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Estimation of Pressure Drop, Liquid Holdup and Flow Pattern in a Two Phase Vertical Flow

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ABSTRACT

In the industries today, diverse range of equipment and processes encounter two immiscible liquids flow. Particularly in the petroleum industry, where mixtures of oil and water are transported in pipes over long distances, and to accurately design and operate oil production facilities in an optimized means, it is necessary to accurately predict the behavior of two-phase flow of hydrocarbon in pipes with different angles. It would be desired to apply a more unified model to every conceivable condition such as inclination angles, pipe diameters, flow rates and pressures practically. Most engineering applications make use of flow pattern, liquid holdup and pressure gradient in the design and processes of surface facilities; which implies that accurate prediction of oil-water flow characteristics is very important. However, despite this importance, liquid-liquid flows have not been explored to the same extent as gas-liquid flows. This study is aimed at developing a model for liquid holdup, pressure drop gradient with DataFit and estimating the bottom hole flowing pressure for single and multiphase system, the liquid holdup and the flow pattern of a vertical well from existing correlations incorporated into MULTIFLOW software developed in this study. Holdup data were obtained for liquid flow rates between 610.68 lb/sec and 6349.31 lb/sec and gas flow rates in the range from 17041.73 lb/sec and 32848.88 lb/sec. The wavy-stratified flow pattern was observed for the liquid rates of 610.68 lb/sec and 17041.73 lb/sec and for all gas flows. For higher liquid rates, the flow pattern was always pseudo-slug flow. A decrease, not far from linear, in the liquid holdup was observed as the gas flow increases.

Keywords: *Liquid Holdup, Pressure Drop Gradient, MULTIFLOW Software, Flow Pattern, Production Facilities, Multiphase Flow, Immiscible Liquids and Mathematical Model.*

1. INTRODUCTION

The problem incur in trying to accurately estimating flow pattern, liquid holdup and pressure drops in a natural flowing or gas lift vertical wells have brought about many discrete solutions with conditions that are limited; the rational being the complex nature of the two phase flow and the difficulty in analyses despite the limited conditions studied. Thus, this study is aimed at estimating the bottom hole flowing pressure for single and multiphase system, the liquid holdup and the flow pattern of a vertical well: a software approach.

The concept of the mixture of two or more fluid phases flowing through a vertical column is widely known and the composition of the flowing fluids are never the same compared with that released from the column even if the conditions are at steady state because of the density difference of the phases with different velocities. Hence, the holdup of various phases in the column is dependent on the slip velocity or relative velocity, which is the measure of the relative motion of the dispersed phases with respect to the continuous phase. In the industries today, diverse range of equipment and processes encounter two immiscible liquids flow. Particularly in the petroleum industry, where mixtures of oil and water are transported in pipes over long distances, and most engineering applications make use of flow pattern, liquid holdup and pressure gradient in the design and processes of surface facilities; which implies that accurate prediction of oil-water flow characteristics is very important. However, despite this importance, liquid-liquid flows have not been explored to the same extent as gas-liquid flows.

In order to accurately design and operate oil production facilities in an optimized means, it is necessary to predict the behavior of the two-phase flow of hydrocarbon in pipes with different angles. It would be desired to apply a more unified model to every conceivable condition such as inclination angles, pipe diameters, flow rates and pressures practically. Some of such models are available in technical literature. Practically all oil well production design involves evaluation of flow lines under two-phase flow conditions. However, the uncertainties in flow regime determination greatly affect the pressure drop predictions. A technique is thus required for accurate calculation of pressure losses. Furthermore, the ability of the oil and gas industry field operators to predict the holdup of each phase is of paramount concern, for instance, in the design and operation of process equipment such as a three phase transport reactor (Pruden, 1969), in which a liquid reacts with gas in the presence of finely divided solid catalyst particles. Consequently, numerous publications, dealing with both the experimental and the theoretical aspects of the two phase solids-liquid, gas-liquid and solids-gas flow systems are presented in the literature. However, in the case of three phase gas-liquid-solids flow system, only a relatively little work has been reported.

2. MULTIPHASE FLOW CONCEPT

The use of multiphase flow- pressure drop correlation is a vital consideration for the development of production system vertical components. Hagedorn & Brown, Duns & Ros, Aziz & Govier developed the most widely used correlations for vertical multiphase flow in the oil and gas industry. In the vertical component of production system, the flow of fluids may probably pass through the annulus between the casing and the production tubing. Therefore, it is necessary to predict the pressure drop in the annulus. Recently, Lage (2000) developed a mechanistic model for upward two-phase flow in vertical and concentric annulus. This model was composed of a procedure for flow pattern prediction and a set of independent mechanistic models for calculating gas friction and pressure drop in each of flow patterns.

The production and transportation of multiphase gas-liquid-solid in the petroleum industry is a common trend, the solid phase is due to the production of sand along with reservoir fluids. Multiphase fluid flow is considered a transient phenomenon since the flow pattern changes, from dispersed bubble to slug, plug, annular and stratified flow patterns as shown schematically in Figure 1 and 2 depending on the topography, fluid properties, pipe size, flow rates and corresponding pressure drop (Bello et al. 2011). Slug and churn flow are sometimes combined into a flow pattern called intermittent flow. It is common to introduce a transition between slug flow and annular flow that incorporates churn flow. Taitel et al., 1980 & Duns and Ros, 1963 named annular flow as mist or annular-mist flow.

The increase in pressure drop is due to the addition of a gaseous phase to an oil-water flow and induces disturbances and instabilities caused by gas bubbles, plugs and slugs especially for the most core annular flow patterns that are favorable. (Sotgia 2006) gave an expression for pressure drop reduction factor in a three phase oil-water-gas flow.

