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RESEARCH ARTICLE

Comparative Study of Pressure Drop Model Equations for Fluid Flow in Pipes

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Abstract

Pressure loss calculation is a very important step in the pipeline design process. As fluid flows through a pipeline some pressure losses occur. These pressure losses are generally a result of viscous losses or dissipation. It is very important to know the pressure loss in a pipeline especially for cases in which the pipe is long. Pressure losses could also be caused by the presence of pipe fittings such as valves and bends in the pipeline.

In this thesis, the different equations available for the calculation of pressure loss in liquid line (oil, gas,)and two-phase (gas- oil, oil- water)fluid lines are discussed. The Weymouth, Panhandle A, Panhandle B and, Spitzglass equations are used to predict gas pressure loss. The modified Bernoulli/Fanning equation, Hazen-Williams and an empirical equation developed by Osisanya (2001) are used to predict pressure loss in liquid lines. The two phase gas- oil pressure loss calculation is carried out using an equation from the American Petroleum Institute (API) recommended practices and the Lockhart-Martinelli and Chisholm correlations while the two phase oil- water pressure loss was determined from three friction factor equations, Haaland, Nikrudase and Blasius.

The gas equations are observed to give varying results depending on the flow rate, pressure and pipe diameter. The liquid (oil and water) equations gave similar results with the accuracy of the results increasing with the pipeline diameter. The two-phase pressure loss prediction provides a good match with the data in the textbook for both the API and Lockhart-Martinelli methods.
In general, the gas equations give similar results for small diameter, low flow rate and low pressure problems. The liquid equations give more accurate results for larger diameter pipelines. The gas- oil mixture equations gave results that match the published data while the results obtained for the oil- water mixture were compared with one another.

INTRODUCTION

Background of Study

In the petroleum industry, transportation of the produced oil and gas from the wellhead to the production facilities as well as to the end-users (consumers) is a very important part of the production operations. The transportation can either occur in single phase or two phase and sometimes multiphase. The most common and safest means of transporting the oil and gas from the wells to the consumers is through pipelines. Pipeline is used to transport the fluids from the wellhead through different pieces of equipment taking into consideration the pressure requirements of the producer and customer.

It is highly desirable in pipeline design to be able to accurately predict this phase inversion point for the flowing oil-water system, since the pressure drop in the pipeline could greatly differ between an oil-in-water and a water-in-oil systems.

The basic steps in the pipeline design process are calculating the change in pressure along the pipeline, the line size, pressure rating, and selecting the pipe material. The piping material chosen is dependent on the properties of fluid to be transported, type of flow expected in the line, and the operating temperatures and pressures.

A number of pipelines are used depending on the function of the lines. Below is a general description of pipelines in the oil and gas industry.

a) Injection lines: Pipelines injecting water/steam/polymer/gas into the wells to improve the lift of fluids from the wells.

b) Flow lines: Pipelines from the well head to the nearest processing facility carrying the well fluids.

c) Trunk lines/ Inter field lines: Pipelines between two processing facilities or from pig trap to pig trap or from one block valve station to another processing facility.

d) Gathering lines: One or more segmental pipelines forming a network and connected from the well heads to processing facilities.

e) Subsea pipelines: Pipelines connecting the offshore production platforms to on-shore processing facilities.

f) Export lines / Loading lines: Pipelines carrying the hydrocarbons from the processing facility to the loading or export point.

g) Transmission pipelines: These are pipelines that are used to transport natural gas (methane) over several kilometers at the pressure of say 100bar

A thorough knowledge of relevant flow equations is very important for calculating pressure drop of the pipeline as these affect the economics of pipeline transportation. All the equations used in pipeline design require an understanding of the basic principles of flow regimes, Reynolds number (to indicate whether flow is laminar or turbulent), Bernoulli’s theorem, Moody friction factor and a general knowledge of the energy equations. As gas flows through a pipeline, the total energy contained in the gas is made up of energy due to velocity, pressure, and elevation. Modified Bernoulli’s equation based upon conservation of energy, connects these components of energy for the flowing oil and gas between two points.

Problem Description

Pipeline transportation is a very important part of the oil and gas industry and it is important to have a fast and efficient way of calculating the size and pressure requirements of the pipeline to use in transporting the fluids (oil and gas mixture). The aim of this study is to evaluate the accuracy of pipeline pressure loss equations and develop a software program using visual basic with Microsoft excel to ease the calculation of the pressure and size requirements of a pipeline for single phase(oil, water and gas) flow and two phase (gas- oil, oil- water) flow. There are numerous equations available for calculating the pressure drop across the pipeline for single phase and two-phase flows. Based on the review of the equations, appropriate ones for each of the phases will be selected.

Aims and objective of study

The major objectives of this study are as follows:
1. To evaluate available equations for pipeline calculations and to determine the most suitable equations for transportation of oil, water, gas and gas- oil, oil- water mixtures.
2. To write a visual basic program to ease the calculation of the pressure drop in the pipeline and to size pipelines.
3. To validate the calculation with field data as necessary.

These objectives will be achieved by doing a thorough review of the equations available for the transportation of gases, oil and oil mixtures (gas- oil, oil- water) mixtures in pipelines and comparing the predictions of these equations with measured data.

Chapter 2: THEORETICAL BACKGROUND LITERATURE REVIEW

Literature Review

A thorough understanding of some basic principles and equations is required for the calculation of pressure loss across a pipeline. These fundamental principles are used to derive equations for pressure loss across a pipeline. They include the use of dimensionless groups such as the Reynolds number and the Moody friction factor, modified Bernoulli’s theorem, Darcy’s equation and the concept of flow regimes.

Single Phase

a) Liquid Line (Oil, Water) Flow

The Reynolds number Re is a dimensionless number that gives a measure of the ratio of inertial forces to viscous forces and thus shows the contribution of these forces to fluid flow (Reynolds, 1844). The Reynolds number is an indicator of the flow regime of the flowing fluid. In general, less than 2100 implies laminar flow, greater than 4000 implies turbulent flow and a number in between is considered as transitional flow and can be either laminar or turbulent. Laminar flow occurs when there is little mixing of the flowing fluid, and this means that the fluid flows in parallel with the pipe wall.

The Bernoulli equation is another essential equation to fluid flow calculations. Bernoulli's principle states that for an inviscid (non-viscous) flow, an increase in the speed of the fluid occurs simultaneously with a decrease in pressure or a decrease in the fluid's potential energy.

(Bernoulli, 1738).The simplest form of the Bernoulli equation can be used for incompressible flow.

Darcy's equation in head loss form is another fundamental equation to fluid flow. It was first proposed by Darcy and modified by Weisbach in 1845. It related the head loss or pressure loss due to friction along a given pipe length to the average velocity of the fluid.

The Moody friction factor, credited to Moody (1944) after his study on friction factors for pipe flow is an important parameter in describing friction losses in pipe and open channel flow. It is highly dependent on the flow regime which is another reason why the Reynolds number is very important. The Moody chart relates the friction factor, f, Reynolds number, and relative roughness for fully developed flow in a circular pipe. It is used to calculate the pressure drop across the circular pipeline. The Moody chart can be divided into laminar and turbulent regions. For the laminar flow region, the friction factor is expressed as a function of the Reynolds number alone while for turbulent flow however, the friction factor is a function of Re and pipe roughness.

The majority of the material transported in pipelines is in the form of a liquid (crude oil). The pressure loss for liquid lines (oil and water) can be calculated using a variety of methods all based on the modified Bernoulli's equation. A simple empirical equation to calculate the pressure drop was developed by Osisanya (2001). This equation was developed based on the pressure recorded between a berth operating platform (BOP) and a single point mooring system (SPM). This equation was developed in order to select the right pipeline diameter to use to design a loading pipeline.

In the early stages of natural gas transportation, simple methods were used to calculate the pressure loss across pipeline due to the low pressure and small diameters of pipeline. As the industry developed over the last several years, demand for natural gas has increased and the need for more refined and exact equations to calculate pressure losses in larger-diameter, high-pressure pipelines with very high velocities and flow rate have been developed.

b) Gas Line

The general flow equation derived from the law of conservation of energy is the foundation of all equations used to calculate the pressure distribution in a gas pipeline (Katz et al, 1959). The main difference in the different pipeline equations for gas flow is the specification of the friction parameter.

Weymouth (1912) derived one of the first equations for the transmission of natural gas in high-pressure, high-flow rate, and large diameter pipes (Menon, 2005). Brown et al. (1950) modified the Weymouth equation to include compressibility factor. The compressibility factor is included in this equation because unlike liquids (oil and water) where the density is constant in the pipeline, the gas expands or contracts as it flows through the pipe and thus the density varies. The addition of heat or compressor stations to the pipeline also causes the density to decrease or increase respectively (Arnold and Stewart. 1986).

Previous studies (Hyman et al. 1976) have shown that the Weymouth equation can give a value for the pressure loss that is too high especially for large-diameter, low-velocity pipelines. This is because the friction factor correlation for the Weymouth equation is diameter dependent and is only useful for 36-in pipeline under fully turbulent flow conditions and is not recommended for use in calculating pressure loss for new pipelines (Asante, 2000).

The Panhandle A equation was developed in 1940 to be used in large- diameter, long-pipelines with high-pressure. This equation was initially developed based on data from the Texas

Panhandle gas pipeline in Chicago, which operated at 900 psi mostly under turbulent flow condition (Asante, 2000).

The modified Panhandle equation, usually referred to as the Panhandle B equation, was developed in 1956 for high flow rates. Both Panhandle equations are dependent on Reynolds number but the Panhandle B is less dependent than the former because it included implicit values for pipe roughness for each diameter to which it is applied. The disadvantage of the Panhandle equation as highlighted by Asante (2000) is that a good estimate of the efficiency factors is required and this can only be obtained from operating data. This equation is thus not recommended for planning purposes.

The Spitzglass equation (1912) was originally used in fuel gas piping calculations (Menon. 2005). There are two versions of this equation for low pressures and high pressures but it is generally used for near-atmospheric pressure lines. A study of this equation by Hyman et al. (1976) shows that, for pipe diameters over 10 inches, the Spitzglass equation gave misleading results. This is because the friction factor in this equation is diameter dependent and as the diameter increases, the friction factor also increases. For fully turbulent flow, the relative roughness is controlling and so as the diameter increases, the relative roughness decreases. This is what causes the error in the values obtained for the Spitzglass equation.

