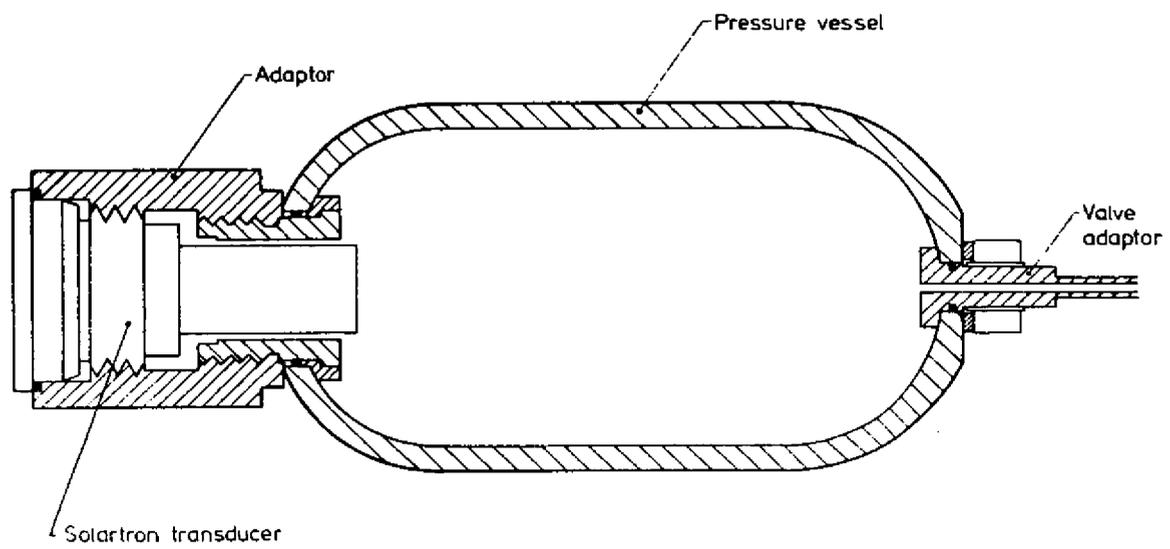


Fig. 6 Outline diagram of NPL pressure vessel (1200cc capacity)



Fig. 7 The pressure vessel used by Shell (5000cc capacity)

Table 1 NPL argon results

Temperature (T°C)	Periodic Time (τ μsec)	True Density (kg/m³)	Calc. Density (kg/m³)	ρ <sub>Cal</sub> - ρ <sub>True</sub> (kg/m³)		Vel. of Sound (m/s)	VOS Cor. Density (kg/m³)	ρ <sub>Vos/cor</sub> - ρ <sub>True</sub> (kg/m³)		Offset ρ <sub>Press</sub> (%)
				(kg/m³)	(%)			(kg/m³)	(%)	
15	1028.422	399.70	399.70	0.00		375	399.63	-0.07	-0.02	-0.04
20	1028.266	399.54	399.55	0.01		378	399.51	-0.03	-0.01	-0.02
25	1028.086	399.38	399.38	0.00		382	399.38	0.00	0.00	0.00
30	1027.925	399.22	399.22	0.00		386	399.26	0.04	0.01	0.02
45	1027.534	398.88	398.85	-0.03		397	398.98	0.10	0.03	0.07
15	895.391	279.98	279.99	0.01		348	279.90	-0.08	-0.03	-0.04
20	895.289	279.89	279.90	0.01		352	279.86	-0.03	-0.01	-0.02
25	895.173	279.80	279.80	0.00		356	279.80	0.00	0.00	0.00
30	895.041	279.70	279.69	-0.01		360	279.73	0.03	0.01	0.04
45	894.722	279.47	279.43	-0.04		371	279.58	0.11	-0.04	0.07
15	737.884	160.13	160.13	0.00		330	160.05	-0.08	-0.05	-0.05
20	737.794	160.07	160.07	0.00		333	160.03	-0.04	-0.03	-0.03
25	737.692	160.00	160.00	0.00		337	160.00	0.00	0.00	0.00
30	737.588	159.94	159.92	-0.02		340	159.95	0.01	0.01	0.01
45	737.340	159.81	159.75	-0.06		350	159.88	0.07	0.04	0.05
15	533.925	40.15	40.17	0.02		318	40.14	-0.01	-0.02	-0.02
20	533.875	40.13	40.15	0.02		321	40.13	0.00	0.00	0.00
25	533.800	40.11	40.11	0.00		324	40.11	0.00	0.00	0.00
30	533.730	40.09	40.08	-0.01		327	40.10	0.01	0.02	0.02
45	533.513	40.05	39.97	-0.08		337	40.04	0.01	-0.02	-0.02

Table 2 NPL ethylene results compared against argon calibration

Temperature (T°C)	Periodic Time (μsec)	True Density (kg/m³)	Calc. Density (kg/m³)	ρ <sub>Cal</sub> - ρ <sub>True</sub>		Vel. of Sound (m/s)	VOS Cor. Density (kg/m³)	ρ <sub>Vos/cor</sub> - ρ <sub>True</sub>		Offset ρ <sub>Eth</sub> (%)
				(kg/m³)	(%)			(kg/m³)	(%)	
15	1027.146	399.07	398.47	-0.60	-0.15	644	399.62	0.55	0.14	0.04
20	1026.863	398.88	398.20	-0.68	-0.17	656	399.37	0.49	0.12	-0.01
25	1026.624	398.70	397.97	-0.73	-0.18	663	399.16	0.45	0.11	0.04
30	1026.385	398.51	397.74	-0.73	-0.18	674	398.94	0.43	0.11	0.05
45	1026.724	398.91	398.07	-0.84	-0.21	705	398.32	0.41	0.10	0.09
15	897.063	280.10	281.39	1.29	0.46	311	280.81	0.71	0.25	0.12
20	896.534	280.01	280.94	0.93	0.33	320	279.56	0.45	0.16	0.02
25	896.140	279.90	280.61	0.71	0.25	329	280.29	0.39	0.14	0.00
30	895.826	279.79	280.35	0.56	0.20	338	280.14	0.35	0.13	-0.03
45	895.197	279.55	279.82	0.27	0.10	369	279.95	0.40	0.14	-0.01
15	740.590	159.94	161.99	2.05	1.27	236	160.17	0.23	0.14	0.12
20	740.058	159.86	161.62	1.76	1.09	241	159.95	0.09	0.05	0.02
25	739.657	159.80	161.34	1.54	0.96	247	159.84	0.04	0.02	-0.03
30	739.292	159.72	161.09	1.37	0.85	253	159.74	0.02	0.01	-0.05
45	738.452	159.58	160.52	0.94	0.58	270	159.55	-0.03	-0.02	-0.10
15	533.979	40.06	40.20	0.14	0.35	288	39.96	-0.10	-0.25	-0.22
20	533.867	40.03	40.14	0.11	0.28	291	39.93	-0.10	-0.25	-0.24
25	533.773	40.00	40.14	0.14	0.35	294	39.95	-0.05	-0.13	-0.12
30	533.668	39.97	40.05	0.08	0.20	297	39.88	-0.09	-0.23	-0.24
45	533.433	39.92	39.93	0.01	0.03	306	39.82	-0.10	-0.25	-0.22

\* Taken from NPL results: Reference NPC 3/05 Page 5

Notes:

1.  $\rho_{Cal} = K_0 + K_1\tau + K_2\tau^2$  where  $K_0 = -85.462$ ,  $K_1 = -0.020001$ ,  $K_2 = 4.78166E-4$

K factors are optimised for argon at 25°C

2. 
$$\rho_{VOS} = \rho_{Cal} \left( \frac{1 + \left(\frac{K}{\tau c_0}\right)^2}{1 + \left(\frac{K}{\tau c}\right)^2} \right)$$

$$K = 2.62 E4$$

$$c = \text{Actual VOS}$$

$$c_0 = \text{Argon VOS at 25°C}$$

3.  $\rho_{Press} =$  Pressure corrected density offset  
 $= 0.0017\%/bar$  from argon pressure at 25°C  
 $= (\rho_{Vos} - \rho_{True})\% + 0.0017(P - P_0)$  where  $P =$  Vessel pressure  
 $P_0 =$  Vessel pressure with argon at 25°C

4.  $\rho_{Eth} =$  Pressure and temperature corrected density offset  
 $= (\rho_{Press})_{ethylene} - (\rho_{Press})_{argon}$

Table 3 shows the measurement deviation on a density transducer when calibrated with methane and nitrogen, and how this deviation is reduced after the inclusion of the velocity of sound correction.

**Table 3** *The Ruhrgas/VDI results for methane and nitrogen*

Nominal Density ( kg/m <sup>3</sup> )	Deviation Methane/Nitrogen ( % )	Deviation after VOS Correction ( % )
22	0.93	+0.01
	0.97	-0.03
35	0.83	+0.04
	0.86	+0.07
47	0.71	+0.01
	0.73	+0.03
59	0.59	-0.03
	0.60	-0.04

Figure 8 is a summary of the measurement results on a number of natural gases from the Ruhrgas tests based on a methane calibrated sensor. Figure 9 demonstrates the consequence of applying velocity of sound correction.

It is important to note that there have been reports of calibration offsets which cannot be explained by the velocity of sound effect. In most cases an explanation has later been found, either with respect to gas compositions uncertainties, measurement errors, calculation errors or sensor contamination. This clearly highlights that considerable care and skill is necessary in order to carry out these tests and, whilst these tests may be important in order to confirm an effect, they should not form the basis of routine calibrations. In general, for best performance and confidence, it is recommended that calibrations are performed on a pure gas such as nitrogen with suitable corrections for changes in gas composition and operating conditions.

## 5 METHODS OF CORRECTION

As clearly shown by theory and by measurement results, a systematic measurement offset will be experienced if the velocity of sound of the measured gas is different from that of the calibration gas. If this measurement offset is not acceptable then one of the following two procedures must be applied:

- (a) To calibrate the density transducer with the user gas at the mean operating conditions. Good calibrations using this procedure are very difficult and are limited in their application. It is often the case that better calibrations would result using pure gas (e.g. nitrogen) calibrations and a fixed estimated offset.

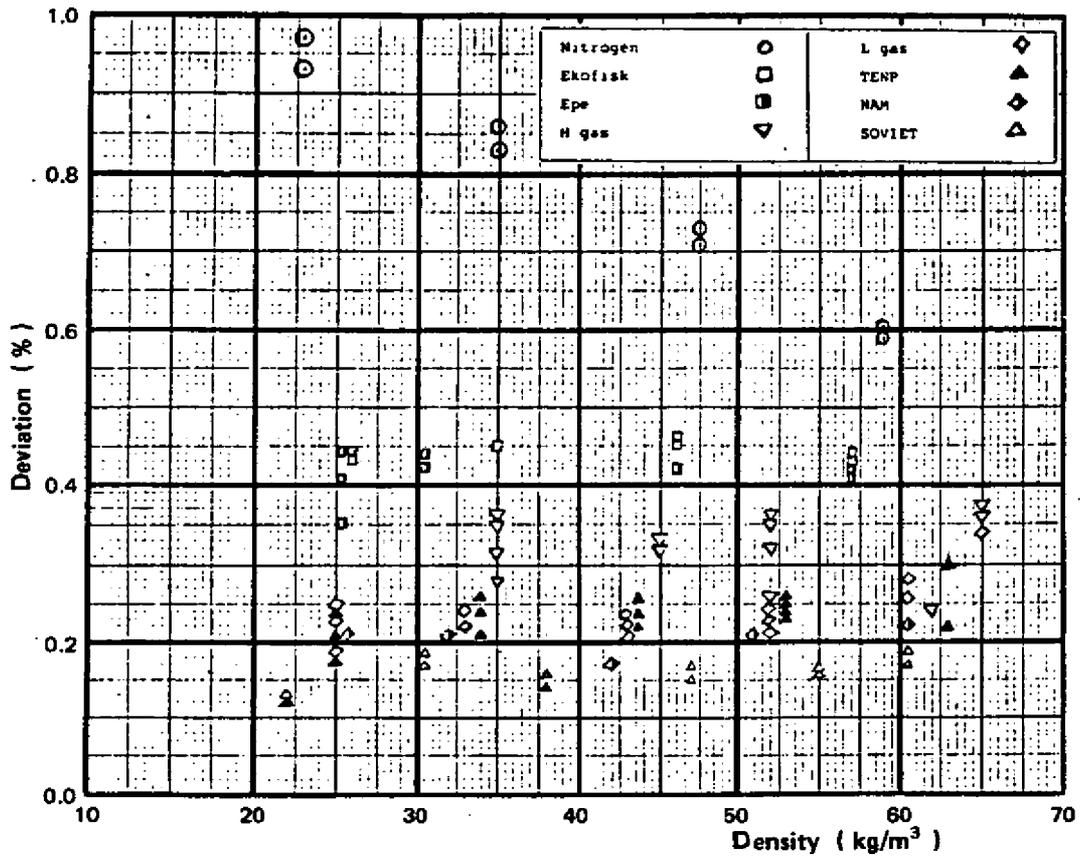


Fig. 8 Ruhrgas natural gas results - uncorrected

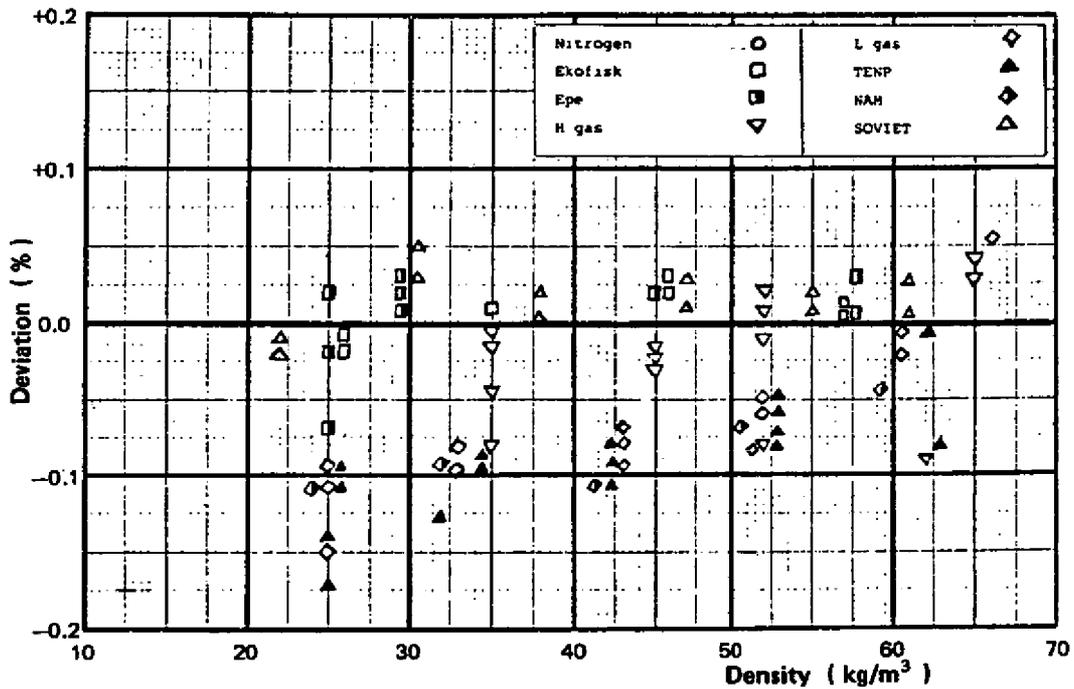


Fig. 9 Ruhrgas natural gas results - VOS corrected



- (c) Temperature/Density Composition Method
- (d) Temperature/Specific Gravity Composition Method

These methods are described in Appendix A of this paper and may be expanded or simplified as necessary in order to obtain the desired accuracy. Similarly, they may result in the application of fixed calibration offsets or they may be applied continuously from measurements of pressure, temperature and composition. Experience has shown that the Pressure/Density method, whilst being one of the simplest to apply, is also one of the most effective.

For further simplicity it is sometimes the practice to combine the sensor effect with the gas effect to form one correction equation. This is often referred to as the User Gas Equation and its derivation is described in Appendix B. Its use is somewhat limited to specific gas types over closely defined operating ranges and it is chiefly intended to highlight that for the best accuracy a gas composition related correction factor should be applied.

It follows that there is an almost unlimited variation of correction methods, depending primarily on how the VOS of the User Gas can be described from the available measurements. This wide choice does sometimes cause difficulties, but it should be stressed that the velocity of sound effect only generates a small offset and in consequence there is little justification in using complex procedures to accurately define these offsets when simple procedures are quite adequate

It is often best to consider the velocity of sound correction as part of the total calibration requirements for the density transducer and in this respect the following general recommendations should be considered:

1. Calibration:

- (a) For low density and natural gases use nitrogen at 20°C (Figure 10).
- (b) For high densities use argon at 20°C.
- (c) Only use defined gases at defined conditions if good density standards are available, if gas quality can be assured and if calibration conditions cover the full range of operating conditions.

2 Velocity of Sound Correction

- (a) If measuring a defined gas at a relatively constant temperature, use fluid offsets as provided by the 'User Gas Certificate' (Figure 11) or similar.
- (b) If measuring different gases and/or the measurement conditions are changing significantly, use continuous correction for VOS, preferably by the Pressure/Density method or alternatively by the Temperature/Specific Gravity method but as defined by available measurements.

3 Temperature Corrections (Excluding VOS Effect)

The vibrating cylinder density transducers normally have a very small temperature coefficient (typically  $0.001 \text{ kg/m}^3$ ) and correction for this is only necessary if operating at low densities and at temperatures which are far removed from the calibration temperature (20°C). Where necessary, corrections can be applied using the equation on the prime calibration certificate to either a mean fixed temperature condition or by using temperature measurements.

CALIBRATION CERTIFICATE

Farnborough Division

Solartron Transducers

7810N GAS DENSITY METER

Serial No: 100108  
 Cylinder No: 004887  
 Amplifier No: 001393  
 Cal Date: 20JAN86

Unit Pressure Tested to 375 BARS

DENSITY CALIBRATION FOR NITROGEN AT 20 DEG.C  
 (Based on Pressure-Temperature-Density Data in IUPAC Tables)

DENSITY [KG/M3]	PERIODIC TIME [uS]
0	212.277
1	213.201
2	214.102
5	216.78
10	221.161
15	225.446
20	229.639
30	237.78
40	245.519
50	253.193
60	260.522

$$\text{DENSITY} = K0 + K1.T + K2.T^{**2}$$

K0 = -1.008782E+02  
 K1 = -1.515094E-01  
 K2 = 2.951956E-03

TEMPERATURE COEFFICIENT DATA

$$Dt = DI(1 + K18(t - 20)) + K19(t - 20) \quad K18 = -2.33E-05$$

$$K19 = -1.88E-04$$

USER GAS OFFSET DATA

Nitrogen/Methane Gas Mixture Over Density Range 10 to 60 KG/M3

$$DA = Dt \left( 1 + \frac{K3}{Dt+K4} \left( \frac{G}{t+273} - 0.00236 \right) \right) \quad K3 = 831$$

$$K4 = 59$$

where

T = Periodic Time (uS)  
 DA = Actual Density (KG/M3)  
 t = Temperature (DEG.C)  
 DI = Indicated Density (KG/M3)  
 Dt = Temp.Corrected Density (KG/M3)

$$G = \frac{\text{Gas Specific Gravity}}{\text{Ratio of Specific Heats}}$$

TESTER

QC

Ref No:-GD01/L

DATE-20JAN86

Fig. 10 Nitrogen calibration certificate

USER GAS CALIBRATION CERTIFICATE

Farnborough Division

Solartron Transducers

7810N GAS DENSITY METER

Serial No: 100100  
Cylinder No: 004887  
Cal Date: 20JAN86

NITROGEN CALIBRATION DATA AT 20 DEG.C

K0 = -1.008782E+02      K18 = -2.33E-05  
K1 = -1.515094E-01      K19 = -1.33E-04  
K2 = 2.951956E-03

USER GAS DATA AT 20 DEG.C

COMPOSITION BY % VOLUME :- (SINGLE PHASE FLUID IS ASSUMED)

HYDROGEN	0.0000
HELIUM	0.0000
NITROGEN	0.4183
CARBON MONOXIDE	0.0000
CARBON DIOXIDE	1.8985
OXYGEN	0.0000
ARGON	0.0000
METHANE	84.6505
ETHANE	8.7505
ETHYLENE	0.0000
PROPANE	3.1074
PROPYLENE	0.0000
BUTANE	0.9684
PENTANE	0.1677
HEXANE +	0.0387
TOTAL	100.0000

VELOCITY OF SOUND AND ERROR DATA WITH USER COEFFICIENTS

DENSITY [KG/M3]	PERIODIC TIME [μS]	V.O.S [M/S]	MAX. ERROR [%density]
5	216.746	408	0.235
10	221.102	403	0.208
20	229.545	395	0.174
30	237.665	390	0.181
40	245.495	389	0.160
60	260.400	392	0.186

USER GAS COEFFICIENTS

TESTER

K0 = -1.071680E+02  
K1 = -1.004218E-01  
K2 = 2.850954E-03

QC

Ref No: GD02/F

DATE-20JAN86

Fig. 11 User gas calibration certificate

## CONCLUSIONS

All vibrating density sensors are influenced by changes in the velocity of sound of the fluid being measured. By understanding this effect, sensors can be designed which exhibit minimum effect but without the loss of other features. By quantifying this effect with respect to a particular measurement task, the most suitable correction method can be defined and agreed by all parties.

This characteristic of these gas density sensors should be considered alongside details of the calibration and the installation which are often of much greater significance. When correctly applied, measurement performance to 0.1% of reading can be demonstrated in the laboratory environment and to 0.2% to 0.3% of reading in the pipeline environment. This compares very favourably with alternative methods of continuous gas measurement.

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## APPENDIX A

### V.O.S. DETERMINATION OF GAS MIXTURES

#### Prime Influence

From the thermodynamics of a gas, the speed of sound is given by the equation:

$$c = \sqrt{\gamma \left( \frac{\delta P}{\delta \rho} \right)_T} \dots \dots \dots A1$$

where  $c$  = speed of sound ( m/s )

$$\gamma = \frac{C_p}{C_v} \text{ Ratio of specific heats}$$

$$\left( \frac{\delta P}{\delta \rho} \right)_T = \text{ratio of pressure change (in Pa) to density change (in kg/m}^3\text{) at constant temperature}$$

At low pressures this equation may be simplified to:

$$c = \sqrt{\gamma \frac{P}{\rho}} \dots \dots \dots A2$$

Also since

$$\frac{P}{\rho} = \frac{R T_A Z}{M} \dots \dots \dots A3$$

where  $R$  = universal gas constant  
 $T_A$  = absolute temperature  
 $M$  = molecular weight  
 $Z$  = compressibility factor

it follows

$$c = \sqrt{\gamma \left( \frac{R T_A Z}{M} \right)} \dots \dots \dots A4$$

#### Pressure/Density Method

The Pressure/Density method of calculating the velocity of sound of a gas is based on equation A2. However, to include for changes in the specific heat ratio and the pressure density ratio at high pressure, the equation is expanded as follows:

$$c = \sqrt{\gamma_0 \frac{P}{\rho} + K_1 \rho^2 + K_2 \rho^3} \dots \dots \dots A5$$

where  $\gamma_0$  is the zero pressure specific heat ratio.

By correct selection of  $\gamma_0$ ,  $K_1$  and  $K_2$ , this equation is more than adequate for V.O.S. determination. Furthermore, these values are not very sensitive to changes in gas composition. It is this equation which is used in Solartron Flow Computers types 7900 and 7910.

### Temperature/Density Composition Method (2nd Gas Certificate)

A procedure has been developed by Solartron which allows the velocity of sound to be calculated for a defined gas mixture, at a defined operating temperature and over a specific density range.

The velocity of sound for each component gas is determined by the following equation:

$$c = K_{00} + K_{01}x + K_{02}x^2 + (K_{10} + K_{11}x + K_{12}x^2)y + (K_{20} + K_{21}x + K_{22}x^2)y^2 + (K_{30} + K_{31}x + K_{32}x^2)y^3 \dots \dots \dots A6$$

where  $x$  = temperature ( °C )  
 $y$  = component density ( kg/m<sup>3</sup> )

The velocity of sound of a gas mixture is determined by the combination of the component velocity of sounds.

This procedure is used by Solartron to generate a Users Gas Calibration Certificate (2nd Gas Certificate)

### Temperature/Specific Gravity Method

This procedure is described in V.D.I. Report 162 and for natural gases uses the following equation:

$$c = B_0 + B_1d^{-0.5} + B_2T^2\rho^{0.5} + B_3d^{0.5}T\rho^2 + B_4dT\rho + B_5dT^{1.5}\rho + B_6d^{1.5}T^{0.5}\rho^{1.5} + B_7d^{1.5}T^{1.5} + B_8d^{1.5}T^{1.5}\rho^{0.5} + B_9d^2T^{1.5} \dots \dots \dots A7$$

where  $c$  = velocity of sound ( m/s )  
 $\rho$  = density ( kg/m<sup>3</sup> )  
 $T$  = temperature ( °K )  
 $d$  = density ratio ( Specific Gravity )

The coefficients  $B_0$  to  $B_9$  are selected from one of three tables as a function of the calorific value of the gas.

This procedure should only be considered if a pressure measurement is not available and in general is considered unnecessarily complex when compared with the Solartron User Gas Equation.

### Temperature/Specific Gravity Method (Reverse PTZ Procedure)

This procedure uses the Pressure/Density method (page A1). Equation A5, in combination with a method of calculating line pressure from temperature, density, specific gravity and the Z factor. One of several available procedures can be applied for the determination of Z such as NX19.

This procedure, like the V.D.I. procedure, should only be considered if a pressure measurement is not available and in general is considered unnecessarily complex when compared with the Solartron User Gas Equation.

## APPENDIX B

### SOLARTRON USER GAS EQUATION

The Solartron User Gas Equation is a simplified combination of the density sensor V.O.S. effect (Equation 2 on page 4 of this paper) and the gas V.O.S. definition (Equation A4). The combination method is as follows:

From Equation 2

$$\rho_A = \rho_1 \left( \frac{1 + \left(\frac{K}{T c_c}\right)^2}{1 + \left(\frac{K}{T c_g}\right)^2} \right)$$

If  $\left(\frac{K}{T c_c}\right)^2$  and  $\left(\frac{K}{T c_g}\right)^2$  are small with respect to 1.0 then

$$\rho_A = \rho_1 \left( 1 + \left(\frac{K}{T}\right)^2 \left( \frac{1}{c_c^2} + \frac{1}{c_g^2} \right) \right) \dots \dots \dots B1$$

The sensor Density/Time period relationship is approximately

$$\rho_1 = K_0 + K_2 T^2 \dots \dots \dots B2$$

also from Equation A4

$$c^2 = \gamma \frac{RT_A Z}{M} \dots \dots \dots B3$$

substituting into Equation B1

$$\rho_A = \rho_1 \left( 1 + \frac{K^2 K_2}{(\rho_1 - K_0) R} \left( \left( \frac{M}{\gamma T_A Z} \right)_c - \left( \frac{M}{\gamma T_A Z} \right)_g \right) \right) \dots \dots B4$$

This can be simplified further

$$\rho_A = \rho_1 \left( 1 + \frac{K_3}{(\rho_1 + K_4)} \left( K_5 - \frac{G}{\gamma_0 (T + 273)} \right) \right) \dots \dots \dots B5$$

Where  $K_3$  and  $K_4$  are coefficients which can be selected to give no error between a calibration gas and a user gas at minimum and maximum densities.  $K_5$  is the calibration gas factor.

- $G$  is the specific gravity of the user gas
- $\gamma_0$  is the zero pressure specific heat ratio
- $T$  is the temperature in °C.

This equation is presented on the Primary Calibration Certificate for Solartron Density sensors where the factors  $K_3$  and  $K_4$  have been selected to give no error when the sensor is used on the calibration gas and on methane.

Alternative values of  $K_3$  and  $K_4$  can be determined to give no error for any specified gas at minimum and maximum operating densities.

For most applications, this correction equation can be further simplified with only a small loss in accuracy, by assuming a constant value of  $\gamma_0$ . Hence:

$$\rho_A = \rho_1 \left( 1 + \frac{K_6}{\rho_1 + K_4} \left( K_7 - \frac{G}{(T + 273)} \right) \right) \dots \dots \dots \text{B6}$$

Where no pressure measurement is available, this method is normally recommended due to its simplicity and effectiveness.

EXPERIENCE OF OFFSHORE ON-LINE GAS DENSITY MEASUREMENT

by

M F MARSHALL  
MARSHALL INSTRUMENTATION LTD

---

Paper 2.3

NORTH SEA FLOW METERING WORKSHOP 1986

7-9 October 1986

National Engineering Laboratory  
East Kilbride, Glasgow

## EXPERIENCE OF OFFSHORE ON-LINE GAS DENSITY MEASUREMENT

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M.F. MARSHALL

### INTRODUCTION

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The measurement of gas density using density transducers is common place on offshore fiscal gas metering stations. In this paper I have attempted to describe some of the problems I have encountered with these Instruments in the design & commissioning of offshore gas metering stations on both the U.K and the Norwegian sectors of the Northern North Sea. I have also given advice on avoiding some of the more common reasons for transducer failures. The paper contains some basic design guidelines to help alleviate problems in new Fiscal Gas Metering Systems.

## THE DESIGN STAGE

=====

At the design stage of a new gas metering project very little information will be available regarding the exact composition of the gas & the expected operating conditions of the new station . Normally the Instrument Engineer or Gas Metering Consultant will use the educated guesses of the Process Engineers in order to proceed with the design calculations . Inevitably he will guess wrong. The gas composition may be heavier in hydrocarbons (or lighter) than was assumed ,the actual operating conditions may not be as predicted or the Gas / Oil Ratio may have dramatically increased since then resulting in the metering station not being capable of the throughputs it was designed for .

Invariably the instrumentation will be ordered early on in the project and left in stores until required. In the case of Density Transducers this can be a fatal mistake . For fiscal applications the certificate given with a transducer is only valid for one year. As we all know one year is the typical timescale for the design and construction of an offshore Gas metering station. Invariably a few weeks before the system is due for final tests and inspection by the various interested parties and auditors, the Engineer responsible for organising the calibration checks and functional tests will be sitting in his office checking through the project paperwork and find that some if not all the Density Transducers will require re-certification. The turn-around time from the manufacturers is approximately 6 weeks (if you haven't hit upon the various two week holiday periods). The Engineer thus finds himself in a panic situation with telexes to the platform and to the manufacturers organising a quick turn-around and rapid transportation back to the platform. If all goes well, enough Instruments will be back in time for the tests. The density transducer vendor that I have been involved with in the past , has been very helpful in this type of situation.

The design criteria concerning the number of density transducers required per stream is a subject that over the years I have studied in great detail. In most cases I would recommend the fitting of dual density transducers per stream. This allows maximum flexibility of operations and gives the operator greater confidence in the density being used in the fiscal calculations.

The use of a back-up density calculation within the stream micro-computer has the advantage of allowing automatic fall back to the calculated density on detection of a discrepancy between the density transducers or between calculated and a single density transducer if only one is fitted.

## THE INSTALLATION

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The most practical method of installing gas density transducers is to use the "Pressure Recovery Method". This method has proved itself over the years and is now the industry standard. This method relies on the recovered pressure downstream of the orifice carrier to provide a sample differential pressure back to the downstream tapping point of the orifice carrier. The typical hook-up shown in a manufacturers technical handbook (chapter 2) titled "Typical Orifice Plate Metering System" leaves a lot to be desired.

The diagram is lacking in several essential areas. The tubing itself should be 1/4in or 3/8ths in. diameter, any larger and you may encounter problems due to high velocity causing damage to the transducers. The tubing arrangement should be such that it is installed as close as possible to the meter tube and should be kept as short as possible.

Never install a needle valve between the density transducer and the orifice carrier downstream tapping sample return. Since we are trying to measure the density at the downstream tapping of the orifice carrier any restriction will invalidate the accuracy of the measurement. The use of a needle valve between the sample take off and the transducer is advantageous in that it allows the operator or Instrument Technician to slowly pressurise the transducers after any maintenance work without causing damage to the transducer.

Consideration should be given to installing external filters to the sample inlet of the density transducers. The location of the filters fitted to the inlet and outlet of the density transducers are difficult to access without having to remove the instrument from its sample pocket. The use of external filters has the added advantage of providing a sample supply liquid trap for installations where lub. oil carry-over is possible. The filter elements should be two microns. Ideally two filters should be installed in parallel to allow changeout without having to shutdown the stream and depressurise the sample system.

The start-up of any system can give instrument problems. With gas density transducers it is during pressurisation and start-up that most problems occur. Dirt and contamination tend to collect on the downstream area of an orifice carrier. During pressurisation the gas will take the path of least resistance to pressurise the transducers. This path unfortunately is also the path of least protection to the instrument with only a 90 micron filter fitted at the outlet. This can be prevented by automating the downstream sample valve and tying it into the valve control logic of the metertube upstream (or downstream) shutoff valves. The use of a nonreturn valve is not recommended as this can introduce a pressure drop in the sample return line.

## DESIGNED FOR CONVENIENCE

=====

Fiscal regulations on both sides of the North Sea , require operators to check the accuracy of their gas metering stations monthly. The practice I have recommended in the various metering stations that I have been involved with , is to pull a vacuum on the density transducers to ensure that they still can achieve the periodic time given on their original calibration certificate. This has given good results & it is very seldom that a density transducer will pass this test & fail online.

