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SENSITIVITY STUDY OF THE RESERVOIR FLUIDS PVT PROPERTIES CALIBRATION ON SUPERFICIAL VELOCITIES AND LIQUID HOLDUP

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ABSTRACT

The upward two-phase flow is encountered in many applications in petroleum industry as it is in nuclear and chemical industries. This kind of flow depends on several factors as flowing pressure and temperature, PVT properties of reservoir fluids, trajectory of well, well completion etc. The PVT properties of fluids can be determined in laboratory based on oil and gas samples or can be estimated with different correlations. However, these correlations often lead to different results that are far from the measured data. The good practice is to calibrate a PVT correlation based on measured data in order to obtain a model which matches these data.

In our paper, we investigate how the calibrated and non calibrated PVT properties of reservoir fluids influence the superficial velocities of fluids and holdup fraction in the case of the upward two-phase flow through the tubing string. In the first stage, we study the differences between calibrated and non calibrated values of oil PVT properties which influence the superficial velocities and liquid holdup. Then, we determine the superficial velocity of the fluids and the liquid holdup based on of the calibrated and non calibrated PVT properties of fluids.

The general conclusion in our studied case is that the differences between the values of the superficial velocities and the liquid holdup calculated with the calibrated, respectively non calibrated PVT properties of fluids are not very large. However, it is better to calibrate the PVT properties of the fluids in order to minimize the errors that will propagate in the calculation of the pressure gradient.

Keywords: holdup fraction, upward two-phase flow, superficial velocity, PVT properties.

INTRODUCTION

The complex nature of upward two-phase flow through tubing poses a number of problems in terms of predicting the flow regimes, the liquid holdup and the pressure gradients along the tubing string. Since the 1970s, a number of researchers have tried to solve these problems. Therefore, they developed a series of multiphase flow models based on experimental data which were initially empirical. Several researches have been performed for a better understanding of the mechanisms of the two-phase flow through tubing. Also, a more accurate determination of the parameters of the flow regimes and therefore of the pressure gradients was also tried by using mechanistic models.

In recent years, efforts have increased to develop the predictive methods to determine flow regime and liquid holdup using artificial neural network, fuzzy logic approach, machine learning algorithms[3][10][12].

The flow regimes along the tubing string can be established if the superficial velocities of liquid, respectively of gas are known. Liquid holdup is also an important parameter of upward two-phase flow. The mixture density, in-situ phase velocities and finally pressure gradient are determined taking into account of liquid holdup. On the other hand, the superficial velocities and liquid holdup depend on PVT properties of fluids which in turn depend on the pressure. Consequently the accuracy of the superficial velocities and liquid holdup depends on the accuracy of fluids PVT properties.

COMPARISON BETWEEN MEASURED, ESTIMATED AND CALIBRATED PVT PROPERTIES OF FLUIDS

The calculation of upward two-phase flow parameters like superficial velocities of fluids and liquid holdup requires knowledge of the PVT properties of these fluids for a wide range of pressures and temperatures that may exist along the tubing string.

The PVT properties of fluids can be measured in laboratory or can be estimated with different empirical correlations.

Sometimes, experimental data are not available because the representative samples cannot be obtained. In this case, it is necessary to use empirical correlations and to choose the appropriate one. In the better case, the measured data of PVT are available at some pressures and reservoir temperature. In this case, we can calibrate PVT properties using the most suitable correlations and the measured data in order to extrapolate these at different conditions of pressure and temperature.

Further we analyze the most used correlations to estimate bubble point pressure, formation volume factor, solution gas ratio, and oil viscosity. For this purpose we will use the measured data shown in table 1.

To study the differences between the estimated and calibrated PVT properties of fluids, we consider two working scenarios: 1. estimating the PVT properties of fluids with different correlations; 2. calibrating the PVT properties of fluids.

In the case of the first working scenario, the correlations used to estimate the formation volume factor, solution gas ratio and oil viscosity are shown in table 2. The measured data and the estimated values of fluids PVT properties calculated with correlations shown in table 2 are shown in figures 1, 2 and 3.

