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North Sea FLOW Measurement Workshop

Paper 3.1

The Influence of Liquid Viscosity on Multiphase Flow Meters

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North Sea FLOW Measurement Workshop

Paper 3.2

Multiphase Flowmeter Experience From A Research Perspective

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Multiphase Flowmeter Experience From A Research Perspective

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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;

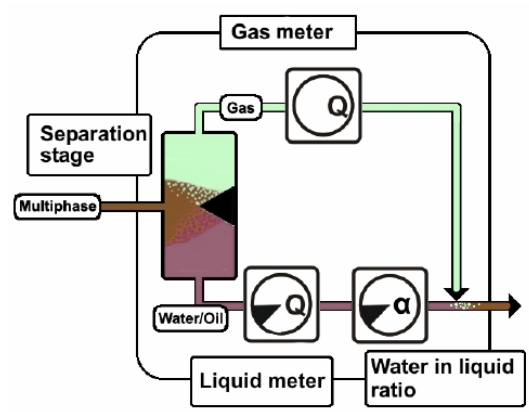
- One or more phases are completely or partially separated and then measured. The separated streams may or may not be recombined to form the original stream.
- All three phases go through a single conduit and are measured at the same time. This category includes all the so-called inline meters.

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:



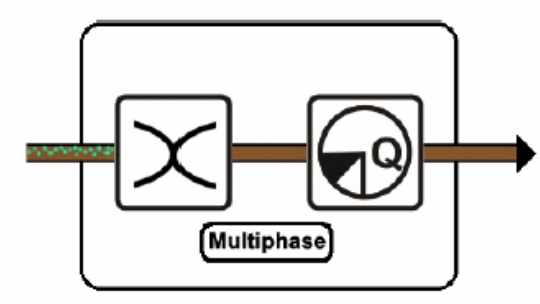
[1]Fig. 1 – Separation Type Meter

- 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.



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.

[2]Fig. 2 – Inline Meter

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

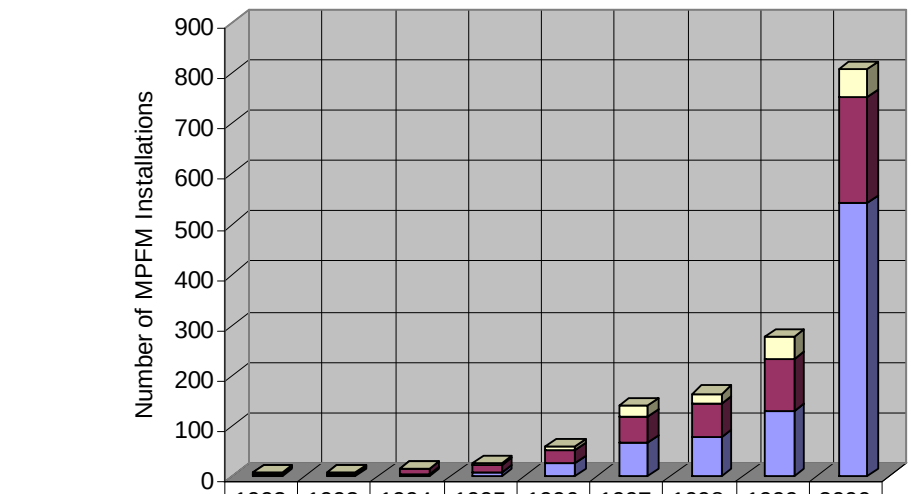
The details on each measurement technologies will not be discussed in this context and the readers are referred to the references for further details.

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]

