Estimation of Pressure Drop and Liquid Holdup for Oil-Gas 2 Phase Flow through Vertical Tubing String

by

Ahmad Haziq b Mohd Shah Zainudin

Dissertation submitted in partial fulfillment of

the requirements for the

Bachelor of Engineering (Hons)

(Petroleum Engineering)

JUNE 2012

Universiti Teknologi PETRONAS

Bandar Seri Iskandar

31750 Tronoh

Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

Estimation of Pressure Drop and Liquid Holdup for Oil-Gas 2 Phase Flow through Vertical Tubing String

by

Ahmad Haziq b Mohd Shah Zainudin

A project dissertation submitted to the

Petroleum Engineering Programme

Universiti Teknologi PETRONAS

in partial fulfillment of the requirement for the

BACHELOR OF ENGINEERING (Hons)

(PETROLEUM ENGINEERING)

Approved by,

____

(Dr Reza Ettehadi Osgouei)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

June 2012

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

AHMAD HAZIQ B MOHD SHAH ZAINUDIN

ABSTRACT

The oil and gas is a very vast industry. The production well is the crucial thing in oil and gas because it is the measurement of the profitability of the reservoir itself. It is a common thing that the production system will undergo multiphase condition due to the condition of the reservoir. Besides oil, other substance such as gas, water, sand, hydrates and waxes will be produce through the tubing string. The simultaneous flow of those substances will occur from the reservoir until the chrismas tree. It is very crucial to have a prediction tool so that optimum flow rate can be achieved with less pressure gradient and liquid holdup. Theoretically, a zero friction factor in a flowing fluid in a pipe cannot be achieved because it is only applicable to static fluid. Recovery from the wells need special challenges and requires accurate multiphase flow prediction tool for several applications, such as the design and schematic of the production systems, separation of phases in vertical wells, and multiple separation (topside, seabed or bottom-hole). As for any multiphase flow, the inlet condition such as flow rates, flow patterns, volume fractions of the fluids and the pressure need to be known. Due to that, it is crucial to have more accurate and efficient multiphase flow prediction tool.

The method that being used now separates flow pattern and flow behaviour prediction modelling. Due to that, the results that being produced was inaccurate. As an example, a multiphase flow of oil and gas are treated as both single phase, and ignoring the interactions between both of the fluids such as the slippage. However, the improved prediction tools now will allow such interaction and more accurate result can be obtained.

ACKNOWLEDGEMENTS

In the name of Allah, the Most Gracious, the Most Merciful. Praise to Him the Almighty that in his will and given strength, I managed to complete this Final Year Project for the Petroleum Engineering Department, Universiti Teknologi PETRONAS.

A lot has transpired during the study and I am indebt with so many people who has made this course an illuminating and enriching venture. My deepest gratitude goes to my supervisor, Dr Reza Ettehadi Osgouei for guiding me through this course thoroughly and giving me all the support to finish this study. Not to forget my lab colleague, Mr Tham Keat Fu for helping and giving continuous support towards this course.

Last but not least, to all that help me directly or indirectly helped me out in completing this study.

Thank you.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLE

NOMENCLATURES

$\rho_g = density\ of gas$

$\rho_l = density\ of\ liquid$

$\rho_s = density\ of solution/mixture$

$\sigma_l = liquid\ surface\ tension$

$H_l = liquid\ holdup$

$v_{sl} = liquid\ superficial\ velocity$

$v_{bf} = rise\ volocity\ of\ small\ gas\ bubbles$

$v_{sg} = gassuperficialvelocity v_m = mixture\ velocity$

$v_{bs} = rise\ velocity\ of continuous\ swarm\ of\ small\ bubbles$

$g = gravity\ acceleration$

$\frac{dp}{dZ} = pressure\ gradient$

$f = friction\ factor$

$d = diameter$

$\mu_l = viscosity\ of\ liquid$

$N_{Re} = Reynolds\ number$

$E_k = dimensionless\ kinetic\ energy$

$\varepsilon = roughness\ of\ pipe$

CHAPTER 1

Introduction

1. Background

Almost 100% wells in Malaysia are at the offshore. After the completion part has been assembled, the transportation of the oil n gas from the seabed to the christmas tree is one of the main part that need to be looked for. This study will show the liquid holdup due to the pressure drop inside of the tubing and the flow pattern itself. The study is being done on this particular part; seabed to the chrismas tree is because there are no restrictions in the string here.

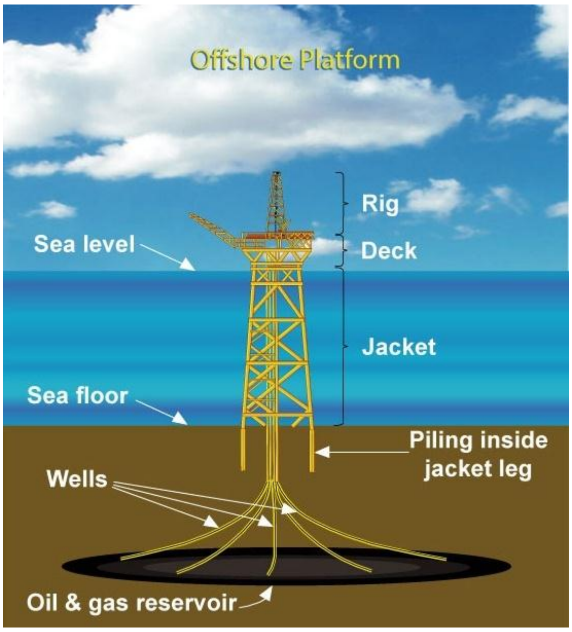


Figure 1: Example of an oil rig

Pressure gradient can be defined as the difference of pressure between to point. The pressure gradient prediction for a single phase flow inside tubing is pretty easy compared to the multiphase flow fluid. However, the prediction of the pressure gradient for the multiphase fluids is basically based on the single phase flow prediction method. The pressure gradient equation for a single-phase flow can be modified for the multiphase flow by considering the fluids to be a homogeneous mixture. The pressure gradient for the multiphase flow can be simplified by:

$$\left(\frac{dp}{dZ}\right)_t = \left(\frac{dp}{dZ}\right)_f + \left(\frac{dp}{dZ}\right)_{el} + \left(\frac{dp}{dZ}\right)_{acc}$$

which is the total pressure gradient inside the tubing for a multiphase flow is a sum of the pressure drop due to the friction losses, pressure drop due the elevation of the tubing and the pressure drop due to the acceleration of the fluids.

The pressure drop component caused by friction losses requires evaluation of a two-phase friction factor. The pressure drop caused by elevation depends on the density of the two-phase mixture which is usually calculated. Except for conditions of high velocity, most of the pressure drop in vertical flow is caused by this component. The pressure drop component caused by acceleration is normally negligible and is considered only for cases of high velocities.

Liquid holdup is defined as the fraction of an element of pipe which is occupied by liquid at the same instant. It is necessary to be able to determine liquid holdup to calculate such things as mixture density, actual gas and liquid velocities, effective viscosity and heat transfer. The value of liquid holdup varies from zero for single phase gas flow to one for single phase liquid flow. Liquid holdup may be measured experimentally by several methods, such as resistivity or capacitance probes or trapping a segment of the flow stream between quick closing valves and measuring the volume of liquid trapped. The liquid holdup cannot be calculated analytically. It must be determined from empirical correlations and is a function of variables such as fluids properties, flow patterns, pipe diameter and pipe inclination. The liquid holdup equations are functions of dimensionless liquid and gas velocity numbers in addition to liquid viscosity number and angle of inclination.

The flow pattern prediction is crucial for a specific location in the well. The empirical correlation or mechanistic model used to predict flow behavior varies with flow pattern. Basically all the flow pattern prediction is based on data from low pressure system, with negligible mass transfer between the phases and with a single liquid phase. Consequently, these predictions may be adequate for high pressure, high temperature wells and for wells producing oil and water or crude oils with foaming tendencies.

The prediction methods to predict the occurrence of the various flow patterns in wells have divided by two categories. The conventional method is to observe the experimental tests in the small diameter pipes at low pressures with air and water. The values of the various flow parameters at the transition between flow patterns were determined. Empirical flow pattern maps were drawn that could be used to predict the transition. The other method to predict the flow patterns considers the basic mechanisms that are important in causing a flow pattern change. This approach is not restricted to a narrow range of flow parameters and has proved to be highly successful.

