UPM 18130

Multiphase Flow Meter Implementation, Verification and Use for Calibration of Virtual Metering in Kashagan Project

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Abstract

Production metering is one of the essential measurements that are performed in the field. Kashagan is a giant oil field, which has a set of challenges to tackle in order to implement production flow rate measurement. These challenges are: high pressure and high temperature environment, high H2S content, harsh weather conditions and most importantly unmanned production islands. To overcome all these challenges non-intrusive technology is required, which is able accomplishing multitude of tasks with minimum intervention.

Multiphase flow in well conduits, e.g. production tubing, tubing head and flow line, is most likely inevitable phenomenon during whole production life of any oil field. Kashagan is not an exception.

The technology that used to address the challenges in Kashagan field is multiple energy gamma ray source MPFM. After performing flow loop tests in Norway and getting approval from the State Authorities for production reporting using MPFM, unmanned satellite production islands had been equipped with MPFMs. There is one MPFM serving a group of wells installed on one of the islands, and some of the other islands have a MPFM installed on each well.

The MPFM technology is used for hydrocarbon allocation, well performance evaluation, production optimization, well flow line integrity monitoring, etc. in Kashagan project. The technology is also used to test and calibrate virtual flow metering methods. The last made it possible to increase confidence in virtual metering which is used as real time performance estimation for wells which are not equipped with individual meters and also as backup for existing MPFM installations during their malfunctioning.

The MPFM technology was verified by both the operator and manufacturer during first and subsequent operation of the meters. Since the MPFMs per well do not have any possibility to cross check against reference, like test separator, the operator used other means of checking the MPFM data.

The implementation of the MPFM technology per well improved the well performance evaluation and enhanced the understanding of the well behavior.

This paper discusses NCOC N.V. and Schlumberger experience with this technology at Kashagan conditions. It also discusses challenges of having MPFM upstream of production choke manifold versus downstream choke manifold and defining PVT model around bubble point pressure. The paper also describes the methods of MPFM data validation touches on the impact of MPFM technology on production allocation. The brief description of virtual metering method and results is also described.

Introduction

Although there is large amount of information on MPFM technology, it is evident that each oil and gas field has its own set of challenges with regards to production measurement. It is not always possible to find solution to all challenges with one technology and approach.

Measurement specialists of operating companies need to be in close contact with manufacturers to specify the problems and challenges in timely manner so that the solutions are applied before valuable information is lost. This paper demonstrates how the collaboration between manufacturer and the operator can lead to meeting production measurement requirements of an oil and gas field operator.

MPFM technology

One of the MPFM technologies used in Kashagan is Vx PhaseWatch (MPFM).

The selected technology is based on mixture velocity and uses venturi equation based on the same concept as that used in the monophasic flow, which combines the differential-pressure measurement together with the mixture density measurement. The fraction measurements are based on a dedicated smart detector associated with a chemical source (Ba-133) set at the venturi throat to acquire data at high frequency to account for the fluctuation of the flow in a multiphase environment.

The flowmeters are composed of the following main components:

- Venturi section
- Barium-133 chemical source and detector assembly

- differential-pressure sensor
- pressure sensor
- temperature sensor.

Primary fraction measurements are made from the two first energies of the multiple-energy nuclear measurements called high- and low-energy. Two energy level count rates are measured by detector and coupled with individual phase attenuation coefficients and density values are used to calculate phase fractions at line conditions.

The main principle of VX flowrate measurements are based on combination Venturi tube and the dual energy gamma ray meter. The general schematic and actual picture os VX is shown in Figure 1. The multiphase flow passing through Venturi section creates pressure drop, enabling measurement of total mass flow, while gamma ray measurement provides data on oil, water and gas phase fractions. Combining the results of two measurements and using PVT properties of the fluids, volumetric flow rates of each phase are provided at standard conditions [2].

