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Metering in the real world

by

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METERING IN THE REAL WORLD

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SUMMARY

This paper highlights some of the problems experienced by metering practioners once they step outside of the ivory towers and warm laboratories and enter the real world. The real world of course is not real at all, it vibrates, it rusts, it surges and gets hot and cold at all the wrong moments. But to many of us in the North Sea, its home and where we have to account for the products "won or saved" from our facilities. In addition the paper looks briefly at the cost of ownership of some simple metering stations.

The paper does discuss highly theoretical matters, these are left to more learned colleagues who will come later in the workshop.

INTRODUCTION

As an introduction to metering, we are all aware that there are certain golden rules which must apply to ensure consistent, reliable and even accurate metering. These are:

- Stable conditions with respect to
  - flow rate.
  - pressure.
  - temperature.
  - metered product composition.

- Cleanliness.

- Good metrology.

However, at times we experience changes in one or more of the above, and this has effects which may be of a greater or lesser degree. As 'flow metering' is not a discrete standard we sometimes ignore or don't even notice the offending parameter.

In addition we concentrate (naturally) on our cash registers - our fiscal metering systems..... ignoring our ancillary metering systems. Whilst not advocating that we should ignore our fiscal meters, we should perhaps pay a little more heed to those systems which might enable us to monitor and manage the one limited resource we have - our reservoirs. Lets look at these ancillary meters, which surpass in large quantities, the fiscal system meters.

If we consider that a fiscal skid for oil or gas will probably have 3 or 4 meters each and ancillary metering systems for a typical North Sea platform will have upwards of 50 meters then you will see that the opportunity for error in ancillery metering is large. The typical quantity of flow meters on a minimum facility are shown in Table 1.

So lets get back to our real world, and look at all those conditions, which are so important for consistent, reliable and even accurate metering.

TABLE 1 - TYPICAL NORTH SEA PLATFORM METERS			
FISCAL			
GAS	3 off		
OIL	3 off		
ANCILLARY			
TEST SEPARATOR	1 oil	1 gas	1 water
1ST STAGE SEPARATOR	1 oil	1 gas	1 water
2ND STAGE SEPARATOR	1 oil	1 gas	1 water
GAS COMPRESSION		3 gas	
GAS TREATMENT	2 NGL		
GAS LIFT		15 gas	
WATER INJECTION			10 water
FUEL GAS		2 gas	
FLARE		2 gas	
FIRE WATER			2 water
SUB TOTAL	5 oil	25 gas	15 water

- IGNORES MISCELLANEOUS MINIMUM FLOW BYPASS LOOPS, AVIATION FUEL, DIESEL, CHEMICALS, ETC

STABLE CONDITIONS

An area of the process plant where we hope that stable conditions are designed in, is the test separator. Its purpose is of course to test the flow of individual wells and meter the constituents of the flowing products, in order to enable us to monitor and manage the performance of the reservoir. With the advent and discovery of smaller satellite fields, a secondary purpose has been allocated to some test separators - that is the allocation metering of the production from satellite fields in relation to the total (fiscally metered) output of the parent production facility.

So lets look at a typical test separator and its performance both perceived and real.

At the commencement of operations the field is assumed to produce under its own pressure in a relatively stable state with little or no water and in the initial stages, with no gas lift or ESP production enhancements. Under these conditions, the control of the separator is stable and metering poses few problems unless of course, the production rate is so high that the residence time is small. Later, once the reservoir pressure drops, enhanced oil recovery activities are undertaken, ie

- Water injection : to maintain reservoir pressure.

- Gas lift : to lift the products in the well tubing to the surface by reducing the specific gravity of the liquids.

- Submersible pumps.

These EOR activities certainly perform - they enhance the reservoir recovery. However, when we look into this, it also give us a myriad of problems in metering technology. We'll look at this again in a shortly.

WATER PRODUCTION

Water production is a natural byproduct of oil production, whether it be aquifer water driving the oil or injection water for reservoir pressure maintenance. Eventually water break through will occur, and increasing amounts of water will be produced. It is not unusual for mature fields to produce 2, 3, 4, 5 and 6 times more water than oil.

Separator performance at these levels of water production often falls and the water content in the "metered oil" may rise. Separator performance has been shown to be severely effected by the EOR facilities as these tend to break down and mix the fluids extremely efficiently.

If we look at Table 2 we can see a wide range of typical water cuts found at a typical test separator and at the inlet / outlet of first and second stage separators. These are dependant upon crude oil parameters, mixing regimes previously described, temperatures and the basic efficiency of the separators. Often this means that we are in fact trying to meter, not an oil with known pressure and temperature characteristics, but rather an oil / water mix.

Our traditional metering of flow, pressure and temperature and inputting this data into an efficient and complex flow computer provides us with a correct flow rate having carried out some complex calculations. Two of the computations carried out are :

- temperature compensation for crude oil volume changes between the operating temperature and 15°C.

- pressure compensation for crude oil volume changes between the operating pressure and 1.01325 bar g.

In a paper presented by T.J. Hollet of BP "Measurement errors in North Sea Exploration and Production Systems Resulting from ignoring the Properties of Water" to this workshop in 1984, the topic was rigorously explored. Some of the conclusions from this paper stated that the use of dry oil density to calculate total wet fluid thermal expansion coefficients and hence volume correction factors can generate significant underestimates of metered volumes at standard conditions if water contents are >3% wt and the use of

wet oil densities to calculate total wet fluid thermal expansion coefficients and hence volume correction factors does produce sufficiently accurate results over the range 1 - 10% water.

From the figures presented I have no doubt that this problem exists in many ancillary systems, and more than a few of the more mature production facilities, within their fiscal metering systems. However to my knowledge little further work has been done on this topic except for a few projects to look at water cut sampling, and the figures shown in Table 2 would indicate that the problem is still with us.

Further problems are present with water production and gas metering. One of the regular questions I am asked by my Production Engineers is "What have I done to the metering?". I now know what they mean - as I've now seen it happen a few times. With a new production well the gas oil ratio is steady at a level predetermined by the field GOR and then after a while the GOR begins to rise. The implication is that I or one of my colleagues has 'tweaked' the flow meters or the flow computer without saying anything. The reservoir gas oil ratio in a composite field is uniform - it does not change with time or production. However if you look at the change in GOR of a typical well over time, you may find it changes dramatically. Figure 1 shows a typical well GOR versus BS & W. The GOR hasn't actually changed but we are now metering gas plus water vapour carry over plus steam. The amount of steam depends upon the separator temperature and pressure and this can be investigated further via the steam tables.

