AN ANALYTICAL STUDY OF PRODUCTION OPTIMIZATION AND WELL COMPLETION DESIGN

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An Analytical Study of Production Optimization and

Well Completion Design

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CERTIFICATE

This is to certify that Sagun Devshali, Aditya Kotiyal and Apurv Agarwal, students of B.Tech (Applied Petroleum Engineering) have written their thesis on "An Analytical study of Production Optimization and Well Completion Design" under my supervision and have successfully completed their project within the stipulated time.

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Abstract

This work presents a theoretical and numerical algorithm that permits the production optimization of oil/gas wells using the concept of nodal analysis and producing the well completion design using the optimum size of the tubing string. The study of the reservoir drive mechanisms is followed by the flowing well performance for the radial flow theory and the multiphase theory within the reservoir.

The IPR behaviour of the well is explained using both the Vogel's method and the Fetkovich's method. Pressure gradient curves are used to plot VLP curves for nodal analysis. And the validation of all the curves is done by PROSPER. The other part of the project includes determining the free length changes and the changes in the forces due to the effect of various stimulation processes.

The completion design based on the optimum tubing sizes with explanation of various completion equipments have been included. The theoretical part is being supported by analysing two different case studies, one based on the optimization using nodal analysis and the other one for the tubing movement with the results, there validation and discussions.

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1. INTRODUCTION

1.1 BACKGROUND

The critical goal of practically all effort spent on modelling a petroleum field is to work out an optimal approach to develop, handle, and control the field. For some petroleum fields, optimization of production operations can be a major factor in increasing production rates and reducing production costs. In petroleum fields, hydrocarbon production is often forced by reservoir conditions, deliverability of the pipeline network, fluid managing capability of facilities, safety and economic considerations. The duty of field operators is to develop best possible operating strategies to accomplish certain operational goals.

These goals can vary from field to field and with time. Typically one may wish to maximize daily oil rates or minimize production costs. This research aims to develop optimization methods that ease and automate the decision making of field operators for certain operations. In this section, the major components (the objective, the control variables, and the constraints) of the petroleum field optimization problem are described in detail. Production optimization using nodal analysis is being done to find the optimum size for tubing string. Various forces acting on the tubing string during stimulation processes are also being determined.

1.2 AIM OF THE PROJECT

The aim of the project is to design the optimum completion design for afield. Production optimization using nodal analysis has been done to find the optimum sizes for the tubing strings. Various forces acting on tubing string during stimulation processes like acidization, fracturing etc are also determined.

1.3 PROJECT OBJECTIVES

The main objectives of this project include:

- To devise optimal operating strategies to achieve operational goals.
- Optimize the producing well configuration so that the net profit over the life of the well is maximized.
- To calculate different types of movements acting on tubing string during stimulation.

1.4 SCOPE OF THE PROJECT

The project includes the determination of optimum tubing size using production optimization. Pressure gradient curves have been used to plot VLP curves for nodal analysis. All the curves have been validated using PROSPER. The second part of the project includes the determination of free length changes and the changes in the forces due to the effect of various stimulation processes. The need for the completion design to be optimum and the detailed analyses of the various completion equipments are covered during this project with the help of two case studies.

The project does not include the detailed completion design procedures and steps for the completion of any well.

1.5 PROJECT METHODOLOGY

In petroleum fields, hydrocarbon production is often constrained by reservoir conditions, deliverability of the pipeline network, fluid handling capacity of facilities, safety and economic considerations, or a combination of these considerations. In the present study, optimization of production system design and operation has been performed by nodal analysis combined with trial and error. For example, by holding all other parameters fixed, a single variable is varied to see which value of this variable gives the optimal objective function value. IPR and VLP curves for different tubing sizes are drawn and the results are validated using the software PROSPER.

The project aims to cover the major considerations of completion design. The results of production optimization are integrated with the completion parameters and the systematic completion design for the well is drawn.

1.6 PROJECT LIMITATIONS

The main limitation of the project is the complete analysis of the optimum sizes of all the completion jewels using production optimization for live field data. The project does not cover the complete analysis of the tubing design in terms of burst, collapse, and triaxial forces.

2. LITERATURE REVIEW

INTRODUCTION TO PRODUCTION SYSTEM

The ***production system*** is a composite term describing the entire production process and includes the following principal components:-

(1) The reservoir - it productive capacity and dynamic production characteristics over the envisaged life of the development.
(2) The wellbore - the production interval, the sump and the fluids in the wellbore
(3) Production Conduit - comprising the tubing and the tubing components
(4) Wellhead, Xmas Tree and Flow Lines
(5) Treatment Facilities

These are shown in following figure

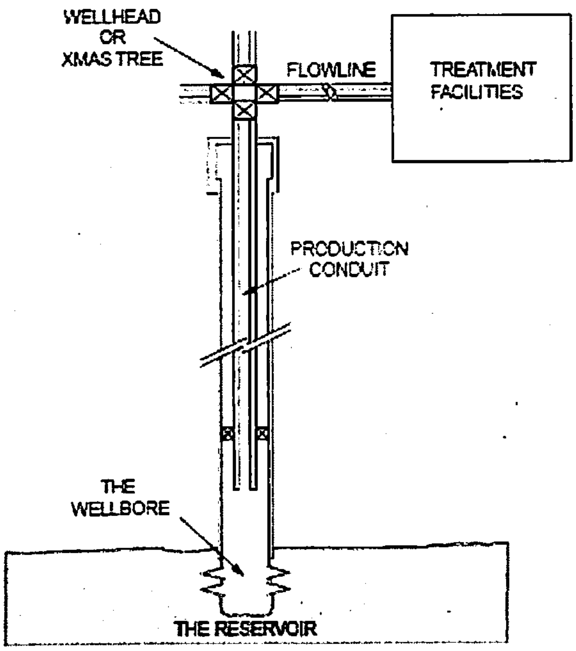


Figure 1: Elements of the production technology system

The role of the Production Technologist is one of achieving optimum performance from the production system and to achieve this the technologist must understand fully the chemical and physical characteristics of the fluids which are to be produced and also the engineering systems which will be utilised to control the efficient and safe production/injection of fluids.

The main disciplines which are involved in Production Technology are:
(1) Production Engineering:
- Fluid flow
- Reservoir dynamics
- Equipment design, installation, operation and fault diagnosis

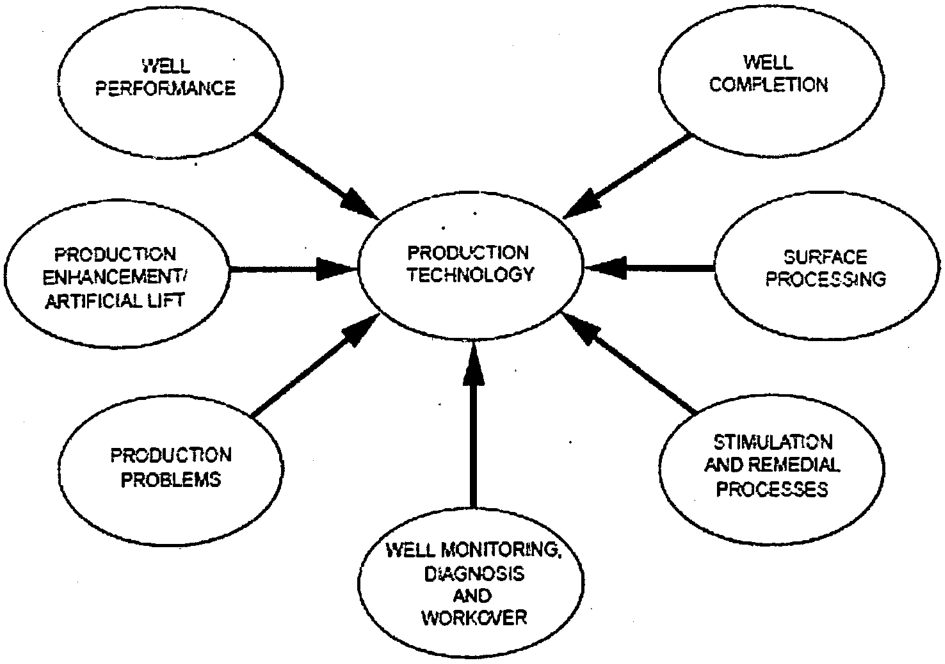
(2) Production Chemistry:

- The Fluids - produced, injected and treatment fluids
- The Rock - mineralogy, physical/chemical properties and rock strength and response to fluid flow

2.1 KEY SUBJECT AREAS IN PRODUCTION TECHNOLOGY

Production technology is both a diverse and complex area. With the on-going development of the Petroleum Industry the scope of the technological activities continues to expand and as always increases in depth and complexity. It is however, possible to identify several key subject areas within Production Technology namely:-

1) Well Productivity
2) Well Completion
3) Well Stimulation
4) Associated Production Problems
5) Remedial and Workover Techniques
6) Artificial Lift / Productivity Enhancement
7) Surface Processing



2.1.1 Well Productivity

An oil or gas reservoir contains highly compressible hydrocarbon fluids at an elevated pressure and temperature and as such, the fluid stores up within itself considerable energy of compression. The efficient production of fluids from a reservoir requires the effective dissipation of this energy through the production system. Optimum utilisation of this energy is an essential part of a successful completion design and ultimately of field development economics. Where necessary and economic, this lift process can be supported by artificial lift using pumps or gas lift.

The productivity of the system is dependent on the pressure loss which occurs in several areas of the flow system namely:-

- The reservoir
- The wellbore
- The tubing string
- The choke
- The flow line
- The separator

Under natural flowing conditions, the reservoir pressure must provide all the energy to operate the system i.e. all the pressure drop in the system.

$P_R = P_{SYSTEM} + P_{SEP}$

where;

P_R = reservoir pressure

P_{SYSTEM} = total system pressure drop

P_{SEP} = separator pressure

The optimum distribution of energy between these various areas has a major bearing on the cost effectiveness of a well design and hence production costs. The pressure drop which occurs across the reservoir, P_{RES} and is defined as the ***inflow performance relationship*** or ***IPR***. The pressure drop and causes floe is in the tubing and wellbore P_{TBG} is that which occurs in lifting the fluids from the reservoir to the surface and it is known as the ***vertical lift performance*** or ***VLP***, or ***the tubing performance relationship*** or ***TPR***, i.e. for natural flow $R = P_{RES} + P_{TBG} + P_{TH}$

Where;

P_{TH} = Tubing head pressure

The pressure drop across the reservoir, the tubing and choke are rate dependant and these relationships therefore define the means by which we can optimise the production of the fluid from the reservoir.

2.1.2 Well Completion

Historically the major proportion of production technology activities have been concerned with the engineering and installation of the down hole completion equipment. The completion string is a critical component of the production system and to be effective it must be efficiently designed, installed and maintained. Increasingly, with moves to higher reservoir pressures and more hostile development areas, the actual capital costs of the completion string has become a significant proportion of the total well cost and thus worthy of greater technical consideration and optimisation. The completion process can be split into several key areas which require to be defined including:-

(1) The fluids which will be used to fill the wellbore during the completion process must be identified, and this requires that the function of the fluid and the required properties be specified.

(2) The completion must consider and specify how the fluids will enter the wellbore from the formation i.e., whether infact the well will be open or whether a casing string will be

run which will need to be subsequently perforated to allow a limited number of entry points for fluid to flow from the reservoir into the wellbore.

(3) The design of the completion string itself must provide the required containment capability to allow fluids to flow safely to the surface with minimal loss in pressure.

2.1.3 Well Stimulation

The productivity of a well naturally arises from the compressed state of the fluids, their mobility and the flow properties of the rock, primarily in terms of permeability. In some cases reservoirs may contain substantial reserves of hydrocarbons but the degree of inter-connection of the pore space and the ease with which the fluids can flow through the rock, may be very poor. In such situations it may be beneficial to stimulate the production capacity of the well. Stimulation techniques are intended to:-

(1) Improve the degree of inter-connection between the pore space, particularly for low permeability or vugular rocks
(2) Remove or bypass impediments to flow, e.g.. damage.
(3) Provide a large conductive hydraulic channel which will allow the wellbore to communicate with a larger area of the reservoir.

In general, there are four principal techniques applied, namely:-

(1) ***Propped Hydraulic Fracturing***
(2) ***Matrix Acidization***
(3) ***Acid Fracturing***
(4) ***Frac Packing***

2.1.4 Associated Production Problems

The on going process of producing hydrocarbons from a well is a dynamic process and this is often evidenced in terms of changes in the rock or fluid production characteristics.

Problems are frequently encountered as a results of:-

(1) ***Physico-chemical changes*** of the produced fluids as they experience a temperature and pressure reduction as a result of flow through the reservoir and up the wellbore. This can result in a deposition of heavy hydrocarbon materials such as asphaltenes and waxes.

(2) Incompatibility between reservoir fluids and those introduced into the wellbore which may result in formation damage, e. g., scale deposits or emulsions.

(3) The mechanical collapse or breakdown of the formation may give rise to the production of individual grains or "clumps" of formation sand with the produced fluids.

(4) In formations containing siliceous or clay fines, these may be produced with the hydrocarbons creating plugging in the reservoir and wellbore.

(5) Corrosion due to the inherent corrosive nature of some of the components contained in the hydrocarbon system, for example, hydrogen sulphide (H2S), carbon dioxide (CO2), etc. chloride ions in produced water and oxygen in injected water can also create corrosion

2.1.5 Remedial and Workover Techniques

The production technologist is responsible for monitoring and ensuring the ongoing safe operation of the well. As such the responsibilities include:-
The identification and resolution of problems that will occur with the production system. This area of work is critical to the on going viability of field developments and wells, and can be sub divided into a number of areas namely:-

(1) ***Identification of problems and their source*** - this is normally conducted on the basis of surface information which indicates changes in production character istics such as rate and pressures. In addition down hole investigations using ***production logging techniques and transient pressure surveys*** (flow tests) can also help to identify the location of problems and the reasons for the changes
(2) ***Plan the required corrective action*** - this requires considerable attention to detail and will necessitate:-
(a) Identifying the equipment, manpower and other capabilities required.
(b) Identification and assessment of the unknowns/uncertainties.
(c) Identification and evaluation of the key safety points and mile stones.
(3) The assessment of the probability of technical and economic success.
(4) To identify the required resources, skills and their supervision.

2.1.6 Artificial Lift

As stated above, wells will produce under natural flow conditions when reservoir pressure will support sustainable flow by meeting the entire pressure loss requirements between the reservoir and separator. In cases where reservoir pressure is insufficient to lift fluid to surface or at an economic rate, it may be necessary to assist in the lift process by either:-

• Reducing flowing pressure gradients in the tubing e.g. reducing the hydrostatic head by injecting gas into the stream of produced fluids. This process is known as gaslift.

• Providing additional power using a pump, to provide the energy to provide part or all of the pressure loss which will occur in the tubing. In the case of gas lift, the pressure gradients will be reduced because of the change in fluid composition in the tubing above the point of injection. When pumps are used, apart from fluid recompression and the associated fluid properties, there is no change in fluid composition.

2.1.7 Surface Processing

In some cases surface processing falls within the domain of production technology but in other cases it is the responsibility of a separate production department. The objectives of surface processing are as follows:-

(1) To effectively separate oil, gas, water and remove other produced materials such as sand.

(2) To monitor and adjust the chemical properties prior to separation/transport/ reinjection for example:-

- Deaeration
- Defoaming
- Filtration
- Scale Inhibition

2.2 RESERVOIR PRODUCTION CONCEPTS

RESERVOIR DEPLETION CONCEPTS

The basic concept regarding the production of fluid from a reservoir is that for fluid to be produced as a result of its high pressure, then the reservoir system will deplete and must therefore compensate for the loss of the produced fluid by one or more of the following mechanisms:

(1) Compaction of the reservoir rock matrix
(2) Expansion of the connate water
(3) Expansion of hydrocarbon phases present in the reservoir:
    (a) If the reservoir is above the bubble point, then expansion of the oil in place.
    (b) If the reservoir is below the bubble point then expansion of the co-existing oil and gas phases
    (c) Expansion of any overlying gas cap.
(4) Expansion of an underlying aquifer.

In most cases, as oil is produced, the system cannot maintain its pressure and the overall pressure in the reservoir will decline.

The pressure stored in the reservoir in the form of compressed fluids and rock represents the significant natural energy available for the production of fluids and requires to be optimised to ensure maximum economic recovery.

The mechanism by which a reservoir produces fluid and compensates for the production is termed the **reservoir drive mechanism.**

2.2.1 Reservoir Drive Mechanisms

The reservoir drive mechanism refers to the method by which the reservoir provides the energy for fluid production. There are a number of drive mechanisms and a reservoir may be under the influence of one or more of these mechanisms simultaneously.

Dissolved Gas Drive

A dissolved-gas-drive reservoir is closed from any outside source of energy, such as water encroachment. Pressure is initially above bubblepoint pressure, and, therefore no free gas exists. The only source of material lo replace the produced fluid is the expansion of the fluids remaining in the reservoir. Some small but usually negligible expansion of the connate water and rock may also occur. The reservoir pressure declines rapidly with production until

$$\bar{p}_R = p_b.$$

Since only the oil is expanding to replace the produced fluids. The producing gas/oil ratio will be constant at R= R_{si} during this period.

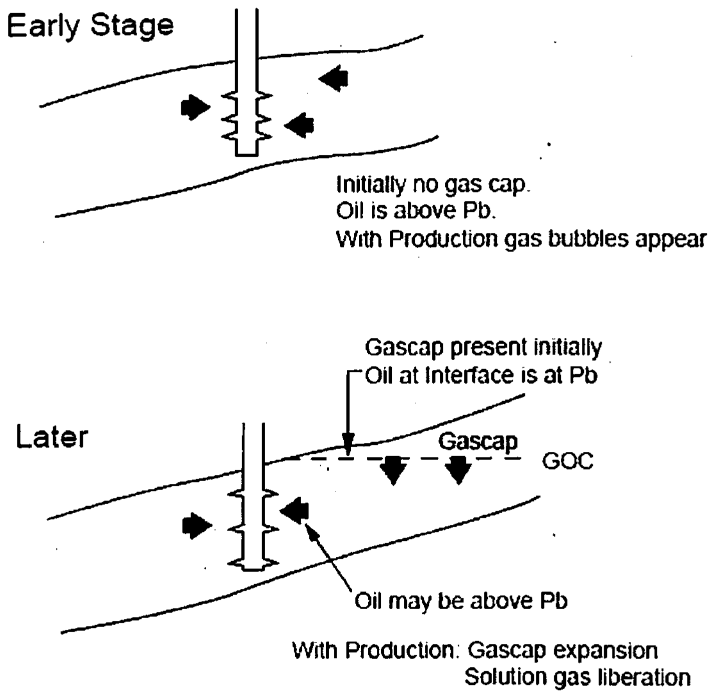


Figure 2: Solution gas drive reservoir in both the early and later stages of production

The gas will come out of solution as dispersed bubbles throughout the reservoir wherever the pressure is below the bubble point but will be concentrated in areas of low pressure such as the rear wellbore area around production wells. However, the relative permeability to the gas will not be significant until the gas saturation within the pore space increases. Thus, until this happens, gas which has come out of solution will build up in the reservoir until its saturation allows it to produce more easily and this will be evident in a reduction in the volumetric ratio of gas to oil produced at surface, ie, the GOR in the short term. The produced GOR may be observed to decline at surface once the bubble point is reached due to the retention of gas in the pore space once liberated. The other effect will be a reduction in the oil production rate because as the gas comes out of solution from the oil, the viscosity and density of the oil phase increases and its formation volume factor decreases (ie, less shrinkage will occur with production).

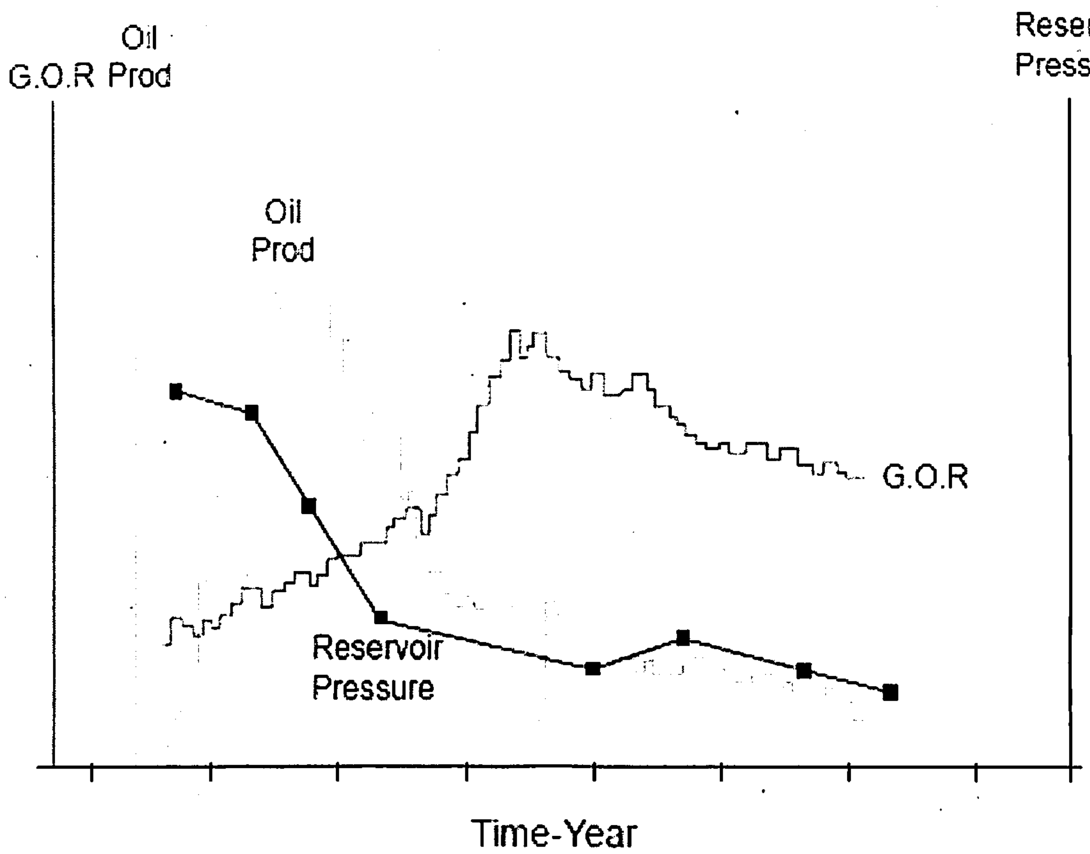


Figure 3: Performance of a solution gas drive reservoir

Gas Cap Expansion drive

A gas cap drive reservoir is also closed from any outside source of energy, but the oil is saturated with gas at its initial pressure and, therefore free gas will exist. As oil is produced the gas cap will expand and help to maintain the reservoir pressure. Also, as the reservoir pressure declines from production, gas will be evolved from the saturated oil. The reservoir pressure will decline more slowly than for a dissolved gas drive. But as the free gas cap expands, some of the up structure wells will produce at high gas/oil ratios. Under primary conditions, the recovery may be between 20% and 40% of the initial oil in place. This may be increased by re -injecting the produced gas into the gas cap. Also, the effects of gravity may in-crease recovery, especially if producing rates are low and the formation has un appreciable clip.

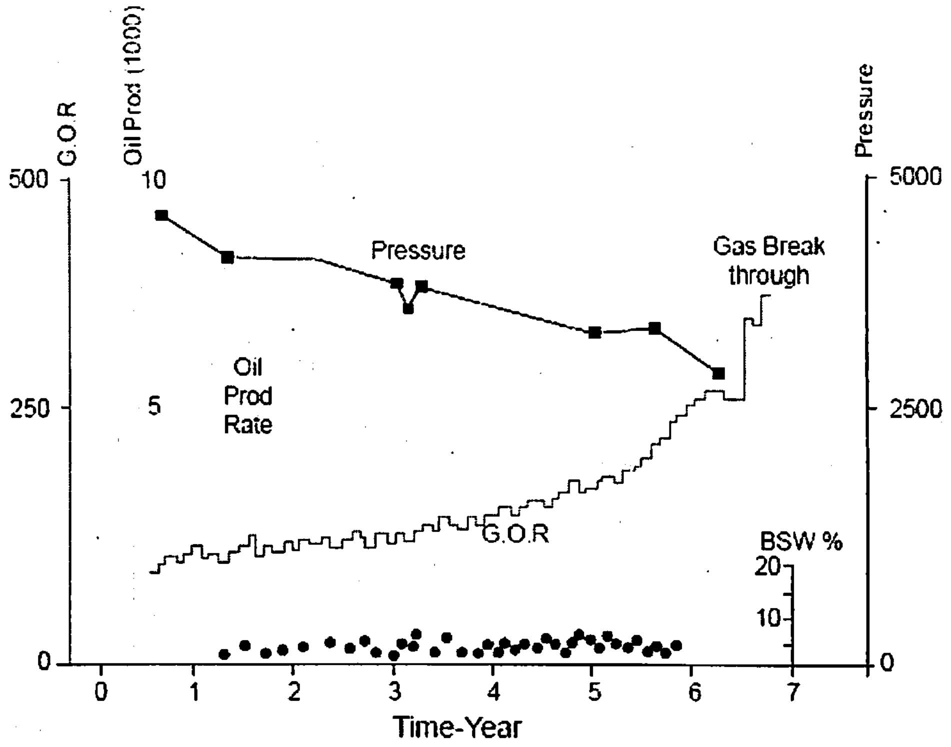


Figure 4: Performance of a gas cap drive reservoir-impact of substantial gas cap

Water Drive Reservoir

In a water-drive reservoir, the oil zone is in contact with an aquifer that can supply the material to replace the produced oil and gas.. The water that encroaches may come from expansion of the water only, or the aquifer could be connected to a surface outcrop. The oil will be under saturated initially, but if the pressure declines below the bubble point, free gas will form and the dissolved-gas drive mechanism will also contribute to the energy for production. The recovery to be expected from a water drive reservoir may vary from 35% to 75% of the initial oil in place. If the producing rate is low enough to allow water to move in as rapidly as oil and gas are produced or if the water drive is supplemented by water injection, recovery may be even higher. If reservoir pressure remains above bubble point, no free gas will form and the pressure function based on p_r, will remain constant.

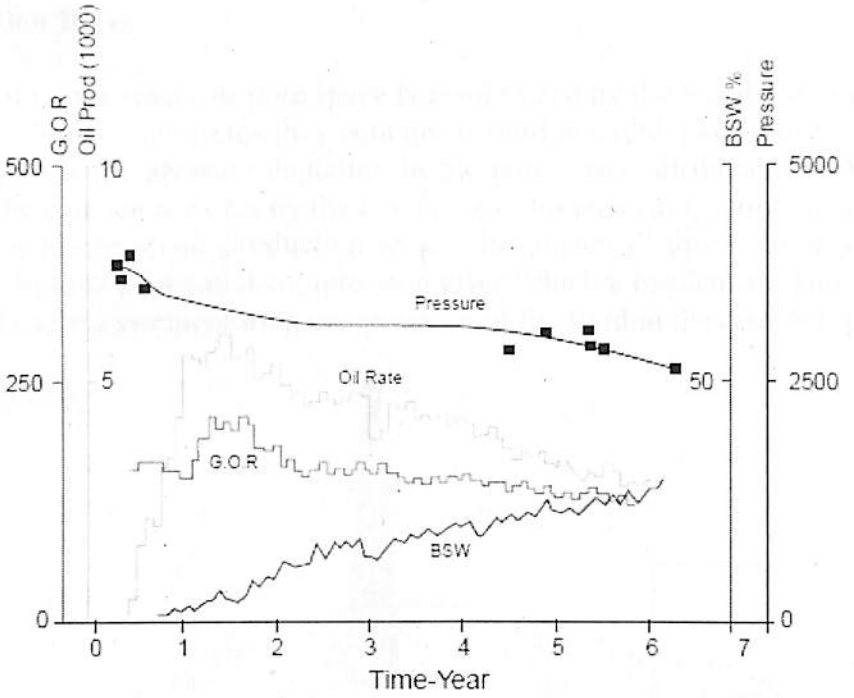


Figure 5: Performance of a well with water drive

Gravity Drive

Efficient gravity drive within a reservoir, although being an ideal recovery mechanism, is less common. In gravity drive, the hydrostatic pressure due to the oil column and pressure of the gas cap provides the drive down dip to a producing well system .In addition the stable upwards expansion of the underlying aquifer supports the oil rim compression although in many cases the aquifer is small or nonexistent. For such a system to be effective requires maximum structural dip, low oil viscosity, good vertical and horizontal permeability, preferably an active gas cap and negligible aquifer activity.

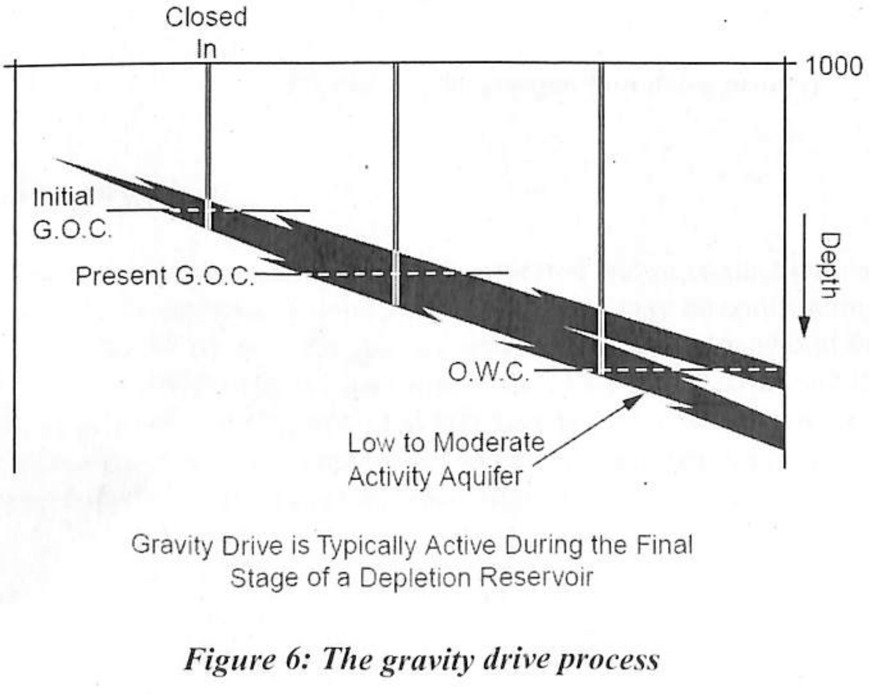


Figure 6: The gravity drive process

Compaction Drive

The oil within the reservoir pore space is compressed by the weight of overlying sediments and the pressure of the fluids they contain. If fluid is withdrawn from the reservoir, then it is possible that the pressure depletion in the pore space attributable to the production of fluid can be compensated for by the overlying sediments compacting lower sediments such as those of the reservoir production zone. The impact of this is to create a reduction in porosity and thus a potential compression effect. Such a mechanism known as compaction drive will cause a compensating compression of the fluid in the reservoir pore system.

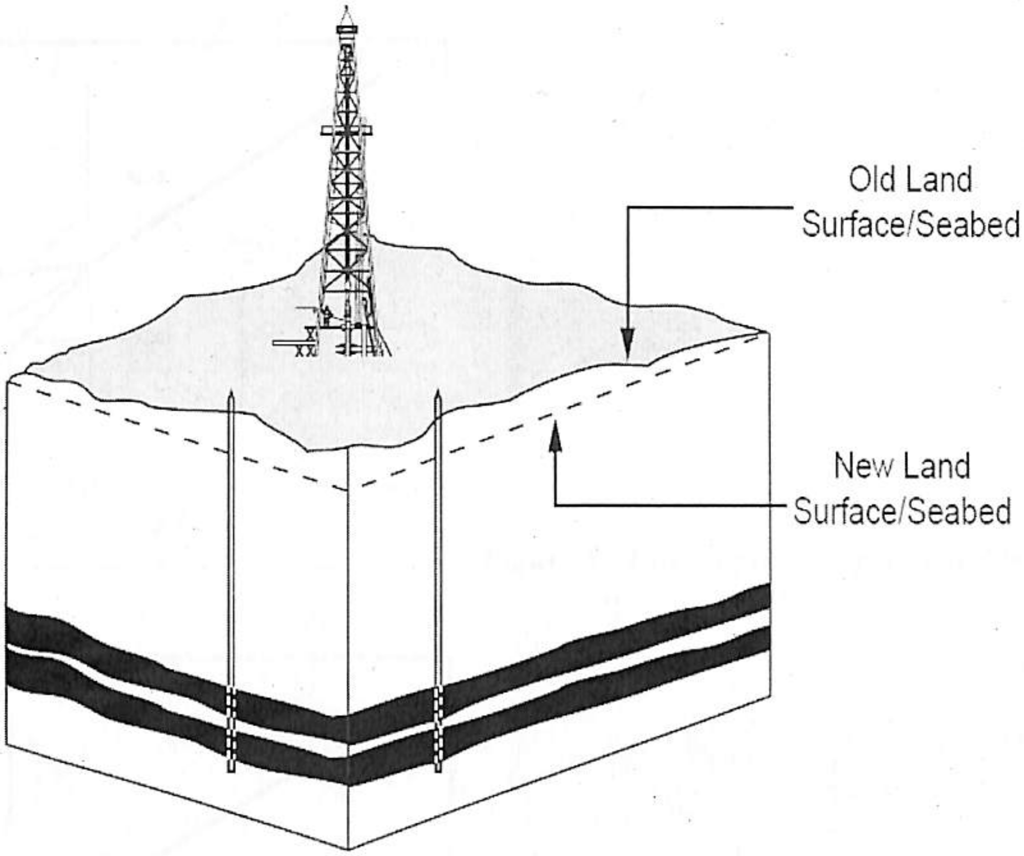


Figure 7: The compaction drive process

Combination Drive

In many cases, an oil reservoir will be both saturated and in contact with an aquifer. In this case, all three of the previously described mechanisms may be contributing to the reservoir drive. As oil is produced, both the gas cap and aquifer will expand and the gas/oil contact will drop as the oil water contact rises, which can cause complex production problems. It is impossible to generalize on the expected recovery and performance of a combination-drive reservoir because of the wide variation in gas cap and aquifer sizes. The drive mechanisms may be supplemented by both gas and water injection.

2.2.2 *Drawdown or Producing rate*

The principal reason for a change in the productivity index was the change in the pressure function, $f(p) = k_{ro} / \mu_o B_o$. If the pressure anywhere in the reservoir drops below bubble point pressure, gas will evolve and the permeability to oil will decrease, causing a decrease in J. Even though the average reservoir pressure may be above p_b to attain a reasonable inflow rate it may be necessary to reduce p_{wf} below p_b. When this happens, a zone of reduced k_{ro} exists around the wellbore out to the radius at which the pressure in the reservoir equals p_b.

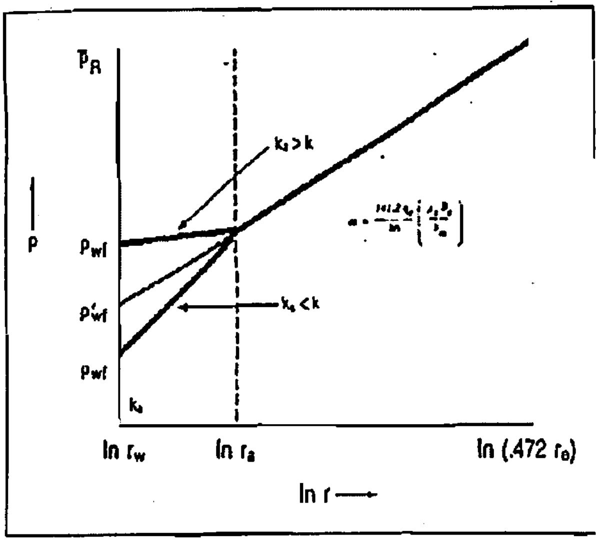


Figure 8: Effect of altered permeability

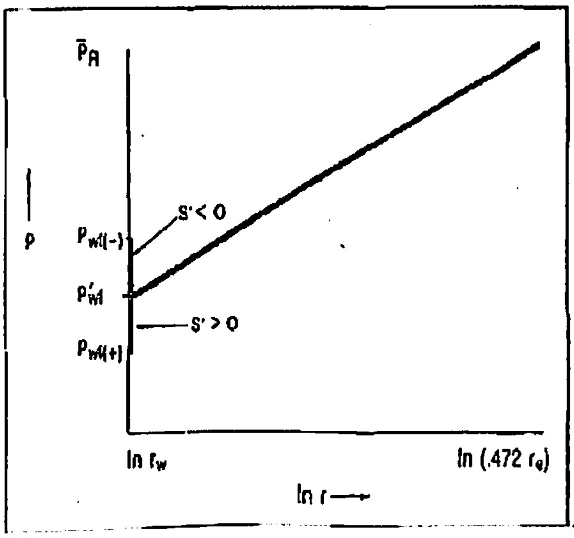


Figure 9: Effects of skin factor

2.2.3 Effect of Depletion

In any reservoir in which the average reservoir pressure is not maintained above the bubble point pressure. Gas saturation will increase in the entire drainage volume of the wells. This will cause a decrease in the pressure function in the form of decreased k_{ro} *which* will cause an increase in the slope of the pressure profile and the IPR. Therefore, to maintain a constant inflow rate to a well it will be necessary to increase the drawdown as p_R declines from depletion.

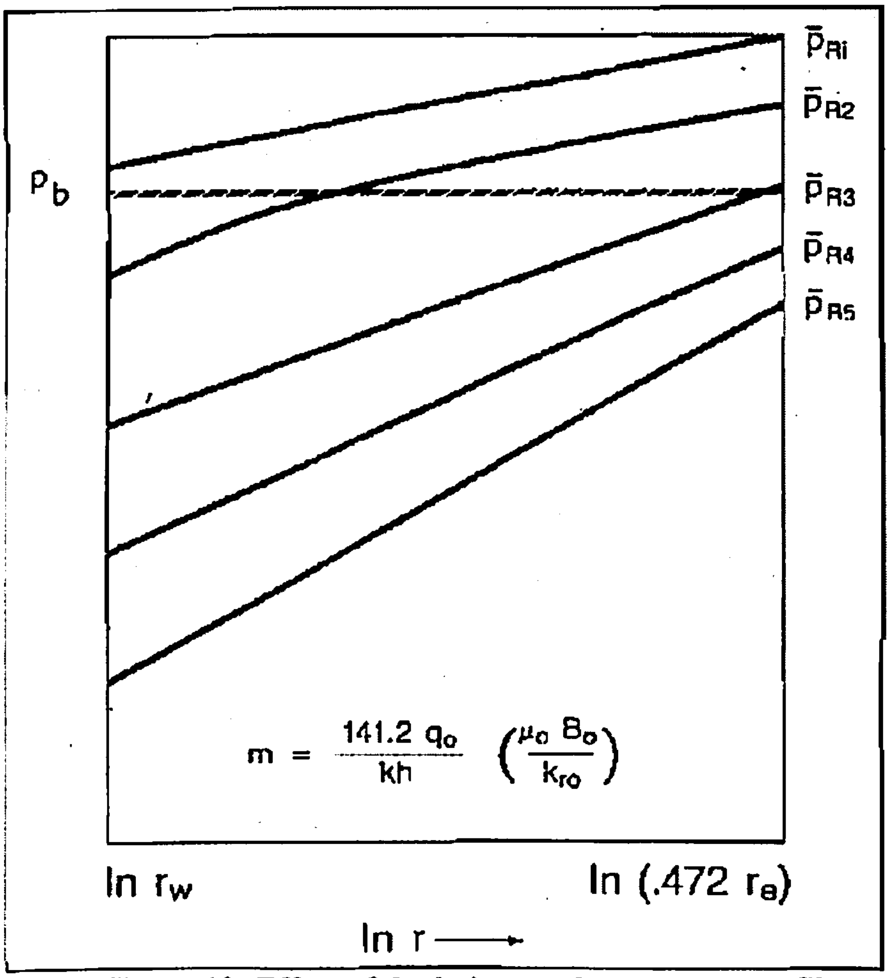


Figure 10: Effect of depletion on the pressure profile

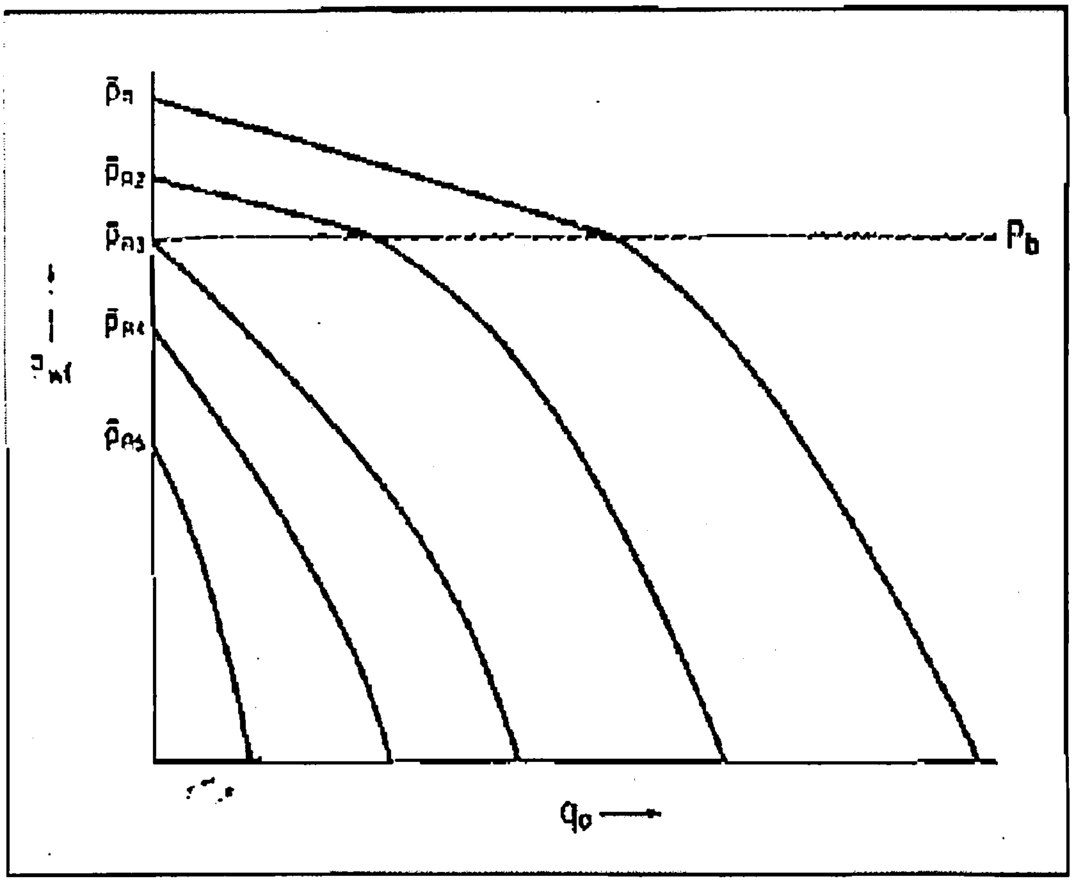


Figure 11: Effect of depletion on the IPR

2.2.4 IPR behaviour of Gas wells

The IPR *for* a gas well will not be linear because the inflow rate is a function of the square of p_{wf}. For dry-gas and wet-gas reservoirs, in which no liquid condenses in the reservoir, gas saturation and, therefore, permeability to gas will remain constant as p_R declines. If turbulent flow exists, the pressure drop due to turbulence will increase with flow rate, causing deterioration in the inflow performance. If no liquid forms in the reservoir, the effect of depletion will not cause a decrease in k_{rg} but turbulence may increase due to the higher actual velocity required to maintain a constant-mass flow rate. Also, the value of the product μZ will change as reservoir pressure changes. In the case of a retrograde condensate-gas reservoir, that is, where *TR* is between the critical temperature and the cricondentherm , if the pressure anywhere in the reservoir drops below the dew point pressure p_d liquid will form and decrease k_{rg}. This can occur from either reducing p_{wf} below p_d or as p_r declines below p_d from depletion. Prediction of retrograde-gas reservoir behaviour or water drive gas reservoir behaviour is very complex and, in most cases, requires the use of a reservoir model.

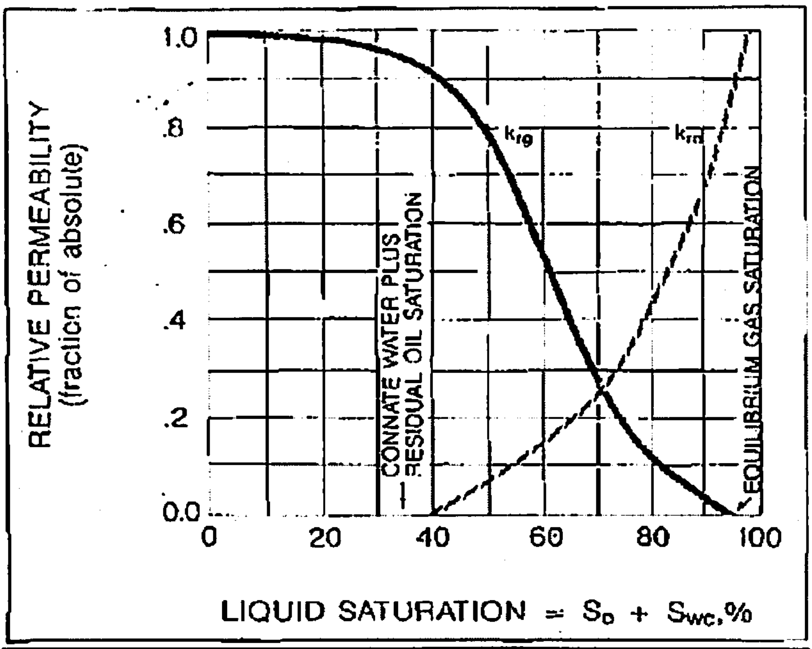


Figure 12: Gas – Oil relative permeability data

<u>**Predicting present time IPR of oil wells**</u>

2.2.4.1 Vogel's METHOD

Vogel reported the results of a study in which he used a mathematical reservoir model to calculale the IPR for oil wells producing from saturated reservoirs. The study dealt with several hypothetical reservoirs including those with widely differing oil cbaractcri5tics, relative permeability characteristics well spacing and skin factors. The final equation for Vogel's method was based on calculations made for 21 reservoir conditions.
The Vogel method was developed by using the reservoir model proposed by Weller to generate IPR's for a wide range of conditions. He then replotted the IPRs as reduced or dimensionless pressure versus dimensionless flow rate. The dimensionless pressure is defined as the flowing wellbore pressure divided by average reservoir pressure, p_{wf} / p_R. The dimensionless flow rate is defined as the flow rate that would result for the value of p_{wf} being considered, divided by the flow rate that would result from a zero wellbore pressure, that is $q_o / q_o(max)$.

After plotting dimensionless IPR curves for all the cases considered, Vogel arrived at the following relationship between dimensionless flow rate and dimensionless pressure:

$$\frac{q_o}{q_{o(max)}} = 1 - 0.2\frac{p_{wf}}{\overline{p}_R} - 0.8\left(\frac{p_{wf}}{\overline{p}_R}\right)^2$$

Where,

q_o = inflow rate corresponding to wellbore flowing pressure

$q_o(max)$= inflow rate corresponding to zero wellbore flowing pressure

p_R = average reservoir pressure existing at the time of interest

The dimensionless IPR *for* a well with a constant productivity index can be calculated from:

$$\frac{q_o}{q_{o(max)}} = 1 - \frac{p_{wf}}{\bar{p}_R}$$

Vogel pointed out that in most applications of his method, the error in the predicted inflow rate should be less than 10%, but could increase to 20% during the final stages of depletion. Errors made by assuming a constant *J, were* found to produce errors on the order of 70% to 80% at low values of p_{wf}.