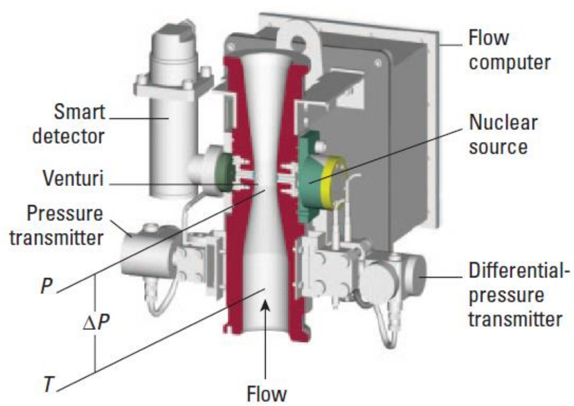

Figure 1: Simplified sketch of Vx (Source: Fundamentals of Multiphase Metering, Schlumberger).

Figure 2: VX MPFM installation on unmanned island

Challenges in Kashagan for production measurement

Kashagan is giant shallow water oil and gas field located in North of Caspian Sea. The oil reserve is categorized as volatile at high pressure and temperature, which also contains high content of H2S. The H2S content is one of the reasons which led to unmanned satellite islands and central island (hub) for preprocessing the crude before sending to onshore facilities.

The unmanned island (island), which is subject of this paper, is equipped by MPFM per well. The MPFMs were installed upstream the choke. This installation, as it would be evident down the line, poses several measurement challenges:

1. Conditions at upstream the choke valve varies with the choke operation which leads to changes in PVT properties, e.g. shrinkage, density, etc. which impacts the phase and rate calculations;
2. The MPFMs were not tested and validated at pressure and temperature conditions present at Kashagan wells which as a consequence means that there should be validation tool.
3. No downstream test separator to compare against.

First challenge was identified in the very beginning of the operation of the MPFMs. The phase and volumetric rate values per phase from MPFMs were unrealistic and led to operations with lack of confidence on these meters.

Second and third challenges are more related to how the operator can be confident, and to what extent, about MPFM readings before using for hydrocarbon allocation. The operator has built validation tool to check the MPFM calculations.

The approaches taken to solve these problems are explained in subsequent sections.

Well testing requirements

Well testing requirements and frequencies are set by government. It is not allowed to start newly drilled well without testing equipment, i.e. before commencement of production all the well test equipment shall be ready.

Kashagan consists of several satellite islands, one of which is manned and the others are unmanned. Manned island has one test separator and one MPFM. One of the unmanned islands has one MPFM. At these islands wells are diverted to test separator and/or MPFM through test line one by one. It is possible to comingle several wells to test line. Other unmanned islands are/will be equipped with MPFM per well, i.e. real time well performance measurement.

Company's policy is to test each well at least once a week.

In order to not penalize the rate values from MPFMs per well in the island the well testing in other two islands should be well planned and executed. Penalty for MPFMs per well in the island comes from the fact that **total theoretical quantity** of oil is reconciled to **fiscal measurements** at offtake points. Total theoretical quantity is sum of estimated quantities for wells which are not equipped by individual meter and measured quantities from MPFMs per well in the island. Since accuracy of estimates is lower than accuracy of MPFM measurement, a common reconciliation factor will "correct" MPFM readings more than necessary. Allocation scheme is discussed below.

Allocation scheme

Hydrocarbon allocation in Kashagan consists of estimating well theoretical values and reconciling against measurements at delivery and internal usage points.

For wells which have real time measurements, the theoretical well performance values are derived directly from MPFMs. The estimation of theoretical quantities for wells which are routinely tested against test separator and MPFM through test lines and which have bottom hole pressure/temperature gauges is based on Vertical Lift Performance (VLP) equation, while for wells which are not equipped by downhole gauges the estimation is based on Performance (PQ) Curves.

Reconciliation factor (RF) equation is as below:

$$RF = \frac{\sum_{i=0}^{n} M_i^{Theoretical}}{M^{Actual}}$$

Where $M_i^{Theoretical}$ is estimated mass of i-th well and M^{Actual} is measured mass at delivery point. M^{Actual} is sum of oil measured by fiscal metering skid at custody transfer point and tank delta stock.

The simplified allocation scheme is shown in Figure 3.

