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Basic Design and Simulation of Gas Production Pipelines

A Thesis

by

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To be submitted to:

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DEPARTMENT OF MINERAL RESOURCES ENGINEERING

The undersigned hereby certify that they have read and recommended to the Faculty of Mineral Resources Engineering for acceptance a thesis entitled "**Basic Design and Simulation of gas Production Pipelines**" by **Suleiman Ahmed Yusuf** in partial fulfillment of the requirements for the degree of **Master of Science**.

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Committee Members,

Dr. Marinakis

Prof. Varotsis

Dr. Gaganis

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Abstract

This research involves the modeling of a gas field through the use of the petex simulation software. The reservoir is modeled to estimate the reserves followed by modeling the wells to generate the Inflow performance curve and the vertical lift performance. Then followed by a thorough design of the pipelines that will deliver the gas to the separator from the wellheads.

The gas field in study consists of a single reservoir with four wells drilled for production. Two manifolds were used to connect producing fluid from the wells. The fluids were sent to a separator with an inlet pressure of 1000psig. The objective here is to develop a pipeline network that will satisfy the constraint and at the same time maximize the gas production.

Three sets of pipeline each with diameters 2inches 10inches and 20inches were studied. The simulation was conducted with individual pipe diameter and the result was analyzed and compared against the result of the other pipes in study. Economic Analysis was performed to determine the present worth of the three pipes in study before a conclusion was made.

The simulations show that increasing diameter increases the cumulative production but only up to a point after which the difference will not be significant. In this study, pipelines with diameter 20 inches increases the production more than the other two cases.

Table of Contents

Chapter 1: Basic of Natural Gas

1.0 Introduction

Natural gas unlike coal and oil is a gaseous phase fossil fuel. It is colorless, odorless, and lighter than air. During combustion, it is expected to release about 1,000 Btu (British thermal unit) per scf (standard cubic foot) and is used for domestic applications such as space heating, cooking and, increasingly, to generate electricity. Gas ignites in the presence of air at concentration between, between 5 and 15% natural gas. Natural gas contributes to about 24% of the world energy consumption as of 2017, and this will certainly increase with time.
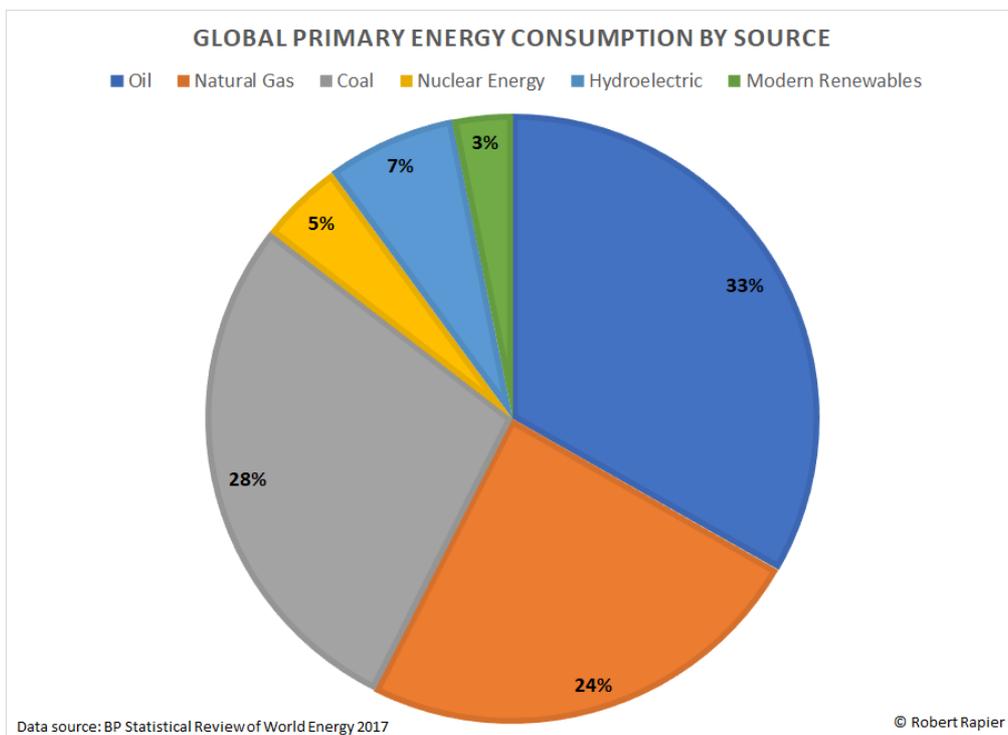

Figure 1.1 BP Statistical review of world energy 2017 (BP statistical review of world energy, 2017)

In comparison to oil and coal, it burns cleaner, more efficiently, and with lower levels of potentially harmful byproducts (CO, CO_2, SO_2, NO_X) that are released into the atmosphere. The deposit of natural gas around the world exceeds the deposit

of oil (Wang, 2000). The IEA (2012) estimates that there are nearly 404 trillion cubic meters (tcm) (14,285 trillion cubic feet (tcf)) of remaining recoverable resources (including all resource categories) of conventional gas worldwide, a value that is equivalent to almost 130 years of production at 2011 rates. There are very large deposits of natural gas labeled as "stranded''. Due to this reason, new technologies are now being used in gas exploration, field development, and production activities. What follows is a summary of basic petroleum geology, natural gas origins, resources, and properties.

1.1 Natural gas origin and accumulation

Like in the case of oil, natural gas has been generated from organic debris embedded along with organic matter that was buried at a considerate depth below the sea surface. This buried organic matter over time (million of years) gradually became coal, oil, or natural gas.

For a gas reservoir to exist, three key components must be identified: the **source rock**, which is the compacted organic material that will be converted to natural gas, the **reservoir** which is the porous media that will store the gas and an **impermeable rock** on top to trap the gas.

1.2 Natural gas composition and phase behavior

The composition of natural gas is characterize by high methane content with small quantities of ethane, propane, butane and pentane. Natural gas contains other non-hydrocarbon gases like carbon dioxide, oxygen, nitrogen, hydrogen sulfide and the traces of rare gases like (Ar, He, Ne, Xe). After being processed, natural gas will be almost pure methane. The phase envelope or the PVT diagram illustrates the phase

behavior. It is a function of three variables namely the temperature, pressure and volume. Below is definition of some concepts associated with phase behavior.

- **Bubble Point Curve** this is the curve that separates the liquid phase from the two-phase region. Pressure above the bubble point is only liquid while below it is a two-phase mixture. At a given temperature, when the pressure decreases, gas will be release and two-phase will be encountered.

- **Dew Point Curve** this the curve where the last droplet of liquid exist. Below the dew point, a single gas phase exists. The dew point curve separates the single-phase gas from the two-phase region.

- **Critical Point** this is a point on the phase envelope where the bubble and dew point curve meet. The pressure and temperature that prevail are termed as critical pressure and temperature respectively. At that given pressure and temperature, the gas properties are identical to the liquid properties.

- **Cricondentherm** this is the highest temperature at which liquid and vapor can coexist. If the temperature is greater than cricondentherm, the mixture will be gas irrespective of pressure.

- **Cricondenbar** this is the highest pressure at which a liquid and vapor can coexist. At pressure higher than the cricondenbar, the mixture will remain liquid irrespective of the temperature.
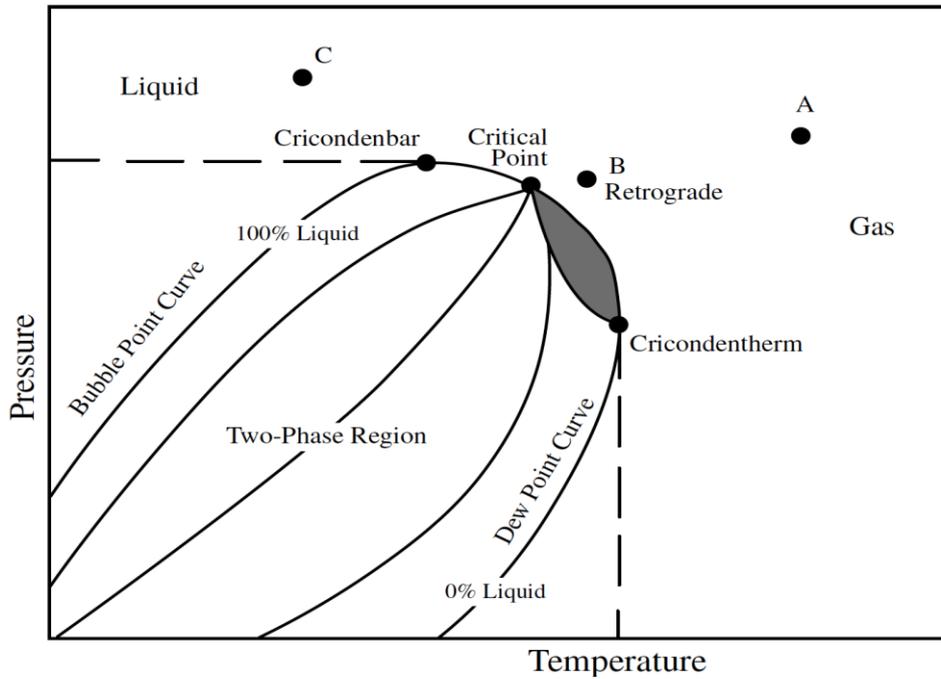
Figure 1.2 Phase diagram

1.2.1 Dry- and Wet-Gas Phase Behaviors

Under reservoir conditions, dry gas exists as a gaseous phase. Dry gas composes of mainly methane and lighter hydrocarbon like ethane and butane and little or no heavier compounds. When dry gas is produced in the surface, it will remain in gaseous phase with no liquid. Found in reservoirs where the temperature is above the critical temperature. Wet gas, on the other hand, will have liquid dropped out once it reaches the surface, which means that the surface conditions of pressure and temperature will fall inside the two-phase region.

1.2.2 Retrograde-Condensate-Gas Phase Behavior

Retrograde condensate systems and reservoirs are a phenomenon that appears among hydrocarbon mixtures. As pressure decreases from point B to the two-phase shaded area in Figure 1.2, the amount of liquid in the reservoir increases. As pressure decreases further, liquid starts to revaporize. Between the dew point and the point

where liquid revaporizes is the region (shaded area in Figure 1.2) of retrograde condensation (McCain, 1973). Many natural gas mixtures behave in this manner. During production from such reservoirs, the pressure gradient formed between the reservoir pressure and the flowing bottom hole pressure may reduce so as to result in liquid condensation and form a condensate bank around the wellbore, leading to reduce gas relative permeability and lower recovery.

1.2.3 Associated Gas Phase Behavior

At reservoir conditions, gas is dissolved in oil phase as associated phase. As production begins, and oil is produced to the surface under low pressure and temperature, the dissolved gas will be release. Under saturated oil reservoirs are reservoirs whose pressure is above the bubble point pressure (point C in Figure 1.2). If the pressure is inside the two-phase, the reservoirs are called saturated reservoirs and form a gas-cap on top of the oil zone.

1.3 Natural gas properties

1.3.1 Gas Specific Gravity

This is defined as the ratio of the molecular weight of the natural gas to that of air. Since a gas mixture contains several compounds, the molecular weight will be the summation of the products of the individual mole fractions times the molecular weights of each individual component. Air is a mixture of gases. The molecular weight of air has been calculated as 28.97.

In the industry, gas reservoir is sometimes called lean or rich gas reservoirs. A lean reservoir contains purely methane and ethane with very small traces of ethane and other light gases (Wang, 2000). Specific gravity of pure methane will be (16.04/28.97 =) 0.55. A lean gas reservoir has a low gas specific gravity where as a rich gas reservoir may exhibit a gas gravity value of 0.75 or, in some rare cases, as high as 0.9.

1.3.2 Gas deviation factor

A natural gas at reservoir temperature and pressure does not behave as ideal gas thus its behavior is that of a real gas.

$$pV = nRT \text{ (Ideal gas)} \qquad \text{(Eqn 1.10A)}$$

$$pV = ZnRT \text{ (Real gas)} \qquad \text{(Eqn 1.10B)}$$

Where:

P is pressure in psi,

V is the gas volume in ft3,

n is the number of moles of the gas

T is absolute temperature in Rankin

R is the universal gas constant and equals to 10.73 psi ft3/lb-mol-R.

Z is the gas deviation factor or "Z-factor"

The gas deviation factor is an important gas property and it is involved in calculating gas properties such as the formation volume factor, density, compressibility, and viscosity. All these properties are necessary in calculating initial

gas-in-place (and, thus, reserves), predicting future gas production, and **designing production tubing and pipelines**

1.3.2.1 Pseudo reduced Properties

Since gas is not a pure component, but rather a mixture of components. Critical temperature and pressure are referred to as Pseudo critical temperature and pressure. These properties can be calculated as

$$P_{PC} = \sum_{i=1}^{n} y_i P_{ci} \qquad\qquad \text{(Eqn 1.1)}$$

$$T_{PC} = \sum_{i=1}^{n} y_i T_{ci} \qquad\qquad \text{(Eqn 1.2)}$$

Pci and Tci denote the criticial pressure and temperature of the individual components. The temperature is given in rankine or kelvin. The pseudoreduced pressure and temperature can be calculated from the below equations after which Figure1.3 can be use to determine the deviation factor.

$$P_{pr} = \frac{P}{P_{pc}} \qquad\qquad \text{(Eqn 1.3)}$$

$$T_{pr} = \frac{T}{T_{pc}} \qquad\qquad \text{(Eqn 1.4)}$$
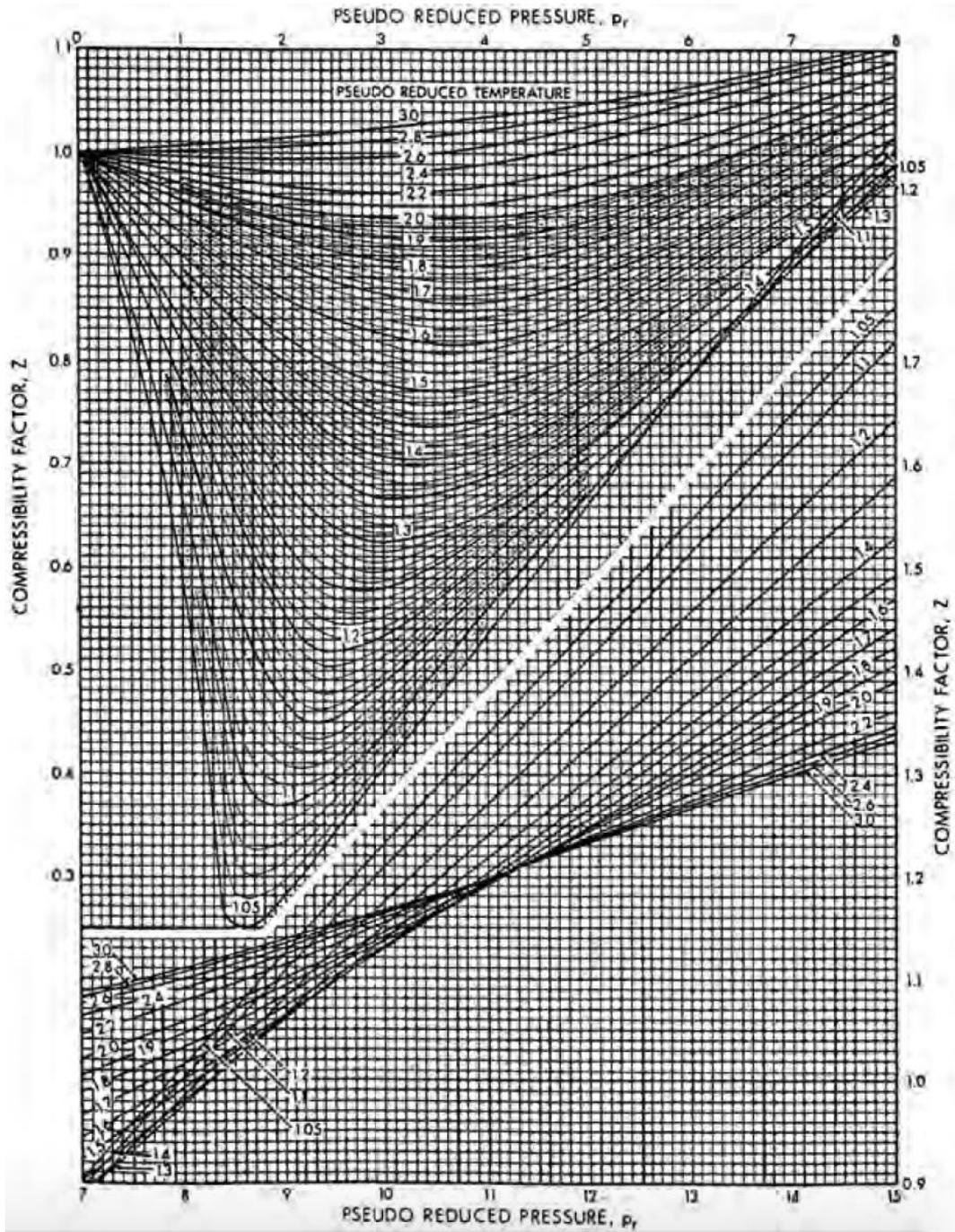
Figure 1.3 The gas deviation factor for natural gases (Standing and Katz, 1942)

1.3.3 Gas Formation Volume Factor

The gas formation volume fact, B_g, is used in relating the reservoir volume to the translated volume at standard conditions of the gas. The B_g is simply the ratio of

volume at reservoir condition to the volume at standard conditions of 60 °F and 14.6 psi. For a gas mixture, the equation of state for reservoir conditions and for standard conditions is used to determine the B_g

$$B_{g\,=}\frac{V}{V_{SC}} = \frac{ZnRT/P}{Z_{sc}nRT_{sc}/P_{sc}} \qquad \text{(Eqn 1.5)}$$

Where

B_g = gas formation volume factor

Z = gas deviation factor

R = universal gas constant

P = pressure

T = temperature

The gas in place Gi can be calculated if the initial gas formation volume factor (B_{gi}) is known.

$$G_i = 43560\frac{Ah\ \varphi Sg}{Bgi} \text{ (scf)} \qquad \text{(Eqn 1.6)}$$

Where A is the reservoir area in acres, h is reservoir net thickness in ft, φ is reservoir porosity, and Sg is gas saturation.