This is an interesting problem, and will not disappear with the use of the more modern non-intrusive / mass flow meters. I'm sure Andy Jamieson in the next paper may say a few words on this topic under 'Wet Gas Metering' - however in its worst aspects this is not just wet gas - its almost multiphase.

TABLE 2 - SEPARATOR PERFORMANCES

WELL	FLOW RATE BOPD	BS & W AT METER	SEPARATOR TEMPERATURE	
1	2,557	2.6%	115°F	
2	1,447	0.8%	188°F	
3	4,796	7.8%	200°F	
4	5,186	1.3%	189°F	
5	1,371	0.6%	200°F	
6	3,874	0.3%	117°F	
7	3,860	51%	50°F	

FIRST STAGE SEPARATOR

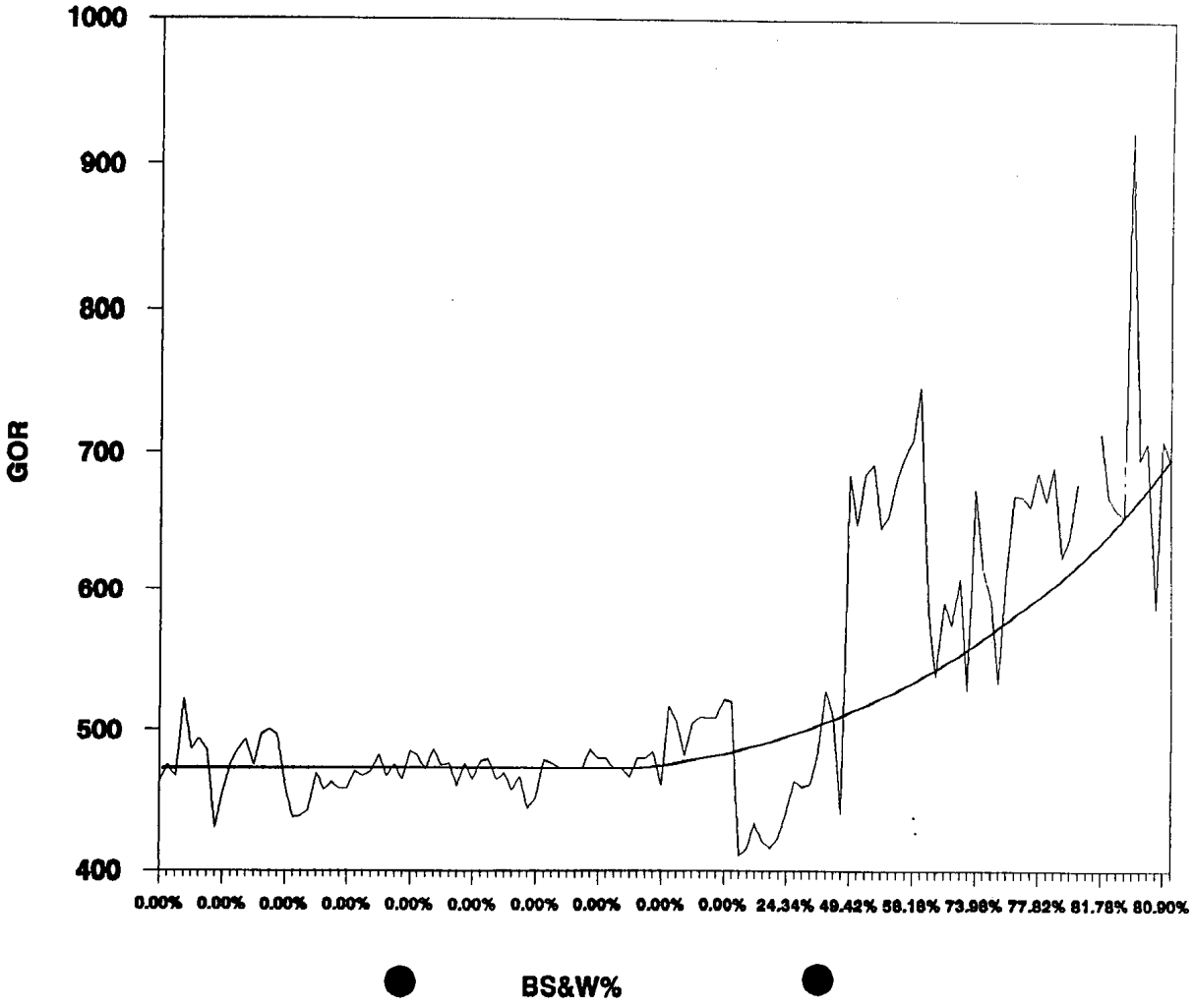
INLET BS & W = 67%

OUTLET BS & W = 47 %

SECOND STAGE SEPARATOR

OUTLET BS & W = 25 %

FIGURE 1: BS&W% Vs GOR



PROCESS CONTROL

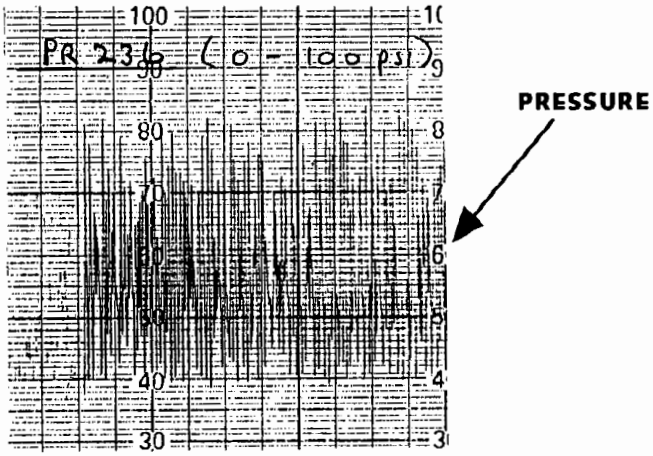
Poor control of the process can have severe effects on metering. A new field generally comes on stream under relatively stable conditions. Once water break through occurs and / or gas lift is used to maintain the production rates and remote satellite fields are brought on stream then test and first stage separators can be subject to large shifts in pressure due to slugging in production risers and production pipelines. These shifts under some conditions can be violent enough to trip the process or create excessive surges in flow which can induce severe metering swings at best or permanent damage to the associated meter. Turbine meters with scored and overheated bearings and orifice plates bowed beyond their elastic limit (plastic deformation) are often the result of such surges.