Application of Vogel's Method- Zero Skin Factor

Saturated Reservoir

The method can be applied to undersaturated reservoirs by applying Vogel's equation only for values of $p_w < p_b$.

Under saturated Reservoir($p_R > p_b$)

Vogel's equation for any flow rate greater than the rate q_b corresponding to $p_{wf} = p_b$

$$\frac{q_o - q_b}{q_{o(max)} - q_b} = 1 - 0.2\frac{p_{wf}}{p_b} - 0.8\left(\frac{p_{wf}}{p_b}\right)^2$$

The reciprocal slope is defined as the change in flow rate with respect to the change in p_{wf} *or,*

$$\frac{dq_o}{dp_{wf}} = (q_{o(max)} - q_b)\left[\frac{-0.2}{p_b} - \frac{1.6\,p_{wf}}{p_b^2}\right]$$

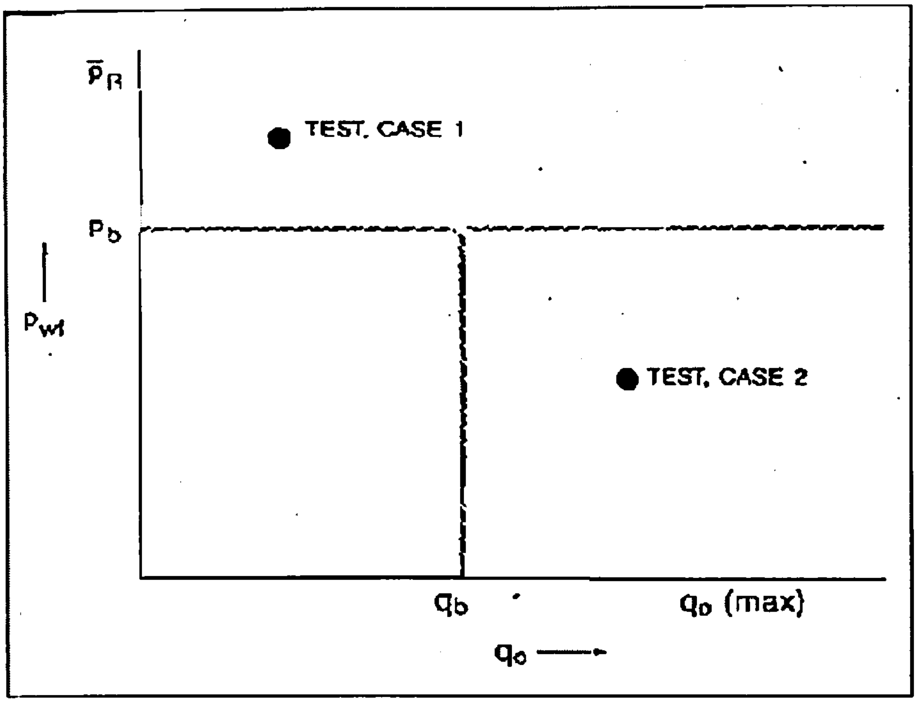


Figure 13: IPR for an undersaturated reservoir

Evaluating the reciprocal slope at $p_{wf} = p_b$ gives

$$-\frac{dq_o}{dp_{wf}} = \frac{q_{o(max)} - q_b}{p_b}(0.2 + 1.6)$$

$$-\frac{dq_o}{dp_{wf}} = \frac{1.8(q_{o(max)} - q_b)}{p_b}$$

In terms of productivity index the above equation becomes as,

$$J = \frac{1.8(q_{o(max)} - q_b)}{p_b}$$

For **saturated reservoir** it becomes as,

$$q_{o(max)} = \frac{J\bar{p}_R}{1.8}$$

After solving we get,

$$q_o = q_b + \frac{Jp_b}{1.8}\left[1 - 0.2\frac{p_{wf}}{p_b} - 0.8\left(\frac{p_{wf}}{p_b}\right)^2\right]$$

<u>**Application of Vogel's Method- Non- Zero Skin Factor**</u>

The method for generating an IPR presented by Vogel did not consider an absolute permeability change in the reservoir. Standings proposed a procedure to modify Vogel's method to account *for* either damage *or stimulation* around the wellbore. The degree of permeability alteration can be expressed in terms of a Productivity Ratio PR *or* Flow Efficiency FE, where:

$$FE = \frac{\text{ideal drawdown}}{\text{actual drawdown}} = \frac{\bar{p}_R - p'_{wf}}{\bar{p}_R - p_{wf}} = \frac{q/J'}{q/J} = \frac{J}{J'}$$

In terms of S' and ? p_{skin},

$$FE = \frac{\bar{p}_R - p'_{wf} - \Delta p_{skin}}{\bar{p}_R - p_{wf}} = \frac{\ln(.472 r_e / r_w)}{\ln(.472 r_e / r_w) + S'}$$

Hence Vogel's Equation becomes as,

$$\frac{q_o}{q_{o(max)}^{FE=1}} = 1 - 0.2\frac{p'_{wf}}{\bar{p}_R} - 0.8\left(\frac{p'_{wf}}{\bar{p}_R}\right)^2$$

2.2.4.2 FETKOVICH METHOD

Fetkovich proposed a method for calculating the inflow performance for oil wells using the same type of equation that has been used for analyzing gas wells for many years. The procedure was verified by analyzing isochronal and flow-after-flow tests conducted in reservoirs with permeabilities ranging from 6 md to greater than 1000 md. Pressure conditions in the reservoirs ranged from highly undersaturated to saturated at initial pressure and to a partially depleted field with a gas saturation above the critical. In all cases, ail-well back-pressure curves were found to follow the same general form as that used to express the inflow relationship for a gas well. That is:

$$q_o = C(\bar{p}_R^2 - p_{wf}^2)^n$$

Where,

q_o = Producing rate

p_R = Avg. Reservoir Pressure

p_{wf} = Flowing wellbore pressure
C= Flow coefficient
n= exponent depending on well characteristics (0.568 to 1)

The applicability of this equation to the oil well analysis was justified y writing Darcy's equations:

$$q = \frac{.00708kh}{\ln\ (.472r_e / r_w) + S'} \int_{p_{wf}}^{\bar{p}_R} f(p)\, dp$$

Where,

$$f(p) = \frac{k_{ro}}{\mu_o B_o}$$

For·an understaurated reservoir, the integral is evaluated over two regions as,

$$q_o = C' \int_{p_{wf}}^{p_b} f_1(p) dp + C' \int_{p_b}^{\bar{p}_R} f_2(p) dp \qquad \text{.................... (a)}$$

Where,

$$C' = \frac{.00708kh}{\ln\ (.472r_e / r_w) + S'}$$

Making substitution in equation (a), we get

$$q_o = C_1(p_b^2 - p_{wf}^2) + C_2(\bar{p}_R - p_b)$$

Fetkovich then stated that the composite effect resu1ts in an equation of the form:

$$q_o = C(\bar{p}_R^2 - p_{wf}^2)^n \qquad \text{.............. (b)}$$

Now taking log on both sides for equation (b),

$$\log\ (\bar{p}_R^2 - p_{wf}^2) = \frac{1}{n} \log\ q_o - \frac{1}{n} \log\ C$$

A plot of $p_R^2 - p_{wf}^2$ versus q_o on log-log scales will result in a straight line having a slope of 1/n and an intercept of $q_o = C$ at $p_R^2 - p_{wf}^2 = 1$.

Three types of tests are commonly used for gas-well testing lo determine C and *n*. These tests can also be used for oil wells and will be described in this section.The type of test to choose depends on the stabilization time of the well, which is a function of the reservoir permeability.If a well stabilizes fairly rapidly, a conventional flow after- flow test can be conducted. For tight wells, an isochronal test may be preferred. For wells with very long stabilization times, a modified isochronal test may be more practical. The stabilization time for a well in the center of a circular or square drainage area may be estimated from:

$$t_s = \frac{380\phi\mu_o C_t A}{k_o}$$

Where,

t_s = stabilization time

Φ = Porosity

C_t= Total fluid compressibility

A= Drainage area

K_o= Permeabiltiy.

2.3PERFORMANCE OF FLOWING WELLS

2.3.1 WELL INFLOW PERFORMANCE

2.3.1.1 Darcy's law

The simplest defining relationship is that postulated by Darcy from his observations on water filtration. The Law applies to so-called linear flow where the cross sectional area for flow is constant irrespective of position within the porous media. Further,

Darcy's Law applies to laminar flow:

$$\frac{q_r}{A} = U = \frac{-k}{\mu}\left[\frac{dP}{d\ell} - \rho g \frac{dD}{d\ell}\right]$$

For a horizontal medium i.e. horizontal flow with no gravity segregation:

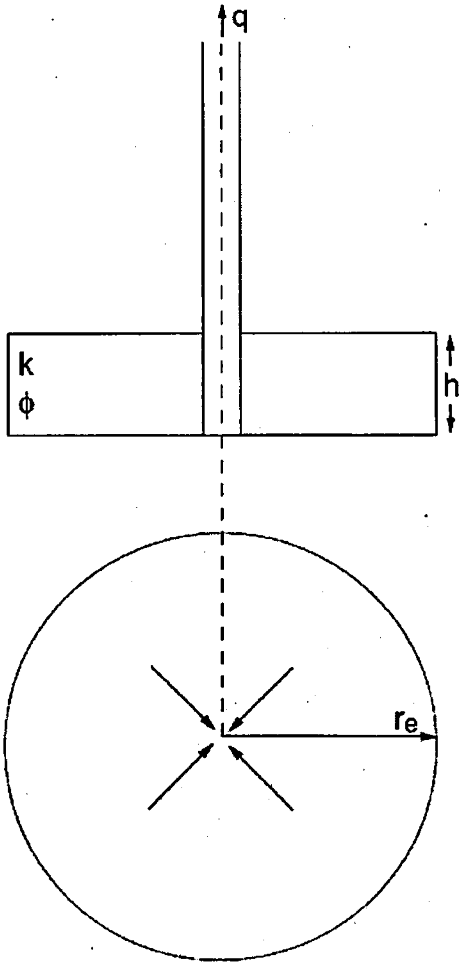
$dD = 0$ and, hence,

$$U = \frac{-K}{\mu} \cdot \frac{dP}{d\ell}$$

2.3.1.2 Radial Flow Theory for Incompressible Fluids

Production wells are designed to drain a specific volume of the reservoir and the simplest model assumes that fluid converges towards a central well as shown in Figure 1. This convergence will cause an increase in fluid velocity as it approaches the wellbore and, as a consequence, an increase in the pressure gradient.

From the above, it is clear that to model more accurately the geometry of the majority of real flowing systems, a different flow model needs to be developed. To account for the convergence effects of flow, a simplified model based upon the assumption of radial flow to a central well located in the middle of a cylindrical reservoir unit is assumed as shown in Figure below.



Two cases are of primary interest in describing reservoir production systems:

(1) Fluid flow occurs into the reservoir across the outer boundary at the drainage radius re. If the volumetric flowrate into the reservoir equals the production rate of fluids from the reservoir, the reservoir is said to be at ***steady state*** conditions i.e. pressure at any part of the reservoir is constant irrespective of the duration of production.

(2) If no fluid flow occurs across the outer boundary then the production of fluids must be compensated for by the expansion of residual fluids in the reservoir. In such a situation,

production will cause a reduction in pressure throughout the reservoir unit. This situation is described as ***semi steady state or pseudo steady state.***

2.3.1.2.1 Steady State - Radial Flow of an Incompressible Fluid

We consider an incompressible fluid, ie, one in which the density is independent of pressure and hence of position. The geometrical model assumed for the derivation of the flow equations is given in Figure above and the terminology defined in Figure below.

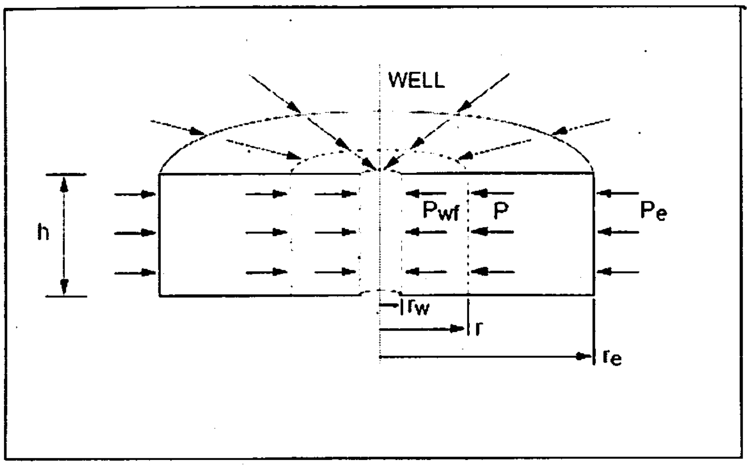


Figure 14: Nomenclature for ideal cylindrical flow

At a radius r the cross sectional area available for flow in 2□rh and the velocity U for a flowrate of q is given by:

$$U = \frac{q}{2\pi rh} \qquad \text{(a)}$$

Using Darcy's Law expressed in radial coordinates;

$$U = \frac{K}{\mu} \cdot \frac{dP}{dr} \qquad \text{(b)}$$

Combining (a) & (b), we get,

$$\frac{q}{2\pi rh} = \frac{K}{\mu} \cdot \frac{dP}{dr} \qquad \text{(c)}$$

Equation (c) can be integrated between the limits of

(i) at the inner boundary i.e. the wellbore sand face.

$r = rw \quad P = Pw$

(ii)at the outer boundary i.e. the drainage radius.
r = re P = Pe

Substituting,

$$\int_{P_w}^{P_e} dP = \frac{q_r\mu}{2\pi kh}\int_{r_w}^{r_e}\frac{dr}{r}$$

After integration and substitution of the boundary conditions.

$$\left[P_e - P_w\right] = \frac{q_r\mu}{2\pi kh}\ln\left(\frac{r_e}{r_w}\right) \qquad \text{(d)}$$

where:

(1) [Pe - Pw] is the total pressure drop across the reservoir and is denoted the ***drawdown***.

(2) qr is the fluid flowrate at reservoir conditions.

If the production rate measured at standard conditions at surface i.e. qs then qs. B = qr

Equation (d) becomes:

$$\left[P_e - P_w\right] = \frac{q_s\mu B}{2\pi kh}\ln\left(\frac{r_e}{r_w}\right)$$

In field units:

$$\left[P_e - P_w\right] = \frac{1}{7.082\text{x}10^{-3}}\frac{q_s\mu B}{kh}\ln\left(\frac{r_e}{r_w}\right) \qquad \text{(d...a)}$$

A plot of Pw versus r indicates how the pressure declines as the incompressible fluid flow and converges towards the wellbore.

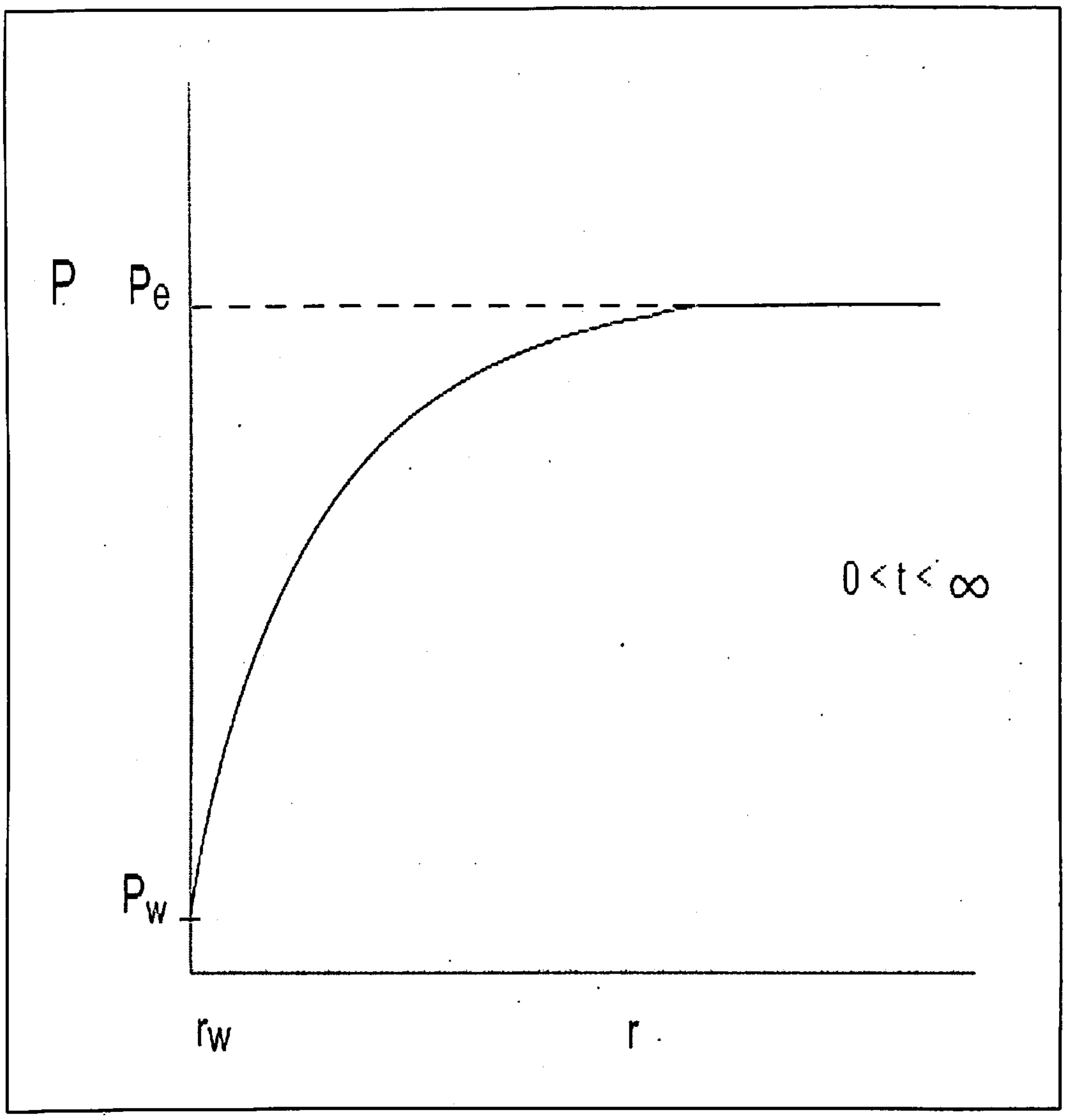


Figure 15: Radial flow ideal pressure profile

2.3.1.2.2 Semi Steady State Radial Flow of a Slightly Compressible Fluid

Under these conditions, flow occurs solely as a result of the expansion of fluid remaining within the reservoir. The reservoir is frequently defined as being bounded since it is assumed that no flow occurs across the outer boundary.

Hence:

$$\left(\frac{dP}{dr}\right)_{r=r_e} = 0 ,$$

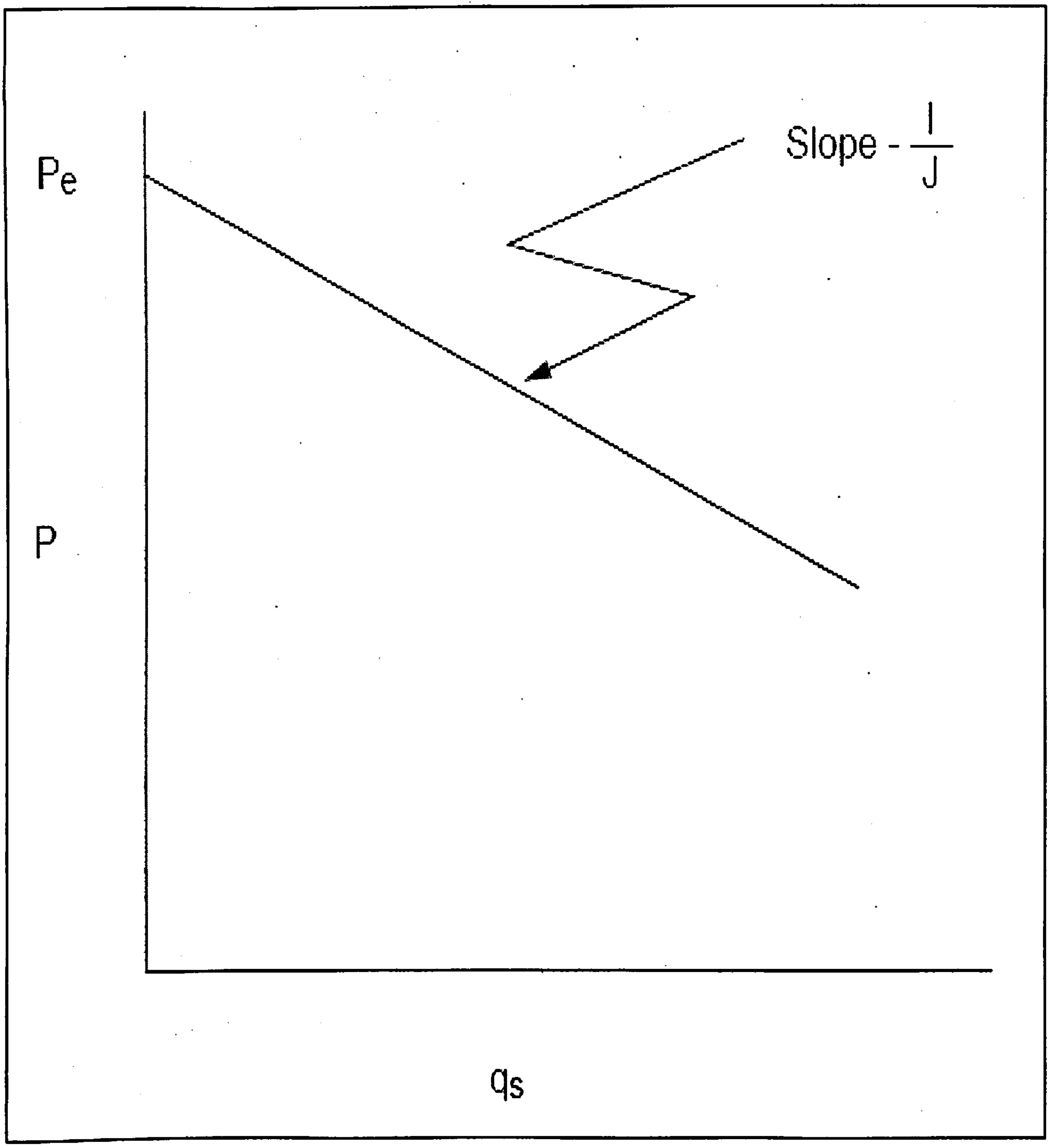


Figure 16: The productivity index plot for a single phase incompressible fluid

i.e. no pressure gradient exists across the outer boundary. Since the production is due to fluid expansion in the reservoir, the pressure in the reservoir will be a function of time and the rate of pressure decline dP/dt will be constant and uniform throughout the system.

The pressure profile with radius for the system will be constant but the absolute values of pressure will be time dependent.

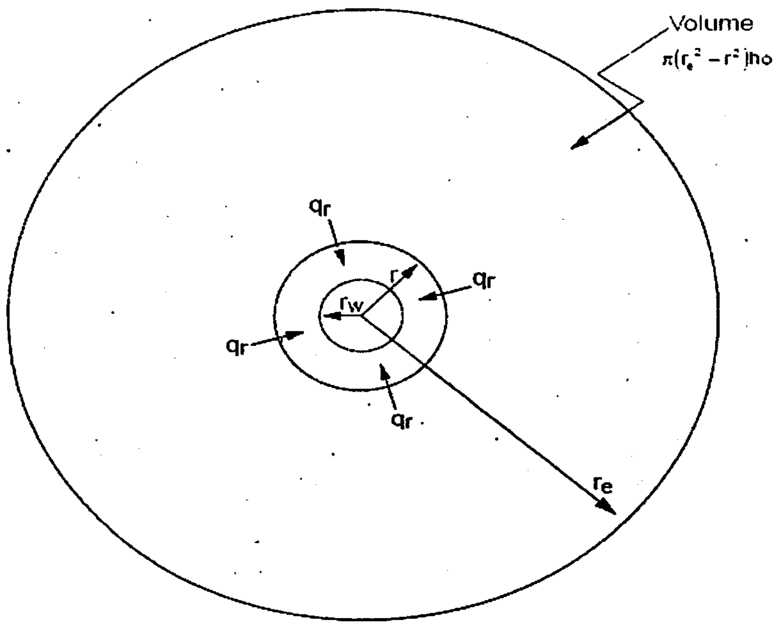


Figure 17: Fluid production at 'r' is provided by expansion of reservoir fluid/rock between radius 'r' and the outer boundary

Production, since it is based upon the volumetric expansion of fluids in the reservoir, will depend upon the fluid compressibility which is defined as "the change in volume per unit volume per unit drop in pressure", i.e.

$$C = -\frac{1}{V} \cdot \frac{\partial V}{\partial P}$$

where C is the isothermal coefficient of compressibility. For a reservoir production system as discussed in section 2, a reduction in pressure within the reservoir will cause an expansion in all of the fluid phases present, ie, potentially oil, gas and water as well as a reduction in the pore space due to rock expansion. The isothermal compressibility should, for realistic evaluation, be the total system compressibility Ct.

For most reservoirs, Ct is usually small, hence large changes in pressure will generate only limited fluid expansion and corresponding production.

The application of Darcy's law with the system compressibility equation applied to cylindrical reservoir volume, results in an equation which needs to be solved analytically to give :

$$q = \frac{2\pi kh(P_e - P_w)}{\mu\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2} + \frac{r_w^2}{r_e^2}\right]}$$

Since,

$$r_w << r_e \quad \left(\frac{r_w}{r_e}\right)^2 \rightarrow 0$$

Giving,

$$\left[P_e - P_w\right] = \frac{q\mu}{2\pi kh}\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right] \qquad \text{(e)}$$

Which, when expressed in field units, becomes:

$$\left[P_e - P_w\right] = \frac{1}{7.08x10^{-3}}\frac{q\mu}{kh}\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right]$$

Since, for a bounded reservoir, Pe has no physical significance, once the reservoir starts to deplete, the produceability of the reservoir at any point in time is best defined by a volumetrically averaged reservoir pressure. This pressure would only be realised if the well were closed in and pressure equilibrated throughout the drainage volume and the average reservoir pressure in thus defined by:

$$\overline{P} = \frac{\int_{r_w}^{r_e} P \cdot dV}{\int_{r_w}^{r_e} dV}$$

After evaluating $\overline{P}$ from Equation above, it can be substituted into the previous semi steady state radial flow derivation, Equation (e), to obtain after integration:

$$\left[\overline{P} - P_w\right] = \frac{q_s\mu B}{2\pi kh}\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4}\right]$$

The basic assumption in the above derivation is that the reservoir is circular and penetrated by a central well. Dietz developed shape factors to account for depletion in wells located in other drainage shapes or where the well is located off centre. The shape of the drainage area will be dictated by the no flow boundaries.

$$\left[\overline{P} - P_w\right] = \frac{q_s\mu B}{4\pi kh}\left[\frac{\ln 4A}{\gamma \cdot C_A \cdot r_w^2}\right]$$

where, ¥ is the Euler's constant and for any specific drainage shape, CA can be substituted by a number obtained from the tabulation of factors prepared by Dietz.

2.3.1.3 Radial Flow Theory for Single Phase Compressible Fluids

Oil, in most cases, can be considered as only slightly compressible and as the average molecular weight of the crude increases so the compressibility normally declines. Gases, however, are highly compressible fluids, containing only the lighter hydrocarbon molecules.

The prediction of inflow performance for gas wells is more complex than for oil for the following reasons:

(1) Gas viscosity is dependent upon pressure.
(2) The isothermal fluid compressibility is highly dependent upon pressure and hence as the gas flows towards the wellbore it expands substantially. Hence the volumetric flowrate of gas rapidly increases as the gas nears the wellbore and flows up the tubing to surface.

Again, by the application of Darcy's Law, we can write for a gas system at a specific radius, r:

$$Q_R = \frac{1.1271\ (2\pi rh)}{1000\mu} k \frac{dP}{dr} \qquad \text{......... } (f)$$

where Q_R is the gas flowrate in reservoir bbls/day.

Converting the gas flowrate to standard conditions, ie, Qs in SCF/d using the real gas law written for both standard and reservoir conditions :

$$Q_s = 5.615\ Q_R \cdot \frac{P_R \cdot T_s \cdot Z_s}{P_s \cdot T_R \cdot Z_R} \qquad \text{......... (g)}$$

Upon back substitution, into equation (f), we derive the general differential equation for gas well inflow performance:

$$\frac{3.9764 \times 10^{-2}\ K \cdot h \cdot T_s \cdot Z_s}{Q_s \cdot P_s \cdot T_R \cdot Z_R \cdot \mu} P \cdot dP = \frac{dr}{r} \qquad \text{......... (h)}$$

2.3.1.3.1 Steady State Radial Flow for a Gas System

The basic assumption for the solution of the radial flow equation under steady state conditions is that the volumetric flowrate is constant and independent of radius.
There are both rigorous and simplified approaches to the solution of this equation for gas.

(a) Rigorous solution - gas pseudo pressure approach.

The standard conditions normally assumed are:
Ts = 520°R Ps = 14.7 psia and Zs = 1.0 and, upon substitution in Equation (g), we obtain:

$$\frac{0.703\ \text{kh}}{Q_s \cdot T} \cdot 2\int_{P_w}^{P_e} \frac{P}{\mu z} \cdot dP = \int_{r_w}^{r_e} \frac{dr}{r} = \ln\left(\frac{r}{r_w}\right) \quad \text{.......................................} (i)$$

The integral term on the LHS is the Kirchhoff integral commonly referred to as the real gas pseudo-pressure function m(P)

$$m(P) = 2\int_{P_w}^{P} \frac{P}{\mu z} \cdot dP$$

The real gas pseudo pressure is normally evaluated with reference to a standard condition or datum reference, thus:

$$2\int_{P_w}^{P} \frac{P}{\mu z} \cdot dP = 2\int_{P_o}^{P} \frac{P}{\mu z} \cdot dP - 2\int_{P_o}^{P_w} \frac{P}{\mu z} \cdot dP$$

$$= \psi_e - \psi_w$$

Hence, Equation (i) becomes by rearrangement:

$$\psi_e - \psi_w = \frac{Q_s \cdot T}{0.703\ \text{kh}} \cdot \ln\frac{r_e}{r_w}$$

where Qs is measured in MSCF/day.

(b) Approximate solution for single phase gas inflow - average pressure or P2 approach.

There are a number of simplified solution techniques including the P2 Technique .
This technique involves removing (□z) from the integrand and evaluating it at an arithmetic average pressure for the flowing system i.e. the average of the sum of the inner and outer boundary pressures.

i.e.,

$$\frac{0.703\ \text{Kh}}{Q_s\ T_R} \frac{2}{(\mu z)_{ave.}} \int_{P_w}^{Pe} P \cdot dP = \ln\frac{r_e}{r_w}$$

And hence,

$$Pe^2 - P_w^2 = 1422\frac{Q_s' \cdot T}{K \cdot h} \cdot (\mu z)_{ave}\left[\ln\frac{r_e}{r_w}\right]$$

where Qs = MSCF/day

If we plot Pw versus Qs we obtain a plot as shown in figure below note that the incremental increase in production rate decline as bottom hole pressure declines.

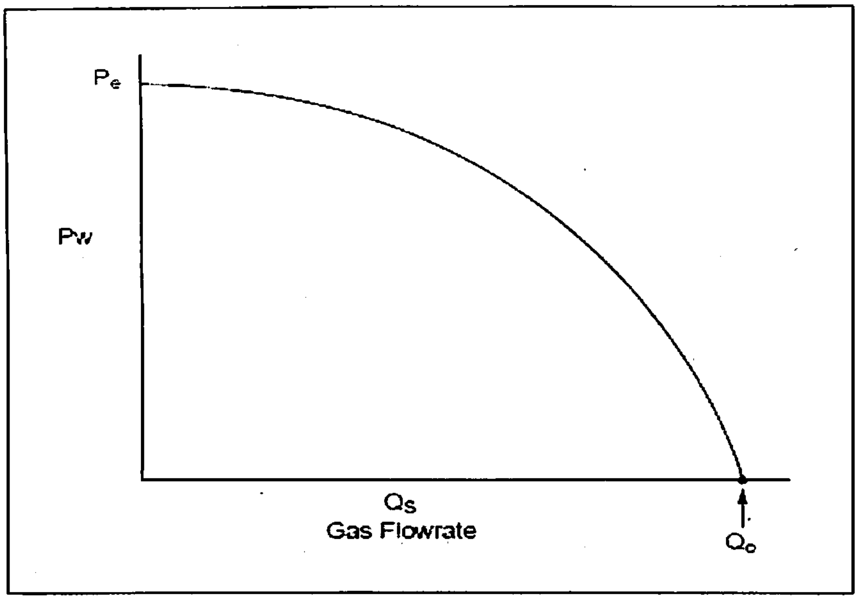


Figure 18: Gas well inflow performance

If we plot pw2 versus Qs we obtain a linear plot, assuming the P2 approach is valid, as shown
in figure below:

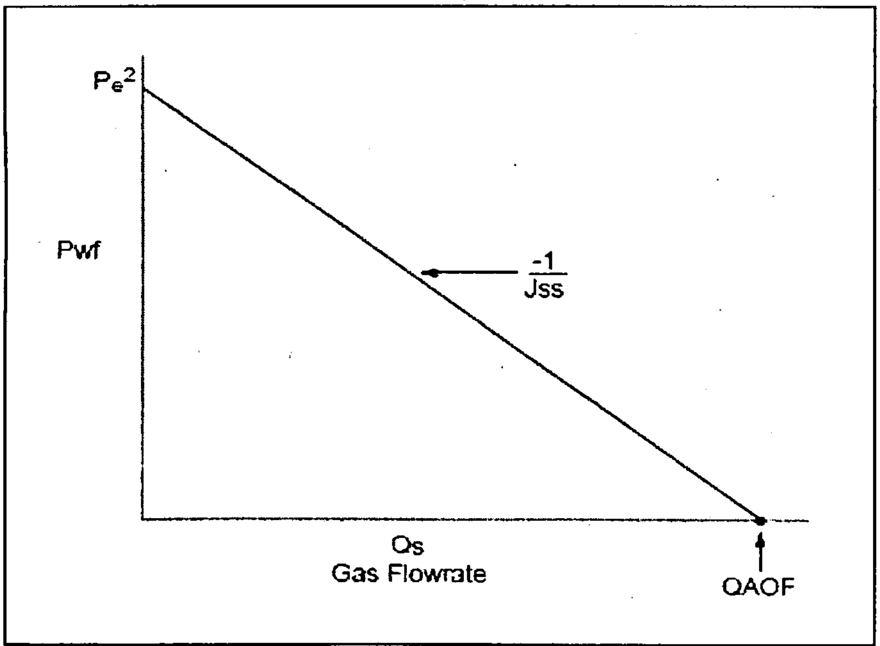


Figure 19:P^2 plot if gas well performance

2.3.1.3.2 Semi-Steady State Flow for a Gas System

Using the bounded reservoir assumption and employing the definition of isothermal compressibility, we can obtain the equation as:

$$\overline{\psi} - \psi_w = \frac{1422\ Q'_s\ T}{Kh}\left[\ln\frac{r_e}{r_w} - \frac{3}{4}\right]$$

in terms of the real gas pseudo pressure term y.

In terms of the P^2 format:

$$Q'_s = \frac{703 \times 10^{-6}\left[\overline{P}^2 - P_w^2\right]}{T_R\ (\mu z)_{ave}\left[\ln\frac{r_e}{r_w} - \frac{3}{4}\right]}$$

2.3.1.4 Multiphase Flow within the Reservoir

Most oil reservoirs will produce at a bottom hole pressure below the bubble point either:-

(1) Initially where the reservoir is saturated
(2) Or after production where the pressure in the pore space declines below the bubble point.

The complexity of modelling the inflow in this case is that we have at that stage moved to a position where we have multiphase flow. The flow of the individual phase is governed by the pore space occupancy or saturation of that phase i.e. So or Sg, which is in itself a function of pressure. Further, each of the phases will only become mobile when its saturation exceeds a critical value. Below this value the phase is static but the volumetric pressure of that phase constrains the flow of the mobile phase i.e. the relative permeability of the mobile phase for example for a gas oil system.

$K_o = K_{ro}.K_{ABS}$
Where, $K_{ro} = f(S_o)$
and $S_o + S_g = 1$

where,
Ko = effective permeability to oil
Kro = relative permeability to oil
So = oil phase saturation of the pore space
KABS = absolute permeability of the rock
Sg = gas phase saturation of the pore space

The relative permeability of the system is defined by a series of saturation dependent curves which are specific to the fluids and rock system.

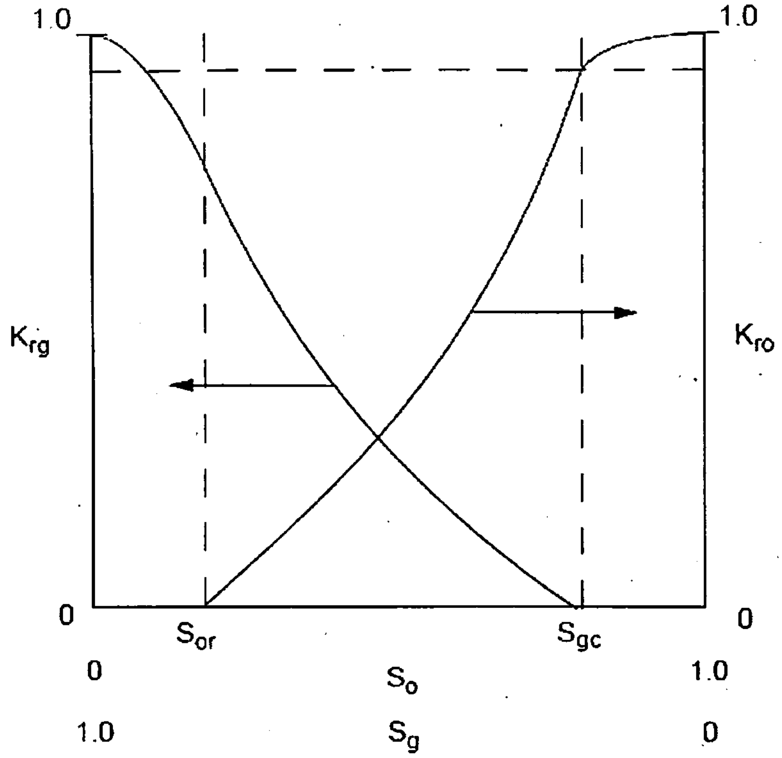


Figure 20: Typical oil - gas relative permeability curve.

Since the fluid system properties are a dynamic formation of pressure and position, we can only rigorously model inflow in such situations using implicit reservoir simulation. A number of approximate techniques have been proposed such as those of Vogel etc.

In Vogels' work he simulated the performance of a solution gas drive reservoir, plotted the data and attempted to derive a generalised relationship. The technique used a system of dimensionless flow rates and pressure as follows:-

QD = dimensionless liquid flowrate $= \dfrac{Q}{Qmax}$

where Q max = flowrate with zero bottom hole pressure

one PD = dimensionless bottomhole pressure $= \dfrac{Pwf}{\bar{P}}$

where Pwf = bottomhole pressure at a finite liquid rate Q
p = Static or closed in average reservoir pressure.

Vogel developed an approximate dimensionless curve,

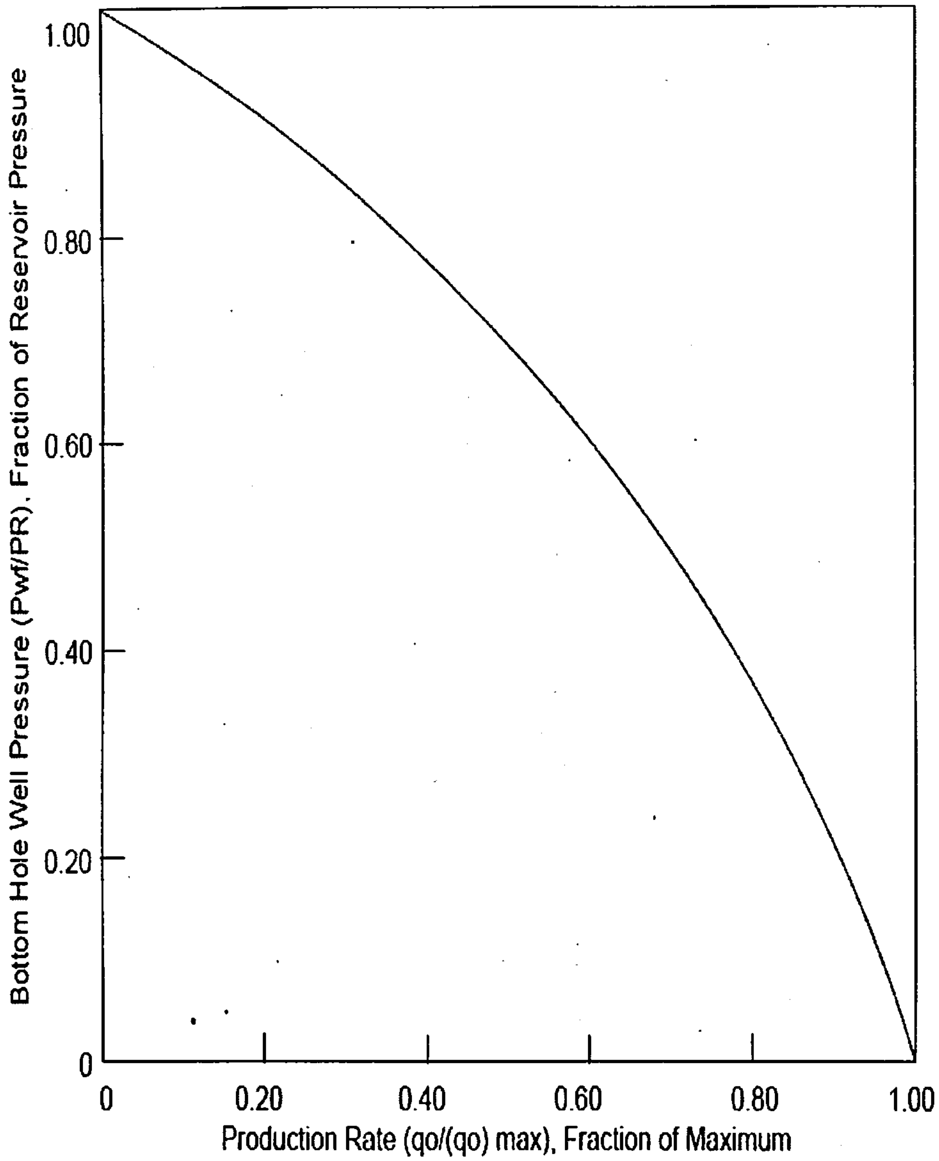


Figure 21: Inflow performance relationship for solution -gas drive reservoir (after Vogel)

An equation was best fitted to the curve and had the general form of :

$$\frac{Q}{Q\max} = 1 - 0.2\left(\frac{Pwf}{\bar{P}}\right) - 0.8\left(\frac{Pwf}{\bar{P}}\right)^2$$

A plot of Pwf versus Q is shown below for an oil reservoir initially producing at a pressure above the bubble point and at or below the bubble point respectively.

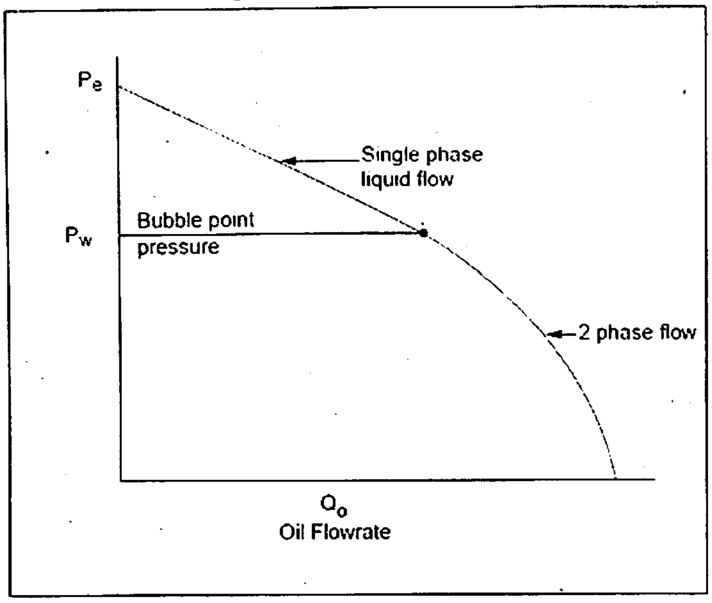


Figure22 (a): Reservoir producing with a pressure initially above the bubble point

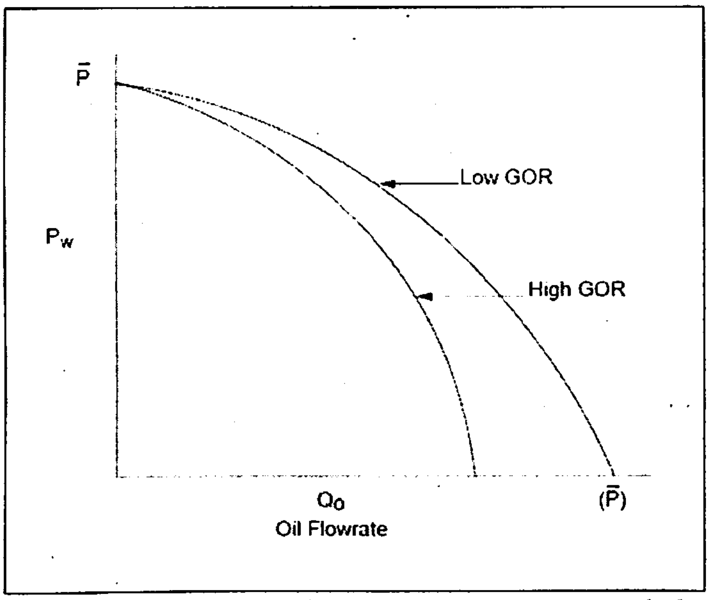


Figure 22(b): Initial reservoir pressure at or below bubble point

2.3.1.5 Non Darcy Flow

Darcy's law only applies to laminar flow situations. This is considered to be a valid assumption for the majority of oil wells where in in situ velocities even around the wellbore are relatively low. For gas wells and some very high flowrate (light crude) oil wells, the volumetric expansion as fluid approaches the wellbore is very high and this can result in turbulent flow. In such cases, we use a modified form of the Darcy equation, known as the Forchheimer equation, where we add to the Darcy viscous flow term μU/K, a quadratic velocity term to account for the inertial flow as follows:

$$\frac{dP}{dr} = \frac{\mu\,\mathrm{U}}{\mathrm{K}} + \beta\,\rho\,U^2$$

2.3.1.6 Productivity Index

The productivity index of PI provides a measure of the capability of a reservoir to deliver fluids to the bottom of a wellbore for production.

$$PI = J = \frac{q_s}{P_e - P_w} \ \text{STB/d/psi}$$

To further assist in defining productivity, taking into account the thickness of producing interval, we can define the Specific Productivity Index Js,

$$J_s = \frac{q_s}{(P_e - P_w) \cdot h} \ \text{STB/d/psi/ft}$$

2.3.1.6.1 PI for Steady State Incompressible Flow

$$J_{ss} = \frac{q_s}{P_e - P_w} \frac{7.082 \ x \ 10^{-3} \ kh}{\mu B \ ln \left[\frac{r_e}{r_w} \right]}$$

It is clear that J will be a constant if μ B and K remain constant.

