North Sea FLOW Measurement Workshop

1988

Paper No	Paper Title	Author Details	Company	Page
1	Field Experience with Flare Gas Meters	Svein Louis Bersaas	Statoil	3
2	A New Gas Density Meter with Reduced Velocity of Sound Effect	J W Stansfield Pieter M A van der Kam	Schlumberger Industries Nederlandse Gasunie	15
3	The EC Nozzle Transfer Package: A Flow Standard for High-Pressure Gas	Jos G M van der Grinten	Netherlands Measurement Institute	21
4	Field Experience with Flare Gas Meters	Gudmund Lindland	Phillips Petroleum Co	46
5	Computer Concepts Data Security and Availability	Marius Wulffers	HCS	56
6	The KO210 Flow Metering Control System	Nils E. Standal	Kongsberg Offshore A/S	60
7	Measuring the Flow of Wet Gas	Greg Washington	KSPEL	75
8	Pipeline Oil Analysis for Allocation oat Ecofisk	Oddfin Thowsen	Phillips Petroleum Co	92
9	Sampling of High Vapour Pressure Liquid	Tom Welker	Welker Engineering Company	106
10	Full Bore Continuous BS&W Measurement and Fiscal Metering	Jon Gjedebo Bjørn G. Bjørnsen Scott Gaisford	Hitec AS Statoil FMS	107
11	Field-Based Water-in-Oil Sampling Studies	Nicholas W. King	National Engineering Laboratory	124
12	Experience of Monitoring Oil Measurement System Performance	T J Hollett & C J Stevenson	Phillips Petroleum Co Norway	150

North Sea FLOW Measurement Workshop

1989

FIELD EXPERIENCES WITH ULTRASONIC FLARE GAS METER AT THE STATPIPE GAS TERMINAL, KÅRSTØ AND AT THE GULLFAKS-B PLATFORM IN THE NORTH SEA.

BY

SVEIN LOUIS BERSAAS
TRANSPORT DIVISION
STATOIL A/S
KÅRSTØ, NORWAY

10.10. 1989

Why ultrasonic flare gas meter at the Statpipe Gas Terminal?

Problem:

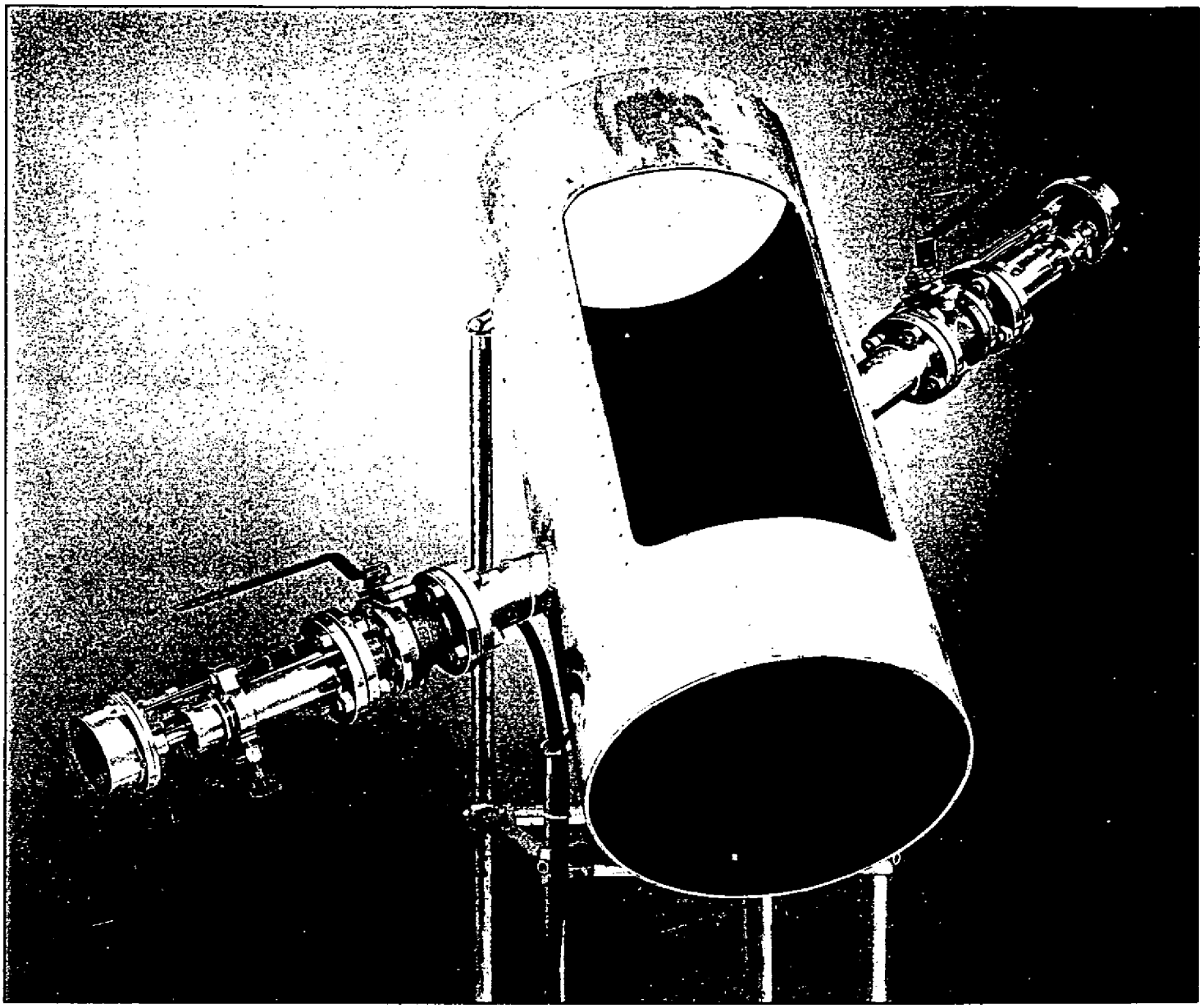
The existing annubar flowmeter with the calculated range of 30.000 - 640.000 Kg/h did not satisfied the necessary range of 200 to 250.000 KG/h as "normal" flaring.

Solution.

The ultrasonic flare gas meter FGM 100 satisfied the required low and middle range 200 - 250.000 Kg/h

The annubar meter will still measure the upper part of the range.

The expected low maintenance cost is also an advantage.



The Fluenta FGM 100 flare gas meter measures volume flowrate and mass flowrate in flare pipes

The Fluenta FGM 100 flare gas meter has been designed to solve difficult measuring problems in flare gas pipes, with low pressure, a wide range of velocities and large pipe diameters.

The FGM 100 Flare gas meter uses the transit time to measure the flare gas velocity. Two specially designed transducers are mounted non-intrusively in the pipe wall. Each transducer transmits and receives ultrasonic pulses, and the electronic system measures the time the pulse needs to travel from one transducer to the other. An unique technique is used to recognise the pulses and measure the transit time.

With a gas flow in the pipe, the pulse travelling against the flow will need longer pulse travelling with the flow. This time difference is used to find the gas velocity, and to calculate the volume flow in the flare gas pipe.

The signals are repeated 100 times per second. The measurements are averaged every two or four seconds, to give a steady meter reading and output.

For the system to be able to give readings in standard cubic meters (Sm^3), signals for temperature and pressure must be given to the flow computer. These signals combined with information about estimated sound velocity are also used in calculation of the gravity of the gas.

Installation

Fluenta A/S has transducer-mounting jigs for several pipe diameters. Transducer adaptors are welded to the pipe at precise angles for optimal pulse transmission.

References

The FGM 100 has been developed by the Chr. Michelsen Institute in Bergen, Norway and the project was sponsored by Mobil and Statoil. It has been installed on platforms in the North Sea as well as on a petrochemical plant. Extensive testing at the Gullfaks B has shown a much better accuracy than the one

Fluenta FGM 100 technical specifications

General

Mains supply:	220 V AC/110 V AC 50/60 Hz
Power consumption:	50 VA max.
Pipe sizes:	8" dia. min., 72" dia max.
Velocity range:	0.05 – 70 m/s for 72" dia. pipe 0.05 – 100 m/s for 36" dia. pipe 0.20 – 100 m/s for 8" dia. pipe
Uncertainty at 95% confidence level:	5% of measured value at fully developed turbulent flow conditions.
Resolution:	Velocity: 0.01 m/s for 36" dia. pipe
Repeatability:	Better than 1% of volume flow (with velocity from 0.3 – 100 m/s).
Calibration:	0.3 – 70 m/s with fully developed turbulent flow profile.

Front panel

Mounted in 19" rack, with:
16-character alphanumeric LED display and
29-key data entry/function keyboard.
2-channel recorder (3-ch. optional).
8-digit electro-mechanical counter.

Display functions:	
Volume flowrate	(Sm3/hr)
Total volume	(Sm3 x resolution)
Mass flowrate	(kg/hr)
Total mass	(kg)
Temeprature	(Centigrade)
Pressure	(bar)
Specific gravity	
Velocity	(m/s)

Flow computer

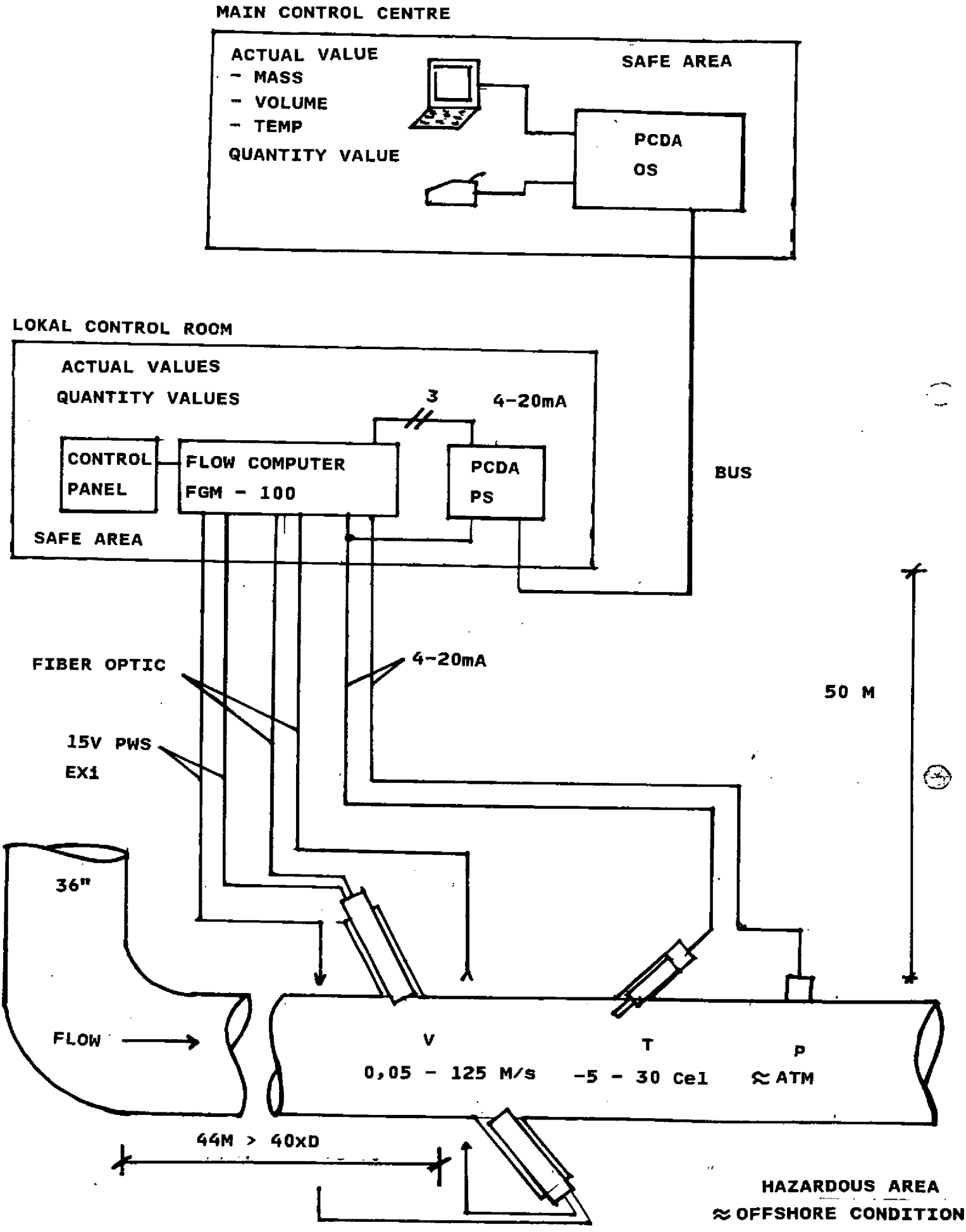
	Flow computer and signal processor mounted in 19" rack with power supplies.
Input:	Velocity: Signal from transducer via optical fibre cable Temperature: 4-20mA Pressure: 4-20mA Specific gravity: 4-20mA
Output:	Recorder: 0 – 10 V DC (4-20mA optional) Ch. 1: Volume flowrate low Ch. 2: Volume flowrate high Ch. 3: Volume outputs optional Counter: 24 V DC pulse for electro-mechanical counter. Resolution: 50 standard cubic meters for total volume.

Ultrasonic transducers

Operating temperature: -10 – + 75 deg.C
Pressure: 0.8 bara – 5.0 bara
Weight: Each 9,6 kg excl. valve and socket.
Dimensions: Lenght 0.70 m (transducer unit).
Signal transmission via optical fibre cable.
Electrical safety: Intrinsically safe with certified power supply and cable.
Safety class: EEx ia IIC T6
BASEEFA approval, cert. no. Ex 86B2411
Ex 872089

For further information, please contact: Fluenta A/S, P.O. Box 162, Fanaveien 13, N-5051 Nesttun, Bergen, Norway. Tel. + 47 5 13 75 10 • Telefax + 47 5 13 68 78

SYSTEM CONFIGURATION ULTRASONIC FLARE GAS METER STATPIPE GAS TERMINAL, KÅRSTØ



Experiences from the installation at the Statpipe Gas Terminal.

* The angle of tilt between the transducers are critical.
  The welding work of then the necessary pipe stubs were therefore performed with highest accuracy.
  Even when using a welding jig this caused some problems because of the heating up and the following drawing when cooling.

* The welding was performed when the plant was shut down and inerted flare system.

* The necesarry holes were drilled by using "hot tapping" technics performed by specialists.
  The special angles gave firstly no specially problems.
  By using dummy transducers the bore and the angles were tested to be in order.
  But later the operating showed something else.

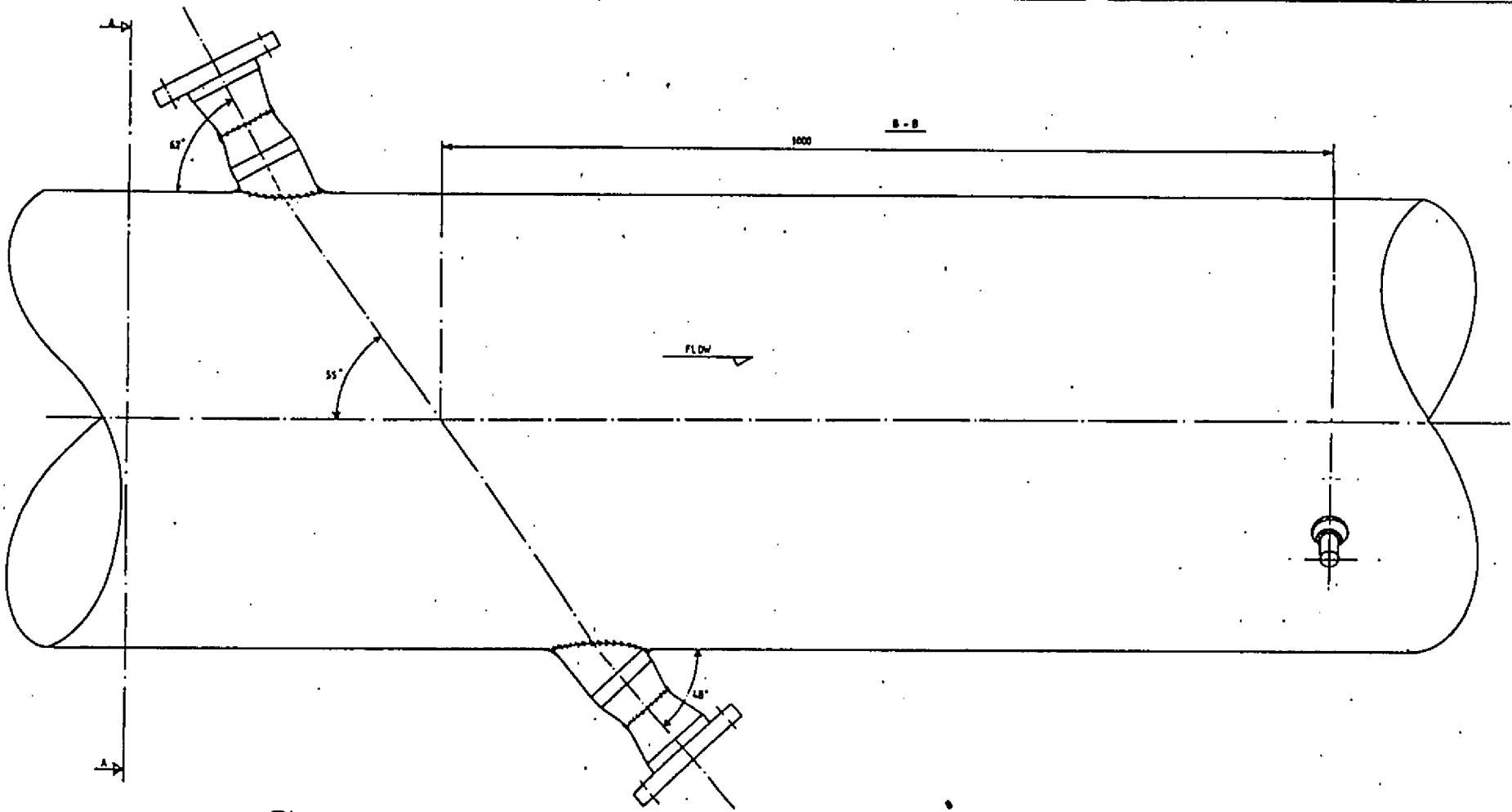
* Due to the mechanical problems a "spool piece" is recommended.

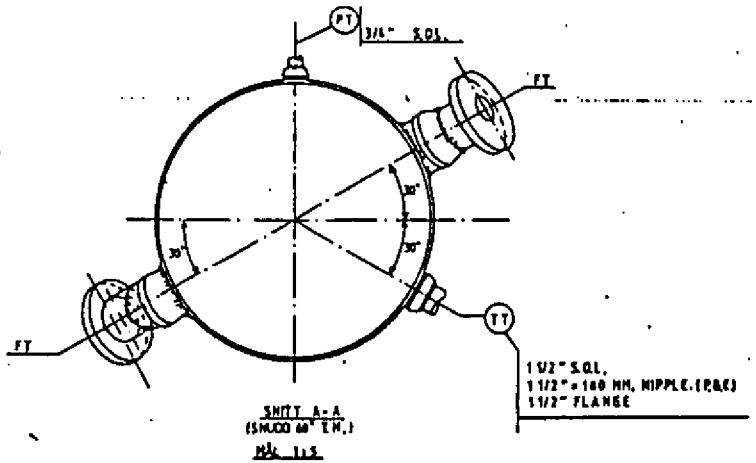
* Because of the high velocities care must be taken regarding the lenght (resonance) of the necessary thermowell.
  For this purposes a special thermowell was made where the critical point were moved.

* The termination of the fiberoptic for signal transmission need accurate work.
  Care must be taken to the higher minimum bending radius compared to ordinary signal cables.

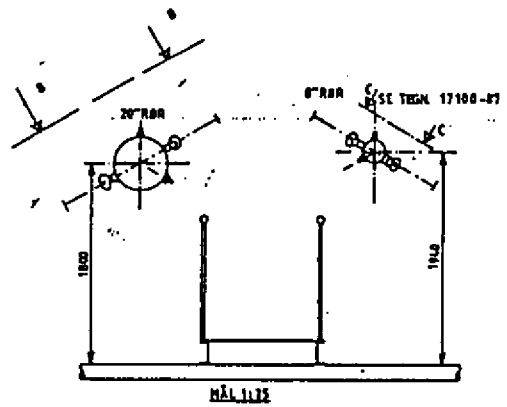
* The insertion of the transducers gave some problems because of the small diameter difference (2 mm) between the transducers and the bore, also that the drill have deviated from the central axis caused by the angle.
The whole arrangement included the ball valve were then moved a litle bit to get "correct" position for insertion.

* The other components like the flow computer etc. gave no problems including the interface to the PCDA.





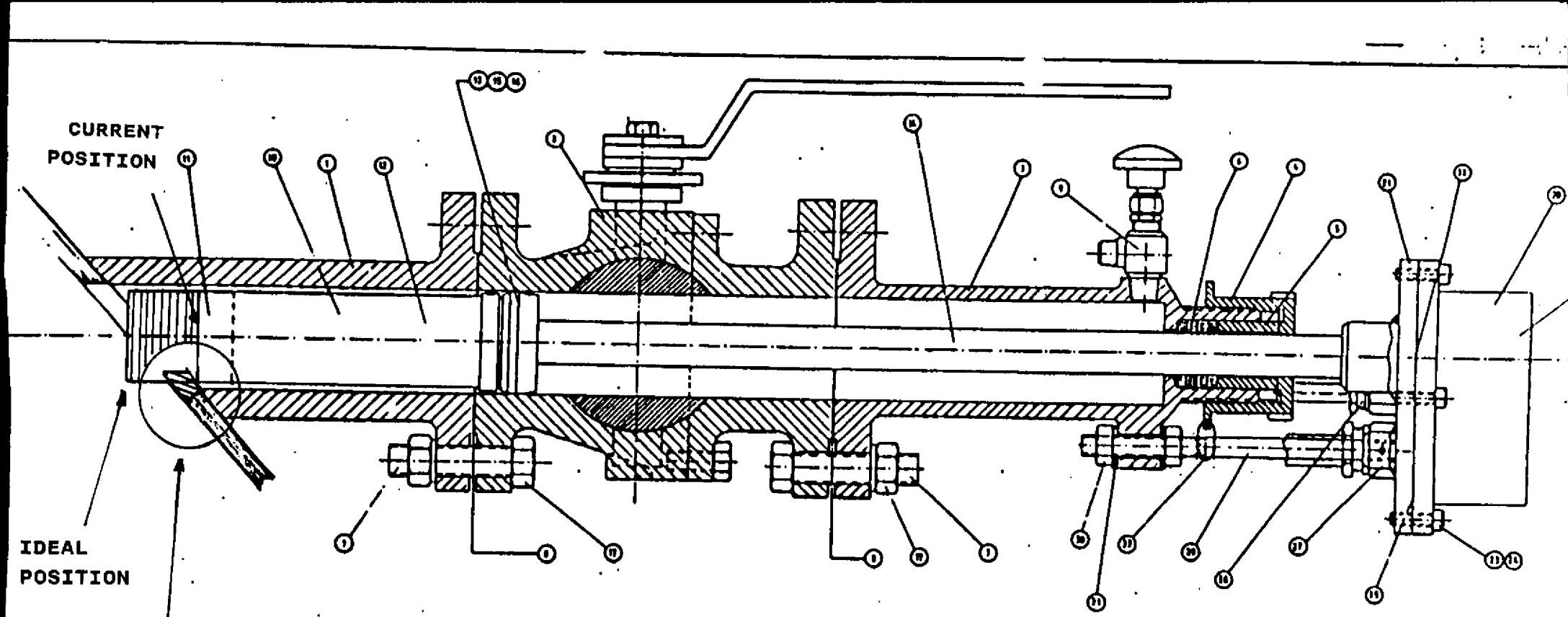
SNITT A-A
(SNUDD 60° I.H.)
MÅL 1:5

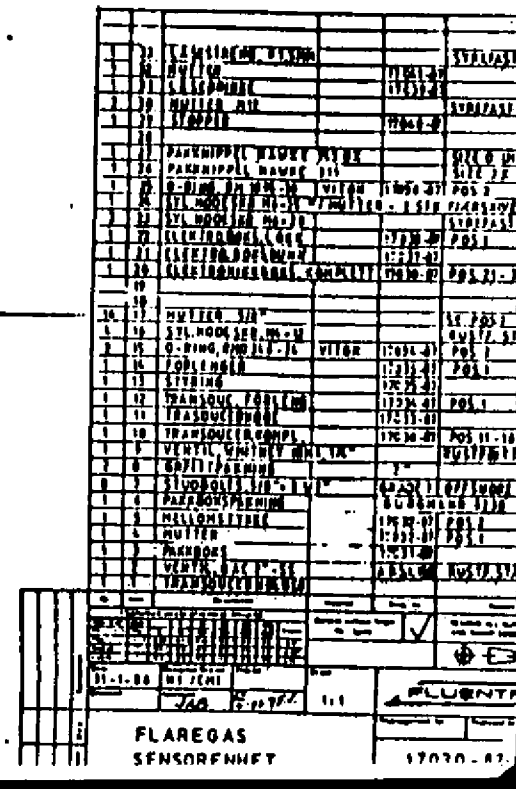


MÅL 1:25

SNITT GJENNOM RØR OG LEIDER
48° MED HORISONTALPLAN

16-9-87	T.F.V.		1:2.5	FLUENTA
	JAG		1:5	
				17057-07 17188-07


CURRENT
POSITION
IDEAL
POSITION
PROBLEM AREA


FLAREGAS
SENSORENHET

Experience from operating at the Statpipe Gas Terminal

* The flare gas meter was partly installed june -88 while an uppgraded version (interface to the PCDA etc.) was installed in january -89.

* No systematically test have been performed yet, due to the fact that there was no good comperable references specially in the lower range.
  For the lower range referance is made to tests at Gullfaks-B plattform.
  For the upper range (>50.000 Kg/h) test is prepared to an annubar meter where the curve display function in the PCDA will be used for logging (30 days.)

* The meter and the measurement is only "tested" by comparing to assumed values.
  This result seemes to be acceptabel.
  The meter is expected to show either real values or rubbish.

* Flow velocities was early measured in the range 0 (-4) to 130 m/s.
  By use of oscilloscope the unstable zero/minus flow seemed to be caused by turbolence or noice/damping in the signal caused by incorrect position or angle.

* One of the transducer failed in des -88 caused by an deffect solenoid.
  A new transducer was made and inserted with the same problems about position.
  Therefore the transducer was positioned outside the pipewall which then caused very high damping of the signal (lobe) with unstable (minus velocity) measurements as a result.

* The several experiments conclude with that the bore must be drilled up again but with a diameter of 52 mm.
  Thereafter the planed test can continue.

* By using the "velocity of sound" the meter is capable to measure the density of the gas in the flare.
For one sample the analyse at the laboratory resulted in a density of 0.69 kg/m3 while the meter indicate 0.77 kg/m3 where T = 29.0 degC, P = 0.993 BARA

Experiences from operating at the Gullfaks-B platform in the North Sea.

* The same type of instrument FGM 100 but for 8" and 20" flare, were installed in the early spring -88.
  Different short and long term test have been performed in the lower range 0 - 20.000 Sm3/h.

* In short term test a deviation of < 1% to a testseparator (orifice based) in the range 20.000 Sm3/h have been measured.

* Comparasion to a heat loss flow sensing element for a short term test resulted in a deviation of about 30 % in a range where the ultrasonic was "correct".
  The heat loss flow sensing element measured to low.

* In long term test good correlation of +-1% of metered production has been obtained.

Conclusion:

The ultrasonic flare gas meter has shown by observations and tests at the Statpipe Gas Terminal and at the Gullfaks-B platform the necessary quality for satisfactory and realibility flare gas metering.

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"A new gas density meter with reduced velocity of sound effect"

Lecturer:
J. W. Stansfeld
Schlumberger Industries

A NEW GAS DENSITY METER WITH REDUCED VELOCITY OF SOUND EFFECT

J. W. Stansfeld

Schlumberger Industries Transducer Division Farnborough

SUMMARY

Gas Density Meters are now widely applied on major Gas Metering Stations where their performance is critical for achieving high accuracy of flow measurement. Over the past few years much valuable experience has been gained and it is now considered desirable that this should be put to good use by the introduction of a new instrument which addresses the main problem areas. These are mainly with respect to a reduction in the gas composition effect (Velocity of Sound), improved temperature response and temperature equilibrium and improved installation and maintenance features. This paper describes the new instrument and its benefits.

INTRODUCTION

A fundamental requirement of most high pressure gas metering systems is the need to know the density of the gas at flowing conditions. This can be calculated from measurements of line pressure, line temperature and gas composition by using gas equations of state or it can be measured directly using an on-line gas density meter. The choice between these two methods is mainly defined by the availability and cost of suitable instruments which will achieve the required accuracy.

Because of the importance of high accuracy, much work has been done analysing these two methods and quantifying the error sources. As far as density meters are concerned this work has now been put to good effect and has resulted in the design of a new instrument.

GENERAL REQUIREMENTS FOR GAS DENSITY METERS

The use of a gas density meter within an Orifice Metering system is illustrated in Fig 1.

The most widely applied Gas Density meters are those which employ a vibrating element which is made to resonate at its natural frequency. The resonant frequency is directly influenced by the mass of gas which is in contact with the vibrating element and therefore by its density. The vibrating element is usually in the form of a very thin metal cylinder and for it to perform its task accurately, the following conditions are important.

1. The vibrating element must be clean of dirt particles and condensate and for this reason adequate filters must be used for the sample gas. The operating conditions must be above the gas dew point.

2. The gas sample in the density meter must be representative of the gas in the pipeline. This is simply achieved by ensuring that there is a small flow of sample gas through the instrument.

3. The gas sample must be at the same pressure as the gas in the pipeline. Again this is easy to achieve by using only a small flow rate of sample gas. The selection of the sample point is however important with respect to the correct selection of the Expansibility Factor as applied to the Orifice Flow Equation.

4. The gas sample must be at the same temperature as the gas in the pipeline. This is achieved by mounting the density sensing element in a thermowell or direct in-line. The sample gas flow rate should be kept to a minimum and the installation should be adequately covered with thermal insulation.

5. The calibration of the Density Meter must use a certified procedure and for best accuracy the use of Pure Nitrogen gas is normally recommended. Secondary influences such as those caused by changes in temperature, pressure and gas composition should also be quantified.

6. The installation and application of Density Meters must be such that the above points can be checked in order to ensure that the accuracy of measurement is as required. Where necessary this may include corrections for secondary effects such as for temperature and gas composition changes. The major influence due to these changes results from the consequential change in the Velocity of Sound.

FEATURES OF EXISTING GAS DENSITY METERS

Most of the Gas Density Meters which are currently in use may be considered as "second generation" instruments and in consequence they incorporate facilities which are effective in addressing the general requirements listed above. These instruments come in two designs to cover density ranges 6 to 60 kg/m and 40 to 400 kg/m.

On the topic of calibration and when applied for Natural Gas metering, these instruments are normally calibrated using pure Nitrogen and then corrected for gas composition effects. These corrections are related to changes in Velocity of Sound between the calibration gas and the natural gas.

This Velocity of Sound effect has been well documented both from a theoretical standpoint and from experimental analysis. It is generally concluded that calibration on Nitrogen plus the application of Sound Velocity correction will result in less measurement uncertainty than calibration on other pure gases or representative gas mixtures. Typically the uncertainty of the Nitrogen calibration is better than 0.1%, and when applied to natural gases better than 0.2%.

On the topics of installation and maintenance, these instruments are normally located in thermowells, however it is often difficult to check that temperature equilibrium is being achieved. Normally an additional uncertainty of 0.1% is added for installation effects giving a total uncertainty of 0.3%.

FEATURES OF THE NEW GAS DENSITY METER

With the wide experience gained from existing instruments it has been possible to focus on areas where further improvement can be made. This has resulted in a "third generation" instrument which is illustrated in Fig. 2 and has the following features.

1. One sensing element to cover all density ranges.

2. All calibrations for use on natural gas to be performed with pure Nitrogen at 20°C traceable to National Standards and with a typical uncertainty of 0.06%.

3. The Velocity of Sound effect is reduced by a factor of three so that, when measuring natural gases, the additional uncertainty is reduced to 0.05%.

4. Temperature response and temperature equilibrium have been improved by improving the thermal conduction from thermowell to sensor, and by reducing thermal conduction to the amplifier electronics. This reduces additional measurement uncertainty due to installation effects to typically 0.05% to give a total measurement uncertainty of typically better than 0.15%.

5. The incorporation of an internal temperature sensor (PRT) for verification of the temperature equilibrium and for use if applying a PTZ check method.

6. The internal filters can now be replaced without disturbing the pipework connections thereby simplifying this procedure if and when it is necessary.

7. These new instruments fit into existing thermowells and are therefore simple direct replacements for existing instruments.

CONCLUSIONS

This new Gas Density Meter, which will shortly be available from Schlumberger Industries, is intended as a direct replacement for existing instruments and for new installation where improved accuracy is required. By reducing the Velocity of Sound effect and by improving the temperature equilibrium features, the on-line measurement uncertainty is reduced by a factor of two. In consequence this instrument offers even greater accuracy benefits over the alternative and indirect methods of determining Gas Density.

REFERENCES

* Velocity of Sound Effect on gas Density Transducers.
  The Theory, Measurement Results and Methods of Correction.
  J W Stansfeld - North Sea Flow metering Workshop 1986.

* Petroleum Measurement Manual Part VII, Density - Sect.2.
  Continuous Density Measurement.
  Institute of Petroleum, London - November 1983.

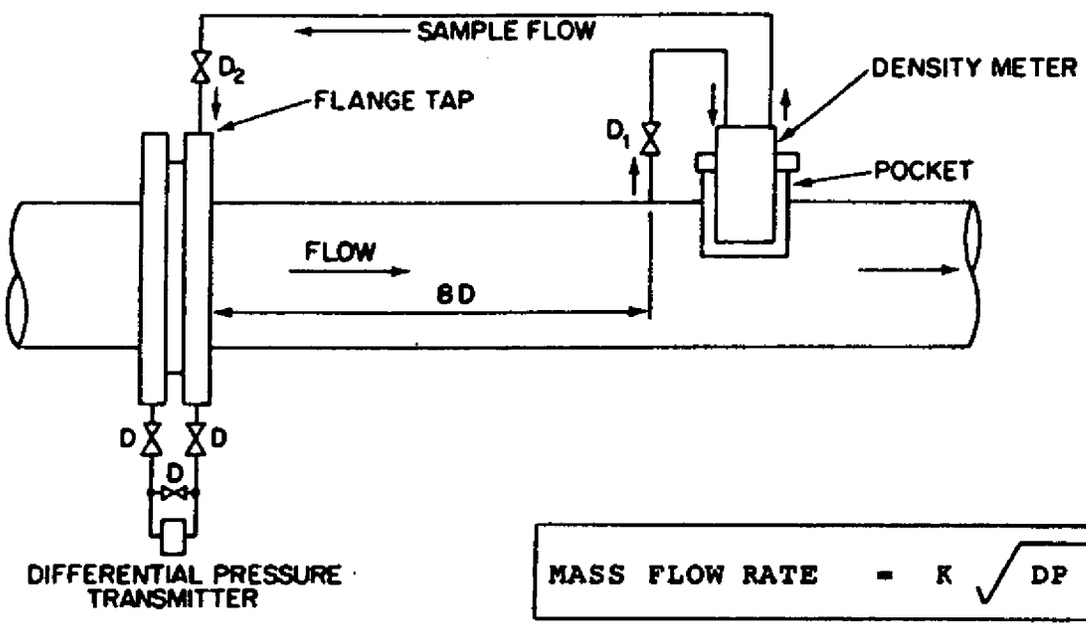


Fig 1 ORIFICE GAS METERING SYSTEM

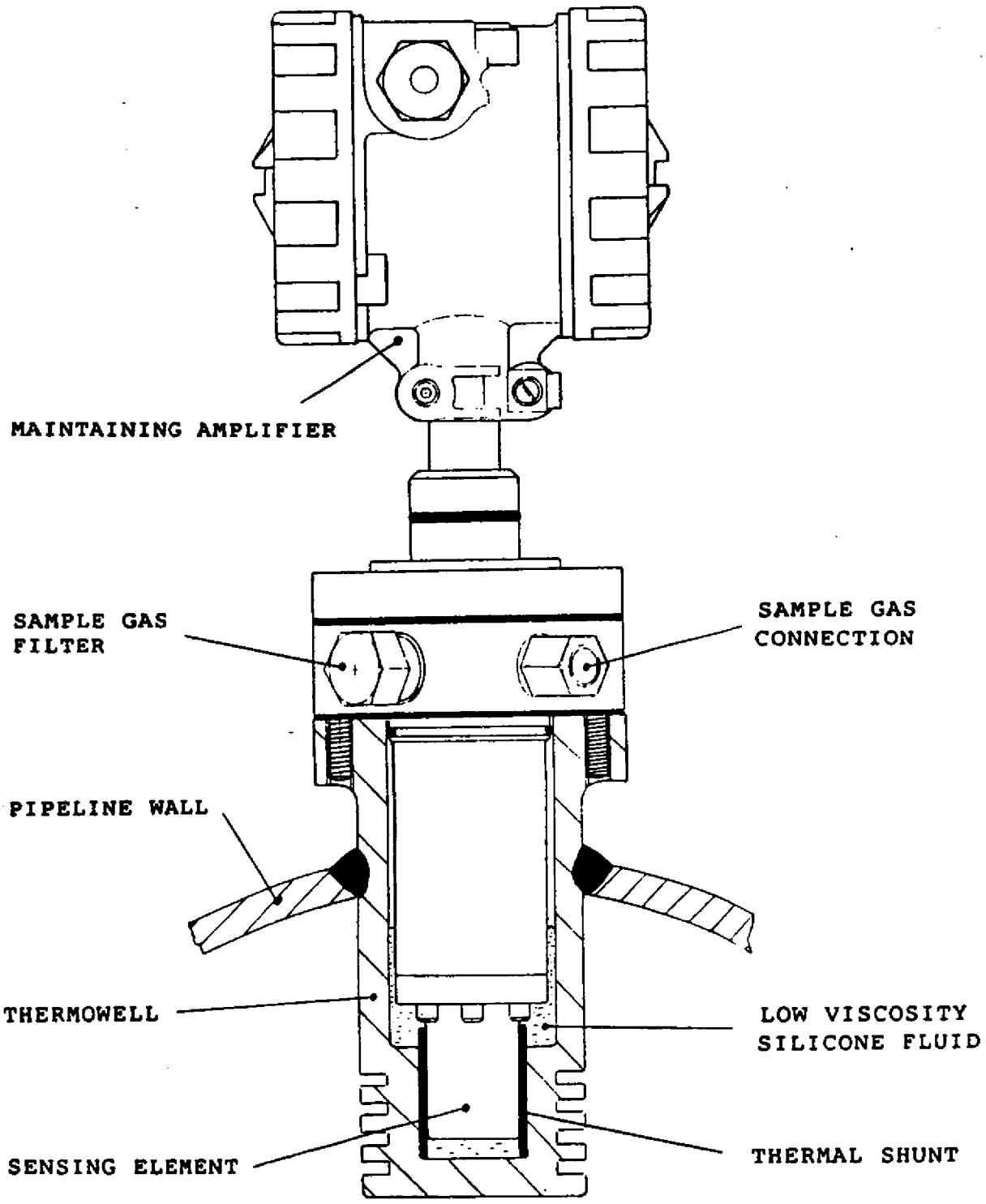


Fig 2 GAS DENSITY TRANSDUCER Type 7812

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"The EC Nozzle Transfer Package: A Flow Standard for High-Pressure Gas"

Lecturers:
Jos G.M. van der Grinten
Netherlands Measurements Institute
and
Pieter M.A. van der Kam
N.V. Nederlandse Gasunie

The EC Nozzle Transfer Package: A flow standard for high-pressure gas

Jos G.M. van der Grinten

Netherlands Measurements Institute, Fluid Dynamics Department,
Hugo de Grootplein 1, 3314 EG Dordrecht, The Netherlands.

and

Pieter M.A. van der Kam

N.V. Nederlandse Gasunie, P.O. Box 19, 9700 MA Groningen, The Netherlands.

SUMMARY

In order to provide a method by which test installations for high pressure gas meters within the EC can be assessed and checked, the Community Bureau of Reference (BCR) funded the construction of a transfer standard flow metering package. This nozzle transfer package (NTP) is a construction of six sonic nozzles. They are arranged such that the gas can flow through any one of the nozzles or through any combination of them.

Calibration of the NTP was performed by four laboratories for single nozzles, nozzle pairs, nozzle triplets, and all six nozzles. The calibration results were intercompared and analysed by means of a least squares technique.

The major conclusions which arise from this study, is that the NTP is well suited to serve as a transfer standard for high-pressure test facilities. The coefficients of the calibration curves of the NTP differ significantly from the values based on the ISO draft international standard[1]. Compared to this standard the uncertainty of the predictions has improved.

1. INTRODUCTION

In order to provide a method by which test installations for high pressure gas meters within the EC can be assessed and checked, the Community Bureau of Reference (BCR) funded the construction of a transfer standard flow metering package. After a first calibration this package should serve as the High Pressure Gas Flow Standard within the EC, that could subsequently be made available to all test installations that show interest.
In order to achieve a stable transfer standard it was decided to use sonic nozzles as flow standards. The nozzle transfer package (NTP) was designed by the N.V. Nederlandse Gasunie. It incorporates six nominally identical toroidal inlet critical flow venturi nozzles. They are arranged such that the gas can flow through any one of the nozzles or through any combination of them. The geometry of the nozzles is as specified in the ISO draft document on these devices[1]. They are sized as to give a volume flow rate of 400 m^3/h at line conditions.
The six nozzles were manufactured by the National Engineering Laboratory in Scotland.

BCR decided that the first calibration of the NTP should be carried out by those laboratories that took part in an earlier intercomparison campaign[2]. These are:
- the high pressure testfacility of the National Engineering Laboratory at East Kilbride, Scotland;
- the high pressure test facility of Gaz de France at Alfortville, France;
- the high pressure test facilities of the N.V. Nederlandse Gasunie at the locations Groningen and Westerbork in the Netherlands.
- the high pressure test facility of the Netherlands Measurements Institute at Bergum, The Netherlands.

The calibration of the NTP took place in the period of December 1984 till February 1987. The NTP is now available to other laboratories for testing.

2. DESCRIPTION OF THE NOZZLE TRANSFER PACKAGE

The NTP consists of six toroidal inlet sonic nozzles of the shape indicated in fig. 1. The nozzles are installed in parallel pipes positioned in a circle, connecting the inlet plenum to the outlet collecting chamber. Each pipe is provided with a flow straightener at the inlet.
The nozzles can be moved axially against seats on the bottom of the outlet collecting chamber to shut off the flow of gas. The movement is induced by applying the pressure of the gas to one of the sides of the nozzle. In fig. 2 a scheme of the assembly is shown with the nozzle in pipe A open and the one in pipe B closed. Leakage along the nozzles or past the seats can be detected by small bleed valves.
The gas pressure can be measured on a pressure tapping provided with each of the inlet pipes.
The gas temperature is measured by means of Pt100 resistance thermometers that are placed in each pipe. Also in the inlet plenum chamber two Pt100's are placed. The pipe Pt100's and one of those at the inlet are installed directly in the gas flow. The second inlet one is placed in a pocket to allow checking without depressurizing the NTP.
The entire assembly is built according to the demands set in the ISO draft document[1].

3. CALIBRATION PROGRAMME AND TEST CONDITIONS

The laboratories agreed on a calibration programme that differed for each of the laboratories. Each laboratory reported to the EC on its results[3,4,5]. A review of the programme is given in table 1.
Typical properties of the natural gas used by Gaz de France and Gasunie / Netherlands Measurements Institute (NMi) are listed in table 2.

Table 1: Nozzle calibrations performed by different laboratories. All pressures mentioned are absolute pressures in bar.

		NEL	Gaz de France	Gasunie / NMi
single	pressure	5, 15, 25, 35	10, 20, 30, 40	11, 21, 31, 36, 61
	geometry	1-6	1-6	1-6
pairs	pressure	5, 10, 15	10, 20, 30, 40	11, 21, 31, 36, 61
	geometry	1+2, 1+3, 1+4	1+3, 2+5, 2+6	1+2, 1+3, 1+4
triplets	pressure	5, 10	10, 20, 30, 36	11, 21, 31, 36, 61
	geometry	1+2+5, 1+3+5	2+4+6, 3+4+6	1+2+3, 1+3+5
all six	pressure			11, 21, 31, 36, 61
	geometry			1+2+3+4+5+6
test gas		air (10-20°C)	natural gas	natural gas

Table 2: Typical properties of natural gas used for calibrations by Gas de France and Gasunie / NMi.

	Gaz de France	Gasunie / NMi
gas composition (mol %)		
N_2	0,93	14,0
CH_4	97	81,4
CO_2	0,06	1,0
C_2H_6	0,69	2,9
C_3H_8	0,23	0,41
C_4H_{10} (I)	0,09	0,08
C_4H_{10} (N)	0,07	0,02
molar weight	16,40	18,65
normal density (kg/m³) (0°C, 1,01325 bar)	0,725 - 0,738	0,774
temperature (°C)	18 - 21	
Groningen		20,0 ± 0,5
Bergum (NMi)		20 - 27
Westerbork		7 - 10

4. TEST FACILITIES

The test facilities at each of the laboratories have been described in detail at numerous occasions before. Below reference is made to those descriptions. Only the most essential features of each of the facilities are given here.

4.1 The test installation of NEL, East Kilbride

The test facility of the National Engineering Laboratory in East Kilbride, Scotland, is shown schematically in fig. 3. The NEL facility is a primary device based on a gravimetric method combined with a secondary facility. It is operated with air.

The basic operation of the test facility is as follows.
A compressor feeds the air into a 12 m^3 storage volume through a plant that dries the air and eliminates oil vapour and dust. From the container a loop system with a volume of 6 m^3 is filled with air at a pressure of 65 bar. When the temperature in the ring conduit is stabilized the valve X is opened. The air, the pressure of which is kept at the desired value by the adjustable pressure controller, flows first of all through a sonic nozzle that serves as a standard and that adjusts to a certain mass flow rate according to the inlet pressure and temperature.
From the nozzle the compressed air flows through a switching device either into a high pressure spherical vessel (diameter 1,5 m) that can be weighed on a scale or into the test line where the flow meter to be calibrated, in this case the NTP, is installed. Downstream of the test line the air flows through a silencer into the open air. Various valves make an adjustment possible of the pressure in the test line. When the valve X is opened to start the measuring process, the loop system is connected at the same time with the storage container. Thus the air with known temperature that flows from the loop to standard nozzles is replaced by air from the storage container. This air cools off due to pressure reduction, but the temperature in the test line is not influenced by this as long as there is still warmed air between the inflowing air from the storage container and the outlet of the loop.

Direct calibration of the NTP installed in the test line on the other side of the diverter is not possible. Either a secondary calibration can be made using one of the calibrated standard nozzles to determine the flow rate or an indirect connection to the gravimetric rig can be made. In the latter case the mass flow rate through a meter on test is not calculated from temperature and pressure data but can be determined from an immediately following gravimetric test. In this case the standard nozzle only serves as a controlling device for the flow rate. A requirement for this method therefore is that the mass flow adjustment during the gravimetric test remains virtually constant.

4.2 Test facilities of Gaz de France, Alfortville, France

Gaz de France has two test facilities, a primary one and a secondary one shown in fig. 4. Both operate on high pressure natural gas. Sonic nozzles serve as standards in the secondary installation, that were calibrated in the primary one.

The secondary installation was used for the calibration of the NTP. As standards seven sonic nozzles with different sizes are installed. They have nominal volume flow rates of 1,5, 5, 10, 20, 40, 100 and 200 m^3/h. Through combinations of nozzles a whole range of flow rates can be selected.

The test facility is in the open air. To guarantee good temperature conditions the essential parts of the installation are thermally insulated. The secondary facility alows for testing of nozzles and gas meters up to pressures of 41 bar and flow rates up to 2,6 kg/s.
The nozzles used in the secondary installation are traceable to the primary test facility based on a volumetric method.

4.3 Gasunie test facilities at Groningen and Westerbork, The Netherlands

A scheme of the installation in Groningen, situated at the Research Laboratory of the N.V. Nederlandse Gasunie is shown in fig. 5. The natural gas enters the installation at a pressure of 40 bar. It leaves the installation usually at a pressure of 8 bar and then flows into the piping system of the municipal gas distribution company. The installation consists of two parts. Part A is called the "primary high pressure standard installation". It consists of 10 CVM meters with a capacity of 400 m^3/h each. This part is used mainly for the calibration of meters to be used as standards in other installations. These meters, installed at position D, can be tested up to 40 bar. The maximum operating pressures of the CVM's is 8 bar. Part B is used for routine verifications.
For the calibration of the NTP the CVM meters were used as standards and thus the NTP was installed at position D.

The installation of the Bernoulli Laboratory in Westerbork is constructed as a bypass around a valve in a main transmission line. A schematic drawing is given in fig. 6. After the gas has passed the test installation it returns to the same transmission line. Due to that no pressure regulation is possible. Both the standard meters and the meters to be tested operate at a pressure of about 60 bar.
The standard meters, 10 turbine meters with a capacity of 4000 m^3/h each, are installed in a building. The meter to be tested is installed in the open air. The outside pipe is insulated and partly roofed in to avoid direct radiation of the sun.

Through a system of transfer standard meters the high pressure standard meters in all Gasunie test facilities are traceable to the primary flow standard of the Netherlands Measurements Institute in Dordrecht.

4.4 The Bergum test facility of the Netherlands Measurements Institute

A schematic drawing of the Bergum installation is given in fig. 7. The installation was built in parallel to a gas line that feeds an electric power plant. The gas enters the station at a pressure of 60 bar and leaves with a pressure of 8 bar. The installation is equipped with 4 turbine standard meters with a capacity of 4000 m^3/h each, a turbine standard with a capacity of 1000 m^3/h, a turbine standard with 400 m^3/h capacity and a CVM standard with a capacity of 100 m^3/h. At the entrance of the installation, the gas passes through a filter and then through a heat exchanger to compensate for the temperature drop due to the pressure reduction furtheron in the installation. The maximum operating pressure of the test installation is 50 bar. The meters to be tested and the standards operate at the same pressure. The flow is controlled at the outlet of the installation. For very low flow rates a set of three sonic nozzles is used to avoid disturbances in the flow due to downstream pressure variations.
Also the Bergum standard meters are traceable to the primary flow standard of the Netherlands Measurements Institute in Dordrecht.

4.5 Uncertainties

In table 3 the systematic, random and total uncertainties in the results of each of the test installations are listed. The systematic uncertainty is due to the test installation. The random uncertainties are based on the random variations in the parameters that add to the final result.
The figures based on a 95% confidence level, are estimated from statements of the participating laboratories.

Table 3: Systematic, random and total uncertainties estimated for the different test facilities based on a 95% confidence level.

	pressure (bar)	uncertainty (%) systematic	random	total
NEL	5 - 35	0,35	0,16	0,38
Gaz de France	10 - 40	0,30	0,07	0,32
Gasunie Groningen	11	0,17	0,18	0,25
	21	0,17	0,21	0,27
	31	0,17	0,24	0,28
	36	0,17	0,26	0,29
Westerbork	60	0,27	0,30	0,40
NMi Bergum	11	0,22	0,19	0,29
	21	0,22	0,22	0,30
	31	0,22	0,25	0,31
	36	0,22	0,27	0,32

5. RESULTS

5.1 Reynolds number

To be able to intercompare the results found they are tabulated as function of the Reynolds number Re, with respect to the nozzle throat d. Re can be calculated from the mass flow rate Q_m and the dynamic viscosity μ of the medium used according to

$$Re = 4\ Q_m\ /\ (\pi\ d\ \mu). \qquad (1)$$

For the calculation of the viscosity NEL has used a polynomial equation based on the upstream temperature and density[4].
Gaz de France, Gasunie and Netherlands Measurements Institute used the Herning-Zipperrer formula for μ as can be found in ref. 6.

Note: Henceforward the Re-number will be given in units of 10^6 for ease of handling.

5.2 C_* calculation

As basis for the calculation of C_d from the experimental results the C_* calculation according to Johnson was taken. This method is presented in the draft ISO standard[1]. It was realized that this method of calculation is not perfect and is even out of the application range for the type of gas used in the Netherlands.
The new calculation method (AGA-8) according to Starling et al.[9] might produce better results, but since that is a complicated calculation method not yet available to every laboratory at the time of the calibration, use of the Johnson method was favoured.

5.3 Single nozzles

In figs. 8(a-f) the results for C_d as function of Re are shown for each of the single nozzles. The results obtained in 1985 by Gasunie and Netherlands Measurements Institute are combined.
Comparing the standard deviation with the reported random uncertainty the values for the NEL results correspond of course since the standard deviation was the basis for the random uncertainty quotation. The Gaz de France results are also in line with their estimated random uncertainty. The Gasunie results reproduce much better than could be expected on the basis of the estimated random uncertainty. This can be explained by the fact that in the uncertainty estimate the largest part (0,16%) came from the uncertainty in the molar mass of the gas calculated from the gas composition. If the gas composition is more stable than expected also the random variation caused by it is small. Subtracting this part from the random uncertainty figure leads to an uncertainty close to the actually found random variations in C_d.

From the results of the nozzle calibrations within the package the following features attract attention:
- All three laboratories have found C_d values that differ significantly from those predicted by the ISO-draft. This is illustrated by fig. 8(g).
- The slopes found are larger than the ISO-prediction.
- The results from Gaz de France are for all nozzles 0,1% to 0,2% lower than those from NEL and Gasunie.
- The results from the Bergum facility lie in the order of 0,10% higher than those obtained from the Groningen facility. This is more than expected from the calibration and intercomparison data from both installations obtained with transfer standard meters.
- The Bergum (NMi) and Westerbork (Gasunie) data coincide within the experimental uncertainty. It is remarkable that the results of C_d at Re = 24 are larger than unity, which is in contradiction with the theoretical background of the sonic nozzle behaviour. However, the C_d values are in line with the extrapolation of the results found at the lower Re values.
- Comparison of the Gasunie results in 1985 and 1987 show a systematic decrease of the latter. This decrease is on the edge of statistical relevance.

5.4 Nozzle combinations

Aim of the testing of nozzle combinations was to find out whether the nozzle performance was influenced by parallel use. Based on the theory of critical flow no mutual influence is expected.
Using the mass flow formula the expected C_d value for the nozzle combination can be calculated. However, Gaz de France has reported that the temperatures

of each of the nozzles was within 0,1 K from the mean temperature which is negligible in the calculation of C_*. NEL and Gasunie have not reported on temperature differences, so it is assumed that the differences can be neglected. Thus only the nozzle diameters influence the average C_d of a combination of nozzles, and it can be calculated using the nozzle throat areas as weighting factors. However, since the nozzle diameters are almost equal the weighted mean calculation does not differ significantly from a simple mean, so that

$$C_d(exp) = (C_{d1} + C_{d2} + ...)/n. \qquad (2)$$

Nozzle combinations should be compared to the single nozzles results under the same conditions, i.e. each laboratory has to be considered separately. The differences found for each laboratory can than be brought together. As already indicated the various laboratories took different combinations. The following combinations can be compared as they involve the same geometrical position.

Gasunie	Gaz de France	NEL
1 + 2	-	1 + 2
1 + 3	1 + 3 / 2 + 6	1 + 3
1 + 4	2 + 5	1 + 4
1 + 3 + 5	2 + 4 + 6	1 + 3 + 5
1 + 2 + 3	-	-
-	3 + 4 + 6	-
-	-	1 + 2 + 5
1 - 6	-	-

The results of the nozzle pairs, nozzle triplets and all six nozzles are shown in figs. 9, 10 and 11, respectively.
The nozzle triplets for which no corresponding geometries were available, are combined in fig. 10(b).

6. ANALYSIS

Some systematic differences can be observed between the various laboratories and some unexplained features have been spotted in the data. They tend to stay within the uncertainties for the measurement results and thus it is considered justified to analyse the results in relation to one another. A set of equations for C_d is developed with uncertainty limits that can serve as the basic calibration results of the NTP.
From the results of the statistical analysis it should also become clear if there are any significant differences between the various geometries.

6.1 Least squares analysis

The data for single nozzles, nozzle pairs, and nozzle triplets were fitted with the relationship:

$$C_d = a + b\,Re^{\frac{1}{2}}, \qquad (3)$$

in which a and b are the calibration coefficients. A linear least squares technique with weighed data was applied as described in ref. 7. The weighing factors were proportional to $1/s^2(C_d)$.
The uncertainty with 95% confidence level of the discharge coefficient predicted by the fit will will be refered to as $s_{95}(C_d)$.
Details of the followed procedure are explained in ref. 10.

6.2 Results

The results of the fits of the single nozzle data are shown in table 4 and fig. 8(a-f). In table 4 the fits of the single nozzle data are shown together with the fit of all single nozzle data, the mean calibration coefficients obtained from the six fits of the single nozzles, and the proposed ISO-values of ref. 1.
From table 4 it appears that the calibration coefficients of the separate nozzles and the mean calibration coefficients agree within their mutual uncertainty bounds. The fits of the separate nozzles agree within uncertainty bounds with the fit of all single nozzle data. Moreover, it appears that the values of the coefficients a and b obtained from the fits differ significantly from the values stated in the ISO draft international standard[1].
As can be found from the last column in table 4, the uncertainty of the discharge coefficient predicted by the fits with 95% confidence is 0,3% which is better than the literature value of 0,5%.
These results also mean that the calibration coefficients obtained from all single nozzle data give a correct description of the results found at each of the nozzles separately.
In all fits of table 4 only one outlier was found: in the fit of all single nozzle data. Due to the high number of data it was not necessary to remove this outlier.
For each of the nozzles the graphical representation of the measurements is depicted in fig. 8(a-f). The measurements are indicated by symbols and the fit is represented by the solid line. The accuracy of the fit based on the standard deviations of the coefficients a and b is indicated by the dashed lines which mark the 95% confidence interval of the fit. The procedure for obtaining this confidence interval is explained in ref. 8. Note that the shown confidence interval in fig. 8 does not indicate the uncertainty of a discharge coefficient predicted by the fit.
The fit for all single nozzle data is shown in fig. 8(g) together with the result following from the ISO values. Again the difference is very clear.

The results of the fits of the nozzle pairs and nozzle triplets are also shown in table 4. The fitted curves and the measurements are depicted in figs. 9 and 10. In table 4 the calibration coefficients for the different nozzle combinations are compared with the equal weight averages of the calibration coefficients of the corresponding single nozzles. In the cases of opposite nozzle pairs and nozzle triplets these calibration coefficients agree within their mutual uncertainty bounds. This agreement is also found for the calibration coefficients of all single nozzle data and the results of the opposite nozzle pairs and nozzle triplets.
When the nozzle pairs do not consist of two opposite nozzles the agreement is less good. The reason for this is not known but the flow geometry may have some effect. The uncertainty with 95% confidence of the predicted discharge coefficients C_d is 0,2% for nozzle pairs and 0,4% for nozzle triplets.

Table 4: Results from the least squares fit of the calibration data of the NTP.

1) Single nozzles in the package

Nozzle	N	a s(a)	b s(b)	s95(Cd)
1	19	1.0032 (12)	-20.8 (4.1)	0.0029
2	18	1.0037 (10)	-18.6 (3.2)	0.0028
3	18	1.0032 (9)	-18.1 (2.5)	0.0027
4	18	1.0019 (13)	-15.2 (4.2)	0.0036
5	18	1.0018 (12)	-14.8 (3.9)	0.0032
6	18	1.0027 (12)	-17.5 (4.0)	0.0033
all data	109	1.0026 (5)	-16.8 (1.4)	0.0029
1-6		1.0028 (11)	-17.5 (3.7)	
ISO		0.9935	- 1.525	0.005

2) Nozzle pairs

Nozzle	N	a s(a)	b s(b)	s95(Cd)
1+2	8	1.0033 (5)	-13.8 (1.6)	0.0013
1,2		1.0035 (11)	-19.7 (3.7)	
1+3,2+6	16	1.0009 (10)	-12.3 (3.0)	0.0024
1,2,3,6		1.0032 (11)	-18.8 (3.5)	
1+4,2+5	12	1.0022 (10)	-14.7 (3.3)	0.0021
1,2,4,5		1.0027 (12)	-17.4 (3.9)	

3) Nozzle triplets

Nozzle	N	a s(a)	b s(b)	s95(Cd)
1+3+5, 2+4+6	10	1.0023 (20)	-16.7 (6.7)	0.0039
1-6		1.0028 (11)	-17.5 (3.7)	
3+4+6, 1+2+5, 1+2+3	10	1.0026 (18)	-17.2 (5.1)	0.0042
1-6		1.0028 (11)	-17.5 (3.7)	

4) All six nozzles

Nozzle	N	a s(a)	b s(b)	s95(Cd)
1+2+3+ 4+5+6	6	1.0030 (5)	-10.9 (1.2)	0.0006
1-6		1.0028 (11)	-17.5 (3.7)	

The fit of the Gasunie results for all six nozzles is shown in fig. 11. The calibration coefficients are listed in the lower part of table 4. The value of a agrees with the mean value of the six nozzle calibrations. The value of b deviates significantly from the mean value of the six nozzle calibrations. A remarkable result is that the uncertainty with 95% confidence in the predicted discharge coefficients (0,07%) is much smaller than the results of previous calibrations. The reason for this low uncertainty is that there are calibration differences between the different laboratories. Therefore, the results of a separate laboratory will be much more consistent than the cumulated results of the three laboratories.

7. CONCLUSIONS

From the present analysis the following conclusions can be drawn.

The calibration curve obtained from all single nozzle data gives a correct description of the observed discharge coefficients in experiments with single nozzles, pairs of opposite nozzles, and nozzle triplets.

The uncertainty in the discharge coefficients predicted with this calibration curve is 0,3% at a 95% confidence level. This uncertainty is exclusive of the specified systematic uncertainties of the laboratories. The reported values of the systematic uncertainties are all about 0,3%. Root square summation of the two types of uncertainties leads to a total uncertainty of 0,4%.

The calibration coefficients resulting from experiments described in this report differ significantly from the values stated in the ISO draft international standard[1]. The uncertainty of the predictions has improved compared to ref. 1.

In view of the fact that the three laboratories used significantly different gases, operated on different principles and have quite distinct traceability paths, the overall level of agreement from the calibrations of the Nozzle Transfer Package is encouraging.

Within the uncertainty limits specified the results from the least squares analysis can be used to calculate mass flow rates through the NTP. This means that the Nozzle Transfer Package is practically available for laboratories which want to use the NTP for testing and calibration puposes.

REFERENCES

1. Measurement of gas flow by means of critical flow venturi nozzles, ISO draft international standard ISO/DIS 9300, December 1988.

2. Intercomparison campaign on high-pressure gas flow test facilities, E.A. Spencer, E. Eujen, H. Dijstelbergen and G. Peignelin, Commission of the European Communities Report EUR 6662, Brussels 1980, ISBN 92-825-1649-0.

3. Calibration of the EC Nozzle Transfer Package, P.M.A. van der Kam, Dienst van het IJkwezen, Dordrecht and G.J. Broekgaarden, N.V. Nederlandse Gasunie, Groningen, July 1985.

4. Calibration of seven critical flow venturi nozzles before and after assembly into a transfer standard package, National Engineering Laboratory, East Kilbride, report EUEC/14, January 1987.

5. Etallonage sous differents pressions d'un étalon de transfer européen par la mesure des débits gazeux, P.Kervevan, Gaz de France, Rapport 85-1195, December 1985.

6. The properties of gases and liquids, their estimation and correlation, A.C. Reid, J.M. Prausnitz, T.K. Sherwood, New York, McGraw-Hill, 3rd edition 1977.

7. Practical Physics, G.L. Squires, McGraw-Hill, London, 1968.

8. Assesment of uncertainty in the calibration and use of flow measurement devices - part 1: Linear calibration relationships, ISO draft international standard, ISO/DIS 7066-1.2, April 1988.

9. Compressibility and supercompressibility for natural gas and other hydrocarbon gases, K.E. Starling, AGA transmission measurement committee, report no. 8, December 1985.

10. Calibration of the EEC Nozzle Transfer Package, P.M.A. van der Kam and J.G.M. van der Grinten, Commission of the European Communities Report EUR 11862, Brussels 1989.

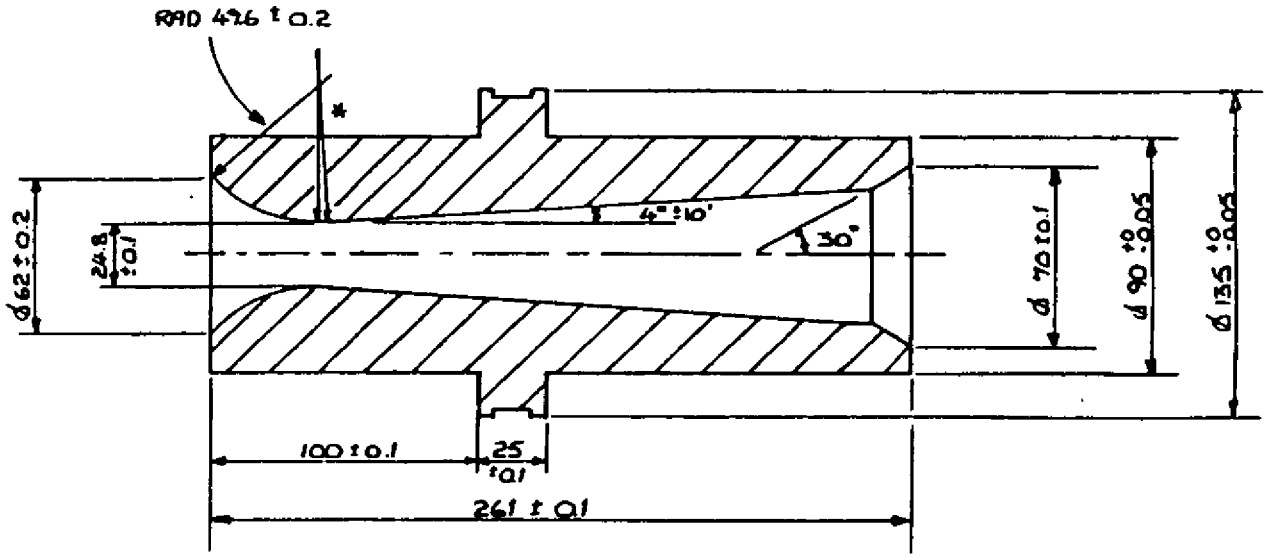


Figure 1: Leading dimensions of the toroidal inlet critical flow venturi nozzles. The inlet radius extends 4° beyond the throat to become tangent to the conical diffuser (*). All dimensions are in mm, the material is SS316. Full details can be obtained from the NEL drawing no. A3-A/19956.

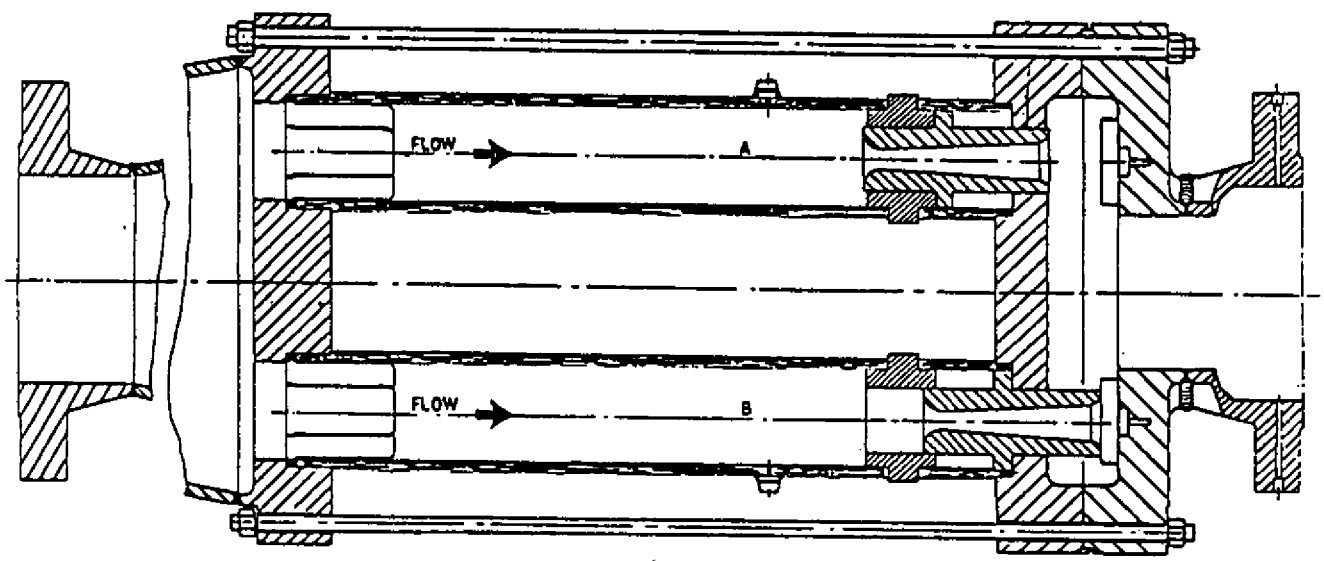


Figure 2: Schematic set-up of the Nozzle Transfer Package. At A a nozzle is shown in the open position, at B in the closed position.