Figures 2 and 3 shows just what the pressure, temperature and flow rate fluctuations can be on a slugging well produced via a test separator with a comparatively 'slow' process control system. The flow rate fluctuations are, along with the pressure changes, large due to the relative slowness in the controls. These of course lead to significant shifts in metering accuracy when compared to more stable wells.

The flow surges are large and with turbine meters the effects of surge or overspeeding can be more damaging to bearings etc. Once the problem is identified then solutions can be put in place. Many of the older generation platforms are often pneumatic controlled (see Figure 5) and it is these that are now troubled by slugging wells and the features shown in Figures 2 and 3 are typical. Improvement in control may be brought about by installing electronic analogue or digital controllers, which of course speed up the control functions by eliminating the transmission lags especially if the controllers are mounted remote (in the control room) from the separator.

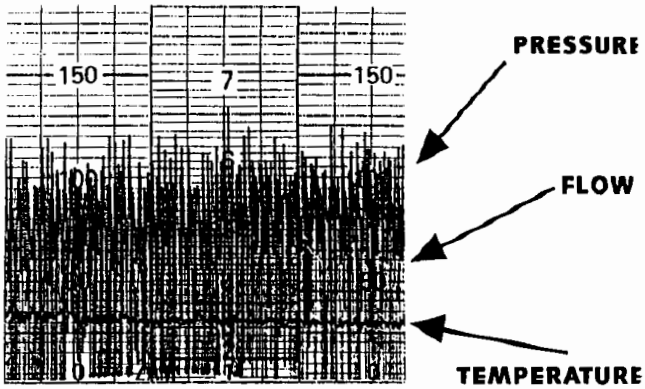
However the assessment of the improvement on metering is difficult to quantify and hence the justification to management for finance to carry out the modifications often has to be concluded as part of a safety or process improvement rather than a straight metering upgrade.