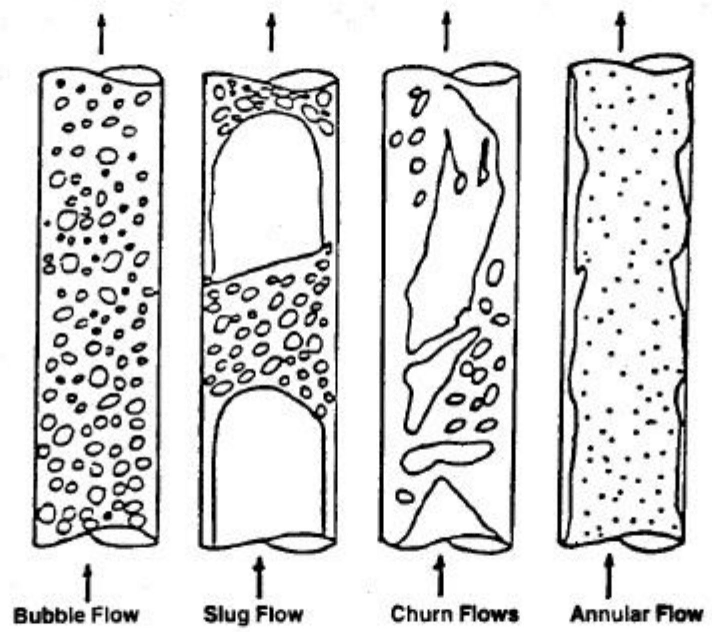


Figure 2: Vertical flows type

2. Problem Statement

An effective well completion needs a proper tubing string design so that the well will produce the optimum flow rate of oil. The pressure drop and the liquid hold up in the tubing string need to be calculated as it involves a 2 phase fluids; oil and gas. This study will estimate the pressure drop of a 2 phase oil-gas flow in a 3.0 inch diameter with 20 feet long vertical tubing string without any restrictions.

3. Objective

- To simulate the flow of multiphase oil-gas flow in the vertical tubing
- To determine the liquid holdup and the friction factor of the flow inside 3.0 inch diameter with 20 feet long tubing string
- To compare the difference of the result obtain from the simulation and Aziz et al correlation

However, few assumptions are being made to simulate a basic flow due to several limitations.

Those assumptions are:

1. Steady flow
2. Isothermal flow
3. Constant compressibility factor
4. Horizontal flow
5. No kinetic energy change
6. No vibration in the pipe

CHAPTER 2

LITERATURE REVIEW

A hydrocarbon compounds or components can be a complex mixture and can exist as a single-phase liquid, a single-phase gas, or as a two-phase mixture, depending on the pressure, temperature, and the composition of the mixture. It is very different compared to a single component or compound, such as water or carbon dioxide; on the contrary a multicomponent mixture will exhibit an envelope rather than a single line on a pressure-temperature diagram when two phase exist simultaneously.

A typical oil reservoir has temperatures below the critical temperature of the hydrocarbon mixture. Volatile oil and condensate reservoir normally have temperatures between the critical temperature and the cricondentherm for the hydrocarbon mixture. Dry gas reservoir have temperatures above the cricondentherm.

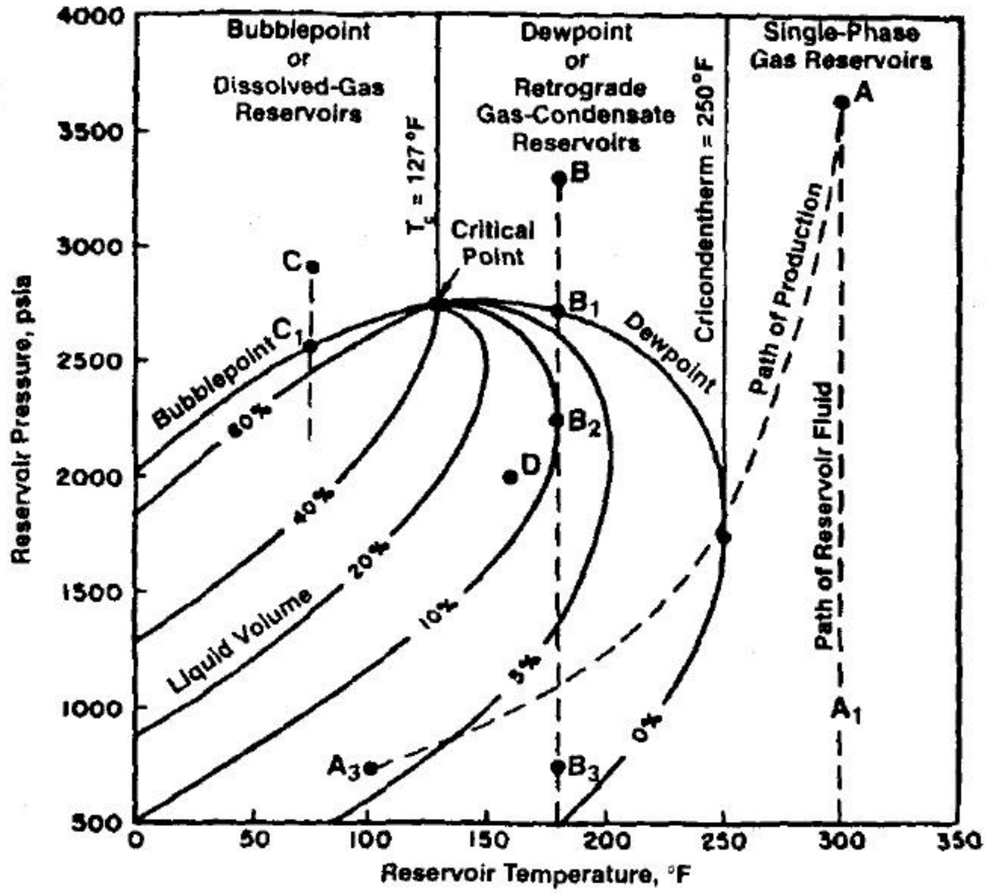


Figure 3 : Typical Phase Diagram

As for the condensate fluids, the fluids will exhibit retrograde condensation, a condition where the condensation occurs during pressure reduction rather than with pressure increase, as for most gases. This abnormal or retrograde behaviour occurs in a region between the critical point and the cricondentherm, and is bounded by the dewpoint curve above and a curve below formed by connecting the maximum temperature for each liquid volume percentage.

Mass transfer occurs continuously between the gas and the liquid phases within the two phase envelope as the pressure and the temperature change. As to describe the mass transfer assume that equilibrium exist between the phases. Two approaches have been used to simulate mass transfer for hydrocarbon system; the black oil or the contant-composition model and the compositional model or variables.

The black oil can be defined as a misnomer and refers to any black liquid phase that contains dissolved gas, such as hydrocarbons produced from oil reservoirs. These oils are typically dark in color, have gravities less than 40° API, and undergo relatively small changes in composition within the two phase envelope. For a better description of the black oil, it has a constant composition model.

The black oil that has associated gas, a simplified parameter has been defined to consider for gas that dissolves (condenses) or evolves from solution in the oil. This gas that condenses, known as $R_{s,}$ can be measured experimentally or determined using empirical correlations. Due to the black oil model cannot predict retrograde condensation phenomena, it should not be used for temperatures approaching the critical point temperature.

The other parameter is the oil formation volume factor, B_o, is defined as the shrinkage or expansion of the oil phase. The oil volume may change as a result of changes in dissolved gas and because of the compressibility and thermal expansion of the oil. The crucial factor that affected the volume changes is the dissolved gas. The oil formation volume factor also can be measured experimentally or determined using empirical correlations. Once the black oil model parameters are known, oil density and the other physical properties of the two phases can be determined.

As for volatile and condensate fluids, vapour/liquid equilibrium (VLE) or “flash” calculations are more accurate to determined mass transfer than black oil model parameters. A VLE calculation will determine the amount of the feed that exist in the vapour liquid phases and the composition of each phase when given the composition of a fluid mixture or feed. From here, it is possible to determine the quality or mass fraction of gas in the mixture. Once the composition of each phase is known, it is also possible to calculate the interfacial tension and densities, enthalpies and viscosities of each phase.