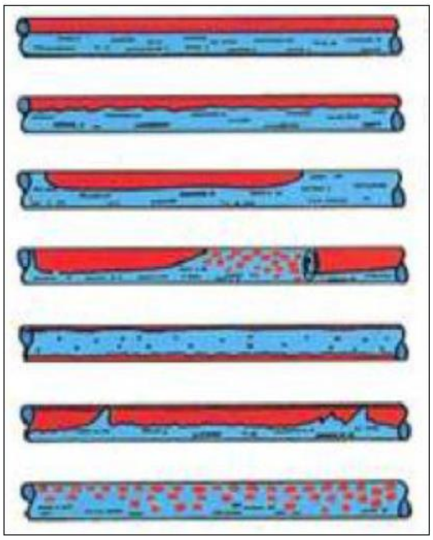


Figure 1: Flow patterns in horizontal pipe

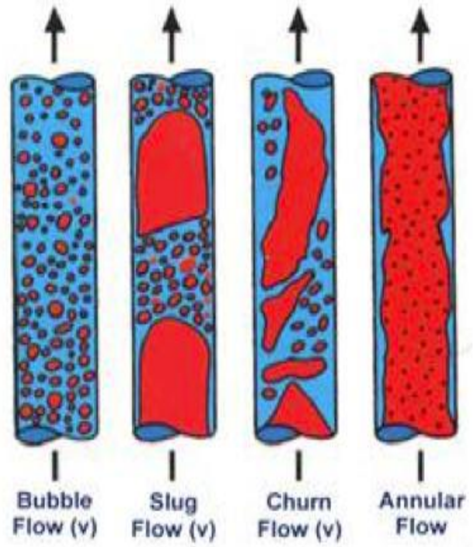


Figure 2: Flow patterns in vertical pipe
Source: (Bello et al. 2011)

3. LIQUID HOLDUP

Liquid hold-up is defined as the fraction of in-situ volume which is liquid in gas/liquid multiphase flow. It is the most important parameter in estimating the pressure drop in inclined or vertical flow (Hagedorn and Brown, 1965). Also, it is of prime importance in sizing downstream equipment, which must be able to operate properly when the liquid hold up in the line changes because of pigging or rate changes (Brill et al., 1981). This major parameter in a co-current pipe flow of multiphase mixtures due to the differences in velocity between the phases have been studied by many groups. The method to calculate liquid holdup and pressure gradient in inclined pipe was proposed by Brill and Beggs (1973) and Mukherjee (1985). While Barnea (1987), drew a chart based on the experimental results taking air and water as medium to predict the flow pattern for upward and downward flow from horizontal to vertical orientations. In 1999, Kaya et al. (1999) put forward a comprehensive mechanical model, that could well calculate liquid holdup and pressure drop.

In the design of surface production facilities and calculations of pressure drop, the knowledge of multiphase flow regimes in pipes and liquid holdup are very important to the success of the facilities operation. To accurately predict holdup, flow regime at a given pressure, temperature, liquid velocities, superficial gas and other flow characteristics has to be well defined. Several mechanistic models, neural networks, flow maps and regression are used to predict holdup and flow regime. However, they often do not perform accurately and thus; suffer from a number of drawbacks.

Nonetheless, there is still a large technological gap that needs attention. Gregory and Mattar (1973) carried out this measurement in the earliest time of this research with quick closing valves and achieved some successes. Although, the cost of operation using this method is low, there are many limitations (which include non-determination of average volume fractions over a length of test section, time consumption, non-conformity with systems operated at elevated temperatures and pressure etc.). They also used an electrical capacitance sensor in measuring the liquid hold-up. This was also validated by Mukherjee and Brill (1985). Other methods demonstrated are the use of photographic and optical techniques, x-ray and gamma ray attenuation, electrode capacitance sensors and conductance probe (Miller and Mitchie, 1969).

4. MULTIPHASE FLOW PATTERNS

Flow pattern is vital to the wide range of industrial and technical applications that encounter two-phase gas-liquid flow. It is important to note that some of the design parameters in mass and heat transfer systems, petroleum industrial processes, distillation processes and numerous chemical are mostly determined by the flow pattern. Hence, a better knowledge of the pressure drop, liquid holdup and flow patterns is require for effective and reliable design of pipe lines, boilers and condensers (Ansari et al, 1994). Recently, modeling approach has been employed to predict the flow patterns of multiphase flow in pipelines. The basic concept of the modeling approach is the existence of flow patterns or flow configurations developed to predict flow patterns like holdup and pressure drop. The prediction of flow patterns is a central problem in two phase gas-liquid flow in pipes (Beggs & Brill, 1973).

Mandhane et al. (1974) created a two-phase flow map based on the superficial gas and superficial liquid velocities. Fluid properties, diameter, and inclination specify the flow map which applies that the Mandhane plots have become a standard format for publishing flow regime data in multiphase flow. The first realistic two-phase mechanistic flow regime transition model was produced by Taitel and Dukler (1976). The theory predicts the effect on transition boundaries of pipe size, fluid properties and angle of inclination. The mechanisms for transition are based on physical concepts and are fully predictive in that no flow regime data are used in their development.

Lin (1985) reported large and small diameter flow regime maps for horizontal air-water flow. Similarly, Jepson and Taylor (1993) and Wallis and Dobson (1973) reported large diameter flow regime maps, but they were also for horizontal air-water systems. Lee (1993) reported the flow regime transitions for a large diameter pipe with horizontal three phase flow. This data was for carbon dioxide gas, water, and a light-oil which is commercially available. Limited flow map data exists for inclined pipelines. Gould et al. (1974) introduced +45° and +90° flow pattern maps.