Table 1 Formation volume factor, solution to gas ratio and oil viscosity, measured data at the reservoir pressure ($t=98.5^oC$)

Pressure, p	Formation volume factor, B_o	Solution gas ratio, R_s	Dynamic viscosity of oil, μ_o
bar		sm^3/m^3	mPas
1.00	1.043	0.000	1.147
29.91	1.152	26.195	0.519
58.80	1.263	57.655	0.413
87.69	1.361	87.439	0.351
116.59	1.454	117.147	0.307
145.48	1.548	148.063	0.272
174.37	1.648	181.364	0.242
177.30	**1.659**	**185.000**	**0.240**
203.27	1.646	185.000	0.248
232.16	1.632	185.000	0.258
261.06	1.620	185.000	0.267
289.95	1.609	185.000	0.276
318.84	1.599	185.000	0.285
347.74	1.590	185.000	0.294
376.63	1.581	185.000	0.303
405.53	1.573	185.000	0.312
434.42	1.566	185.000	0.32
463.31	1.559	185.000	0.329
492.21	1.552	185.000	0.337
521.10	1.546	185.000	0.345
549.99	1.540	185.000	0.354

From the data it follows that the bubble point pressure is p_b =177.30 bar and the gas oil ratio is GOR =185 sm^3/m^3.

Table 2 Correlations used to estimate the oil PVT properties.

Oil PVT properties	**Correlations**
Formation volume factor	Standing(S)[13], Vasquez- Beggs(VB)[14], Al-Marhoun(AM)[1][2]
Solution gas ratio	Standing(S)[13] , Vasquez-Beggs(VB)[14], Al Marhoun(AM)[1][2]
Dead oil viscosity	Beal(B)[4], Beggs-Robinson(BR)[5]
Saturated oil viscosity	Beggs-Robinson(BR[5]),Chew-Conaly (CC)[7], Kartoatmodjo-Schmidt(KS)[11]
Unsaturated oil viscosity	Vasquez-Beggs(VB)[14],Kartostmodjo-Schmidt(KS)[11]

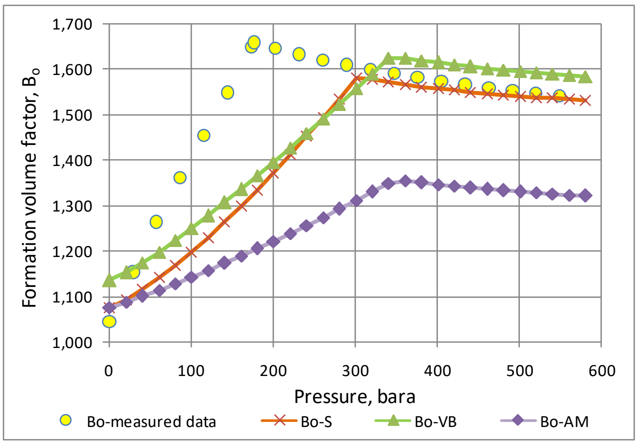

Figure 1 Formation volume factor- measured data and estimated values using different correlations at t=98.5 °C.

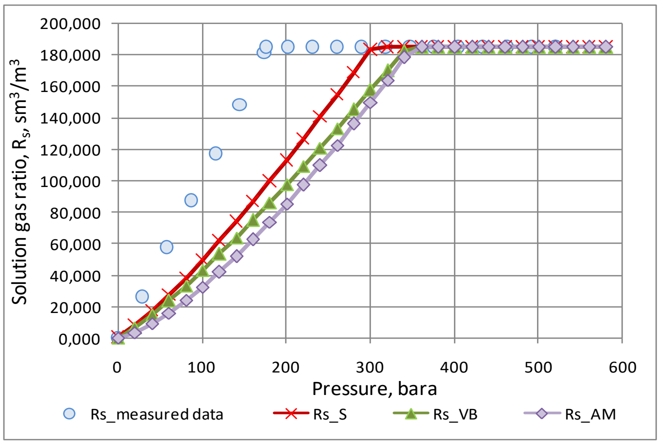

Figure 2 Solution gas ratio- measured data and estimated values using different correlations at t=98.5 °C.

