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Liquid and Gas Superficial Velocities Variation Throughout the Tubing

KEYWORDS: liquid superficial velocity, gas superficial velocity, flow pattern determination, differences between empirical correlations.

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ABSTRACT *Superficial velocities of phases (SVPh) can help to determine the flow pattern delimitations in empirical correlations as they are important to calculate the liquid velocity number and the gas velocity number, but it is possible to determine flow pattern without backing to these delimitations proposed by some researchers, just by putting the values of the (SVPh) correspond to the elevation on Kaya flow-pattern map resulting in knowing the flow regime throughout the tubing. The variation of (SVPh) can help to determine the differences between the empirical correlations even if these use the same equations and same data.*

Superficial velocity is defined as the phase velocity through the pipe that could be equal to the total or to the mixture velocity. In multi-phase flow, superficial velocity can be an agreed parameter for analysis, not just a physical value. The individual phase velocities are normally quite different. Only for the cases of higher turbulent, dispersed-bubble – flow pattern and the annular-flow pattern, in which the fluids exist as a homogenous mixture, the phase velocities are essentially equal. If there were no slippage condition between gas and liquid then the mixture would flow at the mean velocity. If the slip has occurred between phases both will flow at the mixture velocity. Because of the slip between phases, the liquid typically flows with less speed than the mixture velocity, while the gas flows at a higher speed than the mixture velocity.

Time-and space averaged velocities for each phase can be calculated from knowledge of the time-and space averaged liquid hold-up obtained from the empirical correlation. The liquid hold-up is a very important parameter to determine the density and the viscosity of the mixture, and that could affect the pressure gradient. Consequently an accurate prediction of liquid hold-up is normally the most important parameter in calculating pressure drops in wells.

(SVPh) could be affected by some main reasons such as, the dissolved gas, oil ratio and formation volume factor where these last two decrease, as the fluid gets closer to surface due to the decrease of temperature and pressure. The pipe area also could be a main reason to affect the superficial velocities, so higher pipe diameters results in lower superficial velocities.

Parameters of upward flowing through tubing

(SVPh) can help to determine the flow pattern delimitations in empirical correlations and mechanistic models as they are important to calculate the liquid velocity number and the gas velocity number. These numbers are considered by authors to determine the delimitations of flow regimes.

Table 1 Flow regime delimitations propsed by Mukherjee and Brill

Flow regime	Condition of existing
Bubble Flow	$N_{gv} < N_{gv\,B/S}$ $N_{Lv} > N_{Lv\,B/S}$
Slug Flow	$N_{gv} < N_{gv\,B/S}$ $N_{Lv} < N_{Lv\,B/S}$
Annular Flow	$N_{gv} > N_{gv\,S/A}$
Stratified Flow	Highly deviated or horizontal wells $\theta = (0 \dots -30^{o})$

It's important to mention that the calculations of those numbers may differ between methods, for example: (BRILL & MUKHERJEE, 1999) empirical correlation uses equations (1) and (2) then they compared them with velocity numbers of phases for every transition considered in their research as showed in table 1.

$$N_{Lv} = v_{sL} \cdot \sqrt[4]{\frac{\rho_l}{g \cdot \sigma_l}} \qquad (1) \qquad\qquad N_{gv} = v_{sg} \cdot \sqrt[4]{\frac{\rho_l}{g \cdot \sigma_l}} \qquad (2)$$

By mean of (SVPh), and liquid hold-up, real phase's velocities can be calculated as following, in (m/s):

$$v_L = \frac{v_{SL}}{H_L} \qquad (3)$$

$$v_g = \frac{v_{Sg}}{1-H_L} \qquad (4)$$

where superficial velocities can be obtained from, in (m/s):

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$$v_{SL} = \frac{q_L}{A_p} \quad (5)$$

$$v_{Sg} = \frac{q_G}{A_p} \quad (6)$$

$$v_{mix} = \frac{q_L + q_G}{A_p} = v_{SL} + v_{Sg} \quad (7)$$

In this study an analysis of superficial velocities behavior has been made throughout the tubing of certain wells; the behavior analyzed was from the perforations to kick-off point, and from the kick-off point to Christmas tree, as showed in figure 1 (both wells have same profile).