Govier and Aziz (1972) presented a commonly used method of establishing flow patterns for inclined flow. Barnea et al. (1985) proposed a model predicting transitions in inclined pipelines. Stanislav et al. (1986) reported inclined flow pattern data. Kokal and Stanislav (1986) characterized, extensively, the upflow and downflow patterns. The models and data compared well, however all of these studies involved two-phase flow. Additionally, flow in large-diameter pipes and at high-pressure have not been reported in inclined pipelines. Further, little research has been done on three phase flow regimes and their transitions.

5. STATEMENT OF PROBLEM

Multiphase flows modeling in wellbore has always been a problem to the petroleum industry operators and a better understanding of the flow mechanism of two-phase flow leads to more accurate engineering solutions. Therefore, the problem of an accurate estimate of the pressure drops in flowing or gas lift wells have given rise to many discrete solutions for conditions that are limited with the rational being that the two phase flow is complex in nature and difficult to analyze even with the limited condition studied. Numerous attempts have been employed to develop methods to determine liquid holdup in pipes. Empirical and semi empirical generated correlations from experimental data and diverse theoretical models with different degrees of complexity for predicting liquid holdup in pipes have been advanced by a number of researchers and some have attempted to find general correlations for liquid holdup in two-phase flow by curve fitting of experimental data.

6. OBJECTIVE OF STUDY

This study is aimed at:

- Developing an analytical and computer model to determine flowing bottomhole pressure, pressure drop gradient, liquid holdup and flow pattern identification in concurrent and countercurrent flows: two phase gas-liquid and solids-liquid flow; and three phase gas - liquid - solids f1ow in vertical wells.

- Developing a model for liquid holdup and pressure drop gradient in a multi-flow system

7. METHODOLOGY

Field data were obtained in the Niger Delta such as liquid and gas mass flow rates, liquid holdup and pressure drop gradient. These data were quality checked and then used to develop a model for liquid holdup and pressure drop gradient as a function of liquid and gas mass flow rates with a statistical analysis tool (DataFit); several models were generated and the best was selected. Table 1 presents the ranges of liquid and gas mass flow rate, liquid holdup and pressure drop gradient for the data point used.

Table 1: Range of different independent variables of 69 data points

Variable	Mean	Minimum	Maximum
Gas mass flow rate (lb/s)	25984.51	17041.73	32848.88
Liquid mass flow rate (lb/s)	3358.695	610.6805	6349.313
Liquid holdup	25.2333	10.9	37.9
Pressure drop gradient (psi/ft)	0.0003	0.000116	0.000526

The fundamental design methodology adopted in this study to develop a software using Microsoft visual basic dot net frame title Multiphase flow analysis toolkit "MULTIFLOW" is the use of existing models for flow pattern identification, liquid holdup and pressure drop in a multiphase flow in tubing. The flow chart in figure 3 presents the methodology for this study.

