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Technical Paper

Campaign Well Testing of a Complex Reservoir Using an MPM Multiphase Meter

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1 INTRODUCTION

The Menzel Lejmat North (MLN) development in Algeria is a complex hydrocarbon reservoir of black/volatile oil and retrograde gas condensate hydrocarbons. The field production facilities do not include conventional well testing equipment and wells are tested on a campaign basis using the services of a third party contractor and a skid-mounted multiphase meter.

In early 2011, a third party was contracted by 'Sonatrach-ConocoPhillips Association' (SH-COP) to provide mobile well testing services and an MPM meter was deployed in the MLN field. The first campaign was conducted in July 2011. This paper covers testing up to November 2013. Over this period, a total of 140 individual well tests were performed covering 21 wells with approximately 3-4 months between successive campaigns. The wells produce in the GVF range 90-99.5% with an average GVF in the range 95-96%. Hence, a Dual Mode meter (combined multiphase and wetgas meter) was critical for this application.

The MLN reservoir represents a challenging environment for multiphase meters due to the range of fluid types represented. Certain wells in the field operate with co-mingled production from black and volatile oil formations. In addition, lift and injection gas is used in several parts of the development. Assuming that all maintenance, commissioning and calibration procedures are followed correctly, uncertainties in the fluid properties typically have the most important impact on the accuracy of metering results. Such uncertainties introduce biases in the measurements performed at operating conditions and simultaneously impact the conversion to standard conditions.

As such, particular focus was placed on the PVT used to configure the MPM meter both with regards to the fluid properties at operating conditions as well as on how measured flow rates should be transferred to standard conditions. The in-situ verification functionality of the MPM meter was particularly useful in this regard and expensive PVT sampling was completely avoided. At the completion of each campaign, SH-COP used the individual well oil flow rates measured by the MPM meter to back-allocate the totalised stock tank volumes measured at the stock tank over the individual wells.

As experience was gained, several improvements were made to the well test setup and procedures, and importantly the calculation used to transfer MPM measurements at operating conditions to standard conditions. A 'multi-stage flash' (MSF) calculation was implemented in order to account for the various separator stages in the production plant. The difference between the cumulative oil measurements performed by the MPM meter, based on the MSF conversion, was within ±10% of the stock tank. Considering the range of uncertainties inherent in this style of testing, the complexities of the PVT, and the generally high GVF range, this is considered to be a very good result.

Technical Paper

The aim of this paper is to detail the measurement challenges faced as a result of the complex nature of the MLN reservoir, describe some of the sources of uncertainty encountered in this style of campaign well testing, and to provide recommendations for others intending to use this approach.

2 THE MPM METER TECHNOLOGY

The MPM meter employs a patented 3D Broadband™ dielectric measurement system [5] alongside a Venturi, a gamma-ray densitometer and advanced flow models [1], [4] in the measurement of individual phase flow rates in both multiphase and wetgas environments. The 3D Broadband™ system uses a high-speed electro-magnetic (EM) wave based technique for measuring the liquid/gas distribution, phase fractions, water-liquid-ratio (WLR) and gas-volume-fraction (GVF) within the pipe. The 3D Broadband™ system is based on permittivity measurements performed through an EM wave frequency range of 20-3600 MHz across many planes within the sensor section of the meter. The system sweeps the EM wave frequency range 200 times per second, giving unsurpassed sensitivity.

The Venturi is used to create radially symmetrical flow in the downstream 3D Broadband™ section, which would be the natural flow condition if the pipe were infinitely long. These flow conditions are ideal when using tomographic inversion techniques. The Venturi is also used to produce the differential pressure required in determining the total mass flow rate. The gamma densitometer functions simply as a means of measuring the mixture density.

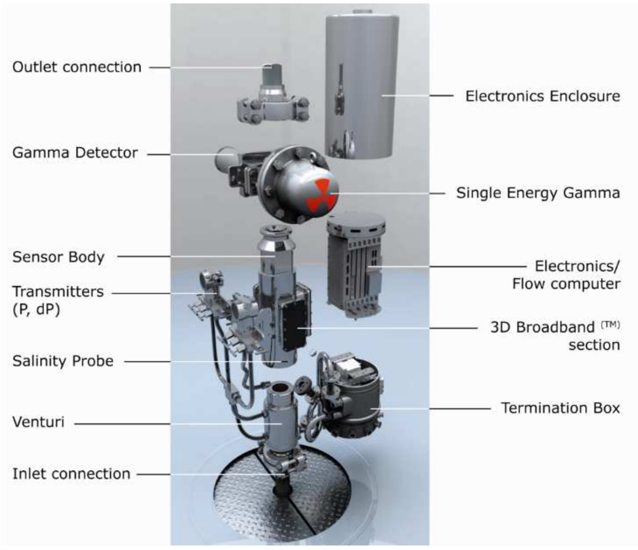

Figure 2.1 The MPM multiphase meter constituent parts

By combining the phase fraction measurements from the 3D Broadband™ with the total mass flow from the Venturi and mixture density measurements from the gamma densitometer, individual flow rates of oil, gas and water are determined.

Through its Dual Mode functionality, the MPM meter is able to operate in both multiphase and wetgas environments and may switch between its two modes of operation automatically based on the instantaneous measured GVF. At ultra-high GVF's, where the liquid volume is very small as compared to the total, the patented Droplet Count functionality significantly improves the measurement of the oil and water fractions. By using Droplet Count, the MPM meter can make precise measurements of minuscule liquid volumes in a GVF range (> 98.5%) where no conventional technology is capable of making true three-phase measurements. The Droplet Count method is also highly tolerant towards uncertainties in fluid properties. This is achieved through using the 3D

Broadband™ rather than the gamma densitometer for making the mixture density measurements. Further technical information about the MPM meter can be found in references [5]-[13], [17], [18], [26] and [28].

3 FIELD CONFIGURATION

3.1 General Configuration Requirements

'Field configuration' is the process by which multiphase meters are setup with information pertaining to the single-phase properties of the oil, gas and water being produced by the well. The term 'PVT' is often used in conjunction with the field configuration, and indeed the PVT properties of the hydrocarbon phases are of paramount importance. The PVT information is used for two purposes, namely:

1. Prediction of single-phase oil and gas properties at the operating conditions of the meter. In the case of the MPM meter, these include oil and gas densities and viscosities as well as the surface tension between the two. These fluid properties are used at various stages throughout the volume flow rate calculation.

2. Converting measured flow rates at operating conditions to a reference condition, typically standard. The MPM meter performs this conversion by assuming that the oil and gas stay in equilibrium from operating conditions to standard conditions – a 'single-stage flash'. The field configuration includes an oil-to-gas mass transfer factor which is used to correct the actual volumetric flow rates for phase transfer in moving to standard conditions.

3.2 Obtaining Reliable Field Configuration Data

The PVT properties of the hydrocarbon phases are typically predicted using an Equation of State (EoS) model generated in a PVT package such as Multiflash or PVT Sim. PVT properties are then downloaded to the MPM meter as pressure and temperature dependent look-up tables covering the range of expected operating conditions.

There are two issues which must be addressed regarding the accuracy of the field configuration. The first is the 'base' uncertainty intrinsic to the PVT data which originates from the sampling, characterization and PVT modelling process. In some cases, only very basic or out-dated compositional information may be available. Tests performed in real field applications at high GVF have shown that this 'base' PVT uncertainty may be in the range of 1-3% on gas density.