Since total theoretical quantity is sum of estimates and real time measurements the total RF will penalize MPFM measurements if the well testing is not planned and managed properly in order to tune the VLP equations and PQ curves. The implementation and validation of virtual flow metering concepts is described in subsequent sections.

The use of MPFM greatly improved the overall RF.

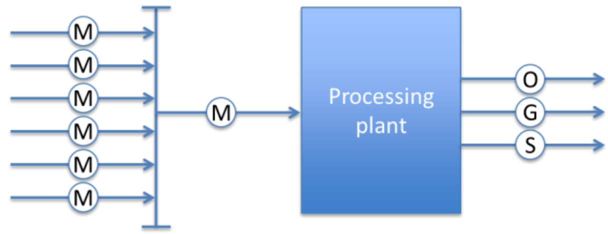

Figure 3: Simplified Allocation scheme. M: multiphase flow, G: gas, O: liquid, S: sulphure

Solving the challenge of upstream choke installation

The MPFM requires PVT inputs for flowrate measurements [2]. There are three main options:

- Using Phase Sampler – take samples of each phase and perform physical measurements of PVT properties
- Using Black-Oil-Model correlations
- Using VX-Fluid-ID based on Equation-of-State

Sampling at unmanned island with high H_2S content was not feasible. Black-Oil-Model correlations had proven to perform with acceptable accuracies, for MPFM that had been installed downsteam of the choke, in one of island. The inaccurate PVT properties from Black-Oil-Model (BOM) correlations have neglible impact on the flowrates [2]. However BOM was not suitable for other MPFM, which were installed upstream of choke manifold, because fluid could be above and below bubble point conditions, depending on the choke size, and this phenomenon could not be accurately predicted by using Black-Oil-Model correlations. Therefore VX fluid ID that uses Equation-of-State had been implemented. The dedicated software module PVTPro is used, that requires Equation-of-State tuned by Operator. The main steps to create VX-Fluid-ID:

1) Tuned EOS (see Figure 4)
2) Create 3D surface from pressure and temperature conditions that are expected at MPFM based on EOS (see Figure 5, that shows 3D surface of oil density)
3) Create set of polynomial coefficients with specified boundary conditions for each property (see Figure 6, that shows 3D surface of oil density). The example set of polynomial coefficients is shown in **Table 1.**

