Experience in field tuning and operation of a multiphase meter based on neural net characterization of flow conditions

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Abstract The paper presents measurements taken with a multiphase flow meter based on neural net methodology at the National Engineering Laboratory and Institute Francais Petrole multiphase test loops and an offshore smart satellite production platform operated by Sarawak Shell Berhad Malaysia. The paper also contains a review of the state of the art of multiphase metering technology and an appraisal of potential sources of error inherent in different technologies. The method provides the basis of a multiphase flow meter which can be used under a wide range of operating conditions in oil and gas production lines by tuning against field references.

Keywords: multiphase metering

1. Introduction

This paper details the preparation, deployment and the field experience of a multiphase flow meter (ESMER MPFM – Expert System for Multiphase Metering) based on pattern recognition technology. ESMER was installed on the SFJT – C off-shore platform operated by Sarawak Shell Berhad (SSB) Malaysia in November 2002 and has been in operation since that date.. SJFT-C can be described as "smart" offshore satellite production platform. The meter was calibrated and tested at the National Engineering Laboratory (NEL) and Institute Francais Petrole (IFP) multiphase flow loops before installation in the field. A series of multi-rate well tests were carried out on gas lifting production wells to evaluate the performance of the meter since November 2002.

2. Multiphase Metering Technology Review

There are two different approaches in multiphase measurement technology [1]. In the conventional approach, phase velocities and cross sectional fractions must be measured individually (six unknowns requiring a total of five measurements for three phase flow as another equation is provide by the simple arithmetic sum of three phases adding to 1). The conventional approach is illustrated Fig. 1

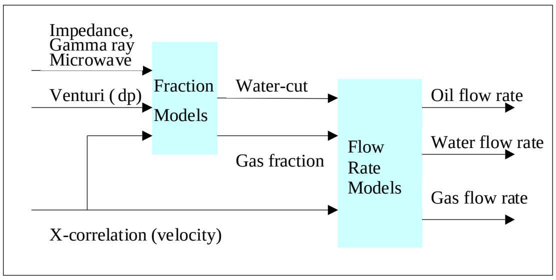


Fig.1. Conventional MPFM Concept

Conventional meters have to overcome a number of problems.The first problem arises from the difficulty of measuring the velocities of individual phases. A number of work arounds have been attempted including

- measure velocity of one phase and estimate the other from empirical "slip" correlations
- homogenise to alleviate slip
- separate phases to remove the problem at source

Each approach introduces more problems than it removes.

One approach for liquid velocity measurement has been the cross correlation method but this approach only worked under slug flow regime and failed in stratified, annular and dispersed flows. For slip, it has been generally found that any empirical correlations failed once taken beyond the laboratory conditions for which it is tuned up.

Homogenisation was found to be effective across a very narrow range of conditions where liquid is the continuous phase (eg bubbly flow).

A side effect arises from the vertical orientation adopted to achieve optimum homogenisation. This orientation gives rise to problems at lower liquid rates when the liquid starts falling back and puts a restrictive lower limit. For example, for a 4" MPFM meter, a minimum of 2000 bpd liquid flow rate may be required[2].

Separating the phases is a highly intrusive approach which appears to defeat the original objective of an in-line multiphase flow meter (why not stick to a test separator?)

Even if we assume that all the problems mentioned above can be solved, there remains one last source of inherent error in front of the conventional approach.. This can be explained as follows.

Let the individual phase flow rates Q_{liquid} and Q_{gas} to be computed from the following equations:

Q_{liquid}= A*V* (1- GVF)
Q_{gas} = A*V* GVF

Where A is the cross sectional area of the pipe and V is the total velocity of the flow (assume no slip). Then, it can be shown that the uncertainty in the measurement of the liquid flow rate will be given by:

Liq_Err =
Sqrt[(V_Err)**2+(GVF_Err/(1-GVF))**2]

Where V_Err is relative error in velocity measurement and GVF_Err is absolute error in GVF measurement. This equation shows that the liquid flow rate uncertainty will deteriorate strongly with increasing GVF. For example, Fig. 2 shows the variation of Liq_Err with varying GVF_Err for V_Err=+/-5% (lets assume V_Err is measured at this accuracy as an optimistic assumption). One can see that the liquid measurement uncertainty will be catastrophic above 90% GVF.