The second issue is related to variations in the flowing composition which mean that the PVT model no longer correctly predicts the behaviour of the well fluids. This typically occurs at a later stage in the life of the well due to changes in the reservoir, the use of Enhanced Oil Recovery (EOR), wellbore effects, or variations in the contributions from individual zones in a multi-reservoir completion. The MLN field consists of black/volatile oil and gas condensate wells which are in some cases comingled or gas-lifted. There is also widespread use of gas injection in different parts of the field. This may contribute an additional variation in the gas density of up to 10%, resulting in an unpredictable total variation of up to 15% in the gas density at operating conditions.

In real world applications significant uncertainties in the field configuration originating from several sources should be expected. In order to provide accurate measurements of all three phases, a multiphase meter should be adequately robust to handle such uncertainties. This is particularly important in applications where the operating point is close to the single-phase end-point of one of the phases. For example, at extremely high GVF approaching the 100% GVF end-point, uncertainties in the gas properties will have a significant impact on the accuracy of the oil and water flow rate measurement. Similarly, at high WLR and low GVF, water properties will have an overriding significance.

3.3 Wetgas

The principal metering challenge in wetgas flows relates to the need to accurately measure small liquid volumes in a gas dominated fluid stream. Once the small liquid volumes have been successfully measured, they must then be split correctly between oil and water. For example, in extreme wetgas applications the flow may contain as much as 99.9% gas, 0.05-0.1% oil and 0.01-0.05% water. In such cases, uncertainties in the gas properties will dominate the measurement accuracy of the oil and water.

A wetgas flow meter should therefore be robust with respect to uncertainties in the field configuration. The relative measurement uncertainty of the liquid fraction stemming from uncertainties in the gas properties increases exponentially as the GVF increases. For example, for a density based fraction measurement and a wetgas case at an operating pressure of 120 barg, the measured mixture density may be 112.7 kg/m3. Assuming a configuration gas density of 110 kg/m3 and an oil density of 650 kg/m3, the calculated GVF becomes 99.5% which corresponds to a liquid fraction of 0.5%. If the configuration gas density was 5% smaller at 104.5 kg/m3, the calculated GVF would then become 98.5% which corresponds to a liquid fraction of 1.5%. In this simple example, a 5% uncertainty in the configuration gas density results in a relative measurement error of 200% on the liquid fraction.

4 PVT SENSITIVITY

A multiphase meter should exhibit robustness to uncertainties in the field configuration such that it is not overly impacted by uncertainties in the field configuration or by changes in the flowing fluid away from the PVT model. The MPM meter has been shown to exhibit low sensitivity to PVT due to its unique measurement system.

4.1 Gamma Densitometer

The count rate at the gamma detector, density and mass absorption coefficient of the fluid within the meter are related according to the following equation:

$$N = N_0 e^{-\mu\rho x}$$

N: gamma photon count rate

N_0: empty pipe gamma count rate

μ: mass absorption coefficient

ρ: density

x: pipe diameter

Solving the above for density indicates that the gamma detector is dependent on knowing the mass absorption coefficient of the fluid.

Figure 4.1 plots mass absorption coefficients for various hydrocarbons and water solutions in addition to pure H_2S and CO_2, versus gamma energy level. The mass absorption coefficient varies considerably at low gamma energy levels such as those used by traditional dual-gamma systems whilst the Caesium gamma source, used by the MPM meter, exhibits a single energy emission at 662 keV and has a significantly higher energy level as compared to traditional dual-gamma systems. At this energy level the mass absorption coefficients of the various fluids are almost constant and do not vary significantly as a function of the fluid composition.

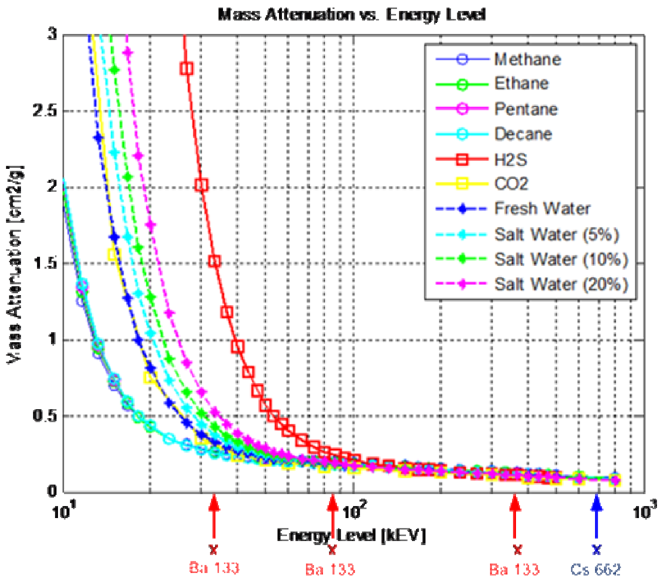

Figure 4.1 Mass absorption coefficient versus gamma energy level for various fluids

This has several important impacts on the meter:

1) As the mass absorption coefficient is relatively constant versus the composition, the meter is generally less sensitive to the fluid composition.

2) There is no requirement to calibrate the mass absorption coefficient for the oil, gas and water phases prior to starting a well test.

3) When a single phase is present in the meter, the gamma densitometer may be used to measure the density of this phase since the mass absorption coefficient is already known.

4.2 3D Broadband™

Permittivity measurements at high EM wave frequency (typically above 1 GHz for microwave and RF based techniques) are more tolerant towards variations in the composition of the oil as compared to permittivity measurements at low EM wave frequency. The permittivity used in mixing formulas (like Bruggerman) is based on the effective permittivity of the oil. Effective permittivity is defined by the following equation:

$$\varepsilon_{eff} = \frac{\varepsilon'}{2} * \{1 + \sqrt{1 + (\frac{\varepsilon''}{\varepsilon'})^2}\}$$

where ε' is the real part of the permittivity and ε'' is the imaginary part of permittivity.

Figures 4.2 and 4.3 below, as published by Friisø et al [14], show the real and imaginary parts of the permittivity of a sample oil with different asphaltene fractions (the concentration dipolar fractions like N, S, and O are highest in heavier fractions like asphaltenes) and illustrate the frequency dependency of the permittivity for different oil compositions. The MPM meter uses frequencies of up to 3.7 GHz such that the 1 GHz upper end of the scale shown below is in fact in the middle of the range used by the

MPM meter. This is much higher than the low frequency measurement (kHz region) which is typical of capacitance based techniques.