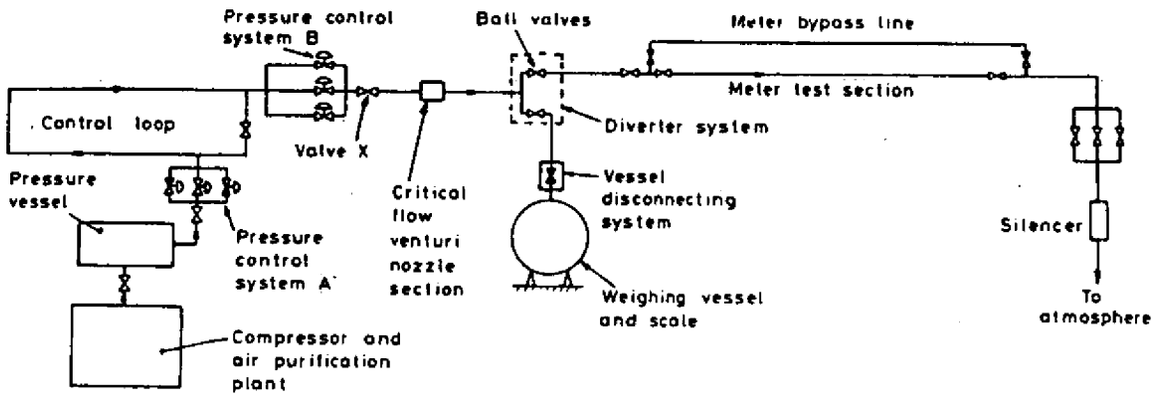


Figure 3: High pressure testinstallation at NEL, East Kilbride, Scotland.

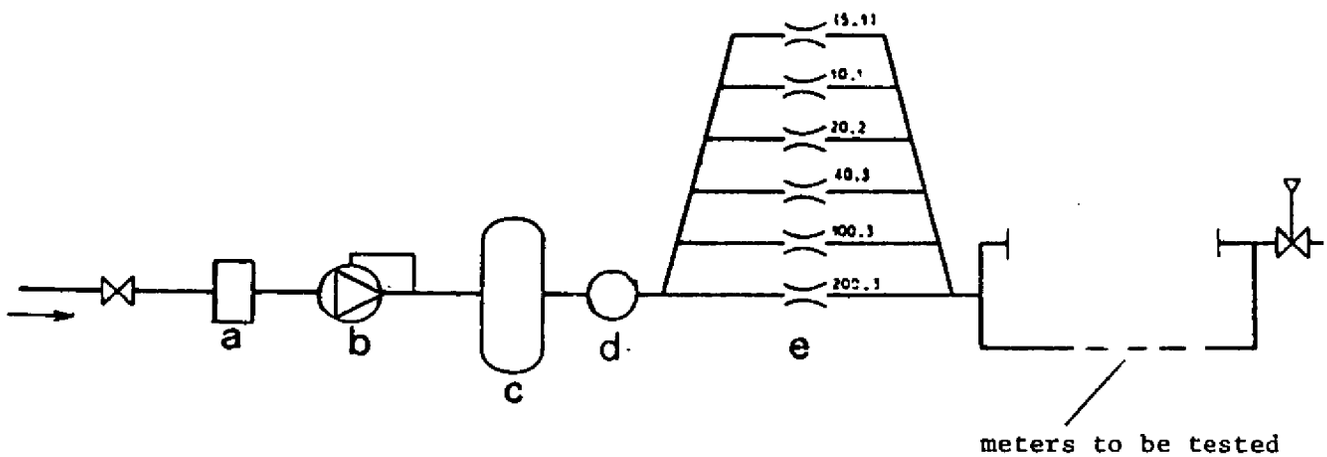


Figure 4: Secondary high pressure test installation of Gaz de France at Alfortville, France.
a = filter, b = pressure regulator, c = vessel, d = densitometer, e = sonic nozzle standards with indicated the nominal volume flow rates in m^3/h.

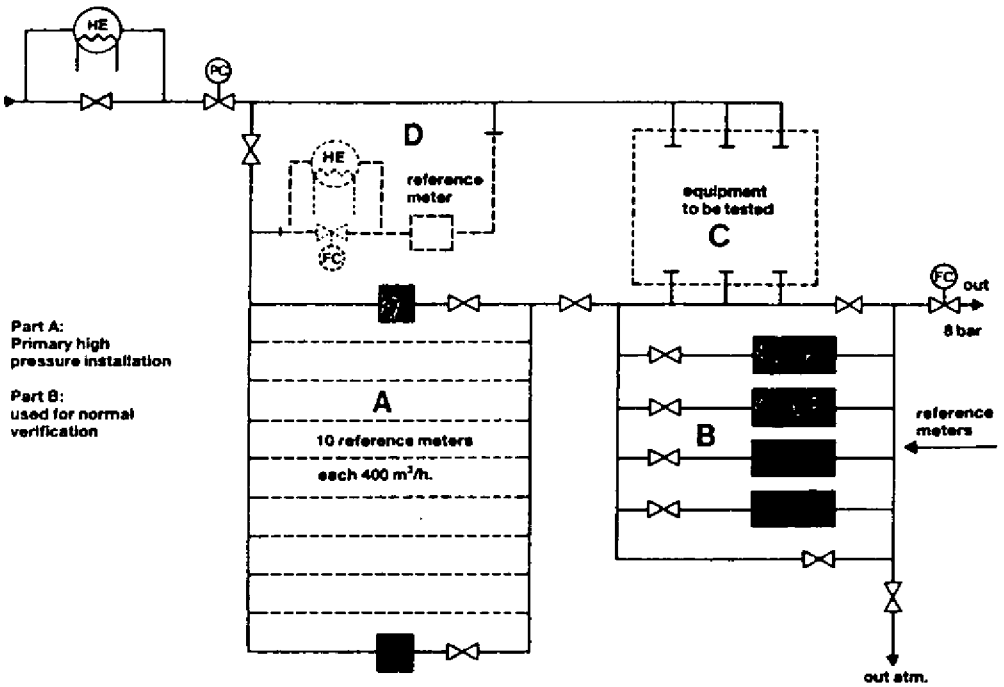


Figure 5: The high pressure test installation of Gasunie at Groningen, the Netherlands. Part A is the primary facility, part B the secondary facility. The NTP was installed at position D for calibration with the standards in part A as reference.
TC = temperature control, PC = pressure control, HE = heat exchanger, FC = flow control.

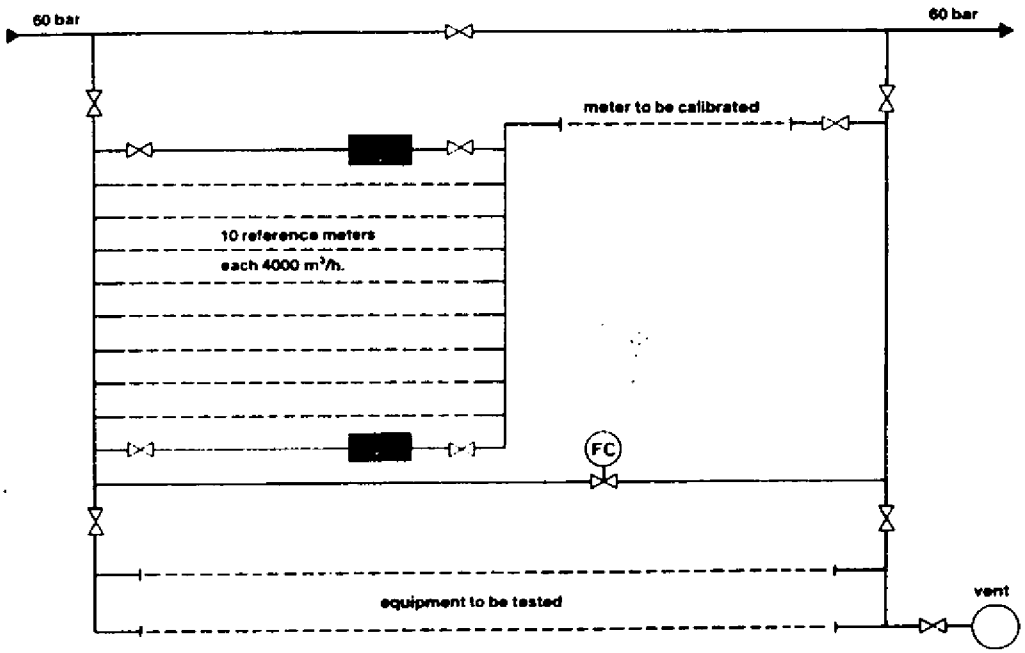


Figure 6: The high pressure test installation of Gasunie at Westerbork, the Netherlands.

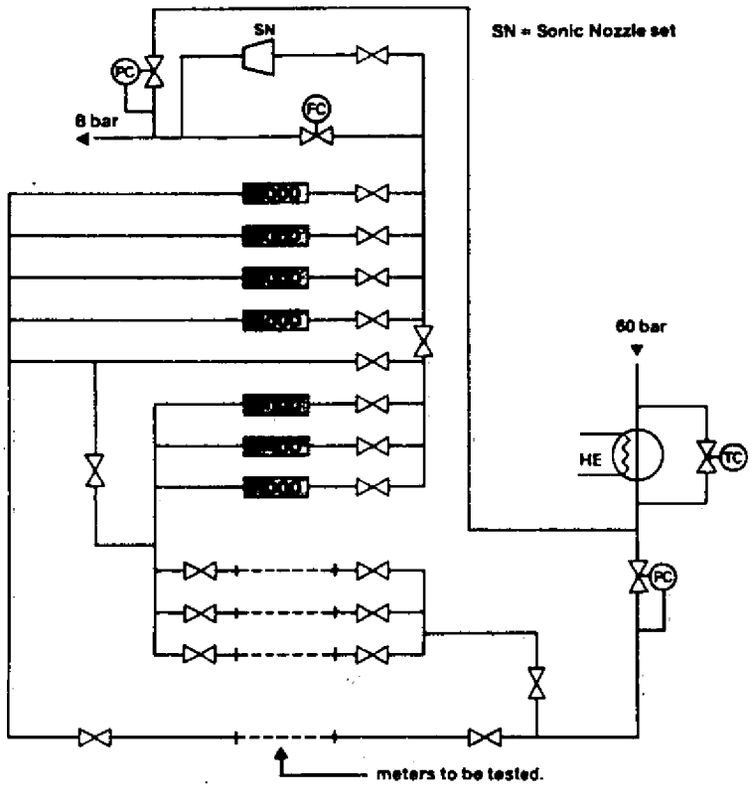
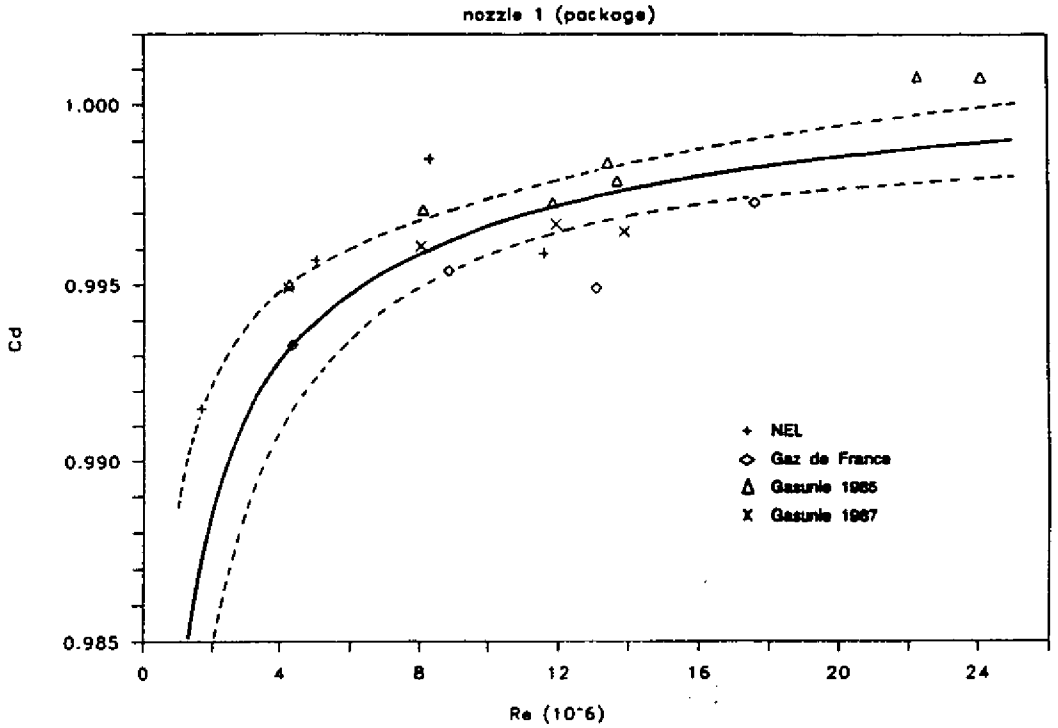


Figure 7: The high pressure test installation of the Netherlands Measurements Institute at Bergum, the Netherlands.



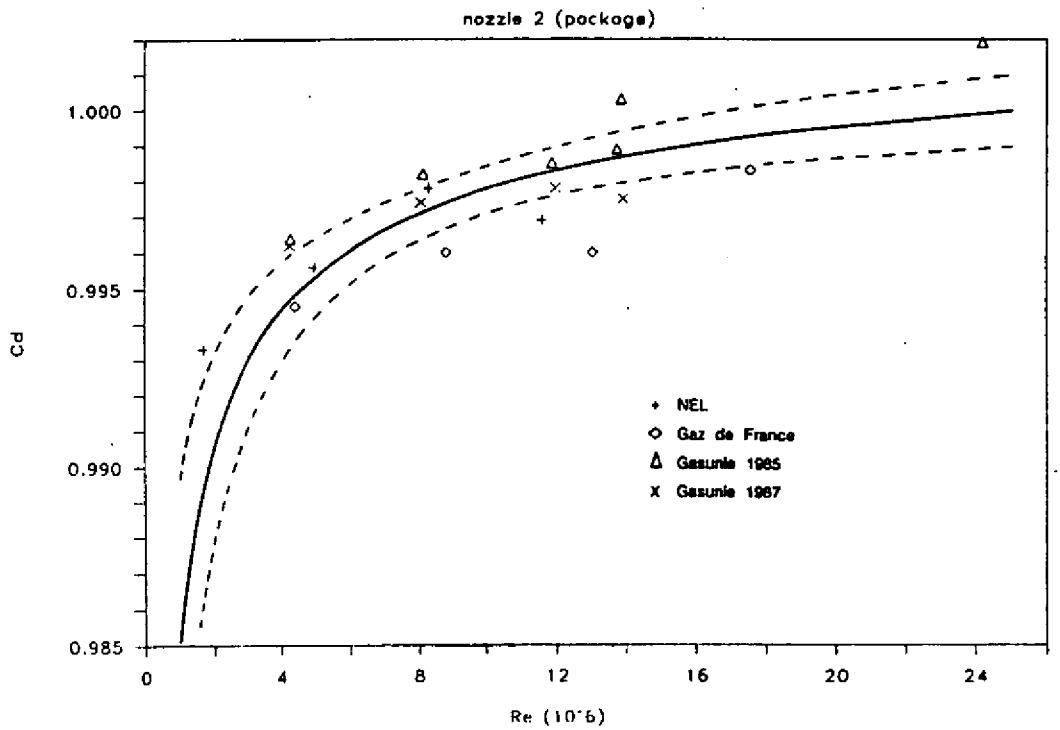
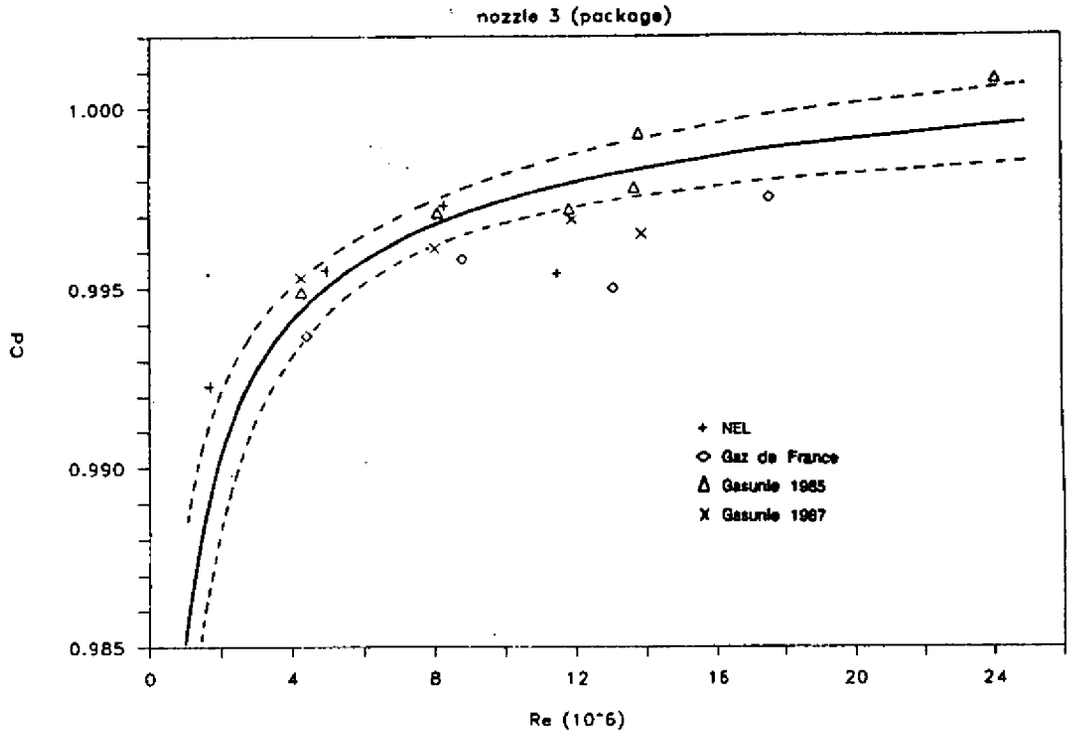


Figure 8 a,b: The discharge coefficient C_d as function of the Reynolds number Re for the individual nozzles.
The solid line depicts the least squares fit of the data points, the dashed lines the 95% confidence interval of the fit.



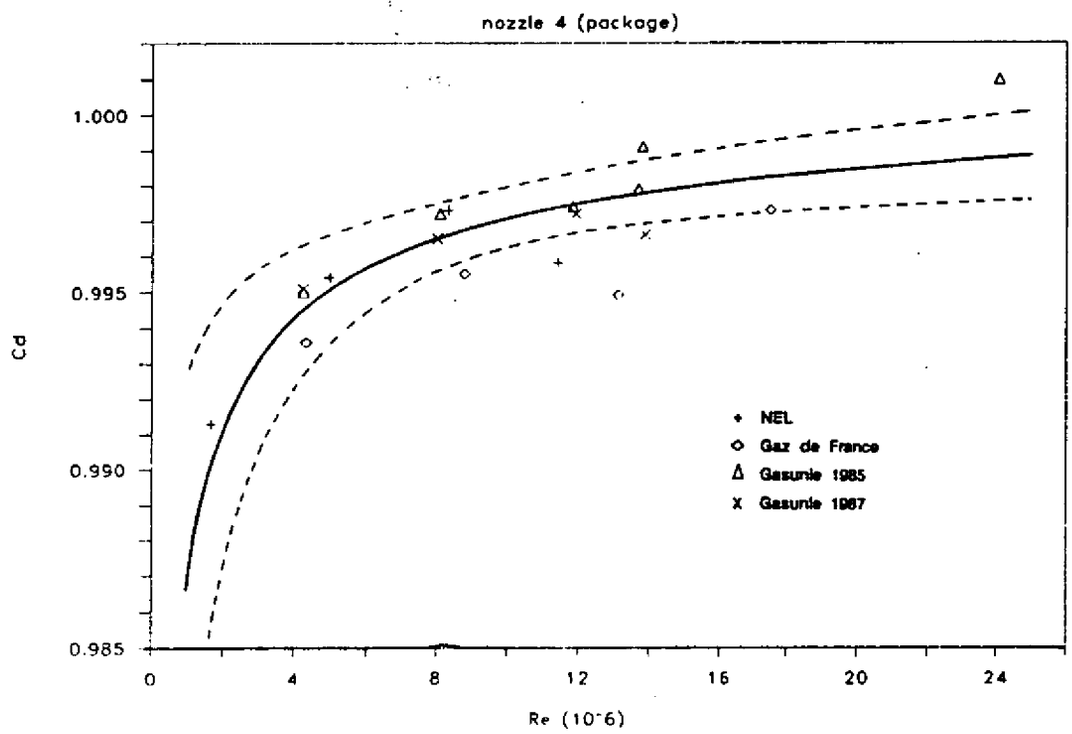
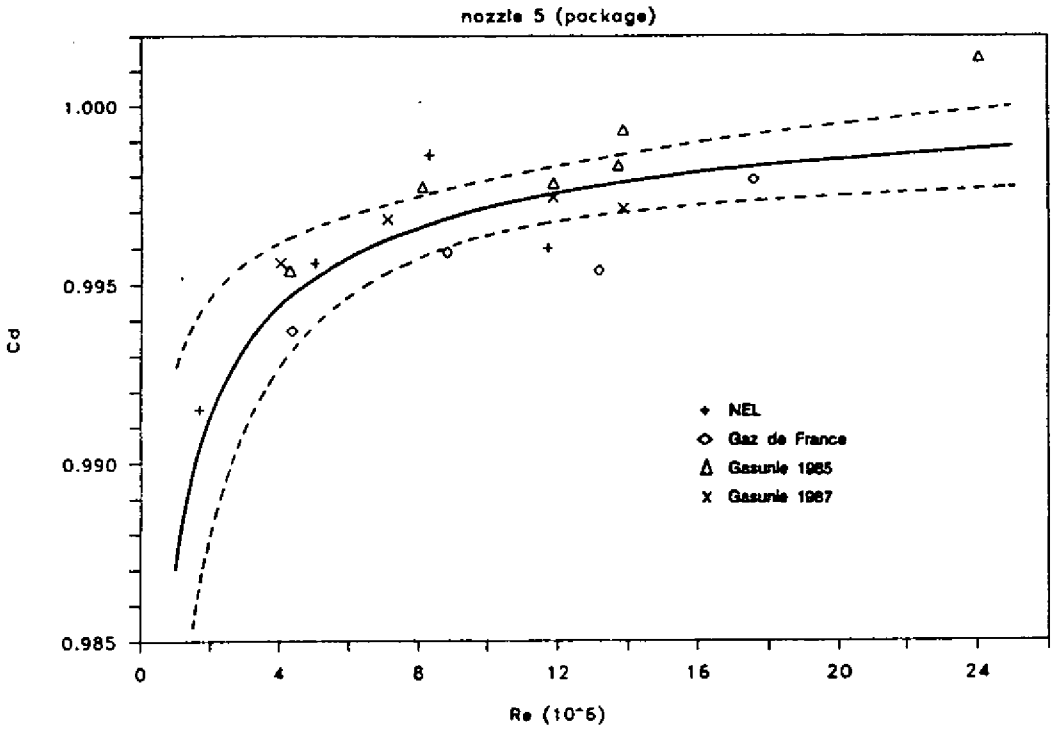


Figure 8 c,d: The discharge coefficient C_d as function of the Reynolds number Re for the individual nozzles.
The solid line depicts the least squares fit of the data points, the dashed lines the 95% confidence interval of the fit.



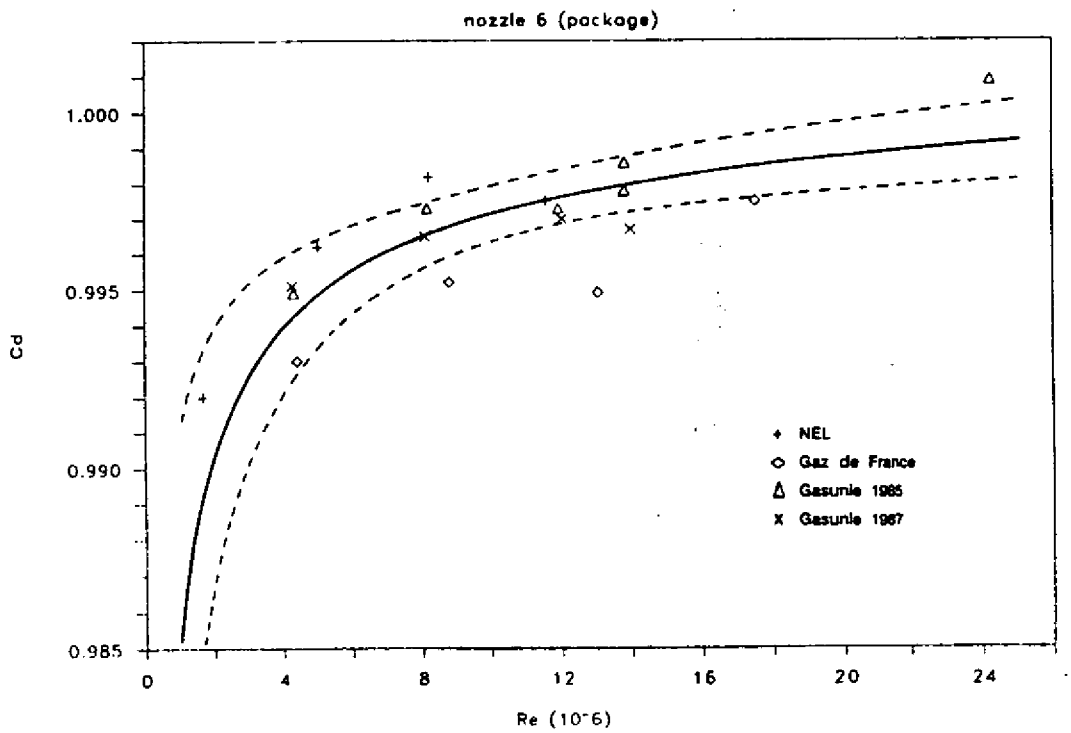


Figure 8 e,f: The discharge coefficient C_d as function of the Reynolds number Re for the individual nozzles.
The solid line depicts the least squares fit of the data points, the dashed lines the 95% confidence interval of the fit.

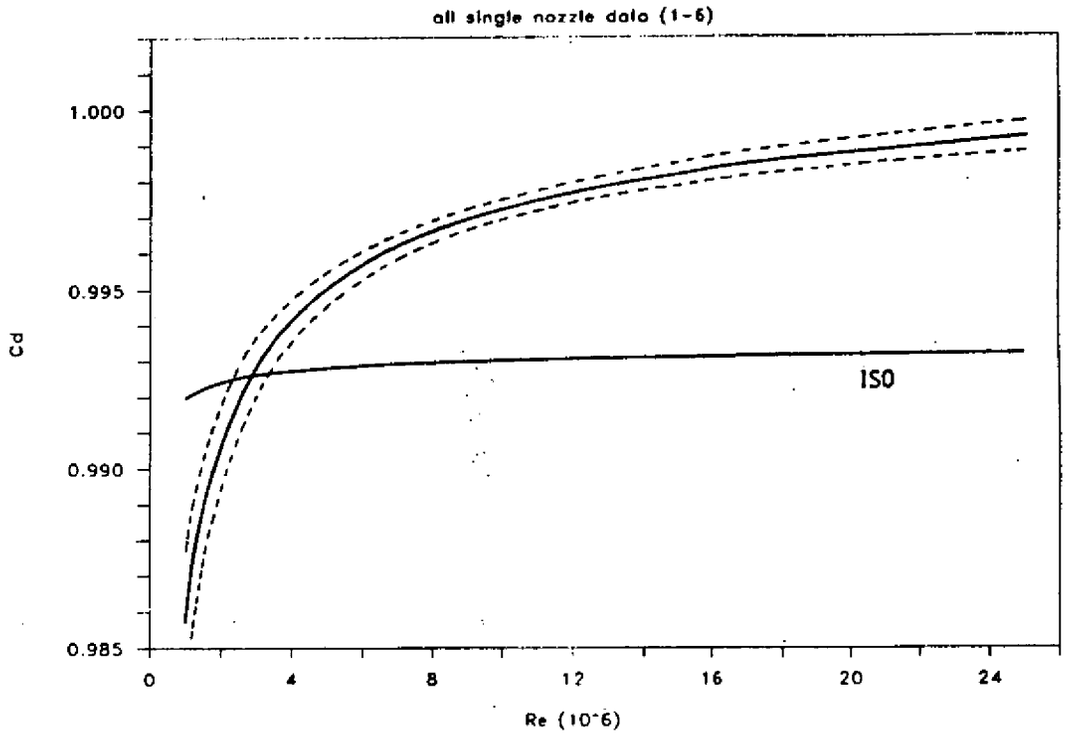
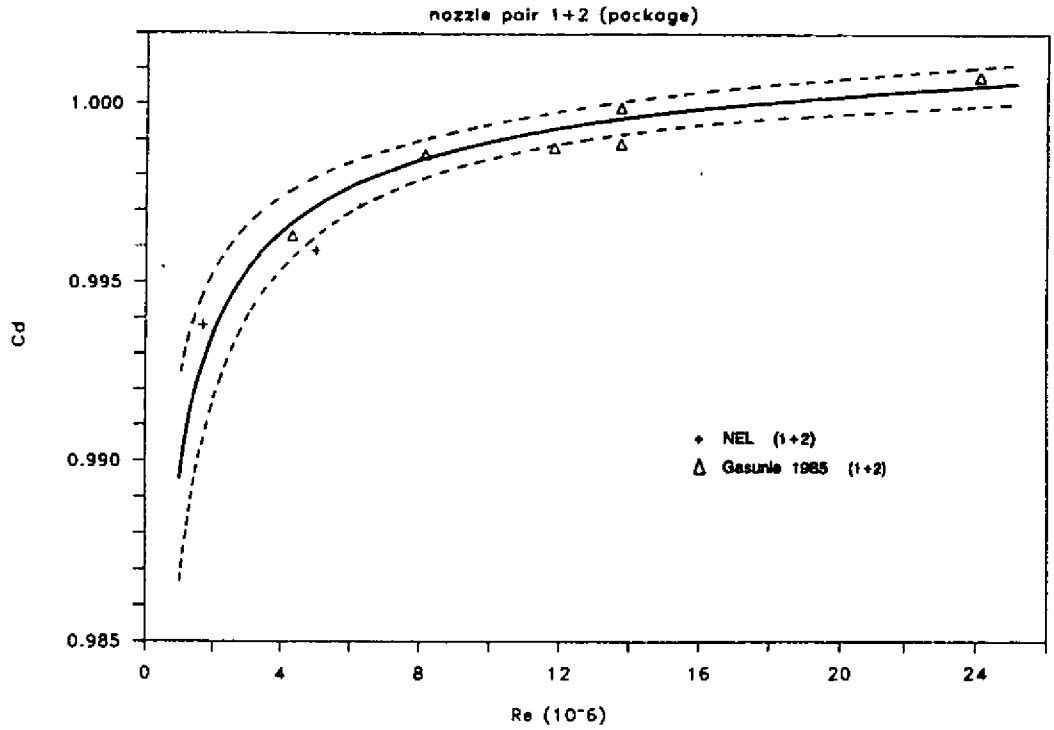


Figure 8 g: The least squares fit through all data points taken together. Shown is also the prediction according to the ISO draft international standard[1].



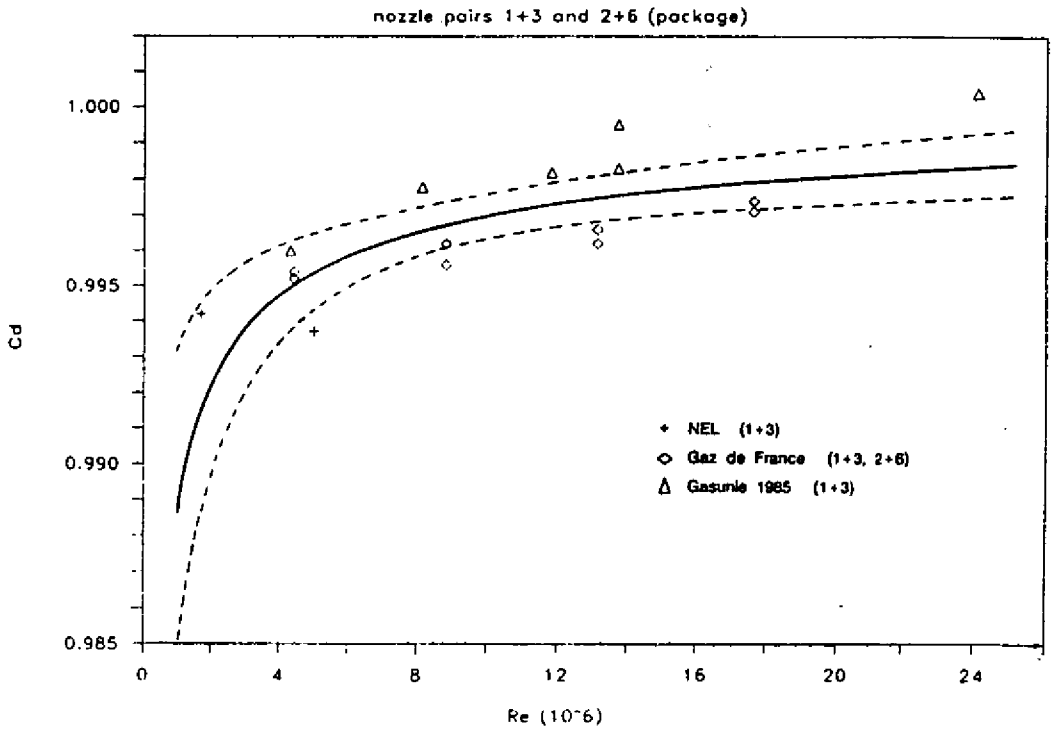


Figure 9 a,b: The discharge coefficient C_d as function of the Reynolds number Re for the nozzle pairs.
The solid line depicts the least squares fit of the data points, the dashed lines the 95% confidence interval of the fit.

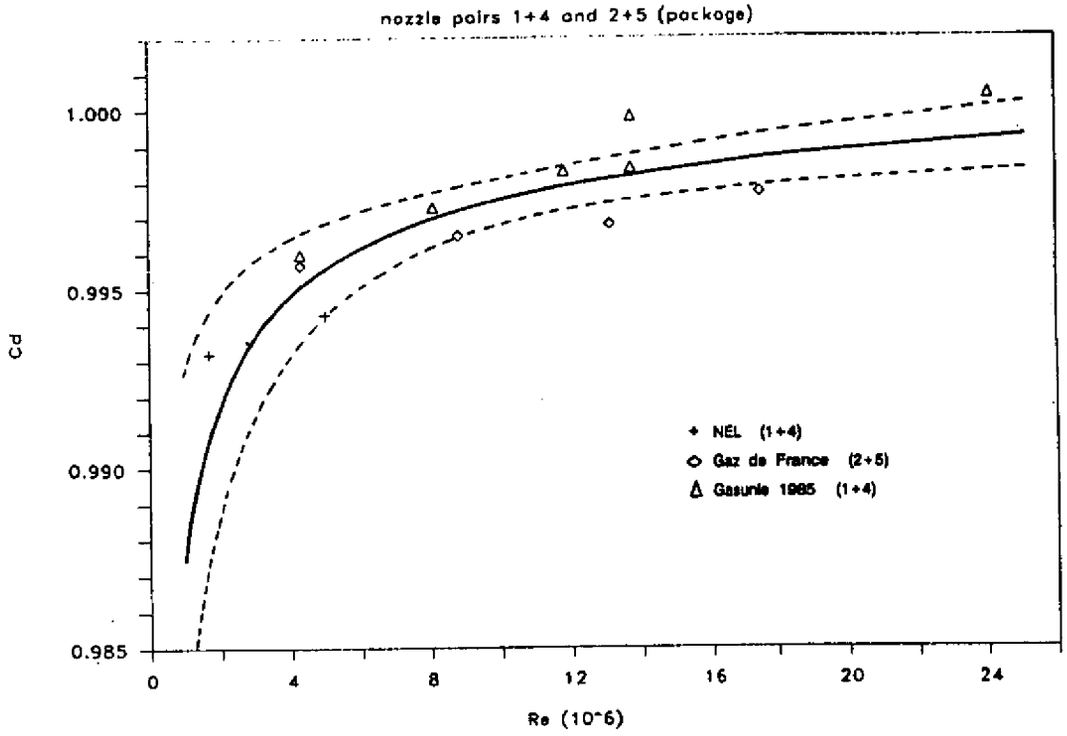
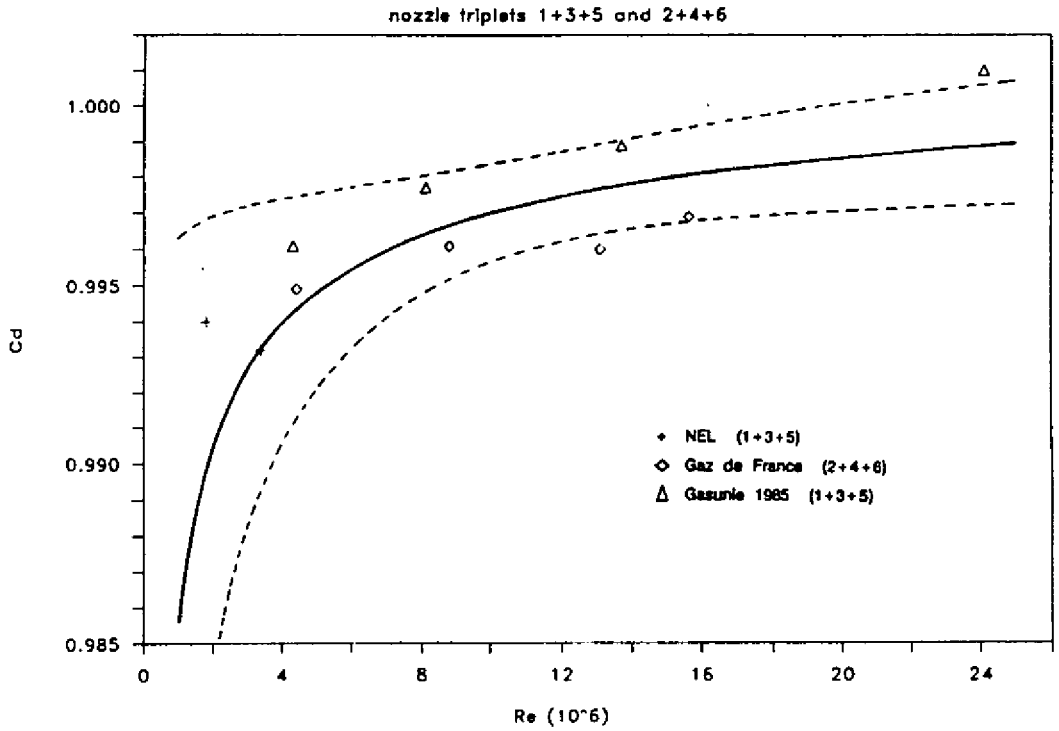


Figure 9 c: The discharge coefficient C_d as function of the Reynolds number Re for the nozzle pairs.
The solid line depicts the least squares fit of the data points, the dashed lines the 95% confidence interval of the fit.



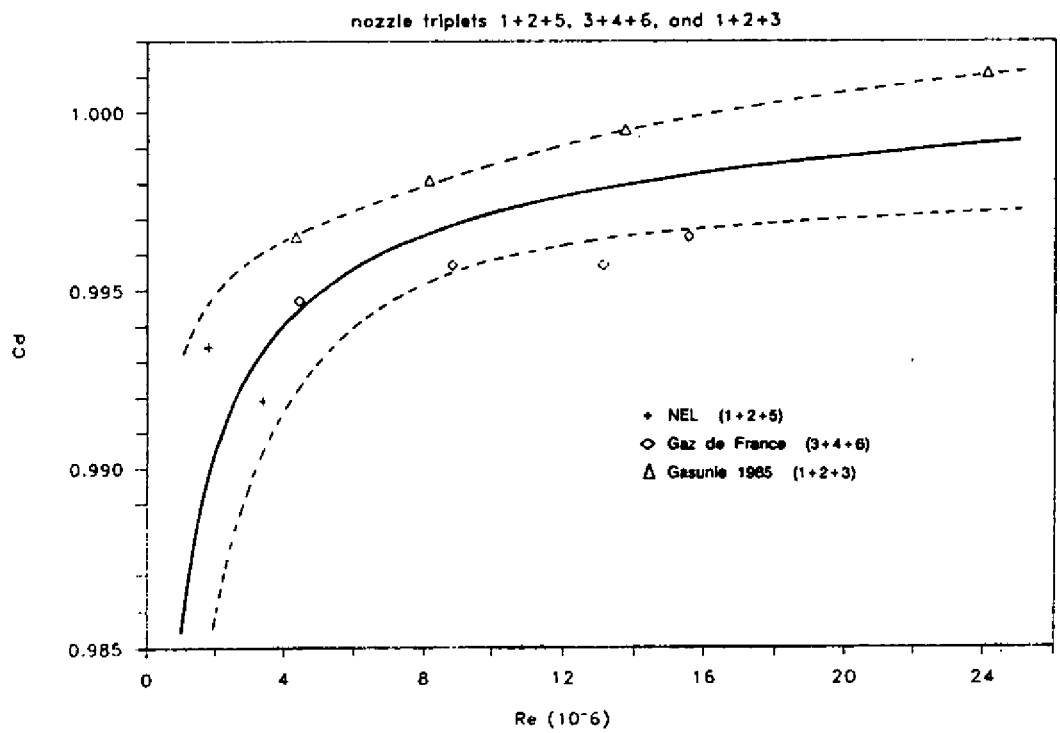


Figure 10: The discharge coefficient C_d as function of the Reynolds number Re for the nozzle triplets.
The solid line depicts the least squares fit of the data points, the dashed lines the 95% confidence interval of the fit.

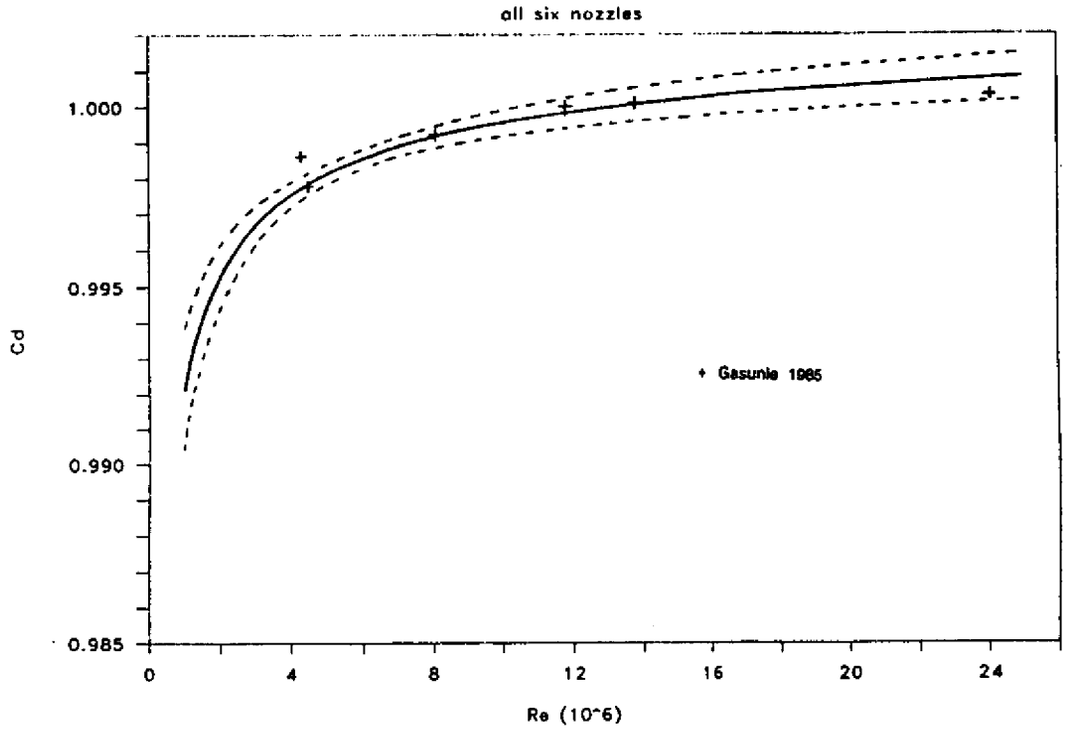


Figure 11: The discharge coefficient C_d as function of the Reynolds number Re for all six nozzle (results from Gasunie only).
The solid line depicts the least squares fit of the data points, the dashed lines the 95% confidence interval of the fit.

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Field Experience with Flare Gas Meters"

Lecturer:
Gudmund Lindland
Phillips Petroleum Co. Norway

FIELD EXPERIENCE WITH FLARE GAS METERS.

INTRODUCTION

All the Greater Ekofisk production is processed at Ekofisk Center. The Ekofisk platforms are preprocessed at Ekofisk FTP on the South end of the Ekofisk Center complex and West Ekofisk at Ekofisk Tank before this production joins the remaining Greater Ekofisk production for the final two stages of separation and treatment at Ekofisk Tank.
All of these processes have relief system into the flare header system with flare towers at the North and South end at Ekofisk. The gas reliefs, vents and leaks into the flare header system are measured through three flare meters in the South direction and three flare meters in the North direction. Each meter run is equipped with an insertion turbine flowmeter and a densitometer for mass flow determination.

From a management and operation point of view a reliable flare gas meter is of great importance. One of the reason for this is that in addition to using the meters for the lost gas accounting, the flare meters are also used as tools to detect abnormal flaring of gas. This abnormal flaring might come from a leaky valve. The flare meters will make the operators aware of the high flaring and they may find the cause and reduce the loss of gas to the flares.
This mean that the flare meters should be capable of measuring a wide range of velocities occurring in the flare pipes.

The flare gas meter on Ekofisk was original designed with a single insertiontype turbine flowmeter. With the limitation in rangeability for a single turbine meter, this system was not able to handle both the high and the low end of the actual flaring. In an effort to increase the rangeability, a dual flare turbine meter was tested and has now been used in normal operation over a period of five years.

In this paper I will share our field experience on this dual flare turbine meter. I will also describe some of the initial problems with the implementation of the dual probe in the original single turbine meter system.
Furthermore I will address a mechanical problem with the dual rotor probe switching system, and a modification carried out by us. Finally some ideas of how to use a dual flare turbine probe in connection with a modern flow computer will be discussed.

An evaluation of those parameters which are significant in the selection and application of a turbine meter system for flare meters, is not a part of this paper.

ORIGINAL FLARE METER SYSTEM

The original flare metering system on Ekofisk was designed with a turbine flowmeter and a densitometer. Both of these instruments are of an insertion type that may be inserted into or removed from the line under normal operating condition. A full bore valve is used between the units and the pipeline, so that the entire assembly may be removed for maintenance or repair without interrupting the flow.

The turbine flowmeter consist of a bearing mounted rotor in a housing through which the fluid to be measured is passed. The rotor spins with a rotation speed proportional to the velocity of the fluid flowing through the meter. An electro-magnetic pickup and associated electronics detect the passage of each rotor blade and generates a pulse. The number of pulses is then proportional to the total actual volume of flow, and the frequency of the pulses is proportional to the actual volumetric flow rate.

The metering system on Ekofisk is based on mass calculation. The densitometer is therefor used to give the additional information needed to convert the actual volumetric flow rate from the turbine meter to a mass flow rate.

The block diagram show the Flare metering system on Ekofisk.

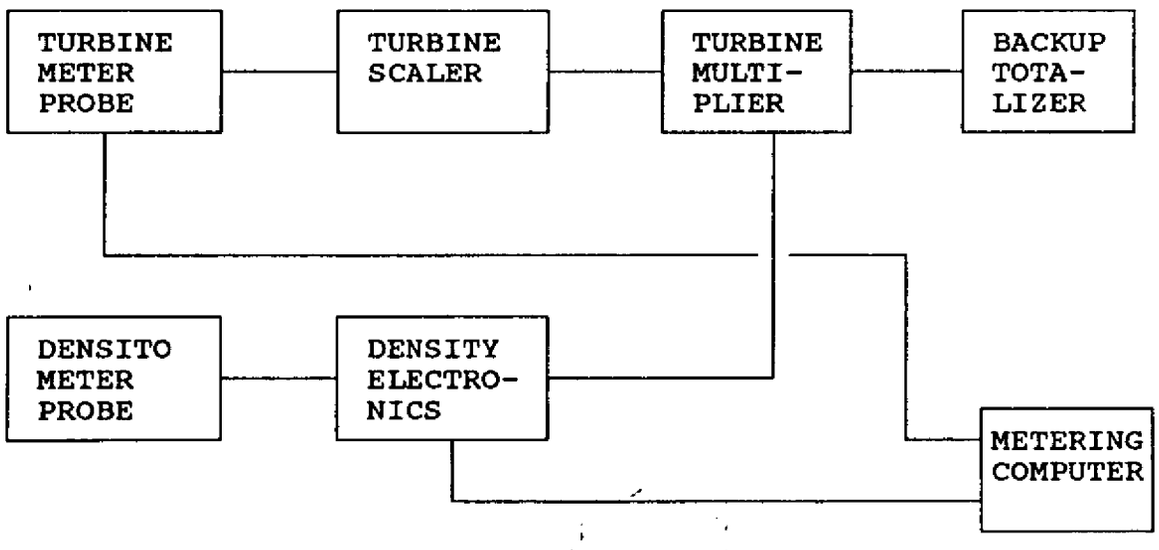


Figure 1 Block diagram of flare metering system on Ekofisk

The turbine meter should be installed with 15 pipe diameters straight section upstream and 10 pipe diameters straight section downstream of the meter.
According to the vendor, their design is based on the average velocity being at .12x pipe diameter from the pipe wall in a pipe of average roughness. The centerline of the rotor must be inserted into the pipe to this depth.
Since the probe obscures a portion of the line, the velocity through the probe is slightly higher than it is either upstream or downstream.
The calibration sheet furnished with the turbine meter defines the velocity at the turbine for specific output frequencies. This must be adjusted according to the meter pipe size.

The velocities are related by:

$$V_p A_p = VA$$

where

V_p = velocity at probe as indicated by output frequency

A_p = unobscured area at probe

V = velocity in unobscured flow line

A = cross sectional area of flow line

One of the important part of the turbine flowmeter is the rotor bearing. Basically, there are three types of bearings used for this type of turbinemeter: the Journal bearing, the Ball bearing and the pivot bearing.
The three types of bearings are shown in figure 2

The meters used on Ekofisk are made with ball bearing. These bearings give a low bearing drag effect to the turbinemeter. Such meters have wide rangeability and good linearity characteristics. The bearings are also easily replaced, and the replacement has a nearly negligible effect on meter performance, so that new bearings can be installed without recalibration. This is also part of the normal maintenance prosedure for the flare gas meters on Ekofisk.

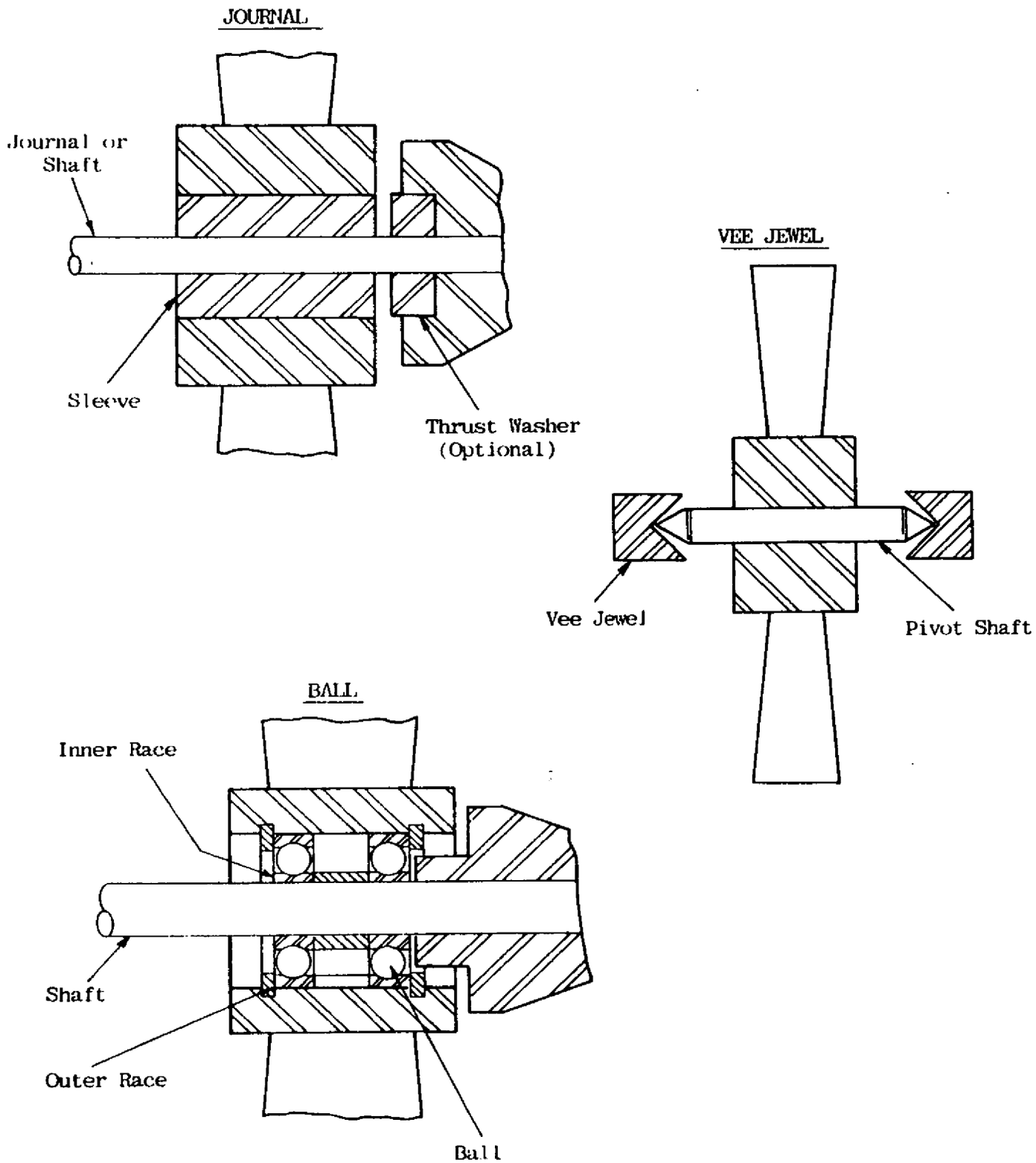


Figure 2 Bearing types used for turbine flowmeter

DESCRIPTION OF THE DUAL FLARE PROBE

The dual flare probe is based on the same principles as the single probe, except it has two separate rotors for measuring respectively high or low flow rates. The two rotors are mounted with the flow direction 90^0 to each other.
The unit has a switching box which turns the probe between the high and low flow rate rotors. The switching is accomplished through a mechanical linkage that turns the probe. The linkage is operated by instrument air pressure and activated by a solenoid valve that gets its signal from the associated instrumentation, where the switching points are set.
The switching points are the points at which the dual probe switches from the low-flow rotor to the high-flow rotor or vice a versa.
The switching points are adjusted in % of the flow range of the two rotors.

The dual flare probe is supply with the following rotors:

Low flow range : 1-inch rotor with range 1.5 to 15 Ft/Sec

High flow range: 1/2-inch rotor with range 15 to 150 Ft/Sec

Figure 3 shows the mounting of the two rotors in the dual flare probe.

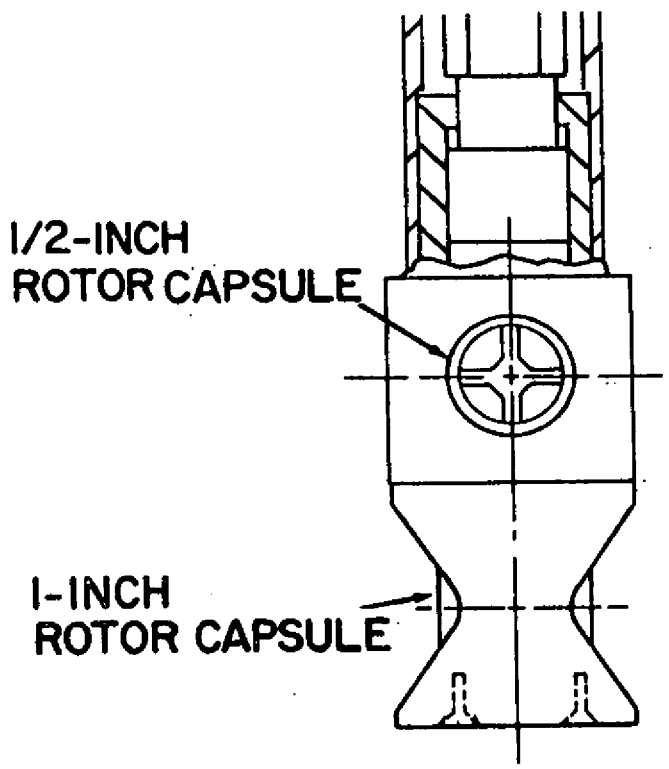


Figure 3 Dual flare probe rotor assembly

INTERFACING OF DUAL FLARE PROBE IN ORIGINAL SYSTEM

The interfasing principle of the dual flare probe in the original flare meter system is shown in the block diagram below.

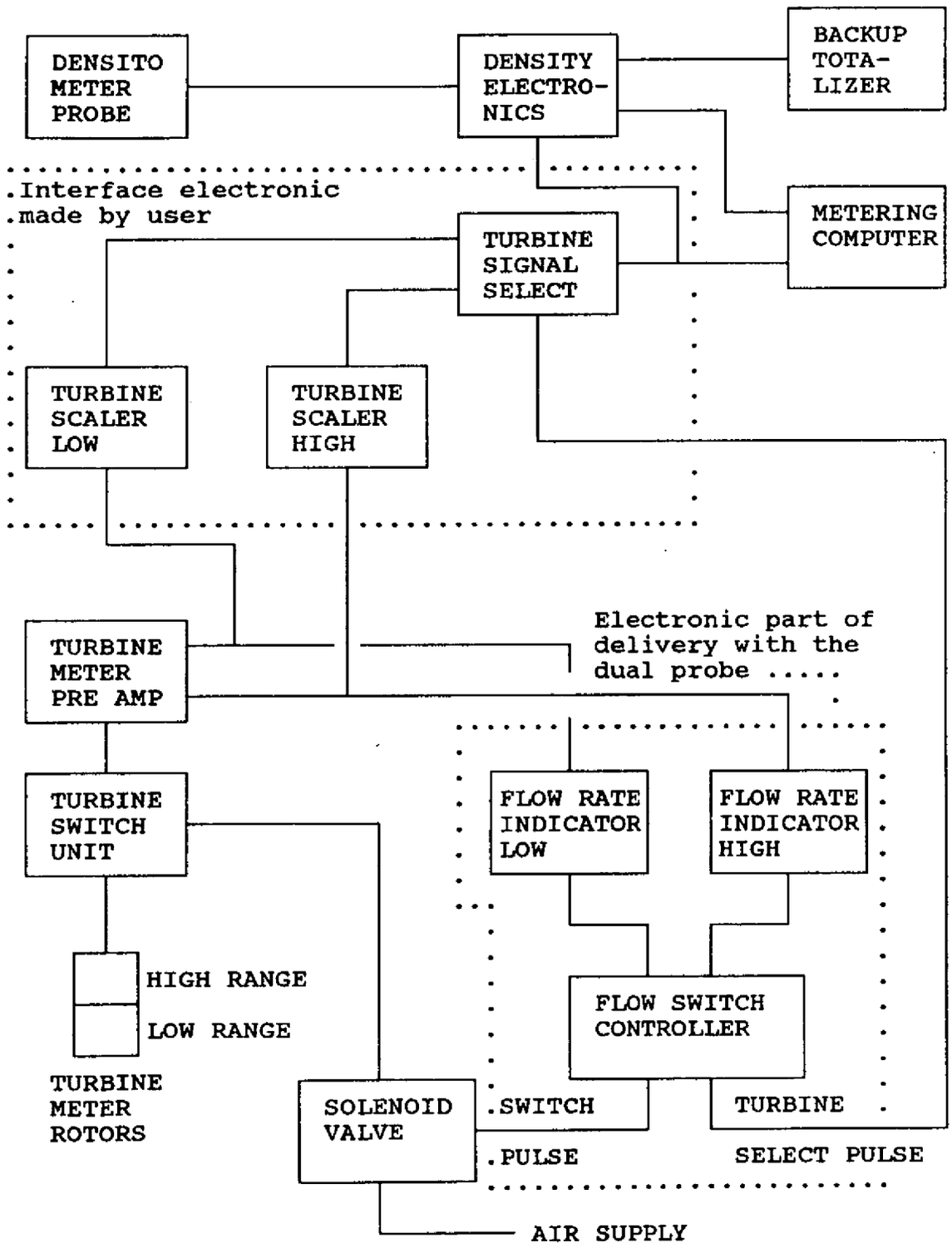


Figure 4 Principle interface of dual flare probe

PRINCIPLE OF OPERATION

Initially when the dual flare probe is powered up, the probe will be in the high flow position. Under normal condition (low flow flaring of gas), the High Flow Rate Indicator will sense that the flow rate is too low and the low flow detector will trip. When the detector trips, the Flow Switch Controller will send a switching pulse to the solenoid valve which turns the probe to the low flow rotor position.

At the same time the Flow Switch Controller will send a turbine select pulse to the Turbine Signal Selector. The function of this selector is to send the turbine signal from the turbine in use to the Metering Computer and the Backup Totalizer.
Using the two Turbine Scaler units makes it possible to scale the signal from the two turbines to eliminate the difference in the meter factors, so that the meter factor to be used for the computer and the totalizer is identical for both rotors.

If the flow rate exceeds the high limit set in the Low Flow Rate Indicator, the sequence described above will be repeated and turn the probe to the high flow rotor position.

As indicated in figure 4 both the Turbine Scaler and the Turbine Signal Selector are made by the user. This was necessary in order to interface the dual flare probe to the original metering system. The old electronic and metering computer can only handle a sigle flare turbine meter signal.

EXPERIENCE WITH THE DUAL PROBE

The rotor in the original single turbine rotor system was selected based on a compromise between the low gas flaring under normal operation and the very high flare rate during a shut down situation. This compromise resulted in less accurate measurement in the low end and very often overranging of the turbine in the high end. A shut down of the platform also often resulted in a damaged turbine rotor.
The gas that is flared during a shut down period, represents a big part of the total gas that is burnt during a month. A metering system that could fail during the most important periods, was not satisfactory.

The dual rotor probe has greatly improved the system. The two rotors are selected so that one is sensitive enough to handle the low end and the other strong enough to withstand the high velocity of the flare gas during a shut down.
The increased range of the two turbines has resulted in more accurate metering both in the low and the high end.
The mechanical stronger high range turbine has also induced less maintenance on damaged turbines from a shut down.

The switching system has proven itself to be fast enough to handle a sudden change in flare gas flow rate.
In the beginning we had some problems with the switching mechanism due to mis-alignment of the mechanical linkage. This mis-alignment caused the linkage to be blocked in the low flow position, resulting in no measured gas above the switching point of the low range turbine. This often led to damaged low range turbine.
We have corrected this problem by a modification of the switching mechanic system. A guiding ring secure that the probe always stops in the correct position and also prevent mis- alignment of the linkage.
After thsi modification the dual flare turbine probe has been performing to our satisfaction.

DUAL FLARE PROBE USED WITH A MODERN FLOW COMPUTER

A suggestion of how to connect a dual flare turbine probe to a modern flow computer is given in figure 5.

The Flow computer may as a minimum have the following possibility:

1 System for automatic selection of either low or high turbine signal,
The pulses from the selected turbine is used in the flow calculation.

2 Ability to set a hysteresis band for the switching.

3 From the switching point, operate a relay contact for turning of the dual probe.

4 A check to ensure that pulses are accepted from just one turbine at the time.

5 Accept a frequency signal from a densitometer and calculate the density necessary for mass calculation of the flow.

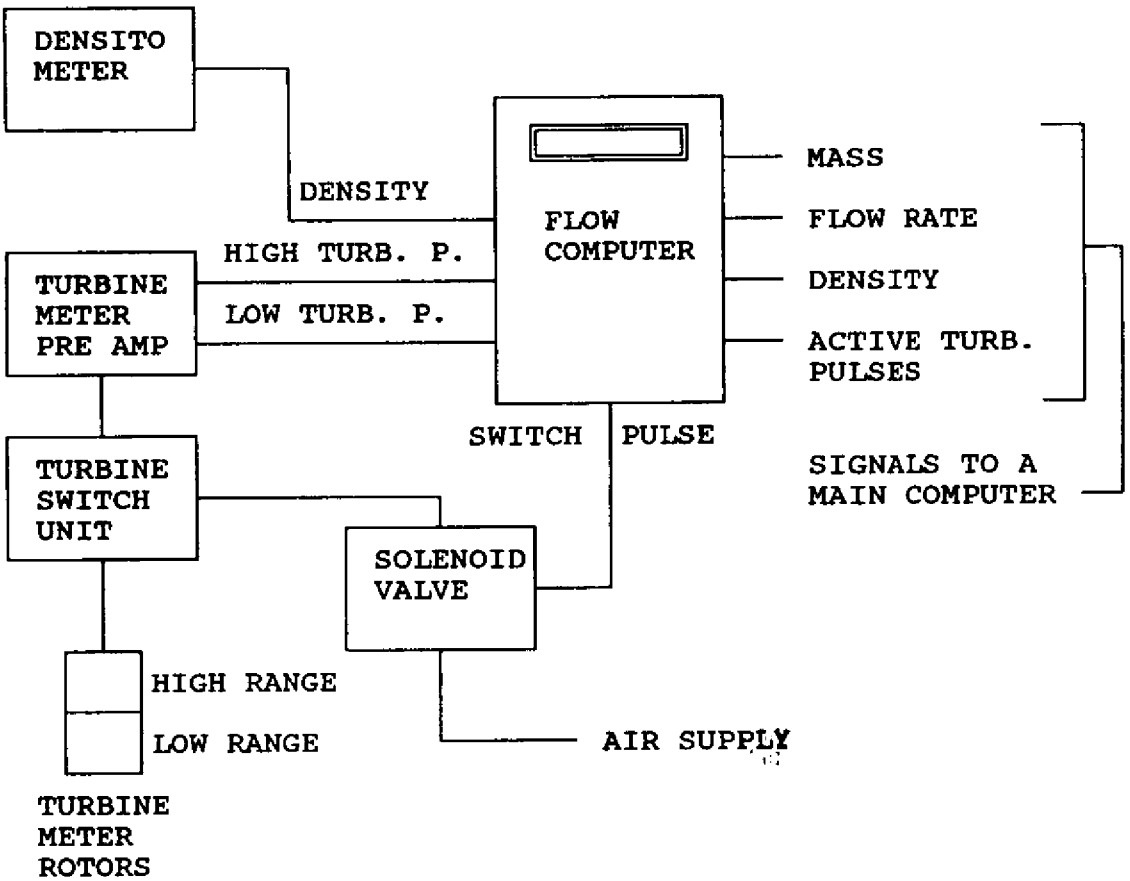


Figure 5 Dual flare probe connected to a Flow Computer

Main Index

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Computer Concepts Data Security and Availibility"

Lecturer:
Marius Wulffers
HCS

M. Wulffers

HCS

COMPUTER CONCEPTS DATA SECURITY AND AVAILABILITY

HCS Industrial Automation is a leading European company in design and implementation of Industrial Automation systems in all kind of industries.
State of the art solutions were found for many technical applications and problem areas.
The fast growing organization has its roots in gas and oil production automation. Many experiences are available with unmanning and demanning operating systems which have high data integrity and availability.
HCS is the first to integrate new developments and systems in their application with prooven success.

Increasing requirements for accuracy, reliability and availability are handled by HCS via smart software and up to date hardware. Crossvertalisation is a keyword in the HCS organization and developments in other branches are watched carefully.

Nonstop or fault tolerant computers increase productivity and limit risks.
On line transaction processing is one of the methodes applied in other branches which might be very valuable for petrochemical industries.

On line transaction processing (OLTP) in automation originates in 1976 and then rapidly increased its markets. Banking (money transfer) cannot affort system downtimes and therefor it was this branch who initially integrated on line transaction processing as a non stop application in their system architectures.

HCS Industrial Automation built its first SCADA (supervisory control and data acquisition) system based on the Tandem non stop computers in 1981 and many have followed since then.

The success of Tandem non stop computersystems can best be shown via turnover figures. Founded end 1974 Tandem shipped its first computer in May 1976 and had revenues of 1.314.721.000 US Dollars in 1988. Also in Europe companies and industries become convinced of high system availability and reliability requirements. This is proved by increasing contribution of Europe customers in total sales.

HCS Industrial Automation has over 25 years of experience in gas and oil production automation. Over these years a software package was developed called "Fast/Tools".
In Fast Tools many gas and oil orientated applications have been built to serve the oil industry. Fast Tools are hardware independant and run on several types of computers.

The following Tools are available: Busfast, itemfast, equipmentfast, colourfast, history fast, compute fast, alarmfast, reportfast and database fast. Typical standard applications which are available: well testing, flowcalculations, leak detection, production forecast, smart production, scraper control, arrival time prediction, etc.

Fast/Tools are applied in over 200 systems all over the world.
The R&D department of HCS produces constantly new applications and developments.

Fast/Tools are available on Tandem, Vax, Vax station, Sun 480 system, Sun Sparc station, Stratus, PC and upon request on many other brands.

Complexity of gas and oil field infrastructures, combined with typical offshore requirements justify the combination of HCS experience and Tandem rigidity.

To solve the flowcomputing problems both on- and offshore, many companies designed dedicated flow computers, however basic requirements from authorities and operating companies cannot be met.

In co-operation with HITEC Stanvanger, HCS is developing a Tandem based flow computer with the following specifications:

- availability : over 99,98%
- accuracy : better then 0,001%
  Depends on the number of processors in the Tandem system e.g.
- capacity : 13 gasflow calculations and 5 oilcalculations
- frequency : every 5 sec. all calculations done
- modular extendable
- online programming and configuration
- prover loop control and supervision
- all further basic and standard functions

Above mentioned requirements were set in close co-operation with Phillips Petroleum Norway., who will be the user of the system.
The Norwegian Petroleum Directorate has to give approval to the configuration

The nonstop configuration (sometimes called fault tolerant) consist of the following items:
- Tandem CLX 620 system
  - double processor
  - double disc
  - double I/O controller
  - double VME system
  - double power supply
  - Fast/Tools

The VME system runs under OS-9 and all programming is in 'C'.
The Tandem hass its own 'Guardian' operating system and alarming options. Report facilities and displays are flexible and can be altered by client without the assistance of supplier.

In Holland HCS supplied flow computing systems for NAM (50% Shell, 50% Exxon) in Groningen (onshore) and Den Helder (offshore application).

