A CASE STUDY OF NATURAL FLOW AND TUBING STRING DESIGN FOR A WATER DRIVE RESERVOIR

A

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By

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ABSTRACT

The design of natural flow and artificial lift tubing strings for the whole life of a water drive reservoir was carried out using data based on synthetic reservoir performance based on a material balance. The effects of reservoir properties on the life of the well was also investigated. Constraints such as maximum production, maximum drawdown, limitations on surface facilities capacities, as well as available gas lift was imposed.

The production conditions for natural flow, continuous gas lift, and an ESP for later phases of the reservoir was designed and simulated along time by imposing either a constant flow rate or a constant bottom hole flowing pressure. A forecast of the production of oil and gas as well as the time where tubing strings should be replaced as a function of both the cumulative production and time was presented.

The work was concluded by reservoir pressure was maintained much longer in comparison to other drive mechanism when there is an active water drive preferably edge water drive reservoirs which maintains a steady-flow condition for a long time before water breakthrough into the well.

Finally the following areas were identified for improvement in the development of the work one is that the assumptions in this work is the use of synthetic reservoir performance data based on material balance a possible extension is by incorporating more practical condition by including more wells and the performance with time better analyzed and further oil production economic analysis should be inclusive in the work so that the optimum production pattern of the reservoir could be determined.

DEDICATION

This project is dedicated to my wonderful and loving parents Late Joseph Olabode Ojo and Mrs Janet Bolanle Ojo (for her constant prayers,love care and support) and to my sweetheart Oladimeji Deborah Funmilayo (for her understanding, love and care.)

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Table of Contents

List of Figures

List of Tables

INTRODUCTION

1.1 OVERVIEW

Fluids are stored in the reservoir and must be produced to the surface facilities in order to be measured, treated and finally sold or discarded. The flow of fluids from the reservoir towards the final processing facility is divided into three phases: Recovery, Lift and Gathering.

Recovery refers to the flow of fluids from the reservoir into the well bore; Lift refers to the flow of fluids from the bottom of the well bore to the surface wellhead and Gathering refers to the flow of fluids from the wellhead through the gathering network towards the production facility.

Recovery is used in a broader sense a referring to the production including the lift and gathering processes. Lift and gathering process will influence the final recovery of hydrocarbons and must be included in a proper economic analysis.

The flowrate from a well depend on the energy level of the reservoir and the energy losses of the fluids as they flow from the reservoir towards the surface facilities. In order to increase production flowrates we may use processes or systems to either increase the energy level or to facilitate the flow of hydrocarbons. Those systems or processes may be used in the reservoir or in the production tubing or gathering system. The recovery of hydrocarbons may then be classified as: Primary where no process or method is used to increase energy level or facilitate the flow of hydrocarbons inside the reservoir; Secondary and Tertiary where methods are used to increase energy level and or to facilitate the flow of hydrocarbons in the reservoir.

The lift and gathering may also be classified as: Natural flow – No process or method used to increase energy level or facilitate the flow of hydrocarbons in the production system; Artificial lift– when processes are used to increase the energy level or facilitate the flow of hydrocarbons inside the well bore; Boosting – When processes are used to increase the energy level or facilitate the flow of hydrocarbons downstream of the wellhead.

The recovery of hydrocarbons is classified in the following categories: Primary Recovery (also called Primary Production); Secondary Recovery (also called Secondary Production); Tertiary Recovery (also called Tertiary Production or Enhanced – EOR or Enhanced Production or Improved

- IOR or Improved Production). Those categories are usually associated with a method or recovery (or production) used - Primary recovery uses the pressure and displacement of hydrocarbons without any external process using solely the reservoir drive mechanism, secondary recovery supplements the natural drive effects on pressure maintenance and displacement by water injection or water flood and natural gas injection ; and Tertiary recovery supplements the natural drive by modifying the properties of the fluids by chemical floods, miscible displacement and thermal methods.

Each reservoir is composed of a unique combination of geometric form, geological rock properties, fluid characteristics, and primary drive mechanism. Although no two reservoirs are identical in all aspects, they can be grouped according to the primary recovery mechanism by which they produce. It has been observed that each drive mechanism has certain typical performance characteristics in terms of :Ultimate recovery factor,Pressure decline rate, Gas-oil ratio, Water production. The recovery of oil by any of the natural drive mechanisms is called primary recovery.

The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as fluid injection) to supplement the natural energy of the reservoir

For a proper understanding of reservoir behaviour and predicting future performance, it is necessary to have knowledge of the driving mechanisms that control the behaviour of fluids within reservoirs. The overall performance of oil reservoirs is largely determined by the nature of the energy, i.e., driving mechanism, available for moving the oil to the well- bore. There are basically six driving mechanisms that provide the natural energy necessary for oil recovery:

Rock and liquid expansion drive, Depletion drive, Gas cap drive, Water drive, Gravity drainage drive, Combination drive.

1.2 METHODOLOGY

In this work the design of natural flow and artificial lift tubing strings for the whole life of a water drive reservoir will be carried out using data based on synthetic reservoir performance based on a material balance. The effects of reservoir properties on the life of the well will also be investigated.

Constraints such as maximum production, maximum drawdown, limitations on surface facilities capacities, as well as available gas lift and horsepower will be imposed. The production conditions for natural flow, continuous gas lift, and an ESP for later phases of the reservoir will be design and simulated along time by imposing either a constant flow rate or a constant bottom hole flowing pressure. A forecast of the production of oil and gas as well as the time where tubing strings should be replaced as a function of both the cummulative production and time will be presented.

1.3 OBJECTIVES AND SCOPE OF THE WORK

The main objectives of this study include:

- To design natural flow and artificial lift tubing strings for the whole life of a well.

- To design and simulate along time the production conditions for natural flow, continuous lift and ESP for the later phases of the reservoir by imposing either a constant flowrate or a constant bottom hole flowing pressure.

- To present a forecast of the production of oil and gas as well as the time where tubing strings should be replaced as a function of both the cumulative production and time.