2.3.1.6.2 PI for Semi-Steady State Incompressible Flow

In the case of a bounded reservoir, the pressure in the reservoir is time dependent which means that it must be defined on an average basis.

$$J_{sss} = \frac{q_s}{\overline{P} - P_w}$$

From Equation (d....a), we get,

$$J_{sss} = \frac{7.082 \ x \ 10^{-3} \ kh}{\mu B \left(\ln \frac{r_e}{r_w} - \frac{3}{4} \right)}$$

Provided the fluid and rock properties (μB and K) are constant, the PI should be constant, irrespective of the degree of depletion. Thus, as for the steady state case, a straight line relationship exists between Pw and qs.

PI for a Gas Reservoir in Steady State Flow

For gas wells, the equations commonly involve a P2 term and hence the PI is redefined in terms of this.

$$PI = \frac{Q_s}{P_e^2 - P_w^2}$$

From equation (i),

$$J_{SSG} = \frac{0.703\ Kh}{T(\mu Z)_{ave}\ \ln\left[\frac{r_e}{r_w}\right]}$$

2.4 TUBING PERFORMANCE

2.4.1 Fundamental Derivation of Pipe Flow Equation

It is possible to derive a mathematical expression which describes fluid flow in a pipe by applying the principle of conservation of energy.

2.4.1.1 Principle of Conservation of Energy

The principle of the conservation of energy equates the energy of fluid entering, existing in and exiting from a control volume.

The energy equation can be written as:

$$\Delta\left[\left[\begin{matrix}\text{Internal}\\\text{Energy of}\\\text{Fluid}\end{matrix}\right]+\left[\begin{matrix}\text{Energy of}\\\text{Expansion or}\\\text{Contraction}\end{matrix}\right]+\left[\begin{matrix}\text{Kinetic}\\\text{Energy}\end{matrix}\right]+\left[\begin{matrix}\text{Potential}\\\text{Energy}\end{matrix}\right]+\left[\begin{matrix}\text{Heat}\\\text{Added to}\\\text{System}\end{matrix}\right]+\left[\begin{matrix}\text{Work}\\\text{Done by}\\\text{System}\end{matrix}\right]\right]=0$$

i.e.

$$U_1 + p_1V_1 + \frac{mv_1^2}{2g_c} + \frac{mg \cdot h_1}{g_c} + Q - W_s = U_2 + p_2V_2 + \frac{mv_2^2}{2g_c} + \frac{mg \cdot h_2}{g_c}$$

Where ,

U = internal energy
V = fluid volume
h = elevation above datum
Q = heat added or removed
m = mass of fluid
v = fluid velocity
p = pressure
W = work done or supplied

In differential form per unit mass:

$$dU + \frac{vdv}{g_c} + \frac{dP}{\rho} + \frac{g}{g_c} \cdot dh + dQ + dW = 0$$

From thermodynamics, we can define the internal energy term as:

$$dU = dH - d\left(\frac{P}{\rho}\right)$$

where H = system enthalpy

$$dH = TdS + \frac{dP}{\rho}$$

where T = absolute temperature
S = entropy

After Substitution, we get,

$$TdS + \frac{dP}{\rho} + \frac{vdv}{g_c} + \frac{g}{g_c} \cdot dh + dQ + dW = 0$$

However, for an irreversible process, we can apply the Clausius inequality:

$$T \cdot dS = dQ + dE_w$$

where dEw = energy losses due to irreversibilities

Assuming above equation is valid and that dW = 0, we can obtain the general equation:

$$\frac{dP}{\rho} + \frac{vdv}{g_c} + \frac{g}{g_c} dh + dE_w = 0$$

Assuming that the pipe is inclined at angle to the vertical,

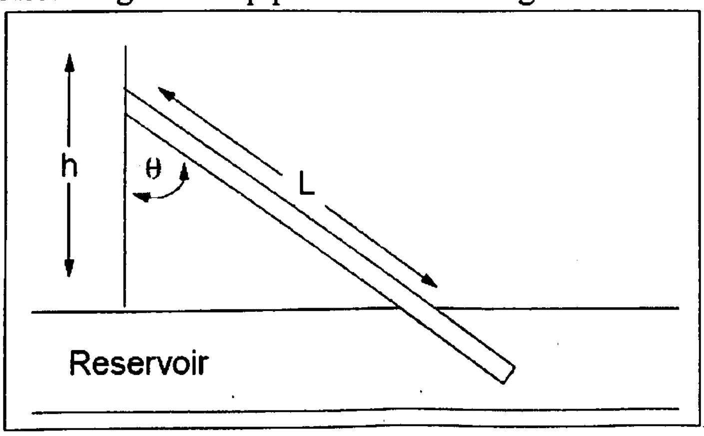


Figure23: Deviated well orientation

dh= dL cos Θ

Therefore, by substitution into last Equation we obtain:

$$\frac{dP}{\rho}+\frac{vdv}{g_c}+\frac{g}{g_c}\ dL\ \cos\theta+dE_w=0$$

Multiplying both sides of the equation by dP/ dL, we obtain:

$$\frac{dP}{dL}+\frac{\rho}{g_c}\cdot v\frac{dv}{dL}+\frac{g}{g_c}\cdot\rho\cdot\ \cos\theta+\rho\cdot\frac{dE_w}{dL}=0$$

In terms of the pressure gradient,

$$\frac{dP}{dL}=\frac{\rho}{g_c}\cdot v\frac{dv}{dL}+\frac{g}{g_c}\rho\ \cos\theta+\rho\frac{dE_w}{dL}$$

If we assume that the irreversible losses are due to friction, the above equation becomes,

$$\frac{dP}{dL}=\frac{\rho}{g_c}v\cdot\frac{dv}{dL}+\frac{g}{g_c}\rho\ \cos\theta+\left(\frac{dP}{dL}\right)_f$$

2.4.1.2 The Friction Factor

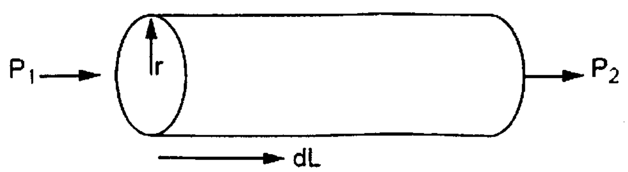
The loss in fluid energy when fluid flows from will comprise:

(1) Loss in fluid pressure
(2) Loss in fluid potential if elevations of points 1 and 2 are different
(3) Loss in energy due to shear stress at the pipe wall

Consider the case where no differential in fluid potential arises, ie, a horizontal pipe.

Applying a force balance:

$$(P_1-P_2)\ dA=\tau_w\ (2\pi r)\cdot dL$$



$$P_1 \cdot dA - \tau_w \cdot 2\pi r \cdot dL = P_2\, dA$$

Or

$$(P_1 - P_2)\,\pi r^2 = \tau_w \cdot 2\pi r \cdot dL$$

$$\frac{(P_1 - P_2)}{dL} = \left(\frac{dP}{dL}\right)_f = \frac{2\tau_w}{r}$$

We can define the Fanning friction factor f as a measure of the shear characterics of the tubular wall:

$$f = \frac{\text{wall shear stress}}{\text{kinetic energy / volume}}$$

$$f = \frac{\tau_w}{\frac{1}{2}\rho\frac{v^2}{g_c}}$$

Substituting in above equation:

$$\left(\frac{dP}{dL}\right)_f = 2 \cdot \frac{1}{2}\rho\, f\frac{v^2}{g_c} \cdot \frac{1}{r}$$

$$= \rho \cdot f \cdot \frac{v^2}{g_c} \cdot \frac{1}{r}$$ or $$\left(\frac{dP}{dL}\right)_f = 2 \cdot \frac{\rho\, f\, v^2}{g_c \cdot d}$$ where d = inside diameter of the pipe

In terms of the Moody friction factor *fm* defined as:

$f_m = 4f$

$$\left(\frac{dP}{dL}\right)_f = \frac{f_m\, \rho\, v^2}{2\, g_c\, d}$$

2.4.2 Single Phase Flow Characteristics

Single phase fluid flow in pipes can be defined in 2 major categories, namely:

- laminar flow where the individual streamlines are parallel to the bulk flow direction
- turbulent flow where the bulk flow is directed towards a location of lower energy but individual stream lines are in random directions, i.e., turbulence

2.4.2.1 Dry Gas Flow

(1) Effect of Pressure

Gas is a low viscosity, low density fluid which possesses a very high coefficient of isothermal compressibility, ie,

$$C_g = 300 \times 10^{-6} \text{ vol / vol / psi}$$

As the gas flows to surface, its pressure will decline and it will undergo the following changes:

(a) as a result of the high compressibility, the density will dramatically decline

(b) as the density declines, the potential energy or hydrostatic pressure gradient will decline proportionally.

(c) as the density declines, the gas will expand, resulting in a proportional increase in velocity.

(d) as the gas velocity increases, the frictional pressure gradient will increase according to the relationship.

For laminar flow:

$$\left(\frac{dP}{dL}\right)_f \infty \text{ v}$$

and for turbulent flow:

$$\left(\frac{dP}{dL}\right)_f \infty \text{ v}^n \text{ where n } = 1.7 - 2.0$$

For most gas production wells, the flow regime in the tubing will be transitional or turbulent depending on the individual well and completion.

The relative contribution of both the frictional and hydrostatic pressure gradients as a function of gas flowrate is illustrated in figure below.

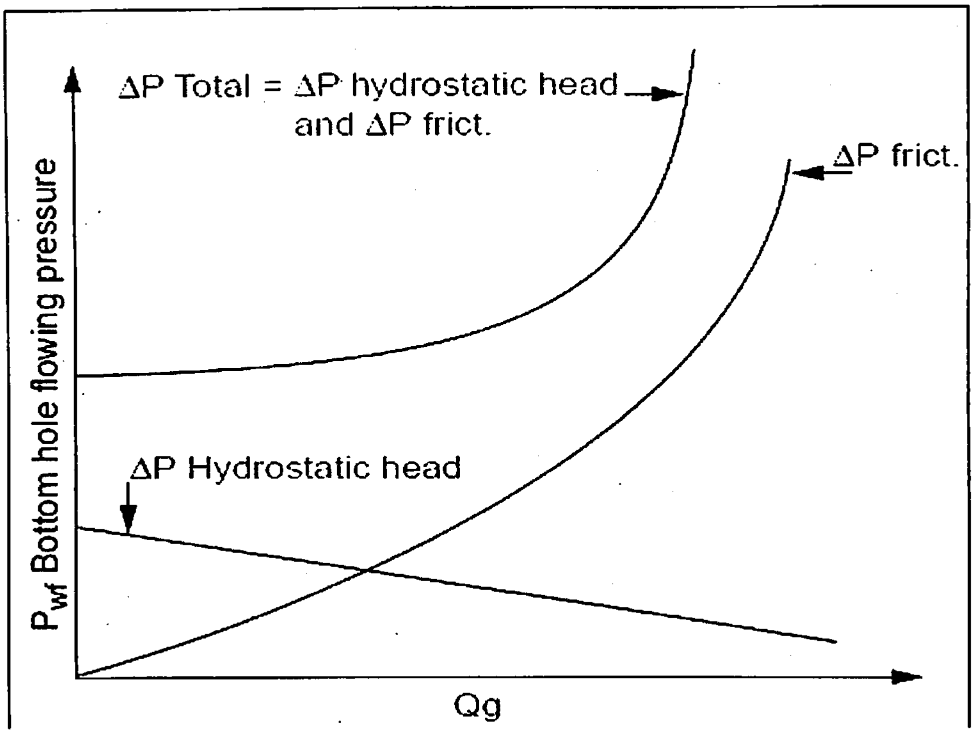


Figure 24: Single phase gas well - tubing pressure loss

Effect of Temperature

For gas, the temperature profile may not exhibit a significant decline (cooling), since the gas will naturally possess a low convective heat transfer coefficient. Extremely high gas velocities in the tubing may significantly increase the heat transfer coefficient but, because of the high mass flowrate, a substantial increase in the degree of cooling may not be seen. Localised cooling due to gas expansion may introduce significant anomalies in the profile.

2.4.2.2 Single Phase Liquid Flow - Oil or Water

In general, crude oil can be classified as slightly compressible, the degree of compressibility being dependent on the crude oil gravity - a light crude oil with an API gravity of, say, 35° would be more compressible than a heavier crude oil with an API gravity of 20° API. A typical oil compressibility (Co) would be 8 - 12 x 10-6 vol / vol / psi.

For the flow up tubing of a single phase liquid, the following will occur:

(a) As the liquid flows upwards, the density will decline by the order of 0.5 - 1.0% for every 1000 psi drop in pressure, ie, the rate of density decline is minimal and the resultant effect on the hydrostatic or potential energy gradient will be negligible.

(b) As pressure declines, the viscosity will decrease slightly.
Hence, for oil or water, the impact of flow on the physical properties of the fluid will be negligible and hence the increase in frictional gradient will remain almost constant, as shown in figure below.

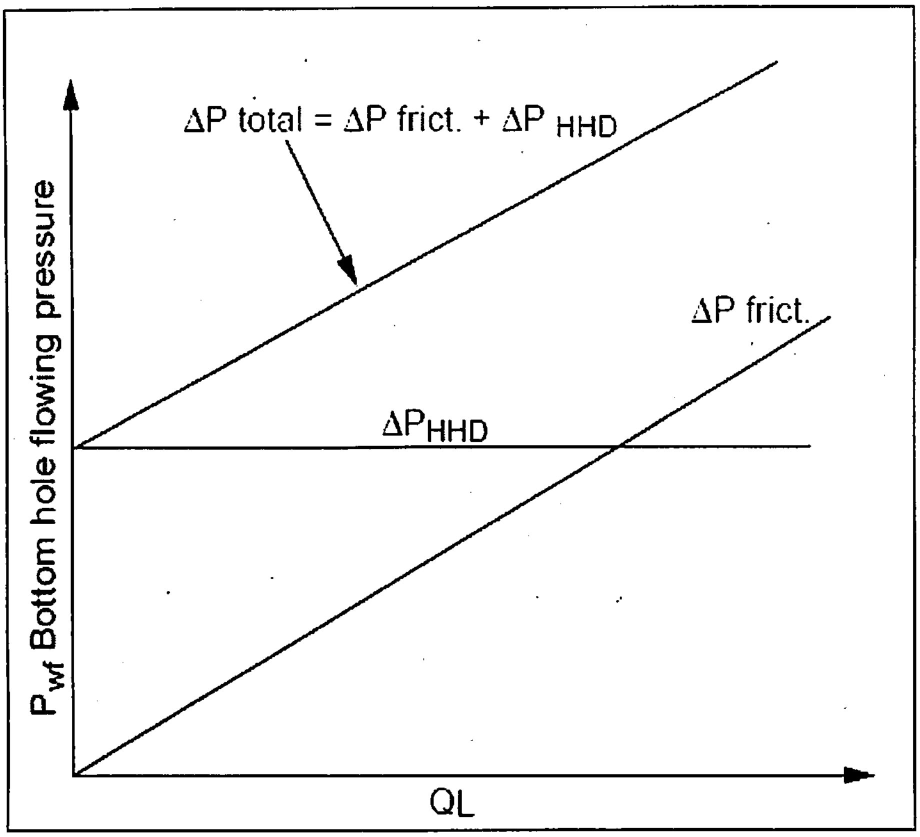


Figure 25: Incompressible liquid flow in the tubing.

(2) Temperature Effects

The convective heat transfer coefficients for oil and water will be higher than for gas but the lower extent of turbulence will offset the heat transfer. In an oilwell, the progressive cooling will serve to:

(a) increase liquid density opposing the decrease in density associated with thereducing flowing pressure. The effect on the velocity and hydrostatic pressure gradient will be self-evident.

(b) increase the liquid viscosity again opposing the decrease generated by reducing the pressure with depth.

2.4.3 Multiphase Flow Concepts in Vertical and Inclined Wells

2.4.3.1 Flow Characteristics in Vertical Wells

Each of the phases, both gaseous and liquid, have individual properties such as density and viscosity which will be a function of pressure and temperature and hence position in the well.

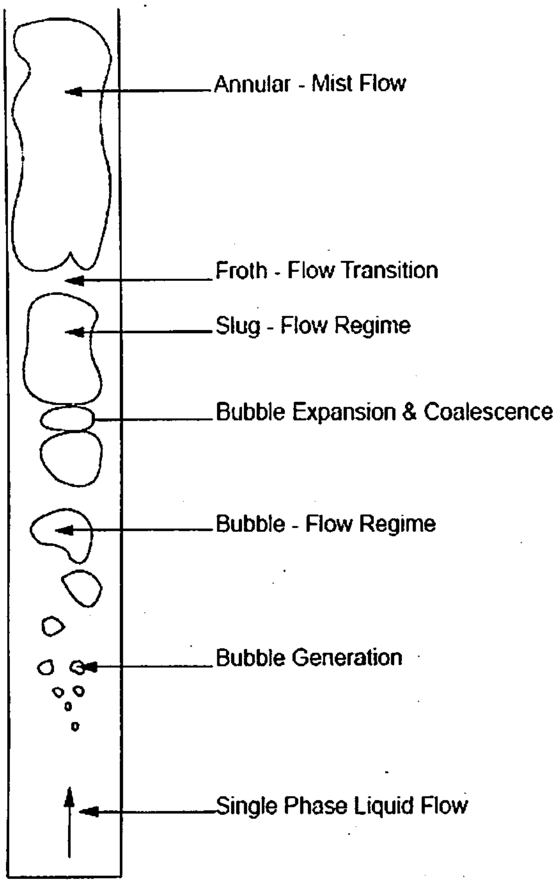


Figure 26: Multiphase flow up the tubing

(1) Gas-Liquid Mixtures

In the production of a reservoir containing oil and gas in solution, it is preferable to maintain the flowing bottom hole pressure above the bubble point so that single phase oil flows through the reservoir pore space.
The oil may enter the tubing at a flowing pressure above the bubble point where no separate gas phase exists. The changing nature of the flow up the tubing can be considered in various stages from the base of the tubing:

(a) single phase liquid will occur in the tubing assuming the pressure is below the bubble point pressure. The pressure gradient is primarily influenced by the density of the liquid phase and is thus dominated by the hydrostatic head component of the pressure loss. Liquid expansion may contribute to a very slight reduction in liquid density and thence the hydrostatic gradient.

(b) At the bubble point, the first gas is evolved which will:

(i) Lower the average density of the fluids in the tubing
(ii) Increase the in-situ velocity
(c) With continued upwards flow, the pressure on the fluid declines. The decline in pressure on the fluid will cause:

(i) Expansion of the liquid phase

(ii) Evolution of additional gas components - increasingly heavier molecules - resulting in an increased mass of hydrocarbon in the gas phase. A simultaneous reduction of the mass of the liquid phase will accompany this mass transfer. The concentration of heavier components in both the gas and liquid phases would increase.

(iii) Expansion of the existing gas phase.

(d) As flow continues higher up the tubing, the number and size of gas bubbles will increase until such a point that the fraction of the tubing volume occupied by gas is so large that it leads to bubble coalescence. The coalescence of bubbles will yield a "slug flow" regime characterised by the upward rise, due to buoyancy, of slugs of gas segregated by continuous liquid columns. The upwards movement of the slugs will act as a major mechanism to lift oil to surface.

(e) Often, as velocity continues to increase in the slug flow regime, it may be possible that a froth type transitional flow occurs where both the oil and gas phases are mutually dispersed, ie, neither is continuous.

(f) With continued upward movement, further gas expansion and liberation will occur, resulting in slug expansion and coalescence, leading to slug enlargement and eventually "annular flow". In annular flow, the gas flows up the centre of the tubing with oil flow occurring as a continuous film on the inside wall of the tubing.

(g) At extremely high velocities of the central gas column, shear at the gas-oil interface can lead to oil dispersion in the gas in the form of a "mist". This "mist flow" pattern will occur at very high flow velocities in the tubing and for systems with a high gas-oil ratio GOR.

The conventional manner of depicting the experimental data from these observations is to correlate the liquid and gas velocity parameters against the physical description of the flow pattern observed. Such presentations of data are referred to as flow pattern maps.

The map is a log-log plot of the superficial velocities of the gas and liquid phases.

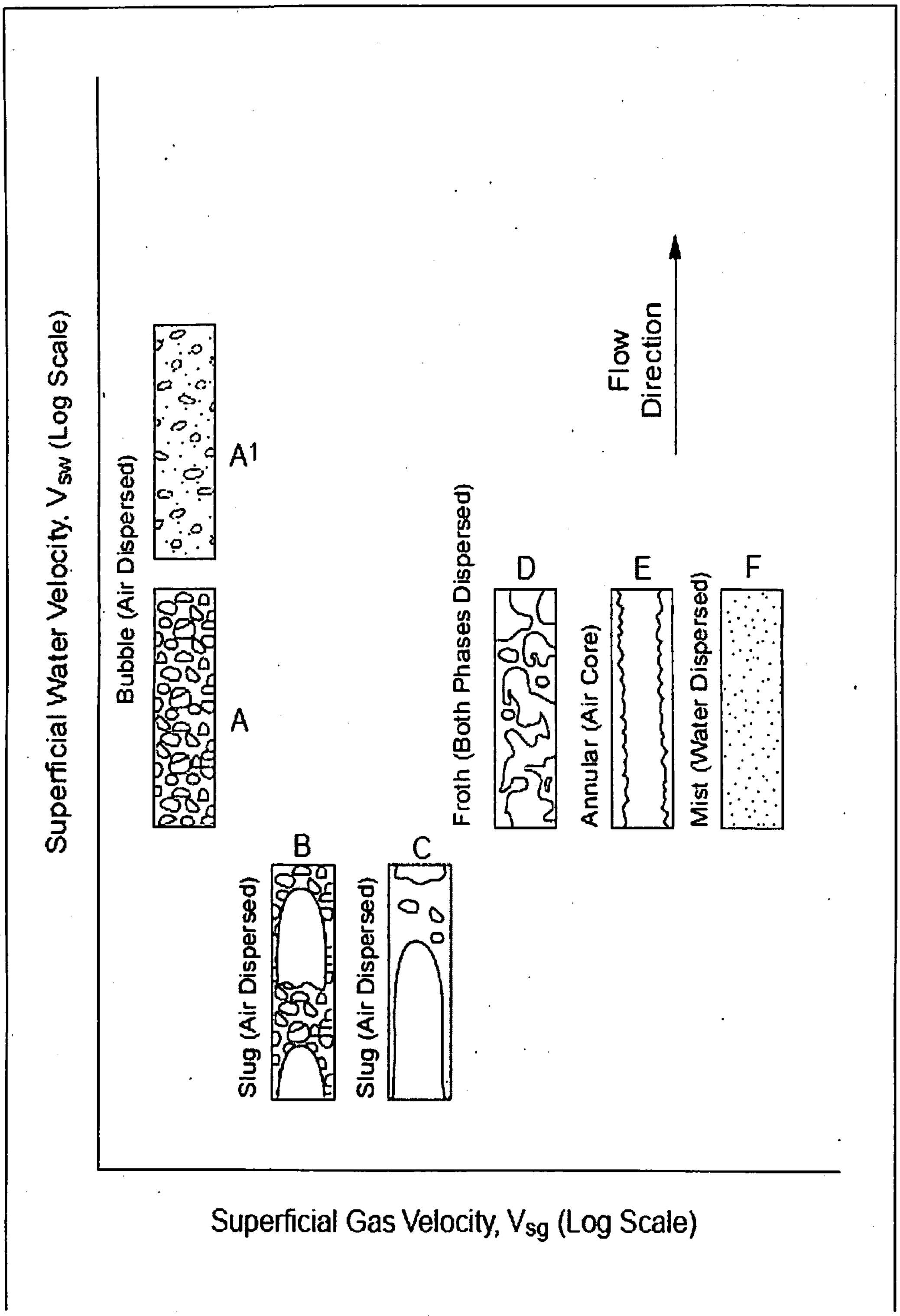


Figure 27: Flow pattern map for a gas/ water mixture

(2) Liquid-Liquid Flow

The case of liquid-liquid flow in production wells may occur in low GOR wells which produce water. Since both phases are only slightly compressible or incompressible, it would be expected that the physical nature of the flow of an oil-water mixture to surface would not be as dramatically different from single phase liquid flow as the oilgas system.

If oil and water enter the wellbore from the reservoir and flow up the tubing to surface, the physical distribution of the phases will depend upon their relative volumetric properties, ie, one phase will be continuous and the other dispersed. For example,

(a) in a high WOR well (say, 90%), the oil would be dispersed in the continuous water phase.

(b) at a low WOR, the oil would be continuous.

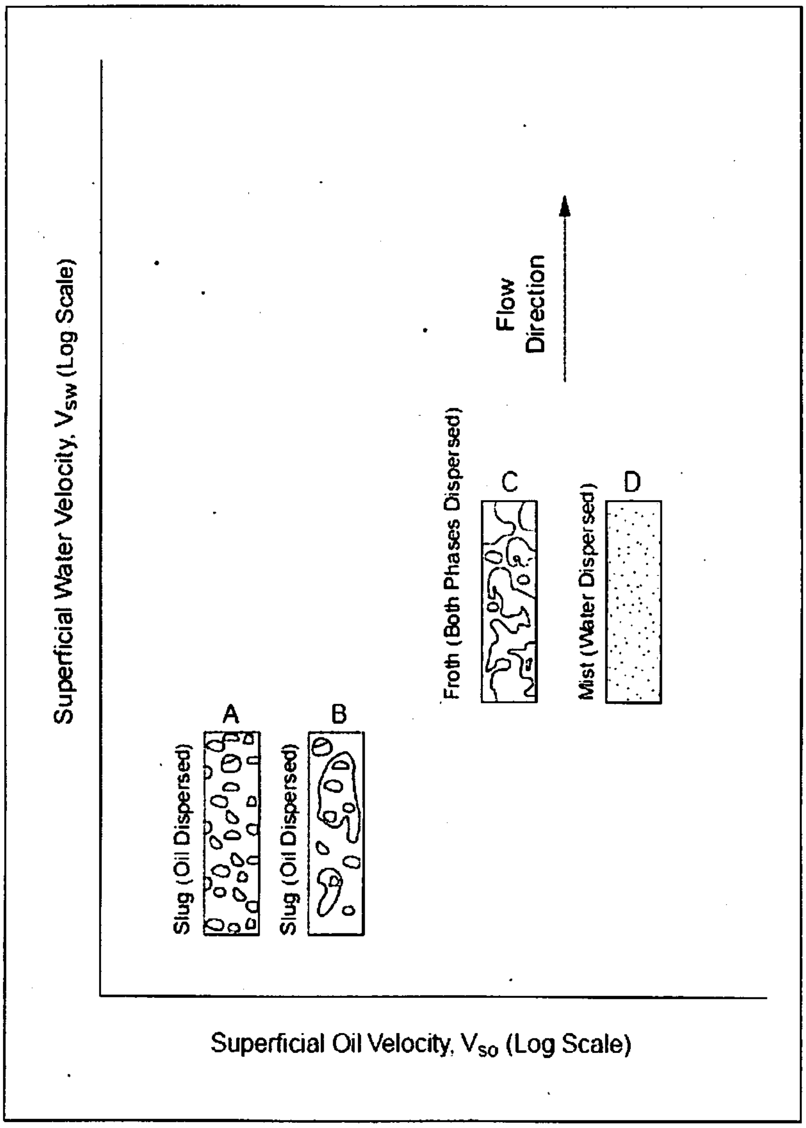


Figure 28: Flow pattern map for a water / oil mixture

(3) Flow Characteristics for Hydrocarbon Reservoir Fluids Systems

The physical flow processes discussed above will define the production of most hydrocarbon fluids.

(a) Dry Gas
Since no liquid phase will be present under any pressure conditions, the flow will be monophasic.

(b) Wet Gas
A wet reservoir gas will have small quantities of gas associated with it. As the gas flows to surface, the pressure will decline to the dewpoint, where the first liquid droplets will appear and be transported as a mist of particles in a continuous gas phase.

(c) Gas Condensate
Gas condensate will contain a larger volume of liquid phase than the wet gas. At low liquid concentration at the dewpoint, the liquid phase could be present as a mist and as an "annular film" or subsequently a "slug" at higher concentrations.

(d) Volatile Oil
A volatile oil is characterised by a high GOR and thus as it flows to surface it may pass through all of the flow patterns discussed in section 1 above, including the single phase regime if $Pwf > P_{BPt}$, where P_{BPt} is the bubble point pressure.

(e) Black Oil
Black oil has a very low GOR and accordingly is unlikely to progress beyond the bubble and slug flow regimes into annular flow.

(f) Heavy Oil
Heavy oil normally has a very low (or nonexistent) GOR and as such it will vary from single phase oil to the bubble flow regime.

2.4.3.2 Multiphase Flow Characteristics in Inclined Wells

The impact on multiphase flow will be to:

(1) Promote increased segregation between the phases, since the impact of density difference (buoyancy) will lead to migration of the lighter phase towards the upper part of the pipe cross-section.

(2) The hydrostatic head pressure component will depend upon the vertical depth of the portion being considered and not the length of tubing to that depth. In the derivation of the generalised pipe pressure loss equation, the pressure gradient due to potential energy will utilise the length of hole L, multiplied by cos θ where θ is the angle of the borehole to the vertical.

(3) The frictional pressure gradient will be based on the alonghole length of the tubing as this defines the area for shear stress between the pipe inner wall and the fluid. Clearly the along hole length will exceed the true vertical depth.

Compared to vertical wells, it would be expected that:

(1) The bubble and slug flow regimes would be modified to account for the effects of buoyancy on the liquid phase, ie, the bubbles and slugs would tend to flow in the upper part of the pipe cross-section.

(2) The expansion of the gas slugs in the upper cross-sectional region of the pipe would lead to a stratified type flow where gas flows in the upper part and liquid in the lower part.

(3) With increasing gas flowrate, the gas would exert increasing drag on the liquid surface, resulting in "wave" flow.

(4) At even higher flowrates, the liquid phase may be distributed as an annular film or eventually as a mist within the continuous gas phase.

These flow patterns are depicted are as follows:

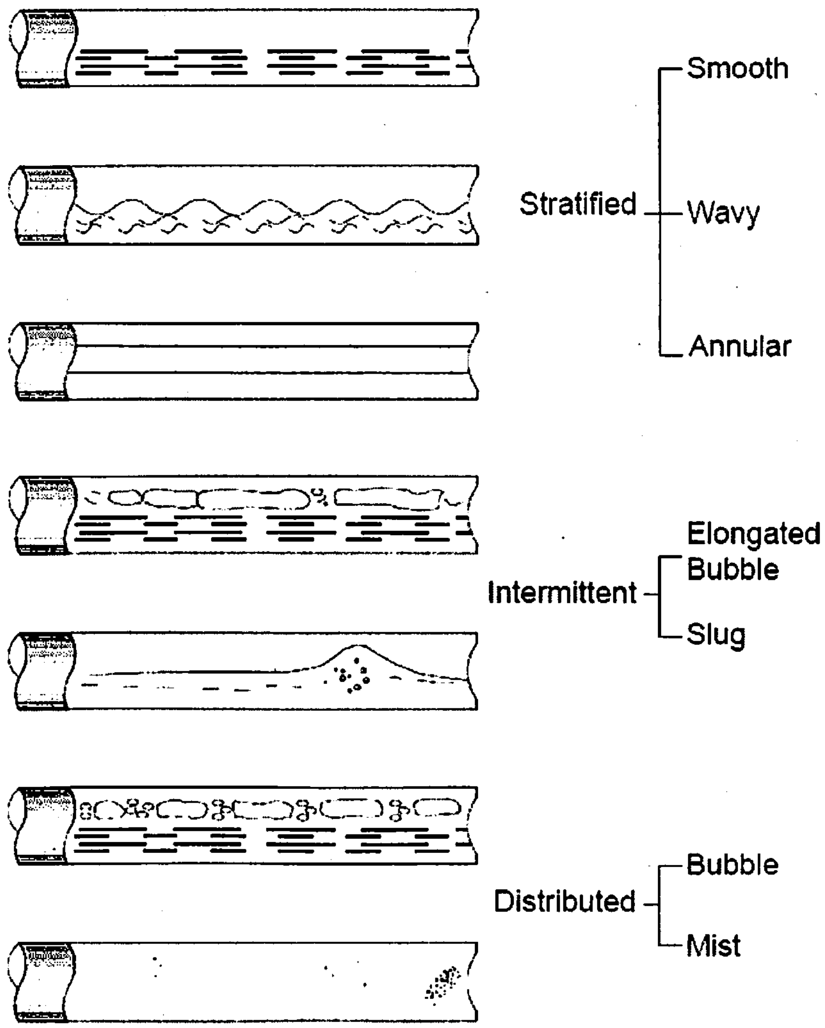


Figure 29: Flow patterns in a horizontal pipe

2.4.3.3 Fluid Parameters in Multiphase Flow

In calculating the pressure loss for single phase flow, fluid properties can be evaluated

at any prescribed pressure and temperature. However, when evaluating the pressure gradient in multiphase flow, values for the various parameters must first be derived which are representative of the multiphase mixture.
Important parameters which will influence the properties of a multiphase flow system are slippage and holdup.

1 Slippage

If a gas-liquid mixture flows up a tubing string, the effects of buoyancy on each of the phases will not be equal. The lighter of the phases, primarily gas, will rise upwards at an incrementally higher rate compared to the oil due to the effects of buoyancy. The slip velocity, Vs, is defined as the difference in velocities of the two phases, ie, for a gas-oil system.

$V_s = V_g - V_o$

2 Holdup

Holdup is a term used to define the volumetric ratio between two phases which occupy a specified volume or length of pipe.
The liquid holdup for a gas-liquid mixture flowing in a pipe is referred to as HL:

$$H_L = \frac{\text{Volume of liquid in a pipe segment}}{\text{volume of pipe segment}}$$

HL therefore has a value between zero and one.
Similarly, the gas holdup Hg is defined as:

$$H_g = \frac{\text{Volume of gas in a pipe segment}}{\text{volume of pipe segment}}$$

And, HL +Hg =1.0

3 Fluid Velocity

A difficulty arises as to how to define the velocity of a specific phase. There are two options:

(a) The first option is to define velocity based upon the total cross-sectional area of the pipe despite the fact that each phase will occupy a fraction of the area. The velocity in this case is termed the ***superficial velocity.***

For gas:

$$V_{sg} = \frac{q_g}{A}$$

where A = cross-sectional area of the pipe

and for liquid:

$$v_{SL} = \frac{q_L}{A}$$

(b) A more accurate value for the velocity of each phase is to correct for the holdup of each phase.

The actual gas velocity:

$$v_g = \frac{q_g}{A \cdot H_g}$$

2.4.4 Single Phase Flow Performance Predictions

The prediction of tubing pressure loss is reasonably simple for situations where a single phase is flowing up the tubing. The derived general equation for pressure loss from the principle of the conservation of energy can be applied:

$$\frac{dP}{dL} = \frac{\rho}{g_c}\frac{vdv}{dL} + \frac{g}{g_c}\rho \cos\theta + \frac{f_m \cdot \rho v^2}{2g_c d}$$

2.4.4.1 Single Phase Liquid Flow

The pressure drop in the tubing can be predicted by applying the general energy equation and ignoring the kinetic energy (acceleration) losses:

$$\left(\frac{dP}{dL}\right)_{Total} = \left(\frac{dP}{dL}\right)_{fric} + \left(\frac{dP}{dL}\right)_{PE}$$

For a vertical well:

$$dP = \frac{\rho g}{g_c} D_{TVD} + \frac{\rho f_m v^2}{2g_c \cdot d} \cdot D_{TVD}$$

with fm being the friction factor evaluated for laminar or turbulent flow.

2.4.5 Multiphase Flow Models

Basic assumptions which can be used to classify the correlations derived as follows:

(1) Methods which do not consider
(a) slippage between phases
(b) the use of flow regime or pattern

(2) Methods which consider slippage between the phases but not flow regimes.

(3) Methods which consider both flow regime and slippage.

Most of the multiphase flow correlations can be used with the following general procedure:

(1) Use will be made of the general equation:

$$\left(\frac{dP}{dD}\right)_{TOTAL} = \left(\frac{dP}{dD}\right)_{elev} + \left(\frac{dP}{dD}\right)_{frict} + \left(\frac{dP}{dD}\right)_{accel}$$

(2) Determine:

$$\left(\frac{dP}{dD}\right)_{elev} = \bar{\rho}_m$$

(3) Calculate:

$$\left(\frac{dP}{dD}\right)_{frict} = \frac{f_m \ \rho_m \ v_m^2}{2g_c \ d}$$

(4) Calculate:

$$\left(\frac{dP}{dD}\right)_{accel} = \frac{\rho_m \ \Delta\left(v_m^2\right)}{2g_c \ dD}$$

2.4.6 Gradient Curves

Gilbert was the first to introduce the concept of a pressure gradient curve. The gradient curve provides a plot of pressure variations with depth in a tubing string for a range of specified flow conditions and as such provides a simplified but less accurate approach to predicting tubing performance using a multiphase flow correlation.

Gilbert obtained data in the form of pressure traverses upon a range of oil production wells and the data was plotted with respect to the following parameters:

- GOR or GLR
- tubing diameter
- liquid or oil production rate

His data was restricted to 1.66", 1.9", 23/8", 27/8" and 31/2"; for flowrates of 50, 100, 200, 400 and 600 BPD. Therefore, for constant values of the above parameters, a range of curves were obtained by plotting the data, each curve reflecting a different tubing head pressure, as shown in figure below. The implication of this was that a specific gradient curve would be required for each tubing head pressure to be considered

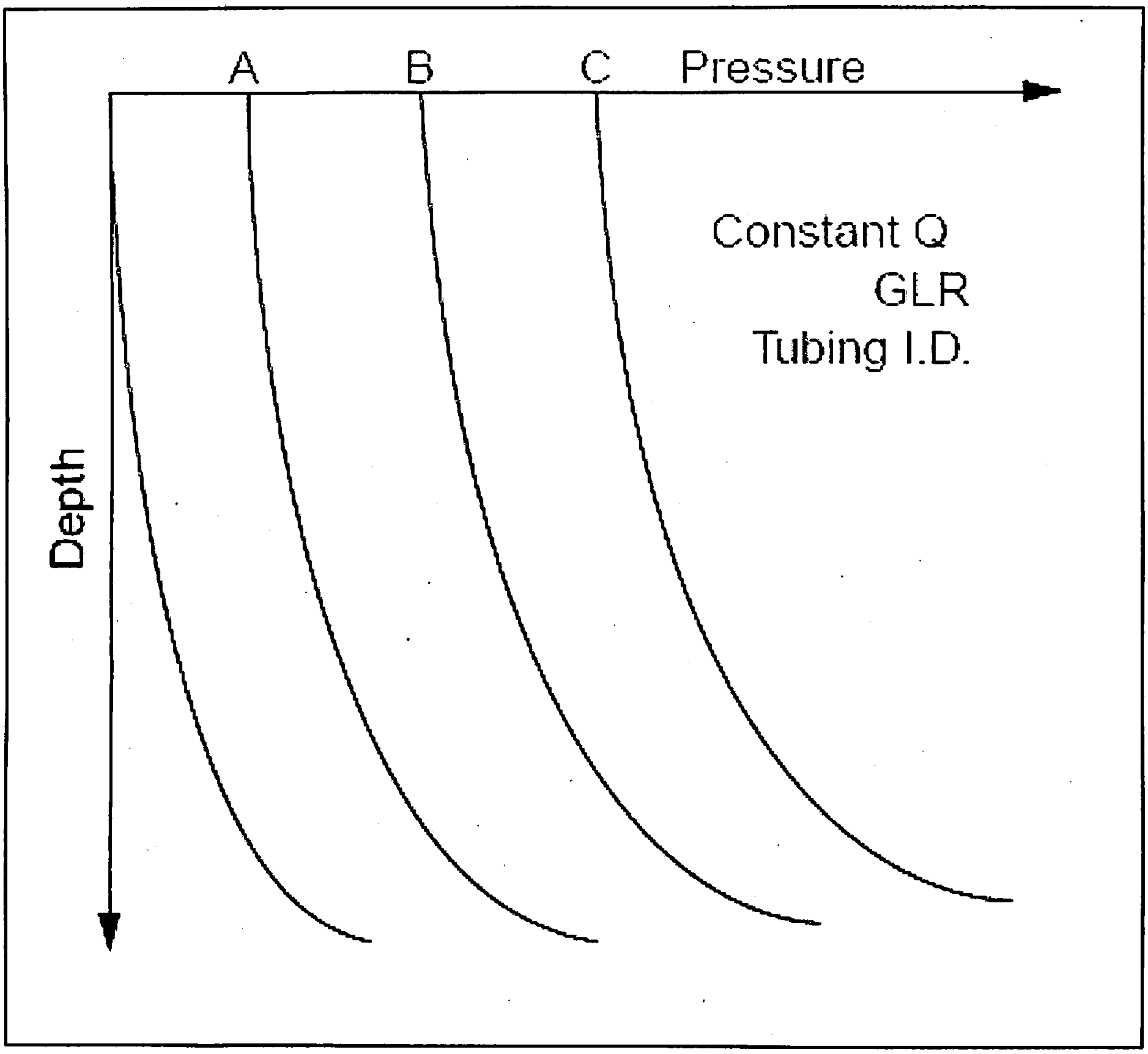


Figure 30: Gilbert's Representation of Well Traverses as P versus depth

However, by shifting the curves downwards, he found that, for a constant GLR, flowrate and tubing size, the curves overlapped, as depicted in figure below. Then, a single curve could be utilised to represent flow in the tubing under assumed conditions. This curve could be constructed to pass through the point of zero pressure at surface. The impact of moving the individual curves down until they overlapped was in effect to extend the depth of the well by a length which, if added to the top of the tubing, would dissipate the tubing head pressure and result in zero pressure at the top.

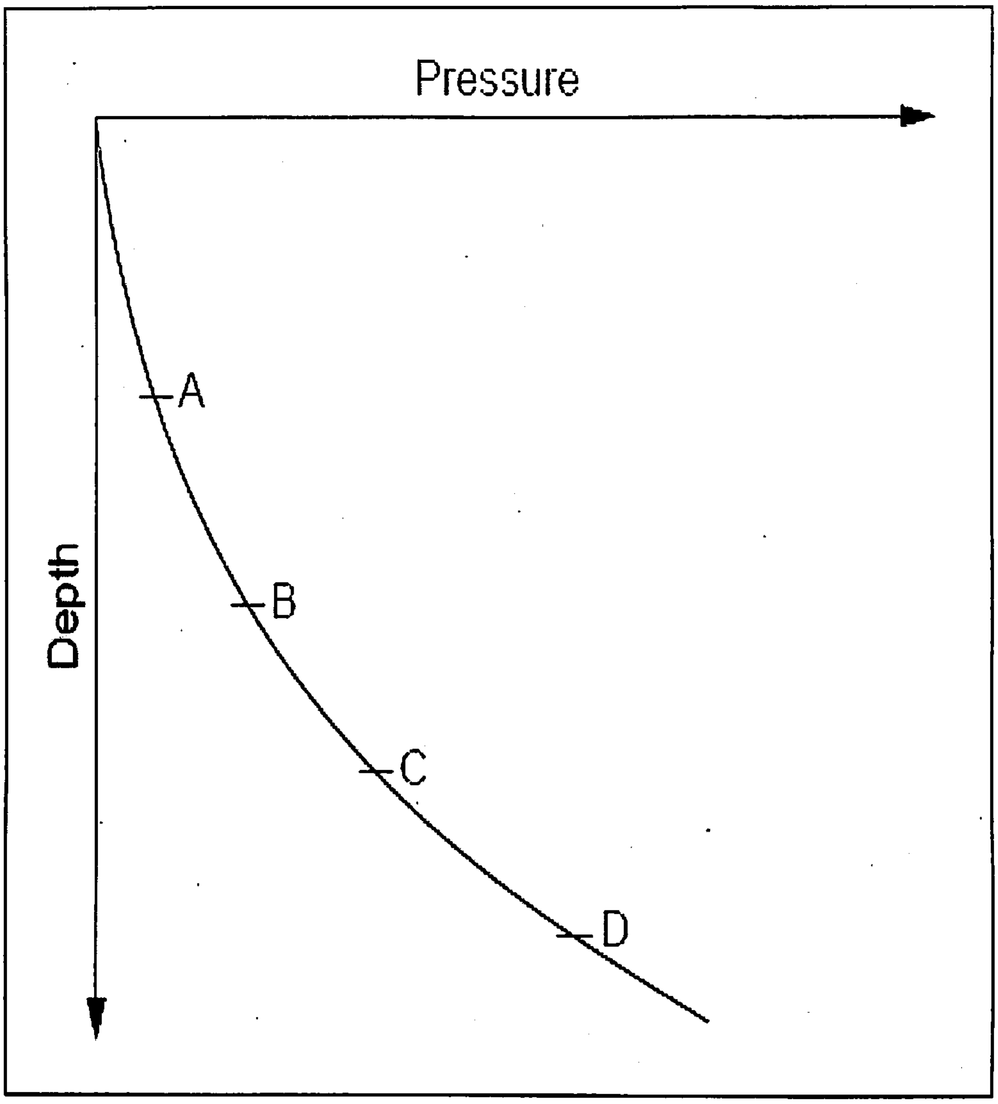


Figure 31: Standardisation of Gilberts Curves

Gilbert was then able to collect all the curves for a constant tubing size and flowrate together on the one graph, resulting in a series of gradient curves which would accommodate a variety of GLRs. He was then able to prepare a series of gradient curves which apply for a constant liquid production rate and tubing size.