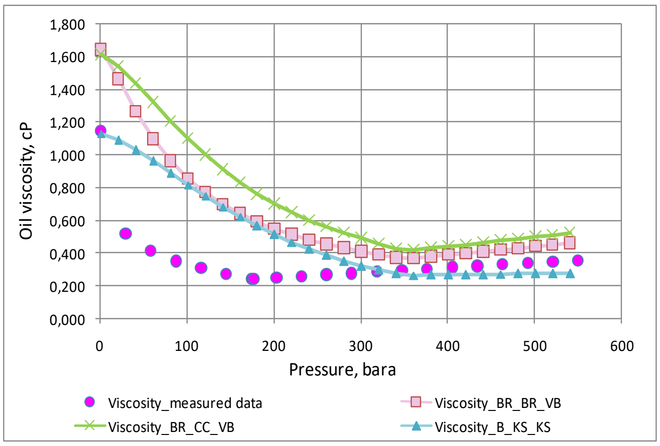

Figure 3 Oil viscosity- measured data and estimated values using different correlations at t=98.5 °C.

As we observe from figures 1, 2 and 3, there are large differences between the measured data and the estimated values of the bubble point pressure, the formation volume factor, the solution gas ratio and the oil viscosity. However, the Standing correlation [13] seems to be more suitable than the other correlations used to estimate the formation volume factor and the solution gas ratio. Regarding the oil viscosity, we also see in figure 3 that the most suitable correlations are those developed by Beal [4] for the viscosity of dead oil, respectively by Kartoatmodjo-Schmidt [11] for the viscosity of unsaturated and saturated oil.

To highlight the importance of PVT calibration we calculated the squared errors only for the bubble point pressure which is shown in table 3. As we see from Table 3 and 4, the estimated values of the bubble point pressure are about twice as high compared to its measured value, while the calibrated value is very close to the measured data.

Table 3 Measured and calibrated data of bubble point pressure and squared error

Bubble point pressure Measured data, bara	Bubble point pressure calibrated at t=98,5 ^{o}C, bara	Squared errors
177.3	182.16	23.62

Table 4 Values of bubble point pressure calculated with different correlations, calibrated value and measured value and squared errors.

Correlation	Estimated bubble point pressure, bara	Squared errors
Standing[13]	303.15	15839.76
Vasquez-Beggs[14]	344.46	27945.31
Al Marhoun[1]	349.77	29747.59

In the second working scenario we calibrate the considered fluids PVT properties at the reservoir temperature (t = 98.5 ^{o}C). Then, we extrapolate the calibrated models at the well average temperature, t = 65.67 ^{o}C. The results are shown in figures 4, 5 and 6.

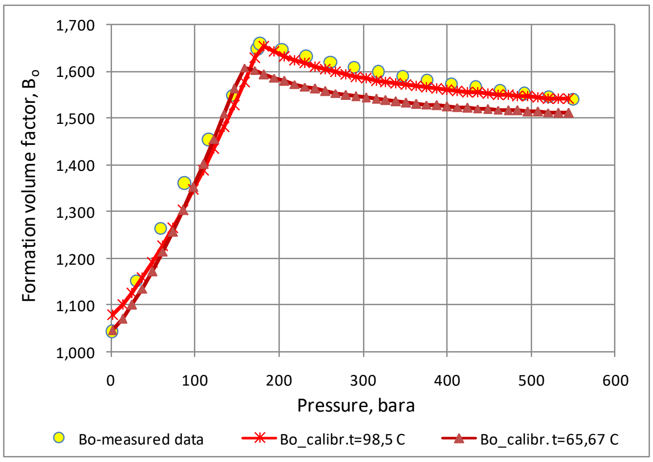

Figure 4 Formation volume factor - measured data and calibrated values at t=98.5 ^{o}C and t=65.67 ^{o}C.

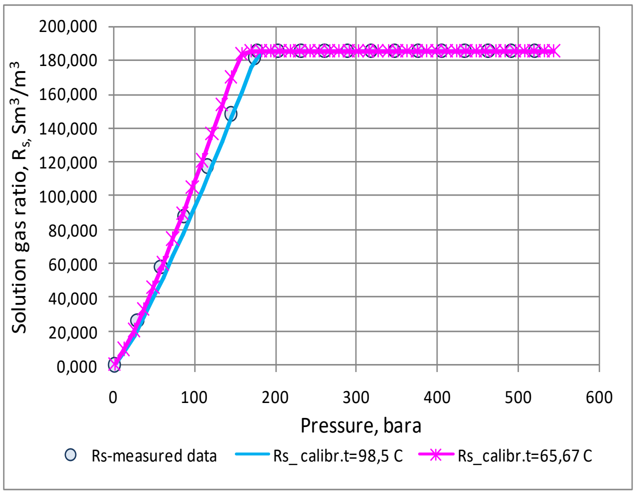

Figure 5 Solution gas ratio- measured data and calibrated values at t=98.5 ^oC and t=65.67 ^oC.