Compared to the black oil model parameters, VLE calculations are considered more accurate to describe mass transfer. However, VLE are much more difficult to perform. It is only possible to generate black oil parameters from VLE calculations if the detailed composition is available for gas/oil system. However, the nearly constant composition those results for the liquid phase and the increased computation requirements make the black oil model more attractive for non-volatile oil.

Basically, the same principles are used for the pressure gradient calculation for multiphase flow as for a single phase flow; conservation of mass and linear momentum. However, the presence of additional phase makes the prediction so much complicated than single phase flow. The liquid hold up and friction effect were dependent on the flow pattern predicted by the empirical flow patterns map, and those properties cannot assume that the fluids used were homogeneous mixture.

1. Empirical Correlation Categories

The pressure gradient prediction used in the simulation was one of the empirical correlations. Basically, there are three types of empirical correlations

1.1 Category A

These types of correlations basically ignore slip and flow patterns. The density of the mixture is calculated based on the input liquid-gas ratio. Those fluids are considered to travel at the same velocity in the pipe. The only correlation required is for the two phase friction factor. It is to be assumed that this pressure gradient prediction method can be used for all flow patterns.

1.2 Category B

As for this type of correlation, slip will be considered but the flow pattern will be ignored. The correlations are required for both liquid holdup and friction factor. a method need to be known to predict the portion of the pipe occupied by liquid at any location due to liquid and gas can travel at different velocities. However, the same correlations are used for all flow patterns

1.3 Category C

These type of correlations considered slip and flow patterns. It is necessary to have methods to predict the flow pattern inside the pipe as well as the method to predict liquid holdup and friction factor. The methods used also depend on the flow pattern. In the other hand, the correlations also considered the acceleration pressure gradient to particular flow pattern.

THEORY

1. Aziz et al. Method

As for the calculation of liquid holdup, Aziz et al. Method is being use. This correlation is under category C. The flow pattern needs to be determined using equation [1] [2]

$$N_x = v_{sg}\left(\frac{\rho_g}{0.0764}\right)^{1/3}\left[\left(\frac{72}{\sigma_L}\right)\left(\frac{\rho_L}{62.4}\right)\right]^{1/4} \quad \text{……………………………...…[1]}$$

and

$$N_y = v_{sl}\left[\left(\frac{72}{\sigma_L}\right)\left(\frac{\rho_L}{62.4}\right)\right]^{1/4} \quad \text{………………………………………...…[2]}$$

The flow pattern is determined using the following figure.

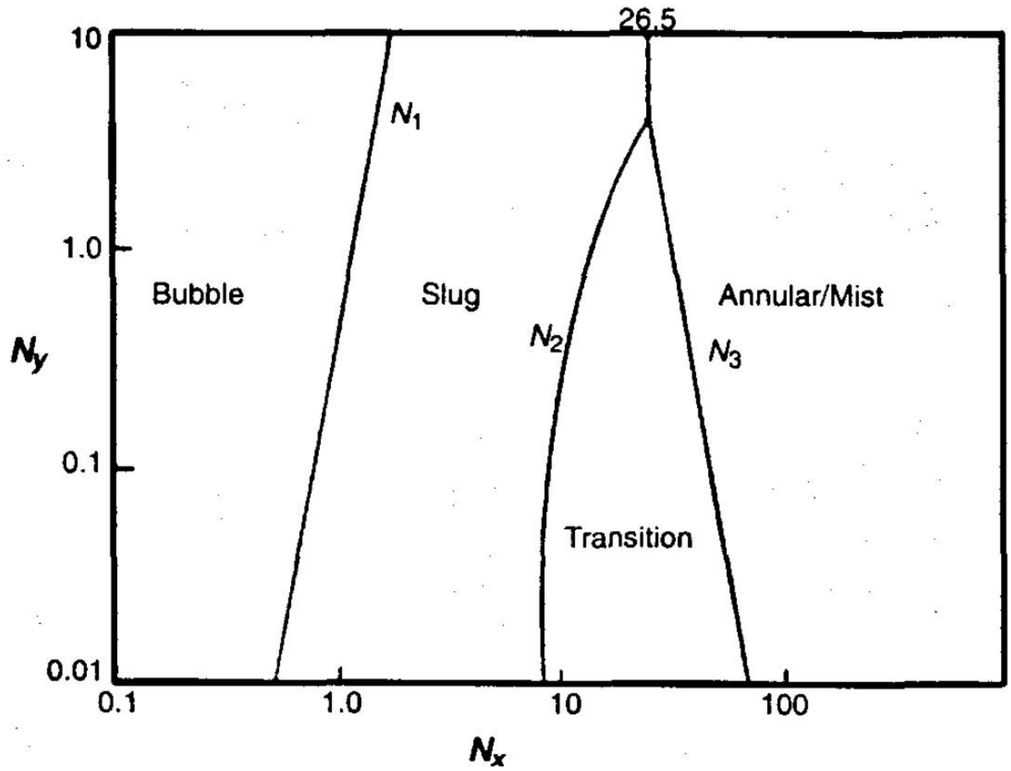


Figure 4: Aziz *et al.* flow pattern map

These equations [3][4][5] represent the flow pattern transitions in Figure 5

$N_1 = 0.51(100N_y)^{0.172}$ ……..………………………………………………...…[3]

$N_2 = 8.6 + 3.8N_y$ ……………………………………………………………..…[4]

$N_3 = 70(100N_y)^{-0.152}$ ……..…………………………………………..…...…[5]

2.1 Flow patterns

There are several flow patterns that being proposed by Alves [1954] that covered all types of flow patterns in horizontal flow.

2.1.1 Bubble flow

This flow is always referred to dispersed bubble flow, and being defined by a train of discrete gas bubbles moving mainly close to the upper wall of the pipe, at almost the same velocity as the liquid. The higher the flow rate in the pipeline, the bubbles becomes more evenly distributed over the cross-section of the pipe.

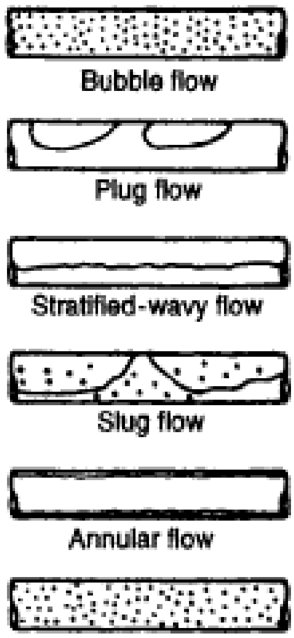


Figure 5: Types of flow pattern

2.1.2 Plug flow

If the volume of gas is increased, the bubbles will interact and coalesce to give rise a large bullet shaped plugs occupying the most of the pipe cross-section, except for a thin liquid film at the wall of the pipe which is thicker towards the bottom of the pipe.

2.1.3 Stratified-wavy flow

The gravitational forces dominate and the gas phase flows in the upper part of the pie. At a relatively low flowrates, the gas-liquid interface is smooth, but becomes ripply or wavy at higher gas rates thereby giving rise to the so-called wavy-flow.

2.1.4 Slug flow

The liquid will carrying entrained gas bubbles alternate with gas slugs surrounded by thin films for the flow.

2.1.5 Annular flow

Here, most of the liquid is carried along the inner wall of the pipe as a thin film, while the gas forms a central core occupying a substantial portion of the pipe cross-section. Some liquid is usually entrained as fine droplets within the gas core.

2.1.6 Mist flow

This flow will occur when a significant amount of liquid is carried along the inner wall of the pipe as a thin film, while gas forms a central core occupying a substantial portion of the pipe cross-section.

