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Live Fluids or Controlled Fluids:
How Should we Calibrate a Multiphase Flow Meter?

Norman Glen and David Millington, NEL

1   ABSTRACT

This paper presents findings on mass transfer-related fluid properties errors that can occur during multiphase flow meter factory acceptance testing (FAT). A dynamic FAT determines the optimum performance of an MPFM before service in the field. Substantial uncertainties in this process can result in poor device qualification that consequently impacts their quality in the field.

Two multiphase flow facility configurations, live hydrocarbon fluids and controlled (inert) fluids, have been assessed using the PPDS thermophysical properties software package. A test programme was constructed to determine fluid properties errors that occur due to component mass transfer between the gas and liquid hydrocarbon phases, thus causing a difference in measured fluid volumes between the reference measurement section and the location of the device under test.

The results show that the effect of component mass transfer for controlled fluids can be considered negligible. However, the live hydrocarbon tests showed significant mass transfer between the liquid and gaseous phases, therefore, potentially impacting the quality and stability of the reference system or possibly corrupting the calibration process if unaccounted for.

2   INTRODUCTION

For over 20 years, multiphase flow meters (MPFM's) have been employed as complex measurement systems for the upstream oil and gas sector, delivering real-time well performance data that allows operators to maximise production and increase field recovery factors.

Although MPFM's are now widely regarded as reliable measurement tools, their claimed theoretical uncertainty will often not meet that of a conventional test separator setup, where the flow is split into its respective phases and each metered as a single phase. Therefore, the accuracy of an MPFM is regularly subject to scrutiny. Although the measurement stability of multiphase metering systems does not yet emulate that of a test separation system in most environments, there is a major industry push towards replacing the test separation procedure with the modernised multiphase flow measurement alternative [1]. This solution is attractive in many respects; enabling production monitoring, minimising cost (both capital and operational), minimising required human resources and also increasing available platform space. Clauses have already been implemented that permit the use of MPFM's for fiscal metering applications of mature fields [2], where the capital and operating expenditure associated with installing test separation equipment is not financially viable. However, it is worth reiterating that questions still remain about accuracy in service, hence employing MPFM's as fiscal meters remains a controversial

approach that has only been adopted in a small number of locations. Generally, MPFM's will not provide the confidence, reliability or combined measurement uncertainty of a conventional fiscal metering assembly [3].

With financial factors driving the implementation of MPFM's into fiscal applications - even though their accuracy may be viewed as undesirable - a potential development could be to improve the baseline uncertainty of the device itself. This may seem perfectly feasible, but could be considered untimely, relying upon heavy research investment during a period of economic uncertainty in the oil and gas industry. Conversely, additional uncertainties that arise from calibration effects could be explored. Calibration effects influence the uncertainty of all metering systems and include geometrical factors, line condition-based errors as well as flow patterns influences to name a few. Understanding these effects is critical to translating between laboratory validation and field validation, therefore bridging the gap associated with the leap from lab to field.

The guidelines directing the validation procedure of a MPFM are open to individual interpretation. Standards state that the dynamic testing of a multiphase meter in a third-party flow facility is at the discretion of the end user [4]. Currently, no standards exist that advise on the pre-requisites of a flow loop trial. Ultimately, this means the meter may be tested in a facility operating at low pressure or high pressure, using live fluids or controlled fluids, or with different operating principles, such as single phase or multiphase fluid transport.

The factory acceptance test (FAT) of the multiphase meter is designed to test the optimum performance of the device and ensure that measurements are within the quoted ranges. This paper will investigate the fluid properties errors that can occur when using live hydrocarbons instead of controlled fluids for a MPFM FAT and how this reflects the qualification of meter performance.

3   CALIBRATION BEST PRACTICE

3.1   A Brief Reminder

Calibration is an essential step for all measurement systems and has been scientifically practiced for thousands of years. The term 'calibration' refers to the process in which a device is compared, and assessed, against a reference transfer standard with good temporal stability [5]. For example, prior to the introduction of a non-physical, coefficient-based reference system, the primary physical reference for a unit of length was contained in a controlled environment. This ensured no expansion/contraction due to changes in critical parameters such as temperature or humidity. Hence, the reference must show a degree of resilience to changes in its physical properties under changing conditions.