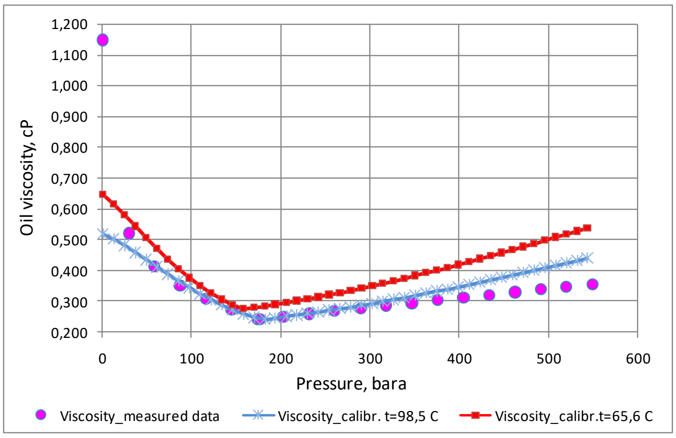

Figure 6 Oil viscosity -measured data and calibrated values at t=98.5 ^oC and t=65.67 ^oC.

As we showed in the figures above, the calibration models of PVT properties lead to a satisfying match of measured data. These models will be used further to determine the superficial velocities of fluids and liquid holdup at the well average temperature.

SENSITIVITY STUDY OF CALIBRATED AND NON CALIBRATED FLUIDS PVT PROPERTIES ON SUPERFICIAL VELOCITIES AND LIQUID HOLDUP

The upward two-phase flow of fluids through a tubing string has a series of particularities which generally depend on the number of phases which flow simultaneously, the PVT properties of fluids, the flowing pressure and temperature, as well as the diameter and profile of the tubing string. During the upward two-phase flow of fluid through tubing, the liquid and gaseous phases have different velocities which determine the appearance of the slippage phenomenon. Also, the gas rate increases as the flowing pressure decreases. Consequently, different flow patterns occur along the tubing string. The laboratory experiments have shown that the values of the superficial velocities of fluids are correlated with the flow patterns along the tubing string.

Therefore, the flow pattern prediction requires an accurate determination of the superficial velocities. On the other hand, the correct prediction of these superficial velocities and the liquid holdup lead to minimal errors in the case of the pressure gradients calculus along the tubing string.

The liquid holdup is determined with a two-phase flow empirical or mechanistic correlation. In our paper, we have considered, for example, the one proposed by Hagedorn-Brown [9].

In table 5, the defined equations of superficial velocities of fluids, void fraction and liquid holdup are shown.

Table 5 The defining equations of the superficial velocities of fluids, liquid holdup and void fraction [6].

Parameters	**Equations**
Superficial velocity of gas, v_{sg} Superficial velocity of liquid, v_{sL}	$v_{sg} = \frac{q_g}{A} \; ; \; v_{sL} = \frac{q_L}{A}$ (1) $v_{sg} = \frac{Q_L\left(GLR - \frac{R_S}{1+R_W}\right)}{86400 \cdot A}\left(\frac{p_S T_m}{T_S p_m} Z_m\right)$ (2) $v_{sL} = \frac{Q_L}{86400 \cdot A}\left(\frac{B_o + B_W R_W}{1+R_W}\right)$ (3)
Void fraction, H_g, Liquid holdup, H_L	$H_g = \frac{A_g}{A} \; ; \; H_L = \frac{A_L}{A}$ (4)

The symbols in the equations in table 5 are: q_g, $q_L -$ gas flow rate and liquid flow rate at some depth inside the tubing string where pressure and temperature are p and t; $A -$ inside area of tubing ;$A_g -$ part of tubing area ocuppied by gas; $A_L -$ part of tubing area ocuppied by liquid; GLR - Gas-Liquid Ratio, $RGL = Q_g/Q_L$; R_w −water-oil ratio, $R_w = Q_w/Q_o$;B_o, $B_w -$ volume factor of oil, respectively of water, $B_w = 1$; $T_m -$ average temperature, K; $p_m -$ average pressure, bar; $z_m -$ average gas compressibility factor; $T_s, p_s -$ standard conditions , $T_s = 288{,}15$ K or $t_s = 15^{\circ}$C , p_s =1 bar.