When the Phillips flow computer system is in operation and NPD approval is received, typical items of the system will be declared standard and become available on the Norwegian market via HITEC Stavanger.
Tandem Norway provides support and service when necessary. Experience learns however that only occasionally their presence is required because the system cann't fail.

Increasing demands from Governments and concession share holder force operator companies to increase functionality and availability of flow computing systems. Extentiability and modulairity cannot be missed in modern computing systems.
Do not invent wheels, find out the similar applications and use them for your particular problem.
This is the message for HCS internally and externally and you will be surprised what results it will bring.

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"The KO210 Flow Metering Control System"

Lecturer:
N.E. Standal
Kongsberg Offshore a.s

THE KO210 FLOW METERING CONTROL SYSTEM

by

N E Standal

KONGSBERG OFFSHORE a.s

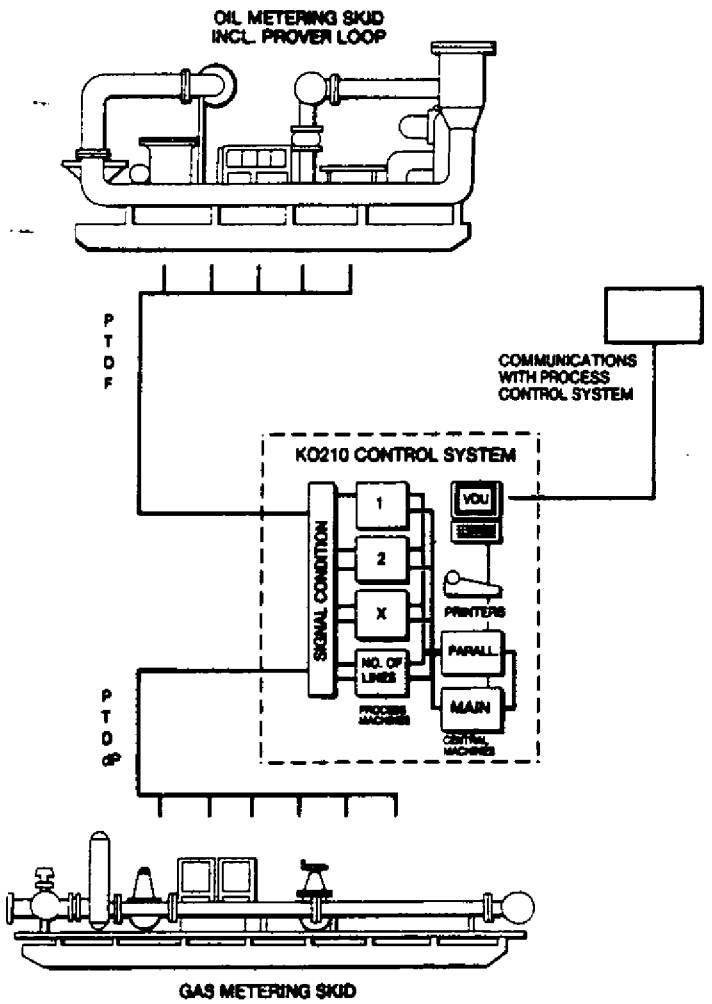
TABLE OF CONTENTS

1 INTRODUCTION

The K0210 Fiscal Metering Control System is a hierarcial, two level computer system. The first level of the system is the Process Machine (PM) performing all interfacing with the metering skids, i.e. all input/output signals are connected to the Process Machine. In a typical installation with both oil and gas metering skids, one common Process Machine can monitor and control one gas line, one oil line including the prover. However, it can be configured as one Process Machine for each metering line.

The other level is the Central Machine (CM) which communicates with all Process Machines of an installation. The Central Machine comprises the Control System main data storage and performs the operator interactions. The Central Machine also performs stations totalising, statistical data computation and it performs the reporting on printers.

The Central Machine can be configured either as two redundant computers with one in charge and the other as standby, or as a single computer according to actual requirements.



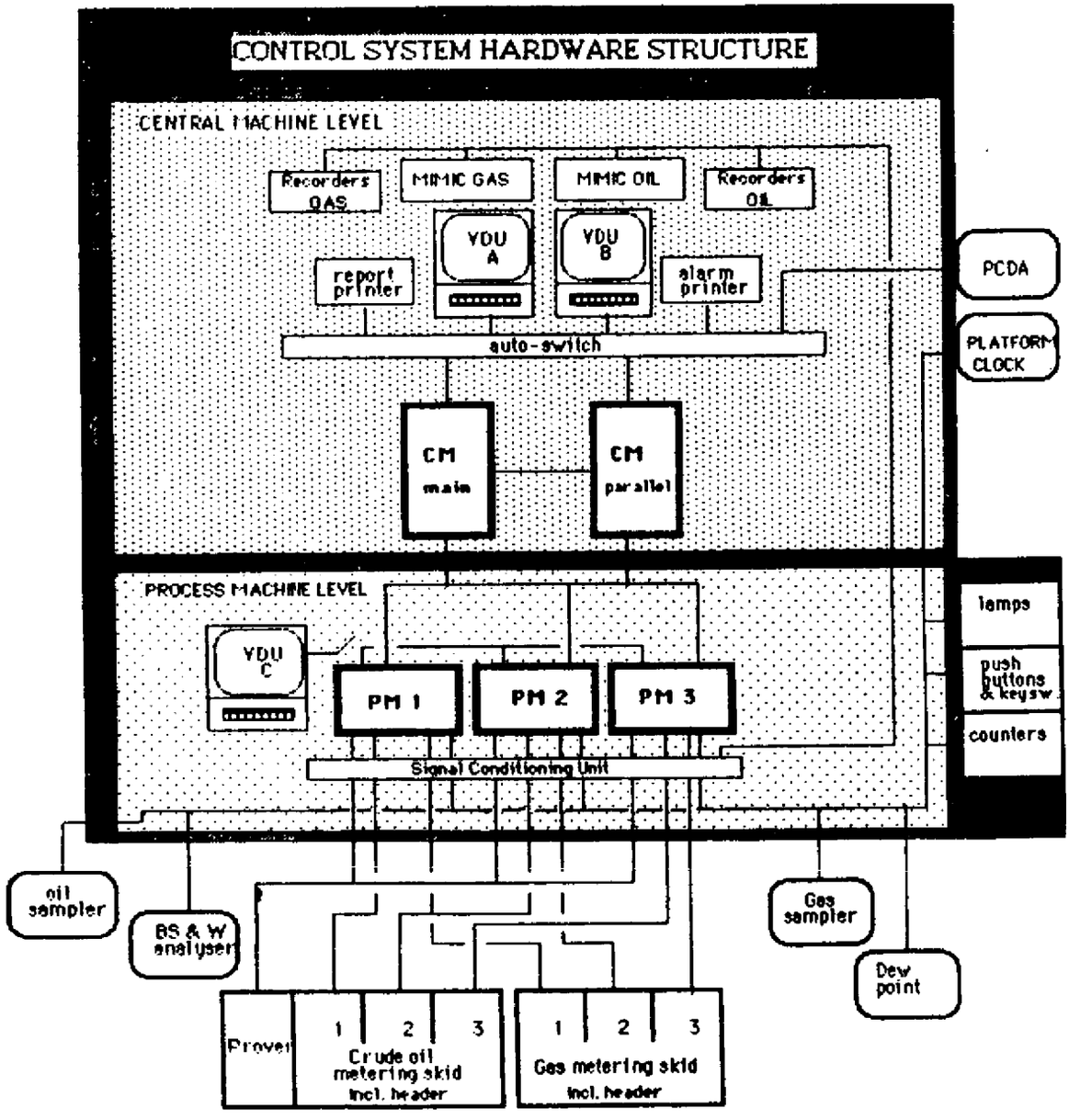
Flow Metering System Structure

2 CONTROL SYSTEM DESCRIPTION

The sketch below indicates a control system equipped with customer requested, additional facilities such as mimic panels and pen recorders. The "process" in this case, is an oil skid with three metering lines (including turbine meters prover) and a gas skid with three orifice based metering lines.

The metering stations are also interfaced with flow proportional samplers, BS&W analyser, Dew point analyser, external (Platform) clock and a Process Control (PCDA) system.

The Control System comprises three Process Machines, two Central Machines, two printers, a monochrome VDU and two colour VDU's. The printers and colour VDU's are connected to the Main Central Machine and the Parallel Central Machine through an automatic switch.



Example of a Flow Metering Control System for two metering stations.

2.1 PROCESS MACHINE FUNCTIONS

A single Process Machine will in the case described above, handle the signal readings and fiscal computation for one oil metering line and one gas metering line. It also interfaces to all signals of the turbine meter prover and will control the proving for the turbine meter of its oil metering line. Each Process Machine is connected to common station equipment, such as BS&W and Dewpoint analysers, flow proportional samplers, and in this actual case, a platform clock. A Process Machine transmits its data simultaneously to both Central Machines.

PROCESS MACHINE FUNCTION OVERVIEW

* COMMUNICATIONS WITH TWO CENTRAL MACHINES
* INFORMATION/DATA DISPLAY
* PARAMETER ENTERING FACILITIES
* ERROR LOGGING
* PROCESS EVENT LOGGING
* ALARM LOGGING
* WATCHDOG
* SAMPLER CONNECTION
* LINE INTERLOCKING FACILITIES
* LINE CALIBRATION MODE
* PROVING SEQUENCING OIL LINE
* CHECKSUM VERIFICATION
* ACCUMULATION
* BACKUP DENSITY CALCULATION
* FLOW CALCULATIONS
* VALVE SEQUENCING (OPEN/CLOSE LINE)
* SIGNAL LIMIT CHECKING (ALARMING)
* INSTRUMENT INPUT/OUTPUT SIGNAL HANDLING

All instruments of a metering line are interfaced with the Process Machine through dedicated input/output (I/O) modules. Depending on the signal type, the I/O module in question will perform signal handling as required. Data is made available for the Process Machine CPU, by the I/O module, for limit checking, calculations and storage once a second, in general, (digital signals are available 10 times a second).

Analogue input signals (pressure, temperature, differential pressure) are converted to digital form by an Analogue Input Module with a resolution of 14 bits and an accuracy better than 0.02%, including resolution and input resistance accuracy figures.

A densitometer is connected to a Pulse Input Module which counts the pulses continously and transfers the frequency to the Process Machine CPU with an accuracy better than 0.01%.

Turbine meter signals are handled by a Turbinemeter Pulse Counter Input Module which counts the two pulse trains individually. Pulse security handling is performed in accordance with ISO 6551, level A.

During turbinemeter proving, pulses from the turbinemeter will be handled by a Proving Pulse Counting Input Module which will perform pulse interpolation according to ISO 7278/3 (double timing method), when required. Number of pulses is available for the Process Machine CPU for each trial.

Within each second, the Process Machine will perform the following calculations according to fiscal standards for both a gas and an oil line:

- volume flows
- mass flow
- increment of volumes
- increment of mass
- accumulated volumes
- accumulated mass
- density
- backup density

The calculations are made using 64 bit real number representation of: 11 bit exponent, 52 bit fraction part and one sign bit. This gives a real number representation of 15 significant digits.

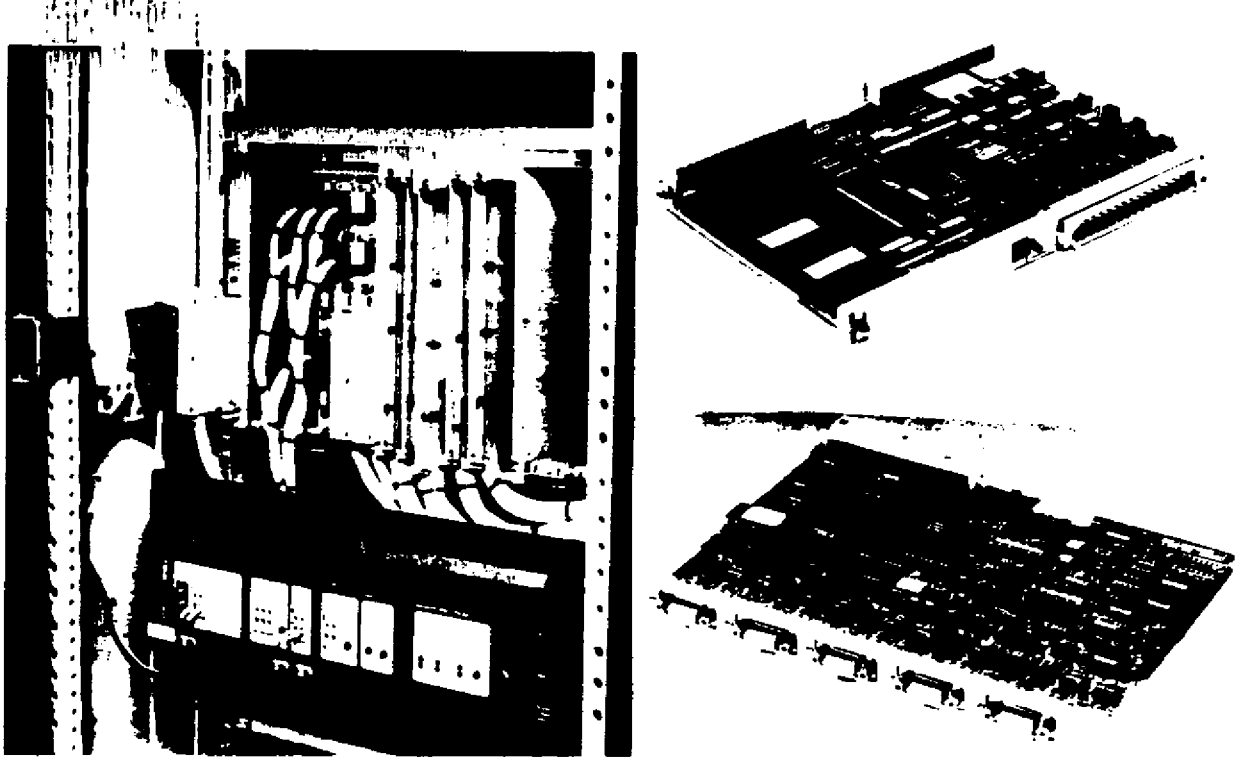
2.2 PROCESS MACHINE HARDWARE

The Process Machine hardware is based on the well proven Sicomp MMC216 microcomputer family from Siemens. Those computers are used in a wide range of applications such as:

* onshore industry installations for:
  - water treatment control
  - pig flesh quality determination
  - airport runway light control
  - steel production control (one system is a multi-computer installation with as much as 80 CPU's).

* marine/offshore installations on:
  - naval vessels
  - metering systems

The hardware construction of the MMC216 computer is a traditionally microcomputer structure with an internal powerful 16 bits bus located in a subrack with power supplies, fans, backup battery and free slots for insertion of CPU, memory and I/O modules. The Process Machine has good computing performance utilizing Intel types of processors including additional numeric data processor.



Process Machine with some typical modules

Most of the Process Machine modules are of the Sicomp type. However, some of the I/O modules are of the Siemens Simatic S5 type since the Simatic and the Sicomp computers are based on almost the same internal bus. The selection of I/O modules are made from a functionality, an industrial experience and a price point of views. The I/O modules are powered by dual redundant power supplies.

The modules of the Process Machine are of the double Europa format.

2.3 PROCESS MACHINE SOFTWARE

A Process Machine comprises software for performing all tasks concerned with metering and control of one gas line, one oil line, turbinemeter prover and communications with two Central Machines simultaneously. In addition, the Process Machine has operator interaction software for data information and manipulation purposes. All signal scanning and calculations are performed within one second.

The data acquisition, scaling and limit check unit performs all signal input and output via the appropriate I/O module. It scales the read-in signal according to the signal engineering unit representation. It also does alarm checking, such as limit violation or rate of change checking. Scaled data is put into the data base, while alarms or events are put into the alarm/event list.

The oil calculation unit and the gas calculation unit perform fiscal calculations according to actual procedures and regulations and enter the results into dedicated registers. Both flows, increments and accumulations of volumes and masses are determined. Implemented algoritms are: gas calculations according to ISO 5167 and oil calculations as described in "IP Petroleum Measurement Paper, no. 2". However, the system is designed for special customer preferences to be installed.

Oil density can be entered as a fixed number, as calculated according to the method of Costald or based on densitometer readings. Gas density can be entered as a fixed number, as calculated according to AGA 8, as calculated according to the KATZ method or based on densitometer readings. Automatic selection of density to be used can be established.

The prover control unit calculates all data related to one round trip trial of proving. The result is placed in the data base for transmittal to the Central Machines and for display on the Process Machine. This unit also performs the prover loop valve sequencing before and after proving, as well as it does pressure, temperature and flow supervision during the stabilisation period.

The communications unit sends data to the Central Machines and it also receives data from those computers and distributes it to the correct data area of the Process Machine data base.

The operator interaction unit gives an operator the possiblities for inspection of the Process Machines database as well as it provides facilities for data manipulation, i.e. line control, proving, sampling and parameter changing.

The checksum control unit calculates and compares checksums for both fiscal algoritmns and data area containing parameters influencing on the calculation results. Alarm will be rised upon any discrepancy.

2.4 CENTRAL MACHINE FUNCTIONS

A Central Machine is connected to all Process Machines by dedicated communication cables, one cable from each Process Machine to each Central Machine. The Central Machine acts as the Control Systems main data base, i.e. it contains all correct information. The Central Machine performs all station totalising of flows and accumulated values. It also calculates average values, the proportional sampling frequency, and it performs the proving management (which line to prove and how many trials to do) and also performs report printing at predefined intervals.

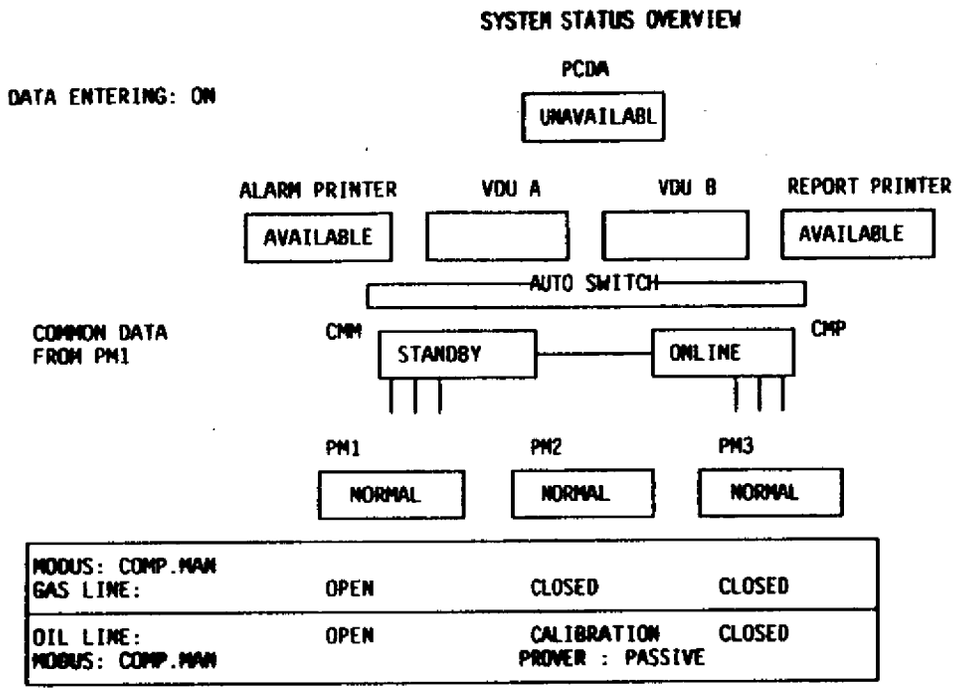
CENTRAL MACHINE FUNCTION OVERVIEW

* PCDA (OR OTHER EXTERNAL) COMMUNICATIONS
* GAS CHROMATOGRAPH CONNECTION
* COLOUR MIMIC DISPLAYS
* PARAMETER ENTERING FACILITIES
* LOGGING OF OPERATOR ENTERED DATA
* PRINTING OF DATA
* PREPARATION AND AUTOMATIC PRINTING OF REPORTS
* ERROR LOGGING
* ALARM LOGGING AND PRINTING
* PROCESS EVENT LOGGING AND PRINTING
* CONTROL SYSTEM CONTROL
* SAMPLING MANAGEMENT
* PROVING MANAGEMENT
* PROVING QUEUE HANDLING
* AVERAGE CALCULATIONS OF SELECTED VALUES
* STATION TOTALISING
* STATION ALARMING
* DEVIATION CHECKS BETWEEN OPEN LINES OF A STATION
* OPEN/CLOSE LINES IN COMPUTER AUTO MODE
* WATCHDOG
* COMMUNICATIONS WITH ALL CONNECTED PROCESS MACHINES

External communication connections to the Control System will be to the Central Machine.

The Central Machine monitors parameter deviation between open lines and will rise alarm if necessary. It opens and closes metering lines of a station depending on flow variations.

The Central Machine supervises the complete Control System status, and will take actions depending on disturbances introduced to the system. In a configuration as described earlier, comprising dual Central Machines and three Process Machines covering one gas and one oil metering station, the information used for making decisitions are showed in the two displays below, the System Status and the Computer Status Overviews.



System Status Overview Display

COMPUTER STATUS OVERVIEW

PICTURE ONLY AVAILABLE ON CM BEING IN STATUS

ONLINE

ALL INFORMATION REPRESENTS THIS CM'S VIEW OF THE ACTUAL SITUATION

TIME PERIOD BY PLATFORM CLOCK: OFF

PLATFORM CLOCK SIGNAL VALUE: WINTER

COMPUTER	STATUS	COMMUNICATION	WATCHDOG STATUS	CONNECTIONS
CMM	STANDBY	CMP:NORMAL PM1:NORMAL PM2:NORMAL PM3:NORMAL	CMM:NORMAL CMP:NORMAL PM1:NORMAL PM2:NORMAL PM3:NORMAL	PCDA:********** APRN:********** RPRN:********** PLATF.CLOCK STS: NORMAL
CMP	ONLINE	CMM:NORMAL PM1:NORMAL PM2:NORMAL PM3:NORMAL	CMM:NORMAL CMP:NORMAL PM1:NORMAL PM2:NORMAL PM3:NORMAL	PCDA:UNAVAILABL APRN:AVAILABLE RPRN:AVAILABLE PLATF.CLOCK STS: NORMAL
PM1	NORMAL	CMM:NORMAL CMP:NORMAL	CKS:NORMAL I/O:NORMAL	ERR:OFF PWR:NORMAL
PM2	NORMAL	CMM:NORMAL CMP:NORMAL	CKS:NORMAL I/O:FAILED	ERR:OFF PWR:NORMAL
PM3	NORMAL	CMM:NORMAL CMP:NORMAL	CKS:NORMAL I/O:NORMAL	ERR:OFF PWR:NORMAL

Computer Status Overview Display

The backup Central Machine will automatically take over as the in-charge Central Machine based on predefined takeover criteria. A takover will be performed mainly for two reasons, either its told by the other Central Machine to take over, or it determines itself that the other is not performing its duties.

The main parameters for decision making, is the watchdog signals, the communication status and the metering line status.

As examples, the following two cases are given. The system status before any disturbances is assumed as described by the two overview displays:

case 1: Disturbance: communication between PM1 and CMP fails.
Action : CMM enters ONLINE status and CMP enters STANDBY status. Printers, VDU's and external connections are switched automatically from CMP to CMM. Totalising and sampling will not be influenced. Alarm is rised.

case 2: Disturbance: PM1 fails.
Action : both gas and oil metering lines are kept open until the oil and gas metering lines of PM3 are opened automatically by the system monitoring task. Then lines of PM1 are closed. Common data will be routed to PM3. Alarm is rised.

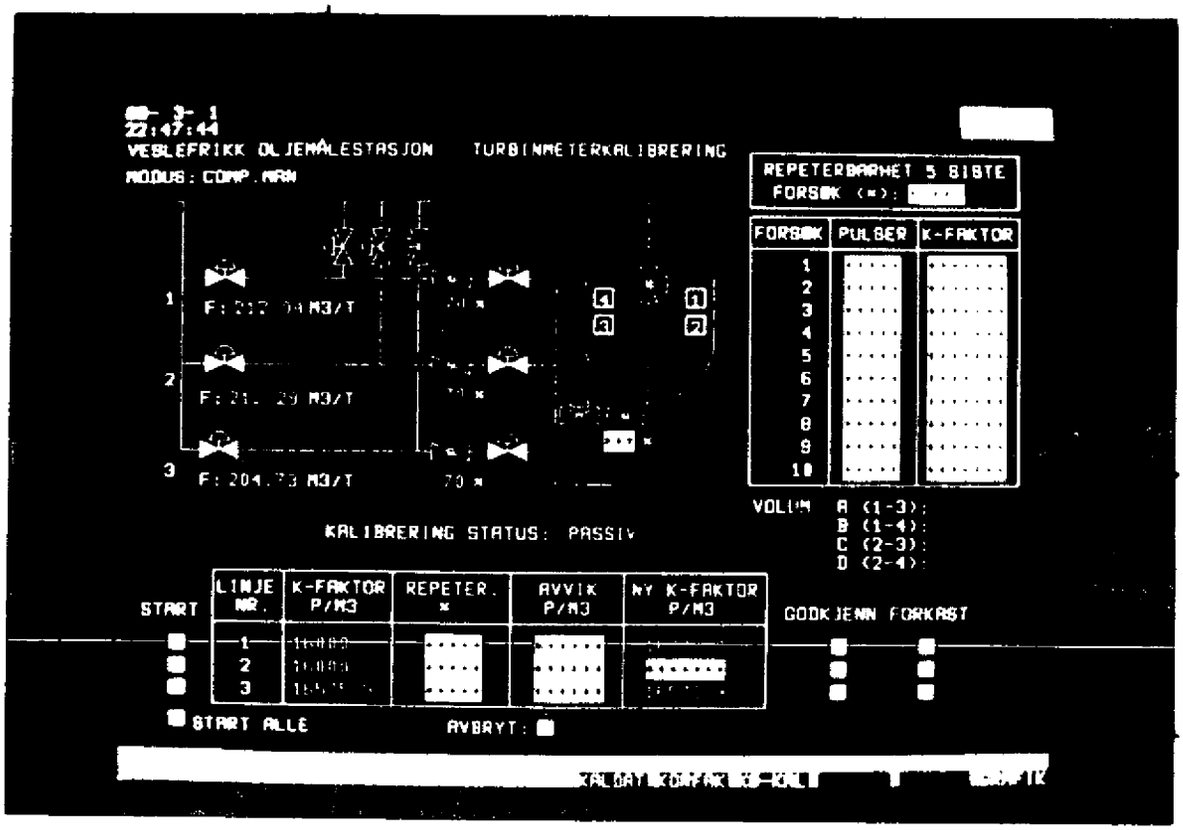
3 CONTROL SYSTEM OPERATIONS

A major contribution for a Flow Metering Control System to do correct metering is to be equipped with a good man-machine interface. The K0210 Flow Metering Control System comprises facilities for easy to use and consistent parameter alterisation, quick process status understanding and good report printing.

Although the system used as an example of this paper comprises several operation equipment, the system can be operated from one single VDU.

The system information is grouped in three main categories: the mimic colour pictures, the parameter entering menues and the reports. All three categories are available at the Central Machine level, whilst the Process Machines supports the menues with some extentions.

An important aspect of an information display is that it contains all data associated with a function and only that. An example of that is the turbinemeter proving control mimic picture.



Turbinemeter proving control picture

Parameter entering menues are available for lookup at any time, but data can only be changed if the access key is switched on. Each parameter is displayed with its currently used value and with an explanatory text along with it. Parameters which logically are related will be grouped together in one menu. An example is shown below. Menues are identically while displayed by a Central Machine or a Process Machine.

89-03-01 23:23 PM NO: 02

PROVER DATA

Volume for one round trip at std. cond.:	Current val	New val
Volume A (1-3).....(Sm3):	1.238353	1.238353
Volume B (1-4).....(Sm3):	1.309503	1.309503
Volume C (2-3).....(Sm3):	1.219373	1.219373
Volume D (2-4).....(Sm3):	1.289783	1.289783
Maximum flow deviation.....(m3/t):	95.3	95.3
Flow transmission period.....(s):	13	13
Pressure deviation prover - line.....(barg):	4.53	4.53
Temp. deviation prover - line.....(DegC):	7.53	7.53
Time to stabilise.....(min):	3	3
Period to first detector.....(s):	23	23
Period to second detector.....(s):	43	43
Period before 4-w valve is turned.....(s):	3	3

Press ESC for return to previous menu

Menu for entering proving related parameters.

Parameters common for all Process Machines will be sent to all of those it concerns. If a Process Machine is unavailable at the time the parameter is changed, the Central Machine will registrate that and update the Process Machine as soon as it becomes available.

The RAM of the Process Machine is battery backed up. If, however, a situation occurs, f.i. a Process Machine replacement, where the configuration data of a Process Machine is lost, the configuration including latest parameter update will automatically be downloaded from the Central Machine at power up of the Process Machine.

The system also supports displays for maintenance and detailed data investigations. Each single prosess signal or calculated value of the data base can be investigated using a specific dislay. For analogue input signals as shown in the figure below, the information available includes both the analogue to digital converters internal representation (the decimal count value) of the signal and the digital (16 bits) representation of the signal in addition to the scaled value in engineering units.

```
89-03-01 23:23                                              PM NO: 02

                                ----------------
                                  POINT DISPLAY
                                ----------------

  TAG no..... :  21-TE108A
  Description :  01: LINE TEMPERATURE
  Signal no.. :  2
  Unit....... :  DegC

                          Value    Status       Alarm     Lock
  Current val :         50.085    ##########   ####      alarm
                           9841
                0010011001110001

  Alarm limits
  High instr. :         101.00                  gen
  High limit. :
  Low limit.. :
  Low instr.. :          -1.00                  gen

Press ESC for return to previous menu
```

Process Machine single point display.

The Process Machine´s system functions comprises facilities such as computer time alteration, list of alarm history (the other alarm list includes only active alarms at the time it is displayed), internal computer program error logging display, forced data base configuration upload/download to/from the Central Machine and a status display of all input/output modules of the actual Process Machine.

```
89-03-01 23:23                                              PM NO: 02

                                ---------------------
                                  I/O-MODULE STATUS
                                ---------------------

        Type                      Address        Status

        Digital in              CE00:0008        OK
                                CE00:0010        FAILED
        Digital out             CE00:0008        OK
                                CE00:0010        FAILED
        Analogue in             CE00:0040        OK
                                CE00:0080        FAILED
        Analogue out            CE00:0020        FAILED
        Counters                CE00:0100        FAILED
                                CE00:0140        FAILED
                                CE00:0180        FAILED
        Watchdog                CE00:0400        FAILED

Press ESC for return to previous menu
```

Process Machine Input/Output Module Status Display.

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Measuring the Flow of Wet Gas"

Lecturer:
G. Washington
KSEPL

MEASURING THE FLOW OF WET GAS

by G. Washington, Koninklijke/Shell Exploratie en Produktie Laboratorium (KSEPL)

Paper for the North Sea Flowmetering Workshop,
in Stavanger, 23-26 October, 1989

SUMMARY

The capability to measure the flow of gas with entrained liquid can play an important role in the economic development of small fields in the North Sea. Such a capability enables separators to be omitted on small developments for which the separator was needed only to provide adequate gas quality for allocation meters. In a search for the best meter this paper presents a number of field tests of gas meters at a production location onshore in The Netherlands. Two aspects are considered, firstly the effect on meter accuracy of increasing quantities of entrained water, and secondly the spot measurement of the ratio of liquid to gas using a tracer technique.

Of the meters tested, the conventional venturi or orifice meter proved the most predictable. With these meters, the already published expressions of Chisholm or Murdock enable the meter reading to be accurately corrected for the effect of wetness. One class of meter for which the performance was not so good was that in which the gas velocity is measured. Tests with a vortex meter showed the wetness effect to be unpredictable because of slip between the liquid and gas.

No technique was found that was independent of the liquid-to-gas ratio. This prompted the development of simple non-nucleonic tracer methods to take spot measurements of the liquid and gas flow rates. The gas measurement has been completed and it gives a gas flow rate to within ±5% independently of the liquid content. The development of liquid tracer methods is still underway.

INTRODUCTION

Many offshore gas-field developments could be simplified if the flow measurements could be made before rather than after the produced liquids have been removed from the gas. This would enable the use of cheap satellite platforms without any separation facilities, it would remove any need to provide a test line to the mother platform for well testing and would enable the commingling of production from different fields before the gas is processed for sale.

There are two problems that stand in the way of this simplification of the measurement: there is no widely recognised technique for measuring gas flow accurately when entrained liquids are present and a method for quantifying the liquid production must be found in order to monitor the performance of the wells. This paper considers these two problems. It first reports on a series of tests on venturi and vortex meters that quantify the error and uncertainty which entrained liquid cause. It then describes the development of non-radioactive tracer methods for independently measuring the liquid and gas flow rates for well-testing purposes.

DIFFERENTIAL-PRESSURE-TYPE METERS

Literature survey

There have been many investigations into the measurement of gas and liquid flow through orifice-plate-type meters (see Ref. 1 for a comprehensive list). Most investigators have proposed their own expression to cover their range of experimental data, with little agreement between the different expressions proposed. However, the range of liquid/gas ratios found in most producing gas fields is limited to 500 m^3 of liquid to 10^6 normal m^3 of gas and, in this range, many of the proposed expressions predict the same effect.

The two most important expressions have been proposed by Murdock[2] and Chisholm[3,4]. Murdock's relationship can be written:

$$Q_g = \frac{Q_{tp}}{1 + 1.26 \frac{(1-x)}{x} \frac{C_g \epsilon_g}{C_l} \sqrt{\left(\frac{\rho_g}{\rho_l}\right)}} \qquad (1)$$

while Chisholm's takes the form:

$$Q_g = \frac{Q_{tp}}{\sqrt{(1 + K/Y + 1/Y^2)}} \qquad (2)$$

where $Y = \frac{x}{1-x} \sqrt{(\rho_l/\rho_g)}$ and $K = (\rho_l/\rho_g)^{1/4} + (\rho_g/\rho_l)^{1/4}$.

These two expressions are plotted in Fig. 1 for natural gas at 100 bar. The agreement between the two expressions is excellent despite them being of very different forms. However, the experimental data base used to derive these expressions does not cover natural gas at 100 bar; this result is an extrapolation from the original measurement.

Field measurements

To establish the validity of either Murdock's or Chisholm's expressions at flowline conditions, a set of field measurements were taken with a 100 mm venturi meter installed in a well flowline at a production station. The test facility (Fig. 2) was constructed between the test header and separator. Here, the gas was passed through a reference venturi flowmeter and then made wet by injecting water either through a wall tapping or through a spray in the centre of the pipe. The wet gas then flowed through the meter under test. The effect of the additional water on the meter under test could be determined by comparing the ratio of the readings of the test and reference meters with and without water injection.

All the instruments were connected to a data logger and each measurement consisted of the average of 10 individual readings over a period of about 15 seconds. The data logger took 1 second to scan all the instruments sequentially and 10 scans were taken for each measurement. Both the average and the standard deviation of the 10 readings were calculated for each instrument and if the standard deviation exceeded 1% for any of the instruments the run was rejected and repeated. The flows were calculated once from the average values.

Venturi test results

Test runs were made at pressures between 80 and 100 bar and at at various gas flow rates between 50 000 and 200 000 normal m^3/day. The actual conditions for each test run are given in Table 1. Typically, 10 liquid flow rates were used in each test run. For the majority of the tests, eight measurements were taken at each injection flow rate, four with the water injected through the spray nozzle at the pipe centre and four with the water injected at the wall tapping. This enabled any mixing effect to be identified.

The effect of the injected water for the whole series of tests is shown in Fig. 3, in which the ratio of the test venturi reading and the reference venturi reading is plotted against wetness fraction. Each point in the figure is the average of four measurements with water injected either through the the spray nozzle or through the wall tapping. The effect of adding water can be seen to be linear over this range with a slope slightly greater than that predicted by Murdock or Chisholm. (The small zero shift is due to small differences between the test and reference venturis.) It can also be seen from this figure that there is no difference between the methods of water injection and hence the way in which the liquid is distributed in the pipe. The actual flow conditions have no effect. Details of individual test runs are discussed more fully in ref. 5.

These results confirm that the expressions of either Murdock or Chisholm can be used for correcting venturi meters for the effect of liquid entrainment at typical gas-well flowline conditions. Others (see ref. 1) have shown that there is no difference between the effect of water or condensate (other than the density dependence shown in equations (1) and (2)), that the size of the meter has no effect and that the expressions can be used up to 64 bar. It is, therefore, reasonable to say that the expressions are valid for any differential pressure meter (except the elbow meter) at any pressure up to 100 bar.

VORTEX METERS

The vortex meter is one candidate from a group of meters in which the fundamental measurement is one of gas velocity. It would be expected that the addition of small amounts of liquid would not effect the velocity of the gas and hence would not affect the reading of a vortex meter. This is not the case. Two sets of tests were carried out on the vortex meter, one in the same test facilities that were used for the venturi meter tests and one in the KSEPL multiphase test loop (Fig. 4).

Vortex meter - field test results

Figure 5 shows the results of four test runs in the field test facilities. It can be seen that, in contrast with the venturi meter, the vortex meter overreading is dependent on gas flow rate. The test run at 130 000 normal m^3/day also showed two distinct behaviours (lines 130 A and 130 B), one for liquid-to-gas ratios below 100 m^3/million normal m^3 and one for ratios above. There is no apparent explanation for the differences and the behaviour was not encountered at a later date.

The explanation for the increases in reading and the apparent variation with gas flow rate is found by considering the cross-sectional areas in the pipe taken up by the liquid and the gas. The vortex meter in gas service is a velocity-measuring device. It is reasonable to suppose that the increase in reading is due to an increase in gas velocity and that this is due to the reduction in cross-sectional area available for the gas because some of the pipe's cross-section is 'blocked' by the liquid. The area blocked is a minimum when the liquid and gas are travelling at the same velocity, i.e. no slip, and in this case the ratio of areas for liquid and gas is the same as the ratio of liquid/gas volumetric flow rates at actual flowing conditions. In practice, there is slip between the liquid and gas, the liquid travels more slowly than the gas. This results in a buildup of liquid in the pipe and this liquid holdup means that less area is available for the gas. As a result, the gas velocity increases by a factor greater than the ratio of the liquid/gas flow rates.

The actual areas taken up by the gas and the liquid are difficult to predict. At normal gas pipeline velocities the liquid travels either as a

small film around the circumference of the pipe or as a rivulet in the bottom of the pipe if mounted horizontally. The thickness of the film or rivulet depends on the relative velocity of the liquid and the gas in the pipe, which in turn depends upon the pipe geometry and the gas and liquid flow rates and properties. For the 75mm line tested, it required a rivulet of only 1.6 mm depth or a film of only 0.9 mm thick to give an increase in gas flow rate of 5%.

Laboratory tests

The laboratory tests evaluated the vortex meter with air/water mixtures at nominally atmospheric pressure. The intention was to confirm that slip between the liquid and gas was the cause of the overreading and to see whether it could be reduced by mounting the meter in a vertical run with the flow down. Immediately upstream of the meter a transparent section of pipe was fitted so that the actual air/liquid distribution in the vortex meter could be seen.

Horizontal tests

Two sets of test runs were made in the horizontal section. Initially the meter was installed in an almost identical manner to the field tests (Fig. 2) and it showed a similar behaviour. The results for this installation are given in Fig. 6. They show that the meter was affected by liquid in the same way as in the field tests although the magnitude of the effect is lower. The difference in magnitude is to be expected because the effect is dependent on the actual distribution of liquid and gas in the pipe and this depends on actual line conditions; the field trials were at a pressure of 80 bar whereas the laboratory tests were at atmospheric conditions. This means that for the same liquid-to-gas ratio at reference conditions, the ratio of liquid-to-gas flow rates at line conditions in the laboratory was one eighthieth of that in the field tests. The effect of the liquid, however, was not one eightieth because the gas could not drive so much liquid through the pipe, since the density was also one eightieth. The resulting difference in velocities between the gas and liquid (slip) was therefore greater in the laboratory than in the field. The two effects, less liquid but more slip, are in the opposite directions. These tend to cancel, giving an overall effect of similar magnitude in both the field and laboratory.

During these first tests the liquid was running in a rivulet along the bottom of the pipe for all but the highest gas flow rate. At the high gas flow rate the liquid spread up around the walls of the pipe to about half the pipe diameter.

A second set of tests were made with a simple liquid bypass around the vortex meter, Fig. 7. This sucessfully removed any effect of entrained liquid for the majority of the conditions, the results are shown in Fig. 8. The bypass was a tube running below the pipe and inserted into the bottom of the pipe by means of T-joints a short distance upstream and downstream of the meter. Its effect was to divert away from the meter the rivulet of liquid that was running along the bottom of the pipe. The liquid was driven through the bypass by the differential pressure across the vortex meter created by the bluff body. The distance of the bypass below the main line was sufficient to ensure that this same differential pressure could not empty it of liquid. This ensured that no gas could go through the bypass once it had become full of liquid. This was completely successful as long as the liquid ran only along the bottom of the pipe. At high liquid-to-gas ratios and high gas flow rates when the liquid was seen to be transported partially along the pipe walls, the bypass only partly reduced the problem. This confirms that the meter overreading was due to liquid holdup in the meter.

Vertical tests

The attempt to reduce the effect of the slip between the liquid and gas by installing the vortex meter in a vertical section was unsuccessful because the liquid distributed itself around the walls of the pipe and, because of this contact, it was slowed down considerably. An attempt was made to inject the liquid in the pipe centre but the liquid had still distributed itself on the walls by the time it passed through the meter only 1.5 m downstream.

A vertical installation, therefore, is not a practical way of reducing the effect of entrained liquid on a gas vortex meter.

TRACER METHODS

The tracer measurement methods have two purposes: firstly they provide a way of carrying out a well test with no test separator, and secondly, they provide a method of measuring the actual liquid/gas ratio so that venturi meters can be corrected for the effect of wetness. Separate methods are required for the liquid and gas phases and both methods will be described, although only the gas method has been tried in the field. The liquid tracer method is currently under development.

Gas tracer method

The main objective of the method is that it must measure gas flow in a well flowline to ±5% at pressures between 65 and 150 bar independently of any produced liquids up to a liquid/gas ratio of 500 $m^3/10^6$ normal m^3. It has to be simple enough to be carried out by operators without any special training, it has to be portable and not require special equipment to be permanently installed at the measurement location. A tracer dilution technique using a non-radioactive tracer was chosen because it is operationally simple and requires no special facilities in the field.

The tracer has to be in gaseous form, must not react with the natural gas, the produced liquids or the pipe walls, and it must not be present in the produced gas. Ideally, it should remain entirely in the gas phase and not partially partition into the liquids. A noble gas satisfies the chemical requirements and neon was chosen because it is not present in natural gas yet is freely available. The drawback of a noble gas is that the required analysis technique is complex because the gas is chemically inert.

The method chosen generally follows the ISO recommended procedure[6]. In this, a chemical tracer is injected at a known flow rate into the gas stream. At some point downstream, at a distance sufficient for the tracer to be mixed uniformly, the stream is sampled. The gas flow rate is calculated from the concentration of the tracer in the sample and the tracer injection rate. The technique is shown schematically in Fig. 9.

Two aspects of the method proved problematic: the choice of injection flowmeter and the analysis technique. The flowmeter eventually chosen was a

gas turbine meter (Fluid Dynamics Inc. type FTO-1/N1/Sa-GHC-5), after the failure of many other meters to retain their calibration. For the analysis two techniques were tried, both using chromatographs but with different detectors for different gas concentrations. At low concentrations of the tracer, 1 to 50 ppm by volume, a system with two columns and a microwave plasma detector was used. This achieved a standard deviation of about 1%. A simpler technique using a single column and a thermal conductivity detector achieved the same target for concentrations over 100 ppm.

Proving the technique was done in two phases, firstly in dry gas against a fiscal standard (±1%) dry gas measurement and secondly in wet gas, for which the effect of entrained water in the gas was evaluated. The results of three trials are shown in Fig. 10. By the third trial, results within ±5% were achieved. This third trial was also in wet gas with liquid/gas ratios between zero and 500 $m^3/10^4$ normal m^3. The method is shown to be independent of wetness fraction.

Liquid tracer method

The liquid tracer method follows very closely the principles of the gas tracer method. Again, the tracer has to be chosen for its abiltiy to remain entirely in the liquid and a suitable analysis technique has to be found. The main problem is that the liquid is made up of two liquids, produced water and condensate. A simple tracer that is suitable for both cannot be found so two tracers have to be used. The selection of a tracer for the condensate phase is still under discussion but glucose is an ideal tracer for water and simple analysers are available.

CONCLUSIONS

A venturi meter can be used to measure the flow of wet gas. The effect of entrained liquid is predictable and can be compensated for by using the expressions of either Murdock or Chisholm. Velocity-measuring meters cannot be used for wet gas measurements. They are affected unpredictably by slippage between the liquid and gas phases and this depends on the pipe geometry and the actual liquid and gas flow rates and properties.

Simple tracer methods can also be used to measure gas flow independently of liquid content to an accuracy adequate for well-monitoring purposes. It should also be possible to extend these tracer techniques to measure the liquid flow in a wet gas stream. This will enable a full well test to be carried out without a test separator.

NOMENCLATURE

Q_g	Flow of gas alone
Q_l	Flow of liquid alone
Q_{tp}	Flow calculated from the measured differential pressure and the dry gas density
x	Gas quality (ratio of mass of gas to mass of liquid)
C_g	Discharge coefficient for gas
ϵ_g	Expansion coefficient for gas
C_l	Discharge coefficient for liquid
ρ_g	Gas density
ρ_l	Liquid density

REFERENCES

1. Lin, Z. H., "Two-phase flow measurements with orifices," Encyclopedia of Fluid Mechanics, chapter 29, vol. 3, Gulf 1986.
2. Murdock, J.W.: "Two-phase flow measurement with orifices," Journal of Basic Engineering, December 1962.
3. Chisholm, D.: "Flow of incompressible two-phase mixtures through sharp edge orifices," Journal of Mechanical Engineering Science, Vol. 9 No. 1 1967
4. Chisholm, D.: "Research note: Two-phase flow through sharp edge orifices," Journal of Mechanical Engineering Science, I.Mech.E. 1977.
5. Nederveen, N., Washington, G. and Batstra, F.: "Wet gas flow measurement," Society of Petroleum Engineers, SPE 19077, June 1989.
6. ISO 4033-1980, International Organisation for Standardisation, 1980

Table 1. Venturi meter test run conditions

Nominal gas flow (m^3/day)*	(kg/s)	Press. (bar)	Temp. (°C)	Maximum liquid/gas ($m^3/10^6 m^3$)*	(actual %v)
180 000	1.7	82	40	100	0.8
150 000	1.4	83	38	100	0.8
95 000	0.9	85	39	240	2.0
56 000	0.5	86	32	150	1.3
75 000	0.7	98	42	400	3.8
108 000	1.0	97	43	180	1.7
72 000	0.7	80	35	365	3.1
180 000	1.7	78	38	100	0.8

* Volumes are at 1 bar and 0°C.

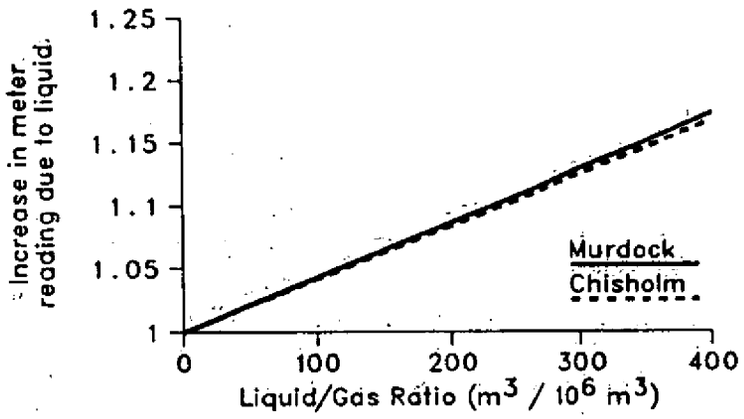


Fig. 1 Wet gas flow equations at 100 bar

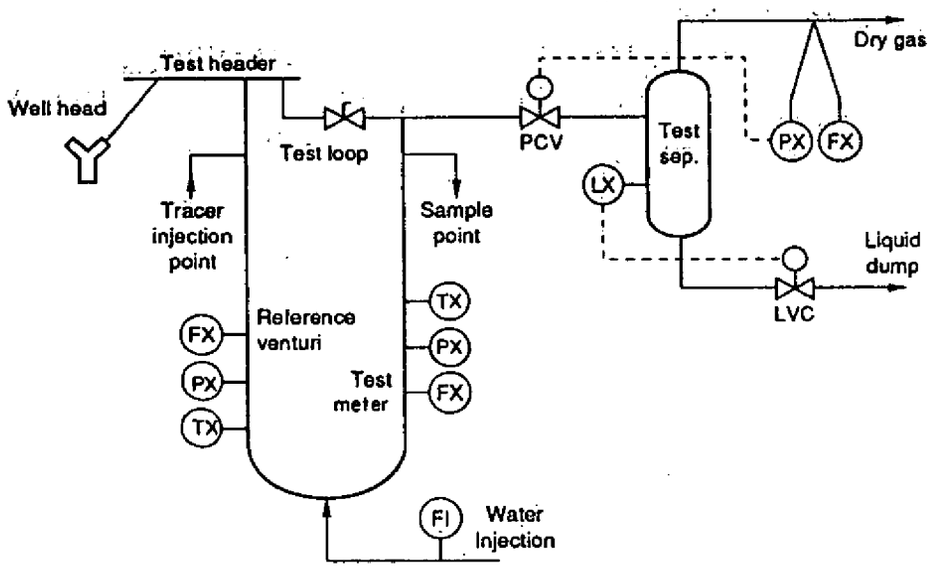


Fig. 2 Wet gas meter test facility

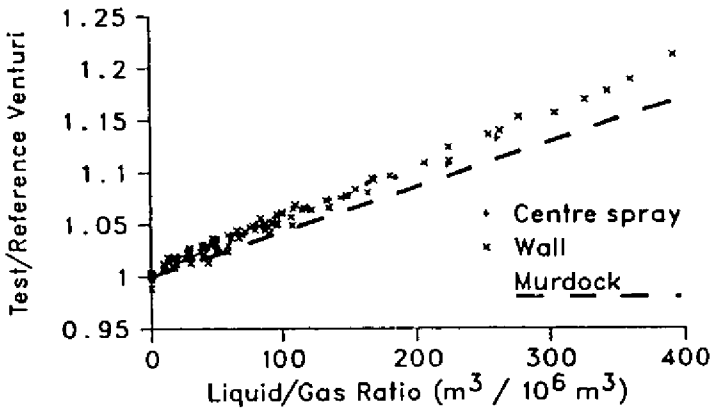


Fig. 3 Venturi trial result

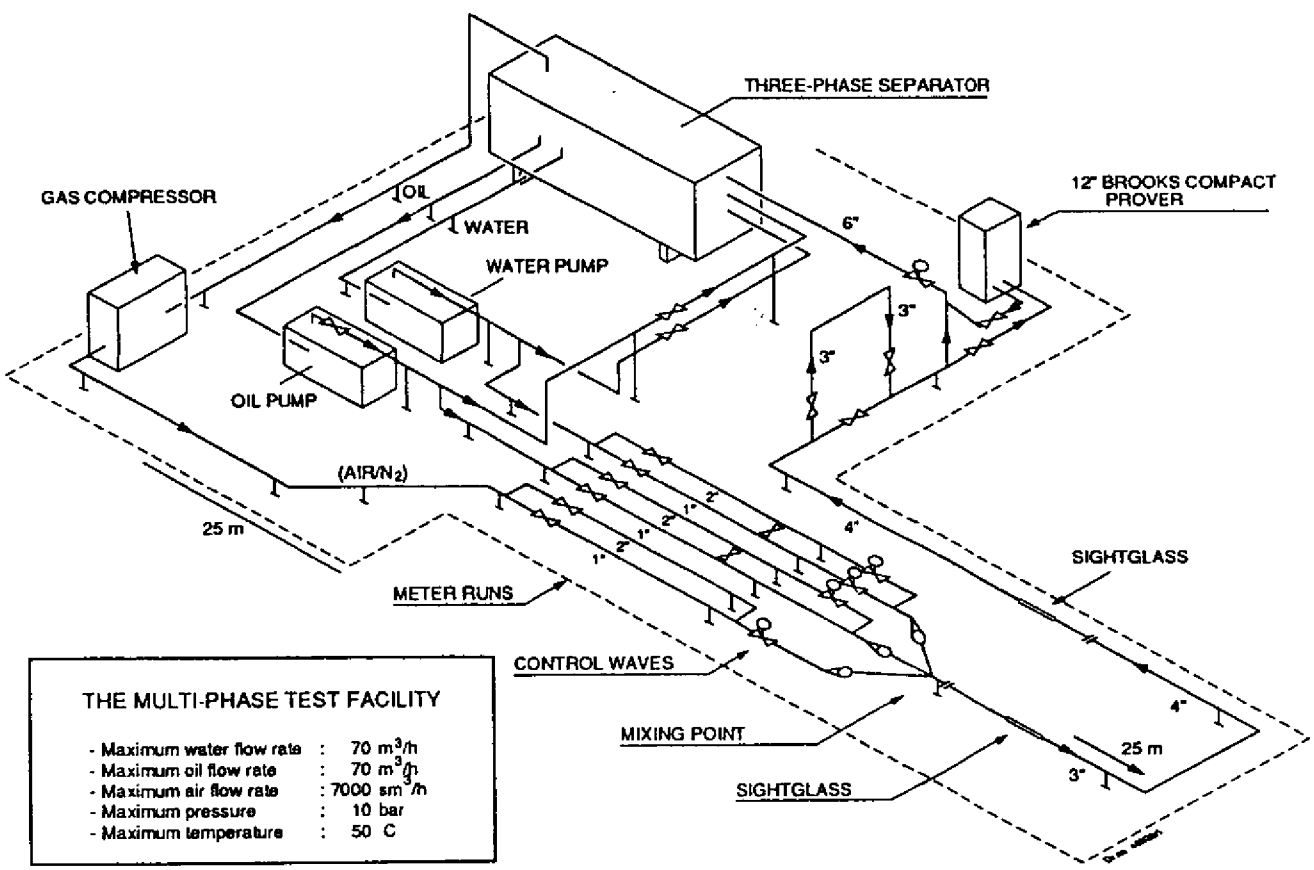


Fig. 4 The KSEPL multi-phase test loop

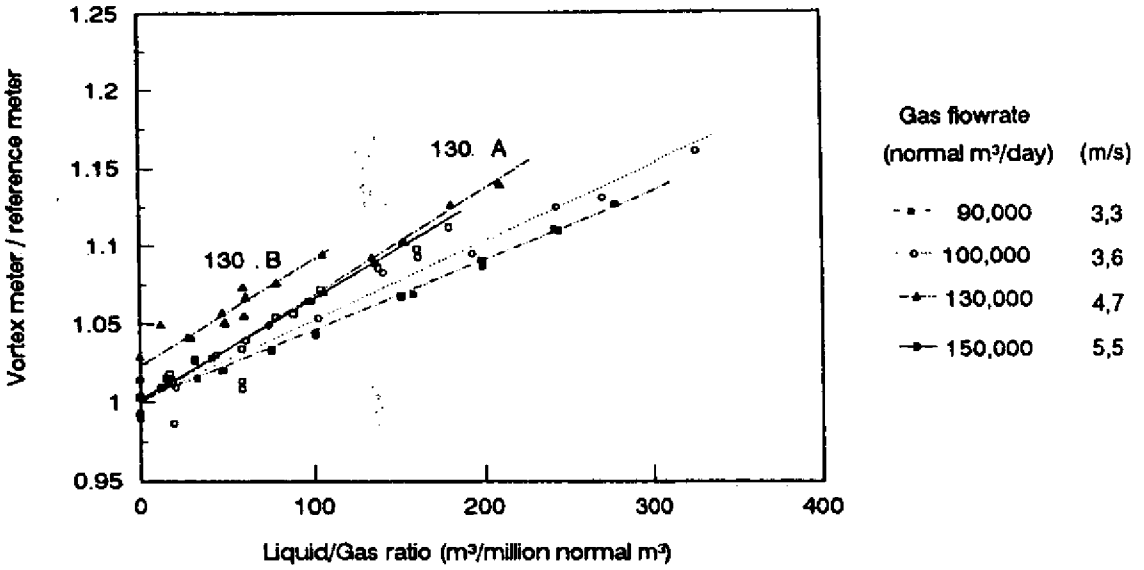


Fig. 5 Vortex meter field test results

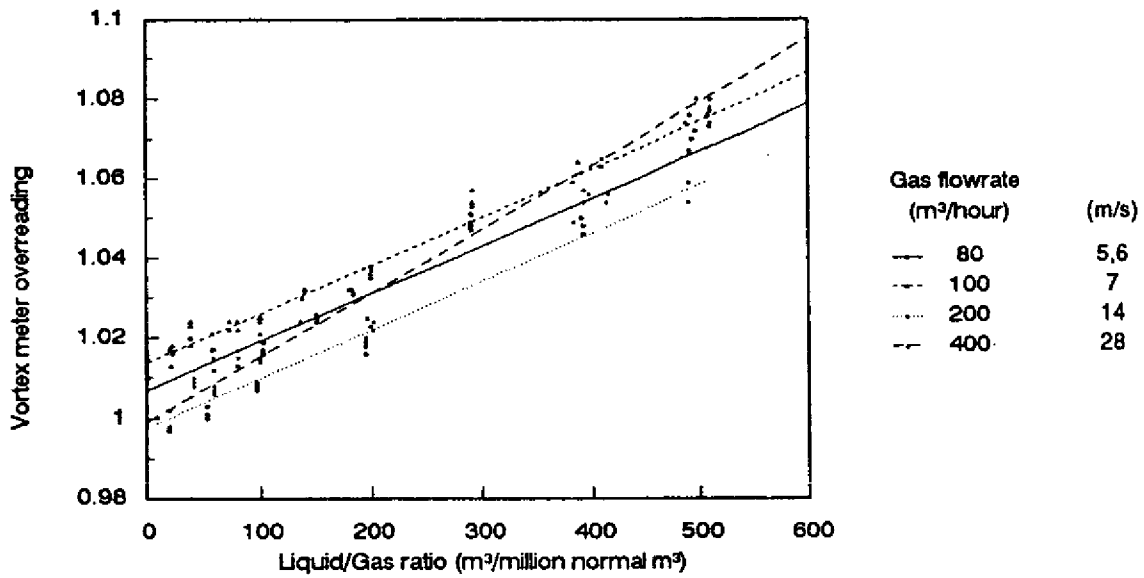


Fig. 6 Vortex meter laboratory results for horizontal installation

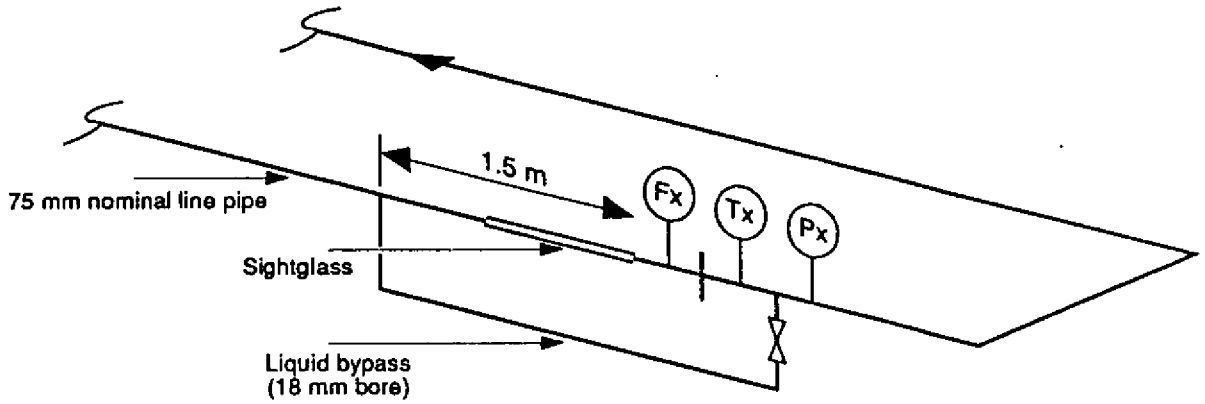


Fig. 7 Liquid bypass

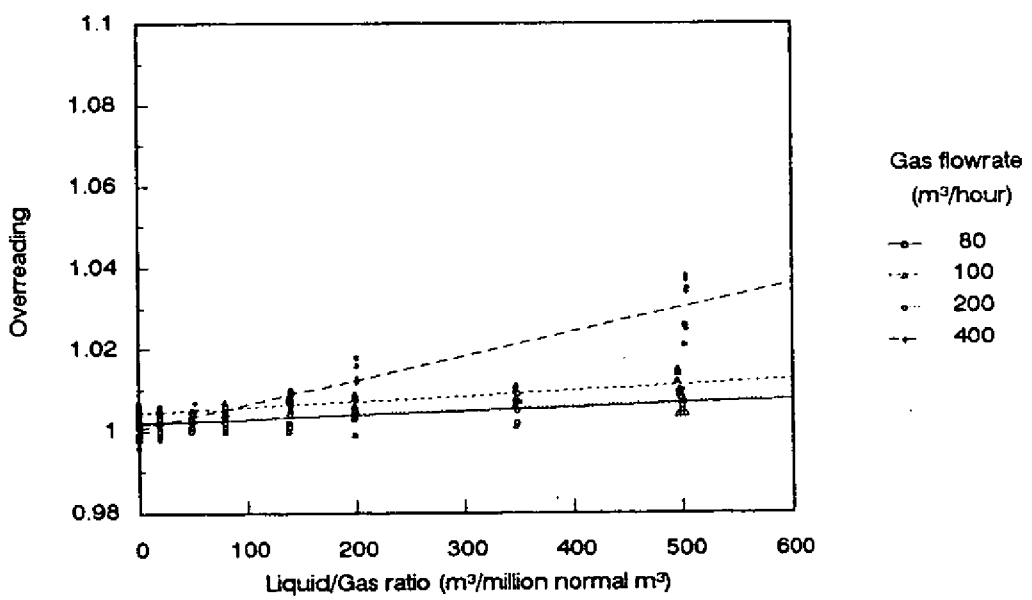


Fig. 8 Vortex meter results with liquid bypass

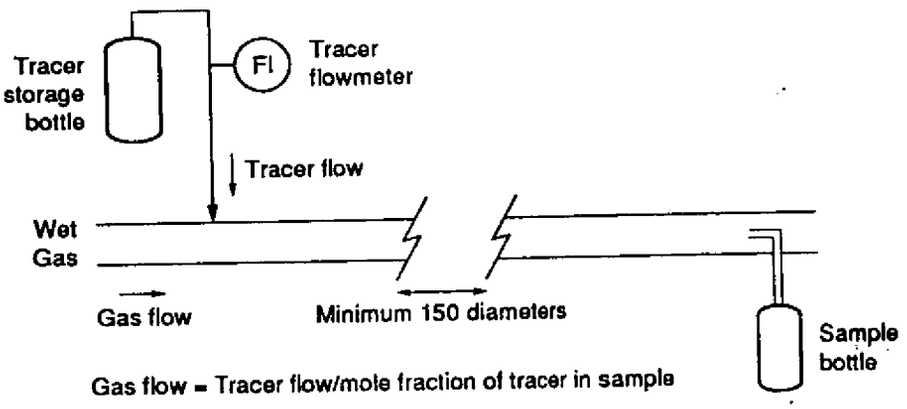


Fig. 9 Schematic of tracer technique

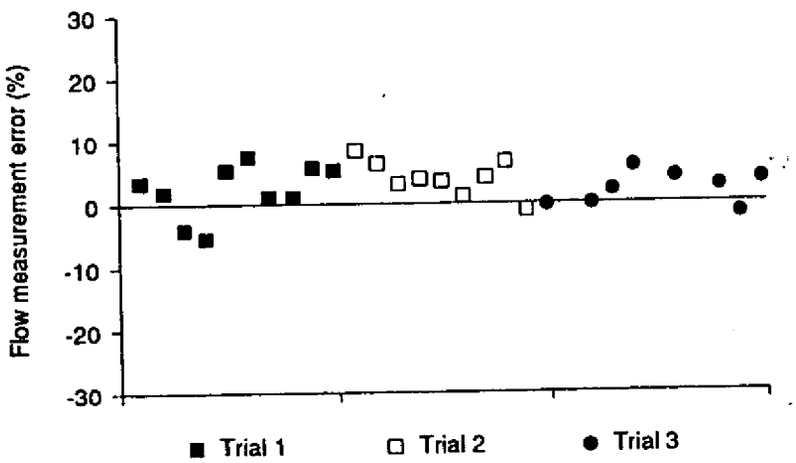


Fig. 10 Tracer trial results summary

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Pipeline Oil Analysis for Allocation at Ecofisk"

Lecturer:
Oddfinn Thowsen
Phillips Petroleum Co. Norway

Pipeline oil analysis for allocation at Ekofisk.

1.0 Introduction

Flow metering is not complete without some sort of quality parameters on the gas or liquid measured.

This paper will give an overview on how we at Ekofisk perform crude oil analysis so that you can see what crude oil analysis for allocation on component basis involves.

I will give you a background for the need of the analysis, the quality parameters that are required, how we find these and share our offshore experience on methods and equipment with you.

2.0 Background

As you know, Ekofisk Centre is an important part of the transport route of both oil and gas in addition to a process plant.
The high vapour pressure oil is processed at Ekofisk Centre and Teeside takes out products before the oil is ready for sale. This is the reason for the need of component allocation. The mass of each component must be allocated back to the fields delivering the oil and gas to Ekofisk Centre.

The Ekofisk lab is both an allocation lab and usual process lab. We analyse 13 oil streams for allocation purpose and the samples are based on spot samples, monthly flow proportional samplers and daily composite samplers.

3.0 Parameters required.

This is regulated in the agreements between involved parties and companies.

The appendix B&C to the agreements gives the guidelines for the sampling and analysis. The following analysis is required for owner ship allocation of oil:

- Water content.

- Salt content.

- Composition of oil in wt%,grouped as:
  Nitrogen
  Carbondioxide
  Methane
  Ethane
  Propane
  Iso and normal butane
  Iso and normal pentane
  Hexanes
  Heptanes plus (C_7+)

- Sp.gravity of heptanes plus (C_7+)

- Average molecular weight of heptanes plus (C_7+).

It is also required that the analytical work on samples should be in an identical manner for all like samples.

The sampling required is monthly composite sampling, this is backed up with spot samples.
In addition we have Daily composite samplers for water determination on the major streams.
ISO 3171, Petroleum liquids-Automatic pipeline sampling is our reference for the automatic sampling of oil.

4.0 Analysis.

I will concentrated on the phase after a representative sample has been obtained, but i will stress that without a representative sample the rest of the work is worthless.

The analytical parameters will be described in the following order:
4.1 Water content of oil.
4.2 Salt content.
4.3 Composition.
4.3.1 Specific gravity.
4.3.2 Average molecular weight.

4.1 Water analysis.

Reference:ASTM D4377-86

Introduction:

The ASTM D4377-86 describes the use of potentiometric titration instrument, but we use a coulometric instrument.It has been proved that this technique is capable of producing the same result as the potentiometric titration. Some of the advantages with coulometric instrument is less chemical cost, less man-handling and no calibration required.

In addition we checked if any of the inhibitors in use had any effect on the results prior to implementing the method.

Apparatus:
Aquatest or equivalent coulometric instrument.

Principle:

A subsample is taken out after proper homogenization and titrated with pyridine free Karl Fisher reagent to an electronic end point. The standard used is one unit of electrolytic current, 96 500 coulombs = 1 chemical equivalent of water. (1 coulomb=1 Amperesecond)

Overall reaction:

$H_2O + I_2 + SO_2 \rightarrow 2HI + SO_3$

The iodine needed for this reaction is generated by the instrument, and the current consumption used for this is the basis for the measurement.
The result is reported as weight %.

Precision Pyridine-Free Karl Fischer reagents:

Repeatability = 0.037 ($X^{1/2}$)
where X = sample mean from 0.0 to 2%.

4.2 Salt determination (Electrometric method)

Reference :ASTM 3230-83

Summary :

The method is based on the conductivity of a solution of crude oil in a polar solvent when subjected to an alternating electrical stress.
This method will measure conductivity due to salts in the crude oil. A calibration curve is made by using a salt solution with a composition typical for a wide range of crude oils.
(NaCl:CaCl2:MgCl2 , 70:10:20)
The sample is dissolved in a mixed solvent(n-butanol,methanol) and placed in a test cell consisting of a beaker and two parallel stainless steel plates. The resulting current is shown on a milliammeter. The salt content is obtained by reference to the calibration curve. (Current versus salt content of known mixtures.)

Apparatus: GCA salt in crude analyzer or equivalent.

Precision:

The ASTM 3230-83 does not give any repeatability data but we use the IP265 as a guideline, this gives the repeatability as 0.3 times the square root of the salt reading.

4.3 Composition

References:
The method is based on the following ASTM methods:
ASTM-D2892-84 Distillation of crude petroleum.
ASTM-D2163-87 Analysis of liquid petroleum gases by gas chromatography.
ASTM-D1945-81 Analysis of natural gas by gas chromatography.

Summary:

The method is a combination of fractional distillation and gas chromatography. The high vapour pressure sample is split into 3 fractions that can be handled separately and then recombined to find the composition.

The method requires the following equipment:

Distillation unit (3650 Semical distillation unit or similar)

Vacuum pump

Calibrated vapour receivers (2 ea 19 l, 1 ea 32 l)

Cooling system

Pressure control system

Pressure indicators

Gas chromatographs (HP 5890 or similar)

Integrators (HP3392 A or similar)

Computer system.
We use an HP A600 computer to control the gas chromatographs and to collect the data. The software for this is delivered by HP. The calculation, reporting and transmission to the main computer onshore are handled by a program developed by PPCON.

Summary of the procedure:
A sample is collected into a sample cylinder (sliding piston type.)

This sample is in our case a high vapour pressure liquid sample that is difficult to handle directly into gas chromatographs. Due to this we need to split this sample into fractions that are more easy to handle.
The distillation unit is used for this purpose.