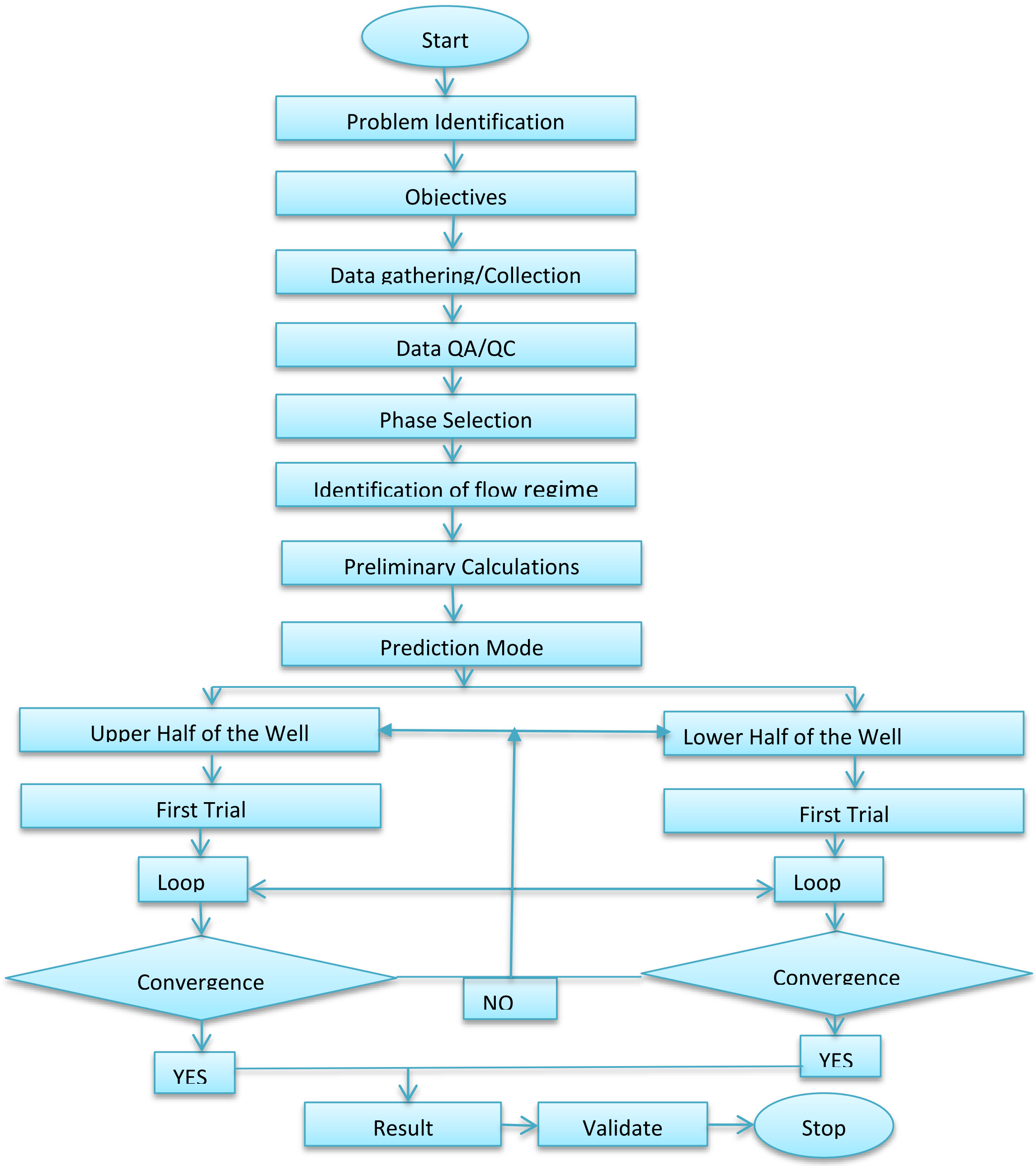


Figure 3: Workflow for flowing bottom hole pressure determination

8. MATHEMATICAL MODEL

The steady state pressure gradient is made up of three components

$$\left(\frac{dp}{dL}\right)_{total} = \left(\frac{dp}{dL}\right)_{friction} + \left(\frac{dp}{dL}\right)_{elevation} + \left(\frac{dp}{dL}\right)_{accelaration} \qquad (1)$$

$$\left(\frac{dp}{dL}\right) = \frac{f\rho_f {v_f}^2}{2d} + \rho_f g\sin\theta + \rho_f v_f \frac{dv_f}{dL} \qquad (2)$$

Neglecting the acceleration component, eqn 2 reduces to

$$\left(\frac{dp}{dL}\right) = \frac{f\rho_f {v_f}^2}{2d} + \rho_f g\sin\theta \qquad (3)$$

For gases (real gas)

$\rho = {}^{pM}/_{zRT}$, $v = {}^{q}/_{A}$, $q = q_{sc}B_g$ and $B_g = {}^{P_{sc}TZ}/_{T_{sc}P}$Combining these expressions into Eq. 3 and by method of separation of variables gives

$$\frac{M}{R}\int_0^L dL = \int_{P_{tf}}^{P_{wf}} \frac{\frac{P}{ZT}}{\left(\frac{P}{ZT}\right)^2 g\sin\theta + \frac{8{P_{sc}}^2{q_{sc}}^2 f}{\pi^2 d^5 {T_{sc}}^2}}dp \qquad (4)$$

Eq. 4 is derived in Appendix A and is applicable for any consistent set of units. Substituting field units and integrating the left side of Eq. 4 gives

$$18.75\gamma_g L = \int_{P_{tf}}^{P_{wf}} \frac{\frac{P}{ZT}}{0.001\left(\frac{P}{ZT}\right)^2 \sin\theta + \frac{0.667f{q_{sc}}^2}{d^5}}dp \qquad (5)$$

Where P is in psia, T in ^{0}R, q_{sc} in MMscf/D, d in inche and L in ft.

$$18.75\gamma_g L = \frac{(P_{mf} - P_{tf})(I_{mf} + I_{tf})}{2} + \frac{(P_{wf} - P_{mf})(I_{wf} + I_{mf})}{2} \qquad (6)$$

Eq. 6 can be separated into two expressions, one for each half of the well.

Upper half

$$\frac{18.75\gamma_g L}{2} = \frac{(P_{mf} - P_{tf})(I_{mf} + I_{tf})}{2} \qquad (7)$$

Lower half

$$\frac{18.75\gamma_g L}{2} = \frac{(P_{wf} - P_{mf})(I_{wf} + I_{mf})}{2} \qquad (8)$$

While this method can be used with any number of steps, Cullender and Smith (1956) demonstrated that the equivalent of four-step accuracy can be obtained with two-steps calculation if the Simpson's rule (1973) numerical-integration approach is used. The resulting equation is

$$\frac{18.75\gamma_g L}{2} = \frac{(P_{wf} - P_{tf})}{6}(I_{wf} + 4I_{mf} - I_{tf}) \qquad (9)$$

For a multiphase flow phase, after the flow pattern, separate models are considered to calculate the pressure drop for the predicted flow pattern. Stratified flow model can be described best with the separate flow. The momentum force balance for the liquid and gas phases in the stratified flow are given respectively by:

$$-A_L\frac{dP}{dL} - \tau_{WL}S_L + \tau_i S_i + \rho_L A_L \sin\theta = 0 \qquad (10a)$$

$$-A_g\frac{dP}{dL} - \tau_{WG}S_G + \tau_i S_i + \rho_G A_G \sin\theta = 0 \qquad (10b)$$

The shear stresses are evaluated in conventional manner as: $\tau_{WL} = f_L \frac{\rho_L u_L{}^2}{2}$; $\tau_{WG} = f_G \frac{\rho_G u_G{}^2}{2}$ *and* $\tau_i = f_i \frac{\rho_G (u_G - u_L)^2}{2}$

Equating pressure drop in the two phases, the combination momentum equation for the two phase is obtained as follows:

$$\tau_{WL} \frac{S_L}{A_L} - \tau_{WG} \frac{S_G}{A_G} - \tau_i S_i \left(\frac{1}{A_L} + \frac{1}{A_G} \right) + (\rho_L - \rho_G) g \sin\theta = 0 \tag{11}$$

For the slug flow pattern, average pressure gradient could be calculated from the following equation:

$$\frac{dP}{dL} = \rho_u g \sin\theta + \frac{\tau_s \pi d}{A} \frac{L_s}{L_u} + \frac{\tau_{WF} S_F + \tau_{WG} S_G}{A} \frac{L_f}{L_u} \tag{12}$$