2.2 Bubble Flow

The liquid holdup [6] for the bubble flow is calculated from equation

$$H_l = 1 - \frac{v_{sg}}{v_{bf}} \quad \ldots\ldots\ldots[6]$$

where v_{bf}[7] is the rise velocity of small gas bubbles in a flowing liquid. As for the velocity, it can be calculated from equation

$$v_{bf} = 1.2v_m + v_{bs} \quad \ldots\ldots\ldots[7]$$

where the first term is the approximate velocity of fluid mixture, and v_{bs}[8] is the rise velocity of a continuous swarm of bubbles in a static liquid column. The rise velocity can be calculated using equation

$$v_{bs} = 1.41\left[\frac{\sigma_l g(\rho_l - \rho_g)}{\rho_l^2}\right]^{1/4} \ldots\ldots\ldots[8]$$

The friction component of the pressure gradient [9] is determined from

$$\frac{dp}{dZ} = \frac{f\rho_s v_m^2}{2d} \quad \ldots\ldots\ldots[9]$$

where ρ_s[10] is determined from equation

$$\rho_s = \rho_l H_l + \rho_g(1 - H_l) \ldots\ldots\ldots[10]$$

and f is obtained from the figure below for a Reynolds number [11] given by

,

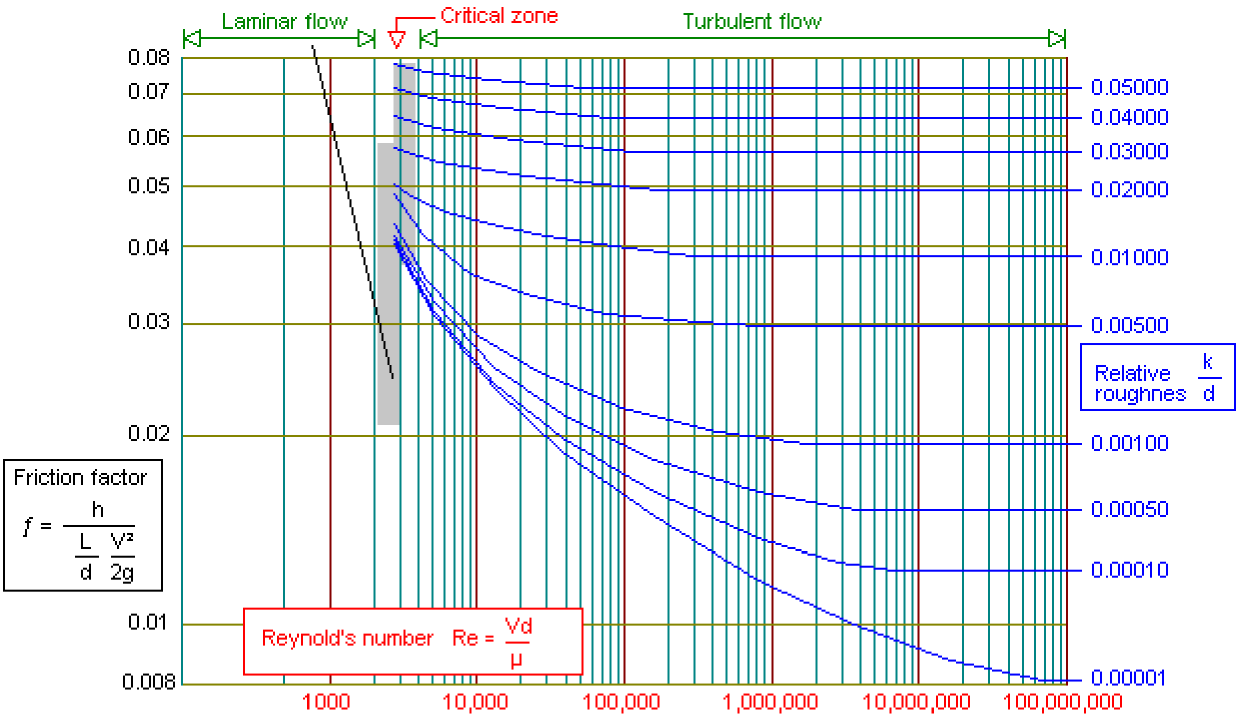


Figure 6: Moody Diagram

The acceleration component of the pressure gradient is considered to be negligible for bubble flow.

2.3 Slug Flow

The liquid hold up calculation for slug flow is using equation [6] but using the bubble-rise velocity [12] in a static liquid column based on a Taylor bubble.

$$v_{bs} = C\sqrt{\frac{gd(\rho_l - \rho_g)}{\rho_l}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots[12]$$

where C[13] was given as

$$C = 0.345\left[1 - e^{(-0.029N_v)}\right]\left[1 - e^{\left(\frac{3.37-N_E}{m}\right)}\right] \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots[13]$$

where the dimensionless number [14] and the dimensionless velocity number [15] are determined with

$$N_E = \frac{gd^2(\rho_l - \rho_g)}{\sigma_l} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots[14]$$

$$N_v = \frac{\sqrt{d^3 g\rho_l(\rho_l - \rho_g)}}{\mu_l} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots[15]$$

and m is determined from

$\boldsymbol{N_v}$	m
$\geq \mathbf{250}$	10
$\mathbf{250} > \boldsymbol{N_v} > \mathbf{18}$	$69N_v^{-0.35}$
$\leq \mathbf{18}$	25

Table 1: ‘m’ values

The friction pressure gradient [16] component for slug flow is determined from

$$\left(\frac{dp}{dZ}\right)_f = \frac{f \rho_l H_l v_m^2}{2d} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots [16]$$

and the friction factor is obtained from Moody diagram, and a Reynolds number [17] is given by

$$N_{Re} = \frac{\rho_l v_m d}{\mu_l} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots [17]$$

The acceleration pressure gradient component was considered negligible for slug flow.

2.4 Mist Flow

As for the pressure gradient for mist flow, Aziz et al. recommended the Duns and Ros mist-flow method [18].

$$\left(\frac{dp}{dZ}\right)_{ftotal} = \frac{\left(\frac{dp}{dZ}\right)_{el} + \left(\frac{dp}{dZ}\right)_{f}}{1 - E_k} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots [18]$$

Where E_k[19] is a dimensionless kinetic energy

$$E_k = \frac{v_m v_{sg} \rho_n}{\rho} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots [19]$$

and the friction component of the pressure gradient [20] is determined from

$$\left(\frac{dp}{dZ}\right)_{f} = \frac{f \rho_g v_{sg}^2}{2d} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots [20]$$

and the value of f[21] for the mist-flow pattern can be found from

$$f = 4\left\{\frac{1}{\left[4\log_{10}\left(0.27\frac{\varepsilon}{d}\right)\right]^2} + 0.067\left(\frac{\varepsilon}{d}\right)^{1.73}\right\} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots [21]$$

2.5 Transition region

The pressure gradient [22] for transition region can be calculated using

$$\frac{dp}{dZ} = A\left(\frac{dp}{dZ}\right)_{slug} + (1-A)\left(\frac{dp}{dZ}\right)_{mist} \quad \text{……..………………………........…[22]}$$

where

$$A = \frac{N_3 - N_x}{N_3 - N_2}$$

CHAPTER 3

METHODOLOGY

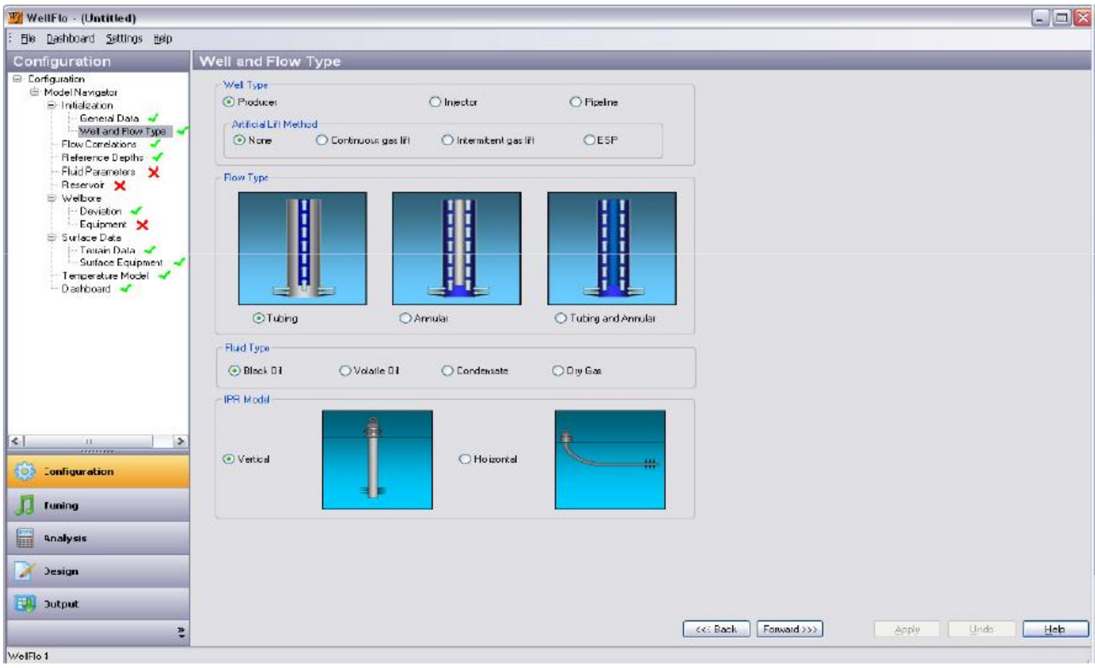
1. The case study consists of a 3 inch diameter tubing string with a 20 feet long. The boundary condition and the fluids rheological properties are determined. The test fluids used in this experiment consists of oil and air. Tulco Tech 80 oil is used as the oil phase due to its good separability. The physical properties of the oil are as below:
   - 33.2 API gravity
   - Density: 858.75 kg/m^3 @ 15.6°C
   - Viscosity: 13.5 cp @ 40°C
   - Surface tension: 29.14 dynes/cm @ 25.1°C
   - Interfacial tension with water: 16.38 dynes/cm @ 25.1°C
   - Pour point temperature: -12.2°C
   - Flash point temperature: 185°C

As for the gas phase, air @ 25°C properties is being used.