There are numerous other equations that have been developed to calculate or estimate pressure loss for gas flow in pipelines, because of the compressibility of gases. During flow through the pipeline compressed gas expands depending on the temperature both within and outside the pipeline. The friction factor and Reynolds number are very important in determining what equation to use to calculate the pressure loss. This study will compare the results obtained from the diameter dependent friction factor equations (Spitzglass and Weymouth equations) and the Reynolds number dependent friction factor equation (Panhandle A and B) for the flow of gas in pipelines.

Two Phase

a) Gas- Oil Flow

Two-phase gas-oil flow is a complex physical process that occurs extensively in petroleum industry and other industrial applications. The most important parameters when dealing with gas-oil flow are pipe geometry, physical properties of the gas and oil such as density and viscosity, and flow conditions such as velocity, temperature, and pressure (Meng et al. 1999). The stratified smooth, stratified wavy, intermittent (plug and slug flow), annular and dispersed bubble flow patterns can be observed in horizontal pipelines. The major problem when calculating the pressure loss for the flow of gas-oil mixtures is the presence of different flow patterns at different locations of the same pipeline. As the gas- oil mixture enters the pipeline, the heavier fluid (oil) tends to flow at the bottom.

Gas- oil flow is common within the wellbore when the fluid is flowing from the reservoir through the production tubing to the wellhead. Flow from the wellhead to separator is also gas-oil flow. Some offshore facilities such as ExxonMobil in Nigeria separate the oil, gas, and water on the platform to know the quantities of each phase present in the produced fluid. The oil and gas are then combined again and flowed to the onshore terminal. Other companies such as Chevron, producing in offshore Nigeria, first separate the crude into oil, gas, and water and flow only oil to the terminal. In both cases, there will be gas entrained in the oil to form a two phase flow because even when gas removal is attempted, it is never completely removed and so there is always a significant amount of gas left in the pipeline.

Lockhart and Martinelli (1949) proposed a correlation to solve horizontal multiphase flow problems. The foundation of their solution was in assuming that for a gas-oil system, the pressure drop is equal to that of one phase as if it were flowing alone in the pipe multiplied by a factor which was found to be a function of the ratio of the single phase pressure loss of the oil to the single phase pressure loss of the gas. Numerous other researchers such as Alves (1954), Baker (1954), Betuzzi et al (1956) tried to improve upon the work done by Lockhart and Martinelli (Katz et al. 1959). In two-phase gas-oil flow, the pressure drop can be defined as the sum of the pressure drop due to acceleration, friction, and elevation (Arnold and Stewart. 1986).

Generally, the pressure drop due to acceleration is negligible and the pressure loss due to friction is much larger than the sum of the equivalent pressure losses for the single phases. This additional frictional loss is due to the interfacial forces between the gas and oil phases. The pressure drop due to elevation is also an important factor because of the effect of elevation on oil holdup and thus the density of the mixture.

The American Petroleum Institute (API RP 14E) recommends an equation to calculate the pressure loss in gas- oil flow. This equation was developed based on the following assumptions: (i) ΔP is less that 10% of inlet pressure, (ii) the flow regime is bubble of mist; and (iii) there are no elevation changes. The equation is also derived from the general equation for isothermal flow.

Sarica and Shoham of the University of Tulsa worked on fluid flow and separation projects for an industry consortium. Research is being done on different aspects of multiphase flow and models have been developed for the analysis of multiphase fluid and their design and application to the petroleum engineering industry (2010).

b) Oil- Water (Liquid- Liquid)

Two phase liquid- liquid pipe flow is defined as the simultaneous flow of two immiscible liquids in pipes. Oil/water flow in pipes is a common occurrence in petroleum production, especially for old oil field and for enhanced oil recovery (EOR) with water injection (cold or hot). Moreover, two-phase liquid- liquid flow is common in the process and petrochemical industries. Although the accurate prediction of oil- water flow is essential, oil- water flow in pipes has not been explored as much as gas- liquid (gas- oil) flow. Models developed for gas- liquid systems cannot be readily used in liquid- liquid ones due to significant differences between them. The oil- water systems usually have large difference in viscosities, similar densities, and more complex interfacial chemistry compared to gas/liquid systems.

During the simultaneous flow of oil and water, a number of flow patterns can appear ranging from fully separated (or stratified) to fully dispersed ones (Lovick & Angeli, 2004). Stratified flow has received more attention during the past decades because of its low phase velocities and well-defined interface. On the other hand, fully dispersed flow can be modeled as a single-phase flow provided that the dispersion effective viscosity is properly estimated. There is limited information on the intermediate flow patterns, which lie in between stratified and fully dispersed flows.

A simple two-fluid oil/water pipe flow model was proposed by Zhang and Sarica (2006) as part of a three-phase unified model. Flat interface was assumed for the stratified oil/water flow. The transition from stratified flow to dispersed flow is based on the balance between the turbulent energy of the continuous phase and the surface free energy of the dispersed phase. The inversion point and effective viscosity of the dispersion are estimated to be using the Brinkman model (1952).

Charles and Redberger (1962) reported on the reduction of pressure gradients in oil pipelines with water addition. They measured a maximum reduction between 12 and 31% for different oils. These observations are among the first important studies of oil-water flow in pipes.

Studies of liquid-liquid flow in a pipe often include observation of flow patterns, that is, the shape and spatial distribution of the two-phase flow within the pipe. But even more important is the investigation of pressure drop. Today, measurements of the pressure gradient in the different flow patterns, as well as the development of models are subjected to a lot of research.

Through the years several investigators have contributed to the understanding of liquid-liquid flow in general and oil-water flow in particular. The inclination angle of the two-phase flow is one parameter that affects the flow pattern. Pure horizontal flow and pure vertical flow are often idealized cases. In reality, (gas)/oil/water flow in transport-pipes and wells often have an inclination angle different from 0 or 90 degrees.

Several models for prediction of pressure drop in liquid-liquid flow exist. Below, the two-fluid model for stratified flow and the homogeneous model for dispersed flow are presented. Among others, Brauner and MoalemMaron (1989) and Valle and Kvandal (1995) employed the two-fluid model for stratified flow on liquid-liquid systems. For dispersed liquid-liquid flow investigators like Mukherjee et al. (1981) and Valle and Utvik (1997) used the homogeneous model.

For the purpose of this study the friction factor governing the liquid- liquid flow is of most interest to us. The friction factors of both phases are calculated using the equation developed by Haaland (1983).Similarly the friction coefficient can be determined by inserting the mixture Reynolds number into for instance the Blasius equation. Nikrudase equation is also considered.

Theoretical background

This section deals with the theoretical background of the fundamental principles, concepts and equations used in pipeline pressure loss calculations. The chapter will review the theories used for the development of the equations for Single phase flow, (oil, water, and gas) and two-phase flow (gas-oil and oil- water) and how these equations will be applied in the development of the program to calculate pressure distribution in pipelines.

Single Phase Flow

Reynolds Number and Friction Factor

The Reynolds number Re is a dimensionless number that gives a measure of the ratio of inertial forces to viscous forces and thus shows the contribution of these forces to fluid flow. It is expressed in the general form as:

$$Re = \frac{Inertial\ Forces}{Viscous\ Forces} = \frac{(\frac{\rho V^2}{D})}{(\frac{\mu V}{D^2})} = \frac{\rho VD}{\mu} = \frac{VD}{v} = \frac{QD}{vA} \qquad 2.1$$

Reynolds Number= $Re = D v \rho / \mu$ 2.2

Where: Re= Reynolds number

D= internal diameter of pipe- inches

V= Mean fluid velocity- ft/ sec

ρ= density

μ= viscosity of fluid

v =kinematic viscosity= μ/ ρ

Q= volumetric flow rate

The Reynolds number can be expressed in different forms for liquid and gases. Equations (2.3), (2.4), and (2.5) give the Reynolds equation in field units for liquid (oil, water) and Equation (2.6) is for gas flow.

$$Re = 7738 \frac{SG * d * V}{\mu} \quad 2.3$$

$$Re = 7738 \frac{SG * Q_L}{\mu * d} \quad 2.4$$

$$Re = 928 \frac{\rho * d * V}{\mu} \quad 2.5$$

$$Re = 20100 \frac{S * Q_G}{\mu * d} \quad 2.6$$

The Reynolds number is very essential to describing the flow regimes of the flowing fluids and then used to determine the necessary equations to be used in the calculation of pressure loss. It is important to know what flow regime the fluid is in before selecting the equation to use to calculate pressure loss. To solve for problems in transitional flow, the values for transitional flow are obtained via interpolation between the laminar and turbulent flow values. Figures 2.1a and 2.1b represent the velocity profiles for laminar and turbulent flow respectively. In laminar flow the velocity profile is parabolic with the maximum velocity at the center of the pipe as shown in Figure 2.1a. For turbulent flow however, the layers of fluid completely mix and this results in a more uniform, slightly varying, velocity profile as shown in Figure 2.1b.

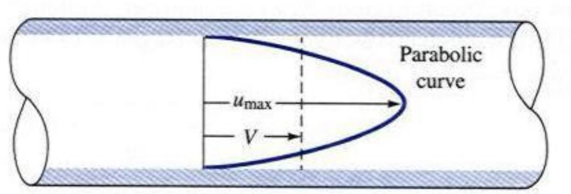

Figure 2.1a: Velocity profiles for Laminar flow

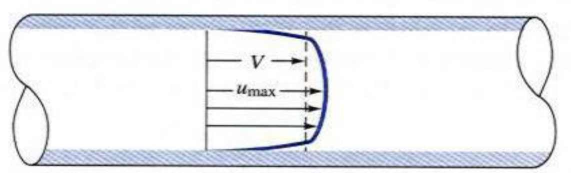

Figure 2.2b: Velocity profiles for Turbulent flow

Energy Equation

The simplest form of the energy equation for incompressible fluid is expressed as

$$Z_1 + \frac{P_1}{\rho_1 g} + \frac{{V_1}^2}{2g} = Z_2 + \frac{P_2}{\rho_2 g} + \frac{{V_2}^2}{2g} + H_L \quad 2.7$$

Darcy's Equation

Darcy's equation is another fundamental equation to fluid flow. Darcy's equation can be stated as follows:

$$H_L = \frac{fLV^2}{2gD} \quad 2.8$$

The above expression is called the Darcy equation in head loss form and another form of the equation called the pressure loss form. The equation in pressure loss form can be written as

$$\Delta P_f = 0.0013 \frac{f \rho L V^2}{d} \quad 2.9$$

Where

$$\Delta P_f = pressureloss, psi$$

Liquid Line Oil, water

The same equations were used for both oil and water throughout only in the Hazen Williams Equation where dimensional consistency was taken into consideration. The majority of the material transported in pipelines is in the form of oil (crude oil). The pressure drop for oil (water) lines can be calculated using a variety of methods all based on the energy equation or modified Bernoulli's Equation.