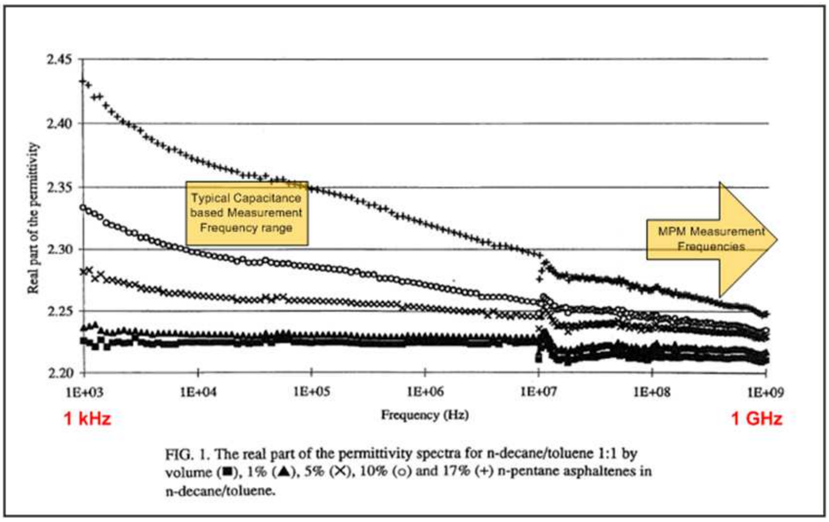

Figure 4.2 The frequency dependency of the real part of the permittivity for different oil compositions [14]

Below is the corresponding Figure for the imaginary part of the permittivity.

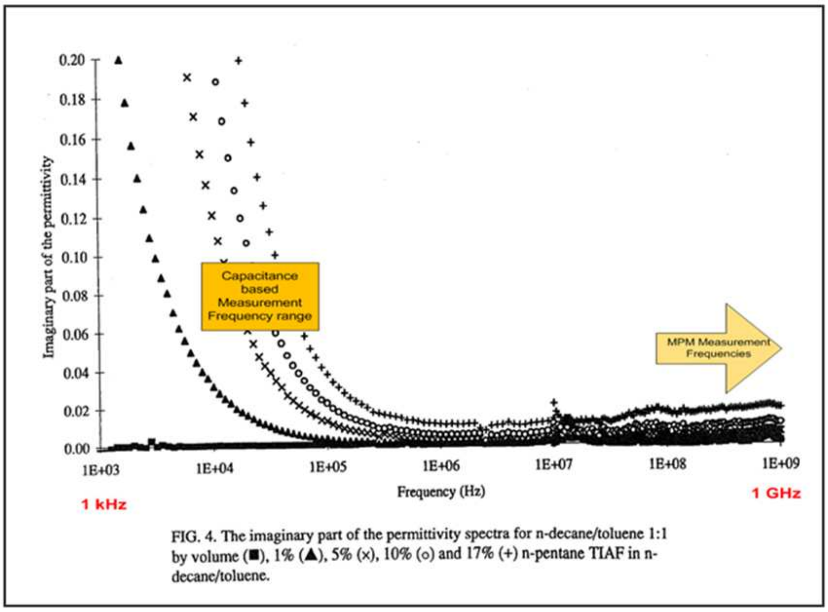

Figure 4.3 The frequency dependency of the imaginary part of the permittivity for different oil compositions [14]

As shown above, the variation in permittivity as a function of asphaltene content is far smaller at high EM wave frequencies when compared to low EM wave frequency. In particular, the spread in the imaginary part of the oil permittivity is very significant at low frequencies whereas it is almost constant at the higher measurement frequencies used by the MPM meter.

It may be seen that the variation in the effective oil permittivity at high frequency is in the range ± 0.5 - 1% due to the presence of asphaltene whereas the variation at low frequencies may be 4 (or more) times larger when adding up the impact from the real and imaginary parts. Using a high EM wave measurement frequency is therefore essential in achieving a permittivity measurement which is tolerant towards variations in the composition of the oil.

4.3 Sensitivity Analysis

It has been demonstrated that the constituent technologies used by the MPM meter exhibit a low sensitivity to the hydrocarbon fluid composition. However, the degree of sensitivity varies with GVF and WLR across the operating envelope of the meter. It is therefore desirable to assess the sensitivity behaviour of the meter for a particular application. MPM have recently completed development of an offline software tool which facilitates this type of analysis.

The tool uses raw data along with the true field configuration to assess the impact of uncertainties in oil/gas density and water conductivity on measurement results. The user may specify the range over which these configuration parameters are expected to vary. For example, for a high GVF application, the user may be interested in the impact that uncertainties in the configuration gas density will have on the accuracy of the oil flow rate measurement. In the MLN field, such uncertainties potentially stem from co-mingled production of several reservoirs, or the impact of gas injection/lift. It was determined at an early stage that for many of the high GVF wells, uncertainties in the gas density configuration would have an important impact on the determination of the oil flow rates.

Though the '*MPM Recalculation Tool*' used to perform sensitivity analysis had not been released when the MLN testing started, the raw data collected during testing has been used to illustrate the impact that PVT uncertainties can have on measurement results.

Four cases have been selected from the database of raw data logged during the various campaigns. These four cases come from the campaign which took place in May/June 2013. The wells selected and the approximate GVF and WLR ranges of each are given in Table 4.1 below.

Well	Average GVF (%)	Average WLR(%)
MLW-2	89.1	18.4
KMD-2	95.1	6.6
MLN-12	98.4	3.5
MLSE-5	99.6	3.4

Table 4.1 Example of typical fluid ratios across the field

The sensitivity study for these wells has been conducted using the '*MPM Recalculation Tool*' as follows:

1) Create a new task and import 10 minutes of raw data along with the field configuration to form the 'base' task on which the study will be performed.

2) Create a set of sensitivity tasks based on variations in the gas density. The selected range for this illustration is from -3 to +3% with a step size of 1%. This means that six additional tasks are created where the configuration gas density is adjusted up or down in the specified range. For example, for the task with a -2% adjustment, the configuration gas density is multiplied by a factor of 0.98. No other change is made to the field configuration. A similar analysis was performed by varying the oil density to demonstrate its relative importance as compared to the gas density.

3) Recalculate the raw data such that each task is calculated individually. The calculated flow rates and fractions are then compared to the 'base' task to assess the impact of the gas density adjustment on the parameters of interest.

4) In this case, the parameters of interest are the liquid and gas volume flow rates, the total hydrocarbon mass flow rate and the water volume fraction (WVF).

Technical Paper

Figures 4.4 to 4.7 show the results of the analysis. The notation 'DC' (well MLSE-5) refers to the fact that the GVF for this well is high enough that the Droplet Count measurement mode was used as opposed to the traditional 3-phase wetgas mode. Droplet Count produces superior results in the ultra-high GVF range (GVF > 98.5%) and is at the same time less sensitive to uncertainties in the gas density configuration.