1.4 STUDY ORGANISATION

Chapter Two covers the literature review on material balance for all the driving mechanisms that is Water-drive reservoir, Gas-cap reservoir and Solution gas drive reservoir. It discusses the major material balance equation for the three drive mechanisms. It discusses the material balance equation for water drive reservoir, the equations from chapter three is used to develop an excel program to conduct material balance (average pressure versus cumulative production, GOR versus cumulative production, WC versus cumulative production, Productivity index versus cumulative production). Chapter 4 comes up with the natural flow design as well as the artificial lift tubing strings with respect to the set constraints. In summary, a forecast of the production and time when tubing strings should be replaced as a function of cumulative production is suggested Chapter Five covers the conclusions of the study and the recommendations.

Chapter 2

Literature Review

The Inflow Performance Relationship (IPR) describes the behaviour of a well's flowing pressure and production rate, which is an important tool in understanding the reservoir or well behaviour and quantifying the production rate. The IPR is often required for designing well completion, optimizing well production, nodal analysis calculations, and designing artificial lift. Different IPR correlations exist today in the petroleum industry with the most commonly used models being that of Vogel's and Fetkovich's (Mohammed et al, 2009).

2.1 RESERVOIR NATURAL DRIVE MECHANISMS

Natural drive mechanisms refers to the energy in the reservoir that allows the fluid to flow through the porous network and into the wells. In its simplest definition, reservoir energy is always related to some kind of expansion (Cosentino et al, 2001). For a proper understanding of reservoir behaviour and predicting future performance, it is necessary to have knowledge of the driving mechanisms that control the behaviour of fluids within reservoirs. Several types of expansions take place inside and outside the reservoir, as a consequence of fluid withdrawals. Inside the reservoir, the expansion of hydrocarbons, connate water and the rock itself provides energy for the fluid to flow. Outside the producing zone, the expansion of a gas cap and/or of an aquifer may also supply a significant amount energy to the reservoir. In this case, the expansion of an external phase causes its influx into the reservoir and will ultimately result in a displacement process (Cosentino et al, 2001). There are basically six driving mechanisms that provide the natural energy necessary for oil recovery:

- Rock and liquid expansion drive
- Depletion drive
- Gas cap drive
- Water drive
- Gravity drainage drive
- Combination drive

The figures below compares various characteristics of the drive mechanisms.