a) Bernoulli Equation

The equation for oil flow derived from the pressure loss form of Darcy's Equation, Eq. (2.8) can be used for both laminar and turbulent flow with the only difference being in the calculation of the friction factor.

$$\Delta \boldsymbol{P_f} = (\mathbf{11.5} * \mathbf{10^{-6}}) \frac{\boldsymbol{fLQ_L}^2(\boldsymbol{SG})}{\boldsymbol{d^5}} \qquad 2.10$$

b) Hazen Williams's Equation

The Hazen-Williams equation can be used to calculate pressure drop (P_1-P_2) in a liquid line is

$$\boldsymbol{Q_L} = \mathbf{0.148} * \boldsymbol{C_h} * \boldsymbol{d}^{\mathbf{2.63}} \left[\frac{\Delta \boldsymbol{P} - \Delta \boldsymbol{P_E}}{\boldsymbol{L} * \boldsymbol{SG}}\right]^{\mathbf{.54}} \qquad 2.11$$

C_h = Hazen Williams coefficient

ΔP_E = elevation changes correction, psia

Experiments and experience have shown that the Hazen-Williams equation does not give reasonable results when the Hazen-Williams coefficient is less than 90. Historical experimental data shows that C is a strong function of Reynolds number and pipe size and has narrow applicable ranges for these two values (Liou, 1998).

c) Empirical Equation

Another empirical equation developed by Osisanya (2001) is also available for calculating the liquid pipeline pressure loss. This equation was developed using actual oilfield data.

$$\Delta \boldsymbol{P_f} = \frac{\boldsymbol{Q_L} * \boldsymbol{V}^{\mathbf{0.253}} * \boldsymbol{SG_L}}{\mathbf{156.4} * \boldsymbol{d}^{\mathbf{4.748}}} \qquad 2.12$$

Gas Flow

The general flow equation derived from the law of conservation of energy in the form of modified Bernoulli's equation is the foundation of all equations used to calculate the pressure drop (P_1-P_2) in a gas. The general isothermal equation for gas expansion can be written as

$$w^2 = \left[\frac{144 g A^2}{\tilde{V}\left(\frac{fL}{D} + 2\log\left(\frac{P_1}{P_2}\right)\right)}\right] \left[\frac{{P_1}^2 - {P_2}^2}{P_1}\right] \qquad 2.13$$

Assuming that: i) there are no compressors, expanders, or elevation changes i.e. no work is done, ii) gas is flowing under steady state conditions, and iii) the friction factor is constant as a function of length. Equation 2.20 can be rewritten in field units as

$$Q_G = 0.199 \left[\frac{d^5({P_1}^2 - {P_2}^2)}{ZT_f fLS}\right] \qquad 2.14$$

The Weymouth, Spitzglass, and Panhandle equations are all modifications of Equation 2.14 in which the correlations discussed above are used to calculate the friction factor. The pressure drop will be calculated by subtracting the downstream pressure, P_2, from the upstream pressure, P_1 for each of the equation stated below.

$$\Delta P = P_1 - P_2$$

For all the equations used for gas a base temperature, T_b of 60°F is used in deriving the equations and this differs from the actual flowing temperature of the fluids in the pipeline, T_f.

a) Weymouth Equation

The Weymouth equation is generally applied to short lines within a production facility. In these lines, the gas velocity is generally low and thus the Re would be most likely low. These lines also have high-pressures, high-flow rates and large-diameters. The Weymouth equation is generally used within the production facility where the Reynolds number is expected to be high. The Weymouth equation in field units is

$$\boldsymbol{Q = 433.45E\left(\frac{T_b}{P_b}\right)d^{2.667} * \left[\frac{{P_1}^2-{P_2}^2}{GT_fL_eZ}\right]^{0.5}} \qquad 2.15$$

b) Panhandle A Equation

This equation was developed for use in natural gas pipelines for Reynolds numbers ranging from 5 to 11 million. The pipe roughness is not incorporated into this equation. It can be expressed in field units as

$$Q = 435.87E\left(\frac{T_b}{P_b}\right)^{1.0788} * \left[\frac{{P_1}^2-{P_2}^2}{G^{0.8539}T_fL_eZ}\right]^{0.5394} d^{2.6182} \qquad 2.16$$

c) Panhandle B Equation

This is also called the Modified Panhandle equation and is used for large diameter, high pressure pipelines. It is applicable for fully turbulent flow in the 4 to 40 million Re range. In this range, the pipe is assumed to be fully rough. In field units, it is expressed as:

The Panhandle B flow equation is given as:

$$\boldsymbol{Q = 737E\left(\frac{T_b}{P_b}\right)^{1.02} * \left[\frac{{P_1}^2-{P_2}^2}{G^{0.961}T_fL_eZ}\right]^{0.51} d^{2.53}} \qquad 2.17$$

d) Spitzglass Equation

The Spitzglass equation originally developed for use in fuel gas piping calculation is expressed in field units as:

$$\boldsymbol{Q = 729.6E\left(\frac{T_b}{P_b}\right) * \left[\frac{{P_1}^2-{P_2}^2}{GT_fL_eZ\left(1+\frac{3.6}{d}+.03d\right)}\right]^{0.5} d^{2.5}} \qquad 2.18$$

The Spitzglass equation is applicable mostly to pipelines that are at near atmospheric conditions and is most ideally suited for diameters less than 12 inches.

Two-Phase Flow

Some companies generally like to separate the gas from the oil as it flows out of the wellhead, while others especially on offshore platforms leave them to flow together. For this reason, two-phase gas- oil flow pressure drop is important.

2.2.2.1 Gas- Oil Flow

In the case of gas- oil flow, the gas may appear as tiny amounts of small bubbles in the oil. That kind of flow occurs when there is relatively little gas compared to oil, at the same time as the oil flows fast enough to create sufficient turbulence to mix the gas into the oil faster than the gas can rise to the top of the pipe.

There are several flow regimes available in gas- oil flow and Figure 2.2a shows some of these regimes. As the gas- oil mixture enters the pipeline, the heavier fluid tends to flow at the bottom.

Figure 2.2b shows the transition from one flow regime to another.

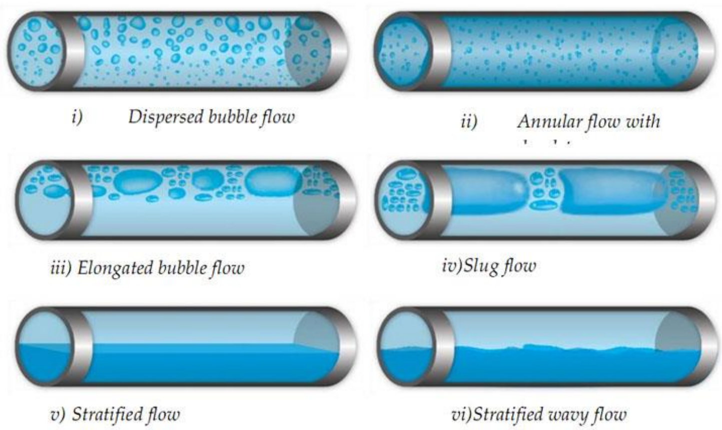

Figure 2.2a Gas-Oil flow regimes in horizontal pipes

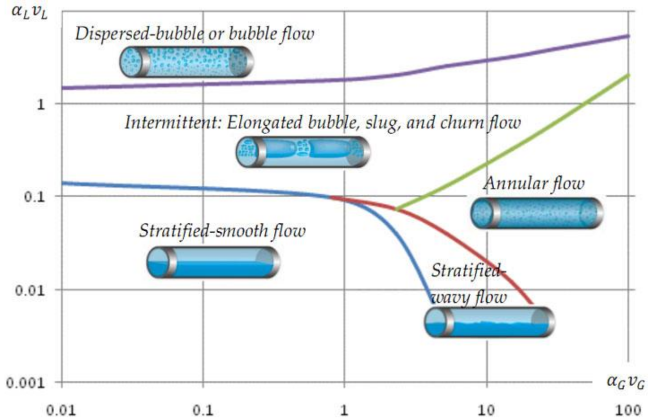

Figure 2.2b. Example of steady-state flow regime map for a horizontal pipe (Mandhane et al., 1974)

Similar flow regime maps can be drawn for vertical pipes and pipes with uphill or downhill inclinations. Notice that even though numerous measured and theoretically estimated such maps are published in literature, and although they can be made dimensionless under certain conditions (Taitel & Dukler, 1976), no one has succeeded in drawing any general maps valid for all diameters, inclinations and fluid properties. Therefore, a diagram valid for one particular situation (one point in one pipeline with one set of fluid data) is of little help when determining the flow regime for any other data set. That is why we need more general flow regime criteria rather than measured flow regime maps. For two phase, gas- oil flow, API and Lockhart-Martinelli Equations are employed.

a) API Two Phase Equation

The American Petroleum Institute (API) recommends the following equation to calculate the pressure loss in two-phase gas- oil flow. The equation is also derived from the general equation for isothermal flow.

$$\Delta \boldsymbol{P_f} = \frac{\mathbf{3.4 * 10^{-6}} \boldsymbol{fLW^2}}{\boldsymbol{\rho_m d^5}} \qquad 2.19$$

Where

L = length, ft

W = rate of flow of oil and vapour, lb_m/hr

$W = (3180 * Qg * SGg) + (14.6 * SG_L)$ 2.20

ρ_m = density of the mixture, lb_m/ft^3

$$\rho_m = \frac{(12409 * SG_L * P) + (2.7 * \frac{Qg*10^6}{Q_L} * SG_g * P)}{(198.7 * P) + (\frac{Qg*10^6}{Q_L} * T * z)} \quad 2.21$$

d = pipe ID, in

b) Lockhart-Martinelli

Another Approach to solving two-phase problems can be done using the Lockhart-Martinelli factor and the Total Pressure Gradient. The individual gas and Oil friction factors are calculated using the friction factor derived from equations developed by Haaland (1983) and Swamee-Jain (1976).

$$f = \frac{1.325}{\left[\ln(\left(\frac{\epsilon}{3.7d}\right) + \left(\frac{5.74}{Re^{0.9}}\right))\right]^2} \quad 2.22$$

The superficial velocities for the Oil and gas are calculated using equations (2.23) and (2.24) respectively.