The primary reference standard tops the calibration hierarchy. The quality of all subsequent references are defined in terms of their position in the calibration pyramid and consequent reference uncertainty. Further down the pyramid, the reference uncertainty increases. An illustration of the calibration pyramid for the unit of mass is shown in Figure 1.

The uncertainty obtained from calibration will be a combination of practicality and operational requirements. For high precision applications, the reference standard should be as high up the calibration pyramid as possible. On the other hand, it is

more practical (and cost effective) to calibrate low precision devices nearer the base of the pyramid.
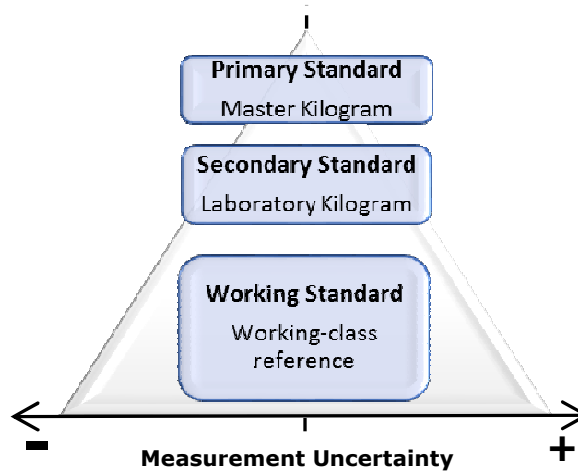

Fig 1 - Calibration Pyramid

3.2   So, How Accurate Should a Multiphase Flow Meter Be?

If this question was asked twenty years ago, then it is likely the answer would be 'not very' - mainly due to a lack of research, knowledge and expectation. However, now that MPFM's have gained industry acceptance as high performance measurement systems, complimented by a few hardware and software upgrades along the way, these initially restricting factors have decayed. This has induced a knock-on effect in the standard of MPFM application, going from delivering low accuracy measurement approximations to now being employed as high accuracy fiscal and allocation flow meters. This step change in performance must be harmonised with a step change in calibration. For multiphase flow meters, the term 'calibration' is rarely used, as the device generally undergoes 'qualification' and is not adjusted to conform with the reference system.

By analogy, if a balance that was used to weigh vegetables is now being used to weigh gold, the application and requirements have changed, hence the quality of calibration and subsequent quality of the device must change to reflect this. Therefore high accuracy reference calibrations are essential for MPFM's progression for use into high accuracy applications.

As discussed, calibration best practice fundamentally relies upon stable conditions (regardless of the system under test) to obtain reliable results with minimum uncertainty. Translating this into multiphase flow measurement terms, the flowing medium acts as the transfer standard, essentially calibrating the MPFM against a multi-component, multiphase mixture. Therefore, a critical aspect of MPFM calibration is the uncertainty that arises from transport of multiphase fluids from the single phase reference measurement section to the device under test. Multiphase test loops do not measure complex phase interaction effects, such as mass transfer, that may occur during component mixing. Therefore, additional uncertainties arise from the fluid properties themselves. This phenomenon introduces the key question - should one use live fluids or controlled fluids in a multiphase flow loop?

3.3 Live Fluids and Controlled Fluids

The advantages of testing in live fluids are easily understood. The meter will undergo service in live fluids, so it seems logical to perform the meter's FAT in a fluid that reflects service conditions.

A MPFM will go through the process of several qualification stages before being considered a competent measurement system; see Table 1 for details. These stages will not be followed for every meter, possibly due to financial or field constraints, but are used as a general qualification guide.