The most common cause of failure of density transducers under vacuum is hydrocarbon liquid drop-out created during depressurisation. It is important to depressurise density transducers slowly to prevent this.

Failures and damage can also occur if the density transducer to be vacuum tested is removed from the line . Inevitably the inlet and outlet threaded fittings of the density transducer are damaged by regular removal . Problems can also occur with the electrical connections which are part of a certified encapsulated assembly . To avoid this I would advocate that a skid mounted air driven vacuum pump and valve assembly be purchased and installed in a suitable location adjacent to the density transducers . The vacuum pump can be permanently connected by small bore pipework to more than one metering tube density installation without too many problems . Good quality fittings should be used throughout, and the complete piping system thoroughly vacuum and leak tested at regular intervals. The pipework should include double block valves and relief valves to protect the maintenance technician from accidentally applying line pressure to the vacuum pump .

To allow maintenance of the density transducers without the necessity of depressurising the complete metering tube, double block valves should be installed both upstream and downstream of the instrument . The connectors on the density transducer side of the valving should be arranged in such a way as to allow removal of the instrument without disturbing the rest of the pipework.

The vacuum pump assembly should include a good quality vacuum gauge with a resolution down to less than 1mm of mercury. There should also be a line pressure gauge upstream of the double block valves to allow the operator to perform a final safety check before proceeding with any further actions. A good idea would be to clearly number all valves and prepare procedures for their operation.

A purge point should be allowed for in the design to facilitate nitrogen purging of the pipework if hydrocarbon liquid dropout is suspected .

## A QUESTION OF TEMPERATURE

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The measurement of gas density is not easy to make accurately in the environments encountered on offshore production platforms. At the design stage it is important to consider the effects of the environment on the accuracy of the density measurement you are trying to make. The insulation of the installation should be designed in such a way as to allow easy access for technicians to replace or check the calibration of the density transducer without having to have the insulation replaced every few months. The insulation should also be of the highest standard available to ensure good thermal stability throughout the length of the downstream portion of the meter-run.

Measurement of the density transducer outlet temperature is to be recommended. The stream micro-computer can be programmed to provide an alarm on deviation between the line temperature and the density outlet temperature measurements. This alarm is an indication to the operator that perhaps something is amiss with the density measurement. It can either mean that the insulation has not been put back around the instruments properly after the last maintenance check or that the flow through the density transducers is restricted (perhaps a valve is closed?).

As a rough guide, if the line temperature is 40 °C, the density outlet temperature should ideally be 39.5 °C or higher. Since nothing is ever ideal a discrepancy limit of approximately 2 °C is acceptable in normal operations. The choice of the density transducer outlet temperature sensor should be carefully made. Consideration should be given to the mass of the sensor itself and the location of the installation. The ideal sensor would be a surface mounted R.T.D. located on the piece of instrument tubing immediately downstream of the Density Transducer itself.

In general, older metering stations have not got the facilities within the stream computers to perform temperature correction to the density signal. The correction may in some circumstances be small but should not be assumed as negligible. The magnitude of correction can vary from instrument to instrument. For these reasons I would strongly recommend the inclusion of temperature correction to density in any new Fiscal gas metering system.

Other corrections are required to the density signal before it can be used in a Fiscal installation. The density should first be corrected for temperature after the basic calculation from frequency and then corrected for velocity of sound differences between the calibration gas and the actual sample gas. The density value should then be corrected to upstream conditions and it can then be used in the flow calculation. If a corrected Expansion factor is used it is difficult to use a calculated density back-up routine without further manipulating the pressure signal. I would therefore recommend correcting the density value rather than the Expansion factor.

## THE COMMISSIONING STAGE

=====

This is the stage of the project where for various reasons we use up all of our spare instruments.

Some rules :-

-----

- (A) Never believe the mechanical engineers who will tell you that the pipework has been completely dried after the hydro testing , because somewhere a valve is full of water just waiting to be opened & flood your metering instrumentation.
- (B) Always leave your density transducers isolated and under vacuum until required.
- (C) Order double the number of spares you first thought of since you are going to use one set as target practice for the slug of water as mentioned in (A) , one set is always going to be at the manufacturers for refurbishment & re-calibration and the other set is somewhere in stores but no-one is quite sure where.

Its during this phase of a gas metering project that the Engineer responsible can suffer from a nervous breakdown or severe hair loss . To avoid this he must be in control of the situation . This is not always possible since a gas metering station is probably only a small part of a large mechanical project . Co-ordination between disciplines is therefore essential. Management should be kept informed of the status of the project to help to prevent misunderstandings .

## START-UP

=====

The start-up of any new process plant is a testing time for everyone and everything involved in the project . In a new Gas Metering project it is the gas density transducers that are most likely to fail spectacularly . Failures can be caused by various types of contamination in the sample lines . The best way of preventing this is to keep the density transducers isolated from the metering tube until the system is fully on line and flow has been established for approximately 15 to 20 minutes . During this time the flow computers can be instructed to use the back - up density calculation in the main flow calculation routines.

## VELOCITY OF SOUND =====

The velocity of sound correction to a particular make of gas density transducers has caused a great deal of controversy over the years. About 2 years ago I was involved in approaching the transducer vendor on the possibility of calibrating high range Density transducers on Nitrogen instead of Argon as it appeared that this was a possible way round the problem. In May 1985 the transducer manufacturer was able to accomodate this.

It is not easy to change from Argon to Nitrogen Certified Density Transducers overnight . This had to be a phased change over with density transducers certified on both nitrogen and argon until all density transducers had dual certificates available .

When all the density transducers had been re-certified on both Nitrogen and Argon the stream micro computers were reconfigured to use the nitrogen certificate constants .

## UNNECESSARY PROBLEMS =====

Earlier this year an unexpected new format suddenly appeared to the certificates being sent offshore with all recently re-furbished and re-certified density transducers. It was only when questions started coming in from various platforms that it was discovered that the vendor had made changes to the 'K' factors and the user gas equation . Since our flow computers had been programmed to accept inputs within certain limits we were unable to use the new values without calling out a software engineer to reprogramme the stream micro computers . My recommendation would be that vendors of this type of equipment should publish regular customer bulletins containing application notes and discussion on forthcoming changes in either product specification or procedures in certification . I am sure this would ease the present tensions between them , and the customers , us !

## CERTIFICATE COMPARISONS =====

As I mentioned earlier ,I had a unique opportunity to study the differences between Nitrogen and Argon certificates. I also had the opportunity to study User Gas Offset certificates against standard Argon certificates and later against Nitrogen certificates. The results were interesting !

I have attached a typical printout of the comparison calculations that I performed on the dual certified transducers . The offset was consistant throughout at approximately 0.3% . This I found disturbing in that the nitrogen and argon standards used for the calibration at the Vendors were prepared in the same standards laboratory . It is even more suprising when compared with the stated accuracy of the transducers of +/- 0.2% !

The use of User Gas Offset certificates is one that I have often been offered by a transducer vendor when discussing new projects. I have compared the use of these certificates against using a standard Argon or Nitrogen derived certificate . I have come to the conclusion that if the gas analysis is constant with only small percentage changes in components and the operating pressure and temperature are very stable ,then a user gas certificate can be used . If however there is any substantial change in gas components and/or operating conditions then the use of a User Gas Certificate is no longer valid. I have calculated the difference in final density ,comparing a standard certificate and a User Gas certificate . The results show that the user gas calculated density compares well with a standard certificate calculated density within the operating range specified . Beyond these limits the accuracy of the calculation is questionable . It is particularly important to standardise spares in systems with more than one gas metering station , but it is very rare that the gas analysis and operating conditions will ever be identical . In these cases the use of User Gas Certificates can be an expensive exercise .

## MAINTENANCE

=====

The procedures for the repair and re-certification of density transducers are generally not suitable for use in the enviroments found in the North Sea . If a transducer fails either on-line or when tested under vacuum , good results can usually be achieved in cleaning the transducer and retesting . If this fails send the instrument back to the Vendor for repair and recertification. The cost in manhours offshore is far greater than the costs charged by the Vendor. So the motto here is "If at first you don't succeed - give up!"

I have in the past attempted replacing the spool piece of a failed instrument with a certified spare purchased from the Vendor. The results were not encouraging with only a 50% success rate. The costs of the exercise were high when the material cost and manhours were added together .

## THE FUTURE

=====

The measurement of gas density using the currently available type of transducers is possible with patience and "tender loving care". The trend with new Gas metering projects currently being designed has been towards the use of a density calculation rather than on-line density transducers. The reasoning behind this move is that density transducers have been unreliable in similar applications. The calculation routine that is proposed is based on the GRI final report. This routine requires a stream micro computer with a larger memory and faster processor than micros currently in use to perform the calculations and iterations that are required. The retro-fitting of this is almost certainly cost prohibitive in the current financial climate that we are all experiencing.

During discussions with the representatives of a well known density transducer Vendor I once asked if it was possible to manufacture a density transducer that is not affected by liquids. The reply that I received was that they had been making one for years and it was better known as an Oil density transducer!

New technology is appearing almost daily. Perhaps an alternative will soon be with us. Until then we must make the most of what we have.

I hope this paper may be useful to engineers faced with density transducers for the first time. Perhaps we can stop the trend towards baldness in new instrument engineers!

-----  
**DENSITY CERTIFICATE COMPARISON**  
 -----

DATE :08-11-1986

TIME :09:22:22

DENSITY TRANSDUCER SERIAL No. 4114

	ARGON FACTORS	NITROGEN FACTORS
K0	= -81.25611	-81.7502
K1	= -.024119	-.023923
K2	= 4.3774E-04	4.3974E-04
K3	= 724	312
K4	= 63.5	45
K18	= -.0000194	-.0000187
K19	= .000182	.000262
PERIODIC TIME (microsecs)	= 900	
SPECIFIC GRAVITY	= .778	
RATIO OF SPECIFIC HEATS	= 1.27	
OPERATING TEMPERATURE	= 40	
UNCORRECTED DENSITY (ARGON CERT.)	= 251.6062	
TEMP.CORR.DENSITY (ARGON CERT.)	= 251.5122	
USER.CORR.DENSITY (ARGON CERT.)	= 252.0115	
UNCORRECTED DENSITY (NITROGEN CERT.)	= 252.9085	
TEMP.CORR.DENSITY (NITROGEN CERT.)	= 252.8192	
USER.CORR.DENSITY (NITROGEN CERT.)	= 252.9129	

PERIODIC TIME	ARGON DENSITY	N2 DENSITY	DIFFERENCE %
-----	-----	-----	-----
900	252.0115	252.9129	.3563703
880	236.9099	237.7413	.3497359
860	222.1578	222.9214	.3425539
840	207.7552	208.4531	.334788
820	193.702	194.3363	.3263657
800	179.9982	180.5711	.317241
780	166.6437	167.1574	.3072893
760	153.6384	154.0952	.2964219
740	140.9821	141.3845	.2845958
720	128.6748	129.0253	.2716361
700	116.7162	117.0175	.2574634
680	105.1063	105.3611	.2418991
660	93.84466	94.05608	.2247788
640	82.93116	83.10235	.2059879
620	72.36543	72.49983	.1853895
600	62.14709	62.24843	.1628013
580	52.27562	52.34799	.1382598
560	42.75041	42.79842	.1121634
540	33.57068	33.59941	8.550295E-02
520	24.73545	24.75067	6.149589E-02
500	16.24337	16.25172	5.138147E-02
480	8.092742	8.101885	.1128488

FLARE GAS MEASUREMENT

by

T COUSINS  
SARASOTA AUTOMATION LTD

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Paper 3.1

NORTH SEA FLOW METERING WORKSHOP 1986

7-9 October 1986

National Engineering Laboratory  
East Kilbride, Glasgow

FLARE GAS MEASUREMENT  
BY  
T.COUSINS  
SARASOTA AUTOMATION LTD.

1. INTRODUCTION

When any chemical process takes place there are waste products produced. The waste gas has to be disposed of and providing that it is not too noxious is allowed to disperse into the atmosphere via a stack or chimney. In the case of hydrocarbon gases they are usually burnt off as a "flare". It has become essential that these waste gases are metered for a variety of reasons:-

- a. To obtain a mass balance to obtain the efficiency of the process.
- b. To evaluate process and control the quantity of wasted energy.
- c. To control emission on the grounds of environmental considerations.

The different reasons for measurement tend to require different emphasis on accuracy. For example, in a refinery or petrochemical works, "repeatability" is more important so that optimum plant efficiency can be maintained by trend recording. An offshore platform however requires "basic accuracy" as primary importance because total volumes of energy have to be accounted for as they disappear "up the stack".

As will be described, the conditions for flow measurement in flare stacks is almost the worst possible. Gas flow measurement presents problems, but when flare conditions such as high liquid/particle content and large flowranges are imposed on the measurement, then the design of a flowmeter to adequately cope and give reasonable results is very difficult.

2. FLARE STACK MEASUREMENT CONDITIONS

The conditions encountered in flare stack metering are as follows:-

- a. Extreme flows - from very high to very low, typically from velocities of 0.5 m/s up to 60 m/s, that is over at least 100:1 in range.
- b. Wide temperature ranges, as the plant can handle both cryogenic and high temperature processes. A recent application required a range of -90 deg c up to +150 deg c.
- c. The majority of gases contain either liquids or particles, typically carbon, sulphur, tar, condensate, and hydrogen sulphide which can contaminate the meter.

cont/..

1/cont..

- d. Varying chemical composition, which makes chemical compatibility of metering materials essential, particularly as many of the products are dangerous. Almost invariably the metals used have to conform to NACE standards.
- e. Density changes are wide enough to require a flow measurement method that is compensated for density and is preferably a direct mass measurement system.
- f. The pipe sizes are invariably "large", that is above 300 mm. The implication being that the cost of a full bore meter is likely to be high.
- g. The pressure drop must be low.

These conditions tell us about the flowmeter required, it should be inert to aggressive chemicals, measure mass flow, have a wide range and if not immune to a second fluid phase should be easily serviceable.

### 3. FLARE STACK EXAMPLE

An example of a flare stack metering application on a plant involves three flares, a high pressure line, a low pressure line and a fuel gas vent. The metering is taken at the main headers with flare feeds from the various plant processes Fig 1. For the high pressure line the flow range required on mass is 10,000:1, for the low pressure line 2000:1 and the vent line 40:1. To achieve these large ranges several meters have to be used, further more they could not be conventional full bore meters, but must be either insertion or non-invasive meters to avoid excessive pressure drop. Density in the lines vary but in the worst case can change from 0.85 to 5 kg/m<sup>3</sup>. All the lines are greater than 200 mm diameter. This is a rather excessive case, due to the requirement for very low through-puts when the plant is shutdown, in the form of a purge to keep the flare going up to full blow-down conditions where there is a major plant problem.

As can be seen from Fig 1 in general the flare gas is taken off separators. Unfortunately these usually only have a limited flowrange over which they are efficient. As a consequence large quantities of liquid are likely to end up travelling down the flare lines.

### 4. STANDARD FLOWMETERS FOR FLARE MEASUREMENT

In an attempt to solve the problem of flare gas measurement nearly every meter type has been tried. The two types most commonly tried were differential pressure meters and differential pressure flowmeters they have both been used in full bore and insertion form. The success has been very limited due to the small flowrange available, the blockage of pressure tappings and in the case of orifice plates excessive pressure drop. The pressure tappings, particularly in pitot type devices, are very prone to blockage as the fluid is brought to rest at the tapping position, thus there is no tendency to remove debris by fluid action. This can only be alleviated by purging to keep the tappings clear. With the advent of autoranging D.P. cells the range has been improved but is still a long way from that required in flare stacks.

cont...

2/cont...

Insertion turbine meters have been used to good effect but are obviously very prone to bearing damage due to particle content. The range is good for such meters but if the meter is designed for the low flow end then a blow down will "wind" the turbine of its bearings. Equally a meter designed for the higher flows will not operate at the very low flows as the drive force to overcome bearing drag will be too small. It is thus not possible to safely cascade the meters to give the very large required range. Also the meter is true velocity measuring and thus requires density compensation.

## 5. CURRENT DESIGNS

In an attempt to solve the problems of flare metering several radically different techniques have been used. These are based on heat loss effects, vortex shedding and ultrasonics.

### a. Heat Loss Meters

Heat loss meters are the most commonly used meters for flare stack measurement. For nearly 15 years they have been used with varying degrees of success. The principle is simple, if an element whose resistance changes with temperature, such as a thermistor or PRT, is heated and placed in a flowing fluid, then the heat will be convected away by the fluid. The amount of convection is related to the mass flow. Thus by for example, heating the elements and forcing them remain at constant temperature it is possible by measurement of power (current) to obtain an output proportional to flow. A typical example is shown in Fig 2. The heat losses  $Q_f$  from the flow thermistor are by forced convection:

$$\text{ie., } Q_f = \frac{E^2_f}{R} = K\Delta TS\phi (R_e) \quad - 1.$$

The reference thermistor which is out of the main flow loses heat through natural convection, thus its heat loss  $Q_R$  is given by:

$$Q_R = \frac{E^2_R}{R} = K\Delta TS\phi (G_r) \quad - 2.$$

$$\text{now Reynolds number } R_e = \frac{V \cdot d_p}{\mu} = \frac{\dot{M}d}{\mu} \quad - 3.$$

Sub 3. in Q

$$Q_f = \frac{E^2_f}{R} = K\Delta TS\phi \left( \frac{\dot{M}d}{\mu} \right) \quad - 4.$$

Where K = Thermal conductivity of the fluid  
 $\Delta T$  = Temperature difference between fluid and element.  
S = Surface area of element  
 $R_e$  = Reynolds number =  $Vd_p/\mu$   
 $G_r$  = Grasholt number =  $d^3 p^2 g\Delta T/\mu^2 T$   
V = Fluid velocity  
d = Thermistor diameter  
 $\mu$  = fluid viscosity  
E = Volts  
R = Resistance

cont....

Thus we have a measured parameter  $E_f$  which is proportional to  $M$ . However, there is also  $K$ ,  $\Delta T$  and  $\mu$  to take into account. This can be alleviated by taking the ratio of  $E_f/E_R$  which immediately removes  $K$  and  $\Delta T$  but still leaves  $\mu$ . In practice  $\mu$  does not change to drastically for flare gases.

Conceptually therefore the method looks attractive particularly as the calibration curve Fig 3, tends to enhance the low flow end allowing the detection of very low flows, but also a reasonable high flow capability. The problem is how to range the meters particularly as they are so sensitive to flow. The main method is to allow the fluid through porting by the action by of a pressure drop across the main body Fig 4. The ported fluid can then be controlled by restrictors.

Heating is carried out in one of two ways either the thermistors/PRTs are heated directly and the current to the thermistor changed as the resistance changed or a heater element is provided seperately, Fig 5, and the thermistor/PRT detects the heat convected from the heater element, which has its heating controlled by the thermistor.

The advantage of this type of instrument is both the very large range and the output is close to a direct mass flow. It should be emphasised however that the meters are insertion meters and are influenced by flow profile, Fig 6.

The two major disadvantages of heat loss meters are the coating of the elements and in the case of using porting to control the flow, blocking of the ports. If the thermistors become coated their thermal conductivity changes and hence the calibration changes. Blocking of the porting will change the calibration, or alternatively in the worst case stop the meter completely. In the case of the meter shown in Fig 5 blockage is not a problem, but this is sacrificed to range.

#### b. Vortex Meters

Vortex shedding meters work on the simple principle that as fluid passes around a bluff body, Fig 7, vortices are shed alternately from either side of the body. The frequency of vortex shedding is directly proportional to flow velocity over a large flowrange. This relationship is summed up in the strouhal number relationship Fig 8, where:-

$$\text{Strouhal number } S = \frac{fd}{V}$$

$d$  = bluff body diameter

$f$  = Vortex shedding frequency

$V$  = Fluid velocity

For a linear relationship  $S$  should be a constant for as large a range as possible. The correct shape of bluff body determines the linearity of the meter. Changes in linearity are due mainly to Reynolds number, although in gas there may be small changes with compressability at high velocities. At high Reynolds numbers there can be a change in linearity due to the boundary layer on the front surface changing from laminar to turbulent.

cont...

4/cont...

If the separation points are not fixed by for example sharp edges, then the value of S will change. At low Reynolds numbers changes in the separated shear layers cause non-linearities. Fig 9 shows the variation in shedding with Reynolds numbers. It will be noted that at very low numbers there is no shedding.

From the point of view of flare stacks a very useful shape is a triangular bluff body with its apex upstream. Such a shape, while it does not give the steadiness of signal and linearity of some shapes, does give a very wide range and is particularly good at low Reynolds numbers. Typically such a design will operate down to less than 0.5 m/s on air, with no upper limit.

A major problem area with vortex meters is in the detection of the vortex shedding. There are a large number of methods, but it is sensible to concentrate on the one method that has worked successfully on flare gas. In this method a beam of ultrasound is sent across the vortices to a receiver, Fig 10. The effect of a forming vortex is to totally change the pressure and hence with gas the density. This represents a changing acoustic impedance which changes the signal amplitude. The receiver thus "sees" an amplitude modulated signal whose modulation frequency is the same as the vortex shedding frequency. To protect the transducers from the fluid the sound is fired through stainless steel "slugs", Fig 11. A typical calibration curve is shown for air in Fig 12. By virtue of the design they can be considered as "inert" meters in that they have no moving parts and by careful design present only metal (stainless steel) to the fluid.

The advantages of the meter are obvious it does have a very wide flowrange, although perhaps not yet to the lowest required flowrates, it has a pulse output and totalised flow involves negligible conversion errors and it is very robust and has been shown to work under very arduous conditions. They are working in lines where the liquid content is very high.

The main disadvantages with the vortex meters are that they do not measure mass and have to be compensated and they are an insertion meter, and they still cannot reach the very low velocities required in many flare metering applications.

#### c. Ultrasonic Meters

Potentially ultrasonic flowmeters are very attractive for flare gas measurement, because they have no moving parts, they represent an unobstructed path to the fluid with a resultant lack of pressure drop. Even with this lack of pressure drop, by careful design a "full bore" meter can be made, compared to the insertion, point velocity measurements of thermal and vortex methods.

cont....

There are several methods using the same basic equations to perform flow measurement using ultrasonics. They rely on the fact that if a pulse of ultrasound is fired into a fluid in motion, the time taken for that pulse to travel from two points will be modified by the fluid velocity. If the sound is travelling against the fluid flow it will take longer to travel the distance than if fired in the fluid flow direction and the difference in time is proportional to the fluid velocity. Referring to Fig 13:-

$$\text{the time to travel upstream } T_{12} = \frac{d}{C - V} \quad - \text{ a.}$$

$$\text{the time to travel downstream } T_{21} = \frac{d}{C + V} \quad - \text{ b.}$$

where d is distance between 1 and 2, C is the velocity of sound and V the fluid velocity.

by rearranging a. and b. we obtain the equation

$$V = Gd \left( \frac{1}{T_{12}} - \frac{1}{T_{21}} \right) \quad - \text{ c.}$$

Where d is the pipe diameter and G is geometric constant. This is written this way as it is usual to design the acoustic path to be at an angle to the fluid flow, Fig 14, to allow for more convenient installation. The advantage of this method of derivation is that the velocity of sound is excluded and the meter is independant of C. This method of direct time measurement is very difficult in liquids but is feasible in gas because of the lower velocity of sound (300 m/s compared to 500 m/s) and the generally higher fluid velocities. This ensures that the measured quantities are in the range of sensible measurement. For example, the total transit time across air in a 0.5 metre duct would be approximately 2ms and the time difference would range from 5 $\mu$ s (at about 0.5 m/s) to 0.5 m/s (at about 150 m/s). An electronic resolution of 100 ns would thus give good answers and such a resolution is readily obtainable.

The current production meter using this principle is designed to allow for "hot tapping" or inserion of the ultrasonic transducers into an existing line. The transducers themselves are piezo crystals mounted in a stainless steel housing and protected from direct contact with process fluid. They are mounted on stems, Fig 15, that allow for insertion into the pipe, such that if the fluid such as CO<sub>2</sub> is high attenuating signal can still be obtained by bringing the transducers closer together, and ease of installation in difficult areas.

The disadvantages of this type of meter are that it measures only direct velocity and must use a densitometer or pressure and temperature correction for mass. Also the quality of received signal will be influenced by the fluid going some repeatability problems (although this is alleviated by sampling). Although the meter can be classed as a full bore meter it is subject to profile changes similar to any single path ultrasonic meter, thus there are corrections for Reynolds number changes and installation effects, but these should be less than for inserion meters.

cont..

The advantages are a wide flowrange, with the facility to measure molecular weight from velocity of sound (if temperature is known). Accuracy is dependant upon method of installation, but can be better than 5% of actual (as opposed to FSD) on velocity measurement. Also the meter is generally less dependant upon profile than insertion meters (unless a profile is performed, but who is going to do it on a flare stack).

## 6. SUMMARY

- a. Flare measurement is one of the hardest flow problems to solve because of the large ranges, aggressive fluids and requirement for mass measurement.
- b. The more standard flowmeters do not, and have not solved the problem, with the result that newer methods are being tried.
- c. Thermal methods have been used the longest for this type of measurement. They have come close to solving the problems, particularly in their range and mass. However the reliability of such meters in high concentrations of liquid and particles is poor.
- d. Vortex meters, particularly using ultrasonic detection, have been very successful from the view of range and reliability, although they as yet have only a limited experience. The two major problems are lack of direct mass measurement and being insertion meters.
- e. Ultrasonic time of flight meters are again a relative new comer but are building a good track record. There are technical problems with large ranges, but these are not difficult to solve. Perhaps the overriding advantage is that they are an easily installed "full bore" meter which few other flare meters can match. They do not however measure mass directly and may have some acoustic transmission problems.
- f. The table below shows a review of the various flare flowmeters:-

TYPE	RANGE	*ACCURACY	REPEATABILITY	COMMENTS
DP devices	Max 10:1	+/- 0.5% FSD on mass	+/- 0.2% FSD	For low pressure loss must be pitot tube - holes tend to be block.
INSERTION TURBINE	20:1	+/- 1% FSD on velocity	+/- 0.1%	Easily damaged by overspeeding and secondary phase.
THERMAL	300:1	+/- 2.5% FSD on mass **	+/- 0.5% FSD	Coating of thermistors a severe problem - also porting blockage.
INSERTION VORTEX	at least 100:1	+/- 1% FSD on velocity	+/- 0.5%	Needs P and T or density to make mass.
ULTRASONIC	500:1	*** +/- 5% or better over 10:1 range on velocity	+/- 1%	Can be a full bore measurement. Needs P and T or density for mass measurement.

cont...

7/cont..

\* with insertion meters there is always an error, undefined due to profile and position.

\*\* depends on the manufacturer may be as high as +/- 5% FSD.

\*\*\* over larger ranges this accuracy decreases.

7. REFERENCES

- a. K.J.ZANKER "Flare Gas Measurement - The Agal FM700 Series Flowmeter"  
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The Metering of Natural Gas and Liquified Hydrocarbon Gases, OYEZ SCIENTIFIC 1984.
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- e. SMALLING, BRASWELL, LYNWORTH AND WALLACE "Flare Gas Ultrasonic Flowmeter"  
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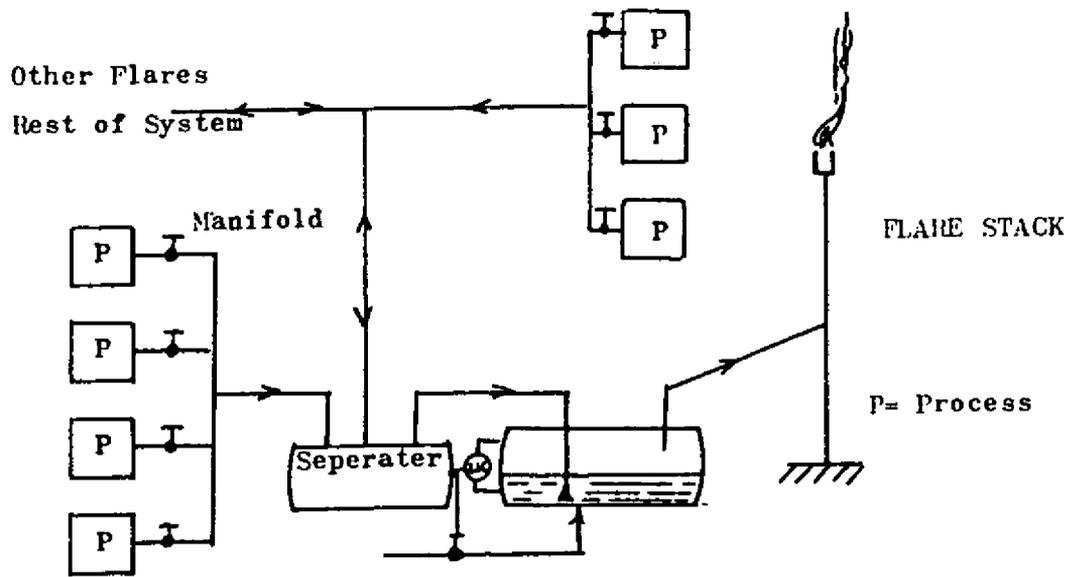


