Comparative Analysis of Multiphase Pressure Drop Equations

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Abstract
The estimation of the pressure drop is quite important for effective design of well completions, production optimization and surface facilities. This study discussed different equations employed for the calculation of pressure drop in liquid, gas, and two-phase flow in pipes. A program for the calculation of pressure drop in a pipeline is developed using Microsoft Visual basic. The Hazen-Williams equation, Bernoulli equation and an empirical equation gotten from Coker are utilized in predicting pressure drop in liquid. The Weymouth, Panhandle A, Panhandle B and Spitzglass equations are used in predicting pressure drop in gas. An equation from the American Petroleum Institute (API) recommended practices and the Lockhart-Martinelli and Chisholm correlations are used in predicting the two-phase pressure drop. Comparing the predictions of these equations with measured data, the two-phase equations gives results that correspond with the published data used to validate the program. The gas equations give related results for small diameter, low flow rate and low pressure problems. The liquid equations give more precise results for larger diameter pipelines.

Keywords: *correlations, multiphase, pressure drop, panhandle A, panhandle B, two-phase flow, bottom-hole pressure*

1.0 Introduction

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 (Arnold, *et.al.*, 1986). 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. 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.

Multiphase flow in pipes is the process of simultaneous flow of two phases or more. In oil or gas production wells the multiphase flow usually consists of oil, gas and water (Christopher, 2005). The estimation of the pressure drop in wells is quite important for cost effective design of well completions, production optimization and surface facilities. However, due to the complexity of multiphase flow several approaches have been used to understand and analysis the multiphase flows. A thorough knowledge of relevant flow equations is very important for calculating capacity and pressure requirements 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.

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). This study objective is to evaluate available equations for pipeline calculations and determine the most suitable equations for transportation of oil, gas and gas-liquid mixture; develop a computer a program to calculate the pressure drop in the pipeline and to size pipelines. This study will be achieved by doing a thorough review of the equations available for the transportation of gases, liquids and gas-liquid mixtures in pipelines and comparing the predictions of these equations with measured data.

2.0 Fundamental Principles

A. *Reynolds Number*

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. 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 expressed in the general form as:

$$Re = \frac{Inertia\ Forces}{Viscous\ Forces} = \frac{\frac{\rho V^2}{D}}{\frac{\mu V}{D^2}} = \frac{\rho VD}{\mu} = \frac{VD}{v} = \frac{QD}{vA} \qquad (1)$$

Where,
Re = Reynolds number
ρ = density
V = velocity
D = internal diameter of pipe
μ = viscosity
ν = kinematic viscosity = μ/ ρ
Q = volumetric flow rate

The Reynolds number can be expressed in different forms for liquids and gases. Equations (2), (3), and (4) give the Reynolds equation in field units for liquids and Equation (5) is for gas flow

$$Re = 7738\frac{SG \times d \times V}{\mu} \qquad (2)$$

$$Re = 928\frac{\rho \times V \times d}{\mu} \qquad (3)$$

$$Re = 7738\frac{SG \times Q_L}{d \times \mu} \qquad (4)$$

Where,
μ = viscosity, cp
d = pipe ID, inches

V = velocity, ft/sec
S.G = specific gravity of liquid, dimensionless
Q_L = liquid flow rate, BPD
ρ = density, lbm/gal

$$Re = 20{,}100\frac{S \times Q_G}{d \times \mu} \quad (5)$$

Where,
QG = gas flow rate, MMscfd
S = specific gravity of gas at standard conditions (air = 1)
d = pipe ID, inches
μ = viscosity, cp

B. *Energy Equation*

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

$$Z_1 + \frac{P_1}{\rho_1 g} + \frac{V_1{}^2}{2g} = Z_2 + \frac{P_2}{\rho_2 g} + \frac{V_2{}^2}{2g}\ H_L \quad (6)$$

C. *Darcy-Weisbach's Equation*

Weisbach first proposed the equation we now know as the Darcy-Weisbach formula or Darcy-Weisbach equation:

$$h_f = f\,(L/D) \text{ x } (v^2/2g) \quad (7)$$

Where,
h_f = head loss (ft)
f = friction factor
L = length of pipe work (ft)
d = inner diameter of pipe work (ft)
v = velocity of fluid (ft/s)
g = acceleration due to gravity (ft/s²)

Although the Darcy Weisbach's equation is an empirical equation, it is also a dimensionally consistent equation.