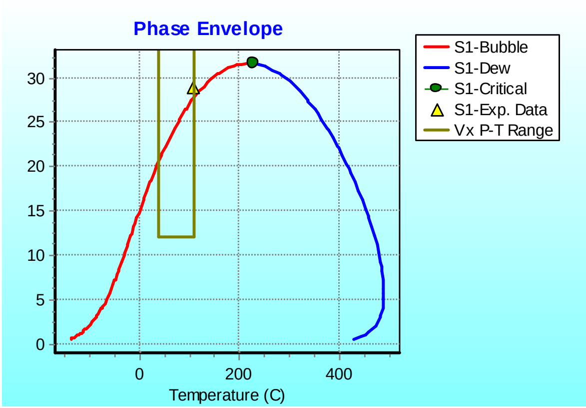

Figure 4: Equation of State

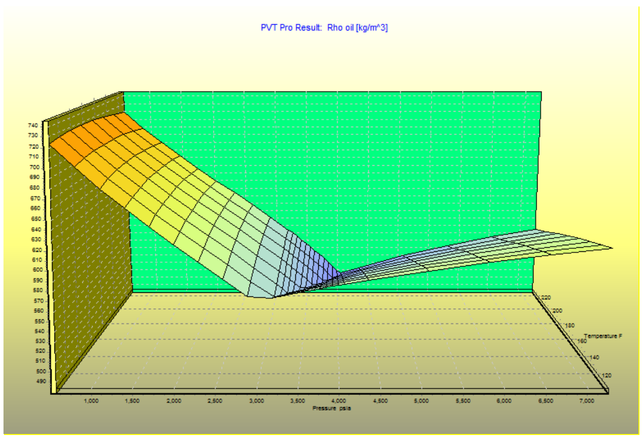

Figure 5: 3D surface of oil density based on EOS

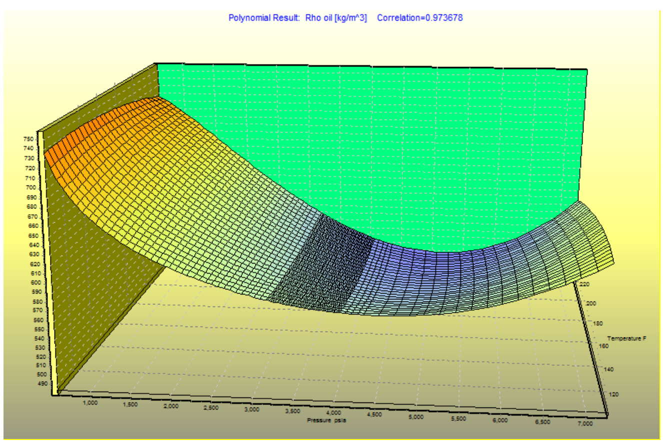

Figure 6: 3D surface of oil density based on sets of polynomial coefficients.

Oil density (Rho oil) [kg/m^3]			
Coefficients	P^{-1}	P^{0}	P^{1}
T^{-1}	7.16E+09	-3.00E+04	-2.01E-03
T^{0}	-4.82E+07	1.23E+03	6.69E-06
T^{1}	8.22E+04	-6.56E-01	-1.57E-08

Table 1: Set of polynomial coefficients

At certain presssure and temperature the density value is calculated using equation below:

Oil Density (P,T)[kg/m3] = 7.16x109P-1T-1 - 3x104T-1 - 2.01x10-3PT-1 – 4.82x107P-1 + 1.23x103 + 6.69x10-6P + 8.22x104P-1T – 6.56x10-1T – 1.57x10-8PT

This VX-Fluid-ID had been implemented for all wells equipped with individual MPFM. However flowrate measurement results did not satisfy accuracy required by Operator. The inaccuracy of results was mainly associated with PVT model deviations, especially near bubble point region. It is clearly shown in Figure 5 that fluid properties change sharply at bubble point and it is impossible to accurately represent using pollynomial coefficients. Figure 6 illustrates the behavior of single polynomial near bubble point region. Figure 7 shows the difference between 3D surface of oil density predicted by EOS and 3D surface of oil density based on polynomial coefficients. The difference could be as high as 30kg/m3.

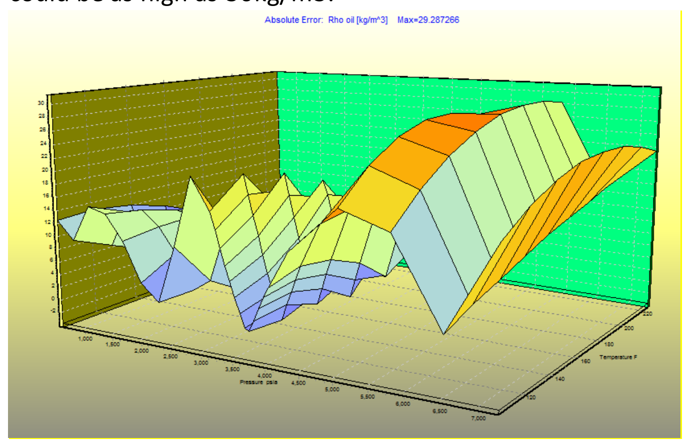

Figure 7: The difference between 3D surface of oil density predicted by EOS and 3D surface of oil density based on polynomial coefficients

Therefore the decision was made to create two separate set of 3D surfaces of PVT properties for above bubble point and below bubble point conditions. Figure 8 shows the difference between 3D surface of oil density predicted by EOS and 3D surface of oil density based on polynomial coefficients decreased down to 1.5kg/m3.

