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Multiphase Flowmeter Experience From A Research Perspective

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technology for life

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ABSTRACT

The worldwide growth of multiphase flowmeter (MPFM) installations is seen to be on a rising trend with uses onshore, offshore and even in subsea development. Data from SPE 74689 show that the growth takes on an exponential direction with up to 210 installations on topside facilities in the year 2000 and therefore this can only mean in the year 2008, this number and also its application would be far greater in field operation and future field development by oil companies. Similarly in Malaysia, there has been a growth in MPFM usage and has been operational since 1999.

This paper presents the importance of three-phase flow measurement, and an overview of the status of multiphase metering technology as well as discusses in detail the performance of the measurement technologies provided by current multiphase flowmeters installed across PETRONAS based on the experiences gained in operating those multiphase flowmeters. It also briefly discusses the limitations of current measurement technologies and identifies areas where more research work may be required to improve the current multiphase measuring technologies.

Keywords: multiphase, flowmeter, performance, PETRONAS, metering

1 INTRODUCTION

Multiphase Flowmeter (MPFM) development over the last 16 years has produced a variety of commercially available meters and in the past 12 years there has been a surge of installations by major oil companies especially in unmanned offshore platforms, marginal field development and deepwater field development.

The multiphase flow measurement for hydrocarbon gas and liquids (oil and water) has been identified as a cost effective alternative to the conventional metering technology using separation techniques due to a reduction in capital investment for the test separator equipment and consequently structural requirements.

MPFMs are light in weight, small in size and can be applied in remote onshore areas or offshore locations. These meters combine techniques to measure oil, gas and water-phase fractions and flow rates in a multiphase flow stream. Measurements are used for well monitoring, reservoir management, production allocation and evaluation of the need for well workovers or stimulations.

PETRONAS began field-installation multiphase well-metering systems in the early 2000s. Significant economic savings and improved well monitoring have been realized by this effort, with more units installed at offshore locations. Continuing development and evaluation of multiphase metering technology will provide additional benefits in both offshore and onshore applications.

This paper will review some of the experiences gained over the past few years in operating multiphase flowmeters and identify areas where more research work may be required to improve the current multiphase measuring technologies. Multiphase metering covers all phases of oil, water and gas in a multiphase flow; however the discussion in this paper will not cover the area of Wet Gas Metering.

2 MPFM REVIEW

In essence the MPFM is to obtain accurate data of flow and today the real-time, multiphase flow rate data are widely acknowledged to be of significant value for production optimization. This is particularly the case for high-cost deepwater and marginal field developments.

In view of the technology limitation in measuring individual flow rates of the multiphase fluid, current multiphase flowmeters are developed using inferential techniques or combined methods, applying a range of sensor technologies to determine the primary parameters such as **phase fractions (derived from the cross sectional area of the pipe occupied by each phase), phase density, temperature, pressure and phase velocities (derived from the axial velocities of each phase through each area).**

Today, the use of MPFM has been field proven and it has been accepted as a key means to reducing capital expenditure, in comparison to the fabrication of the test separator. Currently, most of the MPFM installations are radioactive based with partial separator technology and the accuracy obtained is claimed to be better than +-10%.

The current multiphase flowmeters available on the market can be split into two main groups;

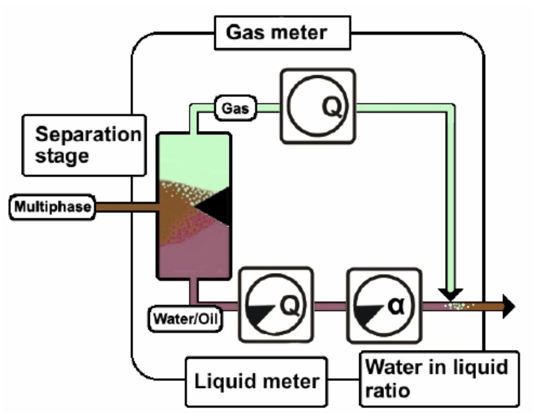
- One or more phases are completely or partially separated and then measured. The separated streams may or may not be recombined to form the original stream.
- All three phases go through a single conduit and are measured at the same time. This category includes all the so-called inline meters.

2.1 Compact or Partial Separation MPFM

The separation type applies the technology of a compact separator or flow diversion device where flow is roughly separated into liquid and gas streams and then it is metered.