FIG .1 TYPICAL FLARE STACK SYSTEM

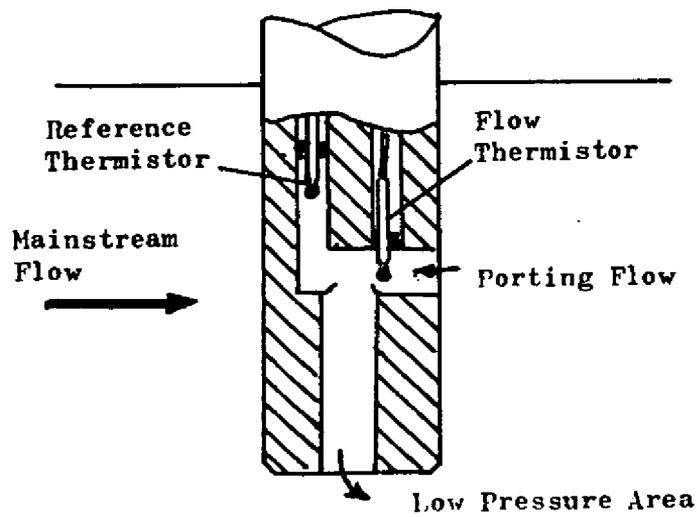


FIG. 2 TYPICAL THERMISTOR DESIGN

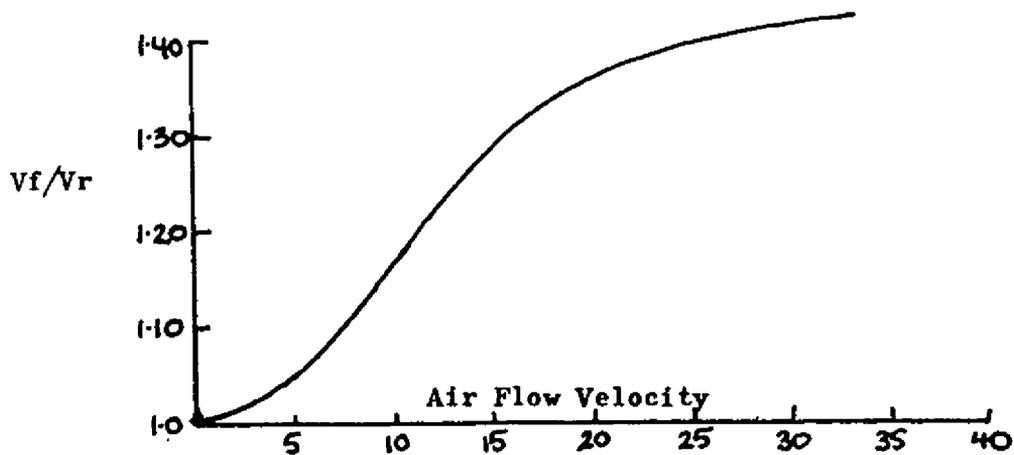


FIG.3 TYPICAL THERMAL METER AIR CALIBRATION

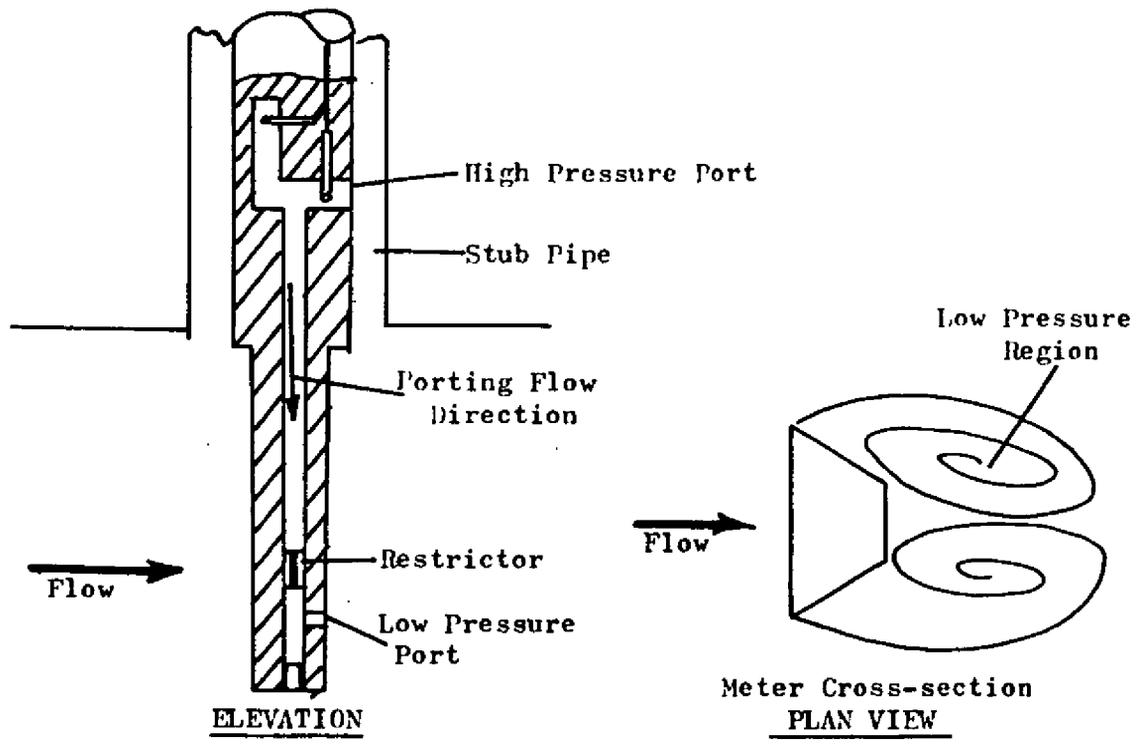


FIG.4 FLOW AROUND AND THROUGH A THERMAL FLOWMETER

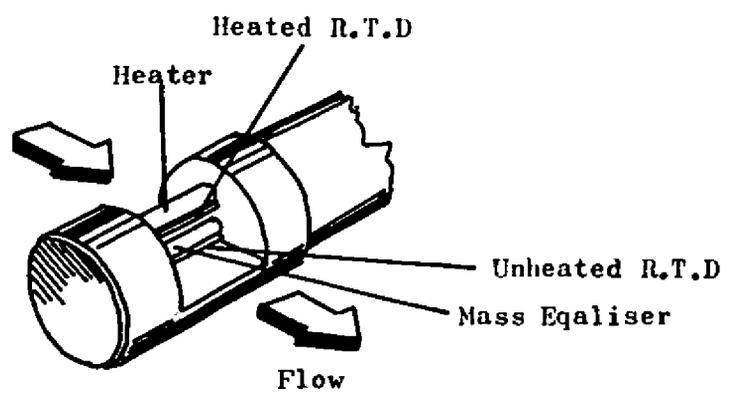


FIG.5 INDIRECTLY HEATED THERMAL METER

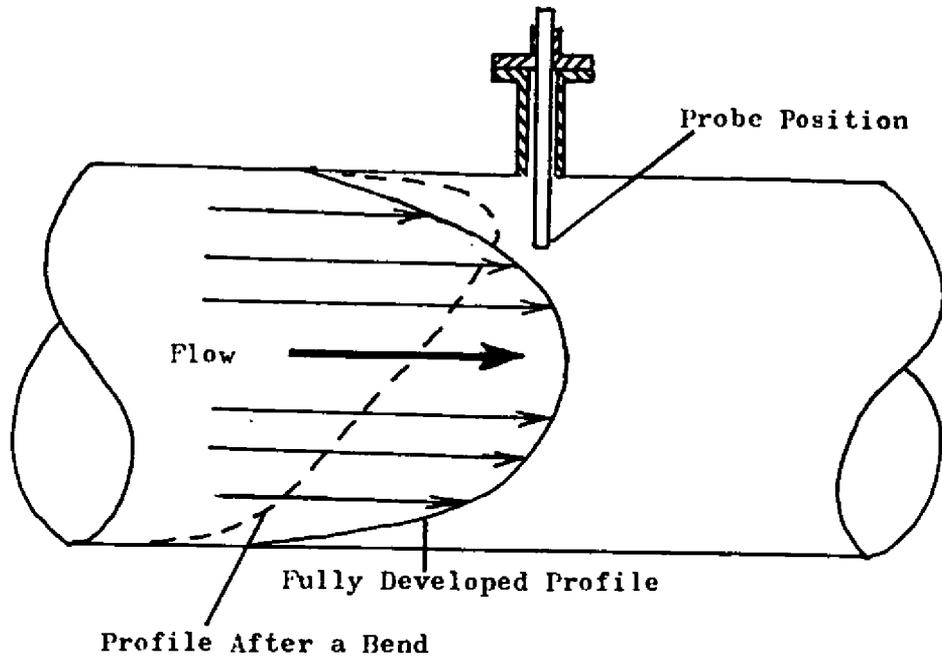


FIG.6 FLOW PROFILE EFFECT ON INSERTION TYPE METER

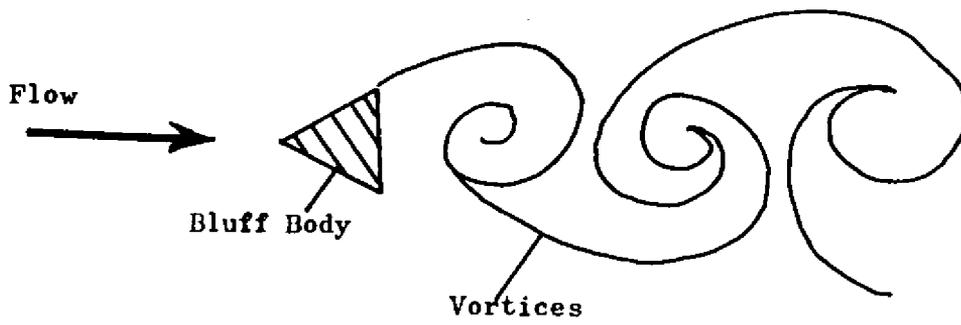


FIG.7 VORTEX SHEDDING

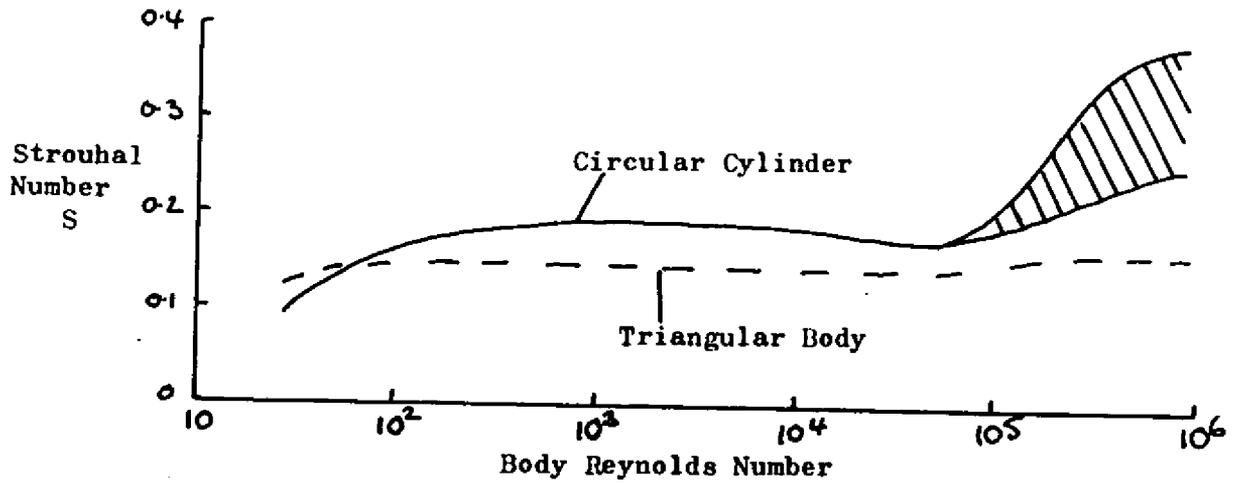


FIG.8 STROUHAL NUMBER AGAINST REYNOLDS NUMBER

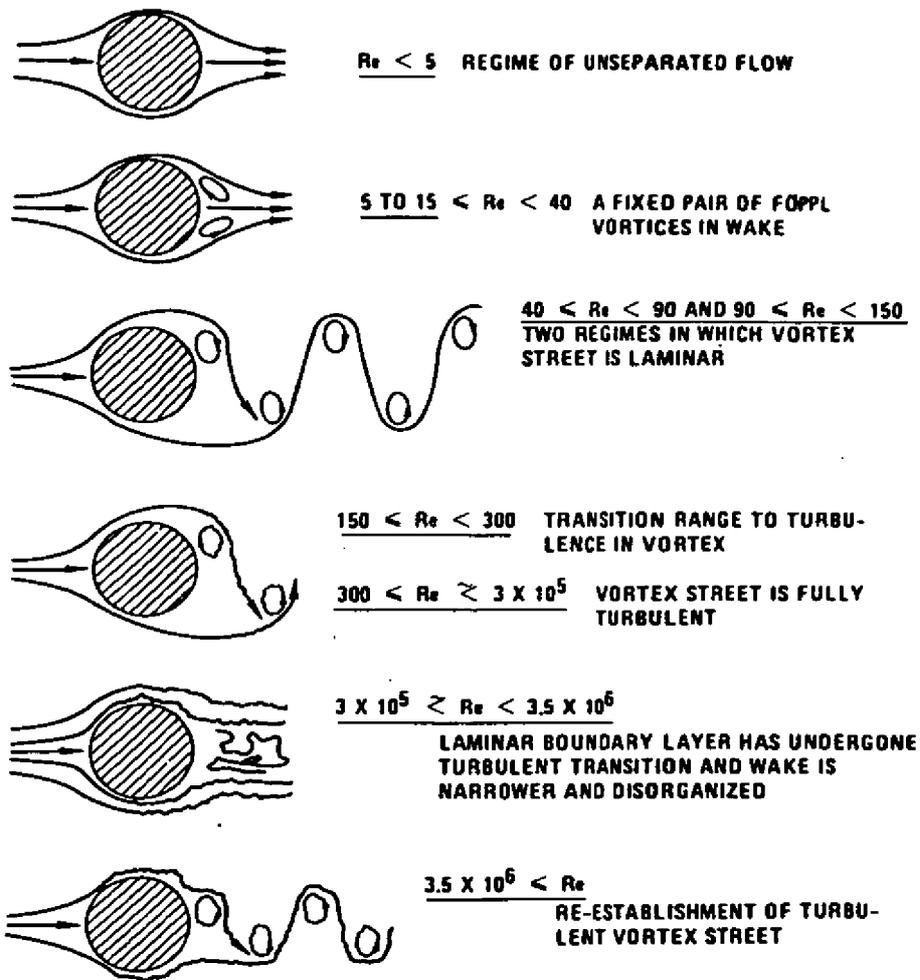


FIG.9 VARIATION OF VORTEX SHEDDING WITH REYNOLDS NUMBER

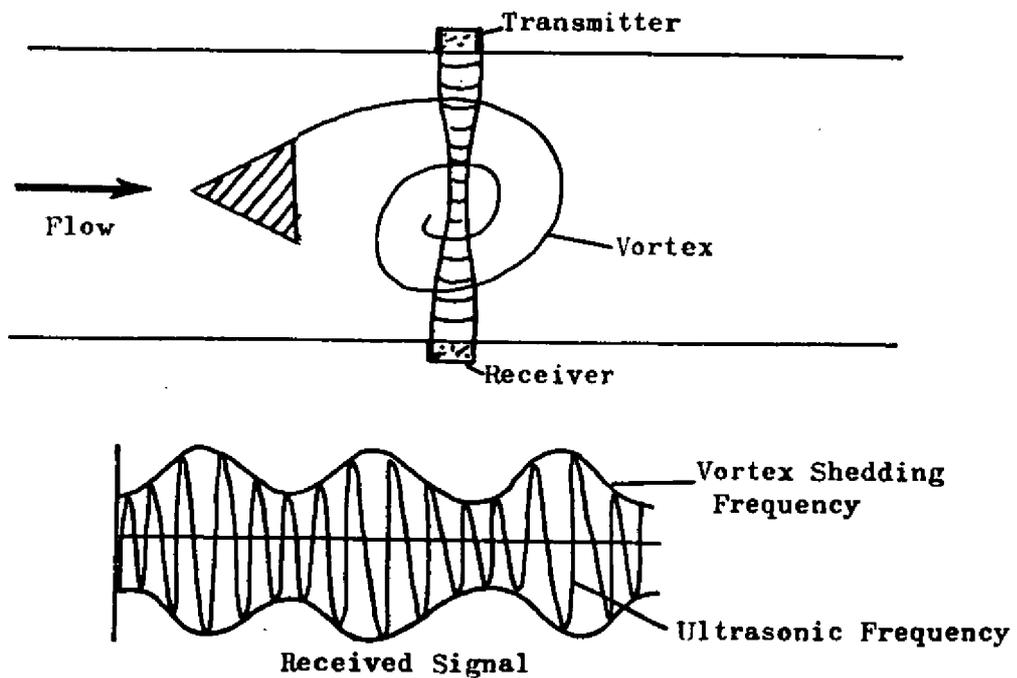


FIG.10 ULTRASONIC VORTEX DETECTION

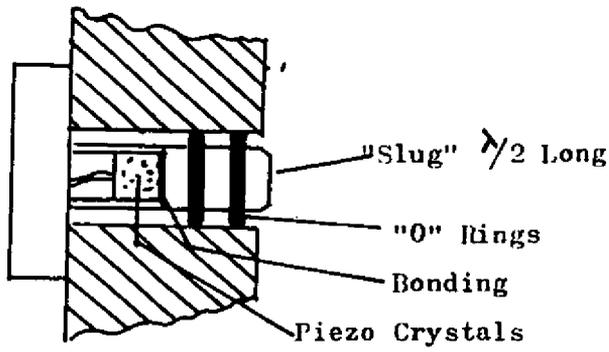


FIG.11 ULTRASONIC TRANSDUCER MOUNTINGS

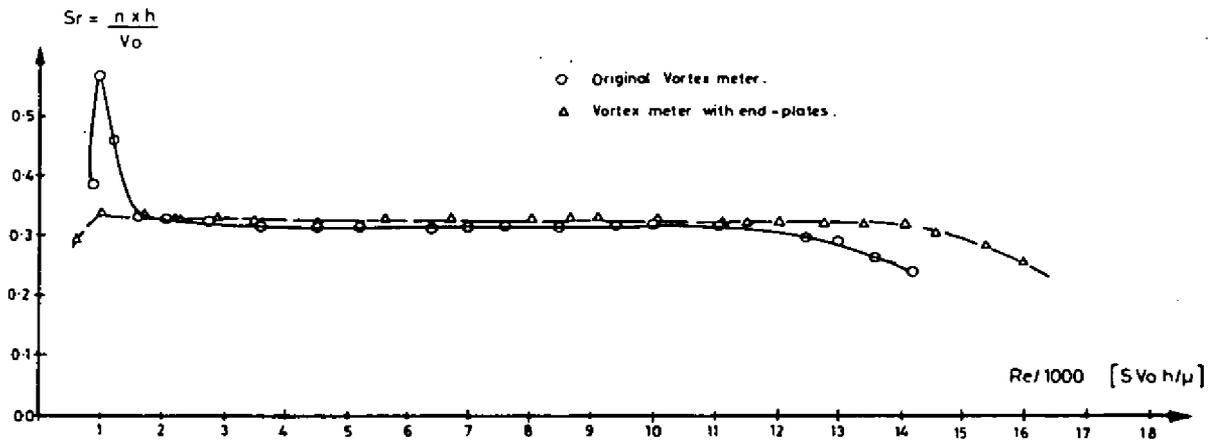


FIG.12 TYPICAL EXPERIMENTAL AIR CALIBRATION CURVES

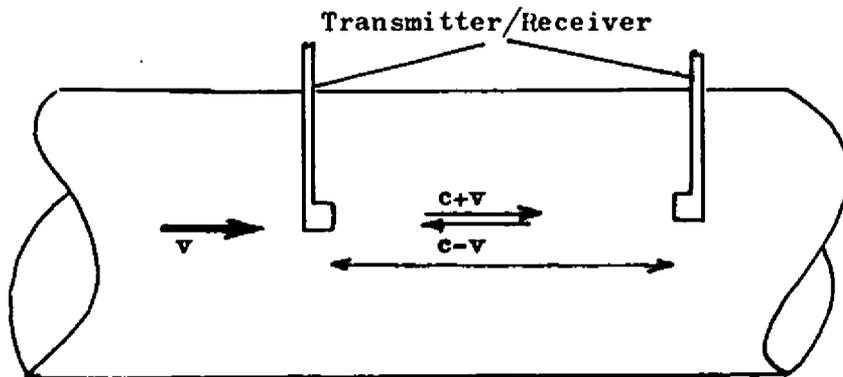
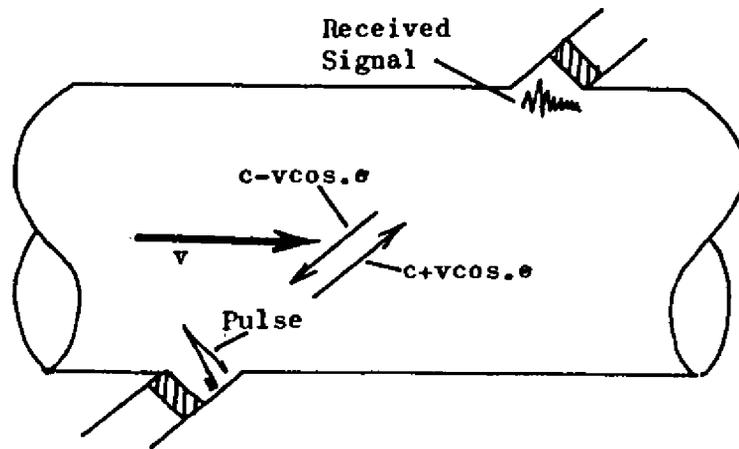
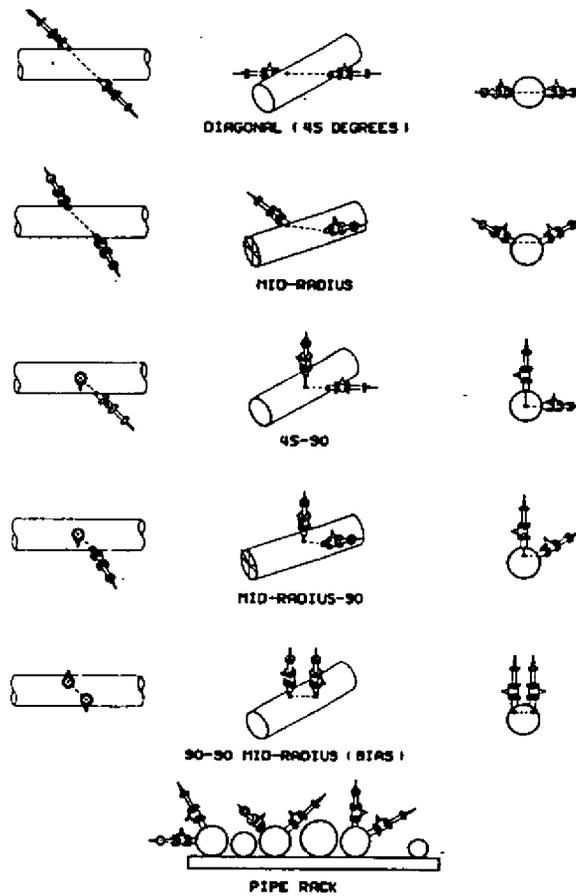


FIG.13 THEORETICAL DIAGRAM OF AN ULTRASONIC FLOWMETER



**FIG.14 PRACTICAL TRANSDUCER ARRANGEMENT**



**FIG.15 INSERTION ULTRASONIC ARRANGEMENTS**

THE COMMISSIONING AND OPERATION OF THE STATPIPE METERING SYSTEMS FOR  
REFRIGERATED LPG

by

H BERENTSEN AND R SAKARIASSEN  
STATOIL

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Paper 3.2

NORTH SEA FLOW METERING WORKSHOP 1986

7-9 October 1986

National Engineering Laboratory  
East Kilbride, Glasgow

THE COMMISSIONING AND OPERATION OF  
THE STATPIPE METERING SYSTEMS FOR  
REFRIGERATED LPG.

Authors: Mr. Hans Berentsen, Statoil  
Mr. Reidar Sakariassen, Statoil

SUMMARY

*This paper discuss problems associated with the turbine measurement of LPG.*

*Special attention is paid to measurement of refrigerated Propane at  $-40^{\circ}\text{C}$ .*

*Experiences with the operation of the LPG Turbine Metering Station at Kårstø, Norway is discussed.*

*As a conclusion, it is stated that the installation and operation of this Turbine Metering Station for refrigerated Propane has been successful.*

INTRODUCTION

Kårstø Gas Terminal is a part of the Statpipe Gas Transportation system.

This system transports rich gas from the Statfjord Fields to Kårstø Gas Terminal. Here the heavy fractions of gas are separated and shipped by boat as Propane-, Butanes- and Gasoline products.

The dry gas is transported further down to the Ekofisk Field where it enters the Norpipe System.

The products are shipped from Kårstø by vessels as cold products. The shipped quantities are metered by dedicated skids of turbine meter-runs on shore.

OPERATING CONDITIONS

Listed below are normal operating conditions for the products at metering location

	Propane	i-Butane	n-Butane	Gasoline
Temperature (°C)	-40	-10	2	3
Pressure (barg)	8	8	8	7
Density (kg/m <sup>3</sup> )	580	590	600	677

These data indicated that Propane measurement could be difficult. To our knowledge, turbine metering of liquified Propane at this temperature has never been carried out to an acceptable degree of accuracy and reliability.

Based upon experiences elsewhere, measurement of the other products was regarded as relatively simple, so hereafter it will be focused on the Propane metering.

## MAIN PROBLEMS FORESEEN

Due to the low temperature special care had to be taken, especially for the prover system. Choice of materials, prover design, shape of piston, type of detector switches and piston sealing was finally made based on a thorough evaluation.

Due to combination of the low temperature and low density, problems in density measurement were foreseen. This is mainly due to lack of satisfactory calibration methods.

Combination of low density and viscosity is likely to cause large shift in K-factor on a turbine meter when operating at a wide range of loading rates. This could be a problem.

Also, operation of valves has been reported to be troublesome under these conditions.

## DESIGN OF THE METERING STATIONS

### Arrangement

Fig. 1 shows how the metering stations are arranged.

The Propane metering skid consists of four meter runs, one 4" and three 8". The metering skid are connected to a dedicated prover, the Propane prover.

Each of the *i*-Butane, *n*-Butane and Gasoline metering skids consists of three meter runs, one 4" and two 8". All these three metering skids are connected to a common prover, the mixed product prover.

Fig. 2 shows the piping arrangements further to the jetties. It includes also the vapour return lines. Vapour products are metered by Vortex meters.

Fig. 3 shows the position of the different elements in more detail. Each meter run is equipped with a densitometer of the vibrating-tube type, using pump to force liquid through the transducer.

In addition, flow controller valves are installed in the individual meter runs as well as in the prover loop.

### Prover design

Fig. 3 indicates the design of the prover.

Both the mixed product prover and Propane prover consist of a straight horizontal tube. Inside the tube is an H-shaped piston. Through the pipewalls four detector switches consisting of a chrome plated steel ball protruding into the pipe and a mercury switch are installed. The volumes between the detector switches are accurately determined.

### Computers

Fig. 4 shows the configuration of the computer system.

A flow computer connected to each meter run receives signals from the turbine and the transmitters. In addition, one flow computer is dedicated to each of the provers performing the necessary calculations for the calibration routines.

A remote terminal unit common for all the LPG metering stations handles the valve status signals and the control output signals.

Signals from the flow computers and the remote terminal unit are transferred to the computer room.

The main computer installed does all the control task for loading and proving and generate reports for the operator on VDU's and printers in the Main Control Room.

### Calculation Method

It is not intended to dwell upon this subject except to say that for the purpose of K-factor calculation the COSTALD method is used for Propane, i-Butane and n-Butane.

The reason for this is that the operating conditions are beyond the limits given for the temperature correction factors and pressure correction factors for liquid entering the formula given in API 2534 for the calculation of the K-factor.

COSTALD method was chosen after a thoroughly evaluation of different methods.

The equation used for the K-factor calculation is

$$K\text{-factor} = \frac{n}{V_{st} \times Ctsp \times Cpsp \times P_p} P_m$$

where

$n$  is number of pulses from the turbine during the calibration run.

$V_{st}$  is gross standard prover volume

$Ctsp$  is correction factor for temperature effect on the steel of the prover.

$Cpsp$  is correction factor for pressure effect on the steel of the prover.

$\rho_p$  is liquid density in the prover according to COSTALD method.

$\rho_m$  is liquid density in the meter according to COSTALD method.

The COSTALD method is also used as a backup method for determination of the density of the metered liquid.

### Prover Calibration

The volumes of the prover were calibrated before it left the manufacturer and after the installation at Kårstø using water and standardised to 15°C.

Results from these calibrations are given in fig. 5. By comparing these figures, the tolerance of the volume standards and method used should be kept in mind.

Both calibrations were carried out using the "master meter method". Uncertainty of the reference volume used for master meter calibration is 0.02 %.

## OPERATIONS

All loading quantities have been measured by shipboard static measurement in addition to the turbine measurement. The experiences so far can be summarised as follows:

- \* Except for two occasions of turbine bearing breakdown, the turbine measurement has been accepted.
- \* In average, the difference between shipboard measurement and turbine measurement is within 0.2 %.
- \* Repeatability of the turbines has been well within the required tolerance limits.
- \* Linearity of the turbines has been well within acceptable tolerance limits.
- \* Problems with valve status signals was experienced during the first period of operation.
- \* Problems of obtaining an acceptable calibration method for the densitometers still exist.

### Comparison Shipboard Static Measurement - Turbine Measurement

Fig. 6 shows the difference between four vessels and the meter station.

From this comparison sheet, it is clear that vessel A gives systematic higher figure than the metering station while vessel D gives systematic lower figures.

It is not the intention here to discuss all the sources of errors.

### Turbine Proving

All turbine meters in service are calibrated at least once during each loading.

Based on the calibration data obtained so far, the experience with the turbine meter for Propane services can be summarised as below.

### Repeatability

Repeatability is defined as the difference between the highest and lowest K-factor of five consecutive runs in percent of the mean K-factor.

For the 8" turbine meters an average repeatability of 0.027 % has been experienced.

For the 4" turbine meter an average repeatability of 0.018 % has been experienced.

### Linearity

Fig. 7 shows the linearity of an 8" turbine meter for water and Propane.

As can be seen, the linearity is about the same for both products for the same turndown ratio. Normal working range is however 800 - 1200 m<sup>3</sup>/hr resulting in a linearity error far below the limit set by NPD.

### Long-term stability

Fig. 8 shows how the K-factor of one 8" turbine meter has developed since start up.

So far it can be stated that the stability has been extremely good. Variations of K-factor are within  $\pm 0.05\%$ .

### Temperature

The accurate determination of temperature is utmost important. All temperature sensors are Pt-100 which are 4-wire connected to the temperature transmitters.

The transmitters are calibrated once per month. Fig. 9 shows an example of the stability of such a transmitter. In addition to these calibrations, all temperatures measured during loadings are compared and checked to be within acceptable differences.

### Density

Comparison between calculated density according to COSTALD and calculated density from densitometer signals, has revealed a difference of 1-1,5 %.

Since the COSTALD method has been experimentally proven to an accuracy of 0.4% and product composition are very stable, the COSTALD density has been used so far.

Reason for problems with the densitometer seems to be unsatisfactory calibration method and difficulties in determination of the velocity-of-sound effects.

CONCLUSION

*We think the Kårstø LPG Metering Stations has proved that reliable and accurate measurement of liquified Propane at  $-40^{\circ}\text{C}$  is possible using turbine measurement.*

*The Metering Station works well within the tolerance limits given by the authorities.*