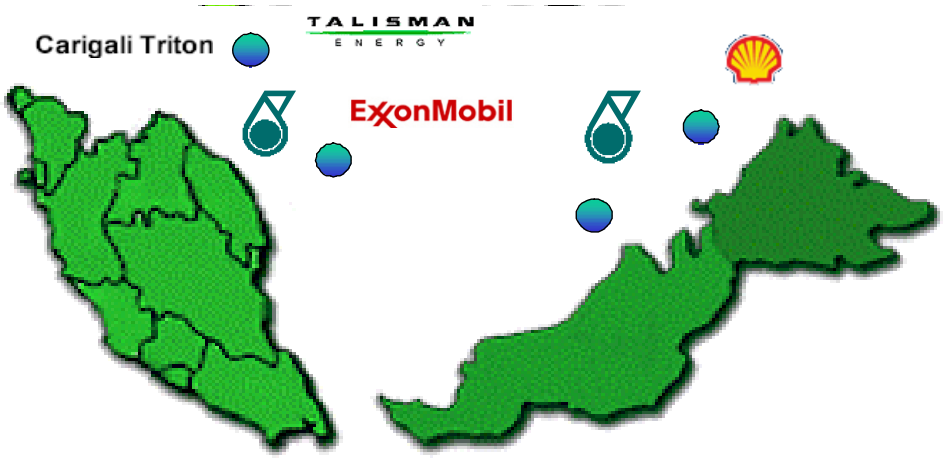


Figure 4: Fields with multiphase flowmeters

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.

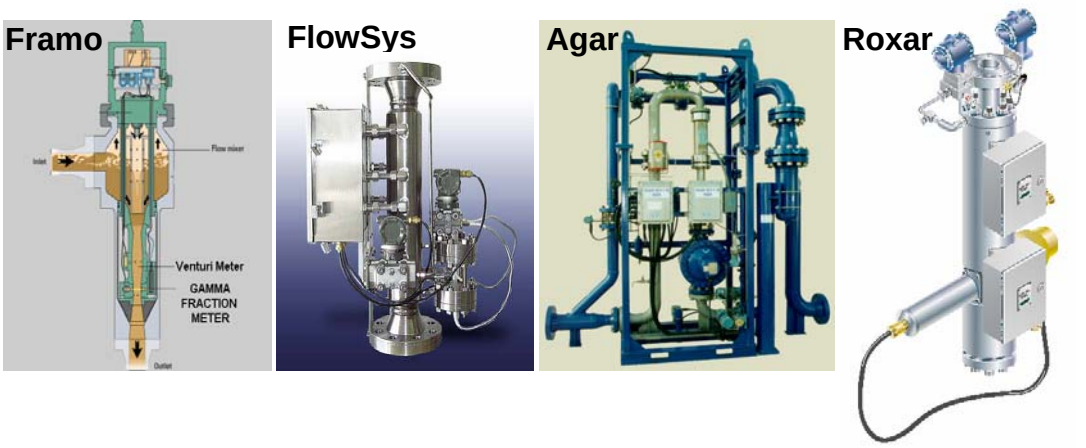


Figure 5: Some of the Multiphase Meters used by PETRONAS

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 ± 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.

6 ACKNOWLEDGEMENT

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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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North Sea FLOW Measurement Workshop

Paper 3.3

Deepwater Measurement Verification – A DeepStar-RPSEA Mandate

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Deepwater Measurement Verification – A DeepStar-RPSEA Mandate

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1 INTRODUCTION

The development of deepwater subsea fields worldwide has increased the need to more accurately measure commingled well production from fields of different ownership or royalty treatment. In these instances, it is crucial that the measurement of the produced fluids be dependable, reliable, and robust over periods of many years in order that a fair allocation is made. Of equal importance is the provision of timely performance information to optimize production.

As early as 2000, deepwater tieback projects in the Gulf of Mexico were dealing with subsea metering and the associated measurement performance. By early 2004 flow measurement experts were beginning to see what the future of subsea commingled flow really entailed from a technical perspective [Ref 1]. Consequently, since early 2005, a program has been underway to address gaps in subsea measurement technology, first under the banner of DeepStar, more recently as part of a program called the Research Partnership to Secure Energy for America (RPSEA). In its 2005 Energy Act, the US Congress created RPSEA, a major goal of which was to fund R&D for deepwater exploration and production, overseen by the US Department of Energy.

Although DeepStar funding is provided solely by the industry, and RPSEA is primarily underwritten by the US Department of Energy, the goal of both is the same – to provide the technology required to improve deepwater exploration and production operations. In the area of measurement, in-situ verification of subsea meters has been identified as a technology crucial to success in deepwater production.

Both the conclusions and recommendations for in-situ meter verification that resulted from the DeepStar program as well as the RPSEA investigation of new verification methods are described in detail in this paper.

2 THE DEEPWATER MEASUREMENT PROBLEM

Prior to the advent of deepwater oil and gas production, a phenomenon of the last ten years, the measurement of flow rates of individual wells in offshore operations was a much easier proposition. Each well would be produced through its own riser to the platform prior to its commingling with fluids from other wells. The flow of a single well could be measured through a test separator, and a sample of its liquid or gas phase could be easily captured and used for whatever purpose necessary.