D. *Friction Factor*

Fanning did much experimentation to provide data for friction factors, however the head loss calculation using the Fanning Friction factors has to be applied using the hydraulic radius equation (not the pipe diameter). The hydraulic radius calculation involves dividing the cross sectional area of flow by the wetted perimeter. For a round pipe with full flow the hydraulic radius is equal to 1/4 of the pipe diameter, so the head loss equation becomes:

$$h_f = f\ f(\frac{L}{Rh}) \text{ x } (\frac{v^2}{2g}) \quad (8)$$

Where,
R_h = hydraulic radius
f_f = Fanning friction factor

The work of many others including Poiseuille, Hagen, Reynolds, Prandtl, Colebrook and White have contributed to the development of formulae for calculation of friction factors and head loss due to friction.

The Darcy Friction factor (which is 4 times greater than the Fanning Friction factor) used with Weisbach equation has now become the standard head loss equation for calculating head loss in pipes where the flow is turbulent.

When Reynolds Number (NR) is less than 2000 flow in the pipe is laminar and friction factor is calculated with the following formula;

$$f = \frac{64}{Nr} \quad (9)$$

When Reynolds Number (NR) is greater or equal to 2000, the flow in the pipe becomes practically turbulent and the value of friction factor (f) then becomes less dependent on the Reynolds Number but more dependent on the relative roughness (e/D) of the pipe. The roughness height for certain common commercial pipe materials is provided in Table 1.

Table 1: Pipe Internal Roughness (Menon, 2005)

Pipe material	**Roughness, in.**	**Roughness, mm**
Riveted Steel	0.0354 - 0.354	0.9000 - 9.000
Commercial steel/welded steel	0.0018	0.0450
PVC, drawn tubing, glass	0.000059	0.0015
Cast Iron	0.0102	0.2600
Asphalted Cast Iron	0.0047	0.1200
Galvanized Iron	0.0059	0.1500
Concrete	0.0118 - 0.1180	0.3000 - 3.000
Wrought Iron	0.0018	0.0450

Also, the Colebrook-White equation which provides a mathematical method for calculation of the friction factor (for pipes that are neither totally smooth nor wholly rough) has the friction factor term f on both sides of the formula and is difficult to solve without trial and error (i.e. mathematical iteration is normally required to find f).

$$1/\sqrt{f} = 1.14 - 2\log_{10}\left(\frac{e}{D} + \frac{9.35}{Re\sqrt{f}}\right) \quad \text{for } Re > 4000 \quad (10)$$

Where,
f = friction factor
e = internal roughness of the pipe
D = inner diameter of pipe work

However, in 1944, LF Moody plotted the data from the Colebrook equation and this chart which is now known as ‘The Moody Chart’ or sometimes the Friction Factor Chart presented in figure 2.1 below, enables a user to plot the Reynolds number and the Relative Roughness of the pipe and to establish a reasonably accurate value of the friction factor for turbulent flow conditions.

E. *Liquid Flow*

The majority of the material transported in pipelines is in the form of liquids (crude oil). The pressure drop for liquid lines can be calculated using a variety of methods all based on the energy equation or modified Bernoulli’s Equation. The equation for liquid flow derived from the pressure loss form of Darcy’s Equation can be used for both laminar and turbulent flow with the only difference being in the calculation of the friction factor.

$$\Delta P_f = (11.5 \times 10^{-6}) \frac{f L Q_L^2 (SG)}{d^5} \quad (11)$$

Where,
ΔP_f = pressure loss, psi
f = Moody friction factor, dimensionless
L = pipe length, ft
Q_L = liquid flow rate, BOPD
SG = specific gravity of liquid
d = pipe ID, in

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.

$$\Delta P_f = \frac{Q^{1.748}{}_L \times V^{0.253} \times SG_L}{156.4 \times d^{4.748}} \quad (12)$$