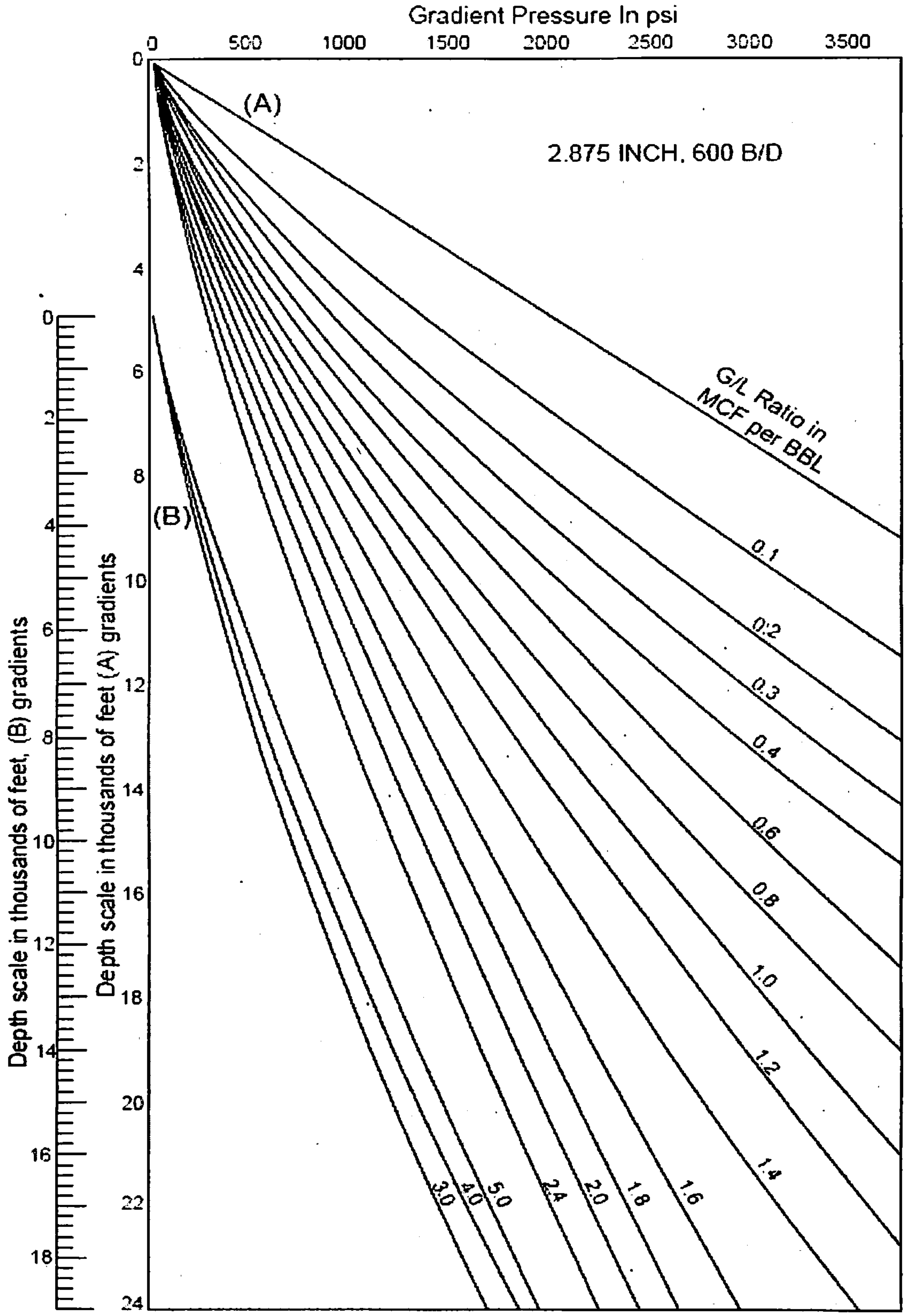


Figure 32: Approximate depth -pressure gradients for 2.875 in. Tubing

The method of using these curves to predict bottomhole pressure is

Given:
Well Depth
Tubing Size
GLR
Production Rate
Tubing Diameter

} Calculate required THP

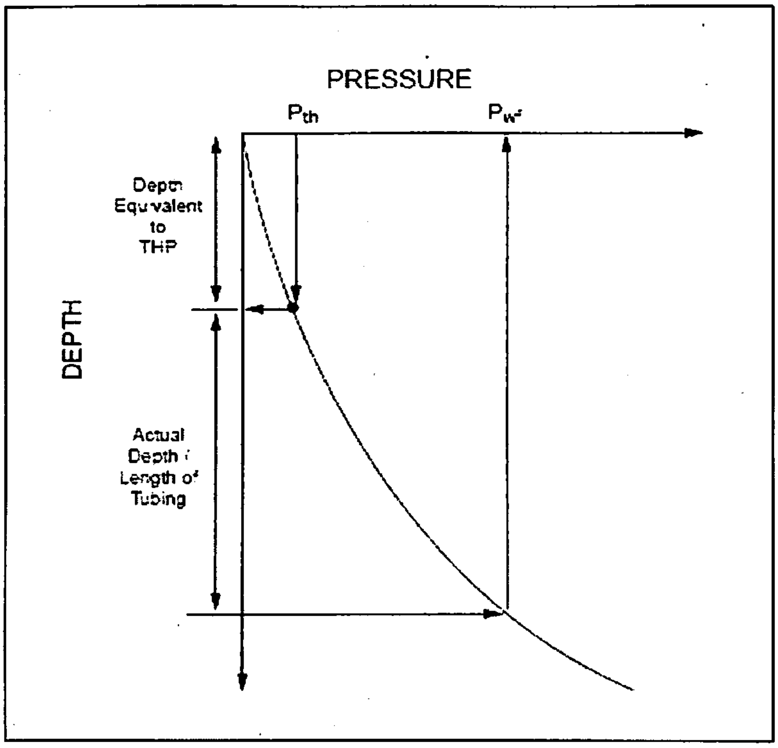


Figure 33: Bottomhole Flowing Pressure Prediction

(1) From the appropriate gradient curve for the specific GLR, Qo and tubing diameter, calculate the depth or length of tubing equivalent to the tubing head pressure Pth.

(2) Add the depth equivalent to the Pth to the actual depth of the well to obtain the total equivalent depth.

(3) Entering the curve with the total equivalent depth and from the intersection with the gradient curve read off the equivalent pressure which is the bottomhole hole flowing pressure.

The gradient curves exhibit several interesting features:

(1) It can be seen that the slope of the curves or pressure gradient is a function of depth. This reflects the effects of phase expansion and slippage.

(2) As the GLR increases, the gradient declines. This reflects the reduction in the hydrostatic head.

(3) Some of the curves will demonstrate turnover or reversal at very high GLR.

This indicates the curves passing through the minimum pressure gradient and the subsequent increase in gradient at a specific depth as frictional losses dominate over the reduction in hydrostatic head due to increase in GOR.

2.4.7 Optimisation of Tubing Flow

Gilbert was one of the first investigators to attempt to explain the complexities of tubing flow performance and its optimisation.

The impact of tubing size on tubing pressure loss for gas flow is dictated primarily by the frictional pressure loss. However, for oil and gas flow in production tubing, it would be expected that for a specific flowrate and GLR there would be two opposing effects, namely:

(1) For small tubing size, in situ flow velocities would be high, thus increasing the frictional pressure loss.

(2) For large tubing sizes, the average upwards velocity would be small enough for the buoyancy forces on the lighter phase, and hence slippage, to be significant. This would result in a higher pressure gradient.

Gilbert illustrated the effects of tubing size and GLR on the optimisation of tubing performance.

2.4.7.1 Effects of GLR

Gilbert presented data on the impact of GLR on the flowing bottomhole pressure requirements in the form of the following figures. This illustrated that the impact of increasing the GLR on the tubing pressure loss was:

(1) To reduce the hydrostatic gradient of the fluid in the tubing, the hydrostatic gradient would approach that of the gas as its volume fraction approached unity.

(2) At high liquid rates, the total volume of gas will be so high that the pressure gradient will increase, reflecting the rise in the frictional pressure gradient.

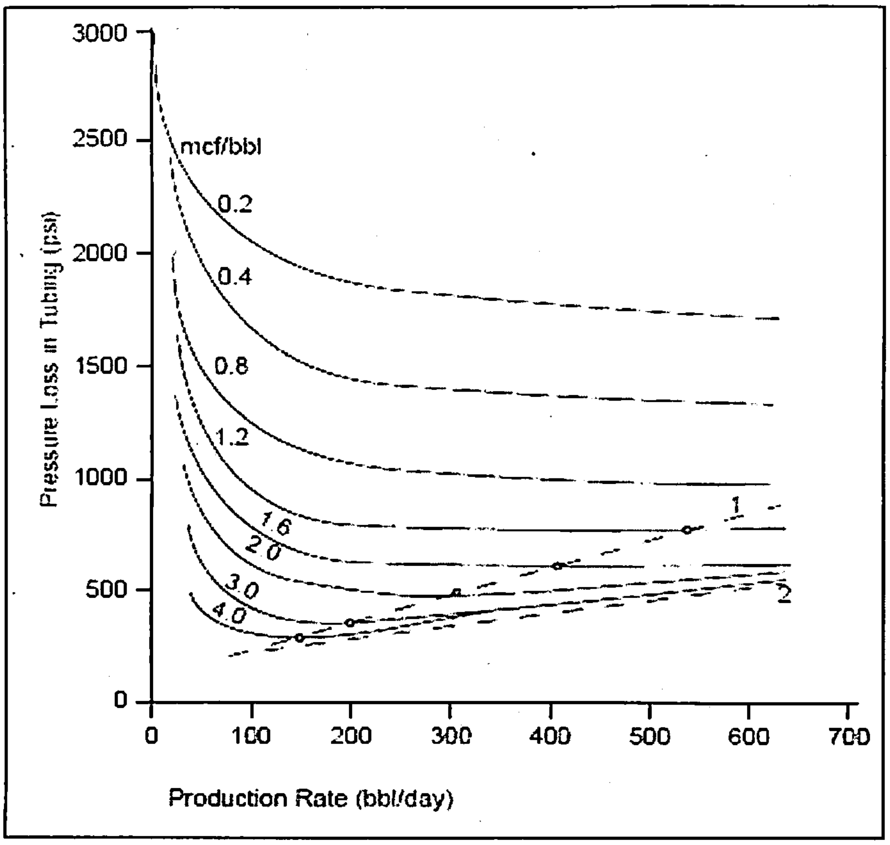


Figure 34: Pressure Loss as a Function of Production Rate at Various Gas/Liquid Ratios (Gilbert)

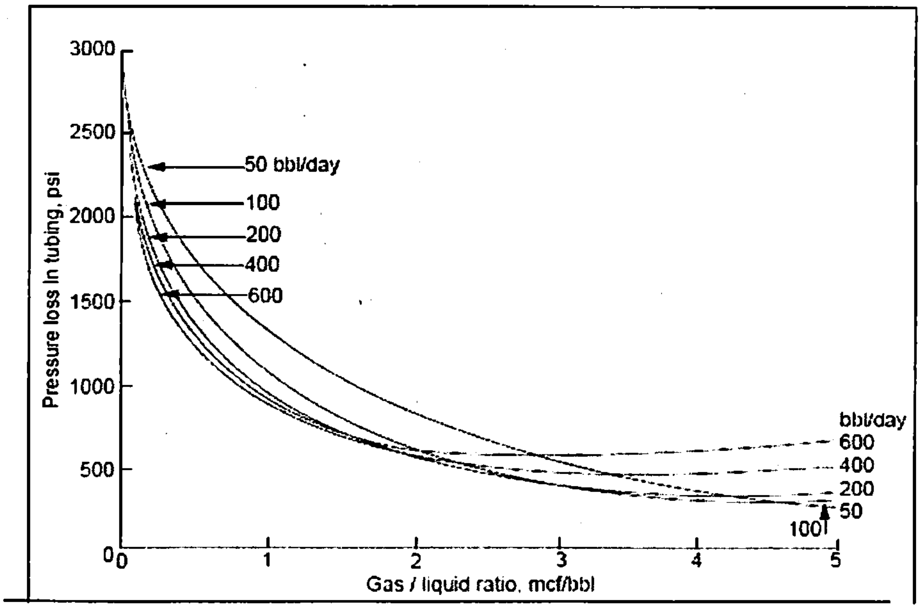


Figure 35: Pressure loss as a function of gas / liquid ratio at various production rates(Gilbert)

Thus, a minimum pressure gradient will exist. The GLR corresponding to theminimum total pressure gradient will increase as production rate declines, reflecting the impact of phase velocities in the tubing.

2.4.7.2 Effects of Tubing Size

Gilbert presented data in relation to his field-derived pressure gradient measurements for GLRs of 400 and 1000 SCF/bbl.

In the figure shown below, the low production rate of 50-100 BPD results in higher pressure requirements in the larger diameter tubings, 27/8" / 31/2", due to phase separation and slippage. At these flowrates, in the smaller tubings, eg, 23/8" diameter and less pressure gradients are lower and the flow is more efficient. At the higher rate of 200 BPD or more, it is possible that the smaller tubing sizes will require higher lift pressures, ie, the smaller tubing sizes exhibit friction pressure increases whilst the larger tubing sizes benefit from reduced slippage between the phases. The smaller tubing sizes of 1.66" - 23/8" exhibit a minimum pressure requirement at an intermediate flowrate.

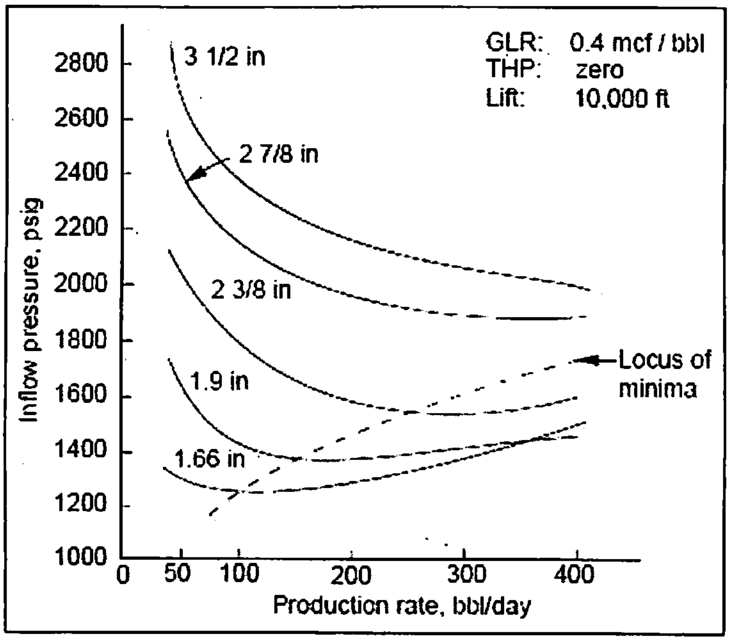


Figure 36: Effect of flow rate on vertical flow pressure losses: various tubing sizes. Low GLR. (Gilbert)

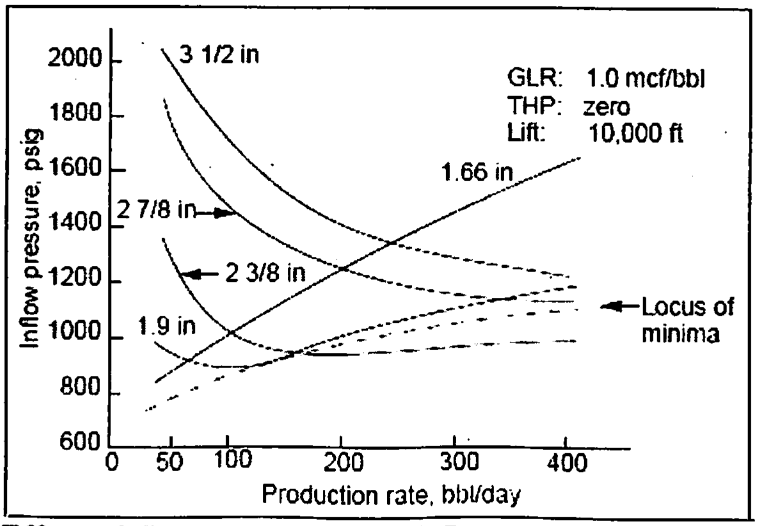


Figure 37: Effect of flow rate on vertical flow pressure losses: various tubing sizes. High GLR. (Gilbert)

The higher GLR case of 1000 SCF / BBL is illustrated in figure above but there are a number of changes compared to the 400 SCF / bbl:

(1) Overall, all tubing sizes require a lower flowing bottom hole pressure in the low production case with 1000 SCF / bbl compared to the 400 SCF / bbl, ie, reduced slippage because of the higher in situ tubing velocities due to the higher gas flowrate.

(2) For all tubing sizes except the 1.66", the minimum FBHP is achieved in the 1000 SCF / bbl case compared to the 400 SCF / bbl.

(3) For the 1.66" tubing, the gas flowrate is too high, even at very low production rates. The FBHP does not pass through a minimum at a GLR of 1000 SCF/bbl and the FBHP increases continuously with increasing production rate as a result of the high frictional gradients.

The data for the 1000 SCF / bbl clearly shows a minimum pressure loss associated with flowrates of 100 bbl / d or more. The tubing size which provides the minimum intake pressure, increases with increasing flowrate.

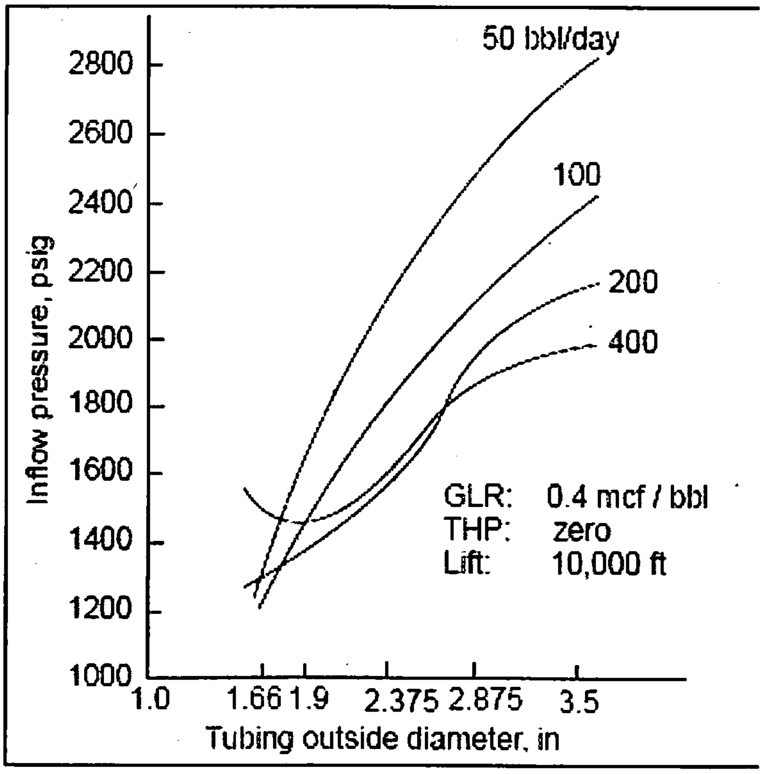


Figure 38: Effect of tubing size on vertical flow pressure losses: various flow rates (Gilbert)

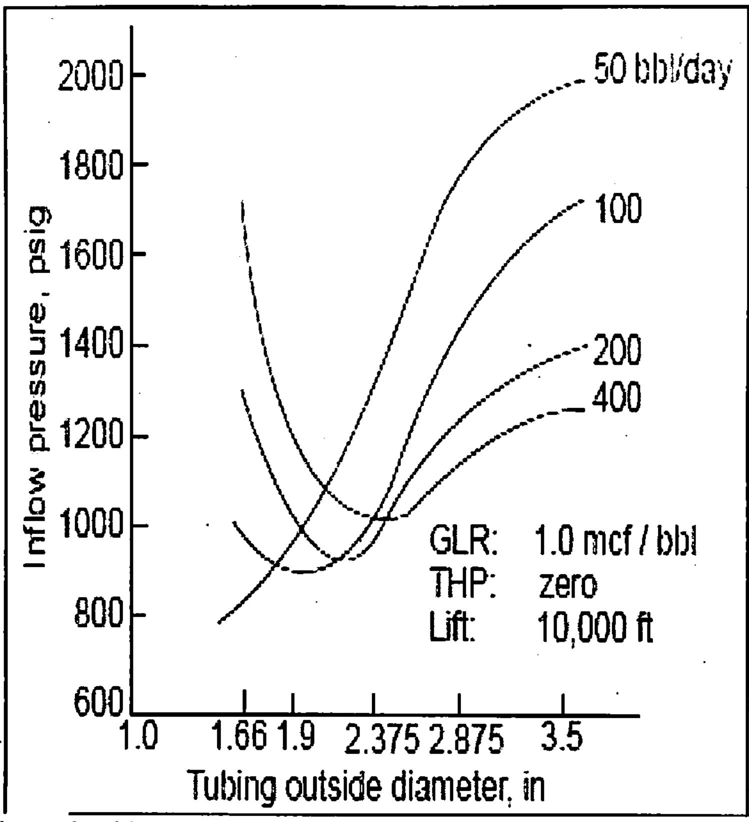


Figure 39: Effect of tubing size on vertical flow pressure losses: various flow rate

2.5FLOWLINE CHOKES

2.5.1 Functions of Flowline Chokes

The fluid pressure within the reservoir provides the driving force to push fluid into the wellbore and, in natural flow wells, up the production tubing to the surface. To maximise the production capacity of individual wells, it is possible to ensure that minimal restriction exists in the flowline.

The implementation of flowline back pressure close to the wellhead may be important for some of the following reasons:

(1) To maintain stable flow/pressure conditions downstream of the choke

(2) To control the drawdown on the well and hence restrict the occurrence of gascusping or water coning into the wellbore or the failure of the formation around the wellbore

(3) To dampen down fluctuations in the well deliverability by applying back pressure to the system

(4) To isolate the well from pressure fluctuations created in the processing, gathering and transportation system

The choke therefore plays an important role in:

(1) well control

(2) reservoir depletion management

2.5.2 Choke Equipment

Chokes are designed to restrict or throttle flow and as such several different designs have been developed. The choke creates the flow restriction by offering a restricted flow path for the fluid to pass through.

This restriction can be selected to be:
• fixed
whereby the orifice size is specified before installation

• adjustable
whereby the orifice size can be adjusted after installation to suit the well and operational requirements.

Positive chokes are particularly useful where the fixed orifice is essential for monitoring well performance, eg, during well tests. The pressure drop across the choke depends upon the fluid characteristics, the flowrate and choke dimensions.

An adjustable choke allows the back pressure on the well to be varied

2.5.2.1 Positive or Fixed Choke

This normally consists of two parts:

(1) A choke which consists of a machined housing into which the orifice capability or "bean" is installed.

(2) A "bean" which consists of a short length 1-6", of thick walled tube with a smooth, machined bore of specified size.

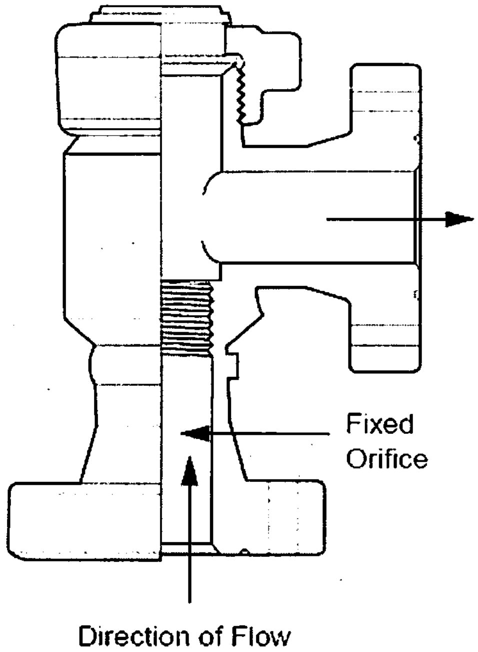


Figure 40: Fixed choke

The term positive refers to the fact that, upon installation, the choke is of a fixed and known dimension.

Fixed chokes are occasionally installed in wireline nipples at depth in the tubing string in certain wells to:

(1) Reduce the tubing head pressure and operating pressures on the Xmas tree and wellhead

(2) Counteract the effects of hydrates and wax deposition associated with fluid expansion and cooling. The location of cooling is moved down into the tubing string where the fluid can extract heat from the surrounding formation as it flows to surface.

2.5.2.2 Valve Seat with Adjustable Valve Stem

In this design, the choke is normally located on a 90° bend. The orifice consists of a valve seat into which a valve stem can be inserted and retracted, thus adjusting the orifice size.

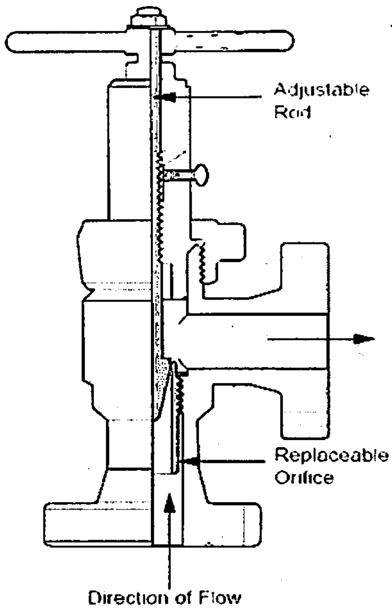


Figure 41: Adjustable choke

2.5.2.3 Rotating Disc Choke

It consists of a 90° flanged bend which can be coupled up to the flowline or Xmas tree. Internally, there are two discs made from tungsten carbide, ceramic or other erosion-resistant material. Both
discs have two ports which are diametrically opposite in each disc. The rear disc is fixed whilst the front disc located on top of it can be rotated through a maximum of 90° via a fork, externally controlled manually or remotely. The ports can be of a circular or of a range of alternative shapes.

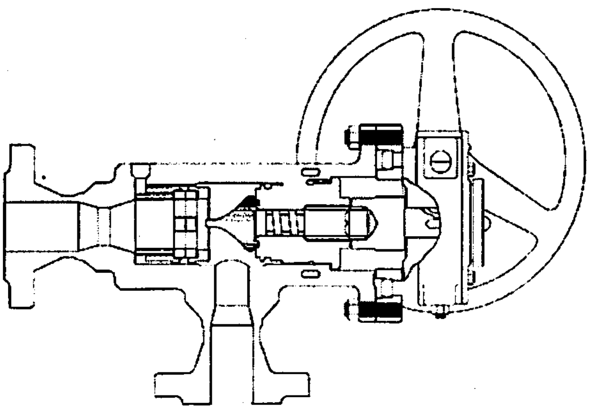


Figure 42: Rotating disc adjustable choke

2.5.3 Choke Flow Characteristics

Production chokes normally operate in a multiphase environment, ie, gas in liquid or liquid in gas flow. Single phase can occur in dry gas wells. Theoretical models exist for predicting the performance of chokes with single phase fluids. It is likely that the flow will be strongly influenced by the choke geometry or configuration as well as multiphase flow.

2.5.3.1 Flow Behaviour and Distribution

However, if we consider flow through a square edged or rounded orifice, the use of a fixed choke will present a reduced orifice of some considerable length.

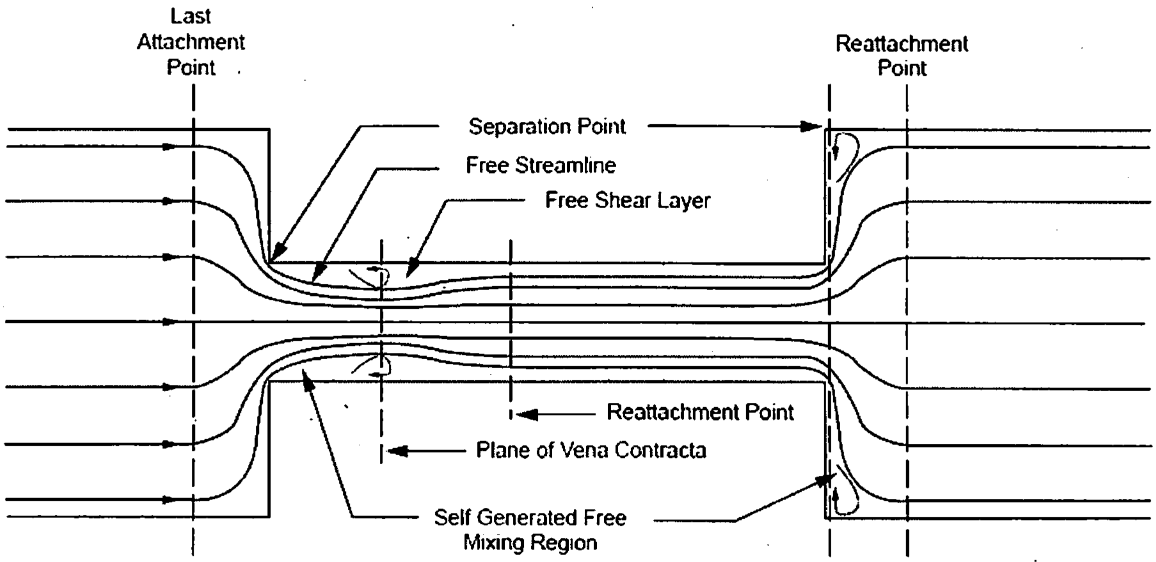


Figure 43: Choke flow model

2.5.3.2 Critical Flow through Chokes

Consider the case of a controlled increase in the flowrate through a fixed choke, accomplished by opening a control valve downstream of the choke. Initially, with the valve closed, the pressure is equal both upstream and downstream of the choke. As the valve is gradually opened, the downstream pressure P2 declines and the flowrate increases. If the valve continues to be opened, the flowrate will start to level off and ultimately reach a plateau. Further decrease in P2 will not produce any increase in production rate.

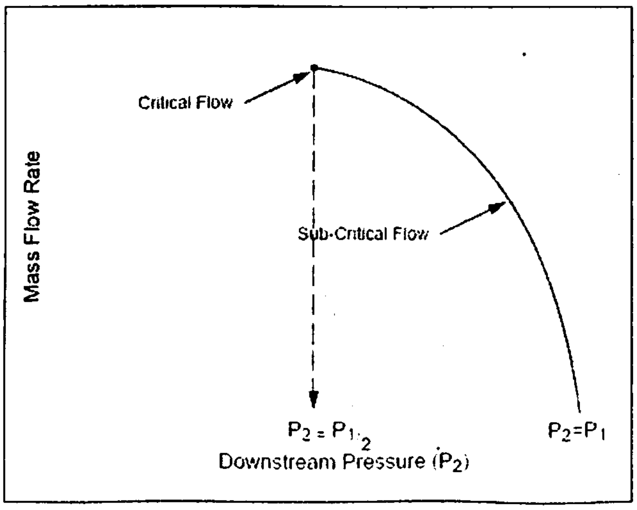


Figure 44: Downstream pressure control

The ratio of upstream to downstream pressure is termed R:

$$R = \frac{P_2}{P_1}$$

where R = pressure ratio
P_2 = downstream pressure
P_1= upstream pressure

Flow at pressure before the plateau production rate is achieved is termed sub-critical flow and, once plateau conditions are achieved, the flow is classed as critical flow. Critical flow behaviour is only exhibited by highly compressible fluid such as gases and gas/liquid mixtures.

2.5.4 CHOKE FLOW CORRELATIONS

Flow through the choke will be largely influenced by whether single or multiphase flow occurs.

2.5.4.1 Single Phase Flow

The rate of flow through an orifice q, if the velocity of approach is neglected, is expressed as:

$$q = C_d\, A \sqrt{2g_c \cdot h_L}$$

where Cd = discharge coefficient
A = cross-sectional area of the orifice
h_L = loss of pressure head across the orifice

2.5.4.2 Multiphase Flow through a Choke

A number of researchers have published studies on multiphase flow through chokes. Some of the studies relate to correlation of field measurements. Assuming a knife edged circular orifice and making several simplifying assumptions with regard to the phase properties, it can be shown theoretically that:

$$P_{TH} = \frac{C_d\, R^{\frac{1}{2}}\, Q}{S^2}$$

Where PTH = tubing head flowing pressure in psia
Cd = constant (about 100)
R = gas liquid ratio (MSCF/bbl)
Q = gas liquid ratio (STB/d)
S = bean size in 1/64"

Several fluid empirical choke performance formulae based on field or experimental data have been proposed, of the form:

$$P_{TH} = M \cdot \frac{q^a R^b}{(A)^c}$$

R = gas liquid ratio
q = liquid flowrate
A = cross-sectional area of the choke

a, b, c and M are constants

The majority of the correlations assume critical flow across the choke.

(1) Gilbert's choke correlation

In 1954, Gilbert proposed the following empirical relationship based on field data:

$$P_{TH} = \frac{465\ R^{0.546} \cdot q}{S^{1.89}}$$

where PTH = flowing tubing head pressure in psig.

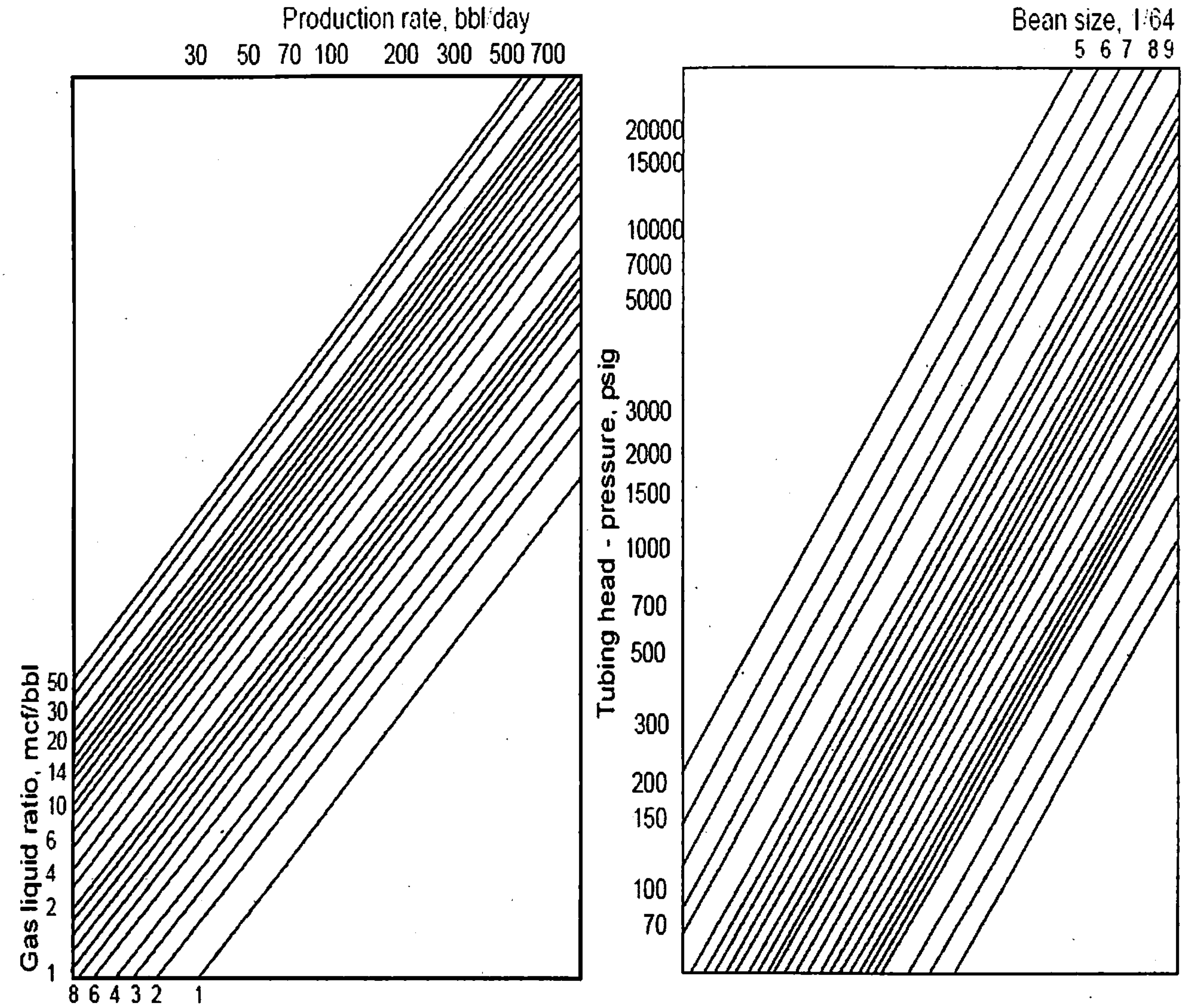


Figure 45: Gilbert's bean performance correlation

(2) Achong choke correlation

Achong proposed a modified version of the Gilbert choke performance equation, based on field data from Venezuela. The correlation is:

$$P_{TH} = \frac{3.82\, R^{0.65} \cdot q}{S^{1.88}}$$

where PTH = psig and R = GLR in SCF/bbl.

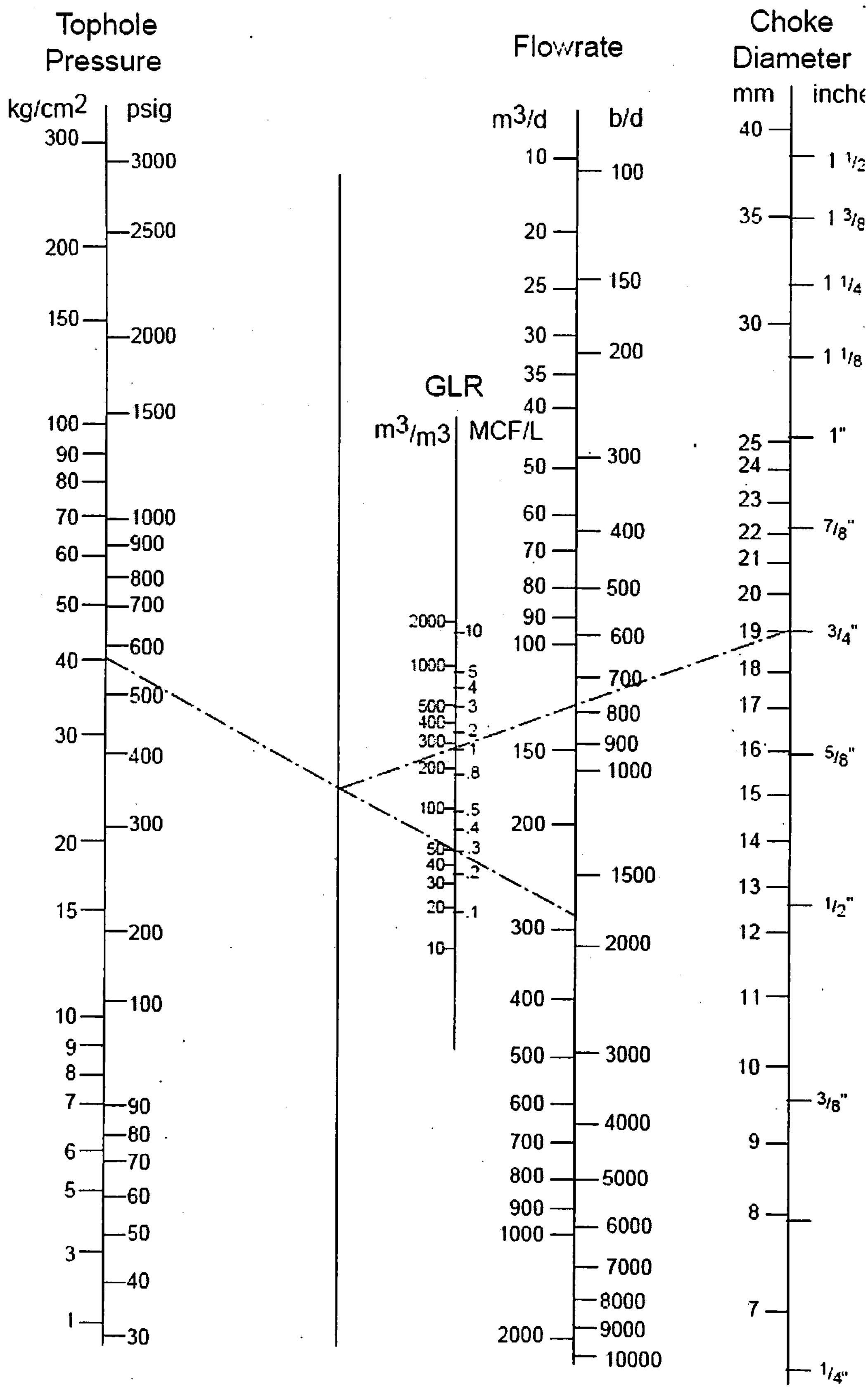


Figure 46: Bean performance chart(after Achong)

2.6COMPLETION FLOW PERFORMANCE AND OPTIMISATION

Matching the Inflow and Tubing Performance

There are various methods of predicting the performance of a flowing well system, each of which can be graphically represented. For simplicity, the case of oil production will be considered.

(1) Method 1 - Reservoir and tubing pressure loss convergence in predicting bottomhole flowing pressure

In this simplified technique, the approach will be to predict the bottomhole flowing pressure, Pwf, from both directions, i.e. converge on predicting Pwf from:

(a) from the separator back up the flowline and down the tubing to the formation and

b) from the reservoir pressure PR or Pe assuming inflow inwards to the wellbore

The calculation of the pressure losses and the identification of the operating flowrate is easily obtained from a plot of bottomhole flowing pressure versus production rate, with Pwf being calculated based on reservoir and tubing pressure loss respectively.

The method is depicted in following figure and comprises the following stages:

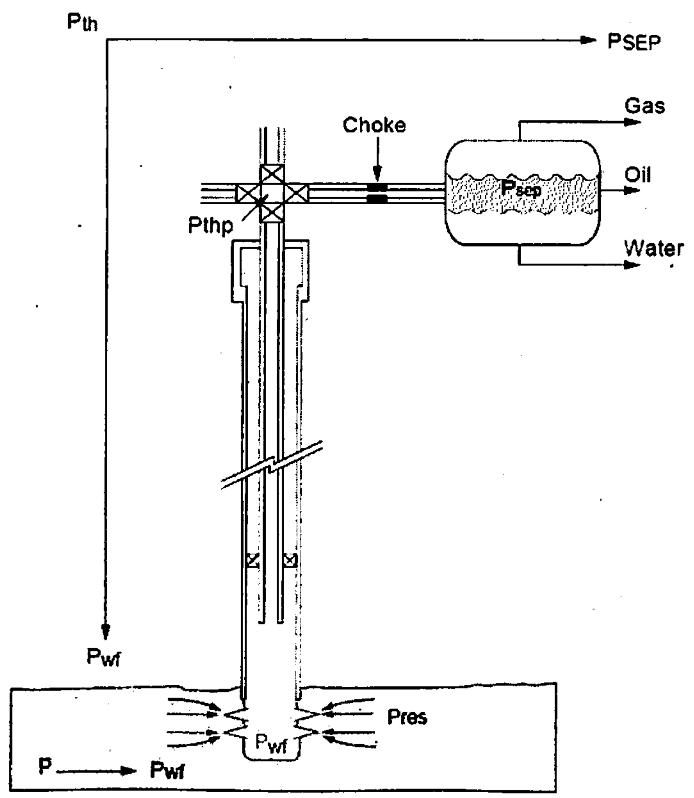


Figure 47: Simplified approach to evaluating bottomhole flowing pressure

(a) Predict Pwf as a function of inflow flowrate q from the reservoir using either

(i) the straight line assumption, the productivity index and reservoir static or average pressure

(ii) a radial inflow performance equation

(iii) Vogel's technique or a variant thereof

(b) Predict Pwf from pressure loss in the tubing using either. We can then plot Pwf versus q, based on tubing pressure loss requirements.

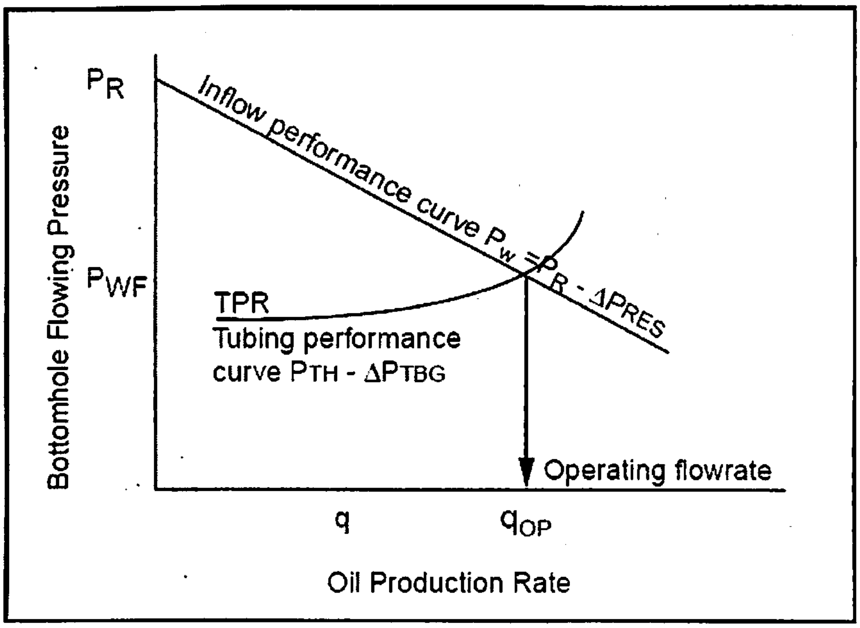


Figure 48: Evaluation of the operating flowrate

(c) At the point of intersection, the bottomhole flowing pressure required based on both the IPR at that rate, and the tubing performance at that same flowrate, are equal.The flowrate at the intersection of the two curves is termed the operating flowrate.

(2) Method 2 - cumulative pressure loss from reservoir to separator

In this method, the basis of pressure availability will be the inflow performance relationship. This method differs from Method 1 in that the tubing head pressure will be calculated as a function of flowrate.

The procedure is as follows:

(a) Calculate Pwf as a function of flowrate using the PI or inflow performance relationship. Plot Pwf versus q.

(b) Assume a range of flowrates q. For each flowrate estimate the available Pwf from the graph. Using this value of Pwf, locate this pressure on the relevant gradient curve. Move up the curve a depth equivalent to the actual vertical depth of the well. Read the pressure at this point. The pressure will correspond to PTH for that particular flowrate.Plot PTH versus q. Repeat over the range of flowrates.

(c) Calculate PTh requirements based on choke performance. Repeat for a range of choke sizes if the choke size (S) was not previously specified. Plot the choke performance line.

(d) The interaction between the actual choke performance PTH specified as required and the predicted PTH based on the IPR/TPR, provide the operating flowrate for the well using that choke size

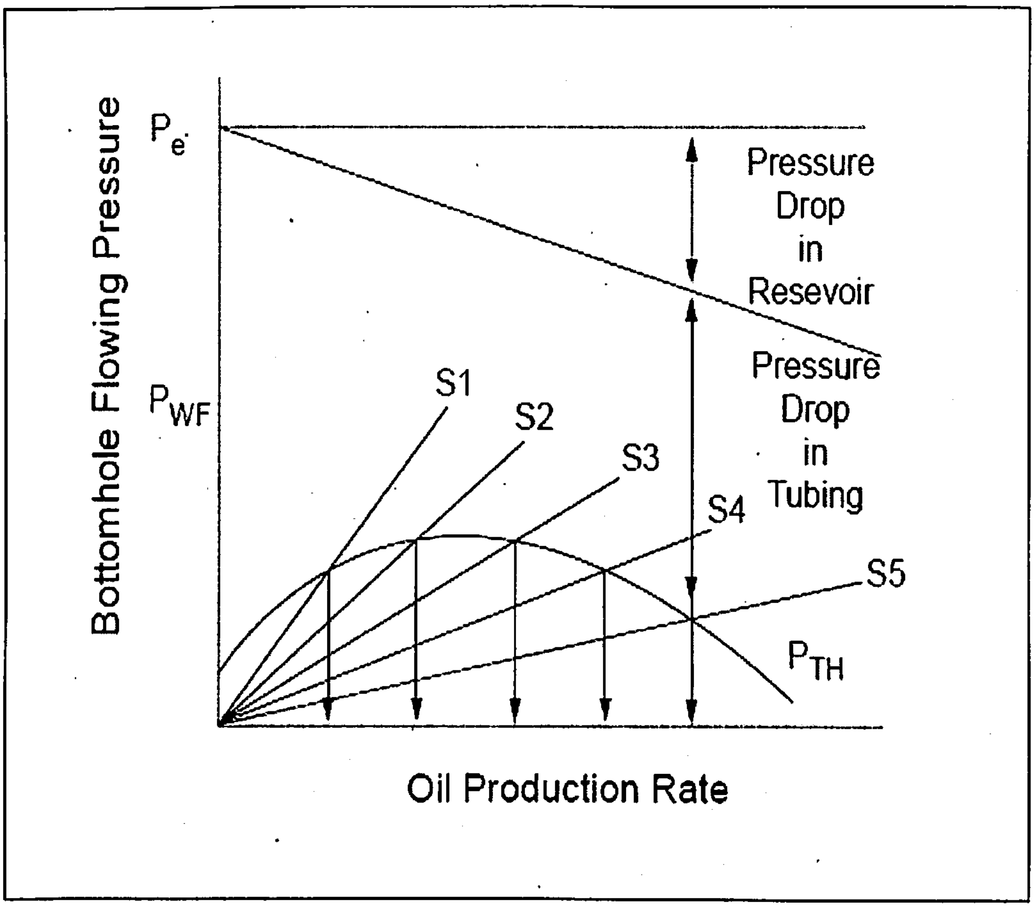


Figure 49: Operating flowrates for various choke sizes

The above techniques allow the prediction of the flow performance for a well utilising the following information:

- IPR or PI relationship
- tubing size(s)and configuration
- tubing length or well depth
- GLR and water cut.