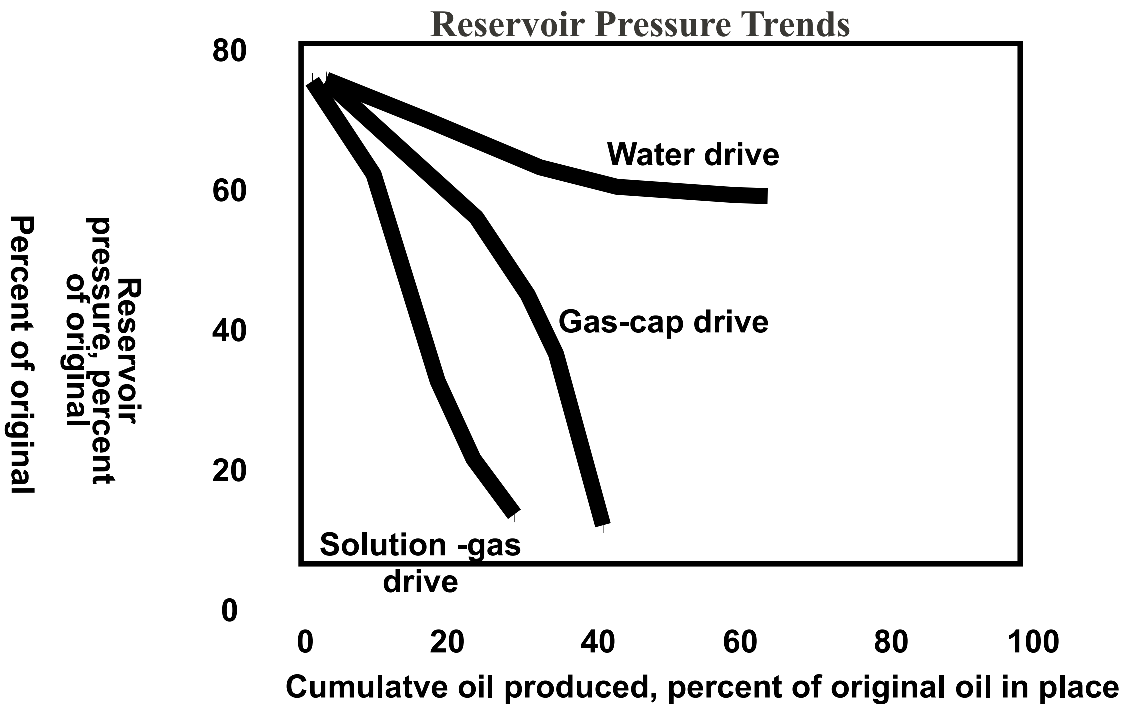


Fig. 2.1 Typical Pressure Trends of some Drive Mechanisms

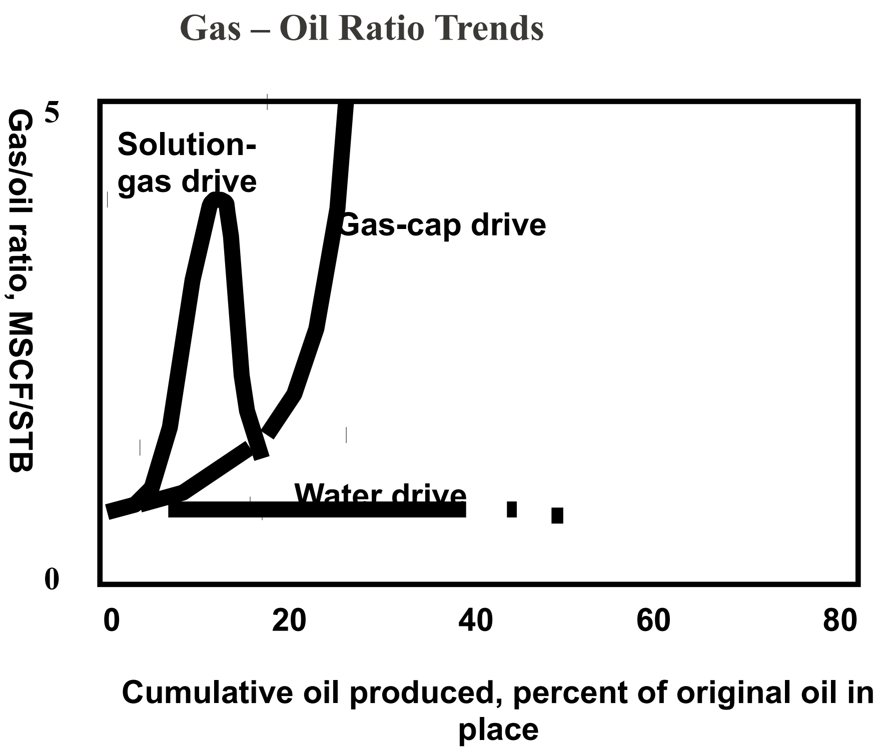


Fig. 2.2 Typical Gas – Oil Ratio Tends of Some Drive Mechanisms

The attention of this project is on the Depletion drive mechanism also known as the solution gas drive mechanism which is reviewed as follows.

2.2 SOLUTION – GAS DRIVE RESERVOIR

This driving form may also be referred to by the following various terms: Solution gas drive, Dissolved gas drive or Internal gas drive. A solution gas drive reservoir is one in which the principal drive mechanism is the expansion of the oil and its originally dissolved gas. The increase in fluid volumes during the process is equivalent to the production (Dake, 1978). A solution – gas drive reservoir is mostly closed from any outside source of energy, such as water encroachment. Its pressure is initially above bubble-point pressure, and, therefore, no free gas exists. The only source of material to replace the produced fluids is the expansion of the fluids remaining in the reservoir (Beggs, 2003). Some small but usually negligible expansion of the connate water and rock may also occur.

When the reservoir falls below the saturation pressure, gas is liberated from the hydrocarbon liquid phase. Expansion of the gas phase contributes to the displacement of the residual liquid phase. Initially the liberated gas will expand but not flow, until its saturation reaches a threshold value, called critical gas saturation (Cosentino et al, 2001). Typical values of the critical saturation ranges between 2 and 10% (Cosentino et al, 2001). When this value is reached, gas starts to flow with a velocity proportional to its saturation. The more the pressure drops, the faster the gas is liberated and produced, thus lowering further the pressure, in a sort of chain reaction that quickly leads to the depletion of the reservoir (Cosentino et al, 2001).

At the surface, solution gas drive reservoirs are characterised in general by rapidly increasing in Gas – Oil Ratios (GORs) and decreasing oil rates. Generally no or little water is produced. The ideal behaviour of a field under solution gas drive is depletion is illustrated in fig. 2.3. The GOR curve has a peculiar shape, in that it tends to remain constant and equal to the initial Rsi while the reservoir pressure is below the bubble point, then it tends to decline slightly until the critical gas saturation is reached. This decline corresponds to the existence of some gas in the reservoir, that cannot be mobilized (Cosentino et al., 2001). After the critical saturation is reached, the GOR increases rapidly and finally declines towards the end of the field life, when the reservoir approaches the depletion pressure.

The most important parameter in solution – gas drive reservoirs is gas – oil relative permeability (Cosentino et al., 2001). Actually, the increase in the GOR curve is related to the increased gas permeability with respect to oil, as its saturation increases. The lower the critical gas saturation, the more rapidly the gas will be mobilised and produced, thus accelerating the depletion and impairing the final recovery (Cosentino et al., 2001).