$$V_{sl} = \frac{Q_L}{d^2} * 0.008938 \quad 2.23$$

$$V_{sg} = \frac{Q_g}{d^2} * 2121.32 \quad 2.24$$

The individual Pressure gradients for the Oil phase and pressure phase are calculated using equations (2.21) and (2.22) respectively.

$$dPdL_L = \frac{124.8 * SG_G * f_g * v^2{}_{sg}}{d} \quad 2.25$$

$$dPdL_G = \frac{124.8 * SG_L * f_l * v^2{}_{sl}}{d} \quad 2.26$$

The two phase multipliers are then calculated using the Lockhart-Martinelli factor and equations for two-phase multipliers developed by Chisholm (1967). The Lockhart-Martinelli factor is calculated by

$$x_n = \sqrt{\frac{dPdL_L}{dPdL_G}} \quad 2.27$$

The Chisholm Oil two-phase multiplier is calculated using

$$\emptyset_L = (1 + 18{x_n}^{-1} + {x_n}^{-2})^{0.5} \quad 2.28$$

The Chisholm gas two-phase multiplier is calculated using

$$\emptyset_G = (1 + 18{x_n}^{1} + {x_n}^{2})^{0.5} \quad 2.29$$

The total pressure loss is then calculated using equations (2.26) and (2.27) and the values obtained should be equal. This is then multiplied by the pipeline length and this gives the two-phase pressure drop.

$$dPdL_{L-Total} = dPdL_L * {\emptyset_L}^2 \quad 2.30$$

$$dPdL_{G-Total} = dPdL_G * {\emptyset_G}^2 \quad 2.31$$

The pressure loss is then calculated using

$$\Delta P_{2-phase} = dPdL_{Total} * L \quad 2.32$$

2.2.2.2 Oil- Water Flow

Oil/water flow is a common occurrence during production and transportation of petroleum fluids through pipes. Understanding of oil/water pipe flow behaviors is crucial to many applications including design and operation of flow lines and wells, separation, and interpretation of production logs.

For the purpose of this study a dispersed fluid flow pattern of the oil- water was considered. The pressure drop for each of the equations below is calculated using the friction factor. Water was emphasized at a constant velocity in order to emphasize the in order to emphasize the effect of water at constant mixture velocity. The values of the friction factor calculated for each of the equation are substituted into the given

$$\Delta P = \frac{Q\mu L d_i f}{2\pi} \qquad 2.33$$

a) Haaland Equation: This equation is generally used for all water cuts. The pipe roughness is assumed to be zero, hence the friction factor

$$\frac{1}{\sqrt{f}} = -1.8log\left(\frac{6.9}{Re}\right) \qquad 2.34$$

b) Blassius Equation:

$$f = 0.312(Re)^{-0.25}$$

c) Nikrudase Equation

$$f = 0.184(Re)^{-0.20} \qquad 2.35$$

$$Re_m = \frac{\rho_m * d_i * U_m}{\mu_m} \text{ Standard Units} \qquad 2.36$$

The mixture density is modeled by

$$\rho_m = \epsilon_w \rho_w + \epsilon_o \rho_o \qquad 2.37$$

By further expressing the mixture velocity as:

$$U_m = U_{so} + U_{sw} \qquad 2.38$$

Where U_{so} and U_{sw} represents the superficial velocity of oil phase and water phase respectively, that of water is put at a constant velocity.

The phase fractions assuming no slip are given by:

$$\epsilon_w = \frac{U_{sw}}{U_m} \epsilon_o = 1 - \epsilon_w \qquad 2.39$$

Table 2.1: Summary of all flow equations used

Single Phase	**Liquid line(oil, water)**	a) Bernoulli Equation $\Delta \boldsymbol{P_f} = (\mathbf{11.5 * 10^{-6}}) \frac{\boldsymbol{f L {Q_L}^2 (SG)}}{\boldsymbol{d^5}}$	b) Hazen Williams's Equation $\Delta P_{Hazen-Williams=} \frac{.015 * {Q_L}^{1.85} * L * 5280 * SG_L}{d^{4.87} * C^{1.85} * 144}$ for oil 3.4 $\Delta P_{Hazen-Williams=}\ 0.00208 (\frac{100}{C})^{1.85} (\frac{gpm}{d^{4.87}})^{1.85} L$ for water
		c) Empirical Equation $\Delta \boldsymbol{P_f} = \frac{\boldsymbol{Q_L * V^{0.253} * SG_L}}{\mathbf{156.4} * \boldsymbol{d^{4.748}}}$	
	Gas line	a) Weymouth Equation $P_{2,Weymouth} = \left[\frac{{P_1}^2 - G T_f L_e \left(\frac{Q_g}{0.0153 E * d^{2.667}}\right)}{e^s}\right]^{0.5}$	b) Panhandle A Equation $P_{2,Panhandle\ A} = \left[\frac{{P_1}^2 - G^{0.8539} T_f L_e Z \left(\frac{Q_g}{0.0204 E * d^{2.6182}}\right)}{e^s}\right]^{0.5}$
		c) Panhandle A Equation $P_{2,Panhandle\ B} = \left[\frac{{P_1}^2 - G^{0.961} T_f L_e Z \left(\frac{Q_g}{0.0279 E * d^{2.53}}\right)^{1/0.51}}{e^s}\right]^{0.5}$	d) Splitzglass Equation $P_{2,Splitzglass} = \left[\frac{{P_1}^2 - G^{0.961} T_f L_e Z \left(\frac{Q_g}{0.0279 E * d^{2.53}}\right)^{1/0.51}}{e^s}\right]^{0.5}$
Two Phase	**Gas- oil**	a) API $\Delta P = \frac{3.4 * 10^{-6} f L W^2}{\rho_m d^5}$ Where $W = (3180 * Qg * S) + (14.6 * S)$ $\rho_m = \frac{(12409 * SG_L * P) + (2.7 * \frac{Q_g * 10^6}{Q_L} * SG_g * P)}{(198.7 * P) + (\frac{Q_g * 10^6}{Q_L} * T * z)}$	b) Lockhart-Martinelli factor and Chisholm $f = \frac{1.325}{\left[\ln\left(\left(\frac{\epsilon}{3.7d}\right) + \left(\frac{5.74}{Re^{0.9}}\right)\right)\right]^2}$ $\Delta P_{2-phase} = dPdL_{Total} * L$
	Oil-water	a) Haaland Equation $\frac{1}{\sqrt{f}} = -1.8 log \left(\frac{6.9}{Re}\right)$	b) Blassius Equation $f = 0.312 (Re)^{-0.25}$ Blasius
		c) Nikrudase Equation $f = 0.184 (Re)^{-0.20}$ Nikrudase	

DEVELOPMENT OF THE PIPELINE PRESSURE DROP PROGRAM

Introduction to writing Program Calculator

The aim of the Microsoft Excel visual basic program is to calculate the pressure loss in pipelines carrying Oil, gas or a gas-Oil mixture. This program was developed using the theories and fundamental equations discussed in chapter two. This software is designed to aid in the designing of pipeline systems to operate at specific flow rate, temperature and pressure conditions. This chapter includes the description and writing of the program calculator. The program code is executed once the known parameters are entered into the excel spreadsheet. At the touch of the command button, the program calculates the compressibility factor, z, then the elevation factor, s, the equivalent length, and the downstream pressure and/or pressure drop. The first step in designing the program was to rewrite the equations discussed in chapter two in terms of the Pressure drop or downstream/outlet pressure.

Pressure Drop Calculation (Assumption and Flow Chart)

Single Phase flow

a) Liquid Oil and Water Flow Line

The following assumptions were made in developing the portion of the program for Oil and water pipelines.

Figure 3.1 shows the flowchart for the calculations for the liquid lines.

1. Base temperature of 60°F or 520°R
2. Base pressure of 1 atmosphere which is equal to 14.73 psia
3. Flowing temperature is constant within the pipeline
4. Oil and water viscosity and density remain constant.

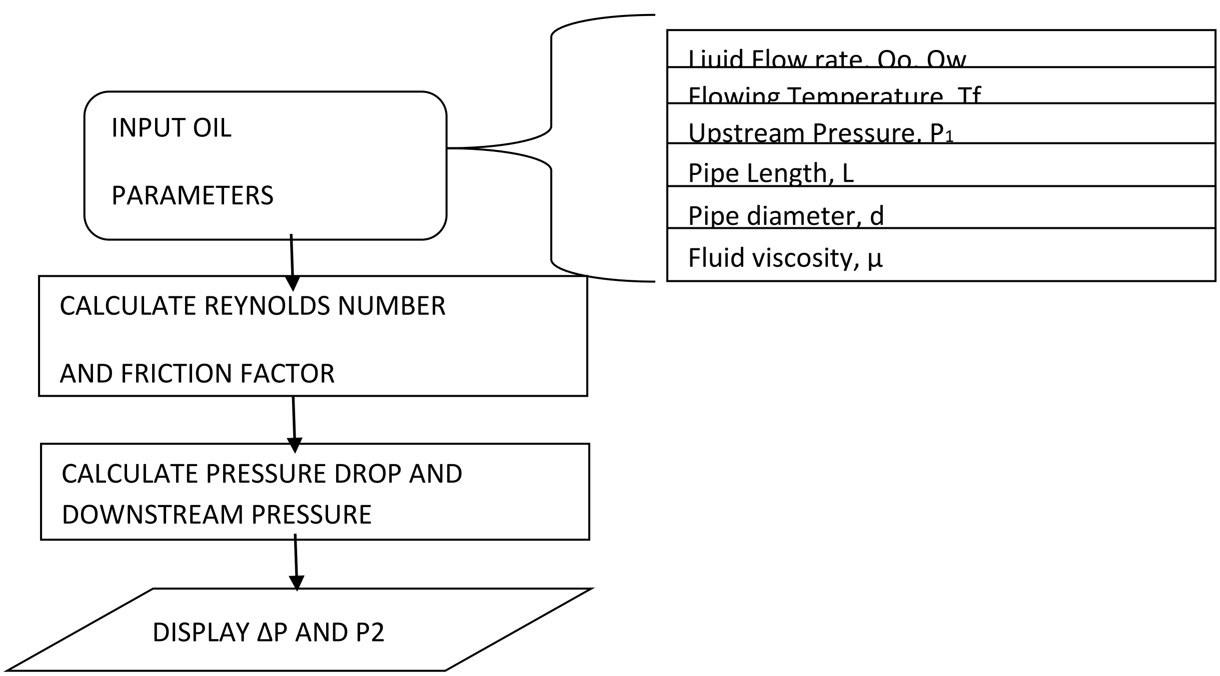

Figure 3.1: Oil Calculation Flowchart

b) Gas Flow line

For the gas transportation, the Weymouth, Panhandle A, Panhandle B, and Spitzglass equations will be used. These equations are selected based on the method of calculating the friction factor. Figure 3.2 shows the flowchart for the gas calculations.