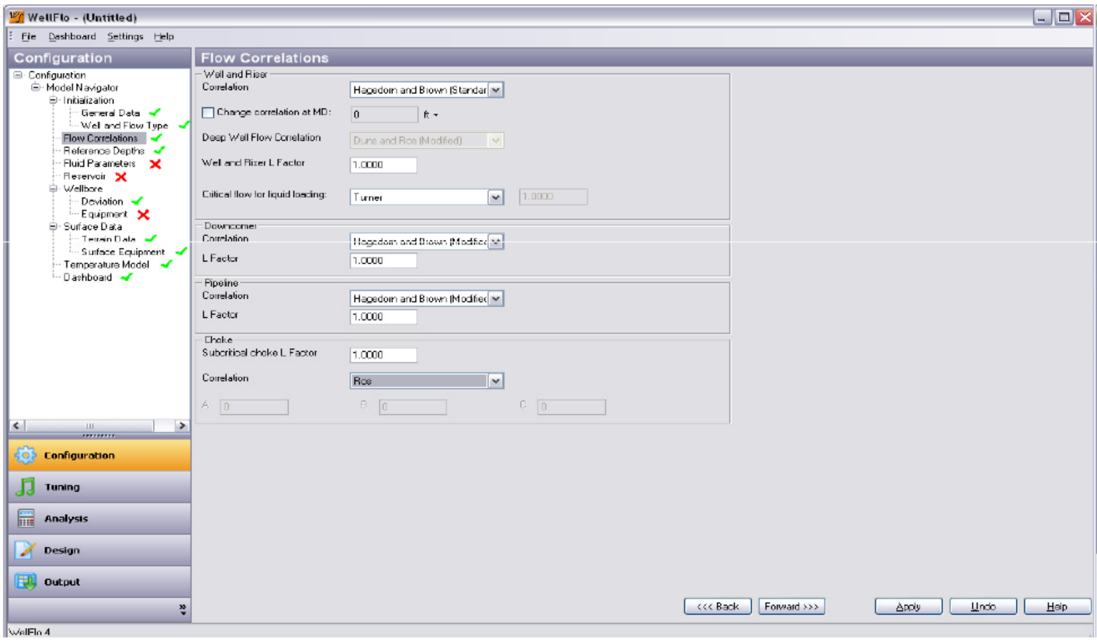
As for the well properties;

a) Oil production rate: 2000 bbl/day
b) Gas production rate: 3.53 MMscf/day
c) Water production: 0 bbl/day

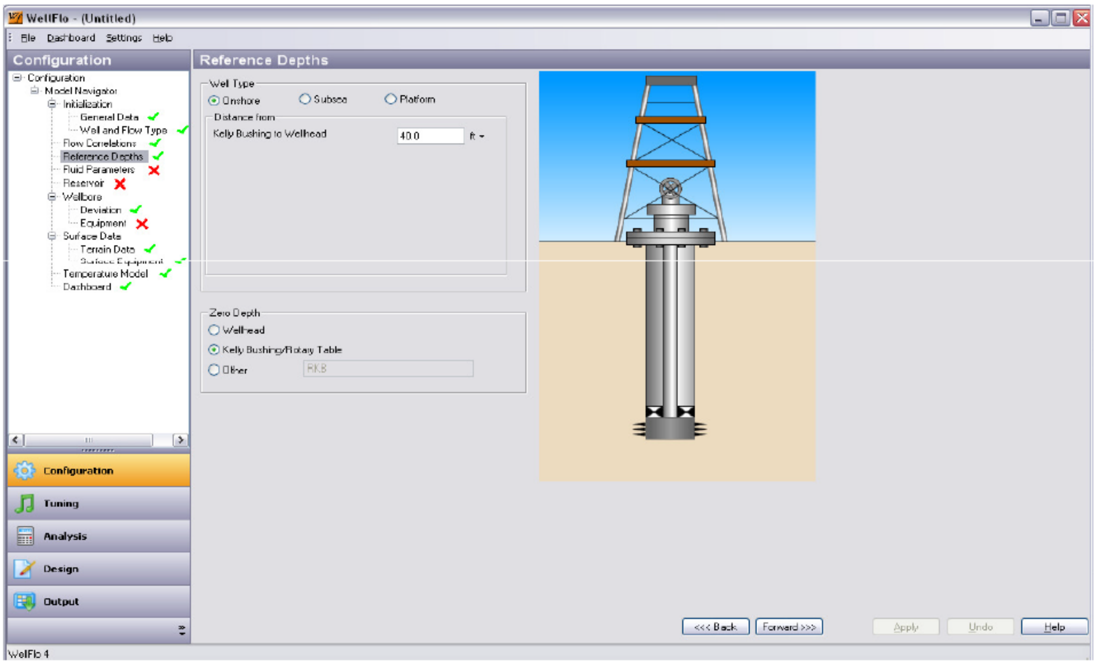
2. The pressure gradient and the liquid holdup for the case is being calculated using Aziz et al method.
3. The simulation was run with Wellflo software and the pressure gradient and the liquid holdup are being determined.
   i. The well and flow type is being set up



   ii. The flow correlation is being set up at the Configuration tab.



iii. The reference depth is being set at the Configuration tab and offshore well type is being selected.



iv. All the fluids properties being filled in at the Fluid Parameter set up.

v. The configuration of the tubing and casing is being filled in at the Wellbore tab.

vi. After all the parameters are being set up properly, and there is no error at the Dashboard, the simulation is run.

4. The calculation and the simulation is repeated using different value of oil flow rate.
5. Both of the result is being calculated and compared.

CHAPTER 4

RESULT AND DISCUSSION

4.1 Aziz et al Method

4.1.1 For Q_o= 2000 bbl/d

<u>Liquid Holdup Calculation</u>

$$v_m = 1.884 * 10^{12}\ m/s$$

$$v_{bs} = 1.41\left[\frac{\sigma_l g(\rho_l - \rho_g)}{\rho_l^2}\right]^{1/4} = 1.0706$$

$$v_{bf} = 1.2v_m + v_{bs} = 2.26 * 10^{12}$$

$$H_l = 1 - \frac{v_{sg}}{v_{bf}} = 0.1640$$

<u>Pressure Gradient Calculation</u>

$$f = 4\left\{\frac{1}{\left[4\log_{10}\left(0.27\,\frac{\varepsilon}{d}\right)\right]^2} + 0.067\left(\frac{\varepsilon}{d}\right)^{1.73}\right\} = 0.003497$$

$$\left(\frac{dp}{dZ}\right)_f = \frac{f\rho_g v_{sg}^2}{2d} = 9.89E + 21$$

$$E_k = \frac{v_m v_{sg}\rho_n}{\rho} = 1.417E + 24$$

$$\left(\frac{dp}{dZ}\right)_{ftotal} = \frac{\left(\frac{dp}{dZ}\right)_{el} + \left(\frac{dp}{dZ}\right)_f}{1 - E_k} = 0.303\ psi/ft$$