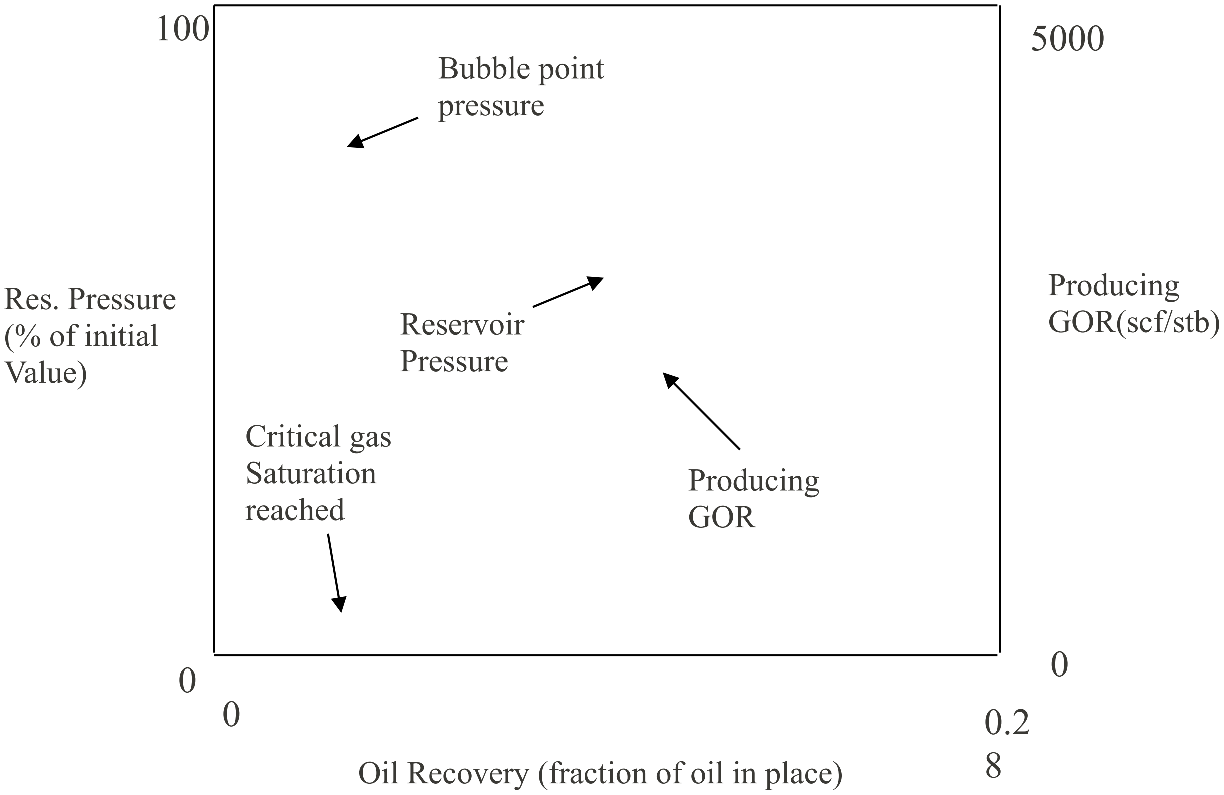


Fig. 2.3 Ideal production behaviour of a solution gas drive reservoir

2.3 Material Balance for some Drive Mechanisms

Material balance has long been regarded as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance (Dake, 2001). In the most elementary form the material balance equation states that the initial volume in place equals the sum of the volume remaining and the volume produced (Lyons, 1996). The zero dimensional material balance is derived and subsequently applied in this report, using mainly the interpretative technique of Havlena and Odeh, to gain an understanding of reservoir drive mechanisms under primary recovery conditions (Dake, 2001).

$$N_p\left(B_o+\left(R_p-R_s\right)B_g\right)=NB_{oi}\left[\frac{\left(B_o-B_{oi}\right)+\left(R_{si}-R_s\right)B_g}{B_{oi}}+m\left(\frac{B_g}{B_{gi}}-1\right)+\left(1+m\right)\left(\frac{C_w S_{wc}+C_f}{1-S_{wc}}\right)\Delta p\right] \quad 2.1$$
$$+\left(W_e-W_p\right)B_w$$

2.3.1 Material Balance for Solution – Gas Drive Reservoirs

A schematic representation of material balance equations for solution gas reservoirs, when the change in pore volume is negligible is shown in fig 2.2 (Lyons, 1996). Above the bubble point, the drive energy is due to the expansion of the undersaturated, single phase oil, the connate water expansion and the pore compaction, while below, the complex solution gas drive process is activated once gas has been liberated from the oil (Dake, 2001).

	Oil		Oil	Free Gas
For $P > P_b$	$N B_{oi}$	=	$(N - N_p) B_o$	
	P_i		$P_i > P > P_b$	
	Oil		Oil	Free Gas
For $P < P_b$	$N B_{oi}$	=	$(N - N_p) B_o$	$[NR_{si} - (N - N_p)R_s - G_p]B_g$
	P_i		$P_i < P_b$	

Fig. 2.4 Schematic of material balance equations for a solution – gas drive reservoir (Lyon, 1996)

A solution gas drive reservoir is one in which the principal drive mechanism is the expansion of the oil and its originally dissolved gas. The increase in fluid volumes during the process is equivalent to the production (Dake, 2001). Two main phases are identified. These are depletion above the bubble point and depletion below the bubble point.

Depletion above bubble point (Undersaturated)

For a solution gas drive reservoir it is assumed that there is no initial gas cap, thus m = 0, and that the aquifer is relatively small in volume and the water influx is negligible. Furthermore, above the bubble point, Rs = Rsi = Rp, since all the gas produced at the surface must have been dissolved in the oil in the reservoir (Dake, 2001). Under these assumptions, the material balance equation (2.1) becomes:

$$N_p B_o = N B_{oi} \left(\frac{(B_o - B_{oi})}{B_{oi}} + \frac{(c_w S_{wc} + c_f)}{1 - S_{wc}} \Delta p \right) \qquad 2.2$$

The component describing the reduction in the hydrocarbon pore volume, due to the expansion of the connate water and reduction in pore volume cannot be neglected for an undersaturated oil reservoir since the compressibilities c_w and c_f are generally of the same order of magnitude as the compressibility of the oil (Dake, 2001) where the oil compressibility is given by:

$$c_o = \frac{(B_o - B_{oi})}{B_{oi}\Delta p} \qquad 2.3$$

Substituting eqn. (2.3) into eqn. (2.2) gives

$$N_p B_o = NB_{oi}\left(c_o \frac{(c_w S_{wc} + c_f)}{1 - S_{wc}}\right)\Delta p \qquad 2.4$$

Since there are only two fluids in the reservoir, that is , oil and water, then the sum of the fluid saturations must be 100% of the pore volume, or

$$S_o + S_{wc} = 1 \qquad 2.5$$

and substituting eqn. (2.5) into eqn. (2.4) gives the reduced form of the material balance as

$$N_p B_o = NB_{oi}\left(\frac{(c_o S_o + c_w S_{wc} + c_f)}{1 - S_{wc}}\right)\Delta p \qquad 2.6$$

or $$N_p B_o = NB_{oi} c_o \Delta p \qquad 2.7$$

where

$$c_o = \frac{1}{1 - S_{wc}}(c_o S_o + c_w S_{wc} + c_f)$$

is the effective, saturation – weighted compressibility of the reservoir system.

Depletion below bubble point (Saturated oil)

For a solution gas drive reservoir, below the bubble point, the following are assumed:

- m = 0; no initial gas cap
- negligible water influx
- the term $NB_{oi}\left(\frac{\left(c_w S_{wc}+c_f\right)}{1-S_{wc}}\right)\Delta p$ is negligible once a significant free gas saturation develops in the reservoir.