The following assumptions were made in developing the portion of the program for gas pipelines:

1. Base temperature of 60°F or 520°R
2. Base pressure of 1 atmosphere which is equal to 14.73 psia
3. Efficiency factor, E, the different values of E are as follows

a. 1.0 brand new pipe

b. 0.95 good operating conditions

c. 0.92 for average operating conditions

d. 0.856 unfavourable operating conditions

4. Gas compressibility, z, varies with flowing temperature and upstream pressure
5. Flowing temperature is constant within the pipeline

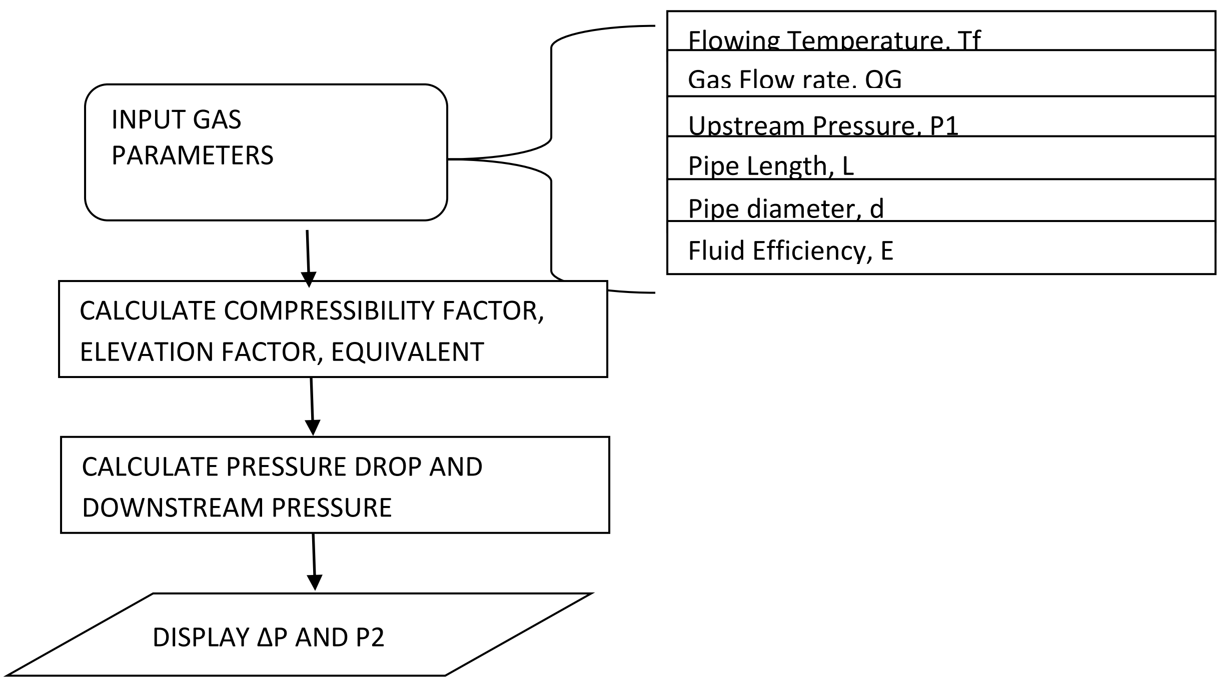

Figure 3.2: Gas Calculation Flowchart

Two-Phase Pressure Drop Calculation

The following assumptions were made in developing the portion of the program for two phase mixture pipelines:

a) Gas- Oil

Figure 3.3 shows the sequence of calculation for the gas- oil flow equations.

1. Base temperature of 60°F or 520°R

2. Base pressure of 1 atmosphere which is equal to 14.73 psia
3. Flowing temperature is constant within the pipeline
4. Oil viscosity and density remain constant.

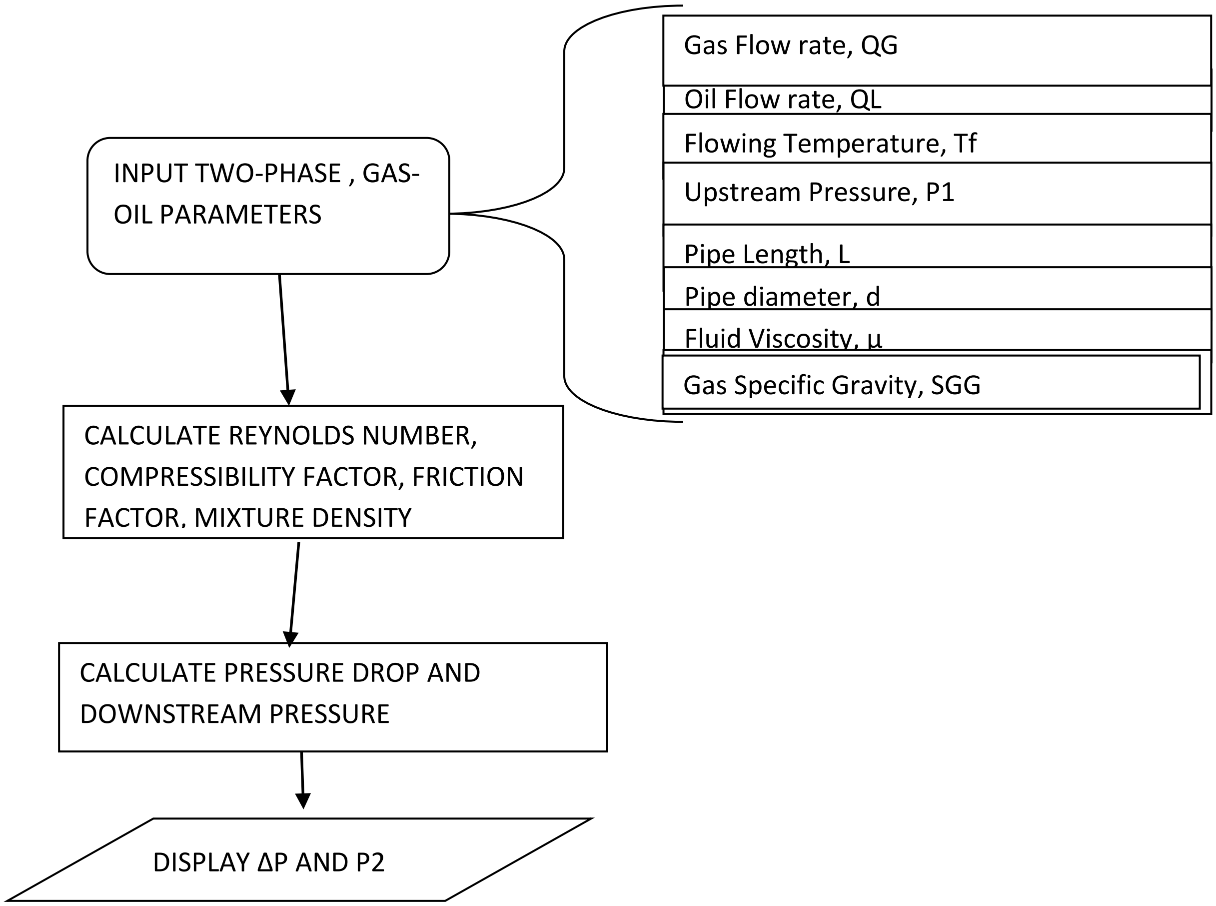

Figure 3.3: Two-Phase Calculation Flowchart

b) Oil- Water

Figure 3.4 shows the sequence of calculation for the oil- water flow equations.

1. relative viscosity, μ_r constant at 1.847
2. dispersed phase concentration, φ, viscosity equal to 100, $\varphi_{\mu=100}$= 0.765
3. Base temperature of 60°F or 520°R
4. Base pressure of 1 atmosphere which is equal to 14.73 psia

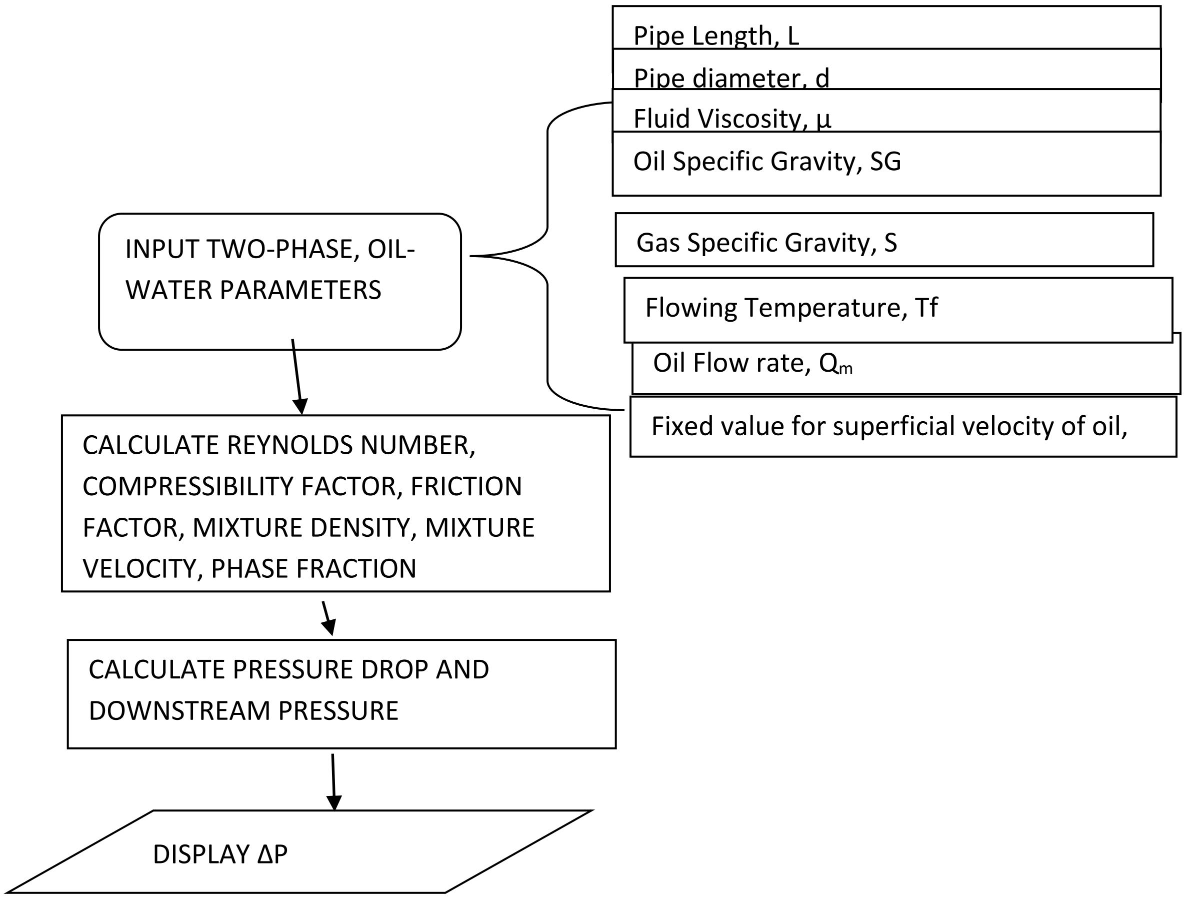

Figure 3.4: Two-Phase oil- water Calculation Flowchart

Equations Used in Program

This program uses simple equations and sub functions typed into the visual basic code to calculate the Pressure drop for the selected flow type as well as the downstream pressure, P_2. The equations used for the program are discussed below. The results of P_2 in psia versus the pipe length in miles are also displayed. In cases where actual pipeline data was available, the results are plotted with the data to show how well they correlate.