2.7WELL COMPLETION DESIGN

INTRODUCTION

In the development of a hydrocarbon reservoir, a large number of wells are drilled and require to be completed, to allow the structure to be depleted. However, the drilling and completion operations are crucial to the long term viability of the wells in meeting the specified objectives. The design and completion of both production and injection wells are required to satisfy a number of objectives including:

1. Provision of optimum production/injection performance.

2. Ensure safety.

3. Maximise the integrity and reliability of the completion over the envisaged life of the completed well

4. Minimise the total costs per unit volume of fluid produced or injected, i.e. minimise the costs of initial completion, maintaining production and remedial measures.

Depending upon the reservoir characteristics or development constraints, the completion may be required to fulfil other criteria, e.g. to control sand production.

The design of a completion can therefore be assumed to proceed concurrently at two different levels. The initial intention would be to produce a conceptual design, or a series of alternatives. From these conceptual designs, one or more would be selected for more detailed development. Thereafter, a detailed design process would be pursued with the intention of producing a completion string design which specifies all components and also assesses the sensitivity of the well and completion performance to variations in the reservoir data used for the design.

The fundamental design of a completion consists of four principal decision areas, namely:

1. Specification of the bottom hole completion technique.

2. Selection of the production conduit.

3. Assessment of completion string facilities.

4. Evaluation of well performance / productivity-injectivity

Subsequently, the detailed design and evaluation of the selected completion concept will be undertaken. In this phase of the design the objectives will be to:

1. Specify all equipment and materials

2. Optimise completion performance

3. Optimise well performance.

It is essential that at both the conceptual and detailed design stages, an interactive approach is adopted. The interactive nature of completion design and the diversity of design data, e.g. reservoir rock and fluid properties, production constraints etc. and the range of disciplines which have inputs to the decision making process, e.g. drilling engineers, reservoir engineers and production technologists, necessitates a broad and far reaching design process. A synergistic approach to completion design is essential.

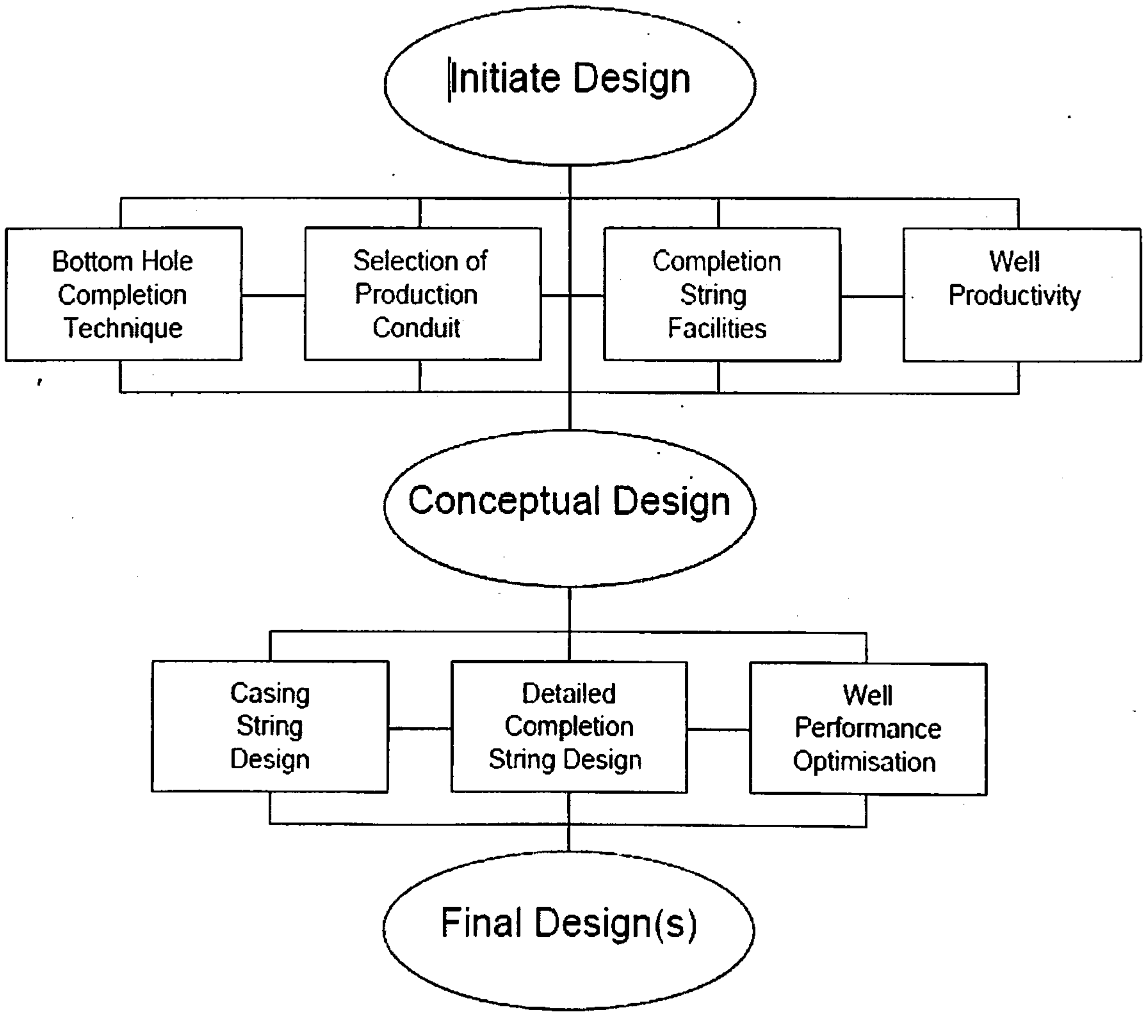


Figure 50: Completion design Strategy

2.7.1 BOTTOM HOLE COMPLETION TECHNIQUES

Once the borehole has been drilled through the reservoir section of interest for production or injection, the method by which fluid communication will occur between the reservoir and the borehole, after completion, has to be decided. There are 3 alternative approaches for the completion of the reservoir zone:

1. Open hole completion

2. Pre-drilled / pre-slotted liner or screen completion (uncemented).

3. Casing or liner with annular cementation and subsequent perforation.

2.7.1.1 Open hole completion

The simplest approach to bottom hole completion would be to leave the entire drilled reservoir section open after drilling, as shown in Fig 2. Such completions are sometimes referred to as "barefoot" completions and the technique is widely applied. Since no equipment requires to be installed there are savings in both costs and time.

However this type of completion does mean that the entire interval is open to production and hence it often provides no real selective control over fluid production or injection. It is therefore not recommended for production or injection wells where distinctive variations in layeral permeability will detrimentally control the sweep efficiency on zones under water flood or gas injection.

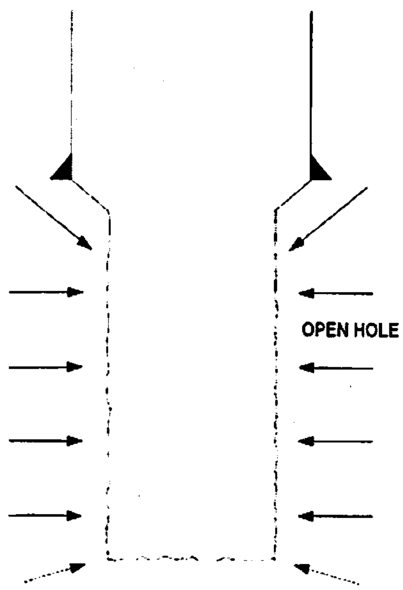


Figure 51: Open Hole Completion

Open hole completions should only be applied in consolidated formations as the borehole may become unstable once a drawdown in applied to induce the well to flow. In such cases either total collapse of the formation or the production of sand may occur.

2.7.1.2 Screen or pre-slotted liner completions

In this technique, once the drilling through completed reservoir section has been completed, a wire-wrapped screen or steel pipe which has slots or alternative sand control screen, is installed.The principal purpose of the screen or liner is to prevent any produced sand from migrating with the produced fluids, into the production flow string. The success of the completion in controlling sand production is dependent upon the screen or slot sizes and the sand particle sizes. The screen will only become 100% effective if it totally restrains sand production which requires that the slot size be equal to the size of the smallest particles.

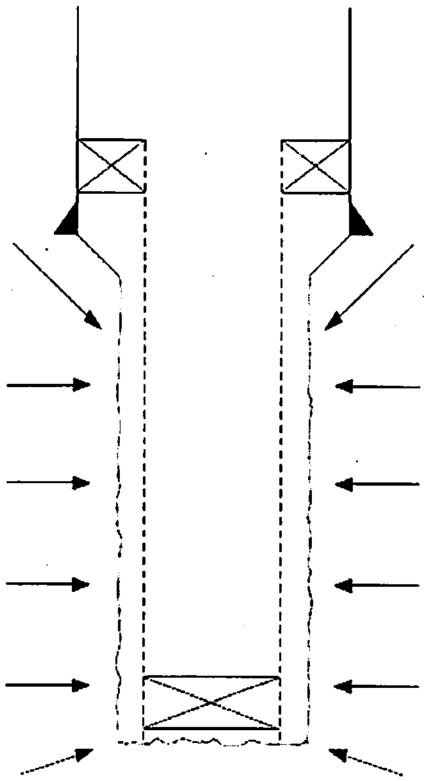


Figure 52: Well completed with slotted liner or wire wrapped screen

This technique suffers from the same inability for zonal control of production or injection as exists in the open hole completion and may only effectively control sand production over a limited range of conditions.

2.7.1.3 Cemented and perforated casing/liner

The final choice is to install either a casing string which extends back to surface or a liner which extends back into the shoe of the previous casing string, which would then be cemented in place by the displacement of cement slurry into the annular space between the outside wall of the casing and the borehole wall.

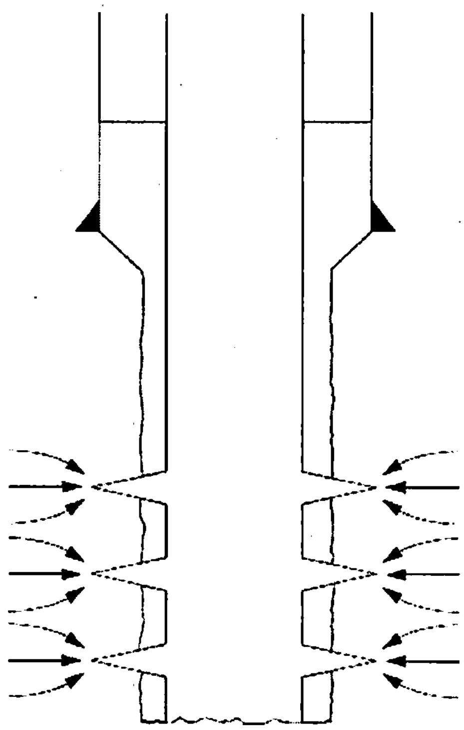


Figure 53: Cement and perforated production casing or liner

The integrity and selectivity of the completion depends to a great extent on an effective hydraulic seal being located in the casing-formation annulus by the cement. For the completion to be effective, a successful primary cement job must provide zonal isolation behind the casing. The absence or failure of the cement can lead to either fluid migration behind the casing to surface, into another zone or into perorations from which it was assumed to be isolated. If required the perforations can subsequently be closed off by a cement squeeze operation.

2.7.2 SELECTION OF THE FLOW CONDUIT BETWEEN THE RESERVOIR AND SURFACE

There are a number of optional methods by which fluid which enters the wellbore will be allowed to flow to surface in a production well, or to the formation in an injection well. In the selection of the method, a range of considerations may influence the choice including: cost, flow stability, ability to control flow and ensure well safety or isolation; ensuring that the integrity of the well will not be compromised by corrosion or erosion. In the case of multizone reservoir, the zonal characteristics will determine to a large extent the flow system selected.

However, for a single zone completion, the following alternatives exist:

1. Tubingless casing flow.

2. Casing and tubing flow.

3. Tubing flow without annular isolation.

4. Tubing flow with annular isolation.

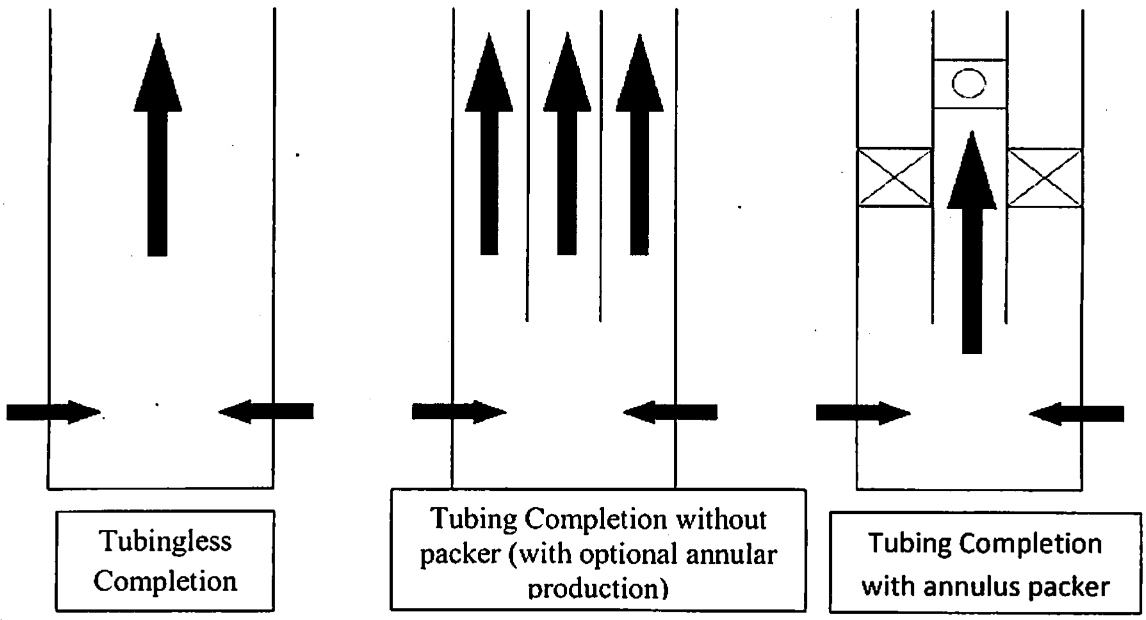


Figure 54: Selection of Production Conduit

2.7.2.1 Tubingless casing flow

In this option, once the well has been drilled and the bottom hole completion technique implemented, eg open hole or perforated casing, the well is induced to flow under drawdown and fluid is produced up the inside of the casing. This technique is very simple and minimises costs. However it is not without its disadvantages. Firstly, the production casing may be of such a diameter that the flow area is so large that the fluid superficial velocities are low enough for phase separation and slippage to occur, resulting in unstable flow and increased flowing pressure loss in the casing. To be effective, this approach is only applicable for high rate wells. Secondly, the fluid is in direct contact with the casing and this could result in any of the following:

1. Casing corrosion, if H_2S or CO_2 are present in produced fluids.

2. Casing erosion, if sand is being produced.

3. Potential burst on the casing at the wellhead if the well changed from oil to gas production. (Note: This should have originally been considered in the design of casing for burst but subsequent corrosion or wear may have reduced burst capacity).

2.7.2.2 Casing and tubing flow

For highly productive wells where a large cross sectional area for flow is desirable, an alternative to the tubingless casing flow would be to install a production tubing and allow flow to occur up the tubing and the tubing- casing annulus. This type of completion has the very important advantage of providing a circulation capability deep in the well where reservoir fluids can be displaced to surface by an injected kill fluid of the required density to provide hydraulic overbalance on the reservoir.

2.7.2.3 Tubing flow without annulus isolation

In situations where annular flow in a casing-string completion would result in excessive phase slippage with consequent increased flowing pressure loss and potential instability, the consideration could be given to merely closing the annulus at surface and preventing flow. However, in reservoirs where the flowing bottom hole pressure is at or below the bubble point, gas as it flows from the formation to the tubing tailpipe will migrate upwards under buoyancy forces and some gas will accumulate in the annulus. This will result in an increase in the casing head pressure at surface. Gas build up in the annulus will continue until the gas fills the annulus and it will offload as a gas slug into the base of the tubing and be produced. This production instability will be cyclical and is referred to as ***annulus heading***.

2.7.2.4 Tubing flow with annular isolation

For cases where a large cross sectional area for flow is not necessary, then an open annulus can cause complications as discussed above. Therefore, in the majority of cases where tubing flow will take place, the annulus is normally isolated by the installation of a packer. The packer has a rubber element which when compressed or inflated will expand to fill the annulus between the tubing and the casing. The packer is normally located as close to the top of the reservoir as possible to minimise the trapped annular volume beneath the packer and hence the volume of gas which could accumulate there.

2.7.3 COMPLETION STRING FACILITIES

For any completion string we can define a range of operations or capabilities which may be required. Some of the capabilities are considered to be essential, such as those providing operational security or safety, whilst others can provide improved performance or flexibility. However, as the degree of flexibility provided by the completion is increased, the more complex is the design process and normally a sophisticated design will result which includes a large number of string components.

2.7.3.1 Basic completion string functions and facilities

The basic facilities provided by a completion string must allow it to continue the production or injection of fluids over as long a period as possible without major intervention to conduct well repairs. Further, at all times, the design must ensure the safe operation of the well and reliably allow for its shutdown in a variety of situations. The completion string, production casing and wellhead must act as a composite pressure system which prevents formation fluids and pressure escaping from the reservoir except via the production tubing and the Xmas Tree into the surface processing facilities.

The following are considered to be the essential attributes for the majority of completion string installations:

(a) The ability to contain anticipated flowing pressure and any hydraulic pressures which may be employed in well operations and conduct fluid to surface (production) or the reservoir (injection wells) with minimal flowing pressure loss and optimal flow stability.

(b) The ability to isolate the annulus between the casing and the production tubing if flow instability is likely or it is desirable to minimise reservoir fluid contact with the production casing.

(c) The ability to affect downhole shut-in either by remote control or directly activated by changing well flowing conditions, in the event that isolation at surface is not possible.

(d) A means to communicate or circulate (selectively when required) between the annulus and the tubing.

(e) A provision for physical isolation of the tubing by the installation of a plug to allow routine isolation e.g. for pressure testing of the tubing.

The above would provide a completion string with the necessary features to allow the well to produce in a safe, controllable manner. Consider each of the functions in turn:

(a) Pressure and flow containment

The pressure communicated between the wellbore and the reservoir is contained within the production casing, production tubing, the wellhead and the surface valve closure system known as the Xmas tree. Further, if a packer is used then reservoir or injection pressure will be retained beneath the packer. Thus, both the casing and tubing will be designed to withstand the internal pressures which could exist in the wellbore. Similarly the wellhead, from which each casing string is suspended as the well is drilled, will be rated for maximum anticipated surface pressures. Overall control of fluid production from, or injection into, the well is provided by the valve system located on top of the wellhead.

(b) Annulus Isolation

The concepts of annulus heading cycle and the potential damage which can be occasioned to the production casing, mean that a method of annulus isolation is required in the majority of production wells. For injection wells, it is frequently necessary to isolate the annulus to prevent surface injection pressures being exerted on the wellhead and possibly giving rise to burst of the production casing. This annular isolation is normally effected by installing a packer in the completion string which is lowered into the wellbore with an elastomeric element in the retracted position.

(c) Downhole closure of the flow string

In the event that access cannot be gained to the Xmas tree to affect valve closure and stop fluid flow or because of valve failure, it is advisable, and in most cases mandatory, to have a secondary means of closure for all wells capable of natural flow to surface. The installation of a sub-surface safety valve (SSSV) will provide this emergency closure capability. The valve can be either remotely operated on a failsafe principle from surface, or will be designed to close automatically when a predetermined flow condition occurs in the well.

(d) Circulation capability

In section 2.1 , the concept of using the production casing as a flow string without production tubing was discussed and one of the major limitations identified was the inability to kill the well by circulation. The alternative killing methods of squeezing or the use of the Volumetric method are not always applicable or desirable. In many cases a coiled tubing unit or snubing unit is unavailable to re enter the tubing concentrically. Hence for the majority of completions a specific piece of equipment

is installed to allow the opening and subsequent closure of a circulation port between the tubing and the annulus. This can be provided by installing one or more of the following devices:

1.Sliding side door (SSD) or sliding sleeve (SS)

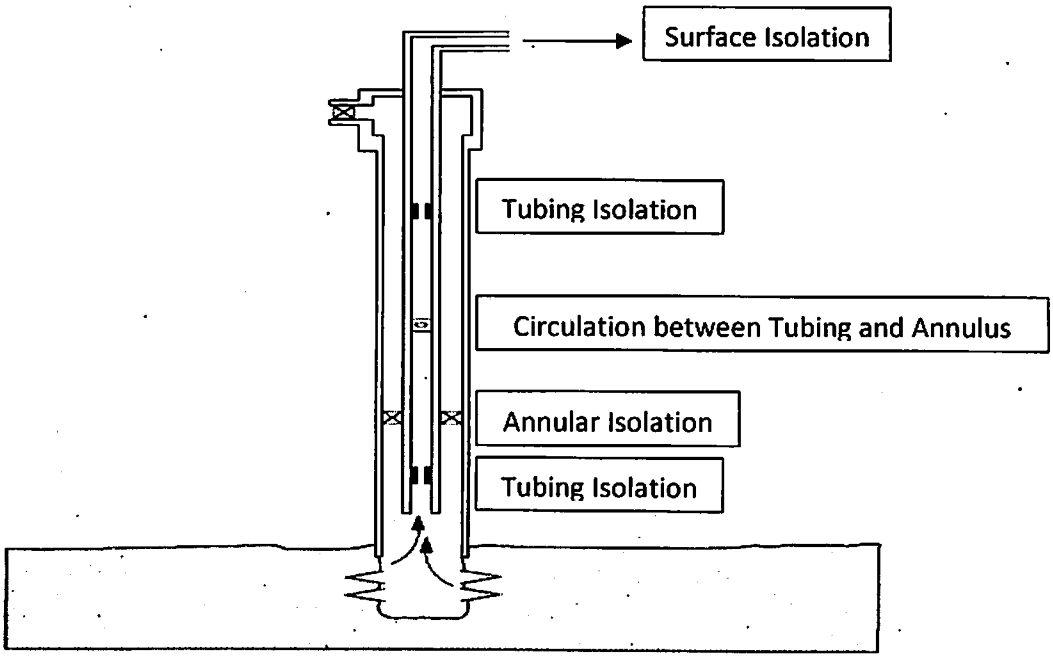
2. Side pocket mandrel (SPM)

3. Ported nipple

(e) Tubing isolation

Normally a secondary means of physical isolation will be installed. This will usually be required to supplement the downhole SSSV and also is intended to provide isolation if the well is hydraulically dead and the SSSV is to be removed. Thus the provision of this isolation is normally provided deep within the wellbore either just above or just below the packer.

The isolation can normally be provided by lowering a plug on wireline down the inside of the tubing string until it lands and locks into a wireline nipple which was incorporated into the design of the tubing string at an appropriate depth.



2.7.3.2 Additional completion string functions

A range of other functions may be necessary or considered worthwhile for incorporation into the string design as a future contingency. Some of the more prevalent are discussed below.

(a) Downhole tubing detachment

In the event of failure of the tubing string it may be necessary to pull the completion from the well to effect replacement of completion components which are more prone to failure and require more frequent replacement. However it would be useful in a number of situations to minimise the amount of equipment which requires to be pulled from the well. Thus a point of easy detachment and reconnection would be useful. This detachment can be obtained by installing a removable locator device which seals with the rest of the tubing string to be left in the well during normal conditions but which can be pulled as required.

In such cases a means of hydraulic isolation of the tubing below the point of detachment is required. Examples of this are a ***packer seal system*** which allows the tubing above the packer to be disconnected and retrieved, or a ***downhole hanger system*** which suspends the tubing in the well beneath the wellhead. Completion components which are more prone to failure and require frequent replacement, e.g. SSSV, will be located above such devices.

(b) Tubing stresses

During the normal cycle of well operations, the tubing string can extend or contract in length due to variations in both pressure and temperature subsurface. Since the string is normally landed off in the wellhead and in contact downhole with the casing through the packer, if the amount of movement were severe, it would give rise to damage to the packer, wellhead or the tubing itself.

A moving seal system could be installed which would allow expansion and/or contraction of the tubing without mechanical failure or disengagement from the packer or seal bore. Various systems are available; however, they all feature a concentric sleeve approach where seals are located in the concentric annulus and one of these sleeves is stationary.

(c) Ability to suspend P & T monitoring equipment

It is frequently required to monitor the bottomhole pressure during production tests and, in such cases, the requirement will exist to be able to run and install at a specific location in the tubing a pressure or temperature gauge. This is normally accommodated by the installation of a wireline nipple as a component of the completion string. Its location is normally as deep in the well as possible.

(d) Controlled fluid injection from the annulus into tubing

Produced fluids can contain corrosive components such as CO2, or have high pour points with attendant flowing pressure loss problems. In such cases, it may be necessary to introduce specific chemicals into the flow string at a location deep within the well to provide maximum benefit and counteract the impact of these characteristics. Examples of this may be the injection of a corrosion inhibitor or pour point depressant. In such cases one option would be to inject these fluids into the casing-tubing annulus and by incorporating a side pocket mandrel with a valve which will open under prescribed pressure conditions, the treatment fluid will then flow from the annulus into the tubing either continuously or intermittently.

(e) Downhole pump system

The selection of a downhole pumping system, whether it be electrical or hydraulically powered, will require the inclusion of the pump in the completion string design.

Important design issues will be:
1) The method of installation and retrieval of the pump upon failure.
2) Constraints on access to the tubing or wellbore beneath the pump.

(f) Wireline entry guide

It will be necessary, in most wells, to conduct wireline or coiled tubing operations below the bottom of the tubing string, e.g. across the perforated interval. In such cases, whilst retrieving the wireline tool string, assistance must be given to guide the tools back into the lower end of the tail pipe of the tubing string.

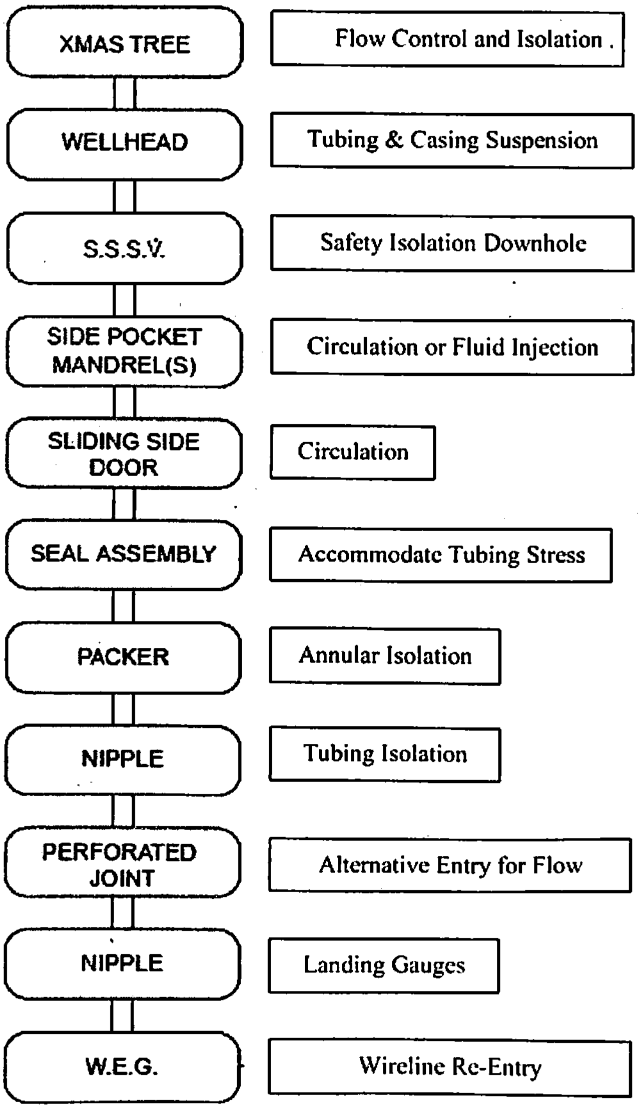


Figure 55: Composite Completion String

2.7.4 COMPLETION STRING COMPONENTS

The design of the completion string involves the selection and specification of all the component parts of the string. There must be literally thousands of potential components available if one considers that there are numerous components and variants and, further, each of the equipment suppliers has their own particular designs. It therefore is easy to understand how this part of design process can be somewhat bewildering to the les experienced. As with all services, the alternatives are usually narrowed down in that the operating company has historically used one particular supplier or has considerable experience with specific types of components. Since the equipment is specified as a certain size and with a certain type of threaded coupling, tubing completion equipment is by neccesity fairly standard and comparable between different suppliers.

In selecting equipment, this should be done on the basis that the component will provide a specific facility deemed necessary to the successful performance and operation of the well under a range of operating scenarios. Each component adds undesirable complexity to the completion and this must be compensated for by the fact that it is ***necessary or provides desirable flexibility***. One approach to discussing the subject is to postulate a typical or conventional well completion string in terms of the facility that each component provides. The discussion of a particular completion could then be made by considering whether that component or facility proposed for the typical completion is required or is beneficial in this particular instance. In this way the design is justified on an "as needs" basis and the benefits of incremental complexity created by incremental flexibility can be assessed.

2.7.4.1 Wellhead/Xmas Tree

The ***wellhead*** provides the basis for the mechanical construction of the well at surface or the sea-bed. It provides for:

1. Suspension of all individual casings and tubulars, concentrically in the well.

2. Ability to instal a surface closure/flow control device on top of the well namely:

i) A blow out preventer stack whilst drilling.

ii) A Xmas tree for production or injection.

3. Hydraulic access to the annuli between casing to allow cement placement and between the production casing and tubing for well circulation.

The purpose of the Xmas tree is to provide valve control of the fluids produced from or injected into the well. The Xmas tree is normally flanged up to the wellhead system after running the production tubing. The wellhead provides the facility for suspending the casing strings and production tubing in the well. There are a number of basic designs for Xmas trees, one of the simplest is shown in Figure 8. Briefly, it can be seen that it comprises 2 wing valve outlets, normally one for production and the other for injection, e.g. well killing. Additionally, the third outlet provides vertical access into the tubing for wireline or coiled tubing tools. The lower valve is the master valve and it controls all hydraulic and mechanical access to the well. In some cases, the importance of this valve to well safety is so great that it is duplicated. All outlets have valves which in some cases are manually operated or in the case of sophisticated platform systems and subsea wells are remotely controlled hydraulic valves operated from a control room.

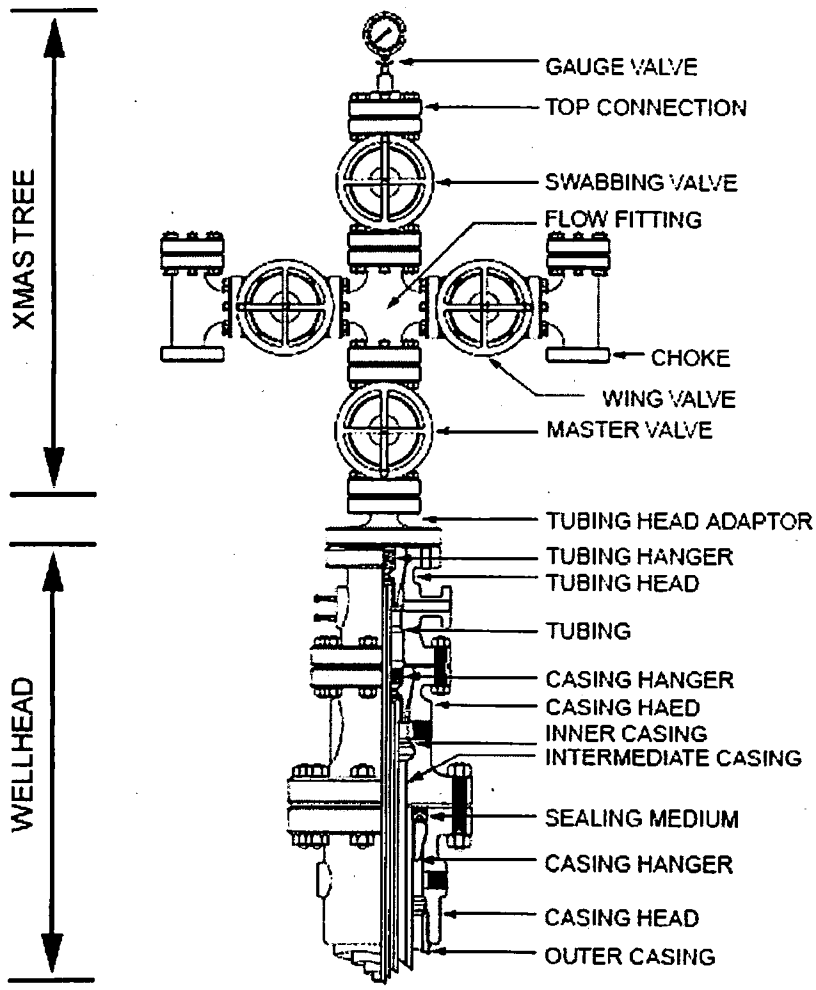


Figure 56: X- Mas Tree flanged on the wellhead

2.7.4.2 Production Tubing

The bulk of the completion string comprises threaded joints of tubing which are coupled together. The integrity of the tubing is vital to the safe operation of a production or injection well. The specification of a production tubing must be carried out based upon the mechanical and hydraulic operating conditions envisaged, the proposed operating environment and "life of well" considerations. The tubing must be specified to provide the following capabilities:

1. The inside diameter of the tubing must provide a produced fluid velocity to minimise the total pressure loss as defined by the tubing performance relationship.

2. The tensile strength of the string of made up tubing must be high enough to allow suspension of all the joints to the production zone without tensile failure occurring of any of the joints above.

3. The completion string must be able to withstand high internal pressures as a result of fluid flow entry into the tubing.

4. The completion string must be able to withstand high external differential pressures between the annulus and the tubing.

5.The tubing must be resistant to chemical corrosion which may arise because of fluid contact in the wellbore, and might ultimately accelerate string failure by one of the loads and stresses mentioned above .

Each of the above facets of tubing selection are discussed below.

2.7.4.2.1 Tubing Diameter

Conventionally the outside diameter of the tubing is specified. The inside diameter is defined by the wall thickness of the steel through the weight per feet of the tubing (lbs/ft). The decision as to the wall thickness to be used will influence the tensile strength of the steel as well as its resistance to failure with high internal or external pressure differentials. The tubing is thus specified as being of a certain outside diameter and of a specific "weight/foot" which thus specifies the wall thickness e.g. 41/2" O.D. x 13.5 lbs/ft or, say, 7" O.D. x 26 lbs/ft.

2.7.4.2.2 Tensile Strength

The tensile load that can be tolerated by a joint of tubing without the occurrence of failure is determined by the tensile strength of the steel specified for the tubing, the wall thickness of the tubing (and hence the "plain end area") and the tensile strength of the threaded coupling. Normally the tensile load tolerable without failure of the threaded coupling, greatly exceeds that of the tubing wall or pipe body itself.

There are several grades of steel considered as standards by the API, namely H-40, J- 55, C-75, L-80, N-80 and P-105. The numbers after the letter grading signify the minimum yield strength in units of a thousand psi. The letter grades indicate the manufacturing process or subsequent treatment of the steel to modify its properties, e.g. the C and L grades are heat treated to remove martensitic steels which will thus lower their susceptibility to H2S adsorption and subsequent sulphide stress cracking/ hydrogen embrittlement and consequent failure. Thus the C-75 and L-80 grades are useful in some environments. In general the higher the yield strength created by working the steel, the more susceptible it would be to embrittlement and failure, if it comes into contact with even small H2S concentrations. The minimum yield strength defines the minimum tensile strength in psi. However, since the tensile load is taken by the plain end area or wall section area of the pipe, the weight/foot of the pipe will also affect the tolerable tensile load. Since each joint suspends the joint immediately beneath it, the design on the basis of tensile load will require an increasing tensile strength in the joints nearest surface.

The design of a completion string to withstand a given tensile load will obviously be dependent upon the depth to which the completion string will be run but the following aspects will also be considered.

1. The minimum tensile strength of the pipe utilised for the design will be based upon the manufacturers data or API specification but will be reduced by the application of a safety factor which will normally have a value in the range of 1.6 to 2.0.

2. The effect of tensile load on a suspended string will be to cause elongation of the string with a subsequent reduction in the plain end area or wall thickness and this will have to be taken into account when considering the possibility of failure due to high external pressures by derating the nominal collapse resistance. This is done by application of the Biaxial Stress Theorem.

2.7.4.2.3 Internal Pressure

Since the tubing string is designed to convey the fluids to surface it must be capable of withstanding the anticipated internal pressures. However, it is not the magnitude of internal pressure which is important but rather the magnitude of differential pressure by which the internal exceeds the external pressure. This condition is referred as "burst" and the limiting condition is usually encountered at surface where the external pressure is at its minimum. The level of burst pressure to be tolerated is normally defined on the assumption that the string is gas filled, i.e. the tubing head pressure (T.H.P.) equals the reservoir pressure minus the hydrostatic head of gas in the well.

In tubing design the A.P.I. figures are derated by a safety factor which varies from 1.0 to 1.33.

2.7.4.2.4 External Pressure

The burst condition referred to above is reversed if the external pressure exceeds the internal pressure and this is defined as being a potential collapse condition. This condition is prevalent at the position of maximum pressure on the outside of the tubing in the annulus. Collapse is therefore most likely to occur deeper in the well. In calculating the collapse condition the criteria for collapse are defined using the published minimum collapse data with the application of a safety factor of 1.0 to 1.125 and derating the calculated values to account for tensile load.

2.7.4.2.5 Corrosion

There are two principal types of corrosion encountered in oil and gas production wells namely:

1. Acidic Corrosion – due to the presence of carbonic acid (from CO2), or organic acids within the produced hydrocarbon fluid.

2. Sulphide Stress Cracking/Hydrogen Embrittlement – due to the presence of H2S in the flowing well fluids from the reservoir. H2S can also be generated by the growth and subsequent action of sulphate reducing bacteria in stagnant fluids, e.g. in the casing-tubing annulus.

Since most corrosion is selective, e.g. pitting, an even reduction in wall thickness due to corrosion will not normally occur and no allowance on wall thickness can be made initially to compensate for corrosion. Corrosion inhibitor treatments will assist in minimising corrosion damage due to acidic compounds. For low partial pressures of H2S, the procedure is to recommend a reasonably low grade steel since these are less susceptible to embrittlement, e.g. C 75 or N-80.

2.7.4.2.6 Coupling Types

There are two general classes of threaded coupling:

(1) Connections which require internal pressure to produce a pressure tight seal - API regular couplings.

This type of coupling includes the API round thread and buttress connection whereby a thread compound applied to the threads must be compressed by external pressure acting on the coupling causing it to fill any void spaces within the coupling.

(2) Metal to metal or elastomeric seal connection - Premium threads.

This class of coupling includes the Extreme Line as well as a range of specialised couplings of specific commercial design, e.g. Hydril or VAM designs. The couplings do not always utilise the threads to give the pressure seal but allow torque to be applied to bring together seal shoulders or tapered surface within the coupling.

2.7.4.2.7 Flow Couplings:

A flow coupling is a short piece of pipe which has a wall thickness greater than the tubing string. Flow couplings are used to delay erosional failure at points inside a completion string, where turbulent flow is expected to occur. Flow couplings offer wall thickness nearly twice the tubing wall thickness. Their internal diameters are the same as the tubing, but they have larger external diameters. Flow couplings are available in 3- to 5-ft and 10-ft lengths. The length selected depends on fluid flow rates (how quickly turbulent flow is expected to dissipate) and the abrasiveness of the particular fluid. API recommended practice suggests the use of flow couplings around a subsurface safety valve (API RP14B, 1994). In addition, flow couplings are typically used downstream of landing nipples or circulation devices. A suggested rule of thumb is to include flow couplings above and below any downhole device which restricts the flow area by more than 10% of the nominal tubing ID.

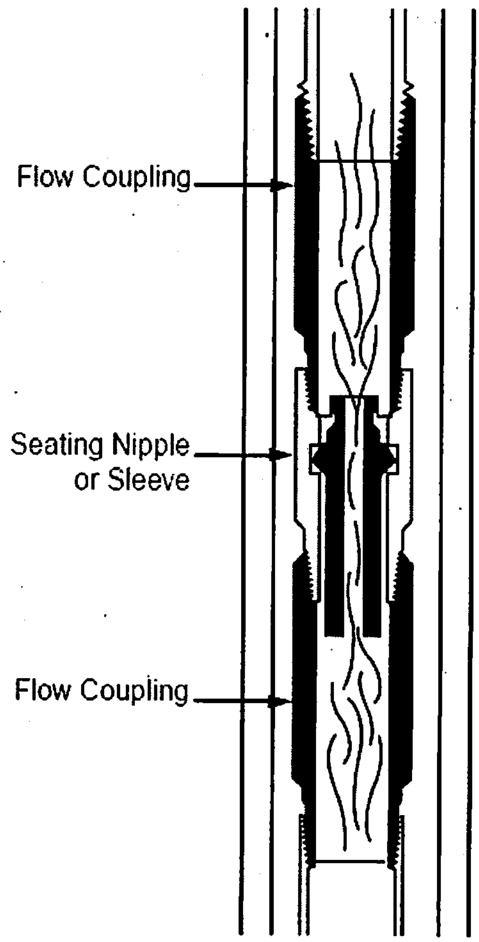


Figure 57: Correct Installation of Flow Coupling

2.7.4.2.8 Blast Joints:

Fluids entering perforations may display a jetting behavior. This fluid-jetting phenomenon may abrade the tubing string at the point of fluid entry, ultimately causing tubing failure. Blast joints are joints of pipe with a wall thickness greater than the tubing. These joints are run in the completion opposite the casing perforations. The blast joint delays the erosional failure at the point where fluids enter the wellbore and impinge on the tubing string.

Blast joints are similar in design to flow couplings. They have the same internal diameter as the tubing, but a larger external diameter. Blast joints are normally available in 20-ft or 30-ft lengths.

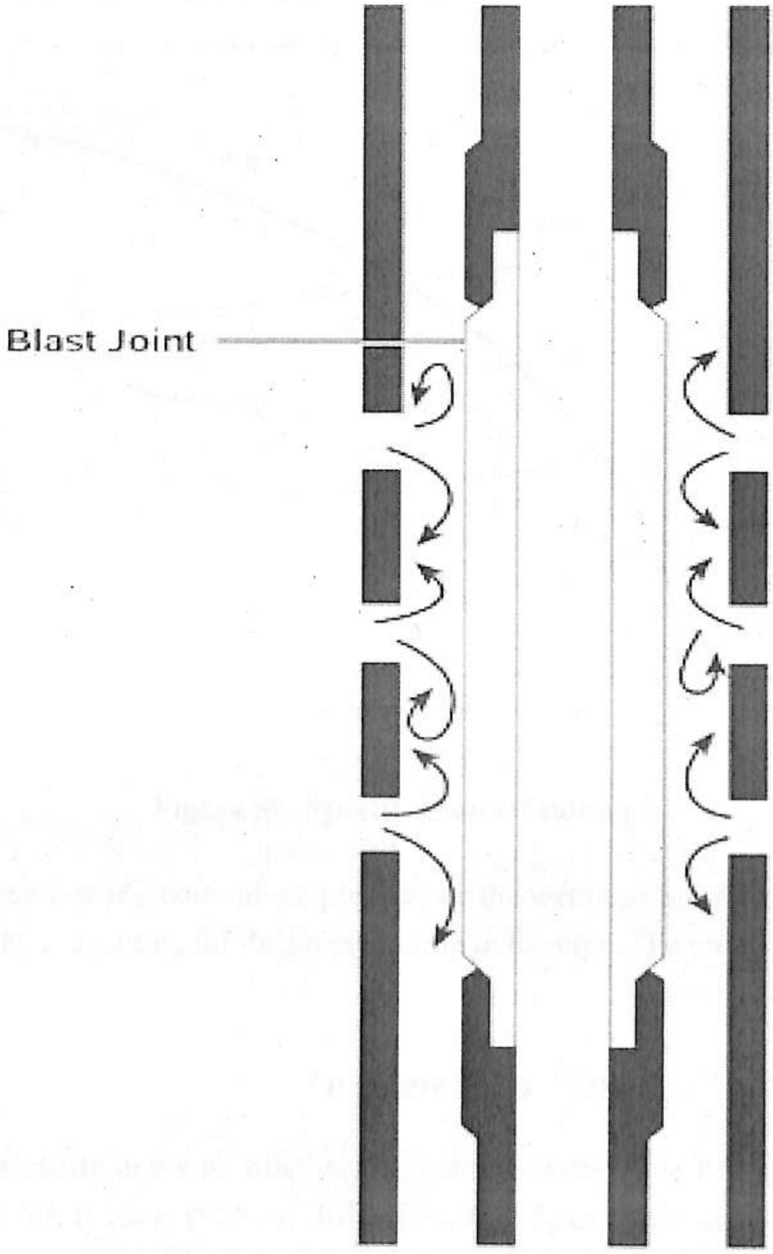


Figure 58: Blast Joint

2.7.4.2.9 Specification of Tubing

The string is defined initially by the well productivity analysis which suggests the optimum tubing ID based upon a range of available sizes.