The annular flow model equations are similar to stratified flow model ones, but with different geometrical configuration and the fact that the gas core in annular flow includes liquid entrainment. Momentum balance on the liquid film and the gas core are given respectively by:

$$-\tau_{WF} \frac{S_f}{A_f} + \tau_i \frac{S_i}{A_f} - \left[\frac{dP}{dL} \right]_f - \rho_L g \sin\theta = 0 \tag{13}$$

$$-\tau_i \frac{S_i}{A_c} - \left[\frac{dP}{dL} \right]_c - \rho_c g \sin\theta = 0 \tag{14}$$

the total two-phase pressure gradient in bubble flow pattern consists of three components which are given in Eq. 1.

the hydrostatic pressure gradient is given by:

$$\left(\frac{dp}{dL} \right)_H = \rho_m g \sin\theta \tag{15}$$

The friction component is given by:

$$\left(\frac{dp}{dL} \right)_f = \frac{2f}{d_h} \rho_m v_m{}^2 \tag{16}$$

Where the fanning friction factor f is a function of Reynolds number Re defined by:

$$Re = \frac{\rho_m v_m d_h}{\mu_m} \tag{17}$$

$$f = 0.0380 Re^{-0.18} \tag{18}$$

8.1 Correlation for flow pattern identification

AZIZ et al. (1972) developed a method which uses many of the fundamental mechanisms that form the basis of modern mechanistic models. Other methods were incorporated into MULTIFLOW software developed in this study

$$N_x = V_{sg} \left(\frac{\rho_g}{0.0764} \right)^{1/3} \left[\left(\frac{72}{\sigma_L} \right) \left(\frac{\sigma_L}{62.4} \right) \right]^{1/4} \tag{19}$$

$$N_y = V_{sL} \left[\left(\frac{72}{\sigma_L} \right) \left(\frac{\sigma_L}{62.4} \right) \right]^{1/4} \tag{20}$$

$$N_1 = 0.51 (100 N_y)^{0.172} \tag{21}$$

$$N_2 = 8.6 + 3.8 N_y \tag{22}$$

$$N_3 = 70 (100 N_y)^{-0.152} \tag{23}$$

Therefore;

Bubble flow exists if $N_x < N_1$
Slug flow exists if $N_1 < N_x < N_2$ for $N_y < 4$ *or* $N_1 < N_x < 26.5$ *for* $N_y \geq 4$
Mist flow exists when $N_x > N_3$ for $N_y < 4$ *or* $N_x > 26.5$ *for* $N_y > 4$
Transition Region exists when $N_2 < N_x < N_3$ for $N_y < 4$
Note that the transition region does not exist for $N_y > 4$

8.2 Correlation for Liquid Holdup

Mukherjee and Brill (1985) generated a liquid holdup correlation with an equation of the form:

$$H_L = \exp\left[\left(0.3902 + 2.3432{N_L}^2\right)\left(\frac{{N_{GV}}^{0.4757}}{{N_{LV}}^{0.2887}}\right)\right] \qquad (24)$$

Mukherjee and Brill (1985) used a mechanistic model to predict both the liquid holdup and the pressure drop in a two phase vertical flow. Based on their model, the expression for holdup in bubble, dispersed bubble, slug/churn flow is given as:

$$H_L = 1 - \frac{V_{sg}}{C_o V_m + V_s} \qquad (25)$$

$$C_o = \{1.2 \text{ if } d < 0.12m \text{ } or \text{ } if \text{ } V_{SL} > 0.02m/s\}$$
$$C_o = \{2.0 \text{ if } d > 0.12m \text{ } or \text{ } if \text{ } V_{SL} < 0.02m/s\}$$

$${V_m}^{1.12} = 4.68 d^{0.48}\left[\frac{g(\rho_L - \rho_g)}{\sigma_L}\right]^{0.5}\left(\frac{\sigma_L}{\rho_L}\right)^{0.6}\left(\frac{\rho_L}{\mu_L}\right)^{0.08} \qquad (26)$$

Bubble/Dispersed bubble flow

$$V_s = 1.53\left[\frac{\sigma_L g(\rho_L - \rho_g)}{{\rho_L}^2}\right]^{1/4} \qquad (27)$$

Slug/Churn flow

$$V_s = 0.35\left[\frac{gd(\rho_L - \rho_g)}{\rho_L}\right]^{0.5}\sqrt{\sin\theta}(1 + \cos\theta)^{1.2} \qquad (28)$$

$$H_{LLS} = 1 - \frac{V_{sg}}{0.033 + 1.25V_m} \qquad (29)$$

Flannigan (1958) developed a holdup correlation based in field data acquired on a pipe with an inner diameter of 16 inches. The liquid holdup correlation is given by

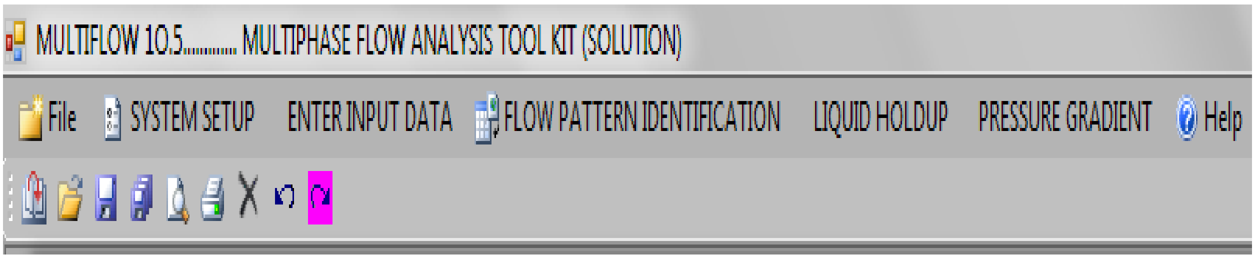
$$H_L = \frac{1}{1 + 0.3264{U_{SL}}^{1.006}} \qquad (30)$$