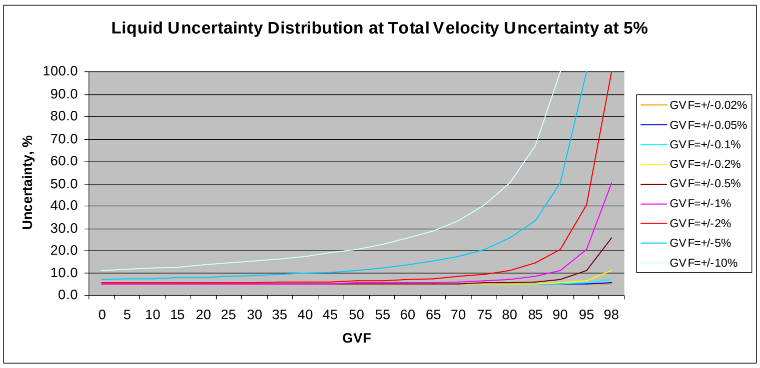


Fig. 2 Liquid Error for Total Velocity Error =+/-5%

We started saying that there are two different approaches to multiphase metering and seen the high likelihood of the conventional approach ending in failure under a number of conditions (eg low flow rates and high GVF).

The second approach is described as follows in a recent review article (1): "…parameters of the flow are measured that are functions of the three flow rates. For example a pressure drop across a venturi, the attenuation of a gamma beam and the impedance of the mixture can be determined and relationships established between these measurements and the flow rates of the respective phases, three independent measurements are required to establish the three flow rates. These relationships cannot be predicted theoretically, therefore, they must be established by calibration. …". The meter described in this paper, named ESMER (Expert System for Multiphase Metering) takes this latter approach (Fig 3).

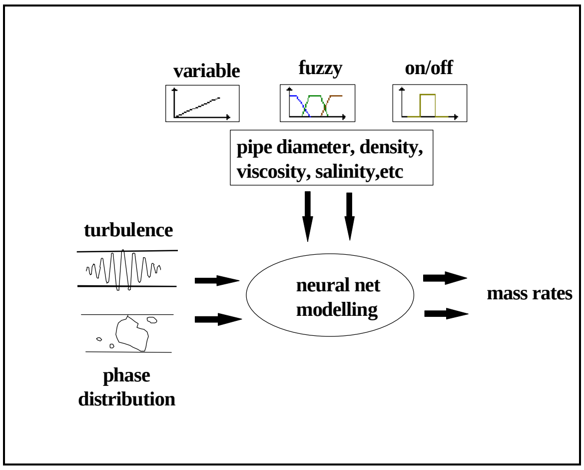


Fig. 3 Schematic diagram of the ESMER concept

ESMER establishes the non-linear relationships described above by pattern recognition / neural net training rather than by theoretical modeling. The end result is that ESMER flow meters can measure the flow rates of individual phases in oil production lines without the need for separation or complex sensor. ESMER does not require a-priori empirical models or knowledge of slip, does not employ cross-correlation, does not determine flow rates from the set of equations shown above (so its accuracy is flat across 1-99% GVF) and it is oriented vertically without a mixer (and therefore can work at very low flow rates).

ESMER depends on the naturally occurring multiphase flow patterns in the pipeline which it characterises by neural net analysis of high frequency signals emitted by simple and standard sensors. The characterisation process starts in the laboratory (factory calibration) and adapted to the field against separator reference measurements (field tuning).

3. ESMER Hardware

ESMER comprises high frequency response differential, absolute pressure and impedance sensors. The spool is normally installed horizontally and the flow passes through the spool in a straight line. The Flow Computer contains a data acquisition board for sampling and digitising the sensor signals at a relatively high frequency (to capture a range of fluid dynamic turbulent fluctuations and features at a range of time and length scales). The digitised signal is processed by neural network algorithms and flow rates of individual phases are identified by the ESMER system on-line with the frequency of once a minute. The neural nets are originally trained at the factory and tuned up under field conditions. At intervals chosen by the operator, field data is transmitted to the Server running at base for re-tuning the neural nets (running on-line). The present meter was trained up to 98% GVF, but in principle the range can be extended beyond this. The expected level of accuracy was in the range ±10% to ±15% for liquid and gas flow rates in relative terms and ±5% water cut in absolute terms.

A photograph of 3-inch ESMER T3 meter installed at SFJT - C is shown in Fig 4.