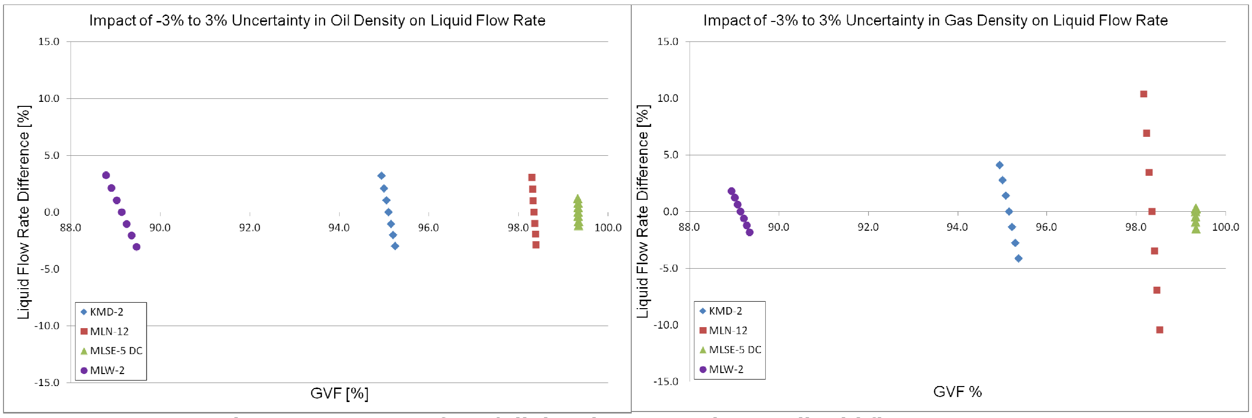

Figure 4.4 Impact of gas/oil density uncertainty on liquid flow rate vs. GVF

From Figure 4.4, the impact of the gas density on liquid flow rates is seen to increase with increasing GVF. The impact is seen to decrease significantly on well MLSE-5 since the Droplet Count mode of measurement used at high GVF is less sensitive to the fluid composition. The impact of oil density uncertainties is seen to be significantly less than that of the gas density.

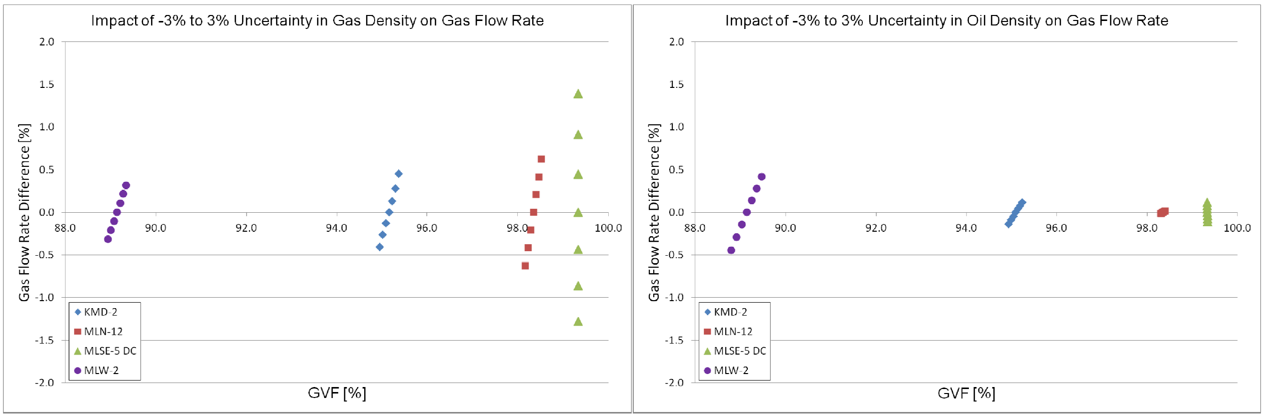

Figure 4.5 Impact of gas/oil density uncertainty on gas flow rate vs. GVF

From Figure 4.5, the impact of gas density uncertainties on the gas flow rate is seen to be very limited, reaching a maximum of about +/- 1.4% at the highest GVF range for MLSE-5. The impact of the oil density is negligible across the entire GVF range but is seen to increase with decreasing GVF.

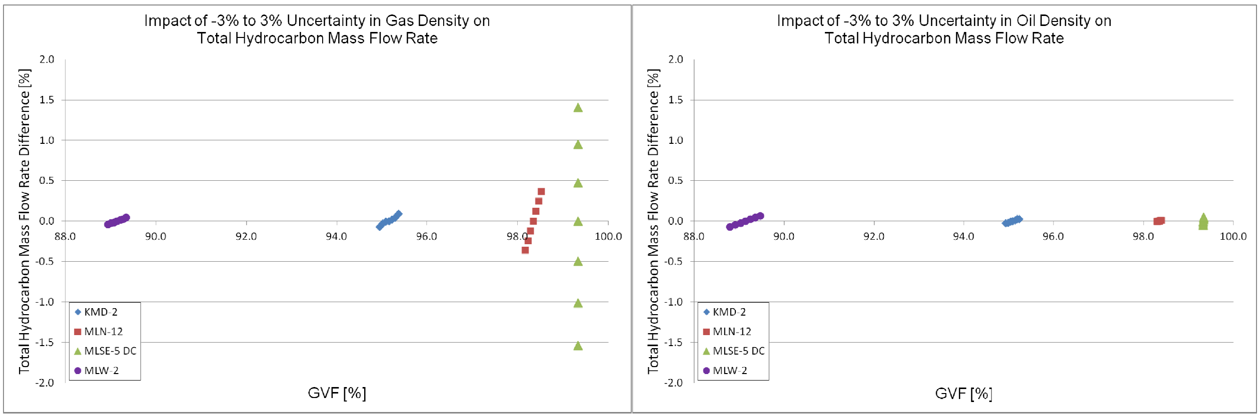

Figure 4.6 Impact of gas/oil density uncertainty on total hydrocarbon mass flow rate vs. GVF

From Figure 4.6, the impact of gas density uncertainties on the total hydrocarbon mass flow rate is, in a similar fashion to the gas flow rate, very limited, reaching a maximum of about +/- 1.4% for MLSE-5 which is the highest GVF case. At low GVF, the impact is seen to be negligible. The impact of oil density uncertainties is negligible across the entire GVF range presented.

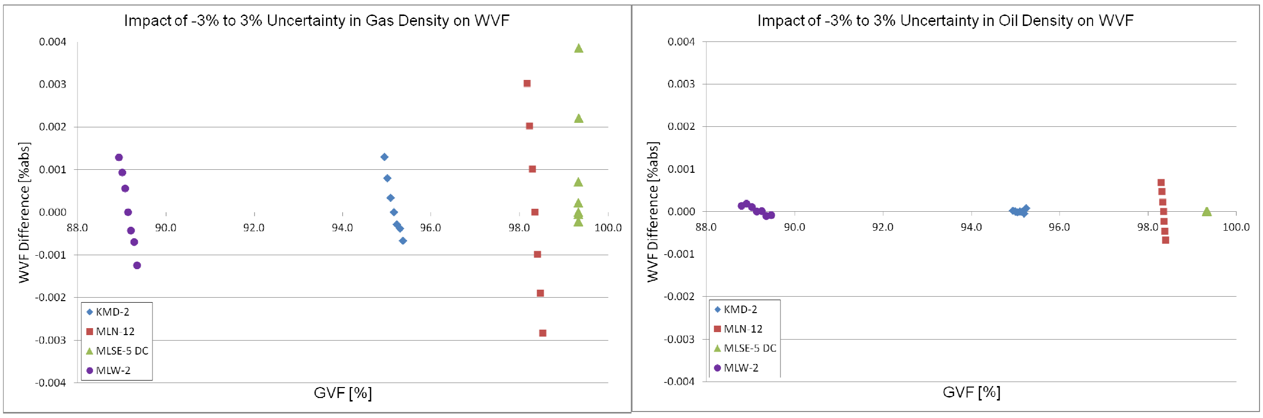

Figure 4.7 Impact of gas/oil density uncertainty on WVF vs. GVF

From Figure 4.7, it can be seen that the impact of gas density uncertainties on the water measurement is extremely limited. In fraction terms this reaches a maximum of 0.004% which is negligible when compared to the stated WVF uncertainty specification in this high GVF range [28]. The impact of the oil density is negligible. To summarise the results of the sensitivity analysis for the GVF range encountered in MLN:

1) The impact of the gas density is more important than that of the oil density on all measurement results. This is increasingly true the higher the GVF.
2) The sensitivity of the measurement to uncertainties in the gas density increases with increasing GVF. At ultra-high GVF however, the use of the Droplet Count mode of measurement demonstrates very low sensitivity to the configuration.
3) The water fraction shows negligible sensitivity to the hydrocarbon configuration
4) Focus should be placed on the gas density configuration for the GVF range > 95% in order to achieve superior liquid flow rate results
5) Any error in the gas properties configuration will result in a systematic bias on the measurement results i.e. it is not a random uncertainty. In the context of mobile well testing, this means that measurement uncertainties stemming from this type of error will not be averaged-out by simply extending the test duration.