1.3.4 Gas Compressibility

The isothermal compressibility of gas has a thermodynamic expression as:

$$Cg = -\frac{1}{V}\left(\frac{dV}{dP}\right)T \qquad \text{(Eqn 1.7)}$$

Where

Cg = gas compressibility

V = volume

P = pressure

T= temperature

For an ideal gas, Cg is exactly equal to $1/P$. for a real gas, the compressibility can be calculated by the use of the equation of state.

$$\frac{dV}{dP} = -\frac{ZnRT}{P^2} + \frac{nRT}{P}\left(\frac{dV}{dP}\right)T \qquad \text{(Eqn 1.8)}$$

Introduce the volume from the real gas equation of state and the derivative dV/dP and substitute them into Eqn (1.7). This will give:

$$C_g = \frac{1}{P} - \frac{1}{Z}\left(\frac{dV}{dP}\right)T \qquad \text{(Eqn 1.9)}$$

Or more conveniently

$$Cg = \frac{1}{P} - \frac{1}{ZP\text{pc}}\left(\frac{dZ}{dP\text{pr}}\right)T \qquad \text{(Eqn 1.10)}$$

Where

Pc = critical pressure

Pr = reduced pressure

The above equation is the equation use in calculating the gas compressibility at any given condition of pressure and temperature.

1.3.5 Gas viscosity

Fluid resistance to flow is called viscosity. The viscosity of a gas will increase with pressure and temperature. This increase is small compare to oil or water thus gas will have a higher mobility in the reservoir than oil and water. There have been several correlations to find the viscosity of a gas. The figure below allows the viscosity to be determined at any given temperature for a fluid at 1 atm. Provided the composition of the gas is known, the mathematical equation below can be use to calculate the viscosity.

$$\mu_g = \frac{\sum \mu_{gi} y_i MW_i^{1/2}}{\sum y_i MW_i^{1/2}} \qquad \text{(Eqn 1.11)}$$
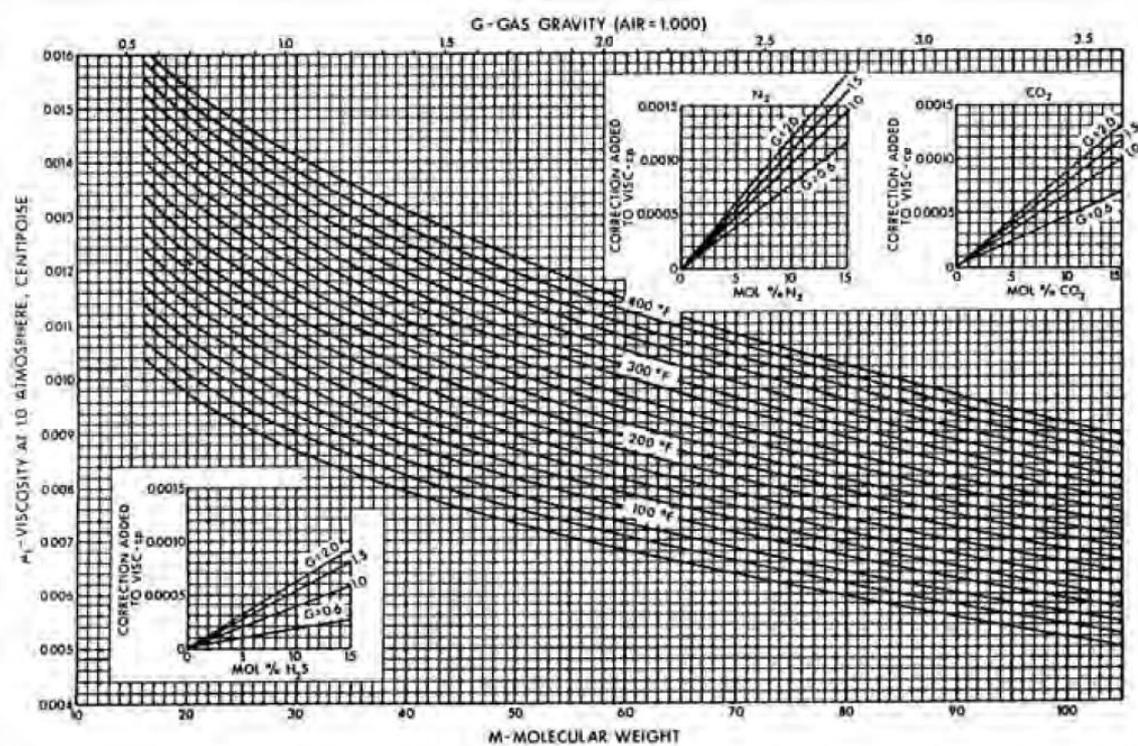
Figure 1.4 Viscosity of natural gases at 1 atm (Carr et al., 1954)
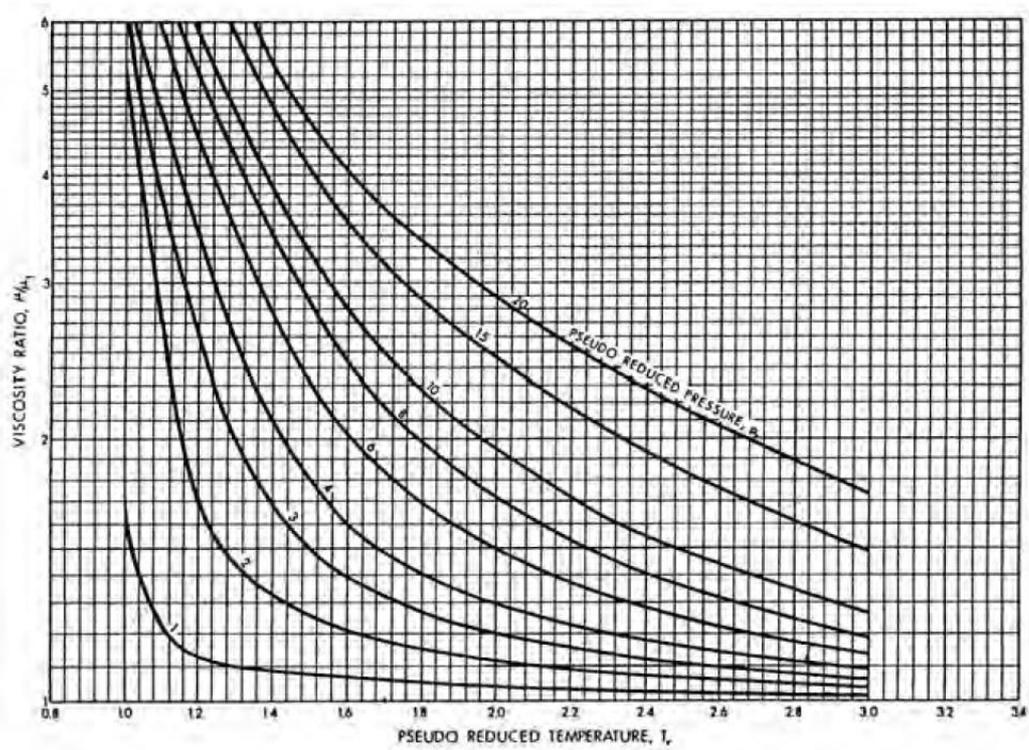
Figure 1.5 Viscosity ratio at elevated pressures and temperatures (Carr et al., 1954)

Figure 1. 5 is use to determine the viscosity for a conditions og higher pressure

(higher than 1 atm).

Chapter 2: MULTI PHASE FLOW

2.0 Introduction

Single-phase flow: When a fluid is single-phase, a constant density characterizes it. Viscosity has a high influence on single-phase fluid. Apart from viscosity, pipe roughness contributes significantly to the frictional pressure drop.

Two-phase flow is when vapor and liquid flow in a pipe simultaneously, the flow situation becomes much more complicated. Liquid and vapor phases will distribute according to flow conditions, pipeline geometry, and the effect of gravity. Correlations are used to predict the pressure drop in the case of a two-phase fluid but only with a certain degree of accuracy, especially in the case of an inclined system.

Multiphase flow is the flow involving two or more phases for example a flow involving mixture of gases, liquids, and particles. Multi phase flow is classified in four groups as:

1. Liquid-liquid or liquid gas flows; example of this category is bubbly flow, slug flow, and droplet flow.

2. Liquid-solid flows, example of this flow category is slurry flow when particles are being transported in liquid.

3. Gas-solid flow, example of this category is particle-laden flow which particles is dispersed flow with continuous flow (gas flow).

4. Three-phase flow combines the three categories above. For example it can be liquid-gas-solid or liquid-liquid-solid.

Multi phase flow prevails at different stage of oil and gas production, beginning from the extraction stage from wells to its transport via pipeline to the separator

2.1 Two Phase Gas –Liquid Flow

2.1.1 Introduction

The presence of multi phase complicates flow in comparison to a single-phase flow. In multi-phase flow where gas and liquid flow, the gas usually flows at a velocity higher than the liquid. Either phase may be in laminar or in turbulent flow, though the most important case is that in which both phases are turbulent. The criterion for laminar or turbulent flow of a phase is whether the Reynolds number for its flow at the same rate on its own is less than 2000 or greater than 4000.

2.1.2 Flow regimes and flow patterns

The diameter of the pipe, the physical properties of fluid and the flow rates are what influences the flow pattern. Flow changes from bubble flow to mist flow as the gas velocity increases as shown in figure 2.1. At high liquid-gas ratios, the liquid forms the continuous phase and at low values it forms the disperse phase. In the intervening region, there is generally some instability; and sometimes several flow regimes are superimposed together. In plug flow and slug flow, the gas is flowing faster than the liquid and liquid from slug tends to become detached, to move as a relatively slow moving film along the surface of the pipe and then to be reaccelerated when the next liquid slug catches it up. This process can account for a significant proportion of the total energy losses. Particularly in short pipelines, the flow develops a repeating pattern arising largely from discontinuities associated with the expulsion of successive liquid slugs.

| Regime | Description | Typical velocities (m/s) | |
		Liquid	Vapour
1. Bubble flow[a]	Bubbles of gas dispersed throughout the liquid	1.5–5	0.3–3
2. Plug flow[a]	Plugs of gas in liquid phase	0.6	<1.0
3. Stratified flow	Layer of liquid with a layer of gas above	<0.15	0.6–3
4. Wavy flow	As stratified but with a wavy interface due to higher velocities	<0.3	>5
5. Slug flow[a]	Slug of gas in liquid phase	Occurs over a wide range of velocities	
6. Annular flow[b]	Liquid film on inside walls with gas in centre		>6
7. Mist flow[b]	Liquid droplets dispersed in gas		>60

Table 2.1 Flow regimes in horizontal two-phase flow.
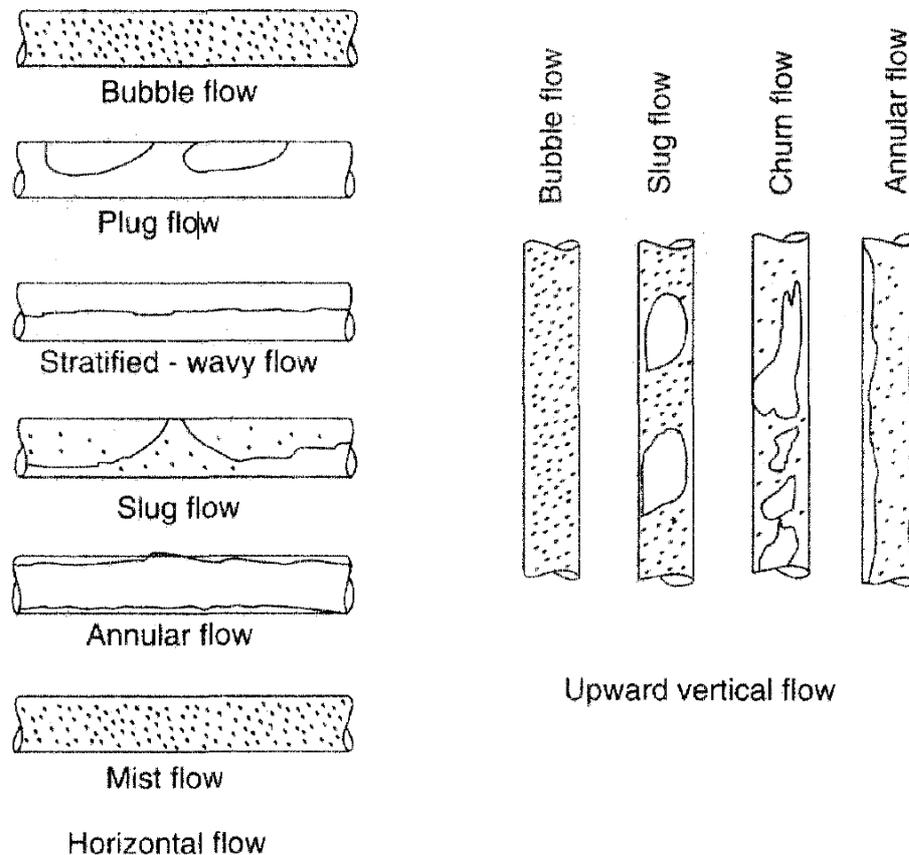
Figure 2.1 Flow patterns in two-phase flow.

The regions over which the different types of flow can occur are conveniently shown on figure 2.2 in which the superficial liquid velocity is plotted against the superficial gas velocity and boundary lines are drawn to delineate the various regions. It should be borne in mind that the distinction between any two-flow patterns is not

21

clear-cut and that these divisions are only approximate as each flow regime tends to merge in with its neighbours; in any case, the whole classification is based on highly subjective observations.
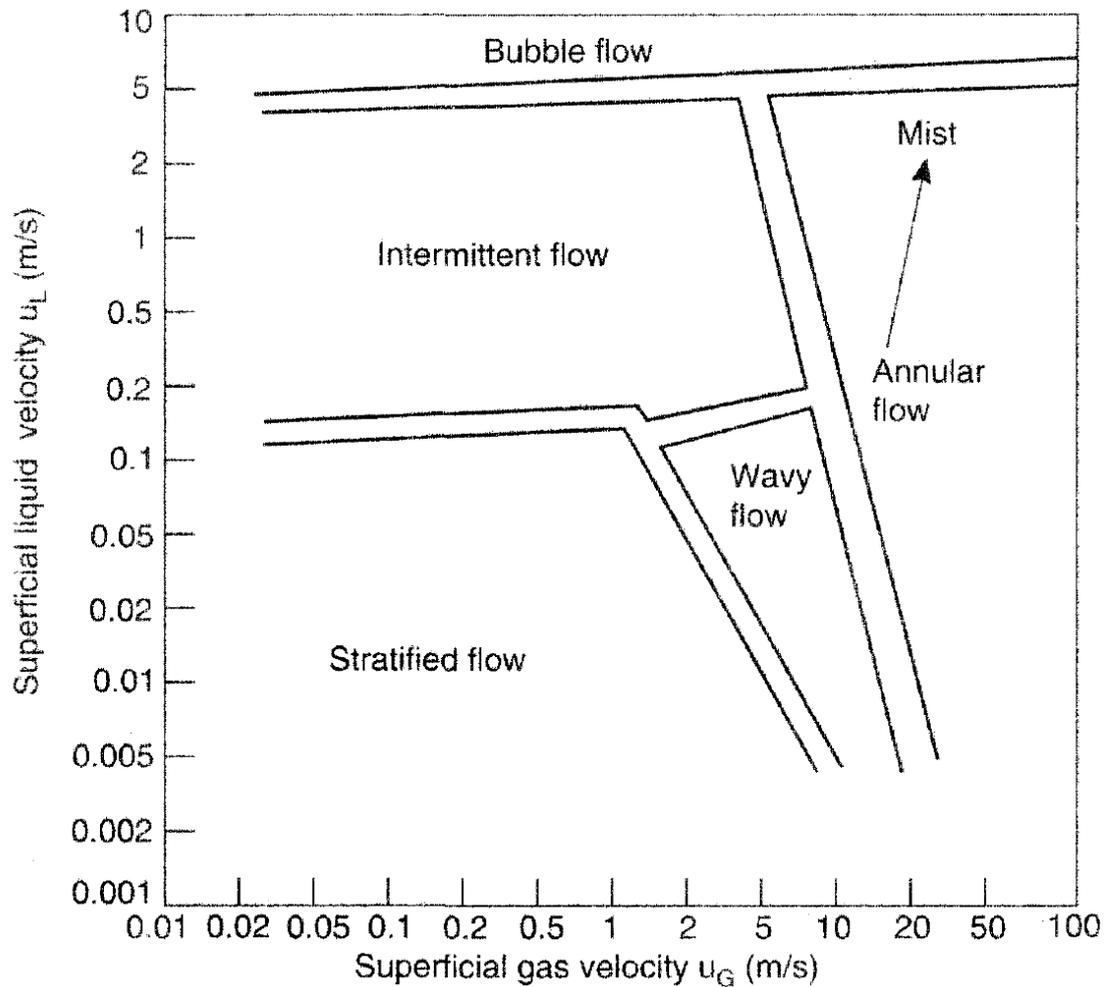
Figure 2.2 Flow Pattern Map

Vertical flow

In vertical flow, the flow is more stable as a result of axial symmetry. This is different in the case of slug flow. When liquids slugs are discharged, there is a sudden change in pressure and this causes oscillation in the flow.