Where,
ΔPf = pressure loss, psi
QL = liquid flow rate, BOPD
SGL = specific gravity of liquid
V = kinematic viscosity, centistokes
d = pipe ID, in

F. *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:

$$w^2 = \left[\frac{144\, g\, A^2}{\bar{V}_1 \left(\frac{fL}{D} + 2\log\left(\frac{P_1}{P_2}\right)\right)} \right] \left[\frac{P_1^2 - P_2^2}{P_1} \right] \quad (13)$$

Where,
w = rate of flow, lbm/sec
g = acceleration due to gravity, 32 ft/sec^2
A = cross sectional area, ft^2
Ṽ = specific volume of gas upstream, ft^3/lbm
f = friction factor, dimensionless
L = length, feet
D = pipe inside diameter, feet
P_1 = upstream pressure, psia
P_2 = downstream pressure, psia

i. *Weymouth Equation*

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 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 & 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 equation below is the general steady-flow equation for isothermal gas flow over a pipeline. It is generally attributed to Weymouth.

$$q_h = 3.23 \frac{T_b}{P_b}\left[\frac{(P_1{}^2 - P_2{}^2)D^5}{\Upsilon_g \check{z} T f L}\right]^{0.5} \quad (14)$$

Where,
Q_h = gas flow rate, cfh at P_b and T_b
T_b = base temperature, ^oR
P_b = base pressure, psia
P_1 = inlet pressure, psia
P_2 = outlet pressure, psia
D = inside diameter of pipe, in.
Υ_g = gas specific gravity (air = 1)
T = average flowing temperature, ^oR
F = moody friction factor
L = length of pipe, miles
Ž = gas deviation factor at average flowing temperature and average pressure

ii. Panhandle A Equation-Horizontal Flow

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 Panhandle A pipeline flow equation assumes that *f* varies as follows:

$$f = \frac{0.085}{N_{Re}^{0.147}} \quad (15)$$

The pipeline flow equation is thus;

$$q = 435.87\left(\frac{T_b}{p_b}\right)^{1.07881}\left(\frac{p_1^2 - p_2^2}{\bar{T}L\bar{z}}\right)^{0.5394}\left(\frac{1}{\gamma_g}\right)^{0.4604} D^{2.6182} \quad (16)$$

Where,
q = gas flow rate, cfd measured at T_b and p_b
NB: Other terms are as in Weymouth equation

iii. Modified Panhandle (Panhandle B) Equation-Horizontal Flow

This is probably the most widely used equation for long lines (transmission and delivery). 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 modified Panhandle equation assumes that *f* varies as

$$f = \frac{0.015}{N_{Re}^{0.0392}} \quad (17)$$

and results in

$$q = 737 \left(\frac{T_b}{p_b}\right)^{1.02} \left[\frac{p_1^2 - p_2^2}{\bar{T} L \bar{z} \gamma_g^{0.961}}\right]^{0.510} D^{2.530} \qquad (18)$$

iv. Spitzglass Equation

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.

$$P_{2,Spitzglass} = \left[\frac{P_1^2 - \left(GT_f L_e z \times \left(1 + \frac{3.6}{d} + 0.03d\right)\left(\frac{Q_g}{0.0279E \times d^{2.33}}\right)^2\right)}{e^s}\right]^{0.5} \qquad (19)$$

G. Two-Phase Flow

Two-phase flow in horizontal pipes differs markedly from that in vertical pipes; except for the Beggs and Brill correlation (Beggs & Brill, 1973), which can be applied for any flow direction, completely different correlations are used for horizontal flow than for vertical flow. The flow regime does not affect the pressure drop as significantly in horizontal flow as it does in vertical flow, because there is no potential energy contribution to the pressure drop in horizontal flow. The flow regime is considered in some pressure drop correlations and can affect production operations in other ways. Fig. 1 depicts the commonly described flow regimes in horizontal gas-liquid flow. These can be classified as three types of regimes: segregated flows, in which the two phases are for the most part separate; intermittent flows, in which gas and liquid are alternating; and distributive flows, in which one phase is dispersed in the other phase.