5 IN-SITU MEASUREMENT OF GAS PROPERTIES

5.1 Methodology

As described above, focus on an accurate gas properties configuration at high GVF will produce superior measurement results on the liquid fraction. As such, the MPM meter incorporates unique functionality in the form of 'gas in-situ verification'. This functionality uses periods when the meter is filled with pure gas at operating conditions to perform direct density (and permittivity) measurements on the gas. Such periods may occur during the passage of long gas slugs, during a scheduled shut-in of the well or during an intentional bypass of the meter. Any differences seen between the measured gas properties and the field configuration can then be corrected as appropriate.

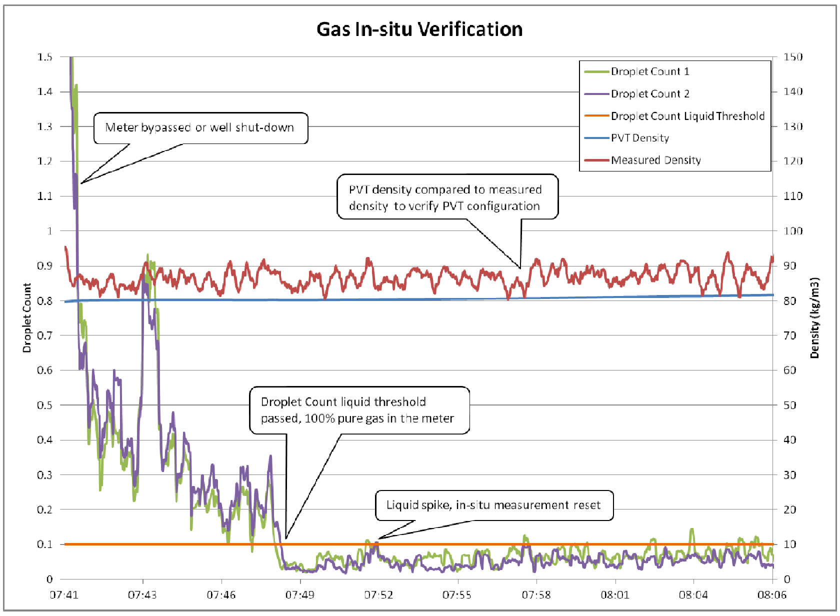

Figure 5.1 An example of a gas in-situ verification measurement

In the example above, the gas in-situ (GIS) measurement is performed by bypassing the MPM meter to trap gas in the section at operating pressure and temperature. The liquids drop to the bottom of the meter and leave pure gas in the measurement section. When pure gas is present, the Droplet Count variable falls below the liquid detection threshold and the meter will automatically begin a GIS measurement period. The average measured gamma density is compared to the average configuration gas density (from the PVT). The measured gas permittivity is also compared to the PVT predicted gas permittivity.

During well testing in the MLN field, pure gas periods were created artificially by putting the MPM meter in a temporary bypass to trap the produced gas at the operating conditions. The 3D Broadband™ was configured to 'look-out' for such periods of pure gas. The 'Droplet Count' variable varies according to the liquid content of the flow such that when pure gas is present, the variable falls below a user-configurable liquid detection threshold. At this point, the meter will make a gas density measurement using the gamma detector and at the same time make a gas permittivity measurement using the 3D Broadband™. The minimum duration over which the gas in-situ measurement becomes statistically significant is also a configuration parameter. Droplet Count is extremely sensitive to the formation of liquid droplets and immediately detects if there are liquid spikes during the measurement period (due to liquid moving on the walls of the meter).

6 WELL TESTING METHODOLOGY

The mobile well testing unit which incorporates the MPM meter is sent to each well site in the test program and the meter is hooked up to the well through a permanent 6” bypass manifold on the production flow line. This means that the well does not need to be shut-in in order to rig-up the well testing equipment.

Prior to starting the test, the Flowing Well Head Pressure (FWHP) and the Flow Line Pressure (FLP) are noted from a gauge on the Christmas tree. Once flow is established through the well test package, the choke on the well test choke manifold is used to control the well. Firstly, an adjustable choke is used to match the Test Well Head Pressure (TWHP) to the previously established FWHP. For the majority of wells, critical flow is maintained over the choke manifold. Only in the case of gas-lifted wells is critical flow not maintained since the choke is already fully-open.

Each well is tested on the main choke and then occasionally a second choke, typically for a period of 2 to 3 hours each. If a second choke is not tested, then the test on the main choke may last for 4 to 6 hours. Where the GVF > 95%, a gas in-situ (GIS) measurement is performed just prior to completion of the test. If the GIS measurement is of ‘high’ quality, then a correction is made to the gas properties configuration and the raw data is recalculated. The measured flow rates of oil, gas and water at standard conditions are reported to SH-COP at the end of the test.

7 RECONCILLIATION AND ALLOCATION

The production measurements made by the MPM meter are used for two purposes:

1) Allocation of totalized tank volumes over the producing wells on a monthly basis
2) Adjustment of choke settings to meet production targets and reservoir management goals

Both objectives would be simpler to achieve with permanent multiphase meters for continuous production monitoring at the wellhead, or more frequent monitoring at remote manifolds. However, in the case of the MLN mobile well testing, production information is only available sporadically. With eight full campaigns over a two and a half year period and an average test duration per well of only 4 to 6 hours, the production data available per well is in the range of 15 hours per year. This corresponds to production data covering only about 0.1% of the producing time per well per year.

At the end of each campaign, the totalized production from all wells is compared to the stock tank in order to allocate the stock tank liquid volumes to the various producing wells. As chokes are continuously being adjusted and/or wells are being shut-in and re-opened, so too the production from each well will vary over the course month. Therefore, a specific date following the completion of the well testing campaign is chosen as the reconciliation date and the tank volumes on that day are used to allocate the production. Differences between a well’s operating parameters during the well test and those on the reconciliation date mean that some level of operator involvement is required to manually adjust the allocation.

From the point of view of the MPM meter performance, it is the reconciliation between totalised MPM oil volumes and the stock tank which is most important. Differences in the reconciliation stemmed from several sources related to the test setup, the method of execution and the basis of comparison.