2.1.3 Hold-up

There have been several experimental studies of two-phase flow in which the liquid holdup has been measured, either directly or indirectly. The direct measurement involves sudden isolation a section of the pipe by means of quick-acting valves and then determining the quantity of liquid trapped. Such methods are cumbersome and are subject to errors arising from the fact that the valves cannot operate instantaneously. Typical of the indirect methods is that in which the pipe cross-section is scanned by x-rays and the hold-up are determined from the extent of their attenuation.

2.1.4 Pressure, momentum, and energy relations

Methods for determining the drop in pressure start with a physical model of the two-phase system, and the analysis is developed as an extension of that used for single-phase flow. In the separated flow model the phases are first considered to flow separately; and their combined effect is then examined.

The total pressure gradient in a horizontal pipe, ($-dP_{TPF}/dl$), consists of two components which represent the frictional and the acceleration pressure gradients respectively,

$$\frac{-dP_{TP}}{dl} = \frac{-dP_f}{dl} + \frac{-dP_a}{dl} \qquad \text{(Eqn 2.1)}$$

The pressure drop due to acceleration is important in two-phase flow because the gas is normally flowing much faster than the liquid, and therefore as it expands the liquid phase will accelerate with consequent transfer of energy. For flow in a vertical direction, an additional term -ΔPgravity must be added to the right hand side of the equation to account for the hydrostatic pressure attributable to the liquid in the pipe, and this may be calculated approximately provided that the liquid hold-up is known.

Chapter 3: Gas Flow In Pipes

3.0 Introduction

In this chapter, gas behavior in pipeline will be discussed since gas is usually transported in pipelines. The main area of focus will be the properties of the flowing fluid, the flow parameters, and equations governing the gas flow. When gas flow in pipes, flow parameters that describe the state and behavior of fluid like velocity, pressure and density are not constant over time. Steady state and unsteady state are some of the techniques used to better understand how gas. For the purpose of simplication, the flow will be divided into two. The gas flows were flow parameters changes with time (Transient or unsteady flow) and the other where flow parameters are assumed to remain constant with time (steady state flow). In the case of gas, steady state flow is hardly the case but the industry used this concept especially for gas flowing under low pressures. Steady state flow is defined as the flow where its parameters do not change with time while uniform flow is defined as that in which the various parameters at any particular time instant do not change with position.

In the presence of a long straight pipe with a uniform distribution across the length, a steady state uniform flow can be considered. For example, flow at a constant rate through a long straight pipe of constant cross section. This assumption is not valid near the pipe walls where viscosity reduces the liquid velocity to zero. In comparison to oil, gas has a relatively low viscosity making it easier to flow through the pipe. The properties of the pipe wall and the fluid viscosity are very important in determining the overall resistance to flow. Also, important is the relationship between these properties.

3.1 Pressure Drop along the Pipeline

Since the pipe diameter determines the cross-sectional area of the pipe, the flow capacity of the pipe is directly related to the pipe diameter.
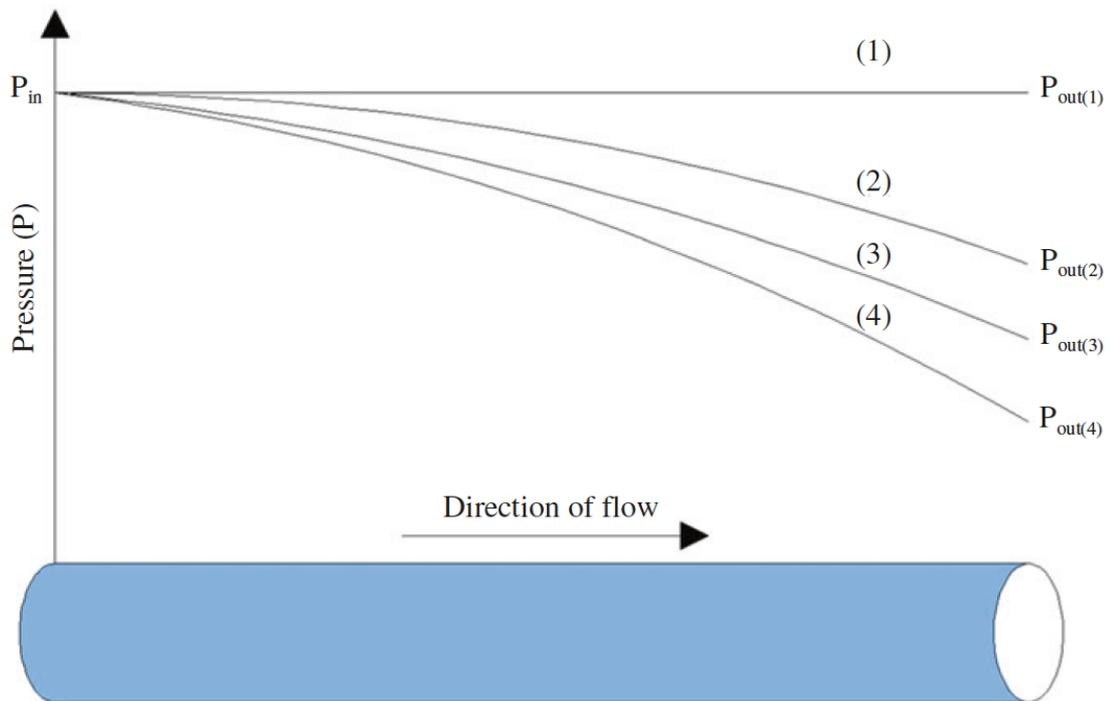
Figure 3.1 Schematic diagram of pressure drop along a pipeline

Figure 3.1 shows the general profile of pressure along the length of a pipe at different flow rates in which for zero flow, there is no pressure loss, so the outlet pressure is the same as the inlet pressure [profile (1)]. The highest flow rate produces the greatest pressure loss giving the lowest outlet pressure Pout (4) [profile (4)] and the lowest flow rate [profile (2)], results in a higher outlet pressure Pout (2). The parameters that affect the pressure drop of gas flowing between two points in a pipe are (i) rate of gas flow, (ii) internal pipe diameter, (iii) pipe length gas temperature, (iv) gas properties (i.e. (iv) viscosity, density), (v) properties of the pipe wall and (vi)

initial pressure of the gas. Unlike liquid (incompressible) flow, gas flow is affected by the compressible nature of the gas, as represented by the equation of state:

$$PV = ZmRT \qquad \text{(Eqn 3.1)}$$

Where P is the gas gauge pressure (N/m2), V is the volume of gas (m3), Z is the compressibility factor of gas, m is mass of the gas (kg), R is the universal gas constant (J/m2 K) and T is the gas temperature (K).

3.2 Properties of flowing fluid

Viscosity: Absolute and Kinematic.

The internal resistance of fluid to flow is called 'Viscosity'. One of the ways to determine viscosity is by measuring the shear force with respect to velocity gradient or by observing the time it will take a given volume of liquid to flow through a capillary tube or restriction. Viscosity is usually referred to in two terms

a. Absolute Viscosity: measured in terms of force. The unit of absolute viscosity is poise or centipoise (cP).

b. Kinematic Viscosity – is the ratio of the fluid's absolute viscosity to its density. The unit of kinematic viscosity is stoke or centistokes (cSt). The relationship between absolute and kinematic viscosity is given by:

$$\mu = \gamma\rho \qquad \text{(Eqn 3.2)}$$

Field units

$$\mu = (SG)\gamma \qquad \text{(Eqn 3.3a)}$$

SI units

$$\mu = 1000(SG)\gamma \qquad \text{(Eqn 3.3b)}$$

Definition of terms,

μ = absolute viscosity (cP or Pa s),

γ = kinematic viscosity (cSt or m2/s),

ρ = density (lb/ft3 or kg/m3),

SG = specific gravity.

Gas	Dynamic viscosity (Pa.s)
Hydrogen	8.4×10^{-6}
Methane	10.7×10^{-6}
Air	17.0×10^{-6}
Water	$1,150.0 \times 10^{-6}$

Table 3.1 Typical value of dynamic viscosity for different gases

Since gas is usually a mixture, the viscosity of gases is calculated from a correlation that utilizes the use of individual viscosity of the components of the gas. Such correlation is

$$\mu_m = \frac{\sum \mu_i x_i \sqrt{MW_i}}{\sum x_i \sqrt{MW_i}}$$

3.3 Pressure and Altitude

3.3.1 Effect of Altitude

The hydrostatic equation presented above (Eqn 3.4) is valid only if the density of the fluid is assumed to remain constant with height. Gases are however compressible, thus to determine the pressure at one point in a static column of gas relative to another point at a different elevation: we first consider that the gas at any point is in equilibrium since the gas is not moving. A thin element from the column will be evaluated in which the density will be taken as constant, this is shown in the figure below.
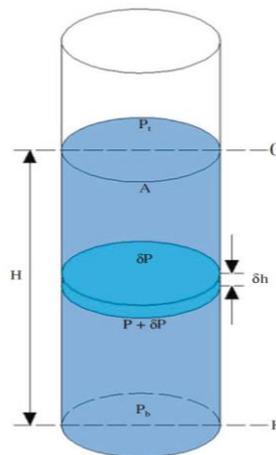
Figure 3.3 The element δh in equilibrium

For the chosen element to be in equilibrium, there must be a balance on the forces (force on the top surface + weight of gas in element = force on bottom surface).

3.4 Laminar and Turbulent Flow

3.4.1 Boundary Layer

When a fluid flows in a pipe, there is a thin layer of the fluid adhering to the pipe wall. The velocity of this thin layer attached to the pipe wall is zero. This lack of flow of the thin layer affects the successive layers of flowing fluid following it. The stationary layer extends only to a point and this is called *'boundary layer thickness'*. The velocity changes from the boundary layer from the velocity of the pipe's wall, which is zero, to the velocity of the main, flow stream approaching the velocity of the flowing stream asymptotically. This is depicted in the figure below
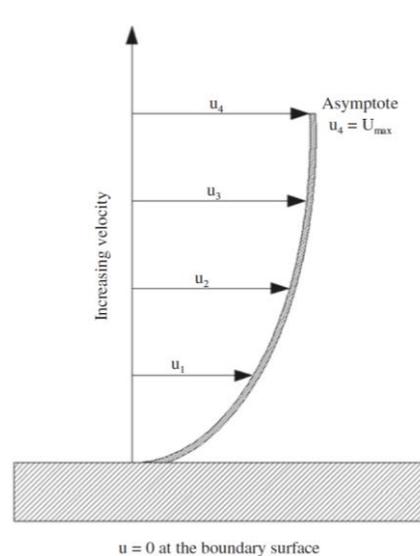
Figure 3.4 Changes in fluid velocity with distance from the boundary surface

In the boundary layer, the velocity gradient normal to the pipe wall, du /dy, is large, so even a low value of viscosity is very significant and cannot be disregarded even though its effect on the main flow may be negligible. Beyond the boundary

layer, the flow is affected much less by the fluid viscosity and in many practical applications it may be treated independently as though the boundary layer did not exist

When a fluid flows in pipes, two types of fluids are to be expected, depending on the velocity at which the fluid flows.

(i)   *Laminar flow* this flow is sometimes referred to as viscous flow. The viscous forces predominate in laminar flow since it occurs at a low velocity. The viscosity of the fluid is responsible for determine the resistance of fluid particles to move parallel to the layers of fluid. If the viscous forces dominate, then the flow of fluid will occur in layers thus laminar flow is associated with the smooth flow of viscous fluids. The velocity profile of a laminar flow will be parabolic where velocity at the pipe wall is zero and then increases to a maximum value at the pipe center. It is of more important to know the quantity of gas that will be transported rather than just knowing the velocity. The continuity equation is utilized in knowing that.

$$Q = U.A \qquad \text{(Eqn 3.5)}$$

The gas flow rate is Q, the mean velocity is denoted by (U) where as (A) denotes the cross sectional area of the pipe. Keeping in mind that the velocity in use here is neither the maximum velocity nor the minimum velocity, which is zero.

$$Q = Ua.A \qquad \text{(Eqn 3.6)}$$

For laminar flow, the average velocity $Ua = 0.5$ Umax. Condition to which the average velocity is used is that the flow is steady and continuous. Hagen-Poiseuille

equation is an important tool for analyzing Laminar flow.

$$Q = \pi d4 \; \Delta P / 128\mu \; L \qquad\qquad\qquad \text{(Eqn 3.7)}$$

Where Q is the volume flow rate, d is the diameter of the pipe, μ is fluid viscosity, ΔP is pressure loss over the length of the pipe and L is the length of the pipe. Two important factors from the equation that holds true for laminar flow is that (i) the volumetric flow rate is inversely proportional to viscosity and (ii) the pressure loss has a directly proportional relationship to the flow rate.

(ii)   *Turbulent flow*

The fluid particles in motion here not travelling in a straight path; rather they take a random flow with no specific pattern. Fluid mixing is still considered in turbulent flow thus the principal motion of fluid in a pipe still holds. The figure below shows how a fluid transit from laminar to turbulent flow.
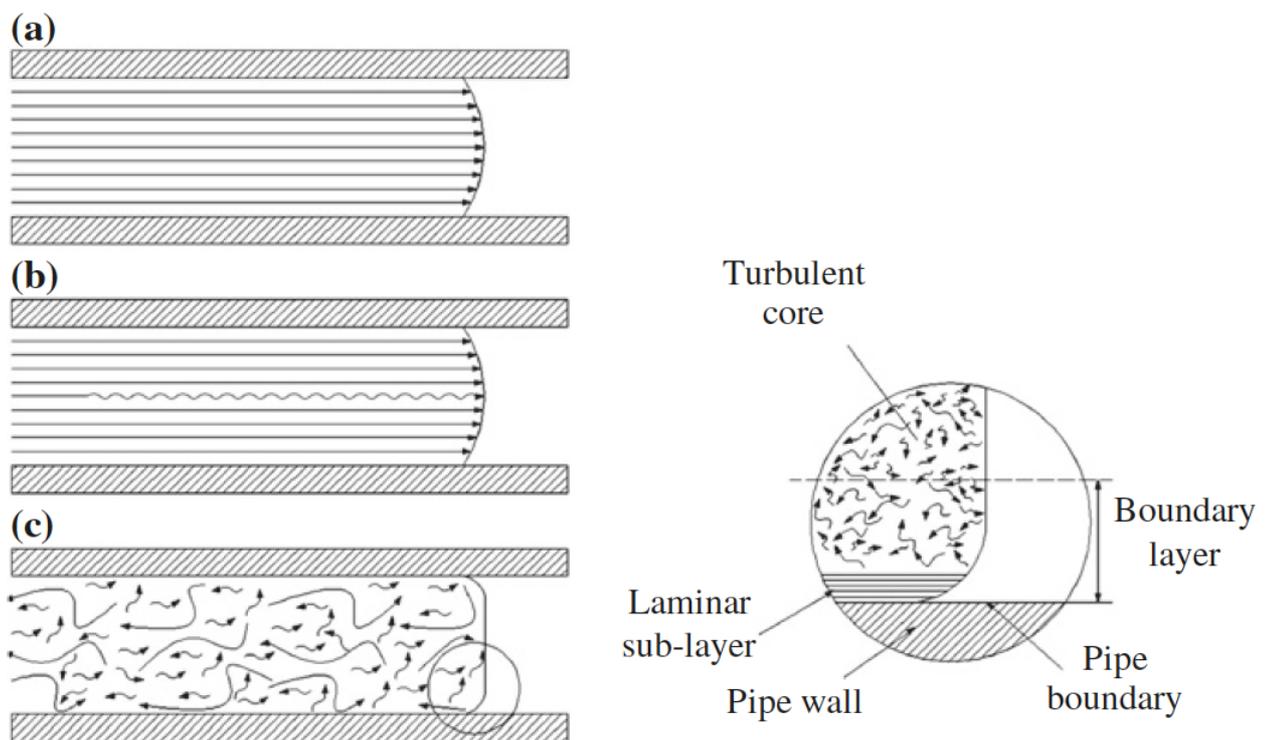
Figure 3.5 The transition of flow from laminar to turbulent

The laminar layer or as popularly referred to as the laminar sub-layer, is where the flow begins to transit from laminar to turbulent. More specifically the flow is referred to as partially turbulent in that region.