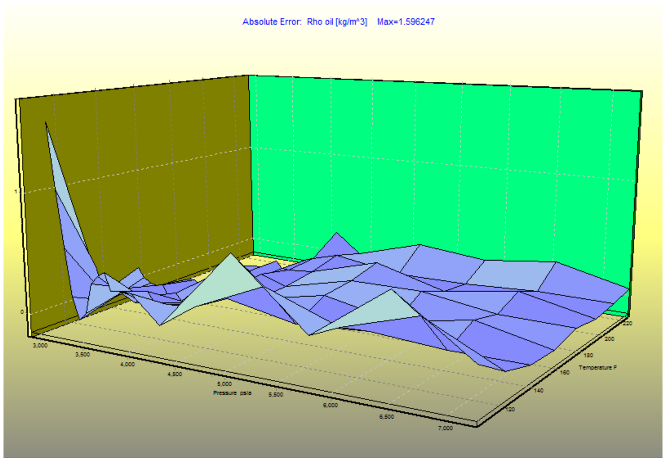

Figure 8: The difference between 3D surface of oil density predicted by EOS and 3D surface of oil density based on polynomial coefficients after splitting the polynomial into above and below bubble point

After implementation of two sets of PVT property tables, flowrate measurement from MPFM had improved and was within manufacturer stated accuracy range. However, this solution required continuous update of PVT table depending on the conditions of flow in MPFM, which was challenging from operational perspective. To automate the process of selection of PVT, manufacturer and operator created a unique code via DCS commands, that continously checks if status of flow conditions in MPFM (if it is above bubble point conditions or below bubble point conditions) and selects required PVT table.

Validation of MPFM data

The first validation of MPMFs was carried out during flow loop test at the manufacturer's laboratory. The objective of the multiphase flow loop test was to demonstrate the functionality and performance of the MPFM at flow loop conditions. Since the Flow Loop test facility is a functionality test loop, the MPFM accuracy can be demonstrated only over a restricted area of flow conditions where the accuracy of the reference instrumentation is correctly known and considered to be sufficient for the functionality test.

Engineers of operating company have developed a tool built on excel and custom built VBA routines to validatethe phase fraction and rate calculations made by MPFM. The tool uses equation of state to calculate the volumetric phase fraction and phase and mixture densities for rate calculations at given pressure and temperature conditions.

Such validation was required because the MPFMs are operating within wide range of pressure conditions (between 120 – 500 barg) due to the fact that they are installed upstream the choke. The Kashagan reservoir fluid is considered as homogeneous, which means that the tool uses same PVT parameters for equation of state.

The initial PVT model was tuned against static bottom hole and tubing head pressure readings during no flow periods, i.e. no impact from friction loss. The tuning consists of calculating bottomhole pressure for given tubing head pressure reading and comparing against measured bottomhole pressure. Then the PVT model was corrected by a factor to match the bottom hole and tubing head pressures.

The deviation between calculated and measured total mass rate is within ±1%. On the other hand, the deviation for phase fraction is on average within ±5% absolute.

It is observed that the MPFM measurements are more accurate the further away is flowing condition from bubble point.

Another validation check was performed by use of gas outlet measurements at production separators. The wells with individual MPFMs were diverted to one production train for one month in order to segregate from other wells. The load ratios between the production trains were calculated using gas measurements at the outlet from the separators. These ratios were applied to total oil production measured at export delivery points in onshore to derive total production from wells with MPFMs which was compared against total accumulated measured volume from MPFMs. The deviation was around 3%.

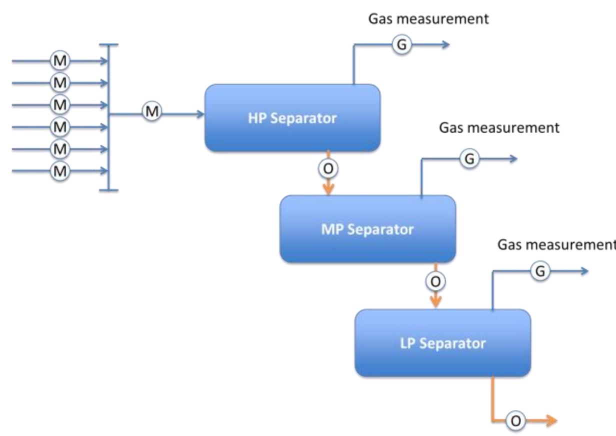

Figure 9: Simplified schematic of separators and gas measurement

Additional test was performed during 20 hours period when the production was only from wells with MPFMs and the produced and treated oil accumulated at one tank in onshore. The MPFM measured cumulative volume was compared against accumulated oil in the tank. The deviation was 3% as well.