Table 1 - MPFM Qualification Stages and API 20.3 Narrative [4]

Qualification Stage	Description	API 20.3 Extract
Static Testing	Calibration of all measurement devices such as pressure and temperature sensors, gamma-ray densitometers etc. This calibration ensures the functionality of the meter components.	*"The individual calibration of the individual sensors and the primary devices is of prime importance in maintaining the performance of the MPFM."*
Dynamic (Flow Loop) Testing	The user must test the meter in flow conditions that are the same as field application –multiphase, wet-gas, heavy oil etc. Choice of dynamic FAT fluid types, either controlled or live, are at the discretion of the end user. However, it is advised that inert fluids may provide a better test of the actual performance of the meter.	*"Meter flow loop verification often may also involve testing on 'inert' fluids – stabilized crudes, kerosene, nitrogen, etc. – which may provide a better test of the meter's basic flow dynamics and sensor responses than can be guaranteed with 'live' fluids."* *"The objective of testing in a reference facility is verification to an agreed level of the manufacturers claimed performance specification for the instrument"*
Field Trial/ Site Acceptance Test (SAT)	A field trial tests the device in actual operating conditions. This gives a good indication of in-service performance, however is unlikely to determine the critical baseline performance of the device upon which it demonstrates minimal measurement uncertainty.	*"Though the meter may have performed well in prior tests, there will likely be sufficient difference between test and field conditions that having the additional data provided at site may prove extremely important"*

As can be observed from the API 20.3 extract in Table 1, the recommended practice for the dynamic qualification (flow loop FAT) of a MPFM is to verify the meters optimum performance and confirm stated uncertainties. The benefits of this approach are also recognised within the UK Oil and Gas Authority Guidance Notes for Petroleum Measurement [2]:

"Where the comparison is on a volume basis, it should be referred to a common set of conditions (e.g. standard conditions) and must take account of possible transfer between phases.

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The calibration fluids may be either 'process' (live crude, hydrocarbon gas, formation water) or 'model' (e.g. oil, water, nitrogen). The latter set-up is by far the most common; not only is it far less hazardous to operate but the PVT characteristics of the fluids are likely to be relatively well understood, so that it becomes possible to compare the reference measurements with those of the MPFM with minimal additional uncertainty."

Generally, good device calibration requires reference accuracy of at least 5-10 times greater than the device under test. This means for a test condition by which a 5% measurement uncertainty would be expected from the MPFM, a 0.5-1% uncertainty should be attained from the reference flow facility.

Following FAT, the MPFM will then undergo testing in live hydrocarbon fluids during a field trial, which acts to assess the performance in real service conditions. It should be noted that live hydrocarbon flow loop testing does not emulate testing of field conditions.

Ultimately, the responsibility of a MPFM is to calculate the flow rates of each phase within a multiphase flow, irrespective of the process fluids. A calibration is input into the meter using the individual phases that comprise the multiphase flow, providing the basis of its operational envelope. This envelope is sensitive to variations in fluid properties, in theory, as long as the fluid properties do not change over time, then the meter should stay within the operating envelope and maintain its accuracy.

4   NEL MULTIPHASE FLOW LOOP

The NEL multiphase flow loop is a three phase (gas-oil-water) facility. The facility features a three phase separation vessel, with the liquid phases re-circulated and metered as single phases. The gas phase is injected externally and also metered as a single phase prior to mixing with liquid phases in the test section. An illustration of this configuration is displayed in Figure 2. The oil, Paraflex HT9, is a controlled reference fluid, pure nitrogen is used for the gaseous phase and the water phase is a synthetic brine to reflect standard operating environments.
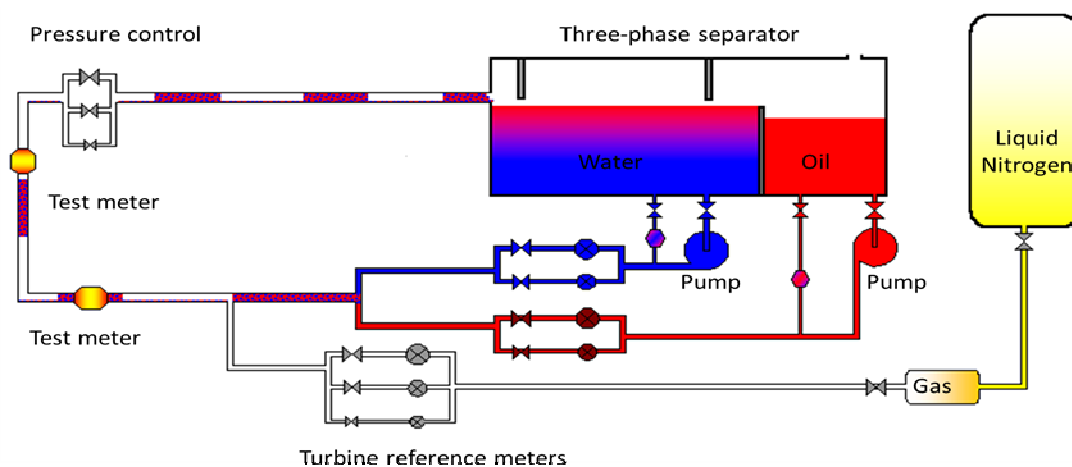