# KÅRSTØ PLANT LPG METERING STATIONS

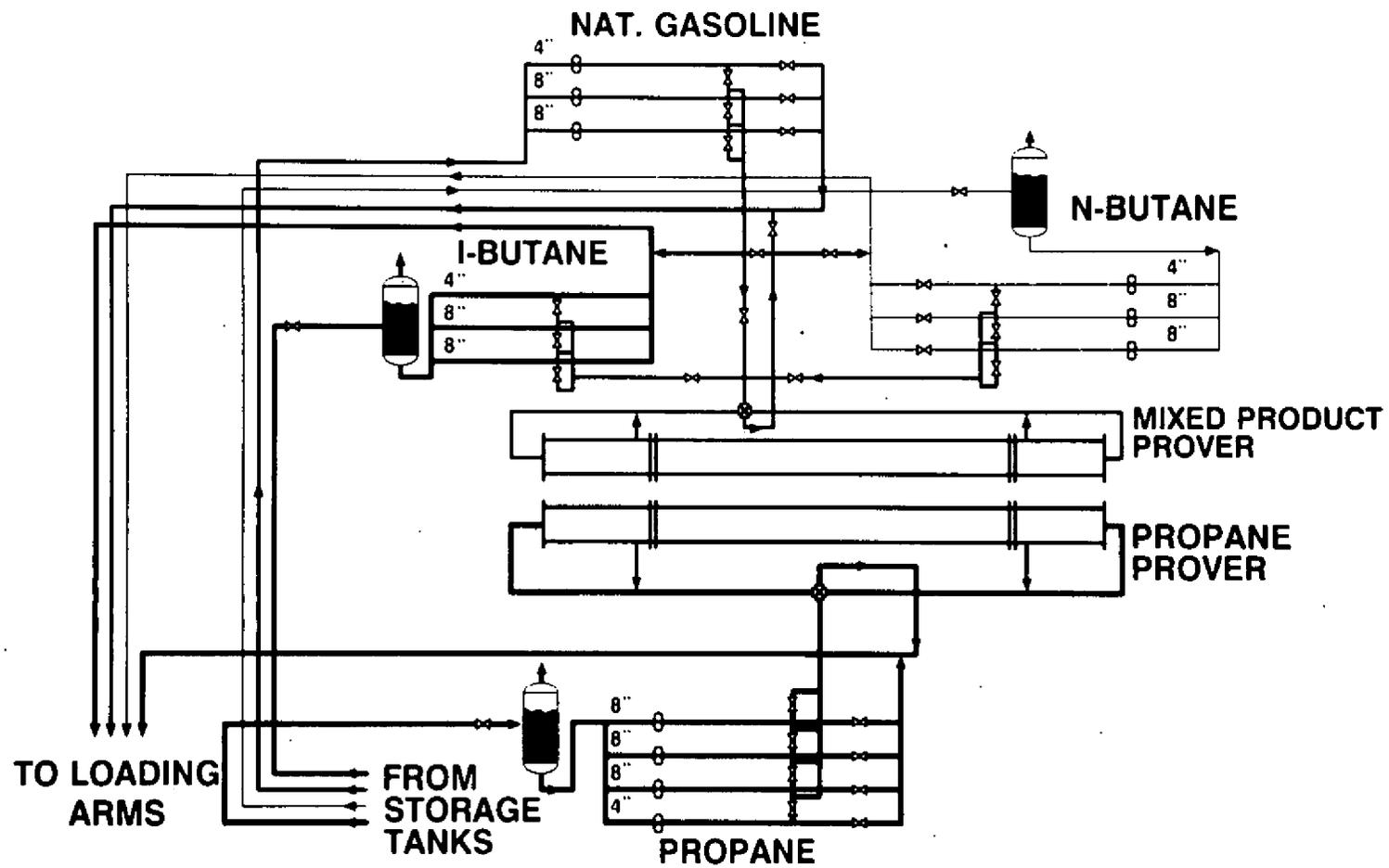


FIG.1

# PIPING ARRANGEMENTS TO JETTIES AND VAPOUR RETURNS

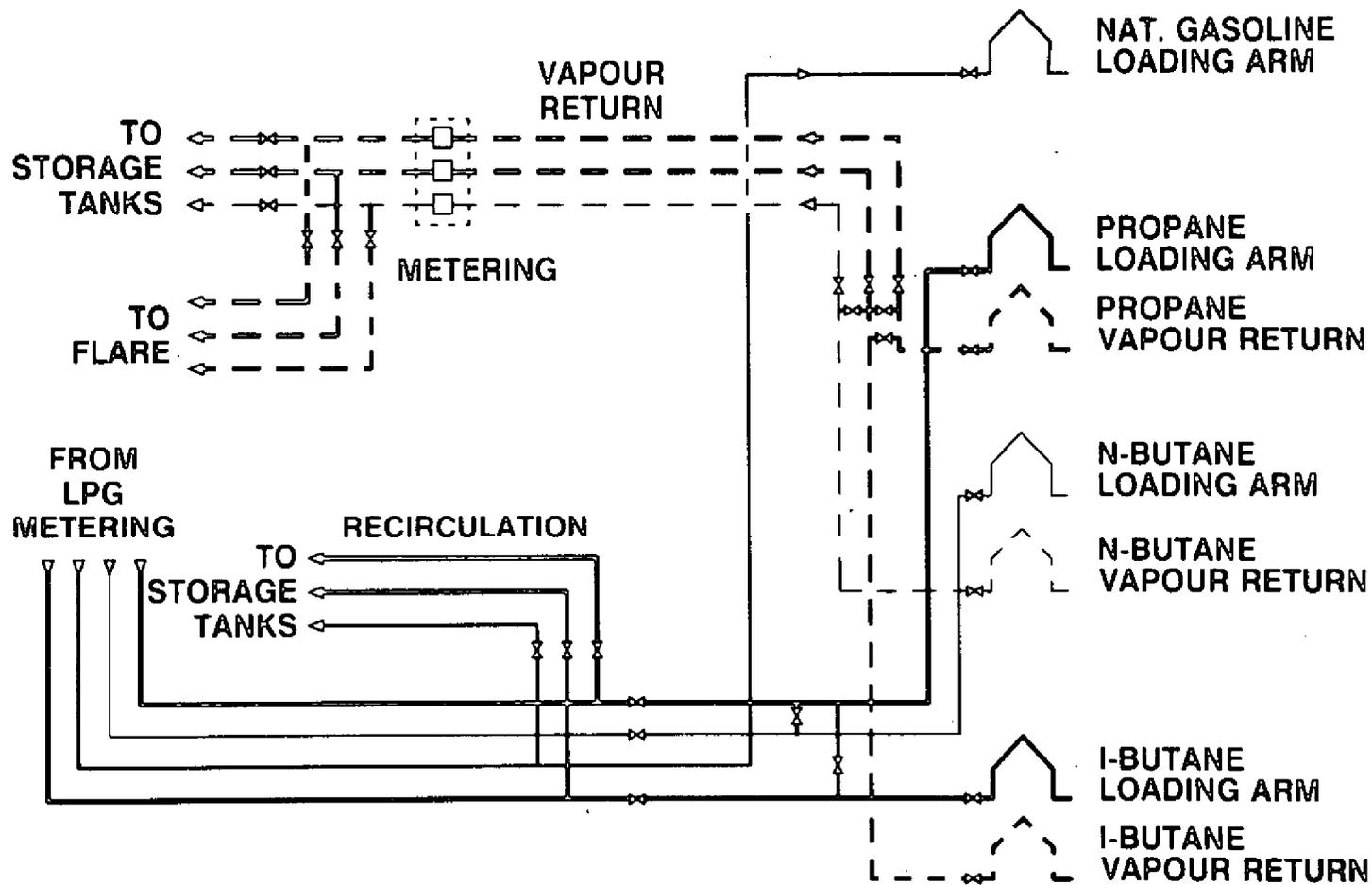
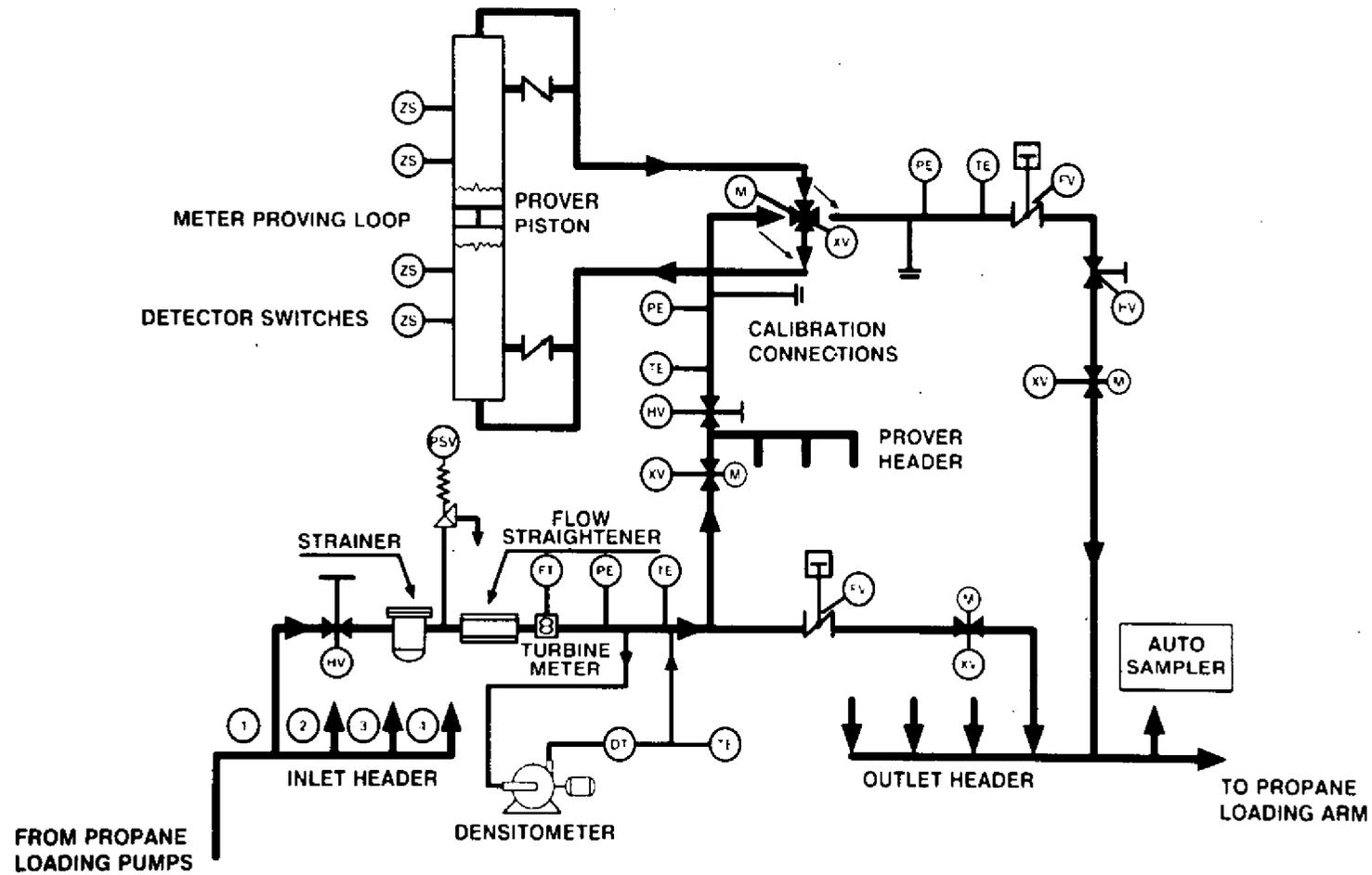


FIG.2

# KÅRSTØ PLANT PROPANE CUSTODY METERING AND PROVING OPERATION



**FIG.3**

# KÅRSTØ PLANT SIGNAL & COMMUNICATION SYSTEM

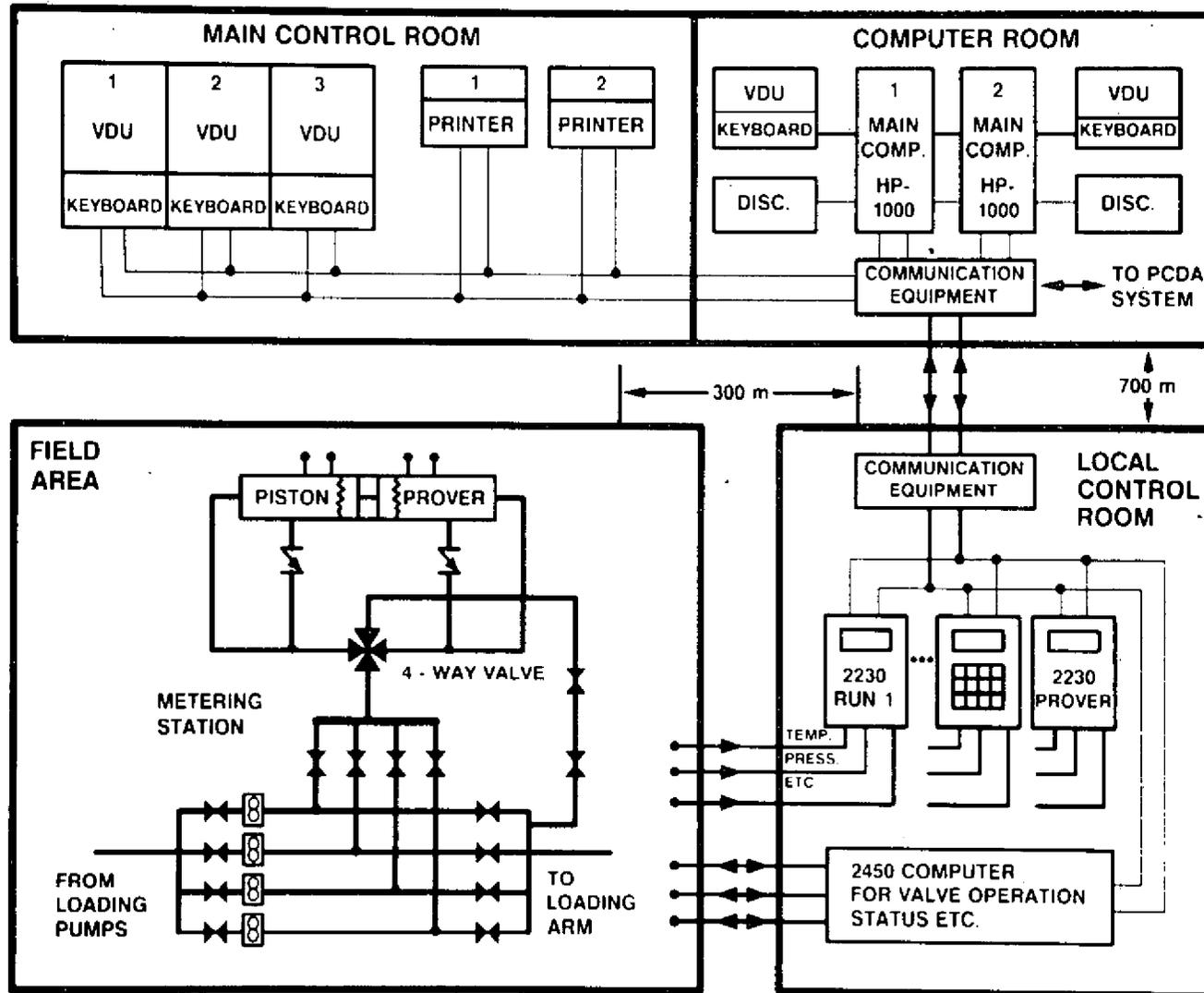


FIG.4

## CALIBRATION OF THE BI-DIRECTIONAL PISTON PROVER FOR PROPANE

TAG NO. ZS ...	0576 & 0578	0577 & 0574	0576 & 0574	0577 & 0578
DETECTOR NO.	1 & 4	2 & 3	1 & 3	2 & 4
MB & R (7/12-84) AT DANIEL IN FALKIRK (LITRES)	6706.888	6380.868	6543.336	6543.770
CON-TECH A/S (27/9-85) AT KÅRSTØ IN NORWAY (LITRES)	6704.859	6379.364	6542.154	6542.401
DIFFERENCE (LITRES)	+ 2.029	+ 1.504	+ 1.182	+ 1.369
DIFFERENCE (%)	+ 0.030	+ 0.023	+ 0.018	+ 0.021

MB & R = MOORE, BARRET & REDWOOD LTD.

CON-TECH A/S = CALIBRATION COMPANY IN STAVANGER

FIG.5

## KÅRSTØ PLANT PROPANE METERING STATION COMPARISON BETWEEN METERING STATION & SHIP FIGURES

SHIP	METERING STATION FIGURES (TONNES)	SHIP FIGURES (TONNES)	DIFFE- RENCE (TONNES)	DIFFE- RENCE (%)	VAPOUR RETURN (TONNES)
A	16 596.1	16 622.1	- 26.0	- 0.15	-
A	9 976.3	10 037.6	- 61.3	- 0.61	-
A	8 296.7	8 337.6	- 40.9	- 0.49	-
A	12 611.9	12 619.6	- 7.7	- 0.06	-
A	12 613.1	12 645.1	- 32.0	- 0.25	-
A	7 350.2	7 383.9	- 33.7	- 0.46	-
A	15 001.9	15 062.5	- 60.6	- 0.40	-
B	13 483.7	13 506.5	- 22.8	- 0.17	-
B	7 354.6	7 371.8	- 17.2	- 0.23	10.4
B	7 355.4	7 359.0	- 3.6	- 0.05	-
B	6 303.1	6 306.4	- 3.3	- 0.05	0.2
C	13 661.8	13 648.3	+ 13.5	+ 0.10	-
C	13 650.2	13 641.1	+ 9.1	+ 0.07	0.6
D	3 200.8	3 172.6	+ 28.2	+ 0.88	-
D	6 869.9	6 811.3	+ 58.6	+ 0.85	-
D	6 829.7	6 795.5	+ 34.2	+ 0.50	-
D	5 250.0	5 236.5	+ 13.5	+ 0.26	-

FIG.6

KÅRSTØ PLANT PROPANE METERING STATION  
TURBINE METERFACTOR REPEATABILITY OVER RANGE  
RUN NO.3 (8") PROPANE & WATER CALIBRATION

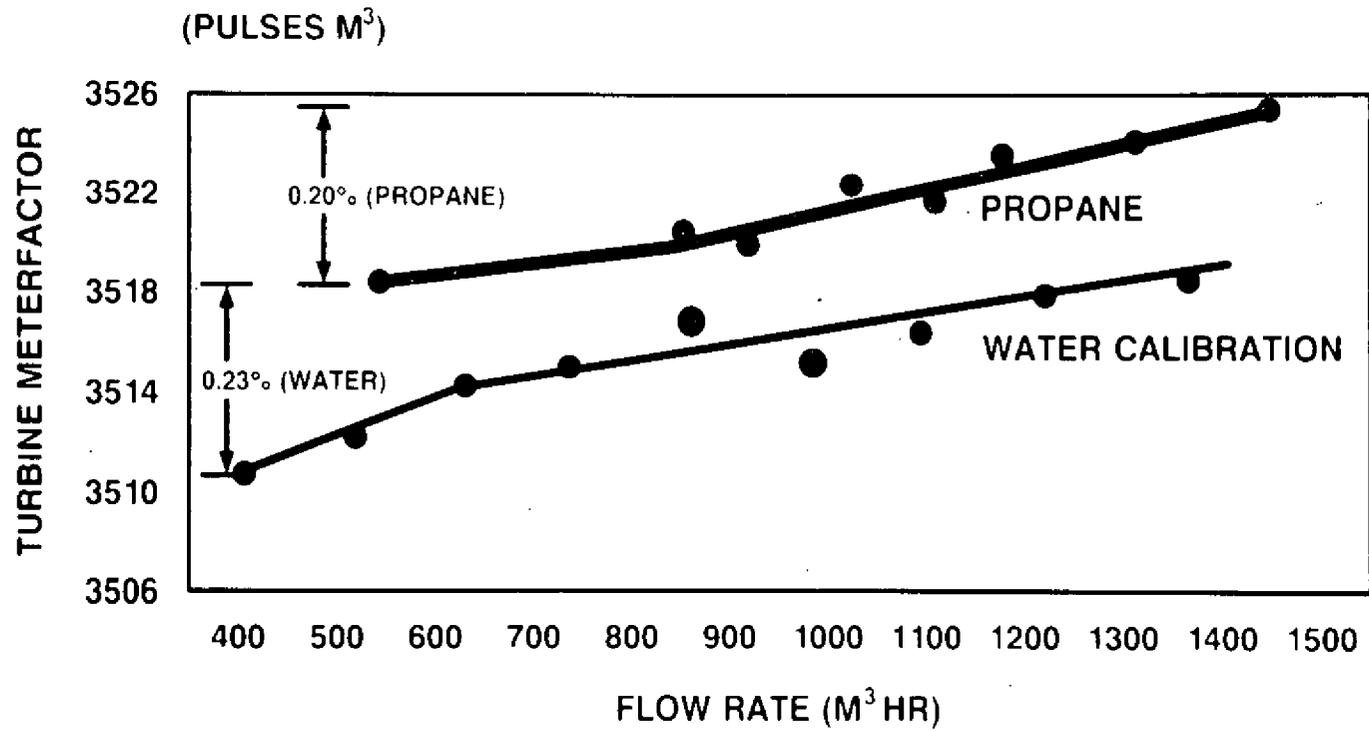


FIG.7

KÅRSTØ PLANT PROPANE METERING STATION  
 TURBINE METERFACTOR LONG-TERM STABILITY FOR  
 RUN NO.3 (8") FLOWRATE BETWEEN 818 & 1149 M<sup>3</sup>/HR

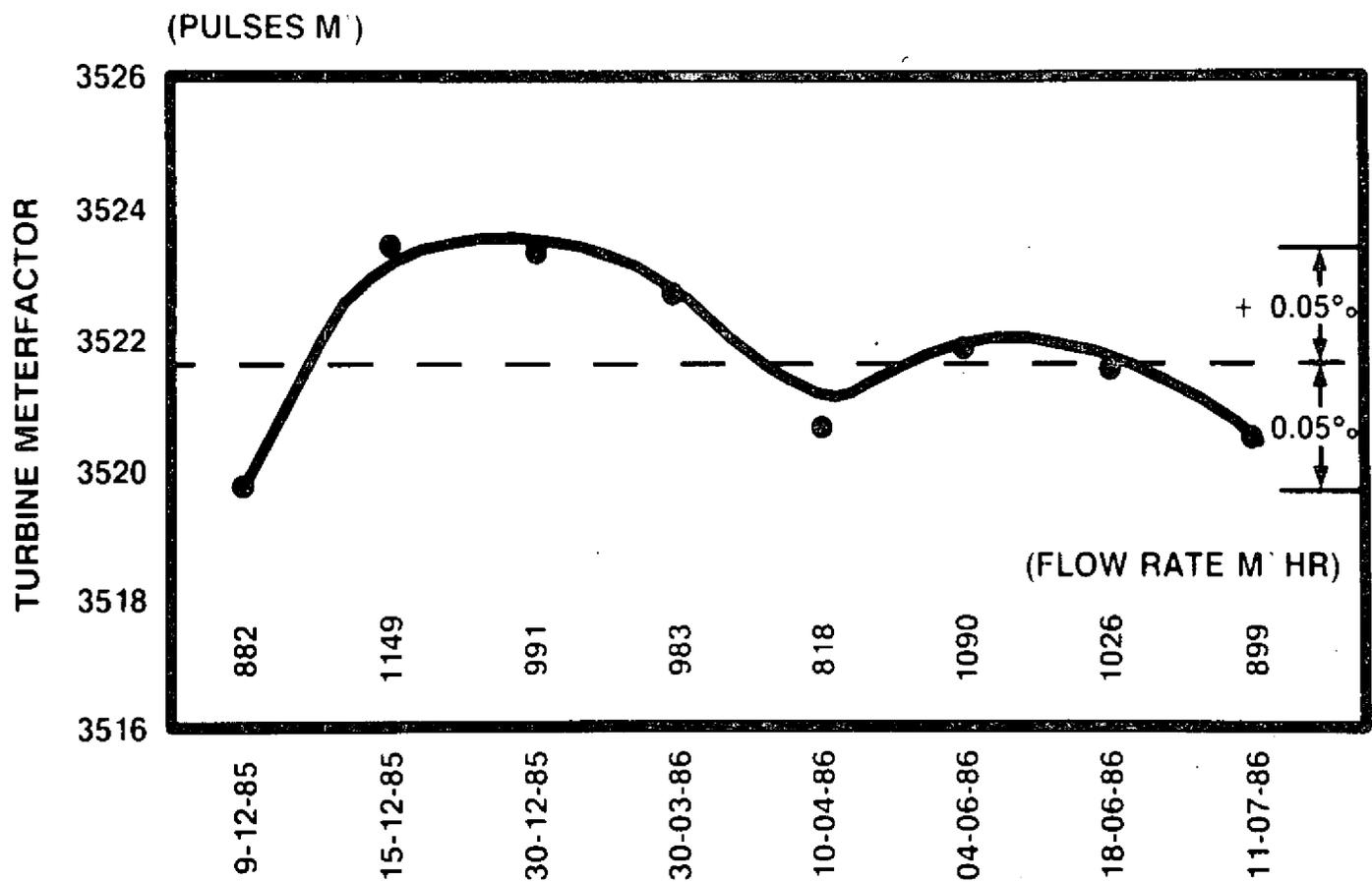


FIG.8

# KÅRSTØ PLANT TEMPERATURE CALIBRATION PROPANE METERING STATION

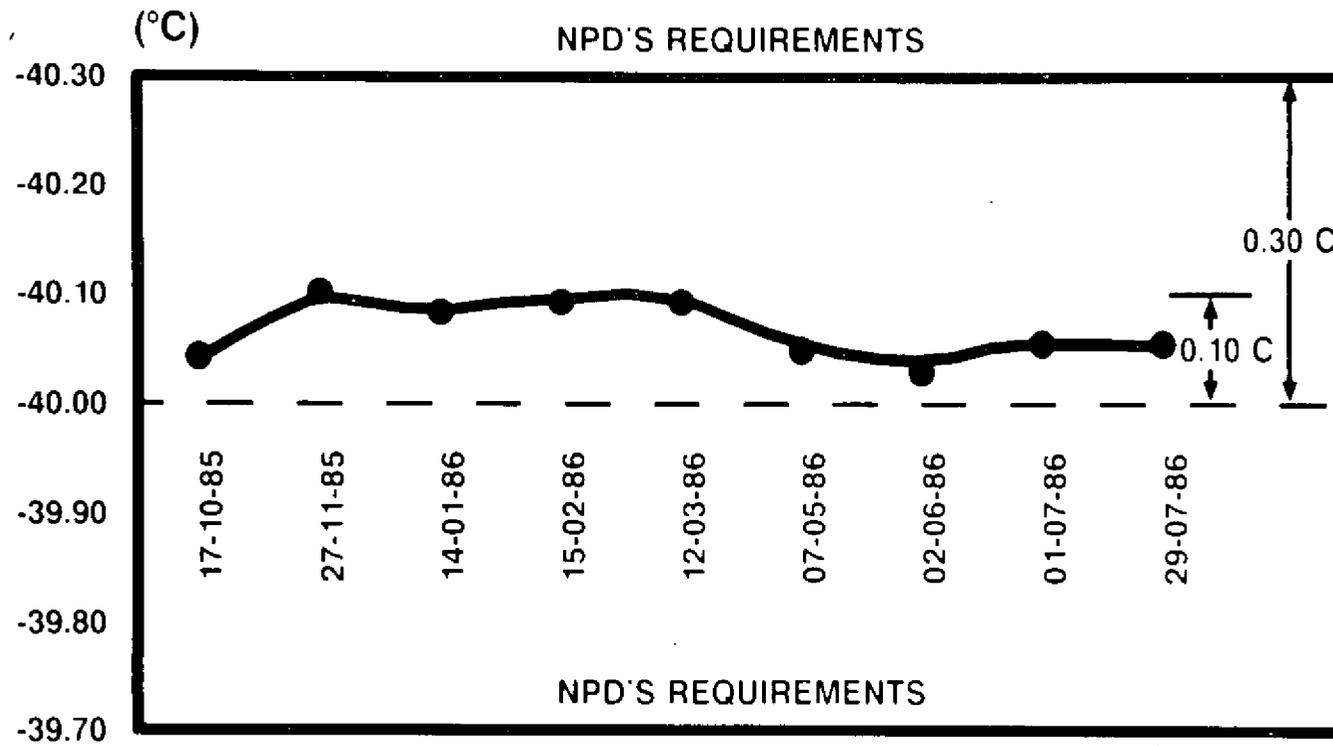


FIG.9

WELLHEAD METERING OF GAS/OIL/WATER PRODUCTION STREAMS

by

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Paper 3.3

NORTH SEA FLOW METERING WORKSHOP 1986

7-9 October 1986

National Engineering Laboratory  
East Kilbride, Glasgow

## WELLHEAD METERING OF GAS/OIL/WATER PRODUCTION STREAMS

### INTRODUCTION

Several prototype instruments for metering gas, oil and water production rates at the wellhead and for monitoring multiphase flow in pipes have been developed by Texaco at the Houston Research Center and by Rogaland Research Institute near Stavanger, Norway, and the Institute for Energy Technology near Kjeller, Norway, in collaboration with and under the support of Texaco. The economic advantages of wellhead metering--especially on offshore platforms and at subsea completions--and of improving multiphase flow transport and handling systems are the driving forces for these instrument developments. In this paper, design details, and laboratory and field tests results of wellhead metering instruments intended to acquire well test data are presented.

The design measurement requirements of these prototype wellhead production meters for acquiring well test data are to determine gas and liquid production rates to within  $\pm 5\%$  of full scale, and percent water (% w) to within  $\pm 2\%$  w for 0 to 10% w, to within  $\pm 3\%$  w for 10 to 20% w, and to within  $\pm 5\%$  w for 20 to 100% w. (Percent water is defined to be one hundred times the water volumetric fraction of the liquid.) The range of the meter should (1) have a turndown of at least eight to one for the total (gas plus oil plus water) volume flow rate at measuring conditions, (2) span the anticipated gas/liquid ratios at measuring conditions, and (3) span anticipated instantaneous water-cuts--which usually range from 0% w to several times the anticipated maximum daily average water-cut. (In many installations instantaneous water-cuts will range well above 40% w and measurements from 0 to 100% w will be required.) These metering systems--especially those for subsea use--should have no moving parts and no regions where solids accumulate. While the size of the meter

can be quite small, appropriate entrance and exit piping is necessary in order to obtain the desired accuracies. Depending on the type of multiphase flow meter, the entrance and exit lengths vary from those of a single phase flow meter--i.e., entrance length of 20 pipe diameters and exit length of 10 pipe diameters--to much greater lengths. We envision the shortest system (meter, and entrance and exit piping) designed to handle 18,000 BBL/D and comparable volumes of gas to be approximately four meters long.

The instruments under development in this program are of two types:

1. flow-nondisturbing instruments--non-intrusive instruments of the same internal diameter as the production line (for monitoring as well as metering multiphase flow), and
2. flow-disturbing instruments--intrusive and non-intrusive wellhead meters with internal geometries different from that of the production line.

At present neither type has any moving parts or solids-accumulation points. Some details of the design of these instruments and results of laboratory and field tests are presented below..

#### FLOW-NONDISTURBING INSTRUMENTS

The sensors of these instruments are either incorporated in a non-intrusive spool piece having the same internal diameter as the entrance and exit piping, or are "clamped-on" to the outside of the production pipeline. Obviously such instruments have the very significant advantage of introducing no changes in the production flow. They are consequently ideal for monitoring multiphase flow in pipelines (for design data--such as holdup) and for metering multiphase flow. However, metering with these flow-nondisturbing instruments requires a precise understanding of the details of multiphase flow in pipes. The instruments used to obtain the required information are discussed briefly below. Enhanced versions of these instruments have

metered oil/gas flow successfully and are now metering oil/water/gas flows.

One of these instruments measures the dielectric distribution within the pipe with sensors external to the flow. The first such system was developed by Mattar and Gregory.<sup>1</sup> The current system developed by Rogaland Research Institute and Texaco has an axial spacial resolution on the order of one millimeter, determines parameters describing the dielectric distribution within a pipe cross section, measures the velocity of propagation of dielectric transients, and has a pressure rating of 3000 psi. Typical time traces for two sensors of the system are shown in Figure 1. The vertical axis is a function of hold-up with high readings corresponding to high hold-ups. The horizontal axis is time in seconds. These traces were acquired while slug flow was present in the pipe. The upstream sensor output is the upper trace and the downstream sensor output is the lower trace. As is typical for slug flow the sensors alternatively "see" gas pockets -- for example, from 8.0 to 8.8 seconds on the upstream sensor -- and liquid plugs -- for example, from 8.8 to 9.4 seconds on the upstream sensor. Small bubbles in the plug part of the slugs can be seen and correlated between the two traces (for example, the bubble in the liquid plug in the upstream trace at 8.9 seconds corresponds to the bubble in the downstream trace at 9.1 seconds). Furthermore, it is clear that the gas pockets are moving at a higher velocity than the small bubbles in the liquid plugs. Similarly the origin or seed of pocket front disturbances (at 7.6 and 9.8 seconds) on the downstream trace can be seen (at 7.5 and 9.7 seconds) on the upstream time trace. A much finer time scale than shown here is required to exploit the full resolution of the instrument.

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<sup>1</sup> G. A. Gregory and L. Mattar, "An In-Situ Volume Fraction Sensor for Two-Phase Flows of Non-Electrolytes," The Journal of Canadian Petroleum Technology, April-June 1973, Montreal, Canada.

Another flow-nondisturbing instrument, the Fast Volume Weight Meter, measures the fluids distribution within the pipe via nuclear techniques. Developed by the Institute for Energy Technology and Texaco, this instrument measures the pipe-cross-sectional liquid fraction or hold-up, determines parameters describing the liquid distribution within the pipe cross section, measures the velocity of propagation of hold-up transients, mounts on the outside of the production line and is "portable." Counting rates as high as 800,000 counts per second are used to determine the hold-up. Time traces from this instrument are qualitatively similar to those of the dielectric based system aside from variations due to nuclear statistics. This instrument -- because of its unique capability to measure cross sectional liquid fraction or hold-up -- is being used by SINTEF at the Two Phase Flow Laboratory near Trondheim, and has been ordered by the Harwell Laboratories, Atomic Energy Research Establishment for their multiclient Pipeline Instrumentation Project.

Metering models are being developed for all flow patterns with these systems. Tests performed at near atmospheric and high pressures yield very similar metering results. Much of the testing has been carried out at Texaco's Houston Research Center. This facility has low and high pressure test loops. The high pressure loop operates at pressures up to 500 psi with oil, water and nitrogen gas. A test hole over 300 feet deep is used to simulate wellhead flow. The fluids from separate gas and liquid lines are merged at the bottom of the hole; the resulting multiphase mixture flows to the surface in 2-, 3- or 4-inch pipe and is used as a "wellhead production stream" to test metering systems. Oil and water flow rates up to 7,000 BBL/D and gas rates high enough to produce annular flow in vertical 4-inch pipe are available. Some test results obtained in July 1984, at Texaco's Houston Research Center are shown in Figures 2 and 3.

Figure 2 displays the percent-of-value error of the metered gas flow rates as a function of gas flow rate expressed in actual cubic feet per minute on the horizontal axis and as a

function of liquid flow rate expressed in U.S. gallons per minute on the vertical axis.

$$\text{percent-of-value error} = 100 * (\text{metered} - \text{actual}) / \text{actual}$$

The metered gas flow rates are in general within three percent of the actual values. The error values are significantly smaller when expressed in terms of percent-of-full-scale error.

$$\text{percent-of-full-scale error} = 100 * (\text{metered} - \text{actual}) / (\text{full scale})$$

All the error values are well within the accuracy requirements of  $\pm 5$  percent-of-full-scale.

Figure 3 displays the percent-of-value error of the metered liquid flow rates as a function of gas and liquid flow rates. All the error values are well within the accuracy requirements of  $\pm 5$  percent-of-full-scale except possibly the value at 500 feet<sup>3</sup>/hour and 73 gallons/minute.

The range of the instrument used to acquire the data in Figures 2 and 3 has been extended, and the instrument has been enhanced to also measure water-cut. Figure 4 displays the percent-water error of the metered water-cut as a function of gas and liquid flow rates for an actual water-cut of 0% w.

$$\text{percent-water error} = [(\text{metered \% w}) - (\text{actual \% w})]$$

The values are all within  $\pm 1\%$  w and satisfy the accuracy requirements of  $\pm 2\%$  w for this range of water cuts.

Figure 5 displays the percent water error of the metered water cut as a function of gas and liquid flow rates for actual water-cuts of approximately 10% w. The results are within the accuracy requirements of  $\pm 2\%$  to  $\pm 3\%$  w for this range of water cuts.

## FLOW-DISTURBING INSTRUMENTS

While these systems do disturb the production stream flow, they do so in ways that are intended to

1. interfere minimally with production -- i.e., without introducing high pressure drops or solids-accumulation regions, and
2. provide accurate reliable metering.

These systems are intended for platform and subsea use. This is the type of metering system Texaco currently plans to install subsea first -- probably in the North Sea. Full details of these instruments are not available for public discussion at this time. One component of some of these systems is a microwave-based water-cut monitor which has been developed by Texaco under partial support by ARAMCO. Results of the most recent offshore test of this water-cut monitor are presented below.

This microwave-based system, like capacitance probes, determines water cut by measuring the fluid dielectric constant. However, the microwave system accurately measures water cuts from 0 to 100% w for water-continuous and oil-continuous systems and does not suffer the problems associated with capacitance probe measurements on water continuous systems. This water-cut monitor system operates on the full oil/water/gas production stream to measure the water-cut of the produced liquids.

Results of the most recent field test are shown in Table 1. Flow rates of the tested wells are shown in BBL/D. The time duration of a well test was typically eight hours. The test pressures ranged from 300 to 400 psi, and GOR's ranged from 300 to 400. The agreement is probably to within the accuracy of the test separator system, and is well within well test accuracy requirements. The displayed water cuts are the test-duration averaged water cuts; instantaneous water cuts varied from 0 to well over 80% w. This microwave test system was designed to handle up to 18,000 BBL/D and comparable volumes of gas, with a pressure drop of at most 2 psi.

SUMMARY

Prototype instruments have proved adequate to measure flow rates to well test accuracies. Texaco's first subsea metering system may be installed as early as 1987.