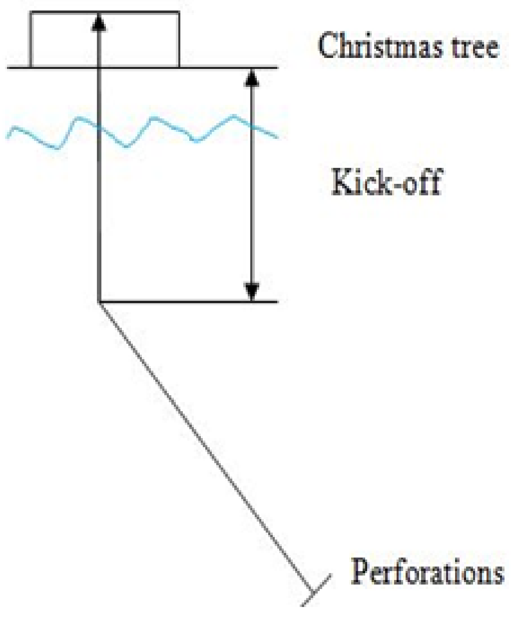

Figure 1 General presentation of the wells

To determine superficial velocities variation for well 1 and 2, it's necessary to choose a suitable empirical correlation or mechanistic model. Hagedorn - Brown (HB) and Orkiszewski (ORK) correlations were the most convenient for both wells compared to the measured data, and the pressure gradient equation from these correlations will be used to determine the elevation that corresponds to the (SVPh). Superficial velocity for both phases can be calculated according to more detailed equations (8) and (9) in (m/s). By representing superficial velocities against the elevation on a chart, determines the variation throughout the tubing from the perforations to the Christmas tree (fig. 2 and 3) (figures for well 2 are similar to well 1).

$$v_{SL} = \frac{q_L}{86400 \cdot A_p} \cdot \left(\frac{B_0 + B_W \cdot R_a}{1 + R_a} \right) \quad (8)$$

$$v_{Sg} = q_L \cdot \frac{\left(GLR - \frac{R_s}{1+R_a} \right)}{86400 \cdot A_p} \cdot \frac{p_{sc}}{p} \cdot \frac{T}{T_{sc}} \cdot Z \quad (9)$$

the results are presented in table 2 and 3.

Definition of variables

1. The solution (or dissolved) gas oil ratio (Sm^3/m^3), which is the number of standard cubic feet of gas which will dissolve in one stock tank barrel of oil when both are taken down to the reservoir at the prevailing reservoir pressure and temperature. The quantity of gas in solution is not always a known measured and an estimate may be necessary to pursue engineering calculations. **a.** The simplest estimate is made from knowledge of only the A.P.I. gravity of the stock-tank oil. **b.** The most accurate estimation would require a knowledge of the composition of gaseous phase, the composition of liquid phase, the temperature and the pressure

Table 2 Variation of superficial velocities against elevation for well 1

Elevation, m		Liquid superficial velocity, m/s	Gas superficial velocity, m/s
Perforation	2598	0.351	0.161
	2410	0.347	0.183
	2134	0.342	0.219
	1857	0.336	0.260
	1581	0.331	0.308
	1305	0.326	0.364
	1029	0.321	0.432
	753	0.317	0.515
	476	0.312	0.618
	200	0.308	0.761
Kick-off	200	0.308	0.761
	0	0.305	0.911

Table 3 Variation of superficial velocities against elevation for well 2

Elevation, m		Liquid superficial velocity, m/s	Gas superficial velocity, m/s
Perforation	2375	0.384	0.335
	2347	0.383	0.340
	2098	0.379	0.387
	1848	0.375	0.438
	1598	0.370	0.495
	1349	0.366	0.556
	1099	0.362	0.624
	849	0.358	0.702
	600	0.354	0.792
	350	0.350	0.897
Kick-off	350	0.350	0.897
	305	0.348	0.919
	0	0.346	1.087