From the figure, boundary layer can be observed. And this is the distance from the pipe wall to which the stationary layer ceases to affect the flowing fluid. So in Fig. 3.5c, the distance defines it and at which the velocity profile no longer changes with distance from the pipe wall. Two type of fluid flow prevailed, Laminar flow in the sub-layer and turbulent flow in the outer region. When the flow rate increases, the velocity will increase too, this will cause the thinning of the laminar sub-layer. In theory, as velocity increases, the laminar sub-layer will continue to decrease indefinitely, but that is not the case in practice, in practice the laminar sub-layer will become so thin that it ceases to cover the surface roughness of the pipe thus, making the internal surface of the pipe in contact with the area of turbulent flow, therefore making the fluid flow a ''fully developed'' turbulent flow

3.5 Predicting flow types

To determine the type of flow that prevails, Reynolds suggest that the ratio of inertial forces to the viscous forces will be used not only in determining similar flow, but also in determining the change in flow regime.

$$Re \ = \ \rho U d / \mu \hspace{3cm} \text{(Eqn 3.8)}$$

The equation above is termed as Reynolds number. Reynolds number is

simply the ratio of inertial forces to the viscous forces thus making it dimensionless. Fluid with low viscosity or high density will have a usually high Reynolds numbers. In the case of natural gas, it has a low viscosity and a low density. Refer to the table below for the kinematic viscosity of some gases.

Gas	Kinematic viscosity (mm^2/s)
Hydrogen	105.0
Methane	15.4
Air	14.0
Water	12

Table 3.2 Typical value of Kinematic viscosity for different gases

When the forces of inertia dominate in a flow, the flow will experience a high Reynolds number and this makes it a turbulent flow. While the opposite case when viscous forces dominate, the Reynolds number will be small and thus, the flow will be categorized as laminar flow. A general rule that is used to differentiate flow type is if the Reynolds number is Re<2,000 flow is laminar, and if Re>4,000 flow is turbulent. Between the two numbers, the forces of inertia and viscous are somewhat equal therefore, the flow is hard to be identified so, this region is called as critical zone (Nasr, 2014).

3.6 Effect of friction on flow

As fluid flow, it loses energy. The equation below describes total energy of a flowing fluid with no friction.

$$dx + dp/\rho g + u\,.du/\rho g = 0 \qquad\qquad \text{(Eqn 3.9)}$$

Where x is the elevation in reference to a datum level, P is the absolute pressure, the fluid velocity is u, and gravitational acceleration denoted by g.

Bernoulli equation states that, as a fluid flows from one point to another in a pipe (upstream to downstream), the sum of the static pressure, potential and velocity heads at the upstream point is equal to the sum of the three heads at the downstream point plus the head loss due to friction between the two points. Bernoulli's equation can be used to describe the energy equation of an incompressible fluid.

It can be observed that the unit of every parameter is length, therefore this equation describe the total energy head of a flowing fluid. This equation encompasses three kinds of energy. The potential energy, which is due to elevation represented by x, the kinetic energy, represented by the velocity head, and the pressure head, which is energy due to the pressure forces. The energy terms in the Bernoulli equation does not represent stored energy but rather energy that will be transmitted between two points. The total energy head between any two points will be constant if there is no pressure loss due to friction. This loss can be incorporated into the Bernoulli as hf equation to obtain

$$x + P/pg + u2 /2pg = x + P/pg + u2 /2pg + hf \qquad \text{(Eqn 3.10)}$$

In laminar flow as discussed earlier, a stationary layer of fluid covers the pipe wall, so the pressure losses are entirely due to the properties of the fluid. In fully turbulent flow, the flowing fluid is in direct contact with the surface of the pipe, therefore the pressure losses are associated also with the friction caused as by the

fluid flowing over the surface of the pipe. In the case of a partially turbulent flow, since laminar sub-layer still exists, the pressure losses are a due to both the flowing fluid properties and the pipe properties.

3.7 Pressure drop equations

The frictional pressure loss in Bernoulli equation can be calculated by the use of The Darcy-Weisbach and Fanning equations

Darcy-Weisbach equation

The head loss due to friction is given by the Darcy-Weisbach equation as follows:

$$Hf \ = \ fm \ LV2/D * 2 \ g \qquad \text{(Eqn 3.11)}$$

The velocity used is the average velocity. The average velocity is just the flow rate over the cross sectional area of pipe which the fluid occupy.

Fanning equation

Fanning equation proposed the below equation to calculate the frictional head

$$Hf \ = \ 4 \ ff \ LV2/D * 2 \ g \qquad \text{(Eqn 3.12)}$$

Where

Hl=frictional head loss (ft. (m)),

FM=Moody friction factor, dimensionless,

fF=Fanning friction factor, dimensionless,

L=pipe length (ft. (m)),

D=pipe diameter (ft. (m)),

V=fluid velocity (ft./s (m/s)),

g = acceleration of gravity (32.17 ft./s (9.81 m/s2)).

3.8 Friction factor Ff

The friction factor is determined experimentally. Although research has been going on referencing friction factor to pipe roughness, the moody friction factor is generally used in pressure drop calculations. And in some texts, fanning friction factor is used. It is worth knowing that the Darcy-Weisbach and Fanning equations differ by a factor of 4.

In laminar fluid flow, the friction factor is a function of the Reynolds number and is given by

$$f - 64/Re = 0.52u/dVp \qquad \text{(Eqn 3.13)}$$

Where

F=Moody friction factor,

Re=the Reynolds number,

μ=absolute viscosity (cP (Pa s)),

d=pipe inside diameter (in. (mm)),

V=average velocity (ft./s (m/s)),

P=density of fluid (lb/ft.3 (kg/m3))

In turbulent flow where the Reynolds number is >4000, the friction factors depend on the pipe relative roughness and Reynolds number. Relative roughness is different from absolute roughness and is given by the ratio of the absolute roughness to the pipe inside diameter. The moody chart can be used to determine the friction factor.
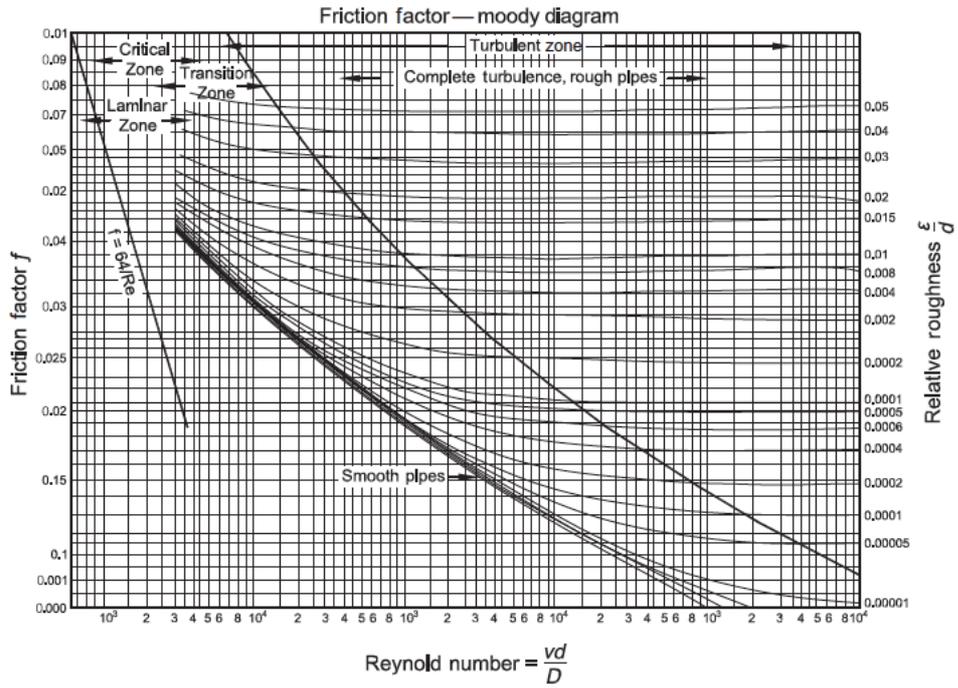
Figure 3.6 Friction factor as a function of the Reynolds number and pipe roughness.

(Courtesy of API).

Chapter 4: Flow Assurance

4.0 Introduction

Flow assurance encapsulates the technical aspects of transporting hydrocarbon mixtures from reservoir conditions to processing conditions. The challenges involved arise because the materials involved are natural fluids: crude oils, saturated gases and formation brines. The crude oils range in density from light-to-heavy (volatile oil and black oil). Extra heavy oil is also produced, increasingly in recent years (Nasr, 2014). The saturated gases range from water vapor, saturated gas, to gas condensate. The formation brines range a lot in salinity and are often comingled (different formations and breakthrough). The challenge for the operator of a hydrocarbon asset is to produce and process the natural fluids to market products.

Sand and erosion are problems affecting the integrity of oilfield installations. The prevention and mitigation of sand in oil and gas production is a major field of study with an overlap with the deposition of flow assurance solids. The collapse of oil and gas producing formations, leads to sand production. The sand can settle out in flow lines and various pieces of equipment, commonly in tank separators where the flow is more quiescent than elsewhere in the total flow stream. Reservoir formations range from consolidated to non-consolidated. The consolidation of sandstone reservoir formations varies. Production wells are fitted with sand screens and other devices to hinder sand production. The operation of wells with sanding-tendencies needs to follow specific operational procedures related to near-wellbore flow conditions. Too high a production flow rate will exuberate sand production problems. The presence of sand and fines may also provide seeding-sites for the nucleation of solids.

Corrosion is found in all oil and gas pipelines and equipment. Corrosion products are commonly found as flow assurance solids. Unfortunately, corrosion and erosion are two problems that commonly appear together. The composition and pH of produced water are the determining factors for the degree of corrosion in wells (production and injection) and flowlines. Care is taken in treating injection water (often seawater) by filtering, degassing and dosing of specialty chemicals (corrosion and scaling inhibitors). Of direct relevance in dealing with corrosion, is the injection of basic chemicals to increase the pH value of produced water. However, increased pH value affects both the formation of calcium carbonate scale and the formation of naphthenates. The operators of oil and gas assets need to find the right balance between the level of corrosion and the risk of solids precipitation and deposition. Corrosion problems affect the integrity of wells and flowlines and processing facilities.

The presence of sand particles in oil and gas flows commonly lead to metal erosion, affecting the integrity of wellhead equipment and installations. Guidelines are offered in the oil and gas industry, specifying maximum flow velocities to avoid serious erosion problems. In flowlines and pipelines carrying natural gas (gas-dominated flow), the maximum recommended velocity is much higher and is given either by the expression

$$umax \ = \ 175\rho g^{-0.43} \qquad\qquad \text{(Eqn 4.1)}$$

Or 60 m/s whichever is lower. The velocity is given in m/s and the in-situ gas density in kg/m3. That is, the gas density at operating conditions, not standard conditions. The term gas-dominated flow is used to indicate that the recommended maximum gas velocity can perhaps also be used for mist flow (gas with some liquid droplets).

4.1 Impacts Of Produced Water On Flow Assurance

As production begins, water will be produced from the reservoir eventually. Water, oil and gas exist in a production pipelines. Water exists in equilibrium with its solute compounds but as a result of temperature and pressure change, the equilibrium will begin to form precipitate and scales. When water comes in contact with the pipeline walls, corrosion can occur. Furthermore when gas and water flow at a given temperature and pressure, gas hydrate can form thus leading to the blockage of pipeline. Produced water causes flow assurance challenges in pipelines.

4.2 Gas Hydrates

Gas hydrates are crystalline compounds that results when gas comes in contacts with water at a given temperature and pressure. Hydrates are formed when the gas molecules get into the hydrogen-bonded water cages. Hydrates consist of water and light gas molecules like methane, ethane, propane, carbon dioxide, and hydrogen sulfide.

Gas hydrates are solids, and their physical properties are similar to those of ice. When hydrates form inside the pipeline, hydrate plugs block the flow. It can take weeks or even months to dissociate the hydrate plug. This make it necessary when designing a pipeline to ensure it is free of hydrate risk or make sure there are efficient ways to mitigate the hydrate formation. Hydrates are easily form at choke where the fluid temperature can drop in to the hydrate formation region as a result of Joule-Thompson cooling effects.

4.2.1 Gas Hydrate Formation Curve

Figure 4.1 is a hydrate formation curve. Left side of the cure is the region where hydrates will form i.e. the hydrate formation region. When temperature and pressure falls on the right side of the curve, hydrates will not dissipate. Factors associated with hydrates formation include fluid composition, water composition. Increasing salinity would shift the curve left and reduce the hydrate formation region.
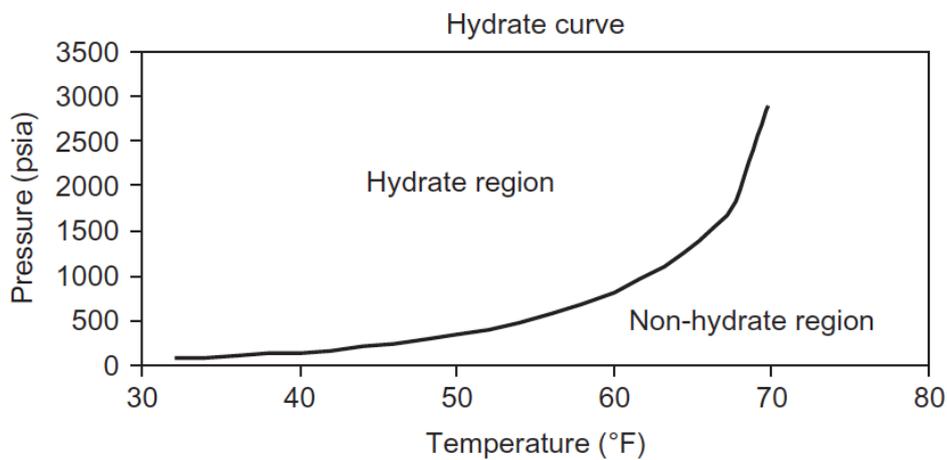
Figure 4.1 Gas hydrate curve

Figure 4.1 demonstrates the hydrate curve. If the initial system is in the non-hydrate region, increasing the pressure while maintaining the temperature constant will cause the system to shift to the hydrate region. The opposite can be said for a system initially in the hydrate region, keeping the pressure constant while increasing the temperature will shift the system to non-hydrate region. Most common way to calculate hydrate curves is by the use of PVT software with known water and fluid compositions.

4.2.2 Hydrate Inhibitors

4.2.2.1 thermodynamic Inhibitors

Since hydrate curves depends on fluid and water composition, thus it is fixed for a specific pipeline design given that the composition of fluid in the pipeline is known. To shift the system out of the hydrate formation region, thermodynamics inhibitors are used. Thermodynamics inhibitors change the pressure and temperature conditions of hydrate formation. Inhibition will either make the hydrate formation temperature lower or make the hydrate formation pressure higher.

Two kinds of thermodynamic inhibitors are commonly used: methanol and monoethylene glycol (MEG). For oil systems, methanol is used the most. Figure 4.2 shows how the hydrate curve shifts with different amounts of methanol inhibition. For a system with pressure of 1000 psia, the fresh water hydrate formation temperature is about 62°F. By adding 10wt% methanol into the freshwater, the hydrate formation temperature is reduced to 54°F. With 20wt% methanol, the hydrate formation temperature is further reduced to about 44°F.
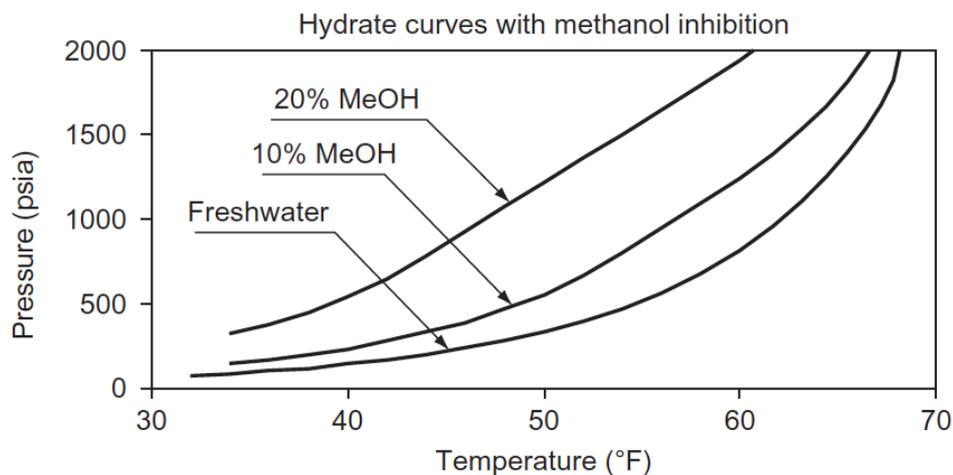
Figure 4.2 Hydrate curve with different amount of methanol inhibitors

If the temperature to be reduce is known, the amount of inhibitor needed in the free water can be estimated using the following equation (Hammerschmidt):

$$Wi = \frac{100 M_I \Delta T_h}{(C_i + M_i \Delta T_h)} \qquad \text{(Eqn 4.4)}$$

Where

Wi5 weight percent of the inhibitor in liquid

Ci5 constant, 2335 for methanol and 2000 for MEG

Mi5 molecule weight of methanol or MEG

ΔTh5 hydrate sub cooling which is the temperature needs to be reduced by inhibitor.