BEFORE



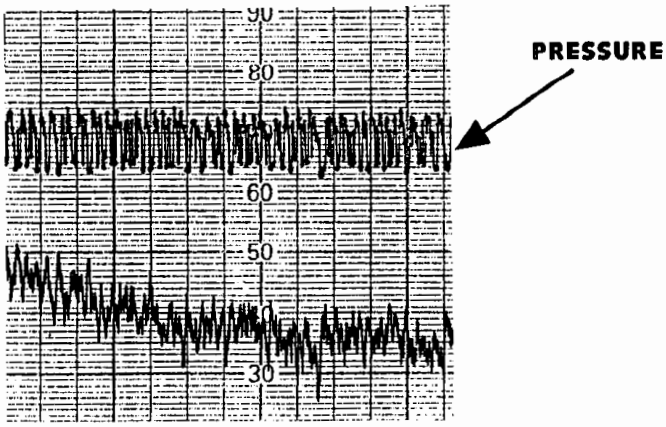
TEST SEPARATOR PRESSURE

BEFORE



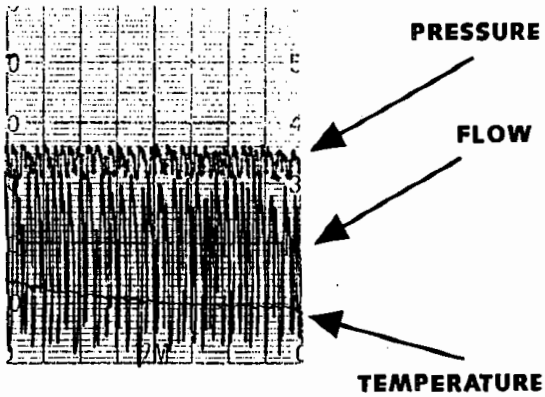
TEST SEPARATOR GAS METERING

AFTER



TEST SEPARATOR PRESSURE

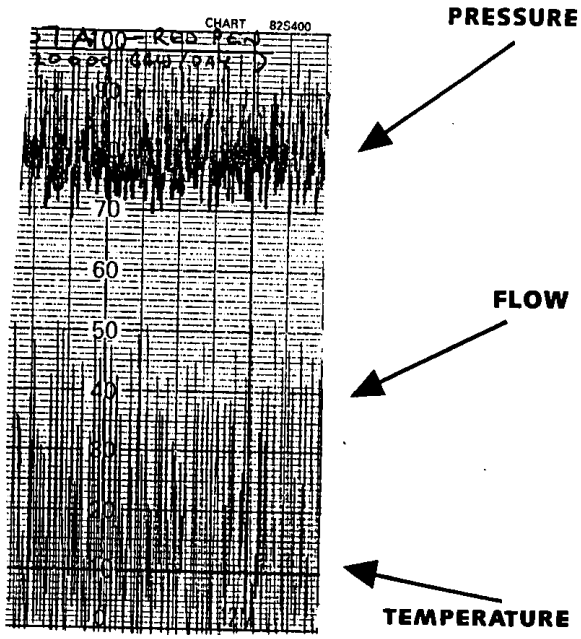
AFTER



TEST SEPARATOR GAS METERING

FIG. 2 SEPARATOR GAS PRESSURE & GAS METERING

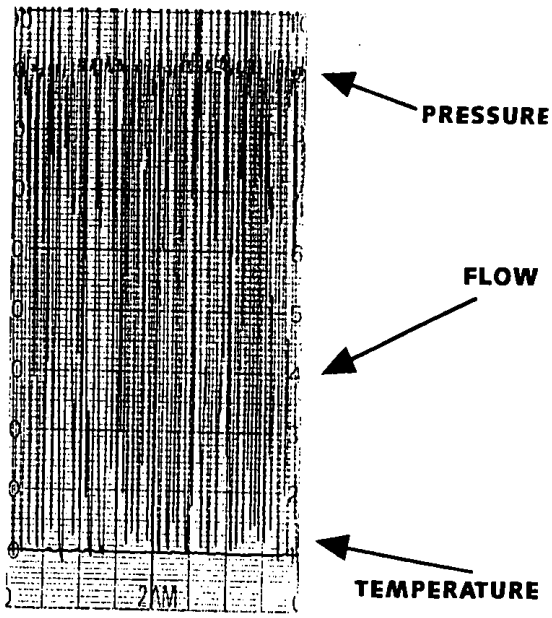
BEFORE



FLOW SCALE 0 - 20,000 BBL/DAY

TEST SEPARATOR OIL METERING

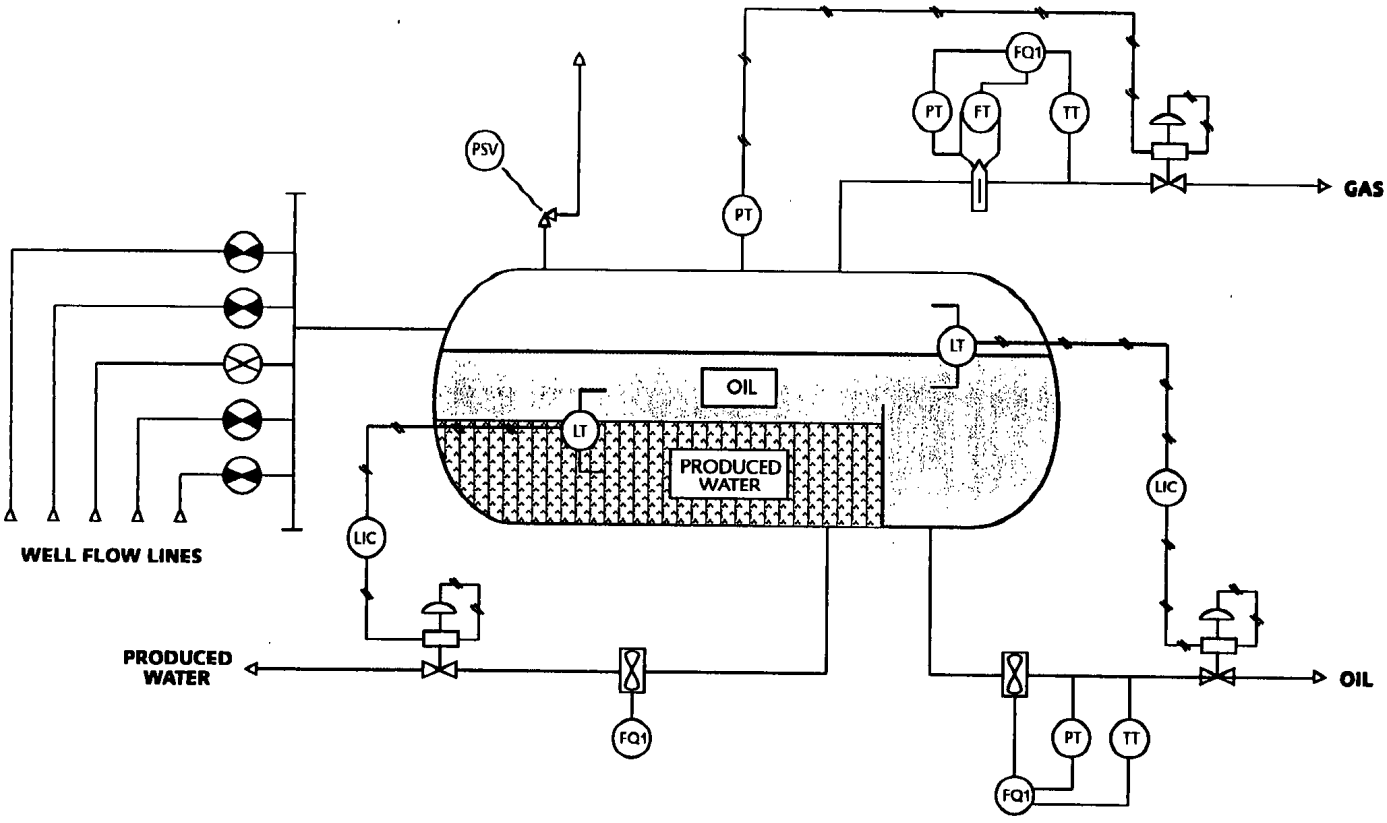
AFTER



FLOW SCALE 0 - 7500 BBL/DAY

TEST SEPARATOR OIL METERING

FIG. 3 SEPARATOR OIL METERING



TYPICAL TEST SEPARATOR - FIG. 5

METERING INTERFERENCE

So far in my career I've come across several cases of interference. These were from electrical sources. The first was from a thyristor powered gas heater. The interference was irregular and rose and fell with the e.m.f. imposed on the turbine cables for the heater supplies.

The second was less easy to spot. This case comprised of a compact metering skid complete with a booster pump, inlet and outlet headers, two parallel meters and a bypass line. During production commissioning it was found that wells flowing through this meter skid were producing flow rates in excess of what had been metered in the past. By accident it was noted that the isolated spare meter was giving a readout. We changed over the meters and again found the metered flow rates were high and the 'spare' meter too had a reading. The final check (days later) was to flow through the bypass line and check the meters. Yes you guessed it - they both gave a readout.

2" meter (MF11400 p/l)	-	18.947368 litres per hour.
3" meter (MF8900 p/l)	-	24.2694 litres per hour.

It took a while of course - but no doubt you can tell me what the frequency of my platform supply is.

The solution to both the above problems was to install a resistance / capacitive bridge across the turbine meter pick-up coils. This was done by trial and error until the interference was eliminated. In the latter case we quizzed the turbine meter vendor on the problem. There was unfortunately no help forthcoming from that source!

METERED PRODUCTS

In the UK our production licenses require us to meter all the products "won or saved". It is here that I must apologise to representatives of Her Majesties Government for not sticking closely to my license requirements. Two products we produce continuously one of which we don't meter with a great deal of certainty.

These are :-

- Sand
- Wax

Sand production from the reservoirs we produce varies enormously. The rate often depends on the reservoir geology and production flow rates. Removal of 2 tonnes of sand from a test separator over an 18 month period is not unusual. This of course doesn't take into account the sand flowed away via the water or oil or even the gas phases.

Sand of course flowing in a liquid not only introduces errors in metering (both volumetric or mass flow) and can introduce some interesting effects on the meters themselves. The effects of course will depend on the sand rate, velocity meter design etc.

Wax production in North Sea crude oil is not uncommon. It's rate varies from field to field, and whilst the crude is hot, and the wax is kept in solution it tends not to be a problem. When it comes out of solution, that's when we can experience problems. Pick up on a stationery turbine meter can increase the meter readout by 10 to 15%. The wax can of course be removed by high velocity flows and high temperature use, however those conditions are not always available and in the interim products will be over-metered.

SYSTEM DESIGN

Between us, the system designers, design contractors and the practioners we know all there is to know about the design of metering system. Right? Wrong!!

The mistakes we made 30 years ago in Texas are those we made 20 years ago in the early days of the North Sea, 10 years ago when the money was big in the North Sea and were making the same ones today when the barrel price is low and we can't afford the mistakes. Why are we making the mistakes?

Basically its because we can never know enough about the subject. So lets look at one or two typical problems we can see on a meter skid.