Under these conditions the material balance equation can be simplified as

$$N_p\left(B_o+\left(R_p-R_s\right)B_g\right)=N\left(\left(B_o-B_{oi}\right)+\left(R_{si}-R_s\right)B_g\right) \qquad 2.8$$

2.3.2 Gas Cap Drive

For a reservoir in which gas cap drive is the predominant mechanism it is still assumed that the natural water influx is negligible ($W_e = 0$) and, in the presence of so much high compressibility gas, that the effect of water and pore compressibilities is also negligible (Dake, 2001). Under these circumstances, the material balance eqn. (2.1), can be written as

$$N_p\left(B_o+\left(R_p-R_s\right)B_g\right)=NB_{oi}\left[\frac{\left(B_o-B_{oi}\right)+\left(R_{si}-R_s\right)B_g}{B_{oi}}+m\left(\frac{B_g}{B_{gi}}-1\right)\right] \qquad 2.9$$

Using the technique of Havlena and Odeh with negligible water influx, the material balance equation can be reduced to the form

$$F=N\left(E_o+mE_g\right) \qquad 2.10$$

2.3.3 Water Drive

A drop in the reservoir pressure, due to the production of fluids, causes the aquifer water to expand and flow into the reservoir. Applying compressibility definition to the aquifer, then

Water Influx $=$ Aquifer Compressibility $\times$ Initial Volume of Water $\times$ Pressure Drop

or

$$W_e = \left(c_w + c_f\right) W_i \Delta p \qquad 2.11$$

Using the technique of Havlena and Odeh (assuming that B_w = 1), the full material balance can be expressed as

$$F = N\left(E_o + mE_g + E_{f,w}\right) + W_e \qquad 2.12$$

If the reservoir has no initial gas cap and coupled with the fact that water and pore compressibilities are small and also the water influx helps to maintain the reservoir pressure (making Δp appearing in the $E_{f,w}$ term reduced), eqn. (2.12) reduces to

$$F = NE_o + W_e \qquad 2.13$$

2.4 Predicting Primary Recovery in Solution – Gas Drive Reservoirs

Several methods for predicting performance of solution-gas behavior relating pressure decline to gas-oil ratio and oil recovery have appeared in literature (Lyons, 1996). These methods include Tracy's method, Tarner's method and Muskat's method. The following assumptions are generally made: uniformity of the reservoir at all times regarding porosity, fluid saturations, and relative permeabilities; uniform pressure throughout the reservoir in both the gas and oil zones (which means the gas and oil volume factors, the gas and oil viscosities, and the solution gas will be the same throughout the reservoir); negligible gravity segregation forces; equilibrium at all times between the gas and the oil phases; a gas liberation mechanism which is the same as that used to determine the fluid properties, and no water encroachment and negligible water production (Lyons, 1996).

2.4.1 Tracy's Method

Neglecting the formation and water compressibilities as well as any form of injection, the general material balance equation as expressed by eqn. 2.1 can be reduced to (Tarek, 2001)

$$N=\frac{N_p B_o+\left(G_p-N_p R_s\right)B_g-\left(W_e-W_p B_w\right)}{\left(B_o-B_{oi}\right)+\left(R_{si}-R_s\right)B_g+mB_{oi}\left[\frac{B_g}{B_{gi}}-1\right]} \qquad 2.14$$

where $G_p=R_p N_p$

Tracy (1955) suggested that the above relationship can be rearranged into a more usable form as:

$$N=N_p\Phi_o+G_p\Phi_g+\left(W_p B_w-W_e\right)\Phi_w \qquad 2.15$$

where ϕ_o, ϕ_g and ϕ_w are considered PVT related properties that are functions of pressure and defined by:

$$\Phi_o=\frac{B_o-R_s B_g}{Den} \qquad 2.16$$

$$\Phi_g=\frac{B_g}{Den} \qquad 2.17$$

$$\Phi_w=\frac{1}{Den} \qquad 2.18$$

with

$$Den=\left(B_o-B_{oi}\right)+\left(R_{si}-R_s\right)B_g+mB_{oi}\left[\frac{B_g}{B_{gi}}-1\right] \qquad 2.19$$

Figure 2.5 gives a graphical presentation of the behavior of Tracy's PVT functions with changing pressure (Tarek, 2001).

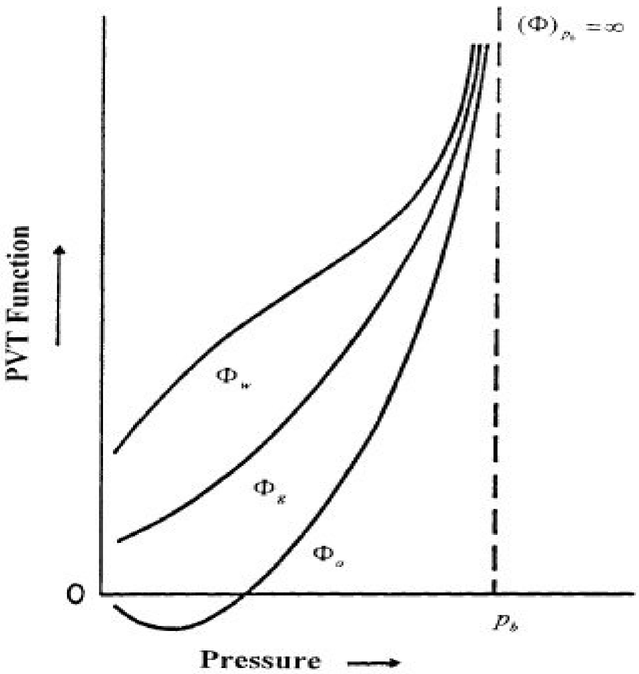


Fig. 2.5 Tracy's PVT functions
(Tarek, 2001)

For a solution gas drive reservoir, equations (2.15) and (2.19) reduce to the following equations respectively:

$$N=N_p\Phi_o+G_p\Phi_g \qquad 2.20$$

and

$$Den=\left(B_o-B_{oi}\right)+\left(R_{si}-R_s\right)B_g \qquad 2.21$$

Tracy's calculations are performed in series of pressure drops that proceed from known reservoir condition at the previous reservoir pressure p* to the new assumed lower pressure p. The calculated results at the new reservoir pressure become "known" at the next assumed lower pressure.