The distillation unit and the vapour receivers are evacuated until constant pressure is obtained. (1-4 mmHg)

The sample cylinder is connected to the 1 l distillation flask at the bottom of the distillation unit.

The valve on the sample cylinder is opened carefully and the evaporated gas from the sample is taken over to the vapour receivers at a controlled rate.

The sample cylinder is disconnected when the whole sample is charged to the distillation flask.

We continue to take off gas until the distillation temp is 28 degree celsius. This phase is called vapour phase or C_1-C_4 fraction.

The next phase is collected into a liquid receiver with a coolant jacket. The collection of this phase is stopped at 93 degree celsius.This phase is called C_5-C_8 fraction.

The remaining phase in the kettle is called kettle bottoms or C_7+ fraction.

The next step is to use the gas chromatograph.

A few words about the principle of a gas chromatograph:The main component of a gas chromatograph is a coiled tubing, called column. This column can be filled with a support (example:finely crushed firebricks 0.15-0.25 mm or 60 -100 mesh ASTM) and covered with a stationary phase(example:Silicon oil.)
This column is placed in a temperature controlled oven, and the gas sample is transported through the column using an inert gas (helium). The components in the gas will be delayed more or less and reach the detector at different times. The component is then detected on the detector and recorded as a peak on the integrator. This peak is integrated and used to quantify the component.

The original high pressure crude oil sample is now split into 3 fractions that can be handled for further component analysis.

The 3 fractions are:
C_1-C_4, vapour fraction
C_5-C_6, liquid fraction.
C_7+, kettle bottoms, liquid fraction.

They are analyzed in the following way:

C_1-C_4

The sample in the vapour receivers are mixed and a subsample is transferred to a sliding piston type sample cylinder.

This sample is analyzed on a gas chromatograph and we find the mol% of each component including C_7+.

The composition, temperature, volume and pressure is used to calculate the amount of vapour and the weight of each component in the vapour.

C_5-C_6

This sample is also analyzed on the GC but here we get the weight % directly. Also the total weight of this fraction is known and this together with the composition gives us the weight of each component.

C_7+

This fraction is analyzed for specific gravity and molecular weight.

4.3.1 Specific gravity measurement.

Reference:
The method used is based on ASTM D 4052-86

Summary:
Approximately 1 ml liquid sample is introduced into a oscillating sample tube. The mass change of the tube cause a change of the oscillating frequency.
Calibration factors is found by using air and deionized water as reference.

Apparatus:
Anton Paar DMA 46 or equivalent.

Formula:
Density = $(T^2 - B) / A$
T=Period of the oscillation
A, B=calibration factors.

Precision:

Range	Repeatability	Reproducibility
0.68 - 0.97	0.0001	0.0005

4.3.2 Average molecular weight.

Reference:
This method is developed by PPCo R&D .

Summary:
The method is based on freezing point depression of benzene.
A known amount of C_7+ is added to benzene. The difference of freezing point between the pure solvent and the mixture is used to estimate the molecular weight of the C_7+ fraction.
The freezing point is reached by supercooling and seeding to create a sudden freezing. The instrument is calibrated with a benzil standard (Molwt 210.23) before each analysis.

Apparatus:
Roebling Kryometer or equivalent.

Precision:
Repeatability:Maximum allowable deviation between two parallels is 4.

The measured specific gravity and molecular weight of C_7+ is corrected for C_7+ present in the other fractions.

When the specific gravity , the molecular weight and the weight of the C_7+ are found we are ready for the recombination calculation.
The weight of each component in the 3 fractions are recombined and the composition of the original sample is found.

The final report is transmitted to the main computer and after a final check by the production control unit it is ready for use in the allocation report.

Precision.
No precision data available from ASTM on this composition method. But the following guidelines was given in the initial method:

Component	Liquid, Wt.% % of amount present.
Nitrogen	-
Methane	5.0
Ethane	3.0
CO_2	3.0
Propane	2.0
Isobutane	2.0
n-Butane	2.0
Isopentane	2.0
n-Pentane	2.0
Hexanes	2.0
C_7+	1.0

Molecular Weight of C_7+ 2% of value.
Specific Gravity of C_7+ Value +/- 0.001

The repeatability checks performed are usually well within these limits, typical value for C_7+ is 0.3 - 0.4% of amount present.

4.4 Experience on analytical methods and equipment.

Personnel
Allocation analysis must be performed by skilled people, the importance of these data requires that. This work can not be left to an operator as a part time job, this includes the important sampling step.

Quality control.
The personnel, instruments, methods and calculations must be followed up on a regular scheduled basis to ensure quality allocation data. All reports are checked thoroughly before transmission to the main computer.

Equipment:

Water determination.
The coulometric Karl Fischer instrument has been used for general water determination since around 1980. The instrument is easy to use and require minimum service. Two new instruments were installed during 1988. Due to the environmental aspects we use Pyridine free Karl Fischer solutions.

Salt in crude.
This method and instrument is used fieldwide by both us and the operators(on well test samples). The method has been used since start up of Ekofisk. The construction is rugged with few moving parts, but those that can be moved need regular replacement (Potentiometers etc).

Density measurements.
The instrument used is reliable and during approx 10 years service only normal maintenance work has been required.
It is also easy to use and calibrate.

Average molecular weight $C_{7}+$.
The present instrument was bought in 1984, and only normal maintenance has been required. The instrument require zeroing and recalibration before each analysis.

Distillation unit.
The original equipment has been modified several times since it was installed around 1975.
The modifications include change out of mercury switch and use of non mercury pressure indicators. This was done to avoid mercury spill sources and to simplify the operation of the equipment. The column handles our distillation needs very well.

We are now looking into more automated equipment to replace the old unit. A new unit can save manhours and give us more space.

Gas chromatographs, integrators and computers.

We increased our analytical capacity in 1985 when we bought new gas chromatographs (GC), integrators and computers. We have also replaced an old GC with a new GC this year.
The investment in 1985 was also a change in instrument layout, we changed from integrated all in one modules to a modular system which i easier to maintain on stream and a less vulnerable system. In my view this is the best approach for an offshore installation, it may be difficult to get a service man offshore and in many cases the module failing can be sent onshore for repair.

Since our deadlines can be tight we need to be able to provide results all the time, even if something breaks down. Our system is relative flexible in that aspect, a major break down of several modules is needed to stop our work.

Software

LAS
A program called LAS (Lab Automation System) is a part of the set up. This programs controls the gas chromatographs and collect data from the integrators. This ensure exact control of the instrument set up and reliable data. Also each run get a unique data file which cannot be altered, this give good data security and confidence in the system.

Calculation and transmission.
The calculation and transmission program was written by Information Services group in PPCoN in close cooperation with us. Involving the users at an early stage as possible is important and this program was up and running from the first day of installation, and the users were satisfied with the program. The Information Services group is responsible for maintaining this program and some additional options have been added after the installation.
The transmission program is used to transfer the data to a holding file after we have checked the report. The data is then transferred to the final destination after a check by Production Coordination Unit (PCU).

The transmission program replaced manual entry of our data to the main computer, this saved manhours and we got rid of a possible error source.

Methods.
The average molweight determination is not covered by an international standard, and we have not yet found an equivalent standard method. The molecular weight measured is in the range 100 - 300.

The other parts of the composition analysis are covered by standards, but the total composition method does not have a separate standard. This has caused different approach to parts of the method, especially the handling of the vapor.
The following variations are known:

- Displacement of Helium + wet meter + sampling bag.

- Vacuum + Receivers + Pressure measurements.

- Vacuum + Water displacement + Volume water displaced.

A standardization would be beneficial and it would also make it possible to establish reproducibility limits.

5.0 Conclusions.

Analysis of crude oil for allocation require skilled people and reliable instruments and methods.

It is important to include quality control as a part of the normal laboratory routines.

6.0 Future work.

-Contribute to a standardization of the composition method.

-Establish reproducibility limits for composition analysis of high pressure crude oil.

-Follow up the development within gas chromatography. Injection of high vapour pressure crude directly on a gas chromatograph can be a standard method in the future.

ATTACHMENTS

1. Distillation Equipment.
2. Flow chart oil analysis.
3. Recombination example.

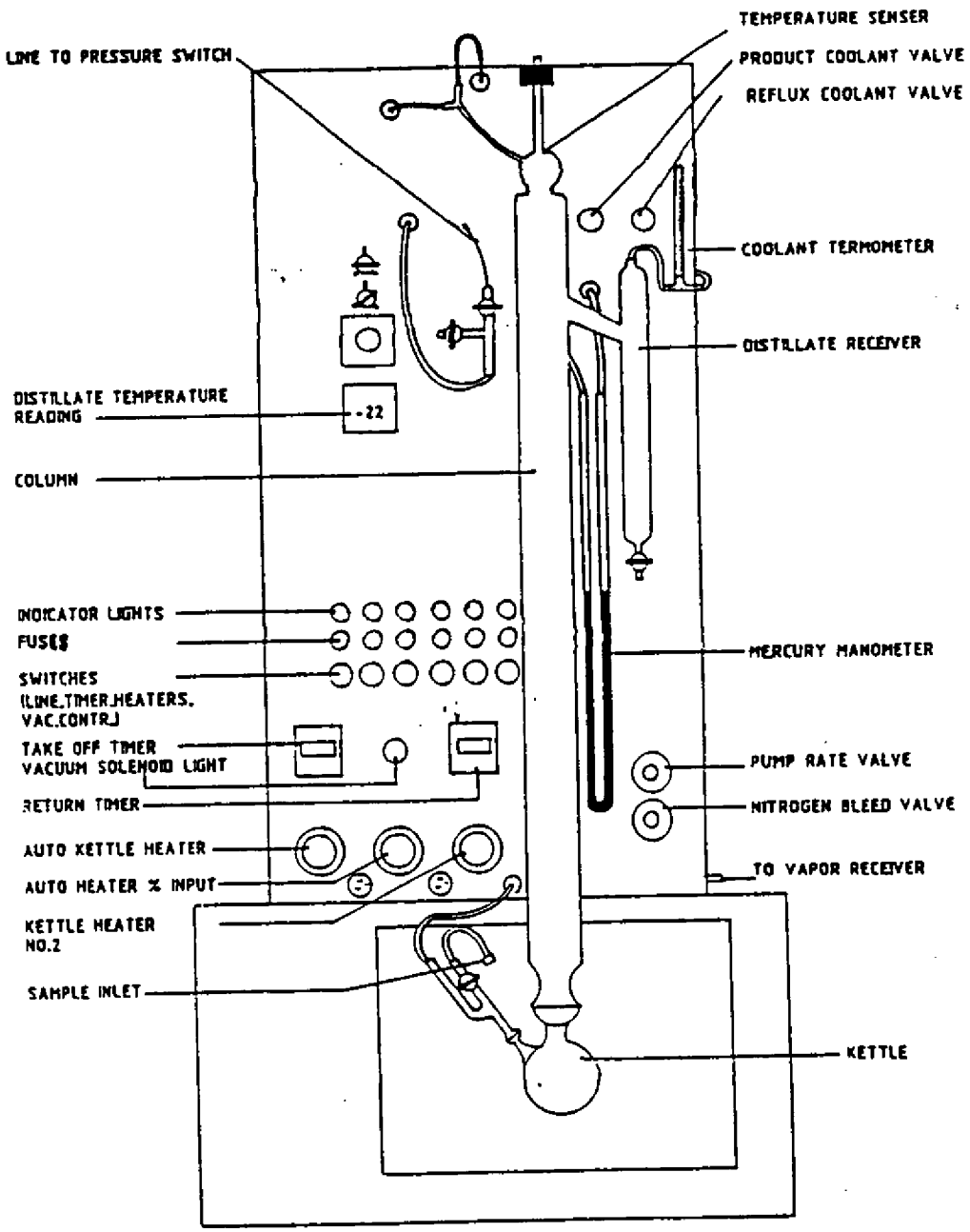
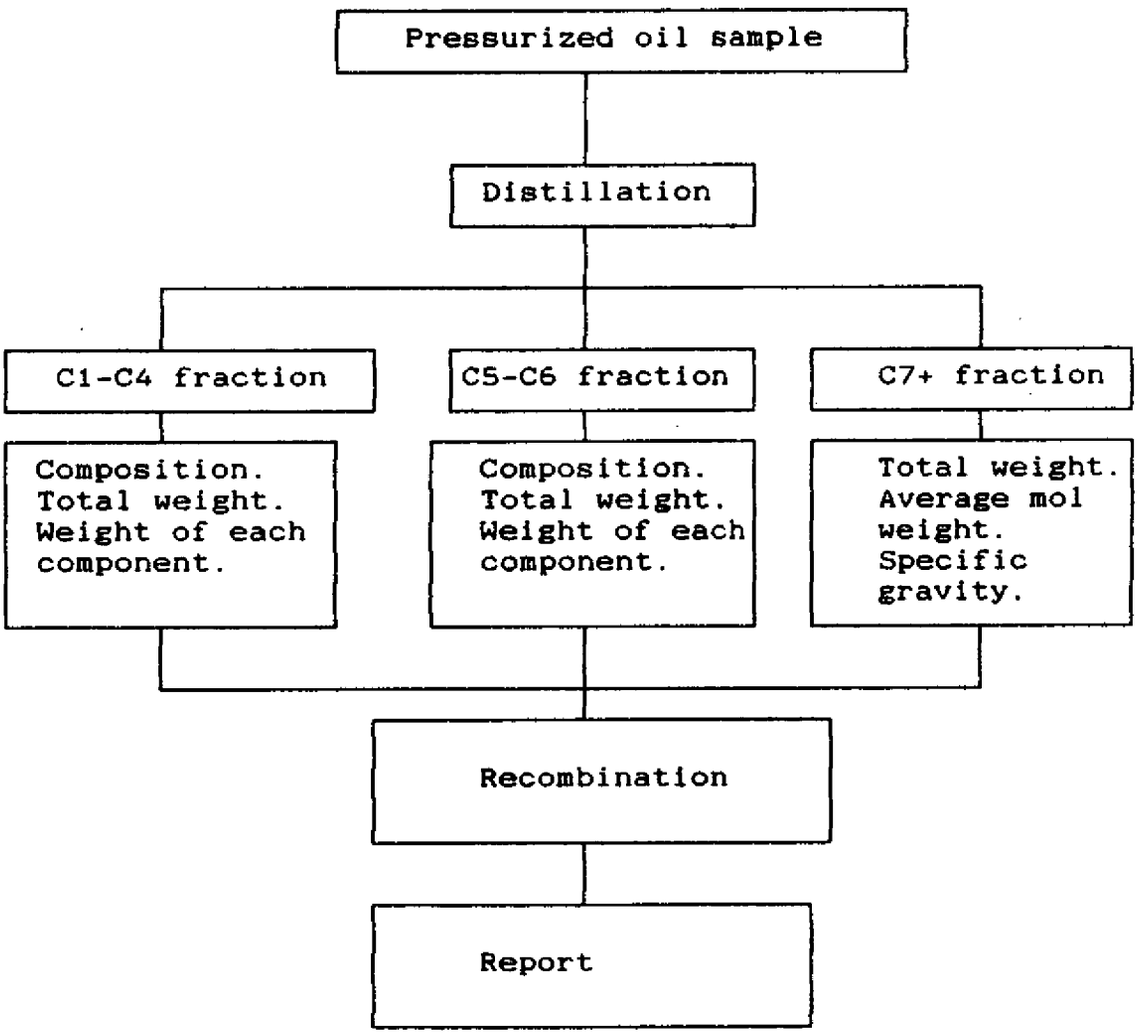


Figure 4.2.1. Arrangement of Semi-Cal Distillation Apparatus, Series 3650

Attachment 2 Flow chart oil composition analysis.



The final composition is determined by adding the weight of each component in the 3 fractions.

Component	Vapor (C_1-C_4)		Distillate (C_5-C_6)		Kettle residue (C_7^+)	Combined	
	wt%	Wt. of each component	wt%	Wt. of each component	wt.	gram	wt%
N_2	0.06	0.02	0.00	0.00		0.02	0.01
CO_2	0.66	0.21	0.00	0.00		0.21	0.09
C_1	1.48	0.48	0.00	0.00		0.48	0.20
C_2	17.98	5.83	0.01	0.00		5.83	2.47
C_3	33.27	10.79	0.11	0.04		10.83	4.58
IC_4	10.10	3.27	0.63	0.24		3.51	1.48
NC_4	24.69	8.00	5.32	1.99		9.99	4.22
IC_5	4.62	1.50	10.43	3.91		5.41	2.29
NC_5	4.22	1.37	16.56	6.21		7.58	3.21
C_6	2.08	0.68	44.21	16.57		17.25	7.29
C_7^+	0.84	0.27	22.73	8.52	166.57	175.36	74.16
Total	100.00	32.42	100.00	37.48		236.47	100.00

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Sampling of High Vapour Pressure Liquid"

Lecturer:
Tom Welker
Welker Engineering Company

Will be handed out during the workshop

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Full Bore Continuous BS&W Measurement and Fiscal Metering"

Lecturers:
Jon Gjedebo, Hitec A/S
Bjørn G. Bjørnsen, Statoil
Scott Gaisford, FMS

FULL BORE

CONTINUOUS BS&W MEASUREMENT

AND

FISCAL METERING

Foreword: The only accepted method for water content measurement in the oil industry is flow proportional automatic sampling followed by laboratory tests. The method obviously has many inherent problems. It gives no real time information such that the measurement results are only available long after the transfer has taken place. Often it gives rise to disputes about how many "grabs" should be used and arguments about its validity is non uncommon. Results are affected by equipment, people, procedures, transportation and mixing. It is not very reliable **and it is definitely not high technology.**

Fortunately, there now exists a new technology capable of continuous measurement of water in crude with an accuracy better than that prescribed by current fiscal requirements. Its repeatability is better than 0.003% and being automatic, its reproducibility is the same.

This paper has previouly been presented at the Fourth Annual Seminar on Pipeling Protection & Maintenance Sept. 19th and 20th in Stavanger this year. It has also been presented at the Workshop on Hydrocarbon Analysis and Sampling in Haugesund, 26. -27. Sept. also this year. It gives non-proprietary information about the technology and results obtained. A separate paper to be presented at The North Sea: "Flow Metering Workshop" Oct. 24, 1989 in Haugesund, Norway, will present results from recent test runs witnessed and confirmed by representatives of BP British Petroleum Co.

ABSTRACT: **This paper descibes a revolutionary technology that makes possible a 3-phase metering system - composition and flow.**

Statoil has funded the R&D of a new and unique high frequency electromagnetic technique for accurately determining the complex dielectric constant of solids, liquids and gases. The technology has been demonstrated by rigorous testing of industrial prototypes. Combined with conventional density measurement it becomes the only real technology in the world for building a full bore (2 to 36 inches and larger) multiphase meter for continuously measuring the quantities of produced oil, water and gas without separation. No probes obstruct the flow and no special liners are required. *All research has been completed.* What remains is engineering, assembly and full scale field tests. The exclusive world wide commercial rights to this technology have been licensed to Fluid Monitoring System, Inc., USA of which Hitec A/S, Stavanger, Norway is a part owner.

State-Of-The-Art MONITORING SYSTEMS FOR MULTIPHASE FLOWS

Bjorn G. Bjornsen, Project Manager, Statoil, Stavanger, NORWAY.
Scott Gaisford, Project Manager, Fluid Monitoring Systems Inc., Ca., U.S.A. (Formerly with SRI International).
Jon Gjedebo, Managing Director, Hitec A/S, Stavanger, NORWAY.

In a host of processes involving solids, liquids, gases and mixtures thereof where the components and mixtures may be stationary, moving in batches or flowing continuously, there are needs for accurate, relatively inexpensive composition monitoring means and methods. Further, it is often desirable that these monitoring means be capable of working in-line with the processes to avoid process detours or by-passes for monitoring reasons and that the monitor be non-intrusive so as not to interfere with the processes being monitored and/or to prevent the monitoring means from being degraded by, for example, processes that are highly corrosive and/or erosive.

Typically such composition monitoring needs are related to the qualities and quantities of products being bought and sold, products being produced or of products being stored. Equally great are the needs for composition monitoring for purposes of process control, production efficiency and safety.

Among the processes having needs for composition monitoring, one particular is oil production.

MULTIPHASE is today's catchword in the oil industry. An example is the article in the August '89 issue of The Oilman entitled "Multiphase Systems: The New Age Dawns".

Multiphase is a good word, but somewhat misleading in that in the oil industry it refers to the production, transportation and metering of comingled oil, water and gas having two phases, liquid and gas.

Today, produced oil, water and gas can only be measured by means of separation followed by the individual measurement of each component. Therefore, many of the "multiphase" on-going efforts concentrate on finding means and methods for measuring the fractional quantities and rates of the three components without separation.

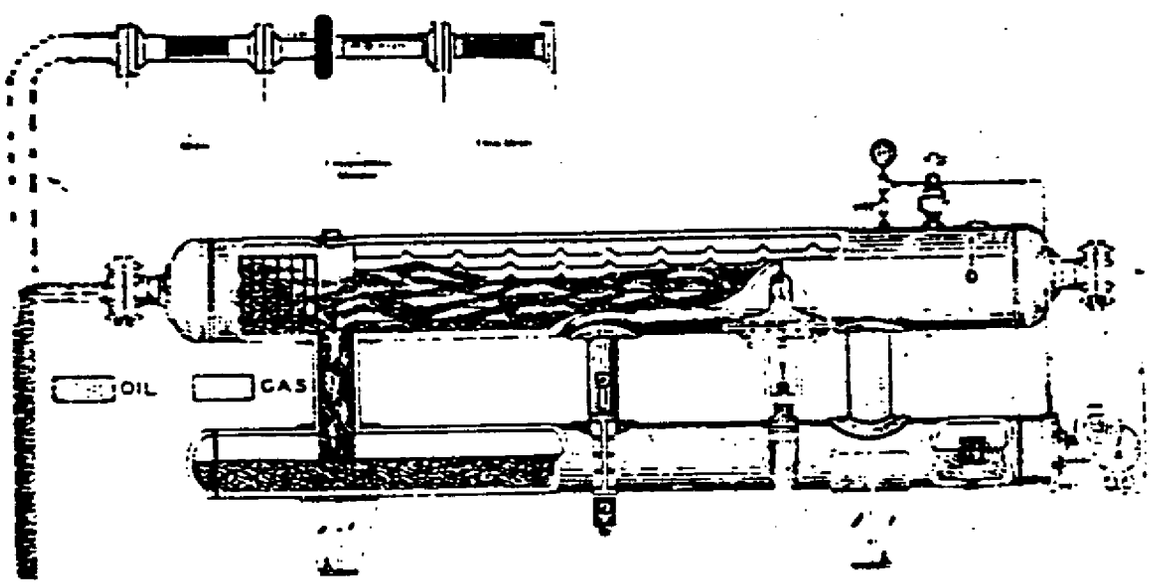
Being able to do so, means enormous cost savings.

This paper reports results obtained using a new, unique and proven technology that makes possible the continuous, unobstructed, full bore component metering without separation

Subsea, such a system could monitor the oil, water and gas productions from each well; and, thereby, eliminate both the test line and the platform test separator.

Ultimately, such a metering system could eliminate all platform separators resulting in significant structural cost savings and make un-manned platform operation a reality.

The figure below dramatically demonstrates the impact of this new technology by comparing a conventional test separator with the resulting "New System".



THE NEW MULTIPHASE TECHNOLOGY

Background:

In January of 1989, SRI International, California and Statoil, Norway completed the successful design, construction and testing of three prototypes for process compositional monitoring.

Statoil has funded the development which began in January 1987. The objective was to build an industrial prototype of a 3-phase monitoring system. From the R/D results it soon became clear that the technology had other applications, and the project was expanded to include the development of custody transfer and fiscal monitoring prototypes.

The above-mentioned three prototypes have been tested extensively in flow loops in the U.S.A. and in Stavanger, Norway at Hitec A/S. Each of the prototypes functions extremely well.

They bring significant new measurement capabilities to the petroleum industry. The tests have also proven the technology useful for application in many other industries.

In particular, the results demonstrates that the technology makes possible the continuous measurement of the fractional quantities of oil, water and gas flowing from individual wells and in pipelines. One important application of the technology is to eliminate the use of test separators. The results further show that the technology makes it possible to build the first, full sized, in-line continuous fiscal metering (BS&W/custody transfer) with an accuracy better than +/- 0,05% water.

The technology employs microwave dielectric spectroscopy in a novel and unique way that increases accuracy, simplifies construction and widens its application for measuring the quantities and rates of multicomponent mixtures. It is being commercialized by Fluid Monitoring Systems, Inc., California of which Hitec A/S, Stavanger Norway is a part owner.

Fluid Monitoring Systems, Inc. is a new corporation with an exclusive world-wide license to manufacture and market products based upon this new metering technology.

The New Technology

- The devices are non-invasive.
- They are real time, full bore in-line devices.
- They have no moving parts.
- They can easily be built into sizes from 2" to 36" diameters and larger. No special liners are required.
- They measure the cross-sectional average of the material flowing in the pipe; i.e. no sampling.
- The devices are extremely stable electrically and impervious to electromagnetic interference.
- The devices are relatively immune to drift problems.
- The devices are low power devices such that remote location of the instrumentation will not be difficult.
- Fast response time: 10-100 msec.

Some Application in the Oil Industry

- Continuous 3-phase metering of production wells.
- Real time custody transfer and fiscal monitoring of pipeline quality crude oil.
- Net oil metering of 2-phase mixtures.
- Custody transfer metering of the water content of liquid natural gas.
- Improved Lease Automated Custody Transfer (LACT) metering.
- Mist flow metering.
- Pipeline transport: Product interface detection device.

Performance Features

- None of the devices show any flow rate sensitivity.
- All the prototypes require good mixing for best results.
- The 3-phase prototype has proven itself capable of accurately measuring mixtures of oil, water, and gas that vary in composition from 0 to 100% in any of the components when the materials are evenly mixed.
- The 3-phase prototype can measure water or oil continuous mixtures and the water can be fresh water or brine.
- The 3-phase impedance monitor, when combined with a densitometer shows great promises in continuously measuring the volumetric ratios of oil, water and gas mixtures.
- The 2-phase prototypes have demonstrated sensitivity and accurace to better than +/- 0,05% over the 0-5% water cut in pipeline quality crude oil.

STATUS

The 3-phase prototype is capable of detecting which state the emulsion is in such that the appropriate calibration curve can be selected for determining the water content.

To date, three 4" prototypes for in-depth flow loop analysis have been built. One of these prototypes is designed for 3-phase monitoring and the results obtained with this prototype will be described briefly. Figure 1 shows the full measurement range of the 3-phase prototype from 0-100% seawater. The curve that starts at 0% water corresponds to measurements of oil continuous mixtures in the flow loop. The curve that extends from approximately 55% to 100% water corresponds to measurements of water continuous mixtures. Note the distinct jump in the measured properties when the emulsion undergoes a phase inversion. The step jump results from the large difference in electrical properties of an oil continuous emulsion versus a water continuous one.

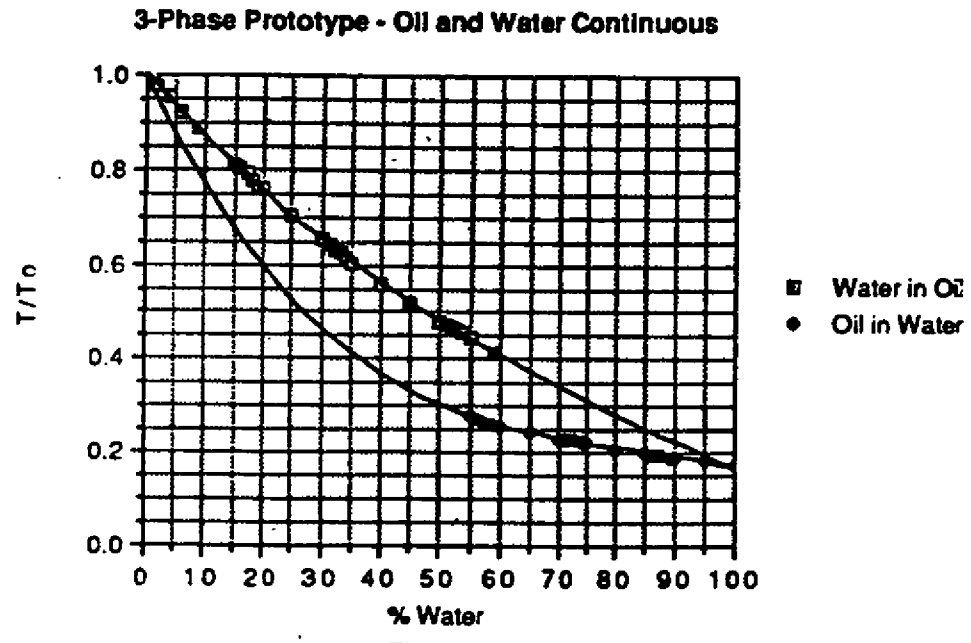


Figure 1

Figures 2 and 3 below show respectively oil continuous and water continuous mixtures at two different salinities.

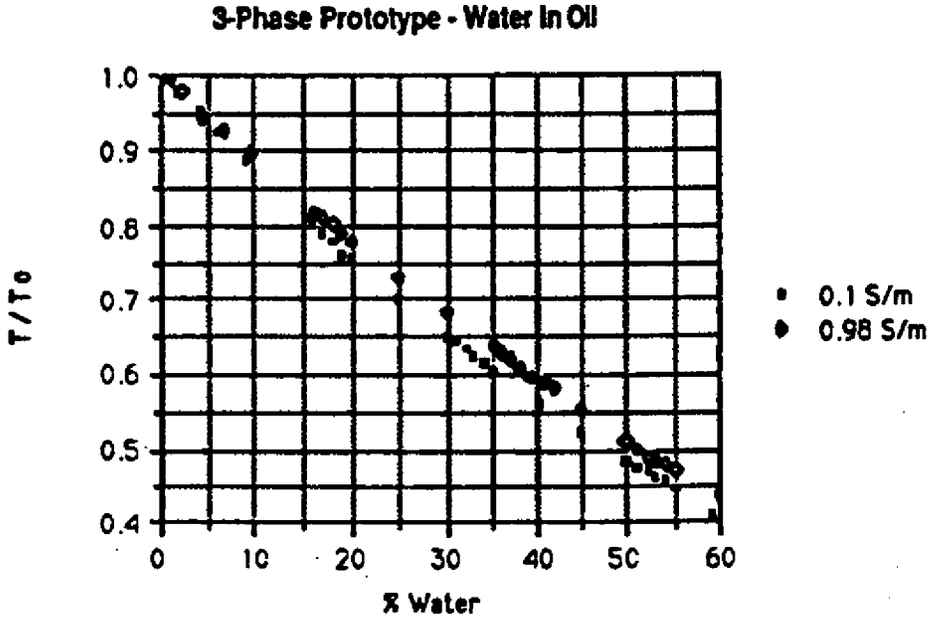


Figure 2

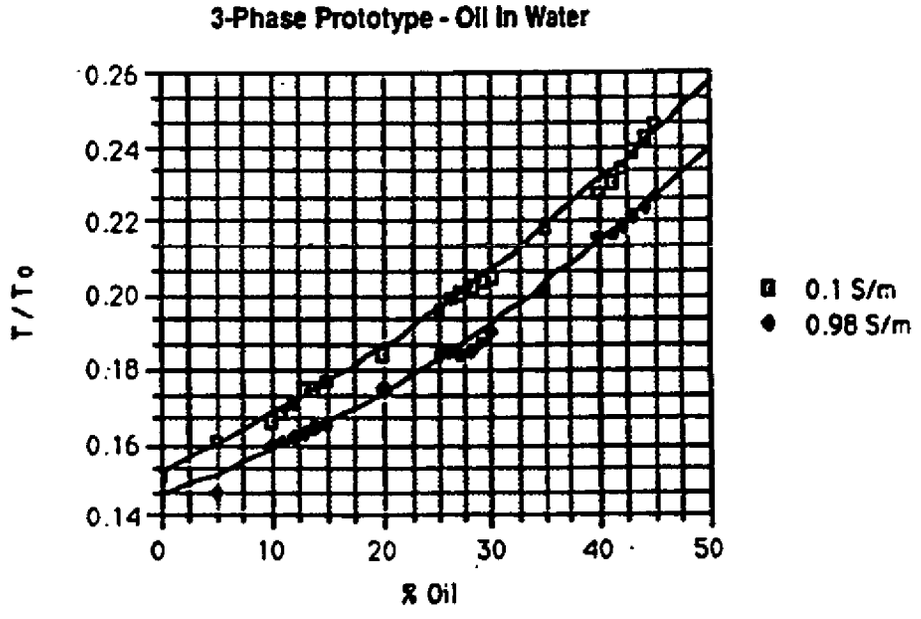


Figure 3

Figure 4 below is also water continuous, but here oil is added to North Sea water.

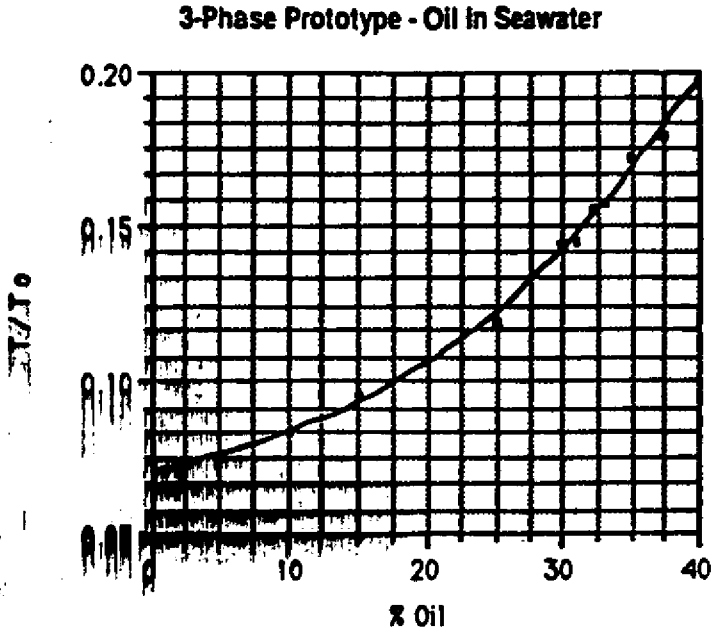


Figure 4

And finally, figure 5 shows the measurement when adding gas to a mixture having 20% water in oil.

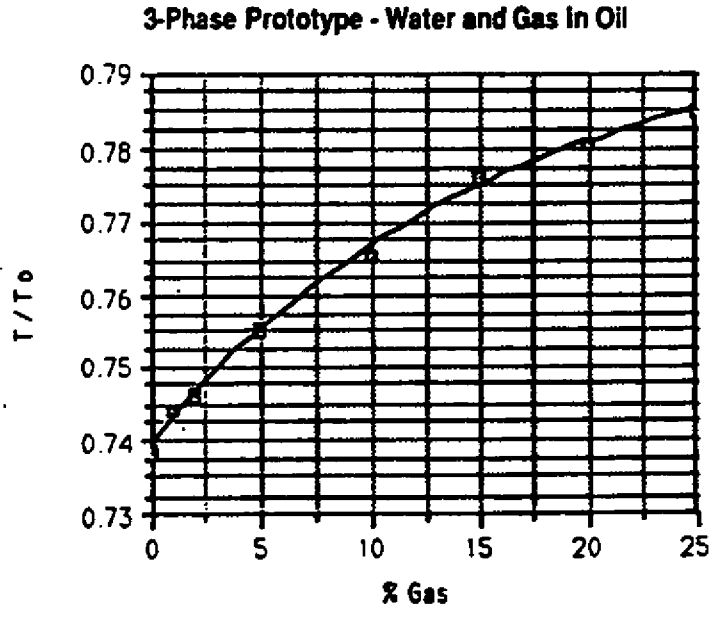


Figure 5

During our flow loop measurements, changes in water cut less than 0,01% or 100 pp could be detected. Flow rates varying between 0,05 m/sec. and 10 m/sec. had no effect. These are important performance features.

Two types of fiscal metering prototypes have been built. One is completely non-invasive while the other has small, non-moving, no-active parts introduced into the pipe. The latter prototype is the most sensitive and the most pressure resistant. The results for both prototypes have been equally promising. Only the results of the second of the fiscal metering prototypes will be described to avoid repetition. Figure 6 shows a typical calibration curve obtained with the fiscal metering prototype for 0-10% water in oil. The line through the points is the best curve fit.

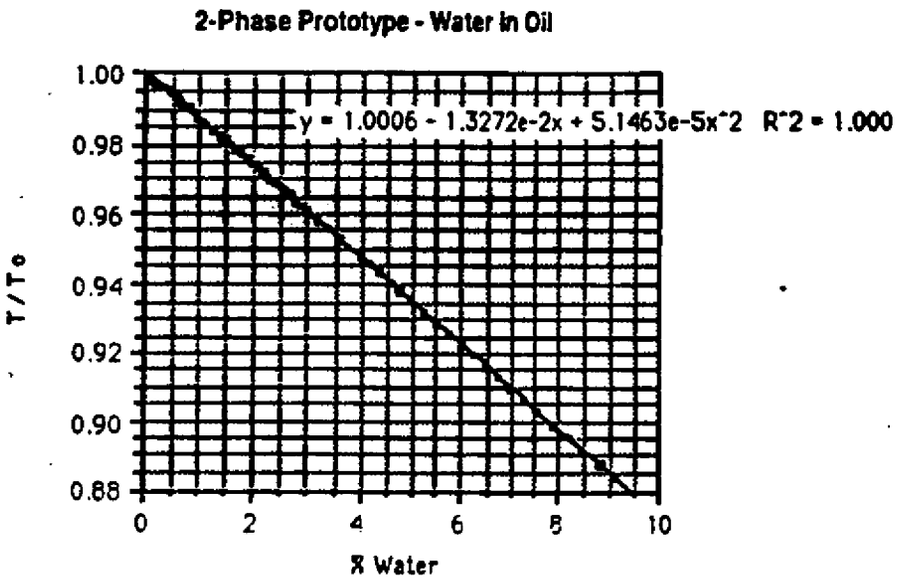


Figure 6

Figure 7 shows a more detailed look at the 0-1% water cut region. The data is very smooth and quite reproducible.

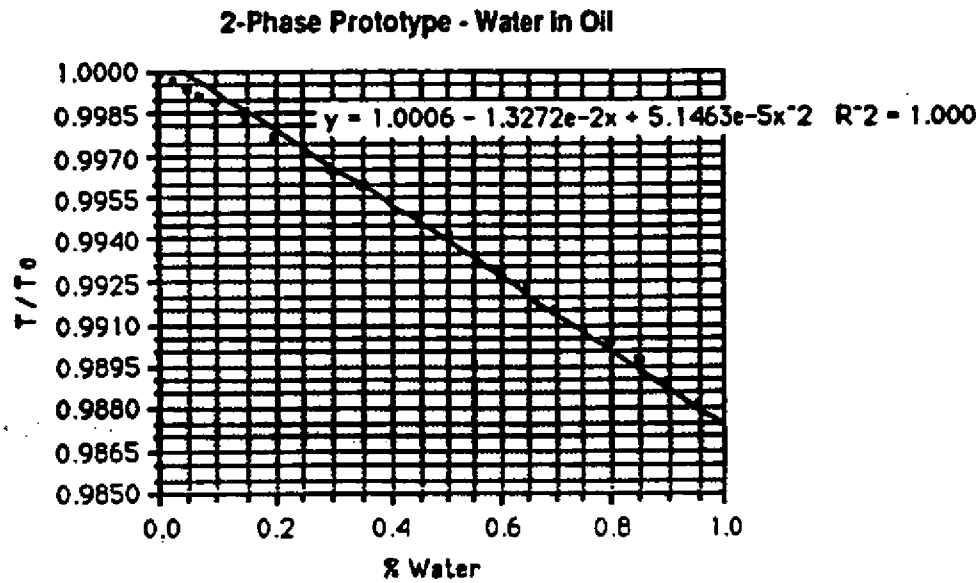


Figure 7

Figure 8 shows temperature calibration curves. When the temperature changes, the calibration curve makes a parallel shift to a different level. The nominal temperature coefficient is 0,018% water per degree Celcius. In other words, without a temperature correction, the inaccuracy of the fiscal meter would be +/- 0,018% per degree changes in the temperature from the calibration temperature. An actual field unit will have a built-in temperature sensor for real time correction.

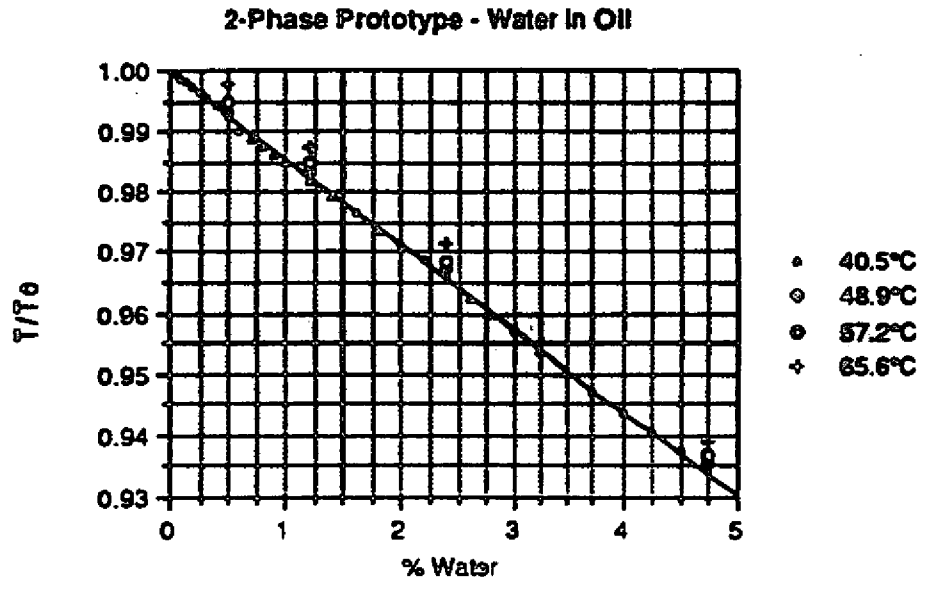


Figure 8

The Future Tasks:

Below follows a summary description of some specific future development objectives.

Oil or Water or Gas Continuous Well Stream Measurement System.

This system has the highest priority. It is a system for measuring well stream composition and flow rate continuously.
It will give the operating companies great savings from better reservoir management (enhanced recovery) and optimal field development. It can also replace the test separator.
The results from tests in California and in Stavanger are very encouraging. It will detect water or gas breakthrough.

BS&W in Fiscal Metering, Custody Transfer and Quality Control Systems.

Fiscal metering is measurements where the government calculates tax or royalty (normally they take both).
The oil companies usually are allowed to reduce the oil volume with the volume of Base Settlement and Water.
The percentage of BS&W are always documented with samples.
The operators have for a long time wanted an automatic and continuous way for doing that.

When buying oil or other products the client does not want to pay for unwanted water. That's the reason why the market for a long time have wanted a sensor to replace today's sampling methods with a continuous measurement of the total water content in the product. The custody transfer system of Fluid Monitoring Systems satisfies this market need.
Similar equipment can also be used for quality control.
Civilian jet fuel, for example, has a quality criterion regarding the maximum water allowed; namely, 30 parts per million.

Leak Detection System.

If there is leakage between a lubrication system and a water cooling system, water goes into the oil or oil into the water. This can easily be detected by our probe.
The same probe can detect the water content in electrical transformer oil. Thus the system can save people and equipment by detecting failures before accidents occur.

Mist Flow Monitoring and Net Oil Monitoring Systems.

The separator is among the largest equipment in oil production. Normally the sizing factor is the time it takes for oil to separate from water. A continuous measurement of the oil and water mixture and its flow rate give better control and increased efficiencies which reduce the size of the separators. **This system can also detect water breakthrough!**

In some separators, particularly in test separators, there can be large carryover of liquid in the gas stream (mist flow) which can lead to the wrong interpretation of the reservoir. **The 2-phase probe can measure both the oil/water ratios and the liquid content in the gas.**

Pipeline Transport:
Product Interface Detection Systems.

Pipelines are often used to transport different products separated by equipment known as "pigs". "Pigs" may be a mixing zone of the two products, a gel substance or a mechanical isolation. Refineries normally want to push the last product out of the line with the new product without mechanical pigs. To accomplish that requires rapid detection of the fluid or gel interfaces. **This new technology has this capability.**

Steam Quality Control Systems.

To monitor the quality of steam is important in many industries. In the oil industry steam is injected into the heavy oil reservoirs in order to lower the oil's viscosity by the heat generated when the steam condenses. Optimum steam quality is about 70%. **The new technology can monitor the steam quality by monitoring the water mist content of the steam.**

The above is by no means an exhaustive listing of the many applications envisioned by this new technology.

Practically every process industry imaginable needs this new kind of metering technology. It has the unique capability of being able to measure a wide variety of compositions, including those being water or brine continuous. Further, it has great sensitivity, is not affected by flow velocity and can be used to measure that very same velocity.

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Field-based Water-in-Oil Sampling Studies"

Lecturer:
Nicholas W. King
National Engineering Laboratory

FIELD-BASED WATER-IN-OIL SAMPLING STUDIES

by

Nicholas W King

S U M M A R Y

The paper describes the water-in-oil sampling field tests performed at a major European oil refinery. Metered supplies of water were injected into crude-carrying pipelines and the results monitored downstream by a bypass grab sampler, an in-the-line grab sampler, a capacitance device and a multi-probe profiler. The response of these instruments was monitored as crude type, flow velocity and water content were varied. Studies were also made of how pipe configurations affect the mixing of water and oil and the modification of slugs of water during passage through these configurations. The work was sponsored by the members of the NEL Automatic Sampling Project.

C O N T E N T S

N O T A T I O N

Symbol	Description	S.I. Unit
B	Background water, ie water already present in the crude oil flow before any water injection	per cent v/v
C	Calculated total water in oil flow = B + I	per cent v/v
I	Percentage of water injected into the main flow $= \frac{W_i}{W_i + K_i} \times 100$	per cent v/v
K_i	Crude oil flowrate	l/s
K_s	Volume of crude oil in the sample	ml
R	Rating sampling system[11] (only applicable if injected water content is $>$ 1 per cent v/v water)	
	$= \frac{\text{Difference between sampled and calculated water content}}{\text{Injected + background water content}}$	
	$= \frac{S - C}{B + I} = \frac{S - C}{C}$	-
	R, rating = A if ratio $< \pm 0.05$ B if ratio $> \pm 0.05$ and $< \pm 0.10$ C if ratio $> \pm 0.10$ and $< \pm 0.15$ D if ratio $> \pm 0.15$	
	Prefix 'd' = uncertainty in measurement of variable prefixed.	
S	Percentage of water in a sample $\frac{W_s}{W_s + K_s} \times 100$	per cent v/v
W_i	Flowrate of water injected into the main flow	l/s
W_s	Measured volume of water in a sample	ml

1 INTRODUCTION

Since 1981 the NEL Automatic Sampling project has been supported by a consortium of between 14 and 18 member companies to perform research work to study and improve automatic water-in-oil sampling systems and methods[1,2]. The work has drawn upon three main resources: Firstly, and predominantly, it has used the purpose-built sampling test facility at the NEL[3,4,5]. Secondly, this has been supplemented by the use of computer simulations[6,7] and thirdly, the subject of this paper, a working refinery was utilised to conduct field test work. Although the field tests described were undertaken in 1985 and 1986[8] it is only now that confidentiality restrictions have been lifted and the results[9] can be presented in this paper.

The objectives of the field tests were to compare different sampling methods - notably In-the-line and External-loop sampling, to investigate the degree of mixing transients experienced and their effect on the different sampling methods, to verify the NEL's laboratory work on the effect of varying sampling flowrate through an External-loop sampler and to effect a comparison between laboratory and field sampling environments.

It should be noted that the results and conclusions arising from this work pertain to one particular situation at one refinery and may not be universally true.

2 SAMPLING FACILITY AND TESTING PROCEDURE

The field test facilities were made available to NEL by BP at their refinery in Europort near Rotterdam in the Netherlands. This location was chosen because BP had already established an experimental sampling facility at the refinery[10] and only a few pipework changes and hot taps were required to make it suitable for the NEL field tests.

2.1 Tests Performed

A total of 19 test 'runs' labelled A-S were performed on three separate occasions, with each occasion having a different type of crude oil. Delays were experienced in the testing programme due to difficulties in obtaining the preferred types of crude oil and problems in finding sufficient spare ullage for tank-to-tank transfers. In all, the tests took a year to complete and included a comprehensive programme of sampling flowrates, water transient studies and sampling comparisons. A summary of the tests performed is given in Table 1, with specific details given in Tables 2 and 3.

2.2 Pipework

The sampling facility was installed at a manifold where lines from the jetty, the tank farm and the refinery all joined together. In this location sampling tests could be conducted on tank-to-tank transfers using several pipe configurations. A schematic of the pipe configuration is given in Fig. 1 which shows the sampling station situated on the No 1 header about 2 m downstream of the jetty/header manifold. The internal diameter of the mainline pipe at the sampling station was 1.197 m. The approximate hold up volume between injection and sampling points on the direct route down the No 2 header, crossover via the No 3 line and up the No 1 header was calculated as 37m^3. Hold up between injection and sampling points via the No 2 header, down the No 3 jetty line, crossover at the jetty end, return by the No 2 jetty line and up the No 1 header was calculated as 379 m^3.

All instrumentation, computers, data loggers, Karl Fischer equipment etc was housed in a 'Portakabin' adjacent to the sampling station. A Commodore PET computer monitored all four flowmeters used and the 'Aquasyst' capacitance cell output and recorded them on disk and gave a hard copy both as a print-out and on a chart recorder.

2.3 Mainline Flowrate Measurement

The total quantity of crude oil transferred during a test was calculated by reading the exporting and receiving tank dip gauges. The maximum uncertainty in the measurement of flowrate calculated from the tank dips was calculated as $\pm$12 l/s. The tank dips, however, did not give a measure of the flowrate at any moment during a test and for this reason a Maurer 'Cruflo' insertion turbine meter reading to $\pm$40 l/s, normally used to pace the sampler, was situated downstream in the No 1 header and was used to monitor the constancy of the flowrate during the course of each test.

2.4 Injected Water Flowrate Measurement

Sea water from the refinery fire ring main was piped to the injection point by two 51 mm (2-inch) fire hoses, each of which was connected via a non-return valve and a ball valve to either the top or the lower injection point. A 51 mm (2-inch) calibrated turbine flowmeter was fitted in each line together with the requisite upstream and downstream lengths of straight steel pipe. Each flowmeter had a range of 4-50 l/s and the total uncertainty in the flow measurement system was calculated at $\pm$0.26 l/s.

2.5 Sampling Instrumentation

The following sampling devices were used:

A Maurer In-the-line grab sampler and a Maurer External-loop grab sampler, both of the 'Maidstone' type, were fitted with identical internal mechanical systems and having their sample receivers immediately after the outlet port of the sampler. In order to obtain a workable sample volume in the minimum time the samplers were set to give the highest grab rate of 20 grabs per minute and each sample collection time was two minutes, giving a sample volume of 40 ml. The In-the-line sampler was mounted horizontally from the side of the mainline pipe, while the External-loop cell sampler was mounted below the main flow pipe in the external-loop which, because of piping complexity, had a sampling probe inserted vertically upwards into the mainline pipe. The sampling probe was of the NEL design as shown in Fig. 2.

The wall tapping, which was only used in the third set of tests, was mounted horizontally at the side of the pipe near the sampling station and consisted of a 50 mm dia. pipe, 315 mm long, with a blanking flange from which an axial 12 mm pipe, 130 mm long, led to the sample control valve.

The Profiler was designed in accordance with the recommendations contained in the Draft ISO Standard, 3171[11] and consisted of five equispaced NEL design sampling probes facing towards the direction of flow in the main line with the top and bottom probes each 20 mm from the pipe wall. All the probes were 9 mm o.d. and 6 mm i.d. with internally chamfered tips. There was also an additional probe facing vertically downwards to enable sampling from within the 5 mm bottom of the main line to check for any separate free water flowing along the bottom of the pipeline.

A dual cell 'Aquasyst' electrical capacitance water-in-oil measuring instrument manufactured by Endress and Hauser was inserted in the external-loop to monitor changes in water content and record the shape of the water transients reaching the sampling station[12].

3 WATER CONTENT MEASUREMENTS

3.1 Injected Water Content

Although the flowrate of crude oil transferred during a test could be measured by tank dips to within ±12 l/s, K_I, the actual flowrate at any moment during a test was assessed using the insertion flowmeter which, because of background fluctuations, could only be read to ±40 l/s. W_I was measured by calibrated turbine meters to within ±0.26 l/s. The total uncertainties associated with the injected water measurement I, was dependent on both K_I and W_I and was calculated for the individual tests to be:

Test(s)	A/B	C/D	E/F	G	H/I	J/K	L/M	N/O	P/Q	R	S
dI = ±	0.08	0.03	0.02	0.03	0.10	0.03	0.10	0.06	0.02	0.05	0.04

3.2 Background Water Content

Background water samples were taken before and after a testing period, usually at the same time as tank dip measurements were taken, ie before and after a change in flowrate or start up or close down of the pumps. Usually three samples were taken from a tapping on the external-loop together with three samples taken from the centre probe of the Profile to obtain each background water measurement. Throughout the tests the background water, with only a few exceptions, remained very constant. This was mainly achieved by the policy of either allowing the crude to remain for a period in the exporting tank before a test or by running tank mixers before and during the tests to ensure uniformity of background water.

3.3 Calculated Water Content

The total water present in the mainline flow during a sampling test was calculated from the sum of the injected water, I, and the background water, B. The uncertainty in measuring the calculated water content was, therefore, a combination of uncertainties due to measurement of both injected and background water contents and was calculated to have a maximum value of ±0.10 per cent v/v water.

3.4 Sampled Water Content

All samples taken were collected in disposable polythene bottles with screw caps. The sample volumes collected were of approximately 250 ml volume, except in the case of the Maurer grab samplers which were of 40 ml. Analysis of each sample was by potentiometric Karl Fischer titration performed volumetrically on 0.1 ml up to 1 ml subsamples taken from the homogenised contents of each 250 or 40 ml sample. Examination showed that the uncertainty of measurement associated with the volumetric Karl Fischer titration would be within the repeatability values given by the gravimetric IP 356/84 Standard. The maximum water content analysed in the field tests was 2.5 per cent v/v water, hence the maximum expected uncertainty in measurement by Karl Fischer analysis was ±0.03 per cent v/v water. For many tests and for the background water measurements the expected uncertainty would be much less because of the smaller percentages of water involved.

3.5 Difference between Calculated and Sampled Water Contents

Taking the uncertainty in the measurement of the calculated water content, ie Injected plus Background, as ±0.10 per cent v/v water and the uncertainty in the sampled water content as ±0.03 per cent v/v water then statistically any calculated and sampled water content measurements were significantly different when they differed by more than ±0.10 per cent v/v water.

4 PROFILE AND MIXING STUDIES

It was expected that all background and injected water would be well mixed in the transit through the bends and valves of the crossover manifold between injection and sampling points[13]. Further, the Reynolds number of the mainline flow at the sampling station varied from 33 000-380 000 so that a fully turbulent flow and an established velocity profile would always be expected to aid mixing. In addition, the water injection points gave the injected water an inlet velocity of about 5 m/s though this could have been higher because of possible constrictions in the hot taps.

In order to check that all background and injected water had been mixed uniformly, profiling measurements were conducted generally, in accordance with ISO DIS 3171, before tests A, C, E, G, H, J, L, N, P and R, using the six-point Profiler. An example of the results obtained is given in Table 4 which gives, in addition to each water content measured, the mean water content measured across the five forward-facing profile probes, the 95 per cent confidence limits of that mean and the 95 per cent confidence limits expressed as a percentage of the mean. The figures in brackets refer to the probe pointing vertically downwards to check for free water in the bottom of the pipe and these were not entered into the calculation of the means. It can be seen from these bracketed figures that no free water was detected at any time during this test and this was true for all the other tests. Beneath the profiling measurements, a similar mean, 95 per cent confidence limits and confidence limits expressed as a percentage of the mean are given for each sampling probe on the Profiler.

Analysis of the profiling results for all tests gave information in three main areas:

4.1 Compliance with ISO 3171

ISO 3171, Section 6 and Fig. 8[11] states that a water concentration profile across a pipeline is acceptable for sampling if the average water content at each position on the Profiler does not exceed ±5 per cent of the mean value. All water concentration profiles, and hence all the flow conditions used in the tests, were found to be well within the ISO recommendations.

4.2 Relative Mixing Characteristics

Statistical analysis of the profiling results for all the tests showed that there was no correlation between profile uniformity and pipeline velocity. Similarly, there was no significant correlation between profile uniformity and type of crude oil for the three crude oils studied.

The effect of pipeline length on mixing was demonstrated by comparing tests C/D, G, N/O and R. Test C/D conducted at 1.46 m/s on Statfiord crude, on the direct injection/sampling route, had a profile scatter of 1.3 per cent while test G ran at 1.43 m/s on the same crude but via the jetty route had a

profile scatter of 0.6 per cent, ie passage down the jetty seemed to further mix the water. However, a similar comparison on the mixed crude with test N/O run at 1.20 m/s on the direct route gave a profile scatter of 1.5 per cent, identical with that of test R run at 1.17 m/s on the same crude via the jetty although in the case of test R the degree of scatter was calculated from only three profiles.

The overall conclusion was that in these cases the background water and injected water was so well mixed that differences in pipeline velocity, type of crude or pipeline mixing length had little effect.

4.3 Sampling System Uncertainties

4.3.1 Random errors

The results of the profiling tests presented an opportunity to evaluate the repeatability of the complete sampling system in measuring water content in that, for each set of profile results, samples were obtained consecutively from the same probe and analysed by the same procedure. The repeatability would also include the random fluctuations in the water content of the crude oil flowing in the pipeline during the time each set of profile measurements were made.

To illustrate this opportunity, the figures below the line in Table 4 show, in addition to the mean water content at each probe position, the 95 per cent confidence limits of the values obtained at that probe position expressed in water content and as a percentage of the mean water content. The average value of the 95 per cent confidence limits for all the profile data for individual probe positions was found to be $\pm$0.12 per cent v/v water.

Examination of individual sets of profile measurements showed some profiles such as H/I had average confidence limits of $\pm$0.04 per cent v/v water while others, such as J/K, had average confidence limits of $\pm$0.25 per cent v/v water. The former value approached the repeatability of the Karl Fischer analysis, while the latter value may reflect the repeatability of obtaining a representative sample from a flow of varying water content.

4.3.2 Systematic errors

The figures given in the box of Table 4 include an overall mean of S, the sampled water content and C, the calculated water content. These values were determined for each set of profiling measurements so the random fluctuations described above would have been removed. It was seen that the values of S generally exceeded C with a maximum difference (test J/K) of 0.16 per cent v/v water. The mean difference of S - C was +0.039 per cent v/v water with 95 per cent confidence limits of the mean of $\pm$0.044 per cent v/v water, ie the difference was not significant. The magnitude of the difference correlated with neither crude oil flowrate nor nominal water content. All the profile tests gave overall means with an 'A' ISO Sampling System Rating (see notation) except, that is, for test J/K which returned a 'C' rating.

Although the change in tank levels occurring during a test might have given rise to a change in flowrate, and hence injected water content, no conclusive evidence of this was observed. The profiles were determined at the start of each test where higher exporting tank levels and lower receiving tank levels could possibly have given a slightly higher than the test mean value of oil flowrate through the pumps. This would have effectively

diluted the injected water content and hence S would be less than C. Because the opposite was observed, it would suggest that although the mean difference was not significantly different, there could be a systematic element in the difference. It should be noted that the discrepancy in the case of test J/K was much larger than the expected $\pm$0.10 per cent v/v water. This could be explained by the water content varying while the profile samples were being taken.

5 TRANSIENT STUDIES

As a further examination of mixing characteristics, water transients of 1-, 2-, and 10-minute duration were injected into the oil flow. The 'Aquasyst' capacitance cell in the external-loop was used to monitor their passage through the sampling station. A summary of the transient tests is given in Table 3 while Table 5 gives a summary of the transient tests results. It must be noted that all the times were taken from the chart recording of the tests and include an element of subjective measurement of first detection and 95 per cent full magnitude times. The values given in the table are the mean values for the 1-, 5-, and 10-minute transients injected at each test condition. Although the three transients varied in length, the shape of their leading and trailing edges on the chart recorder were indistinguishable from each other at each test condition.

One surprising result of the tests was how little distortion the transients experienced in transit from injection point to sampling station. The transients were generated with a square waveform by a rapid opening and closing of the water injection lines and were shown to be so by the square waveform traces of the water injection meters on the chart recorder. The capacitance cell showed the transients were received at the sampling station with only a slight distortion of this square waveform as shown by the times of the leading slope in Table 5. A measure of the received waveform can be given by the fact that approximately 75 per cent of the peak had registered in half the time required for 95 per cent to register.

It could also be seen that there was surprisingly little slip between the water and oil phases as exemplified by the correspondence of calculated and measured time delays which would confirm that the water was well mixed with the crude oil. It would be expected that the measured time delay would exceed the calculated time delay as a finite time would be required to pass through the external-loop to the capacitance cell. This was seen to be so in the majority of tests, though the uncertainty in determining exact measured times from the chart recording and exact calculated times from the hold up volumes and flowrate could account for tests M-S, conducted on the mixed crude, indicating that the water actually arrived ahead of the calculated time.

It was difficult to assess the slip between water and oil components as injection of a given percentage of water was expected to increase the overall mainline flowrate by a similar percentage, ie the injection of water transients into the mainline was accompanied by corresponding mainline velocity transients to accommodate the extra fluid.

6 EXTERNAL-LOOP SAMPLING RATE STUDIES

Previous work in the NEL test facility had shown that samples obtained from the NEL design of external-loop scoop probe, ie the internally chamfered, forward-facing scoop, was least affected by water droplet size or varying sampling flowrates from 10-100 per cent of mainline velocity, ie 10-200 per

cent isokinetic sampling flowrates. Further, these laboratory tests had also shown that the NEL design of probe was relatively unaffected by being turned 30° upwards, or 30° downwards to the axis of the pipe. It would appear, therefore, that this design of scoop in addition to being little affected by sampling flowrate was also little affected by swirl angles of up to ±30°.

Field studies of the effect of external-loop flowrate on sampling accuracy were undertaken on an external-loop fitted with a NEL design of sampling probe. The fluid resistance through the external-loop and the capacity of the external-loop pump were such that external-loop flow of up to a maximum of only 80 per cent isokinetic were possible with the mainline flows used in the tests.

Tests were performed at several external-loop sampling rates using the valve in the external-loop to control the external-loop flow. Samples were taken from the External-loop grab sampler and from the centre probe of the Profiler at three separate instants for each sampling rate. In some tests, samples were also taken at the same time from the In-the-line grab sampler and from the wall tapping.

The results of the tests are given in Table 2 which, for each test and each sampling, gives C, the water content calculated from the oil and water flowrates, and S the sampled water contents from the External-loop cell sampler, the In-the-line sampler, the Profiler and the wall tapping.

Examination of the External-loop sampler results in Table 2 shows an outlier in the data for the 8 per cent isokinetic sampling flowrate for test J. This was due to a surge in background water during the course of the sampling. Although not thought to be significant it has nevertheless been neglected in the analysis below.

Two methods were available with which to compare the results of the External-loop sampler when used at each sampling flowrate; firstly, comparison could be made with C the calculated water content and secondly, comparison could be made with the water content measured at the centre probe of the Profiler. The results of both comparisons are given below.

6.1 Comparison with Calculated Water Contents

It must be noted that the measurement uncertainties associated with the calculated water content could be comparatively large at ±0.10 per cent v/v water and the difference between the calculated and sampled water contents was significant only if it exceeded ±0.10 per cent v/v water.

On this basis, the seven tests which showed significant differences between the calculated water content and the sampled water content from the External-loop cell sampler did not indicate that the difference was due to a change in sampling rate because the differences occurred at high as well as low percentage isokinetic sampling flowrates.

6.2 Comparison with Profiler Measurements

The uncertainties associated with the sampled water contents were less than those for the injected water contents, particularly as three samples were taken at each percentage isokinetic sampling flowrate. Statistical analysis showed these to be ±0.02 per cent v/v water and that any two sampled measurements were significantly different only if the difference exceeded ±0.03 per cent v/v water.

A comparison could, therefore, be made between the External-loop sampler and the other sampling methods with comparatively less uncertainty than a comparison with the calculated water contents. Only the samples obtained from the centre probe of the Profiler were used for this purpose as those obtained from the In-the-line grab sampler and the wall tapping could be subject to errors as described in Section 7 below.

When the External-loop sampler and Profiler results were compared, 15 of the 27 tests gave significant differences but no correlation between these differences and percentage isokinetic sampling flowrate could be found. There was, therefore, no evidence to suggest that sub-isokinetic sampling flowrate effected sampler accuracy. This conclusion was also confirmed by previous exploratory work by BP at the sampling station[10].

7 COMPARISON OF SAMPLING METHODS

The field tests provide an opportunity to compare the results of the in-the-line grab sampler, the External-loop grab cell sampler, the Profiler, the wall tapping and the capacitance cell mounted in the External-loop.

7.1 Comparison of Sampling Methods with Constant Water Content

Accepting the conclusion of Section 6, that the sampling flowrate did not effect the External-loop cell sampler, then the results of the sampling flowrate tests given in Table 2 can be used to compare the two grab samplers, the Profiler and the wall tapping. No quantitative measurements were taken from the capacitance cell as for the purpose of these tests it was only used as a water content monitor. Nevertheless, the output from the capacitance cell was found to qualitatively reflect the calculated and sampled water content measurements in a stable and responsive manner.

Excluding the 8 per cent isokinetic sampling flowrate test J for the reasons given in Section 6, the mean of the differences between the calculated and sampled water contents shown in Table 2 is expressed as shown in part A of Table 6. The mean values for the External-loop cell sampler, the In-the-line sampler, the Profiler and the wall tapping were +0.09, +0.02, +0.06 and +0.74 per cent v/v water respectively. It can be seen that all four methods overestimate the water content which corresponds with the findings of Section 4.3.2. Again no correlation between this difference and the crude oil flowrate or nominal water content could be discerned.

Part A of Table 6 also shows the confidence levels to which these means could be quoted to 95 per cent confidence. This shows that the readings from all four methods except the In-the-line sampler were considered to be significantly different from the calculated water contents. The table also shows that the degree of scatter associated with the In-the-line sampler is greater than that associated with either the External-loop cell sampler or the Profiler but that the wall tapping had, by far, the largest degree of scatter of any method.

An alternative to using the calculated water contents was to use the Profiler water contents for comparison. Use of the Profiler, which had the NEL design of scoop tube, was vindicated both from the findings of the laboratory work which showed it to be the best method of obtaining a representative sample from the main line and also in that all measurements involved in the comparison were based on the Karl Fischer titration and any systematic error from this source was therefore eliminated.

The comparison with the Profiler results is shown in part B of Table 6 which shows that the External-loop cell sampler, the In-the-line sampler and the wall tapping differed on average from the Profiler results by +0.03, -0.02 and +0.70 per cent v/v water respectively. The table also gives the 95 per cent confidence limits to which these means could be quoted and these show that the External-loop cell sampler and the wall tapping were significantly different from the Profiler whereas the In-the-line sampler was not. This statement must be qualified by drawing attention to the fact that the larger scatter exhibited by the In-the-line sampler was largely responsible for no significant difference being found in its case.

The results showed that the wall tapping grossly overestimated the water content though this was most likely due to its very unfavourable geometry. In contrast, point 6, the bottom-facing probe on the Profiler, which also sampled from near the pipe wall and at right angles to the flow was seen to give reasonable results.

The results also showed that the External-loop cell sampler tended to overestimate and the In-the-line sampler tended to underestimate the water content compared to the Profiler. The results also show that the scatter associated with the In-the-line sampler was twice as large as that associated with the External-loop sampler.

Another method of comparing the sampling methods was to compare the ISO Sampling System Rating (see notation). These ratings are given for each sampling method in Table 2 and can be summarised in the table below in which the total number of tests falling in each rating category is given for each of the four sampling methods:

Sampling method	External-loop	In-the-line	Profiler	Wall tapping
Rating 'A'	13	8	16	0
Rating 'B'	5	3	3	0
Rating 'C'	3	2	1	0
Rating 'D'	0	0	1	6
Total tests	21	13	21	6

7.2 Comparison of Sampling Methods with Water Content Transients

The main objective of the transient tests was to assess the response of the different sampling methods to water transients. To achieve this end the two grab samplers and the Profiler were operated while water transients were injected into the oil flow at each test condition. Use of the Profiler in these tests was for academic interest only as the spot samples obtained by the Profiler at two-minute intervals were not intended to form part of a sampling system as in the case of the two grab samplers. Transients of one minute, then five minutes and, in some cases, ten minutes duration were injected into the flow at each test condition. Test S, in which 18 one-minute transients were injected into the line was a special case which was performed to give a comparison with the NEL computer simulation work.

As described previously, Table 3 gives a summary of the individual transients, while Table 7 gives a comparison of the sampling methods in the transient conditions prevailing over the duration of each test. For each test given in Table 7 the transient water, over and above the background water, which was measured by each sampling method is expressed as a percentage of the total amount of water injected evaluated from a knowledge

of injected water flowrates and injection time. The mean of these percentages for the External-loop sampler, the In-the-line sampler and the Profiler, was calculated with allowance for the different numbers of samples taken in each test. This showed that 98, 99 and 84 per cent of the injected transient water was recovered by the External-loop sampler, In-the-line sampler and Profiler respectively. The large uncertainties associated with the measurement of the injected water content makes it difficult to give any statement about the absolute uncertainty to be expected with each sampling method except that, as expected, the Profiler gave a substantially different reading because of the relatively long two-minute interval between successive samples. This difficulty with the accuracy of the Profiler method in transient conditions also removed the possibility of comparing its results with results of the External-loop and In-the-line samplers as above.

Only in test R was the wall tapping used and this, like the Profiler, also had the disadvantage of a long two-minute period between samples but nevertheless, at 173 per cent recovered transient it exceeded the maximum deviation recorded by any of the other methods confirming the conclusion in Section 7.1 that, in this particular case, it was a most inaccurate method of obtaining a sample.