Fig 2 - NEL Multiphase Flow Loop Diagram

The NEL facility is optimised to provide accurate and stable reference measurements:

1. Pure nitrogen is used as the gas phase. This has minimal mass transfer with the liquid phases and its PVT behaviour is well defined. Single pass gas injection means no possibility of separator liquid carry-over into gas outlet stream, improving measurement uncertainty.

2. The oil fluid properties represent that of a standard light crude, however its separation qualities have been improved ensuring reduced residence time and minimal oil carry-under in the outlet water stream. Both oil and water outlet streams are closely monitored in real-time to assess phase contamination levels.

5   MASS TRANSFER OF MULTIPHASE COMPONENTS

When dealing with a multi-component mixture, the fundamental questions that need to be answered are:

- How much of a phase is present? (Phase fraction or quality)
- What are the compositions of the components in a phase?
- Is the phase stable?

A common stumbling point in the understanding of mixture behaviour is the differentiation between how much of a phase is present and the compositions of a phase. Figure 3 illustrates the key definitions for a two phase binary mixture.

Phase split (phase fraction)

$$\alpha = (A+B)_{vap} / (A+B)_{total}$$

$$\beta = (A+B)_{liq} / (A+B)_{total} = 1 - \alpha$$

Phase compositions

Vapour mole fraction

$$y_A = A_{vap} / (A+B)_{vap}$$

$$y_B = B_{vap} / (A+B)_{vap} = 1 - y_A$$

Liquid mole fraction

$$x_A = A_{liq} / (A+B)_{liq}$$

$$x_B = B_{liq} / (A+B)_{liq} = 1 - x_A$$
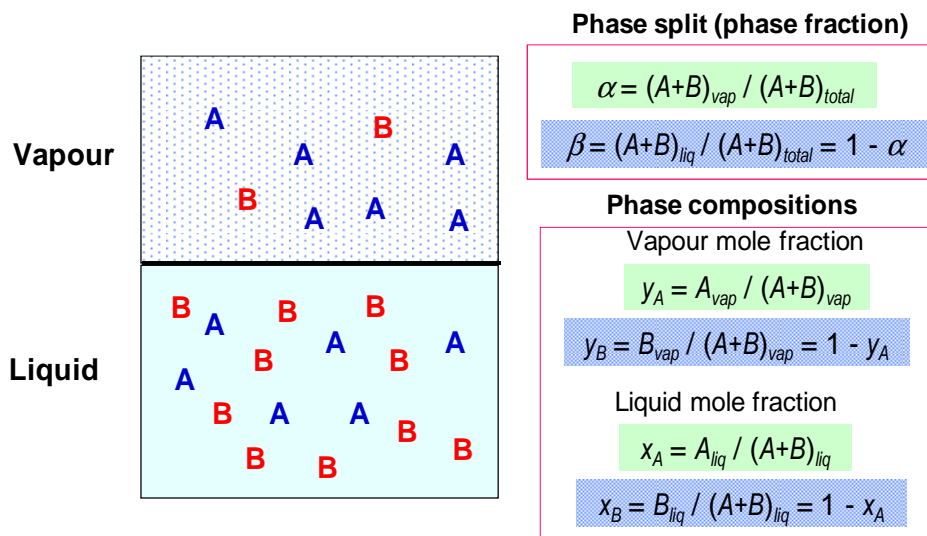
Fig 3 - Phase split and phase composition definitions

The key fact is that the compositions of phases in equilibrium are not, in general, equal. This is completely opposite to the pure component case, where the compositions must be equal because there is only one component! This inequality of compositions in phases that are in equilibrium is the reason why a component can be separated from a mixture by distillation or extraction and also

why the composition of the phases in a multi-component mixture can vary as the temperature and pressure changes.