4.1.2 For Q_o= 2500 bbl/d

Liquid Holdup Calculation

$$v_m = 1.883E + 12\ m/s$$

$$v_{bs} = 1.41\left[\frac{\sigma_l g(\rho_l - \rho_g)}{\rho_l^2}\right]^{1/4} = 1.0706$$

$$v_{bf} = 1.2v_m + v_{bs} = 2.2596E + 12$$

$$H_l = 1 - \frac{v_{sg}}{v_{bf}} = 0.1636$$

Pressure Gradient Calculation

$$f = 4\left\{\frac{1}{\left[4\log_{10}\left(0.27\frac{\varepsilon}{d}\right)\right]^2} + 0.067\left(\frac{\varepsilon}{d}\right)^{1.73}\right\} = 0.003497$$

$$\left(\frac{dp}{dZ}\right)_f = \frac{f\rho_g v_{sg}^2}{2d} = 9.89E + 21$$

$$E_k = \frac{v_m v_{sg}\rho_n}{\rho} = 1.6632E + 24$$

$$\left(\frac{dp}{dZ}\right)_{ftotal} = \frac{\left(\frac{dp}{dZ}\right)_{el} + \left(\frac{dp}{dZ}\right)_f}{1 - E_k} = 0.35595\ psi/ft$$

4.1.3 For Q_o= 3000 bbl/d

Liquid Holdup Calculation

$$v_m = 1.881E + 12 \ m/s$$

$$v_{bs} = 1.41 \left[\frac{\sigma_l g(\rho_l - \rho_g)}{\rho_l^2}\right]^{1/4} = 1.0706$$

$$v_{bf} = 1.2v_m + v_{bs} = 2.2572E + 12$$

$$H_l = 1 - \frac{v_{sg}}{v_{bf}} = 0.16268$$

Pressure Gradient Calculation

$$f = 4\left\{\frac{1}{\left[4\log_{10}\left(0.27\frac{\varepsilon}{d}\right)\right]^2} + 0.067\left(\frac{\varepsilon}{d}\right)^{1.73}\right\} = 0.003497$$

$$\left(\frac{dp}{dZ}\right)_f = \frac{f\rho_g v_{sg}^2}{2d} = 9.893E + 21$$

$$E_k = \frac{v_m v_{sg}\rho_n}{\rho} = 1.9081E + 24$$

$$\left(\frac{dp}{dZ}\right)_{ftotal} = \frac{\left(\frac{dp}{dZ}\right)_{el} + \left(\frac{dp}{dZ}\right)_f}{1 - E_k} = 0.40836\, psi/ft$$

4.1.4 For Q_o= 3500 bbl/d

<u>Liquid Holdup Calculation</u>

$$v_m = 1.879E + 12\ m/s$$

$$v_{bs} = 1.41\left[\frac{\sigma_l g(\rho_l - \rho_g)}{\rho_l^2}\right]^{1/4} = 1.0706$$

$$v_{bf} = 1.2v_m + v_{bs} = 2.2548E + 12$$

$$H_l = 1 - \frac{v_{sg}}{v_{bf}} = 0.16179$$

<u>Pressure Gradient Calculation</u>

$$f = 4\left\{\frac{1}{\left[4\log_{10}\left(0.27\frac{\varepsilon}{d}\right)\right]^2} + 0.067\left(\frac{\varepsilon}{d}\right)^{1.73}\right\} = 0.003498$$

$$\left(\frac{dp}{dZ}\right)_f = \frac{f\rho_g v_{sg}^2}{2d} = 9.893E + 21$$

$$E_k = \frac{v_m v_{sg}\rho_n}{\rho} = 2.149E + 24$$

$$\left(\frac{dp}{dZ}\right)_{ftotal} = \frac{\left(\frac{dp}{dZ}\right)_{el} + \left(\frac{dp}{dZ}\right)_f}{1 - E_k} = 0.0.4599\ psi/ft$$

4.2 Wellflo

The simulation was run and the pressure vs length profile is as follow.

4.2.1 For Q_o= 2000 bbl/day

Length	Pressure Accumulated
0	0.00
2	0.60
4	1.21
6	1.84
8	2.57
10	3.37
12	4.04
14	4.86
16	5.52
18	6.19
20	6.80

Table 2: Length vs Pressure Difference (Q_o= 2000 bbl/day)

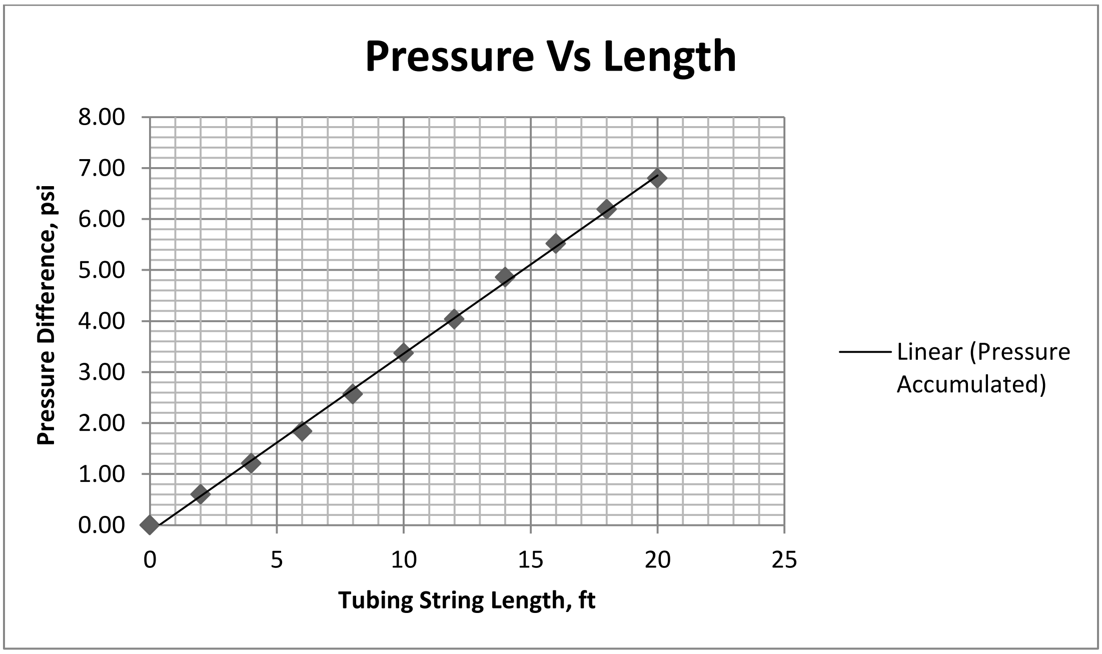


Figure 7 : Pressure Difference vs Tubing Length (Q_o= 2000 bbl/day)

As for the liquid holdup, the value is 0.1953 from the Wellflo simulation using 20 feet of length of study with a 3.0 inch diameter.

4.2.2 For Q_o= 2500 bbl/day

Length	Pressure Accumulated
0	0.00
2	0.76
4	1.47
6	2.35
8	3.12
10	3.90
12	4.68
14	5.43
16	6.25
18	7.05
20	7.84

Table 3 : Length vs Pressure Difference (Q_o= 2500 bbl/day)

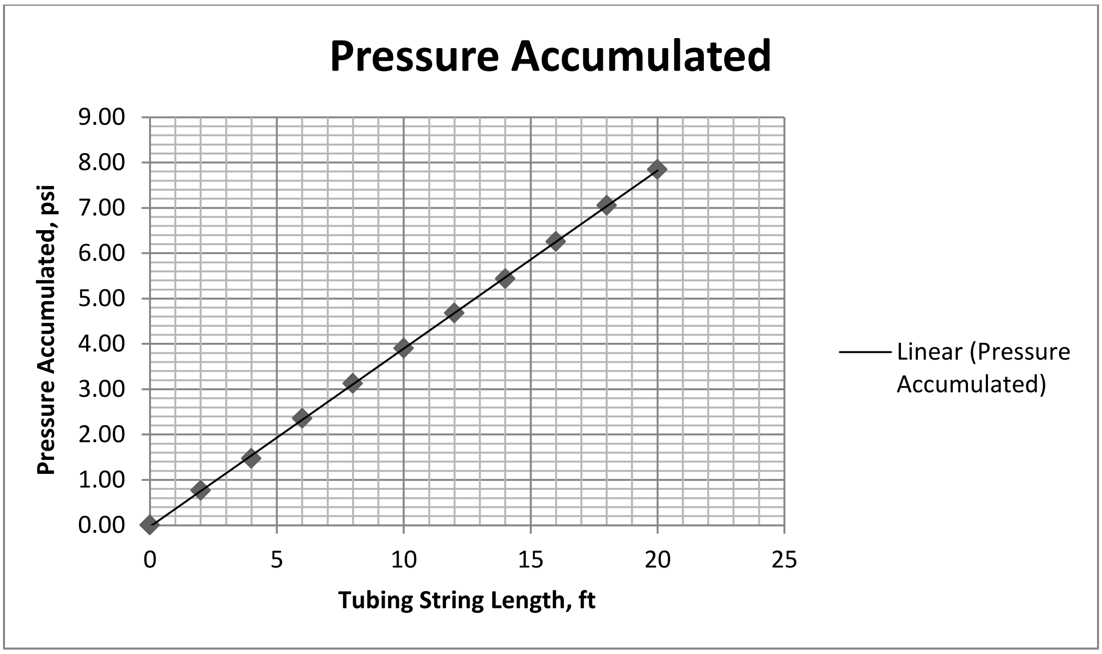


Figure 8 : Pressure Difference vs Tubing Length (Q_o= 2500 bbl/day)

As for the liquid holdup, the value is 0.1894 from the Wellflo simulation using 20 feet of length of study with a 3.0 inch diameter.