In this way a complete dossier could be maintained on the history of flow from each well, with the only deficiency upon which all could agree being the lack of full-time, continuous flow measurement. Recent results [Ref.1] suggest there can be inherent problems with the use of well test as a means of flow rate determination. However, for the purpose here of looking at how deepwater flows can be measured, individual well tests will not be considered, since it is rare that a single deepwater well is not commingled with others and can be isolated through a test line to a test separator.

Thus, the world of deepwater production measurement is driven by the economics that rule how the fluids will be produced and conveyed to the surface. Given the fact that deepwater, high-pressure oil or gas flowlines might cost $5 – 10 million per kilometer to put into place,

the business driver here is obvious, viz., minimize the amount of subsea pipelines in any given situation. This is done by commingling production as soon as feasible.

The implications on well flow measurement are significant. Measurement of flow rates from individual well tests through typically long flowlines is simply not practical due mostly to the cost of deferring production of the other commingled wells while the well in question is tested. This is called well testing by difference. This practice is marginal at best and totally impractical when the wells are no longer under choke control [Ref. 2]. Thus, one is inevitably led to the conclusion that some form of meter is the more practical way to reliably measure well rates in deepwater scenarios.

But one has to ask how reliable is measurement of multiphase flow from each well? Can a meter that was installed on a well at the startup of the field be relied upon to give reasonable estimates of oil, gas, and water flow rates five, ten, or twenty years later? Is it possible that something has changed? Might the properties of the produced fluids have changed? Perhaps the well has produced compounds that in combination with water form scale, which now coats the inner walls of the meter – would the meter response be altered?

The best way to answer the reliability question is by means of a much-used example from the Gulf of Mexico, the Canyon Express Project [Ref. 3]. In that case, eight wells from three fields with several owners and differing royalty rates were commingled in two flow lines. The initial production from each of the wells was gas with small amounts of condensate and, in a few cases, water. At first the two flow lines balanced with topside separator measurement to a marginally acceptable level, about 6-8%, but within a few months the balance on each line had deteriorated to anywhere from 15-25%. At that point in time the total production from all wells averaged about 450 mmscfd, so a 20% imbalance represented 90 mmscfd, or more than $250,000 per day at the prevailing prices of 2003.

It is not the intent here to rehash the details of that work (which ultimately led to a satisfactory conclusion), but simply to point out how quickly bad measurement can adversely influence the economics for both partners and regulatory authorities. It is important to note that the meters and their sensors – pressure, temperature, and differential pressure – appear to have worked properly throughout. The presence of scale on the walls of some (not all) of the meters is felt to have caused the response of the meters – essentially their discharge coefficient – to have changed from what it normally should be.

The important fact here is that conditions changed with time. Whether it is the fluid composition or the condition of the meter itself, the response of multiphase flow meters change over time, and possibly not just in a small way. At a cost of $250,000+ per day, verification of the accuracy of flow rate measurements on commingled wells becomes crucially important.

3 THE DEEPSTAR PROGRAM

DeepStar is a consortium of companies with interest in developing technology for subsea exploration and production. Formed in 1991, it conducts R&D projects that are funded through annual membership fees. Projects are proposed and selections made by member companies on a two-year cycle. The ninth Phase is currently underway, and will run through the calendar years 2008 and 2009.

In 2005, a group of Gulf of Mexico operators, who had conducted their own internal studies of gaps in subsea measurement technology, organized a DeepStar workshop to address deepwater measurement issues. Sixty people attended the DeepStar Workshop in Houston, and concluded by resolving to submit a deepwater measurement CTR. The CTR was submitted, funding was approved, and the DeepStar Project 8302, *Improved Multiphase Metering for Subsea Tiebacks*, was executed over the period from January 2006 through December 2007. Work on eight major gaps resulted in detailed reports that are available to DeepStar members at the DeepStar website.

Of the eight tasks, that of Meter Verification was arguably the most important for the future of deepwater measurement. It will be discussed in detail in what follows, as well as the RPSEA project that resulted.