By separating the multiphase fluid stream into (a) wet gas and (b) gassy liquid streams, conceptually one can address the multiphase flow measurement problem using two meters, each of which operates in a favourable region of the multiphase map. The success of such a strategy is obviously dependent on how well the separation can be achieved, and how well each of the two meters performs on the partially separated streams.

Key features include:



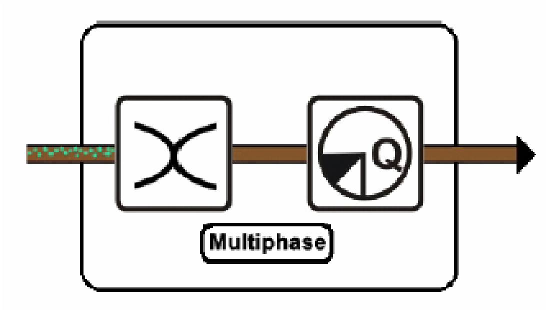
[1]Fig. 1 – Separation Type Meter

- Simple design, cost competitive;
- Not restricted to a particular flow regime;
- Design considerations pertaining to pressure vessels are usually waived;
- Components are usually commercially proven technology and low cost;
- Easy to operate; and
- Relatively mature compared to in-line metering systems.

[1] Norwegian Society for Oil and Gas Measurement, (Norsk Foreing for Olje og Gassmåling), NFOGM, Handbook of Multiphase Flowmetering, Revision 2, March 2005.

2.2 Inline MPFM

Inline or full-bore multiphase flowmeters are characterized by the complete measurement of phase fractions and phase flow rates within the multiphase flow line, with no separation of the flow, either partial or complete.



[2]Fig. 2 – Inline Meter

The volume flow rate of each phase can be represented by its area fraction multiplied by the velocity of each phase. In a typical gas/water/oil application, six parameters must be measured or estimated - three-phase fractions and three phase velocities. Some multiphase flowmeters require that all phases travel at the same velocity, thus reducing the required number of measurements to the three fractions plus the common velocity.

This is usually achieved through use of an ancillary device such as a mixer or a Positive Displacement (PD) meter.

This technology results in a smaller and lighter meter compared to the separation type. It has also been used in subsea conditions, however the components are more complex, leading to a higher cost and sometimes these components are radioactive.

Most of the commercially leading multiphase flowmeters in use today are inline devices, each being based on a subset of the flow and composition measurement principles.

2.3 Measurement Technology

The measurements are made using various combinations of sensors, sometimes in conjunction with auxiliary devices, such as flow mixers or separation systems, and in other cases with no flow conditioning at all. Sometimes the flow is measured in a single-phase gas or liquid state (e.g. separation vessel outflow) but possibly before the gas and liquids are stabilized. Therefore, phase behaviour computations must be applied when comparing these measurements to those made at downstream measurement points. In the context of hydrocarbon measurement, flow measured under these conditions is still defined as multiphase.

The combination of the phase fraction and phase velocity will provide information on specific phase volumetric flow rates while the temperature and pressure measurements will be used to calculate the fluid property variables such as phase density.

The MPFM is then set up to measure component velocities and two of the component fractions, since the fractional sum should equal 1. The phase mass flow rates of oil, gas and water are found by combining the fractional measurement, velocity measurement and density measurement.

The most common principles used for measurement of phase velocities and phase fractions are described below. [1]

Component fraction measurement method can be categorized into two main types;

1. Radioactive Attenuation
    a. Single energy γ -ray absorption
    b. Dual energy γ -ray absorption
2. Impedance (capacitance, conductance and/or resistance)

[2] Norwegian Society for Oil and Gas Measurement, (Norsk Foreing for Olje og Gassmåling), NFOGM, Handbook of Multiphase Flowmetering, Revision 2, March 2005.

Component velocity measurement method can be categorized into the following;

1. Cross-correlation
2. Differential Pressure
3. Positive Displacement Meter - mixture volumetric flow rate

Other measurement methods include

- Neural Networks and Signal Processing
- γ -ray densitometer - mixture density
- Single-phase gas meter
- Single or dual phase liquid meter