TABLE 1

COMPARISON OF TEST SEPARATOR AND MICROWAVE WATER-CUT MONITOR

<u>FLOW RATE</u> <sup>#</sup>	<u>PERCENT-WATER MEASUREMENTS</u>	
	<u>TEST SEPARATOR</u>	<u>MICROWAVE MONITOR</u>
6,100	48.3'	46.8
7,670	30.2	30.4
6,950	17.1	18.2
5,780	1.9	3.1
7,500	29.2	26.1
10,710	0.1	0.1
6,450	0.0	0.1
11,260	1.8	0.7
6,640	0.6	0.9
5,590	0.0	0.0
11,320	42.1	40.2

# Flow rate in BBL/D (barrels (42 U.S. gallons) of liquid per day.

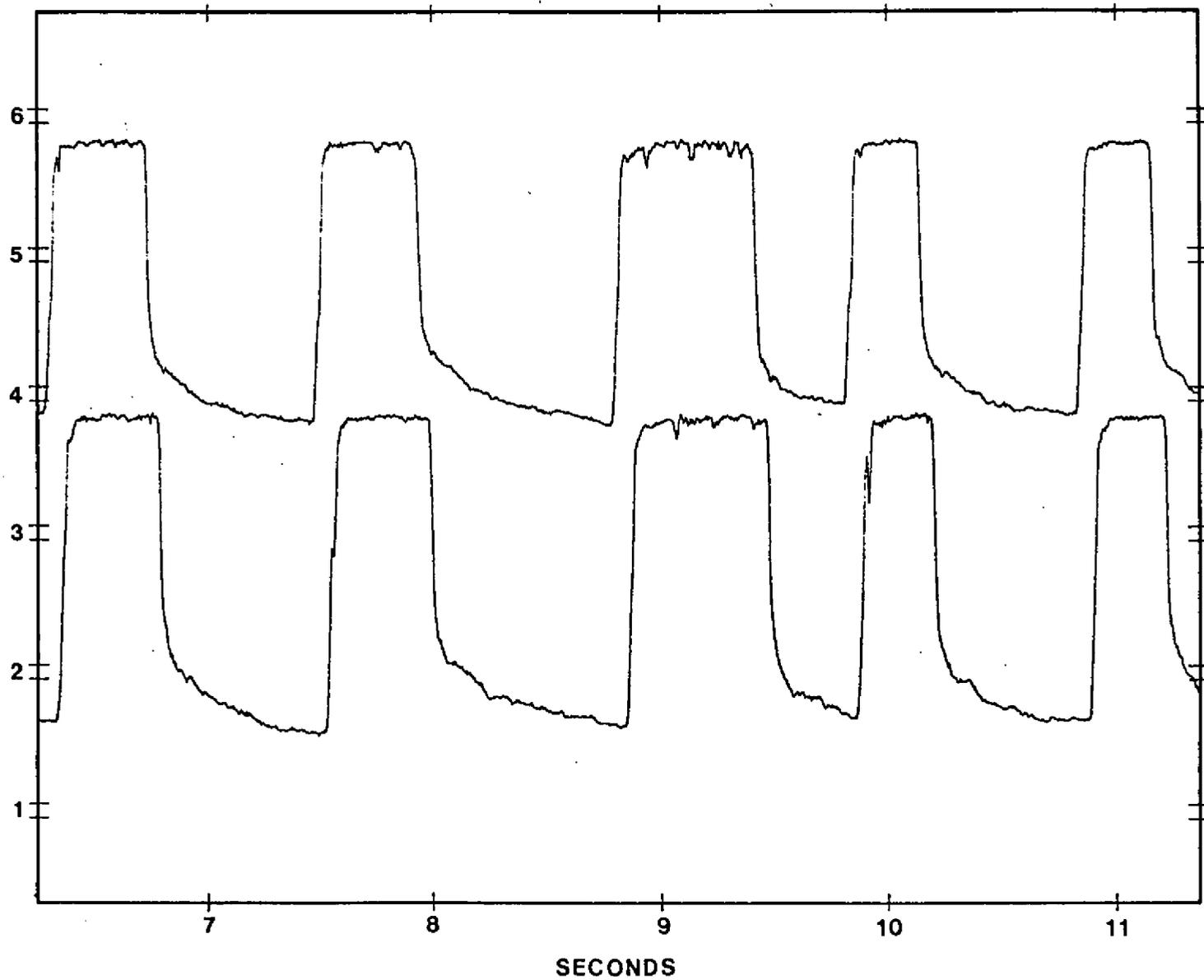


FIGURE 1 SLUG FLOW TRACES

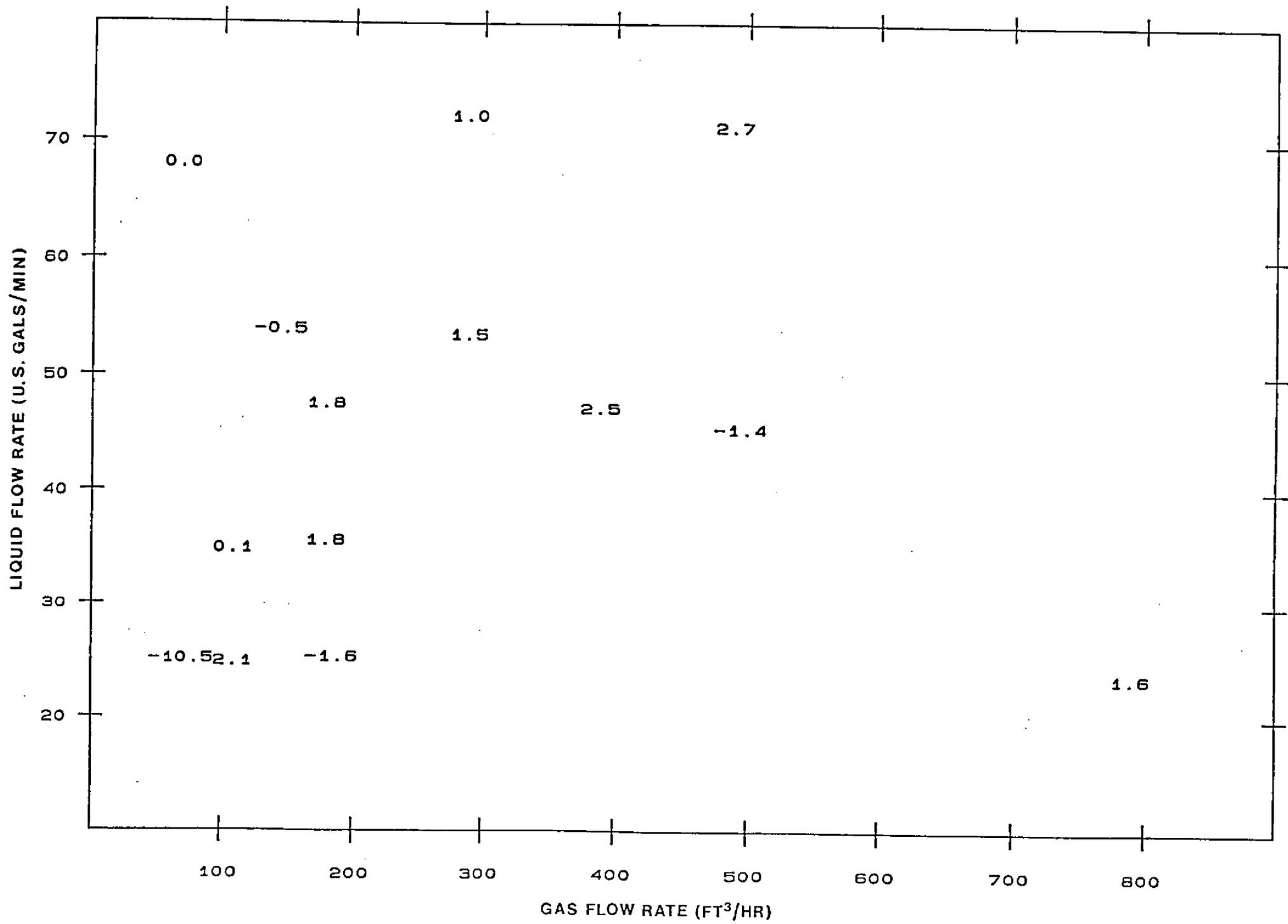


FIGURE 2 GAS RATE PERCENT-OF-VALUE ERROR

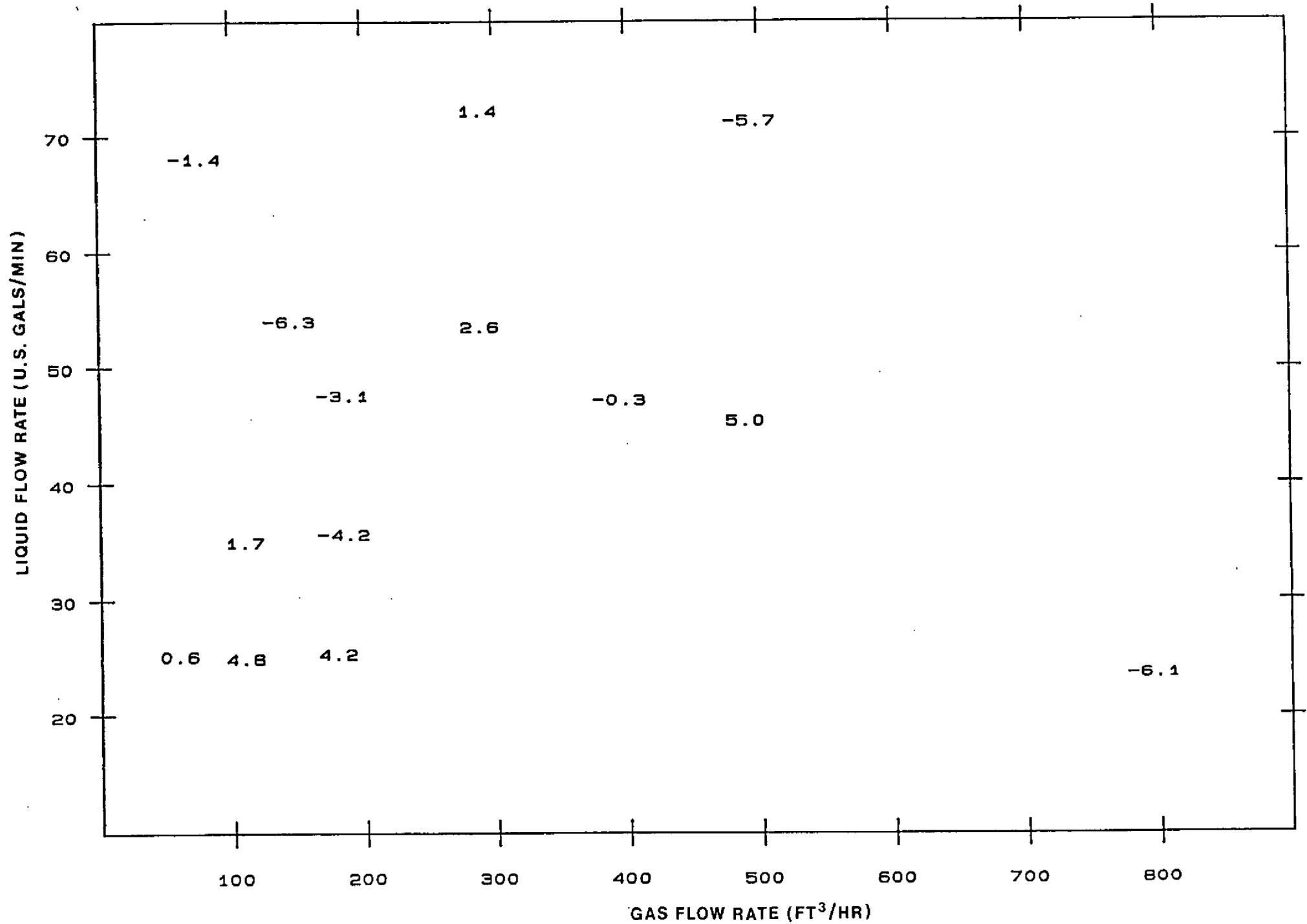


FIGURE 3 LIQUID RATE PERCENT-OF-VALUE ERROR

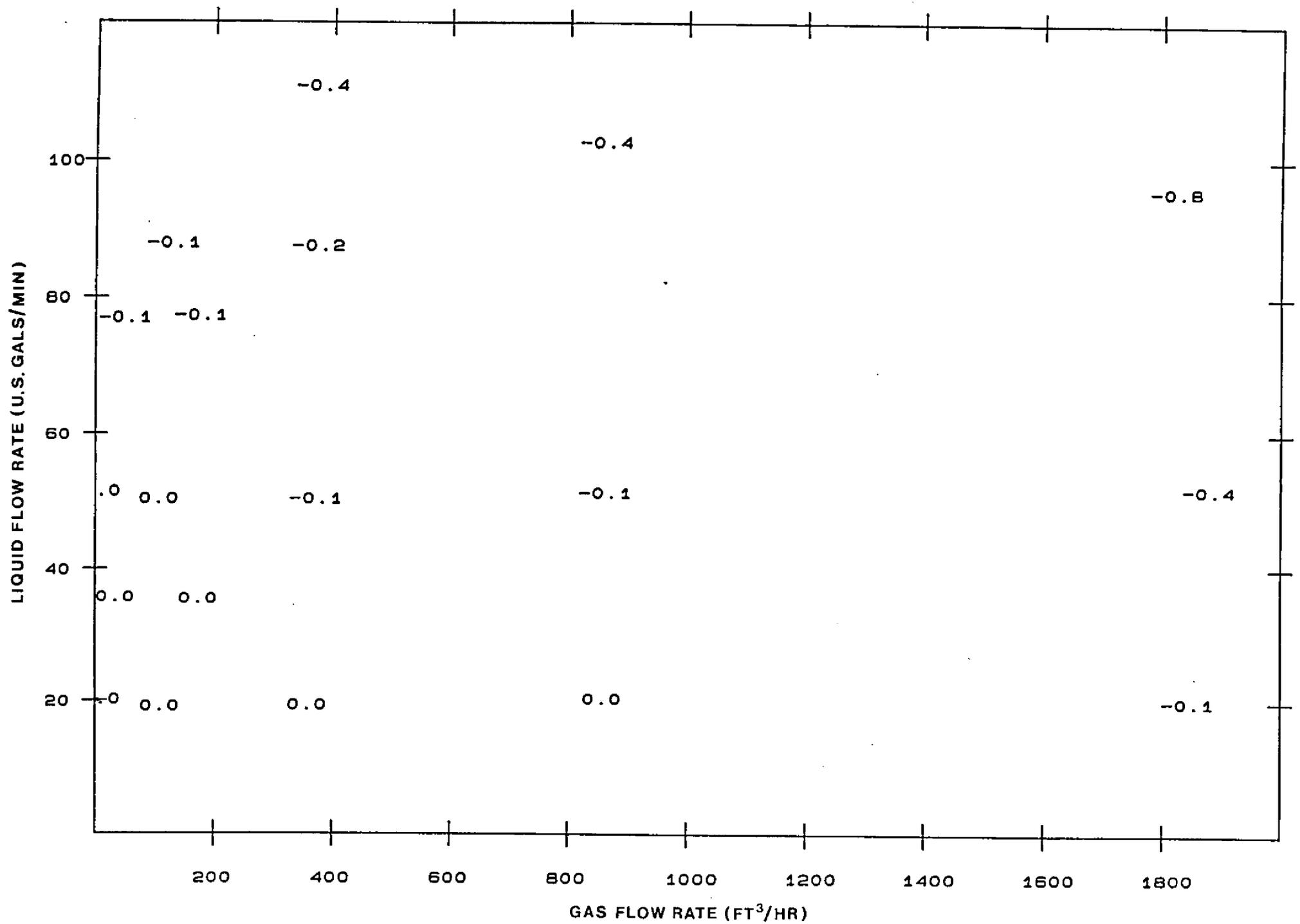


FIGURE 4 PERCENT-WATER ERROR (WATER-CUT ~ 0.0)

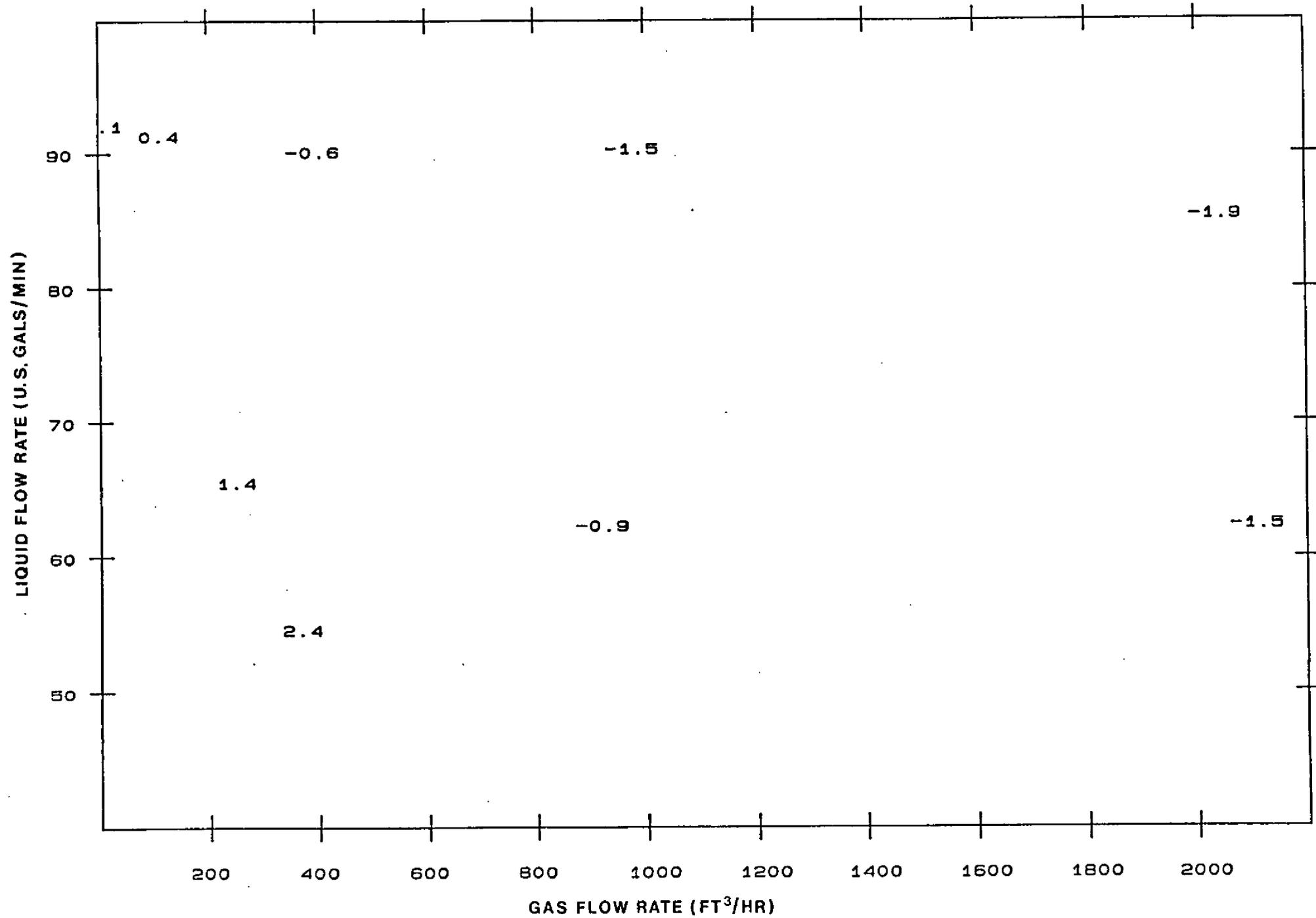


FIGURE 5 PERCENT-WATER ERROR (WATER-CUT~0.10)

THE NEL ORIFICE PLATE PROJECT

by

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Paper 3.4

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East Kilbride, Glasgow

## S U M M A R Y

This paper reviews previous work to investigate the effect of upstream edge sharpness on the discharge coefficient of orifice plates. It traces the development of Standard requirements for edge sharpness and discusses the need for more guidance in the manufacture and inspection of orifice plates. The main methods in current use for the determination of edge radius are outlined. Finally, the project being undertaken at NEL to provide new information on the effects of edge sharpness and other local defects on the orifice coefficient is described.

## 1 INTRODUCTION

While the use of orifice plates to measure fluid flow is well defined in the current International Standard<sup>(1)</sup> there are some aspects of their manufacture and inspection which are not specified in sufficient detail.

One area which gives particular difficulty and, on occasions, grounds for debate is that of the edge sharpness requirement. Most people involved in the use of orifice plates are aware of the great importance of the square edge, but there is no convincing evidence to support the criteria for visual inspection given in various editions of the Standards. For small pipe sizes (less than 125 mm bore) the limiting edge radius of  $0.0004d$  is well nigh impossible to achieve and measure. For larger sizes, the edge sharpness requirement is easier to meet, but the rejection of plates showing 'any peculiarities visible to the naked eye' may be unnecessarily stringent and expensive.

Another deficiency in the current Standard is the quality of surface finish of the downstream face of an orifice plate. Again qualitative, but not quantitative guidance is given.

The NEL orifice plate project was therefore begun to investigate three important topics:

- a The effect of upstream edge sharpness to determine at what degree of rounding the orifice coefficient begins to change.
- b The effect of local damage to the upstream edge or face of an orifice plate.
- c The effect of the finish of the downstream bevel and the surface roughness of the downstream face.

An important part of this project was the survey of previous literature, covering earlier experimental work, and the evolution of the current Standards. Equally important for the manufacture and testing of the orifice plates was the provision of measuring instruments of sufficiently good performance to resolve the small differences in the parameter being investigated and their effect on the orifice coefficient.

## 2 PREVIOUS WORK

Probably the first relevant reference to edge sharpness effects was in the early 1930s when Professor S R Beitler<sup>(2)</sup> examined microscopically the edges of plates which gave coefficients that were higher than expected. Although he considered them to be slightly rounded it was not possible to measure the radius of that time without cutting up the plates.

It was not until the 1960s that a major experimental programme was attempted in which measurements of both edge sharpness and the discharge coefficient were measured. Herning<sup>(3,4)</sup> and his colleagues carried out a programme of tests on a series of different diameter ratio orifice plates installed in meter runs of 50, 100 and later, 150 mm diameter. The edges of the orifice plates were progressively rounded with emery paper and a lead foil method was used to measure the edge radius before each successive calibration.

The results of their work were best summarised in Fig. 6 of reference 4, which is reproduced as Fig. 1 in the present paper. This shows that the

effect of the edge depends only on the ratio of the radius of the edge to the orifice diameter.

More recently, Crockett and Upp<sup>(5)</sup> made further tests using 75 mm (3-inch) diameter plates of 0.2, 0.4 and 0.6 diameter ratio and used the lead foil technique to determine the edge radius.

A little later Benedict<sup>(6)</sup> and his co-workers investigated the edge effect with 0.5 diameter ratio plates in a 101.6 mm (4-inch) nominal bore test line. Some of the plates were rounded to a radius of about 0.2 mm to represent an extreme case of edge roundness. Both optical and lead foil measurements were used to determine the edge radius.

All the above investigations were concerned with the effect of gross changes of the edge radius. Another series of tests were made by Spencer, Calame and Singer<sup>(7)</sup> in the 1960s on the production of orifice plates to the then current standard and the errors that could arise if care was not taken and the quality of finish required was not obtained.

### 3 STANDARDS

The first international standard on orifice plates<sup>(8)</sup> was published by the International Federation of the National Standardising Associations (ISA) in 1936. It included a graph showing the effects of 'dullness' of the edge. No qualitative description of this 'dullness' was given, but the graph is believed to have resulted from the work of Witte in the early 1930s.

Owing to the difficulty of measuring edge radius, most subsequent Standards seem to have specified that the edge be sharp and left it to the user to satisfy himself that this has been achieved. Little guidance has also been given on how to machine a satisfactory sharp edge, quite a problem for some materials, especially for small orifice diameters.

In the ASME Power Test Code<sup>(9)</sup> PTC 19.5; 5-1959 it states:

"e The inlet edge of the orifice shall be square and sharp, free from either burrs or rounding, so that when viewed without magnification a beam of light is not reflected visibly by the edge."

The German Standard DIN 1952 published in 1963 commented that a reflected ray of light from a rounding radius of 0.05 mm is just visible to the naked eye<sup>(10)</sup>. It was concluded that visual inspection could only be justified if the bore diameter was greater than 125 mm at which value the edge radius would be 0.0004d, the criterion given for a sharp edge.

The revised British Standard BS 1042<sup>(11)</sup> published in 1964 included the same criterion for the sharp edge in the specification of the orifice plate. Clause 54 contained the following requirement:

"d Upstream edge of orifice. The upstream edge of the orifice shall be square and free from burrs or wire-edges. It may be regarded as square if its radius of curvature nowhere exceeds 0.0004d."

Elsewhere in the same standard some guidance was given on how to produce such an edge. Clause 40 included the statement:

"A high quality of manufacture is necessary to meet the requirements detailed in Sections Seven to Fourteen especially for devices to be used in smaller sizes of pipe. The square edge of orifice plates may conveniently be produced by taking a fine cut, from the centre outwards, after the orifice has been bored; polishing or cleaning with emery cloth is not advisable. There must of course be no burrs or wire edges."

ISO 5167, 1980 which was adopted as BS 1042, 1981(12) incorporated basically the same message in Clause 7.1.6.

#### "7.1.6 Edges G, H and I

7.1.6.1 The upstream edge G and the downstream edges H and I shall have neither wire edges, nor burrs, nor, in general, any peculiarities visible to the naked eye.

7.1.6.2 The upstream edge G shall be sharp. It is considered so if the edge radius is not greater than  $0.0004d$ .

If  $d \geq 125$  mm this condition may generally be considered as satisfied by mere visual inspection, checking that the edge does not seem to reflect a beam of light when viewed with the naked eye.

If  $d < 125$  mm visual inspection is not sufficient but this condition may generally be considered as satisfied when the upstream face of the orifice plate is finished by a very fine radial cut from the centre outwards.

However if there is any doubt as to whether this condition is satisfied, the edge radius must be actually measured."

Fig. 2 is a reproduction of the drawing of the ISO standard orifice plate and indicates the edges G, H and I referred to the text quoted above. No guidance is given in the Standard on how the edge radius should be measured. A Code of Practice for ISO 5167 is being prepared and this will include brief notes on three suitable techniques, viz lead foil, casting and stylus methods. These, and a few other possibilities, are described in the following section.

#### 4 METHODS OF MEASURING EDGE SHARPNESS

From the foregoing it is apparent that visual inspection is a valuable pre-requisite to a more sophisticated method of measurement even though it cannot give quantitative information. A truly sharp edge will not reflect a beam of light whereas if a line of light is seen it can be concluded that the edge is rounded.

##### 4.1 Optical Method

This method was proposed by Mr A Aschenbrenner of PTB about 1970 and was described by Brain and Reid<sup>(13)</sup>. A narrow beam of light was directed on to the edge of the plate at an angle of  $45^\circ$  to the tangent, Fig. 3. When viewed through a microscope at  $90^\circ$  to the beam, but in the same plane, the rounded edge was seen as an ellipse. The radius of curvature was estimated by measuring the distance from the intersection of the reflected light beam to the tangent of the ellipse. Unfortunately the amount of light scattering

which occurred, blurred the image so the position of the tangent was a matter of judgement on the part of the operator.

The same method was used by Benedict<sup>(6)</sup> in the mid 70s and good results were claimed.

#### 4.2 Lead Foil Technique

Herning described the lead foil technique for measurement of the orifice edge profile which he developed while working for the Ruhrgas Physical Laboratory in Germany. A small piece of lead foil about 0.1 mm thick was clamped in a holder so that a small piece projected. The holder, and protruding foil, was moved at an angle of 45° against the orifice edge to give an impression which could be projected on to a screen to facilitate measurement. So as not to bend the foil the depth of the impression was kept below about 0.3 mm.

This technique was refined by Jepson and Johnson<sup>(14)</sup> at the British Gas Corporation Engineering Research Station as some difficulty had been experienced in getting repeatable impressions. They developed the gauge shown in Fig. 4 which could be clamped to the orifice plate along the appropriate marked diameter and a micrometer adjustment used to present the foil to the edge. The lead foil holder could be removed from the gauge for examination using shadowgraphing equipment. Radii down to 0.005 mm could be measured by this method.

#### 4.3 Casting Method

While the lead foil technique produced accurate replicas, they were easily damaged. Gallacher<sup>(15)</sup> of NEL sought to make a permanent replica which would facilitate microscopic examination. He developed the method in which a liquid cold-forming plastic was poured into a wax or plasticine mold surrounding the location on the orifice plate to be measured, Fig. 5. When hardened, the casting can be removed, sliced and polished to a reference line thus forming a perfect replica of the original edge. Results accurate to 0.005 mm have been obtained.

#### 4.4 Stylus Method

This method is based on a development of the well known 'Talysurf' roughness measuring machine, or its equivalent, which is used to measure the surface finish of plates. By reducing the sensitivity of the machine in the vertical direction to that in the horizontal, a sufficient range can be obtained to examine the edge. A typical record is shown in Fig. 6. Because the roughness of the surface is not of prime interest, and the sensitivity is reduced, it is unnecessary to use a pointed stylus. A small spherical ball, which can be manufactured and measured to fine tolerances, is commonly used being less likely to wear, but of course due allowance must be made for the radius of the ball itself. Magnifications of up to 500 times have been successfully used.

#### 4.5 Assessment of Radius

The lead foil, casting and stylus methods all enable the operator to obtain an enlarged trace of the edge itself. As can be seen from the various illustrations, this is seldom a true circular arc and the estimation of the mean radius depends to some extent on the skill and experience of the operator. Sets of standard radii enlarged to the correct degree of

magnification and printed on transparent plastic film can be used as overlays on the traces of the edge in order to assist with the estimation of the radius. However, as those who have tried this procedure will appreciate, this is not a simple operation.

Some of the instruments used for the stylus method facilitate the use of curve fitting routines. Sets of x and y coordinates defining the locus of the stylus can be down-loaded to a micro-computer and the best fit circle obtained for the curved region. Care has to be taken to define the length of trace to be fitted as the points of tangency may not be clear. This may be helped by examining a plot of the residuals obtained after subtracting the best fit circle from the points selected. It is also a simple matter to allow for the radius of the stylus.

It should perhaps be stressed that this curve fitting routine is intended to augment rather than replace the visual assessment of edge sharpness with the aid of overlays if appropriate. The main purpose is to accomplish the same task, but to remove some of the subjectivity from the assessment.

## 5 NEL EQUIPMENT AND TEST PROGRAMME

As all known previous work was limited to pipes of diameters of 150 mm or less it was decided to base the current measurements on 300 mm (12-inch) nominal bore pipe as being more representative of the sizes commonly used for gas transmission. Three diameter ratios were chosen; 0.4, 0.6 and 0.75, again typical of those in use, giving orifice bores of 120, 180 and 225 mm respectively. A Junior orifice fitting was chosen to facilitate repeated removal and replacement of the test plates.

The flow tests are being made in air using a set of three venturi nozzles in free inlet condition as reference flowmeters. Each nozzle is sized to correspond to one of the three orifice plate diameter ratios in order to give comparable ranges of differential pressure which is being measured using Betz manometers.

In addition to the usual measurements of orifice bore, concentricity, thickness, surface roughness etc, the edge sharpness is being measured at eight positions round the orifice using both the stylus method and by means of cast plastic replicas. NEL has recently bought a Rank Taylor Hobson Talycontor instrument for this purpose, although the replica casting technique has been available for several years.

The first phase of the test programme is to investigate the effect of upstream edge sharpness. Beginning with a radius of about 0.0001d one plate of each diameter ratio is being successively rounded in increments towards a radius in excess of 0.001d and the plate calibrated each time.

The second phase will investigate the effect of local damage introduced to the upstream edge and gradually extended round the circumference. Calibrations will be carried out to determine how extensive the damage has to be before the orifice coefficient is significantly affected.

The third phase will comprise a series of tests to investigate the effect of imperfections on and roughness of the downstream side of the orifice plate.

This work is currently at an early stage and is expected to take a further 12 months to complete.

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#### LIST OF FIGURES

- 1 Multipliers for flow coefficient
- 2 Standard orifice plate
- 3 Apparatus used for optical method
- 4 Gauge used in lead foil method
- 5 Stages of the casting method
- 6 Typical record from stylus method.