4.2.3 For Q_o= 3000 bbl/day

Length	Pressure Accumulated
0	0.00
2	0.90
4	1.83
6	2.73
8	3.54
10	4.46
12	5.37
14	6.31
16	7.18
18	8.10
20	9.02

Table 4 : Length vs Pressure Difference (Q_o= 3000 bbl/day)

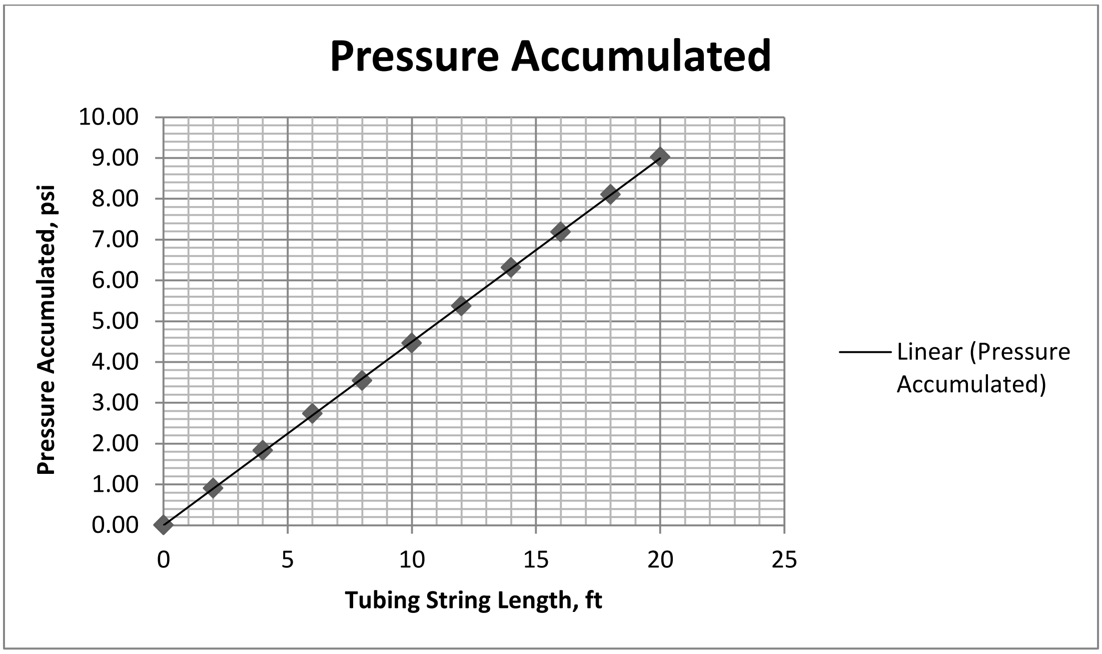


Figure 9 : Pressure Difference vs Tubing Length (Q_o= 3000 bbl/day)

As for the liquid holdup, the value is 0.1873 from the Wellflo simulation using 20 feet of length of study with a 3.0 inch diameter.

4.2.4 For Q_o= 3500 bbl/day

Length	Pressure Accumulated
0	0.00
2	0.95
4	1.82
6	2.81
8	4.01
10	5.41
12	6.27
14	7.22
16	8.55
18	9.53
20	10.44

Table 5 : Length vs Pressure Difference (Q_o= 3500 bbl/day)

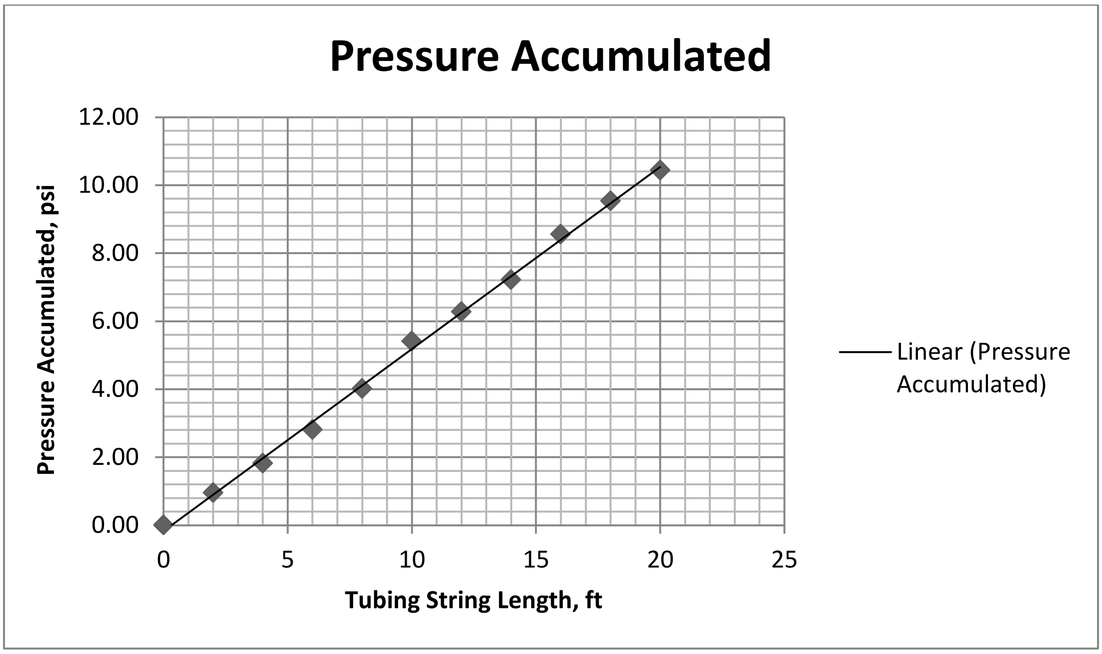


Figure 10 : Pressure Difference vs Tubing Length (Q_o= 3500 bbl/day)

As for the liquid holdup, the value is 0.1848 from the Wellflo simulation using 20 feet of length of study with a 3.0 inch diameter.