3.1 Verification Task

The flow rate of production flow constituents (oil, water, gas) are measured subsea through the use of wet gas or multiphase flow meters. These flow meters are tested in a flow loop during their design phase in order to determine the performance of the meter in different flowing conditions. Flow meter manufacturers incorporate a series of tests in the Factory Acceptance Test (FAT) of the meter to verify its performance, especially that of the sensors.

In addition, representative meters are sometimes tested in flow loops before installation in an attempt to match the expected well output conditions as closely as possible. It is never possible to exactly duplicate the subsea conditions, so compromises must be made.

The flow meter must be given information with regard to the physical properties of the flowing fluids. However, until a well is actually producing, it is difficult to precisely characterize its fluids. As mentioned earlier, fluid properties may also change over time as the well produces.

If only a single well is flowing through a dedicated flowline, a sample can be taken and analyzed on the surface. Since almost all deepwater production involves commingling of several wells into a common flowline, characterizing the flow from individual wells becomes difficult. An approach in that case is to shut-in all wells except the one under study, which results in deferred (sometimes lost) production. Additionally, as suggested in Reference 1, the other wells tend to behave differently as the operating conditions in the flow line change due to the addition or removal of a well. In this situation, the characteristics of the well's production may have changed and the flow meter's parameters will need updating.

But what if the current parameters are correct? How can the producer know that the flow meter is functioning within its specifications and that it has not drifted away from its calibration point, which could occur if the flow meter's electronics or sensors have failed or shifted? Even if the meter and sensors are true, the well fluids may have altered the meter's response by deposition of scale, wax, hydrates, or the like.

3.2 Current Approaches

Subsea multiphase flow meters (MPFMs) have been installed in a number of locations and configurations in the typical subsea pipework structure. Currently, most flow meters are installed as an integral module on either the wellhead tree, in the jumper, or in the manifold. The jumper installation has so far been the most prevalent location for Gulf of Mexico (GoM) installations, although tree installation has become increasingly popular.

For applications where there is either a dedicated test line or individual well flowlines back to a topside facility, the need for subsea MPFMs can be questioned. Therefore, projects with these configurations often do not include subsea MPFMs. However, even when dedicated flow lines exist, often future projects are planned that would constitute a commingled flow situation. In these cases subsea MPFMs may be used such that eventually a fully flow monitored situation can exist.

Thus, the vast majority of <u>deepwater</u> subsea MPFM installations are applications where the production from a number of subsea wells is commingled subsea and transported in one or two flowlines back to a topside facility, or where a new tie back has been added to an existing well system. At the topside facility, the flowline(s) may be diverted to a dedicated test separator, but are usually then commingled before production separation.

As discussed earlier, a major concern with deepwater applications is how to verify that (1) the subsea MPFM has experienced no drift in the sensors or electronics, (2) that the input fluid parameters to the subsea MPFM are up to date, by either subsea or topside sampling, and (3) that well fluid flow through the meter has not altered its response.

The following sections describe processes and procedures that are currently used to verify correct operation of subsea MPFMs in situations where direct well testing through a dedicated test line is not possible.

3.2.1 Flowline Balance

Monitoring the material balance is a simple way to determine that the meters connected to the flowline in question are functioning within their calibrated range. The test might be performed once every month, but it can be done on a real-time basis if necessary.

The method simply compares the topside measurements from the production separator (or whatever is used to monitor the flow through the flowline in question) to the sum of the measurements from the subsea MPFMs. The Field Factor is defined as follows:

$$\text{Field Factor} = \frac{\sum \text{Production Separator Flowrates}}{\sum \text{Subsea MPFM Flowrates}}$$

The sum of the subsea MPFMs should ideally be less than ±5% of the total topside fiscal metering station or test separator, i.e., the Field Factor should typically be between 0.95 and 1.05. A Field Factor outside this limit is an indication of a problem in the system, and diagnostic procedures should be initiated to investigate the cause of the imbalance.

Of course the subsea MPFM flowrates must be made applicable to the pressure and temperature conditions at the outlet of the separator. Normally all measurements are made relative to standard conditions which also involves a phase behavior model. And, since there may be significant dissimilarities in the commingled fluid properties, the combination of the contributors affects the quantities of the respective single phase gas and liquid outflow from the separators. Even obtaining a technically defensible material balance is challenging for this type of application.