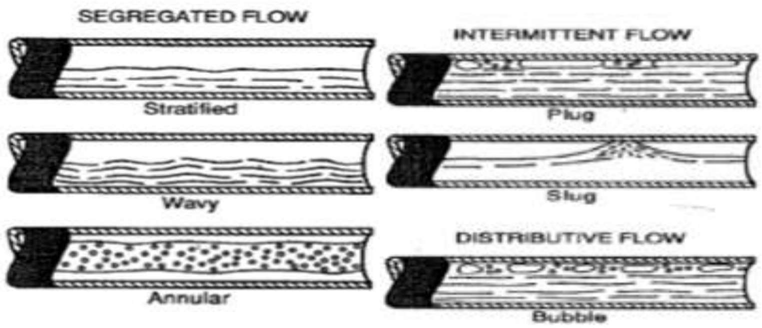

Fig. 1: Two-Phase Flow Patterns in Horizontal Flow (Brill and Beggs, 1973)

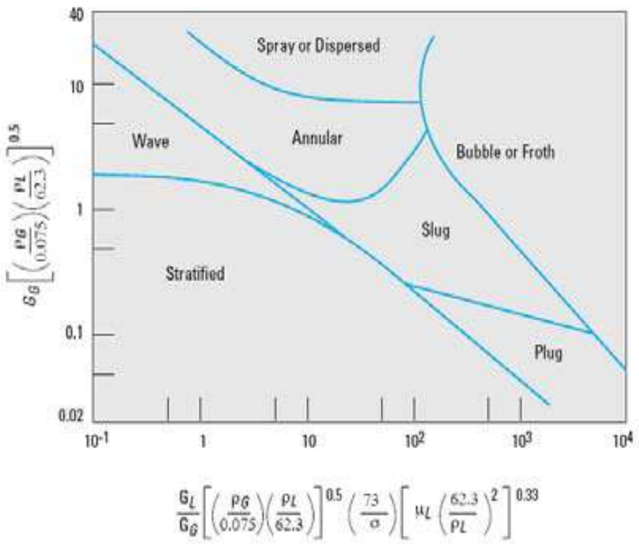

Fig. 2: Flow Pattern Maps for Horizontal

3.0 Pipeline Pressure Drop Program Analysis

The aim of the Pipeline Pressure Drop computer program is to calculate the pressure loss in pipelines carrying liquid, gas or a gas-liquid mixture at the touch of a button (i.e. user-friendly). This program is developed using the theories and fundamental equations discussed in precious sections. The software is designed to aid in the designing of pipeline systems to operate at specific flow rate, temperature and pressure conditions. The program code is executed once the known parameters are inputed. At the touch of the command button, the program calculates the compressibility factor, z, then the elevation factor, s, the equivalent length, and the pressure drop. The PipeΔP software aids in forecasting the amount of pressure loss and pressure drop in the pipe during transportation of fluids from one point to another. The program is written using VBA.

The first step in designing the program was to rewrite the equations discussed in the previous sections in terms of the Pressure drop. The 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 outlet pressure, P_2. Some of other equations used for the program are given below:

$$Re = 92.1\frac{SG_L \times Q_L}{d \times \mu} \quad (20)$$

$$f = \frac{1.325}{\left[\ln\left(\frac{\varepsilon}{3.7d}+\frac{5.7}{Re^{0.9}}\right)\right]^2} \quad (21)$$

$$\Delta P_{Bernoulli} = \left(11.5\times10^{-6}\right)\frac{f \times L \times 5280 \times Q_L^2 (SG_L)}{d^5} \quad (22)$$

$$\Delta P_{Hazen-Williams} = \frac{0.015 \times Q_L^{1.85} \times L \times 5280 \times SG_L \times 62.4}{d^{4.87} \times C^{1.85} \times 144} \quad (23)$$

1ΔP = $P_2 - P_1$. The results of P_2 in psia versus the pipe length in miles are also displayed. In cases where actual pipeline data were available, the results were plotted with the data to show how well they correlate. The preceding sections comprises of the validation of this program and includes a few case studies.