If we study the equations shown in table 5 it results that the two superficial velocities of fluids depend on the formation volume factor, the solution gas ratio and the gas compressibility factor, which in turn depend on pressure and temperature.

On the other hand, the liquid holdup depends on the liquid viscosity. As we showed in the previous paragraph, the PVT properties of fluids can be estimated with the correlations or can be calibrated when the measured data are available.

To estimate the PVT properties of fluids we use the correlations shown in table 2. Also we consider a situation when we know only an average value of oil viscosity. In this case we determine the liquid viscosity, μ_L with the following equation [8]:

$$\mu_L = \frac{\mu_o \rho_0 B_o + \mu_w R_w \rho_w}{\rho_0 B_o + R_w \rho_w} \tag{5}$$

where $\mu_w, \rho_w,$ are water viscosity, respectively water density and ρ_o is oil density.

In the other cases, where we use the correlations or calibrated models to determine the variation of oil viscosity with pressure, the liquid viscosity will be calculated with the following equation:

$$\mu_L = \frac{\mu_o + \mu_w R_w}{1 + R_w} \tag{6}$$

To perform the calculus of superficial velocities and liquid holdup in the cases of non calibrated/ calibrated PVT properties of fluids, we use the data shown in table 6. In addition to these data, we use calibrated models of fluids PVT properties for well average temperature, t= 65.67 °C.

Table 6 Reservoir, completion and PVT data of reservoir fluids.

Parameter	Units	Value
Static pressure, p_{ws}	bar	185
Reservoir temperature, t_R	°C	98.5
Surface temperature, t_s	°C	20
Bottom hole flowing pressure, p_{wf}	bar	150
Liquid flow rate, Q	m^3/d	50
Gas flow rate, Q_G	sm^3/d	6937.5
Water cut, i	%	25
Lenght of tubing string,H_T	m	3000
Tubing inner diameter, d	in	2.5
Casing inner diameter, D	in	5
Wellhead pressure, p_{wh}	bar	20
Oil density, ρ_o	kg/m^3	850
Water density, ρ_w	kg/m^3	1050
Relative density of gas, ρ_{rg}	-	0.7
Gas viscosity, μ_g	cP	0.02
Oil surface tension, σ_o	dyne/cm	40
Water surface tension, σ_w	dyne/cm	60
Bubble points pressure,p_b	bara	177.3

To calculate the superficial velocities of fluids we use the equations from table 5. Also to determine the holdup fraction we use the correlation developed by Hagedorn-Brown [9]. The results of calculus are shown in figures 7 and 8.

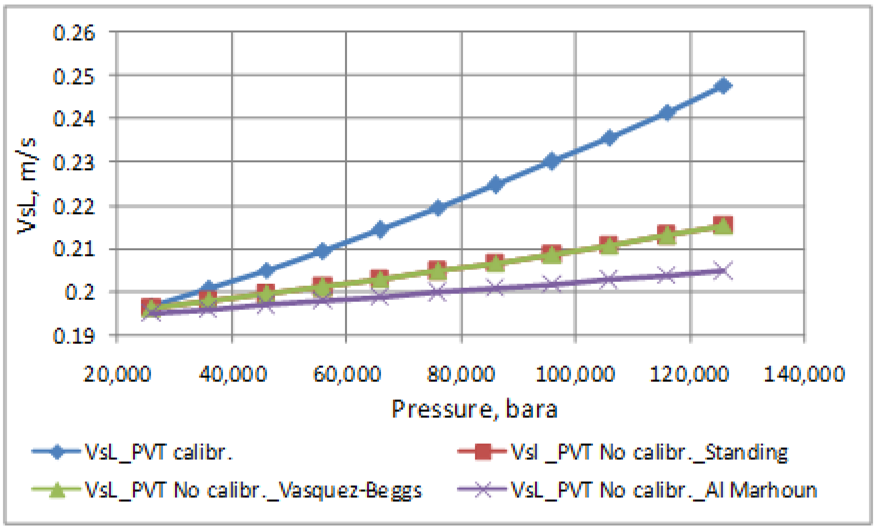

Figure 7 Superficial velocity of liquid dependence on pressure for calibrated and non calibrated oil PVT properties.