Salt can also affect the hydrate formation conditions. By adding more salt into the water, the hydrate formation curve will shift to the left, as shown in the figure 3 below. However, even though salt can be used for hydrate inhibition, too much salt can cause salt deposition and scale deposits in the process facilities. Salt solution is also corrosive and can cause corrosion problems to equipment
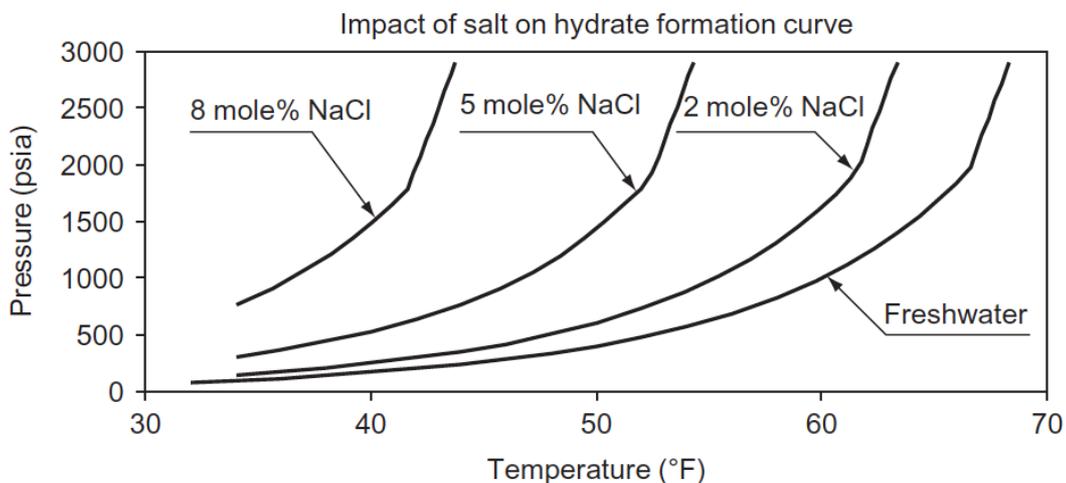
Figure 4.3 Gas hydrate curves with different salt concentrations.

4.2.2.2 Low-Dosage Hydrate Inhibitors

In the presence of large amount of water, large amount of methanol will be required for inhibition resulting in higher operating expenditures. The solution here is the use of inhibitors for which the necessary quantity is not influenced by the amount of water produced. These inhibitors are called low-dosage hydrate inhibitors (LDHI). Two types of inhibitors are used: the first is kinetic inhibitor and the other is the anti-agglomerate.

Kinetic hydrate inhibitors tend to slow down the hydrate nucleation process and delay the formation and growth of hydrate crystals for an extended period of time. Kinetic inhibitors only slow down nucleation process for a finite time after which there is rapid formation of hydrates. These makes it necessary when designing mitigation strategies for the pipelines to make sure the 'hold-time' in the pipeline is more than the residence time.

Anti-agglomerates unlike kinetic inhibitors, they prevent the formation of large hydrate crystals. Together with hydrocarbon, the hydrate crystals are transported in the pipeline as slurry flow.

4.2.3 Hydrate Mitigation Strategies

Getting rid of water is the best way to mitigate hydrate. When water is not flowing n the pipeline, there is no risk of hydrate formation. Getting rid of water might not be as easy as it sounds in practice, so it is necessary to find some other ways like:

- Thermal Insulation
- Chemical Inhibition
- Electric Heating
- Depressurization

4.3 Inorganic Precipitates—Scales

Scales are potential precipitates they pose as a major concern in flow assurance by blocking production facilities, jamming control valves, and restricting flows in tubing and pipelines.

4.3.2 Factors Affecting Scale Precipitation

The major factors affecting the scale precipitation from water are pressure, temperature, Pressure, pH value, and dissolved solids in water are factors influencing scale precipitation. Table 4.1 is a summary of the effect of these factors.

Scales	Temperature Effects	Pressure Effects	pH Value Effects	Dissolved Solids Effects
	Less soluble with increased temperature.	Less soluble with reduced pressure.	Less soluble with increased pH value.	Less soluble with reduced total dissolved solids in water.
Calcium carbonate	More likely scale will form with hotter water.	If waters go through the bubble point, CO_2 would evolve from solution and scale likely to form.		Adding salts into distilled water can increase the solubility.
Barium sulfate	For common temperature range, solubility increase with increased temperature.	Less soluble with reduced pressure.	Little impact.	More soluble with increased dissolved salt.
Strontium sulfate	Less soluble with increased temperature.	Less soluble in NaCl brines with reduced pressure.	Little impact.	More soluble with increased NaCl content.
Calcium sulfate	Less soluble with increased temperature for the common reservoir temperature range.	Less soluble with reduced pressure.	Little impact.	More soluble with increased water salinity.

Table 4.1 Summaries of Major Factors Impacting Scale Precipitations

4.3.3 Scale Prevention and Control

Continuous Chemical injection (Chemical inhibition) is used as a means to control scale formation. The inhibitors prevent scale deposition but do not redisssolve the already formed scales thus inhibitors are used for prevention not as a remedy. Scale prevention depends on the life of the field under production. At the early production period, there is breakthrough of aquifer water causing carbonate scales to form. Scale severity will increase with increased water cut. The main control strategy will focus on carbonate scales at the early life. In the later life of the field during water flooding when seawater is injected and mixes with formation water, strategies at this stage

would include controlling both carbonate and sulfate scales. With production, the seawater faction in the produced water will increase with time, and the severity of sulfate scales will change accordingly.

4.3.4 Scale Removal

After scales are formed, they can be remove by the use of mechanical methods like pigging or by dissolving using chemicals. If the formed scales are not too hard, mechanical equipment like brush or scraper pigs are run into the pipelines to remove the scale deposit on the wall. In the case where the scale deposit is too hard, acid is use to react and dissolve the scale. Hydrochloric acid is used for carbonate scales for calcium sulfate scale, inorganic converters like ammonium carbonate $((NH_4)_2CO_3)$, is used to convert it into calcium carbonate, which is then dissolved using hydrochloric acid. Corrosive inhibitor is added to the acid to prevent the acid from dissolving the pipe wall.

4.4 Corrosion

When hydrocarbon and water flow in a pipeline, corrosion is an aspect of flow assurance to be considered due to the presence of aqueous phase, which will eventually wet the pipe inner surface leading to corrosion. Factors influencing the corrosivity of the aqueous phase are the flow rate, the temperature and pressure, and the concentration of CO_2 and H_2S different forms of corrosion that might arise include, pitting, galvanic corrosion, hydrogen embrittlement, and stress corrosion cracking. Corrosion can result in the loss of millions of dollars if a subsea pipeline is not properly protected.

4.4.1 Fundamentals of Corrosion

Corrosion in pipeline carrying oil, gas and water involves the chemistry of the fluid, pipe material, and flow hydraulics. The pipeline is made of metal and when these metals were refined, they absorb extra amount of energy. This extra energy makes metal unstable in aqueous environment making metals susceptible to corrosion. The corrosion process will make metals loose the extra energy and return to their stable state of low energy. Each metal has its own amount of stored energy, therefore each metal has different corrosion tendency. The basic elements for corrosion to take place are:

1. The cathode

2. The anode

3. Conducting circuit.

4. Electrolyte
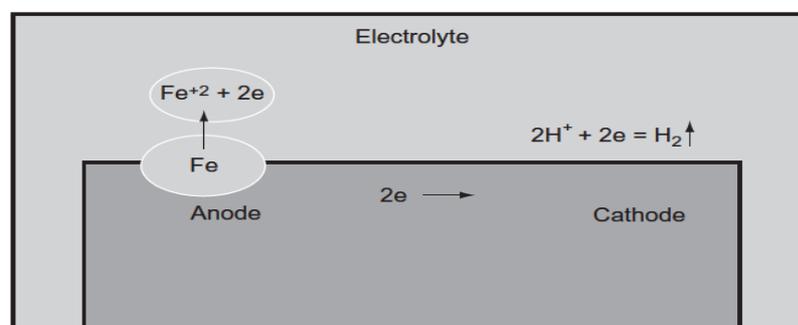
Figure 4.4 Schematic of the corrosion process.

4.4.2 Corrosion control

Methods used to control corrosion in pipeline include the use corrosion resistant alloy rather than carbon steel, use of corrosion inhibitors, cathodic protection, isolating the metal form electrolyte.

Corrosion resistant alloy are important replacement of carbon steel, although they are more expensive as compared to carbon steel. The use of carbon resistant

alloy depends on the overall economics. In pipeline operations, critical components like jumpers, trees and manifolds are made from corrosion resistant alloy. Since CRA is more expensive, the long pipeline is made from carbon steel and is subjected to continuous corrosion inhibitor injection for pipeline protections.

Corrosion inhibitors when added will lower the rate at which corrosion prevails. To protect the pipe, they react with metal surfaces and adhere to the inner surface of the pipeline.

Chemical compounds like methanol or glycol are used in pipeline transporting gas/condensate to reduce corrosion rate. These compounds will thus making the water phase less corrosive.

4.5 SLUGGING

4.5.1 Introduction

Figure 4.5 below shows how slugging will take place in a riser configuration. Typical severe slugging would occur in a pipeline riser configuration as shown in Figure 4.5. The pipeline section coupled with the riser is normally inclined downward. The pipeline sections upstream of the downward inclined section may be upward inclined, horizontal, or downward inclined.

When gas and liquid flowrates are low, the liquid cannot continuously flow out of the riser and start to fall back from the riser and accumulate at the riser base, as shown in Figure 4.5A. This stage is called severe slugging formation or severe slugging generation. During this stage, there is almost no liquid and gas production and no fluid flowing into the separator. While liquid is accumulating at the riser base,

gas and liquids are continuously flowing into the riser base from the pipeline inlet. Thus, the liquid column or slug formed at the riser base would continue to grow into the riser and also grow against the flow direction into the pipeline. Depending upon the GOR and other parameters, like system pressure and temperature, the slug inside the pipeline can be a few times longer than the riser height. Since the liquid slug prevents

The gas from entering the riser, the pressure behind the slug is building up by the gas flow.
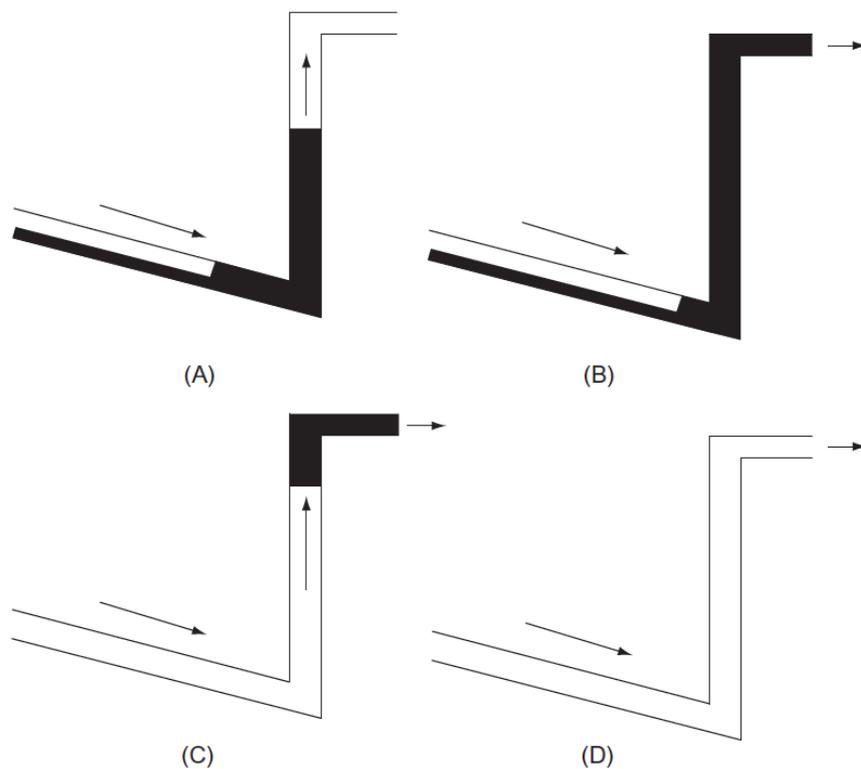
**Figure 4.5** Schematic of classical severe slugging formation process

Figure 4.5A represents severe slugging formation. During this stage, there is almost no liquid and gas production and no fluid flowing into the separator. While liquid is accumulating at the riser base, gas and liquids are continuously flowing into the riser base from the pipeline inlet. Thus, the liquid column or slug formed at the

51

riser base would continue to grow into the riser and also grow against the flow direction into the pipeline. Figure 4.5B this stage is called slug production. During this phase, the liquid is producing into the separator at high velocity and little or no gas is being produced. Because of the high-velocity liquid flow and huge amount of liquid associated with the slug, the separator may reach high liquid level and cause trips or upsets. Figure 4.5C when gas enters the riser, the difference between the separator pressure and the gas pressure behind the slug become higher and higher as the liquid slug becomes shorter and shorter inside the riser. The liquid slug is being produced or being pushed by the gas at higher and higher velocity. This stage is called liquid blowout. This stage is called gas blowdown (Figure 4.5D). During this stage, little or no liquid would flow into the separator, and low liquid level may be reached that would eventually cause system upsets and shutdown. The gas blow down stage in severe slugging can cause as big a problem as the slug production stage.

4.5.2 Slug Elimination

Below are some methods used to mitigate severe slugging.

4.5.2.1 Increasing Gas Flow

When gas velocity is too low, severe slugging tends to occur. This is because the gas velocity is too low to carry the liquid out of the riser. The fluid mixture density is high as a result of the presence of liquid in the pipeline. More gas needs to be introduce into the pipeline riser system to increase the gas velocity and thus lift the liquid out of the riser.

4.5.2.2 Gas-Lift Riser

When gas is injected at the riser base that is enough to change the flow to churn flow or annular flow, the severe slugging problem can be contain. In churn flow, the slugs

are shorter than in severe slugging flow. A significant amount of gas is required to achieve annular flow, which may not be practical.

4.6 EROSION

4.6.1 Erosion

Solid particles that a re suspended in flow causes erosion as a result of their impact on a solid wall. These solid molecules will gradually wash away the material of the boundary through repeated deformation and cutting actions. When fluid containing solid particles flow over metallic surface, erosion will occur. The damage is as a result of the solid particles being transported in the flow. The solid can arise from the deposit of hydrates, sand, waxes and scales. The erosive damage affects the protective oxide film of the metallic surfaces that results in the creation of pits, grooves and other types of deformation of the metallic surfaces.

In wet gas flow, liquid droplets may exist in the flow at high gas velocities and volumetric flow rates. The extension of erosion in this case depends on the droplet size, impact velocity, impact frequency, and type of liquid, gas density and viscosity. The constant collision of the liquid droplets on the walls of the pipeline may cause material fatigue and abrasion

4.6.2 Factors Influencing Erosion

1. The velocity of the solid particles

2. Angle of attack: the collision of solid particles on metallic surface contributes to the surface deformation.

3. Flow rate

4. Flow restriction

5. Change in the direction of flow

4.6.3 Prevention Techniques

1. Modeling the solids flow by the use of correlations that shows the dependence of erosion rate on solids flow. This measure implies the control over the production flow rate.

2. Use of improved pipe materials: The pipelines are made of alloys with improved resistance on erosion. The alloys UNS N06625 and UNS S32750 are some of the materials used for subsea applications.

3. ☐ Sand removal: Use of sand removal equipment's like sand screen or gravel to remove sand from the flow.

Chapter 5: Simulation and Result

5.1 software's comparison

The table below gives a list of commercial softwares that are used for modeling of flow in a pipeline and to conduct flow assurance studies. Depending on the phase and the type of flow, suitable software can be identified from the table below for a given scenario.

Multiphase		Single phase
Transient	Steady state	
Olga	prosper	TGNET
	gap	TLNET
	Pipesim	Natasha plus

Table 5.1 Software use for pipeline simulation

In this thesis, gap was used to conduct the simulation. Other softwares specifically prosper and Mbal was used together with gap to achieve the objective.

Petroleum experts gap (General Allocation Package) is a multiphase flow simulator that is able to model and optimize production and injection networks. The concept of the network here is intended in the fullest sense; therefore it includes both the surface and downhole equipment and allows the engineer to build complete system models including; the reservoirs, wells and surface network. GAP can be linked directly to PROSPER and MBAL to model entire reservoir and productions systems. Furthermore, GAP can handle a combination of different fluids including; oils, dry and wet gases, retrograde condensates, steam and water flowing through complex production or injection systems. The fluid phase behavior can be modeled using the **Black Oil** formulation or **Equation of State Compositional Modeling**

5.2 The case description

After a thorough search for data's from a gas production field with no success, one of the cases given in the gap manual (Example 1) was taken as the basis for this thesis study. In the gap manual, they present several examples on how to develop a gap model with difference in either the example being of a gas or oil, either conventional field or non conventional field. Since the thesis focuses on gas production pipelines, the example of a gas field was used to develop a gap model using three different cases and analyzes the outcome of these cases and conduct further simulation when necessary (Condensate simulation).