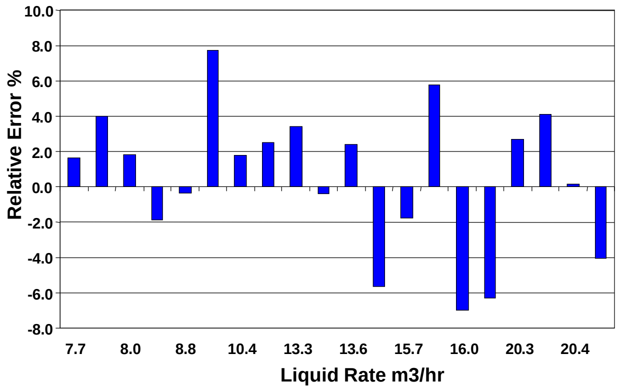
Fig. 4 Photograph of ESMER T3A installed at SFJT – C offshore platform

4. Factory and Site Acceptance Tests

ESMER T3A multiphase flowmeter was tested at the Institute Francais Petrole Lyon Laboratory (IFP) using kerosene substitute fuel and nitrogen gas. The operating envelope covered liquid flowrates range from 373 to 6,038 bpd, GVF from 60 to 99% at 0% water cut under the operating pressure in the range 100 psig (+-5psi). The factory calibration (neural networks) of the meter was based on reference measurements taken at NEL and IFP previously. Performance of the meter was evaluated against reference measurements for varying flow rates across a matrix of 21 measurement points. The details of the results are presented in Fig. 5. RMS average error for liquid rate was 3.9% and gas flow rate was 3.45%.

The meter was commissioned on the SFJT-C platform (South Furious Jacket – C off-shore platform of SSB) in November 2002. The commissioning activities comprised:

- Installation, including connection to the Shell local area network
- Running a number of well tests to verify the factory calibration against the test separator measurements (trend tests)
- Tuning the factory calibration and verifying performance against further well tests.
- Training the operators on the normal usage of the system and its maintenance.



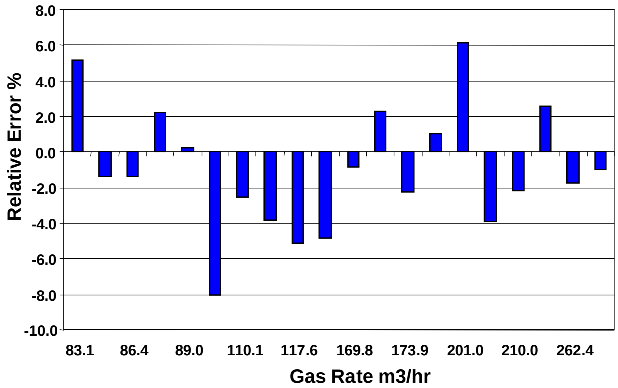


Figure 5 Accuracy of Liquid and Gas Rate Measurements in the Flow Loop

South Furious Jacket off-shore platform is located some 35 km away from the Kota Belud shore. The SFJT-C, although a slim production jacket platform, is a highly-automated platform, with around 800 instrument/measurement points and 3 “smart” wells. The platform was installed in September 2001 and produces from one of the first smart fields in the world. Apart from a few manually-controlled valves, most of the equipment and pumps can be controlled and remotely accessed through the DCS system. For example, the operator can line up wells and run well tests from the main platform (SFP-A) or from onshore. All the process variables can be measured through the DCS and accessed from the main platform or the head office at Lutong in Miri (some 200 km away). Gas lifting to the well heads and the casing pressures can also be remotely controlled.

The platform is equipped with a gas – liquid separator, various temperature, pressure, level, valve control systems, PD meter for liquid measurement and gas (orifice plate) flow meters. Flow rates of each single phase stream are measured at the outlet of the separator. Flow, pressure and temperature (instantaneous) measurements are transmitted to the network via the DCS.

Site acceptance tests were conducted after installation in November 2002 comprising a total of seven well tests across a range of flow conditions. At these tests it was observed that liquid flow rates measured on-line by the ESMER system agreed within +/-5% of the test separator and gas flow rates agreed within +/- 5-10%. Low watercut readings (1-3%) detected by the meter were undetected visually in the manual samples. The summary of well tests conducted during SAT is listed in Table 1.

switched to flow through ESMER and the test separator under widely varying flow rates and GVF conditions.