The lower of the specific gravity of a gas, the greater the percentage of light components indicated and the smaller would be the expected solution in a given oil at a given temperature and pressure. The higher the A.P.I. gravity of oil, the greater would be the expected amount of solubility of a given gas at a specific temperature and pressure. For a given oil and a given gas at a given pressure, the solubility will decrease as temperature increases. It is known that the amount of gas solubility increases directly with pressure, other things beings constant. (Katz, 1942) was first to made a direct correlation of the amount of gas in solution as a function of pressure and A.P.I. gravity of the stock-tank oil involved, but neglecting variations with temperature and gas specific gravity. (Beal, 1946) has extended this correlation and presented a chart that to construct

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a specific curve for gas solubility versus pressure, A.P.I. gravity of the stock-tank oil is the only information necessary. (Standing, 1947) has made an extensive correlation of gas solubility against pressure using gas gravity, A.P.I. gravity of oil, and reservoir temperature. From his correlation, the decrease of gas solubility with temperature rise, all other things being constant.

2. The oil volume factor is defined as the reservoir volume occupied by 1 bbl. of stock-tank oil plus its attendant gas under reservoir conditions of pressure and temperature. The formation volume factors can be estimated as follows. **a.** By use of charts which correlate measurements that have been made on many reservoir oils. (Katz, 1942) has presented a method for estimating formation volume factors based on upon the analysis of both the gas and oil produced along with knowledge of the amount of gas in solution. He also presented a simpler method entirely based upon an empirical correlation. **b.** (Standing correlation, 1947), He presented a complete correlation requires a knowledge of oil gravity, the reservoir temperature, the pressure at which the formation volume factor is desired and gas gravity. Qualitatively, an increase in the value of the formation volume factor occurs with higher gas specific gravities, higher A.P.I. oil gravities, higher temperatures, and increased amounts of gas in solution. **c.** Estimation of volume factors by using the new correlation GMDH technique (Group Method of Data Handling) used by (SULAIMON et al ,2014). This technique is a family of inductive algorithms which executes computer-based mathematical modeling of multi-parametric data sets. The data used consist of solution gas-oil ratio, oil volume factor, oil viscosity, oil gravity, gas gravity, and temperature. Some of these parameters were set as input while the properties to be predicted set as output. The database arrangement was made such that B_o was set the output while the remaining properties were set as the input parameters. Since the GMDH has the capacity to eliminate the least contributing factor to the output, all parameters available were entered as input into the already developed code for GMDH in MATLAB software. The data used were from Malaysian crude oil reservoirs but GMDH was tested on other reservoirs from Niger delta and Middle East. The author mad a statistical accuracy assessing of the newly developed correlation using average absolute relative error (AARE, %), maximum absolute relative error (Max. ARE, %), and minimum absolute relative error (Min. ARE, %) and compare them to other correlations. The results obtained by the authors showed that the new correlation developed by them gave the most accurate estimation of oil formation volume factor. In practice calculations, the water volume factor may be equal to one.

3. The Z-factor is a function of both pressure and absolute temperature but, for reservoir engineering purposes, the main interest lies in the determination of Z, as a function of pressure, at constant reservoir temperature. There are three ways of determining the Z-factor after (Dake, 1983), (Minescu, 1994): **a.** by collecting some gas samples which their composition will be determined and Z can be estimated from known correlations. **b.** by using the cubic equation of state at (p, T) and the direct calculation of Z. **c.** Experimental determination, is determined by measuring the volume of some gas samples at (p, T) and at (p_0, T_0) then by using the ideal gas law would result:

$$Z = \frac{p \cdot V \cdot T_{sc}}{p_{sc} \cdot V_{sc} \cdot T} \qquad (10)$$

Results and discussions

It can be observed from figuree 2 and 3, that the closer as the fluid gets to Christmas tree, the liquid superficial velocity (LSV) decreases, as opposed to this gas superficial velocity (GSV) increasing closer to surface. These phenomena are produced due to pressure drop in tubing; this determines the decrease of gas in solution progressively. Therefore, the oil volume factors decreases, and the dissolved gas and oil ratio in its turn, decreases too. It's important to mention that most methods use similar superficial velocities equations, but there are other methods that use different equations such as (Ansari et al, 1994) mechanistic model, which calculate superficial velocities for every distinct flow pattern.