Numerous equations of state (EoSs) have been developed to enable the calculation of phase fractions and phase compositions for multi-component mixtures, allowing the calculation of phase properties such as density. However, in a multiphase flow facility, in addition to the transfer of components between phases due to chemical thermodynamics, additional mass transfers can occur, due to liquid pick-up into the gas phase and solubility of the gas in the liquid phases.

Mass transfer that occurs within a multiphase environment is thus influenced by many factors including temperature and pressure dependent chemical thermodynamics, flow dynamics effects, multiphase flow patterns and phase area distributions. Not only that, mass transfer may be a time-dependant process – just because it happened before, does not mean it will happen again!. For example, although water is generally not considered a primary contributor in the mass transfer equation, it may contain partially dissolved gas with later potential to contribute to the hydrocarbon phase exchange process.

Good reference systems entail tightly controlled operating conditions, excellent condition understanding and very high levels of stability. Having a difficult to characterise, highly complex phenomena within a reference measurement standard is regarded as poor metrology practice, especially if the reference standard is to be considered for high accuracy multiphase flow devices. Good design and operation can reduce or eliminate many of the physical influence factors causing mass transfer between phases. The use of stable reference fluids is the most obvious way to reduce the effects of chemical thermodynamically driven mass transfer between phases.

In order to test the magnitude of this mass transfer effect, a dedicated physical properties test programme was constructed. This programme featured a selection of multiphase and wet-gas test cases to determine how changing operating conditions influenced the phase transfer for both live hydrocarbon and controlled fluid flows. The test cases were performed using the PPDS thermophysical properties software package.

PPDS [6] is a physical properties data bank containing over 1400 pure components and many pseudo-components, such as light crude, that can be analysed as if it were pure. The software package features many equations of state that enable the calculation of thermophysical properties of multi-component mixtures. In addition, it allows user-defined binary interaction parameters (BIP's) to optimise the calculation depending on the mixture components.

6   PHASE INTERACTION ANALYSIS AND TEST PROGRAMME

Exploring the mass transfer phenomenon in greater detail, the PPDS package was used to perform three phase vapour-liquid-liquid flash calculations. This uses the Peng-Robinson (PR) equation of state to perform an initial vapour-liquid flash calculation followed by use of Henry's Law to split the liquid into two liquid phases. The analysis featured two key stages for a given test point. First, a superficial single phase gas mixture was calculated to determine baseline fluid properties at chosen conditions. Second, this test was repeated including specified quantities of oil and water components. The variation in gas density between both

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calculations therefore describes the levels of mass transfer that has occurred. The test calculation programme is described in Table 2.

$$Gas\ Density\ Difference\ (\%) = \frac{(Mixture\ Density - Superficial\ Density)}{Superficial\ Density} \times 100 \quad (1)$$

Table 2 - Test Programme Parameters

CASE	TEST TYPE	FLUID TYPE	OIL COMPONENT (PPDS)	GAS COMPONENT (PPDS)	TEMP.	PRESSURE	GVF
1A	Multiphase	Live Hydrocarbon	M1	AGA-8	25	10 bar	30%
2A	"	"	"	"	25	80 bar	30%
3A	"	"	"	"	25	10 bar	50%
4A	"	"	"	"	60	10 bar	50%
5A	"	"	"	"	25	80 bar	50%
6A	"	"	"	"	60	80 bar	50%
7A	Wet-gas	Live Hydrocarbon	M1	AGA-8	25	10 bar	90%
8A	"	"	"	"	60	10 bar	90%
1B	Multiphase	Controlled	Kerosene	Nitrogen	25	10 bar	30%
2B	"	"	"	"	25	80 bar	30%
3B	"	"	"	"	25	10 bar	50%
4B	"	"	"	"	60	10 bar	50%
5B	"	"	"	"	25	80 bar	50%
6B	"	"	"	"	60	80 bar	50%
7B	Wet-gas	Controlled	Kerosene	Nitrogen	25	10 bar	90%
8B	"	"	"	"	60	10 bar	90%

M1 = Hexane, Dodecane, Hexadecane and n-Eicosane

For this test programme, the effect of water cut was not explored and was held constant at WC=20%. As can be seen in Table 2, the first set of eight test cases, 1A-8A, were in a live hydrocarbon environment for both multiphase and wet-gas flows. Test points 1B-8B were repeats of the first eight cases only replacing the live hydrocarbons with controlled fluids.