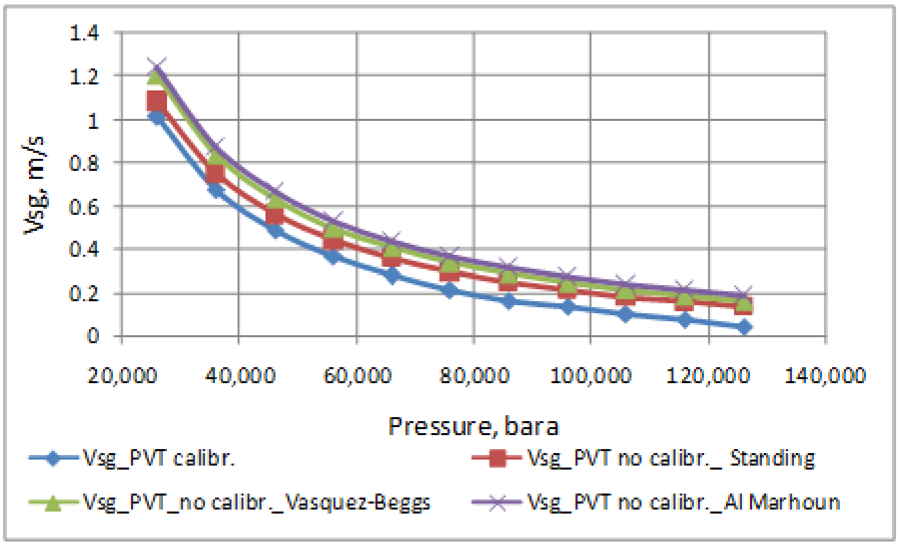

Figure 8 Superficial velocity of gas dependence on pressure for calibrated and non calibrated oil PVT properties.

The tables below show the sums of the squared errors for superficial velocity of liquid, respectively superficial velocity of gas when non calibrated PVT properties of fluids are used.

Figures 7 and 8, as well as Tables 6 and 7 show that the errors between the calculated values of superficial velocities with non calibrated and calibrated fluids PVT properties, respectively, are relatively small.

Table 7 Sums of squared errors for superficial velocity of liquid in the case of non calibrated formation volume factor and solution gas ratio.

Correlations for estimating solution gas ratio and formation volume factor	**Superficial velocity of liquid Sum of squared errors**
Standing(S)[13]	0.003
Vasquez – Beggs(VB)[14]	0.003
Al–Marhoun(AM)[1][2]	0.006

Table 8 Sums of squared errors for superficial velocity of gas in the case of non calibrated formation volume factor and solution gas ratio.

Correlations for estimating solution gas ratio and formation volume factor	**Superficial velocity of gas Sum of squared errors**
Standing(S)[13]	0.067
Vasquez – Beggs(VB)[14]	0.195
Al-Marhoun(AM)[1][2]	0.298

Further we study the influence of calibrated/non calibrated oil viscosity as well as the non calibrated/calibrated formation volume factor and solution gas ratio on liquid holdup. The results of calculus are shown graphically in figures 9 and 10.

In table 8 we show the sums of squared errors between the values of liquid holdup calculated with the calibrated PVT properties of fluids and those calculated with non calibrated formation volume factor and solution gas ratio. Also, we have calculated sums of squared errors in the case of calibrated formation volume factor and solution gas ratio and non calibrated oil viscosity. The results of calculus are shown in table 9.

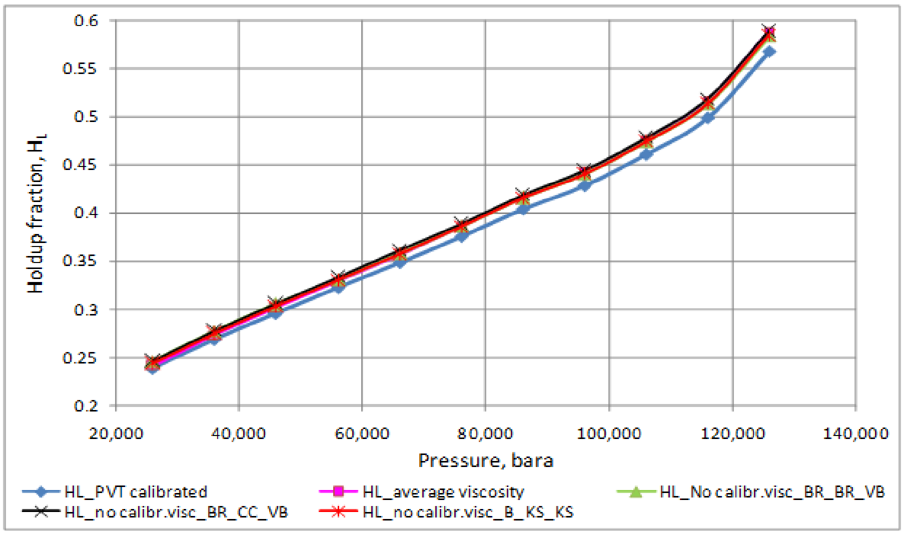

Figure 9 Liquid holdup dependence on pressure for calibrated formation volume factor and solution gas ratio and non calibrated oil viscosity.