3.2.2 Measurement by Difference

Well testing using Measurement by Difference is a common technique to estimate individual well rates, as well as to verify meter performance when a flowline imbalance has been noted. For Verification, there are two ways commonly used to perform Measurement by Difference. In the first, one well is shut-in for a period of time, until the system stabilizes. The difference in flow rate measured topside is the estimated flow of the shut-in well, which is then compared to the reading of the MPFM on that well.

The second method may be useful when there are two flowlines used for production from one or more subsea manifolds, to which there are a number of wells connected, where each well can be directed to either flowline. The split of wells per flowline will generally be grouped with approximately the same amount of total flow in each flowline. During test, one well is switched between flowlines, and the change (negative change in one flowline and positive change in the other) is the rate of the well under test. If the flowline imbalance moves to the second flowline, that well's flow meter is the a source of some or all of the imbalance.

The second method is preferred from a production standpoint, as all wells continue to flow during the test without deferment.

Both methods have flaws, as the backpressure on the wells not being tested changes as a result of either shutting-in a well or switching it from one flowline to another. The change in operating conditions for these other wells will change their flow rates, and hence influence the accuracy of the well test. Because of this, it is essential that care be taken to adjust the chokes on the wells not under test so that their flow rates are as nearly the same as possible after the well under test is shut-in or switched. This of course presumes that the wells are under choke control, a condition not often likely to exist except in early days of field life.

3.2.3 Use of Mathematical Models

A third well test method to verify the performance of the subsea MPFM is through the use of mathematical models. This can be achieved through manual calculations such as nodal analysis, using available pressure and temperature transmitters and a mathematical model of the complete flow path from bottom hole to the topside facility. The system is first established by using available three-phase mathematical models, then setting up the field with well and pipeline trajectories, diameters of all components of sections, friction coefficients for each component or section, heat transfer coefficients, sensor locations, fluid properties, choke geometry, etc. This is a tedious job, with a likelihood for errors. These models also must be "tuned" to the actual conditions – so in a sense, they themselves must be calibrated prior to being used to verify the MPFMs.

To simplify or automate the nodal analysis process, a few companies have developed internal nodal analysis programs (Excel spreadsheets, etc) to reduce potential errors and the amount of work needed to generate these calculations.

Another level in mathematical models is the use of Virtual Meters, or Model-Based Meters. These are fully automated, online, real-time nodal analysis software packages that combine sensor measurements (P,T) with mathematical models. These can be used as stand-alone metering systems, or in combination with subsea and/or topside MPFMs, as well as with other measurement devices such as downhole meters. Virtual Meters are configured with the same models as described above, and are tuned during installation to match the real measurement data. Virtual sensors and meters can be established anywhere on the flow path. For the purpose of subsea MPFM verification, a virtual MPFM is established at the same location as the physical MPFM, and on-line and real-time comparison can be made between the two measurement systems.

Virtual Meter outputs can also be used to automatically calculate the Field Factor, and will assist in selecting the correct choke settings if the Testing-by-Difference method is used. Thus, when there is a flowline imbalance and the topside meters have been verified, mathematical models (Nodal Analysis, Virtual Meters) may be useful in validating the performance of an individual subsea flow meter.

Unfortunately, there are few published studies evaluating the performance of mathematical models in multiphase flow. Currently, the accuracy of the models depends on the well's flow regime.

3.3 Fluid Properties Determination

All MPFMs, to a greater or lesser degree, require knowledge of a variety of fluid properties in order to function properly. This information is used in the meter to account for differences in sensor response at changing conditions, as well as to allow conversion of results from actual to standard conditions. Errors in the values of these fluid properties will have a direct impact on the overall meter uncertainty, and should be quantifiable by the meter vendor through a meter sensitivity analysis for the various measured properties.

Current MPFMs use various measurement techniques within the meter. Most of those used are influenced by fluid properties, such as salinity of produced water and hydrocarbon fluid density, thus it is necessary to insure accurate and up-to-date information on both produced water and hydrocarbon properties. This is especially challenging in cases such as (i) water-flooded reservoirs where there is a possible mixing of aquifer and injected waters, resulting in a varying salinity; (ii) compositionally graded reservoirs, where produced hydrocarbon gravity and composition changes as the well is produced; and (iii) production from multiple zones with differing fluid properties within a single well.