Virtual flow metering and MPFM

One of the advantages of new wells is availability of permanent downhole gauges for pressure and temperature. The downhole gauges are not only important for reservoir engineering and modelling purposes but also for possibility of setting up virtual flow metering techniques for real-time well performance estimations.

The virtual flow metering concepts are well known in the industry and slowly gaining “trust” from subsurface discipline engineers.

One of the virtual flow metering techniques is use of Vertical Lift Performance (VLP) equation. Although there are lots of other names for the equation, VLP is the term used throughout the paper.

VLP equation for pressure drop across the well looks like:

$$\frac{\Delta P}{\Delta L} = \bar{\rho} g + \frac{f \bar{\rho} \bar{v}^2}{2\bar{d}} \quad (1)$$

The acceleration term is not included because contribution to total pressure drop is considered as negligible. Second part of the right hand side of the formula is known as Darcy-Weisbach equation.

Since not all of the wells in Kashagan are equipped with individual MPFM but rather common test separator and/or MPFM is/are shared, it was decided to test and prove the virtual flow metering concept on wells which are equipped with MPFM. Then the technique would be implemented for other wells for real-time well performance estimation during non-test periods or when the test separator or any of the MPFMs are under maintenance or not available.

First of all why do we need real time well rates estimation? There are lots of benefits, but main ones are listed below:

1. Data quality assurance
2. Real time surveillance and daily by well production reviews
3. Real time optimization
4. Etc.

In order to fit the a) MPFM rates, b) BHP and c) THP readings for each well excel VBA functions were built for PVT calculations, pressure profile calculations, etc.

First, hydrostatic head calculation was tuned to fit BHP readings against THP readings during no flow.

Second, friction coefficient (f) was tuned for each well using MPFM flow rates and flowing BHP readings by means of correction. Note that tuned friction coefficient with correction is average factor which takes into account pipe roughness, well curvature and other restrictions in the tubing, i.e. it is more like mathematical mean of fitting rather than physical variable. This coefficient is naturally different among the wells.

The Colebrook-White equation is used for estimation of friction coefficient:

$$\frac{1}{\sqrt{f}} = -2\log\left(\frac{\varepsilon}{3.7\,\bar{d}} + \frac{2.51}{Re\sqrt{f}}\right) \quad (2)$$

Equation (1) is reworked to define mixture average velocity as a function of pressure drop across the well string:

$$\bar{v} = \sqrt{\frac{2\times\bar{d}}{f}} \times \sqrt{\left(\frac{\Delta P}{\Delta L \times \bar{\rho}} - g\right)} \quad (3)$$

The mass and volumetric flow rates are derived from calculated average velocity, and vice versa, using PVT and well dimensional parameters.

The friction coefficient (f) calculated by equation (2) is compared against inferred friction coefficient. It is observed that for some of the wells the Colebrook-White method gives more accurate values of friction coefficient at high flow rates, while at low flow rates the there is a bigger deviation. On the other hand, the Colebrook-White method deviates more from inferred friction coefficient at full range of tested rates.

After tuning process, the simplified “best fit” equations were developed in order to apply as expressions in PI ProcessBook and DataLink (Osisoft© product). PI ProcessBook and DataLink are used to compare the simplified expressions against real-time MPFM values. The comparison is shown in Figure 9 for well which has very small curvature. Same scale is used for both trends. In general, the convergence is better at high rates compared to at lower rates.

Figure 10 shows tuned VLP correlation against MPFM readings for a well with higher curvature. There is still good match between the two, but not to the same extent as for wells with less curvature. Although, this correlation evident for some of the wells, the authors are not conclusive on applicability for all other wells.