The operating points of the individual wells are marked on liquid vs gas coordinates of the Mandhane multiphase map on Fig 9 . The boundaries of the operating envelope of ESMER T3A is also marked on this map with the trapezoid shape bounded by 50% to 97% GVF lines and 20 mbar and 2000 mbar lines (corresponding to the smallest and largest differential pressure measurements tolerated across the orifice). It is seen that a number of well tests are clustered just outside the lowest tip of the operating envelope. It was noted that the performance of the meter deteriorated at low flow rates around 400 bpd. It was considered that a 2 inch diameter system would be better suited to the operating conditions at flow rates below 500 bpd.

WELL NO.	DATE	START TIME	END TIME	ESMER			Separator			Liquid Accuracy	Gas Accuracy	GVF Accuracy
				Liquid bpd	Gas mmscfd	GVF %	Liquid bpd	Gas mmscfd	GVF %	%	%	%
303	11/11/02	10:12	14:52	2232.09	0.876	90.23	2281.95	0.862	89.82	-2.185	1.624	0.42
301	12/11/02	15:00	23:00	453.8	0.606	96.90	433.3	0.651	97.20	4.731	-6.912	-0.30
305	13/11/2002	10:30	15:30	2329.16	1.578	92.82	2409.02	1.607	92.71	-3.315	-1.805	0.11
307	14/11/2002	10:30	14:30	467.27	0.548	96.63	467.85	0.502	96.21	-0.124	9.163	0.42
305	11/16/02	10:30	13:30	2537.68	0.945	89.73	2633.43	0.991	88.83	-3.636	-4.642	0.90
305	11/16/02	14:32	15:04	2500.51	0.922	89.52	2590.11	0.898	88.90	-3.459	2.673	0.63
307	11/16/02	16:00	05:32*	460.63	0.534	96.75	499.6	0.426	95.38	-7.800	25.352	1.37
305	11/17/02	10:30	14:15	2702.67	0.62		N/A	0.77		N/A	-19.481	N/A
301	11/17/02	14:50	22:36	428.96	0.592		N/A	0.578		N/A	2.422	N/A

Table 1 Summary of Well Tests carried out during Site Acceptance Test in November 2002 after installation

5. Operational History

ESMER MPFM has remained in continuous operation since its commissioning in November 2002 to date (July 2004). Measurements and diagnostics comprising stochastic flow features are routinely gathered at the Miri head office. Measurements made by ESMER have been verified against separator measurements during numerous well tests. In this paper we report some representative examples from a very large set of observations.

For example, Figures 6 -8 shows the results of the measurements made between 28 February 2004 to 26 April 2004 on a daily basis. The results show cumulative daily production obtained from measurements made every minute by ESMER and the single phase meters at the exit leg of the separator (PD and Ultrasonic for liquid and orifice for gas). During this time six different wells were

It is seen that ESMER follows the trend across a wide range of flow conditions. However it was noted that ESMER tended to under predict the liquid rate (Fig 6) and the gas rate (Fig7) at high flow rates and over predict them at low rates. This behavior is brought out more clearly in Fig 8 where ESMER measurements are plotted against separator measurements. At the time of writing of the paper, Petroleum Software Ltd is retuning the neural net model to compensate for the deviation between ESMER and separator measurements. For retuning, field measurements comprising features extracted from the flow during well tests are used together with the original flow loop measurements and other well test data. The retuned model can be installed remotely on the ESMER flow computer by downloading a small file (comprising neural net weights).