3.2.1 Single Phase flow

a) Liquid Oil and Water Flow Line

For the oil and water calculations the equations used are:

$$Re = 92.1\frac{SG_L * Q_L}{d * \mu} \quad 3.1$$

$$f = \frac{1.325}{\left[\ln\left(\frac{\epsilon}{3.7d} + \frac{5.7}{Re^{0.9}}\right)\right]} \quad 3.2$$

$$\Delta P_{Bernoulli} = (11.5 * 10^{-6})\frac{f * L * 5280 * (SG_L) * {Q_L}^2}{d^5} \quad 3.3$$

$\Delta P_{Hazen-Williams=}$ $\frac{.015*Q_L{}^{1.85}*L*5280*SG_L*62.4}{d^{4.87}*C^{1.85}*144}$ for oil 3.4

$\Delta P_{Hazen-Williams=}$ $0.00208(\frac{100}{C})^{1.85}(\frac{gpm}{d^{4.87}})^{1.85}L$for water 3.5

$\Delta P_{Empirical} = \frac{Q_L{}^{1.785}*V^{0.253}*SG_L}{156.4*d^{4.748}}$ 3.6

b) Gas Flowline

For gas, the following will be used:

$$P_{2,Weymouth} = \left[\frac{P_1{}^2-GT_fL_e\left(\frac{Q_g}{0.0153E*d^{2.667}}\right)}{e^S}\right]^{0.5}$$ 3.6

$$P_{2,Panhandle\ A} = \left[\frac{P_1{}^2-G^{0.8539}T_fL_eZ\left(\frac{Q_g}{0.0204E*d^{2.6182}}\right)}{e^S}\right]^{0.5}$$ 3.7

$$P_{2,Panhandle\ B} = \left[\frac{P_1{}^2-G^{0.961}T_fL_eZ\left(\frac{Q_g}{0.0279E*d^{2.53}}\right)^{1/0.51}}{e^S}\right]^{0.5}$$ 3.8

$$P_{2,Splitzglass} = \left[\frac{P_1{}^2-G^{0.961}T_fL_eZ\left(\frac{Q_g}{0.0279E*d^{2.53}}\right)^{1/0.51}}{e^S}\right]^{0.5}$$ 3.9

For all equations used in the gas calculation,

$\Delta P = P_1 - P_2$ 3.10

Two Phase Calculation Equations

a) Gas- oil

For Two-Phase the API RP 14E equation is used

$\Delta P = \frac{3.4*10^{-6}fLW^2}{\rho_m d^5}$ 3.11

Where

$W = (3180 * Qg * S) + (14.6 * SG_L)$ 3.11a

$$\rho_m = \frac{(12409* SG_L*P)+ (2.7*\frac{Q_g*10^6}{Q_L}*SG_g*P)}{(198.7*P)+(\frac{Q_g*10^6}{Q_L}*T*z)}$$ 3.11b

The Lockhart-Martinelli factor and Chisholm correlations developed discussed in chapter two are also used for the two-phase pressure drop calculations

b) Oil- water

$$\Delta P = \frac{Q\mu Ld_i f}{2\pi}$$

$\frac{1}{\sqrt{f}} = -1.8log\left(\frac{6.9}{Re}\right)$ Haaland

$f = 0.312(Re)^{-0.25}$ Blasius

$f = 0.184(Re)^{-0.20}$ Nikrudase

$Re_m = \frac{\rho_m*d_i*U_m}{\mu_m}$ Standard Units

The mixture density is modeled by

$$\rho_m = \epsilon_w \rho_w + \epsilon_o \rho_o$$

By further expressing the mixture velocity as:

U_m=$U_{so} + U_{sw}$

Where U_{so} and U_{sw}represents the superficial velocity of oil phase and water phase respectively.

The phase fractions assuming no slip are given by:

$$\epsilon_w = \frac{U_{sw}}{U_m} \epsilon_o = 1 - \epsilon_w$$

PROGRAM VALIDATION AND ANALYIS

Overview

The Program was validated in two stages that is for each of the flow phase. For the single phase, the first part of the validation was done for the oil lines using data obtained by Osisanya in a study to develop a simple empirical pipeline fluid flow equation based on actual oilfield data. Since no field data could be obtained for the water flow line, the pressure drop for Bernoulli's equation and Hazen Williams's equation were compared and the Osisanya empirical equation which was developed in 2001 for oil flow was put to test, if it will be applicable for water flow. There were three cases considered in the oil flow and four cases for water flow in this part using three different pipeline sizes. The second part of the validation was the done for the gas flow calculation portion of the program using data obtained from ONEOK Technical Services, Pipelines group. There were four case studies that were used to test the accuracy of the pressure drop equations for ideal operating conditions. The two-phase flow was validated for gas- oil and oil- water using different equations and comparison was made among the equations.

Single Phase
Oil flow equation Validation

The oil flow equations were validated using three different cases with different pipe diameters with the same oil flowing in each pipeline. The data was validated using results obtained by Osisanya (2001).The actual field data for a 42-inch diameter, 22 mile pipeline is shown in Table 4.1.

Table 4.1: Actual field Pressure data during a typical loading operation

Oil Loading Rates (Bbl/hr)	ΔP BOP-SPM (psi)	ΔP BOP-SPM (psi/mile)	ΔP BOP-SPM (psi) for 1.34 line
45000	204	9	12
56000	308	14	19
60000	359	16	22

The pressure drop is calculated between the Single Point Mooring (SPM) pressure gauge and the downstream Berth Operating Platform (BOP). The pressure drop values are shown in Table 4.2 and the results per mile of pipeline is also shown. Because field data was only available for the 42-inch pipeline, the oil flow equations were validated with a 36-inch and 24-inch pipeline as was done with the data in the paper in which the simple empirical equation was developed.

Table 4.2: Pressure drop from actual field data

Oil Loading Rates (Bbl/hr)	ΔP BOP-SPM (psi)	ΔP BOP-SPM (psi/mile)	ΔP BOP-SPM (psi) for 1.34 line
45000	204	9	12
56000	308	14	19
60000	359	16	22

The specific gravity and viscosity of the oil flowing in the pipelines and the internal pipe roughness of the pipes is given in Table 4.3.

Table 4.3: Common parameters for Oil Flow

Parameters	**Values**	Units
Flow rate, Q	1080000, 1344000, 1440000	BOPD
Specific Gravity (SG)	0.84	
Oil Viscosity (μ)	9.84	cP
Pipe Roughness, (ε)	0.00018	inches
Pipe diameter, (d)	42, 36, 24	inches
Length, (L)	1.34, 2.34,3.34	miles
pipe coefficient, (C)	140	
kinematic viscosity of oil (V)	17 (@25^{o}C)	cSt

a) Case 1: 42-inch Pipeline

The 42-inch pipeline pressure drop predictions are directly validated using the field data. The results are shown in Table 4.4. The results obtained for the 42 inch pipeline with an ID of 41-inches is presented in Tables 4.5 and 4.6. The predictions of the program are very similar to the results presented in Osisanya (2001). The average deviation for the modified Bernoulli equation is 3%, the average deviation for the Hazen-Williams equation is 0% and the average deviation for the Empirical model is 2%. These slight deviations can be neglected for all practical purposes since most pressure gauges record whole numbers and there are only very few pressure gauges that record data to more than 1 decimal point. The Hazen-William equation gives the best result for this large diameter (42-inch) pipeline.

Table 4.4: Program Validation with 42-inch Pipeline Data from Field Data

	ΔP actual (psi)	ΔP predicted (psi)			% Deviation from actual field data $=\left[\frac{\Delta P\ actual - \Delta P\ predicted}{\Delta P\ actual}\right] * 100\%$		
Flowrate, BPD		Bernoulli	Hazen-Williams	Osisanya	Bernoulli	Hazen-Williams	Osisanya
1080000	12	11	11	13	8	8	8
1344000	19	16	17	19	16	13	0
1440000	22	18	19	22	18	17	0

Table 4.5: Results obtained from 42-in Oil Line

		ΔP (psi) (Osisanya, 2001)			ΔP predicted (psi)		
Pipe Length, miles	Flow rate, BPD	Bernoulli	Hazen-Williams	Empirical	Bernoulli	Hazen-Williams	Empirical
1.34	1080000	11	11	13	11	11	13
2.34		19	20	22	19	20	23

3.00		24	25	29	24	25	29
1.34	1344000	16	17	19	16	17	19
2.34		28	29	33	28	29	33
3.00		36	37	42	35	38	43
1.34	1440000	18	19	21	18	19	22
2.34		32	33	37	31	33	38
3.00		41	43	47	40	43	48

Table 4.6: Deviation of PPDC from Osisanya Results for 42-in

		ΔP predicted (psi)			% Deviation from Osisanya (2001) Data= $\left[\frac{\Delta P\ Osisanya\ -\Delta P\ predicted}{\Delta P\ actual}\right] * 100\%$		
Pipe Length, miles	Flow rate, BPD	Bernoulli	Hazen-Williams	Empirical	Bernoulli	Hazen-Williams	Empirical
1.34	1080000	11	11	13	0	0	0
2.34		19	20	23	0	0	5
3.00		24	25	29	4	0	0
1.34	1344000	16	17	19	6	0	0
2.34		28	29	33	4	0	0
3.00		35	38	43	3	0	2
1.34	1440000	18	19	22	6	0	5
2.34		31	33	38	3	0	3
3.00		40	43	48	2	0	2

b) Case 2: 36-inch Pipeline

The results obtained for the 36-inch pipeline with an ID of 35.10-inches is shown in Tables 4.7 and 4.8. The results obtained for the program and the Osisanya's data vary a little more for this 36-in pipeline. The average deviation for the modified Bernoulli equation is 5%, the average deviation for the Hazen-Williams equation is 0% and the average deviation for the Empirical model is 0%. The higher deviation for the modified Bernoulli equation can be attributed to the calculation of the friction factor and pipe fitting losses that are not included in the equation.