7.1.1 Matching Test Well Head Pressure

The principal complication stems from matching the TWHP to the FWHP. As the reservoir has several high Productivity Index (PI) wells, a difference of only a few bar between the TWHP and the FWHP can result in a significant difference in the well test flow rates. This is demonstrated below for two tests on the well MLW-2:

Campaign	Date	Choke Setting (%)	WHP (barg)	Oil Flow Rate at Standard Conditions (sbpd)
7	01/2013	35	165.30	2,330.80
	01/2013	45	161.90	3,001.70
8	06/2013	28	175.50	1,774.90
	06/2013	35	173.20	2,258.10

Table 7.1 A high productivity index for MLW-2

As shown above, one bar in WHP corresponds to approximately 200 sbpd of oil production. Therefore, strong focus was placed on ensuring that the match between FWHP and the TWHP was as close as possible.

However, it is in fact the match between the TWHP and the FWHP of each well on the reconciliation date (16th June 2013 for campaign 8) as opposed to the test date which is most important. As shown below (Fig 7.1), although every effort was made to match the FWHP to the TWHP on the test date, an exact match was not always achieved on the reconciliation date. It is worth noting that uncertainties stemming from this source tend to cancel each other out when the entire campaign is considered. In the example of campaign 8, there were two wells where TWHP – FWHP > 3 barg on the reconciliation date as compared to 3 wells where FWHP – TWHP > 3 barg. In this case therefore, the impact on the totalised production is somewhat balanced out.

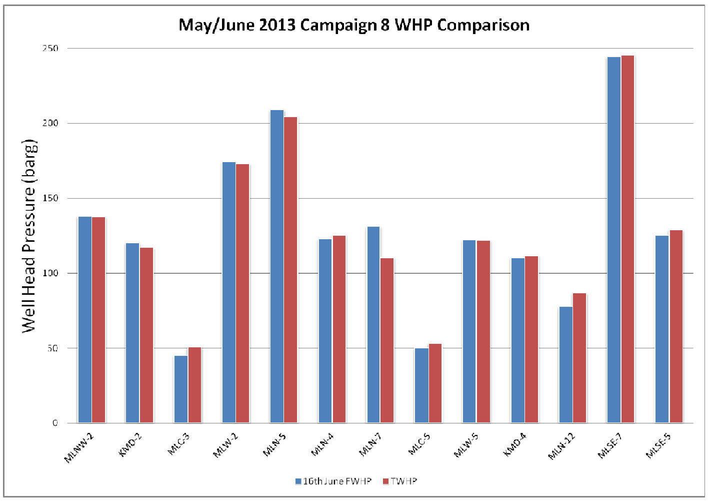

Figure 7.1 TWHP vs. FWHP for campaign 8

7.1.2 Restrictive Pipe Work

The MPM meter used in this project was a 3" meter with a beta ratio of 0.7. This gives a throat ID of approximately 2" and a pressure recovery in the outlet of the Venturi in the order of 70-80%. The pressure recovery was verified during the early campaigns. With an average dP of about 1000 mbar, the pressure loss in the meter was of the order of 0.2-0.3 bar and therefore negligible.

The test package pipe work was mostly 3"NB and 2"NB in the case of some cross-overs. The pipeline ID was 6"NB which meant that the test package represented a significant ID reduction resulting in potential back-pressure on the well. This was not a problem in the majority of tests as critical flow was maintained at the choke manifold. The problems occurred for gas-lifted wells where the choke was already fully-open. This meant that where the TWHP was lower than the FWHP, no adjustment could be made to further open the choke and decrease the TWHP. It is noted that in almost every campaign, the TWHP < FWHP for the MLC series of wells which are all gas-lifted, resulting in a lower well test rate than during normal production.

7.1.3 Automatic vs. Manual Gas In-situ

Two methods for conducting a GIS verification measurement have been implemented in the MPM meter. The first is an automatic method whereby the meter is configured with the measurement duration and the permissible number of liquid spikes (a maximum 'spike count'). If the meter detects pure gas and starts a GIS measurement, the measurement duration and spike count conditions need to be fulfilled in order for a result to be recorded.

During testing in MLN, it was noted that in many cases the pressure and temperature of the trapped gas fell significantly during the GIS measurement period. When the average conditions during the GIS measurement period are significantly different from the average operating conditions, the GIS correction cannot be applied. Therefore, some degree of operator interaction is necessary in order to accept or reject a given GIS measurement. After an initial period where MPM support engineers were used to help field engineers decide whether measurements were acceptable, MPM decided to develop a manual method whereby the meter would give recommendations as to the quality of the GIS measurement. The MLN MPM meter was updated with this new software in Q2 2013.

The significant difference between the automatic and manual measurements is that in the manual version, the user is asked to enter the following information prior to starting the measurement:

- Requested duration
- Operating pressure
- Operating temperature

The term 'operating' is used here to signify the conditions prevailing just prior to performing the GIS. Thereafter, the user starts the measurement through a mouse click in the graphical user interface (GUI). The same liquid detection threshold and spike count settings are used by the meter to carry out the manual GIS. When the GIS measurement results are reported, they are accompanied by a quality rating. Various quality parameters have been implemented, for MLN the most important of these are given below:

- *Pressure/Temperature*: the average pressure/temperature during the GIS measurement should be within specific, configurable limits as compared to the operating pressure/temperature.

- *Duration*: a long average is desirable but the pressure and temperature in the section tends to drop if the duration is too long and this impacts the pressure and temperature quality rating.

At the operating conditions encountered in the MLN field, the following conditions were applied:

	High	**Medium**	**Low**
Pressure	$\Delta P \leq 1.5$ bar	$1.5 < \Delta P \leq 2.5$ bar	$\Delta P > 2.5$ bar
Temperature	$\Delta T \leq 3.0$ deg C	$3.0 < \Delta T \leq 6.0$ deg C	$\Delta T > 6.0$ deg C
Duration	$Duration > 300$ s	$100 < Duration \leq 300$ s	$Duration \leq 100$ s

Table 7.2 Manual GIS settings applied in the MLN field

Once a GIS measurement has been successfully completed, the user is given a report describing the results. For the MLN field, the most important results are given below in Table 7.3:

Overall Measurement Quality, 0-Low, 1-Medium, 2-High	2
Pressure Quality	2
Temperature Quality	2
Duration Quality	2
Operating Temperature	42.5 ^oC
Average Temperature	41.7 ^oC
Operating Pressure	54.1 barg
Average Pressure	53.7 barg
Average Measured Density	50.33 kg/m^3
Average PVT Density	49.29 kg/m^3
Measured Density Factor	1.021
Average PVT Permittivity	1.103
Average Measured Permittivity	1.098
Permittivity Offset using Measured Density	-0.006

Table 7.3 Important results reported for a manual GIS measurement

In the example above (Table 7.3), the manual GIS measurement is acceptable as the overall measurement quality is ‘high’. The user may therefore use the ‘*measured density factor*’ to correct the gas density look-up tables. At the same time, the ‘*permittivity offset using measured density*’ may be used to correct the configuration gas permittivity. Making these two simple corrections means that the MPM meter is now configured with gas properties which closely match the properties of the flowing gas. As already described, this will produce superior liquid flow rate results.