The simulation focuses on a new discovered gas field in a harsh environment that is subjected to large temperature swings. The gas reservoir will be depleted by four wells that are tied to two manifolds. The produced fluid will then travelled a distance of 40km via a main pipeline to the gas station with no elevation.
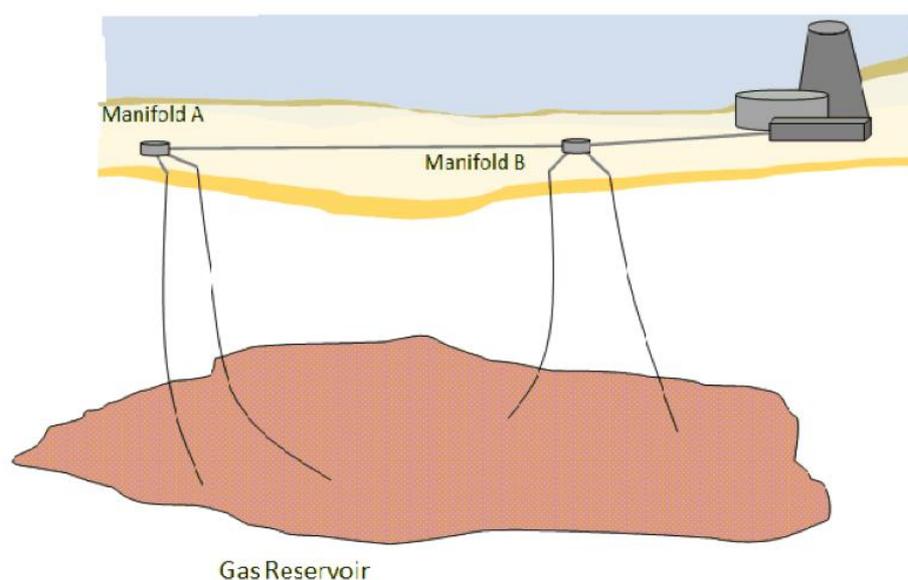
Figure 5.1 sketch of the field being studied

The gas station has a processing capacity of 250MMscf/day of gas and required the gas to be delivered at 1000psig,

Objectives

-Determine ''how long'' the field can be producing at target rate over a ten-year period commencing 01/01/2008.

Constraints

-Facility can only processed a maximum of 250MMscf/day

-The gas is delivered at a pressure of 1000psig.

5.2.1 Reservoir description

The reservoir in study is a gas reservoir with no production history. A model was run in Mbal to estimate the GIIP. The gas initially in place is estimated to be 2000 Bscf. This model was exported to GAP for analysis.
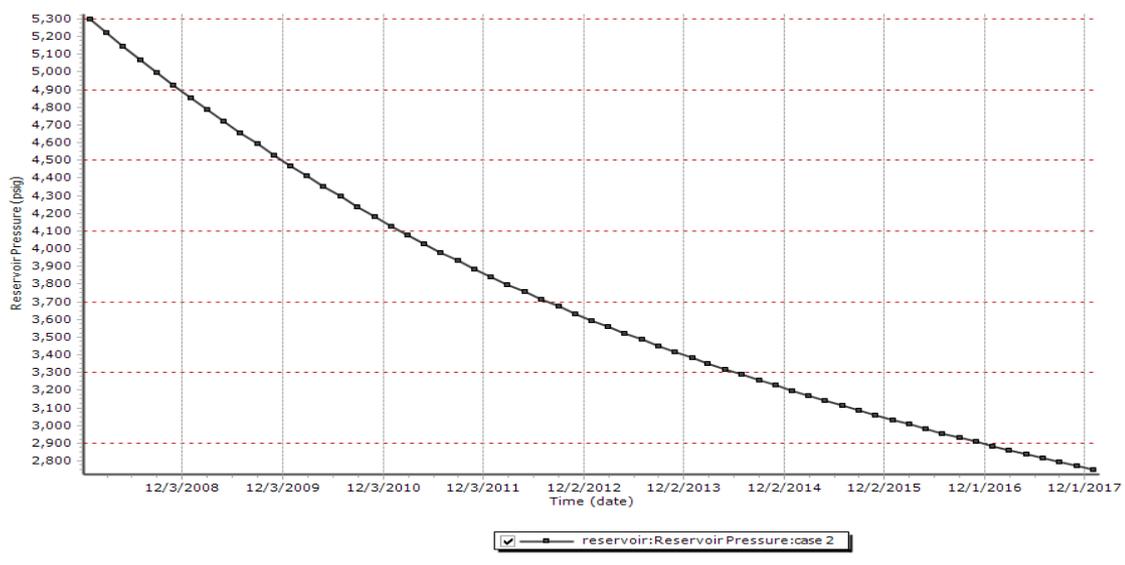
Figure 5.2 Reservoir pressure against time

Figure one presents the pressure draw down in the reservoir over time. The initial reservoir pressure is 5300psi. As production begins, pressure will decline as a result of pressure drop cause by the flowing fluid.
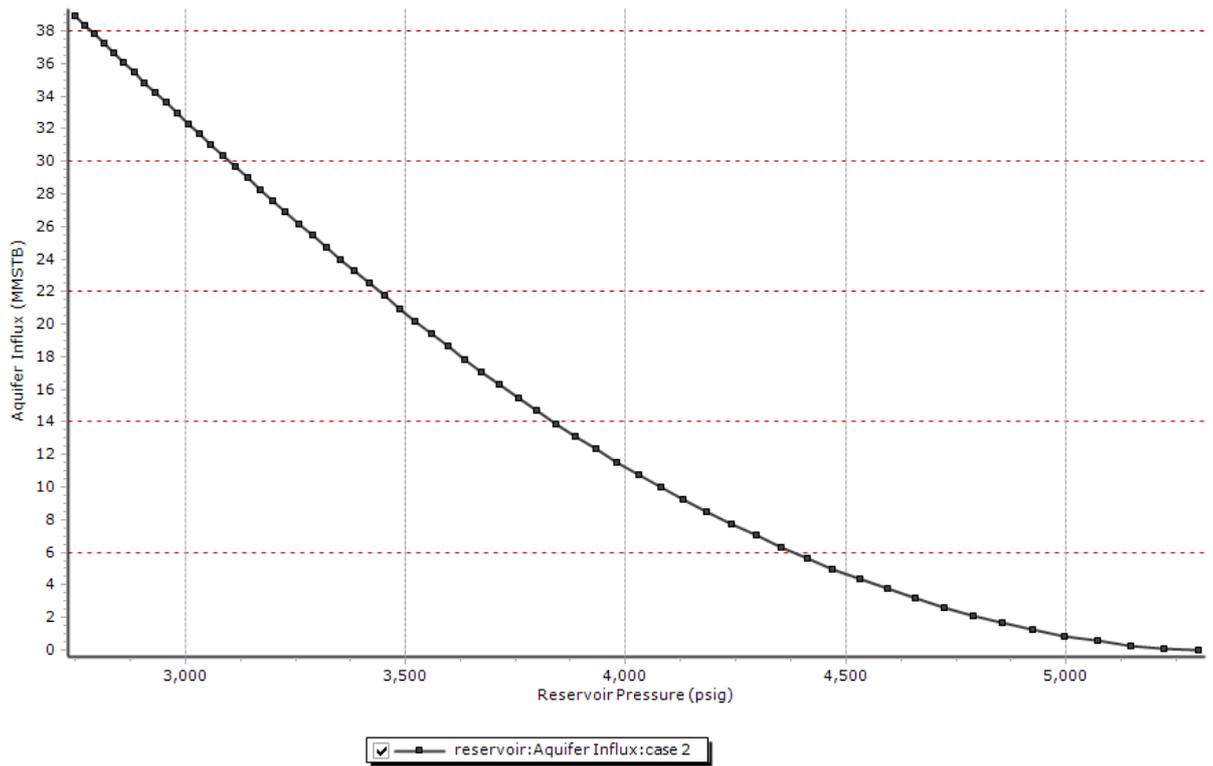
Figure 5.3 Aquifer Influx against Reservoir pressure

The reservoir is expected to have an early water production. From the figure above, it can be observe that as the pressure decreases from 5300Psi to 5000Psi, the water within the aquifer will now begin to flow thus helping in overcoming the declining pressure. Since there is an aquifer, this means that there will be water production, so it is important to know that because when gas flow with water, flow assurance challenges will be experienced.
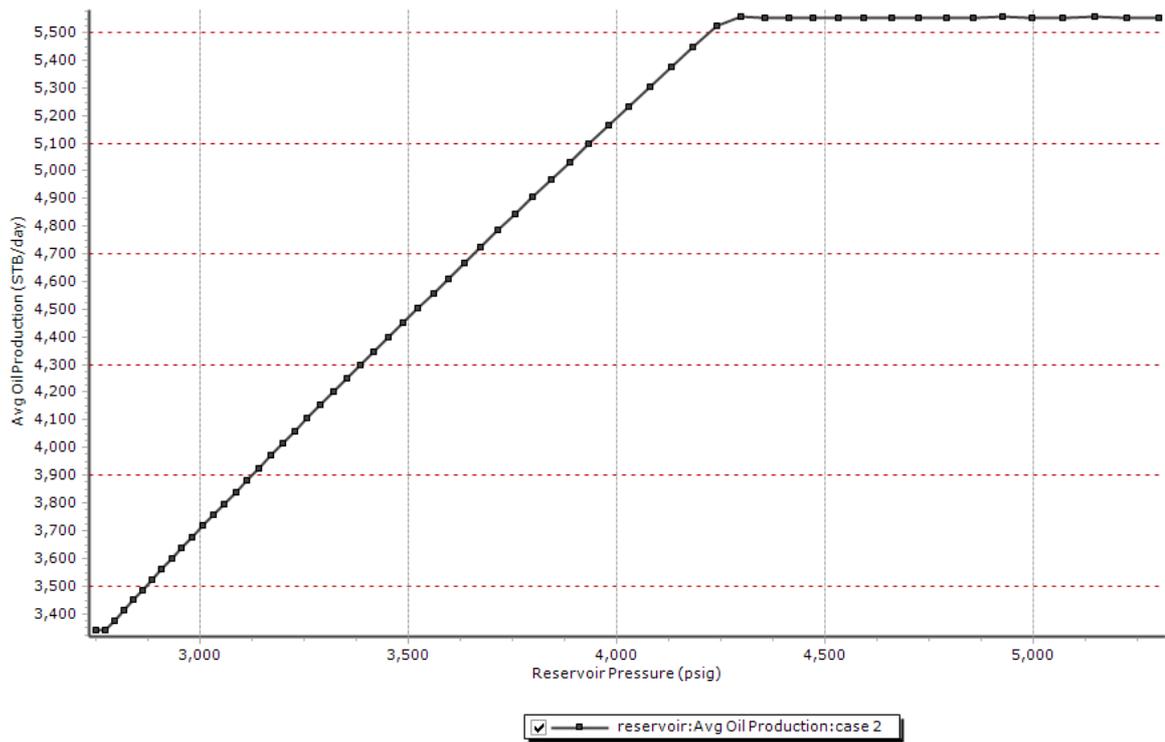
Figure 5.4 Reservoir pressure against Oil Production

The reservoir will not only be producing gas but oil too. Figure 5.4 shows oil production with respect to pressure drawdown. It is important to know the kind of fluids that are coming out of the reservoir as this will assist in designing the production pipelines and the surface equipment like the separator.

5.2.2 Wells description

Gas is produced from four wells. PROSPER was used to build the well models and to generate their IPR and VLP curves. The PROSPER output files for all six wells were then imported into GAP to represent the wells.
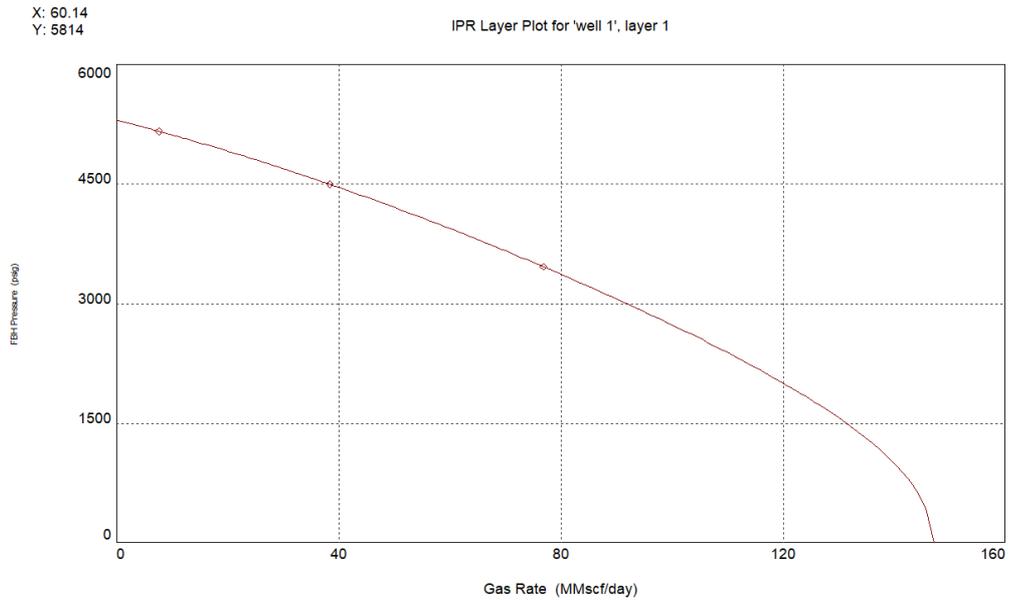
Figure 5.5 Inflow performance relation curve

Inflow performance relation often termed as IPR curve represents the relationship of the flowing pressure to the flow rate of the gas. In a case of an undersaturated reservoir, the IPR curve is a straight line, but as can be seen from the figure above that is not the case. The IPR curve is not linear and this is as a result of gas. The reservoir in studies is a gas reservoir and a vogel equation was used in deriving the IPR curve.

Figure 5.6 below depicts the vertical lift performance curve that is also called the Outflow; it describes the bottom-hole pressure as a function of flow rate. The VLP depends on many factors including fluid PVT properties, well depth, tubing size, surface pressure, water cut and GOR. It describes the flow from the bottom-hole of the well to the wellhead.
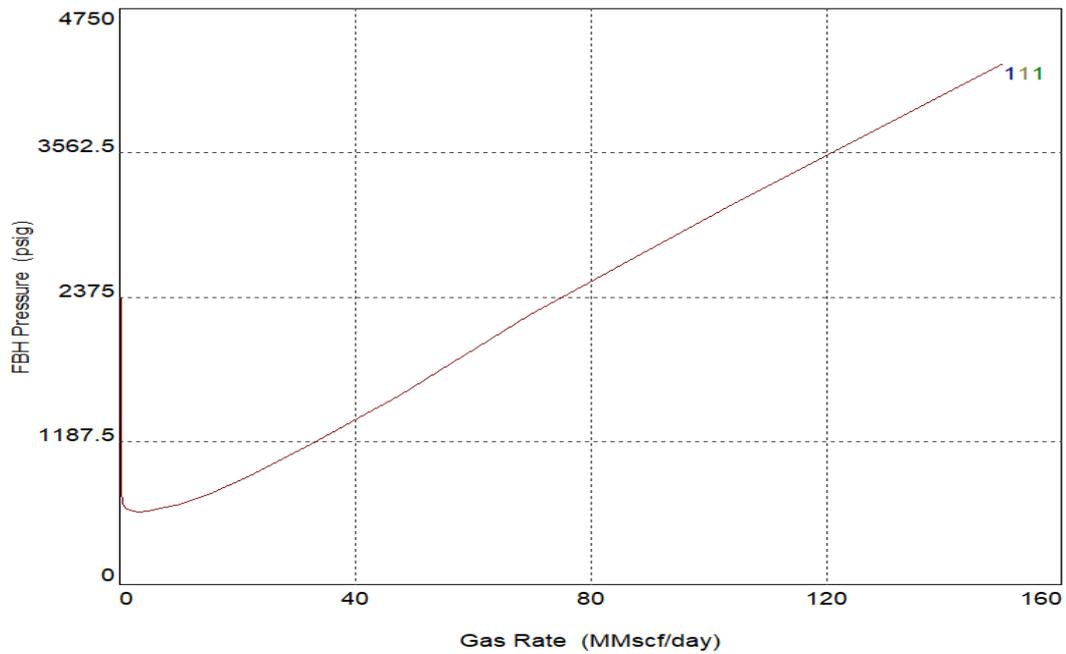
Figure 5.6 vertical lift performance curve

The above plots are important because they determined the flow rate at which production will take place. Early estimates of gas well performance were conducted by opening the well to the atmosphere and then measuring the flow rate. Such "open flow" practices were wasteful of gas, sometimes dangerous to personnel and equipment, and possibly damaging to the reservoir. But now the IPR and the VLP curve can be coupled together to determine the flow by identifying the intersection of the two.