For meters that employ nuclear measurements, mass attenuation coefficients for the oil, water and gas are needed, and are best obtained by in-situ measurements. If it is not possible to make the required mass attenuation measurements in-situ, they can be obtained by collecting and analyzing produced fluid samples. If samples are not available initially, they

could be obtained later, and the output data from the flow meter could be re-processed with the new properties.

In general, the required fluid samples needed to allow correct operation of the subsea multiphase flow meter can be obtained in one of two locations, topside or subsea. While topside sampling is more readily achieved, subsea sampling is far more useful, but also far more challenging, and not commonly done at this point in time in deepwater. To take subsea samples of the production fluid will require the use of an ROV. The sampling location should be ideally located close to the meter to ensure that conditions are close to those experienced by the meter. For example, if the meter is located close to the production choke, the sample point must be located on the same side of the choke as the meter. It is not necessary that the proportions of liquid and gas be "representative", but it is required that the liquid and gas samples be representative of their respective phases.

While deepwater subsea sampling is in its infancy today, it is anticipated that this activity will become routine in the future, particularly as subsea processing becomes commonplace.

3.4 ROV-Deployed Check Meter

The DeepStar Verification program as originally formulated was called *ROV-Deployable Check Meter*, to consider the possibility of using an ROV (Remotely Operated Vehicle) to deploy a 'check meter' into a flowline to verify the performance of a deepwater subsea wet gas or multiphase meter. However, it soon became apparent that this approach presented considerable structural and operational challenges, such as additional by-pass pipes and valves, as well as additional leak-paths in the system. Other approaches were clearly needed.

The possibility of utilizing ROV-conveyed measurements that didn't compromise the pipe integrity – e.g, clamp-on – to verify the correct operation of a permanently installed subsea multiphase flow meter was considered. Even though subsea clamp-on measurements are currently almost non-existent, there have been encouraging tests that indicate that such may be available in the future.

One promising technology that has been evaluated on surface flow lines is a clamp-on, sonar-based flow measurement for simultaneously measuring volumetric flow rates and process fluid sound speed [Ref. 4]. The technology utilizes a sonar array processing technique to achieve these two independent measurements that characterize the process fluid. When used in conjunction with a differential pressure measurement, it is possible to estimate both gas and liquid flow rates in a wet gas stream [Ref. 5].

Another flow measurement technology that might be considered, one that has achieved wide adoption for single-phase measurement, is ultrasonic transit-time flow measurement. Testing of gas ultrasonic flow meters with wet gas was first tried over a decade ago, and the methods have shown promise for two-phase wet-gas measurement [Ref. 6]. Even though there are as yet no marinized ultrasonic flow meters, there are commercially available clamp-on ultrasonic flow meters from several vendors. A marinized version of an ultrasonic flow meter may offer an alternative verification technique for use with certain wet gas flow regimes.

A third meter system that will be a candidate for subsea clamp-on multiphase measurement in some flow regimes is that offered by Neftemer [Ref. 7]. Consisting of a gamma-ray source-detector system sampled at a fast rate, the meter provides credible results in low-GVF flow regimes when used in combination with pressure and temperature.

4 RESEARCH PARTNERSHIP TO SECURE ENERGY FOR AMERICA (RPSEA)

In its 2005 Energy Act, the US Congress allocated $50 million per year for ten years for R&D in exploration and production technology, with almost 40% of that sum directed toward E&P research for "Ultra Deepwater Applications." The first Cost-Time Resource Sheets (CTRs) were received and evaluated by RPSEA during Q2 and Q3 2007.

As the DeepStar work was moving toward its conclusion, having identified areas for future investigations in Verification and a number of other sectors, those operators that had actively been involved began looking at RPSEA as a vehicle for pressing forward with their ideas that might lead to Real-World solutions. A CTR was prepared for this purpose and submitted to RPSEA, which selected it as one of its earliest projects. A Request for Proposal was posted in November 2007 for DW1301, *Improvements to Deepwater Subsea Measurement*. In April 2008, the Letton-Hall Group and its technical partners, Oceaneering International (OII) and Multiphase Systems Integration (MSI), were selected to oversee execution of the work.