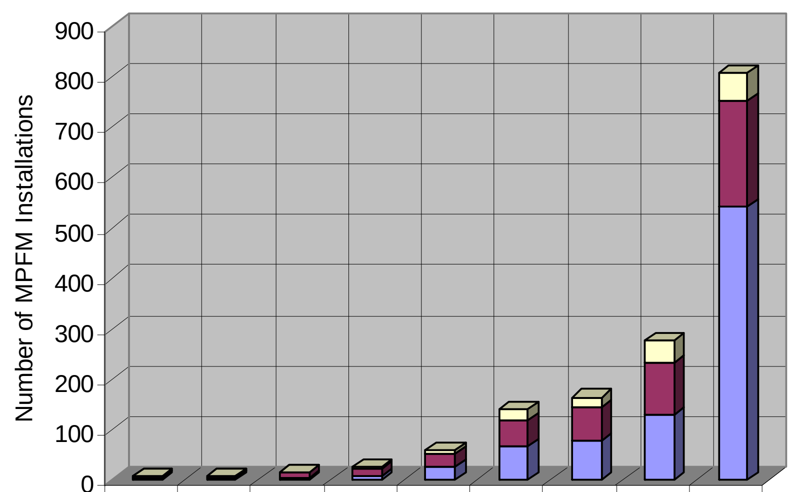
The details on each measurement technologies will not be discussed in this context and the readers are referred to the references for further details.

3 MULTIPHASE FLOWMETER IN PETRONAS

The worldwide growth of multiphase flowmeter installations are on a rising trend with uses onshore, offshore and even in subsea development. As the fields matured, the increase in gas and water production created more unstable flow conditions requiring more flexible multiphase solutions.

These meters have been in use as early as 1992 and data from SPE 74689 show that the growth takes on an exponential direction with up to 210 installations on topside facilities in the year 2000. This can only mean in the year 2008, this number would be greater and proves to show why many oil operators have considered multiphase meter installations in their operating fields and for new or future field developments.

Figure 3 below shows the rising trend in the use of multiphase flowmeters in the oil and gas industry. [8]



	1992	1993	1994	1995	1996	1997	1998	1999	2000
Offshore Subsea	0	0	0	1	5	22	20	43	55
Offshore Topside	1	2	10	17	29	52	66	103	210
Onshore	5	5	3	6	24	65	78	129	542

Figure 3: The use of Multiphase Flowmeter in oil and gas industry

Similarly in Malaysia, there has been a growth in multiphase flowmeter usage, whether by PETRONAS or other operators. The multiphase flowmeters are widely used in Peninsular Malaysia, Sabah and Sarawak and have been in operation since 1999.

Multiphase flowmeters are generally used as a replacement for the test separator for the purposes of production planning, reservoir management & monitoring, well allocation and field allocation in PETRONAS.

Figure 4 shows a location map of fields in Malaysia where these multiphase meters are in operation according to their field operators. [10]

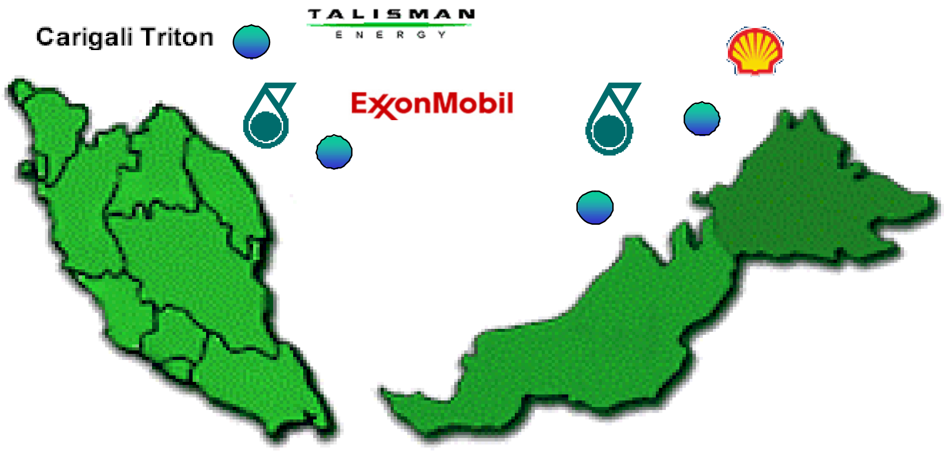


Figure 4: Fields with multiphase flowmeters

Performance data of individual flowmeters in PETRONAS' operations have been sourced and collected over the past few years.

The following are examples of the multiphase flowmeters used in PETRONAS' operations.