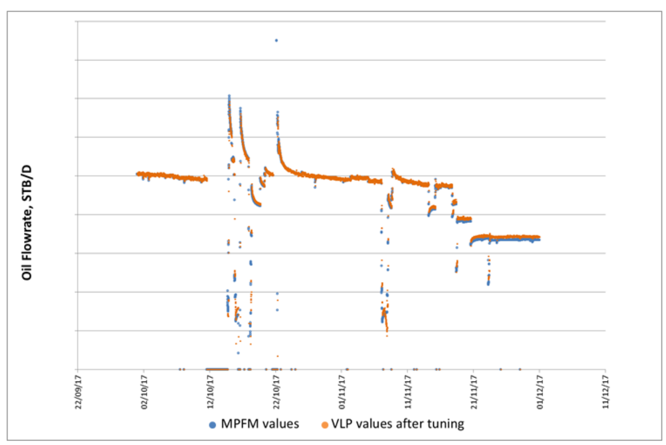

Figure 10: Comparison between MPFM real time measrement and tuned VLP expression for well with little curvature

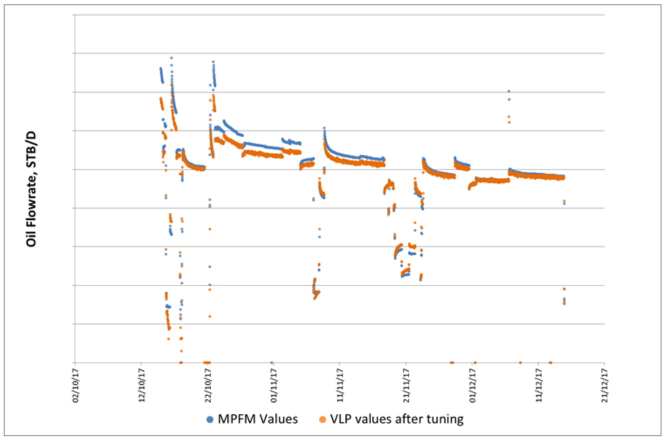

Figure 11: Comparison between MPFM real time measrement and tuned VLP expression for well with higher curvature

After testing the method on real time MPFM readings, it was applied for wells which are only routed to test separator through test line as per planned sequence for several hours. Since there is at least a week between the tests it is crucial to have alternative real-time measurement method.

The wells were tested at different choke settings in order to have test points covering wide well flow range. The test points were recorded after a well is stabilized in terms of tubinghead pressure, bottomhole pressure and test separator flow rate.

Figures 11, 12 and 13 show results of tuning VLP correlation against test separator metering measurements. The well numbers are arbitrary.

Figure 14 shows an example of VLP correlation trend between two consecutive tests for one of the wells.