7.3 Field and Laboratory Comparisons

After the completion of the field tests the In-the-line grab sampler was shipped to the NEL and installed horizontally in the NEL water-in-kerosine sampling facility. When the facility was operated on closed loop at a nominal 5 per cent v/v water content the sampler was found to underestimate the water content on average by -0.25 and -0.22 per cent v/v water in two separate tests. The uncertainty in measuring the calculated water content in the test facility was $\pm$0.01 per cent v/v water and the 95 per cent confidence limits of the mean of the two tests was $\pm$0.04 per cent v/v water which made the sampled water content significantly different from the calculated water content. The laboratory results of -0.25 and -0.22 per cent v/v water were also significantly different from the field result of -0.02 per cent v/v water though it must be remembered that the field water content seldom rose above 2.5 per cent v/v water. It was also noted that between 200 and 400 grabs were required to obtain a representative sample in the laboratory facility, but that 40 grabs in the field appeared to be sufficient to obtain a representative sample.

The discrepancy in measured water content and the longer time taken to obtain a representative sample would indicate that the water-in-kerosine laboratory facility provides a more demanding sampling environment than in the field where the water does not usually experience rapid separation from the oil.

8 CONCLUSIONS AND RECOMMENDATIONS

The main findings of the work conducted at the refinery were:

a The mixing of background and injected water was well within the ISO 3171 specifications showing that the method of water injection and the simple crossover manifold used in the tests provided sufficient mixing even at the low flow velocities used. No correlation between mixing efficiency and flow velocity or crude type was found over the range of variables studied.

b Transients of water were found to experience relatively little distortion or slip even after passage through long pipes, bends and valves.

c Uncertainties of up to ±0.10 per cent v/v water were associated with the measurement of the calculated injected water content. This was mainly due to tank dips being used to measure the total volume transferred during a test and an insertion flowmeter to indicate any change of the flowrate during a test. The ISO 3171 recommended limits of ±2 per cent on crude oil and injected water volumes may not be sufficient to give confident comparisons between injected and sampled water contents.

d External-loop flowrate did not effect the sampling accuracy of an External-loop cell sampler when used over a range of 6 to 79 per cent of the isokinetic sampling rate.

e In steady-state conditions, the In-the-line and the External-loop cell samplers overestimated water content on average by +0.02 and +0.09 per cent v/v water respectively compared to the calculated injected water. Because of the large uncertainties involved in the measurement of the calculated water content (see g below), only the cell sampler was considered to have a significant difference. Compared to the Profiler, the In-the-line sampler underestimated on average by -0.02 per cent v/v water and the cell sampler overestimated on average by 0.03 per cent v/v water. Again, the cell sampler result was considered to be significantly different. A wall tapping gave samples that overestimated by 0.74 per cent v/v water.

f In sampling water transients, on average the External-loop cell sampler recovered 98 per cent and the In-the-line sampler 99 per cent of the water in the transients. By contrast, the spot samples obtained from the Profiler recovered 84 per cent and the wall tapping 173 per cent of the water in the transients.

g The In-the-line grab sampler was found to underestimate the water content by 0.02 per cent v/v water in the field, but to underestimate the water content by 0.25 per cent v/v water and to have a longer delay in producing a representative sample in the NEL laboratory facility. Both the larger underestimation and the longer delay in obtaining a representative sample indicate that the NEL water-in-kerosine test facility is more demanding than normal field conditions.

ACKNOWLEDGEMENT

The National Engineering Laboratory would like to thank BP and all BP staff at London Central Engineering, Sunbury Research Centre, and the BP Rotterdam Refinery for their enthusiastic assistance and collaboration in the field tests.

This paper is published by permission of the Director, National Engineering Laboratory, Department of Trade and Industry, East Kilbride, Glasgow, UK.

REFERENCES

1 KING, N. W. The NEL sampling project, North Sea Flow Metering Workshop. East Kilbride, Glasgow: National Engineering Laboratory, October 1984.

2 KING, N. W. Improvements in water-in-oil sampling equipment and procedures resulting from the NEL automatic sampling research project. SIRA Seminar on Cost-effective Sampling Systems, London, 12-13 Nov. 1986. Also Analytical Proc., July 1987, Vol. 24, p. 211.

3 KING, N. W., PURFIT, G. L. and PURSLEY, W. C. Improving the performance of automatic grab samplers using a unique laboratory test facility. Spring National AIChemE, Houston, Texas, USA, March 1985.

4 KING, N. W., PURFIT, G. L. and PURSLEY, W. C. Design and operation of a test facility for evaluating water-in-oil samplers. BHRA Conf. Multi-phase Flow, London, June 1985.

5 KING, N. W. Multi-phase flow measurement at NEL - Instrumentation and control, October 1988, 21(8).

6 KING, N. W. Computer simulations to determine the optimum sampling frequency during custody transfers. North Sea Flow Metering Workshop. East Kilbride, Glasgow: National Engineering Laboratory, October 1986.

7 KING, N. W. Sampling frequency for water-in-oil measurement; computer simulations and field experience. 3rd Int. Conf. Multi-phase Flow, BHRA, The Hague, The Netherlands, May 1987.

8 KING, N. W. Comparison of sampling methods by water injection. North Sea Flow Metering Workshop, Stavanger, Norway, October 1987.

9 KING, N. W. and PURFIT, G. L. The study and improvement of the design and operation of automatic samplers used in the petroleum industry. Phase 3, part 2. NEL Report No AUSA/03. East Kilbride, Glasgow: National Engineering Laboratory, 1987.

10 GOLD, R. C. and MILLER, J. S. S. A comparison of the performance of in-line and by-pass type sampling devices in the BP, Rotterdam tests. Proc. Conf. Determination of Water Content in the Custody and Transfer Metering of Crude Oil, London Hilton, 24 Feb. 1986. IBC Technical Services.

11 INTERNATIONAL STANDARDS ORGANISATION. Petroleum liquids: automatic pipeline sampling. ISO 3171.

12 WILSON, M. B. and RICHARDS, B. O. Continuous measurement of the water content of crude oil using electrical capacitance techniques. Development and Applications Conf. Oil Loss Control in the Petroleum Industry, London, 24 Feb. 1984. Inst. of Petroleum.

13 JISKOOT, J. J. Comparative survey of mixing methods for crude oil in pipelines to provide conditions for representative sampling. Proc. Conf. Determination of Water Content in the Custody and Transfer Metering of Crude Oil, London Hilton, 24 Feb. 1986. IBC Technical Services.

LIST OF TABLES

LIST OF FIGURES

TABLE 1

SUMMARY OF TESTS PERFORMED AT THE BP ROTTERDAM REFINERY

Test	Date	From tank	To tank	Tank dips min.	Oil type	Vis. cSt	Pipe config.	Flow vel. m/s	Per cent v/v water			Ext-loop per cent isokin. flowrate	Time of transients min.	No. pro-files
									Back. B	Inj. I	Calc. C			
A	19/11/85	T109	T101	253	Statfiord	6.5	direct	0.89	0.43	1.82	2.25	8, 17, 31, 63	continuous	3
B	19/11/85	T109	T101	253	Statfiord	6.5	direct	0.89	0.43	1.82	2.25	36	5, 10	
C	19/11/85	T109	T101	146	Statfiord	6.5	direct	1.46	0.43	1.07	1.50	9, 16, 36, 49	continuous	3
D	19/11/85	T109	T101	146	Statfiord	6.5	direct	1.46	0.43	1.07	1.50	20	1, 5, 10	
E	19/11/85	T109	T101	47	Statfiord	6.5	direct	2.06	0.43	0.69	1.12	10, 19, 34	continuous	3
F	19/11/85	T109	T101	47	Statfiord	6.5	direct	2.06	0.43	0.69	1.12	38	5	
G	20/11/85	T101	T109	118	Statfiord	6.5	jetty	1.43	0.61	0.91	1.52	37	1, 5, 10	3
H	16/02/86	T110	T104	138	Iran. heavy	30.0	direct	0.89	0.15	2.32	2.47	11, 20, 38, 79	continuous	10
I	16/02/86	T110	T104	138	Iran. heavy	30.0	direct	0.89	0.15	2.32	2.47	37	1, 5	
J	16/02/86	T110	T104	117	Iran. heavy	30.0	direct	1.63	0.15	1.23	1.38	8, 20, 47	continuous	10
K	16/02/86	T110	T104	117	Iran. heavy	30.0	direct	1.63	0.15	1.23	1.38	40	1, 5, 10	
L	02/09/86	T104	T107	120	Mixed	7.0	direct	0.89	0.24	2.29	2.53	15, 34, 56	continuous	10
M	02/09/86	T104	T107	120	Mixed	7.0	direct	0.89	0.24	2.29	2.53	56	1, 5	
N	02/09/86	T104	T107	100	Mixed	7.0	direct	1.20	0.24	1.73	1.97	9, 21, 41	continuous	10
O	02/09/86	T104	T107	100	Mixed	7.0	direct	1.20	0.24	1.73	1.97	41	1, 5	
P	02/09/86	T104	T107	67	Mixed	7.0	direct	2.01	0.23	0.86	1.09	6, 13, 24	continuous	3
Q	02/09/86	T104	T107	67	Mixed	7.0	direct	2.01	0.23	0.86	1.09	24	1, 5	
R	03/09/86	T107	T104	151	Mixed	6.8	jetty	1.17	0.81	1.28	2.10	30	1, 1, 5	10
S	03/09/86	T107	T104	126	Mixed	6.8	direct	1.37	0.67	1.28	1.95	29	18 x 1	

TABLE 2

SUMMARY OF SAMPLING FLOWRATE TESTS

Test	Date	Oil Type	Vis. cSt	Flow vel. m/s	Per cent isokin. flowrate	Per cent v/v water				
						Calculated C	Ext-loop sampler	In-the-line sampler	Profiler	Wall tap
A	19/11/85	Statfiord	6.5	0.89	8	2.25	2.42 B		2.34 A	
A	19/11/85	Statfiord	6.5	0.89	17	2.25	2.35 A		2.34 B	
A	19/11/85	Statfiord	6.5	0.89	31	2.25	2.54 C		2.50 C	
A	19/11/85	Statfiord	6.5	0.89	63	2.25	2.55 C		2.46 B	
C	19/11/85	Statfiord	6.5	1.46	9	1.50	1.52 A		1.53 A	
C	19/11/85	Statfiord	6.5	1.46	16	1.50	1.54 A		1.56 A	
C	19/11/85	Statfiord	6.5	1.46	36	1.50	1.55 A		1.55 A	
C	19/11/85	Statfiord	6.5	1.46	49	1.50	1.54 A		1.57 A	
E	19/11/85	Statfiord	6.5	2.06	10	1.12	1.14 (A)		1.18 (B)	
E	19/11/85	Statfiord	6.5	2.06	19	1.12	1.17 (A)		1.17 (A)	
E	19/11/85	Statfiord	6.5	2.06	34	1.12	1.17 (A)		1.15 (A)	
H	16/02/86	Iran. heavy	30.0	0.89	11	2.47	2.47 A	2.34 B	2.49 A	
H	16/02/86	Iran. heavy	30.0	0.89	20	2.47	2.50 A	2.37 A	2.52 A	
H	16/02/86	Iran. heavy	30.0	0.89	38	2.47	2.49 A	2.49 A	2.50 A	
H	16/02/86	Iran. heavy	30.0	0.89	79	2.47	2.51 A	2.54 A	2.49 A	
J	16/02/86	Iran. heavy	30.0	1.63	8	1.38	1.58 C	1.56 C	1.67 D	
J	16/02/86	Iran. heavy	30.0	1.63	20	1.38	1.40 A	1.38 A	1.41 A	
J	16/02/86	Iran. heavy	30.0	1.63	47	1.38	1.40 A	1.36 A	1.41 A	
L	02/09/86	Mixed	7.0	0.89	15	2.53	2.72 B	2.80 C	2.58 A	4.05 D
L	02/09/86	Mixed	7.0	0.89	34	2.53	2.73 B	2.62 A	2.63 A	3.23 D
L	02/09/86	Mixed	7.0	0.89	56	2.53	2.75 B	2.71 B	2.70 B	3.32 D
N	02/09/86	Mixed	7.0	1.20	9	1.97	2.01 A	1.95 A	1.95 A	3.81 D
N	02/09/86	Mixed	7.0	1.20	21	1.97	2.05 A	2.05 A	1.97 A	2.30 D
N	02/09/86	Mixed	7.0	1.20	41	1.97	2.07 B	2.10 B	2.00 A	2.32 D
P	02/09/86	Mixed	7.0	2.01	6	1.09	1.14 (A)	0.96 (C)	1.10 (A)	1.65 (D)
P	02/09/86	Mixed	7.0	2.01	13	1.09	1.14 (A)	0.98 (C)	1.10 (A)	1.38 (D)
P	02/09/86	Mixed	7.0	2.01	24	1.09	1.16 (B)	1.02 (B)	1.12 (A)	1.40 (D)

All figures in per cent v/v water - letters denote ISO ratings, those in brackets are where I ≤ 1.0 per cent.

TABLE 3

SUMMARY OF WATER CONTENT TRANSIENT TESTS

Test	Date	Oil Type	Vis. cSt	Flow vel. m/s	Pipe config.	Transient duration min.	Per cent of actual transient sampled		
							Ext-loop	In-the-line	Profiler
B	19/11/85	Statfiord	6.5	0.89	direct	5	105	96	85
B	19/11/85	Statfiord	6.5	0.89	direct	10	108	95	105
D	19/11/85	Statfiord	6.5	1.46	direct	1	102	106	113
D	19/11/85	Statfiord	6.5	1.46	direct	5	100	94	87
D	19/11/85	Statfiord	6.5	1.46	direct	10	105	97	109
F	19/11/85	Statfiord	6.5	2.06	direct	5	109	114	84
G	20/11/85	Statfiord	6.5	1.43	jetty	1	87	96	83
G	20/11/85	Statfiord	6.5	1.43	jetty	5	97	87	88
G	20/11/85	Statfiord	6.5	1.43	jetty	10	104	90	104
I	16/02/86	Iran. heavy	30.0	0.89	direct	1	103	125	20
I	16/02/86	Iran. heavy	30.0	0.89	direct	5	99	101	83
K	16/02/86	Iran. heavy	30.0	1.43	direct	1	104	112	12
K	16/02/86	Iran. heavy	30.0	1.43	direct	5	101	98	85
K	16/02/86	Iran. heavy	30.0	1.43	direct	10	102	100	104
M	02/09/86	Mixed	7.0	0.89	direct	1	117	220	23
M	02/09/86	Mixed	7.0	0.89	direct	5	104	95	89
O	02/09/86	Mixed	7.0	1.20	direct	1	106	250	11
O	02/09/86	Mixed	7.0	1.20	direct	5	105	97	84
Q	02/09/86	Mixed	7.0	2.01	direct	1	104	263	11
Q	02/09/86	Mixed	7.0	2.01	direct	5	103	116	82
R	03/09/86	Mixed	6.8	1.17	jetty	1	52	52	85
R	03/09/86	Mixed	6.8	1.17	jetty	1	59	59	85
R	03/09/86	Mixed	6.8	1.17	jetty	5	96	90	100

TABLE 4

RESULTS OF PROFILE MEASUREMENTS BETWEEN TESTS H AND I

	Top		Centre			Bottom	Mean	95 per cent conf. lim.	Per cent conf. lim.
	1	2	3	4	5	(6)	(a)	(b)	(c)
	2.47	2.46	2.49	2.47	2.50	(2.48)	2.48	0.05	2.00
	2.50	2.48	2.49	2.50	2.50	(2.49)	2.49	0.02	0.80
	2.48	2.50	2.49	2.50	2.50	(2.51)	2.49	0.02	1.10
	2.50	2.47	2.49	2.50	2.50	(2.49)	2.49	0.04	1.50
	2.49	2.50	2.50	2.51	2.52	(2.50)	2.50	0.03	1.10
	2.49	2.49	2.50	2.50	2.51	(2.50)	2.50	0.02	0.80
	2.51	2.51	2.52	2.53	2.52	(2.51)	2.52	0.02	0.80
	2.52	2.53	2.52	2.56	2.53	(2.51)	2.53	0.05	1.80
	2.53	2.50	2.52	2.51	2.53	(2.51)	2.52	0.04	1.40
	2.52	2.50	2.50	2.49	2.53	(2.50)	2.51	0.05	1.80
Mean	2.50	2.49	2.50	2.51	2.51	(2.50)			
95 per cent conf. lim.	0.04	0.05	0.03	0.05	0.03	(0.02)			
Per cent conf. lim.	1.70	1.80	1.20	2.20	1.20	(1.10)			

Overall mean = 2.50
Scatter = 0.40 per cent
Calc. water = 2.47

(a) = Mean of all figures in column or row.
(b) = 95 per cent confidence limits or degree of scatter of figures in column or row (with Student's 't' adjustment).
(c) = 95 per cent confidence limits as per cent of mean.

TABLE 5

SUMMARY OF WATER TRANSIENT TIMES

Test	Flowrate m/s	External-loop flowrate l/s	Calc. delay s	Measured delay s	Diff. s	Leading slope s
B	0.89	0.52	37	45	8	45
D	1.46	0.48	38	35	7	30
F	2.06	1.29	16	23	7	20
G	1.43	0.89	236	245	9	30
I	0.89	0.53	37	45	8	50
K	1.63	1.06	20	25	5	25
M	0.89	0.92	37	35	-2	25
O	1.20	0.92	27	28	1	25
Q	2.01	0.89	16	17	1	16
R	1.17	0.65	324	295	-29	50
S	1.37	0.65	24	25	1	20

Calc. delay = Calculated time delay between injection point and arrival at sampling station based on flow-rate and volume of passage between injection and sampling points.

Measured delay = Measured time delay between start of injection and the first detection of the transient by the capacitance probe.

Diff. = Difference, measured - calculated time delay.

Leading slope = Time transient takes to increase from 0-95 per cent of full magnitude on the capacitance cell readout.

TABLE 6

COMPARISON OF SAMPLERS WITH CONSTANT WATER CONTENT

	External-loop	In-the-line	Profiler	Wall tapping
A Differences between Sampled and Calculated water contents expressed as per cent v/v water				
Mean of (S - C) values	+0.087	+0.017	+0.062	+0.743
±95 per cent confidence limits of the mean	0.035	0.066	0.027	0.435
±95 per cent scatter of (S - C) values	0.177	0.255	0.134	1.305
B Differences between Profile and other Sampled water contents expressed as per cent v/v water				
Mean of (S - Profile) values	+0.025	-0.020	0.000	+0.701
±95 per cent confidence limits of the mean	0.020	0.058	0.000	0.439
±95 per cent scatter of (S - Profile) values	0.101	0.225	0.000	1.317

Mean = Mean of all the (Sampled - Calculated) or (Sampled - Profile) water content readings given in Table 2.

±95 per cent confidence limits of the mean = the confidence level to which the mean value can be read.

$$= \frac{\sigma \times t}{\sqrt{\text{No Samples}}}$$

where

σ = σ value of the data about the mean
t = Student's 't' value for the appropriate number of data
No. Samples = Number of samples used to derive the mean.

±95 per cent scatter of (Sampled - Calculated) (Sampled - Profile) values = the ±scatter from the mean within which 95 per cent of the data lie

$= \sigma \times t.$

TABLE 7

COMPARISON OF SAMPLERS WITH WATER CONTENT TRANSIENTS

Test	No. samples	Background water	Calculated water	External-loop sampler		In-the-line sampler		Profiler spot sampler		Wall tapping spot sampler	
		B	C	Mean	% Trans.	Mean	% Trans.	Mean	% Trans.	Mean	% Trans.
B	15	0.430	1.339	1.409	108	1.298	95	1.335	100		
D	18	0.430	0.904	0.914	102	0.892	97	0.877	94		
F	6	0.430	0.719	0.720	100	0.760	114	0.678	86		
G	23	0.611	0.927	0.927	100	0.893	89	0.918	97		
I	12	0.150	0.731	0.734	101	0.762	105	0.572	73		
K	22	0.150	0.597	0.599	100	0.592	99	0.565	93		
M	13	0.235	0.812	0.800	98	0.854	107	0.632	69		
O	13	0.235	0.625	0.647	106	0.712	122	0.518	73		
Q	11	0.235	0.470	0.482	105	0.564	140	0.398	69		
R	22	0.820*	1.025	0.985	80	0.977	76	0.995	85	1.175	173
S	46	0.665*	0.924	0.909	94	0.914	96	0.867	78		

Background, Calculated and Mean Sampler water contents expressed at per cent v/v water.
No. samples = Number of samples taken during the test.
Background water = Average background water-in-oil flow.
* = Background water changed during test.
Calculated water = Background water plus Injected water.
Mean = Mean water content of samples collected.
% Trans. = Amount of injected transient water recovered by sampler expressed as a percentage of injected water only in transient, ie background water not included in calculations.

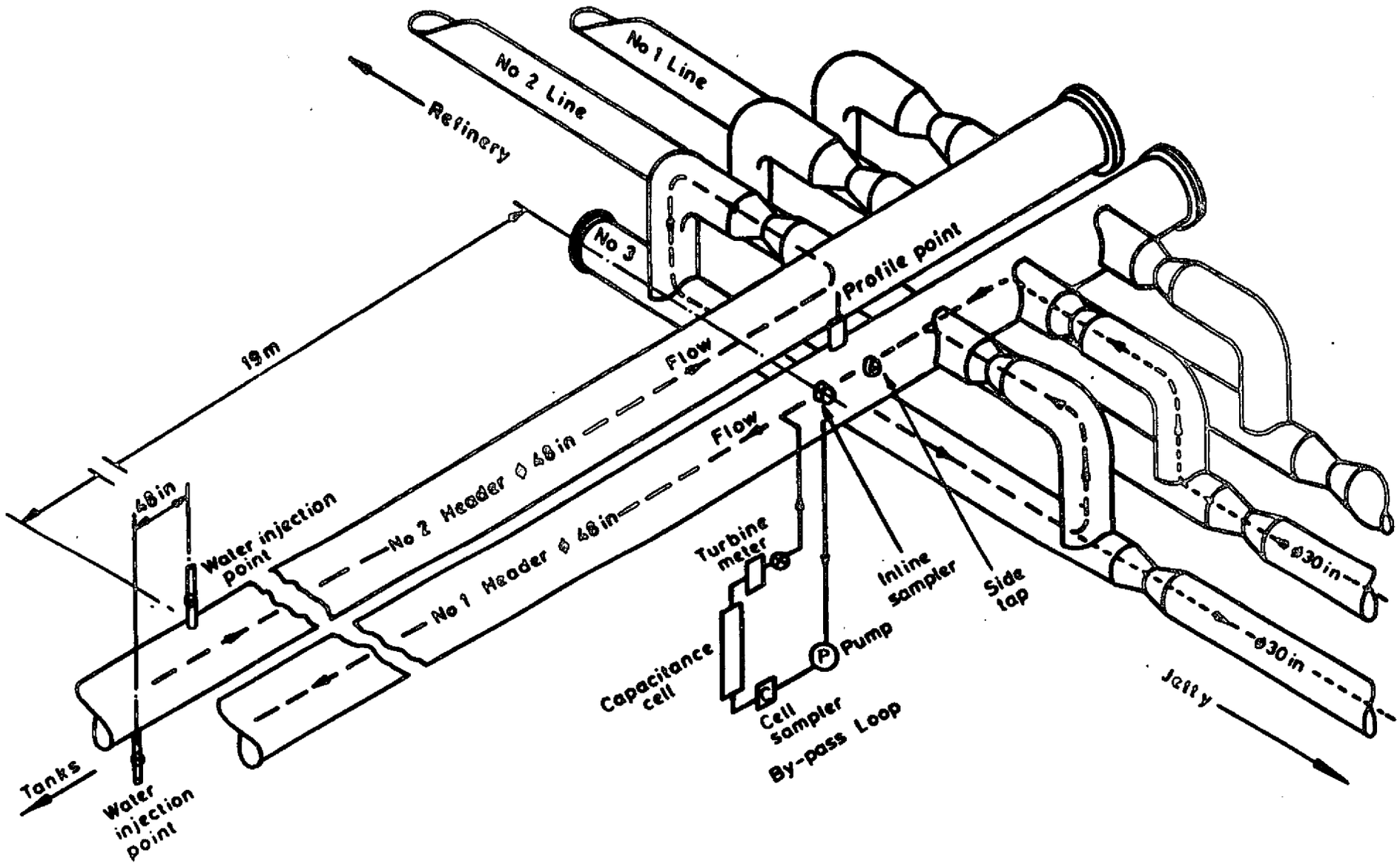


Fig 1 Schematic of Rotterdam Sampling Facility

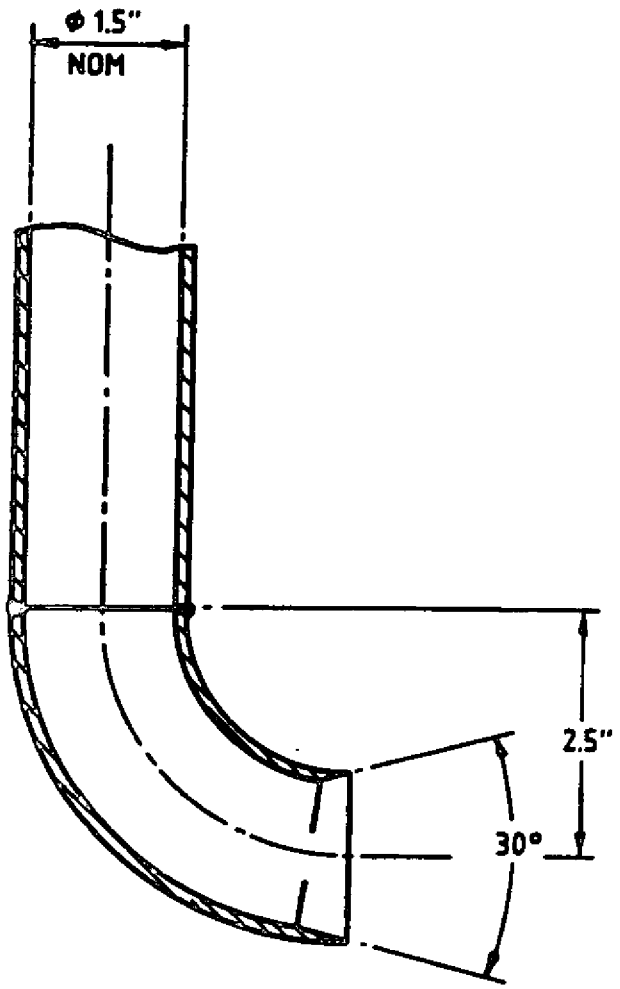


Fig 2 External-Loop Scoop Probe

Norwegian Society of
Chartered Engineers

Main Index

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Experience of Monitoring Oil Measurement System Performance" (and the most common errors)

Lecturers:
T.J. Hollett
and
C.J. Stevenson
BP Exploration

EXPERIENCE OF MONITORING OIL MEASUREMENT SYSTEM PERFORMANCE (AND THE MOST COMMON ERRORS)

by T.J. Hollett & C.J. Stevenson

BP EXPLORATION

1. INTRODUCTION

There are several shared pipeline systems in the North Sea and they all operate allocation procedures to ensure that the total pipeline output is equitably distributed to the Fields who originally produced it. The raw input data for these procedures is the quantity and quality measurements made at the point where users of the shared systems deliver their material and the points where products are sold from, or used by, the system. How this raw data is used is governed by commercial agreements signed by the participants in any given system. This paper looks at the ways the operator of a shared pipeline system can monitor the performance of the measuring systems producing the raw data and hence establish confidence that the final allocation of sales products from the shared pipeline system is equitable. In discussing the procedures and techniques employed the paper also highlights those areas where the authors have most commonly identified errors.

The paper is written from the perspective of the operator of a pipeline transportation and onshore processing system. The activity of monitoring is carried out to ensure that the system is within control. The paper therefore describes how a new platform is brought into a pipeline system which is already operating, in a way that ensures that overall control is maintained.

The word "control" is used in its widest sense as applied to measurement. That is every aspect of control from control charts at the meter station to overall management control.

2. INPUT MEASUREMENT LOCATIONS AND RESPONSIBILITIES

There are two options, either each input Field measures on its own platform, or the Pipeline Operator measures at some central collection point. As the Pipeline Operator has the responsibility to maintain equitable treatment for all, it is obvious that one way of achieving this is for him to take the measurements himself. Unfortunately, this has some technical drawbacks, particularly on liquid systems. The turbine meters would be downstream of a line on the sea bed which may require frequent pigging. The meters could therefore see cold fluids, wax and water slugs. This can cause severe problems with sensitive measurement equipment. It is more normal, therefore, for Field Operators themselves to make the necessary measurements. The Pipeline Operators responsibility for equity to all users still exists and therefore he must ensure full

compliance with agreements as they affect standards of design, maintenance and operation of the measurement equipment. The maintenance of high operating standards is achieved by a combination of the Field Operators professional integrity, comprehensive procedures manuals, routine inspection visits by Pipeline Operator staff, routine reporting of performance parameters to the Pipeline Operator; often audits by independent Companies are used as an additional control. In addition to these activities the Department of Energy or Norwegian Petroleum Directorate inspectors will be conducting checks.

The one area of measurement which is invariably put into the hands of independent people is hydrocarbon analysis. This is because skilled chemists and sophisticated laboratory equipment are required, making it a difficult task to perform offshore. It is also more difficult to audit most laboratory measurements after the event unlike metering stations where automatic records are kept.

3. WHY MASS MEASUREMENT AND WHAT ABOUT COMMERCIAL UNITS OF SALE?

3.1 All systems start by dealing with input quantities in mass terms. This is for three reasons:

3.1.1 A metering station can measure mass by multiplying volume by density at operating conditions (provided both are measured at the same temperature and pressure). This avoids the introduction of uncertainties from correcting to a standard temperature and pressure using generalised relationships. Accounting in volume requires all measurements to be corrected to standard conditions of temperature and pressure because, unlike mass, volume varies with temperature and pressure.

3.1.2 When liquid streams of markedly different molecular weight (e.g. NGL and crude oil) are mixed, their volumes are not additive. This phenomenon is known as shrinkage. Working in mass avoids the need to specify the magnitude of volume shrinkage in any given mixing situation thus avoiding additional uncertainty.

3.1.3 When high vapour pressure crude is processed to produce usable and saleable products changes of state occur. The terminal will receive a single phase liquid stream, separate off a gaseous phase by reducing pressure and possibly re-liquify some of the gaseous phase for onward transportation. To effectively reconcile inputs and outputs across such systems, mass must be used. Reconciliation is required to identify, control and allocate losses. Mass measurement allows useful loss control techniques to be established as described later, because mass cannot be created or destroyed.

3.2 Mass cannot, however, be carried right through to the end of the allocation process because very few products are sold in units of mass. Normally units of sale are:

Crude Oil	- barrels @ 60°F and 14.73 psia.
LPG	- weight in air. Tonnes.
Natural Gas	- mass, tonnes or energy, megajoules, therms,etc

4. SEQUENCE OF CONTROL ACTIVITIES WHEN BRINGING ON A NEW PLATFORM

The Pipeline Operators responsibility to ensure common standards are employed, thus giving each user a fair deal, mean that something like the following steps need to be taken every time a new entrant joins the system.

4.1 The first essential is that a commercial Transportation Agreement is agreed and signed. This commits the new user to compliance with Pipeline Operators measurement and accounting standards.

4.2 The Pipeline Operator should then supply the Field Operator with a statement of requirements for the measurement system. The output from the accounts and allocation procedures used by the pipeline operator is only as good as the quality of the input data used. It is therefore essential that all inputs to the system are measured to a similar standard to avoid bias between users.

The statement of requirements should specify:-

- Standards to be complied with.
- Data required by the Pipeline Operator from the measurement system.
- Procedures to be provided by the Field Operator.
- In limited cases equipment vendors that must be used.
- Pipeline Operator approval procedures for from design through to commissioning and use.
- Requirements for on-stream and off-line analysis.
- Form and frequency of data transmissions via the telemetry system.

4.3 The Field Operator should then provide Pipeline Operator with the following for approval (in chronological order):-

- design specification and drawings prior to tender.
- design specification, equipment specification, and computer calculation routines and data transmission routines prior to placement of order.
- procedures for factory calibration testing and inspection.
- pre-commissioning and commissioning procedures.
- operating procedure.
- calibration and maintenance procedure.

All of this documentation forms the bed rock for the provision of sound measurement equipment and control procedures. It is essential that adequate time is spent by the Pipeline Operator thoroughly reviewing this information and agreeing it with the Field Operator, to avoid misunderstandings and problems occurring in the future.

4.4 Pipeline Operator should then witness selected activities in the factory testing through to commissioning phases. It is essential that the third party equipment is completed to the required standard before start up of production is allowed. The Pipeline Operator has a responsibility to protect the existing users of the system. The Pipeline Operator should therefore issue a letter of authorisation to the Field Operator to use the system.

4.5 As soon as possible after start up the Pipeline Operator should visit the measurement system to check that the agreed operating, calibration and maintenance procedures are being adhered to.

4.6 The above describes the controls exercised by the Pipeline Operator. Additional approvals must be given by regulating authorities like the Department of Energy or the Norwegian Petroleum Directorate. Endorsement may also be required by the end customer.

5. ONGOING MONITORING POST START UP

Our experience suggests that the following frequency of visits is required:-

Initially monthly to review progress against check lists of outstanding items from previous audits/reviews. During these monthly visits experience and confidence builds up within both Pipeline and Field Operator.

Sometime within the first 6 months of operation, visiting frequency can be reduced to quarterly. We find that this is a frequency that is consistent with allowing a single inspector to review the measurement system operation within the reasonable time scale of a 1 to 2 day visit. By the time visiting is reduced from monthly to quarterly a bank of operating and monitoring information has been built up by the Pipeline Operator which allows the remote identification of potential measurement problems. These will either take the form of obvious errors or deviations from normal that can be immediately referred to the Field Operator for action, or less definite trends that provide guidance on where effort should be concentrated during the next quarterly inspection. In some circumatances, as the level of confidence and operating experience increases, Pipeline Operator visiting frequency can be further reduced, with the need to visit controlled by the results of the remote monitoring.

Up until this point all dealings have been directly between Pipeline Operator and Field Operator. We believe that measurement is so important that it is necessary to bring in independent auditors from time to time who are external to the two companies operating the field and the pipeline. It is important that such audits are carried out to the same terms of reference on all measurement systems feeding the pipeline. It is particularly important that measurement system performance is subjected to independent review when the operator of the Pipeline and the Field are the same company. Large oil companies organise themselves in such a way that the Pipeline and Field Operator functions are separate, however to satisfy other companies using the pipeline, independent review is the only answer. Currently we are using a frequency of annual independent audits in the Forties Pipeline System.

6. REMOTE MONITORING TECHNIQUES

We have talked about monitoring the performance of a Field Operators measurement system by visits; what can be done from a remote office location? Experience shows that the earlier a problem is identified the easier it is for Pipeline and Field Operators to agree a correction. Daily information must therefore be monitored by the Pipeline Operator.

6.1 Meter Control Charts

Meter K factors can be reported to the beach and plotted on the same control charts as available to the offshore operator. These types of control charts are in common use throughout the North Sea and are therefore not considered in detail in this paper. Their value cannot be overstated. Examples are provided in Figures 1 & 2.

6.2 Density Control Charts

We have found that one of the most powerful control charts that a Pipeline Operator can keep is dry density at standard conditions plotted against time. Examples of such a control chart are given in Figures 3 & 4. The dry oil density is calculated from the following daily information reported to Pipeline Operator from Field Operator:-

- mass produced.
- standard volume produced.
- average water content.

The successful use of this control chart does depend on reasonable stability in the quality of the oil passing through the metering system; with most North Sea fields this is generally the case. The primary requirement of a control mechanism is that it alerts you to a problem.

This particular control chart will show deviations if:-

- densitometers begin to drift.
- meters begin to collect deposits. (Meter control chart should also detect this).
- water content incorrectly measured.
- conversion from operating to standard conditions incorrectly calculated (e.g through incorrect temperature input or change in constants in the flow computer).
- transcription errors occur on information sent to pipeline operator. This is a useful check before data is input to the hydrocarbon allocation and accounting programs.

It is therefore necessary to refer to other monitoring mechanisms to home in on the most likely cause of the error. Our experience does show that densitometer drift due to deposition is quite a common cause of measurement error.

When this occurs both master and tracking densitometer usually drift together so that the discrepancy alarm on the difference between them is never activated.

6.3 Gross Mass Balance Information

Unlike volumes, masses are additive. Mass is a fundamental measurement and mass cannot be destroyed. Comparing mass in against mass out from a system is therefore a powerful monitoring tool. An example of a total system mass balance is given in Figure 5. This particular example quotes the deviation in the mass balance as the "Pipeline Loss". This is convention and does not mean that the pipeline is leaking; it is mainly made up of measurement errors with very little real loss. Usually the only real losses in a system will be the escape of volatile hydrocarbon components to the atmosphere during tankage and loading operations and the loss of hydrocarbon in the liquid effluent disposal. Both of these sources of real loss are carefully controlled for environmental reasons and in terms of relative magnitude are insignificant.

The example in Figure 5 is derived by comparing the mass at a common point in the system calculated from 2 independent sets of data. The common point chosen is often the shore interface between the pipeline and the processing terminal. The two sets of data used to calculate the mass passing this point in the month are:-

i) Sum of offshore metered mass from each platform +/- change in pipeline stock.

ii) Sum of sales from the terminal +/- changes in tank and process equipment stocks.

A common question is "what is a typical loss for a system?". There is no simple answer. Experience must be gained to define an acceptable loss for any given system. The complexity of the system will have a bearing, as will the standards of measurement employed. The example given is for a North Sea Pipeline system that has been in operation for over a decade where the measurements are well understood. Ideally one would hope to see the "pipeline loss" oscillating from month to month about the zero line. This is not usually the case, in our experience. Using the conventions described above often leads to there being a bias in favour of "loss". In our experience there are many reasons for this but the predominant one is due to water. The higher the water content the more likely it is that any measurement of it will be an understatement. System input measurements are made at pipeline input qualities whereas measurements at the terminal are usually made after significant water has been removed from the oil.

6.4 Subset mass balance information

6.4.1 Balances over parts of the equipment

The mass balance concept can be used throughout the system on any part where measurements in can be compared with measurements out. Examples would be comparing production measurements of LPG as the material leaves the fractionation unit with final point of sale measurements. This could be used, for example, to monitor and control the losses around an LPG refrigeration plant.

Figure 6 shows an example of comparing measurements into a stabilised crude oil pipeline with quantities coming out of the line computed from quantities sold +/- stock changes. This example is particularly interesting because totally different types of measurement are used for the input and the output. Input is measured by full fiscal quality turbine meters with on-line densitometers and a flow proportional sampler. Output measurements are made by tank dips, laboratory density (IP160) and tank samples. As this is a simple system with no opportunity for shrinkage to be caused by adding volumes a volume balance is also carried out. As can be seen from Figure 6 the system typically shows a volume loss and a mass gain. The graphs are plotted on a dry hydrocarbon basis and water is drained after metered measurements in but before tank measurements out; this probably accounts for the small loss.

The mass gain is caused by the small increase in density that occurs as light hydrocarbons are lost from the tank samples during collection, transportation and laboratory application of IP 160. This example also shows what happened to the normal trends when the sphere in the prover developed a split. This was picked up earlier on the meter control charts.

6.4.2 Balances over parts of the material

Many allocation procedures used in the North Sea require that the total hydrocarbon streams in and out are analysed by component. Typically the components analysed for are:-

methane
ethane
propane
iso butane
normal butane
the rest (often called C5+)

Mass balances over these individual components can give important indications regarding the accuracy of sampling and analytical measurements made. Errors in components will manifest themselves by producing mis-allocations of sales products, particularly gases, to the rightful owners. As the different products attract different prices in the market place this could lead to financial losses and gains to the individual users of a shared system even if the overall system mass balance is entirely acceptable. Experience shows that the lighter the hydrocarbon the larger the discrepancy in the mass balance is likely to be.

Looking at component balances across a gas plant can give valuable information about which streams have been mis-measured, sampled or analysed when investigating an overall mass balance discrepancy. In Figure 7 a hypothetical gas processing plant is shown with an overall mass balance gain of 1 percent. Examination of the mass balances by component shows that a large discrepancy is present for condensate (C5+). There must therefore be an error in either the C5+ output meter or the analysis of the input. These specific points can therefore be investigated.

6.4.3 Theory compared to Actuals

The allocation system used in the Forties Pipeline system is unique in the North Sea and produces some very useful control information. The heart of the allocation procedure is a chemical engineering model of

the process equipment. The total input to the terminal, as determined by offshore mass measurements and analysis of offshore samples, is fed into the model and this is used to predict the quantities and qualities of products made. These predictions are compared with the actual measurements and deviations investigated, thus providing another level of control.

7. MONITORING QUALITY

Quantity is not the only important measurement required to enable equitable allocation of sales products, fuel and flare, quality must also be measured. Hydrocarbon quality is also used for the important function of giving each user a quantity of crude oil which is consistent in value terms with the material put into the pipeline system. An example of analytical information monitoring is given in Figure 8. The reasonableness of the information can be monitored by following trends; for example if two components from the group show a different trend then an error may be present. Once sufficient data has been collected it can be subjected to statistical analysis and control limits placed on the trend graph.

8. MOST COMMON ERRORS

Time only permits a few examples to be explained in more detail in the text above. In summary the most common errors in our experience are:-

- Densitometer fouling.
- Temperature differences which are not compensated for.
- Flow computer constants incorrectly entered. Particularly common examples are densitometer constants and the constant for the thermal expansion of steel.
- Data transposition errors at points of manual intervention in transferring the data from the meter station to the hydrocarbon accounting computer program.
- Sampling & analytical errors. Water is the biggest problem and has a direct effect on dry mass.
- Line clearing operations. This causes an accounting problem when one quality of product is replaced by another or ownership changes.
- Any operation that has no dedicated automatic logging equipment and therefore relies on manual logging.
- Flaring measurement and/or estimation.

9. CONCLUSIONS

The general conclusions we have drawn from our experience in monitoring measurements as a Pipeline and Terminal operator are:-

9.1 To be successful, a control procedure must have a simple output and preferably be based on data already collected for other reasons.

9.2 Control procedures that either, produce a single number that can be used as a target, or produce a graphical trend against a target can be used as an effective senior management tool by individuals who do not understand the technical detail.

9.3 A large quantity of useful control information can be obtained by analysing the output of Pipeline and Terminal system hydrocarbon accounts. This should be borne in mind when designing computer systems to produce such accounts.

9.4 Successful "loss control" depends on closing the loop back to senior management to provide the required levels of commitment and motivation.

10. ACKNOWLEDGEMENT

We thank BP Exploration for permission to publish this paper and express our gratitude to the many colleagues in BP who have helped us prepare this presentation.

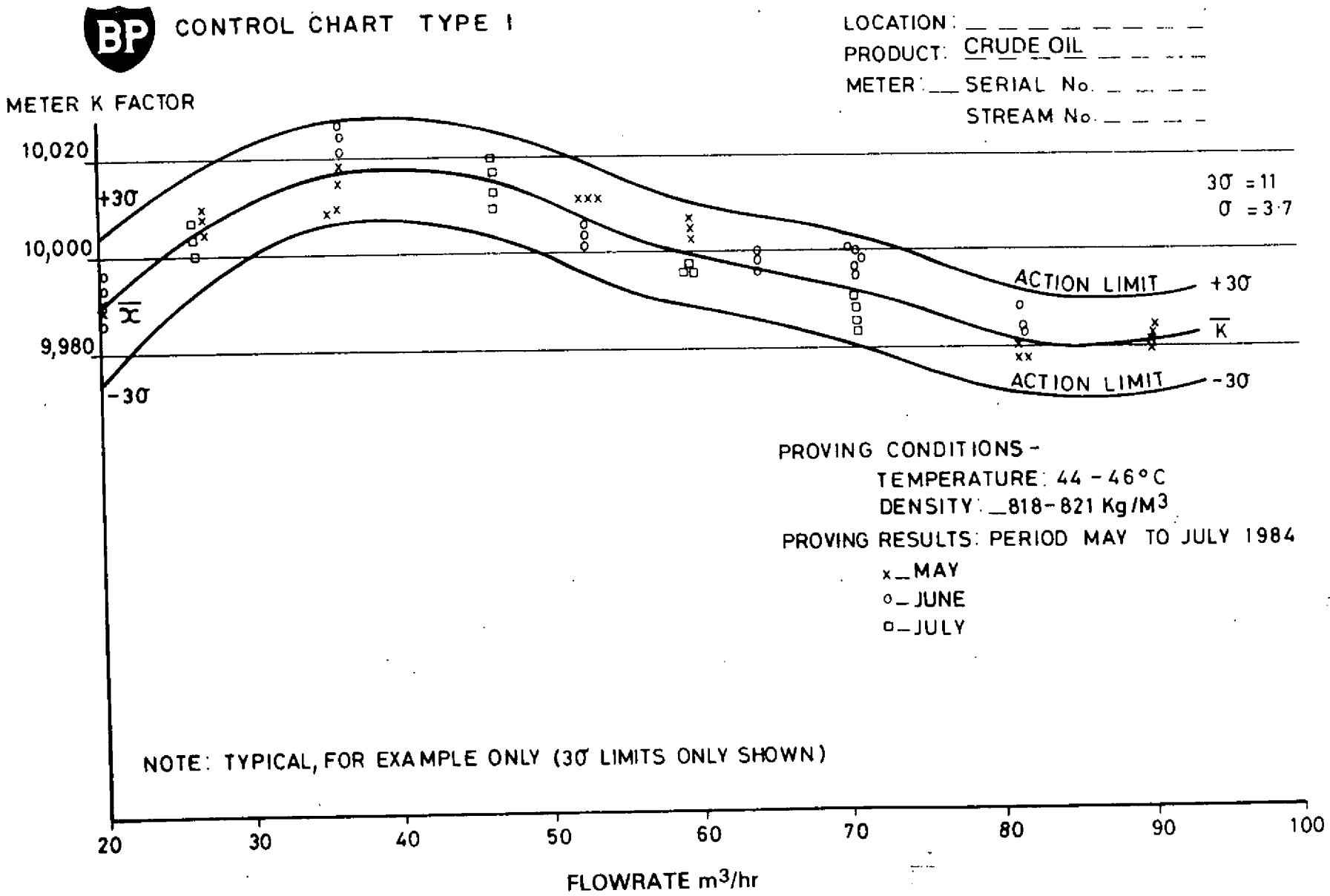
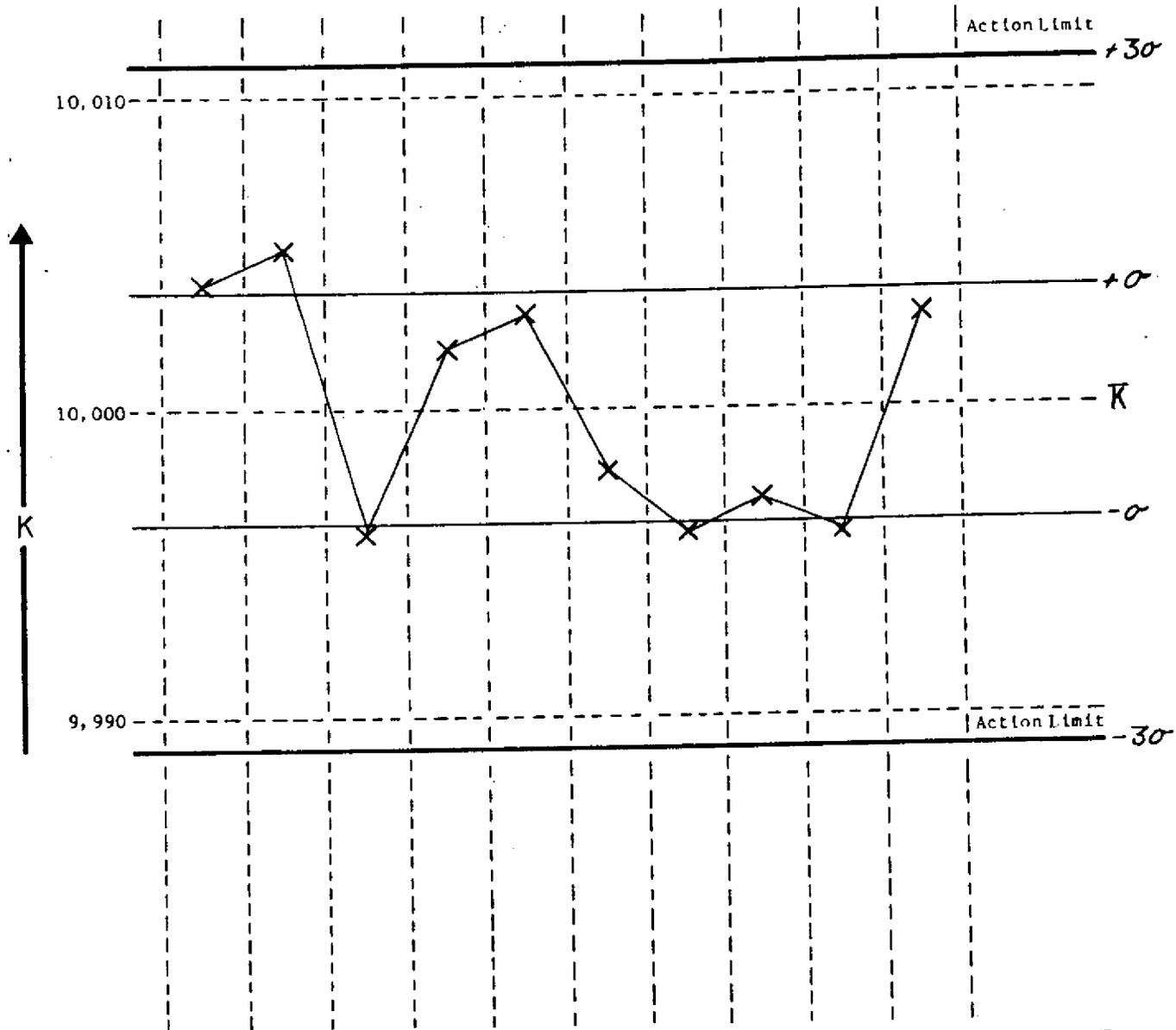


FIGURE 1 CHARACTERISTIC PERFORMANCE CURVE CONTROL CHART

CONTROL CHART TYPE 2

LOCATION:
PRODUCT: Crude Oil
METER: Serial No.
Stream No.



Flowrate	65.0	64.8	65.3	64.9	64.9	65.0	65.1	65.1	65.2	64.8	m^3/hr
Temp	45.25	44.5	46.0	45.0	43.75	46.25	44.9	45.1	45.8	44.5	°C
Density	820.2	819.7	820.8	820.4	819.2	820.2	820.0	820.1	820.7	819.7	Kg/m^3
Proving Report no.	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	
Date	8/5/84	15/5/84	22/5/84	29/5/84	5/6/84	12/6/84	19/6/84	26/6/84	3/7/84	10/7/84	

FIGURE 2 SINGLE POINT CONTROL CHART

FIGURE 3 : CRUDE OIL DENSITY

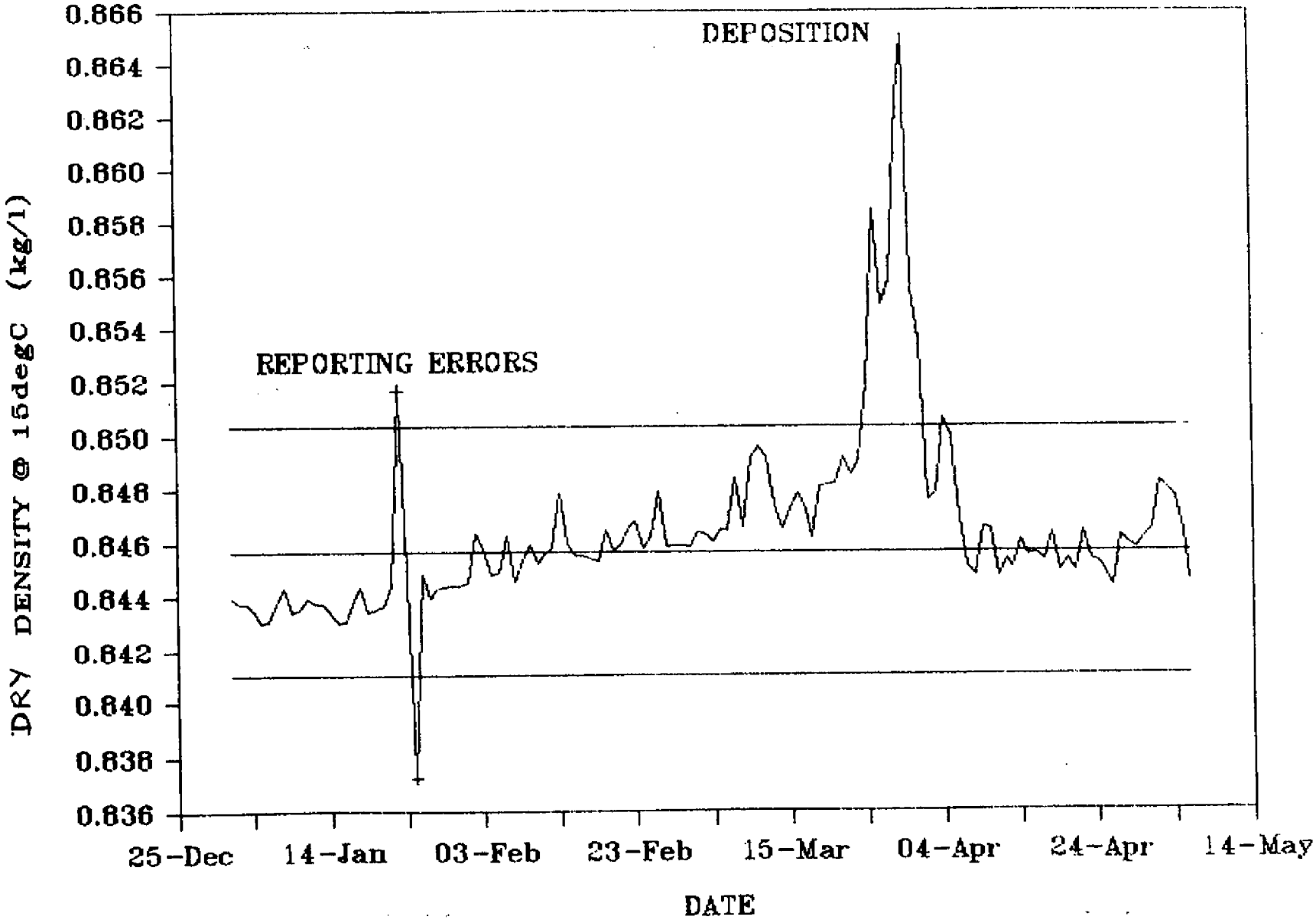
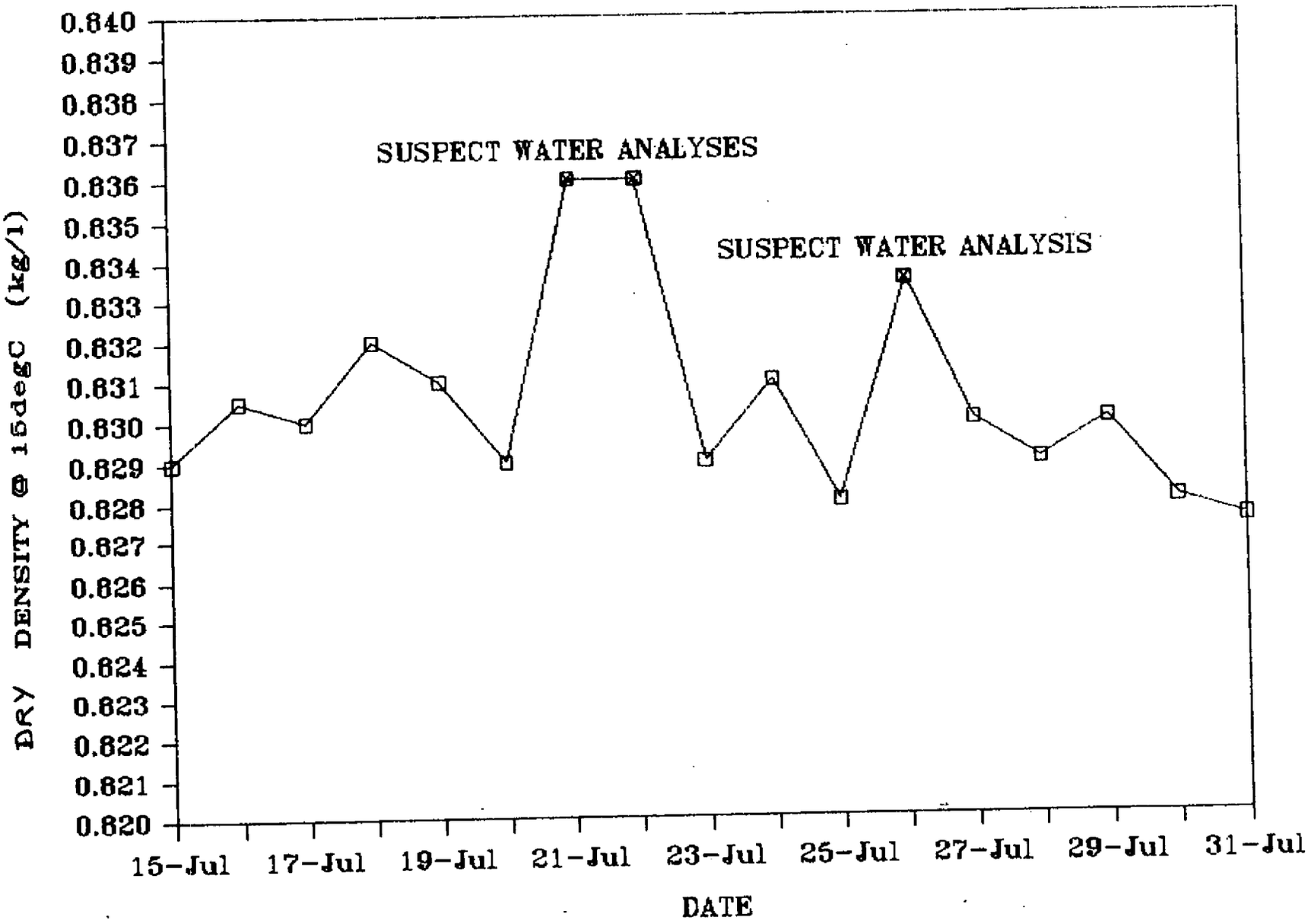


FIGURE 4 : CRUDE OIL DENSITY



h1

FIGURE 5

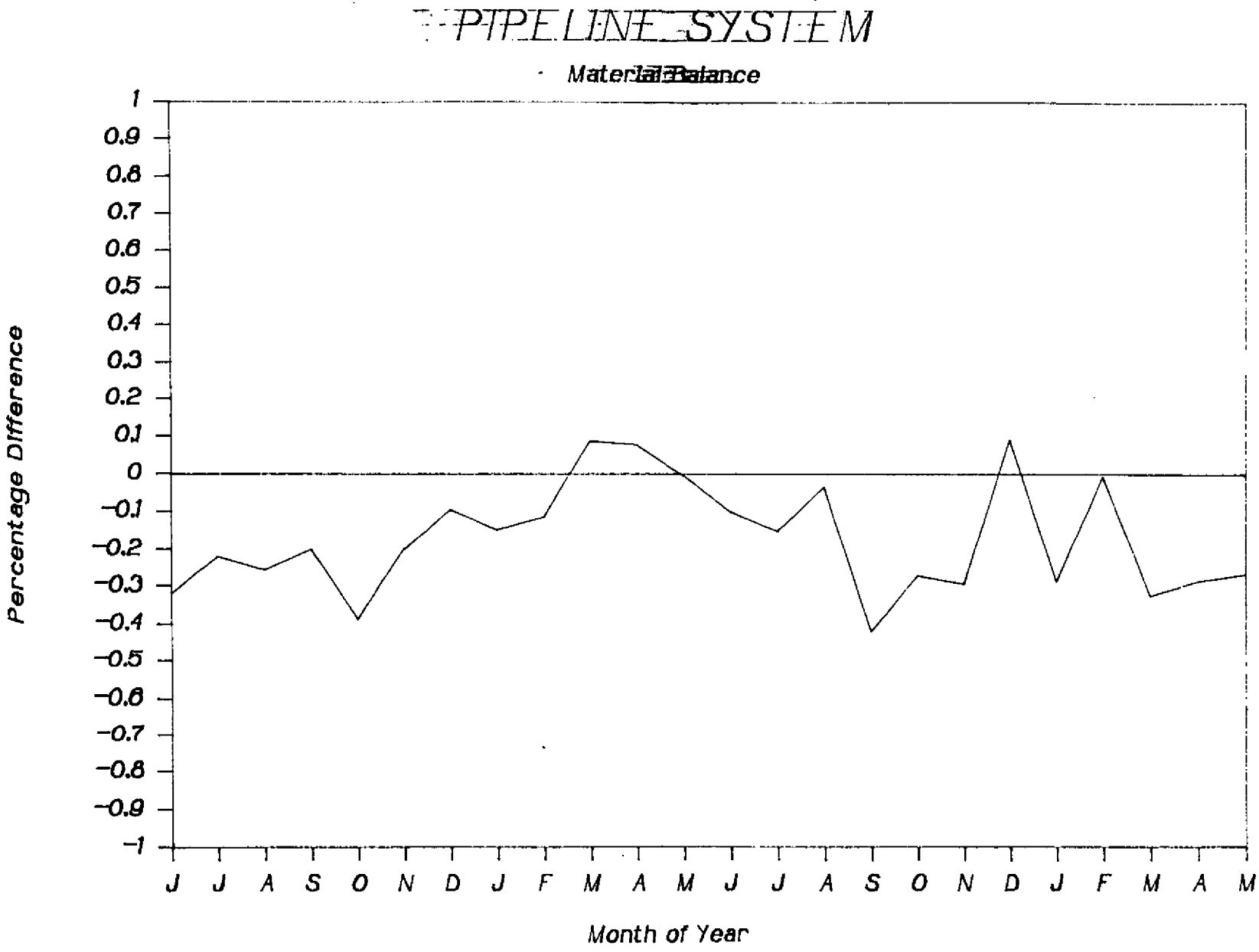

PIPELINE SYSTEM
Material Balance
Percentage Difference
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
-0.5
-0.6
-0.7
-0.8
-0.9
-1
J J A S O N D J F M A M J J A S O N D J F M A M
Month of Year

FIGURE 6 : PIPELINE RECONCILIATION

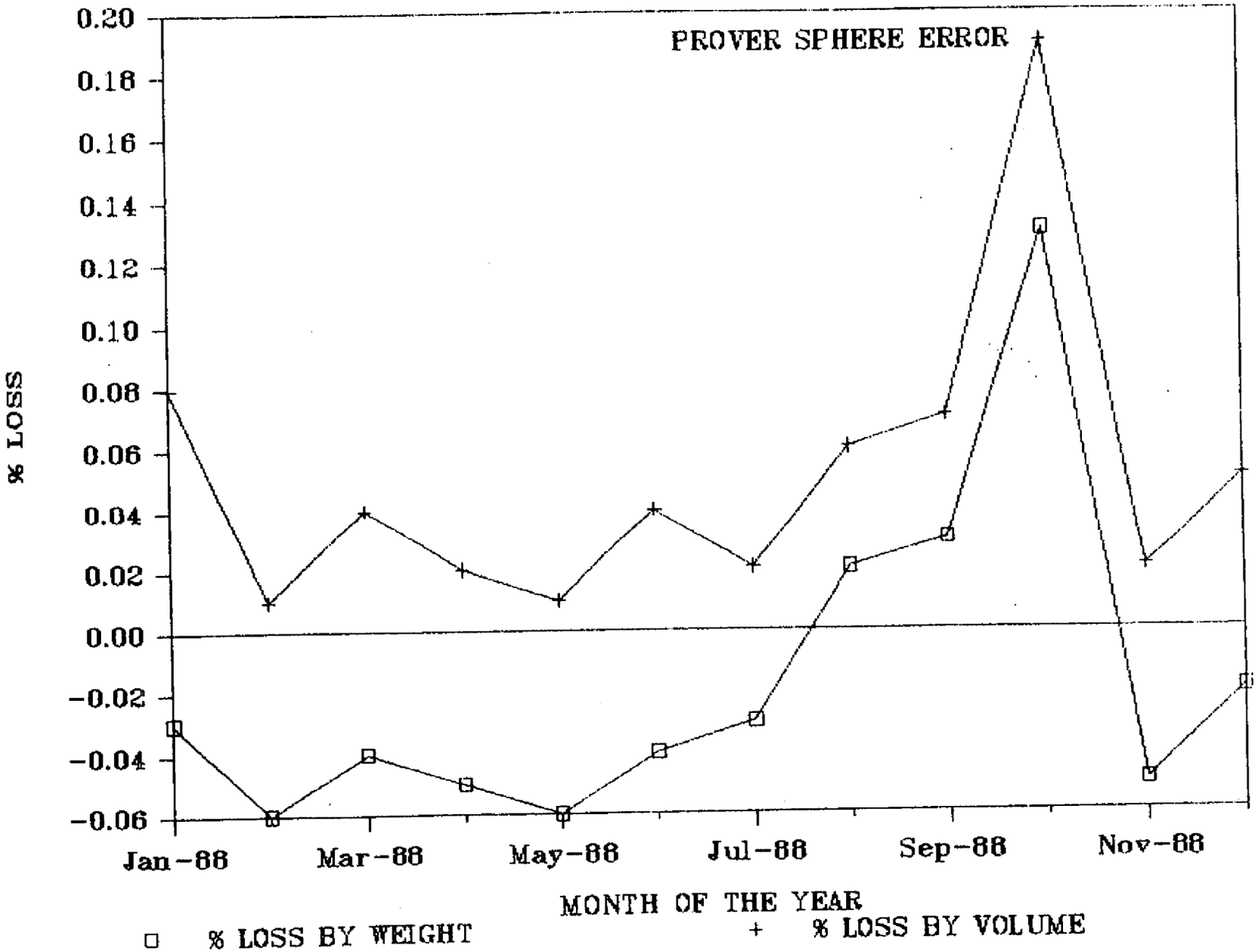


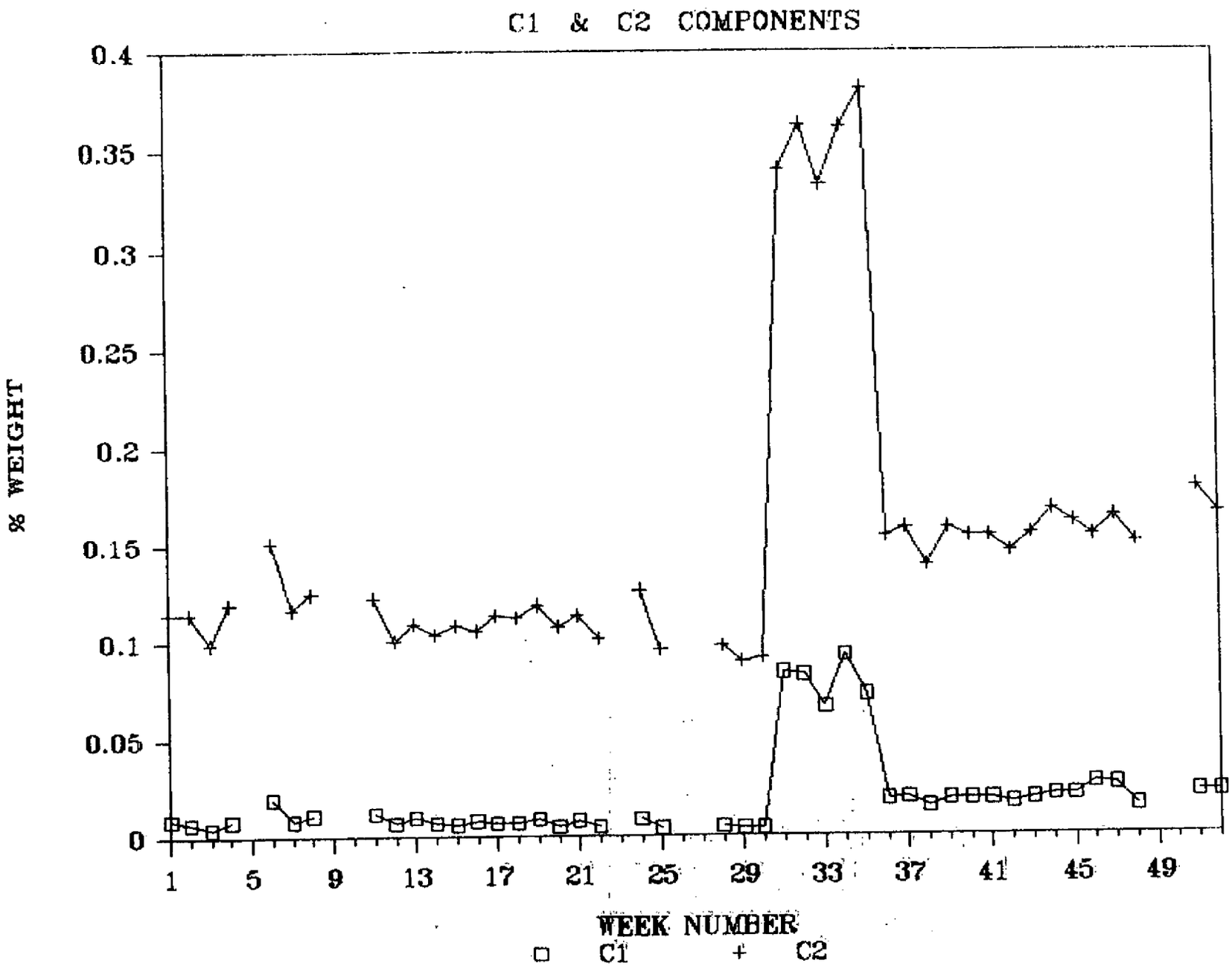
FIGURE 7

COMPONENT MASS BALANCE

COMPONENT	OUTPUT TONNES	INPUT TONNES	% GAIN/LOSS	
CONDENSATE (C5+)	110.00	98.91	1.11	*
BUTANE (C4)	300.00	300.36	-0.04	
PROPANE (C3)	300.00	300.36	-0.04	
ETHANE (C2)	200.00	200.24	-0.02	
METHANE (C1)	100.00	100.12	-0.01	
TOTAL	1010.00	1000.00	1.00	

* Conclusion: Potential measurement problem with condensate could explain overall mass balance discrepancy.