Table 4.7: Results obtained for 36-in Oil Line

		ΔP (psi) (Osisanya, 2001)			ΔP predicted (psi)		
Pipe Length, miles	Flow rate, BPD	Bernoulli	Hazen-Williams	Empirical	Bernoulli	Hazen-Williams	Empirical
1.34	1080000	23	24	27	22	24	27
2.34		40	41	47	39	42	47
3.00		52	53	60	50	53	60
1.34	1344000	35	36	39	33	36	39

2.34		61	62	68	58	62	68
3.00		79	80	88	75	80	88
1.34	1440000	40	40	44	38	41	44
2.34		70	71	77	66	71	77
3.00		89	91	99	85	91	99

Table 4.8: Deviation of PPDC from Osisanya Results for 36-in

		ΔP predicted (psi)			% Deviation from Osisanya (2001) Data= $\left[\frac{\Delta P\ Osisanya - \Delta P\ predicted}{\Delta P\ actual}\right] * 100\%$		
Pipe Length, miles	Flow rate, BPD	Bernoulli	Hazen-Williams	Empirical	Bernoulli	Hazen-Williams	Empirical
1.34	1080000	22	24	27	4	0	0
2.34		39	42	47	3	2	0
3.00		50	53	60	4	0	0
1.34	1344000	33	36	39	6	0	0
2.34		58	62	68	5	0	0
3.00		75	80	88	5	0	0
1.34	1440000	38	41	44	5	0	0
2.34		66	71	77	6	0	0
3.00		85	91	99	4	0	0

c) Case 3: 24-inch Pipeline

The results obtained for the 24 inch pipeline with an ID of 23.30-inches is shown in Tables 4.9 and 4.10. The average deviation for the modified Bernoulli equation is 18%, the average deviation for the Hazen-Williams equation is 0% and the average deviation for the Empirical model is 6%. The predictions from each equation vary significantly. This can also be attributed to the same reasons for the discrepancies in the 36 inch diameter pipeline. The smaller diameter of the line makes the effect of the losses and friction factor even more pronounced.

Table 4.9: Results obtained for 24-in oil Line

		ΔP (psi) (Osisanya, 2001)			ΔP predicted (psi)		
Pipe Length, miles	Flow rate, BPD	Bernoulli	Hazen-Williams	Empirical	Bernoulli	Hazen-Williams	Empirical
1.34	1080000	197	175	199	162	175	187
2.34		344	306	347	283	306	326
3.00		441	392	445	362	392	418
1.34	1344000	293	262	291	241	262	274
2.34		512	458	421	421	458	478

3.00		656	587	540	540	588	613
1.34	1440000	332	298	275	275	300	310
2.34		580	521	480	480	523	542
3.00		743	667	616	616	671	695

Table 4.10: Deviation of PPDC from Osisanya Results for 24-in

		ΔP predicted (psi)			% Deviation from Osisanya (2001) Data= $\left[\frac{\Delta P\ Osisanya - \Delta P\ predicted}{\Delta P\ actual}\right] *$ 100%		
Pipe Length, miles	Flow rate, BPD	Bernoulli	Hazen-Williams	Empirical	Bernoulli	Hazen-Williams	Empirical
1.34	1080000	162	175	187	18	0	6
2.34		283	306	326	18	0	6
3.00		362	392	418	18	0	6
1.34	1344000	241	262	274	18	0	6
2.34		421	458	478	18	0	6
3.00		540	588	613	18	0	6
1.34	1440000	275	300	310	17	1	5
2.34		480	523	542	17	0	5
3.00		616	671	695	17	1	5

4.1.2 Water flow: The calculation and program development is still in progress.

a) Case 1: Pipe Size: 10in

Pipe length(mile)	Flow rate		ΔP(Bernoulli)	ΔP(Hazen Williams)	ΔP(Empirical)
	Hazen Williams (gpm)	Bernoulli, Empirical, Q_w (bbl/day)			
6.0	100	54857.14			
12.5					
20.0					
6.0	200	68571.43			
12.5					
20.0					
6.0	300	82285.71			
12.5					
20.0					

b) Case 2: pipe size: 16in

Pipe	Flow rate	ΔP(Bernoulli)	ΔP(Hazen	ΔP(Empirical)

length(mile)	Hazen Williams (gpm)	Bernoulli, Empirical Qw (bbl/day)		Williams)	
6.0	1600	54857.14	17.774	17.655	
12.5			37.03	36.782	
20.0			59.25	59.556	
6.0	2000	68571.43		26.68	
12.5				55.58027	
20.0				88.93	
6.0	2400	82285.71			
12.5					
20.0				124.6	

c) Case 3: pipe size: 24in

Pipe length(mile)	Flow rate,		ΔP(Bernoulli)	ΔP(Hazen Williams)	ΔP(Empirical)
	Hazen Williams (gpm)	Bernoulli, Empirical, Qw (bbl/day)			
6.0	1600	54857.14			
12.5					
20.0					
6.0	2000	68571.43			
12.5					
20.0					
6.0	2400	82285.71			
12.5					
20.0					

d) Case 4: pipe size: 30in

Pipe length(mile)	Flow rate,		ΔP(Bernoulli)	ΔP(Hazen Williams)	ΔP(Empirical)
	Hazen Williams (gpm)	Bernoulli, Empirical, Qw (bbl/day)			
6.0	1600	54857.14			
12.5					
20.0					
6.0	2000	68571.43			
12.5					

20.0					
6.0	2400	82285.71			
12.5					
20.0					

Program Validation for gas flow

a) Case Study 1

The data used for this case study is most suitable for the Panhandle A equation. The criteria for the best results from the Panhandle equation are

- Medium to large diameter pipeline
- Moderate gas flow rate
- Medium to high upstream pressure

The Input Parameters for this Case Study are shown in Table 4.11. Putting these values into the program gave the results in Table 4.12. The result shows that the downstream pressure closest to the field data is that obtained by the Weymouth equation. This value is approximately 18% more than the field data. The next closest match is the Panhandle A which is ideally supposed to be the closest match since the data fits the conditions for its use.

Table 4.11 Input Parameters for Gas Case 1

Parameters	*Values*	*Units*
Flow rate (Q_g)	*35*	*MMSCFD*
Pipe Inside Diameter	*10.192*	*in*
Length of pipe (L_m)	*5.212*	*Miles*
Length of pipe (Le)	*$2.751936*10^4$*	*ft*
Flow temperature(T_f)	*523*	*R*
Inlet Pressure(P_1)	*625.0*	*Psi*
Specific Gravity(S)	*0.6024*	
Upstream Elevation(H1)	*842*	*Ft*
Downstream Elevation (H2)	*831*	*ft*
Pipe Efficiency (E)	*0.92*	

Table 4.12: Results for Gas Case 1, $P_1=625.0psi$

	Downstream Pressure Output P_2 (psia)	**Pressure drop ΔP(psia)=** P_1- P_2	**%Deviation from Field Data**
ONEOK Field Data	598.5	26.5	
General Equation	621.5	3.5	87
Weymouth Equation	593.7	31.3	18
Panhandle AEquation	605.6	19.4	27
Panhandle B Equation	608.1	16.9	36
Spitzglass Equation	585.1	39.9	51

b) Case Study 2

The data for this case study is ideally most suitable for the Panhandle B equation. The criteria for obtaining the best results from the Panhandle B equation are

- Large Diameter

- High flow rate
- High pressure

The Input Parameters for this Case Study are shown in Table 4.13. Putting these values into the program gave the results in Table 4.14. It is observed in this case that the Weymouth equation also provides the closest results to the ONEOK data. The data from the other equations deviates greatly from the data with the Spitzglass equation being the least matched.

Table 4.13: Input parameters for Gas Case 2

Parameters	*Values*	*Units*
Flow rate (Q_g)	*482.2*	*MMSCFD*
Pipe Inside Diameter	*23.188*	*In*
Length of pipe (L_m)	*18.64*	*Miles*
Length of pipe (Le)	*$9.84192*10^4$*	*ft*
Flow temperature(T_f)	*518*	*R*
Inlet Pressure(P_1)	*1124.0*	*Psi*
Specific Gravity(S)	*0.6122*	
Upstream Elevation(H1)	*1054*	*Ft*
Downstream Elevation (H2)	*923*	*ft*
Pipe Eficiency (E)	*0.92*	

Table 4.14: Results for Gas Case 2, *P_1= 1124.0psi*

	Downstream Pressure Output P_2 (psia)	**Pressure drop ΔP(psia)**	**%Deviation from Field Data**
ONEOK Field Data	990.6	139.4	
General Equation	1035.42	88.58	37
Weymouth Equation	988.48	135.5	3
Panhandle A Equation	1040.88	83.1	40
Panhandle B Equation	1036.09	87.9	37
Spitzglass Equation	850.34	273.7	96

c) Case Study 3

The data for this case study is ideally most suitable for the Weymouth equation. The criteria for obtaining the best results from the Weymouth equation are

- Large Diameter
- High flow rate
- High pressure

The Input Parameters for this Case Study are shown in Table 4.15. Putting these values into the program gave the results in Table 4.16. For this case study, the Weymouth equation gives the best match while the Panhandle A and B equations give pressure drop values that are about 3 psi less that the field results. The Spitzglass equation as in the previous two cases gives the worse data for the pipeline pressure drop.