Application of the Tracy's method in prediction primary recovery in water drive reservoir is further developed in chapter 3.

2.4.2 Tarner's Method

This is a trial and error procedure based on the simultaneous solution of the material balance equation and the instantaneous gas-oil ratio equation (Lyons, 1996). For a pressure drop from p_1 to p_2, the procedure involves a stepwise calculation of cumulative oil produced $(Np)_2$ and of cumulative gas produced $(Gp)_2$. The stepwise procedure as enumerated in Lyons, 1996 is as follows:

- During the pressure drop from p_1 to p_2, assume that the cumulative oil production increases from $(Np)_1$ to $(Np)_2$. At the bubble point pressure, Np should be set equal to zero.
- By means of the material-balance equation for $W_p = 0$, compute the cumulative gas produced $(GP)_2$ at pressure p_2 as:

$$(G_p)_2=(N_p)_2(R_p)_2=N\left[(R_{si}-R_s)-\frac{B_{oi}-B_o}{B_g}\right]-(N_p)_2\left(\frac{B_o}{B_g}-R_s\right) \qquad 2.22$$

- Compute the fractional total liquid saturation $(S_L)_2$ at pressure p_2 as:

$$(S_L)_2=S_w+(1-S_w)\frac{B_o}{B_{oi}}\left[1-\frac{(N_p)_2}{N}\right] \qquad 2.23$$

- Determine the k_{rg}/k_{ro} ratio corresponding to the total liquid saturation $(S_L)_2$ and compute the instantaneous gas – oil ratio at p_2 as:

$$R_2=R_s+\left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{\mu_o B_o}{\mu_g B_g}\right) \qquad 2.24$$

- Compute the cumulative gas produced at pressure p_2 as:

$$(G_p)_2=(G_p)_1+\frac{R_1+R_2}{2}\left[(N_p)_2-(N_p)_1\right] \qquad 2.25$$

where R_1 is the instantaneous gas – oil ratio computed at pressure p_1.

2.4.3 Muskat's Method

Muskat expresses the material balance in terms of finite pressure differences in small increments.

The changes in variables that affect production are evaluated at any stage of depletion or pressure (Lyons, 1996). Assumption is made that values of the variables will hold for a small drop in pressure, and the incremental recovery can be calculated for the small pressure drop (Lyons, 1996). Knowing PVT data and the gas- oil relative permeabilities at any liquid saturation, the unit recovery by pressure depletion can be computed from a differential form of the material balance equation as:

$$\frac{dS_o}{dp} = \frac{\frac{S_o B_g}{B_o}\frac{dR_s}{dp} + \frac{S_o}{B_o}\frac{k_{rg}\mu_o}{k_{ro}\mu_g}\frac{dB_o}{dp} + \left(1 - S_o - S_w\right) B_g \frac{d\left(1B_g\right)}{dp}}{1 + \frac{k_{rg}\mu_o}{k_{ro}\mu_g}} \qquad 2.26$$

From the change in saturation at any pressure, the reservoir saturation at that time can be related to the change in oil production and the instantaneous gas – oil ratio (Lyons, 1996).

Using ($\Delta S_o/\Delta p$) which is mostly the average, the oil saturation S_o is computed as:

$$S_o = S_o - \left(p - p\right)\left(\frac{\Delta S_o}{\Delta p}\right)_{avg} \qquad 2.27$$

The cumulative oil production is then calculated as:

$$N_p = N\left[1 - \left(\frac{B_{oi}}{B_o}\right)\left(\frac{S_o}{1 - S_{wi}}\right)\right] \qquad 2.28$$

And the cumulative gas production is computed as:

$$G_p = G_p + \Delta G_p \qquad 2.29$$

where $\Delta G_p = \left(GOR\right)_{avg} \Delta N_p$ 2.30

2.5 Artificial Lift Methods

Most oil reservoirs are of the volumetric type where the driving mechanism is the expansion of solution gas when reservoir pressure declines because of fluid production. Oil reservoirs will eventually not be able to produce fluids at economical rates unless natural driving mechanisms (e.g., aquifer and/or gas cap) or pressure maintenance mechanisms (e.g., water flooding or gas injection) are present to maintain reservoir energy (Boyun et al., 2007). When reservoir pressure is insufficient to sustain the flow of oil to the surface at adequate rates, natural flow must be aided by artificial lift. There are two basic forms of artificial lift: continuous gas lift and bottomhole pumping (Golan and Whitson, 1995). Both methods supplement the natural drive energy of the reservoir and increase the flow by reducing backpressure at the wellbore caused by flowing fluids in the tubing (Golan and Whitson, 1995). Approximately 50% of wells worldwide need artificial lift systems (Boyun et al., 2007). The commonly used artificial lift methods include the following:

- Sucker rod pumping
- Continuous Gas lift
- Intermittent Gas Lift
- Electrical submersible pumping
- Hydraulic piston pumping
- Hydraulic jet pumping
- Plunger lift
- Progressing cavity pumping

In naturally flowing wells, the well flowrate capacity is usually higher than the recommended or desired flowrate and the well production is controlled by the use of a choke . There are some naturally flowing wells that although able to produce steadily the desired flowrate, can not start production without some help. Those wells need a kick-off operation after a shut down in order to produce a steady flowrate. In this case an artificial lift method can be used whenever necessary to kick-off the well (Prado, 2008).

In certain cases, the bottom hole flowing pressure may be sufficient only to produce the well at flowrates smaller than the recommended or desired flowrate. In some cases the bottom hole flowing pressure may not be capable to produce any flowrate at all and the well is called a dead well. In those two cases artificial lift methods can be used to achieve the recommended flowrate (Prado, 2008).

And finally there are conditions when the bottom hole flowing pressure is able to produce the fluids to the surface but the production is unsteady. In those cases artificial lift methods can be used to stabilize the well (Prado, 2008).