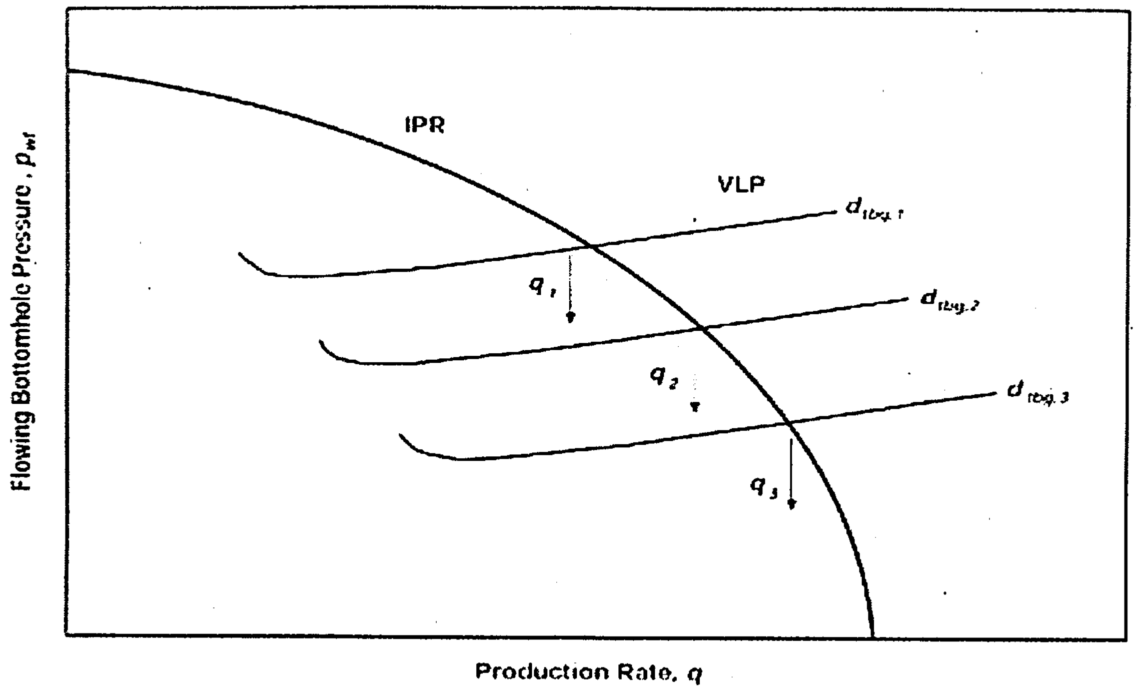


Figure 59: Specification Of tubing

Given either the flowing bottomhole pressure or the wellhead pressure, the other can be calculated by accounting for the pressure drop in the pipe. The total pressure drop is simply,

$$?p = ?p_{PE} + ?p_F + ?p_{KE}$$

$?p_{PE}$ is the difference in the potential energy (often referred to as hydrostatic pressure drop), $?p_F$ is the friction pressure difference, and $?p_{KE}$ is the pressure difference caused by kinetic energy. The latter has an appreciable value if changes in the conduit diameter are involved and is generally negligible when compared to the other two pressure drops.

The system analysis is done by considering the IPR curve and the VLP curves for various tubing diameters, and getting the optimum flow rate through any given tubing.

Impact of Length and Force Changes to the Tubing String

Changing the mode of a well (producer, injector, shut-in, or treating) causes changes in temperature and pressure inside and outside the tubing. After the packer is installed and the tubing landed, any operational mode change will cause a change in length or force in the tubing
string. The resultant impact on the packer and tubing string is dependent on
(1) how the tubing is connected to the packer
(2) the type of packer
(3) how the packer is set
(4) tubing compression or tension left on the packer.

The length and force changes can be considerable and can cause tremendous stresses on the tubing string, as well as on the packer under certain conditions. The net result could reduce the effectiveness of the downhole tools and/or damage the tubing, casing, or even the formations open to the well. Failure to consider length and force changes may result in costly failures of such operations as squeeze cementing, acidizing, fracturing, and other remedial operations. Potential tubing-length changes must be understood to determine the length of seal necessary to remain packed off in a polished sealbore packer, or to prevent tubing and packer damage when seals are anchored in the packer bore. Potential induced forces need to be calculated to prevent tubing and packer damage, unseating packers, or opening equalizing valves.

There are four factors that tend to cause a change in the length or force in the tubing string: the temperature effect, which is directly influenced by a change in the *average* temperature of the string; the piston effect, caused by a change in the pressure in the tubing or annulus above the packer acting on a specific affected area; the ballooning effect, caused by a change in *average* pressure inside or outside the tubing string; and the buckling effect, which occurs when internal tubing pressure is higher than the annulus pressure. Buckling will shorten the tubing string; however, the others may tend to lengthen or shorten the string depending on the application of the factors. As long as the tubing is allowed to move in the packer bore, the temperature and ballooning effects will only have an impact on tubing-length changes, but if movement is prevented (or restrained) at the packer, these two factors would then create a force. It is important to remember that a string of tubing landed in any packer is initially in a neutral condition, except for any subsequent mechanical strain or compression loads applied by the rig operator. After the tubing is landed, the factors that cause changes in length or force are always the result of a change in temperature and pressure.

2.4.7.2.9.1 Piston Effect

The length change or force induced by the piston effect is caused by pressure changes inside the annulus and tubing at the packer, acting on different areas.The length and force changes can be calculated as follows:
$?L1 =- LE As(A p - Ai)? pi - (A p - Ao)? po$ .... (2.1)
and $F1 = (A p - Ai)? pi - (A p - Ao)? po$, ... (2.2)

where
? $L1$ = length change because of the piston effect
$F1$ = force change because of the piston effect
L = tubing length
E = modulus of elasticity (30,000,000 for steel)
As = cross- sectional area of the tubing wall
Ap = area of the packer bore
Ai = area of the tubing ID
Ao = area of the tubing OD
? pi = change intubing pressure at the packer
? po = change in annulus pressure at the packer
Note that the length change ? $L1$ is a product of L/EAs and the piston force ($F1$). The piston force is the sum of two pressures acting on two areas—one for the tubing and one for the annulus. The area acted upon by changes in pressure in the tubing is the cross-sectional area between the area of the packer bore and the area of the tubing ID in square inches ($Ap–Ai$). The area acted upon by changes in pressure in the annulus is the cross-sectional area between the area of the packer bore and the area of the tubing OD in square inches ($Ap–Ao$). shows a large-bore packer with a tubing string that has both a smaller OD and ID than the packer bore. In this instance, annulus pressure causes downward force, while tubing pressure causes an upward force. For a small-bore packer, this situation is reversed.The force greatest in magnitude will determine the resulting direction of action. An accurate schematic of the tubing and packer bore for each case should be made for proper determination of areas, forces, and the resulting direction of action. It is possible to eliminate the forces generated on the tubing string by the piston effect by anchoring the seals in the packer bore. In a string that is restrained at the packer from movement in either direction, the piston effect on the tubing string is zero. All the forces are now being absorbed or contained completely within the packer.

2.7.4.2.9.2 Buckling Effects

Tubing strings tend to buckle only when the internal tubing pressure (pi) is greater than the annulus pressure (po). The result is always a shortening of the tubing string, but the actual force exerted is negligible. The decrease in length occurs because of the tubing string being in a spiral shape rather than straight. The tubing-length change is calculated with the following:

? L_2 = - $r2$ A p 2 (? pi - ? po)2 $8EI(Ws$ + Wi - Wo) , ...
(2.3)Where
? L_2 = length change because of the buckling effect
r = radial clearance between tubing OD and casing ID
[(IDC – ODt)/2]
Ap = area of the packer bore
Ai = area of the tubing ID
Ao = area of the tubing OD
? pi = change in tubing pressure at the packer
? po = change in annulus pressure at the packer
E = modulus of elasticity (30,000,000 for steel)
I = moment of inertia of tubing about its diameter [I = p/64 ($D4$ –$d4$, where D is the tubing OD d is the tubing ID*]
Ws = weight of tubing per inch
Wi = weight of fluid in tubing per inch

Wo = weight of displaced fluid per inch

TABLE 2.1—AREA OF PACKER BORES

Bore (in.)	Area (in.^{2})	Bore (in.)	Area (in.^{2})
6.00	28.26	2.50	4.91
5.24	21.55	2.42	4.60
4.75	17.71	2.28	4.08
4.40	15.20	2.06	3.33
4.00	12.56	1.96	3.00
3.87	11.76	1.87	2.75
3.62	10.29	1.68	2.22
3.25	8.30	1.53	1.84
3.00	7.07	1.43	1.61
2.68	5.67	1.25	1.23

2.7.4.2.9 .3Ballooning and Reverse Ballooning

The ballooning effect is caused by the change in average pressure inside or outside the tubing string. Internal pressure swells or "balloons" the tubing and causes it to shorten. Likewise, pressure in the annulus squeezes the tubing, causing it to elongate. This effect is called "reverse ballooning." The ballooning and reverse ballooning length change and force are given by

? *L3* = - 2*L*? *E* ? *pia* - *R*2? *poa* (*R*2 - 1) .... (2.4)

*F*3 = - 0.6(? *pia Ai* - ? *poa Ao*), ... (2.5)

where

? *L3* = length change because of ballooning/reverse ballooning

*F*3 = force change because of ballooning/reverse ballooning

L = tubing length

? = Poisson's ratio (0.3 for steel),

E = modulus of elasticity (30,000,000 for steel)

? *pia* = change in average tubing pressure

? *poa* = change in average annulus pressure

Ai = area of the tubing ID

Ao = area of the tubing OD,

R = ratio of tubing OD to ID for common tubing sizes and weights.

The ballooning effect will always result in tubing-length changes, but it does not become a force unless the tubing movement is restrained at the packer.

2.7.4.2.9.4 Temperature Effect

Thermal expansion or contraction causes the major length change in the tubing. Heated metal expands, and cooled metal contracts. In a long string of tubing with a temperature change over its entire length, this contraction or elongation can be considerable.

The three operational modes that influence temperature effect are producing, injecting (water, gas, or steam), and treating.

The change in tubing length because of temperature effect is calculated as follows:

$? L4 = L\beta? t,$ .... (2.6)

where

$? L4$ = change in tubing length

L = tubing length

β = coefficient of thermal expansion (0.0000069 for steel)

$? t$ = change in average temperature.

Length changes are calculated readily if the average temperature of the tubing can be determined for the initial condition and then again for future operations. The average string temperature in any given operating mode is approximately one-half the sum of the temperatures at the top and the bottom of the tubing. Thus, in the initial condition, the average temperature would be based upon the mean yearly temperature and the BHT. The mean yearly
temperature is generally considered to be the temperature 30 ft below ground level; $? t$ is the difference between the average temperatures of any two subsequent operating modes.

If tubing movement is constrained, forces will be introduced as a result of the temperature change. The temperature-induced force is

$F4 = 207AS? t,$ .... (2.7)

Where.

$F4$ = pounds force (tensile or compression, depending on the direction of $? t$)

AS = crosssectional area of the tubing wall

$? t$ = change in average tubing temperature.

2.7.4.2.9.5 Net Results of Piston, Buckling, Ballooning, and Temperature Effects

The net or overall length change (or force) is the sum of the length changes (or forces) caused by the temperature, piston, and ballooning effects. The direction of the length change for each effect (or action of the force) must be considered when summing them. It follows that for a change in conditions, the motion (or force) created by one effect can be offset, or enhanced, by the motion (or force) developed by some other effect. Mosely presented a method for graphically determining the length and force changes as a result of buckling and ballooning ($L2$, $L3$, and $F3$). This method is particularly useful on a fieldwide basis, where wells have the same-size tubing, casing, and packers. When planning the sequential steps of a completion or workover, care should be taken to consider the temperatures and pressures in each step once the tubing and packer systems become involved. By careful selection of the packer bore and use of annulus pressures, one pressure effect (or a combination of pressure effects) could be used to offset the adverse length or force change of another effect.

TABLE 2.2—WEIGHT PER INCH OF TUBING AND FLUID

$W_s + W_i - W_o$

Tubing OD (in.)	Weight (lbm/in.)	W and W_o (lbm/in.)	7 0 52 3	3 0 59 8	9.0 67.3	10.0 74 8	11 0 82.3	12.0 89 8	13 0 97.2	14.0 104.7	15.0 112.2	16.0 119.7	17 0 127 2	18.0 134 6	lbm/gal lbm/ft³
1.660	W_s = .200	W_i	045	052	.058	.065	.071	.078	.064	.091	.097	104	.110	116	
		W_o	.065	.075	.084	.094	103	112	.122	131	140	.150	.159	169	
1 900	W_s = 242	W_i	062	070	.079	.088	.097	.106	.115	.123	132	141	.150	.159	
		W_o	.086	.098	110	.123	135	147	.159	172	184	.196	.209	221	
2.000	W_s = 283	W_i	.066	.076	.085	.095	104	.114	.123	.133	.142	.152	161	.171	
		W_o	.095	109	122	.136	150	163	177	.190	204	.218	231	245	
$2^1/_{16}$	W_s = .283	W_i	073	.083	.094	104	114	.125	.135	.146	156	.167	177	.187	
		W_o	.101	116	130	.145	.159	174	188	.202	217	.231	.246	260	
$2^3/_8$	W_s = .392	W_i	095	108	.122	135	149	.162	.176	.189	.203	217	.230	243	
		W_o	.134	153	172	.192	.211	230	.249	268	288	.307	326	345	
$2^7/_8$	W_s = 542	W_i	142	162	182	203	.223	243	.263	.284	.304	324	.344	364	
		W_o	.196	.225	.253	.281	309	337	.365	.393	421	.450	478	506	
3½	W_s = .767	W_i	.213	.243	.274	.304	.335	.365	.395	.426	.456	.487	.517	.548	
		W_o	.291	333	.365	.416	.458	.500	.541	.583	.625	.666	708	749	

Formula for W_s, W_i and W_o:

Weight of steel: W_s = Pipe weight (lbm/ft)/12

Weight of fluid in tubing W_i = Mud weight (lbm/gal) x A_i/231

Weight of displaced fluid: W_o = Mud weight (lbm/gal) x A_o/231

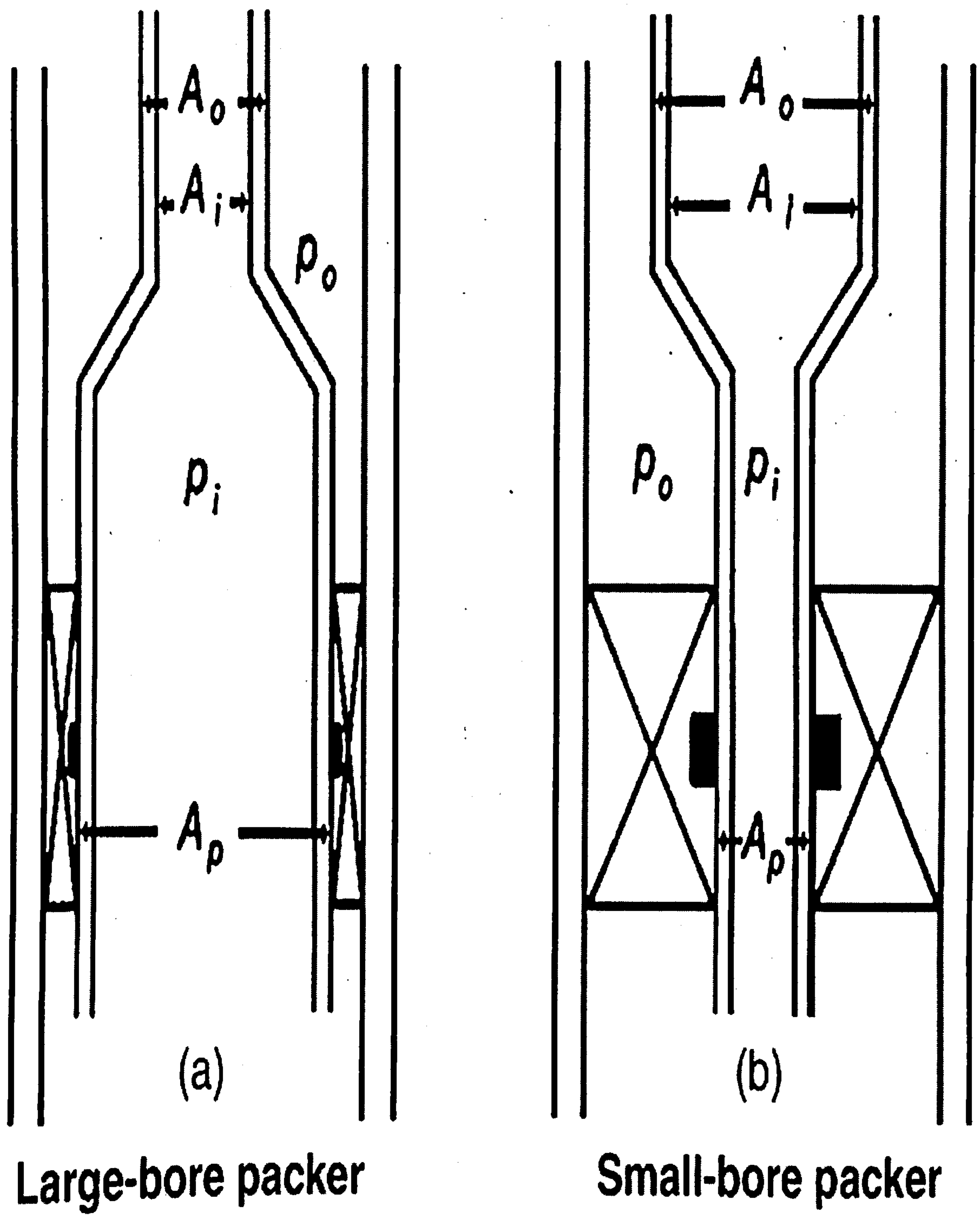


Figure 60: Area acted upon by pressure in tubing and annulus

2.7.5 Packers

A packer is a downhole device used to provide a seal between the outside of the tubing and the inside of the production casing or liner. The packer seal is created by resilient elements that expand from the tubing to the casing wall under an applied force. When set, this seal prevents annular pressure and fluid communication across the packer.

2.7.5.1 Basic Packer Components and Mechanics

Even though a great number of types of packers exist, there are a few basic parts common to all packers. These parts are the:

1. Elements
2. Flow mandrel
3. Wedge
4. Slips

The elements' sole function is to form a seal between the packer's flow mandrel and the casing in which the packer is set. Elements are made of various elastomeric materials depending upon down hole conditions. They are also available in various hardness again depending on down hole conditions or pipe weight availability.

The flow mandrel (sometimes called the packer mandrel) is the "tube" part of the packer which allows production to enter the tubing and, in turn, on to the surface. It can be generally stated that a packer consists of external components built around the flow mandrel. In many instances, the pressure differential rating of a packer is dependent on the strength of the flow mandrel. Down hole conditions will dictate the type of alloy used to make the flow mandrel.

The wedge is simply that part of the packer which forces the slips to move outward during the setting sequence. The wedge is known by several other names such as the cone, expander, or expander cone.

Slips are serrated or "tooth-like" parts of the packer. Once forced outward by the setting action, the slips "bite" into the casing wall preventing the packer from moving when pressure differentials exist across the packer. Some packers have two sets of opposing mechanical slips. The top set of slips prevents the packer from moving up hole while the bottom slips prevent downward motion. Some packers incorporate bi-directional slips, that is, one set of slips which prevent movement in either direction. There are a few packer designs with a set of lower slips and a set of hydraulically activated hold-down button slips. Other designs include packers with only one set of slips and therefore can hold pressure from one direction only. Certain types of isolation packers have no slips at all.

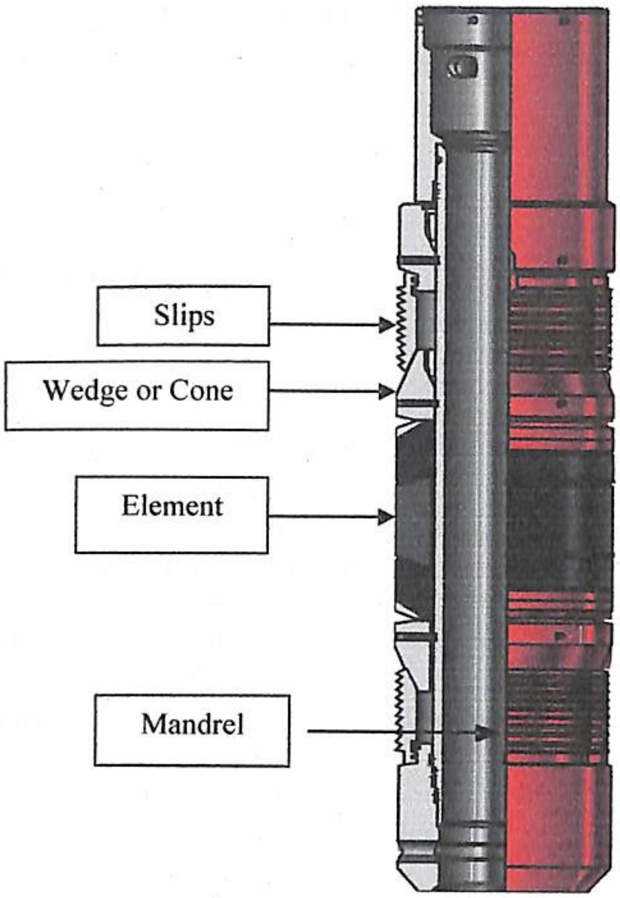


Figure 61: Basic Packer Components

2.7.5.2 Types of Packers:

1. Cased Hole Packers or Production Packers
2. Open Hole Packers

2.7.5.2.1 Production Packers:

Production packers are those packers that remain in the well during normal well production. Production packers are specified for many reasons (Greene, 1966). For example, they are used to protect the casing from pressure and produced fluids, isolate casing leaks or squeezed perforations, isolate multiple producing horizons, eliminate or reduce pressure surging or heading, hold kill fluids in the annulus, and permit the use of certain artificial-lift methods. On rare occasions, well completions may not incorporate a packer. For example, many high-volume wells are produced up both the tubing and the annulus and therefore will not include a packer. Packers are not normally run in rod-pumped wells. However, in offshore wells and in many other applications, it is considered a safer practice to produce with at least one packer downhole.

The Production Packers can be further divided into major types depending on certain mechanical criteria. The following is one possible categorization scheme:

1. Permanent packers
2. Seal bore retrievable packers
3. Mechanical retrievable packers
4. Hydraulic retrievable packers

1. Permanent Packers

Permanent packers are thus described because their design permits the sealing elements, once extruded onto the inside of the casing wall, to be mechanically locked in place. This is accomplished by having two opposing sets of mechanical slips, one located below and the other above the sealing element. Thus the packer is designed to create an effective seal independent of any subsequent changes in wellbore conditions following the completion operation.
General characteristics common to permanent packers include:

1. Permanently set. Once set, they cannot be released and retrieved from the well. A milling tool is required to remove a permanent packer from the well. The milling process will "mill over" the packer's slips thus destroying it. The packer may then be pushed to the well's bottom or retrieved to the surface.

2. No weight or tension requirements. Once set, no tubing weight down on or tension against a permanent packer is required to keep it in the set position.

3. Economical. Permanent packers have, by design, very few components. As a result, these packers are less costly than other packers of comparable size and composition.

4. Highest pressure rating. Permanent packers, due to simple design and few components can be built sturdier than other types of packers. Pressure differential ratings as high as 15,000 psi are possible.

5. High temperature rating. Element packages are available to withstand temperatures in excess of 500 °F.

6. Popularity. Worldwide, permanent packers are the most frequently used of all packer types.

7. Seal assembly required and accessories can be used with permanent packers.

Permanent packers can be sub-divided according to the method required to set the packer. Electric wireline, hydraulic, and tubing rotation are the three setting methods available. The electric wireline and hydraulic are by far the most common methods used to set permanent packers. Tubing rotation is rarely used so it is not included here.

Wireline Set

The wireline set packer is the most commonly used of any type of packer. It can be run and set quickly and accurately at a pre-determined depth. After the packer is set, a production seal assembly and production tubing is then run into the well. Once the seal assembly seals into the packer, tubing length are adjusted at the surface (spaced out) and the well is then completed.

Hydraulic Set Permanent Packer

The hydraulic set permanent packer is run in the well on production tubing. This type of packer contains a piston/cylinder arrangement usually located in the lower end of the packer. A plugging device must be installed in the tubing below the packer. This plugging device is usually a ball catcher sub or a wireline landing nipple. The entire assembly (seal arrangement, packer, plugging device) must be made up on the surface before the packer is run into the well. Once the proper depth is reached and the plug in place, pressure applied down the tubing sets the packer.

Permanent Packer Accessories

Seal Assembly

Since a permanent packer cannot be pulled out of the well, the tubing cannot be attached directly to a permanent packer. Occasionally, the tubing may have to be retrieved and repaired or replaced. However, a pressure tight seal must exist between the tubing and packer bore forcing the production into the tubing. This is accomplished by using a seal assembly which attaches to the tubing and seals off in the packer.

Seal assemblies vary greatly in length, elastomeric composition and metallurgy selection, again depending on down hole conditions.

The basic seal assembly consists of a locator, a seal unit, and a mule shoe guide.

The locator is designed to prevent any further downward travel of the pipe once it has encountered the head of the packer. The two standard locators are the (1) straight-slot locator and the (2) jay-slot locator.

(1) The straight slot locator is used when a "free-to-move" seal assembly is required such as in cases where large forces and tubing movement is anticipated.

(2) The jay-slot locator is used in situations where small forces and little tubing movement is expected. The "jay" slots of the locator latch onto the lugs in the packer's head preventing motion.

The seal unit forms a seal into the packer's bore. Hole conditions may permit the use of a standard molded seal unit or require a premium seal unit be used. Standard molded seals units are used in wells where pressures differentials are less than 10,000 pounds per square inch and temperatures are less than 275 ^{o}F.

Premium seals are used for harsh conditions - high temperatures, high pressures, and severe environments such as hydrogen sulfide, carbon dioxide, amine inhibitors and steam injection.

The sole purpose of the mule shoe guide is to facilitate the entry of the seal assembly into the packer bore.

The overall length of a seal assembly can be adjusted by the number of seal units used and the number and length of seal extensions used. A seal extension is simply a length of pipe without any seals.

Sealbore extensions are designed to extend the polished surface of the packer bore to permit the use of longer sealing units to compensate for the contraction and/or elongation of tubing.

The ratch-latch seal assembly must be used with a ratch-latch head packer. This seal assembly is short because movement is prevented by the threaded ratch-latch arrangement.

Millout Extension

When a permanent packer must be milled up, either a flat or overshot mill is used to mill up the packer. The choice of mill depends on the type of packer. For example, if the slips, cones and packer elements are designed to be milled, an overshot mill is used, and the inner body of the packer is retrieved. Alternatively, the flat mill is used when the entire packer must be milled.

After milling, the slips retract and the packer can fall to the bottom of the well when the setting mechanism is released. A fishing job is therefore required to retrieve the remaining body of the packer. If a fishing job is not desirable, a millout extension is run below the packer at the time the packer is installed. The millout extension provides the ability to run a packer-retrieving spear with the mill. This spear engages in the millout extension and prevents the packer from falling when the packer slips collapse.

2. Seal Bore Retrievable Packers

Seal bore retrievable packers are production packers designed for intermediate-pressure wells. They are used in applications with bottomhole pressures of up to 10,000 psi and BHT of 275°F. These packers have the production features of permanent packers with the added feature of retrievability. External components are millable for cases when conventional release is not possible. These packers are designed to be retrieved with a retrieving tool. They can be set with electric line or hydraulically on the tubing string.

Seal bore retrievable packers may be used in many of the same applications where permanent packers are used. Their application depends on downhole pressure requirements, temperature requirements, and cost considerations.

In short, the seal bore retrievable packers may be used in many of the same applications where permanent packers used. A few factors which need to be considered when deliberating between the use of a permanent or seal bore retrievable packer are:

1. Retrievability

2. Pressure requirements

3. Temperature requirements

4. Initial cost - purchase price more than that of a permanent packer but may be released, pulled and redressed for use again

5. Gravel pack application

3. Mechanical Retrievable Packers

Mechanical-set retrievable packers are designed to be run and set on tubing, released, and moved and set again without tripping the tubing. In general, these packers are capable of BHT up to 275°F and a pressure differential of 6500 to 7500 psi. Mechanical-set retrievable packers may have slips above and below the seal element. Depending on their internal locking mechanism, they can be set with tension, compression, or rotation and, once set; the tubing can be left in tension, compression, or neutral mode.

Certain types of mechanical-set retrievable packers can be used for production, steam injection, disposal, injection, testing and reservoir stimulation. Typically, they cannot be used in deep, deviated wells because it is difficult to transfer sufficient tubing movement to set and maintain the packer.

4. Hydraulic Retrievable Packers

Hydraulic-set retrievable packers are designed to be set by pressuring up the tubing string against a plugging device below the packer. Once the packer is set, the tubing may be put into tension or compression or left in a neutral mode. A hydraulic packer has bidirectional slips or a set of slips to resist downward movement and a hydraulic hold-down system to prevent upward movement. The packer is released by a straight pull on tension-actuated shear pins.

In general, hydraulic-set retrievable packers can normally be used in applications with a BHT up to 275°F and a pressure differential of 6500 to 7500 psi. They have a nearly universal application and are used for highly deviated wells or wells with small control lines (where rotation may be a problem). Hydraulic-set packers are also used in completions requiring multiple packers and one-trip operations.

2.7.5.2.2 Open Hole Packers:

In horizontal well completions it is difficult to effectively cement the voids along the horizontal section during a cementing operation. Effective cementing of the tubing to the wellbore is routinely accomplished in vertical wellbores. However, in horizontal wellbores and severely inclined wellbores, i.e. those having an angle of deviation greater than about 45°, cementing is much more difficult.

Therefore, the efficiency of zone isolation diminishes considerably. Often a failure of the cementing operation occurs in horizontal wellbores because the density of the cement does not allow sufficient displacement of drilling mud and other residue from the tubing/wellbore annulus, thereby resulting in channelling of cement and improper tubing or pipe/formation bonding also the casing string itself tend to lay on the lower side of the wellbore thereby decentralizing the casing so that cement cannot uniformly be displaced completely around the casing itself.

One of the more important drawback of cementing is that, Cement potentially impairs near-wellbore permeability (increase in skin), and a poor cement job allows uncontrolled flow in the annulus, which, in a long, horizontal well, can lead to hot spots, water coning or gas breakthrough.

Therefore Open hole packers or External casing packers are used to solve these problems.

How does ECP help to solve these problems?

Prevent Loss of Cement

External Casing Packers can be positioned in the casing string directly above a lost circulation zone. The packer effectively prevents the loss of high-density cement slurries into the lost circulation zone. For these applications, a second stage cementing operation is normally performed above the ECP, after setting the packer.

Prevent Gas Migration through Cement Columns

In many wells; gas migration through cement slurry can be prevented by setting an External Casing Packer directly above a high pressure gas zone. Improved cement integrity will be achieved.

Prevent Unwanted Water Production

An External Casing Packer can be positioned slightly above an oil-water or a gas-water contact, in order to minimize water production from those zones.

Minimize Damage to Sensitive Formations and Barefoot Completions

In the past, barefoot completions were used to minimize formation damage to production zones. However, today's technology, using under-balanced drilling methods, allows drilling of the well to the required total depth, and to set External Casing Packers directly above sensitive formations.

Baker oil manufactures various types of open hole packers like

1) MPAS (Extruding packer)

2) ECP (cement inflated)

3) RE (reactive element) packer (Swell packer)

4) RC (reactive core) packer.

All the above are used for sealing the annular space along with the advantage of it being used for isolation of oil, gas and water zone.

2.7.6 Landing Nipples:

Landing nipples are short sections of thick-walled tubulars that are machined internally to provide a locking profile and at least one packing bore. The purpose of a landing nipple is to provide a profile at a specific point in the completion string to locate, lock, and seal subsurface flow controls, either through wireline or pumpdown methods.

Every subsurface control device set inside a landing nipple is locked and sealed in the profile with a locking mandrel. The profile and bore area in the nipple offer an engineered and controlled environment for the locking mandrel to form a seal. For this reason, the lock mandrel must conform to the profile of the nipple; for example, an 'X' nipple requires an 'X' lock profile and an 'R' profile requires an 'R' lock mandrel.

Landing nipples can be used at virtually any point in the completion string. Typically, they are used in conjunction with a wireline subsurface safety valve at an intermediate point in the tubing above a packer to pressure test the tubing or set a flow-control device, immediately below a packer for packoff above perforations in multi-zone completions, and at the bottom of the tubing string for setting a bottomhole pressure gauge.

There are three principal types of landing nipples. These are no-go nipples, selective nipples, and subsurface safety valve nipples. The characteristics of these nipples are discussed below:

2.7.6.1 No-Go Landing Nipples

A no-go landing nipple includes a no-go restriction in addition to the profile and packing bore. The no-go restriction is a point of reduced diameter, i.e. a shoulder. This no-go shoulder is used to prevent the passage of larger diameter wireline tools and offers the ability to positively locate subsurface control devices in the nipple.

No-go profiles may be included either above or below the packing bore of the landing nipple. When the no-go occurs below the packing bore, it is referred to as a bottom no-go. In this case, the minimum internal diameter is the diameter of the no-go restriction. When the no-go occurs above the packing bore, it is referred to as a top no-go. In a top no-go, the no-go diameter is the same as the packing-bore diameter.

The no-go restriction determines the largest size of wireline equipment or other devices that can be run through the device. Therefore, in completions that include many no-go profile devices, each successively deeper profile device must have a smaller internal diameter than the one above, so that the wireline equipment for the deeper profile can pass through the no-go of the profile device immediately above it. This design is often referred to as "step-down" sizing.

No-go profiles aid in positive setting for the wireline equipment because the wireline tool physically bumps against the no-go shoulder when the tool is landed in place. However, if many profiles are required in the design, the step-down sizing phenomenon may mean that the bottom no-go will be too small, either for the desired production rate or for well servicing. For this reason, many profile systems include only one no-go at the bottom, or deepest set, profile device.

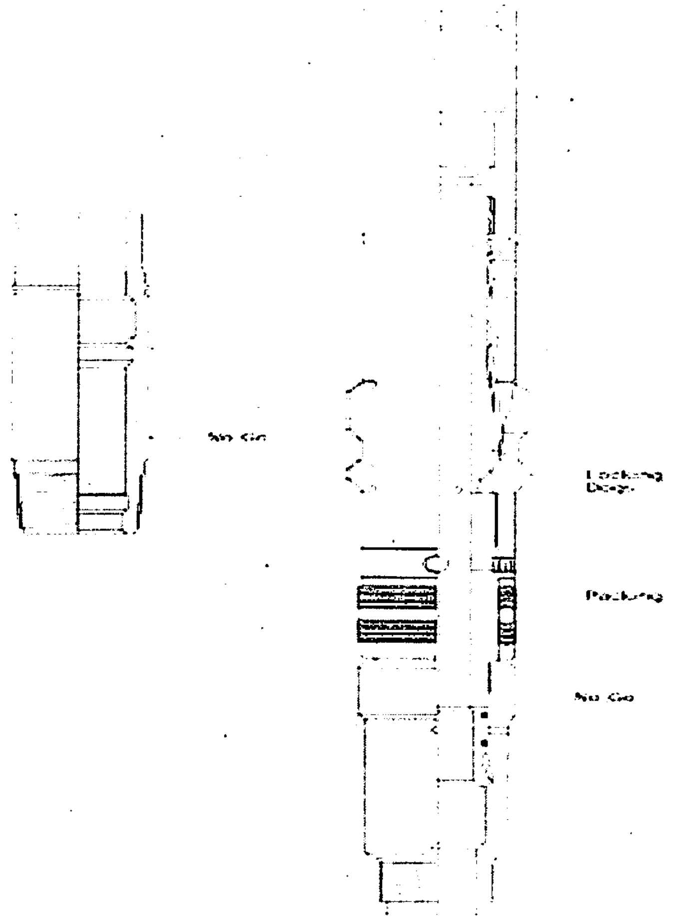


Figure 62: No Go Landing Nipple and lock mandrel

2.7.6.2 **Selective Landing Nipples:**

Landing nipples that do not include a no-go, or diameter restriction, are referred to as selective. In a completion equipped with selective nipples, it is possible to "select" any one of the nipples to install a flow-control device in it.

For a given tubing size, all selective nipples run in the tubing string will have the same internal diameter. Unlike the no-go nipples, there is no progressive restriction of the minimum diameter.

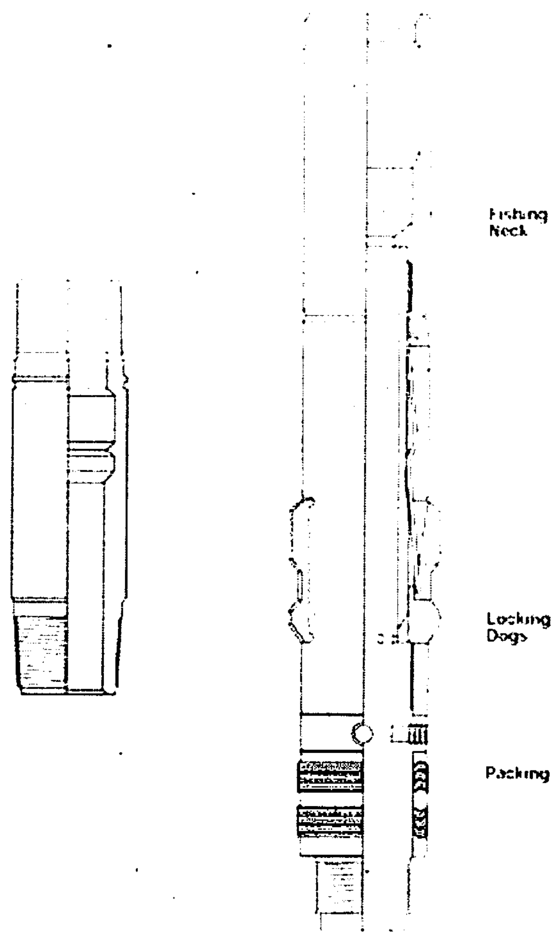


Figure 63: Selective nipple with lock mandrel

Selective nipples are divided into two categories. One type is a profile-selective landing nipple. The second type is a running-tool-selective landing nipple.

Profile-selective landing nipples have the same minimum internal diameter, the same locking profile, and the same packing bore. However, these nipples include a different locating profile. When setting a control device in one of these nipples, the lock mandrel used with the control device must be equipped with a locator assembly that matches the locating profile of the nipple in which it will be installed.

Running-tool-selective landing nipples are selected according to the running tool that is used to install the lock mandrel and the control device in that nipple. Each running-tool-selective landing nipple of a given size and type in the tubing string is identical, allowing a virtually unlimited number of running-tool-selective landing nipples to be used in a single tubing string.

Selective nipples offer the advantage of providing a profile without restricting the minimum diameter of the completion string. However, it may be more difficult to positively set equipment in selective profiles, particularly in highly deviated wells.

2.7.6.3 Subsurface Safety Valve Landing Nipples

A subsurface safety valve landing nipple is a special type of nipple designed to hold a wireline-retrievable safety valve.

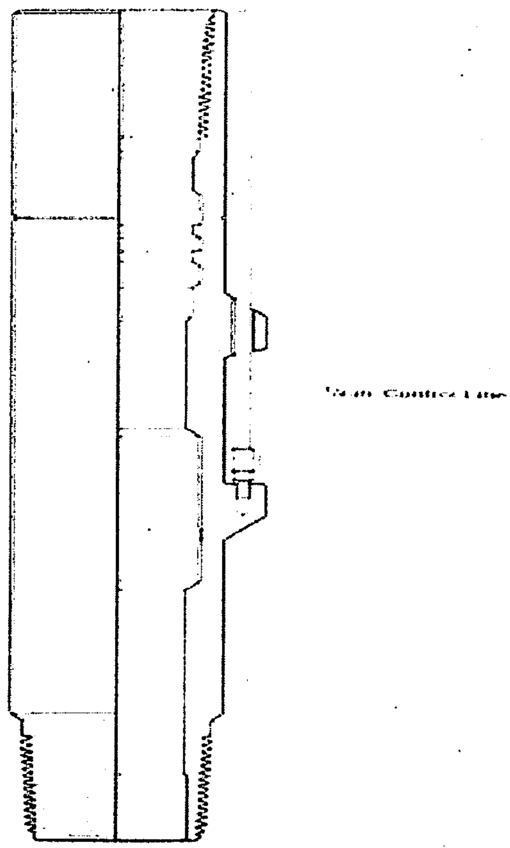


Figure 64: SSSV nipple

The nipple differs from a standard landing nipple because the nipple body is adapted to accept a 1/4-in. hydraulic control line. The body is bored so that the control line pressure feeds into the safety valve, which is sealed between an upper and a lower packing bore.

2.8 Subsurface Safety Systems

For well isolation or closure under normal operating conditions, the production wing valve and mastergate valve will be used. The advantage of these valves is that if the valve malfunctions, then it can be repaired or replaced with little difficulty. These valves are therefore defined as being the primary closure system for the well.

However, in the absence of an effective surface closure system, well security is endangered. This could occur in a variety of situations:

1. Xmas tree removal during workover preparations to pull tubing

2. Removal of valves or valve components for servicing

3. Accidental damage to Xmas tree

4. Leakage on wellhead - Xmas tree flange seals

To provide some degree of security in the event of any of the above situations occurring, it would be ideal to have a safety valve system located beneath the wellhead within the tubing system. This component is termed a Sub-Surface Safety Valve or SSSV. These valves are available based upon two different control philosophies, namely:

1.Direct Controlled SSSV (D.C.SSSV) which are designed to close when downhole well conditions of pressure/flowrate vary from preset design values. These valves are often refered to as "storm chokes".

2.Remotely or Surface Controlled SSSV (S.C.SSSV) whereby closure and opening of the valve is actuated and accomplished using a surface control system which feeds hydraulic pressure directly to the downhole valve assembly. Both valve systems are designed to provide protection in the event of a catastrophic loss of well control.

2.8.1 Direct Controlled Sub Surface Safety Valve

These valves are installed on the basis of a design flow condition within the tubing string. The valves can be run and installed within specific landing nipples within the production tubing.

The preset control for closure of these valve systems is:

either

1. Pressure differential operated valves assume a specific fluid velocity through a choke or bean, which is part of the valve assembly. The valve has a spring to apply the closure force. The valve will remain open provided the differential pressure does not exceed the present design value. If an increase in flowrate occurs sufficient to increase the differential pressure beyond the preset level, then the spring will affect valve closure.

or

2. Ambient type or precharged dome/bellows valves utilise a precharged gas pressure in a dome to act as the valve control. If the flowing pressure drops below the precharged pressure, then the valve will automatically close.

Advantages of Direct Controlled Sub Surface Safety Valves

1. Simple construction and operating principle

2. Easy installation and retrieval since no control line from surface is required

3. Cheaper installation cost

Disadvantages of Direct Controlled Sub Surface Safety Valves

1. The valve systems are not 100% reliable since they depend upon preset deliverability and pressure conditions.

2. Especially for the choke type valves, the valve performance and closure may be affected by wax deposition or erosion of the orifice. It is imperative that with these systems the valve is pulled and regularly inspected or replaced.

3. The valve system can only be designed to reliably operate if an extreme condition occurs in relation to changing flowrate and pressure.

(4) Declining productivity may make it impossible for the designed closure conditions to be actually realised.

2.8.2 Remotely Controlled Sub Surface Safety Valves

These valves are designed to be installed downhole in the tubing string and are held open by hydraulic pressure supplied to the valve via a control line. The closure mechanisms utilised in these valves are either ball or flapper type assemblies.
The valves available are of two distinct types, namely, the ***tubing retrievable*** and the ***wireline retrievable*** valves.

The tubing retrievable valve system is a screwed tubular component which is made up as an integral part of the tubing string and run into the well. Removal of the valve can only be accomplished by pulling back the tubing string.

The wireline retrieval valve system consists of a conventional wireline nipple which will accept the appropriate mandrel which in this case is the valve assembly itself.

1. Tubing Retrievable Sub Surface Safety Valves

The tubing retrievable valve is a threaded top and bottom tubular component whereby the valve assembly is held open by hydraulic pressure fed down the control line on the outside of the tubing.

In all cases the valve assembly consists of a spring loaded flow tube and piston assembly, whereby hydraulic pressure fed into the cylinder above the piston provides compression of the spring beneath the piston. The resultant downwards movement of the flow tube serves to keep the ball valve or flapper open. If hydraulic pressure is bled off the control line, the spring supplies the return pressure to cause upwards movement of the flow tube and closure of the valve.

2. Wireline Retrievable Sub Surface Safety Valves

Again the completion equipment supply companies offer a range of wireline retrievable SSSV. The operating conditions are similar to the procedures employed with the tubing retrievable valves except that the valve is run on a wireline mandrel into a special tubing nipple profile and not a tubing sub. This type of valve is available either as a ball type system or as a flapper valve.

The figure 15 below shows the working of a ball type remotely controlled SSSV

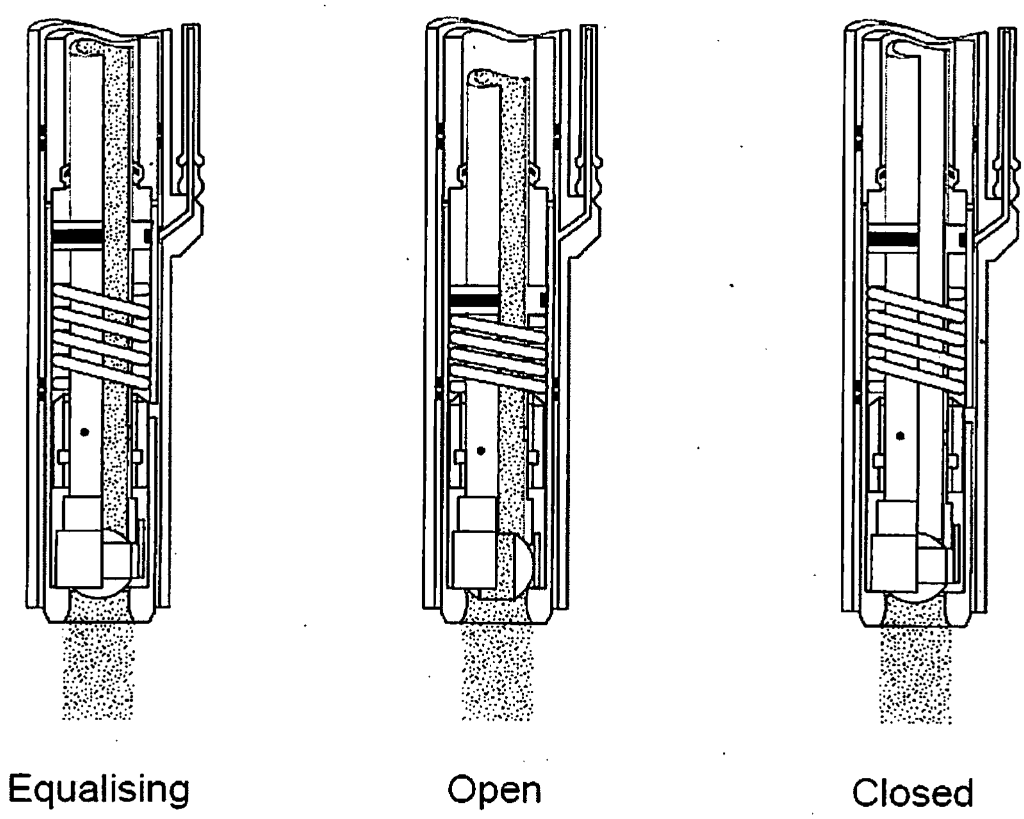


Figure 65: Mechanism of Remotely Controlled TRSSSV

2.9TUBING - ANNULUS COMMUNICATION EQUIPMENT

One vital operation which frequently has to be performed on a well is to circulate between tubing and annulus. This is required during the following situations:

1. To displace out the tubing contents during completion to provide a fluid cushion which will initiate production. This is normally done by displacing down the tubing and taking returns up the annulus, i.e. forward or normal circulation.

2. To displace out the tubing contents to a heavier kill fluid to provide hydrostatic over balance of reservoir pressure prior to pulling tubing or other workover activities.

3. To allow continuous or intermittent injection from the annulus into the tubing of fluids, e.g., pour point depressant corrosion or scale inhibitor, gas for a gas lifts process.