As shown in the sensitivity study of section 4.3, the GVF limit of 95% which is notionally the dividing line between liquid and gas dominated multiphase flow, is also the minimum GVF at which gas properties start to have an appreciable impact on the liquid measurement. Below this GVF, the impact of uncertainties in the gas density is limited. GIS measurements were therefore performed on all wells where the GVF > 95%. As shown in the composition map (Figure 7.2), roughly 70% of the wells meet this criteria and it can therefore be surmised that the accuracy of configuration gas properties is important in accurately metering the total field liquid production.

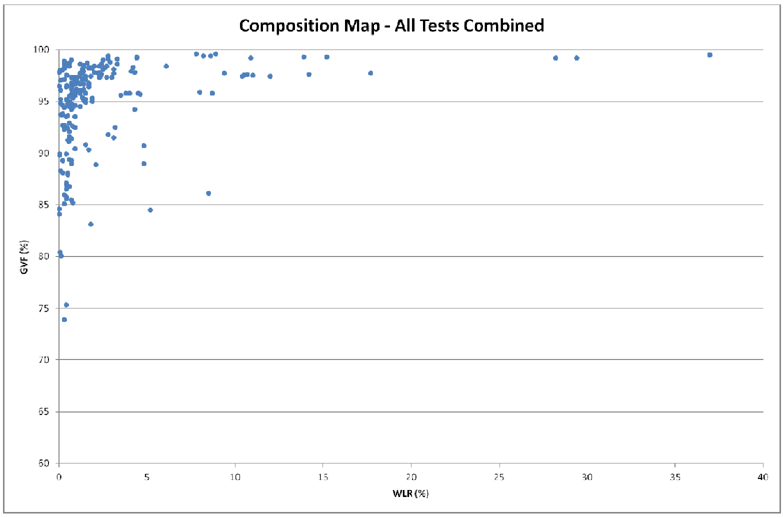

Figure 7.2 Composition map for all tests combined

Table 7.4 below summarizes the GIS measurements performed per campaign. Note that campaigns 2 and 6 consisted of fewer than 5 well tests each and have been removed from the discussion of results.

Campaign	Number of well tests	Number of well tests with GVF > 95%	Number of GIS measurements	Average GVF of Campaign	Maximum GVF of Campaign
1	21	14	5	94.3	98.5
3	19	12	1	95.6	99.3
4	18	12	5	95.2	99.0
5	20	12	6	94.5	99.3
7	15	11	2	94.3	98.6
8	15	12	5	96.3	98.4
9	16	11	8	96.2	99.5
10	15	12	9	96.3	99.4
Total	**108**	**73**	**24**		
Average				**95.3**	**98.9**

Table 7.4 Summary of gas in-situ measurements performed per campaign

Campaigns 3 and 7 have very few GIS measurements - principally due to an excessive drop in pressure and/or temperature during the measurement period. This drop was attributed to operational issues.

The range of correction factors for gas density seen over all campaigns was from -9 to +6%. This represents a significant difference between the true flowing gas density and the PVT predicted gas density. It is, however, still within the expected range (a variation of ±10 to 15% can be reasonably expected as described in section 3.2).

7.1.4 Conversion to Standard conditions

Well test results are typically reported at standard conditions. For test separators, a black-oil correlation is often used alongside a shrinkage and/or meter factor. As described in section 3.1, the MPM meter uses a single-stage flash to standard conditions which assumes that the oil and gas are in equilibrium from operating conditions all the way to standard conditions. Total hydrocarbon mass is conserved and therefore, the calculation can be achieved with knowledge of the following:

- Single-stage flash densities of oil and gas at standard conditions
- Mass-transfer factor which accounts for the mass of oil which becomes gas during the transfer and vice-versa

This approach is the only feasible method for a multiphase meter which has no knowledge of the downstream process and is therefore commonly used. However, in the case of the MLN field, the allocation calculation is performed based on the oil flow rate results coming from the individual well tests as reported by the MPM meter and the total oil production measured at the stock tank. In-between the two is a production process consisting of several separator stages, a boiler, compressors and dehydration units. Thus, the assumptions of the single-stage flash are invalid as the oil and gas do not stay in equilibrium all the way to standard conditions.

The simplified process flow diagram in Figure 7.3 outlines the complexities of the MLN production process. It is noted in particular that there are three stages (two separators and one oil stabilizer/boiler) where gas is removed from the oil. Therefore, the correct method of transferring MPM measured flow rates to standard conditions is to perform a 'multi-stage flash' (MSF) that mimics the effects of the three separation stages and further shrinkage in the stock tank.

In performing the multi-stage flash, it is assumed that:

- The Equation of State (EoS) models for each fluid correctly predict the fluid's behaviour through the production process. This is a reasonable assumption since reservoir pressure is generally still above the saturation pressure.
- The pressure and temperature of each separator stage remains constant. This is also a reasonable assumption since the running of the plant does not change significantly over time.
- Each fluid may be treated individually despite the fact that the total production is in fact co-mingled just prior to the HP separator V-101.

It should be noted that the most appropriate method for verifying the MPM results would be to perform a total hydrocarbon mass-balance at the V-101 separator. At the inlet to V-101, the pressure and temperature conditions are only a few bar/^{o}C lower than the MPM meter operating conditions. However, the V-101 gas and oil meters are not trusted and therefore the only reliable measurement in the process is the oil level at the stock tank.

The single-stage flash is performed by the meter using conservation of mass between the two conditions. The equation below gives the oil volume flow rate at standard conditions and as input requires the oil density at standard conditions and *M* which is the mass transfer factor used to account for phase transfer between oil and gas.

$$Q_{VOsc} = \frac{Q_{VOac}\rho_{Oac}(1-M)}{\rho_{Osc}}$$

Where: Q_{VOsc} – oil volume flow rate at standard conditions

Q_{VOac} – oil volume flow rate at actual conditions

ρ_{Osc} – oil density at standard conditions

ρ_{Oac} – oil density at actual conditions

M – Mass transfer factor

The process by which the multi-stage flash (MSF) transfer was calculated is given below:

1) Flash fluid PVT model to conditions at separator V-101. Save resulting oil as new fluid ‘Oil V-101’
2) Flash ‘Oil V-101’ to conditions at separator V-102. Save resulting oil as new fluid ‘Oil V-102’
3) Flash ‘Oil V-102’ to conditions at oil stabilizer T-101. Save resulting oil as new fluid ‘Oil T-101’
4) Flash ‘Oil T-101’ to stock tank conditions. Save resulting oil as new fluid ‘Oil Stock Tank’
5) Flash ‘Oil Stock Tank’ to standard conditions