Artificial lift is the area of petroleum engineering related to the use of technologies to promote an increase in the production rate of flowing oil or gas wells, to put wells back into

production or to stabilize production by using an external horsepower source. The external source helps the bottom hole flowing pressure to overcome the pressure drops in the system downstream of the perforations or to use methods that reduce the pressure drop in the production system by improving the multiphase flow conditions in the well . In any case either energy or products will be consumed at the surface (costs) to obtain higher flowrates from the well (income). The main purpose of artificial lift is to increase the profit of the operation (Prado, 2008).

2.5.1 Gas Lift

Gas lift technology increases oil production rate by injection of compressed gas into the lower section of tubing through the casing–tubing annulus and an orifice installed in the tubing string (Boyun et al., 2007). Upon entering the tubing, the compressed gas affects liquid flow in two ways: (a) the energy of expansion propels (pushes) the oil to the surface and (b) the gas aerates the oil so that the effective density of the fluid is less and, thus, easier to get to the surface (Boyun et al., 2007). Gas lift technology is a simple and flexible method seen as an extension of natural flow. It mostly requires a source of high pressure gas and casing and lines must withstand injection pressure (Prado, 2008).

A continuous gas lift operation is a steady-state flow of the aerated fluid from the bottom (or near bottom) of the well to the surface. Intermittent gas lift operation is characterized by a start-and-stop flow from the bottom (or near bottom) of the well to the surface. This is unsteady state flow (Boyun et al., 2007). In continuous gas lift, a small volume of high-pressure gas is introduced into the tubing to aerate or lighten the fluid column. This allows the flowing bottom-hole pressure with the aid of the expanding injection gas to deliver liquid to the surface. To accomplish this efficiently, it is desirable to design a system that will permit injection through a single valve at the greatest depth possible with the available injection pressure (Boyun et al., 2007). The type of gas lift operation used, continuous or intermittent, is also governed by the volume of fluids to be produced, the available lift gas as to both volume and pressure, and the well reservoir's conditions such as the case when the high instantaneous BHP drawdown encountered with intermittent flow would cause excessive sand production, or coning, and/or gas into the wellbore (Boyun et al., 2007). A complete gas lift system consists of a gas compression station, a gas injection manifold with injection chokes and time cycle surface controllers, a tubing string with installations of unloading valves and operating valve, and a down-hole chamber.

Gas Lift with Velocity Strings

Velocity strings are a commonly applied remedy to liquid loading in gas wells. By installing a small diameter string inside the tubing, the flow area is reduced which increases the velocity and restores liquid transport to surface. The disadvantage of the velocity string is the increase in frictional pressure drop, constraining production. Hence an optimal velocity string has to be selected such that liquid loading is delayed over a long period with a minimal impact on production. This requires accurate methods to predict pressure drop in the velocity string as well as tubing-velocity string annulus (Oudeman, 2007).

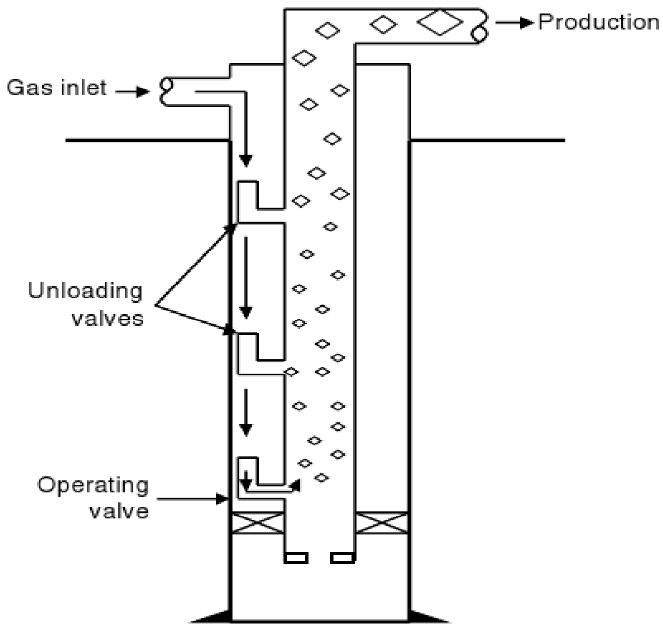


Fig. 2.5 Configuration of a typical gas lift well

2.5.2 Bottomhole Pumping

Bottomhole pumping provides mechanical energy to lift oil from bottom hole to surface. It raises the pressure in a liquid by transforming mechanical work into potential energy, that is, pressure. Liquid enters the pump at a given pressure, called discharge pressure. Pump pressure usually refers to the difference between the discharge and the suction pressures

(Golan and Whitson, 1995). Pump pressure corresponds to the gain in potential energy of the liquid. This gain represents only a fraction of the total work used to drive a pump. It is efficient, simple, and easy for field people to operate. It can pump a well down to very low pressure to maximize oil production rate (Boyun et al., 2007). The efficiency of a pump depends on how efficiently it can transform the driving forces into fluid potential energy (Golan and Whitson, 1995).

Pumps are generally classified according to the physical principle used to transform driving forces into pressure (Golan and Whitson, 1995). The main classes of conventional pumps are: positive – displacement and dynamic – displacement pumps. Positive – displacement pumps develop pressure by moving a piston or cam to reduce the volume of a compression chamber. This compression raises the pressure of liquid in the chamber (Golan and Whitson, 1995). Dynamic – displacement pumps develop pressure by a sequence of accelerations and decelerations of the pumped liquid (Golan and Whitson, 1995).

Positive – Displacement Pumps

1. *Sucker Rod Pump: a positive* – displacement pump that compresses liquid by the reciprocating motion of a piston. The piston is actuated by a string of sucker rods that extend from the bottomhole pump to the pumping unit at the surface (Golan and Whitson, 1995).