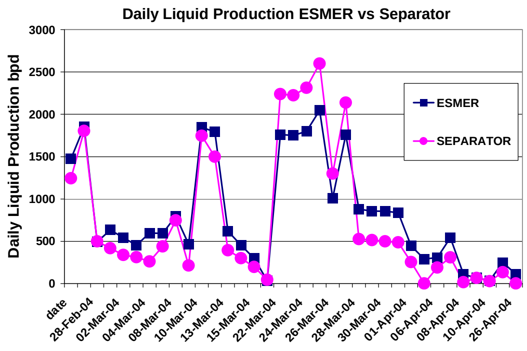


Figure 6 Daily liquid production Feb – April 2004

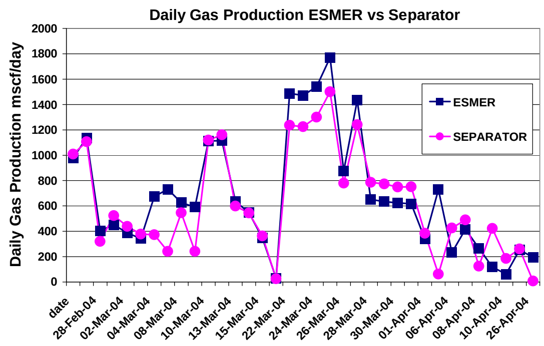


Fig. 7 Daily gas production Feb – April 2004

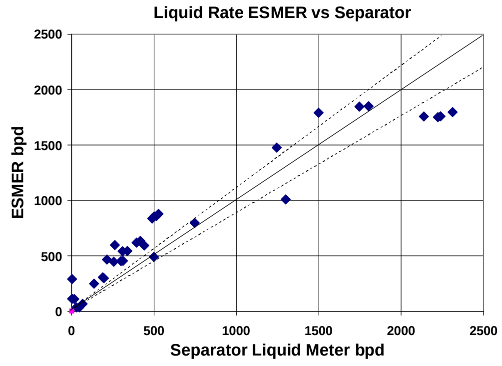


Fig. 8 ESMER vs Separator liquid prediction

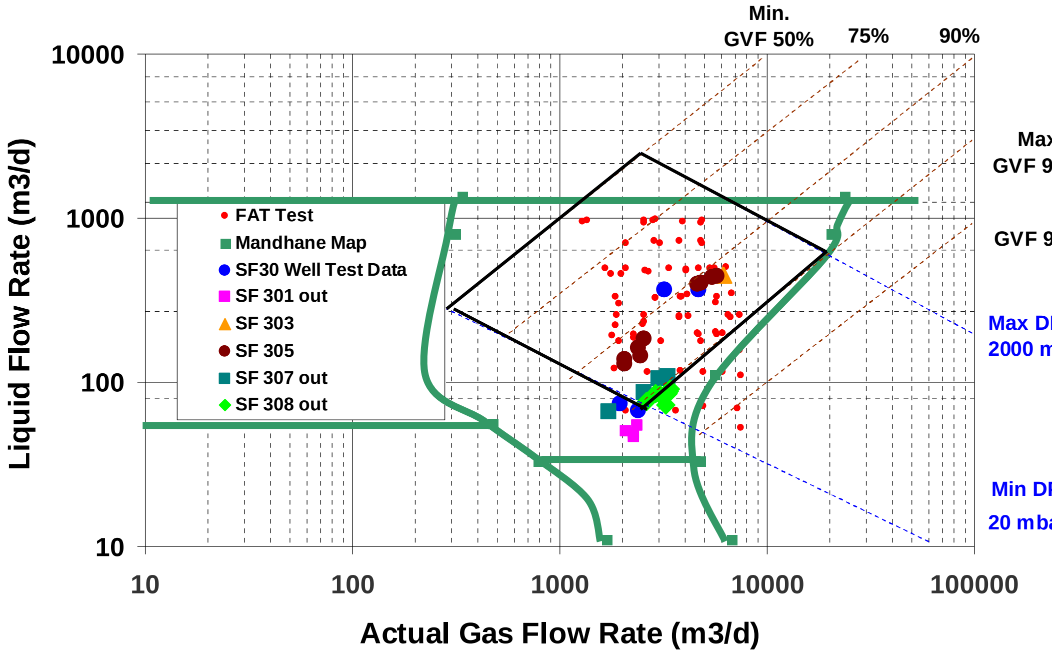


Fig.9 Operating envelope of ESMER T3A superimposed against well tests

6. Conclusions and Further Work

Our experience with a multiphase meter on the SFJT – C offshore platform between November 2002 and July 2004 have confirmed that multiphase meters can be used for unmanned well testing and thereby allow significant cost savings for offshore operations. In addition to its advantages for well testing, on-line measurement of GVF, water-cut and individual phase flow rates allows operators to monitor changes in the gathering facilities continuously and provides a real-time view of the status of production and flow lines. Another advantage of the multiphase meter is that instantaneous measurements performed during start up and shut down transients allows us to improve our understanding of the hydrodynamics of the reservoir near the well bore and should help to optimize gas lifting.

ESMER measurements were compared against separator measurements in a number of well tests. The repeatability and trending of the meter against different production rates and flow patterns was considered to be good during the 20 month observation period. ESMER measurements matched the separator measurements within +-10% for wells which were inside the operating envelope but the accuracy of the meter deteriorated for wells at the edges of the operating envelope and with the passage of time. Retuning of the meter at certain intervals is recommended to adapt to the changing characteristics of the flow conditions in the wells. ESMER methodology permits retuning by software and without any changes to the hardware reconfiguration.

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