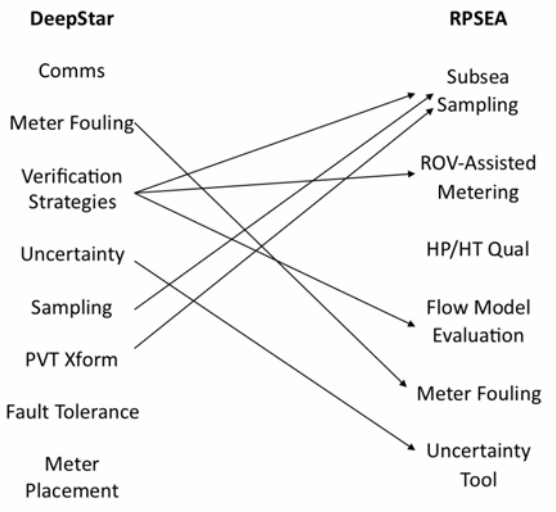

Figure 1. Influence of DeepStar Project 8302 on RPSEA Project DW1301.

In retrospect it is interesting to note how the DeepStar subsea measurement project spawned so much further effort in this important area in the RPSEA program. Figure 1 is an illustration of this stimulating effect.

4.1 Program Description

The RPSEA Measurement Project, *Improvements to Deepwater Subsea Measurement,* is the largest program included in the current Ultra Deepwater Program. Eighty per cent of the $4.5 million funding for the work is provided by U. S. Department of Energy, with twenty per cent by a JIP of companies from the industry. Work on this 30-month program should begin in November 2008.

Of the six technical tasks included in this project, three of them are related to areas identified in the DeepStar program as key elements for improved verification of the performance of subsea multiphase flow meters. These Tasks are described in the following sections.

4.2 Deepwater Subsea Sampling

Sampling at or near the wellhead is needed to provide samples representative of the fluid flowing through the subsea meter. This will yield more accurate fluid properties, and hence more accurate multiphase measurements. A method for ROV-deployed subsea sampling is required to capture representative fluid samples at the multiphase meter and other locations at various times throughout the life of the well.

The few subsea sampling systems that exist are unique to specific manufacturers, and information about their effectiveness and reliability is scarce. Developers and manufacturers appear to have focused on subsea multiphase flow meters, rather than the sampling systems needed to support them.

Another approach that would relieve users and manufacturers from the costs and complications of proprietary systems with varied designs and procedures is to develop standardized sampling systems, ROV interfaces, and sampling protocols. The standardized interface would be available to manufacturers so they could provide the connections required to obtain samples from their meters as well as standalone sample systems. The interface would be mountable in various subsea locations, in order to facilitate sampling for reasons other than multiphase metering. A standardized approach is consistent with the desires of the production companies. The DeepStar report recommended a guideline or protocol for

collecting subsea samples to minimize concerns about sample quality, repeatability and success rate.

In this RPSEA task, existing sample systems and conceptual designs of sampling systems deployed via an ROV will be reviewed for their potential as standardized sampling systems. A candidate system will be selected, developed and tested with an ROV, in a pressurized reference loop as well as in a special test tank that supports ROV work. Draft standards for sampling connections (interfaces), tools, equipment and operations will be developed.

4.3 ROV-Assisted Subsea Measurement

While the subsea flow meters may be perfectly capable of measuring multiphase flow from wells when they are first installed, this becomes an increasingly difficult task as fields (and equipment) age. The Verification portion of the DeepStar program suggested that it may be possible to utilize a clamp-on subsea meter to identify which permanently-installed meter in a commingled system is generating incorrect measurements. This second task in the RPSEA program will address the issue by developing methods to convey measurement equipment to the well site where it will be clamped on at a pre-defined position.

A candidate clamp-on device will be selected for the purpose of demonstrating the concepts and testing the system of conveyance. It should be emphasized that the meter selected for the project will simply be a demonstration vehicle; the system will be designed in such a way that other clamp-on meters can be accommodated in future projects.

The scope of work includes basic engineering design to marinize the candidate sensors for use in deepwater, non-intrusive, multiphase metering. Requirements will be determined for the following meter interfaces for a “clamp-on” installation:

- Meter-to-subsea piping interface, including so-called “landing zone” specification;
- Subsea meter power from ROV;
- Subsea meter signals from/to ROV;
- Subsea meter communications protocols between sensors and ROV;
- Establish real-world methods for acquiring, storing, transmitting, manipulating, and displaying data from the meter.