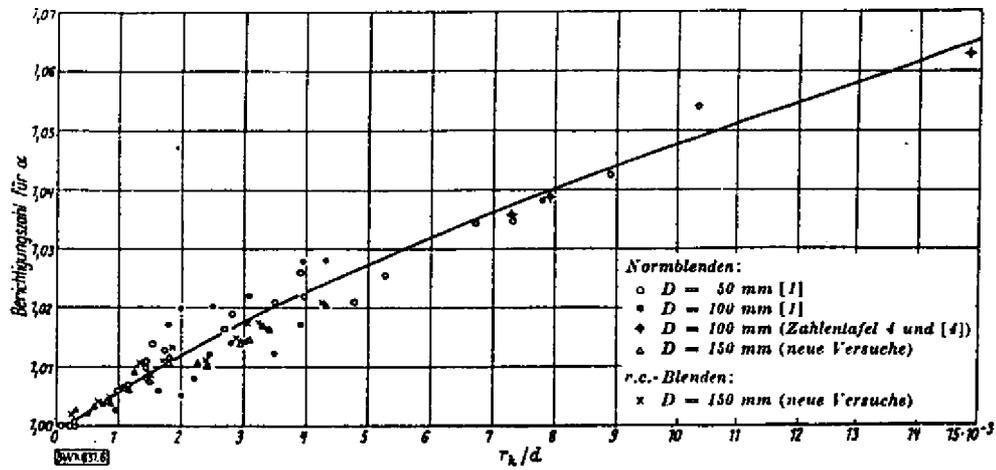


FIG 1 MULTIPLIERS FOR FLOW COEFFICIENT

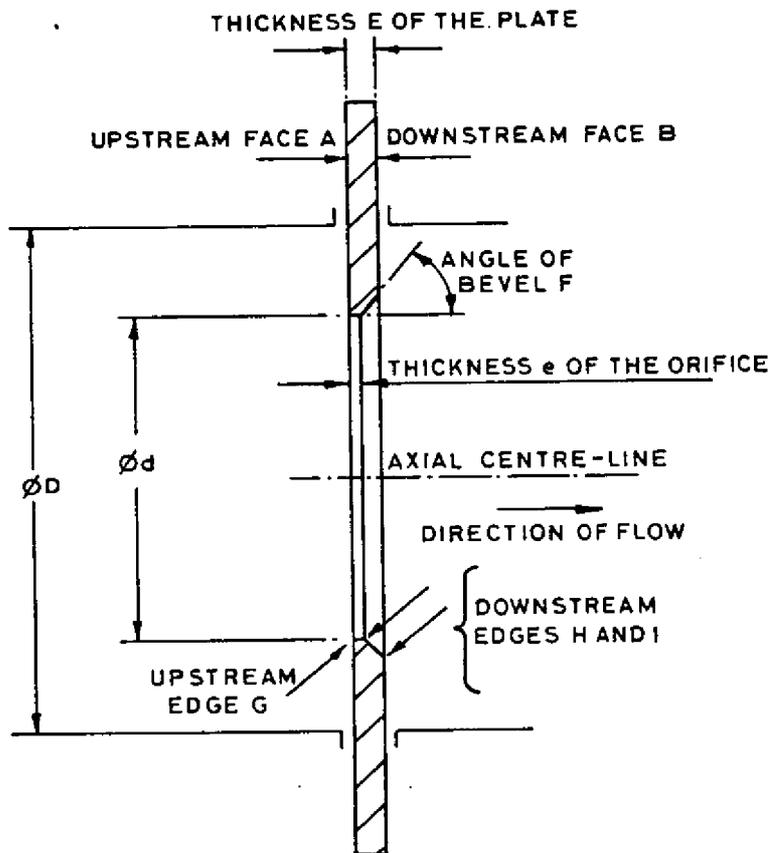


FIG 2 STANDARD ORIFICE PLATE

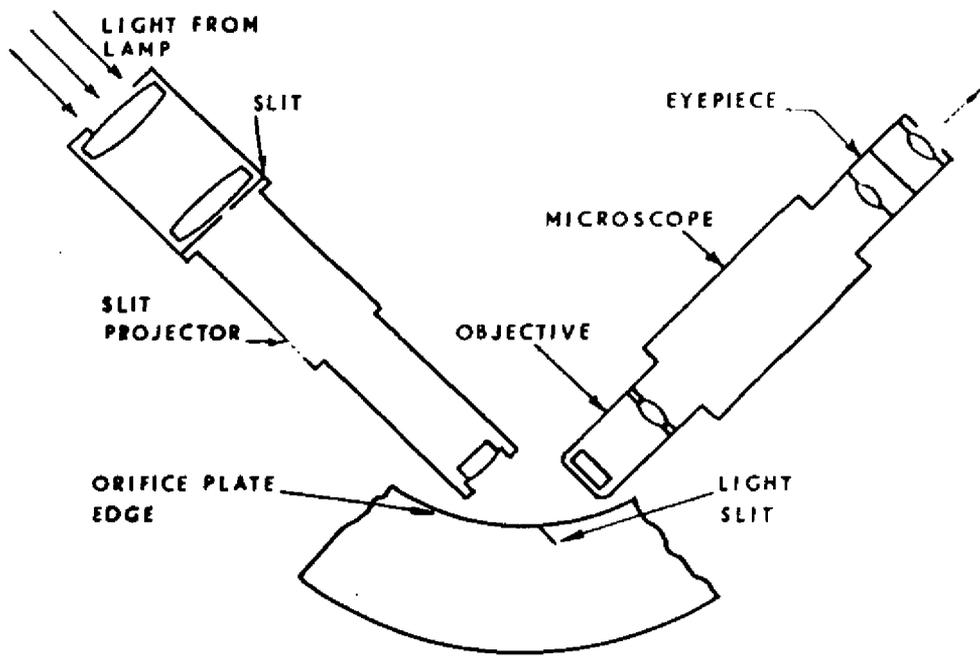


FIG 3 APPARATUS USED FOR OPTICAL METHOD

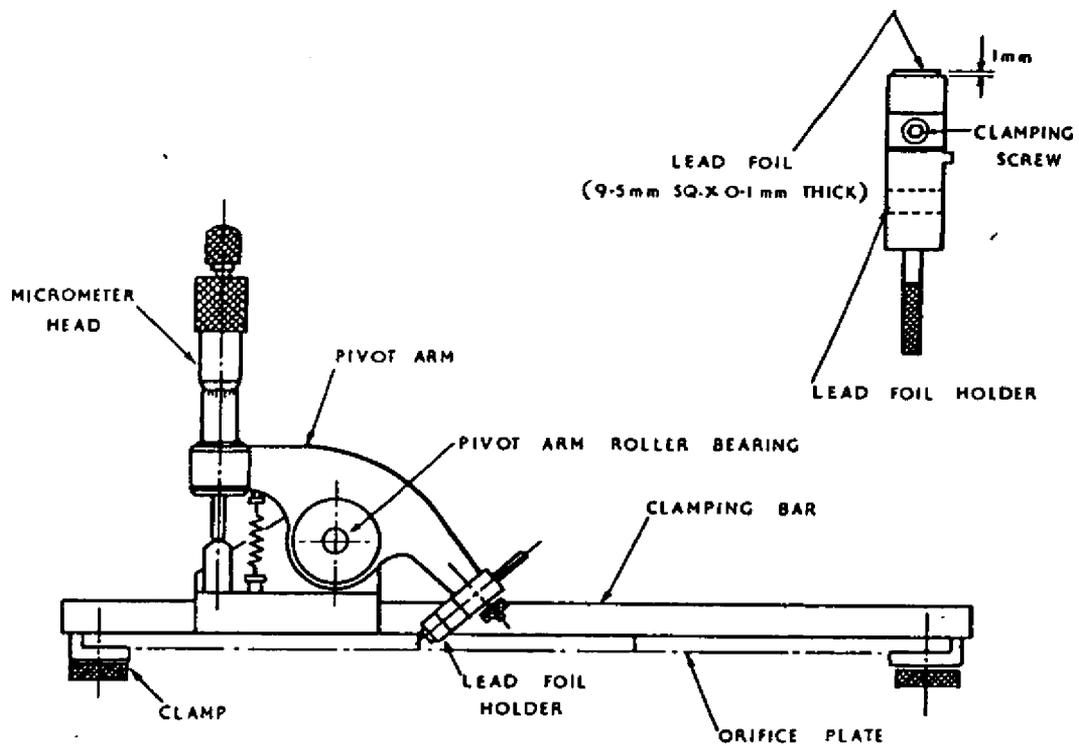


FIG 4 GAUGE USED IN LEAD FOIL METHOD

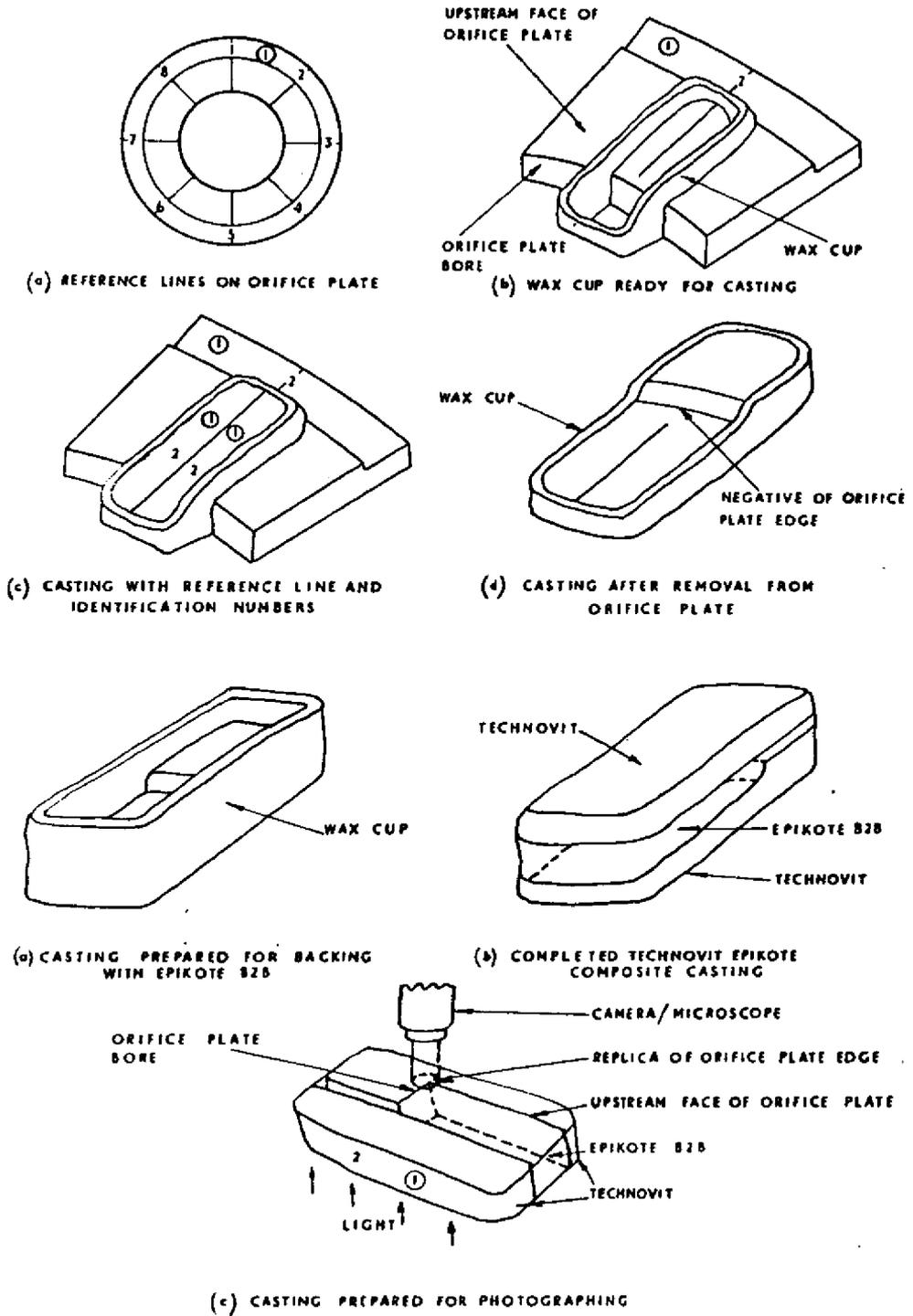


FIG 5 STAGES OF THE CASTING METHOD

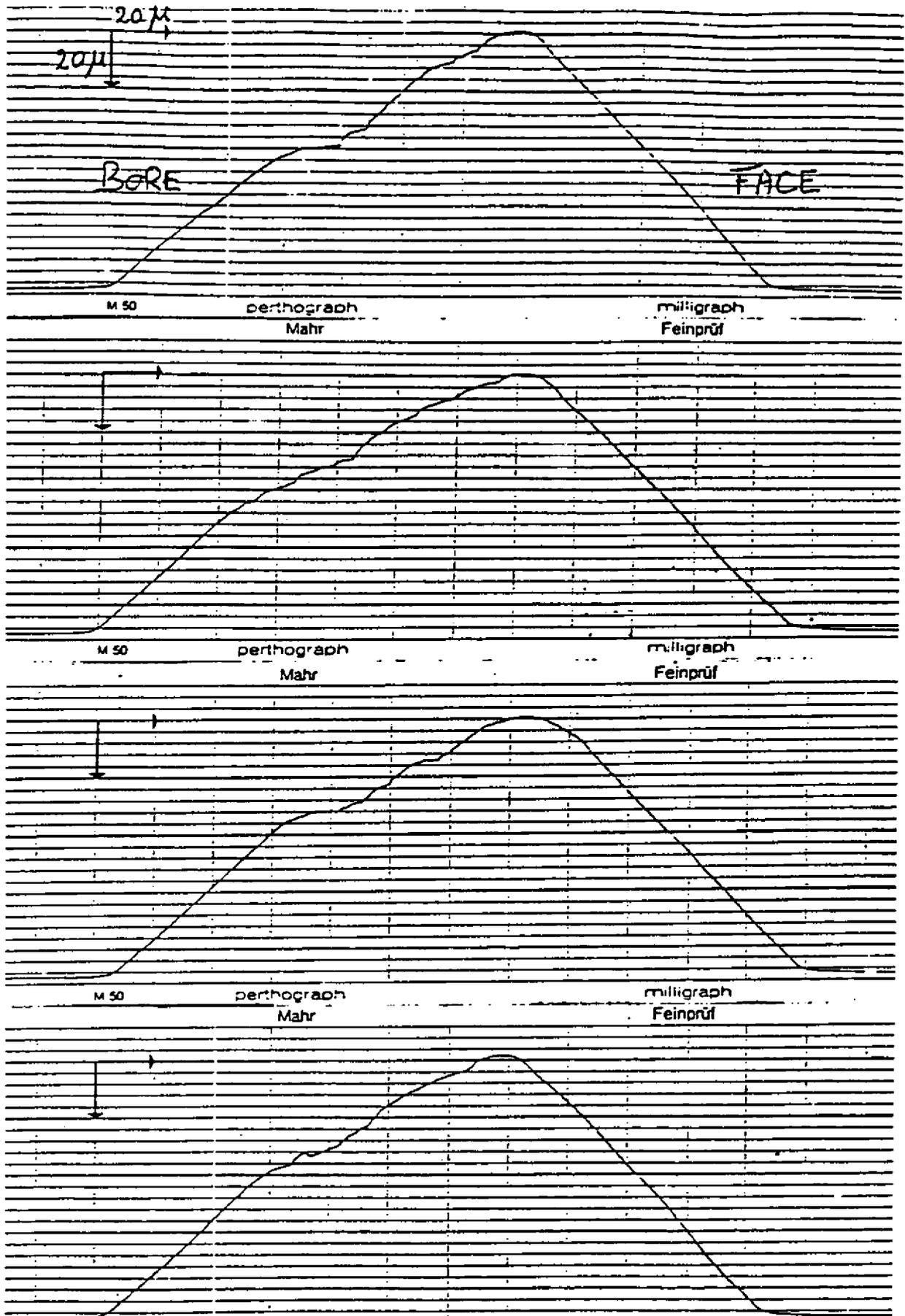


FIG 6 TYPICAL RECORD FROM STYLUS METHOD

EXPERIENCE WITH COMPACT PROVERS AND PULSE INTERPOLATION AT NEL

by

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Paper 5.1

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National Engineering Laboratory  
East Kilbride, Glasgow

EXPERIENCE WITH COMPACT PROVERS AND PULSE INTERPOLATION AT NEL

by

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S U M M A R Y

Two compact meter provers have recently been evaluated at NEL. Drawing from the results of these evaluations, the paper provides an assessment of the general features common to compact provers. The test and calibration data are presented and the reasons for some anomalies and limitations in use are explored in some detail.

The paper ends with some guidelines for operators of compact provers, and recommendations for further work.

## 1 INTRODUCTION

Compact provers are now available commercially and are being used in both fiscal and non-fiscal applications. Differing reports as to their effectiveness are being given, some users providing very good reports, for example in respect of repeatability and reliability, while others are less enthusiastic.

In order to provide a detached evaluation of the main characteristics of compact provers NEL is presently carrying out a systematic programme of tests on a range of commercially available units.

This paper is concerned only with compact provers as generic devices, and not with an assessment of the performance of individual units, so that common characteristics such as their effectiveness as calibrators of different meter types, and the performance of the pulse interpolation systems used with them are discussed, rather than the individual repeatability and accuracy levels of each manufacturers device.

The feature of meter calibration is common to both provers, as a result the information has been presented without identifying the prover from which it was obtained.

## 2 CALIBRATION OF METERS

Calibrations of different types of meter - turbine meters, sliding-vane type displacement meters and vortex meters were carried out using the compact provers. In each case the calibration of the meter using the compact prover was compared with the calibration using the NEL gravimetric standard. In all the tests the average meter factor, computed from a number of meter passes, normally six, was taken.

It is evident from each of these comparative calibrations that a small systematic difference exists between the two curves, arising from slight errors in the value of the base volume supplied by the two manufacturers.

The two turbine meter calibration curves (Fig. 1) are approximately parallel showing good agreement between the prover and the NEL system, with the compact prover showing slightly better repeatability than the gravimetric system.

The comparative calibrations of an Avery Hardoll 3-capsule displacement meter with a high resolution shaft encoder fitted directly to the output shaft are shown in Fig. 2. In this case the meter pulses were divided by six to overcome frequency limitations before being counted by the prover. For comparison purposes the meter factor obtained from the prover system has subsequently been divided by six. Again the calibration curves are parallel with the prover repeatability being superior, in common with other volumetric methods, to the gravimetric calibration.

However, an identical meter with a gearbox and pulse generator shows a different calibration (Fig. 3). In this case the prover calibration repeatability increases by about a factor of 10 while the repeatability obtained from the gravimetric calibration remains virtually unchanged. No evidence of hysteresis was found.

A smaller single capsule version of the previous meter was calibrated and the curves are shown in Fig. 4. Again two parallel calibration curves are

obtained, with the prover giving slightly poorer repeatability than the gravimetric system.

Finally, the comparative calibration of a vortex meter is shown in Fig. 5. Although less linear than the previous calibrations the two curves are again parallel, with the gravimetric calibration repeatability being better than the prover calibration.

### 3 SINGLE PASS REPEATABILITY

On the discovery of the anomalous repeatability behaviour described in the previous section, the technique of averaging prover passes was investigated.

The same meters were used and, at a fixed flowrate, the meter pulses from a number of passes were collected. The results are shown, for the 4-inch turbine meter, in Fig. 6, where both the meter factor from the individual passes, together with the running average of the meter factor, are shown.

The individual pass results scatter by about  $\pm 0.04$  per cent and the running average settles out after about eight passes, although even at 50 passes some fluctuations are still evident. A general decrease in average meter factor over 50 passes is also observed.

The results from the 3-capsule positive displacement meter with no gearbox are shown in Fig. 7. Here the running average of the meter factor decreases slowly for the first 50 passes before settling to a steady value. The scatter of the individual passes is about  $\pm 0.05$  per cent.

The meter fitted with a gearbox (Fig. 8) shows a scatter greater than  $\pm 0.5$  per cent on the meter factor from individual passes; the running average meter factor settles to a comparatively steady value after about 15 passes, but here the subsequent variations are still larger than those found with the meters without a gearbox.

Similar effects are observed for the smaller P.D. meter with gearbox (Fig. 9) and the vortex meter (Fig. 10), although the magnitude of the scatter is less than with the meter with gearbox case.

### 4 PULSE PERIOD MEASUREMENTS

In the previous section large variations were found in the repeatabilities of the meter factors obtained from different meters. It was also shown in Figs 1-5 that increasing the total number of pulses collected does not necessarily lead to an improvement in the repeatability. The source of this anomaly was investigated by first studying the variation in individual pulse periods obtained from the different meters.

A micro processor controlled time interval measurement counter was designed and built at NEL, allowing the measurement of the time stability of individual pulses. Up to 100 consecutive time intervals can be measured, stored and reproduced. Using this unit the variations in pulse period of four of the five meters described previously were measured.

The results from the 4-inch turbine meter are shown in Fig. 11. A distinct pattern is observed. Every eighth pulse has a significantly shorter period. Since the meter has eight blades this presumably shows that one blade is unevenly spaced on the hub. The meter shows a random fluctuation in pulse period of about 1.5 per cent with the cyclic effect being around 3 per cent. This gives a maximum scatter of about 4 per cent.

The divide-by-six circuitry was not available at the time of these tests to allow testing of the P.D. meter with the shaft encoder. The P.D. meters with gearboxes were tested, however and the results are shown in Figs 12 and 13.

Both meters show a similar pattern although the magnitude of scatter is very different. The meters show three separate effects. First, a cyclic effect with a period around 250 pulses corresponding to a revolution of the rotor inside the meter. For the large meter this has a magnitude of around 35 per cent while for the smaller meter it is around 10 per cent. The second effect is of two short periods followed by one long. This is repeated every 26 pulses, marked by \* on Figs 12 and 13, and must be due to some characteristic of the gear train. The magnitude of this effect is around 10 per cent for both meters. The third effect appears to be of a random nature with a magnitude of around 4 per cent for both meters. (The larger meter was found to have a fault which was rectified before timing tests were carried out. If this fault was present when the meter was used with the provers, it would have meant that the pulse stability was poorer during the calibrations.)

Finally the vortex meter appears to have a random pattern with a magnitude of around  $\pm 4$  per cent. The apparent cyclic effect in Fig. 14 is not constant in either period or amplitude and is not maintained in other tests.

It is clear from these results that the meter pulse period stability is the main feature to be considered when using compact provers. It is also clear that the complexity of different cyclic effects will certainly make prediction of behaviour difficult.

The reason why the pulse fluctuation has such a large effect is that so few pulses are collected when a compact prover is used, in contrast with a conventional calibration system. The effect of increasing pulse period variation appears to be to remove any advantage gained by using pulse interpolation at low numbers of collected pulses.

It is estimated that at fluctuation of around 15 to 20 per cent, pulse interpolation gives no benefit in repeatability at all. This has been confirmed by computer simulation, to be published in a separate report.

Until simultaneous calibration and timing tests are carried out, care should therefore be taken in assuming that the pulse stability reported was the same during calibration of the meters.

## 5 CONCLUSIONS AND RECOMMENDATIONS

1 Compact meter provers are extremely good volume calibrators, but have problems calibrating certain types of meters.

2 The technique of averaging results from meter passes appears to be acceptable. However it is proposed that ten passes should be the maximum number to avoid long term drift effects. Also it appears that the scatter on the averages is a factor of about eight times less than the scatter on the individual passes.

3 Meter outputs should be monitored for pulse period stability before being proved.

#### 6 FURTHER WORK

1 Meter manufacturers should be encouraged to examine their meters and to improve the stability of pulse generation without recourse to phase-locked loops.

2 More detailed guidelines should be drawn up to advise on repeatability levels as a function of pulse stability and numbers of collected pulses.

NEL has been working on this and will repeat the results given here along with correlating these with computer simulations.

3 An electronics or prover manufacturer should examine the possible design of a pulse timing monitor to provide users with the pulse variation information they require.

The sophistication required of this device will not be known however until more details of the guidelines regarding cyclic effects are known.

#### LIST OF FIGURES

- 1 Calibration of 4-inch turbine meter
- 2 Calibration of 3-capsule P.D. meter (without gearbox)
- 3 Calibration of 3-capsule P.D. meter (with gearbox)
- 4 Calibration of single capsule P.D. meter (with gearbox)
- 5 Calibration of 3-inch vortex meter
- 6 Single pass repeatability of 4-inch turbine meter
- 7 Single pass repeatability of 3-capsule P.D. meter (without gearbox)
- 8 Single pass repeatability of 3-capsule P.D. meter (with gearbox)
- 9 Single pass repeatability of single capsule P.D. meter (with gearbox)

- 10 Single pass repeatability of 3-inch vortex meter
- 11 Pulse period variation of 4-inch turbine
- 12 Pulse period variation of 3-capsule P.D. meter (with gearbox)
- 13 Pulse period variation of single capsule P.D. meter (with gearbox)
- 14 Pulse period variation of 3-inch vortex meter.