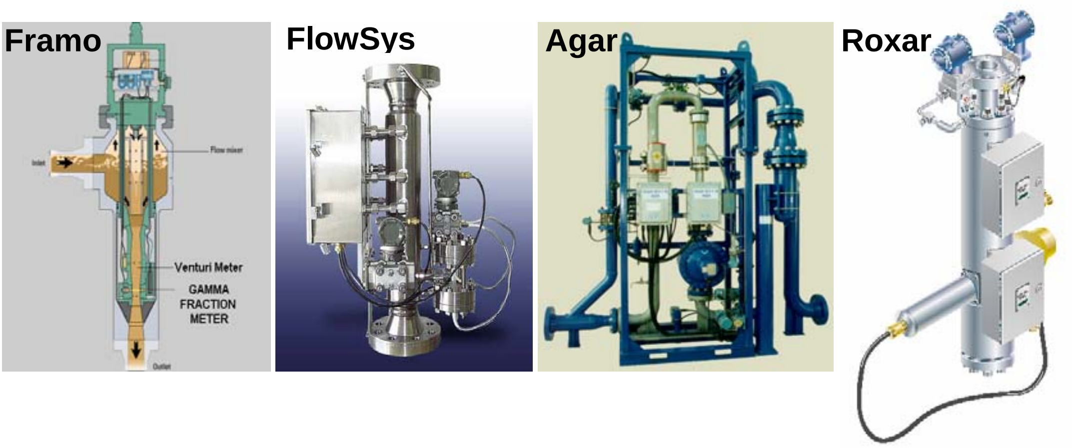


Figure 5: Some of the Multiphase Meters used by PETRONAS

4 TECHNOLOGY EXPERIENCE

All the currently available techniques used in most of the MPFMs require some knowledge of the fluid properties to enable measurement, for example dielectric constant or mass absorption coefficients at the measurement frequency are usually required. In-situ calibrations of sensor dielectric constants or gamma densitometer 'dry' constants are required. Should the fluid properties change over a period of time or should the flowmeter be linked to a multiple well manifold switching different wells through the meter, the new fluid properties are required for correct functioning of the meter.

Hence, the most important aspect in operating MPFM is to know the fluid properties and the expected flowrate of all phases of oil, water and gas throughout the expected life time of the reservoir. Fluid properties change as wells mature and thus the relevant fluid properties must be periodically updated to maintain MPFM measurement credibility. Industry's rule of thumb is that MPFM may have difficulties in measuring liquid with Gas Void Fraction (GVF) of more than 85% and oil with Water Cut (WC) of more than 85%.

The loss in reservoir pressure will cause a decrease in reservoir drive and hence fluid production. To continue production at the required level, gas lifting and/or water injection is introduced. In these cases, it will have an impact on both PVT and fluid properties. Gas lifting in an oil production well normally increases the Gas Oil Ratio (GOR), which generally means increase in GVF. Similarly water injection in an oil production well normally increases WC in the produced fluid. In the case of water injection, fluid salinity will be affected in addition to the fluid PVT. Hence the changes in fluid properties shall be analyzed regularly and updated in the MPFM algorithm.

In most of the MPFMs, capacitance or microwave sensors are common means of estimating water cut or water fraction in oil-continuous or wet gas flows. This capacitance measurement works as long as the flow is oil continuous, the water cut is below approximately 60 – 70%. For higher water cuts, the flow will normally become water continuous and in these situations the capacitance measurement must be replaced by a conductivity measurement.

From our experience, if the fluid has a GVF of more than 80%, partial separation meters tend to perform better than the inline meters. By separating the multiphase fluid stream into wet gas and gassy liquid streams, one can address the multiphase flow measurement problem using two meters; wet gas meter and conventional MPFM, each of which operates in a favourable region of the multiphase map. Therefore if gas lifting/injection is primary for a long period of production, partial separation meters are possibly the best option assuming no other limitations.

The use of partial separation meter may add to the weight, instrumentation and cost, however experience has shown that it will be beneficial for the fluid which has varying composition of GVF and WC over a long period of production life time.

Many of the commercial MPFM, which uses nucleonic densitometer (dual energy type), may not work well for heavy crude due to the difficulties in discriminating between water and hydrocarbon since their ionizing radiation properties can be very close.

For extra heavy crude, the use of MPFM which employs the Venturi or other Differential Pressure (DP) type meter to infer bulk or phase flow rate should be avoided since extreme changes in the viscosity of the fluid as it flows through will cause errors in the Discharge Coefficient. In these cases, it may be necessary to test at various flow rates in order to establish a range of discharge coefficients or correction factors for the anticipated operating envelope.