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A liquid hydrocarbon combination of Hexane, Dodecane, Hexadecane and n-Eicosane was chosen to reflect the liquid phase, defined as M1 in Table 2. A representative natural gas mixture was also used (AGA-8, Gas 3, Table C.1 [7]).

For the controlled fluid calculation, kerosene was used as the oil and nitrogen was used for the gas. A standard pure water was used for both hydrocarbon and controlled fluid test cases.

7   PPDS RESULTS

To illustrate the basic calculation objectives, a summarised calculation process is displayed in Figure 4. This example shows the calculation of live hydrocarbon test case 1A.

Table 3 - Test Case 1A

Fluid	Oil	Gas	Temp.	Press.	Water Cut	GVF
Live Hydrocarbon	M1	AGA-8	25°C	10 bar	20%	30%

Input Stream Composition	Mol Fraction	Mol Weight (g mol^{-1})	Mass (g)	Volume (m³)	Density (kg/m³)	GVF (%)
CARBON DIOXIDE	0.015	44.00999832	0.660149975			
NITROGEN	0.01	28.01300049	0.280130005			
METHANE	0.859	16.04299927	13.78093637			
ETHANE	0.085	30.06999969	2.555949974			
PROPANE	0.023	44.09700012	1.014231003	2.194	**8.554**	
ISOBUTANE	0.0035	58.12400055	0.203434002			
BUTANE	0.0035	58.12400055	0.203434002			30
ISOPENTANE	0.0005	72.15100098	0.0360755			
PENTANE	0.0005	72.15100098	0.0360755			
HEXANE	1.5132355	86.1780014	130.4076111			
DODECANE	4.5397065	170.3399963	773.2935887	4.096	793.995	
HEXADECANE	6.052942001	226.447998	1370.676598			
n-EICOSANE	3.026471	282.5559998	855.1475392			
WATER	56.71408895	18.01499939	1021.704278	1.024	997.694	

Output Stream Composition	Volume (m³)	Density (kg/m³)	GVF (%)
GAS	2.436	**7.704**	
HYDROCARBON LIQUID	4.165	751.421	31.95
WATER	1.025	996.757	

$$Gas\ Density\ Difference\ (\%) = \frac{(Mixture\ Density - Superficial\ Density)}{Superficial\ Density} \times 100 \qquad (1)$$

$$Gas\ Density\ Difference\ (\%) = -9.94\%$$

The calculation process illustrated in Table 3 was repeated for all 16 test cases. The resultant mass transfer, in terms of gas density difference, for each test case is provided in Table 4.

Table 4 - PPDS Results for all 16 Test Cases

LIVE HYDROCARBON FLUIDS

CASE	TEST TYPE	TEMP	PRESS.	GVF		DIFFERENCE FROM SUPERFICIAL GAS FLOW
						DENSITY (%)
1A	Multiphase	25	10 bar	30%		-9.93
2A	"	25	80 bar	30%		-13.54
3A	"	25	10 bar	50%		-8.57
4A	"	60	10 bar	50%		-4.46
5A	"	25	80 bar	50%		-10.68
6A	"	60	80 bar	50%		-7.01
7A	Wet-gas	25	10 bar	90%		-2.75
8A	"	60	10 bar	90%		0.71

CONTROLLED FLUIDS

CASE	TEST TYPE	TEMP	PRESS.	GVF		DIFFERENCE FROM SUPERFICIAL GAS FLOW
						DENSITY (%)
1B	Multiphase	25	10 bar	30%		-0.04
2B	"	25	80 bar	30%		0.05
3B	"	25	10 bar	50%		-0.04
4B	"	60	10 bar	50%		-0.17
5B	"	25	80 bar	50%		0.05
6B	"	60	80 bar	50%		0.22
7B	Wet-gas	25	10 bar	90%		-0.04
8B	"	60	10 bar	90%		-0.17

The results described in Table 4 are also portrayed graphically in Figure 4 below.