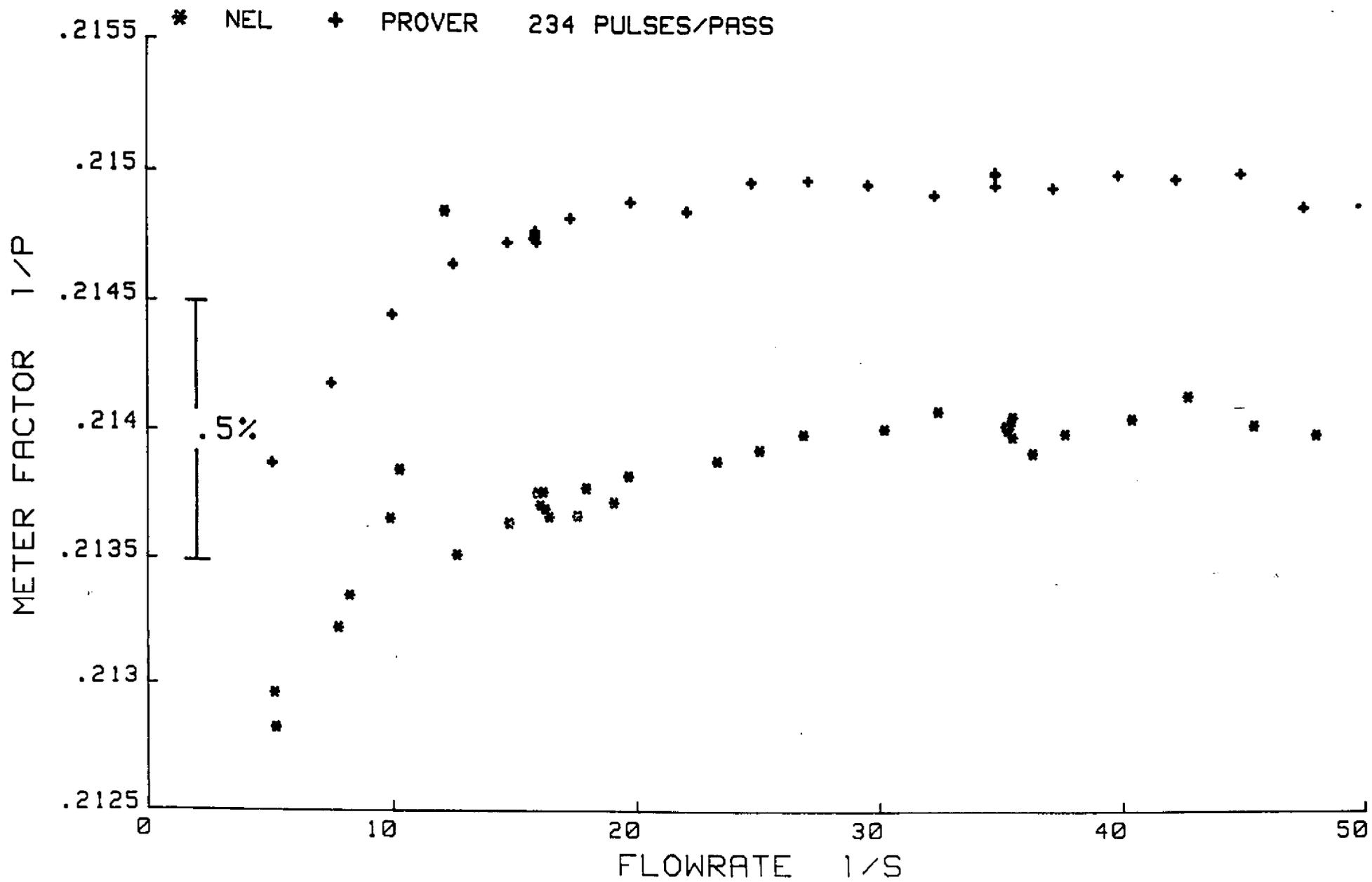


FIG 1 4 in TURBINE METER

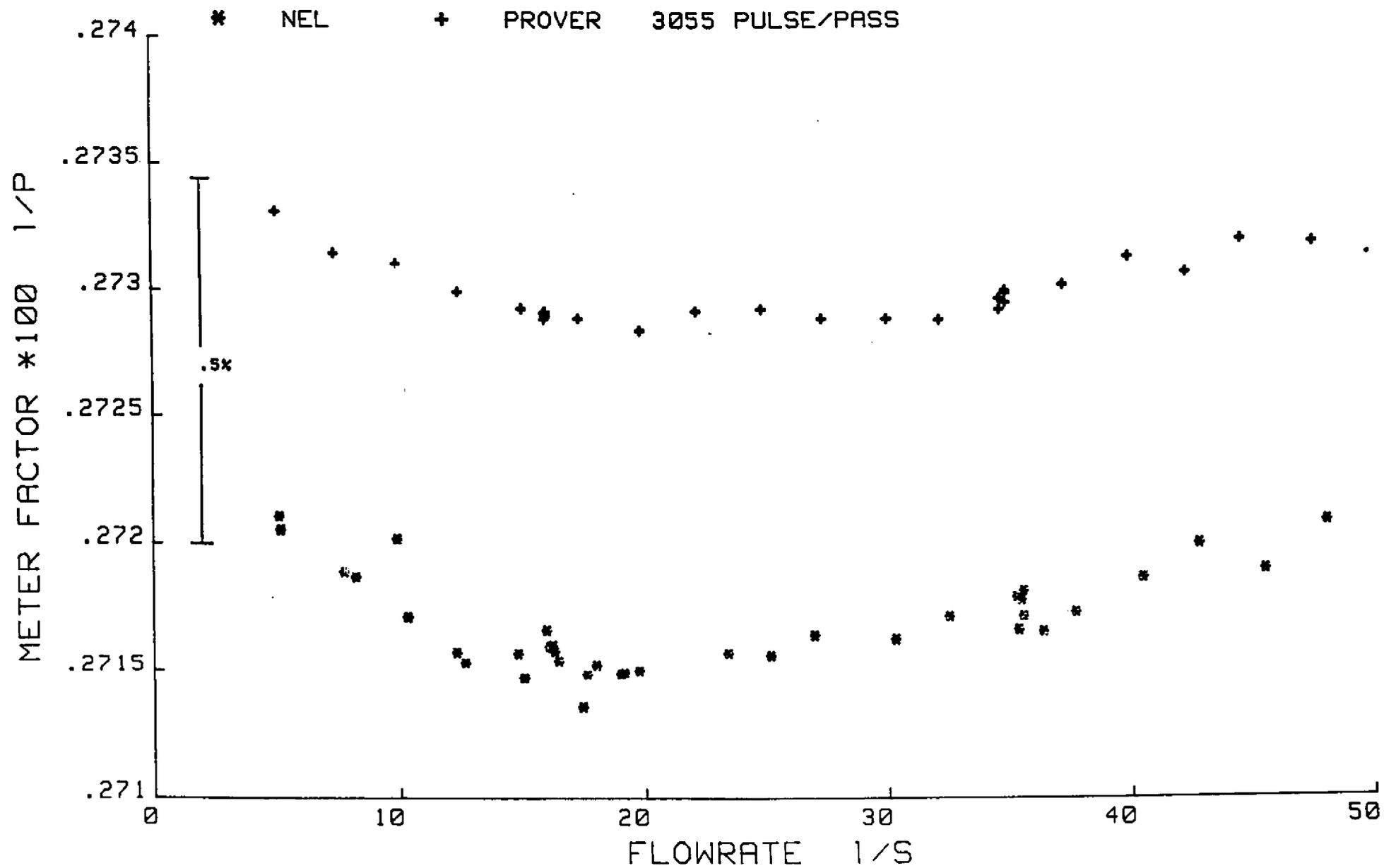


FIG 2 3 CAPSULE P.D. METER NO GEARBOX

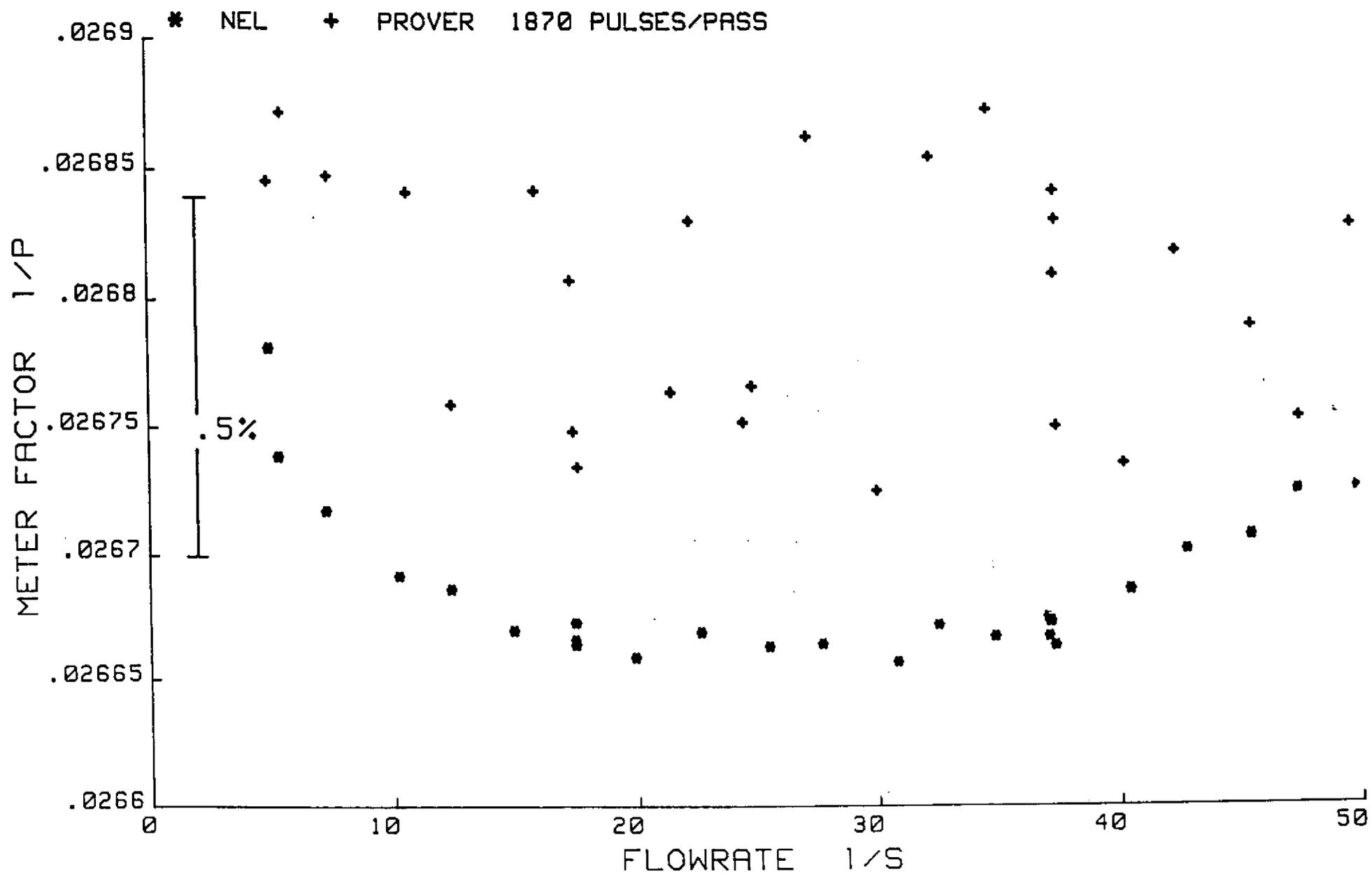


FIG 3 3 CAPSULE P.D.METER WITH GEARBOX

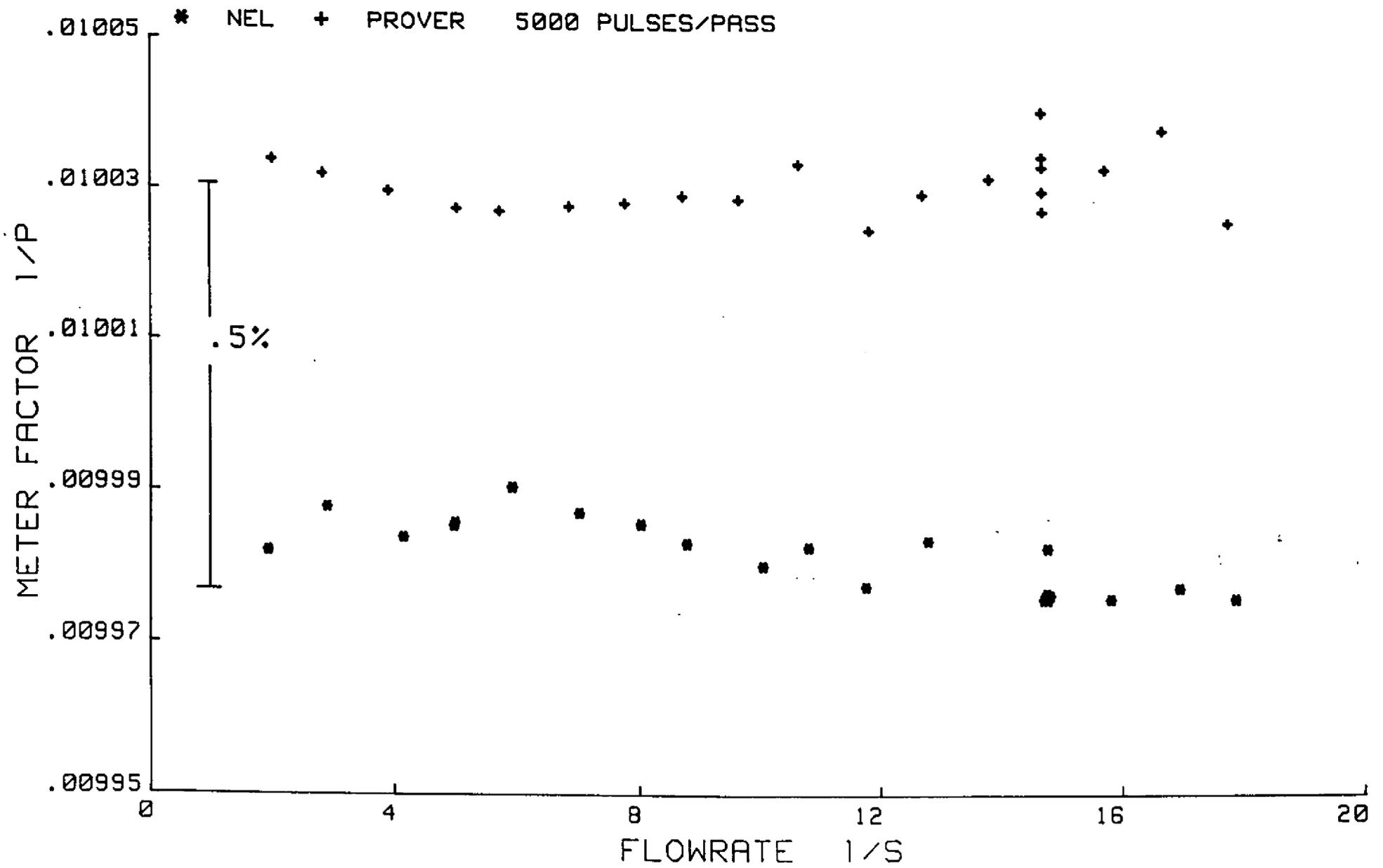
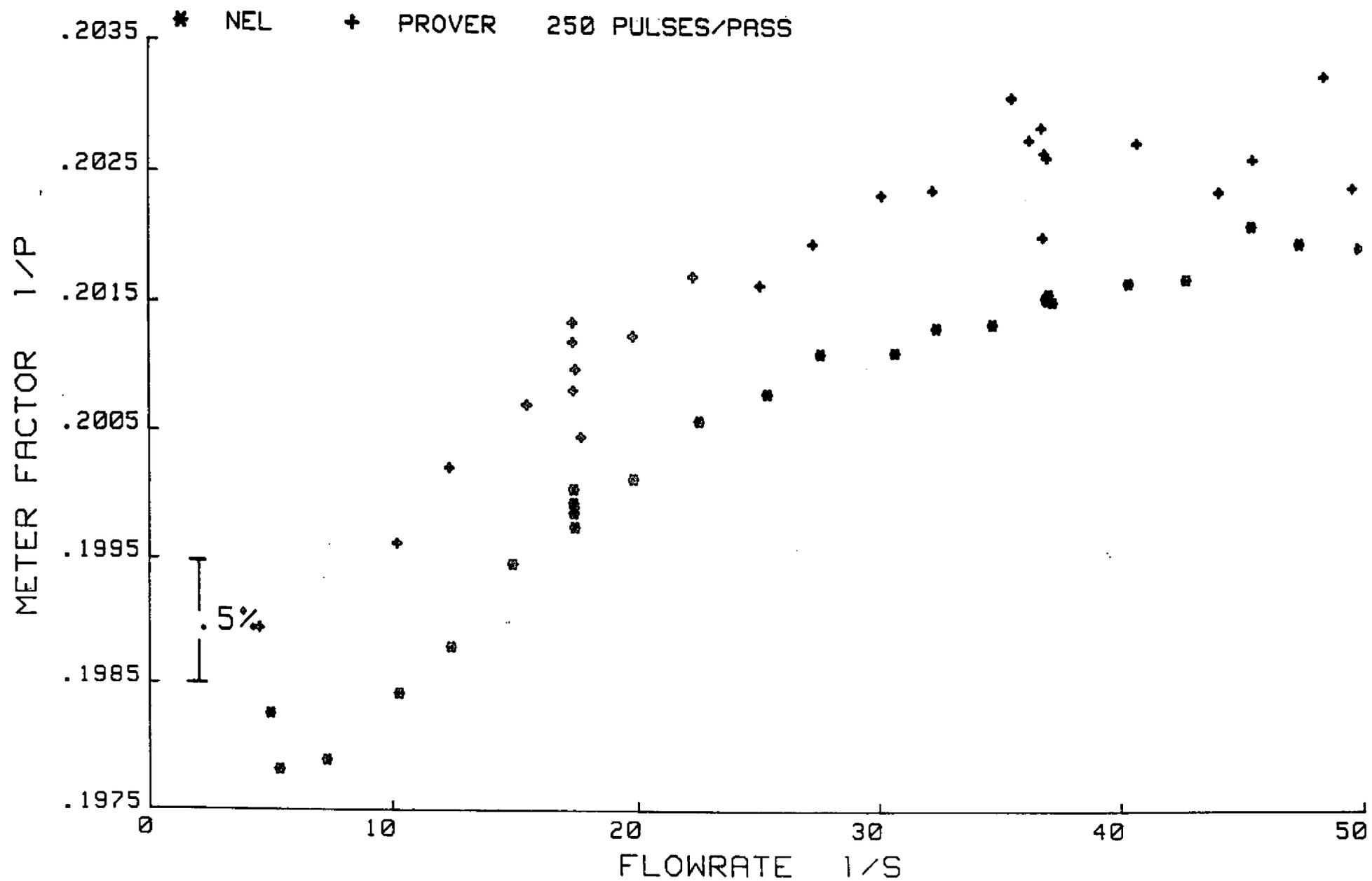