Mattar and Gregory (1974) generated a correlation to evaluate the holdup for air-oil slug flow in an upward-inclined pipe.

$$H_L = 1 - \frac{U_{SG}}{1.3(U_{SG} + U_{SL}) + 0.7} \qquad (32)$$

9. DESCRIPTION OF THE MULIFLOW

The Multiphase flow performance analysis tool (MULTIFLOW 10.5) is a package designed to help production engineers to gain a better understanding of the multiphase flow behaviour in production tubing and perform a sensitivity analysis on key parameters. The tool determines liquid and gas superficial velocities, mixture or total density, identifies flow regime, determine liquid holdups and pressure drop in a multiphase flow system. MULTIFLOW is setup in a way that user can go from left to right on the options menu and from each option, user can navigate top to bottom. Thus, this tool is broken down into various components and these are



- Setting setup to define the case options
- Enter of input data
- Perform preliminary calculations
- Flow pattern identification
- Liquid holdup and sensitivity analysis
- Pressure drop gradient which is further broken down into:
  - Single phase flowing pressure
  - Multiphase flow pressure drop gradient
- Help

10. RESULTS

10.1 New model for liquid holdup

$$H_L = a + b\ln X_1 + c\ln X_1{}^2 + d\ln X_1{}^3 + e\ln X_1{}^4 + f\ln X_1{}^5 + gX_2 + hX_2{}^2 + iX_2{}^3 + jX_2{}^4 + kX_2{}^5 \quad (33)$$

10.2 New model for pressure drop gradient

$$Y = a + bX_1 + c\ln X_2 + dX_1{}^2 + e\ln X_2{}^2 + fX_1\ln X_2 + gX_1{}^3 + h\ln X_2{}^3 + iX_1\ln X_2{}^2 + jX_1{}^2\ln X_2 \quad (34)$$

Where $X_1, X_2, H_L and\ Y$ are the liquid mass rate, gas mass rate, liquid holdup and pressure drop gradient respectively. The coefficients a to k are presented in Table 2 of appendix A.

10.3 Result of developed correlation

The liquid holdup model developed in this study as a function of liquid and gas mass flow rate presented in Eqs. 33 & 34 were selected as the best model from the various models generated and racked by DataFit software. Table 3 of appendix A shows some key statistical parameters which tell how close the predicted values are from the observed field data.

To evaluate the performance of the models and empirical correlations used, graphs of the experimental values and the calculated values are plot versus gas mass flow rate of the experimented values were constructed. The holdup data were obtained for liquid flow rates between 610.68 lb/sec and 6349.31 lb/sec and gas flow rates in the range from 17041.73 lb/sec and 32848.88 lb/sec. The wavy-stratified flow pattern was observed for the liquid rates of 610.68 lb/sec and 17041.73 lb/sec and for all gas flows. For higher liquid rates, the flow pattern was always pseudo-slug flow. A decrease, not far from linear, in the liquid holdup was observed as the gas flow increases.

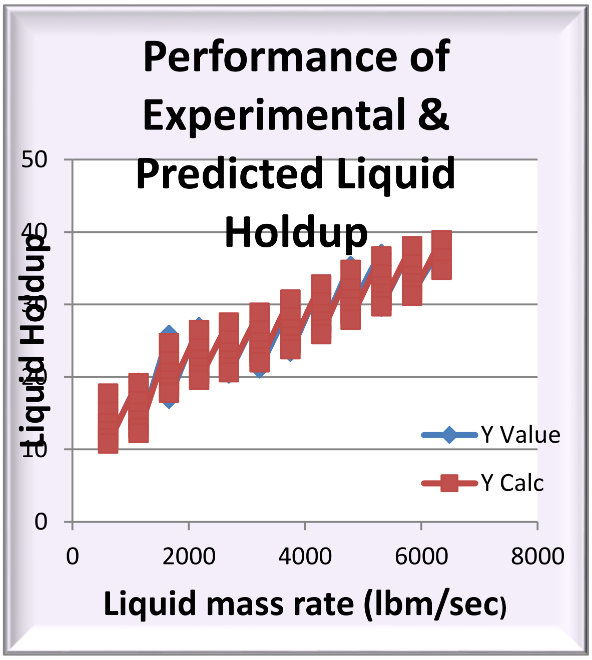


Figure 4: Plot of liquid holdup predicted and field data

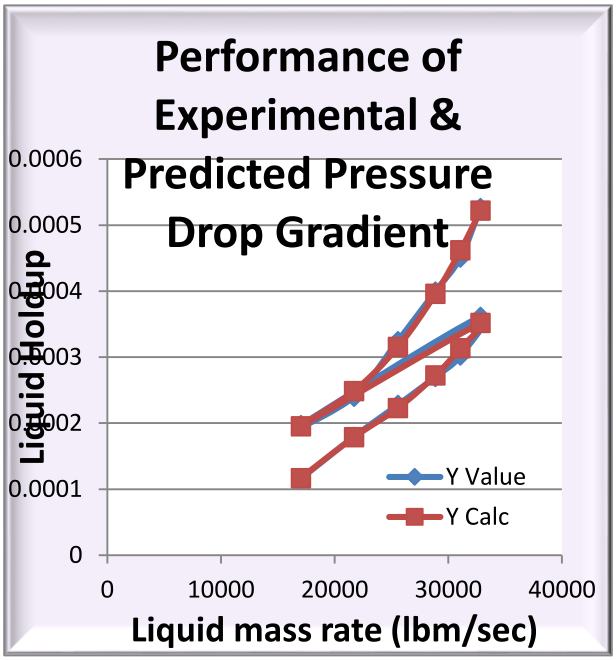


Figure 5: Pressure drop gradient predicted and field data

10.4 Results of Liquid Holdup and Pressure Drop Gradient from Existing Correlations

The data used for this study were obtained from three wells (well J3, J21 & J12) of an X field in Niger Delta region. These data were analyzed as oil reservoir and are presented in Table 4 of Appendix A.