3.1 Discussions, Analysis and Program Validation

The first part of the program validation was done for the Liquid lines using published data obtained in a study to develop a simple empirical pipeline fluid flow equation based on actual oilfield data. There were three cases used in this part; using three different pipeline sizes. The second part was the done for the gas flow calculation portion of the program using anonymous data obtained from a Pipeline company. There were four case studies that were used to test the accuracy of the pressure drop equations for ideal operating conditions.

3.1.1 Liquid flow equation Validation

The Liquid flow equations were validated using three different cases with different pipe diameters with the same liquid flowing in each pipeline. The data was validated using published results obtained by Osisanya (2001).The field data for a 42-inch diameter, 22 mile pipeline is shown in table 2.

Table 2: Field Pressure data during a typical loading operation

Liquid Loading Rates (Bbl/hr)	Line Pressure (psi)	Pump Discharge Pressure (psi)	BOP upstream pressure (psi)	BOP Downstream pressure (psi)
45000	275	280	76	74
56000	375	390	82	80
60000	440	465	106	104

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 3 and the results per mile of pipeline is also shown. Because field data was only available for the 42-inch pipeline, the liquid 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 3: Pressure drop from actual field data

Liquid 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.

Table 4: Common parameters for Liquid Flow

Parameters	Values	Units
Specific Gravity (SG)	0.84	
Oil Viscosity (μ)	9.84	cp
Pipe Roughness (ε)	0.00018	inches

i. Case 1: 42-inch Pipeline

The 42-inch pipeline pressure drop predictions are directly validated using the field data. The results obtained for the 42 inch pipeline with an ID of 41-inches is presented in fig. 3. 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.

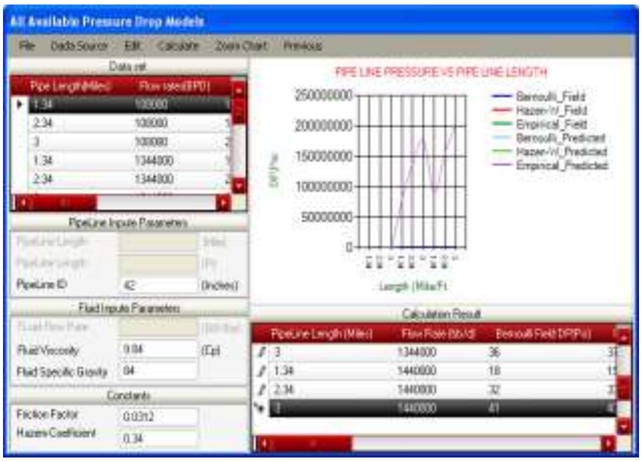

Fig. 3: Results obtained from 42-in Liquid Line

ii. Case 2: 36-inch Pipeline

The results obtained for the 36-inch pipeline with an ID of 35.10-inches is shown in fig. 4. 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.

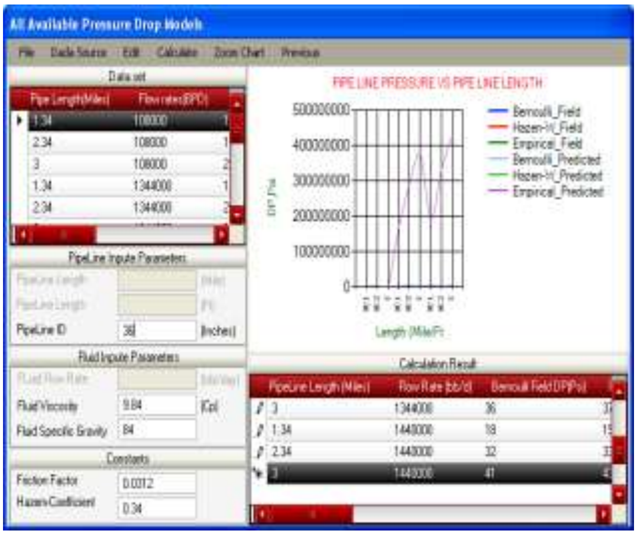

Fig. 4: Results obtained for 36-in Liquid Line

iii. Case 3: 24-inch Pipeline

The results obtained for the 24 inch pipeline with an ID of 23.30-inches is shown in fig. 5. 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.