FOUR WAY VALVES

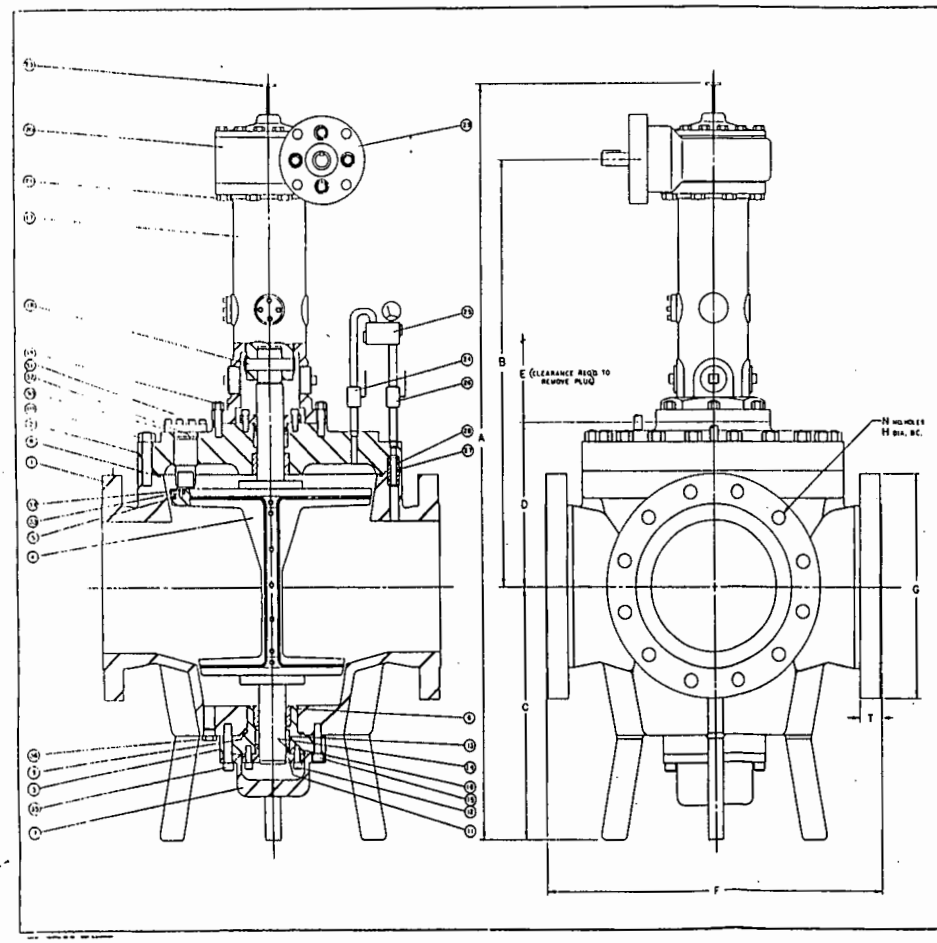
Traditional bi-directional prover loops utilise a 4 way valve to reverse the flow in the loop. These are relatively simple devices but require very tight dimensional tolerances to maintain a product seal. I've no doubt that some serious design work has been carried out over the years to calculate the stress levels in the pressure containing parts and the loadings on the flanges etc. I'm also equally confident that the system designers (and builders) prepare a competent design and carry out all the necessary pipe stress calculations to ensure no part of the design is working outwith its design limits. This is all well and good provided there is very tight dimensional control during fabrication. Without this control, additional stresses can be induced in the flange faces leading to ovality or distortion of the internal bore. This can result in early failure of at least one set of slips. The evidence for this is usually leakage through one flow path and sealing in the other flow path, or motor drive failure due to torque fluctuations.

If you're the system builder out there, I know you'll be saying that cannot possibly be your skid. But if you surveyed the offshore maintenance teams who have had reason to remove a 4 way valve and refit it - you'll find that a good proportion had to use a come-along lever to line up the pipework. I can't say I've observed it - but the valve always appears to be in place first thing in the morning! My Irish friends talk about the "little people", no doubt my Norwegian friends talk about the Trolls who have carried out the installation.

Figure 6 shows a typical 4 way diverter valve. If we review a 10 inch 600 lb raised face valve, the fixing bolt details are :- =

-	number of holes	-	16
-	pitched circle diameter	-	17 inch.
-	bolt diameter	-	1.25 inch.
-	bolt torque	-	560 ft / lb for stress of 40,000 psi (ok for ASTMA - A193-B7 bolts).

It is difficult enough to align a two way valve and a 4 way valve requires all four mating surfaces to be square and accurate. Any slight deviation in even one face during assembly could impose torque loadings on flange faces and valve bodies in the region of 45,000 ft / lb. No wonder we from time to time find the valve failing. It needs a lot of care in assembly.



ITEM	DESCRIPTION	MATERIAL
1	BODY	CAST STEEL
2	BONNET	CAST STEEL
3	TRUNNION HSG.	STEEL
4	PLUG	CAST STEEL
5	PLUG SEAL	VITON
6	TRUNNION BUSHING	TYPE 2 NI-RESIST
7	TRUNNION CAP	STEEL
8	O-RING	BUNA
9	O-RING	BUNA
10	STUD & NUT	STEEL
11	PACKING GLAND	STEEL
12	CAPSCREW	STEEL
13	PACKING SET	VITON & ASBESTOS
14	T SEAL	BUNA
15	CAPSCREW	STEEL
16	O-RING	BUNA
17	OPERATOR ASSEMBLY	
18	TRUNNION-OPERATOR PIN	STEEL
19	OPERATOR STUD & NUT	STEEL
20	GEAR HSG. ASSY	
21	GEAR HSG CAPSCREW	STEEL
22	HANDWHEEL (NOT SHOWN)	STEEL
23	INDICATOR FLAG	STAINLESS STEEL
24	BODY ISOLATION VALVE	STEEL
25	THERMAL & PRESSURE RELIEF MANIFOLD	STEEL
26	POST ISOLATION VALVE	STEEL
27	BONNET ALIGNMENT PIN	STEEL
28	O-RING W/BACK-UP	BUNA
29	MOTOR ADAPTER FLANGE	STEEL
30	ADJUSTABLE ROTATIONAL STOP	STEEL
31	CAPSCREW	STEEL
32	O-RING	BUNA
33	SEAL RETAINER PLATES	STEEL
34	CAPSCREW	STEEL
35	CAPSCREW	STEEL
36	DRAIN PLUG	STEEL