Table 4.15: Input parameters for Gas Case 3

Parameters	*Values*	*Units*
Flow rate (Q_g)	*508.6*	*MMSCFD*

Pipe Inside Diameter	*40.75*	*In*
Length of pipe (L_m)	*42.804*	*Miles*
Length of pipe (L_e)	*$2.2600512*10^5$*	*ft*
Flow temperature(T_f)	*512*	*R*
Inlet Pressure(P_1)	*1077.0*	*Psi*
Specific Gravity(S)	*0.6086*	
Upstream Elevation(H1)	*714*	*Ft*
Downstream Elevation (H2)	*594*	*ft*
Pipe Eficiency (E)	*0.92*	

Table 4.16: Results for Gas Case3, *P_1= 1077.0psi*

	Downstream Pressure Output P_2 (psia)	**Pressure drop ΔP(psia)**	**%Deviation from Field Data**
ONEOK Field Data	1062.1	13.9	
General Equation	1071.13	5.87	58
Weymouth Equation	1062.42	13.6	2
Panhandle A Equation	1065.36	10.8	22
Panhandle B Equation	1030.83	10.6	23
Spitzglass Equation	850.34	45.2	225

d) Case Study 4

The data for this case study is ideally most suitable for the Spitzglass equation. The criteria for obtaining the best results with this equation are

- Small Diameter
- Low flow rate
- Low pressure (usually around atmospheric pressure)

The Input Parameters for this Case Study are shown in Table 4.17. Putting these values into the program gave the results in Table 4.18. The pressure drop in this case study is for all practical purposes identical to the pressure drop obtained by the Panhandle B equation and very close to the data obtained by the other three equations. This pipeline has an inlet pressure that is very low and the conditions are best for the Spitzglass equation. This case study provides the best match for all the equations with the exception of the general equation. This is most likely a result of the low pressure, short pipeline with less elevation than the other previous pipelines.

Table 4.17: Input Parameters for Gas Case 4

Parameters	*Values*	*Units*
Flow rate (Q_g)	*2.4*	*MMSCFD*
Pipe Inside Diameter	*6.313*	*In*
Length of pipe (L_m)	*0.281*	*Miles*
Length of pipe (L_e)	*$1.48368*10^3$*	*ft*

Flow temperature(T_f)	*512*	*R*
Inlet Pressure(P_1)	*24.2*	*Psi*
Specific Gravity(S)	*0.6042*	
Upstream Elevation(H1)	*814*	*ft*
Downstream Elevation (H2)	*808*	*ft*
Pipe Efficiency (E)	*0.92*	

Table 4.18: Results for gas Case 4, $P_1 = 24.2psi$

	Downstream Pressure Output P_2 (psia)	**Pressure drop ΔP(psia)**	**%Deviation from Field Data**
ONEOK Field Data	22.7	1.5	
General Equation	24.2	0	150
Weymouth Equation	21.9	3.0	100
Panhandle A Equation	22.03	2.2	44
Panhandle B Equation	22.72	1.5	1
Spitzglass Equation	20.72	3.5	132

Two-Phase Program Validation
Gas- oil

The two phase gas-oil pressure drop calculator was developed using both the API RP equation and the Lockhart- Martinelli and Chisholm correlations. There was no field data available to test the two-phase calculator because most of the companies contacted separate out the phases and if there is any small amount of the removed fluid, the effect is neglected in the calculation. There was, however, an example problem available in Arnold and Stewart (1986) that was used to validate the program. The parameters used for the two-phase example are shown in Table 4.19.

Table 4.19: Gas- oil Input Data

	Parameters	**Values**	**Units**
Oil	Flow rate (Q)	1030	BPD
	Specific Gravity (SG)	0.91	
	Pipe diameter	6	In
	Oil viscosity(μ)	3	cP
	Length of pipe (L)	7022.4	miles
Gas	Flow rate (Q)	23	mmscfd
	Pipe diameter (d)	6	In
	Length of pipe (L)	1.33	Miles
	Flow temperature (T)	540	^oR
	Inlet Pressure (P_1)	900	Psi
	Specific Gravity (S)	0.85	
	Pipe roughness	0.0018	In
	Gas Viscosity	0.013	cP

The results published in the textbook (Arnold & Stewart. 1986) and the program predictions are shown in Table 4.20 for different pipe diameters. The published results obtained in the textbook are approximately equal to the predictions of the program. These results may not be ideal because they are textbook values which are usually designed to give good results.

Table 4.20: Two-Phase Results

	ΔP_(2-phase)(psi)			**%deviation**	
Pipe diameter(in)	Arnold & Stewart(1986)ΔP	$\Delta P_{predicted, L-M(psi)}$	$\Delta P_{predicted, API(psi)}$	For L-M	For API
4	392	393	393	0.3	0.3
6	52	56	53	7.7	1.9
8	12	14	13	16.7	8.3

Liquid- liquid (Oil- water) flow

The Halland equation gave off values when compared with the other two equations with percentage deviation of more the a 100, therefore it shall be neglected in the analysis. (The analysis is still in progress.)

a) **Case 1:** Pipe Diameter **2.5 inches**

Superficial velocity of water U_{sw}(m/s)	Flow rate (m^3/s)	ΔP(Nikrudase)	ΔP(Blassius)	ΔP(Halland)	ΔP(Nikrudase)-ΔP(Blassius
3.0	50	532.298	558.048	103.463	-25.75
5.5		494.989	509.591	94.8617	-14.602
10.0		453.544	456.827	84.8617	-3.283
3.0	70	745.218	781.267	144.848	-36.049
5.5		692.984	713.427	132.065	-20.443
10.0		634.692	639.558	118.806	-4.866
3.0	100	1064.600	1116.100	206.926	-51.5
5.5		989.977	1019.180	188.664	-29.203
10.0		907.089	913.655	169.723	-6.566

b) **Case 2:** Pipe Diameter **4.25 inches**

Superficial velocity of water U_{sw}(m/s)	Flow rate (m^3/s)	ΔP(Nikrudase)	ΔP(Blassius)	ΔP(Halland)	ΔP(Nikrudase)-ΔP(Blassius
3.0	50	813.794	830.822	153.90	
5.5		756.753	758.679	141.14	
10.0		693.392	680.125	127.784	
3.0	70	1139.31	1163.15	215.461	
5.5		1059.45	1062.15	197.596	
10.0		970.749	952.175	178.897	
3.0	100	1627.59	1661.64	307.801	
5.5		1513.51	1517.36	282.28	

10.0		1386.78	1360.25	255.568	

c) **Case 3:** Pipe Diameter **5 inches**

Superficial velocity of water U_{sw}(m/s)	Flow rate (m^3/s)	ΔP(Nikrudase) Nm/sec^2	ΔP(Blassius) Pascal	ΔP(Halland) Pascal	ΔP(Nikrudase) - ΔP(Blassius)
3.0	50	926.785	938.521	174.103	-11.736
5.5		861.825	857.026	159.93	4.799
10.0		789.666	768.289	145.057	21.377
3.0	70	1297.5	1313.93	243.744	-16.43
5.5		1206.56	1199.84	223.903	6.72
10.0		1105.53	1075.6	203.08	29.93
3.0	100	1853.57	1877.04	348.206	-23.47
5.5		1723.65	1714.05	319.861	9.6
10.0		1578.33	1536.58	290.115	41.75

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

Summary

The major objective of this study evaluate the pressure drop equations used in a pipeline design which will help in selecting the correct pipeline diameter for a given pipeline length. This objective was achieved in three phases. The first part involved doing a literature review of the equations currently being used and selecting the ones to be used in developing the program. The second part was the programming a calculator for some computation using Microsoft visual basic platform, and the third and final part involved validating the program using previously field data and equation comparism. The program was developed to calculate the pressure drop for single phase oil, water, gas, and two phase gas-oil, oil- water mixture pipelines. From the results obtained using the program and comparison of the results to the field or previously published data, the following conclusions were made.

Conclusions

1. The Weymouth equation gives reasonable results for pipeline diameters between 10 and 42 inches.
2. The Panhandle A and B equations work well for extreme conditions with high- diameters, high-flow rates and high-pressures or small-diameter, low-flow rates and low-pressures. The results obtained by both equations are very similar with the Panhandle A predicting slightly higher values for pressure drop. This might be due to the fact that the Panhandle A is equation is not as Reynolds number dependent as Panhandle B.
3. The Spitzglass equation is not suitable for large pipeline diameters. This equation gives an erroneous result for diameters larger than 10 inches.
4. The equations for the liquid flow (both oil and water) give very similar values and hence anyone of them can be used to predict pressure drop. This may be because the equations are not

dependent on the inlet pressure to calculate pressure drop. The results obtained were closer for the larger diameter (36 and 42-inch) in oil pipelines. No one equation can be considered the best for liquid pressure drop calculation as the results obtained from all three equations were almost identical.

5. The pressure drop for a fluid mixture cannot be calculated without considering the pressure drops for each phase individually, the textbook data matches the predicted results but this may have been designed to give good results and may not represent actual field data.

Recommendations

1. The effect of Reynolds number on pressure drop equations should be studied further especially in the case of the Panhandle A and B equations in which the friction factors are Reynolds number dependent.
2. Field data can be used to develop a modified general equation for flow of gas in pipelines that would take care of most or all the problems of each of the individual equations. The general equation available for now is not suitable at all for most conditions as it has been shown in section 4.1.3, table 4.11- 4.18
3. Additional work should be done on the effect of elevation on liquid lines. There are little or no equations available for elevated liquid pipelines in the industry.

NOMENCLATURE

A = pipe cross sectional area
BOP = Berth Operating Platform
C_h = Hazen- Williams coefficient
D = pipe ID, feet
d = pipe ID, inches
E = pipeline efficiency
f = Moody friction factor
f_f = Fanning friction factor
g = acceleration due to gravity (ft/sec^2)
G = specific gas gravity
H_L = head loss (ft)
L = pipe length
L_m= pipe length (miles)
L_e = pipe length (ft)
P = pipe pressure (psia)
P_1 = upstream pressure (psia)
P_2 = downstream pressure (psia)
P_b = base pressure (psia)
ΔP = pressure drop (psia)
ΔP_f = pressure drop due to friction
Q = volumetric flow rate
Q_g = gas flow rate (MMSCFD)
Q_L = liquid flow rate (bbd)
Q_o=oil flow rate (bbd)
Q_w=water flow rate(bbd or gpm)
Re = Reynolds number
SG, SG_L= specific gravity of liquid
SPM = Single Point Mooring
T_b = base temperature
T_f = average flowing temperature
$\tilde{V}$ = specific volume of gas
V = velocity
V_{sg} = superficial gas velocity
V_{sl} = superficial liquid velocity
w = rate of flow
W = rate of flow of liquid and vapour
Z = elevation head
z = gas compressibility factor

Greek Symbols
ε = internal pipe roughness
ρ = density
μ = viscosity
ν = dynamic viscosity
ρ_m = density of mixture

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