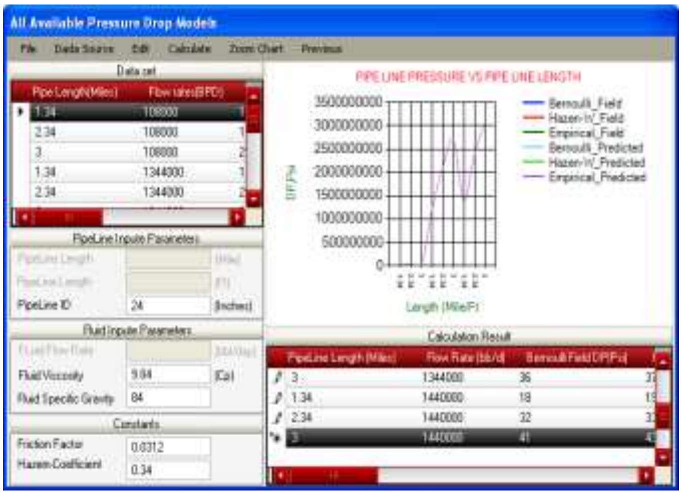

Fig. 5: Results obtained for 24-in liquid Line

3.1.2 Program Validation for Gas flow

i. 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 5. Putting these values into the program gave the results in fig. 6. It 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 5: Input Parameters for Gas Case 1

Parameters	**Values**
Flow rate (Q_g)	35.0 mmscfd
Pipe Inside Diameter (d)	10.192 in
Length of pipe (L)	5.212 miles
Flow Temp (T_f)	523 ^oR
Inlet Pressure (P_1)	625.0 psi
Specific Gravity (SG)	0.6024
Upstream Elevation (HI)	842 ft
Downstream Elevation (H2)	831 ft
Pipe Efficiency (E)	0.92

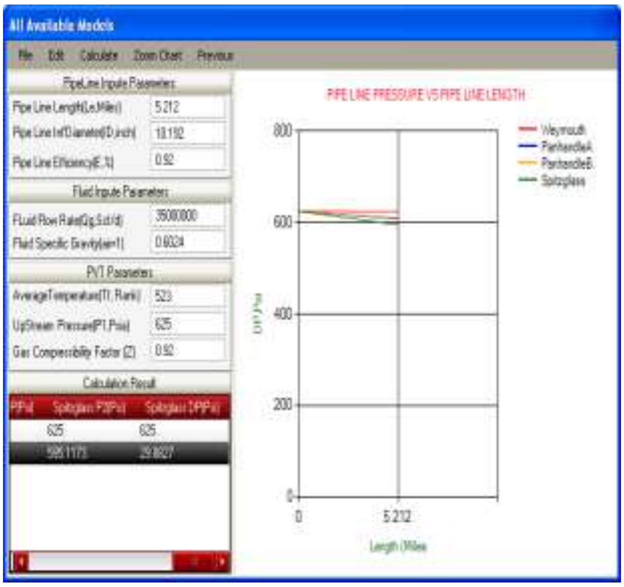

Fig. 6: Results for Gas Case 1

ii. 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 6. Putting these values into the program gave the results in fig.7. It is observed in this case that the Weymouth equation also provides the closest results to the anonymous Pipeline company's data. The data from the other equations deviates greatly from the data with the Spitzglass equation being the least matched.

Table 6: Input parameters for Gas Case 2

Parameters	**Values**
Flow rate (Q_g)	482.2 mmscfd
Pipe Inside Diameter (d)	23.188 in
Length of pipe (L)	18.64 miles
Flow Temp (T_f)	518 ^oR
Inlet Pressure (P_1)	1124.0 psi
Specific Gravity (SG)	0.6122
Upstream Elevation (HI)	1054 ft
Downstream Elevation (H2)	923 ft
Pipe Efficiency (E)	0.92