SIZE	ANSI	WEIGHT	A	B	C	D	E	F	G	T	H	H	Cv
2	150				9	6 5/8	17 1/4	17	6	5/8	4	4 3/4	250
	300				9	6 5/8	17 1/4	17	8 1/2	5/8	8	8	250
	600				9	6 5/8	17 1/4	18	8 1/2	1	8	8	250
3	150				9	6 5/8	17 1/4	17	7 1/2	1 1/8	4	6	400
	300				9	6 5/8	17 1/4	17	8 1/2	1 1/8	8	8 3/4	400
	600				9	6 5/8	17 1/4	18	8 1/2	1 1/2	8	8 3/4	400
4	150				9	6 5/8	17 1/4	17	9	1 1/8	8	7 1/2	647
	300				9	6 5/8	17 1/4	17	10	1 1/4	8	7 1/2	647
	600				9	6 5/8	17 1/4	18	10 3/4	1 3/4	8	8 1/2	647
6	150				13 3/8	11 1/8	24 3/8	24	11	1 1/16	8	9 1/2	1950
	300				13 3/8	11 1/8	24 3/8	24	12 1/2	1 1/16	12	10 3/4	1960
	600				13 3/8	11 1/8	24 3/8	26	14	2 1/4	12	11 1/2	1890
8	150				13 3/8	11 1/8	24 3/8	24	13 1/2	1 3/8	8	11 3/4	2425
	300				13 3/8	11 1/8	24 3/8	24	15	1 3/8	12	13	2425
	600				13 3/8	11 1/8	24 3/8	26	16 1/2	2 1/4	12	13 3/4	2425
10	150	2230	67 1/2	39 1/8	21 1/2	15	32 3/4	32	16	1 1/2	12	14 1/2	4250
	300	2400	67 1/2	39 1/8	21 1/2	15	32 3/4	32	17 1/2	1 1/8	16	15 1/4	4290
	600	3350	67 1/2	39 1/8	21 1/2	15	32 3/4	36	20	2 3/4	16	17	4250
12	150	3175	67 1/2	39 1/8	21 1/2	15	32 3/4	32	19	2	12	17	5100
	300	3375	67 1/2	39 1/8	21 1/2	15	32 3/4	32	20 1/2	2	16	17 3/4	5100
	600	4150	67 1/2	39 1/8	21 1/2	15	32 3/4	36	22	2 1/2	20	19 1/4	5100
16	150	5875	74 1/2	42 3/8	25	18 1/2	33 3/4	40	23 1/2	2 1/4	16	21 1/4	6800
	300	6175	74 1/2	42 3/8	25	18 1/2	33 3/4	40	25 1/2	2 1/4	20	22 1/2	6800
	600	8100	75	42 3/8	25 1/2	18 1/2	33 3/4	48	27	3 1/4	20	23 3/4	6800

DANIEL 4-WAY DIVERTER VALVE 2" THRU 16
150 THRU 600 ANSI

NONE
05-18-78
PROPERTY OF
DANIEL IND

FIGURE NOS.
471G, 473G, 475G

SKC-0069

FIGURE 6 TYPICAL FOUR WAY DIVENTER VALVE

SKID DESIGN

Too often we design meter skids wherein we are unable to remove individual meters without disassembling the majority of the skid.

In our rush to preserve straight lengths and the minimum of bends prior to and after the flow meter we build in considerable maintenance problems. Figure 7.1 is typical of our design. By the judicial use of flange elbows (see Figure 7.2) we are able to drop our individual meters easily, with a (hopefully) small cost in weight.

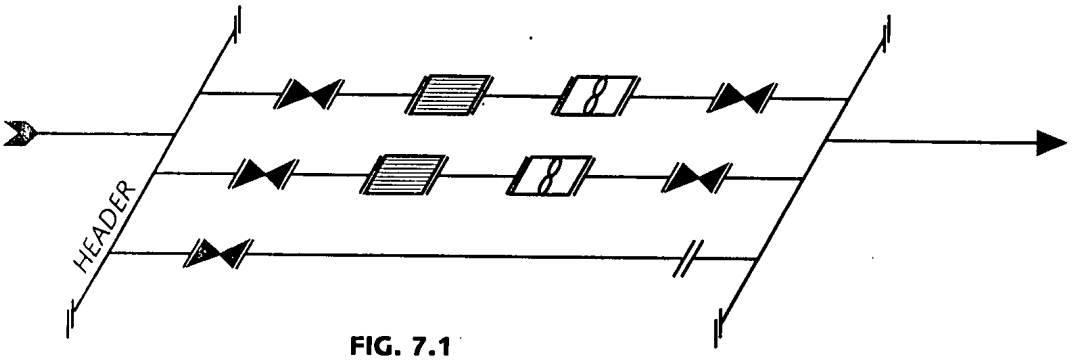


FIG. 7.1

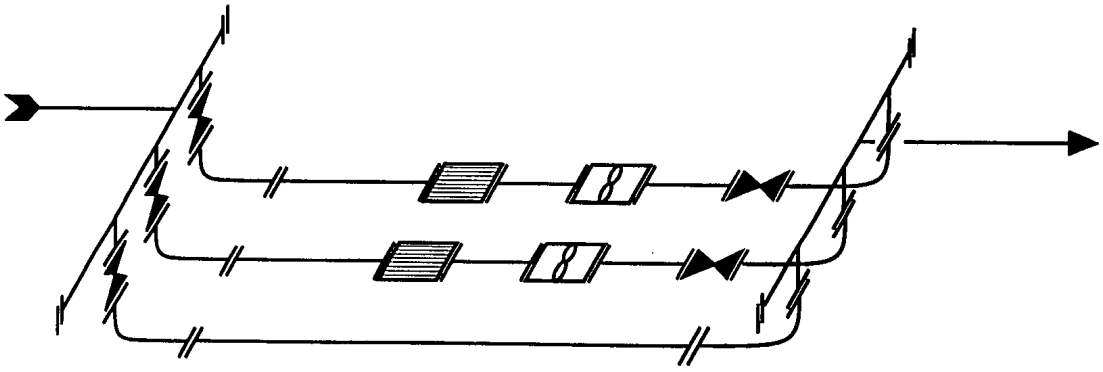


FIG. 7.2

FLOW METER SKID DESIGN FIG. 7

SIMPLE METERING PROBLEMS

Some of the simple metering errors which seriously affect our ability to meter accurately and repeatedly :

- Turbine meters which have been oversped during commissioning. During commissioning it has been known for plant equipment to be filled too quickly, displacing nitrogen which overspins the turbines.