FIGURE 8 : ANALYSIS TREND CHART



Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Measurement and Allocation for Production through Ekofisk"

Lecturer:
Arne S. Nielsen
Phillips Petroleum Co. Norway

INTRODUCTION

The planning and development of the Ekofisk allocation system in the early 1970's was a remarkable challenge that required a wide range of innovations and new developments to solve a number of problems.

A basic requirement considered during the planning phase, was that each field's contribution of the finished products in Emden and Teesside, was to be determined with a high degree of accuracy. The ownership of the Ekofisk fields are not all the same and the composition of produced hydrocarbon vary substantially from field to field. It was therefore important that each field's production of light components could be tracked through the system, to be able to allocate the Natural Gas Liquid (NGL) products to the owners of each of the fields.

It was decided early that weight rather volume was to be used as the standard for measurement of flowing streams. The problem with volumetric measurements was that the tables available for liquid volume corrections, were not applicable for the pressures and stream compositions present at Ekofisk.

The complexity and size of the operation made it obvious from an early date, that extensive use of computers would be required. A system was necessary to capture, integrate, store and retrieve operational data, metered flows and laboratory analysis. This data is required for several purposes: for production monitoring, for reporting on a day-to-day basis and for product allocation purposes.

It was probably not appreciated at the time of planning, that the system installed would later be expanded, using very much the same computer hardware and allocation principles, to meter and allocate third party fields discovered later and tied-in with Ekofisk production.

The solutions chosen for Ekofisk have served as an example for others and to some extent has been used as basis for NPD's regulations for fiscal measurements of oil and gas.

DEVELOPMENT HISTORY

At the time of discovery in 1969, Ekofisk was the largest oil field in Western Europe, and the first commercial oil field in the North Sea. The Ekofisk Area development encompassed seven fields: Ekofisk, West Ekofisk, Cod, Tor, Eldfisk, Albuskjell and Edda, of which four are oil fields and three are categorized as condensate fields.

The construction of the Ekofisk facilities was one of the largest offshore development projects that has ever been undertaken. The project was conducted in several phases. During the first phase, four subsea Ekofisk wells were produced through separation facilities located on a converted

jackup rig. Oil was loaded to tankers through single-point mooring buoys and associated gas was flared.

In the second phase the Ekofisk field was developed, which included setting of three drilling platforms (two for production and one for gas injection), one field terminal platform and one million barrel concrete storage tank (figure 1).

The subsequent phases included installation of drilling and production platforms on all fields. A central processing facility was located at the Ekofisk Center on top of the underwater storage tank. Pipelines were laid from all the "outlying platforms" to feed oil and gas to the central processing facility. The central processing facility was designed to produce a 100 Reid Vapor Pressure crude consisting of a mixture Natural Gas Liquid and crude for delivery to Teesside, England, and a low dew point pressure residue gas to be delivered to a treating plant in Emden, Germany.

A 36" pipeline 441 km long was constructed, to transport gas to Emden and a 34" pipeline 354 km long was constructed to transport oil to Teesside. At Teesside a terminal was built to extract the NGL products (ethane, propane, isobutane and normal butane) and to stabilize crude before loading into tankers.

Ekofisk is important not only for its own production of oil and gas, but also for its role as transportation hub. Almost all of the gas and much of the oil produced in the Norwegian sector of the North Sea is transported to market through the Ekofisk Complex (figures 2 and 3).

MEASUREMENTS AND SAMPLING

Measured mass of oil and gas, and component analysis are the important input parameters to allocate the finished products of gas in Emden, and NGL and crude in Teesside. The finished products consists of a blend of the various streams feeding into Ekofisk Center. One objective of the allocation system is to determine a fair and equitable split of finished products based upon results of measurements and tests of the various input and output streams to Ekofisk Center. Another objective, is that the metering and allocation system shall be automatic, in the sense that the gathering of measurement data, data transfer, data storage and allocation calculations shall be automatic, with a minimum influence of operator's judgement and intervention.

The oil and gas streams are metered and sampled at several points during the flow from wellhead to Emden and Teesside terminals. At Ekofisk oil and gas is separated in a three stage separation process. The gas is dehydrated and dew point controlled before delivered to the export pipeline. Extracted NGL is "spiked" into the oil stream before pumped to Teesside.

The first point of measurement is after the first stage of separation, before the fields production is delivered into the central processing facilities at Ekofisk center. The streams measured after the first stage of separation are termed as "Ekofisk Input Streams" (figure 4).

The second point of measurement is at Ekofisk Center as the production of oil and gas leaves Ekofisk and is delivered into the export pipelines after processing. The export streams are termed as "Ekofisk Center Output Streams" (figure 5).

The third and final point is at the sales metering points, for gas the gas sales meters in Emden and for crude and NGL products the sales meters before the finished products are loaded on board ships (figure 6) at Teesside.

All measurements and testing at the various metering points at Ekofisk are done according to the same principles, codes and standards.

Total weight of oil is measured continuously by turbine meters and densitometers. Total weight of gas is measured continuously by orifice meters and densitometers. All accounting gas flow measurements were originally done according to AGA 3. The formula to compute mass flow is now being modified according to ISO 5167.

Automatic flow proportionate samplers are installed at all oil and gas meter stations.

ANALYSIS

Composite samples are obtained monthly at the measurement stations. Spot samples are taken with sufficient frequency to serve as back-up, if the composite sample should fail.

Located at Ekofisk Center is an allocation laboratory, where analysis of oil and gas samples are performed. The samples are analyzed by fractional distillation (according to ASTM D-2892), gas chromatography (NGPA-2261, NGPA-2162 and ASTM-1945) to determine the content of nitrogen, carbon dioxide, methane, ethane, propane, isobutane, normal butane, pentanes, hexanes and heptanes and heavier hydrocarbons.

The heptanes and heavier fraction of the oil samples are further tested to determine specific gravity at $60^{o}F/60^{o}F$ (ASTM D-4052), salt content and water content (according to Karl Fischer).

DATA ACQUISITION, DATA TRANSMITTAL, DATA STORAGE

The data acquisition, data transmittal and data storage system was designed to provide a flexible and automatic system to transfer metering and process data to a mainframe computer

located at the onshore base without the need to keypunch data. Data from "outlying platforms" are transferred to Ekofisk Center via microwave and further from Ekofisk Center on to onshore via satellite communication. Data from 45 gas metering stations, 17 oil meter stations, numerous valve statuses and process readings are continuously being transmitted from offshore and received by the onshore computer.

Each measurement system on the field producing platform and on the Ekofisk Center is tied in to a dedicated on-line computer to monitor and control station operations, perform all flow calculations and prepare various reports. Pressure, temperature, density, flow and mass data are sent from the measurement computers to the Telemetry Computer System (TCS) located at Ekofisk Center. The TCS calculates 2-hour averages for the pressure, temperature and density as well as mass flow data. The 2-hour information is sent every second hour to onshore (figure 7). The TCS also communicates with Emden, Teesside and Ula measurement systems.

Onshore, the 2-hour data is collected and stored by the TIS (Technical Information System). The TIS is a major computer system for organizing, storing and reporting of operational data. It is implemented on an IBM mainframe computer (IBM 4381) and consists of a total of 250,000 lines of source code, 140 programs, 100 library routines and 55 data files. The work to develop TIS started in 1974. To date a continued effort has been done to expand and maintain the system. From 1974 to date at least 100,000 manhours have been spent on the TIS development.

The described computerized system has proved highly successful. The only human intervention is for quality control purposes and possible corrections of data received in the TIS files. Corrections done in TIS data are tracked in a separate file available for third party audits. Included in this file is a reason given for each correction. All manual corrections to measured data are to be documented with a reason given for the correction.

ALLOCATION OF EKOFISK INPUT STREAMS

The data collected from the measurements and tests are used to determine the ownership of products in a stepwise fashion following the direction of flow. The first step is to determine the ownership of the input streams to Ekofisk Center, the next step is to determine the ownership of the output streams from Ekofisk Center, and the final step is to allocate the finished products at Teesside and Emden amongst the owners of the production, based upon ownership calculated in the preceding steps.

Measured masses are accumulated during the accounting period, which at Ekofisk is a month. The results of the sample analysis yields the stream composition as weight fraction of

each component. The weight of the components produced from the various fields are calculated as the accumulated measured mass during a month times weight percent of each component.

By considering the component ownership in all input streams to Ekofisk Center, the fractional weight shares and the fractional volume shares are calculated. Each owner's fractional weight share of each component in all input streams is that owner's input weight of each component divided by the total weight of that component in the input streams.

The fractional volume shares are calculated by converting the accumulated masses of pentanes, hexanes, heptanes and heavier to volume by using component mass to volume conversion factors generally accepted in the oil industry. The measured C7+ specific gravity of the oil samples is used to convert weight to volume of C7+ in oil. Each owner's fractional volume share, is that owner's input volume of pentanes and heavier divided by the total volume of pentanes and heavier in the input streams.

The fractional shares so calculated are used as split keys in the following steps of the allocation procedure.

ALLOCATION OF EKOFISK CENTER OUTPUT STREAMS

The component weight in the export oil and gas pipelines are determined similarly as described for the input streams. The ownership of the output oil and gas export streams from Ekofisk Center are allocated component by component in accordance with the input streams:

1) Each component in the gas output stream is allocated in accordance to each owner's fractional weight share of that component in the input stream. All components other than pentanes and heavier in the oil output stream are allocated in accordance with each owner's fractional weight share of that component in the input stream.

2) The pentanes and heavier components in oil output stream are allocated in accordance with each owner's fractional volume share of pentanes and heavier in the input streams.

The allocation of the output streams are done in two steps. The first step is to calculate ownership in the oil and gas that has been processed at central processing facilities at Ekofisk as described above. The second step is to reallocate ownership in the export pipelines to 1) account for gas injected into Ekofisk field owned by others than the owners of the Ekofisk field, 2) to include the production of third party fields tied-in to Ekofisk Center (Ula oil, Valhall oil and gas, and the gas from Statfjord, Gullfaks, and Heimdal fields delivered through Statpipe) and 3) to reflect adjustments in ownership in gas due to fuel and purge gas arrangements at

Ekofisk Center. Figure 8 shows the metering at Ekofisk Center of the streams to be reallocated. The final results after the reallocation is the component weight ownership in oil and gas pipelines, and thereby are the split keys to allocate production in Teesside and Emden calculated (figure 9).

FUELS

Fuel gas streams are measured and sampled similarly to the gas stream accounted for in the ownership allocations. However, all fuel gas streams are deemed as lost for the purposes of product ownership. As a loss, the fuel quantities are not considered and do not appear in the allocation reports. An exception is the fuel gas consumed by oil pipeline pumps and gas pipeline compressors at Ekofisk Center, which is allocated to the owners of products shipped.

SALES GAS ALLOCATIONS

At the Emden terminal gas is conditioned to meet buyers specifications and thereafter metered at the sales point. Gas is sold and allocated in terms of energy. Each owner's fractional energy shares are calculated by converting component weight ownership of the reallocated Ekofisk Center Output Stream to energy, using factors to convert weight of components to heating value units.

At the end of each month an "over/short" account is prepared showing the balance between each owner's accumulated daily sales and monthly allocated deliveries. A payback schedule is then prepared for each owner group, considering possible substitution arrangement and operational flexibility agreements between the owners.

A matter of some controversy and discussion amongst certain third party shippers, is the fact that the final Emden allocations do not consider quantities of gas delivered from the pipelines inventory during a month. However, with the current high utilization of the pipeline, the linepack available is only 0.2-0.4% of the total monthly deliveries. The error introduced by not accounting correctly the split amongst the shippers of these 0.2-0.4% is not great. In addition, any error in one month, tends to be balanced out in the coming months, when the linefill volume is restored to the original state.

ALLOCATION OF TEESSIDE PRODUCTS

The high vapor pressure crude received at Teesside Plant is stabilized to provide a crude ready for shipment with vapor pressure of 3 to 8 RVP. The light components are fractionated to commercial grades of ethane, propane, iso- and normal butanes. Methane is used as plant fuel. Stabilized crude is

sold and allocated in terms of volume (barrels). NGL products are sold and allocated in terms of weight (tonnes).

On the condition that the stabilized crude has a vapor pressure less than 7 RVP, the Teesside oil is allocated in accordance with each owner's fractional volume share in the oil to pipeline stream at Ekofisk Center. The NGL products are allocated in accordance with each owner's fractional weight share of the predominant component in the oil to pipeline stream.

At the end of each month an "over/under lift" account is prepared for each owner, showing the balance between allocated quantity of finished product and actual shipped quantity.

To avoid biases, the allocation contracts state that in the case that the NGL product has a content of less than 95% of the predominant component, then the product shall be allocated on a component by component basis. With the current hydrocarbon feed, the error introduced by allocating only by the predominant component is very small, typically less then 0.05%. The 7 RVP limit for the crude allocations is to limit possible problems occurring because not considering contents of NGL components in the crude in allocation of the crude (particular n-butane).

METERING ACCURACY

By comparing measured mass through the Ekofisk process and transportation system, it is possible to evaluate consistency in data from metering point to metering point. In Table I are given factors, calculated by dividing mass measured at the outlet point with measured mass at the inlet point.

Table I - Material Balance Factors

	Ekofisk Center		Oil Pipeline		Gas Pipeline	
Component	Mean	Std.Dev.	Mean	Std.Dev.	Mean	Std.Dev.
N_2	.894	.056	-	-	.805	.122
CO_2	.994	.014	.994	.068	1.013	.030
C_1	.987	.007	1.020	.066	1.001	.006
C_2	1.011	.009	.962	.058	1.017	.021
C_3	1.031	.011	1.025	.042	.980	.050
IC_4	1.055	.020	1.102	.049	1.051	.040
NC_4	1.035	.023	1.157	.061	1.048	.048
IC_5	1.080	.036	1.140	.053	1.068	.072
NC_5	1.093	.032	1.094	.066	1.097	.101
C_6	1.055	.037	1.026	.035	-	-
C_{7+}	1.005	.007	.986	.007	-	-
Total Mass	1.004	.003	1.000	.004	1.002	.001

The factors are calculated using monthly total metered masses and sample analysis over a twelve month period during 1988 and 1989. The factor for "total mass" is the ratio of total metered mass at outlet with total metered mass at inlet, and thus expresses the accuracy of the metering excluding the possible errors introduced by sampling and testing.

It is evident that there is a high degree of consistency of measured mass at the various metering installations through the Ekofisk processing and transportation system with a difference of less than ±0.4% total measured mass from metering point to metering point. However, for the individual components the difference and potential absolute error is greater. These errors may be explained by biases introduced by the sampling and gas chromatography methods.

W.J.Hines/3/ concludes that gas chromatography analysis is the limiting factor in the component mass measurement system. This seems also to be the case at Ekofisk. According to Hines, an error of ±0.25% of the total stream is to be expected for continuous integration of orifice flow data and of densitometer data into mass units. For measurement of NGL components by gas chromatography the error is given to be 1-3%.

THIRD PARTY SHIPPERS

From being a producer and transporter of its own production, the role of Phillips Petroleum Co. Norway, is changing more and more to be that of also being a transporter of third party oil and gas. The importance of third party oil and gas transportation has increased, as the number of third party fields tied in to Ekofisk facilities has increased, and third party share of production has progressively become greater. The effort to utilize spare capacity in the Ekofisk/Norpipe system has been successful as demonstrated by figure 10 and 11. In addition to the original 7 Ekofisk Area fields, the total production from Valhall, Ula and Tommeliten and the gas from Heimdal, Statfjord and Gullfaks are tied in to Ekofisk Center. Ekofisk Center is today the hub of transportation of gas from the Norwegian Sector to the Continent.

For the owners of the transportation network the third party production gives additional income and profits. For the operator there is not only income to be received, but also increased responsibilities. Each of the 26 oil companies that provide their production of oil and gas at Ekofisk, wants to be certain that they get their fair share of products sold in Teesside and Emden. For Phillips Petroleum it has been a challenge to refine procedures and routines to an extent and to a standard that can meet the third party audits. Comprehensive documentation, quality of data, unbiased metering and allocation, compatibility of design and calculation methods, and mode of operation at the various levels of metering are some of the key areas where efforts

have been concentrated. Frequent third party and authority audits has been useful to pinpoint weaknesses and to identify improvements.

The incorporation of each new shipper group in the TIS database and allocation reports has proved to be a task on its own. The TIS database has been designed for flexibility, and can relatively easily be expanded to include data from new third party fields.

The allocation procedures applied for a new field is contingent upon to what extent the production is processed at Ekofisk. The Tommeliten Field, for instance, undergoes full 3-stage separation and dew point control after the unprocessed Tommeliten wellstream is received at the Edda platform. In the allocation procedures Tommeliten production is incorporated as an Ekofisk "Input Stream".

The Valhall case is an example of allocation of production where no processing occurs at Ekofisk. Valhall oil and gas is received at the 2/4 G platform at the Ekofisk Center processed to pipeline specifications. The oil and gas is metered and sampled on 2/4 G, before it is delivered directly to export oil and gas pipelines for shipment. In the allocation procedures Valhall production is incorporated as an Ekofisk "Output Stream".

The inclusion of new fields requires a careful effort by the program analysts to ensure that allocations are done according to agreements and that computer "bugs" are avoided.

For new fields it has been established as a principle, that the production shall be allocated according to the same procedures and standards as applied for the existing fields. One of the reasons behind this, is that amendment of the existing agreements to cater for changes will, at best, be a time consuming exercise, considering the many parties involved. Any change that will benefit certain shippers, will inherently be at the expense of others. Actually, the Appendix B "Allocation of Ownership of Production Ekofisk Facilities" has remained unchanged and unamended since first time signed in 1975.

CONCLUSIONS

The metering and allocation system designed for Ekofisk early in the 1970's has proven to be a reliable and a practical system. It is in use today using very much the same principles and hardware to incorporate new fields and new third party shipper groups. To improve the quality of the product allocations further, emphasize must be made to improve the accuracy of determination of component analysis of oil and gas samples.

ACKNOWLEDGEMENTS

The author would like to thank Phillips Petroleum Company Norway and Ekofisk co-venturers, including Fina Exploration Norway Inc., Norsk Agip A/S, Elf Aquitaine Norge A/S, Norsk Hydro a.s, Total Marine Norsk A/S and Den norske stats oljeselskap a.s. for permission to publish this paper.

REFERENCES

1. Giles, B.L. and Wells, S.W.: "Use of Computers in the Operation of the Ekofisk Complex", JPT, July 1987.

2. Tuck, L.: "Mass Measurements at Ekofisk", Pet. Eng. (Oct. 1975) 47, No. 11, 99-100.

3. Hines, W.J.: "Improved Mass Calculations of NGL Products Utilizing New Extended Analysis", presented at 66th Annual G.P.A. Convention, March 16-18, 1987.

4. Heidbreder, W.L.: "The Development History of Greater Ekofisk", presented European Offshore Petroleum Conference in London October 1978.

5. Roth, Ø.: "Kommunikasjonssystemer og andre elektroniske systemer på Ekofisk", Elektronikk nr. 9A-1980.

6. Dahlstrøm, M.: "Måling av Ekofiskgassen", presented at NIF Seminar "Gassteknologi", June 1981.

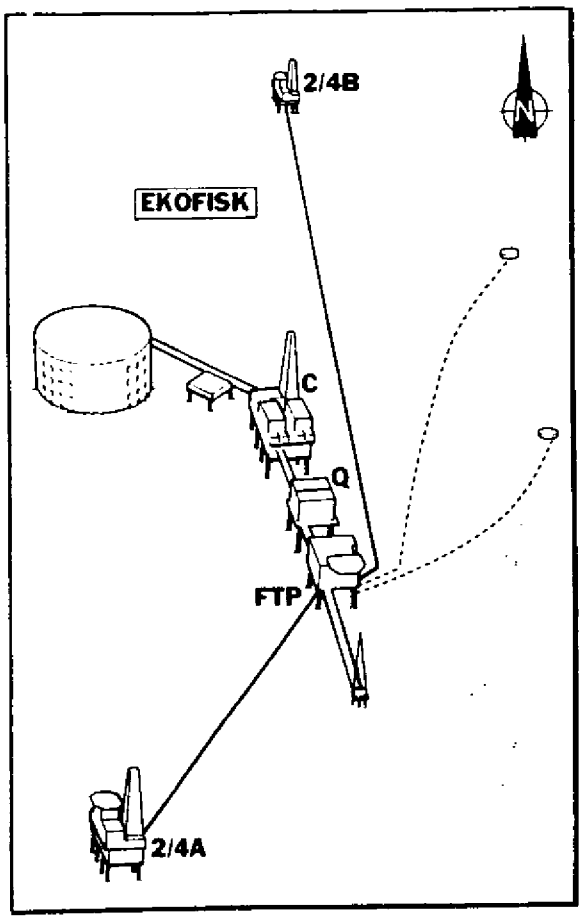


Figure 1 - Ekofisk Field development - Phase II.

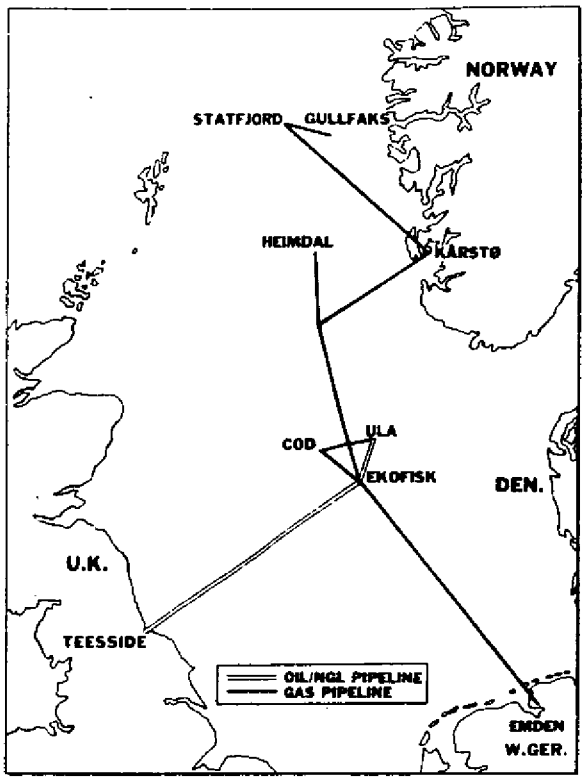


Figure 2 - Location of the Greater Ekofisk area and pipelines.

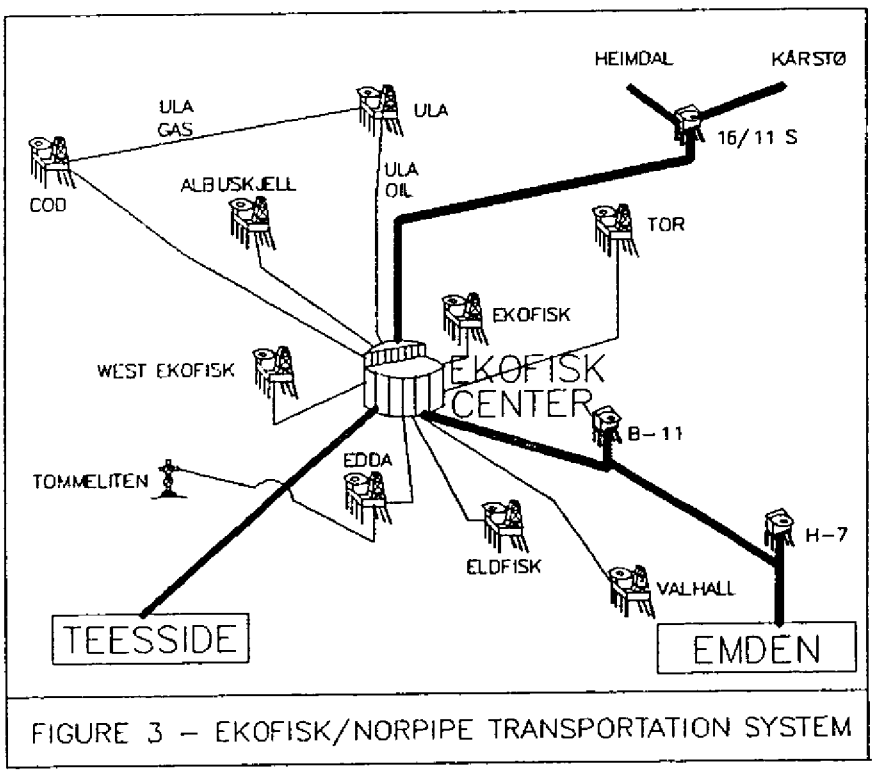


FIGURE 3 – EKOFISK/NORPIPE TRANSPORTATION SYSTEM

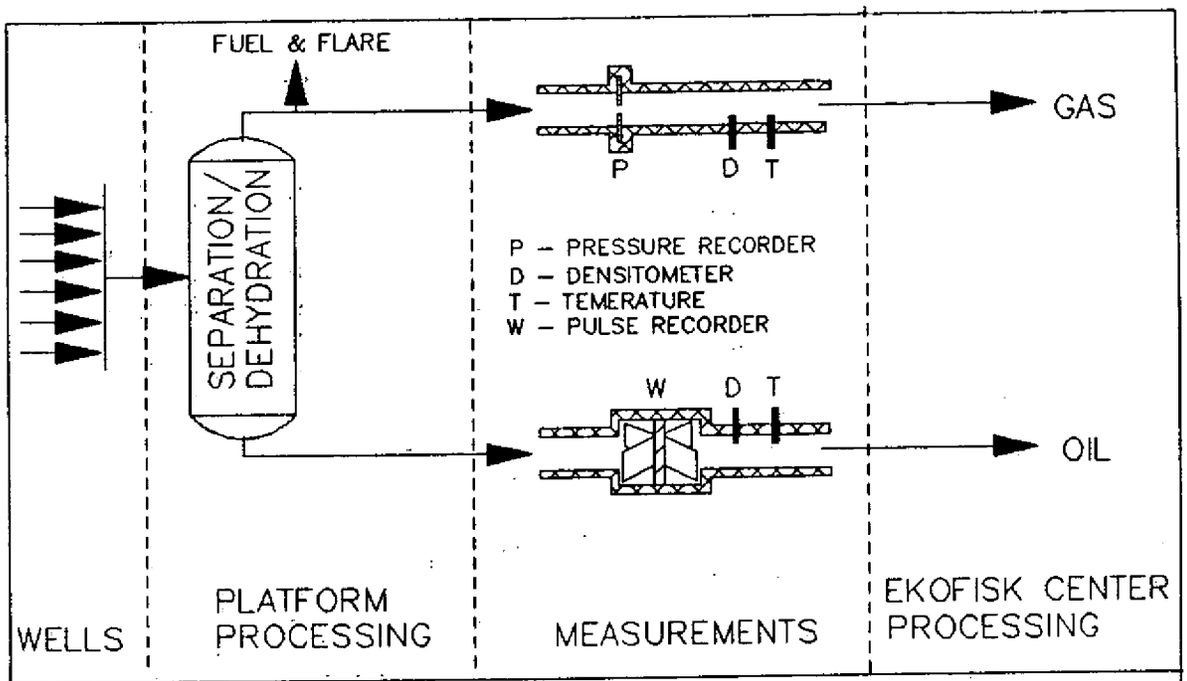


FIGURE 4 – EKOFISK INPUT STREAMS

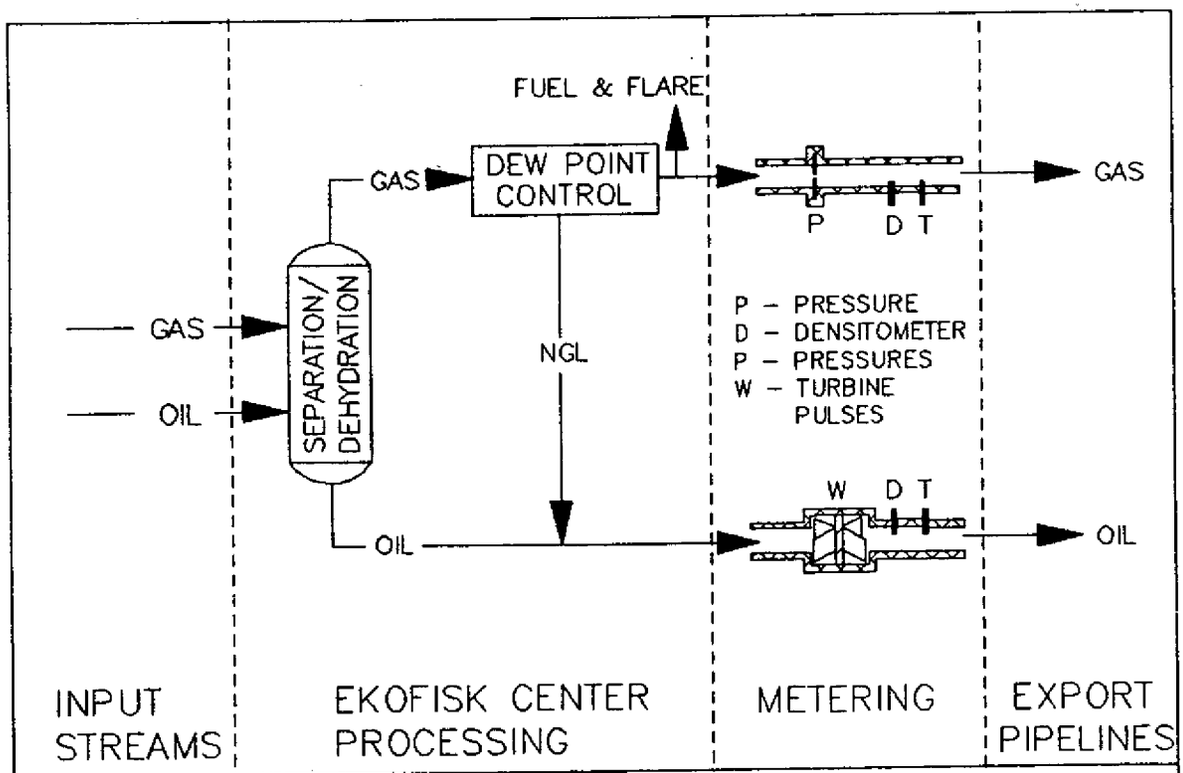


FIGURE 5 – EKOFISK CENTER OUTPUT STREAMS

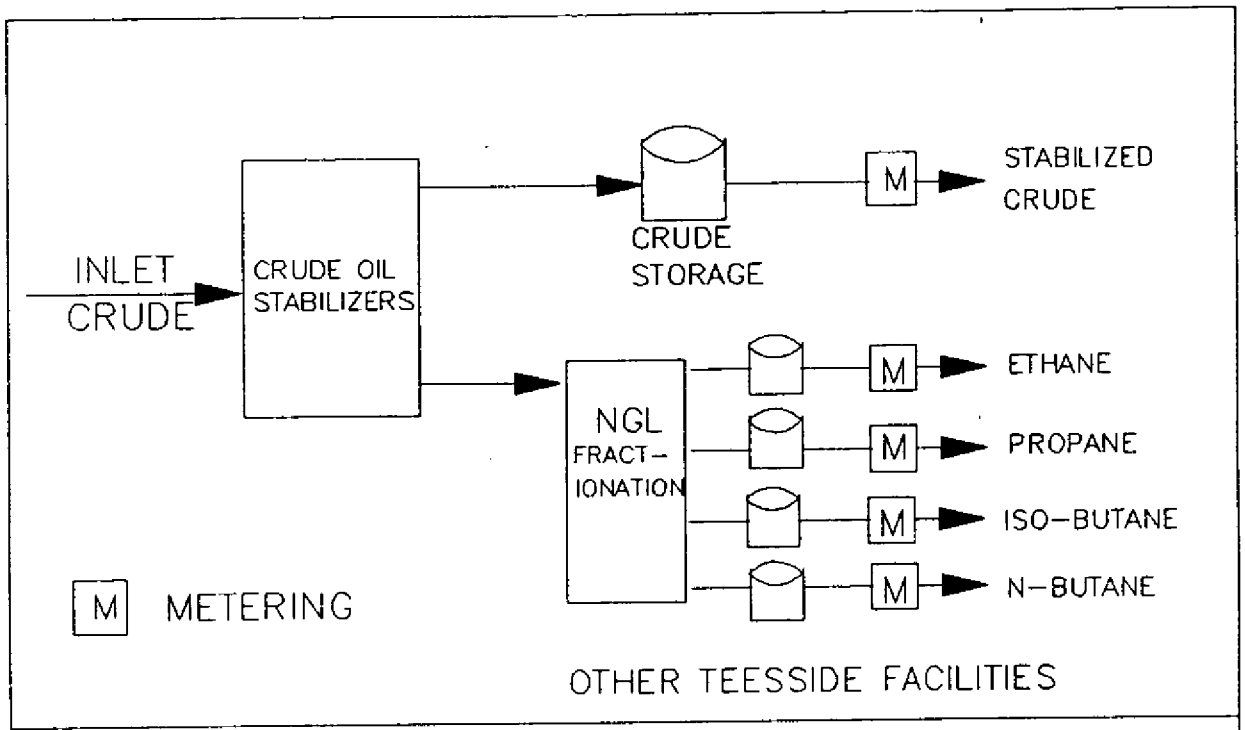


FIGURE 6 – TEESSIDE METERING

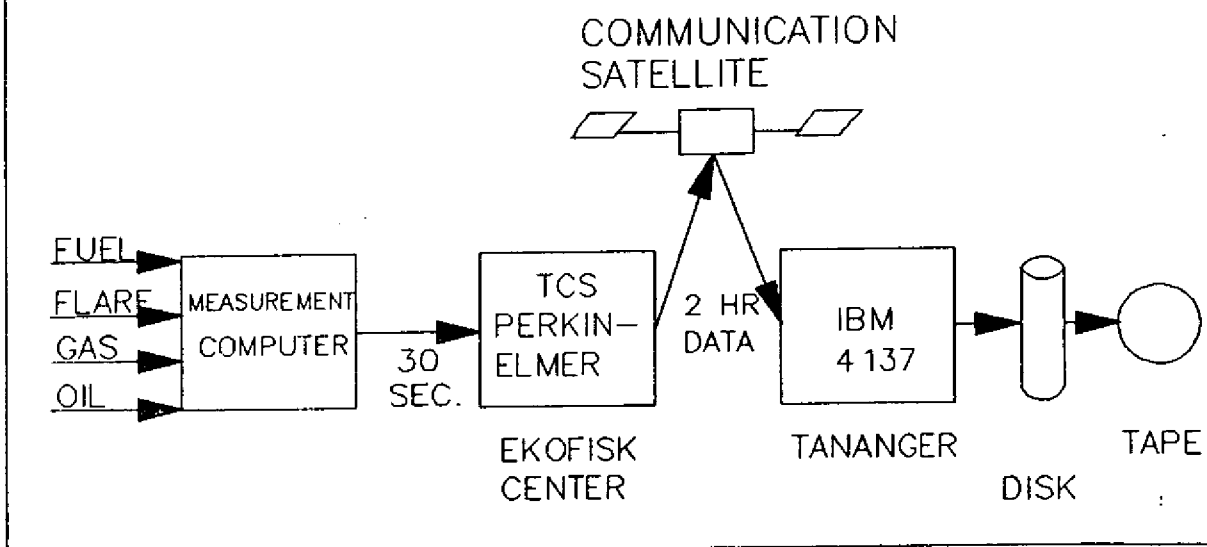


FIGURE 7 – TRANSFER/STORAGE OF METERING DATA

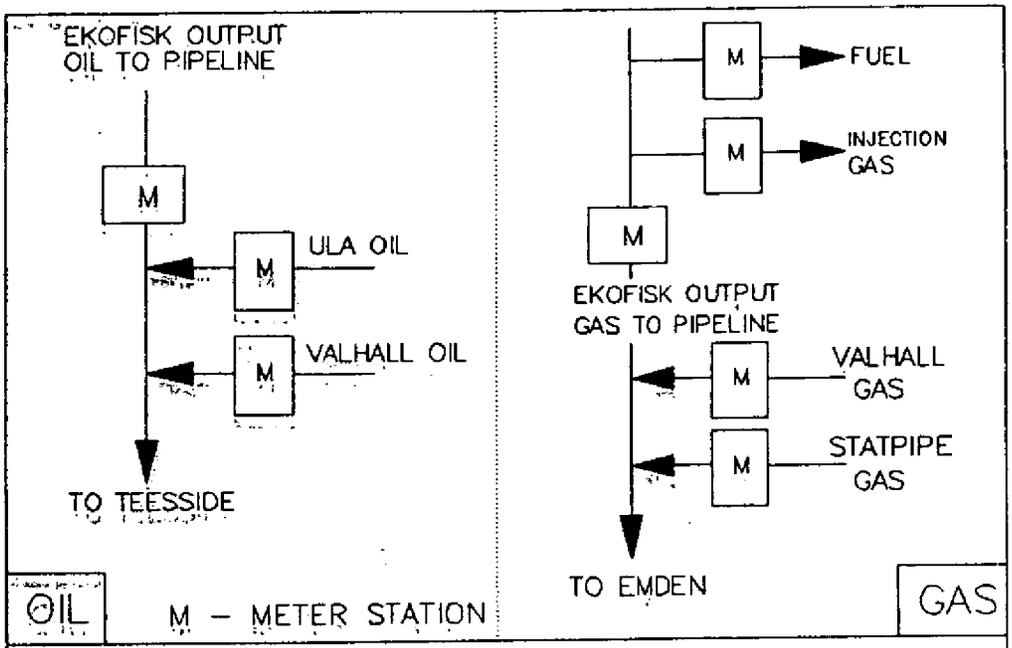


FIGURE 8 REALLOCATION OF EKOFISK CENTER OUTPUT STREAMS

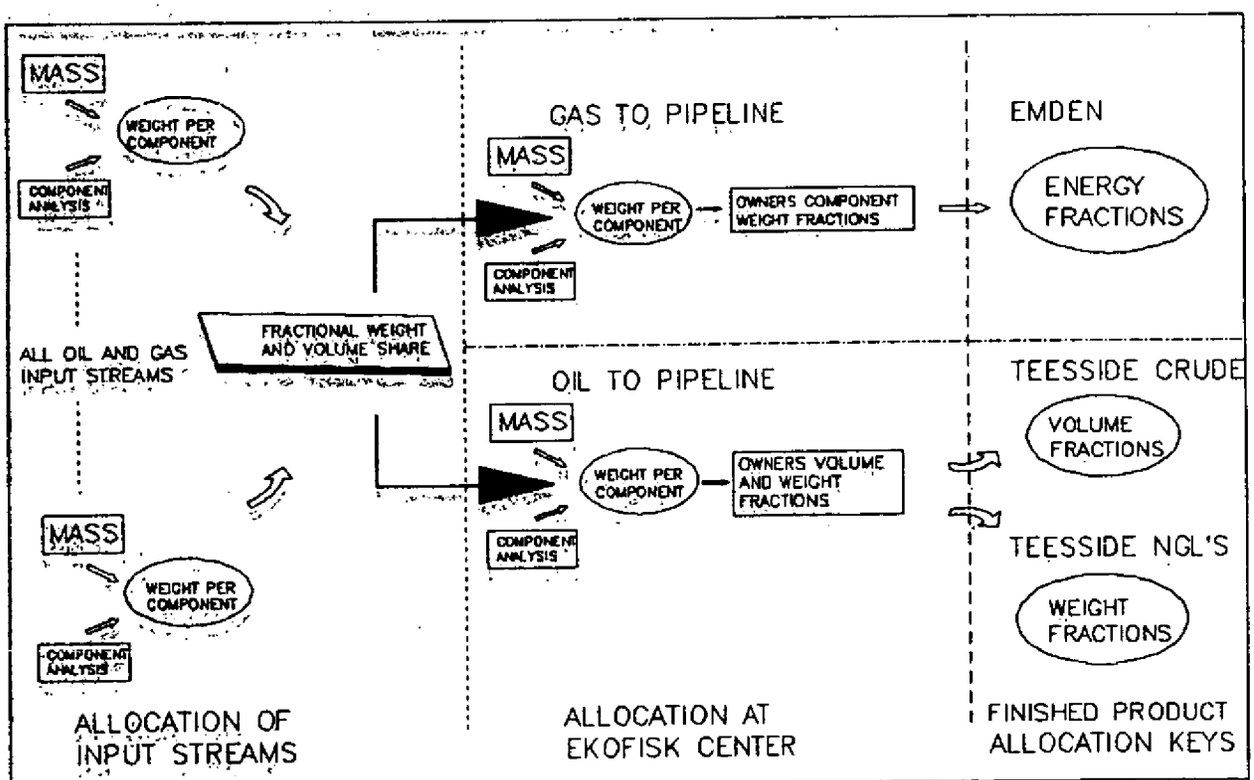


FIGURE 9 – ALLOCATION OF FINISHED PRODUCTS

OIL PRODUCTION 1979 - 1989

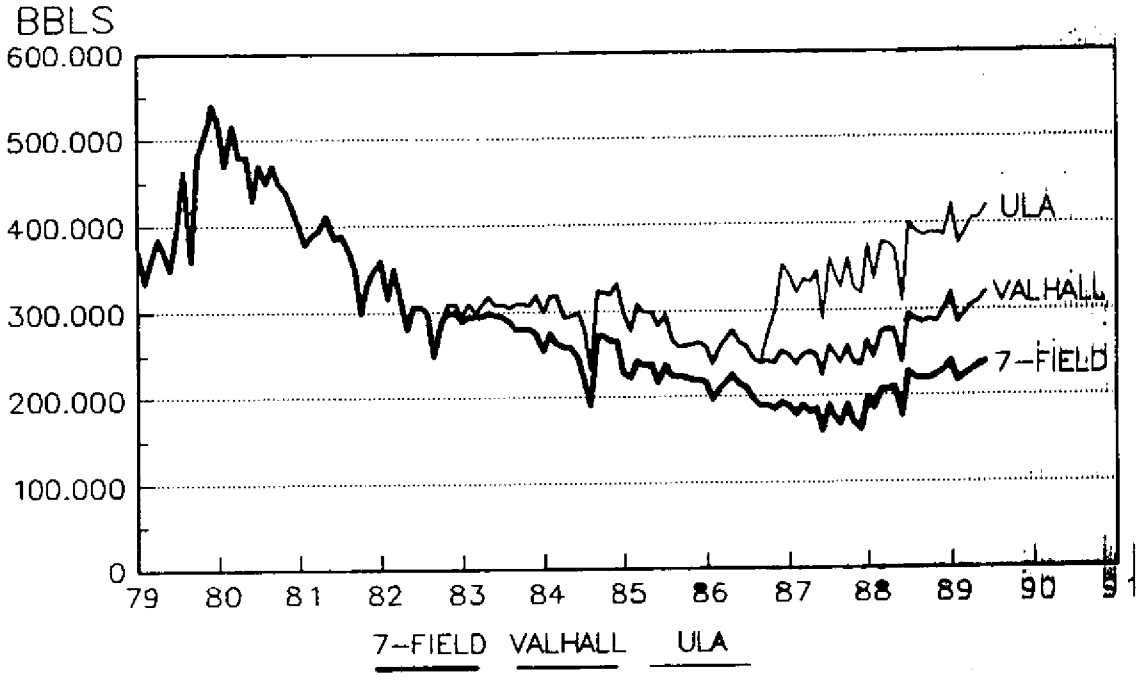


FIGURE 10

GAS PRODUCTION 1979-89

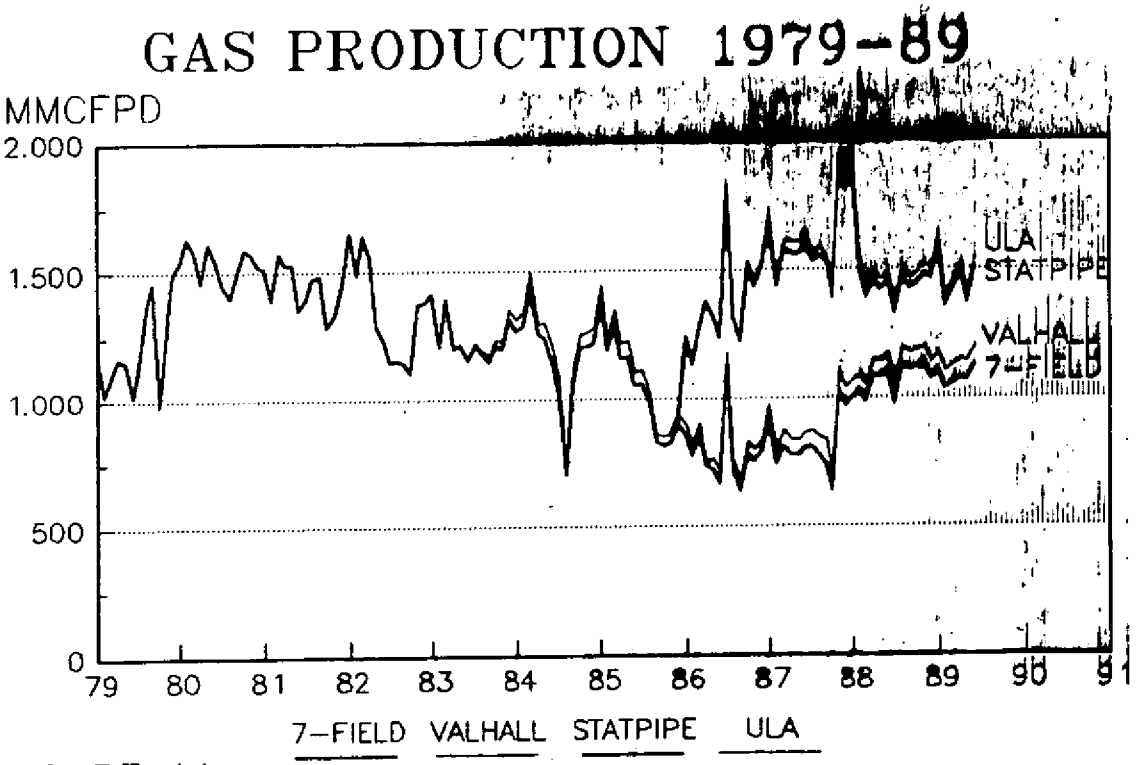


FIGURE 11

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Auditing the Management of Measurement"

Lecturer:
L.C. Britton
BP Petroleum Dev. Ltd.

THE MANAGEMENT OF MEASUREMENT

INTRODUCTION

This paper is prepared for presentation to the Norwegian Society of Chartered Engineers at their North Sea Metering Workshop to be held in Haugesand, Norway 24 - 26 October 1989.

The paper will use the Engineering concept of a closed loop feedback system to develop principles for Management Control Systems appropriate to offshore oil and gas measurement, hydrocarbon accounting and allocation, and data manipulation within computer systems.

Measurement is the cash register of an upstream oil company and let no-one under-estimate its significance. A measurement understatement of just 0.1% to a 100,000 barrel per day producer could result in a pretax cash loss of over $600,000 a year. Ensuring the accuracy and auditability of measurement data is a challenging managerial role spanning the disciplines of Engineering, Production and Management.

As this paper is targeted on the "Management of Measurement", I shall place emphasis on crude oil measurement examples, rather than gas, primarily because of its greater economic value. Hence any weaknesses in control exposes the producer to a greater financial risk.

I shall then develop the role and benefits of Technical Audit, giving practical examples of typical control weaknesses identified, their cause, their effect on the business and the recommendations we made for improvement.

I am employed by BP Exploration, Aberdeen, as Head of Technical Audit, a branch of the Internal Audit Department. I am a Chartered Mechanical Engineer by profession with over 11 years in the oil industry, predominately in project related work. My team of three auditors comprise two Engineers and a Physicist within an environment of Financial Accountants.

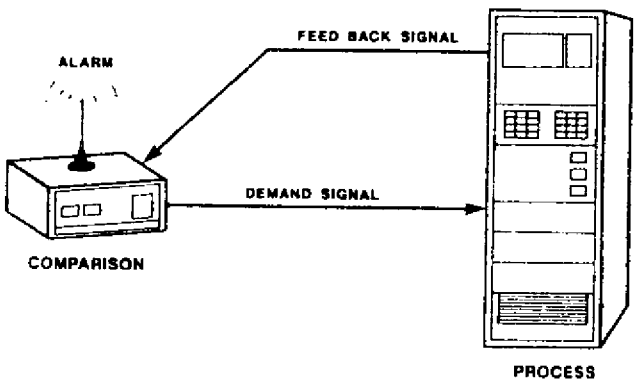
This structure is conducive to our mission which is to identify business risks arising from Engineering and Operational activities and to make practical recommendations for improvements to the control environment, where appropriate.

Oil and Gas Measurement Audits occupy about 50% of our Technical Audit program. Each audit requires a team to spend approximately four days on the producing platform and a further five to eight days in the Beach based offices, auditing hydrocarbon accounting and Management control procedures. We have undertaken measurement audits of most BP operated North Sea Platforms on behalf of our Senior Management; in addition we have conducted measurement audits of Third Party platforms and installations in UK, Norway and in Alaska where BP has operator and non-operator interests.

CONTROL ENVIRONMENT CONCEPT

Most of you will be familiar with the engineering concept of closed-loop control systems. A demand signal is used to initiate an action from a process, the process responds with a feedback signal indicative of the action actually performed. A black box then compares demand and feedback signals and if they match within a defined tolerance it will take no action. If they fail to reconcile an alarm is raised or some other correction automatically initiated.

CLOSED-LOOP CONTROL SYSTEM



This concept may be extended to the management control of a pipeline system transporting crude oil from a number of offshore platforms to an onshore processing plant.

The demand signal becomes the mass of live crude oil as measured by the platform meters. The feedback signal is the mass of all products and stock changes produced by the onshore plant over the same time period. Comparison of the offshore crude measurement with the onshore product quantities, a mass balance, will result in a discrepancy but by graphical trending of this imbalance and assigning warning and action limits based upon experience and statistical methods, a Management control over measurements within the pipeline system will have been effectively and economically produced.

The mass balance control will not be sufficiently sensitive to pick up minor mis-measurements nor identify the source of any data error but it will form the basis for triggering management investigation when necessary. Management, therefore, have a useful control tool and have established a good control environment.

OFFSHORE CONTROL ENVIRONMENT

The above was an example of the feedback control concept applied to a measurement system. Now let us apply the control principle to the work of offshore Operators and Technicians.

As reliable and sophisticated as metering equipment may be, it is all to no avail if the tasks and responsibilities of the individual Operators and Technicians are not clearly defined and there is no systematic check to verify they are being performed fully and diligently.

Tasks are usually defined in written procedures. Responsibilities, in our experience, are less clearly specified. We consider that the Offshore Operations Management is accountable for the quality of the measurement data produced by the Platform and that accountability must not be diluted even when certain tasks are undertaken by visiting Contractors. Regular instrument calibration, routine verification of approved constants within the flow computers, graphical trending of data all provide good quality controls.

However, in order to "close the loop" one needs a feedback signal. This is often achieved by making a Beach based Metering Engineer accountable fot the quality assurance of measurement. Regular reviews of procedures and actions will ensure a consistency of approach between crews and between

platforms. He will also produce greater awareness of the importance of measurement and provide feedback reassurance to the Technicians that their technical performance is acceptable.

Metering Engineers at BP perform regular and detailed measurement QA. Technical Audit takes a wider view covering measurement, organisation, data flow, responsibilities etc. and where weaknesses are found will identify the potential financial risk involved.

Procedures are important to control as they provide the approved basis for performing given tasks. Witnessing an offshore Technician actually performing the tasks is essential. The Technician's knowledge of the procedures, job training, adequacy of documentation and record keeping all become quickly evident. If a Technician's performance is not entirely satisfactory, it should not be viewed as a failing of the individual but as a failing of a Management control. Was Technician selection, training, supervision, equipment adequate?

DATA CONTROL ENVIRONMENT

Even on the best managed platforms, mis-measurement will occur due, for example, to flow computer breakdown, water samples incorrectly analysed or flow computer testing.

Production data from the platform is usually handed off to the Beach office via a daily telex or automatic transfer. Handling mis-measurements can cause confusion unless there is a clear procedure in place. Confusion has been known to exist as to which is the corrected quantity. Phone calls can resolve the difficulty or just add to the confusion.

Adjustments made to production data must have a clear audit trail. This data forms the basis upon which large sums of money are shared between Partners and vast tax bills are levied. Would you be happy if the electricity company increased your meter reading without full justification?

One method of feedback control to demonstrate the integrity of the daily data flow is to reconcile the month end fiscal quantities produced onshore by the hydrocarbon accountant, with the change in the appropriate non-resettable totalisers on the flow computers offshore, adjusted by sequentially numbered mis-measurement reports.

Computer systems are a potential risk area where data corruption can remain undetected unless adequate controls are in place.

When crudes from different unitised areas are commingled, usually within a pipeline system, agreements specify the basis upon which the blend is allocated back to the producers. Adjustments reflecting the sharing of apparent losses/gains, differential values, tariffs taken as allocated product rather than cash, over/underlift provision, all lead to complex computer systems. As with most computer systems procedures should be in place to ensure data archiving, authorised changes are documented, the confidentiality of information is maintained.

One simple method to demonstrate that complex software is unchanged over a period of time is to retain a set of old input data and the corresponding output. By re-running say one year old input data and comparing the output generated now with that of one year ago will provide reassurance that the software is probably unchanged.

COMPLIANCE CONTROL

However detailed the wording of any agreement or statutory obligation, there is always scope for interpretation. A Technical Auditor's review of a platform's operating and calibration procedures ensures an independent assessment of their compliance and a view as to whether the interpretation could result in a favourable or unfavourable measurement bias. Either could be considered a business risk of which Management should be aware.

If the Transportation Agreements do not define the water-in-oil test procedure to be used, a Technical Auditor will recommend consistency of method to avoid the risk of one producer gaining a financial advantage over another. This method may not be the most accurate available but it should result in equality.

TECHNICAL AUDIT

A Technical Audit team works with the Operator to provide him with an independent assessment as to whether his control systems are in place and effective. Primarily, the Audit Team works for the Client to provide reassurance that his business risk is effectively controlled.

Technical Audit does not seek measurement perfection. All recommendations made must be justifiable against actual or potential business exposure. We accept that an audit is a snapshot in time, the alternate shifts could be adopting a different method of work. For this reason our audits concentrate on establishing suitable controls. **A good control environment will highlight future operational weaknesses long after the Audit Team has left.**

Technical Audit has the advantages that it is external to the operation being auditted and is therefore independent and objective. It brings together individuals from different disciplines and backgrounds creating a broader view. We consider it more of a independent consultancy service to both client and auditee. Our recommendations are not executive therefore Management's responsibility to manage remains undiluted.

A disadvantage with Technical Audit is that it is a detailed review over a limited time period. Additionally, being an audit, it is not ethical for us to refrain from reporting our professional conclusions, whatever the impact, provided they are factually accurate and without bias.

AUDIT PROCEDURE

Prior to an audit the lead auditor will have requested a copy of relevant documentation such as meter skid schematics, operating, calibration and maintenance procedures, Transportation and Operating Agreements, an organigram etc.

The lead auditor will propose a series of tests and procedures that he will wish to witness. Typically these include the proving of a turbine meter, calibration of an RTD, withdrawal of an orifice plate, injecting defined signals into stream micro-computers to verify computation, a temperature survey across the metering skid, taking and analysing a sample and densitometer validation. Responsibility for undertaking the tests remains with the platform operator.

The audit team will also gather production, laboratory, hydrocarbon accounting and allocation data for a selected month and verify there is accuracy and consistency throughout. The selected month(s) is not advised until the start of the audit.

AUDIT METHODOLOGY

Conventionally we audit within agreed Terms of Reference and against Company Standards and Agreements. Areas of concern to the Audit are termed FINDINGS. These may relate to actual errors (eg an incorrect constant in a flow computer) or, in the opinion of the Audit, there is a practical risk that they could exist (eg the absence of a critical spare metering component would create a finding if a breakdown occurred).

Findings have EFFECTS or potential effects, either a loss of revenue or an increased business risk. Where possible we will assess its significance and place an order of magnitude value on it although we see Technical Audit as more of a means of improving the control of operations rather than as a vehicle for looking for financial claims.

Findings also have CAUSES. An incorrect number in a flow computer happened because there was no routine check of the constants against a checksheet. Where possible we will identify the CONTROL WEAKNESS.

We will then make practical RECOMMENDATIONS to correct findings, mitigate effects and prevent control weaknesses. Our intention is to concentrate on preventing tomorrow's risk rather than apportion blame for yesterday's findings.

The written report invites Operator response to each of our recommendations together with his TARGET DATES for their implementation. Audit FOLLOW-UP by a client representative every six months or so, reporting implementation progress to his Management with copy to Audit, will complete the process. Follow-up ensures that the resources of the client and the audit team expended during the audit period generate maximum long term effect.

TYPICAL AUDIT FINDINGS

During the audit we look, question, analyse but above all listen. Many a finding exposing a substantial control weakness and business risk has been identified through interview and subsequently verified. The following are some of the typical audit findings ..... to date:

a) Meter Proving

Turbine meter proving is always an interesting test to witness. The Operators confidently select the stream, show the pulse counters, plot the result on a meter factor control chart and download the acceptable factor.

Having previously checked the procedures we then ask why the block and bleed valves were not verified, how the operator is assured that the automatic leak detection on the four-way valve is working, why is the meter skid outlet RTD reading higher than the inlet?

Unfortunately these obvious measurement findings are not the exception. The cause invariably results from inadequate operator awareness of the importance of measurement, weaknesses in quality assurance and failings in the overall measurement control environment.

The meter control charts provide good measurement control, if interpreted correctly. A control chart without action limits or with action limits that are regularly adjusted without full justification, miss their objective. Limits may be changed if the viscosity of the crude changes but should not be changed to reflect bearing wear, unless approved by the Beach Metering Engineer.

Meter control charts indicate achieved linearity and compliance with Department of Energy/NPD requirements for reproving procedure. They also show whether standby meter stream capability exists, that is whether 100% flow rate could be achieved with one meter stream out of commission and no increase in measurement uncertainty. Significant business risk will occur if findings are identified.

b) Calibration

The request to witness the calibration of a temperature RTD is usually well received. We meet with the Technician and, just prior to leaving his workshop enquire why he has not verified his field instruments against the Instrument Shop transfer standard. To calibrate using non-verified instruments may result in a measurement bias.

One site possessed not one but two certified resistance transfer standards - unfortunately they differed by a resistance equivalent to $1^{o}F$ which in itself resulted in a volume measurement uncertainty of over 0.05%.

We expect the Technician to have a proforma on which he enters the 'as found' reading, a defined acceptance tolerance band, and an 'as left' reading. This will permit analysis of instrument stability and permit the frequency of recalibration to be optimised. The use of the back of a restaurant bill to record data was not acceptable! I should note that our criticism was directed at the training and quality assurance exercised over the Technician's work and not at the performance of the individual.

In the North Sea BP frequently use contractors for calibration. It is obviously pointless to have a BP Technician accompanying a contractor to verify his work. However,if prior to signing acceptance of the calibration, the Technician exercises control by comparing the reading of a suitable located mercury in glass thermometer with the flow computer display. Agreement to within 0.2°C is indicative of a good calibration. This control ensures responsibility for calibration remains clearly defined and demonstrates to the contractor that his employer has controls in place. Such recommendations have been implemented.

c) **Orifice Plate**

Withdrawal of an orifice plate to inspect for edge sharpness and contamination is a standard test.

Although constructed to ISO 5167 standards we verified an instance where upstream swirl effects in a gas measurement system produced a significant discrepancy in the measured flow between primary and stand-by meter tubes. This discrepancy had been been identified by the Beach Metering Engineer through his data monitoring. However, supported by an Audit recommendation, together with the quantified business risk, his Management supported expenditure on improved pipework routing. An example of working with the Auditee to achieve improvement.

d) **Flow Computers**

Controls over fl[illegible]computer constants is always a measurement risk area. Audit confidence is increased when there is an authorised list of constants and evidence that the Instrument Technician regularly

verifies those and only those constants are in place. We also check. In addition we use independent computer programs and hand calculation to validate the constants. Whenever possible we request the inclusion of a pulse counter to verify totaliser summation. These checks verify compliance with appropriate standards but also demonstrate the level of awareness offshore of the flow measurement parameters.

Incorrect constants or any confusion usually suggest a need for tighter procedural control and greater awareness of their importance. During one audit we found that the tag number on one flow computer had been transposed with another, as had all the relevant constants. Fortunately they were measuring process quantities rather than fiscal quantities - but that was good fortune. Our recommendation for improved control was unambiguous.

e) **Temperature Survey**

The importance of temperature in crude oil measurement is often overlooked in the offshore operating environment; an error of only $1^{o}C$ will result in a volume error of 0.1% worth $400,000 per year from a 60,000 bbls/day field. The error can be either to over or understate quantity.

Although modern flow computers will compensate for temperature differences between flow meter and prover outlet, measurement uncertainty is reduced when that difference is very small.

Using the turbine meter RTD as a reference we use a certified mercury-in-glass thermometer, positioned, with good thermal contact, in available thermowells

throughout the meter and prover runs. Temperature drop across the skid and a comparison between the mercury and RTD readings can then be made.

We rarely find the temperature drop to be excessive although we often find anomalies in the calibration of the RTDs. The system may have been designed to the required measurement uncertainty, its operation is perhaps another matter.

f) **Sampling and Sample Analysis**

We generally find that the key areas of risk associated with crude oil sampling are the representivity of the sample stream, sampler hardware and the extraction of a subsample out on the skid. Fiscal analysis performed by dedicated Technicians within well equipped laboratories is usually well managed.

The oil velocity in the sampler bypass loop is isokinetic or greater by design. Wear in the pump or a partially blocked filter can reduce this flow rate resulting in the flow in the sample line becoming non-representative.

The reliability of some flow proportional samplers leaves much to be desired. On certain platforms, from log book entries, it is easier to count the days when the sampler is working rather than count when it is down.

Mixing a large sample (10 litres or more) at the sample skid and extracting a sub-sample for laboratory analysis is undesirable. Mixing procedures using a circulating pump for 30 minutes should be adequate but we would question the control to ensure the full mixing

time is always used. Layering, resulting from inadequate mixing, could result in the subsample containing excess water. Proof is difficult but the business risk of overstating water is not worth taking.

The above all lead to increased uncertainty in water measurement and hence dry oil determination

g) **Densitometer**

Mass measurement systems are essential if there is to be control over systems containing commingled crudes. Volume shrinkage effects preclude accurate reconciliation in volume terms and hence the control environment is compromised. Mass measurement systems require a measure of density. This is usually achieved using densitometers situated in a bypass loop.

Control over these instruments is best achieved by using one as master and a second as an on-line comparison. Significant discrepancy can then be alarmed. But what if they both degrade together due to wax build-up on the probe, for example?

A third densitometer kept off-line and used as a transfer standard provides one alternative validation control. An alternative is to cycle three densitometers between master, comparison and Beach recalibration. Saving a few thousand pounds on the purchase of densitometers could expose the business to risks of millions through increased measurement uncertainty. It is cheap insurance.

h) **Hydrocarbon Accounting**

Allocating commingled production between several owners, in compliance with all the Agreements, is the responsibility of the Hydrocarbon Accountant. Data processing is obviously a prime role. However BP encourage the Hydrocarbon Accountant to exercise quality assurance checks to ensure the reasonableness of the source input data and to question anomalies. Responsibility for the accuracy of the data remains with the Operator.

The feedback control is provided by the owner of the crude. Although he does not have the full picture a set of trend graphs will give him a good idea, within a defined tolerance, of his expected product entitlement after transportation, processing and losses. Circumstances may change and the product yield may legitimately fall. The Hydrocarbon Accountant would be willing to answer the owner's query or, if necessary, initiate an investigation. In the final analysis the owner is responsible for ensuring he receives full and fair allocation.

i) **Business Accountability**

A poignant example of devolved business accountability arose during one audit when we were trying to determine responsibility for monitoring and minimising crude oil shipping and transportation losses. Losses typically were 0.2% but had a pretax value of $0.75 million per year.

We were advised that Fred in the Shipping Offi.. compares Bill of Lading and Out-turn reports and would report if excessive losses occurred. When we asked to interview Fred we learnt he had passed away three months previously - no one had taken this role. The control weakness resulted from the geographic remoteness between the two offices and their separate Management structures. This weakness has been rectified.

SUMMARY

This paper has attempted to put into a practical context the concept of the **"control environment"** and its application to the **"Management of Measurement"** within the oil industry. The paper has also developed the role of **Technical Audit** as an important element of that control environment and has stressed the importance that such audits, though independent in opinion, are conducted as a partnership with the operator, are practical and are forward looking.

When a Technical Audit Team arrives, look upon it as an opportunity for a constructive, informed opinion - I hope it will be.

L C BRITTON
31 August 1989

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"NPD's view on Cost Effective Fiscal Metering by Means of Test Separator and Well Allocation Methods"

Lecturer:
Steinar Fosse
Oljedirektoratet

Will be handed our during the workshop

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Automatic Transmitter Calibration Ideas and Practical Implementation"

Lecturers:
Rolf Skatvedt
and
Rune Øverland
Norcontrol Training a.s

English Version

Flow measurement of oil and gas quantities, which should be executed determining the Governmental Royalties and Licencee´s income, is called *Fiscal Flow Measurement.*

Licencee also normally use this flow measurements to split income by a percentage key (allocation).

With reference to the enormous sums of money, which is transported out from the offshore installations in Norwegian sea territorial waters, it should be evident that this flow measurements are of greatest interests.

Consequently, these measurements will meet great claims of measurement accuracy and regulation of management.

Pages 6 and 7 shows general examples of piping and loop diagrams describing fiscal oil and gas metering stations used in the Norwegian sea territorial waters, while page 8 is a general block diagram of the computer control system of such metering stations.

As it shows from these figures, there are a great number of parameters, which first must be measured, before the final result kan be presented.

If the final result should be presented by a given accuracy, we must set claims to each individual parameter. The Norwegian regulation sets claims to each individual parameter with consideration of accuracy, stability and interval between calibration.

The interval between calibration of field instrumentation, which measures parameter as pressure and temperature, shall be performed at least once per month, which again requires that sufficient personnel with necessary knowledge are available.

This costs a great deal of money and consequently, it is important to find the point which describes expenses vs income.

Everyone knows that a chain will brake at its weakest point, despite the overall performance. Money investments must be seen in conjunction with this, and keywords for what described above, are:

1. Increase the grade of automation of calibration of field instrumentation.

2. Simplify calibration routines.

Norsk Versjon

De mengdemålingene av olje og gass som den norske stat beregner sine avgifter etter, kalles med med et felles navn for fiskale mengdemålinger.

Rettighetshaverne bruker også normalt disse målingene for å fordele inntektene seg imellom.

Med referanse til de enorme summer i kroner og øre som skipes ut av offshore plattformene i Nordsjøen pr. år skulle det være innlysende at disse målingene er av aller største betydning.

Følgelig settes det store krav til målenøyaktighet og driftsregularitet, noe som igjen har ført til at det fra norsk hold er utarbeidet egne forskrifter for dette med måling av olje og gass som tas ut av et petroleumsreservoar.

Sidene 6 og 7 viser generaliserte eksempler på piping og instrumentdiagrammer for fiskale olje og gass mengdemålingsstasjoner brukt i Nordsjøbassenget, mens side 8 er et generalisert blokkdiagram for kontrollsystemet av slike målestasjoner.

Som det skulle fremgå av disse figurene er det en god del parametere som må måles før et endelig måleresultat kan presenteres.

For at det endelige måleresultatet skal kunne presenteres med en gitt nøyaktighet, settes det krav til hver enkel måleparameter. De norske forskriftene setter krav til hver enkel måleparameter med hensyn på nøyaktighet, stabilitet og kalibreringsintervall.

Kalibreringsintervallet for feltinstrumenter som måler parametere som trykk og temperatur er satt til en måned, og fordrer at tilstrekkelig antall personer med de nødvendige kunnskaper er tilgjengelig.

Dette koster penger og følgelig er det viktig å finne balansepunktet mellom hva vi putter inn og det vi får igjen.

Det er ellers en kjennsgjerning at et produkt ikke blir bedere en det svakeste leddet. Penge investeringene bør derfor sees i sammenheng med dette, og stikkord i så måte er:

1. Øke automatiseringsgraden i kalibreringen av feltinstrumenter.

2. Forenkle kalibreringsrutinene.

3. Prolong calibration intervals.

4. Increase intelligence in both field instrumentation and computer control system.

5. Avoid unnecessary modification of measurement parameters.

6. Concentrate attention to parameters which contribute to largest inaccuracies i final result.

To expand the extent of the above, we will below try to deepen this more in detail.

We start with the pressure transmitters, and look at how calibration can be simplified. Pages 9 and 10 demonstrate the object.

As we all see, all transmitters are connected to the same process pressure by manifolds and motor actuated valves, which again are controlled by the computer system.

This system also has the ability of connecting a transfer standard to it, which again has a sufficient accuracy to function as a standard reference against the installed pressure transmitters, and if we combine this with static datacomputation (normal-distribution), this gives us by far the best ability to check the accuracy to each pressure transmitter related to operating conditions, and at the same time measurement lines are still operating.

The process pressure, used as reference, comes from one of the process lines which is in use. Consequently, flow calculation for the rest of the process lines must employ the values they had before the calibration check started.

When the test is finished, pressure transmitter again will arrive to normal operating status.

The test can be performed 100 % in automatic mode, and can therefore be done relativly often, with the confidence this entail to flow measurement, and at the same time cost can be held at minimum.

This should also satisfy The Norwegian Petroleum Directorate, particularly when we see how little these measurements affect the result of measurement, contrary to other parameters. Please refer to pages 11 and 12.

Corresponding system philosophy can be used for checking densitometers (gas densitometer against vakuum, and liquid densitometer against a known liquid).