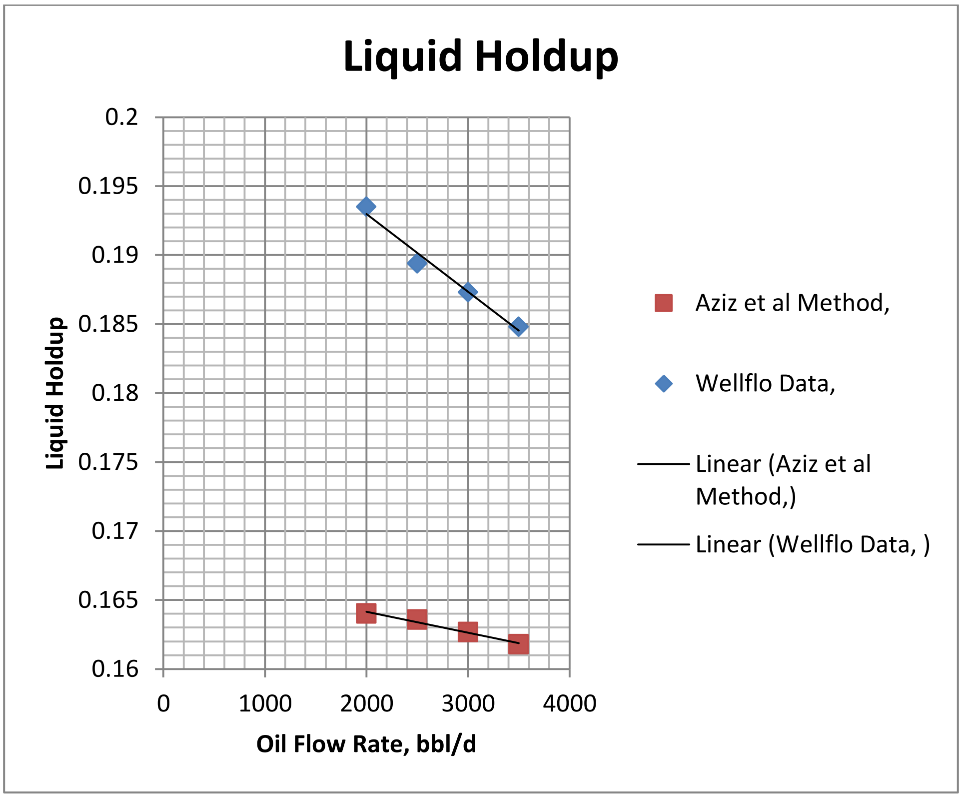
4.3 Error calculation

$$Error\ percentage = \left|\frac{Simulation\ data - Calculated\ data}{Calculated\ data}\right| * 100$$

4.4 Comparison between Simulation data and Aziz et al Correlation

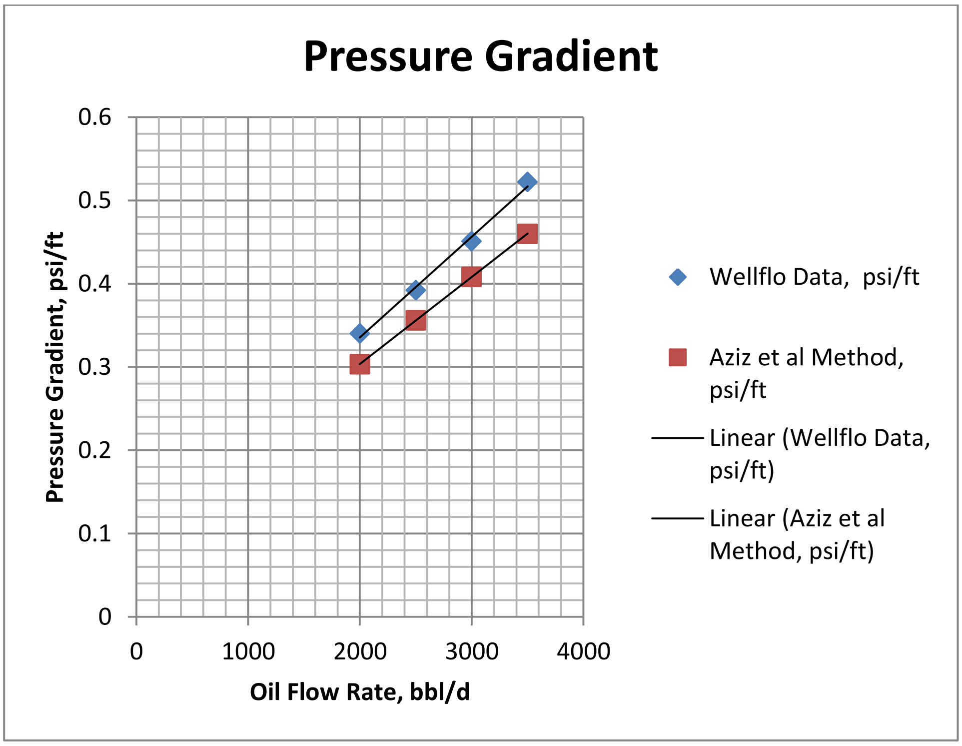
4.4.1 Liquid Hold up

Oil Flow Rate, bbl/d	Wellflo Data	Aziz et al Method	Error Percentage, %
2000	0.1935	0.164013	17.97
2500	0.1894	0.163569	15.79
3000	0.1873	0.162679	15.13
3500	0.1848	0.161788	14.22



4.4.2 Pressure Gradient

Oil Flow Rate, bbl/d	Wellflo Data, psi/ft	Aziz et al Method, psi/ft	Error Percentage, %
2000	0.340	0.303263	12.11
2500	0.392	0.35595	10.12
3000	0.451	0.408364	10.44
3500	0.522	0.459891	13.51



4.4 Discussion

From the simulation, the pressure inside the tubing string increases with an almost the same rate. The flow pattern that being determined using Aziz et al Method is apparently a mist flow. Thus, it is significant that the pressure inside the tubing string increases gradually because the pressure distribution along the tubing string is almost the same.

There are slightly difference between the simulation data and the calculation using Aziz et al Method. As for the pressure difference for 2000 bbl/d oil flow rate, the error percentage is about 12.11%. This error maybe due to lack of the field data that need to be analysed in the first place. The simulation may consider the occurrence of the condensate inside the tubing string.

As for the liquid holdup for 2000 bbl/d oil flow rate, the Wellflo data came out with 0.1935 and the calculation with the Aziz et al Method come out with 0.164013. The small value at the liquid holdup is due to the high production of gas from the well itself. As for the liquid holdup, the study obtained about 17.97% error due to the consideration for the study.

The errors that being obtained because the study only focusing at the middle of about 2000 feet tubing string as the control system. The result may be different if the study simulates the whole tubing string. However, the study is unable to be achieved due to the time constraint of the study.

CHAPTER 5

CONCLUSION

As a conclusion, the liquid holdup of a 20 feet length tubing string of a 2 phase oil-gas flow is gradually decrease as the oil flow rate increase. However, the pressure gradient will gradually decrease as the oil flow rate increase.

The flow that being simulated is just a basic flow due to several limitations for the study. As for the assumptions:

1. Steady flow
2. Isothermal flow
3. Constant compressibility factor
4. Horizontal flow
5. No kinetic energy change
6. No vibration in the pipe

The result that can be obtained will be accurate after assuming all the conditions from the simulation. However, those conditions can be considered crucial due to industry limitations. As for example, the industry can never prevent the vibration of the pipe inside the casing. The vibration effect can only be minimized by inserting packers.

However, the result that the study obtained can be used as a basic flow of a 2 phase oil-gas flow inside the tubing string.

References

1. Garland, Bill. 2004 < http://canteach.candu.org/library/20040601.pdf>*Fluid Mechanics*
2. Jepson, W. P. 18 February 1993, *Slug Flow And Its Transitions In Large-Diameter Horizontal Pipes*, Pergamon Press Ltd 1993.
3. Vallee, Christophe. 2007*, Experimental Investigation And CFD Simulation Of Horizontal Stratified Two-Phase Flow Phenomena*
4. Asante, Ben. 2000*, Two Phase Flow: Accounting For The Presence Of Liquids In Gas Pipeline Simulation*
5. Sarica, Cem. 2006, "*Tulsa University Fluid Flow Projects*
6. Spedding, P.L. P*rediction Of Pressure Drop In Multiphase Horizontal Pipe Flow*
7. Kumara, W A S, Pressure *Drop, Flow Pattern and Local Water Volume Fraction Measurements Of Oil-Water Flow In Pipes*, Telemark University College.
8. Griffith, Peter. 1984, *Multiphase Flow in Pipe*, MIT
9. Oddie, G. 2003*, Experimental Study Of Two And Three Phase Flows In Large Diameter Inclined Pipes*, Pergamon.
10. Xie, T. 2003, *Flow Regimes And Gas Holdup In Paper Pulp-Water-Gas Three-Phase Slurry Flow*,Pergamon
11. Brill, P. James 1999, *Multiphase Flow in Wells*, Richardson.
12. Corradini, L. Michael 1997, *Fundamental of Multiphase Flow*, BahramEng
13. Tulsa University Fluid Flow Projects, 2008, *Development of Next Generation Multiphase Pipe Flow Prediction Tools*, US Department of Energy.
14. Kumara, W A S, *Velocity And Turbulence Measurements Of Oilwater Flow In Horizontal And Slightly Inclined Pipes Using PIV*
15. Imperial College, *Simulation Of Intermittent Flow In Multiphase Oil And Gas Pipelines*