If sand production is anticipated during the production life time, MPFM with moving parts should be avoided. Although claims by vendors on the use of special material, from experience, the sand carried with the fluid is a source of erosion. This may be abrupt or gradual in the form of passing. In addition to that, sand presence may affect the accuracy of the flow rates. In-house experiences have shown that asphaltene/wax deposition, poor fluid lubrication property and the tendency to over-speed at high GVF will cause a number of instrumentation malfunctions such as physical damage due to sand erosion on oval gears, bearings and the inside wall of measuring chamber.

From experience, MPFM which uses the PD meter technology suffers from over spinning due to the fact that the production gas is too dry and therefore provides very little lubrication to the meter.

In-house experiences have shown that the gamma ray attenuation property varies with temperature since it has been observed that there has been a drift in the accuracy of density values. If significant temperature variation is expected throughout the operating period, it may be worth while to check the possible effect of fluid temperature change on the performance of the meter.

Pressure may be a factor with high GVF fluid since the density of gas is a function of pressure. If the accuracy of gas flow rates is of importance, it may be necessary to test across the possible pressure range rather than at one or two possible operating pressures.

Pneumatics valves, actuators, bearings and other instrumentation of the multiphase flowmeter also malfunction from time to time. Hence it is important for the meter suppliers to provide technical support in the areas of operation and maintenance locally to ensure the availability of the relevant technical focal persons to look into any problems arising from the breakdown of the multiphase meters.

5 CONCLUSION AND WAY FORWARD

In summary, experience shows that apart from the obvious financial benefits, the multiphase meters allow operators and reservoir engineers to monitor oil and gas production in ways not possible before, thus aiding production optimisation. In the long term, this will probably be the biggest benefit from the use of multiphase metering. [5]

Current multiphase metering systems are most certainly not “fit and forget” equipment in their present state of technology development which still require continuous fluid property inputs by operation as well as meter calibration and revalidation over the field life. [5]

It is also deduced that some of the multiphase meters seem to be unable to handle complex fluid properties such as wax, hydrates, emulsion and this is obvious in wax producing fields. Accuracy of such meters is also highly dependant on the composition map of a fluid flow and therefore when operating in a different regime other than the design, there will be misreading of production flow rates. Most meters require accurate and comprehensive subsurface data to ensure suitable selection of multiphase flowmeters since the initial phase subsurface data are not only limited but also have high uncertainty.

The potential market world wide for multiphase metering systems is very large and no single type of meter or metering approach can cover all applications at the current state of technology.

Research and development initiatives need to be conducted to develop a multiphase flowmeter for not only well testing, but also for the allocation purposes. Efforts have been started for a universal ideal multiphase flowmeter which can measure (typically better than $\pm$ 5 % of rate for each phase), and is non-intrusive, reliable, flow regime independent, and suitable for use over the full component fraction range.

In light of this there are a number of technology projects which are attempting to develop low cost multiphase flow measurement devices intended not only to be used for well testing but also for allocation metering (+/-5%) and then in custody/fiscal metering (+/-2%) in the future as well as in individual flow line for continuous real time well testing. These projects include the use of Neural Networks, measurement of Specific Heat Capacity, Process Tomography techniques, Laser Doppler Velocimetry (LDV) and the application of down-hole measurement techniques to areas where process conditions dictate that little or no gas is present.

Neural networks are being considered seriously to resolve the difficulties that arise from having to combine several measured signals to obtain the phase velocities and void fractions. Using neural computing has proven to be successful in predicting flow regime and transition in two-phase air–water vertical flow. More research is needed in this area if this technology is to be used in the multiphase flow meters successfully.

Tomographic methods could be applied to multiphase flow measurement in two ways [9]: (1) as an instrument to determine the flow regime in order to correct or compensate the readings from currently available MPFM, which are flow-regime dependent, and (2) as a radically new flow regime-independent method of multiphase flow measurement in its own right, without having to resort to any other principles.

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7 NOTATION

DP	Differential Pressure
GOR	Gas Oil Ratio
GTS	Group Technology Solutions
GVF	Gas Volume Fraction
LDV	Laser Doppler Velocimetry
MPFM	Multiphase FlowMeter
PD	Positive Displacement
PETRONAS	Petroliam Nasional Berhad
SPE	Society of Petroleum Engineers

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