As part of the program, representative sensor hardware will be acquired and marinized. The details of standardized meter-ROV and ROV-subsea hardware interfaces for clamp-on meter will then be designed, built, tested, and published.

Finally, methodologies that use clamp-on measurements like these to reduce the uncertainty in allocation among wells will be developed. It is felt that the accurate comparison of readings among all meters in an allocation group is conceivably more important than the reading of any single meter in the group.

4.4 Evaluation of Flow Modeling

Flow modeling, commercially called Virtual Flow Meter (VFM) technology, appears to be maturing rapidly and is becoming increasingly popular. Unfortunately, very few studies have been published that critically evaluate the performance and accuracy of commercially available VFM’s for subsea systems. This hinders the utilization of the VFM by the industry.

This RPSEA task will address this gap in documented studies of current VFM technology. The critical performance evaluation of existing VFM’s will be carried out by comparing the predictions of the VFM’s with actual field data from subsea multiphase or wet gas flow meters, or from other measurement sources, including by-difference techniques utilizing surface separators. As such evaluations are documented in publications, positive results will encourage the industry to utilize the VFM technology in verification or allocation applications where it makes sense to do so, and to avoid its use in applications for which it does not fit.

In the evaluation of current VFM systems over a range of multiphase flow conditions, the objective will be to identify areas of strengths and weaknesses. By documenting where existing VFM's can function within the required error limits, boundaries can be established on their use. By categorizing the operating regions where the existing VFM's need enhancements, this program will provide guidance to future needed developments to extend the operating envelope. Both oil- and gas-dominant systems will be investigated.

VFM software is not something that must be installed at the same time as the physical multiphase flow meters, as long as care is taken to install proper sensors to be used at the various points of measurement (nodes). The fault tolerant nature of the VFM system is an advantage, since a failed "hard" sensor will reduce the number of nodes, but will not cause a complete loss of information.

While VFM technology appears to be maturing rapidly, it is not now an equivalent replacement for good physical metering. It is generally viewed as a back up to be maintained and used in case the primary metering system is unable to function.

Several commercial vendors of VFM systems have offered to work with the project team on this program. The purpose of this Task is **not** to rank the performance of the systems from the different suppliers, but to evaluate the flow modeling systems with regard to their applicability for use in various subsea monitoring, verification and allocation applications.

Development and application of methods to benchmark the selected flow modeling methods and criteria for evaluation of several commercial VFM systems will be subcontracted. The subcontractor will conduct the evaluations utilizing recorded and "live" sensor data from wells over a range of operating flow conditions.

5 RECOMMENDATIONS

The most important point to remember when utilizing subsea wet gas or multiphase flow meters for monitoring or allocation is that their performance must be verified periodically. For commingled production, an initial indication of a problem would be a change in the flow line balance outside an established limit. The challenge is then to identify the responsible flow meter or meters through the use of a chosen verification technique.

At the conclusion of this DeepStar Subsea Meter Verification Program, the following recommendations were offered:

- When designing a subsea tieback system, give careful attention to the placement of the flow meter and how it will be verified. As a minimum, the control system must be configured for ease of flowline balance monitoring.
- Consider adding a sampling port near the subsea flow meter to enable periodic sampling of fluids from individual wells whenever a ROV is on site for required inspections. RPSEA will hopefully provide guidance on how this is best accomplished.
- If flow meter verification will utilize a by-difference technique, design the control system to allow the flow from the wells not under test to be maintained at a constant flow rate where such is possible. If the flow rate cannot be maintained, try to estimate it in some way.
- For a new system, be sure to provide sufficient bandwidth in the communication system to allow better flow meter diagnostic data, and permit possible recalculations using prior 'raw' data if fluid properties are found to have changed.
- Be diligent in the maintenance and calibration of the topside meters on the output legs of the separators.
- For new tieback wells, consider the addition of sensors, both downhole and along the flowline that can be utilized with ever-improving mathematical modeling systems to provide verification means for the subsea meters.

The RPSEA Ultra Deepwater program *Improvements to Deepwater Subsea Measurement* will provide improvements in the ability to verify the performance of subsea multiphase flow meters in the areas of:

- Deepwater Subsea Sampling;
- ROV-Assisted Subsea Measurement;
- Evaluation of Flow Modeling

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