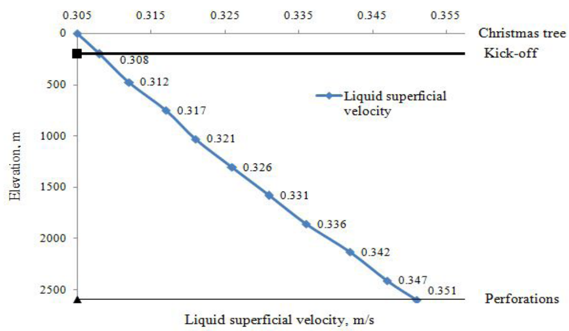

Figure 2Variation of liquid superficial velocity against elevation for well 1

Superficial velocities ca make comparisons among empirical correlations. Figure 6 highlights the diference between two empirical correlations which were used in this determination for both wells 1 and 2. The liquid hold-up represents the essential

In upward flow, the prediction of the flow-pattern is very important. Empirical correlations and mechanistic models can forecast the flow pattern by delimitations proposed by authors, but by using (Kaya et al, 1999) flow-pattern map and putting superficial velocities values on, it became very easy to determine the type of flow throughout the tubing. Figure 4 for well 1, shows that the flow is existent on the transition zone (bubbly-slug), then passes to slug flow as gas superficial velocity increases. Figure 5 for well 2 shows the flow pattern is in slug flow inside the tubing. This was confirmed by manual calculations and by specialized software.

difference because the researchers use different equations, even if same data were used. In equations (3), (4), (8) and (9) the liquid hold-up is important to predict each phase's velocity in single or multiphase flow, because the liquid hold-up is a main factor to determine the physical properties of mixture's density and viscosity, where this could alter the flow rates of liquid and gas.

The liquid hold-up can be calculated depends on the method used, for example (Mukherjee and Brill, 1999) correlation has the following equation:

$$H_L = exp\left[\left(C_1 + C_2 \cdot \sin\theta + C_3 \cdot sin^2\theta + C_4 \cdot N_L^2\right) \cdot \left(N_{gv}^{C_5} / N_{Lv}^{C_6}\right)\right] \quad (11)$$

(Hagedorn-Brown, 1965) correlation uses:

$$H_L = \left(\frac{H_L}{\Psi}\right) \cdot \Psi \quad (12)$$

(Orkiszewski, 1967) correlation calculates the liquid hold-up depending on the transition zone, for Bubbly-slug transition

$$H_L = 1 - 0.5 - 2.05 \cdot v_m + 2.05 \cdot \sqrt{(0.244 + v_m)^2 - 0.976 \cdot v_{sg}} \quad (13)$$