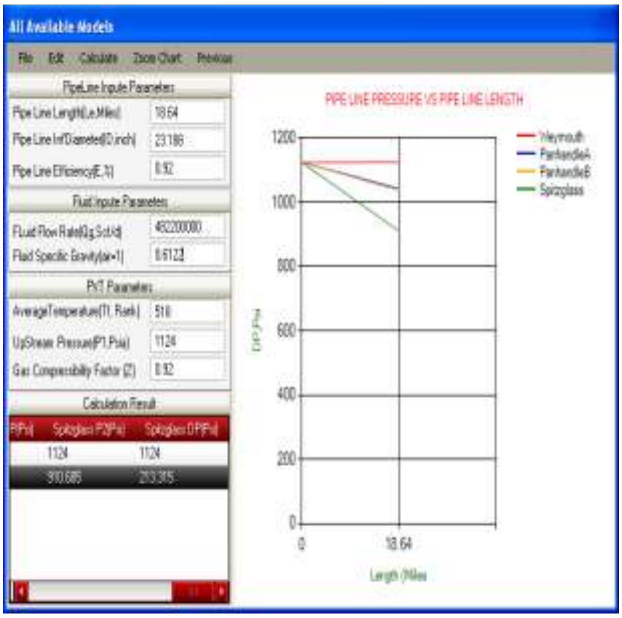

Fig. 7: Result for Gas Case 2

iii. 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 7. Putting these values into the program gave the results in fig. 8. 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 7: Input parameters for Gas Case 3

Parameters	**Values**
Flow rate (Q_g)	508.6 mmscfd
Pipe Inside Diameter (d)	40.75 in
Length of pipe (L)	42.804 miles
Flow Temp (T_f)	512 ^oR
Inlet Pressure (P_1)	1076.0 psi
Specific Gravity (SG)	0.6086
Upstream Elevation (HI)	714 ft
Downstream Elevation (H2)	504 ft
Pipe Efficiency (E)	0.92

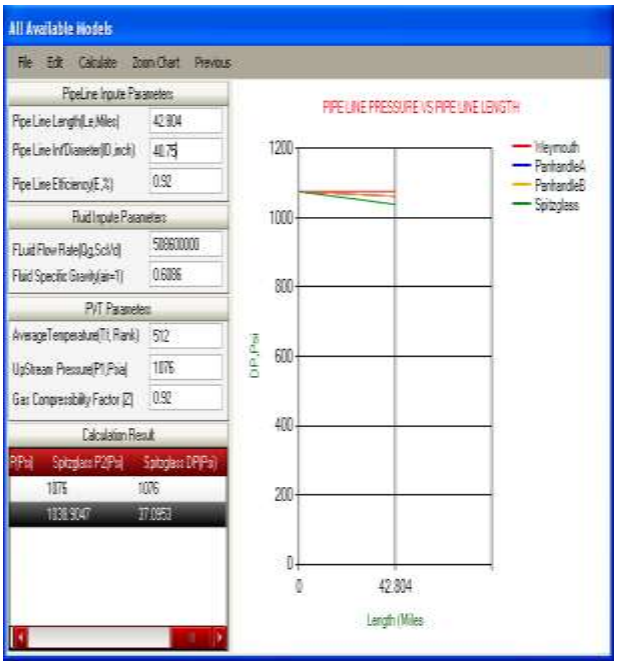

Fig. 8: Results for gas Case 3

iv. 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 8. Putting these values into the program gave the results in fig. 9. 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. This is most likely a result of the low pressure, short pipeline with less elevation than the other previous pipelines.

Table 8: Input Parameters for Gas Case 4

Parameters	**Values**
Flow rate (Q_g)	2.4 mmscfd
Pipe Inside Diameter (d)	6.313 in
Length of pipe (L)	0.281 miles
Flow Temp (T_f)	512 ^oR
Inlet Pressure (P_1)	24.2 psi
Specific Gravity (SG)	0.6042
Upstream Elevation (HI)	814 ft
Downstream Elevation (H2)	808 ft
Pipe Efficiency (E)	0.92