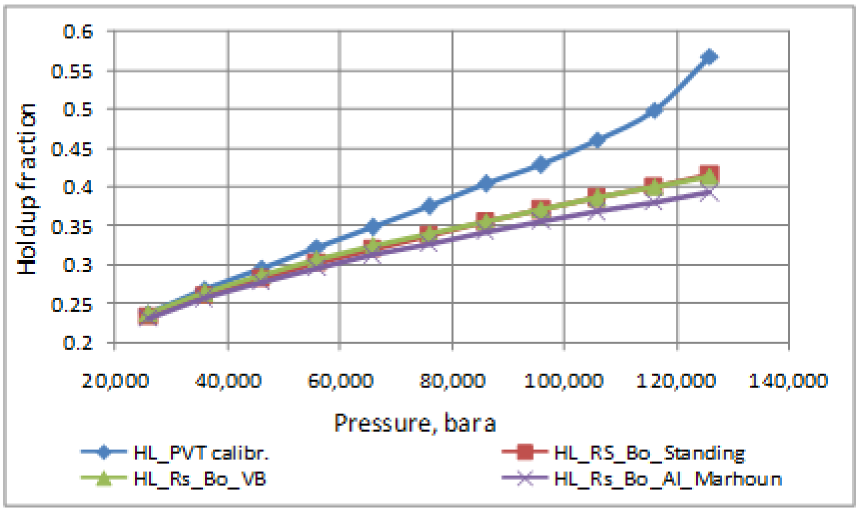

Figure 10. Liquid holdup dependence on pressure for calibrated oil viscosity and non calibrated formation volume factor and solution gas ratio.

Table 8 Sums of squared errors for liquid holdup when using non calibrated formation volume factor and solution gas ratio, respectively.

Correlations for estimating solution gas ratio and formation volume factor	**Liquid holdup Sums of squared errors**
Standing(S)[13]	0,04672
Vasquez – Beggs(VB)[14]	0,04648
Al-Marhoun(AM)[1][2]	0,06671

Table 9 Sums of squared errors for liquid holdup when using non calibrated oil viscosity and calibrated formation volume factor and solution gas ratio, respectively.

Correlations for estimating oil viscosity	**Liquid holdup Sums of squared errors**
Average viscosity of oil	0,00148
Dead oil viscosity(BR)/Saturated oil viscosity(BR)/Unsaturated oil viscosity(VB)[5][14]	0,00145
Dead oil viscosity (BR)/ Saturated oil viscosity (CC)/ Unsaturated oil viscosity (VB)[5][7][14]	0,00221
Dead oil viscosity (B)/ Saturated oil viscosity (KS)/ Unsaturated oil viscosity (KS)[4][11]	0,00121

As we observe from figures 9 and 10 and table 8 and 9, the calibration of formation volume factor and solution gas ratio is more important than oil viscosity calibration.

CONCLUSION

In this paper we investigate the influence of the calibrated and non calibrated PVT properties of reservoir fluids on the superficial velocities of fluids and liquid holdup. The conclusions of our study are:

1. The estimated values of the bubble point pressure with different correlations are about twice as high compared to its measured value used in this study.

2. The differences between the estimated values and measured data of volume factor, solution gas ratio and oil viscosity can be large. Therefore the calibration of PVT properties of fluids is required.

3. The non calibrated PVT properties of fluids lead to underestimated values of the superficial velocity of liquid and to overestimated values of the superficial velocity of gas.

4. The values of liquid holdup determined on the basis of non calibrated oil viscosity do not differ much from those determined on the basis of calibrated oil viscosity, the errors being very small. On the other hand, the influence of the formation volume factor and the solution gas ratio, both non calibrated, is more important than the influence of the non calibrated oil viscosity.

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