There are 3 principal items of down hole equipment designed to provide selective communication capability:

(a) Sliding side door or sliding sleeve

(b) Side pocket mandrel with shear valve

(c) Ported nipple

2.9.1 Sliding Side Door or Sliding Sleeve

Equipment of similar design is available from the major service companies but all designs feature a tubing sub with external ports through the tubing wall within which is located an inner mandrel with slots and seal rings above or below the slots figure 16. In the closed position, the inner mandrel or sleeve is located such that the ports in the outer tubing wall are isolated by seals above and below on the inner mandrel. Movement of the inner sleeve either upwards or downwards can produce alignment of the slots on the inner mandrel with the ports in the outer tubing. After completion of the circulation operation, movement of the inner sleeve in the reverse direction will return the circulation device to its closed position. To achieve the movement of the inner sleeve requires the running of a shifting tool to open and close the sleeve. The shifting tool lands in the top or bottom of the inner sleeve and by jarring, the sleeve can be moved up or down. Normally movement of the sleeve cannot be accomplished if a extremely high differential pressure exists across the sleeve. Any number of sleeves of the same size can be run in the same completion.

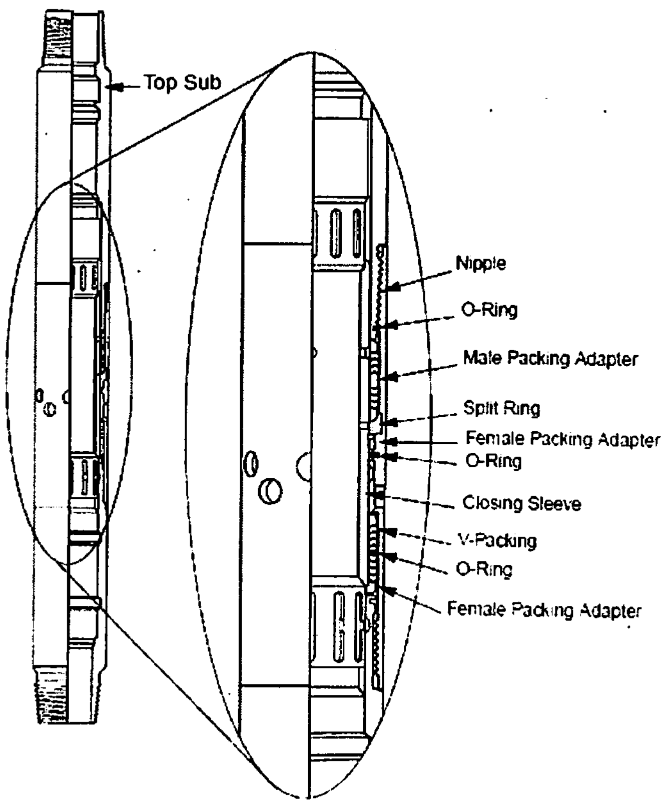


Figure 66: Sliding Slide Door

If failure to close the sleeve on jarring occurs it might be due to solids in the seal area or the effect of well deviation and the resultant inefficient jarring. In such cases if the sleeve cannot be closed, a separation sleeve could be run which will land inside the sliding sleeve and seal in the seal bores above and below the slotted section of the inner sleeve.

Baker Oil Tools manufactures SSD of the CM family which includes CMU (Upshift to open), CMD (downshift to open), and CMP defender (pressure actuated sliding sleeve)

CMP defender has two sleeves. The outer sleeve is pressure actuated and the inner sleeve(normally open) is downshift to close.

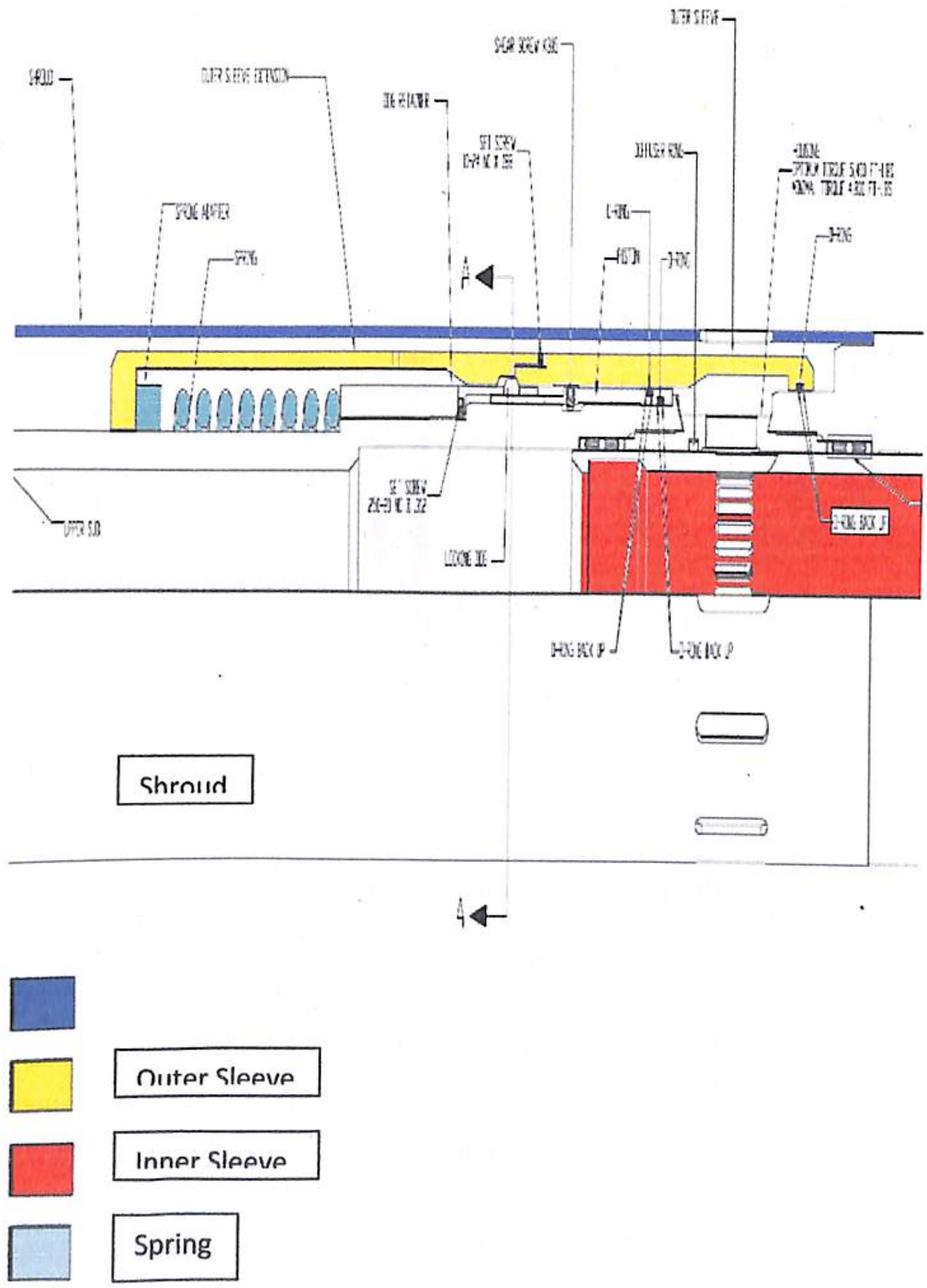


Figure 67: CMP defender

2.9.2 Side Pocket Tubing Mandrel

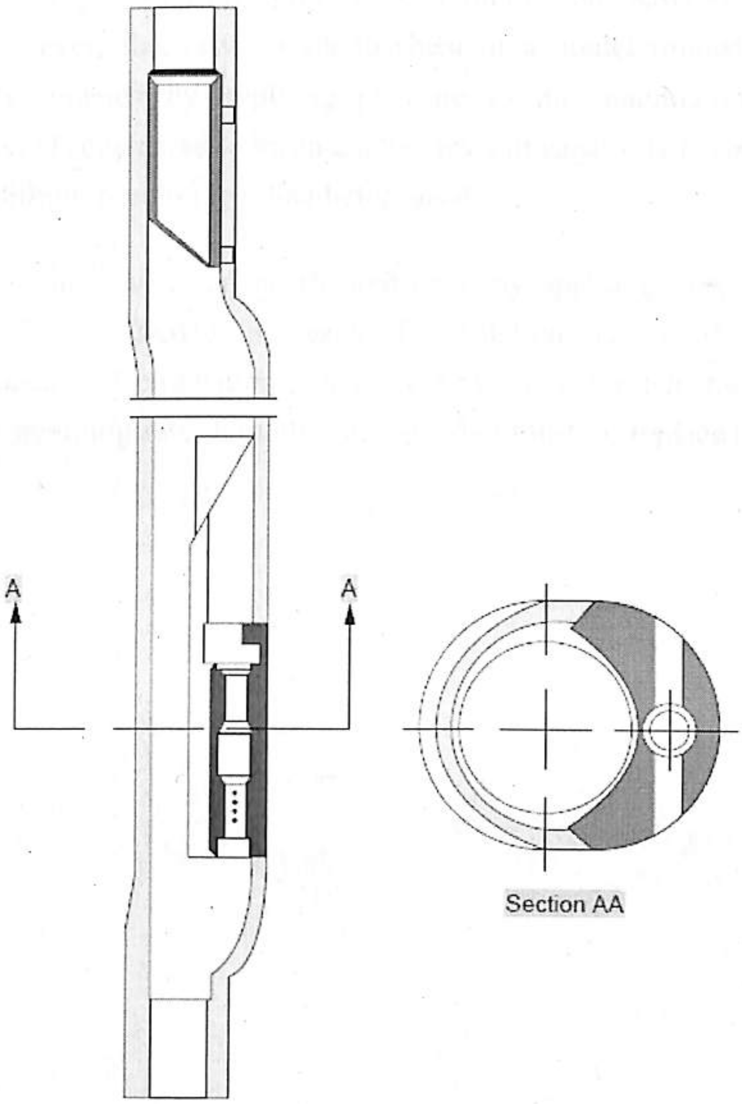


Figure 68: Side Pocket Mandrel

A side-pocket mandrel, or SPM, is a special receptacle with a receiving chamber parallel to the flow chamber. The tubular side of the device mates with the tubing string and leaves the bore of the mandrel fully open for wireline tools to pass without interruption. The parallel receiving chamber is offset from the string. This chamber is used to house a number of flow control or sealing devices.

The side-pocket mandrel was originally designed to house retrievable gas-lift equipment, and this function is still the primary use of the component. However, at least two other uses of the SPM are now recognized. These include providing an emergency kill device and providing a means of circulating fluids.

To provide an emergency-kill capability, the SPM is fitted with a dummy valve. This valve is normally closed and prevents communication between the tubing and the annulus. However, the valve is set to shear at a predetermined pressure and can, therefore, be opened by applying pressure to the annulus or the tubing. This configuration is considered to be an emergency-kill capability because kill fluid can be circulated without running wireline beforehand.

Since the dummy valve can be sheared open by applying pressure to the annulus, SPM's can also be used as a means of circulation. The SPM is one of the least preferable means of circulation, since the flow area through the SPM is small and restricts the pumping rate. In addition, the valve must be replaced once circulation is completed.

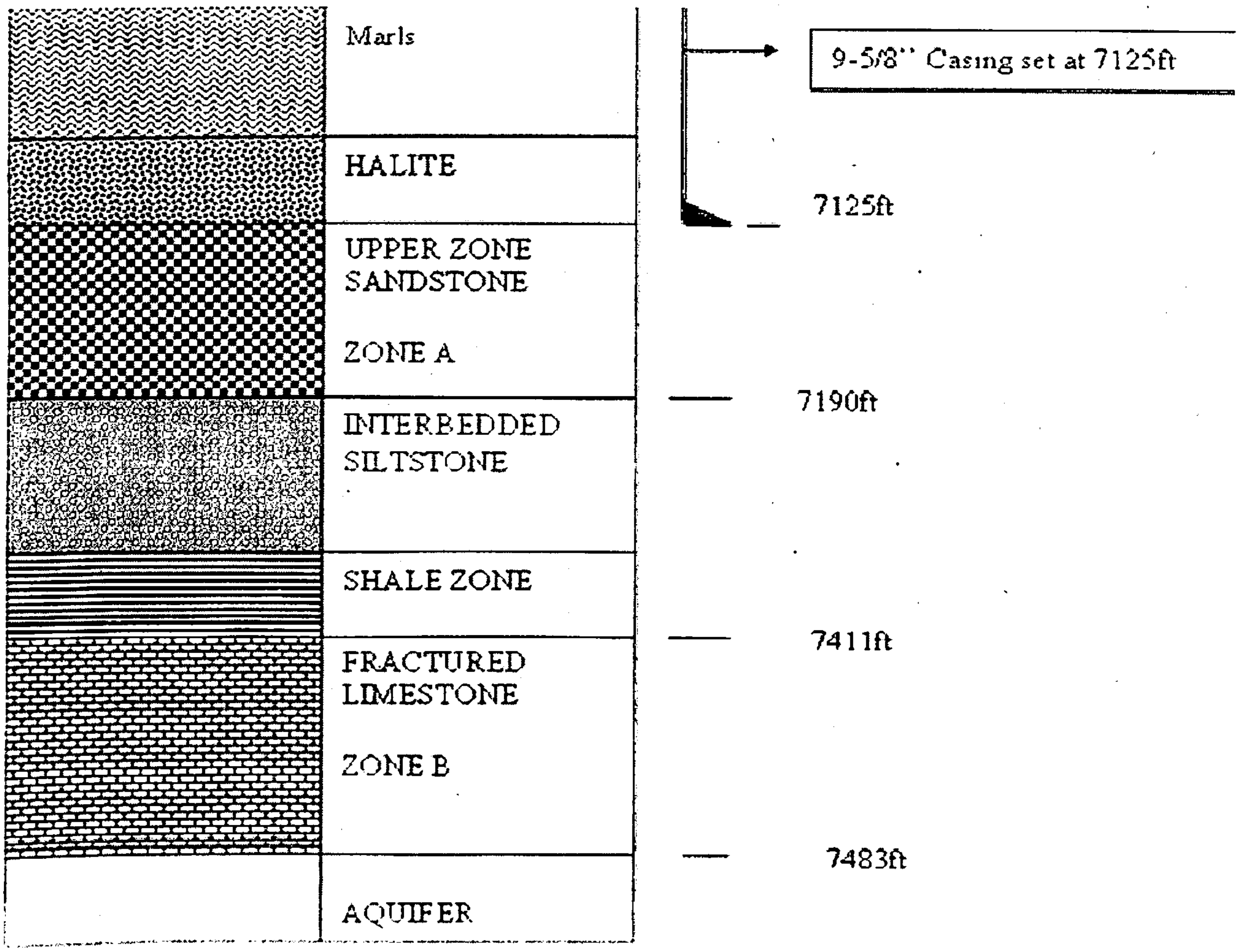
4. CASE STUDY ANALYSIS:

4.1 OFFSHORE FIELD DEVELOPMENT: CASE STUDY

4.1.1 Overview of Blackfriars field :

Blackfriars field is located offshore in approximately 250ft of water. Initial exploration and appraisal drilling confirmed the presence of two oil reservoirs with the following characteristics:

Fig Q1: LITHOLOGY COLUMN



ZONE A: UPPER ZONE

Depth Interval	Depth 7125ft – 7189ft TVDSS .
Lithology	Partially consolidated sandstone, fine grained, 500mD but with 7% mixed layer sensitive clays
Oil type	30^0 API gravity oil
GOR	700SCF/BBl
Reservoir PI	8 stb/day/psi
Reservoir pressure	3000psi at 7125ft

ZONE B: LOWER ZONE

Depth Interval	7411ft – 7483ft TVDSS
Lithology	Massively fractured limestone reservoir [Matrix Permeability = 0.5mD]
Oil Type	35^{o} API
GOR	420SCF/Bbl
Reservoir PI	10stb/day/psi
Reservoir pressure	3860psi @ 7411ft

Between the upper and lower zones, there are a series of mud/siltstones sequences with a shale layer on top of the lower zone as shown in FigQ1. A strong aquifer underlies the lower zone.

4.1.2 Problems with respect to drilling and completion

4.1.2.1 Drilling Associated Problems

a Upper zone has partially consolidated sandstone mixed with sensitive clays therefore there can be problem of lost circulation. Also, Zone B has massively fractured limestone so the problem of lost circulation can even be severe here at the base of this zone. Lost circulation is the loss of mud or cement to the formation during drilling operations.

Lost circulation causes:

- Increased well costs, due to lost rig time and loss of expensive drilling fluid.
- Loss of accurate hole monitoring
- Well control problems.

Therefore, following measures should be considered to prevent lost circulation:

1. **Volume of drill cuttings in the annulus**
   The increase in annular mud weight due to drill cuttings must be calculated and taken into account. It may be necessary to reduce the ROP in order to keep the annular mud density to an acceptable value.

2. **Controlling viscosity and gel strength of drilling mud and ensuring that the filter cake is good.**
   The viscosity and gel strengths of the mud affect the equivalent circulating density (ECD) and therefore should be maintained within the programmed specification. If the yield point of the mud is too high, breaking circulation will induce high ECD before the mud shears and flows. To prevent this, break circulation slowly and increase the pump speed only after returns are obtained. If viscosities are very high, circulation should be broken at stages whilst running through the open hole. This will help shear the mud reducing the high surge pressures when running in and ECD when initially circulating.

3. **Controlling surge pressure**
   Fast running of pipe in hole induces surge pressures which when added to the mud hydrostatic pressure can fracture exposed formations. Typically, the weakest formations are near the casing shoe and these usually fracture when the pipe is run too fast resulting in lost circulation. Surge pressure is applied on the formation as soon as the string is run in the hole.
   However, the maximum permissible speed will be greater when the bit is near surface and will decrease with depth. In areas of potential lost circulation, surge pressure calculations should be performed and the driller instructed as to the maximum allowable speed for running pipe. Running speeds can be monitored and alarmed in the mud logging unit to assist the driller in maintaining a safe tripping speed.

b Zone B has limestone therefore there can be problem of clay swelling. Permeability of the formation is decreased due to formation damage like clay swelling or pore plugging.

c There can be problem of borehole instability in shales.

4.1.2.2 Completion Associated Problems

Problems associated with the well completion account for the majority of workovers conducted on oil and gas wells.

a) Upper zone has unconsolidated sandstone so perforating the weakest sites in this zone should be avoided. Perforation in this zone will lead to the problem of sand control. The breakdown of formation or the production of sand can result in the following:
(1) Casing damage due to formation slumping
(2) Plugging and erosion of down hole and surface equipment
(3) Sand disposal problems

b) There are two producing zones with different API gravity oil. If we let the production being comingled and flow through single tubing string there can be following problems.
(1) The mixing of produced fluids in the wellbore can be disadvantageous if one or more fluids have any of the following characteristics:
- Corrosive or potentially corrosive materials e.g. acids, H2S, CO2.
- Produced sand and a potential erosive effect. The implementation of sand control procedures may be more complicated.
- Fluids having different Hydrocarbon compositions and hence economic value.
- Different WOR and GOR as this would influence the vertical lift performance of the total well system.

(2) Variation in individual zone pressures and permeability can lead to a back pressure effect on the less productive or lower pressure reservoirs.
(3) The use of co-mingling removes the capability for continuous control of the production process, i.e. closure of one individual zone cannot necessarily be affected unless a relative configuration is used.

(4) Injection of fluids, e.g. stimulation fluids cannot easily be diverted into individual layers without temporary isolation using sealants (diverters) or bridge plugs.

c) Completions Equipment Malfunctions or Failure

A typical completion string is complex and when we are dealing with a well which is offshore then the removal or replacement of the equipment becomes really difficult. Equipment may fail for a number of reasons, including:

(1) Effects of pressure
(2) Effects of thermal stress
(3) Applied and induced mechanical loadings can cause the tubing to part or unset packers. They can also be induced by temperature & pressure changes.
(4) Internal corrosion failure due to O_2, CO_2, H_2S and acids. External casing corrosion can result from corrosive formation waters.
(5) Erosion due to high rate flow and/or sand production.

4.1.3 Bottom hole completion strategy

Once the borehole has been drilled through the reservoir section of interest for production, the method by which fluid communication will occur between the reservoir and the borehole, after completion, has to be decided. On the basis of the information provided, **~~Open hole completion with~~ cemented liner** seems to be the preferred choice here.

In this technique, once the drilling through completed reservoir section has been completed a steel pipe is installed and cemented opposite the layer. Then it is perforated opposite the zone that is to be produced in order to restore a connection between reservoir and the well.

Since perforations can be placed very accurately in relation to the different levels and interfaces between the fluids, this method gives better selectivity for levels and produced fluids.

4.1.4 IPR- VLP Calculations

4.1.4.1 Calculation for IPR

(a) For zone A

J= 8 STB/day/psi
Pr= 3000 psi

Step-I

Qob= J(Pr-Pob)
Qob= 8(3000-2000)
Qob= 8000 STB/day

Step-II

Pwf (psig)	Qo (STB/day)
3000	0

2700	2400
2500	4000
2300	5600
2000	8000
1500	11555.56
1000	14222.2
500	16000
0	16888.9

(b) For Zone B

J= 10 STB/day/psi
Pr= 3860 psi

Step-I
Qob= J(Pr-Pob)
Qob= 10(3860-2000)
Qob= 18600 STB/day

Step-II

Pwf (psig)	**Qo (STB/day)**
3860	0
3500	3600
3200	6600
3000	8600
2700	11600
2300	15600
2000	18600
1500	23044
1000	26378
500	28600
0	29711

Equations used to calculate Q

(i) Above bubble point
Qo = J(Pr – Pwf)

(ii) Below bubble point

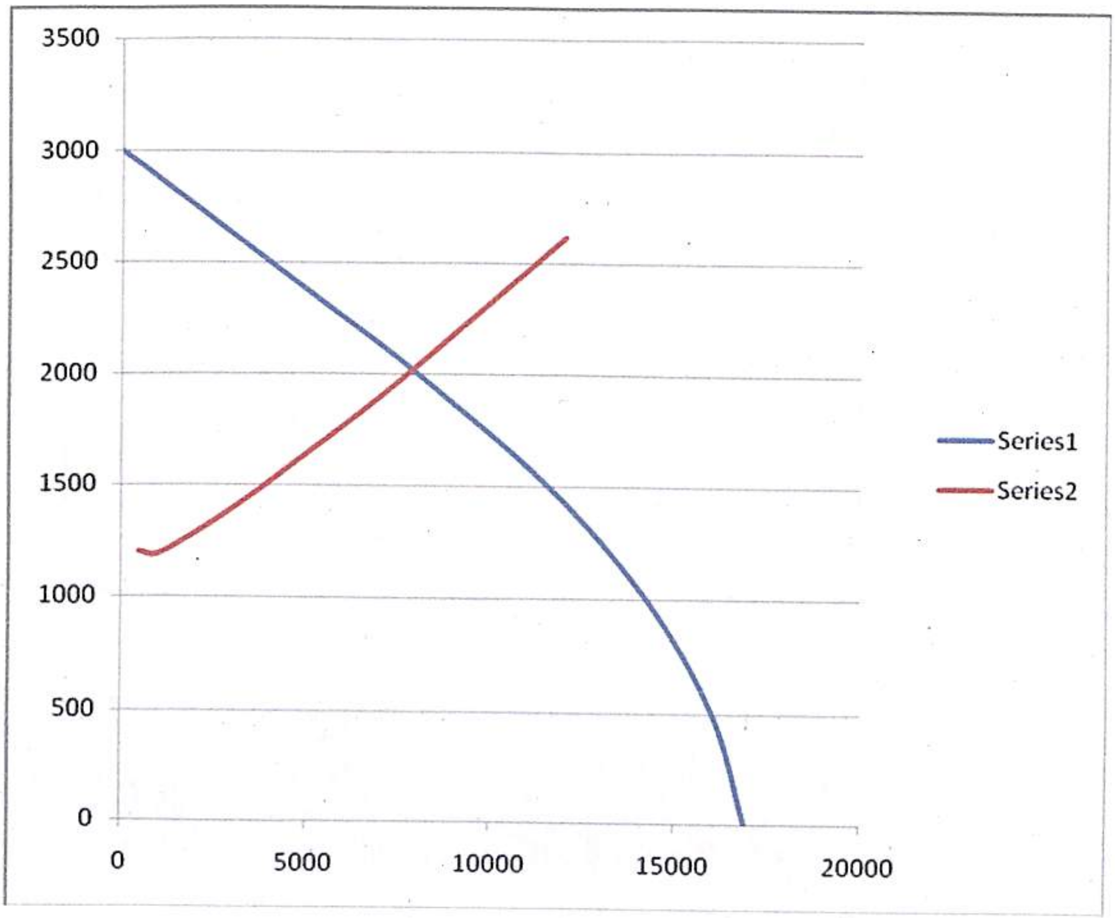
Qo = Qob + Jpb/1.8 [1- .2(Pwf/Pb) - .8(Pwf/Pb)^2]

4.1.4.2 Calculations for VLP

(i) **For zone A**

(a) For 3.5'' ID tubing

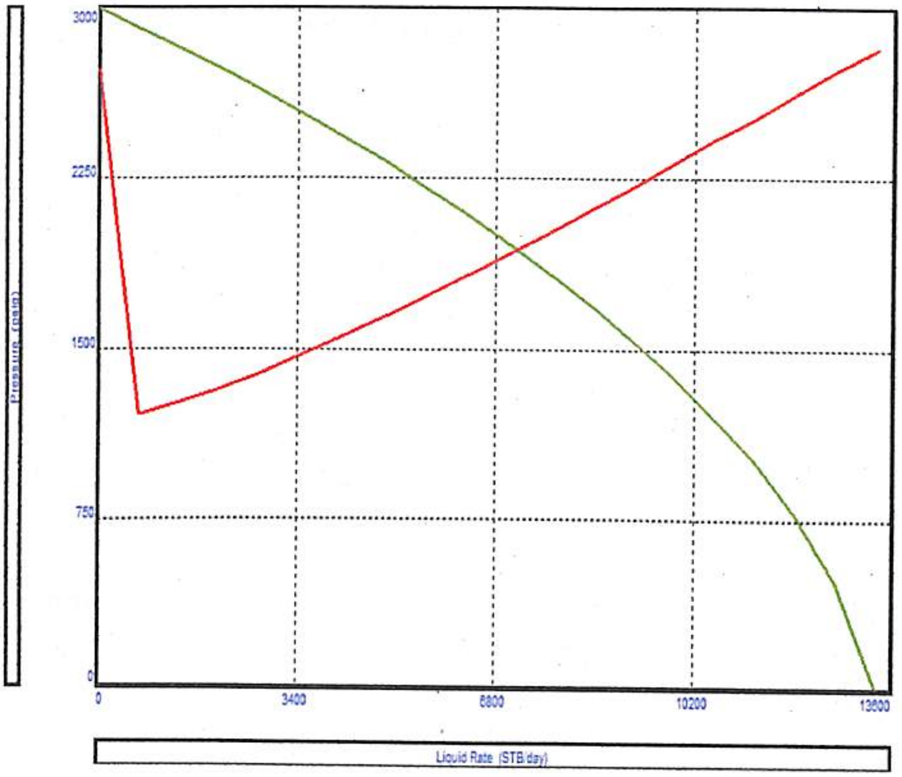
A. Using Pressure Gradient curevs



Liquid Rate : 7200 STB/ day

Figure 69: Calculation of VLP(For 3.5" tubing, Zone A)

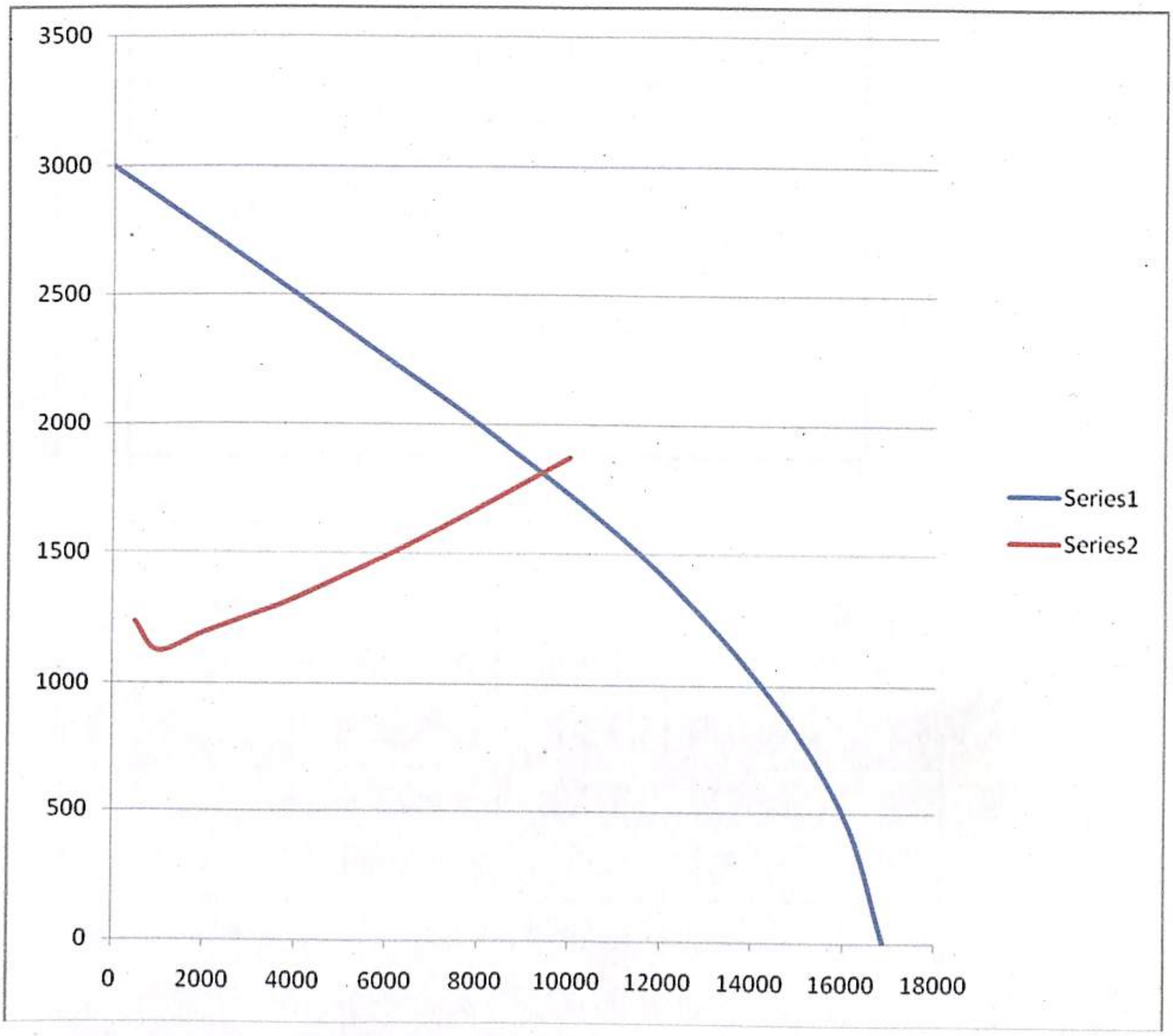
B. Validation Using Prosper



Liquid Rate	7168.5	STB/day
Gas Rate	5.018	MMscf/day
Oil Rate	7168.5	STB/day
Water Rate	0	STB/day
Solution Node Pressure	1935.70	psig
Wellhead Pressure	200.00	psig
Wellhead Temperature	117.63	deg F
First Node Temperature	117.63	deg F
Total Skin	0	
Total dP Skin	0	psi
dP Friction	343.63	psi
dP Gravity	1365.77	psi

(b) For 4'' ID tubing

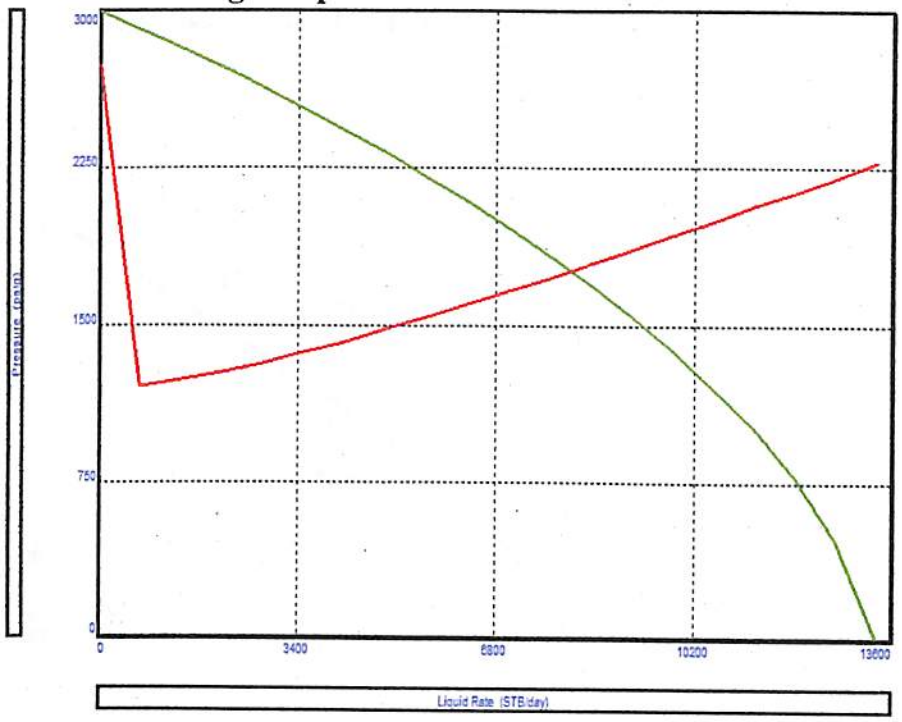
A. Using Pressure Gradient curevs



Liquid Rate: 9000 stb/day

Figure 70: Calculation of VLP (For 4" tubing, Zone A)

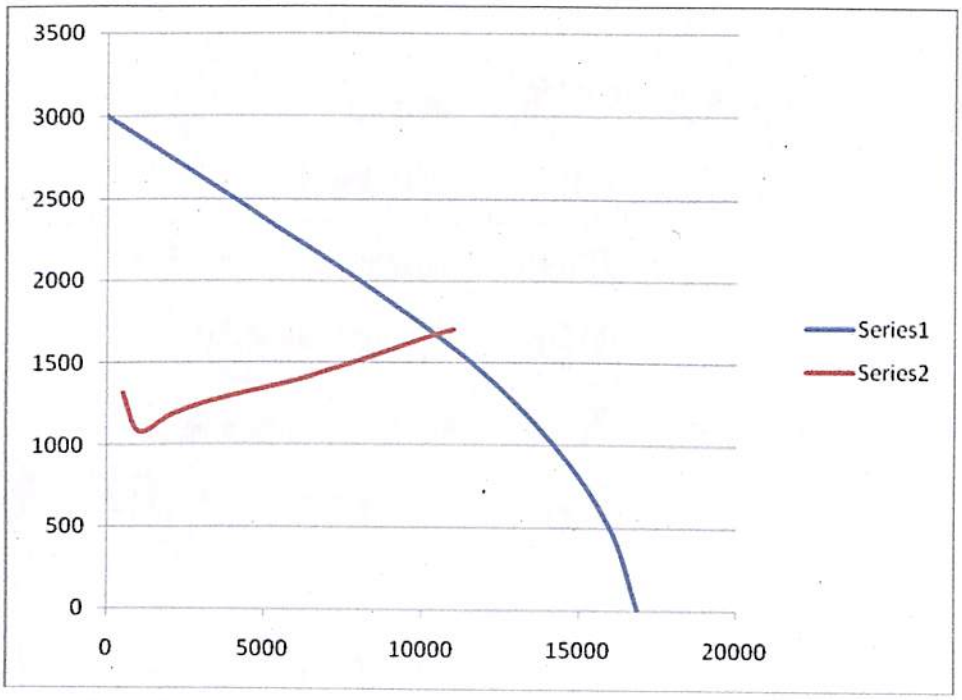
B. Validation Using Prosper



Solution Details		
Liquid Rate	8077.8	STB/day
Gas Rate	5.654	MMscf/day
Oil Rate	8077.8	STB/day
Water Rate	0	STB/day
Solution Node Pressure	1762.81	psig
Wellhead Pressure	200.00	psig
Wellhead Temperature	104.56	deg F
First Node Temperature	104.56	deg F
Total Skin	0	
Total dP Skin	0	psi
dP Friction	237.11	psi
dP Gravity	1306.43	psi

(c) For 4.5'' ID tubing

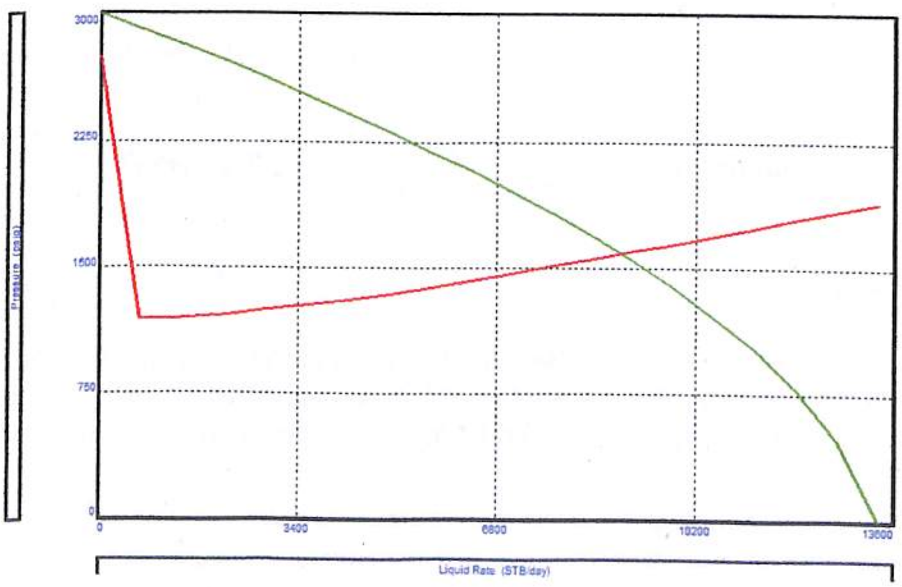
A. Using Pressure Gradient curevs



Liquid Rate: 9900 STB/ day

Figure 71: Calculation of VLP (For 4.5" tubing, Zone A)

B. Validation Using Prosper



Solution Details		
Liquid Rate	8932.2	STB/day
Gas Rate	6.253	MMscf/day
Oil Rate	8932.2	STB/day
Water Rate	0	STB/day
Solution Node Pressure	1587.09	psig
Wellhead Pressure	200.00	psig
Wellhead Temperature	104.25	deg F
First Node Temperature	104.25	deg F
Total Skin	0	
Total dP Skin	0	psi
dP Friction	173.84	psi
dP Gravity	1198.47	psi

Conclusion

The flow capacities for the various tubing sizes as read from the intersections of the inflow and outflow curves are:

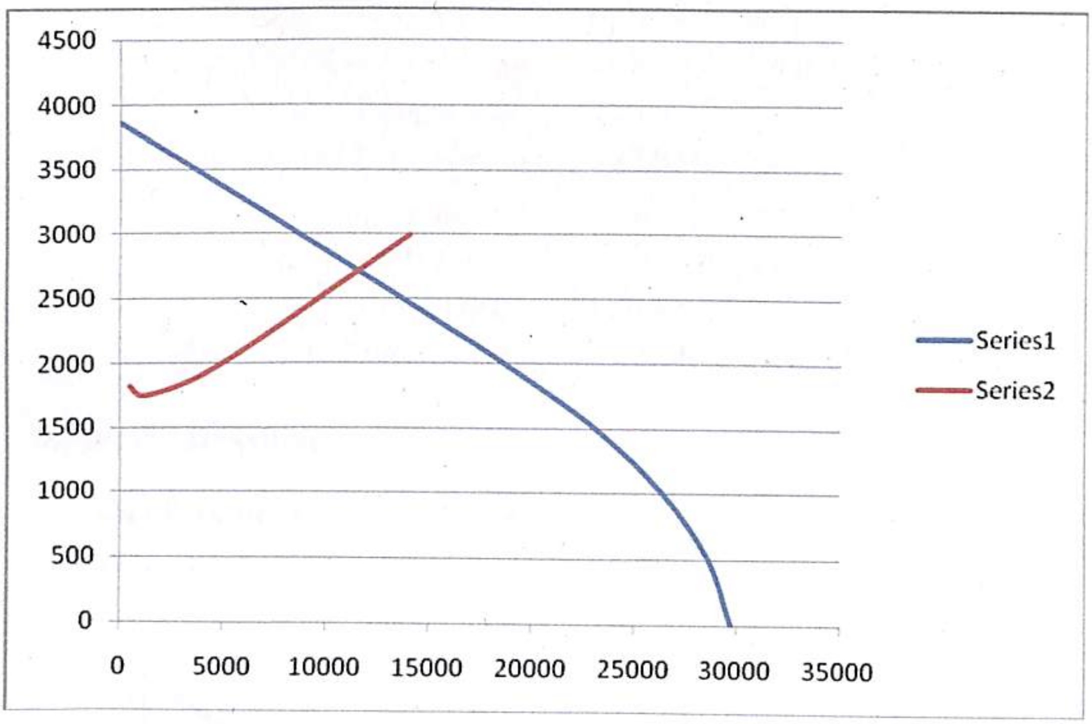
Tubing I.D., inch	Production Capacity, STB/day
3.5	7168
4	8077
4.5	8932

For 4 inch tubing, the producing capacity of well is 12% more as compared to 3.5 inch tubing and only 10.5% less as compared to 4.5 inch tubing. The optimised size of tubing keeping in consideration the cost, solution node pressure and production capacity is 4 inch tubing.