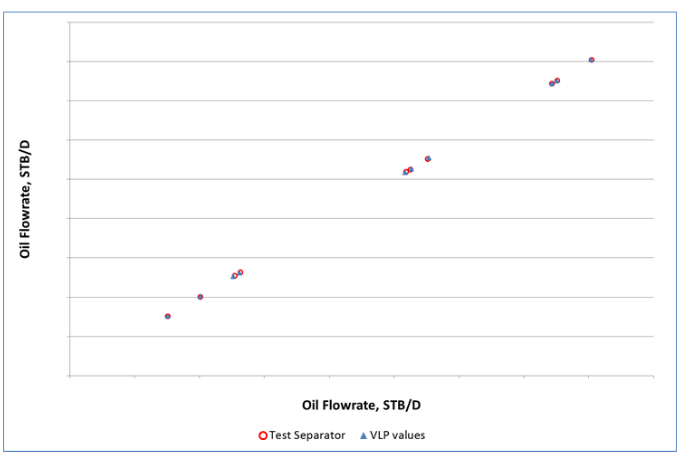

Figure 12: Tuned VLP expression against Test Separator for well number 1

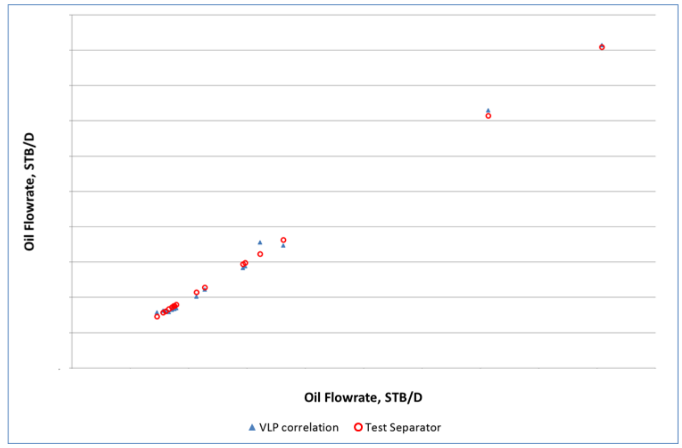

Figure 13: Tuned VLP expression against Test Separator for well number 2

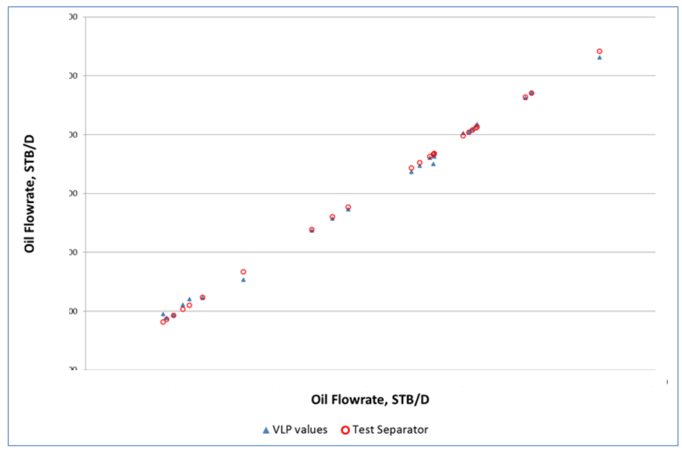

Figure 14: Tuned VLP expression against Test Separator for well number 3

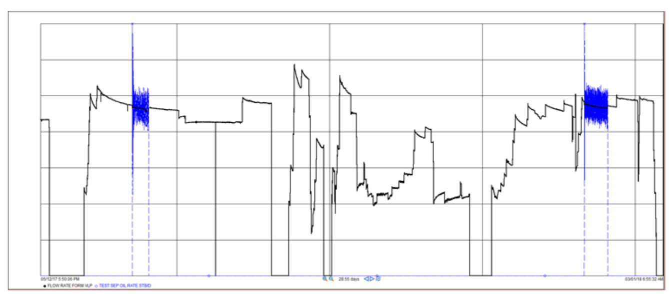

Figure 15: VLP correlation values between two consecutive tests for well number 1. Blue line for test separator values, black line for VLP correlation trend. Y axis = oil flow rate.

Observations and conclusions

The implementation of MPFM technology in Kashagan project is successful mainly due to good cooperation between the operator and the manufacturer. Even during mismeasurement instances the timely notification from the operator and provision of the raw data to the manufacturer leads quick solutions and reinstatement of desired MPFM accuracy.

It is also very crucial for operator, as data owner, to have own methods and tools for verification of the MPFM data.

The installation of dedicated MPFMs for some of the wells gives great atvantage to test the virtual flow metering methods and techniques, and implementation of such methods to other wells which don't have individual meters. The simplified "best fit" correlations are capable of providing well flow rate estimation at acceptable accuracy.

Future improvements and recommendations

The real-time MPFM measurements should be used for better understanding the following:

- Impact of slippage between phases to friction loss in the well production tubing;
- Impact of flow pattern to friction loss;
- Impact of well curvature (deviation) to friction loss.

The authors are planning to implement real time PVT and VLP calculations on PI ACE™ engine. It is expected that such real-time and more complex calculations will improve the accuracy of the method.

Acknowledgements

The authors wish to thank NCOC N.V. for their permission to publish this work.

Nomenclature

ΔP – Pressure drop across the well;
ΔL – True vertical depth of bottomhole gauge,
$\bar{\rho}$ – Average mixture density;
$\bar{v}$ – Average mixture velocity;
$\bar{d}$ – Sverage production tubing diameter.
f – Friction coefficient
ε – Pipe surface roughness
Re – Reynolds number
BHP – Bottomhole pressure
THP – Tubinghead pressure
VLP – Vertical Lift Performance
DCS – Distributed Control Systems

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