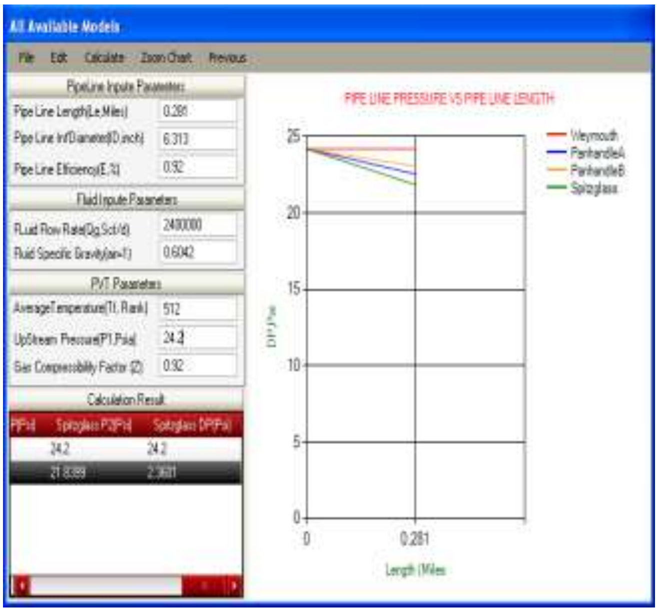

Fig. 9: Result for Gas Case 4

3.1.3 Two-Phase Program Validation

The two phase gas-liquid pressure drop calculator was developed using both the API RP equation and the Lockhart-Martinelli and Chisholm correlations. No field data was used to test the two-phase calculator; however an example problem available in Arnold and Stewart (1986) was used to validate the program. The parameters used for the two-phase example are shown in table 9 and the result for the program predictions is shown in fig. 10.

Table 9: Two-Phase Input Data

	Parameters	**Values**	**Units**
Liquid	Flow rate (Q_L)	1030	bpd
	Specific Gravity (SG_L)	0.91	
	Pipe Diameter (d)	6	In
	Length of pipe (L)	1.33	Miles
Gas	Flow rate (Q)	23	Mmscfd
	Pipe diameter (d)	6	In
	Length of pipe (L)	1.33	Miles
	Flow Temp (T)	540	R
	Specific Gravity (SG_G)	0.85	
	Inlet pressure (P_1)	900	Psi
	Gas viscosity	3	Cp
	Pipe roughness	0.0018	in

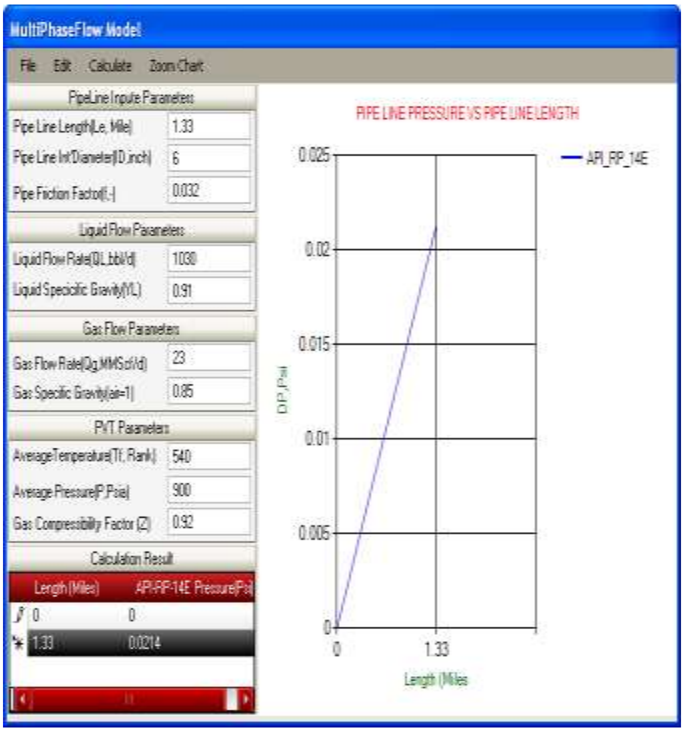

Fig. 10: Two-Phase Results

4.0 Conclusion

Despite numerous theoretical and experimental investigations, no general models are available that reliably predict two-phase pressure drops. In this study, the Weymouth equation gives reasonable results for pipeline diameters between 10 and 42 inches. Also, 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. 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 though there are expensive programs that can calculate this. 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.

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