(ii) **For zone B**

A. Using Pressure Gradient curves

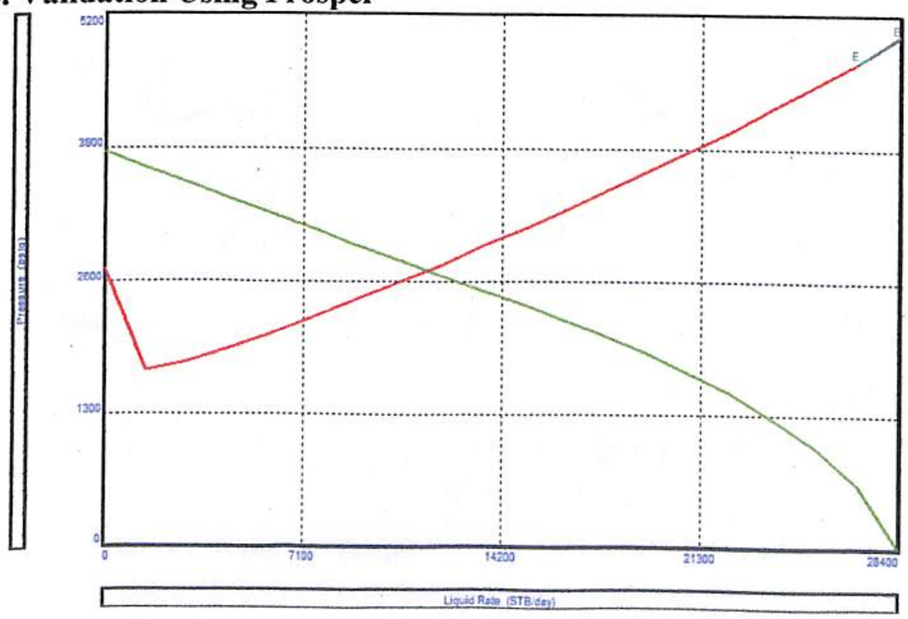
(a) For 3.5'' ID tubing



Liquid Rate = 11600 bbl/stb

Figure 72: Calculation of VLP (For 3.5" tubing, Zone B)

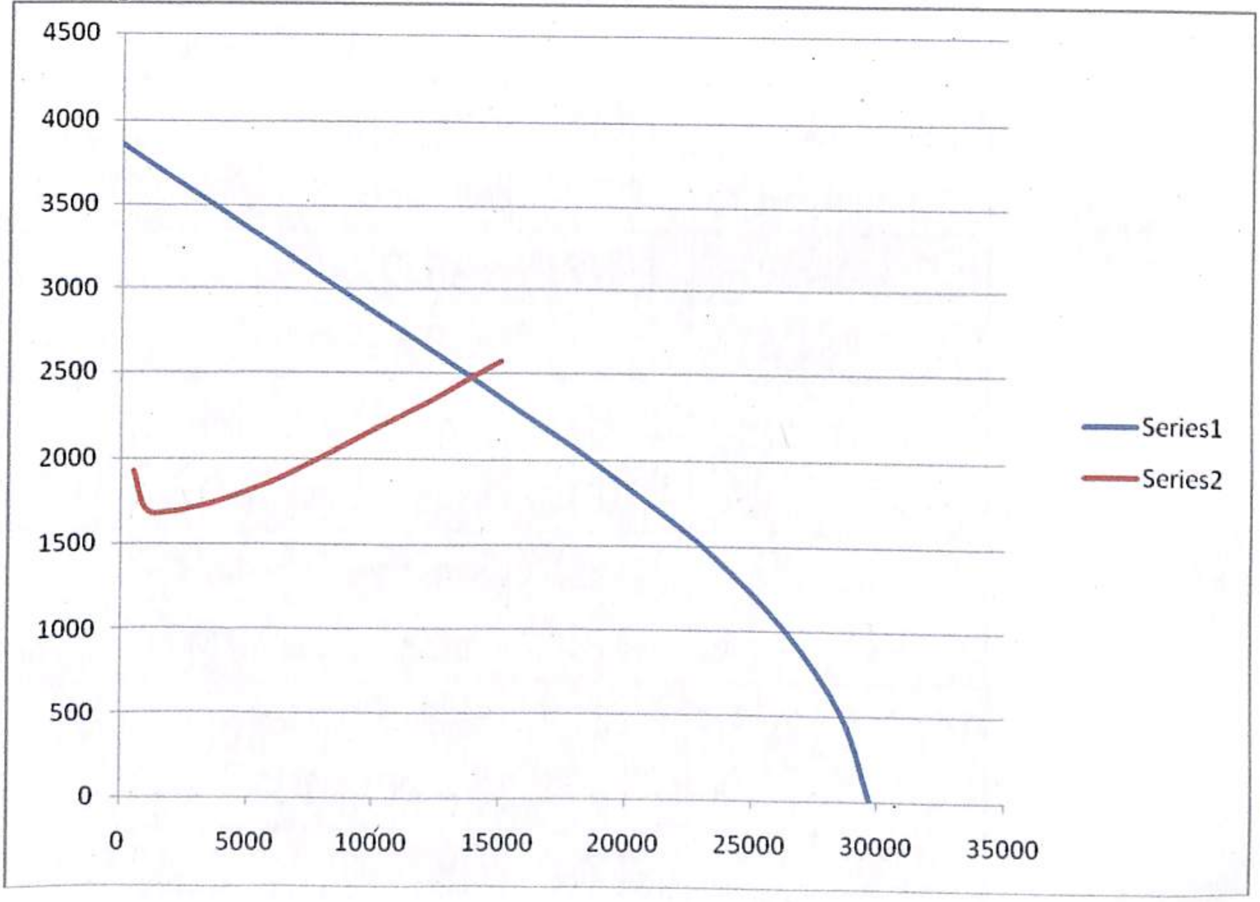
B. Validation Using Prosper



Solution Details		
Liquid Rate	11524.7	STB/day
Gas Rate	4.840	MMscf/day
Oil Rate	11524.7	STB/day
Water Rate	0	STB/day
Solution Node Pressure	2707.53	psig
Wellhead Pressure	200.00	psig
Wellhead Temperature	125.51	deg F
First Node Temperature	125.51	deg F
Total Skin	0	
Total dP Skin	0	psi
dP Friction	560.47	psi
dP Gravity	1914.48	psi

(b) For 4'' ID tubing

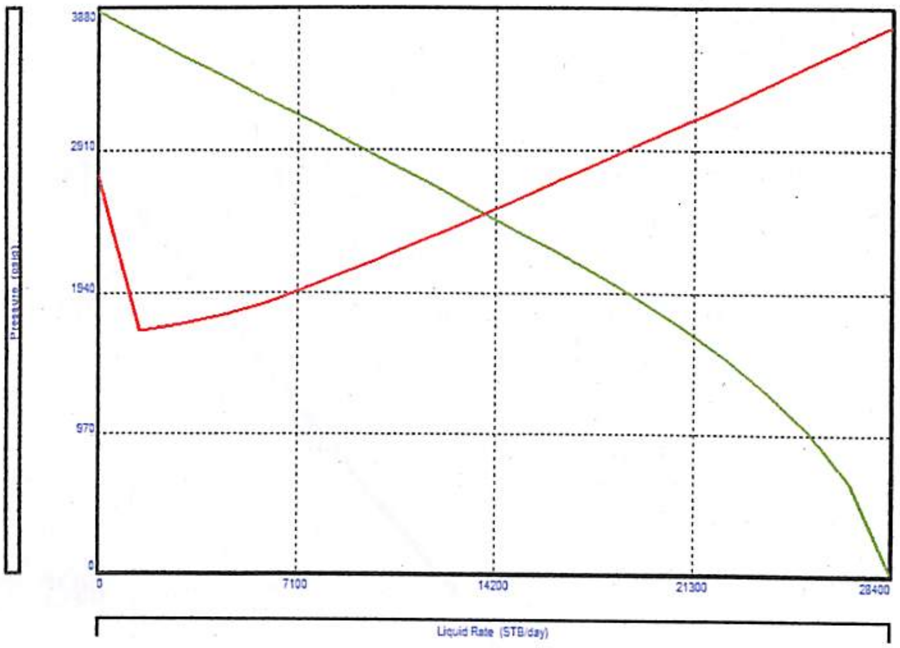
A. Using Pressure Gradient curves



Liquid Rate : 14000 STB/day

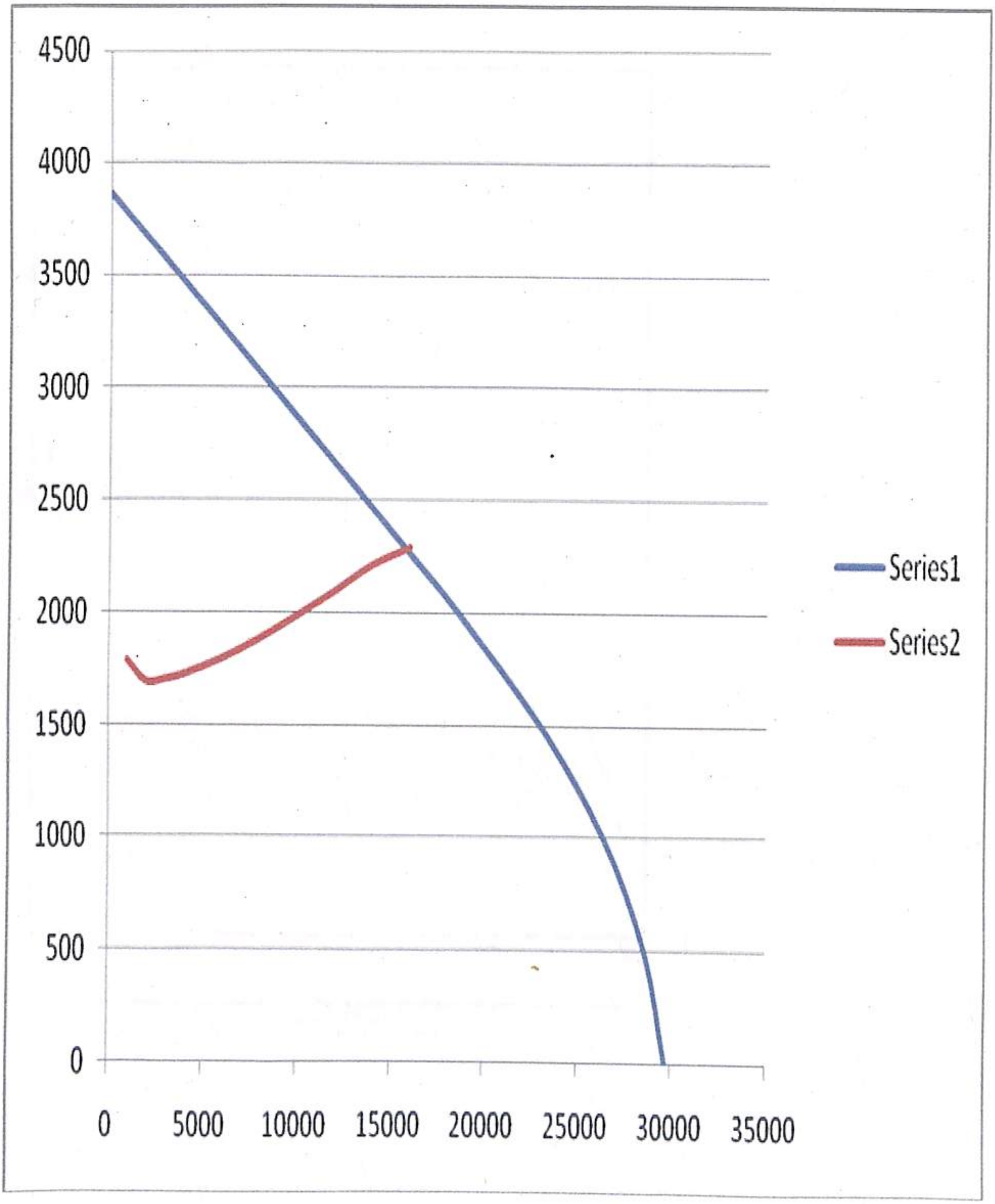
Figure 73: Calculation of VLP (For 4" tubing, Zone B)

B. Validation Using Prosper



Solution Details		
Liquid Rate	13807.1	STB/day
Gas Rate	5.799	MMscf/day
Oil Rate	13807.1	STB/day
Water Rate	0	STB/day
Solution Node Pressure	2479.29	psig
Wellhead Pressure	200.00	psig
Wellhead Temperature	126.44	deg F
First Node Temperature	126.44	deg F
Total Skin	0	
Total dP Skin	0	psi
dP Friction	435.45	psi
dP Gravity	1818.25	psi

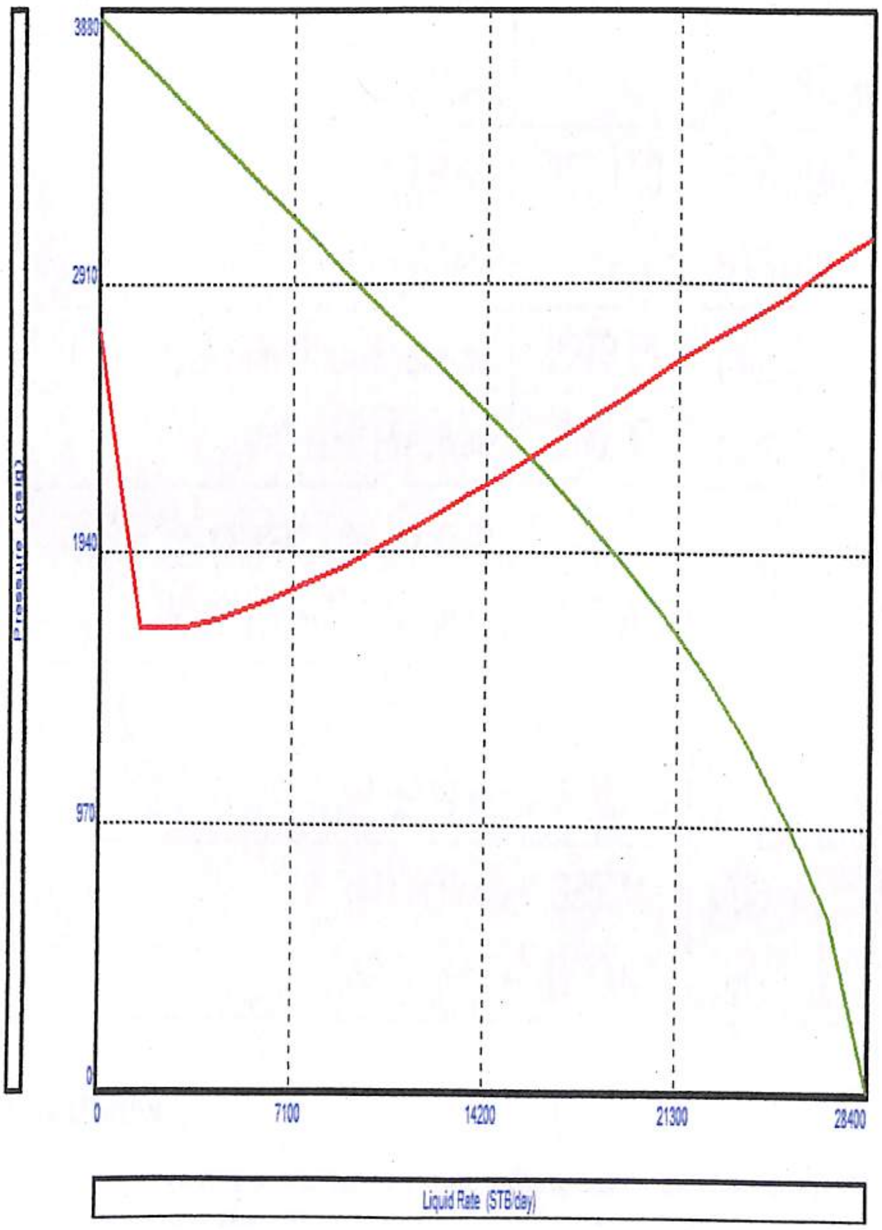
(c) **For 4.5'' ID tubing**



Liquid Rate: 16000 stb/ day

Figure 74: Calculation of VLP (For 4.5" tubing, Zone B)

B. Validation Using Prosper



Solution Details		
Liquid Rate	15797.3	STB/day
Gas Rate	6.635	MMscf/day
Oil Rate	15797.3	STB/day
Water Rate	0	STB/day
Solution Node Pressure	2279.55	psig
Wellhead Pressure	200.00	psig
Wellhead Temperature	126.76	deg F
First Node Temperature	126.76	deg F
Total Skin	0	
Total dP Skin	0	psi
dP Friction	335.74	psi
dP Gravity	1723.87	psi

Conclusion

The flow capacities for the various tubing sizes as read from the intersections of the inflow and outflow curves are:

Tubing I.D., inch	Production Capacity, STB/day
3.5	11524
4	13807
4.5	15797

For 4 inch tubing, the producing capacity of well is 16% more as compared to 3.5 inch tubing and only 12.5% less as compared to 4.5 inch tubing. The optimised size of tubing keeping in consideration the cost, solution node pressure and production capacity is 4 inch tubing.

4.1.5 Completion Design

As the reservoir characteristics of the two zones are entirely different, completion with dual tubing string has to be employed for allowing separate production from the two zones. Now, as the only casing string size available is 95/8'' OD. So we will have to use tubing string sizes of 3.5'' ID for both the zones otherwise the completion with dual tubing will not be possible. Also, we can use tapered tubing string. That is, tubing of 4inch ID can be run from the surface to the top of 9 5/8'' casing. The effect of size of upper string on the producing capacity can be determined by selecting the point at which the tubing changes size as the node.

The lower packer is a permanent packer and the longer tubing string is connected to it using a seal assembly. The upper packer is the retrievable dual packer. To combat erosion on the longer tubing string at the point of entry of fluid from the upper zone into wellbore, thick walled joints known as "Blast Joints" are used.

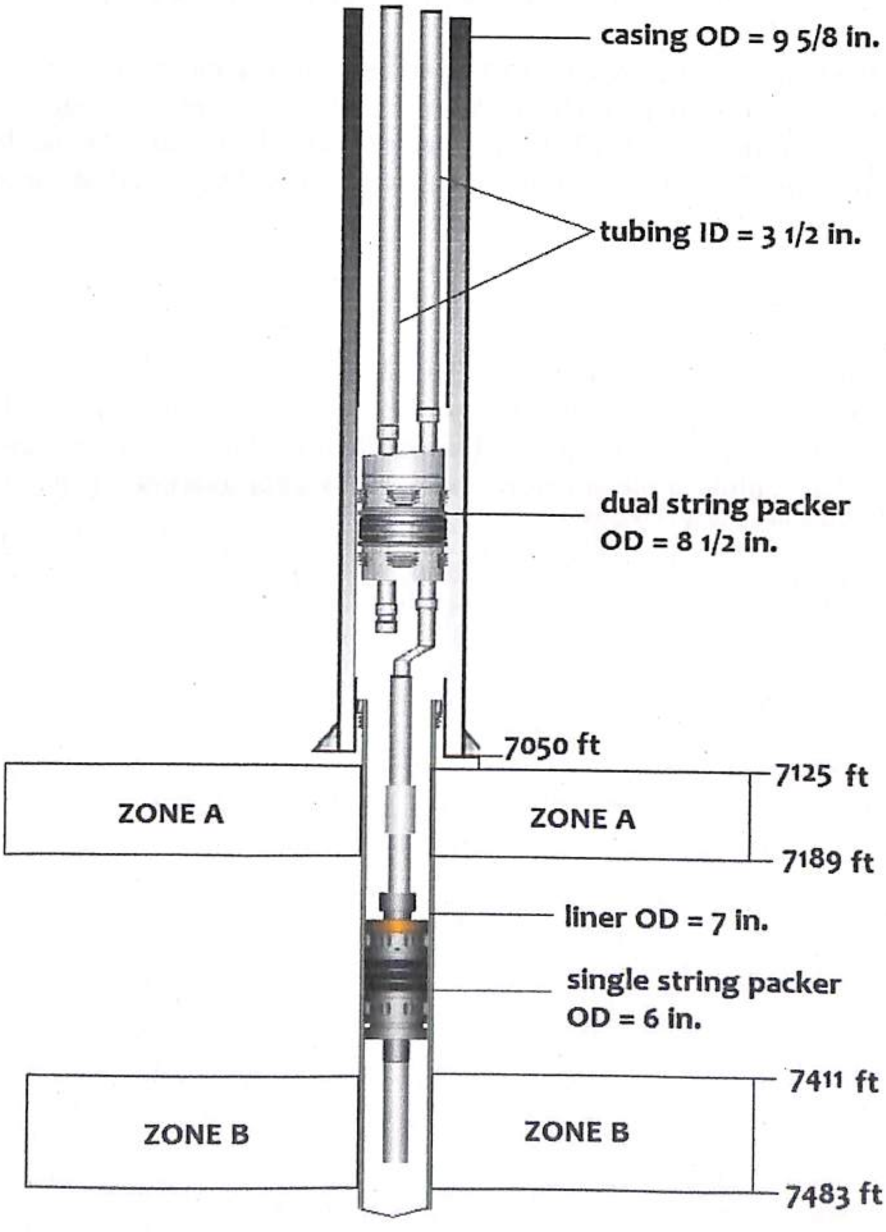


Figure 75: Completion Design

4.1.6 Stimulation Strategy

(a) For zone A

In order to boost the productivity of Zone A we can use the technique of Frac Pac.

Hydraulic fracturing is a very effective method for completing a weak or unconsolidated formation. Fracturing can help reduce or eliminate sand production by a number of methods:-

- By reducing the drawdown on the formation
- By re-stressing the formation
- By acting as a filter, provided the proppant is sized correctly.

A hydraulic fracture can also be used as part of a gravel pack completion, providing a so-called frac and pack treatment. This is probably the most effective way of developing an unconsolidated formation. This combination of hydraulic fracturing and gravel pack leads to the completiobs with a lower skin and hence much higher well productivities.

(b) For zone B

In order to boost the productivity of Zone B we can use acidization. As this zone is heavily fractured so acidizing will remove the excess pressure drop. Also the permeability of the zone is very less i.e., 0.5md so acidizing will dissolve the formation rock and materials which are either natural or induced thus increasing the permeability.

4.2 Case Study-II

CALCULATION OF TUBING MOVEMENT

A well on onshore location is about to be acidized to increase the production rate. The tubing is expected to move during acid treatment due to various load conditions. The required data for the well is given as below:

Packer. SD = 12000ft
Packer Bore = 2.75"
Casing 5-1/2", 17ppf, ID = 4.95"
Tubing 2-3/8", 4.7ppf ID = 1.875"
Casing Fluid Weight when tubing was landed = 11ppg
Tubing fluid on landing = 11ppg
BHT on landing = 270oF
Surface temperature = 45°F
Treating acid = 9.2ppg
Acid Temperature = 45°F
Surface pump pressure during treatment = 6000psi
Casing fluid during treatment = 11ppg
Casing pressure during treatment = 2000psi
Estimated BHT during treatment = 110°F
Total well depth = 13250ft

Acid jobs are carried out to remove formation damage caused during drilling by the invasion of fluids and cuttings or to stimulate the formation by improving permeability. The primary purpose of any acidizing treatment is to dissolve either the formation rock or materials, natural or induced, within the pore spaces of the rock. Originally, acidizing was applied to carbonate formations to dissolve the rock itself. Over a period of time, special acid formulations have been developed for use in sandstone formations to remove damaging materials induced by drilling or completion fluids or by production practices.

With regard to the stresses on the string, it is important to assess the drop in temperature caused by the injection of colder fluid. Also, the maximum pressure able to be applied at the well head must be considered in order to determine the rate of acid which can be applied. To check the string design is suitable, the pressure and temperature trends can be plotted.

During the acid jobs the tubing is expected to move. The various effects which produce forces and thus move the tubing during acidization are:

1. Piston Effect
2. Temperature Effect
3. Ballooning Effect
4. Buckling Effect

CALCULATIONS:

1. PISTON EFFECT:

The equations for the force and length are:

$$F = \Delta Pi\ (Ap - Ai) - \Delta Po(Ap - Ao)$$

$$\Delta L = (12\ L / E\ As)\cdot(\Delta Pi\ (Ap - Ai) - \Delta Po(Ap - Ao))$$

Where,

E = 30 * 10^6 psi
Ap = 3.14 * 2.75^2/4 = 5.936 sq in.
Ai = 3.14 * 1.875^2/4 = 2.759 sq in.
Ao = 3.14 * 2.375^2/4 = 4.4278 sq in.
As = Ao- Ai = 1.6688 sq in
ΔPi = 6000+ 9.2 *.052 *12000- 11*.052 *12000 = 4876.8 psi
ΔPo = 2000+ 11*.052 *12000- 11*.052 *12000= 2000psi

So,

F1 = (5.936- 2.759) * 4876.8- (5.936- 4.4278) * 2000
F1 = 12477 lbf

ΔL1 = - (12477* 13250* 12)/ (30*10^6* 1.6688)
ΔL1 = 39.626 inch

2. TEMPERATURE EFFECT:

The equations for the force and length are:

$$\Delta L = \alpha\ L \Delta T$$

$$F = 207\ As \Delta T$$

Where,

$$\Delta T = [(T_{final} - T_{initial})_{top} + (T_{final} - T_{initial})_{bottomhole}] / 2$$

ΔT = [(45– 45) + (110 – 270)] / 2 = **-80°F**

α = 6.9 * 10^-6 in/in/°F for steel

So,

ΔL2 = 6.9 * 10^-6 * (-80) * 13250 * 12

ΔL2 = 87.768 inch

$F2 = 207 * 1.668 * 80$

$F2 = 27624.15$ lbf

3. BALLOONING EFFECT:

The equations for the force and length are:

$$\Delta L = [(2 * L*v) / E] * [(\Delta Pia - R^2*\Delta Poa) / (R^2 - 1)]$$

$$F = 0.6 \,(? Pia\ Ai - ? Poa\ Ao)$$

Where,

$$\Delta P_{ia} = [(P_{i(final)} - P_{i(initial)})_{top} + (P_{i(final)} - P_{i(initial)})_{bottomhole}] / 2$$

$$\Delta P_{ia} = [(6000 - 0) + \{6000 + (.052 * 9.2 * 12000) - (.052 * 11 * 12000)\}] / 2$$

$\Delta P_{ia} = 5438.4$ psia

$$\Delta P_{oa} = [(P_{o(final)} - P_{o(initial)})_{top} + (P_{o(final)} - P_{o(initial)})_{bottomhole}] / 2$$

$$\Delta P_{oa} = [(2000 - 0) + \{2000 + (.052 * 11 * 12000) - (.052 * 11 * 12000)\}] / 2$$

$\Delta P_{oa} = 2000$ psia

R= Tubing OD/ Tubing ID

$R = 2.375 / 1.875 = 1.2667$

So,

$$\Delta L3 = [(2 * 13250 * 12 * .3 / 30 * 10^6] * [(5438.4 - 1.2667^2 * 2000) / (1.2667^2 - 1)]$$

$\Delta L3 = 11.7$ inch

$F3 = .6\,(5438.4 * 2759 - 4.4278 * 2000)$

$F3 = 3689.36$ lbf

4. BUCKLING EFFECT:

The tubing length is calculated as:

$$\Delta L = [r^2 * F_f] / [8 E I w]$$

Where,

r = (Casing ID – Tubing OD)/ 2

r = (4.95 – 2.375) / 2

r = 1.287

I = [3.14* (Tubing OD^4 – Tubing ID ^4)]/64

I = [3.14* (2.375^4 – 1.875 ^4)]/64

I = .95

$$F_f = A_p (\Delta P_i - \Delta P_o)$$

F_f = 5.936 (4876.8 – 2000)

F_f = 17076.68 lbf

Also,

The neutral point can be calculated from the following:

$$n = F_f / w$$

$$w = w_s + w_{fi} - w_{fo}$$

$w_{fi} = A_i * \gamma_{fi}$

w_{fi} = 2.759 * .0331626

w_{fi} = .0915 lb/in^3

$w_{fo} = A_o * \gamma_{fo}$

w_{fo} = 4.4278 * .039167

w_{fo} = .17556 lb/in^3

w_s = 4.7/12 = .3076 lb/in
w = .39167 + .0915 - .17556 = .3076 lb/in

So, n= 17076.68/ .3076 = 55515.88 inch

Neutral point is within the tubing length so helix can fully develop. Therefore the length reduction can be calculated by:

$\Delta L4 = [1.287 ^2 * 17076.68 ^2] / [8 * 30 * 10^6 * .95 * .3076]$

ΔL = 6.887 inch

The total free length due to acidization is the summation of variation in length due to each effect discussed above.

Variation in total length of tubing is given by:

$\Delta L = \Delta L1 + \Delta L2 + \Delta L3 + \Delta L4$

ΔL = -145.981 inch = 12.16 feet

5. RESULTS & DISCUSSION

CASE STUDY 1:

For ZONE 1

Results:

The flow capacities for the various tubing sizes as read from the intersections of the inflow and outflow curves are:

Tubing I.D., inch	Production Capacity, STB/day
3.5	7168
4	8077
4.5	8932

For ZONE 2

Results:

The flow capacities for the various tubing sizes as read from the intersections of the inflow and outflow curves are:

Tubing I.D., inch	Production Capacity, STB/day
3.5	11524
4	13807
4.5	15797

DISCUSSIONS

·Selecting 4 in. tubing over 3.5 in tubing gives a increased production rate of 12.7% and selecting 4.5 in. tubing over 4 in. tubing further gives an increased production of 10.5% in case of zone 1.
Similarly, for zone 2, selecting 4 in. tubing over 3.5 in. tubing gives an increased production rate of 16% and selecting 4.5 in. tubing over 4 in. tubing further increases the flow rate by 12.5%.
Keeping in mind the cost consideration, 4 in. tubing should b selected as it gives a better production rate then the 3.5 in. tubing and much more economical then the 4.5 in tubing taking into consideration only an increase of 10.5% production.
But as we have a production casing of 9 5/8 in. casing, and we have to carry out a dual string completion, we can accommodate a tubing of 3.5 in. ID.
So a tubing with an ID of 3.5 in. is selected.

CASE STUDY 2

Results:

Variation in total length of tubing is given by:

$\Delta L = \Delta L1 + \Delta L2 + \Delta L3 + \Delta L4$

ΔL **= -145.981 inch = 12.16 feet**

Total forces acting on the tubing is given by:

Total F= F1 + F2 + F3 + F4

FT = 12477 + 27624.15 + 3689.36 + 17076.68

FT= 60867.19 lbf

Discussion:

The total changes in the length of the tubing is 12.16 ft and the net forces acting due to the various tubing movements is 60867.19 lbf. So, the grade of the tubing should be selected so that it can bear the calculated force and change in length, without failure.

6. CONCLUSION & RECOMMENDATIONS

This project started with the general concepts of reservoir performance and well productivity. Key points include:

(a) Reservoir recovery performance and production rate profile is controlled by the reservoir drive mechanism.

(b) Reservoir production can be maximised by system pressure dropoptimisation.

(c) Maintaining production rates can be achieved by fluid injection

(d) Artificial lift processes can maintain or enhance production rates

(e) Gas lift reduces the hydrostatic head pressure loss

(f) Pumps provide additional energy to assist lifting oil to surface

Well design is crucial to the control of fluid movement into the wellbore, their retention in the reservoir and hence maximising recovery and rates of hydrocarbon recovery.
The use of Darcy's Law was discussed and in particular its application in radial co-ordinates. The response of the system to the of depletion was defined by two models namely the steady state model in which no depletion occurs and the semi or pseudo steady state model in which the outer boundary is closed.
Initially we considered for single phase flow the case of incompressible fluids such as liquids, which approximately have a constant viscosity and density. The case of slightly compressible fluids such as volatile oils and compressible fluids such as gas were then considered.
The concept of Productivity Index was presented as a sample means of characterising well deliverability. For both the incompressible and slightly compressible fluids it was demonstrated that the PI was constant over a wide range of conditions. However, for gas it was clear that the PI would continuously decline with reducing pore pressure.
The case of multi-phase flow in the reservoir was particularly relevant to solution gas drive reservoirs and the physics of the production process were discussed. The majority of pressure loss in oil wells is attributable to losses in the tubing string.
Pressure drop in pipe was reviewed with respect to energy and momentum balances.
The physical concepts of multi-phase flow in pipe was presented emphasising concepts such as flow patterns, slippage and hold up.
The representation of pressure-depth traverses using gradient curves was presented and their use in predicting bottomhole pressure requirements and their rate dependance, through a tubing performance relationship was outlined.
The need for chokes was presented as a means of imposing production control. The

sizing and performance of chokes as predicted by a number of correlation was discussed.
Finally, the integration of predicting both inflow and tubing performance requirements was considered to define and select tubing sizes as well as optimise well design.

RECOMMENDATIONS

The thesis can be complimented by implementing the following recommendations in the further study.

1) Investigate whether well interactions within the reservoir are important for short-term production optimization problems. And if so, how to handle them efficiently.

2) In the thesis, completion string design has been limited to tubing sizes, packer sizes and liner size. We can further add other completion jewels like Sub surface safety valves, landing nipple etc in the systematic design along with the depths.

3) The system analysis approach for estimating the improvement in well capacity due to stimulation and evaluation of effect of restrictions on the production capacity of well can be included.

4) Economic risk assessment for Authorization for Expenditure can be included.

5) The tubing movements calculated manually can be validated using software like TDAS.

REFRENCES

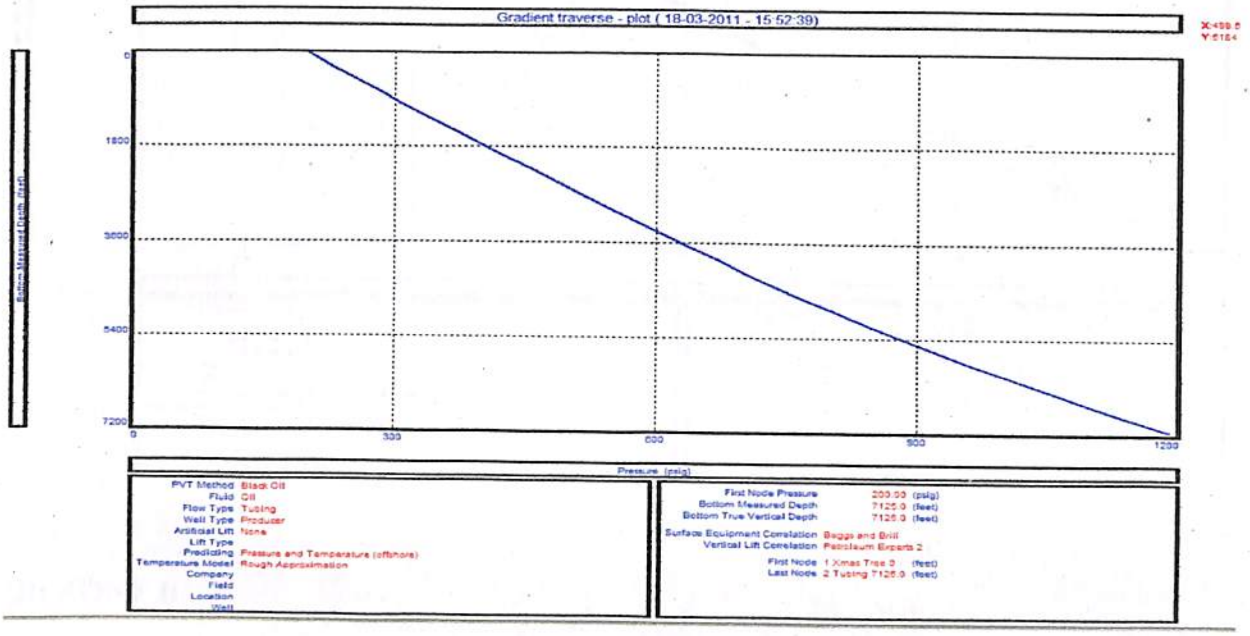
1. Beggs, H.D. (2003).*A Production Optimization using Nodal Analysis*. (pp 14-35).
2. Herriot Watt University. *Production Technology-I.*(pp 003- 157)
3. Bellarby Jonathan. *WELL COMPLETION DESIGN*

APPENDIX

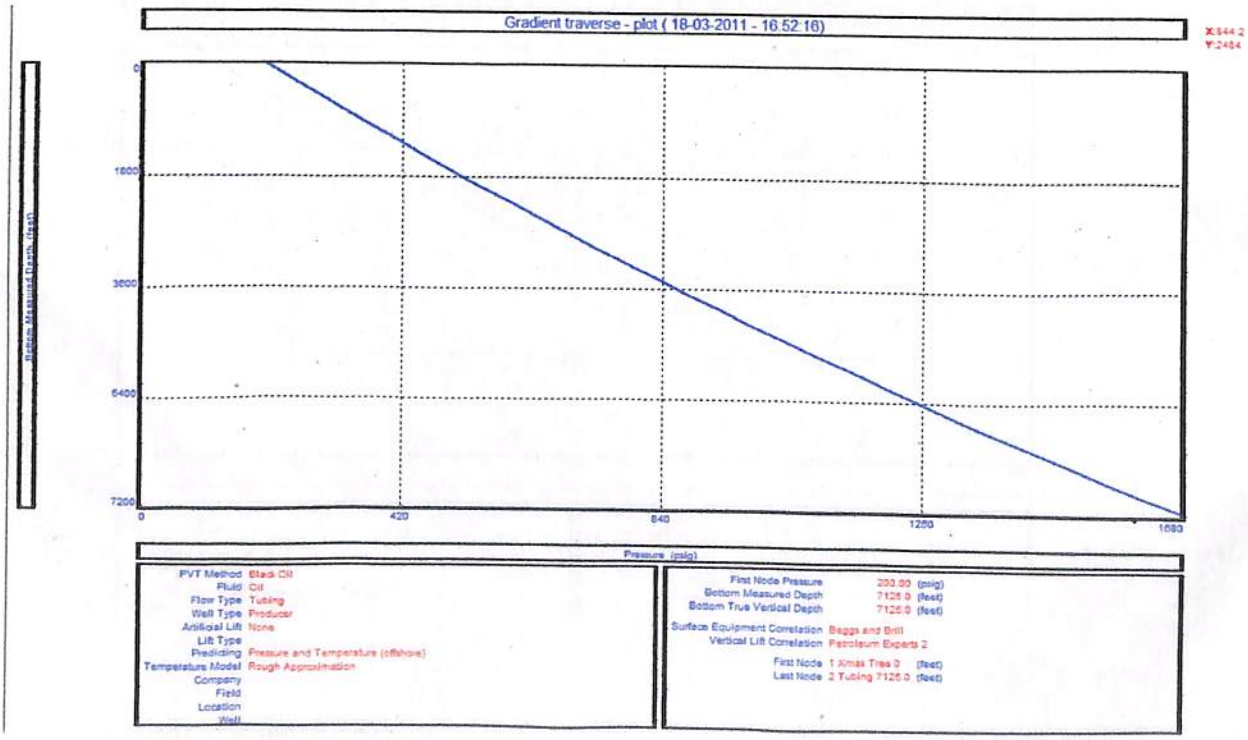
In the course of study, for production optimization of tubing string due to unavailability of Gilbert curves we had to generate the pressure gradient curves using the software PROSPER. Following are few examples of the gradient curves generated for different tubing sizes.

(A) ZONE A

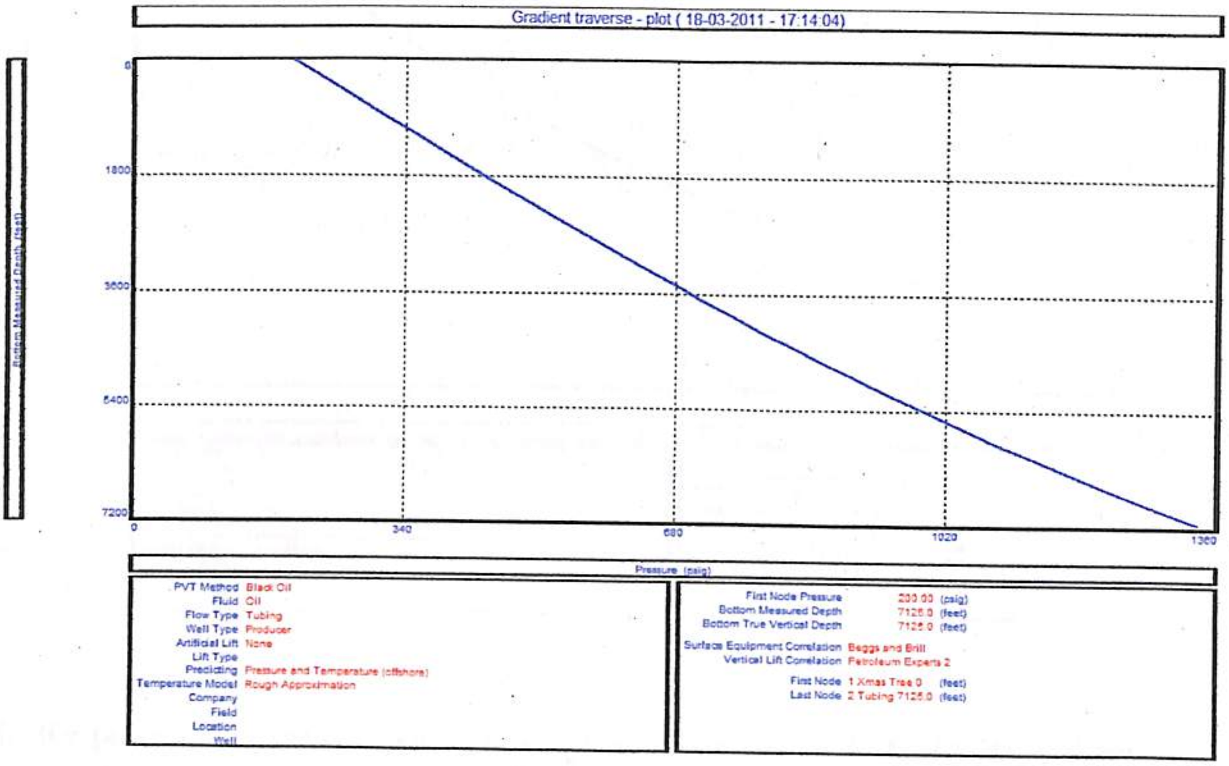
(i) 3.5'' tubing , 1000 STB/ day



(ii) 4'' tubing , 8000 STB/ day

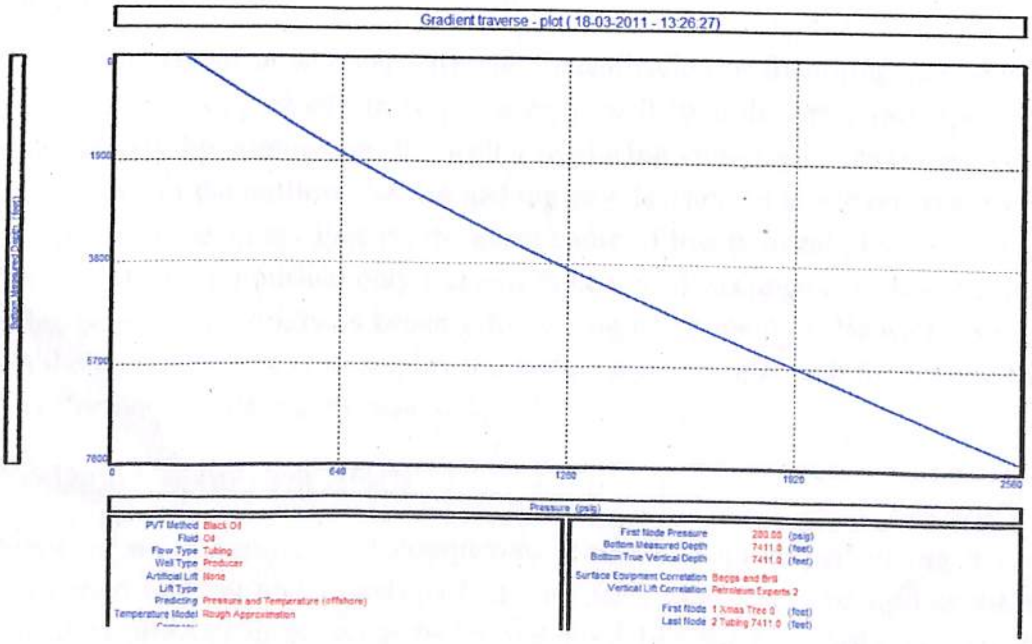


(iii) 4.5'' tubing , 6000STB/day

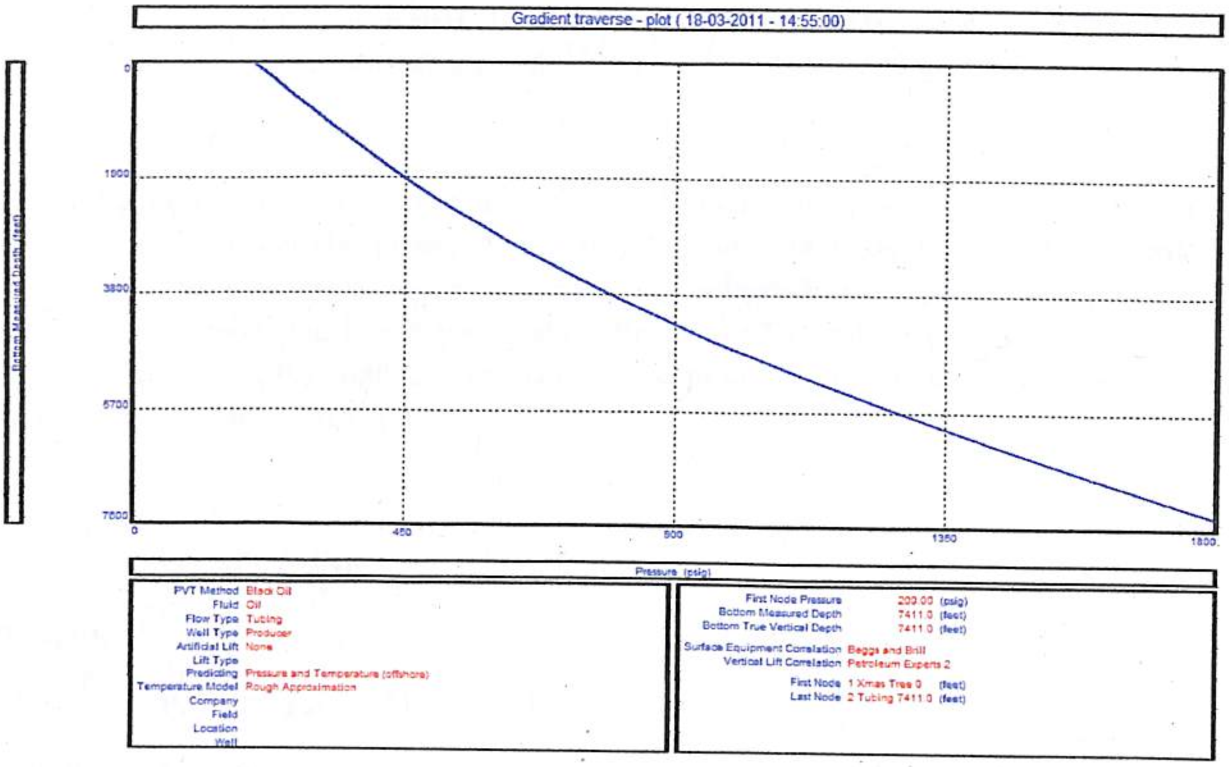


(B) ZONE B

(i) 3.5'' tubing, 10000 STB/ day



(ii) 4.5'' tubing, 6000 STB/day



In the preceding chapters production optimization for tubing string has been discussed along with generic completion designs for a well. However, optimization is not just limited to tubing string. The procedure can also be applied to analyze the performance of well under different situations. Some other applications of optimization are discussed below with no particular order.

Effect of stimulation

The improvement in well capacity due to acidization or fracturing can be analyzed using system analysis approach. In some cases even though the reservoir capacity is increased considerably by stimulation; the well's producing capacity increase may be small due to restrictions in the outflow. Before making any decision as to see on what steps to take the increase in producing capacity, the exact cause of low permeability should be determined. This can be accomplished only through system analysis approach. Large sum of money is often wasted on workovers because the wrong component of the well system is changed. So the best technique is to employ the system analysis approach for finding the benefits of an effective stimulation process.

Evaluating completion effects

For comparing various well completion schemes, such as perforating density and total perforated interval nodal analysis is a convenient and most appropriate method. We can calculate pressure drop across the completions like for open hole, perforated and gravel pack completions. The completion pressure drop, P_{wfs}-P_{wf} may be included in the reservoir pressure drop component or it may be isolated to compare effects of various completion methods. For each completion scheme a different inflow curve would be drawn.

If gravel pack completions are considered, it is advantageous to isolate the pressure drop across the gravel pack. This is necessary so that the critical pressure drop is not exceeded. By treating the completion or gravel pack as an independent component and plotting pressure drop across the gravel pack versus flow rate. To analyze the completion, the system is divided at the wellbore. The node pressure for the inflow is P_{wfs} and the node pressure for the outflow is P_{wf}.

Inflow,

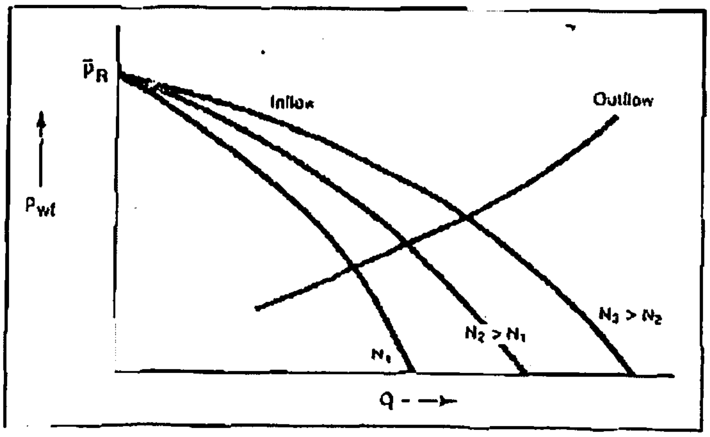
$$P_r - \Delta P_{res} = P_{wfs}$$

Outflow,

$$P_{sep} + \Delta P_{flowline} + \Delta P_{tubing} = \Delta P_{wf}$$

Both P_{wfs} and P_{wf} are determined for various flow rates and plotted versus flow rates. The producing capacity that would result if no pressure drop across the gravel pack occurs can be estimated from the intersection of the inflow and outflow curves. The required P_{wfs} is calculated using equations for oil and gas reservoirs. The pressure drop available for overcoming the gravel pack's resistance for flow rates less than the maximum system rate can be read from figure 1.

Figure 1



The pressure drop available for overcoming the gravel pack's resistance to flow for rates lower than the maximum system rate can be read from figure 2. These are designated as $\Delta p1$. Values of $\Delta p1$ versus q are plotted as illustrated by figure 3.

Figure 2

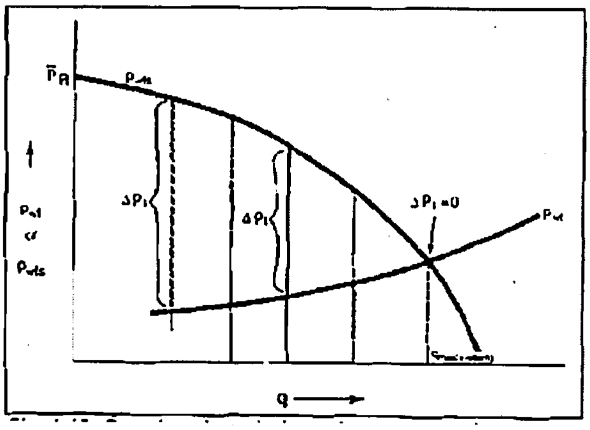
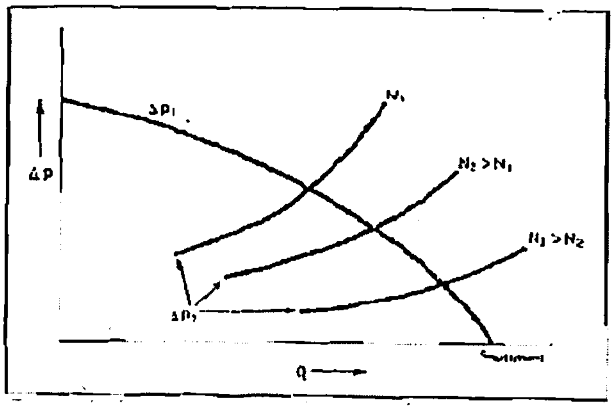


Figure 3



The pressure drop occurring across the gravel pack for various flow rates can be calculated as a function of the number of perforations, perforation size, perforation length, and gravel permeability. These pressure drops, designated as Δp2 are plotted on figure 3. The intersection of the Δp1 and Δp2 curves gives the producing capacity and pressure drop across the gravel pack for various completion schemes. This permits determination of the maximum producing rate allowed for any number of perforations to keep Δp below the critical value.