5.2.3 Pipeline description

The model in study consists of four wells. Well 1 and well 2 are connected to Manifold A through pipeline named "line 1' and "line 2" respectively. Well 3 and well 4 are connected to manifold B through pipelines named "line 3 and line 4" respectively. The commingled fluid of well 1 and well 2 are transported to Manifold B through pipeline A where they are combined with the fluid from well 3 and well 4

61

and transported to the separator via 'pipeline line B'. Figure 5.7 represents the sketch
of the simulation carried out in GAP.
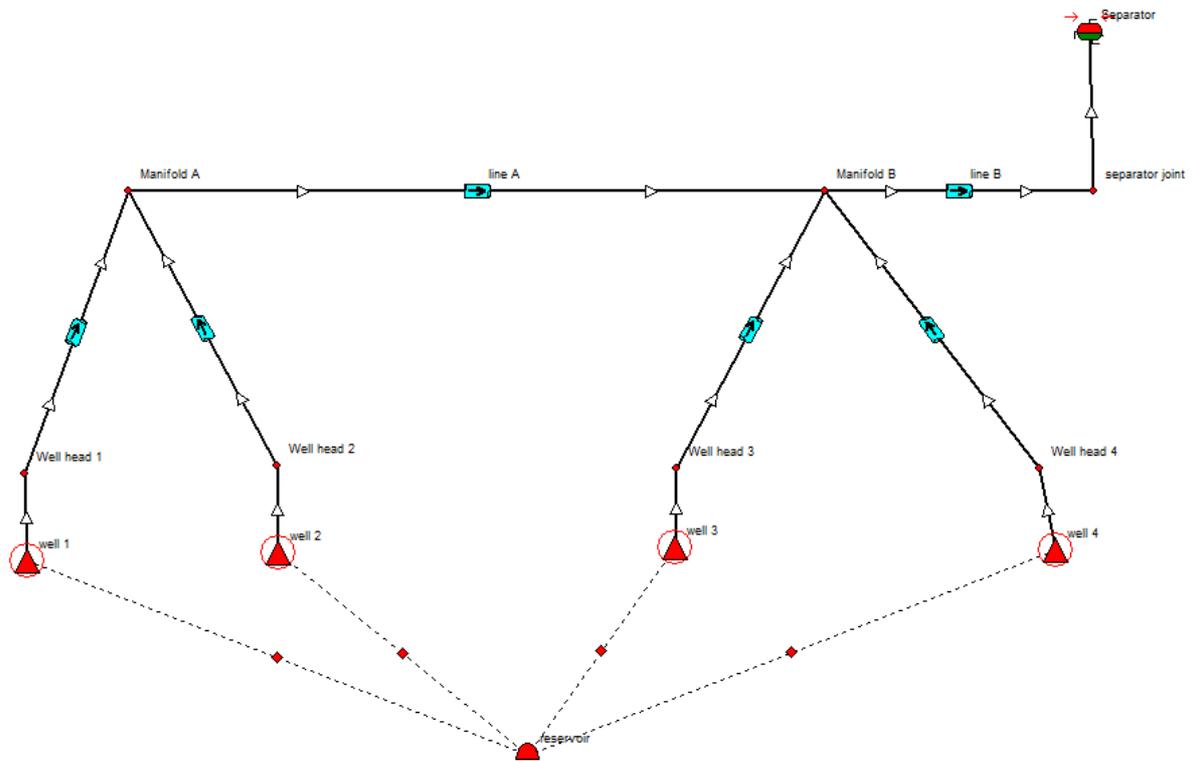
Figure 5.7 GAP simulation sketch

Three case studies on the pipe design were carried out. The objective is to find
out which of the pipeline design will give the optimum production while respecting
the giving constraints. The environmental conditions will be put into consideration so
as to avoid any flow assurance challenges.

Label	Pipe Segment Length	Cases			Overall heat Transfer Coefficient
		Case 1	Case 2	Case 3	
	km	inches			Btu/h/ft^2/f
Line 1	0.8048	2	10	20	3
Line 2	1.1096	2	10	20	3
Line 3	0.5	2	10	20	3
Line 4	0.5	2	10	20	3
Manifold_A to Manifold_B	0.3	4	20	40	3
Manifold_B to separator joint	0.4	4	20	40	3

Table 5.1 Pipeline data's for the three case in study.

Table 5.1 provides the detail of the three cases in study, length of the pipes and the diameter. The pipelines are not subjected to any elevation.

In the pipeline dimension of case 1, the pipelines that carry the fluid from the wellhead to the manifold where given a dimension of 2 inches each. While the pipeline that connect the manifold to the separator exhibits a much bigger size

because it transport fluid from all the wells, so it should have a bigger diameter. 4 inches were used.

5. 3 Result and Discussion

5.3.1 Cumulative gas production

All the three cases were simulated differently with different given data in respect to the size of the pipeline, as such this lead to different cumulative production that results in the separator from the three cases.
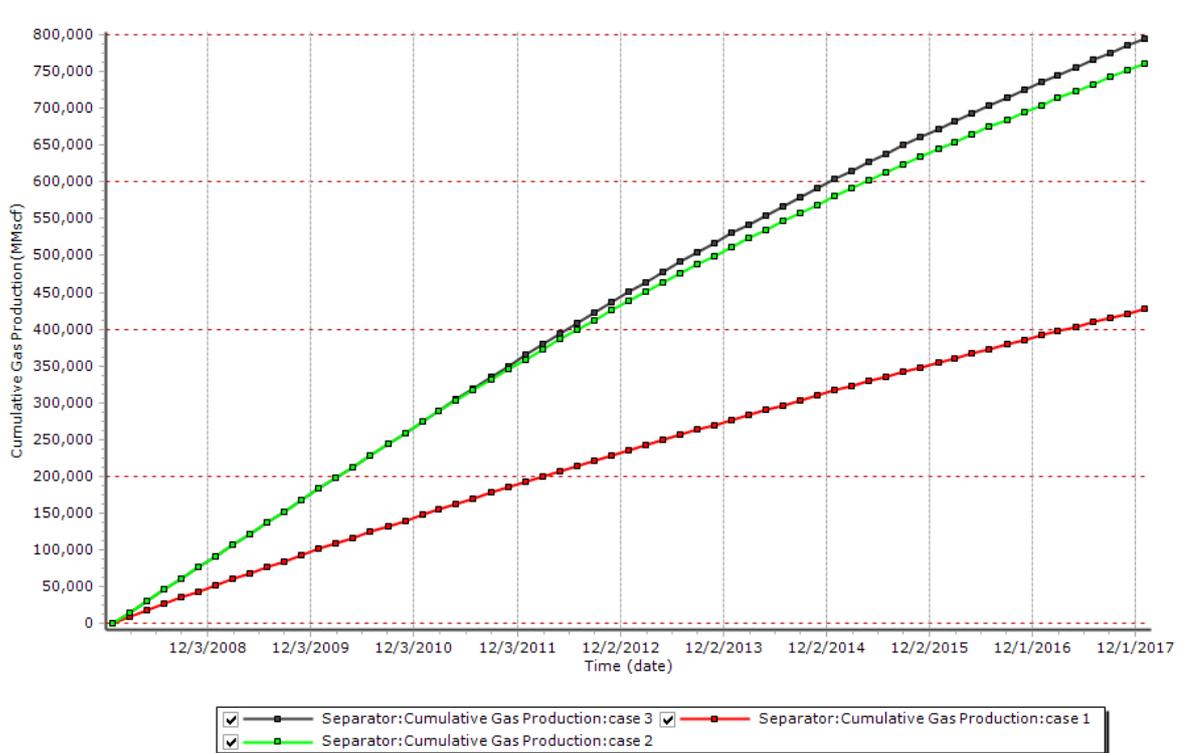
Figure 5.8 Total gas productions from all cases.

Figure 5.8 shows in the case of low diameter, the lowest cumulative production occurred. The diameter selected happens to be too small to carry the fluid, especially the diameter of the pipe carrying the commingled fluid to the separator.

The two other cases shows a much increase production totaling to 800MMscf of gas over the ten years period. Case 3 has a higher gas production compared to case 2 and this is as a result of pipeline size used in case 3 which is two times the size of case 1.

5.3.2 Well performance
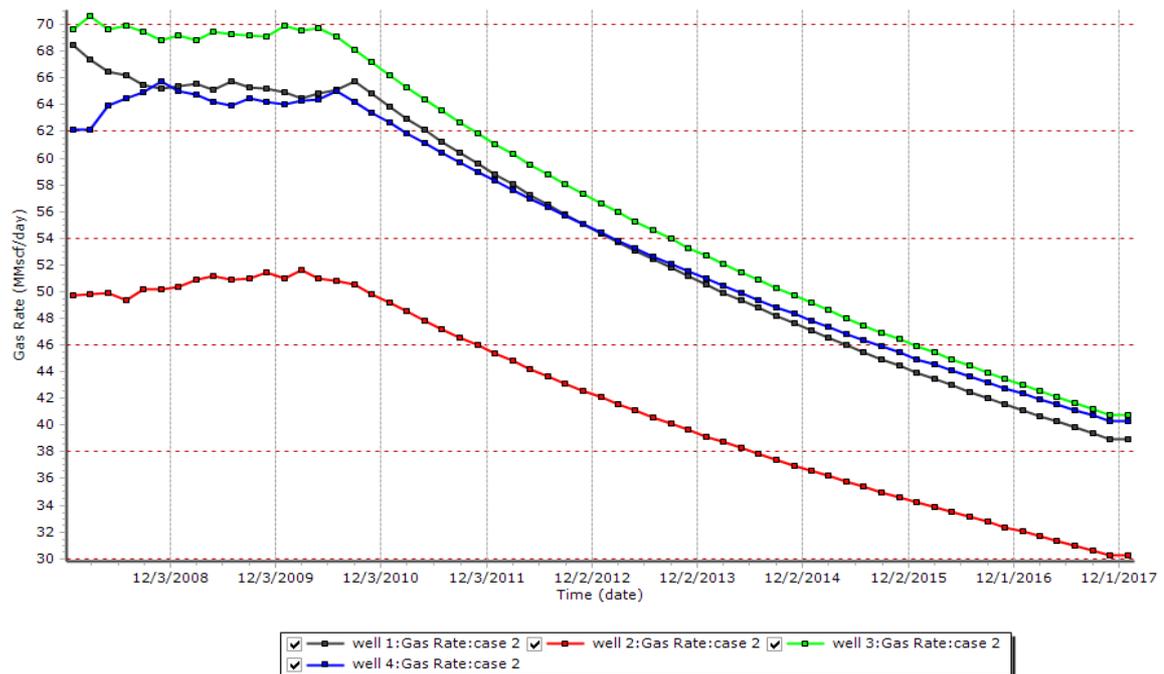
Figure 5.9 well performance plots

Figure 5.9 above presents the performance of each well in terms of how much gas it contributes to in the production. From the first day of production, well 1, 3 and 4 contributes significantly to the amount of gas produced. Well 1 which at its peak contributes to about 53MMscf/day of gas comes in last compared to the other wells. What can be notice is that all wells were able to stay active throughout the ten years of production.

Table 5.4 Result obtain from the wells

Wells	Reservoir Pressure	Bottomhole Pressure	Wellhead Pressure	Wellhead Temperature	Average Liquid Rate	Average Gas Rate	Average Water Cut	Draw down	ΔP Choke
	psig	psig	psig	*deg* F	STB/day	MMscf/day	%	psi	psi
Well1	5300	3526	2211	116.5	1734	74.7	4.31	1773	530
Well2	5300	3409	2576	112.9	1135	48.9	4.31	1891	1132
Well3	5300	3712	2626	115.9	1524	65.6	4.31	1582	1243
Well4	5300	3684	2702	115.1	1409	60.7	4.31	1615	1364

From table 5.4, the wells operate with the same water cut of 4.31%. Well 1 produces gas at a higher rate than the rest of the wells while at the same time having a low-pressure drawdown when compared to well 2.
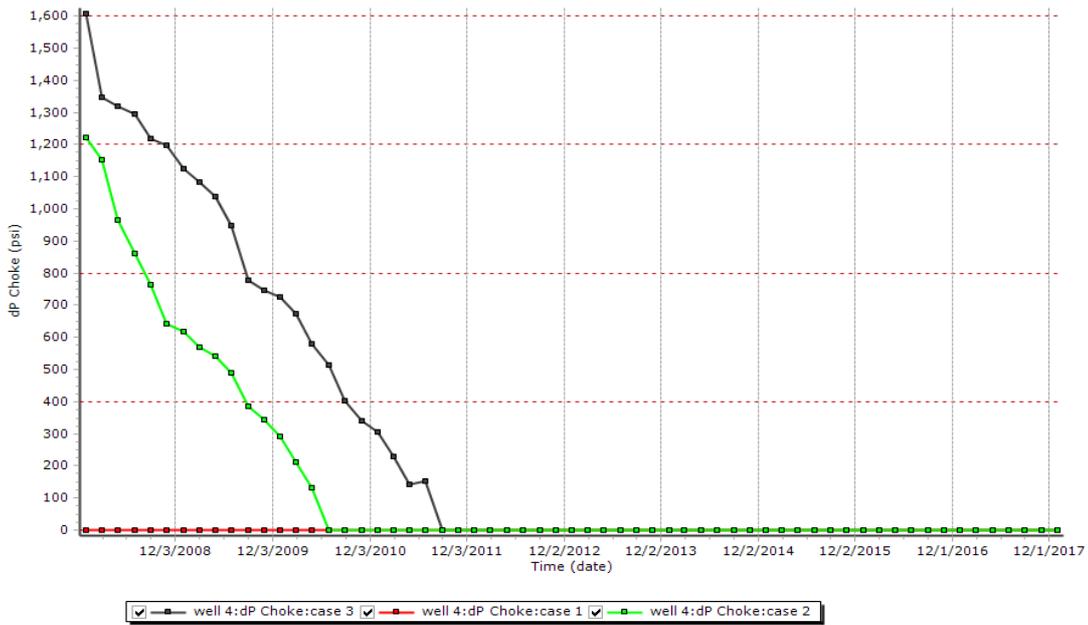
Figure 5.10 Choke Pressure

The dP choke in figure 5.10 represents how much the pressure should be reduced in order to meet the separator pressure constraint of 1000psig in respect to well 2.

In the case of low diameter, the well was operating at a relatively low wellhead pressure and no dP choke was necessary. As the diameter increase, the wells operate at a higher pressure, and thus the well had to be choked. The dP choke in case 2 and case 3 is 1200psi and 1600psi respectively for well 2.

5.3.3 Separator

The separator in this simulation is the end of the production chain. It has a known pressure of 1000psig and a gas capacity of 250MMscf/day. The gas rate should not be more than 250MMscf/day. From the three cases presented, both of them have satisfied the given constraint.
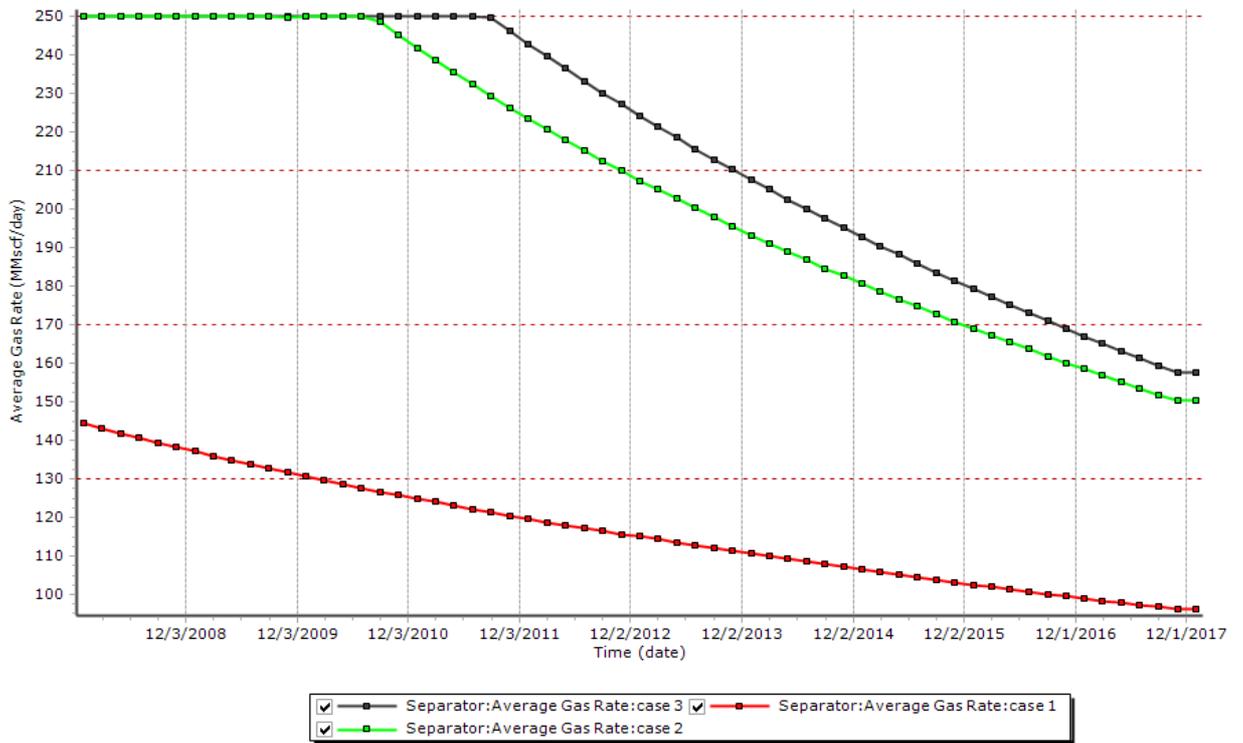
Figure 5.11 Separator Production Rate

Production with bigger pipe diameters results in higher gas production as depicted in the figure 5.11. Plateau will be maintained for approximately two years and 3 years for case 2 and case 3 respectively. If production is to be carried out with low diameter pipeline, the average gas rate is smaller compared to the other cases.

Separator	Average liquid rate	Average oil rate	Average gas rate	Separated gas rate	Separated water rate	Water cut	GOR	Active wells
	STB/d	STB/d	MMscf/day	MMscf/day	STB/day	%	Scf/STB	
Case 1	3730	3569	160	158	160	4.31	43065	4
Case 2	5805	5555	249	246	250	4.31	45003	4
Case 3	5805	5555	249	246	250	4.31	43065	4

Table 5.5 Separator results

At the separator, gas, oil and water are produced. The liquid in all cases is mainly dominated by oil. Water is also produced in all cases with a maximum rate of

250STB/day for case 2 and case 3. The gas rate as expected is higher in case 2 and case 3 exhibiting a maximum of 249.998STB/day in respect to case 2. Water was separated from the flowing gas.

The water cut in all cases is the same, while the gas oil ratio differs slightly. The first case exhibits a slightly smaller GOR while the remaining cases have a GOR of similar value. This shows change in diameter has a less influence on the ratio of gas produced to oil; this is mostly influence by the operating temperature and pressure. In the ten years period of productions, all the wells remain active possibly signaling that the wells can produce further.