As to temperature measurement, regulation for fiscal measurement prescribes the use of Platinum resistance

3. Forlenge kalibreringsintervallene.

4. Øke intelligensen både i feltinstrumenteringen og computer kontrollsystemet.

5. Unngå unødvendige konverteringer for måleverdiene.

6. Konsentrere seg om de parameterne som bidrar til størst usikkerhet i slutt resultatet.

For å få litt kjøtt på beinet vil undertegnede i den påfølgende tekst prøve å utdype dette litt mere i detalj, sett i lys av de punktene som er beskevet ovenfor.

Vi begynner med trykkmålingene, og ser på hvordan kalibreringene kan forenkles, sidene 9 og 10 tjener som referanse.

Som vi ser kan alle transmitterne koples til samme prosess trykk via rørmanifolder og motoriserte ventiler som styres av computersystemet.

Til dette systemet er det også mulighet for å tilkople en transfer standard, som har tilstrekkelig nøyaktighet til å fungere som en referanse ovenfor de installerte trykk transmitterne, som kombinert med statistisk databearbeidning (normalfordeling), gir oss den aller beste mulighet for å sjekke nøyaktigheten til hver enkelt trykktransmitter i arbeidspunktet, samtidig som linjene er i drift.

Prosess trykket som brukes som referanse kommer fra en av prosess linjene i bruk, følgelig må flow beregningene for de andre linjene benytte seg av de verdiene de hadde før kalibreringssjekken ble satt igang.

Når testen er ferdig antar de sin normale driftstilstand igjen.

Testen kan gjøres helautomatisk og kan følgelig gjøres relativt ofte, med den fortrolighet til målingene det medfører, samtidig som kostnadene kan holdes til et minimum.

Dette bør også tilfredsstille myndighetenes krav, spesielt når vi ser hvor lite disse målingene påvirker måleresultatet, kontra andre parametere (ref. sidene 11 og 12).

Tilsvarende system filosofi kan brukes for sjekk av tetthetsmålere, (gasstetthetsmålere mot vakuum og væsketetthetsmålere mot en kjent væske).

Når det gjelder temperaturmålingene er det i forskriftene foreskrevet at det skal brukes platina motstandselement

element according with IEC 751, "Tolerance class A" or equivalent. The accuracy for the complete circuit including any drift over a period of one month shall be better then ± 0,3°C in the temperature range of measurements.

Experience shows that the greatest contributor of inaccuracy in temperature measurements is related to the electronics itselfs. However, there are available today commercial transmitters that are classified as "Smart". Smart transmitters are also available for other measurement parameters.

This smart transmitter has "intelligence", and can by the use of internal algorithme correct it self by means of the most parameters which influence measurement accuracy.

They can also perform digital communication. This gives the opportunity of automatic change of measurement range, improved diagnostic etc (ref. page 13).

As an example, a purveyor states his instrument has a measurement range from 0 to 50°C, and the accuracy is better than ± 0,025°C, while long term stability is said to be better than ± 0,1 °C over a 6-th month period.

It should thus be sufficient to check these transmitters in a minimum 6-th month interval.

The check can consist of comparing the result of measurement against a transfer standard, which is installed in a termowell very close to the location of the measurement of process temperature, and under the same operating conditions (ref. page14).

Regarding the individual parameter that to the largest extent contributes in inaccuracy in the final result, we should thoroughly study the following:

Viscosity. Example: Meter K-factor of the turbine meter is depending on change in viscosity, and should be compensated regarding to batch loading, where temperature and therefore viscosity will vary a great deal. (ref. page15).

Puls interpolating technique (PIT). This technique is used to determine the meter K-factor of a turbine meter, and is used on some installations, while other do not implement this technique, despite we know PIT will increase accuracy of measurement.

Is the Metering station been operated in an optimum way with respect of measurement accuracy? Example 1: The value of meter K-factor of turbine meter will vary with variation

i henhold til IEC 751, toleranseklasse A eller tilsvarende. Måleusikkerhet for hele sløyfen, inkludert kalibreringsdrift pr. måned skal være mindre enn ± 0,3 grader celsius.

Av erfaring viser det seg at det som gir opphav til størst måleusikkerhet i disse målingene er elektronikken, imidlertid finnes det idag på markedet kommersielle transmittere som blir omtalt som såkalt "smarte" (er også tilgjengelig for de andre måleparameterne).

Disse har egen intelligens, og kan ved hjelp av interne algoritmer korrigere seg selv med hensyn på de fleste parametere som påvirker målenøyaktigheten.

I tillegg er de istand til å kommunisere på digitalt vis noe som gir mulighet for automatisk forandring av måleområde, forbedret diagnostikk osv (se side13).

En leverandør oppgir som et eksempel at for et måleområde på 0 til 50 grader celsius er nøyaktigheten bedre enn ± 0,025 grader celsius, mens langtidsstabiliteten angis til bedre enn ± 0,1 grader celsius på 6 måneder.

Det skulle således være tilstrekkelig å sjekke disse med et minimum intervall på 6 måneder.

Sjekken kan bestå i å sammenlikne måleresultatet mot en transfer standard som monteres i en termolomme tett opptil der målingen foretas, og under de samme driftsforhold (se side14).

Når det gjelder punktet vedrørende det å konsentrere seg om de måleparameterne som bidrar til størst måleusikkerhet i slutt resultatet bør også følgende forhold studeres :

Viskositet (eksempelvis er turbinmeterets K faktor avhengig av denne,og burde vært kompensert for ved batch laster hvor temperaturen og derav viskositeten kan variere en god del, se side15).

Brukes pulsinterpolasjonsteknikk ved bestemmelse av turbinmeterets K faktor (brukes på enkelte installasjoner mens andre bruker det ikke, selv om vi alle vet at dette øker målenøyaktigheten) ?

Opereres målestasjon optimalt med hensyn på måleusikkerhet (Som eksempler nevnes: 1, turbinmeterets K faktor er avhengig av flowraten og fordrer følgelig at det kalibreres ved samme

of flowrate, and K-factor should therefore be proved at operating flowrate. Example 2: All instruments, which range is specified as a function of span, should be used as close to maximum value as possible.

Is it correct to use standard reference conditions for pressure and temperature as common reference when we decide meter K-factor, or should we use operating condition as reference? Methods will vary from oil company to oil company.

Is it correct to use correction factors on crude oils, as given in API 2534, correcting meter K-factor due to changes in pressure and temperature? API do not recommend the mathematical treatment, but several oil companies on the Norwegian shelf use this correction factor anyway.

Are the maintenance procedures and repair routines good enough, for example will remaining water in oil sampler system after an examination lead to too high water-in-oil content?

Can the computer control system under all circumstances guarantee that all flow that pass through the metering station is being completely measured?

Is the analyses from the laboratories good enough to really represent the liquid/gas flowing through the metering station?

Is it given sufficient training of personnel?

CONCLUSION

The main object, as we see it, is to achieve solutions that benefit the technical measurement result, and at the same time security can be maintained and costs be held at a level that gives the largest profit in proportion to invested capital. To achieve this goal both involved in this situation, have in common several problems that have to be solved:

Oil companies

Install transmitters, which to the largest extent are not effected of changes in environment, example temperature, pressure, humidity etc. This is important, because in some cases stability is more important than accuracy itself.

flowrate som det skal brukes ved. 2: Alle instrumenter som har nøyaktigheten oppgitt som funksjon av span bør brukes så nære maks måleverdi som overhodet mulig).

Er det riktig å bruke standard betingelser for trykk og temperatur som felles referanse ved utarbeidelse av turbinmeterets K faktor, eller bør det brukes operasjonsbetingelser? Her er det forskjellig fra oljeselskap til oljeselskap.

Er det riktig å bruke korreksjonsfaktorene som er gitt i API 2534 vedrørende turbinmeterets påvirkning av trykk og temperatur for råoljer? API standarden anbefaler det ikke, men de fleste oljeselskapene på Norsk sektor gjør det.

Er prosedyrene for vedlikehold og reparasjon gode nok, eksempelvis vil gjenværende vann i oljeprøvetakerne etter en uttesting føre til at vannprosenten i oljen blir bestemt alt for høy.

Er sikkerheten i kontrollsystemet god nok til at det ikke under noen omstendighet kan passere fluider gjennom målesystemet uten at det blir registrert på målestasjonens telleverk.

Er laboratorie analysene som foretas representative for hva som virkelig passerer målestasjonene?

Er tilstrekkelig opplæring gitt?

KONKLUSJON

Hensikten med denne konklusjon slik undertegnede ser det er å komme frem til løsninger som kan gagne det måletekniske resultatet samtidig som sikkerheten kan opprettholdes og kostnadene holdes på nivå som gir størst avkastning iforhold til investert kapital. For å komme frem til dette er det to berørte parter, og som hver for seg og i fellesskap har noen oppgaver som må løses:

Oljeselskapene

Installere måleverdigiverne slik at de i størst mulig grad er upåvirket av forandringer i omgivelsene, som eksempelvis temperatur, trykk, fuktighet, etc. Dette er viktig da stabiliteten ofte er viktigere enn selve målenøyaktigheten.

Choosing transmitters, which to the largest extent correct themselves related to changes in environment, that is to choose "smart" transmitters. Choosing solutions that make it possible to have a very quick and reliable calibration (check) of transmitters.

To achieve correction factors, which are valid for crude oil, which in a correct manner compensate changes in parameter that occur when exporting crude oil from the North Sea.

Influence officical authorities to a larger extent to make it possible to introduce new measurement techniques, for example use of "compact prover", gas turbine meter etc.

To achieve new computer arrangements, which gives more secure operating and safer running.

To give operators and maintenance personell sufficient training, so they thoroughly understand how differently measurement parameters influence final measurement result.

Norwegian Petroleum Directorate

Removing obligations about interval between calibration in their regulation, and to a larger extent concentrate checking long term stability of measurement parameters, when environmental conditions are changing.

To achieve mathematical treatment for crude oil and gas, which is as correct as possible, and make oil companies use correct formula.

To give opportunity to measure oil and gas at alternative methods, but after strict regulations, for example to use gas turbine meter instead of orifice plate.

To a larger extent see to it that fiscal metering stations are operated and maintained in a optimal way.

Velge transmittere som i så stor grad som mulig korrigerer for skiftende omgivelsesforhold, dvs å velge "smart" transmittere. Velge løsninger som muliggjør hurtig og sikker sjekk/kalibrering av måleverdigiverne.

Finne frem til korreksjonsfaktorer som har gyldighet for råolje, og som kompenserer for de forandringene som virkelig inntreffer ved utskipning av råolje fra felt i Nordsjøen.

Påvirke offentlige myndigheter til i større grad enn idag til å gi rom for nye måletekniske løsninger, her nevnes "compact prover", gassturbinmeter etc.

Finne frem til computerløsninger som gir god bruker vennlighet, og sikrere drift.

Gi operatører og vedlikeholdspersonell tilstrekkelig opplæring til at de forstår hvordan forskjellige måleparametere påvirker sluttresultatet.

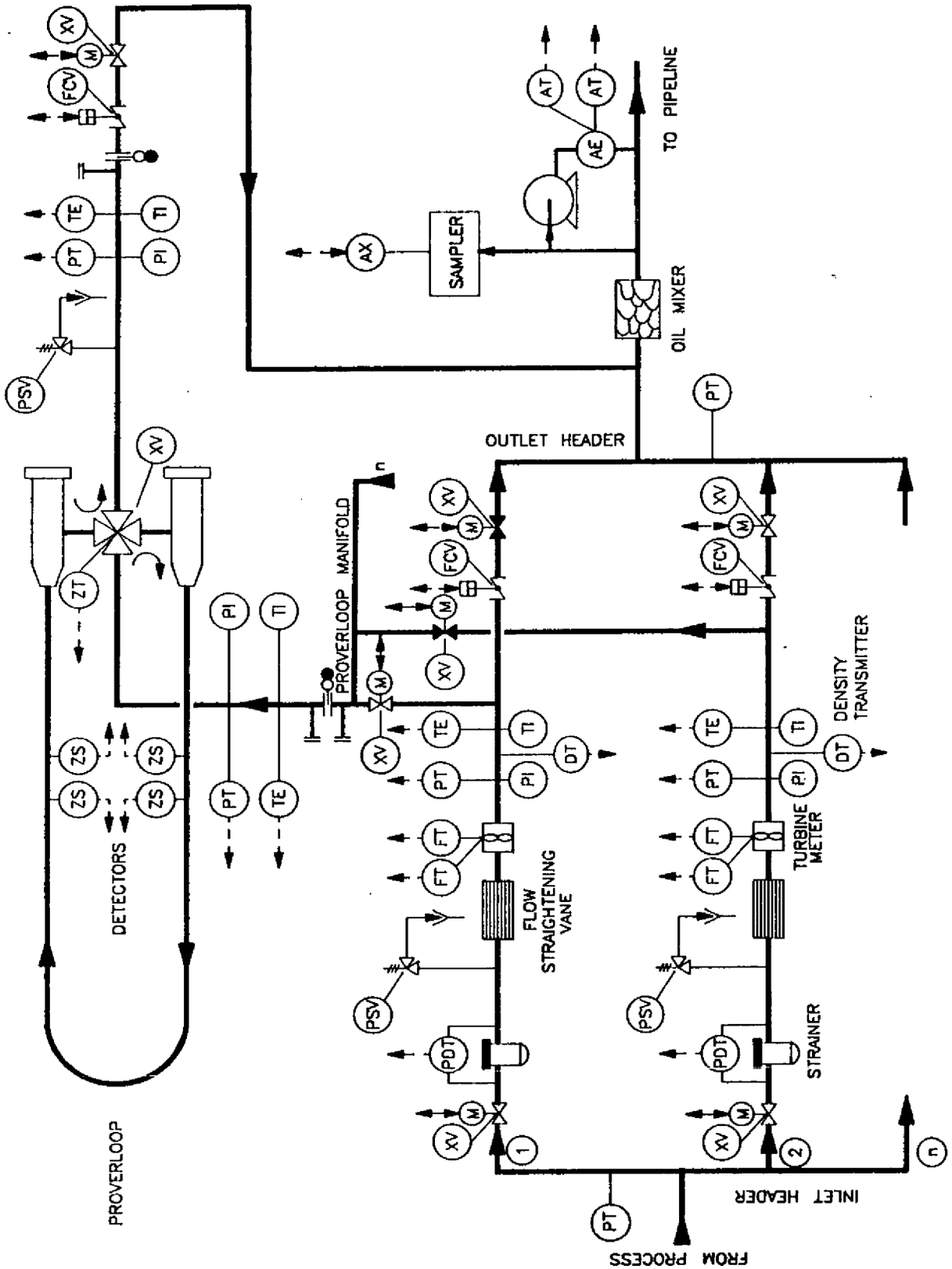
Oljedirektoratet

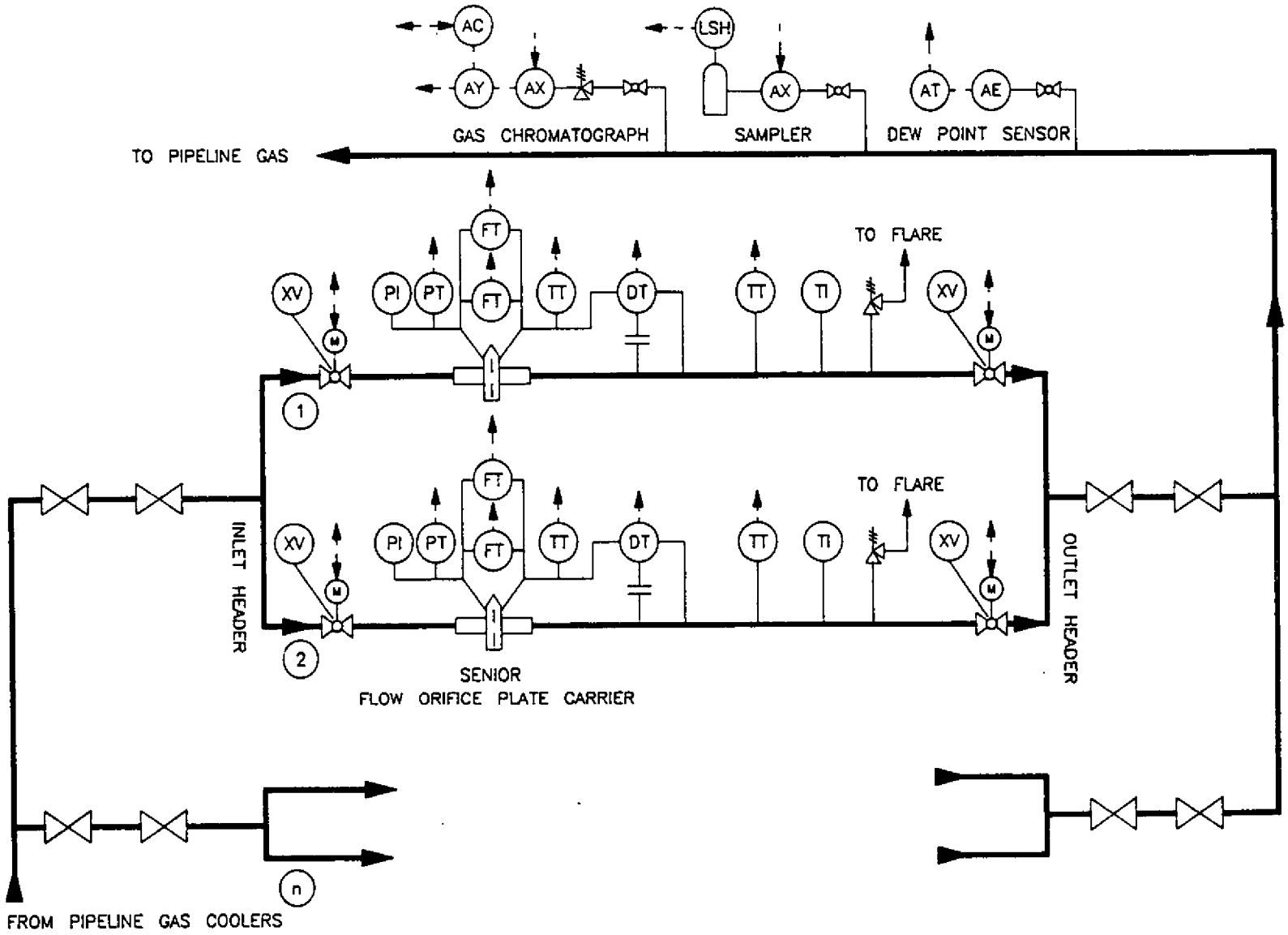
Fjerne kravet i forskriftene vedrørende kalibreringsintervall, og i større grad konsentrere seg om å sjekke at at måleverdiene er stabile over tid og med vekslende omgivelsesforhold.

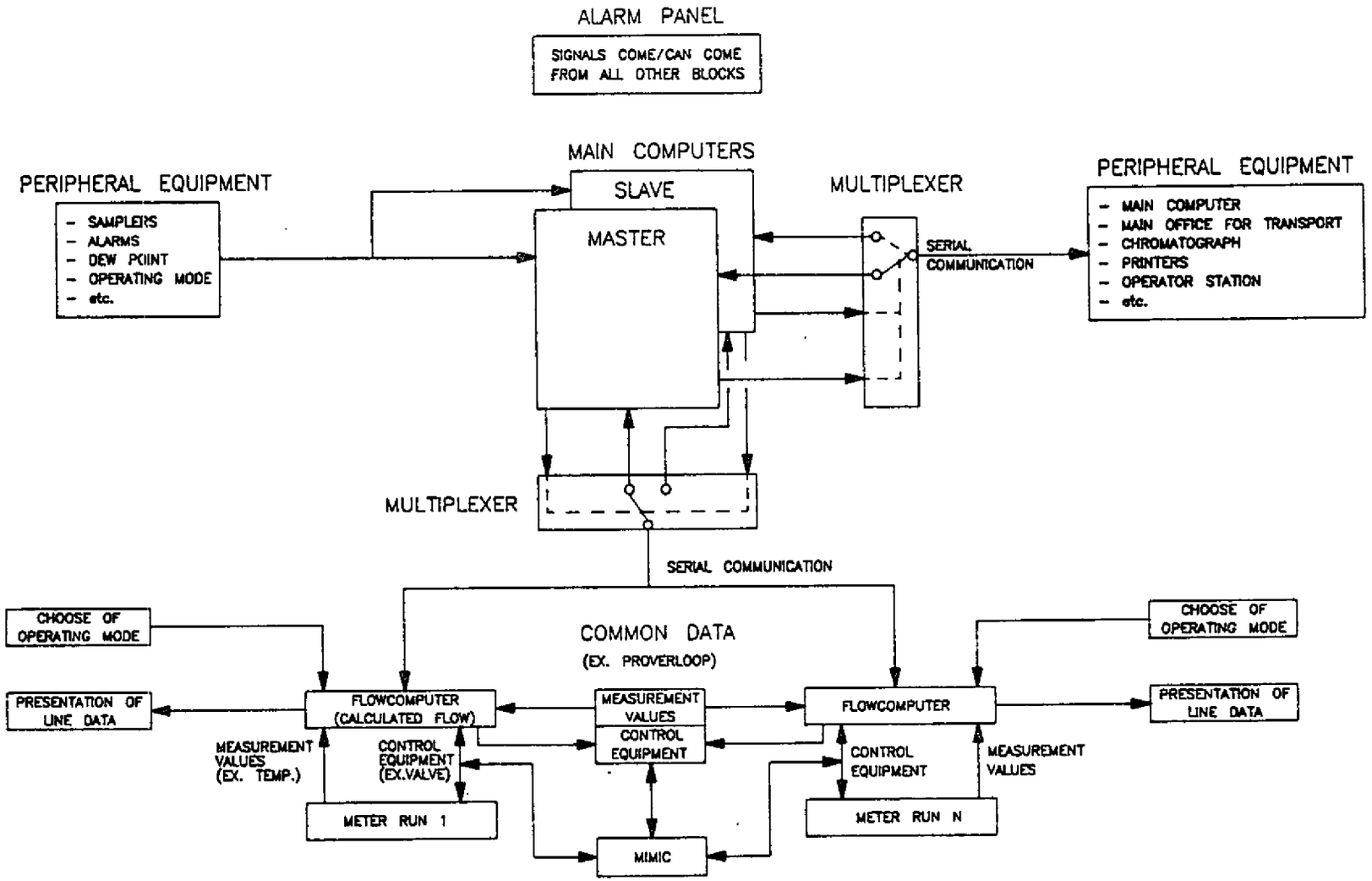
Finne frem til beregningsmåter for råolje og gass som er så korrekte som overhodet mulig, samt påse at alle oljeselskapene følger disse.

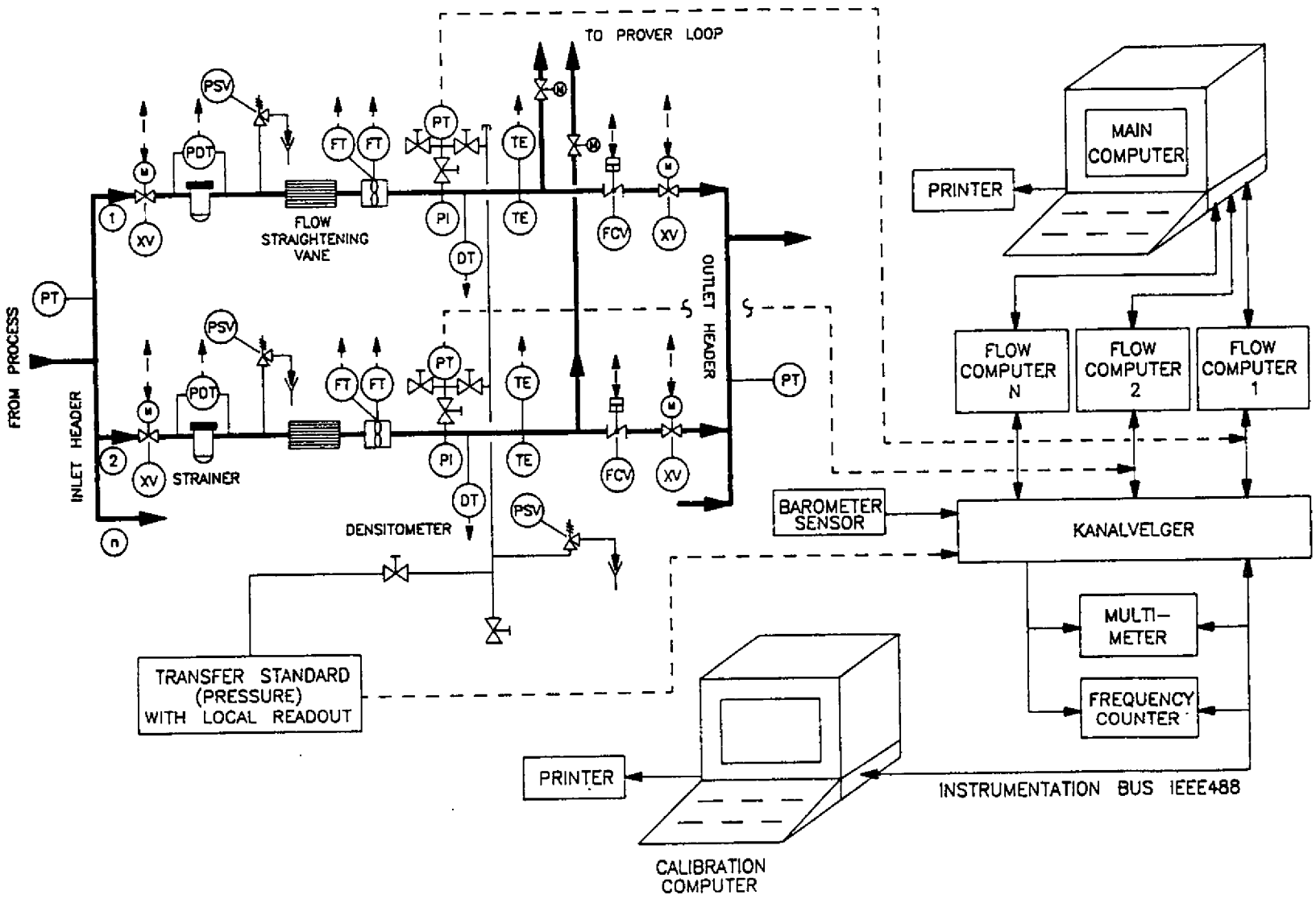
Gi mulighet for å måle olje og gass på alternative måter, men etter fastlagte retningslinjer, eksempelvis gassturbinmeter kontra måleblende.

Påse i sterkere grad enn idag at målestasjonene opereres og vedlikeholdes optimalt.


XV
M
FCV
TE
TI
PT
PI
PSV
AX
SAMPLER
AT
AE
TO PIPELINE
OIL MIXER
OUTLET HEADER
ZT
ZS
DETECTORS
PROVERLOOP
PROVERLOOP MANIFOLD
DT
DENSITY TRANSMITTER
FT
FLOW STRAIGHTENING VANE
TURBINE METER
PDT
STRAINER
INLET HEADER
FROM PROCESS
1
2
n


AC
AY
AX
LSH
AX
AT
AE
GAS CHROMATOGRAPH
SAMPLER
DEW POINT SENSOR
TO PIPELINE GAS
FT
TO FLARE
XV
PI
PT
FT
TT
DT
TT
TI
XV
1
FT
TO FLARE
INLET HEADER
XV
PI
PT
FT
TT
DT
TT
TI
XV
OUTLET HEADER
2
SENIOR
FLOW ORIFICE PLATE CARRIER
n
FROM PIPELINE GAS COOLERS

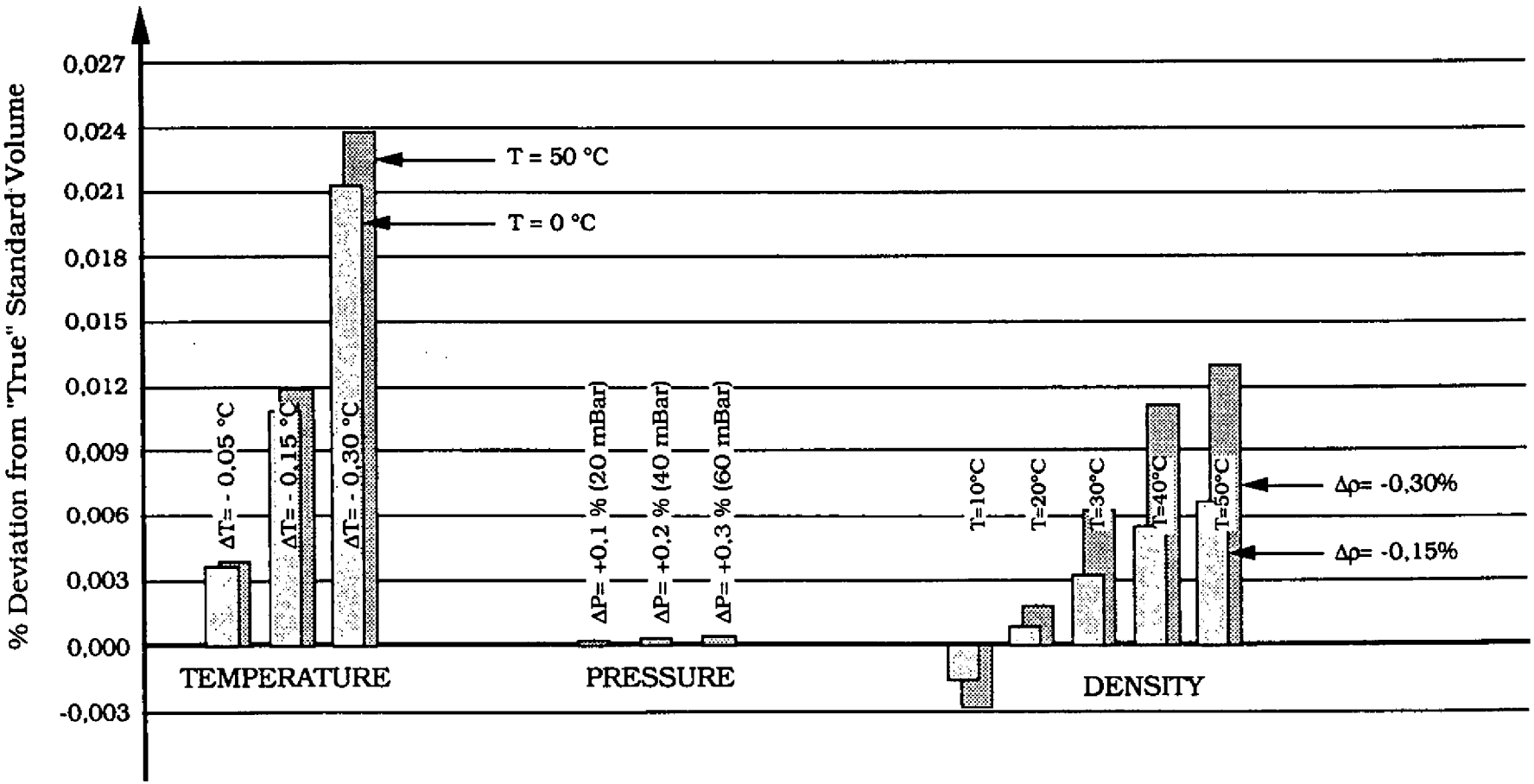

ALARM PANEL
SIGNALS COME/CAN COME FROM ALL OTHER BLOCKS
MAIN COMPUTERS
PERIPHERAL EQUIPMENT
- SAMPLERS
- ALARMS
- DEW POINT
- OPERATING MODE
- etc.
SLAVE
MASTER
MULTIPLEXER
SERIAL COMMUNICATION
PERIPHERAL EQUIPMENT
- MAIN COMPUTER
- MAIN OFFICE FOR TRANSPORT
- CHROMATOGRAPH
- PRINTERS
- OPERATOR STATION
- etc.
MULTIPLEXER
SERIAL COMMUNICATION
CHOOSE OF OPERATING MODE
COMMON DATA
(EX. PROVERLOOP)
CHOOSE OF OPERATING MODE
PRESENTATION OF LINE DATA
FLOWCOMPUTER (CALCULATED FLOW)
MEASUREMENT VALUES
CONTROL EQUIPMENT
FLOWCOMPUTER
PRESENTATION OF LINE DATA
MEASUREMENT VALUES (EX. TEMP.)
CONTROL EQUIPMENT (EX.VALVE)
CONTROL EQUIPMENT
MEASUREMENT VALUES
METER RUN 1
METER RUN N
MIMIC


TO PROVER LOOP
MAIN COMPUTER
PRINTER
FLOW COMPUTER N
FLOW COMPUTER 2
FLOW COMPUTER 1
FROM PROCESS
INLET HEADER
OUTLET HEADER
FLOW STRAIGHTENING VANE
STRAINER
DENSITOMETER
BAROMETER SENSOR
KANALVELGER
MULTI-METER
FREQUENCY COUNTER
TRANSFER STANDARD (PRESSURE) WITH LOCAL READOUT
PRINTER
INSTRUMENTATION BUS IEEE488
CALIBRATION COMPUTER
PT
PSV
PDT
FT
TE
PI
DT
FCV
XV

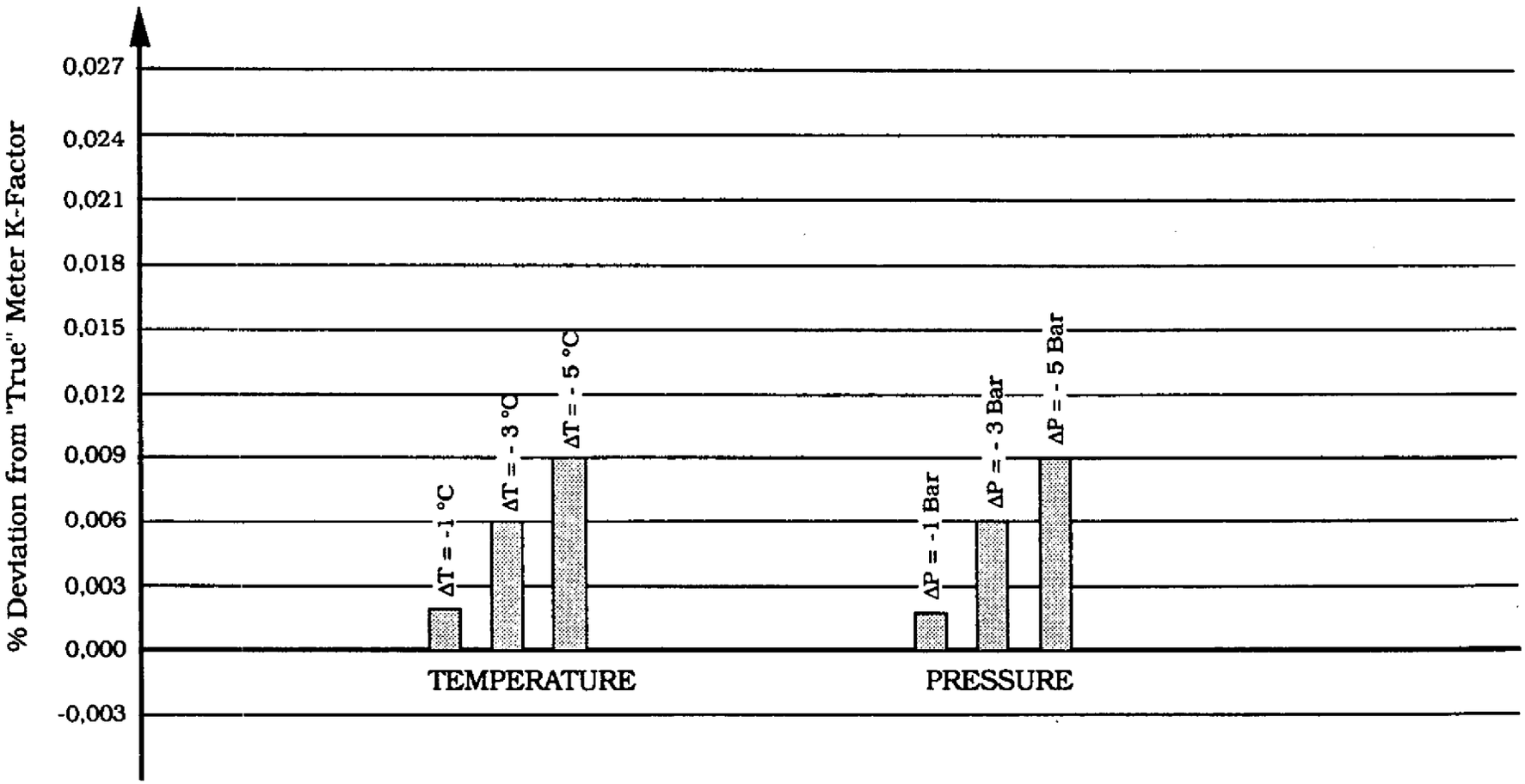
HIGH RANGE
LOW RANGE
PT
ΔP
H
L
LINE 1
LINE N
TRANSFER STANDARD
DIFF. PRESSURE
LOCAL READOUT
SNAP CONNECTION

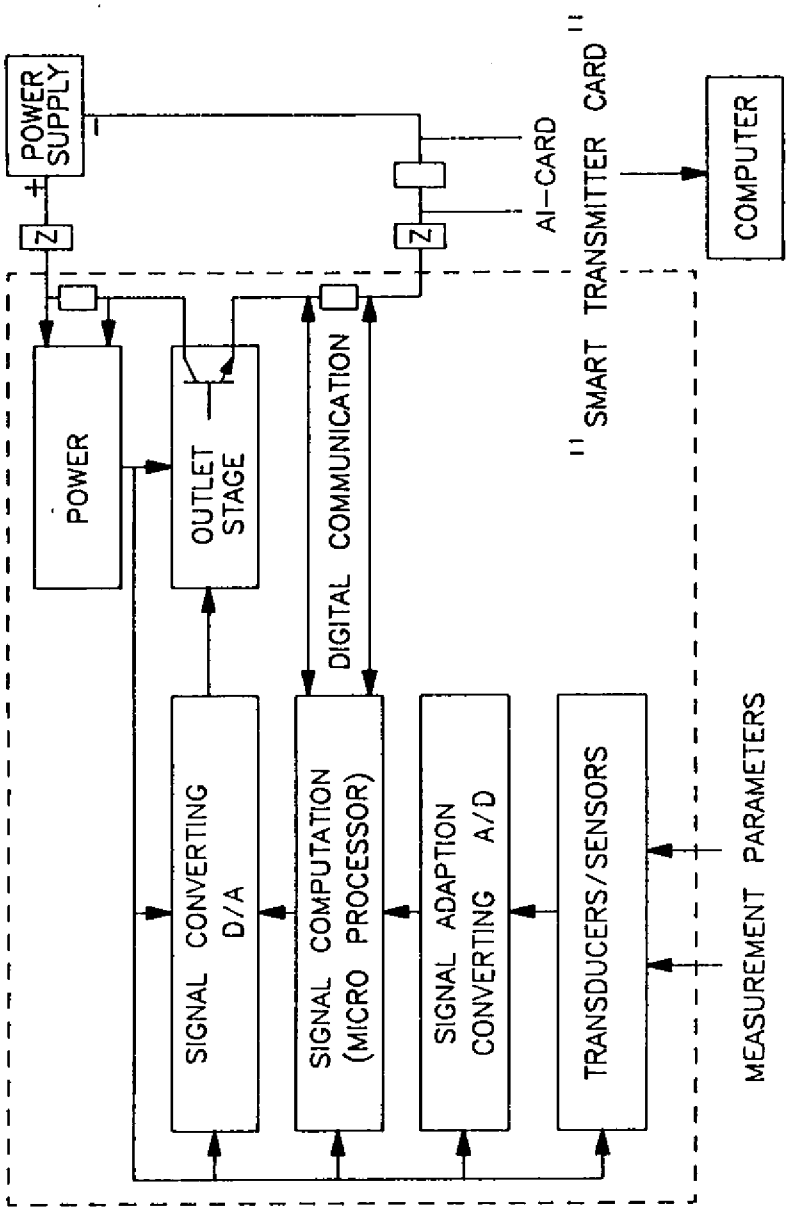
UNCERTAINTIES IN OIL FLOW MEASUREMENT
ACCORDING TO API 2534 FORMULA

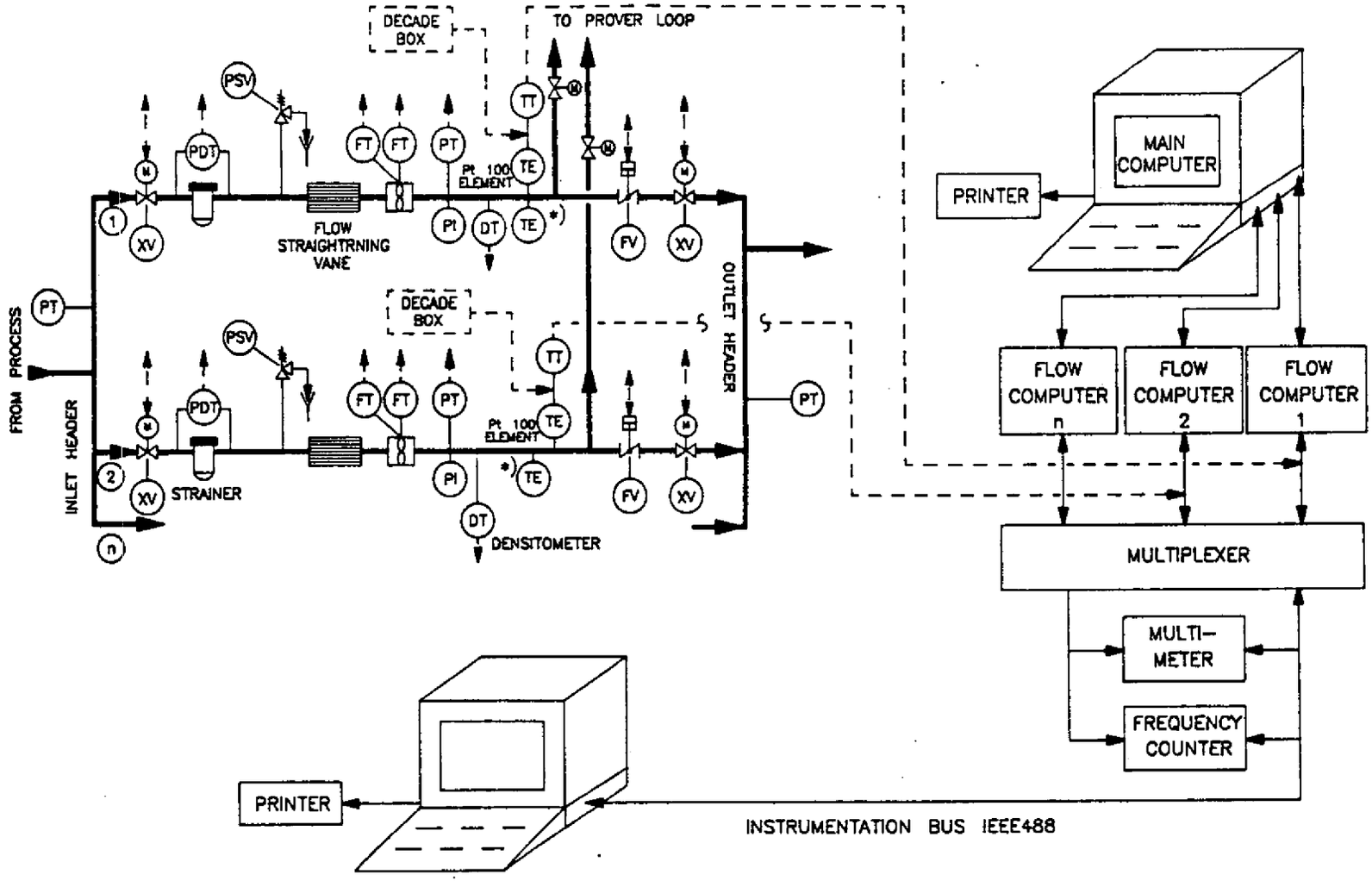
Temperature & Pressure in prover loop.
Density



VARIATION OF METER K-FACTOR IN OIL FLOW MEASUREMENT
ACCORDING TO API 2534 FORMULA

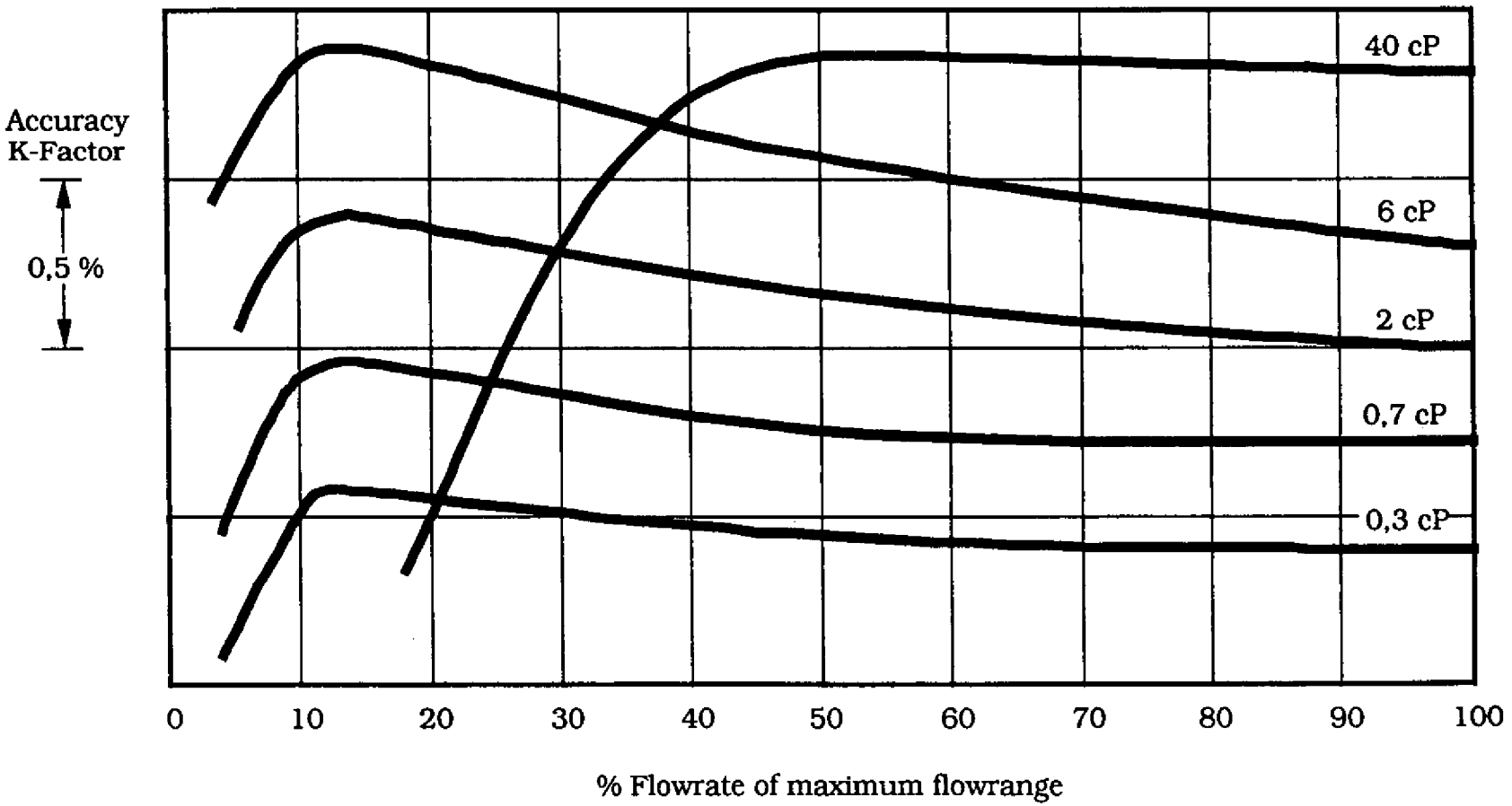



POWER SUPPLY
+
−
Z
Z
AI–CARD
COMPUTER
SMART TRANSMITTER CARD
POWER
OUTLET STAGE
DIGITAL COMMUNICATION
SIGNAL CONVERTING D/A
SIGNAL COMPUTATION (MICRO PROCESSOR)
SIGNAL ADAPTION CONVERTING A/D
TRANSDUCERS/SENSORS
MEASUREMENT PARAMETERS



*) REFERENCE ELEMENT MOUNTED IN TERMOWELL, DISPLAY CAN BE CONNECTED FOR LOCAL READOUT.

ACCURACY OF METER K-FACTOR DUE TO VARIATION OF VISCOSITY AND FLOWRATE



Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Automatic Transmitter Calibration Ideas and Practical Implementation"

Lecturer:
Bjørn Ullebust
Statoil

STATOIL

AUTOMATIC TRANSMITTER CALIBRATION IDEAS AND PRACTICAL IMPLEMENTATION

Introduction

The development of a new generation of instruments has improved the accuracy and stability, this have made it possible to increase the interval between calibration intervals without reducing the quality standard.

Calibration of the new instruments, requires reference instruments with better accuracy and calibration procedures.

Process transmitters with accuracies of +/- 0.15 % or better , require references which are five to ten times better. This means that a reference should have an accuracy of +/- 0.02 %.

Maintenance of metering systems are time consuming and depend havily on high quality calibration equipment and personell. A common problem is that the reference standards either are not accurate enough, or the instruments are used for applications they are not designed for.

New calibration and test methods are intended to reduce the maintenance expences and ensure good quality measurements.

New methods and technical implementation must not conflict with national codes and standards.

Statoil and other companies have been given dispensation for longer calibration intervals in cases where experience shows that the new equipment and methods are maintaining good quality.

Experience has proved that the calibration intervals can be reduced if high quality instruments are installed. Accurate

measurements depends on the whole instrument loop, it is therefore important to test all part of the instrument loop, together with the transmitter. The best solution is to calibrate the instrument with a reference instrument while they both are connected to a common process.

Statoil has installed Quartz reference tranducers. They are in use on the platforms both as field instruments and as laboratory standards.

Calibration with the transmitters on line with a stable process condition give the instruments the same condition from one interval to the next.

Experience with field calibration has shown that pressure transmitters have been stabil for a full year without drifting outside the specification. This would not have been possible without the new technique.

Technical implementation

Instruments must have long stability and high accuracy.

Tubings and fittings shall not create any leaks. It is therefore necessary to use instruments fittings that can be maintained with no danger of leaks if reinstallation should be necessary. Instruments that require dismantling more often than every 6 months, ougth to be installed with flexible hoses and quick connectors.

Manifolds must be installed to supply all transmitters with the same pressure in order to allow calibration of all pressure transmitters at the same time. The reference transmitter shall be connected to the same manifold such that pressure can ble applied to one or all transmitters simultaneously.

Signals from transmitters and the reference transmitter shall be connected to a test panel located close the metering computers. Signals from the reference must be transferred as a digital or frequency signal to minimize accuracy loss in signal transmission.

Automatic calibration requires a high precision voltmeter with a accuracy of 0.001 % (1-5 volt). The voltmeter must be able to measure the transmitters through a multiplexer (scanner).

Figur 1. Installation Hook Up

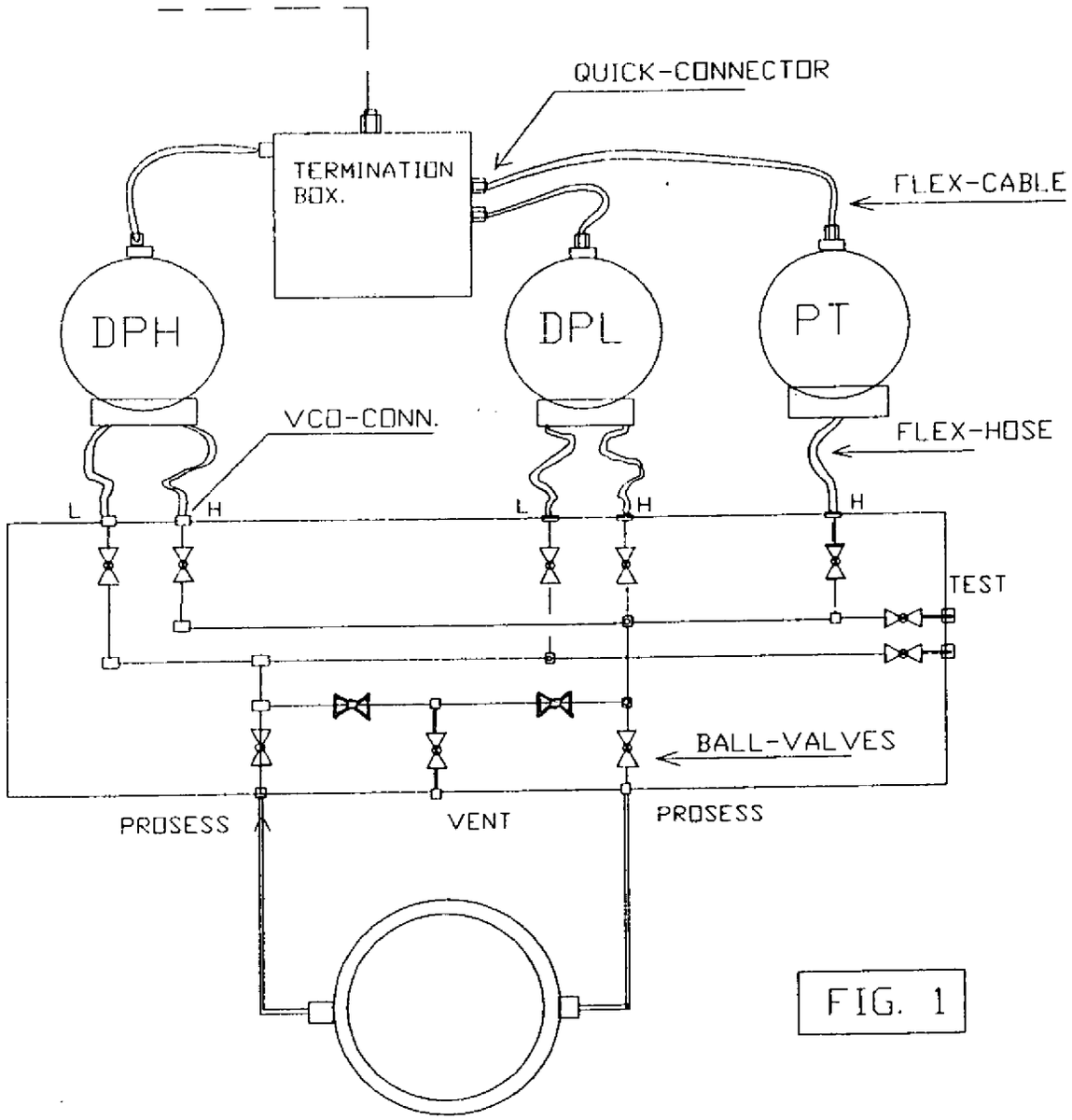

QUICK-CONNECTOR
TERMINATION BOX.
FLEX-CABLE
DPH
DPL
PT
VCO-CONN.
FLEX-HOSE
L
H
L
H
H
TEST
BALL-VALVES
PROSESS
VENT
PROSESS

FIG. 1

Pressure Calibration

By use of a smart calibration technique it is possbile to improve the accuracy of the tranducer. Calibration is performed at a standard laboratory with nine different temperatures intervals (-3 to 39) grad C and 5 different pressures.

During the measurement process the computer calculated the measured values according with the input factors from the reference laboratory.

The absolute accuracy is +/- 0.015 % scale, including hysterese, drift in temperature.

The resolution is (0.05 mbar) 210 bar. The signals are converted from a frequency pulsemodulated signal and are propotional to the pressure.

Calibration of pressure transmitters are done on line with a quart reference tranducer. The pressure is supplied directly from the process or from a nitrogen reservoir.

A personal computer is used to collect all data from the reference and process transmitters. The automatic logging program in the computer does not allow any approved logging before the process is stabil (within the defined limits). When the process is stable the deviation in tolerance is measured and either approved or disapproved.

Figure 2. Shows process hook-up of a reference tranducer in an actual installation.

Figure 3. Shows a graph of logging pressure online with one Quartz and two process transmitters over a period of 20 minutes.

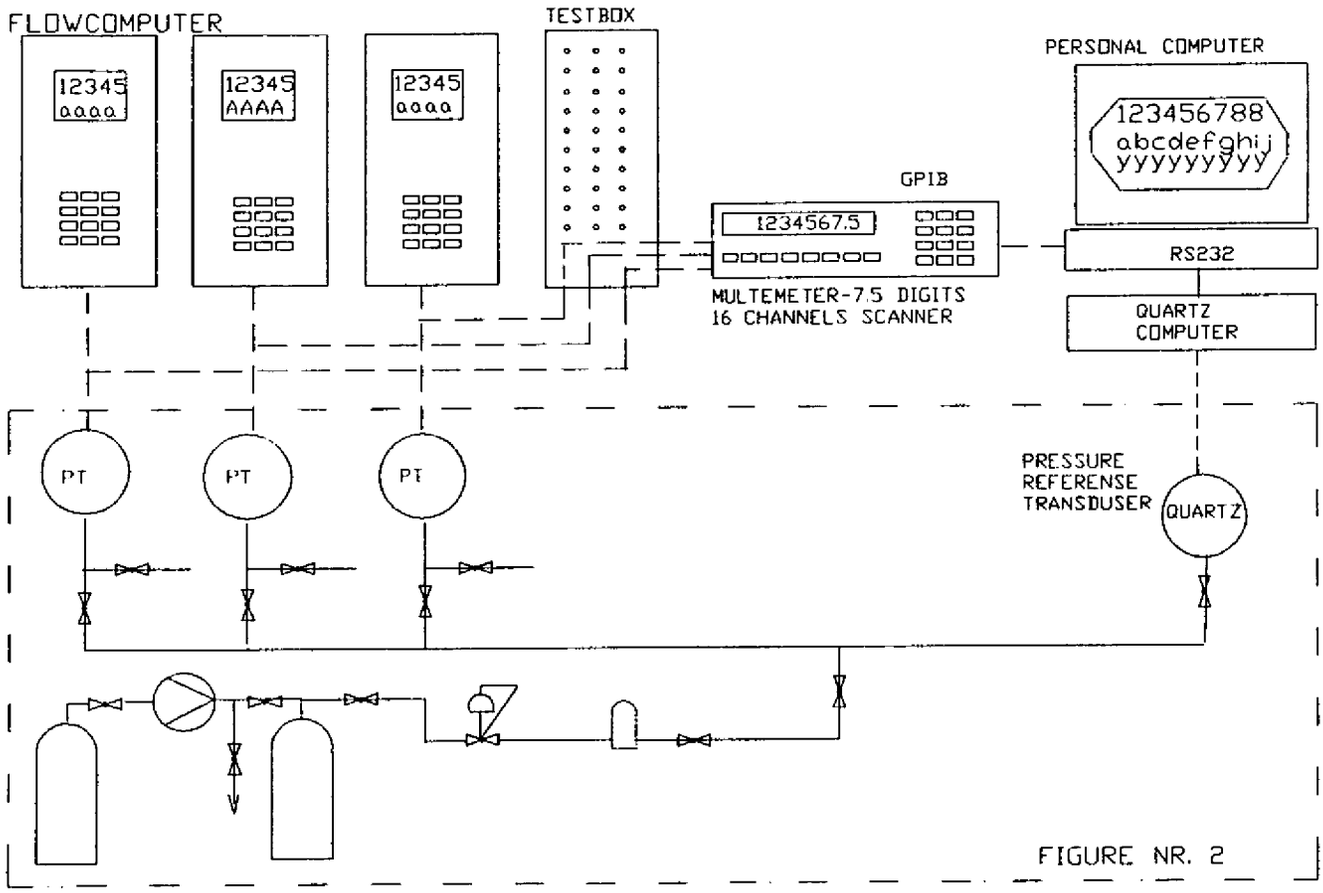

FLOWCOMPUTER
12345
aaaa
12345
AAAA
12345
aaaa
TESTBOX
GPIB
1234567.5
MULTEMETER-7.5 DIGITS
16 CHANNELS SCANNER
PERSONAL COMPUTER
123456788
abcdefghij
yyyyyyyyy
RS232
QUARTZ
COMPUTER
PT
PT
PT
PRESSURE
REFERENSE
TRANSDUSER
QUARTZ

FIGURE NR. 2

AUTOMATIC LOGGING OF PRESS. TRANSMITTER

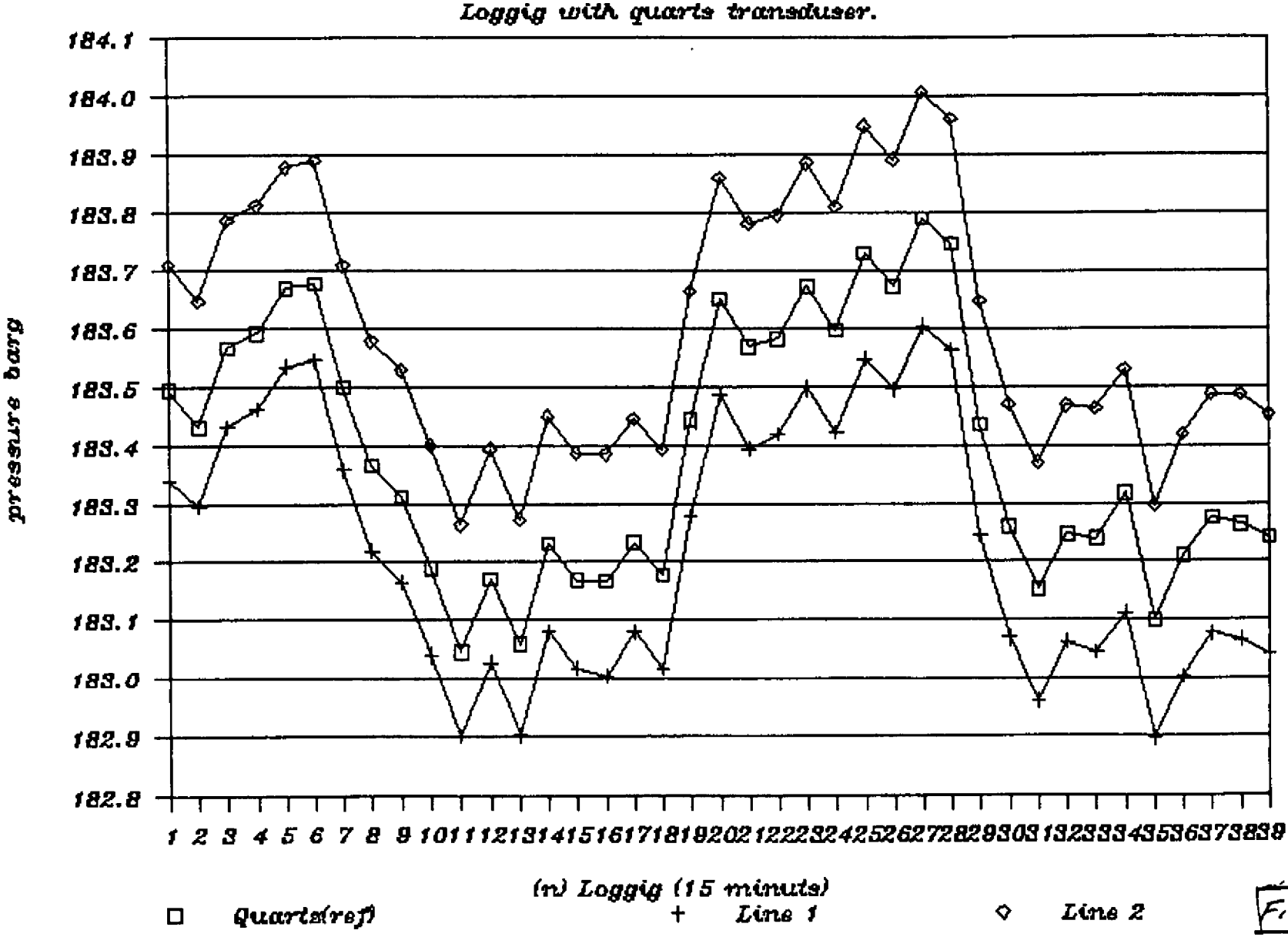
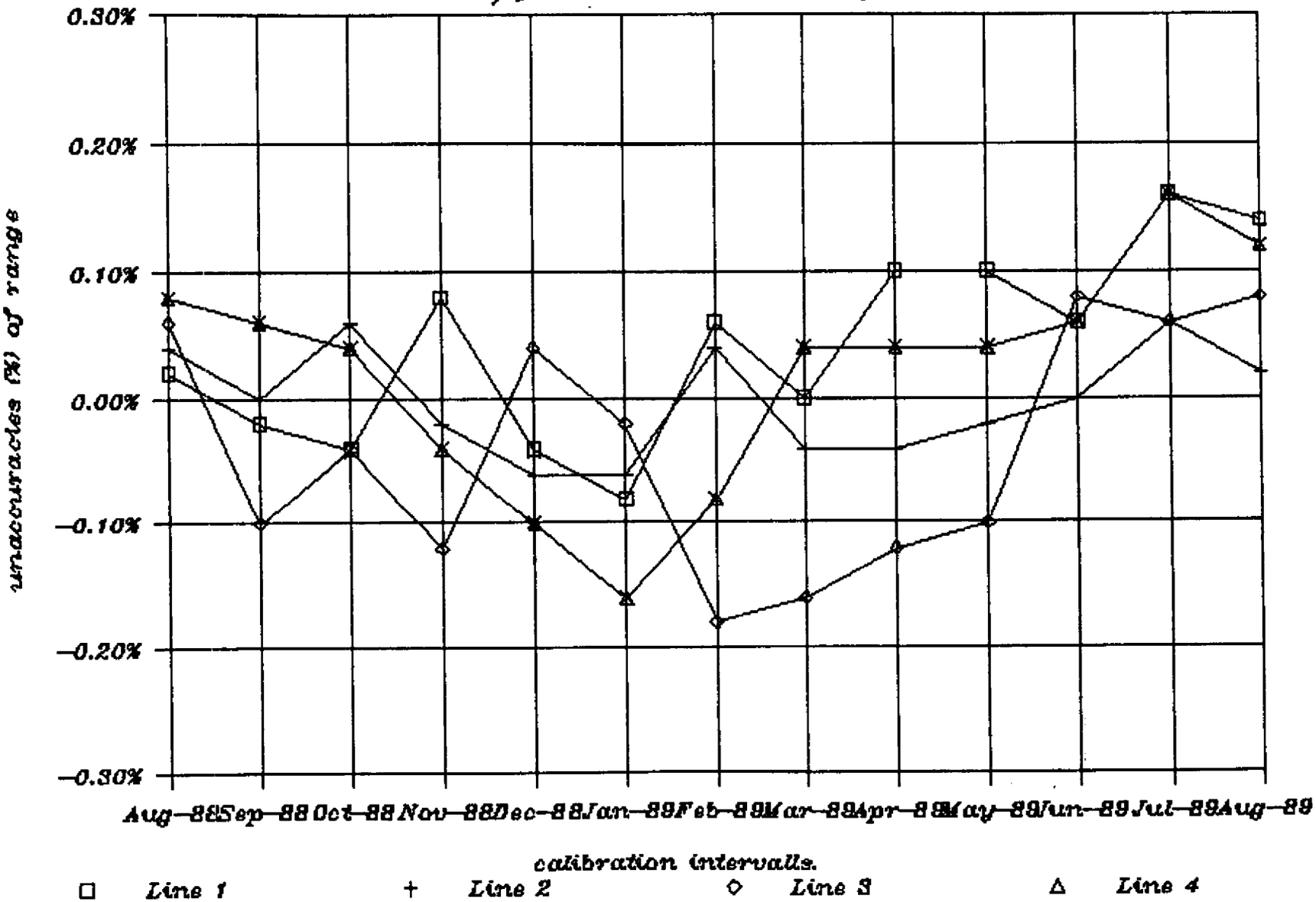


Fig. 3.

Testing of gass over one year.

Calibration of static pressure 210 barg

Testingof 4 lin transmitters in a year.



Calibration of differential transmitters

Calibration of differential transmitters with full pressure is normally done with a complicated deadwigth tester. These expensive instruments are constructed for standars laboratories and not suitable for platforms.

Calibration is done at the standards laboratories every three months. Foot print calibration at atmospheric pressure is done every month.

By use of two quart pressure transducers the differential pressure is tested with full static pressure.

Both transducers are zeroed at the same pressure before the differential pressure is measured. By comparing the readings form the two transducers, change or drift of the transducers will be discovered.

The measurement are done online and the signals are collected in the control room from the reference and process transmitters. A computer loggs the data continuously where stability and toleranse are measured. The computer logs the data via a precision multimeter (1-5) volt. Both transmitters are measured at the same time.

This method only checks the working point of the transmitters. Longer logging periods over several hours can be done to cover a bigger range.

Adjustment in the field over the whole instrument range has not been tested, some testing have been done by isolating the system while the differential pressure are kept in the system, and result shows that it can be very difficult to avoid small leaks. Adjustment of transmitters must be done at a stable condition, off line in a work shop where the instrument can be stabilized under static pressure before adjustment take place.