- Meters installed back to front. If the meter is flow direction sensitive - get it marked with flow directions. I don't doubt we all know what way up a meter goes, but we as practioners don't install that many meters these days. The number of meters installed back to front is surprising. The problem is two way though... sometime we don't know which way the flow is going with a convoluted pipework set-up!.

- Self draining impulse lines. One major manufacturer of replaceable orifice fittings installs the orifice tappings on the horizontal. The only way to get vertical lines (for gas service) is to install the meter on the horizontal.

- Test equipment. From time to time test equipment has to be returned to the beach for calibration or maintenance. It is a relatively frequent occurrence for the test equipment to be returned with a certificate of conformity and a note saying the calibration certificate "will follow later". It does of course follow later - not a lot later, with the invoice! So guess where the certificate is when the external auditor is checking? Yes, in the invoice files! And no, you cannot have the original, you can only have a copy..... so says the invoice clerk, when you've back-checked the calibration laboratory, the buyer, the engineer, etc.

METER CALIBRATION

The calibration of meters on a live plant is always a problem. There are enough papers in the public domain on the use of meter provers, compact provers, etc. However even with the use of an (expensive) compact prover, it is difficult on a live plant to fully characterise a meter, because we are often unable to provide the full range of flow rates.

I have in the past calibrated turbine meters on test separators using a compact prover, but generally, due to cost and time constraints, its been a one or two point calibration. This does have limitations. So I discussed the problem with Nick King and Richard Paton at the National Engineering Laboratory.

I didn't want to calibrate using water - this could be done by one of several certified test houses - and I did want to use oil. I would have preferred dead crude, and still would prefer that product, but processed oil of the right density and viscosity, I am assured is just as good. So we thought we'd give it a try.

The real problem is to get a laboratory to simulate your real world conditions. In general they cannot meet your operating pressures, which in a test separator can range from 4 to 40 barg, or temperature ranges which as you will have seen earlier can range from 50°F (10°C) to 200°F (95°C). The results of the controlled test are shown in Figure 8, and the calibration data is shown in Table 2.

However as soon as the meter went offshore and was calibrated against a compact prover we came up with the real world problems.

We ran out of time, had a boat to catch and could only get one calibration run in - and of course we certainly couldn't attain the process figures for which the meter now had a certified calibration curve.

We ran at 90°C, 11.6 barg, 0.9913 kg/l and 8.7 litre / second. Our meter factor was close - but not close enough at 29.37012 p/l. Thus area needs much more work by both parties.