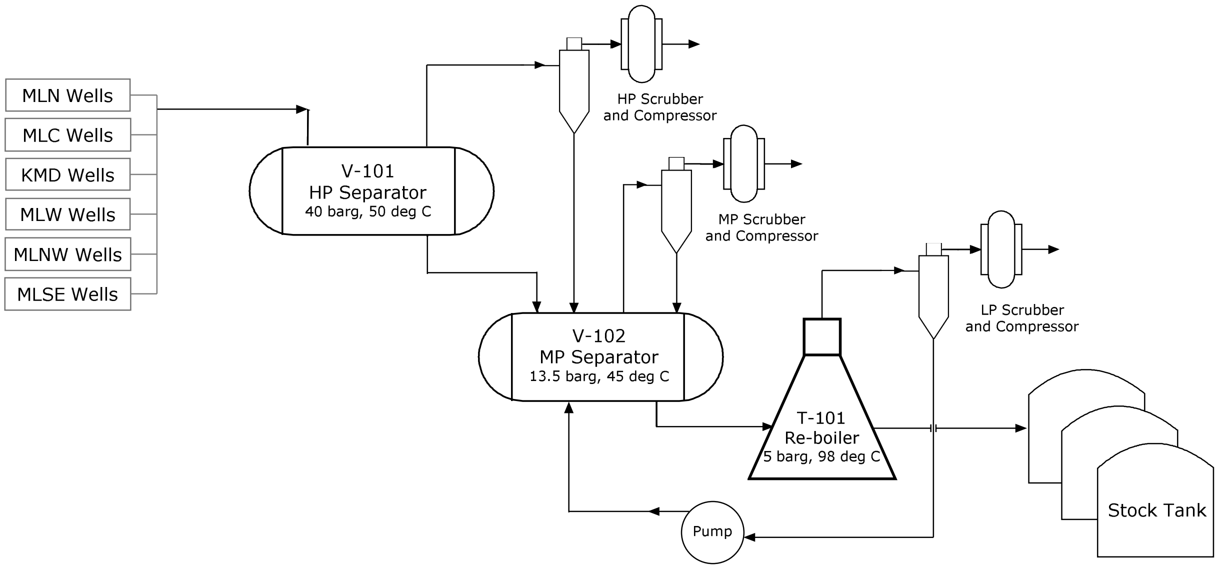

Figure 7.3 MLN simplified process flow diagram

Using this process, the MSF oil density at standard conditions – which is smaller than through the single-stage process, may be calculated. For example, the single-stage flash for the MLN-4 fluid (gas condensate) gives an oil density of 800.5 kg/m3 at standard conditions as compared to 783.3 kg/m3 for the multi-stage flash. This simple difference produces a 2% increase in the oil flow rate at standard conditions. However, the most important difference between the two approaches is the impact on the mass-transfer factor *M*. Taking the example of MLN-4 for an operating condition of 40 barg and 50 ^{o}C, the mass transfer factor *M* for the single-stage flash would be 0.235. This means that in moving from the operating conditions to standard conditions, 23.5% of the oil mass is transferred to the gas phase. For the multi-stage flash calculation, the mass transfer factor for the same operating conditions would be 0.137 – representing a transfer of only 13.7% of the oil mass to the gas phase.

The multi-stage flash calculation was first implemented following campaign 5 in July 2012. The raw data for this campaign was recalculated using the MSF oil density and mass-transfer factors. In the case of MLN-4, the SSF oil flow rate was 1650 sbpd as compared to 1890 sbpd for the MSF approach. This represents an increase of 14.5% as compared to the original data – clearly a significant area of uncertainty in the reconciliation and allocation.

Due to the range of fluid types, not all wells displayed such a considerable change when the MSF calculation was implemented. However, taking the entire campaign 5 together, a difference of approximately 1500 sbpd was observed for a total production of 26,000 sbpd, representing almost 6% of the total production. It was decided that the multi-stage flash approach should be used thereafter and that all prior tests should be recalculated using this method.

As shown in Figure 7.3, the gas from each stage is passed through a scrubber and thereafter to a compressor for use in gas lift and injection. The liquid recovered at each scrubber is pumped back into the V-102 separator such that it is reported in the total stock tank volume. The multiphase meter cannot account for this condensation volume, but an estimation can be made based on an understanding of the process.

Using the same case of the test on MLN-4 in campaign 5, the condensed oil volume was calculated to be about 98 sbpd for a production rate of 1890 sbpd. This corresponds to just over 5% of the MSF calculated oil flow rate at standard conditions. The volume of condensed liquids is negligible for the black oil wells, but noting that the well MLN-4 has a GVF ranging from 95 to 96% which is close to the average for all campaigns, 5% is a reasonable estimation for all volatile oil and condensate wells.

8 COMPARISON VS STOCK TANK

The comparison below summarises the totalised oil production from the various MPM well tests as compared to the stock tank volumes on the reconciliation date of each campaign.

Campaign	Reconc. Date	No. of well tests	Ave GVF (%)	Stock Tank (sbpd)	MPM (sbpd)	Delta (%)	Number of GIS Meas'mts
1	08/11	21	94.3	30,614	28,494	-6.9	5
3	02/12	19	95.6	28,182	23,989	-14.9	1
4	05/12	18	95.2	26,182	24,261	-7.3	5
5	07/12	20	94.5	26,609	25,795	-3.1	6
7	01/13	15	94.3	23,705	21,076	-11.1	2
8	06/13	15	96.3	15,406	15,907	+3.3	5
9	08/13	16	96.2	18,783	18,911	+0.7	8
10	11/13	15	96.3	18,219	17,534	-6.7	9

Figure 8.1 Summary of total production rates versus the stock and the correlation with GIS measurements

The reconciliation data given in Figure 8.1 shows that when all of the factors described in section 7.1 are considered, the difference between the MPM and stock tank oil flow rates are generally within +/- 10%. Note that the total MPM measured production rate is based on the multi-stage flash calculation, includes gas in-situ correction factors for individual wells and includes an estimation of oil condensation from the gas at the various production separator stages.

A general bias is seen towards an underestimation of the total field oil flow rate. It is suggested that this bias would be accounted for if more gas in-situ measurements were performed per campaign since this is seen to be correlated to the difference between MPM totalised volumes and the stock tank volumes. In campaigns 3 and 7 where the largest differences were seen, significantly fewer gas in-situ measurements were performed. Additionally, as mentioned in section 7.1.2, the gas-lifted wells were generally always tested at a lower rate than during normal production due to the piping differences of the well testing package versus the production system.

9 CONCLUSIONS

Several important conclusions can be made based on the above results which may serve as useful considerations for future testing in MLN and for others wishing to undertake campaign well testing as opposed to installing permanent multiphase meters.

1) The difference between the cumulative oil measurements performed by the MPM meter, based on the multi-stage flash conversion, was generally within ±10% of the stock tank. Considering the

range of uncertainties inherent in this style of testing, the complexities of the PVT and the generally high GVF range, this is considered to be a good result.

2) Using a multiphase meter which exhibits low sensitivity to PVT properties simplifies the field configuration, reduces the calibration requirements at the well site and results in greater confidence in the measurement results.

3) The gas in-situ (GIS) verification tools available in the MPM meter eliminate the need for repeated PVT sampling for field configuration. As a result of the experiences in the MLN field, MPM have developed the GIS measurement functionality to include quality parameters which make it more user-friendly for operators.

4) A field specific sensitivity analysis undertaken during the well test planning phase is a useful activity in order to understand the relative importance of the various configuration parameters upon measurement results from the MPM meter.

5) A comparison of totalised MPM rates with the stock tank must take into account the production process through the use of a suitable multi-stage flash calculation. A single-stage flash cannot mimic the process correctly and can lead to significant underestimation of the oil flow rates at standard conditions. This is particularly true in the case of gas condensates and volatile oils where the differences between a single and multi-stage flash prediction of oil volume flow rate can be in the order of 20%. In addition, standard conditions transfers whether single or multi-stage, do not take into account the condensation of liquids from the gas train of the production process. This was estimated to represent about 5% of the total production for volatile oil and gas condensate wells.

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