FIG 4 1 CAPSULE P.D. METER WITH GEARBOX



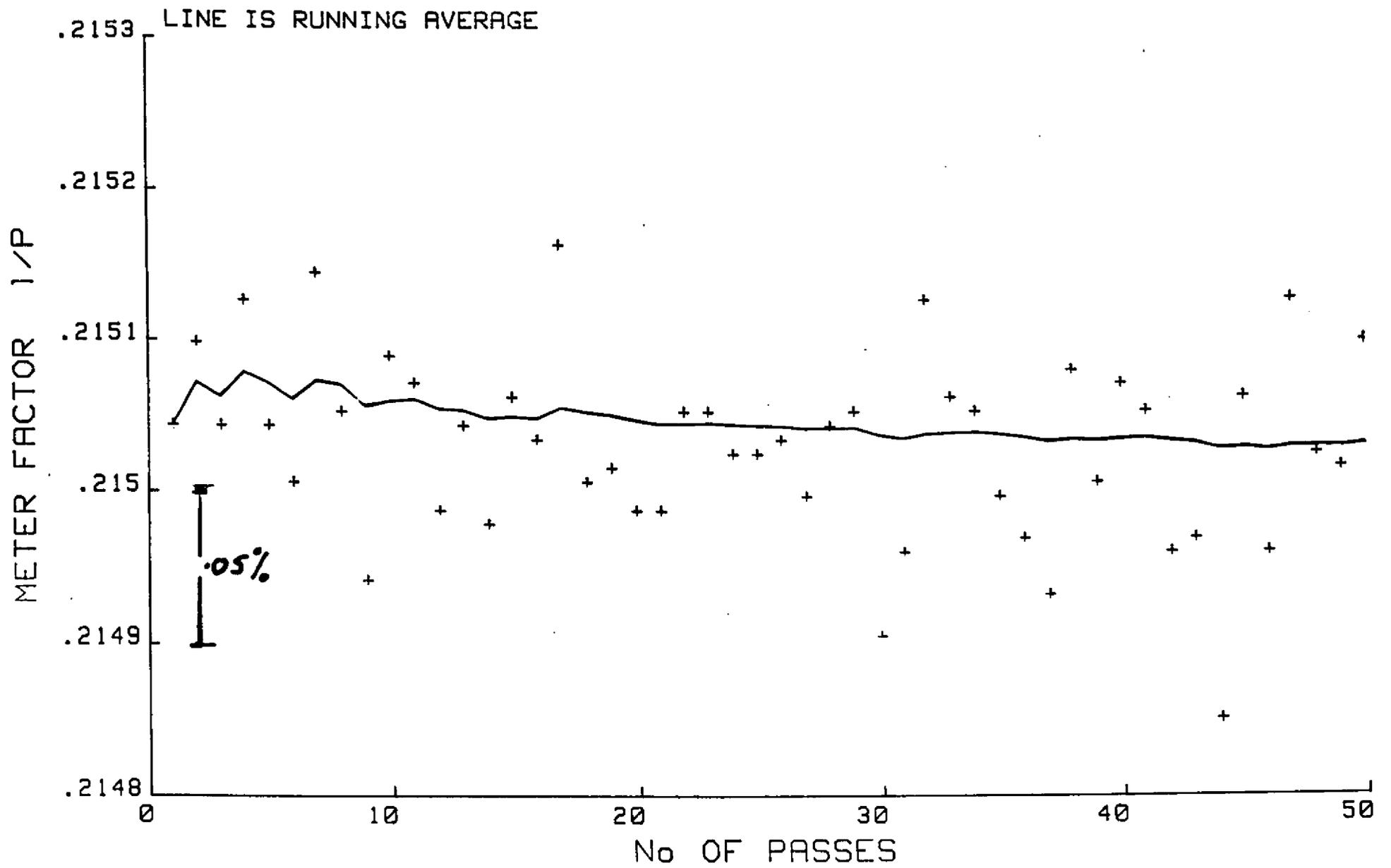


FIG 6 4 in TURBINE METER

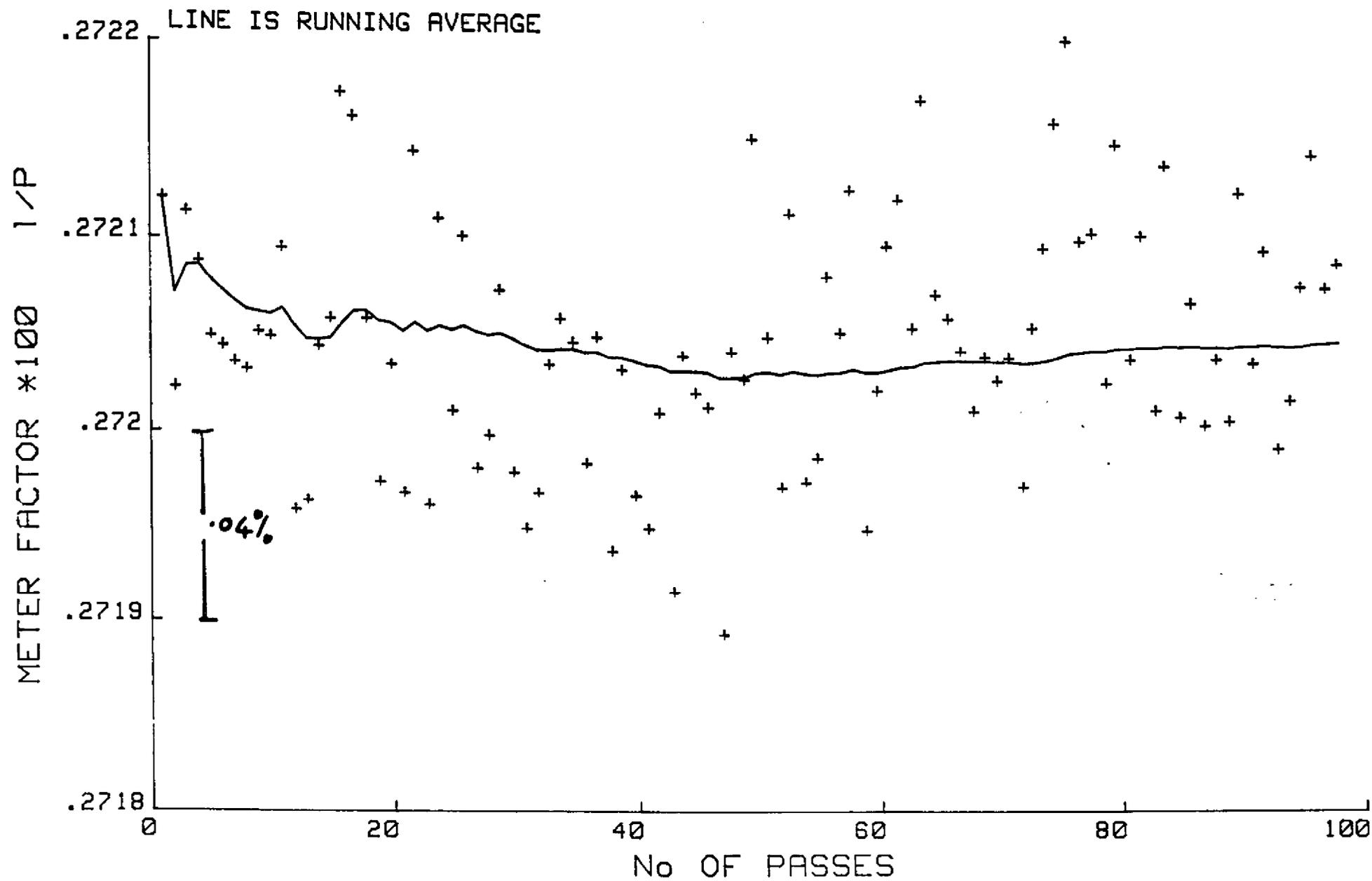


FIG 7 3 CAPSULE P.D.METER NO GEARBOX

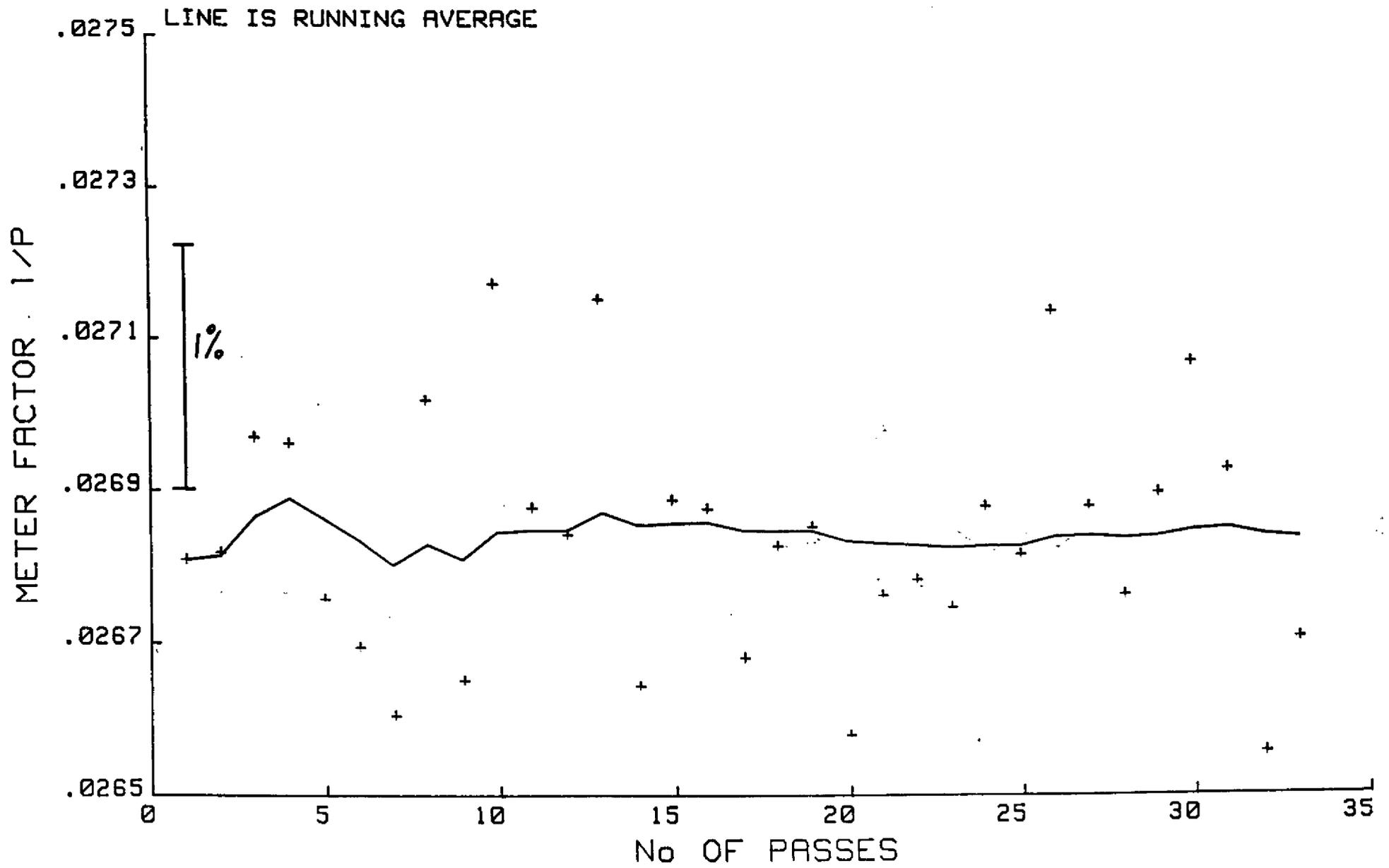


FIG 8 3 CAPSULE P.D. METER WITH GEARBOX

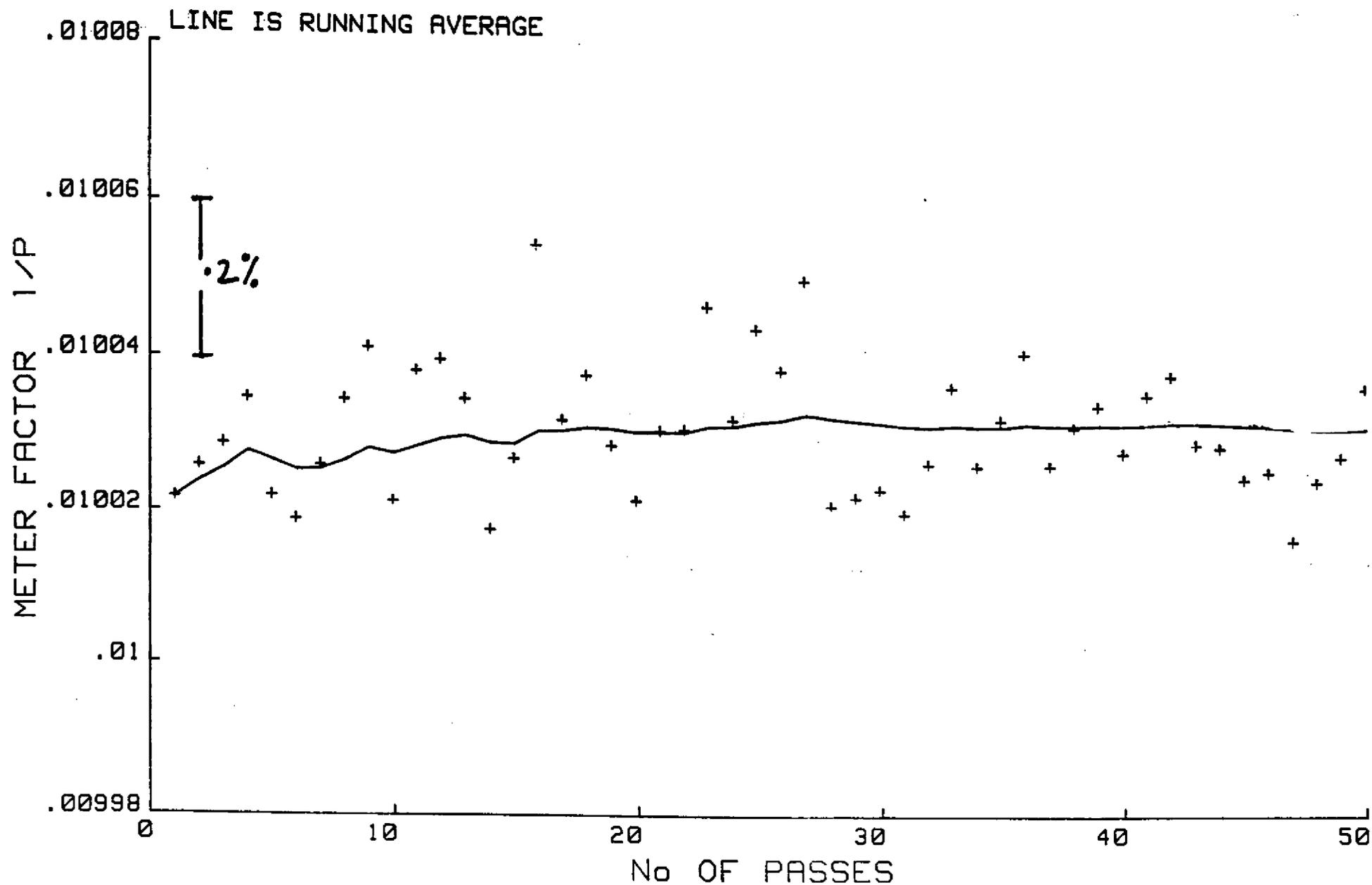


FIG 9 SINGLE CAPSULE P.D.METER WITH GEARBOX

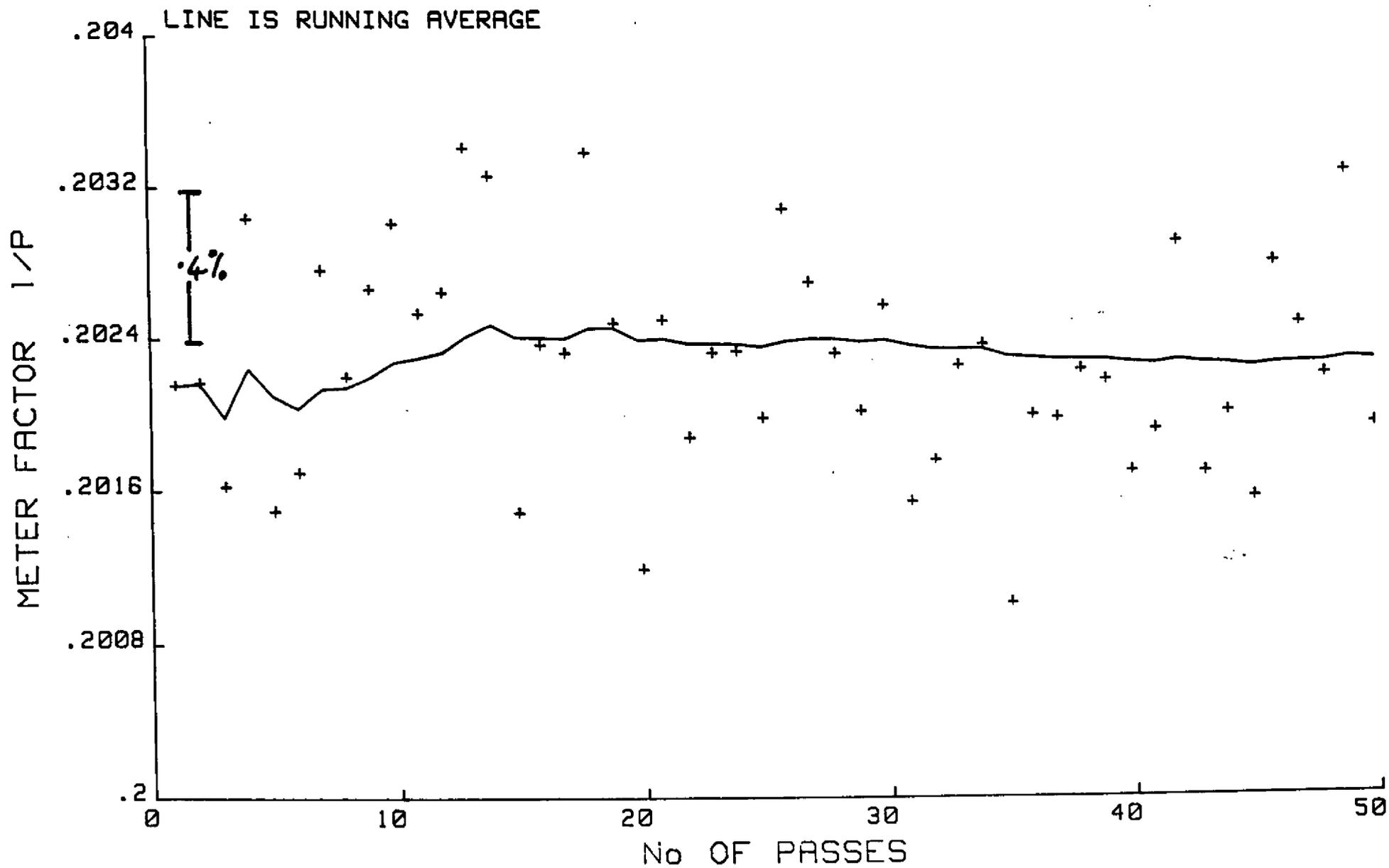


FIG 10 3 in VORTEX METER

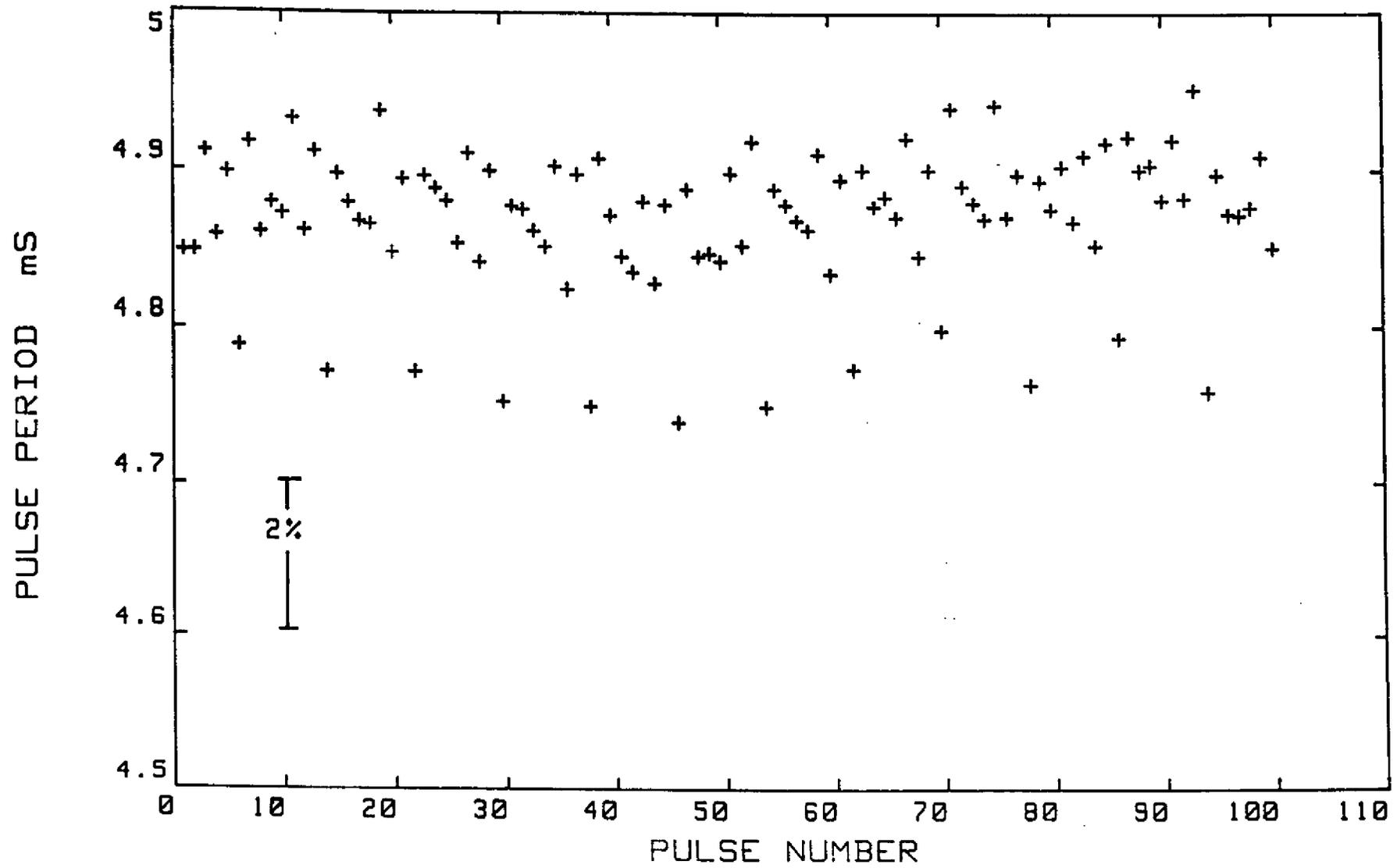


FIG 11 4 in TURBINE METER

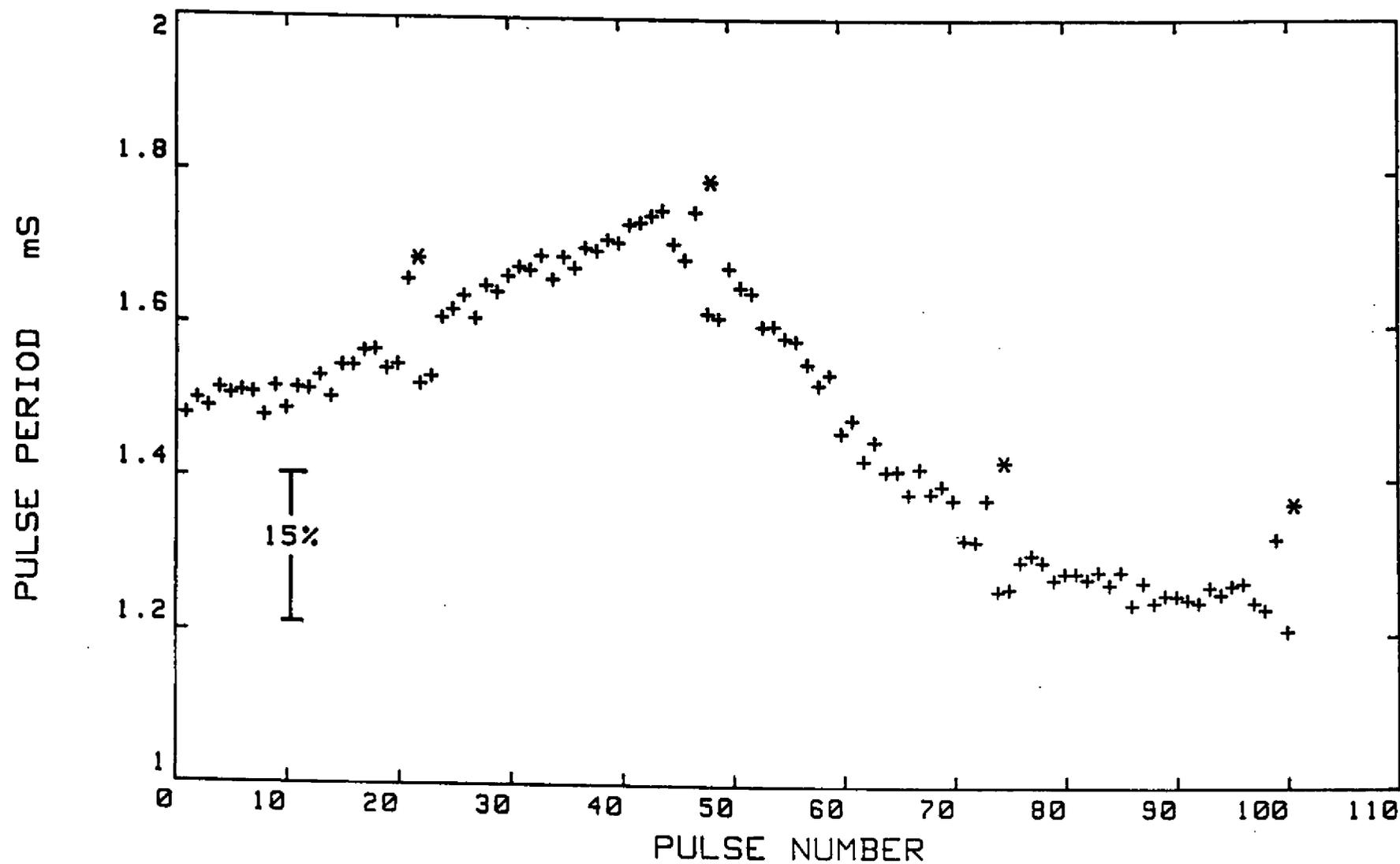


FIG 12 3 CAPSULE P.D.METER WITH GEARBOX

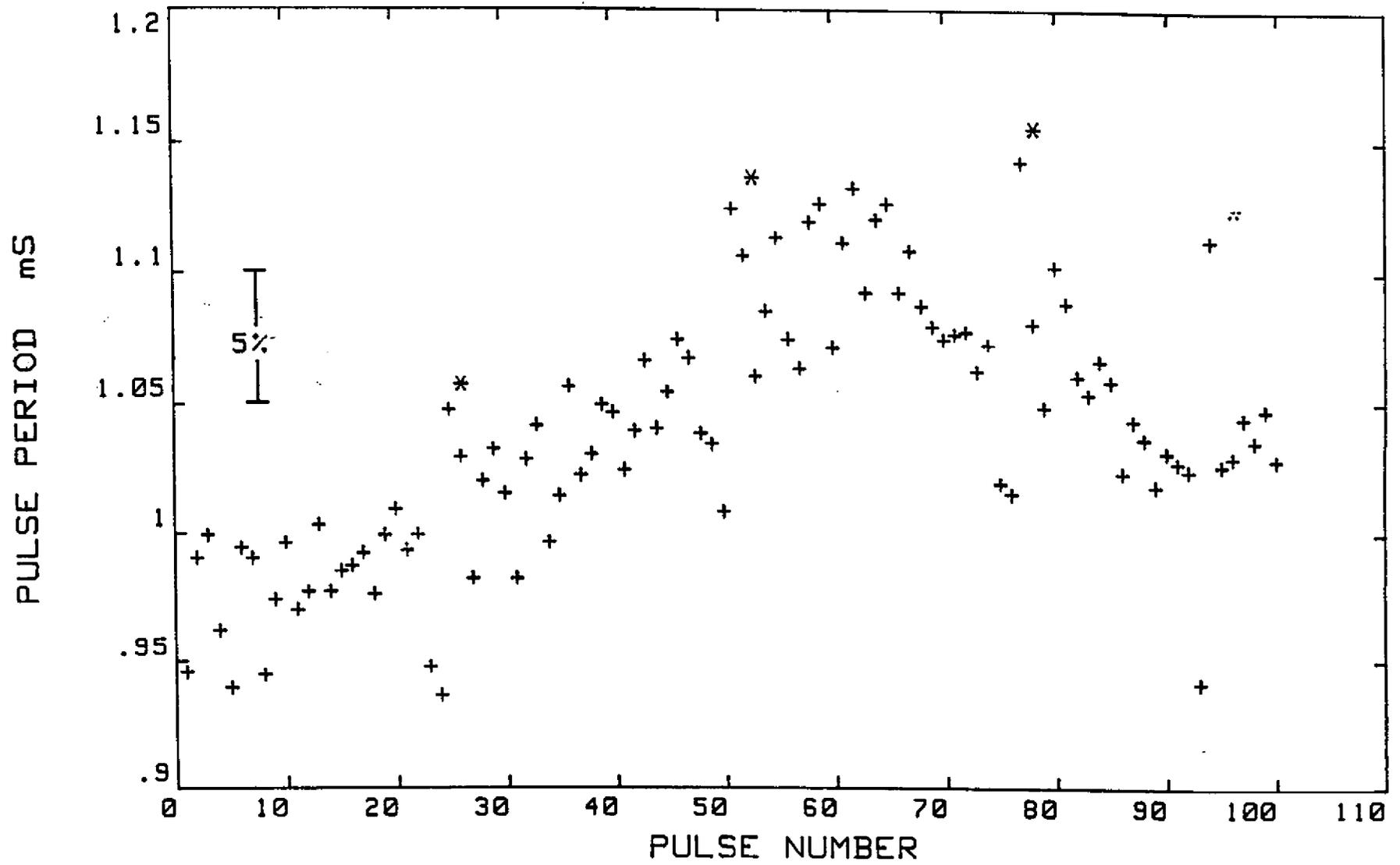


FIG 13 SINGLE CAPSULE P.D.METER

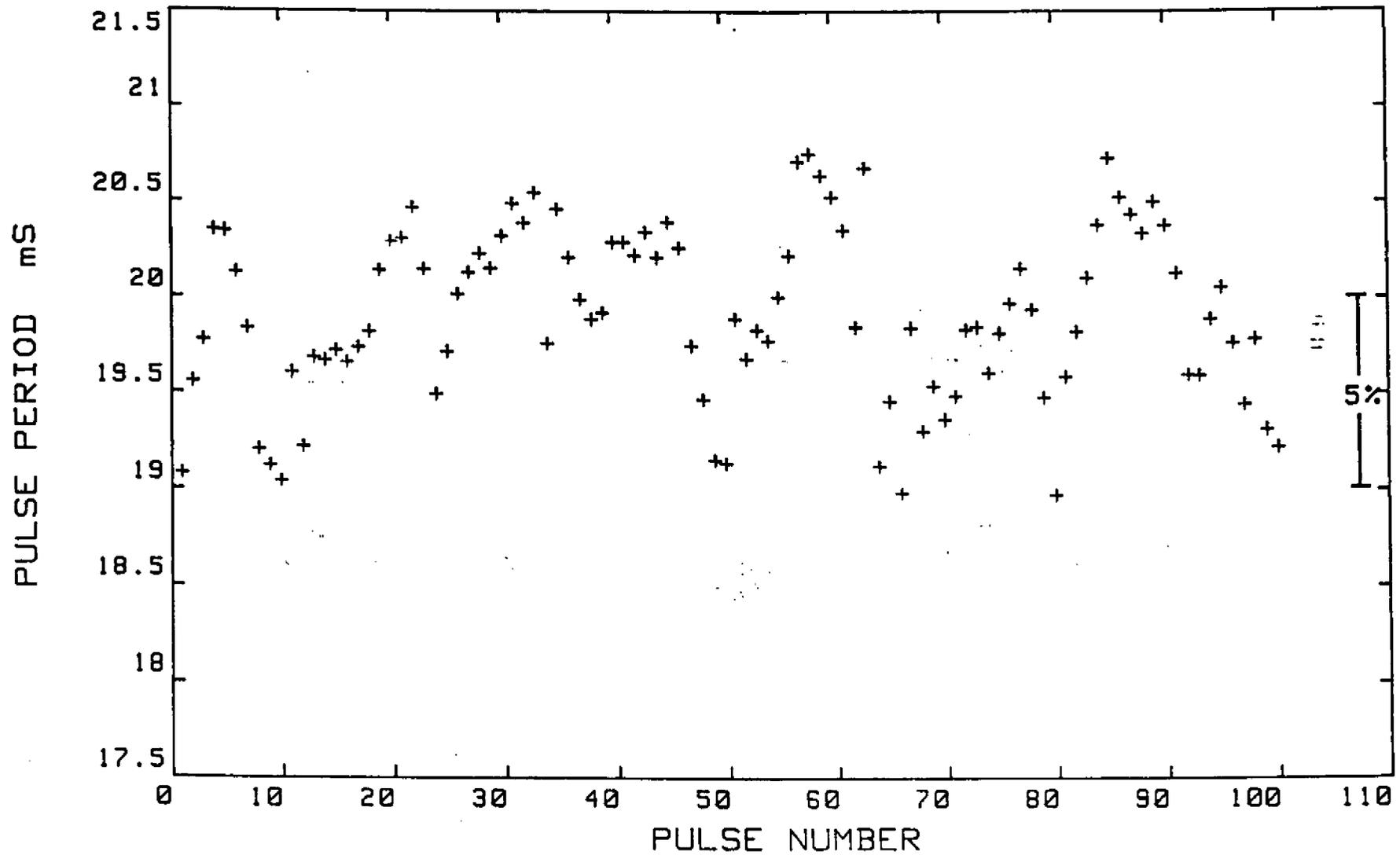


FIG 14 3 in VORTEX METER

THE RELATIONSHIP BETWEEN THE NUMBER OF PASSES AND  
THE ACCURACY OF A COMPACT PROVER

by

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Paper 5.2

NORTH SEA FLOW METERING WORKSHOP 1986

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National Engineering Laboratory  
East Kilbride, Glasgow

# THE RELATIONSHIP BETWEEN THE NUMBER OF PASSES AND THE ACCURACY OF A COMPACT PROVER

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## SUMMARY

Compact provers are becoming increasingly attractive for use within the petroleum industry. At present their use is based on practices which were devised for conventional provers and which are not necessarily the best way of utilising the newer devices. In particular the ability of the compact prover to carry out large numbers of passes in a short period of time suggests that a statistically-based approach should be adopted. This paper discusses possible alternative methods and considers the statistics involved.

## 1. INTRODUCTION

It has been accepted in the petroleum industry for many years that a meter is proved in-situ by carrying out several runs against a proving device as the reference standard; from each of these a meter factor (K-factor) is determined and the process continues until a specified number (usually 3 or 5) of successive values fall within a certain percentage range of each other. The mean of these values is then taken as the meter factor.

This approach was originally developed for use with conventional "sphere-type" provers for which each proving run involves the metering of a large amount of fluid; with the advent of the compact prover the same method has continued with the modification that each run consists of several passes, the average meter factor being taken as the value for the run. The use of multiple passes is based on the fact that most meters exhibit a certain amount of intra-rotational non-linearity (IRNL); a meter factor based on metering a small amount of fluid is therefore suspect. An idea of the magnitude of the IRNL is given by the number of passes required per proving run: for a turbine meter this is usually between 1 and 5, while a positive displacement meter will generally require between 5 and 20 passes per proving run to satisfy the same criterion.

The main cause of IRNL in a turbine meter is the mechanical tolerance between the points triggering the pulses. This effect is greater when the rotor is not shrouded. In that case the blade tips are counted and the IRNL arises from the inaccuracies in the angular positions of the blades; for a shrouded rotor the pulses are usually generated by slots or buttons which are positioned to a much tighter

tolerance with a consequent reduction in the IRNL. In either case the effect is cyclic within one rotation of the rotor, i.e. it is genuinely intra-rotational.

With a positive displacement meter the cause of the IRNL is generally the gear train between the metering element and the pulse transmitter. The main problem comes from non-concentricity between gears; with multiple gear trains and an adjusting mechanism involved, the cyclic effect can be over a long period, i.e. the non-linearity may not be truly intra-rotational.

Although the use of a set number of passes for each proving run has enabled the compact prover to be brought within the framework of the conventional proving technique it is not clear that this is the best way in which the compact prover can be utilised. Clearly the presence of the IRNL means that each pass of a compact prover cannot be used in the same way as a single run of a conventional prover: the amount of fluid metered is too small for this approach to succeed. However, each pass provides information which can be used if a more statistical approach is adopted; at present much of this information is discarded.

In the next section we shall consider three different proving techniques: the first is the current approach, the second a modification of it designed to make more use of the statistical information available and the third a more purely statistical approach which dispenses with the idea of a proving run consisting of a number of passes. (The statistical basis of Methods 2 and 3 is outlined in the Appendix.) Each method will be applied to the data given in Table 1, relating to a 6" turbine meter at a flowrate of 1690 GPM; the data are also shown graphically in Figure 1.

## 2. PROVING TECHNIQUES

### 2.1 Multiple pass runs

This is the system outlined at the start of the Introduction. Runs are carried out (each consisting of a number of passes) and the results compared until a number of consecutive runs produce sufficiently close figures; taking a range of 0.04% (i.e.  $\pm 0.02\%$ ) as acceptable this will occur when

$$\frac{\text{high} - \text{low}}{\text{mean}} \times 100 \leq 0.04 \quad (1)$$

over the chosen number of runs (usually 3 or 5). The mean calculated from these runs is then taken as the meter factor. There is flexibility in this method over the selection of the number of consecutive runs to be considered and also over the number of passes per run. It is the latter factor which we shall consider.

#### 2.1.1 Method 1: fixed number of passes

One way of establishing the appropriate number of passes per run would be to estimate all the uncertainties involved in the proving

operation, including that due to the IRNL. Adding these in quadrature (root-sum-square method) gives the total uncertainty in the measured meter factor on each pass. The number of passes can then be selected to reduce this uncertainty to an acceptable level. This number of passes will then be sufficient to prove any meter for which the uncertainties fall within the assumed values.

Adopting this approach is possible but its value is totally dependent on the validity of the assumptions which have to be made. The IRNL is particularly difficult to estimate because although it may be regarded as part of the prover's uncertainty (owing to the small volume) its size cannot be estimated from test runs on other meters. In general it is unlikely that the use of data involving various meters can be used to provide useful estimates of the uncertainties. Such estimates can really only be used as 'worst case' figures because of the difficulty in assessing how much of the uncertainty comes from other sources, for which only upper bounds are known. Only if the total uncertainty in the results is within limits which are acceptable for the prover itself can these data be used to justify the general use of a particular number of passes per proving run.

The simplest application of this approach is to use a number of passes based on experience with the particular types of meter and prover being used, say 5 passes per run for a turbine meter and 10 for a positive displacement meter. Although this approach is very simplistic it does hold good for the majority of such meters. The disadvantage is that it ignores the inherent statistical nature of the operation because

(i) no account is taken of the number of runs carried out before achieving the ones which are sufficiently close,

and (ii) the resulting K-factor is presented with an indication of the spread of the figures from the final runs but this is not expressed in the more meaningful form of confidence levels.

Applying this method to the data in Table 1, based on 3 successive runs being within a range of 0.04%, yields a K-factor of 22.42912 with a range of  $\pm 0.011\%$ .

#### 2.1.2 Method 2: number of passes calculated using standard deviation

The second method of estimating the number of passes required per run is to take the prover to the meter and carry out a 'large' number of exploratory passes (20 should be sufficient). On the basis of the data thus gained it will be possible to calculate the number of passes needed per proving run to satisfy the appropriate criterion.

Once established, this number could be entered on the meter control sheet and used for future provings; it is, however, preferable to carry out the whole procedure on each occasion so that any decline in meter and/or prover performance can be detected.

Two advantages arise from this method. Firstly, it involves no assumptions about the size of the IRNL of the meter being proved (or indeed about any other meter, prover or system uncertainties) for which the appropriate adjustment is automatically made. Secondly, it gives an early indication if excessive uncertainties are present, whatever their source; the statistics of the initial exploratory passes indicate this in a way which will be discussed later in this section.

The method for estimating the number of passes indicated above is based on conventional statistical calculations, the details of which are contained in the Appendix. If  $e_{acc}$  is the acceptable error for the meter factor from each proving run, expressed as a proportion of the actual meter factor (percentage error =  $100 \times e_{acc}$ ), we find from (A9) that the number of passes per run can be taken as the smallest integer  $M$  for which

$$m > \left\{ \frac{\hat{s}_n t_{n-1, .975}}{e_{acc} \bar{X}_n} \right\}^2 \quad (2)$$

Here  $\bar{X}_n$  is the mean meter factor from the  $n$  initial passes,  $\hat{s}_n$  is the corresponding estimate for the standard deviation (given by (A2)), and  $t_{n-1, .975}$  is the appropriate percentage point of the Student's- $t$  distribution with  $n-1$  degrees of freedom.

Applying this method to the data of Table 1 we find that  $\bar{X}_{20} = 22.42954$  and  $\hat{s}_{20} = 0.0084913$ ; if the acceptable percentage error is  $\pm 0.02\%$  we require, from (2), the smallest  $m$  greater than

$$\left\{ \frac{0.0084913 \times 2.093}{0.0002 \times 22.42954} \right\}^2$$

This results in 16 passes per proving run. Carrying out the proving runs then generates a K-factor of 22.42947 with a range of 0.006%.

[Note: To provide sufficient data values the original 20 have been repeated. In practice the initial set of passes would not form part of the proving runs at all.]

Although this technique will always provide a number of passes to be used, it is possible that the uncertainties present in meter, prover and system may be too great for proving to the required accuracy to be worthwhile. The question arises: how should such a problem be recognised? Excessive total uncertainty corresponds to  $s$ , and thus  $\hat{s}_n$ , being large. If the acceptable limit on  $s$  is given as  $s_{acc}$  (expressed as a proportion of the correct meter factor), we can be confident that  $s$  is not excessive if

$$\left| \frac{\hat{s}_n}{\bar{X}_n} \right| < s_{acc} \quad (3)$$

It is important to recognise the distinction between  $e_{acc}$  and  $s_{acc}$ . The first is the accuracy to which the meter factor is required, the second indicates the level of overall repeatability of the meter, prover and system which is regarded as acceptable. In fact  $s_{acc}$  is likely to depend on  $e_{acc}$ : a greater uncertainty can be tolerated if lower accuracy is required.

Using the data from Table 1 we find that

$$\frac{\hat{s}_{20}}{\bar{X}_{20}} = 0.000378576 .$$

Thus the overall repeatability corresponds to a standard deviation of about 0.038% of meter factor. It may well be that this is not small enough to make it worthwhile proving the meter to an accuracy much higher than that chosen above, but the appropriate cut-off level would depend in part on the use which was to be made of the meter.

A precis of the approach is therefore:

- 1) Obtain data from 20 passes
- 2) Calculate the standard deviation estimator  $\hat{s}_{20}$
- 3) Calculate the average K-factor  $\bar{X}_{20}$
- 4) Check that the total uncertainty is acceptable
- 5) Calculate the number of passes required per proving run
- 6) Carry out the proving runs.

## 2.2 Individual passes

### 2.2.1 Method 3: running evaluation of meter factor

In the previous method use was made of statistical information from a number of passes to refine the existing method of meter proving. However, the use of runs, each consisting of several passes, is really not necessary at all and has only arisen so that the compact prover can be used in a similar way to the conventional prover. With a microprocessor to carry out the statistical calculations there is no reason why a series of passes should not be carried out, continuing until the average meter factor can be claimed to be sufficiently accurate at the required confidence level, i.e. until after  $n$  passes

$$\frac{\hat{s}_n t_{n-1, .975}}{\sqrt{n} \bar{X}_n} \leq e_{acc} \quad (4)$$

where  $e_{acc}$  is again expressed as a proportion of meter factor. As indicated for Method 2, the value of  $\hat{s}_n/\bar{X}_n$  gives the uncertainty of the meter, prover and system; the proving can then be abandoned if  $\hat{s}_n$  is too great.

Applying this technique to the sample data, aiming at an acceptable error ( $e_{acc}$ ) of  $\pm 0.02\%$  of meter factor, yields the following results:

n	K-factor	$\bar{X}_n$	$100 \times \frac{\hat{s}_n}{\bar{X}_n}$	$100 \times \frac{\hat{s}_n t_{n-1, .975}}{\sqrt{n} \bar{X}_n}$
1	22.4381			
2	22.4238	22.43095	0.04508	0.40502
3	22.4334	22.43177	0.03249	0.08072
4	22.4275	22.43070	0.02818	0.04485
5	22.4276	22.43008	0.02518	0.03126
6	22.4137	22.42735	0.03737	0.03922
7	22.4401	22.42917	0.04031	0.03728
8	22.4291	22.42916	0.03732	0.03120
9	22.4309	22.42936	0.03501	0.02691
10	22.4330	22.42972	0.03340	0.02389
11	22.4211	22.42894	0.03374	0.02267
12	22.4259	22.42868	0.03241	0.02059
13	22.4326	22.42898	0.03140	0.01898

At this point the current value of  $X_{13}$  would be taken as an acceptable estimate of the K-factor.

### 3. COMPARISON OF RESULTS

Applying the three methods to the test data in Table 1 for a 6" turbine meter resulted in:

Method 1 : 22.42903 (range 0.011%)  
 Method 2 : 22.42947 (range 0.006%)  
 Method 3 : 22.42898 ( $\pm 0.02\%$  at 95% confidence level).

These agree to within 0.0022%.

Table 2 contains data from a 4" positive displacement meter with a pulse transmitter mounted above the accuracy adjuster in the conventional manner; the data are plotted out in Figure 2. Applying the different methods gives:

Method 1 : 39.88164 (range 0.013%)  
 Method 2 : 39.88305 (range 0.005%)  
 Method 3 : 39.88193 ( $\pm 0.02\%$  at 95% confidence level)

These agree to within 0.0035%. [Note: Only 3 successive runs have been used for Methods 1 and 2, and 5 passes per run for Method 1.]

The question remains: what happens when an attempt is made to prove a 'bad' meter. Table 3 gives data from a 6" positive displacement meter in which the coupling between meter and off-take has been deliberately off-set to give a high IRNL. Using Method 1 we find that the meter can only be proved easily if a very large error range is acceptable. (There are insufficient data for a more specific statement to be made.) Method 2 indicates that 1355 passes per proving run would be necessary for a range of 0.04%: this is a clear

indication of trouble. Method 3 fails to produce a result within 20 passes unless an accuracy as large as  $\pm 0.2\%$  is given. Methods 2 and 3 also give a standard deviation estimate of 0.35% of meter factor: this would undoubtedly be regarded as excessive, indicating problems with meter, prover or system, and proving would not continue.

#### 4. CONCLUSIONS

Three methods of meter proving using a compact prover have been considered. The first is the current practice of using a standard number of passes (5 or 10) per proving run and continuing until successive runs are sufficiently close to satisfy an acceptance criterion. This procedure will generally work but involves throwing away a lot of valuable statistical information.

Either of the alternative methods discussed takes more account of the statistics of the operation. Method 2 represents a compromise between a strictly statistical approach and the existing practice: the result is still obtained and expressed conventionally, but the number of passes used per run is determined statistically. Additionally, a check is made to ensure that the combined repeatability of the meter, prover and system lies within acceptable bounds before the proving runs are conducted. This gives greater confidence that the final result is meaningful. Method 3 dispenses with the idea of proving runs comprising a number of passes, and simply uses the outcome of each pass directly. By this technique the proving time is reduced to a minimum, the repeatability is checked and the result can be presented in terms of an error bound and its associated confidence level. It is felt that, given the nature of the proving operation, this would be a more satisfactory approach. The use of such a method (or Method 2 if the number of passes per run is calculated afresh before each subsequent proving) requires a microprocessor to carry out the calculations involved but the program would be a simple one, incorporating a look-up table for the Student's-t values, and this is not seen as a problem.

The statistics presented in this paper are based on the assumption that successive passes can be regarded as independent, normally distributed random variables. However, Figures 1 and 2 both suggest an underlying periodicity which is not accounted for in the statistics; this has also been observed in other sets of data. The effect of this is that the theory tends to overestimate the number of passes required per proving run when Method 2 is adopted because the periodicity causes the mean K-factor to settle down more quickly than would otherwise be the case. As far as Method 3 is concerned it is unlikely that the periodicity would have a detrimental effect unless the complete set of passes occupied less than one or two periods of the oscillation.

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## APPENDIX

This appendix contains the statistical basis for the discussion in the main text. It is assumed that the meter factor found from a single pass can be regarded as a normally-distributed random variable with mean  $\mu$  (equal to the correct meter factor) and standard deviation  $s$  (corresponding to a variance of  $s^2$ ); the passes are assumed to be statistically independent.

From  $n$  passes, estimators can be computed for  $\mu$  and  $s$ , given by

$$\bar{X}_n = \frac{1}{n} \sum_{i=1}^n X_i \quad (A1)$$

and

$$\hat{s}_n^2 = \frac{1}{(n-1)} \sum_{i=1}^n (X_i - \bar{X}_n)^2, \quad (A2)$$

from which

$$\frac{(\bar{X}_n - \mu) \sqrt{n}}{s} \sim N(0,1) \quad (A3)$$

and

$$\frac{(n-1) \hat{s}_n^2}{s^2} \sim \chi_{n-1}^2 \quad (A4)$$

$N(0,1)$  is a normal distribution with mean 0 and standard deviation 1,  $\chi_{n-1}^2$  is a chi-squared distribution with  $n-1$  degrees of freedom.

For Method 2, we consider an initial set of  $n$  passes followed by proving runs of  $m$  passes each, where  $m$  is determined from the initial set. Combining (A3) and (A4), with  $m$  replacing  $n$  in the former, we find

$$\frac{(\bar{X}_n - \mu) \sqrt{m}}{\hat{s}_n} \sim t_{n-1} \quad (A5)$$

where  $t_{n-1}$  is the Student's- $t$  distribution with  $n-1$  degrees of freedom.

We can therefore be 95% confident that

$$\left| \frac{\bar{X}_m - \mu}{\mu} \right| < \frac{\hat{s}_n t_{n-1,.975}}{\sqrt{m} |\mu|} \quad (A6)$$

Now  $\mu$  is not known but we have an estimate for it, given by (A1). The error introduced by substituting this for  $\mu$  in the above expression is small and we can be effectively 95% confident that

$$\left| \frac{\bar{X}_m - \mu}{\mu} \right| < \frac{\hat{s}_n t_{n-1,.975}}{\sqrt{m} |\bar{X}|} \quad (A7)$$

Thus  $m$  can be chosen on the strength of the initial set of  $n$  passes to be the smallest integer  $m$  for which

$$\frac{\hat{s}_n t_{n-1,.975}}{\sqrt{m} |\bar{X}_n|} < e_{acc} \quad (A8)$$

$$\Rightarrow m > \left\{ \frac{\hat{s}_n t_{n-1,.975}}{e_{acc} \bar{X}_n} \right\}^2 \quad (A9)$$

where  $e_{acc}$  is the acceptable error in the meter factor calculated from each proving run, expressed as a proportion of the actual meter factor (percentage error =  $100 \times e_{acc}$ ).

For Method 3 the passes are considered individually and the statistical calculation updated after each one. Identical reasoning to that above shows that after  $n$  passes we can be effectively 95% confident that

$$\left| \frac{\bar{X}_n - \mu}{\mu} \right| < \frac{\hat{s}_n t_{n-1,.975}}{\sqrt{n} |\bar{X}_n|} \quad (A10)$$

Once the term on the right of (A10) falls below a predetermined accuracy figure we can be confident that the running average to that point is satisfactory as an estimate of the meter factor.

TABLE 1

6" turbine meter

Pass No	K-factor
1	22.4381
2	22.4238
3	22.4334
4	22.4275
5	22.4276
6	22.4137
7	22.4401
8	22.4291
9	22.4309
10	22.4330
11	22.4211
12	22.4259
13	22.4326
14	22.4247
15	22.4339
16	22.4397
17	22.4091
18	22.4426
19	22.4285
20	22.4355

TABLE 2

4" p.d. meter

Pass No	K-factor
1	39.8617
2	39.8629
3	39.8878
4	39.9080
5	39.8749
6	39.8693
7	39.9042
8	39.8810
9	39.8649
10	39.9020
11	39.8850
12	39.8703
13	39.8954
14	39.8959
15	39.8613
16	39.8875
17	39.8888
18	39.8739
19	39.8748
20	39.9110

TABLE 3

6" p.d. meter (misaligned)

Pass No	K-factor
1	100.1371
2	99.5347
3	99.9230
4	100.0872
5	100.4572
6	100.5970
7	100.4058
8	100.4318
9	99.5435
10	99.7330
11	99.6846
12	100.3115
13	100.0221
14	100.4590
15	100.2056
16	100.7953
17	100.2924
18	99.9690
19	100.0084
20	100.4572

FIGURE 1: 6" TURBINE METER

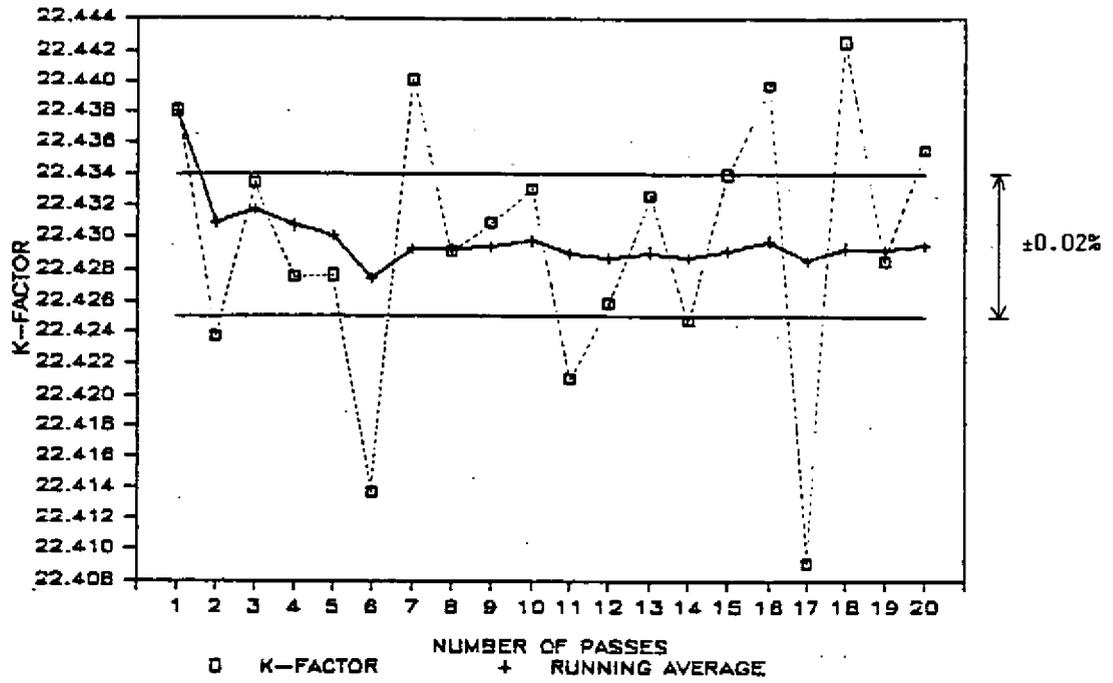


FIGURE 2: 4" PD METER

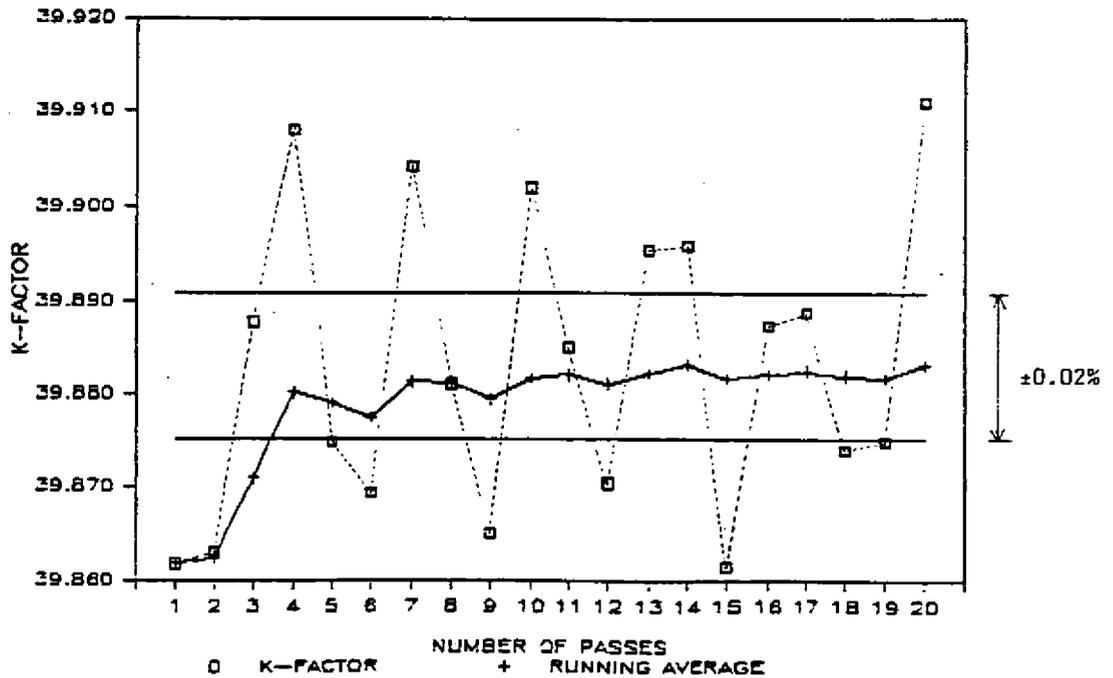


FIGURE 3: 6" PD METER (MISALIGNED)