FIGURE 8. TURBINE CALIBRATION CURVE

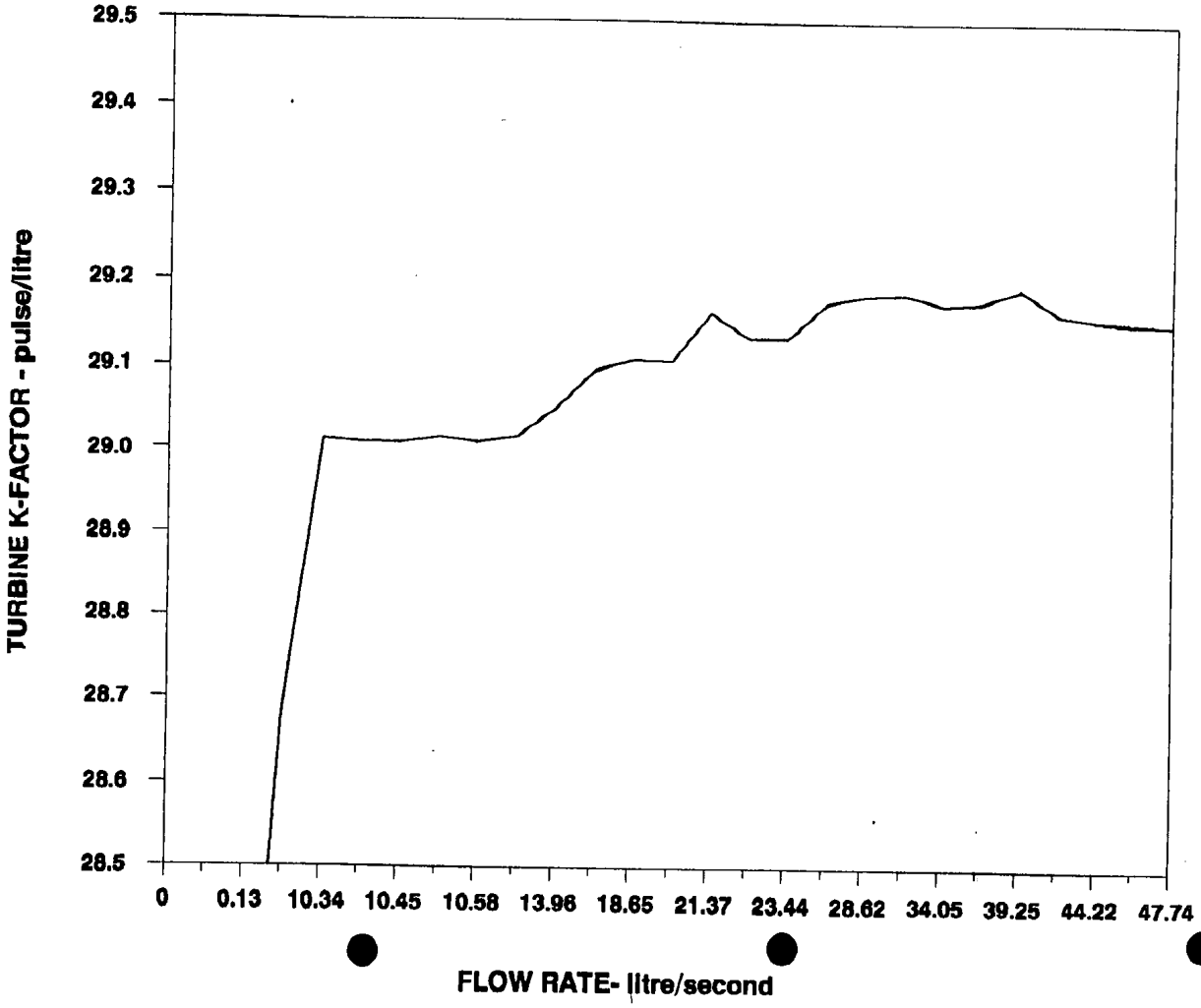


TABLE 2 - CALIBRATION DATA

TEST NUMBER: 6524/1	DATED: 23 Jul 93	TEST OPERATOR RB

CALIBRATION OF 3 INCH TURBINE METER

Fluid Density @ 20 C :	0.817032 kg/l	Exp. Factor : -0.0008482/deg C

Point No.	Time s	Temp. C	Corr/ Weight Kg	Volume l	Flow Rate l/s	Turbine Pulses P	K-Factor P/l
1	227.77	20.26	741.56	907.82	3.99	26037	28.681
2	114.23	20.42	757.50	927.46	0.12	28887	28.001
3	74.87	19.87	767.39	939.14	12.54	27250	29.016
4	79.14	21.27	1106.28	1355.45	17.13	37437	29.095
5	68.57	20.05	1119.29	1370.01	19.88	38877	29.107
6	75.79	20.73	1450.83	1776.83	23.44	51767	29.134
7	136.37	21.27	2840.76	3491.70	25.60	101871	29.175
8	103.97	20.59	2891.41	3540.69	34.05	103296	29.174
9	125.53	20.07	3961.22	4848.58	39.25	141547	29.193
10	87.44	20.93	2899.82	3552.02	40.62	103500	29.164
11	80.77	20.93	2922.95	3580.34	44.33	104381	29.154
12	74.55	20.89	2905.63	3559.02	47.74	103757	29.153
13	80.64	20.73	2911.84	3588.14	44.22	103977	29.157
14	99.44	20.36	2911.04	3564.02	35.84	103985	29.177
15	110.17	20.17	2887.00	3534.05	32.08	103143	29.186
16	128.35	20.60	2999.25	3672.79	28.62	107186	29.184
17	161.80	20.71	2823.12	3457.42	21.37	100829	29.163
18	79.58	20.57	1468.41	1788.13	22.80	52387	29.134
19	73.85	20.15	1125.22	1377.38	18.65	40094	29.109
20	67.70	20.40	771.88	945.05	13.96	27454	29.050
21	87.88	20.83	758.24	929.92	10.58	26975	29.008
22	89.70	20.77	767.51	940.00	10.48	27274	29.015
23	89.04	20.81	759.88	930.53	10.45	26992	29.007
24	89.80	20.45	762.18	933.23	10.39	27071	29.008
25	89.98	20.30	760.24	930.73	10.34	27003	29.013
26	148.45	20.24	743.06	908.85	8.13	28322	28.838

COST OF OWNERSHIP

The term 'cost of ownership' is now the vogue terminology with many oil companies. Our managements are seeking routes by which economies can be made, especially as fields mature, production (revenue) declines and overheads probably climb.

We as Metering Engineers may be looked at in one of two ways :

- an expensive overhead who constantly demands additional monies to 'improve' his black art / black box systems, with no perceived pay back.

or - the keeper of the cash register.

I fear, due to our own reticence, we fall into the first bracket, and unfortunately many of our managers fail to understand what we do or how we do it - or even in some cases why.

I have not spent a long time on this, but have wanted to explore the area of 'cost of ownership' for some time.

The problem is, to do it properly you need a large data base, and it is perhaps an area for a Joint Industry Project. I'll admit its not an exciting topic, but one in which we perhaps as Engineers should be looking at.

As an example I have selected a semi-fiscal 8 inch gas flowline and tried to compare an orifice fitting with say a ultrasonic meter. See Tables 3 and 4.

On a straight CAPEX and OPEX summation the orifice plate appears to be cheaper of the two units, until about year 6. However to carry out the study to its end conclusion we need to look at :

- replacement costs within this life time in terms of seals, lubricants, bolts, gaskets and primary and secondary instruments.
- theoretical and actual (real life) metering uncertainties,

and there is no doubt that this latter topic could swamp the calculation dramatically one way or the other should one meter be just 10 or 15% "better" with respect to overall metering uncertainty.

TABLE 3 - COST OF OWNERSHIP
8 INCH ORIFICE METER

CAPEX

8 INCH FLOWLINE, HP CHAMBER, STRAIGHTENER, AND ELEMENT	£	12,500
FLOW TRANSMITTER	£	1,200
PRESSURE TRANSMITTER	£	1,200
TEMPERATURE ELEMENT & THERMOWELL	£	1,000
FLOW STRAIGHTENER	£	1,500
FLOW COMPUTER	£	5,000
FLOW RECORDER	£	1,000
SUPPORT STEEL (1 TONNE)	£	8,000
CAPEX (Excl cabling)	£	31,400

OPEX

CHECK FE	12 TIMES / PA	48 man hours
CHECK FX	4 TIMES / PA	12 man hours
CHECK PX	4 TIMES / PA	6 man hours
CHECK TX	4 TIMES / PA	12 man hours
INSPECT BORE	1 TIMES / PA	24 man hours
CHECK FR	4 TIMES / PA	4 man hours
	OPEX	106 man hours per year

For £50 per hour -	The cost of ownership : Year 1	£	36,700
	The cost of ownership : Year 2	£	42,000
	The cost of ownership : Year 3	£	47,300

TABLE 4 - COST OF OWNERSHIP
8 INCH ULTRASONIC FLOWMETER

CAPEX

FLOW ELEMENT, TRANSMITTER, FLOW COMPUTER AND RECORDER	£	50,000
PRESSURE TRANSMITTER	£	1,200
TEMPERATURE ELEMENT AND THERMOWELL	£	1,200
8" FLOWLINE	£	4,000
SUPPORT STEEL (3/4 TONNE)	£	6,000
CAPEX (Excl cabling)	£	62,400

OPEX

CHECK PX	4 TIMES / PA	6 man hours
CHECK TX	4 TIMES / PA	12 man hours
CHECK - "No Flow" Conditions		2 man hours
	OPEX	20 man hours per year

For £50 per hour -	The cost of ownership : Year 1	£36,700
	The cost of ownership : Year 2	£42,000
	The cost of ownership : Year 3	£47,300

THE FUTURE

Nick King of the NEL at the 1991 North Sea Flow Metering Workshop asked us as a group, where we thought we ought to be in 10 years time. Its taken me 2 years to prepare a response to this.

Firstly we need to understand why we exist - and in this respect it is to protect the revenue due to our employers, and we do this by minimising possible losses. In order to do this we need flow meters that are :

- accurate.
- repeatable.
- process tolerant.
- reliable.
- economically viable.

and finally - easily verifiable,

and I hope that's why we're all here this week, to determine just what this elusive beast will look like.

ACKNOWLEDGEMENTS

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1. T.J. Hollett Measurement Errors in North Sea Exploration and Production Systems Resulting from ignoring the Properties of Water. North Sea Flow metering Workshop, 1984.