10.4.1 Preliminary calculation

Table 5: Preliminary calculation result

PARAMETERS	WELL J3	WELL J21	WELL J 12
Liquid superficial velocity, ft/sec	3.9612	4.7417	4.2038
Gas superficial velocity, ft/sec	3.8622	2.8867	3.0584
Mixture velocity, ft/sec	7.8233	7.6284	7.2621
Multiphase flow mixture density, lbm/ft^3	27.0079	31.8881	30.1067

Engineers performing multiphase-flow design calculations for wellbores are clearly faced with an immediate dilemma. Which correlation or model should be used? Many companies have their favorites, often based on experience not documented in the literature. Unfortunately, decisions often are made without awareness of the serious limitations or the availability of more accurate methods. The evaluation of different correlations for liquid holdup and pressure drop gradient are presented in Figure 6 & 7 which are based on a very limited set of data.

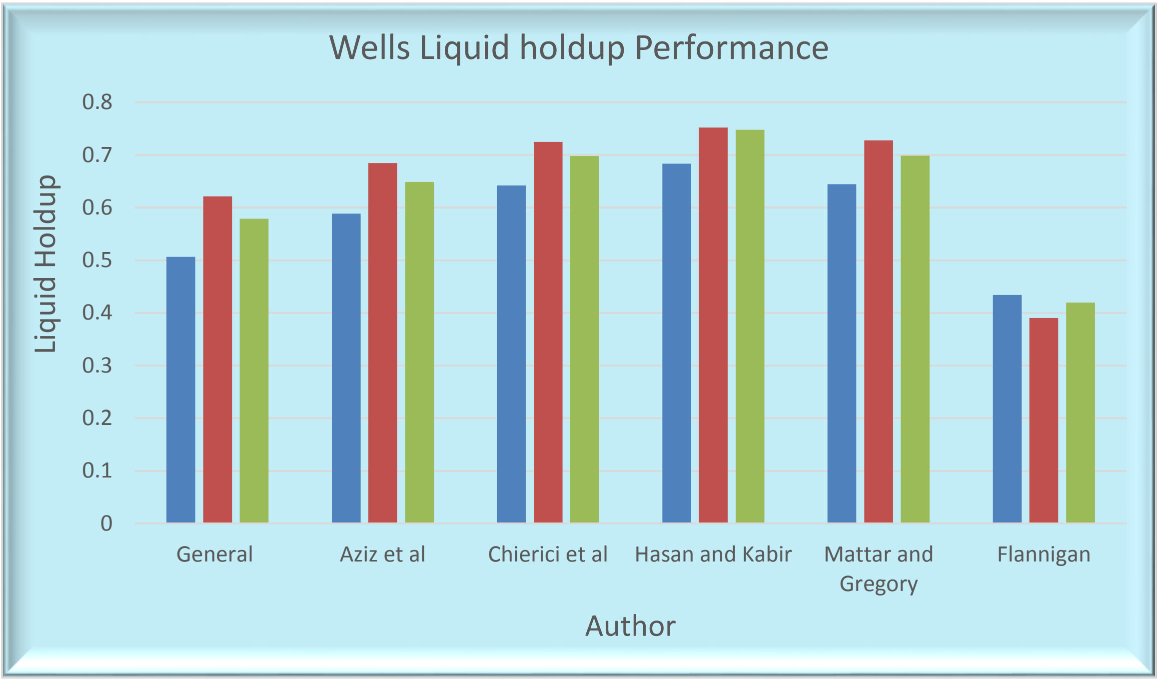


Figure 6: Comparison of well J3, J21 & J12 liquid holdup

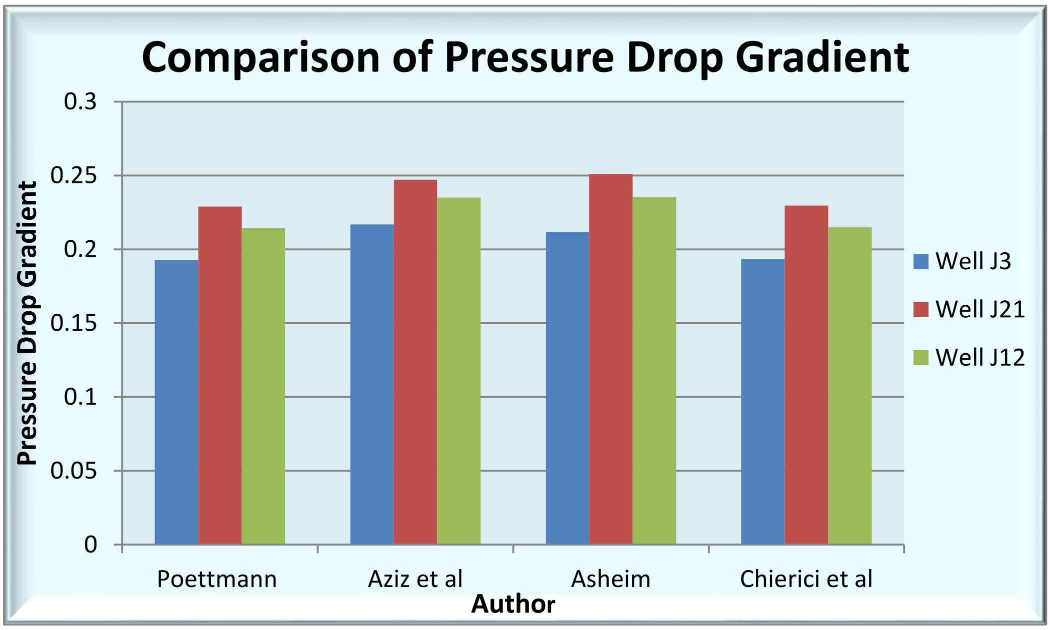


Figure 7: Comparison of well J3, J21 & J12 pressure drop gradient

11. CONCLUSION

Multiphase flow is a complex problem occurring in most industries. In the oil and gas industry, the ability to predict the holdup of each phase is of considerable importance. Therefore, in order to design and operate oil production systems in an optimized manner, it is necessary to accurately predict the behavior of two-phase flow of oil and gas in pipes with several different angles.

Engineers performing multiphase-flow design calculations for wellbores are clearly faced with an immediate dilemma. Which correlation or model should be used? Many companies have their favorites and in the MULTIFLOW developed in this study, several of these models are incorporated.

Also, inclination is found to have a dramatic effect on flow regime transitions. Stratified flow was eliminated in upflow while slug flow was found to dominate.

No existing comprehensive model properly accounts for all the effects of inclination angle on flow behavior. Although excellent models are available to predict flow patterns at all inclination angles, many of the variables used to predict flow behavior in mechanistic models are sensitive to inclination angle.

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APPENDIX A

$$dp=\left[\frac{f\rho_L V_f^2}{2d}+\rho_f g\,\mathrm{Sin}\theta\right]dL \qquad (A1)$$