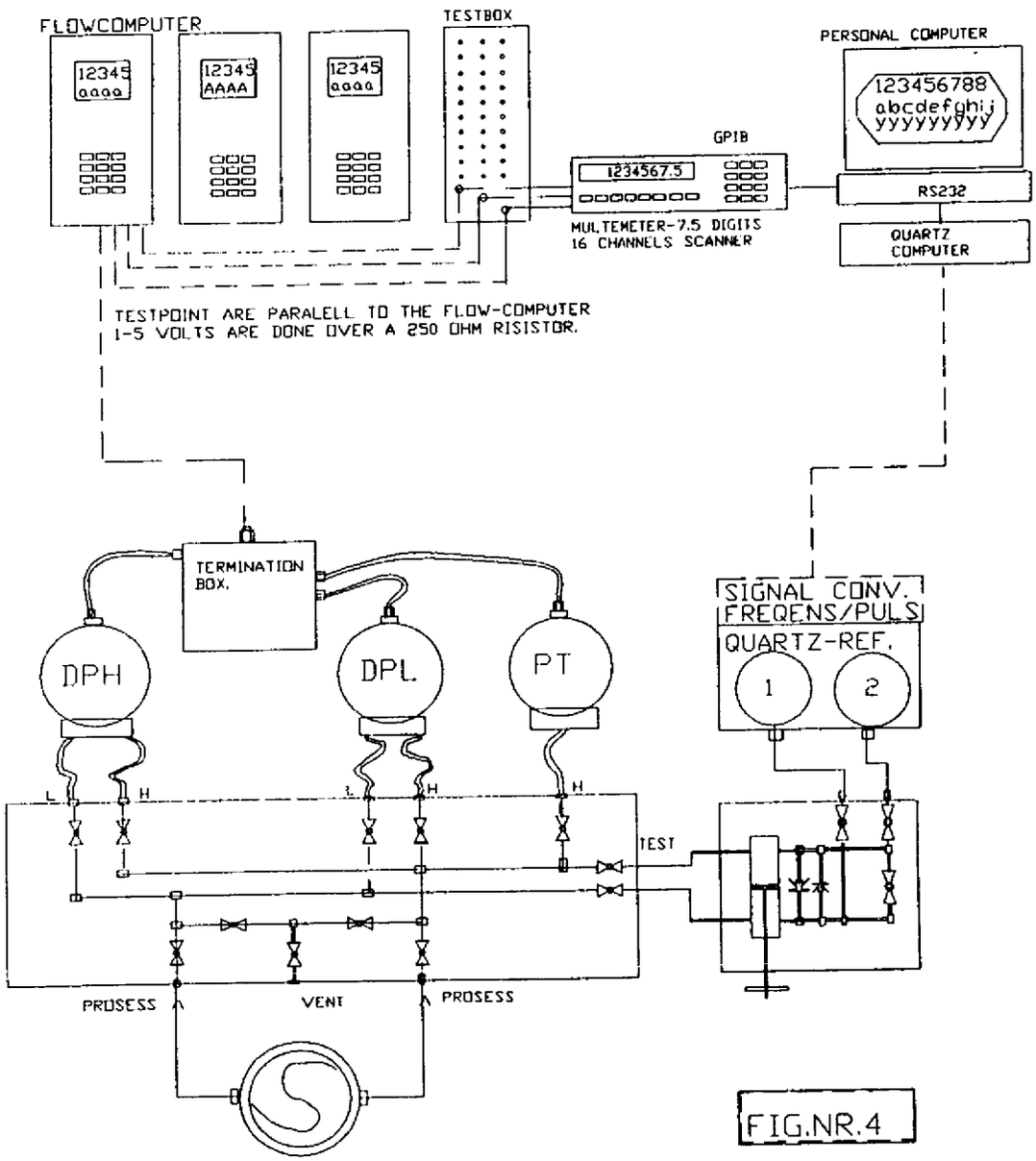

FLOWCOMPUTER
12345
aaaa
12345
AAAA
12345
aaaa
TESTBOX
GPIB
1234567.5
MULTIMETER-7.5 DIGITS
16 CHANNELS SCANNER
PERSONAL COMPUTER
123456788
abcdefghij
yyyyyyyyy
RS232
QUARTZ
COMPUTER
TESTPOINT ARE PARALELL TO THE FLOW-COMPUTER
1-5 VOLTS ARE DONE OVER A 250 OHM RISISTOR.
TERMINATION
BOX.
DPH
DPL
PT
SIGNAL CONV.
FREQENS/PULS
QUARTZ-REF.
1
2
L
H
L
H
H
TEST
PROSESS
VENT
PROSESS

FIG.NR.4

Temperature calibration

Testing of instrument loops have been carried out in a 2 year period, and results have shown that the process temperatures at a crude metering station have a very stabil tamperature. The differences are less than +/- 0.15 grad C. The method compares all readings on the metering station during a tanker loading. Before the test can start, the prosess on metering station must be stabil. After the proving starts, the inlet temperature on the prover is used as the reference. All other transmitters in the system are than compared with the reference, an shall not have bigger deviation than 0.15 grad C.

The logging is performed with a multichannel multimeter which measures 1-5 volt over a 250 ohms resistor with an accuracy of +/- 0.01 %.

Experience has shown that the transmitters are very stabil, and normally no additional calibration is necessary.

The problewm is rather that the PT-100 elements become damaged or their resistance changes due vibration or other environmental factor.

Figure 5. Shows a process hook-up of metering system with logging equipment.

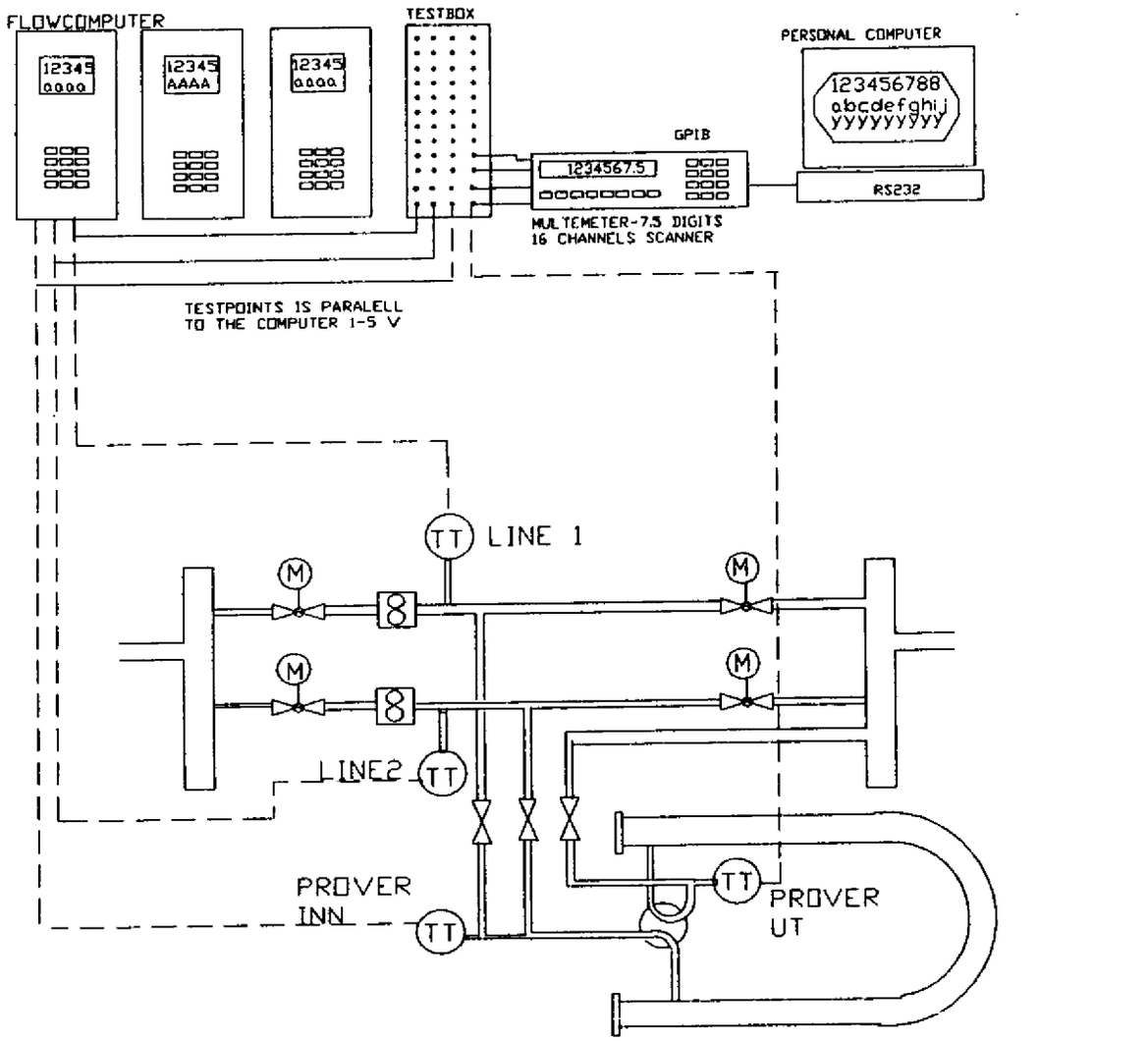

FLOWCOMPUTER
12345
0000
12345
AAAA
12345
0000
TESTBOX
PERSONAL COMPUTER
123456788
abcdefghij
yyyyyyyyy
GPIB
1234567.5
RS232
MULTEMETER-7.5 DIGITS
16 CHANNELS SCANNER
TESTPOINTS IS PARALELL
TO THE COMPUTER 1-5 V
TT
LINE 1
M
LINE2
PROVER
INN
PROVER
UT

FIGURE NR.5

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Quartz Pressure Standards for high-performance measurements and automatic transmitter calibration"

Lecturer:
Øivind Godager
PTL A/S

NEW APPLICATIONS FOR

DIGIQUARTZ®

PRESSURE SENSORS.

THE QUARTZ PRESSURE SET

A COMPLETE SYSTEM FOR HIGH-PERFORMANCE PRESSURE MEASUREMENTS

You may already know that DIGIQUARTZ® are pressure sensors with superior accuracy, proven stability and ruggedness. Now there is a new version for applications in hazardous areas and with direct computer interfacing.

The intrinsic safe DIGIQUARTZ® transducers and PTL signal telemetry package transmits real-time quartz pressure and temperature data through a centre conductor or a two-wire, shielded-electric line.

The Quartz Pressure Set give you the possibility to replace existing low or medium accuracy transducers or transmitters with high accuracy DIGIQUARTZ® sensors and communication on RS232 data format. All this with minimal modification to existing analog sensor installations.

* **TWO-WIRE FIELD MOUNTED QUARTZ PRESSURE SET**
  Ideal for installations where central data processing and control are required. Minimal installation costs.

* **HAZARDOUS AREA INSTALLATION**
  Intrinsically safe when used with approved safety barrier.

* **HIGH-PERFORMANCE PRESSURE MEASUREMENTS**
  0.01 % accuracy, 5*E-08 resolution, calibrated over wide temperature range.

* **INTERFACE TO PAROSCIENTIFIC INC. PRESSURE PRODUCTS**
  The Quartz Pressure Set interface directly to model 700 Pressure Computer and series 1000 Intelligent Transmitters.

* **CONDITIONED QUARTZ CRYSTAL FREQUENCY OUTPUTS**
  Conditioned signal to drive a frequency counter.

FEATURES AND APPLICATIONS

The two-wire field mounted Quartz Pressure Set, with DIGIQUARTZ® or Well Test Instruments, Inc. sensor, are designed to continuously measure pressure in industrial processes.

The set includes all the circuitry necessary for the measurement and transmission of a modulated current signal representing the sensor crystal pressure and temperature output frequency. The conditioned signal can be processed by a data acquisition system by including a Universal Counter or directly by a Paroscientific, Inc. model 700 Pressure Computer or series 1000 Intelligent Transmitter. The series 1000 Intelligent Transmitters have remote control option and makes all information and communication available on a RS232 interface port.

Pressure sensors are available in full scale absolute pressure ranges from 15 psi through 10,000 psi and may be calibrated over wide temperature range.

The field mounted electronic printed circuits are protected from the environment by weather-proof, corrosion resistant enclosures. No field calibration is required. The system is certified intrinsically safe when installed with an approved barrier

SOME PETROLEUM INDUSTRY APPLICATIONS:

* Onshore and offshore precise pressure measurements.
* Pressure calibration systems
* Pressure standards for oil and gas metering stations.
* Energy exploration and well testing applications.

OTHER APPLICATIONS:

* Deep-sea oceanographic experiments.
* Draught measurements.
* Sub-sea wellhead pressure measurements
* Center conductor, armoured-electric line applications.

HOW IT WORKS

The vital components in the Quartz Pressure Set are; DIGIQUARTZ Quartz pressure sensor with built in quartz temperature sensor, STX Signal Converter and SDX Signal Decoder. The STX and SDX represents the telemetry package.

The quartz crystal resonator in the pressure sensor changes its resonance frequency as a function of applied pressure. However, temperature changes also The built in quartz temperature sensor, which is protected from the applied pressure, detects thermal gradients within the pressure sensing element and its output signal is used for thermal compensation of the measured pressure signal.

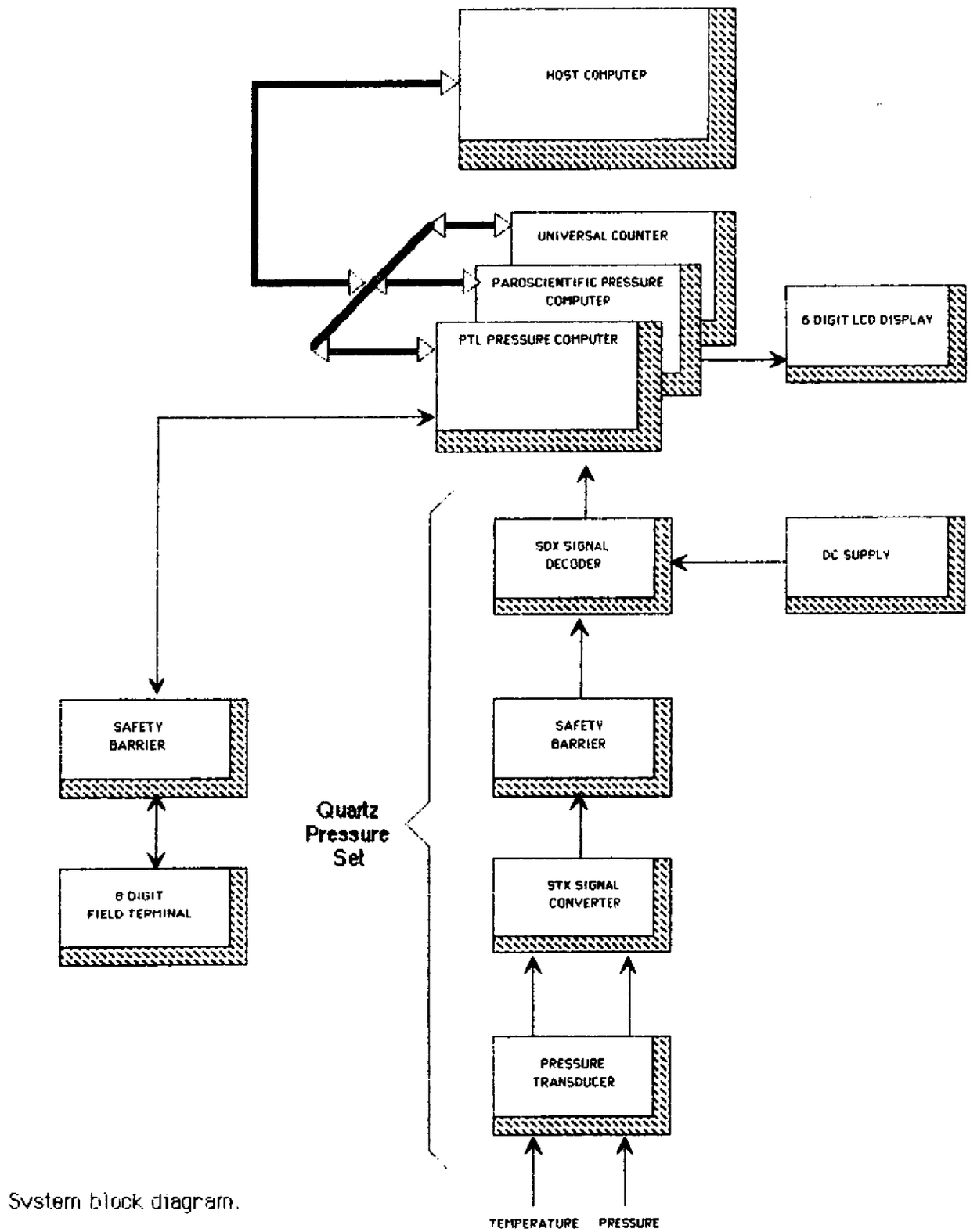
Specifically designed to process the pressure and temperature -related signals from DIGIQUARTZ® or Well Test Instruments, Inc. sensors, and part of the PTL Signal Telemetry Package, the STX Signal Converter condition and transmit the frequency signals through a center conductor or a two-wire electric line to a signal decoder. The Signal Converter also supplies dc operating power to the sensor.
The SDX Signal Decoder operates as the Telemetry Package Receiver. The SDX decode and conditions the signal to drive a frequency counter or a Paroscientific Inc. pressure computer board. Abnormal operating condition is indicated by two LED's; one indicates loss of pressure signal and the other indicates loss of temperature frequency.
The SDX Signal Decoder supplies dc operating power to the STX Signal Converter and require no adjustments or tuning during operation

The pressure and temperature related outputs from the SDX Signal Decoder can drive a frequency counter, or if directly connected to a Series 1000 Intelligent Transmitter card present RS232 pressure data for direct communication to any computer using this data format.
The counters signal can be converted to pressure and temperature readings when processed with the calibration data in a desktop computer

PTL

Pressure Test Laboratory a.s.

Quartz Pressure Standards Configuration.

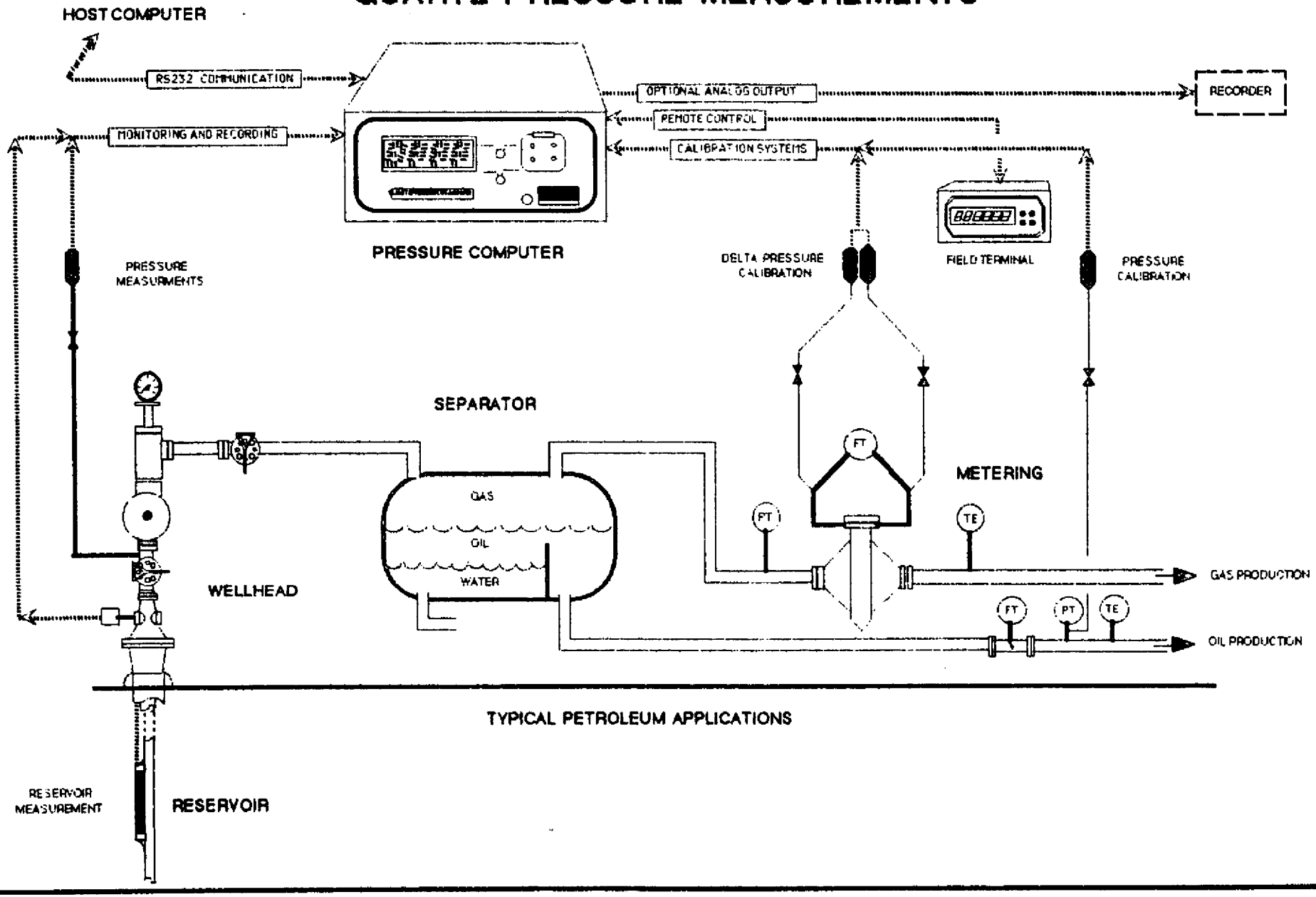


System block diagram.

PTL

Pressure Test Laboratory a.s.

QUARTZ PRESSURE MEASUREMENTS



Pressure Test Laboratory a.s

P.O.Box 37, N-3173 VEAR , NORWAY. Phone 47 33 65211, Fax 47 33 65443

THE Series 1004 DIGITAL PRESSURE COMPUTER CONCEPT

Released Oct. 1989

The first transfer standard that can read absolute, gage and differential pressures up to 10000 psi line pressure.

This test set is specifically designed to meet the pressure calibration requirements of the offsore metering workshop. Designed for shop and field applications, it uses rugged quartz pressure transducers (Digiquartz®) combined with monoconductor telemetering to provide excellent accuracy, resolution and long-term stability.

The PTL Series 1004 Pressure Computer allows *in situ* calibration of transducers and transmitters in absolute, gage or differential pressure mode over a wide pressure range when using the Quartz Pressure Set technology. A remote Field Terminal assists the *in situ* operation.

Each unit is uniquely designed for the customer's pressure application and you need no longer have to sacrifice accuracy to get portability or precise measurements from harsh environments.

The 1004 Pressure Computer is self contained with dc supplies to the sensors, the telemetry package and the Field Terminal. Each of the field mounted units operates on a traditional two-wire transmitter electric line.

The local 1004 front panel and the remote terminal prompts the operator(s) through the calibration and system operation.

Complete automation of calibrations are possible when connected to a host computer.

The unit is supplied with built-in House-Keeping functions such as; signal error detection, audible pressure alarm, a *Rezeroing* process that improves long-term stability, Key-Lock functions, one protecting the transducer calibration coefficients and one disabling manual system operation, and finally a software *Overpressure Event Recorder* to avoid system use if sensors have been bursted and to improve system reliability.

The unit may be delivered as portable.

Accuracy to 0.01 % FS - and intrinsic safe.

The maximum uncertainty for the linearity, repetability, hysteresis and temperature compensation is the three sigma value of 0.01 % FS. This includes temperature compensation over the entire operating range without further correction.

In addition to the accuracy specification, the stability and sensitivity slope is better than 0.01 % FS per year. By using the Series 1004 Pressure Computer and the

built-in Rezeroing function stability and sensitivity effects are nearly eliminated. These uncertainty specifications are valid for all pressure ranges from 15 psi through 10000 psi.

The uncertainty for the differential pressure mode is based on simple error analyses of the quartz pressure sensors. Each sensor are digitally calibrated. The digital calibration is performed without potentiometers or analog adjustments; constants are stored and secured in the 1004 EEPROM.

The rate of conformity or nonconformance is small and indicating a boundary of 0.05 mBar differential pressure uncertainty. Differential pressure uncertainty is not affected by the line pressure and is valid for line pressures above 0.1 percent of transducer full scale pressure (FS).

Automatic functions make it easy to use.

This instrument provides transfer-standard accuracy yet it is easy for unskilled personnel to operate. The transducer(s) is not effected by temperature, local gravity, attitude or vibration. All operations are performed from the front panel, host computer or the remote Field Terminal.

Software displays pressure and temperature in selected units (by computer) and prompts the operator through the rezeroing process. Both front panel mounted and the field mounted displays are large and easy to read.

Applications

- Accurate transfer standard for field and calibration labs.
- Convenient *in situ* calibration - almost anywhere.
- Absolute, Gage and Differential pressure measurement systems.
- Precision pressure standard for oil and gas metering stations.
- Fluid-density measurements.
- Energy exploration and oil / gas well testing applications.
- Centre conductor, armoured-electric line applications.

SYSTEM OPERATION

Power can be either 115 or 230 V , from 50 to 60 Hz, covering a wide range of electrical sources. Battery power and capacity is maintained at maximum by the internal automatic battery charger. Front panel mounted LED indicates battery and charge status.

Media can be either dry or wet gas, or oil.

System communication port is standard RS232 serial data port . Available baud rates are; 1200, 2400, 9600, and 19.2 k baud. Handshaking is not required, the 1004 Pressure Computer is always ready to receive commands.

Computer control mode is selected at the front panel. The CONTROL mode switch can be set to; REMOTE , LOCAL, or HOST . REMOTE enable calibration from field at

the Field Terminal, LOCAL selects local 1004 front panel control and finally HOST that enables the entire pressure calibration system to be automatically controlled by a host computer. The default CONTRTOL mode is HOST when the Operational Key-Lock (EFPK) is activated.

Ranges available in intrinsic safe and standard versions are; 15, 30, 100, 200, 300, 400, 900, 2000, 3000, 6000, and 10000 psi. The accuracy for all ranges degrades slightly when measuring below 0.1 percent of full scale pressure value. In the Tare mode the maximum gage pressure is the net difference between the full scale and the value removed as the tare, i.e., barometric in gage pressure mode and the static line pressure in the Delta (differential) mode.

Key switch functions (locks) protects the transducer calibration constants from overwriting (accidental from host computer) the other key function enable local and remote calibration / operation (*in situ* at the field terminal) and it disables these features when the key-lock is activated. The key-lock functions are named; CAL= Calibration Enable , and EFPK = Enable Front Panel Keys:

Pressure, temperature and period output display have normally a conversion period of 100 ms, updating every 250 ms Each display show an average of the n previous conversions. The n factor is selected by the digital filter mode (WWDF).

The remote terminal display is parallely connected to the front panel display and display the same output.

Walking window filter mode is activated when front panel push button "WWDF" is activated (WWDF= Walking Window Digital Filter). The walking window size n is determined by host computer command and can be any integer from 5 to 30.

The first result presented in the display is the average of n. Thereafter new measurements are added, while the earliest ones are discarded. Thus each output is the most recent measurements.

Walking window filter mode deactivates when repushing the front panel switch WWDF.

Pressure measurement mode is activated by host computer command or manually on the Series 1004 front panel. Pressure measurement mode is activated by pressing the " TARE", or, the "DELTA", or both . Default (no key is activated) the system operates in absolute pressure mode.

The TARE feature subtracts the value of the ambient reading before the instrument is connected to the device under test, allowing gage pressure measurements.

When DELTA mode is selected TARE is used as a equalizer . When TARE is activated the ambient reading from each sensor derives a differential pressure reference point (equalizing point) and allows any change in pressure, high or low, to be displayed as a differential pressure.

TARE and DELTA also deactivates their modes by n by repushing the function key.

Sensor select position defines the sensor to be displayed in gage or absolute pressure mode. In DELTA mode it defines the system high-pressure sensor select.

REZEROing once a month improves the stability value and helps the internal oil filled system to be evacuated and refilled with pressure fluid, further reducing overall uncertainty. With a quality vacuum pump, the instrument can be rezeroed simply at a

push of a button when 100 microns of vacuum is achieved. CAL key must be activated to get any Rezeroing response.

Linear engineering units enable the operator to perform calibration quickly, without conversion tables. The differential pressure is displayed as an absolute value when positive an as a negative value when negative. There are no rounding errors from look-up table interpolations. Engineering units are selected by special function host computer commands only.

Calibration is protected and the unit is suited with externally mounted calibration key-lock CAL to enable calibration constants write cycle. All calibration constants are stored in EEPROM.

PASS READING command enables the operator to signal the host computer when calibration is in progress and a reading from the Series 1004 Pressure Computer is to be stored as a valid calibration point. When function is activated the 1004 sends last conversion to the host computer as a high priority message telegram. The reading is acknowledged by toggled LED at the front panel and the remote terminal as the host accepts the reading.

House-keeping functions improves system reliability and helps the operator to avoid overpressure situations. The Quartz Pressure Sets have built-in Error Detection that alerts the operator if parts of the pressure sensing system fails to operate. Error can occur due to power failure, faulty connections or damaged safety barrier etc.. The Error Detection is only viewed at the 1004 Pressure Computer front panel and abnormal conditions are illuminated with red LED's.

If pressure exceeds 100 percent FS value an audible alarm will activate and maintain until pressure is brought back within the operating pressure range. The audible alarm is located at the 1004 front panel.

Overpressure can damage sensor calibration and discard sensor performance. To provide maximum system reliability the unit is equipped with an internal "Event Recorder". If pressure exceeds 120 percent full scale value it is most likely that sensor calibration is damaged. The Overpressure-Event trigger the 1004 Pressure Computer who fetches and stores the maximum pressure reading in its EEPROM.

The operator may use this information in his operating procedures to yield best possible system reliability and avoid using the system when sensors have been bursted.

The Rezeroing process is also part of the House-keeping features.

Two-wire operated Field Terminal and Quartz Pressure Set (transducers and telemetry package). The entire system requires minimal installation costs and is intrinsically safe when installed with safety barriers. The Field Terminal and the Quartz Pressure Sets are easily connected to the 1004 Pressure Computer back panel by electrical quick connectors. Field outputs may be connected directly to the safety barriers.

INSTRUMENT HOUSINGS. The 1004 Pressure computer case is rugged and designed for 19" rack mounting. Transducers are made in stainless steel and the field terminal and signal converter in reinforced polyester with IP65 protection.

Field Terminal has an 8 digit LCD display and updates every 250 ms.. The terminal has additional two prompt LED's and push button switches for operator (field) control.

The field mounted push button functions are the "TARE" and the "PASS

READING". The LED's indicate the function activated and prompts the operator when the host computer accepts calibration data "PASSED" down the communication line.

The Field Terminal operates in a two-wire mode and is intrinsically safe when connected to a safety barrier.

OPTIONS.

The system may be ordered with the following options:

- IEEE-488 / GPIB interface bus.
- Long-distance current modem (serial).
- Portable system with built in sensors.
- Aluminium carrying case. Air-line approved.
- Analog 4 to 20 mA output. Software configurable 12 bit DA.
- High quality vacuum pump for Rezeroing.
- Quartz Pressure Set ratings to 175 deg C.
  (Well testing or in-line applications)

PTL Limited Warranty

PTL warrants the instrument against defective materials and workmanship for a period of one year from the date of shipment to the purchaser.

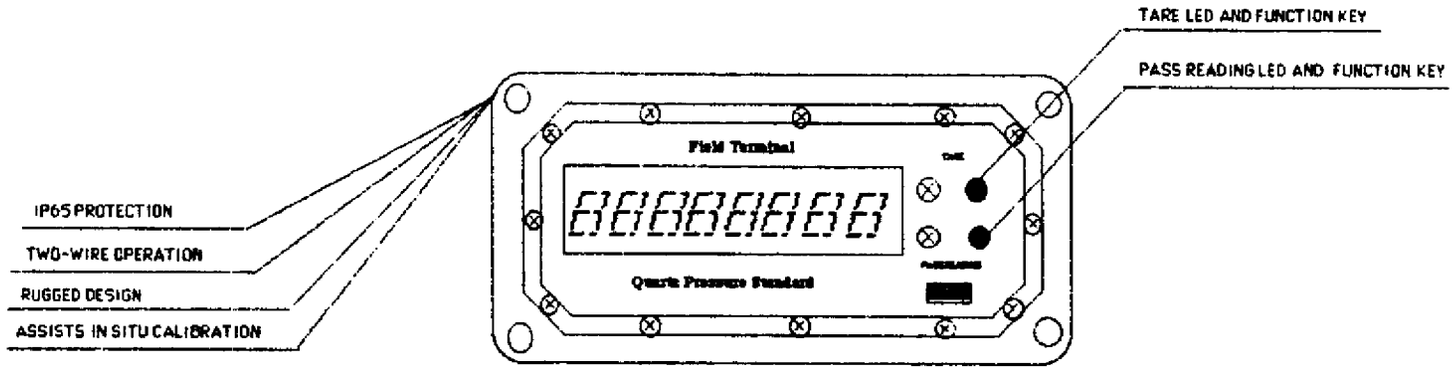
SPECIFICATIONS; 1004 PRESSURE COMPUTER and QUARTZ PRESSURE SET

Ranges:	Low pressure series;	15, 30, 100, 200, 300, 400, and 900 psi
	High pressure series;	2000, 3000, 6000, and 10000 psi
Pressure modes:	Absolute, Gage and Differential pressure mode. Line pressures to FS value.	
Linearity:	< 0.003 % FS value.	
Repetability:	< 0.001 % FS value.	
Hysteresis:	< 0.002 % FS value.	
Temperature compensation:	< 0.004 % FS value.	
Accuracy:	< 0.01 % FS value. (RSS of the above for one year) < 0.05 mBar in differential pressure mode.	
Stability / year:	< 0.01 % FS. Reduced by periodic rezeroing.	

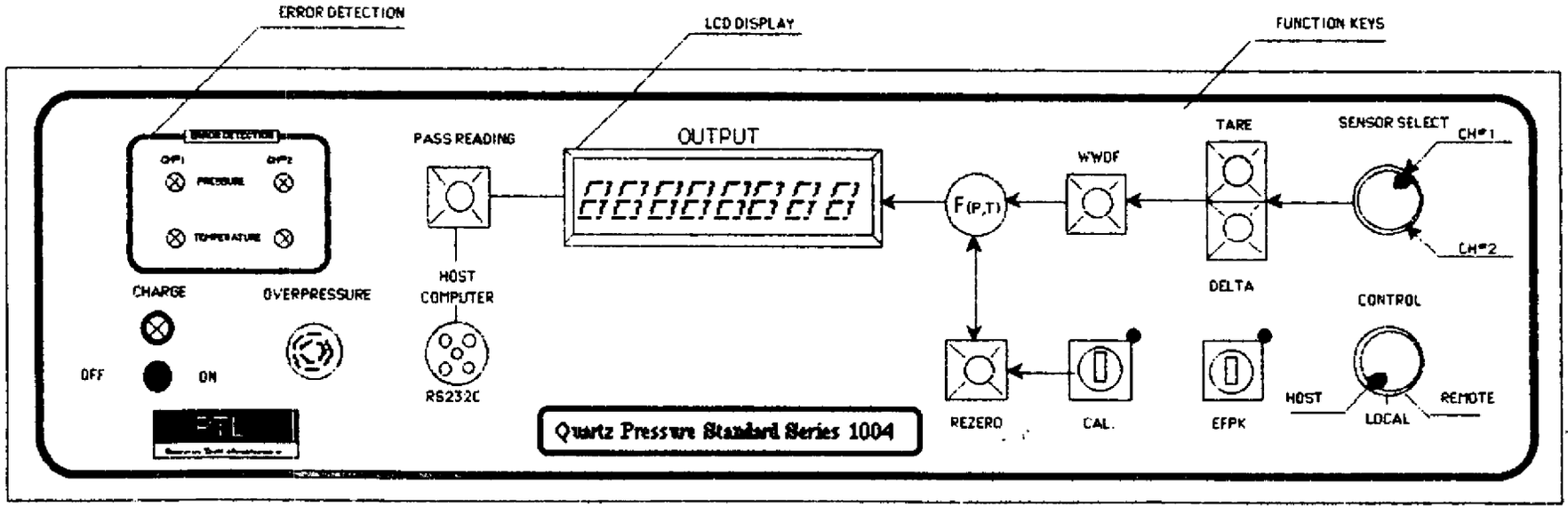
Resolution:	down to 5* E-08 (0.05 ppm) FS, (0.02 mBar).
Overpressure:	120 % FS without recalibration.
Temperature range:	0 to 50 degrees centigrade .
Warm-up time:	5 minutes
Calibration report:	Standard certificate of compliance.
Display:	8 digit LCD, conversion period 100 ms. Update time for local and remote terminal display are 250 ms.
Engineering Units:	psi, mBar, Bar, mmWC, kPa, Pa, and mmHg.
Output:	Serial RS232 communication port. 1200, 2400, 9600, and 19.2 k baud. No handshake or parity required.
Pressure media:	Dry or wet gas and all non-corrosive fluid-filled systems.
Pressure connection:	Standard Cajon VCO quick connections, 1/4 " ,Size 4.
Power:	115 or 230 Vac , 50 to 60 hertz.
Computer housing:	Standard 19 " Rack mounting, 3HU.
Field Equipment:	IP65 Protection, EEx ia IIC T6

PTL

Pressure Test Laboratory a.s.



THE SERIES 1004 PRESSURE COMPUTER FIELD TERMINAL

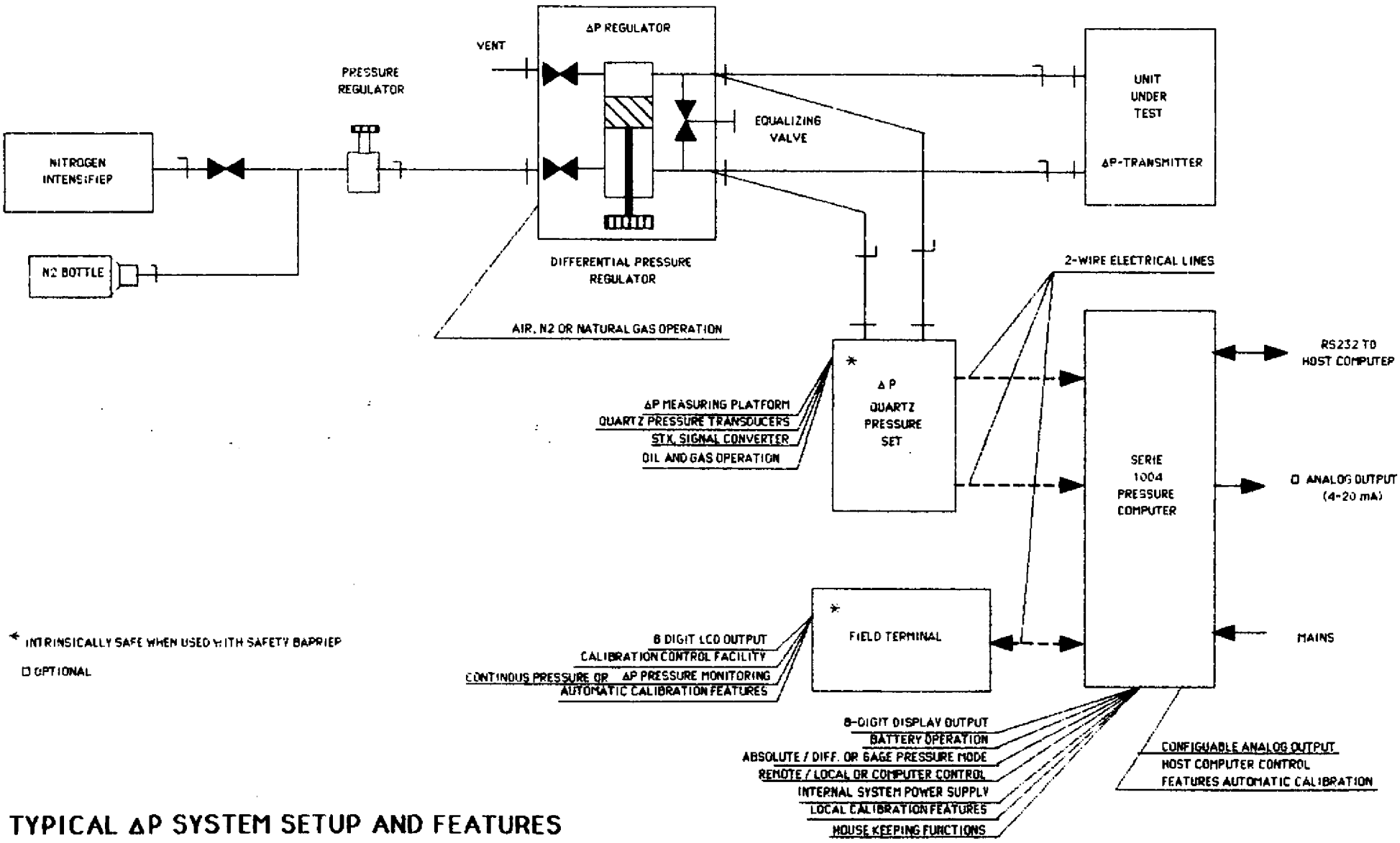


THE SERIES 1004 PRESSURE COMPUTER FRONT PANEL LAYOUT

PTL

Pressure Test Laboratory a.s.

ΔP QUARTZ CALIBRATION SYSTEM

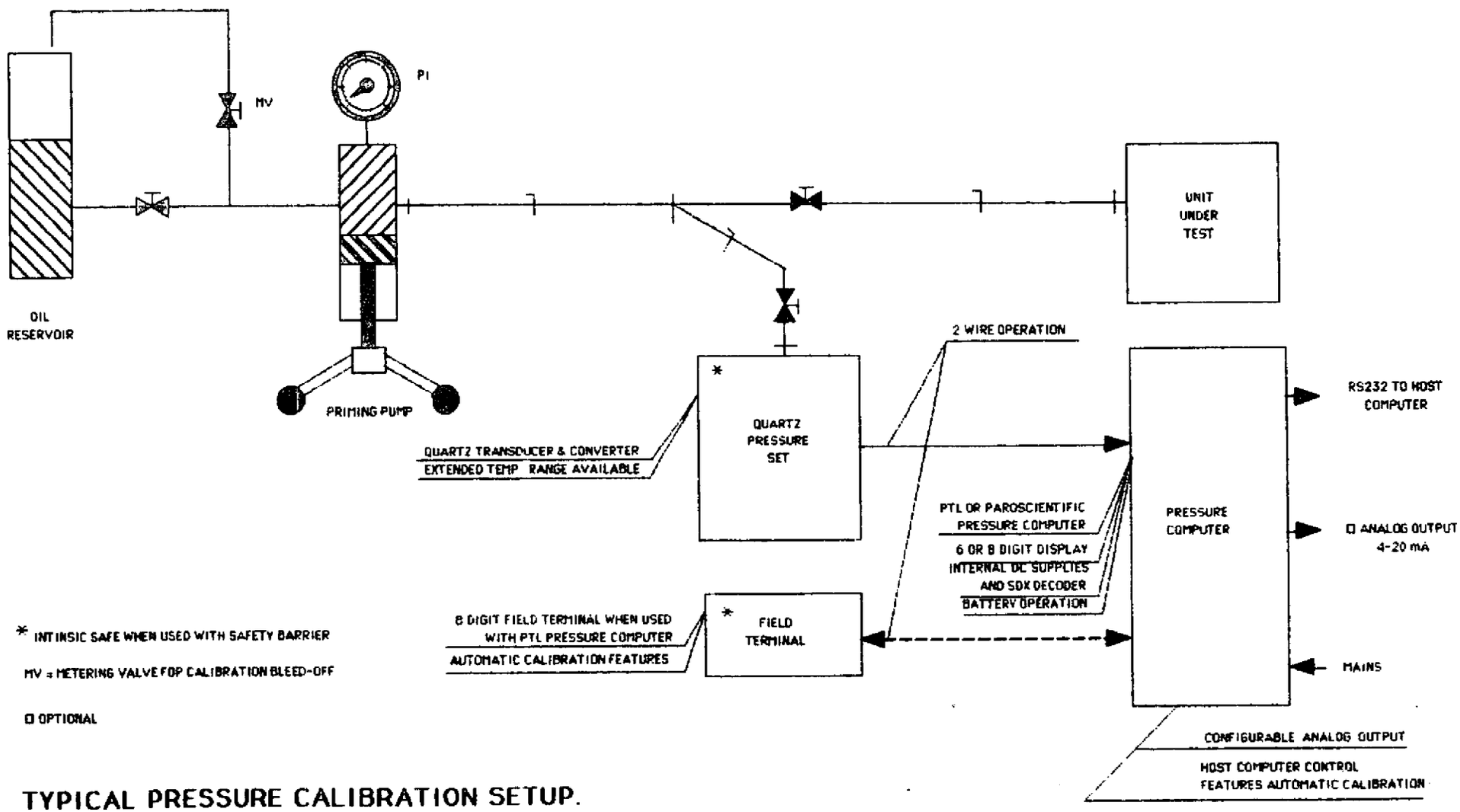


TYPICAL ΔP SYSTEM SETUP AND FEATURES

PTL

Pressure Test Laboratory a.s.

QUARTZ PRESSURE MEASUREMENT AND CALIBRATION



TYPICAL PRESSURE CALIBRATION SETUP.

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Presentation of the Norwegian Calibration Service"

Lecturer:
Hans-Petter Klemmetsen
Norwegian Calibration Service

North Sea Flow Metering Workshop
October 24-26, 1989, Haugesund

Presentation of the Norwegian Calibration Service

Hans-Petter Klemmetsen
Norwegian Calibration Service

The name, Norwegian Calibration Service, is a little misleading. We do not calibrate, but we are the official Norwegian accreditation body for calibration- and test-laboratories.

Before I go on to give you more spesified information as to how Norwegian laboratories can get the necessary accreditation, I would like to give you the status for the work on quality measures for industrial products by the EC-commission up to today.

The commission of the European Comunities has made a proposal for a council decision concerning the modules for the various phases of conformity assessment procedures which are intended to be used in the technical harmonisation directives. It is called A Global Approach to Certification and Testing. One key word in this connection, is conformity. The basic structures for the evaluation of conformity are, the bodies responsible for certification and inspection of the testing laboratories, and the manufacturers' quality systems.

At present, these guidelines (drawn from ISO-documents) have been transposed into European standards (EN 29000 and EN 45000).

The commission calls on the member states to promote the implementation of these standards both in their regulations and in private certification systems, and to introduce accreditation systems based on these standards.
This implementation has already started in Norway.

To secure the acceptance of Norwegian test results and calibration certificates in Europe, the ministry of industry has instructed the National Measurement Service to create "A national control- and accreditation system for measuring-laboratories". By "measuring laboratories" is among others meant industrial test- and calibration laboratories, which, in their work, are in the need of measuring instrument's with a known traceability and accuracy.

Together with our National Standards Laboratory, the accredited calibration laboratories will form the core in this system. This is the reason why we have started accrediting a series of calibration laboratories before we proceed with accreditation of test laboratories.

The accreditation system for calibration laboratories has been in operation from the spring 1989. Laboratories are accredited according to the international standards which are available for the accrediting of laboratories.

The accreditation system is based on standards and competence in our National Standards Laboratory department, and on our European and international cooperations (BIPM, OIML, ILAC, Euromet, WECC, etc.).

The first calibration laboratories will receive their accreditation by the end of this year, assuming that they satisfy the international standards and other requirements.

We have started the process of building up the accreditation system for testing laboratories.

The time consuming factor in the accreditation prosess is the time a laboratory need to be able to meet the requirements to technical competence we have specified. Normally it takes from 3 to 18 months to be able to fulfil the requirements. From 1.1. 93 the complete technical harmonisation in EC, and the EFTA countries who want to sell industrial products to EC must be fulfiled.

We hope that the calibration- and testing laboratories in Norway realise this, if not we will have a problem.

The normal norwegian way to do things will be to ring up the calibration service on Christmas eve 1992 and ask for accreditation from 1.1. 93. I am afraid that it would be a difficult situation. Therefore I am very happy to have the possibility to adress you and other audiences in this matter.

International cooperation

Within the field of metrology, international conformity is essential. Hence, activ and extensive international cooperation is absolutely necessary. The National Measurement Service in Norway has, ever since the Meter Convension was ratified in 1875, actively participated in international cooperation.

Bureau International des Poids et Mesures (BIPM) and the Meter Convention form the base for all measurement. Our national prototypes and national standards are compared, and traceable, to BIPM's standards. All measuring laboratories in Norway accredited by the Norwegian Calibration Service, must have their standards and instruments traceable to BIPM.

The international organisation for legal metrology (OIML) was established in the early 1950s and the treaty was ratified by Norway in 1957. OIML draws up international recommendations which the member countries are bound to adopt as national regulations. Norway has solely, and consistently, adopted these international recommendations throughout the past 20 - 25 year. The director for The National Measurement Service in Norway, Mr. Knut Birkeland, is OIML's president.

The participation in BIPM and OIML is bound by treaty.

In addition to this, Norway is involved in a number of international organisations such as International Laboratory Accreditation Conference (ILAC), in whose every conference Norway has participated, and the director of The National Measurement Service, appointed by the Ministry of Foreign Affairs, has each time been the leader of the Norwegian delegation.

The Norwegian Calibration Service is a member of the Western European Calibration Cooperation (WECC). WECC has et system of reciprocal acceptance of calibration certificates already in operation. The system consists of a network of bi- and multi-lateral agreements. This system is under further development and completion, and a Memorandum of Understanding (MoU) on reciprocal acceptance has already been signed.

WECC is recognized as the technical organisation for calibration in the EC-commissions' "A global approach to certification and testing" in all fields concerned with calibration.

The experiences from WECC are now used as a basis in the attempt of establishing a similar organisation for accrediting test laboratories in general, EUROLAB.

We participate in the work around the establishment of EUROLAB. Inspiration is drawn from WECC, which has already found its' form during many years of efficient cooperation, and which functions admirably. Norway - and we believe the rest of Europe - will gain from the WECC-model being chosen and that the two organisation, WECC and EUROLAB, cooperate.

The Norwegain Calibration Services' active work within WECC and ILAC especially, gives Norway a good starting position in the meeting of the requirements in the EC-commissions' "A global approach to certifiaction and testing" which so far only exists as a draft, but which is expected to be adopted as it is.

I have now tried to give you an overview of the European picture and how the Norwegian activities fit in.

I will now inform you how you, as a norwegian calibration or test laboratory, can get your accreditation from the Norwegain Calibration Service.

You apply for accreditation as a calibration- or testing-laboratory in writing. You can contact us and ask us to send you the guide stating the requirements for accreditation and the list of the technical fields. Maybe you also would like to have our price-list - may be better not.
Together with the application, we would like to have a list showing which field(s) you would like to have accreditation in. We also need to know how you state your uncertainties. In addition to this, we need to have a copy of your quality assurance handbook, and a summary of the qualifications, practical and theoretical, of the members of staff who actually calibrate or do the testing.

Western European Calibration Cooperation (WECC) has made a guide which sets forth the general procedures and necessary administrative conditions for a system of assessment and accreditation of calibration laboratories. All the WECC members use this guide for accreditation of calibration laboratories. The guide is translated into Norwegian, and you have both the English and the Norwegian text in this guide. You have to meet all procedures and conditions set forth in this guide. We therefore recommend you to study the guide carefully before applying for accreditation. We will, however, try to work in an un-bureaucratical way, and therefore recommend that an official from the Norwegian Calibration Service visits you and has an informal look at your laboratory and your quality assurance handbook, and discuss what has to be done before the official accreditation team visits you.

Copies of the guide are available from our office, and I have also brought some with me to this workshop.

In the beginning, we have decided to make use of assessors from the other WECC member countries. This is not because we do not ourselves have enough qualified personell in Norway, but to get the fastest and best possible acceptance of Norwegian laboratories abroad.

There is an overall similarity between the operations of calibration and testing, and the requirements of ISO/IEC-guides 25, 38 and 49 applies equally to calibration, and testing laboratories and accreditation bodies. There are, however, essential differencies which necessitates additional requirements to be applied to calibration laboratories and services. These additional requirements are presented in the WECC-guide.

The fees for accreditation of calibration laboratories, are as follows:

For the first field, the price is	NOK 30'000.-
For the next fields, the price is	NOK 20'000.- per field.

These amounts cover all the expences besides our direct cost for travel and fees for the assessors from the other WECC-countries. The fees cover the costs for one year, whereafter you pay NOK 18'000.- per field per year. This includes a limited amount of consulting as well as the costs of measurement audits you have to participate in. You will be included in our catalog over accredited calibration laboratories or test laboratories.

The competence of the calibration laboratories is controlled by, among other things, audit- (testing object-) circulation. In the audits, a testing object controlled at the National Standards laboratory, is measured by different users, whereafter the results are compared to the national and international standards.

From our accreditation work so far it is our experience that norwegian calibration and testlaboratories normally do a very good technical job, but that we now and then have a tendency to have incomplete documentation.
I will therefore stress the following points from the accreditation guide.

The laboratory shall operate an internal quality assurance programme appropriate to the type, range and volume of work performed. The quality assurance programme shall be documented in a quality manual which is available for use by the laboratory staff. The quality manual shall be maintained relevant and current by a responsible member of the laboratory staff.

Staff shall have the necessary education, training, technical knowledge and experience for their assigned functions.

There shall be a job description for each technical position category, which includes the necessary education, training, technical knowledge and experience.

The calibration laboratory shall establish and maintain an effective system for the control and calibration of measurement standards, measuring equipment and reference materials used in the fulfilment of specified requirements.

The calibration laboratory shall have adequately documented instructions on the use and operation of all relevant equipment, on the handling of equipment to be calibrated, and on standard calibration and measurement techniques, where the absence of such instructions could jeopardize the efficacity of the calibration and measurement process. All instructions, standards, manuals and reference data relevant to the work of the calibration laboratory shall be maintained up-to-date and be readily available to the staff.

All manual calculations and data transfers shall be subjected to appropriate checks. All computer programs shall be validated.

The laboratory shall maintain records of all measurement standards, measuring equipment and reference materials used to establish conformance to specified requirements. These records shall demonstrate that each measurement standard and item of measuring equipment are found to be outside these limits, the extent of the errors shall be recorded and appropriate action taken.

Results obtained during calibration or measurement shall be recorded and retained. These records shall contain the following data:

- the calibration or measuring method, together with the measuring equipment and reference materials used;
- measurements prior to adjustment when requested;
- a statement of the adjustments made;
- measurement conditions;
- the direct readings taken during the calibrations or measurements;
- the method of calculation of the results, together with any corrections which have been applied;
- measurement uncertainty together with its method of calculation;
- the date of calibration or measurement

All measurement standards, measuring equipment and reference materials shall be labelled, coded or otherwise identified to indicate their calibration status.

Reference standards of measurement shall be calibrated by a competent body that can provide traceability of measurement to a national or international standard of measurement. The intervals between re-calibration of the reference standards shall be prescribed by the national calibration service.

The best measurement capability for each measurement quantity and specified range is the smallest uncertainty of measurement assigned to the laboratory, determined by assessing a budget of contributing uncertainty components, and/or by means of a measurement audit.

The best measurement capability of the laboratory shall be determined over specified ranges for each quantity for which accreditation is granted.

The best measurement capabilities shall be published by the national calibration service as a laboratory accreditation schedule for the quantities and their specified ranges.

All measurement results stated by the laboratory shall have an associated measurement uncertainty. The determination and combination of the uncertatinty components shall be in accordance with the documented procedures agreed by the national calibration service. The details of the components of the total uncertainty shall be recorded. Corrections to the measurement results shall be applied when necessary.

Calibration and measurement work carried out by the calibration laboratory shall be recorded on a certificate which accurately, clearly, an unabiguously documents the calibration and measurement results and all other relevant information.

May I end by giving you all interested in accurate measurements my sincere best wishes and to give you my assurance that the Norwegian Calibration Service stands ready to give you all the support we can.

Thank you!

Norwegian Society of
Chartered Engineers

NORTH SEA FLOW METERING WORKSHOP

Rica Maritim Hotel, Haugesund
October 24-26, 1989

"Code of Practice for ISO 5167"

Lecturer:
Philippe Grenier
GAS DE FRANCE

NORTH SEA FLOW METERING WORKSHOP

HAUGESUND, NORWAY

CODE OF PRACTICE FOR ISO 5167

by

Philippe GRENIER

Research & Development Division (DETN)
GAZ DE FRANCE

October 24-26, 1989

0. Introduction

In 1977, an ISO working group was created (ISO/TC30/SC/WG8) in order to prepare a draft Code of Practice (COP) for the use of ISO 5167 (refer to the simplified standardization structure given in annex). Since then, it took more than 10 years to have a document ready. In what follows, the main steps of that work are recalled and some conclusions are drawn.

1. Main Time Steps of COP Preparation

1977/03/16-18	Working Group 8 created by ISO/TC30/SC2 at ESSEN meeting. WG 8 should propose a first design of the future document for next SC2 meeting. Chairmanship is vacant.
1980/04/23-24	SC2 meeting in PARIS. WG 8 has not started yet. Mr PEIGNELIN is appointed chairman of WG 8.
1981/03/04	WG 8 meets in PARIS. The objective of the COP and a first working plan are settled down.
1981/12/10-11	SC2 meeting in BRAUNSCHWEIG. Mr GRENIER is appointed chairman of WG 8.
1982/03/19	WG 8 meets in PARIS. A new plan of COP is designed (close to the actual one). Basic features are agreed. The very first papers are being looked at. Future papers are promised by a number of delegates.
1982/02/14	WG 8 meets in EAST KILBRIDE. Chapter 11, covering secondary instrumentation, is added. Numerous points are made, in particular on geometrical and mechanical requirements. COP is growing quickly.
1983/03/24-25	WG 8 meets two days in PARIS examining papers, rewording, criticizing, questioning, etc. It appears that many things are still unclear and need clarification. User guidance has to be increased.
1983/06/13-14	WG 8 meets two days in LONDON. The later changes and additions are discussed so that a draft can be presented at next SC2 meeting.
1983/07	The first COP draft is being circulated to SC2 members (SC2 doc. n°145).
1983/11/3-4	SC2 meets in GAITHERSBURG. The general features of COP are approved, but the paper is considered to be merely a first sketch of what COP should be. There should be more on nozzles and Venturi tubes, and there should be more information on calculations and physical data.
1984/06/14-15	WG 8 meets in PARIS. The numerous comments that were received after SC2 GAITHERSBURG meeting are taken into

	account. WG 8 efforts apply essentially on calculation examples, uncertainties, physical data and secondary instrumentation.
1985/01	The new version of COP is circulated to SC2 members (SC2 doc. n°162).
1985/06/25-27	SC2 meets in STAVANGER. Merely editorial comments have been received. They have to be considered. In addition, computer programmes examples are being wished.
end 1985-early 1986	Letter exchanges between the members of WG 8.
1986/08	The new version of COP is circulated to SC2 members (SC2 doc. n°205). It is the thickest one (221 pages).
1986/11/19	WG 8 meets in NEW YORK to take account of the latest comments that are available.
1986/11/19-21	SC2 meets in NEW YORK. COP, as just revised by WG 8, is approved by SC2. Computer programmes examples shall be deleted. COP will be reworded in proper english language by BSI. It will have to be consistent with the new version of ISO 5167.
1987-1989	Rewording, translation, re-typing, etc. COP should be made available quite soon now.

2. Problematic Starting, Difficult Ending

In the elaboration of the paper, two periods of time were long and difficult : the earliest and the latest ones.

It took a lot of time to be able to decide what should be the features of COP. At earlier stages, that document was supposed to be issued quite rapidly, and anyhow far before the next version of ISO 5167.

This was stated because ISO 5167, as published in 1980, had encountered strong criticisms and its revision had been decided since its very publication. At that time, COP was considered as a means to make the defects of ISO 5167 bareable to users. It was then supposed to correct the situation before the next version of the standard could be made available.

When starting to write something that could be incorporated into COP, people realised that the above vision was not realistic : whatever happens, COP had to comply with ISO 5167 statements, whether found satisfactory indeed or not. Unless WG 8 would have started on the writing of a new version of the standard (which it was not supposed to do), there should be no contradiction between both documents.

The information given in COP had then to comply with ISO 5167-1980 statements. But it should not be a simple repetition of what the standard already stated.

The dilemma was then : COP should go further than the standard. But, if the standard was not going far enough, it was obviously because on many points it had not been possible to reach agreement on more detailed statements. For more or less the same technical reasons that limited ISO 5167 statements, COP new proposals seemed bound to be rejected if too daring.

This explains while it was quite long and difficult to find the right style. Fortunately it was decided quite early that COP would not be a compulsory document, thus would be a technical report and not a standard.

As a guideline, WG 8 members came to decide that anything clear, reasonable, giving effective and practical guidance and not contradicting ISO 5167 statements would be acceptable and should be incorporated into COP and submitted to SC2 judgement. On the other hand, any sentence already included in the standard should be banned from COP. That open-minded attitude led to some developments that appeared eventually as non-needed, but it helped keeping a creative behaviour and allowed to achieve a rich document.

The particular situation of COP facing ISO 5167 standard posed also some very practical problems which were not that easy to solve. For instance, should COP be usable alone, or should it be usable only together with the standard ? In the earlier case, COP should include the standard statements. In the latter, how to make it easy for the user to refer to two separate papers dealing with the same subject in different styles ?

The last period was not easier than the first one. Some reasons can be found in the quite long duration of the project and in the huge size of the final paper. For instance, the final rewording lasted about one year and translation into french by the secretariat further longer (COP was worked out in its english version only, which helped a rapid progression but required a heavy task at the end).

An extra delay of more than one year came when it was clear that COP was not going to be published many years before the new version of ISO 5167. It was then needed to put COP in accordance with the new version of the standard, and consequently to wait for the latter to be available at a sufficiently advanced state.

It was also needed to retype large parts of the paper, as ISO is now publishing the drafts as they are, without any printing reprocessing, and the working documents had not always been made for that purpose.

Although those multiple delays are quite frustrating, it is not simple to decide what should have be done to have COP ready earlier : a better plannification of SubCommittee Secretariat charge plan would may be have permitted a faster translation, but it would not have made the new version of ISO 5167 available earlier.

The only attitude that could indeed lead to faster results would probably have consisted in not changing one's mind and keeping the objective of issuing COP without taking care of ISO 5167 revision. The counterpart would have been the necessity to revise COP as soon as new ISO 5167 was made available, but it could be that some revision will be needed in the near future anyhow.

3. Various stages of the document

In 1982 meeting in PARIS, COP was made of a few pages only. These were the first timid attempts to comment and give guidance. A first period of intense work happened between 1982 and 1983, that resulted in the first draft presented at GAITHERSBURG. The latter is a document of 77 pages that looks already quite like the final version : there is some guidance on calculation methods, mechanical problems and secondary instrumentation.

The main point that was not approved (and thus disappeared in the later versions) was a large table comparing all the techniques that could be used to measure the flow, including non-pressure difference devices.

A second period started then : it was indeed very active, as SC2 had approved almost all that had been written in COP and was just asking for more.

WG 8 concentrated on questions other than mechanical ones : edge sharpness, flatness, centering, straight lengths, flow straighteners, etc. were already covered, and more guidance was needed on calculations, uncertainties, physical data and secondary instrumentation. This period was not less active than the previous one and it appeared that many things were unclear or uneasy.

COP grew then almost to its final state and was presented at SC2 meeting in STAVANGER.

Many editorial comments were made, preventing COP to be approved by SC2 at that time. It was asked to incorporate some computer programmes examples.

COP entered then a rather editorial period during which the working group members exchanged information by telephone or mail. All the comments made at STAVANGER were taken into account, computer programmes examples were incorporated and a new version presented in NEW YORK. It was the biggest version of COP : 221 pages thick.

To prevent another delay due to many possible additional comments, the working group met in NEW YORK just before SC2 in order to take account of all the comments made since last version circulation.

The COP was then approved by SC2 provided the computer programmes examples would be removed (they appeared to be of less help than expected first). The final version was then 202 pages thick. British Standards Institution was asked for rewording COP in correct english language before the final paper to be sent to SC2 Secretariat.

4. ISO 5167 Code of Practice

It was very difficult to the members of the working group themselves not to get lost ("... paragraph 3.2.4 of the Code of Practice, dealing with clause 6.5.3.3 of ISO 5167, will now be referred to as 4.3.4 in the Code of Practice because of the addition of ...") untill a parallel numbering was adopted, making the clause numbers the same in both papers.

That posed again some problems at the latest stage because of ISO general requirements for clause numbering, making consequently a non continuous

numbering unacceptable. That question of numbering was eventually solved by adding some dummy paragraphs in COP so as to meet at the same time a parallel to ISO 5167 and continuous numbering.

On the technical side, many points had to be tackled.

At the earlier stage, merely mechanical and geometrical topics were studied. ISO 5167 is often unclear or evasive on what should be done practically to meet the various requirements. WG 8 had then to make some decisions and guess acceptable proposals. Although sometimes quite daring, they were practically all approved by SC2.

For instance, ISO 5167 states (Clause 6.5.1.1) that "no diameter measured in any plane (must) differ by more than 0.3 % from the value of D ...". In COP, it is assumed that this can be checked by measuring local diameters in few cross-sections, namely two in addition to those already used to establish the mean pipe diameter.

Another example is related to the question of the separation of upstream fittings : ISO 5167 requires minimum straight lengths for various upstream fittings, including single bend or multiple bends configurations listed in Table 1. But it does not specify which distance between two bends is necessitated so as to allow the downstream one to be considered as single. Furthermore, Note (5) of Clause 6.2.8 (b) states that Table 1 can be applied for multiple bends whatever the length between two consecutive bends. Strictly speaking, the user could then have to consider any bend as a multiple one, which can lead him to install quite long straight lengths. COP proposes then an alternative to Note 5 giving a criteria to decide whether a bend can be considered as single or not.

The flatness of an orifice plate is quite a delicate topic and COP tried to make clear the various sources of problems : machining, mounting arrangement stresses, deformation due to flow during normal operation or special actions.

The edge sharpness is also an important and difficult point related to orifice plates. It can be uneasy to obtain accurate measurements and then to interpret them. So, It was attempted to provide the user with the necessary information so that he can decide his own control process.

Chapter 11, that covers secondary instrumentation, is entirely new as ISO 5167 is not dealing with that subject. Most of it was then inspired from other existing standards and engineering books.

After mechanical and measurement topics came other ones.

A large effort had to be made upon the uncertainty calculations. The data needed to perform the computation are scattered in various parts of the standard, and many questions arose because most parameters are not statistically independent from each other. A whole section giving background, guidance and examples was prepared, showing in particular the effects of several meter runs in parallel.

Whilst preparing numerical examples of flow calculations, some efforts was needed to make three computer programmes to give the same results. This was

quite a surprise and, although the involved people were familiar with the equations and the computers, several differences were found when comparing the results on given sets of data and it was quite long to reach a perfect agreement. It appeared then useful to give substential guidance on the calculations procedures.

This task was quite difficult and long as there are many ways to present the iterative process needed in most cases and as it is always a hard task to be at the same time scientifically rigorous and easy to understand . A whole Annex was then written giving some theoretical background considerations, numerical examples. Computation flowcharts and examples of calculation sheets were also defined.

Incorporating computer programmes, although desired by SC2 members, was eventually considered of little help : it necessarily implies an arbitrarily choice among available languages. Moreover, the relevant information is somewhat drowned among commands that are purely dependent on the operating system or of less interest (eg. data acquisition or results editing subroutines). Despite many efforts, it was not possible to find a universal computer language permitting to write examples that would make programming really easier and safer for the user. As a substitute, many numerical examples were incorporated so that a user can check rapidly on a few data sets that his computer code is faultless.

The last topic covered by COP is related to physical data. These were strongly asked for by SC2 members, and they are partly responsible for COP size. Giving the right quantity of information is quite a hard task in that field : the number of fluids and the number of properties to be gathered can be very high, and the problem was indeed to select a reasonable amount of data, sufficient for a number of practical purposes.

Lastly, COP is very few dealing with primary devices other than orifice plates. Many efforts were made to gather specialists advices and information, new people were asked by SC2 at every meeting, but in vain. The reason for that situation might be that orifice plates are widely used and permit the lowest error level : it would be then less important to nozzles or venturi tubes users to improve the level of understanding and applicability of the standard if they feel satisfied with the actual situation. That guess needs anyway to be confirmed.

5. Future Perspective

COP is now about to be published as a Draft Technical Report. Despite all efforts that were made, reaching that point has demanded a lot of time. It will probably be needed to update it within the near future.

Indeed, most writing tasks were technically finished by 1985 and mostly editorial rewording was undertaken since then. On the other hand, several major developments have taken place in between and will be sources of important technical changes ;

The EEC campaign on orifice plate coefficients determination, continued by and linked to several other research programmes in Europe or USA, will likely

bring changes in discharge coefficient equations, required straight lengths tables and flow conditioners usage.

New state equations, using new experimental data sets, are or have been developed : AGA 8 or GERG equations are reaching accuracy levels far better than previous equations. Despite their increased complexity, that type of equation will undoubtlessly be used more and more because of the improvements they permit in calculations accuracy.

Research is being made on new flow conditioners or packages, in order to be able to obtain good accuracies within the shortest possible straight lengths. Such research present potential high economic advantages and could bring about quite new concepts, such as the use of non freely developed but yet repeatable flow profiles.

Obviously, it will be necessary in the future to take account of these new developments.

On a more general level, a fundamental question is whether such a system (a standard to be used together with a Code of Practice) is the best way.

On the one hand, it allows specialists not to have to bother with reading COP whilst less skilled people can refer to a rather thick and documented paper. It might also help to reach agreement more easily while preparing the standard itself as one can hope that COP will explain and make practical all the unclear or difficult statements.

On the other hand, one can wonder if writing a standard clause in an unclear way is really a good practice : having the statement approved by all body members will not ensure that the basic technical requirements covered by the clause are fulfilled in practice.

6. Conclusion

More generally, the trend to improve systems performance will probably bring more and more complexity in flow measurement standards. With the growth of scientific knowledge and the increasing need to optimize the cost of flow metering facilities, users will wish to take account of eg. geometrical effects in a more refined, thus more complex way, in order to avoid for instance unduly long straight lengths.

It is clear whatsoever that improving the technical level of both knowlegde and standardization will not be sufficient. An important effort will have to be made also on the ergonomial side : it is not really useful to have a perfectly correct standard (from a scientist point of view) that half people cannot apply perfectly.

COP can be considered as a first attempt in that direction. How useful and valuable is it ? It will be up to users to answer.

REFERENCES

[1] ISO Draft Technical Report 9464, "Code of Practice for ISO 5167", August 1989

[2] ISO/TC30/SC2 documents N° 145, 162, 205

[3] ISO International Standard 5167, "Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full", 1980

[4] ISO/TC30/SC2 meeting resolutions at ESSEN, March 1977

[5] ISO/TC30/SC2 meeting resolutions at PARIS, April 1980

[6] ISO/TC30/SC2 meeting resolutions at BRAUNSCHWEIG, December 1981

[7] ISO/TC30/SC2 meeting resolutions at GAITHERSBURG, November 1983

[8] ISO/TC30/SC2 meeting resolutions at STAVANGER, June 1985

[9] ISO/TC30/SC2 meeting resolutions at NEW-YORK, November 1986

Standardization Environment of Working Group 8

Simplified structures