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Fig 4 - Gas density difference for hydrocarbon and controlled fluids

8   RESULTS DISCUSSION

From initial observation of each test case, it is clear that the stability of controlled fluids far outweighs the stability of the live hydrocarbon fluids for all test cases. The live hydrocarbon test points improve as the conditions transition into the wet-gas regime. However, it should be noted that the PPDS solver will not account for flow pattern-based interaction effects that may also influence the mass transfer process.

The minimum gas density difference for controlled fluids was -0.04% for Test Cases 1B, 3B, 7B and maximum 0.22% in Test Case 6B. In comparison to the live hydrocarbons where the minimum deviation was 0.71% in Test Case 8A and maximum deviation of 13.54% in Test case 2A. As expected, increasing pressure increased the mass transfer of gas into liquid phase. Increasing temperature had the reverse effect, encouraging the flashing of gas from the liquid phase.

The PPDS results for the controlled fluids are in good agreement with the expected physical behaviour of these fluids, i.e. they are essentially immiscible , thus minimising errors due to mass transfer of components between phases. Using this approach largely eliminates the need to use EoSs to correct for any changes in fluid properties due to component mass transfers.

Whilst it is possible to account for the effects of component mass transfers between phases for a multiphase loop using live fluids by using EoSs, it should be noted that all EoSs will introduce their own errors. The magnitude of these errors will be a function of the combination of EoSs chosen, the test point conditions and the compositions of the hydrocarbon gas and liquid phases and the availability, if required, of binary interaction parameters for all the components.

As noted above, the PPDS package uses a combination of the Peng-Robinson (PR) EoS and Henry's Law to perform vapour-liquid-liquid equilibrium (VLLE) calculations. The Peng-Robinson EoS generally performs well for mixtures containing relatively short chain hydrocarbon molecules and the use of Henry's Law is a reasonable approximation since the two liquid components will consist of

a hydrocarbon-rich mixture with very little water and an aqueous phase with very little hydrocarbons.

Although the VLLE calculations in PPDS can only use the PR/Henry's Law combination of models, it is possible to attempt to perform VLLE calculations in two stages: the output liquid phase compositions from an initial VLE calculation are used as the inputs for a subsequent liquid-liquid equilibrium (LLE) calculation. Case 1A was examined in this manner, to assess the potential differences in calculated gas densities due to varying the EoSs used.

Applying the PR EoS to the input compositions at the specified temperature and pressure indicated that the system would be a single phase liquid only! Applying the Lee-Kesler-Plocker (LKP) EoS did predict a two phase, vapour + liquid system. For this calculation the difference in density of the gas phase from the superficial gas density was -4.83% but although this value is smaller than that from the full VLLE calculation, it may have a larger uncertainty, as this VLE calculation does not properly account for the formation of three phases.

In the absence of measured data, it is therefore very difficult to assign realistic uncertainty estimates to the calculated fluid properties and hence it is better metrology practice to use a reference system that avoids this problem.

9   CONCLUSION

It has been found that live fluids create significant additional uncertainties in fluid properties through phase interaction effects that could otherwise be assumed negligible when using controlled fluids. The significance of these effects can be subject to flowing conditions, where additional uncertainties may also arise in the choice of EoS. Ultimately, these effects alter the volume of each phase that has been assessed during single phase reference measurement and also changes fluid properties. The outright impact that unstable fluid properties and volume flow rate measurements may cause on a MPFM has yet to be explored, however, it can be expected that a significant change in phase concentration and fluid properties will have a significant effect on the quality of an MPFM dynamic test.

Controlled fluids showed much less sensitivity to changing conditions and align to the objectives of calibration best practice, ensuring stability of the transfer fluid across the full range of test cases and a resilience to changing properties across all test conditions. Without accurate qualification, the optimal baseline performance of MPFM's will be unknown. With the multiphase flow measurement sector looking towards high accuracy allocation and fiscal measurements, high accuracy meter qualification must be performed. This means ensuring that you can accurately determine the characteristics of the transfer fluid, as changes from its state following reference metering could result in substantial errors and the incorrect assessment of the MPFM in question.

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