5.6 Pipeline result

	Case 1	Case 2	Case 3
Flow Assurance	**Bottleneck**	**None**	**None**
Production Target	**No**	**Yes**	**Yes**
Constraints	**Satisfied**	**Satisfied**	**Satisfied**
Pressure Drop	**Huge**	**Medium**	**Low**

Figure 5.12 Summary of Pipeline Result

In case 1 where low diameter size was used, bottlenecking occurs. The bottlenecking occurs at the pipe that transports the entire produced fluid to the separator. This is something common because the quantity of fluid is significantly huge compared to the one from the individual wells.

Pipe segment	Average gas rate	Upstream		Downstream		dP Friction	dP Acceleration	ΔP	Max Mixture Velocity
		Pressure	Temperature	Pressure	Temperature				
	MMscf/d	psi	ºF	psi	ºF	psi	psi	psi	Ft/s
WH1 to Manifold_A	74.7	1681	116	1025	110	655.5	0.18	655.7	65.6
WH2 to Manifold_A	48.9	1443	113	1025	101	418.3	0.04	418.3	63.6
WH3 to Manifold_B	65.7	1382	116	1020	111	362.5	0.06	362.5	90.6
WH4 to Manifold_B	60.7	1338	115	1021	110	317.3	0.05	317.7	85.3
Manif_A to Manifold_B	123	1025	106	1021	103	3.98	0	3.98	22.7
Manifold_A to Sep Joint	249	1021	106	1000	104	21.25	0	21.25	45.884

Table 5. Detailed result of the pipelines

From table 5, the pressure drop in all the pipelines is due to friction. The pipes are horizontal with no elevation, so the pressure loss due to gravity is negligible. The pressure due to acceleration is calculated but it has a very low value.

Chapter 6.0 Economic analysis

Economic analysis will be performed to select the optimum diameter that will deliver the gas at the separator. In the case of small diameter pipe, they have a low initial investment but at the same time, the cumulative production will be low thus affecting the revenue. Big diameter pipes are associated with a high initial investment but at the same time with high cumulative production thus increasing the revenue. In this thesis, an economic analysis was conducted for every case to see which investment will be more profitable at the end of the ten-year period.

6.1 Capital cost

Capital cost can be breakdown into several other costs. Here, the capital cost will be the cost of pipe material, the cost of shipping and labor. To determine the cost of pipe material, the material used in study is galvanized iron, and the price per length for varying size was obtained from an article (Sonowal 2015). The pipe with diameters 40, 50, 70, 90, 110 and 160 mm were chosen to develop mathematical formulae.

The table below present the relationship between cost and diameter

Pipe diameter (mm)	Cost per unit length ($)
12.7	0.153
19.1	0.229
25.4	0.305
31.8	0.382
38.1	0.457
50.8	0.610
63.5	0.762
76.2	0.914
127	1.524

Table 6.1: diameter cost relationship of galvanized iron pipes.

The cost and diameter relationship was plotted in the form of linear plots are shown in the figure below. Power curve equations between cost and diameter of the pipe were developed from the plot along with the coefficient of regression (R2) values. Trend line was also plotted.

Table 6.2 shows linear relationship between cost and diameter because the primary cost influencer is the diameter so as the diameter of the pipe increase the cost does too.

Cost diameter relationship

$P = 0.012(d) + 0.0003$

$R^2 = 1$
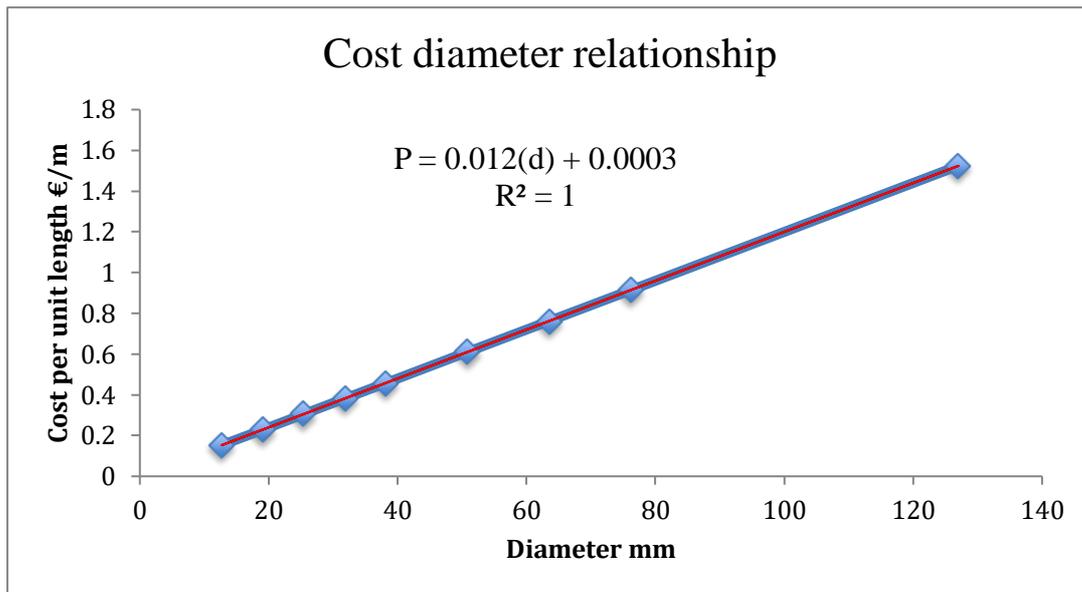
Table 6.2 cost diameter plots

	Cost $ (million)
Case 1	0.9
Case 2	5.s3
Case 3	9.2

Table 6.3 Cost estimations of the three cases in study

6.2 Revenue

This is the expected amount of money generated by selling the gas produced. This will depend on the cumulative production from the three cases

	Gas Cumulative production (MMscf)
Case 1	425,000
Case 2	750,000
Case 3	800,000

Table 6.4 cumulative productions per individual case

Wit the average gas price of $4/Mscf; the total amount that will result from the produce gas is given below.

	Revenue $ (Billion)
Case 1	1.7
Case 2	3.0
Case 3	3.2

Table 6.5 Revenue calculated for the three cases.

6.3 Present Worth Analysis

In other to determine the current value of the future amount, present worth analysis is carried out. The present value always exhibits a value less than the future value. In all the three cases in this thesis, they have an equal production life of ten years. The alternatives (three cases) are mutually exclusive meaning that the choice of one is at the expense of the other two cases. Since the cases here are mutually exclusive alternatives, the one with the largest Present worth will be selected as the best among the alternatives.

Problem formulation

	Cost (Million $)	Revenue (Billion $)
Case 1	0.9	1.7
Case 2	5.3	3.0
Case 3	9.2	3.2

Table 6.6 Cost versus revenue comparison.

The costs represent the cost of the pipe material. The smaller the diameter, the less iron required thus the less the cost. Case 3 being the one with the biggest diameter, has the much cost.

$$PW_. = -cost + revenue\left(\frac{p}{f}, i\%, n\right)$$

PW = Present worth

I = Interest rates (6%)

N= years (10)

p/f = present value factor

The equation was used to conduct calculation to find the present worth. Where current interest rates in the United States is 6%. The present value factor is used to bring the future worth of money to present because any amount of money received today is worth more if the same amount is to be received at an after date.

	Present Worth $ (Billion)
Case 1	1.26
Case 2	2.25
Case 3	2.29

Table 6.7 Present Worth per individual case

The present worth shows case 3 to be more favorable followed by case 2 then case 1. The size of pipe used in case 3 is double the size of pipe used in case 2. And the size of pipes used in case 2 are double the size of pipes used in case 1. Case 2 exhibits a present worth almost double that of case 1 as shown in table 6.7, while The difference in present worth of case 2 and case 3 is not significant enough compared to the huge diameter increase.

Conclusion

The results obtained from the simulation shows case 3 to have the highest cumulative production of gas compared to the remaining two cases followed by case 2 and then case 1. Case 3 has a total production of 800 BScf where as case 2 and case 1 has 750,000 and 425,000MMScf respectively.

To draw conclusion on the best possible case, monetary value of the three cases can be put into consideration. Giving the current price of gas at 2.5$/gal, the total revenue obtained from selling the cumulative produce gas is calculated and yields for case 1 €**1.7 billion** and €**3.0 billion,** €**3.2 billion** for case 2 and case 3 respectively.

Since each year's gas production is sold separately, it will be wrong to assume the total revenue after ten years due to the time value of money and the interest rate.

A more thorough economic analysis using present worth was carried out where the initial capital investments of the three cases were considered. The interest rate was spread each year over the period of production. As a result, case 3 provides the highest present worth value of 2.28 billion followed by case 2 with 2.25 billion and then case 3 with 1.26 billion.

An economist will conclude that case 3 is the best option, since it shows the highest present worth. Case 3 has a present worth 300 million higher than case 2. But the more feasible case here is case 2. Because case 2 utilizes pipeline of average diameter since huge diameter pipelines are associated with higher

operating costs. Furthermore, larger diameter pipelines have a high cost of design due to the amount of material needed for construction and the labor required in constructing them while the opposite is for low diameter pipelines like the case 2 chosen here.

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A mathematical model for the selection of an economical pipe size in pressurized irrigation systems

https://academicjournals.org/journal/AJAR/article-full-text-pdf/B24F64357316

Appendix

Compound Interest Factors

	Single Payment		Uniform Payment Series				Arithmetic Gradient		
	Compound Amount Factor Find F Given P F/P	Present Worth Factor Find P Given F P/F	Sinking Fund Factor Find A Given F A/F	Capital Recovery Factor Find A Given P A/P	Compound Amount Factor Find F Given A F/A	Present Worth Factor Find P Given A P/A	Gradient Uniform Series Find A Given G A/G	Gradient Present Worth Find P Given G P/G	
n									n
1	1.060	.9434	1.0000	1.0600	1.000	0.943	0	0	1
2	1.124	.8900	.4854	.5454	2.060	1.833	0.485	0.890	2
3	1.191	.8396	.3141	.3741	3.184	2.673	0.961	2.569	3
4	1.262	.7921	.2286	.2886	4.375	3.465	1.427	4.945	4
5	1.338	.7473	.1774	.2374	5.637	4.212	1.884	7.934	5
6	1.419	.7050	.1434	.2034	6.975	4.917	2.330	11.459	6
7	1.504	.6651	.1191	.1791	8.394	5.582	2.768	15.450	7
8	1.594	.6274	.1010	.1610	9.897	6.210	3.195	19.841	8
9	1.689	.5919	.0870	.1470	11.491	6.802	3.613	24.577	9
10	1.791	.5584	.0759	.1359	13.181	7.360	4.022	29.602	10
11	1.898	.5268	.0668	.1268	14.972	7.887	4.421	34.870	11
12	2.012	.4970	.0593	.1193	16.870	8.384	4.811	40.337	12
13	2.133	.4688	.0530	.1130	18.882	8.853	5.192	45.963	13
14	2.261	.4423	.0476	.1076	21.015	9.295	5.564	51.713	14
15	2.397	.4173	.0430	.1030	23.276	9.712	5.926	57.554	15
16	2.540	.3936	.0390	.0990	25.672	10.106	6.279	63.459	16
17	2.693	.3714	.0354	.0954	28.213	10.477	6.624	69.401	17
18	2.854	.3503	.0324	.0924	30.906	10.828	6.960	75.357	18
19	3.026	.3305	.0296	.0896	33.760	11.158	7.287	81.306	19
20	3.207	.3118	.0272	.0872	36.786	11.470	7.605	87.230	20
21	3.400	.2942	.0250	.0850	39.993	11.764	7.915	93.113	21
22	3.604	.2775	.0230	.0830	43.392	12.042	8.217	98.941	22
23	3.820	.2618	.0213	.0813	46.996	12.303	8.510	104.700	23
24	4.049	.2470	.0197	.0797	50.815	12.550	8.795	110.381	24
25	4.292	.2330	.0182	.0782	54.864	12.783	9.072	115.973	25
26	4.549	.2198	.0169	.0769	59.156	13.003	9.341	121.468	26
27	4.822	.2074	.0157	.0757	63.706	13.211	9.603	126.860	27
28	5.112	.1956	.0146	.0746	68.528	13.406	9.857	132.142	28
29	5.418	.1846	.0136	.0736	73.640	13.591	10.103	137.309	29
30	5.743	.1741	.0126	.0726	79.058	13.765	10.342	142.359	30
31	6.088	.1643	.0118	.0718	84.801	13.929	10.574	147.286	31
32	6.453	.1550	.0110	.0710	90.890	14.084	10.799	152.090	32
33	6.841	.1462	.0103	.0703	97.343	14.230	11.017	156.768	33
34	7.251	.1379	.00960	.0696	104.184	14.368	11.228	161.319	34
35	7.686	.1301	.00897	.0690	111.435	14.498	11.432	165.743	35
40	10.286	.0972	.00646	.0665	154.762	15.046	12.359	185.957	40
45	13.765	.0727	.00470	.0647	212.743	15.456	13.141	203.109	45
50	18.420	.0543	.00344	.0634	290.335	15.762	13.796	217.457	50
55	24.650	.0406	.00254	.0625	394.171	15.991	14.341	229.322	55
60	32.988	.0303	.00188	.0619	533.126	16.161	14.791	239.043	60
65	44.145	.0227	.00139	.0614	719.080	16.289	15.160	246.945	65
70	59.076	.0169	.00103	.0610	967.928	16.385	15.461	253.327	70
75	79.057	.0126	.00077	.0608	1 300.9	16.456	15.706	258.453	75
80	105.796	.00945	.00057	.0606	1 746.6	16.509	15.903	262.549	80
85	141.578	.00706	.00043	.0604	2 343.0	16.549	16.062	265.810	85
90	189.464	.00528	.00032	.0603	3 141.1	16.579	16.189	268.395	90
95	253.545	.00394	.00024	.0602	4 209.1	16.601	16.290	270.437	95
100	339.300	.00295	.00018	.0602	5 638.3	16.618	16.371	272.047	100

Table X

Present worth Analysis

$$PW = -cost + revenue\left(\frac{p}{f}, i\%, n\right)$$

Where

PW = Present worth

I = Interest rates (6%)

N= years (10)

p/f = present value factor

THE COST

Recall from table 6.3, the cost is presented below.

	Cost $ (million)
Case 1	0.9
Case 2	5.3
Case 3	9.2

THE REVENUE

To calculate the revenue, the price of gas is taken as $2.5/gal and a conversion factor

of 0.012 was used to convert scf to gallon.

i.e. Production (gal) * price ($/gal)

Example is: (30000*1000000*0.012) gal * (2.5) $/gal = $914,400,000

Year	Production (Mscf)		
	Case 1	Case 2	Case 3
1	30,000.00	90,000.00	90,000.00
2	60,000.00	90,000.00	90,000.00
3	30,000.00	70,000.00	70,000.00
4	80,000.00	100,000.00	100,000.00
5	25,000.00	75,000.00	75,000.00
6	35,000.00	65,000.00	65,000.00
7	40,000.00	90,000.00	90,000.00
8	50,000.00	45,000.00	50,000.00
9	50,000.00	75,000.00	80,000.00
10	25,000.00	50,000.00	55,000.00

Table Y

Year	Revenue		
	Case 1	Case 2	Case 3
1	914,400,000.00	2,743,200,000.00	2,743,200,000.00
2	1,828,800,000.00	2,743,200,000.00	2,743,200,000.00
3	914,400,000.00	2,133,600,000.00	2,133,600,000.00
4	2,438,400,000.00	3,048,000,000.00	3,048,000,000.00
5	762,000,000.00	2,286,000,000.00	2,286,000,000.00
6	1,066,800,000.00	1,981,200,000.00	1,981,200,000.00
7	1,219,200,000.00	2,743,200,000.00	2,743,200,000.00
8	1,524,000,000.00	1,371,600,000.00	1,524,000,000.00
9	1,524,000,000.00	2,286,000,000.00	2,438,400,000.00
10	762,000,000.00	1,524,000,000.00	1,676,400,000.00

Table Z

PRESENT WORTH

Recall that $PW = -cost + revenue\left(\frac{p}{f}, i\%, n\right)$

Since the cost and revenue has been calculated, the only unknown is the present value factor. Table X was used to identify the present value factor for every year for the ten-year production period.

1.e. for the first year, the p/f is 0.9434 then utilizing the present worth equation will yield

PW_1= - 900,000*(914,400,00*(0.9434)) = $861,744,960

Year	P/F	Present Worth		
		Case 1	Case 2	Case 3
1	0.9434	861,744,960.00	2,582,634,880.00	2,578,734,880.00
2	0.89	1,627,632,000.00	2,441,448,000.00	2,441,448,000.00
3	0.8396	767,730,240.00	1,791,370,560.00	1,791,370,560.00
4	0.7921	1,931,456,640.00	2,414,320,800.00	2,414,320,800.00
5	0.7473	569,442,600.00	1,708,327,800.00	1,708,327,800.00
6	0.705	752,094,000.00	1,396,746,000.00	1,396,746,000.00
7	0.6651	810,889,920.00	1,824,502,320.00	1,824,502,320.00
8	0.6274	956,157,600.00	860,541,840.00	956,157,600.00
9	0.5919	902,055,600.00	1,353,083,400.00	1,443,288,960.00
10	0.5584	425,500,800.00	851,001,600.00	936,101,760.00
		9,604,704,360.00	17,223,977,200.00	17,490,998,680.00

Table XY