$$dL=\frac{1}{\left[\frac{f\rho_L V_f^2}{2d}+\rho_f g\,\mathrm{Sin}\theta\right]}dp \qquad (A2)$$

$$\int_0^L dL=\int_{P_{tf}}^{P_{wf}}\left[\frac{1}{\frac{f\rho_L V_f^2}{2d}+\rho_f g\,\mathrm{Sin}\theta}\right]dp \qquad (A3)$$

$$\int_0^L dL=\int_{P_{tf}}^{P_{wf}}\left[\frac{1}{\frac{fPMq_{sc}^2 P_{sc}^2 T^2 z^2}{2zRTdA^2 T_{sc}^2 P^2}+\frac{PMg\,\mathrm{Sin}\theta}{zRT}}\right]dp \qquad (A4 \int_0^L dL$$

$$=\int_{P_{tf}}^{P_{wf}}\frac{1}{\frac{M}{R}\left[\frac{fq_{sc}^2 P_{sc}^2 Tz}{2dA^2 T_{sc}^2 P}+\frac{Pg\,\mathrm{Sin}\theta}{zT}\right]}dp \qquad (A5)$$

$$\frac{M}{R}\int_0^L dL=\int_{P_{tf}}^{P_{wf}}\frac{1}{\left[\frac{fq_{sc}^2 P_{sc}^2 Tz}{2dA^2 T_{sc}^2 P}+\frac{Pg\,\mathrm{Sin}\theta}{zT}\right]}dp \qquad (A6)$$

$$\frac{M}{R}\int_0^L dL=\int_{P_{tf}}^{P_{wf}}\frac{\frac{P}{zT}}{\left[\frac{8fq_{sc}^2 P_{sc}^2}{\pi^2 d^5 T_{sc}^2}+\left(\frac{P}{zT}\right)^2 g\,\mathrm{Sin}\theta\right]}dp \qquad (A7)$$

Substituting field units and integrating the left side of Eq. 4 gives

$$18.75\gamma_g L=\int_{P_{tf}}^{P_{wf}}\frac{\frac{P}{ZT}}{0.001\left(\frac{P}{ZT}\right)^2\sin\theta+\frac{0.667fq_{sc}^2}{d^5}}dp \qquad (A8)$$

Table 2: Regression variables

Variable	Value (Liquid holdup)	**Value (Pressure drop)**
a	245290.3	-4.5E+08
b	-161145	731.6146
c	42097.58	-1385339
d	-5481.1	2220.256
e	355.7038	-2.59E-02
f	-9.20504	3491.044
g	0.134437	-1.64857
h	-1.10E-05	8.52E-04
i	4.42E-10	8.07E-07
j	-8.74E-15	-2.00191
k	6.80E-20	

Table 3: key statistical parameters

Average error = 0.06539
Absolute average residual = 0.0415298
Standard Error of the Estimate = 0.611454331682951
Coefficient of Multiple Determination (R^2) = 0.9937219177
Proportion of Variance Explained = 99.37219177%
Adjusted coefficient of multiple determination (Ra^2) = 0.9926394897

Table 4: Input data

PARAMETERS	WELL J3	WELL J21	WELL J 12
Length of tubing, ft	10000	9800	10500
Tubing diameter, in	6	5.5	6
Liquid flow rate, bbl/day	10000	10000	10600
Gas flow rate, scf/day	10000000	10000000	9400000
Liquid viscosity, cp	0.97	1.83	1.089
Gas viscosity, cp	0.016	0.0196	0.0182
Liquid density, lbm/ft^3	47.61	47.6	47.83
Gas density, lbm/ft^3	5.88	6.078	5.742
liquid surface tesion, dynes/cm	8.41	8.41	8.41
Gas gravity	0.78	0.82	0.794
Oil FVF, rb/STB	1.197	1.204	1.1984
Gas FVF, cuft/scf	0.0097	0.00823	0.009973
Solution GOR, scf/STB	280	500	396