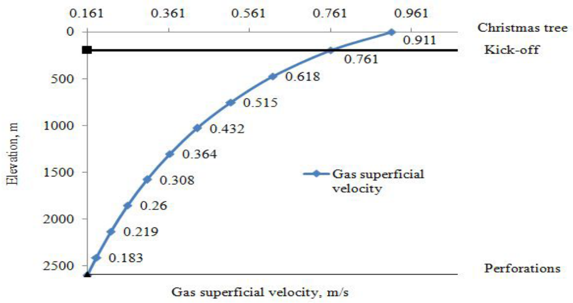

Figure 3 Variation of gas superficial velocity against elevation for well 1

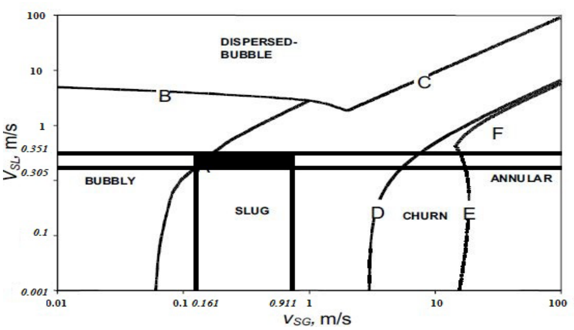

Figure 4 Flow pattern for well 1

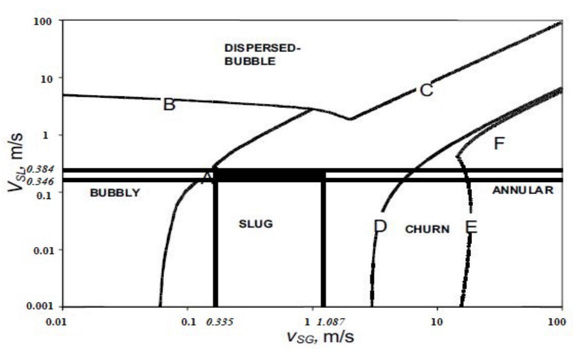

Figure 5 Flow pattern for well 2

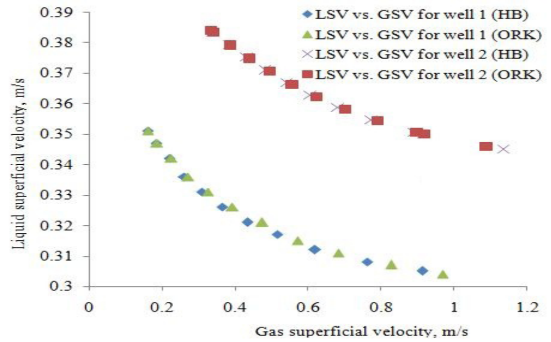

Figure 6 Comparison between empirical correlation methods

Conclusions

The variation of superficial velocities throughout the tubing is carried out in this study, from the data of two natural flowing wells (1 & 2), resulting in:

a. The closer the fluid gets to surface, the more the liquid's superficial velocity decreases. As opposite to this, the gas superficial velocity increases as the fluid gets near the surface. These phenomena are produced due to pressure drop in tubing, which determines the progressive decrease of gas in solution. Therefore, the oil volume factor decreases and the dissolved gas and oil ratio in its turn decrease too.

b. On the basis of superficial velocities, it's easy to determine the flow pattern of any well, throughout the tubing just by using Kaya flow-pattern map, (in our case bubbly-slug transition to slug flow in well 1 and slug flow in well 2).

c. The liquid hold-up represents the essential difference between the empirical correlations, because the researchers use different equations.

NOMENCLATURE

A_p pipe area
B_o oil volume factor
B_w water volume factor
$C_{1 \ldots 6}$ Mukherjee and Brill empirical coefficients for liquid hold-up
g gravitational acceleration

GLR liquid-to-gas ratio
H_L liquid hold-up
N_{gv} gas velocity number
$N_{gv\ B/S}$ gas velocity number for bubbly-slug transition zone
$N_{gv\ S/A}$ gas velocity number for slug-annular transition zone
N_L liquid viscosity number
N_{Lv} liquid velocity number
$N_{Lv\ B/S}$ liquid velocity number for bubbly-slug transition zone
p pressure
p_{sc} pressure at standard conditions, $p_{sc} = 1$ bar
q_g gas volumetric flow
q_L liquid volumetric flow
R_s solution (or dissolved) gas oil ratio
R_a water oil ratio
T temperature
T_{sc} temperature at standard conditions, $T_{sc} = 288.15$ K
V volume
V_L liquid volume

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v_{mix} mixture velocity
V_{sc} volume at standard conditions
v_{Sg} gas superficial velocity
v_{SL} liquid superficial velocity
Z Z-factor
ρ_L liquid density
σ_L liquid surface tension
Ψ HB parameter for liquid hold-up
HB relation for liquid hold-up

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