2. *Reciprocating Hydraulic Pump: a positive* – displacement pump with a reciprocating piston. The piston is actuated by a reciprocating hydraulic motor coupled and assembled with the pump. The downhole motor is driven by a power fluid injected at high pressure from the surface (Golan and Whitson, 1995).

Centrifugal submersible pump and jet pump are examples of dynamic – displacement pumps.

Chapter 3
Material Balance For Predicting The Primary Recovery

Tracy's calculations are performed in series of pressure drops that proceed from known reservoir condition at the previous reservoir pressure p* to the new assumed lower pressure p. The calculated results at the new reservoir pressure become "known" at the next assumed lower pressure.
In progressing from the conditions at any pressure p* to the lower reservoir pressure p, consider that the incremental oil and gas production are ΔNp and ΔGp, or:

$$N_p = N_p + \Delta N_p \tag{3.1}$$

$$G_p = G_p + \Delta G_p \tag{3.2}$$

where N_p, G_p = " known " cumulative oil and gas production at previous pressure level p*
N_p, G_p = " unknown " cumulative oil and gas production at new pressure level p

Replacing Np and Gp in Equation 2.20 with those of Equations 3.1 and 3.2 gives:

$$N = \left(N_p + \Delta N_p\right)\Phi_o + \left(G_p + \Delta G_p\right)\Phi_g \tag{3.3}$$

Define the average instantaneous GOR between the two pressure p* and p by:

$$\left(GOR\right)_{avg} = \frac{GOR + GOR}{2} \tag{3.4}$$

The incremental cumulative gas production ΔGp can be approximated by :

$$\Delta G_p = \left(GOR\right)_{avg} \Delta N_p \tag{3.5}$$

Replacing ΔGp in Equation 3.3 with that of 3.4 gives:

$$N = \left[N_p + \Delta N_p\right]\Phi_o + \left[G_p + \Delta N_p \left(GOR\right)_{avg}\right]\Phi_g \tag{3.6}$$

If Equation 3.6 is expressed for N = 1, the cumulative oil production Np and cumulative gas production Gp become fractions of initial oil in place. Rearranging Equation 3.6 gives:

$$\Delta N_p = \frac{1-\left(N_p \Phi_o + G_p \Phi_g\right)}{\Phi_o + \left(GOR\right)_{avg} \Phi_g} \qquad 3.7$$

Equation 12-44 shows that there are essentially two unknowns, the incremental cumulative oil production ΔNP and the average gas oil ratio (GOR)avg.

3.1 Tracy's Method

Tracy suggested the following alternative technique for solving Equation 3.7.

Step 1. From the list of given pressure data select an average reservoir pressure p.

Step 2. Calculate the values of the PVT functions Φo and Φg from equation 2.16

Step 3. Estimate the GOR at reservoir pressure P

Step 4. Calculate the average instantaneous GOR (GOR)avg = (GOR* + GOR)/2.
Where GOR * is instantaneous GOR

Step 5. Calculate the incremental cumulative oil production ΔNp from Equation 3.7 as:

$$\Delta N_p = \frac{1-\left(N_p \Phi_o + G_p \Phi_g\right)}{\Phi_o + \left(GOR\right)_{avg} \Phi_g}$$

Step 6. Calculate cumulative oil production Np:

$$N_p = N_p + \Delta N_p \qquad 3.8$$

Step 7. Calculate the oil and gas saturations at selected average reservoir pressure by using :

$$S_o = \left(1 - S_{wi}\right)\left(1 - N_p / N\right)\left(B_o / B_{oi}\right) \qquad 3.9$$

$$S_g = 1 - S_o - S_{wi} \qquad 3.10$$

Also using Oil saturation adjustment for water influx ,t he proposed oil saturation adjustment methodology is illustrated is described by the following steps:

Step 7a. Calculate the pore volume in the water-invaded region, as:

$$W_e - W_p B_w = (P.V)_{water}(1 - S_{wi} - S_{sor}) \qquad 3.11$$

Solving for the pore volume of water-invaded zone (P.V)water gives:

$$(P.V)_{water} = \frac{W_e - W_p B_w}{1 - S_{wi} - S_{orw}} \qquad 3.12$$

where (P.V)water = pore volume in water-invaded zone, bbl

Sorw = residual oil saturated in the imbibition water-oil system.

Step 7b. Calculate oil volume in the water-invaded zone, or:

volume of oil = (P.V)water Sorw 3.13

Step 7c. Adjust Equation 3.8 to account for the trapped oil by using Equations 3.12 and 3.13:

$$S_o = \frac{(N - N_p B)B_o - \left[\frac{W_e - W_p B_w}{1 - S_{wi} - S_{orw}}\right] S_{orw}}{\left(\frac{NB_{oi}}{1 - s_{wi}}\right) - \left[\frac{W_e - W_p B_w}{1 - S_{wi} - S_{orw}}\right]} \qquad 3.14$$

Step 8. Obtain relative permeability ratio krg/kro at Sg.

Step 9. Calculate the instantaneous GOR from Equation 3.14

$$GOR = R_s + (K_{rg}/K_{ro})(\mu_o B_o/\mu_g B_g) \qquad 3.15$$

Step 10. Compare the estimated GOR in Step 3 with the calculated GOR in Step 9. If the values are within acceptable tolerance, proceed to next step. If not within the tolerance, set the estimated GOR equal to the calculated GOR and repeat the calculations from Step 3.

Step 11. Calculate the cumulative gas production, from 3.16

$$G_p = G_p + \Delta N_p (GOR)_{avg} \qquad 3.16$$

Step 12. Since results of the calculations are based on 1 STB of oil initially in place, a final check on the accuracy of the prediction should be made on the MBE, or, from equation 3.17

$$\Delta N_p \Phi_o + G_p \Phi_g = 1 \pm tolerance \qquad 3.17$$

Step 13. Repeat from Step 1.

As the calculation progresses, a plot of GOR versus pressure can be maintained and extrapolated as an aid in estimating GOR at each new pressure.

This procedure is used in predicting the primary oil recovery using synthetic data from a solution gas drive reservoir for this project.

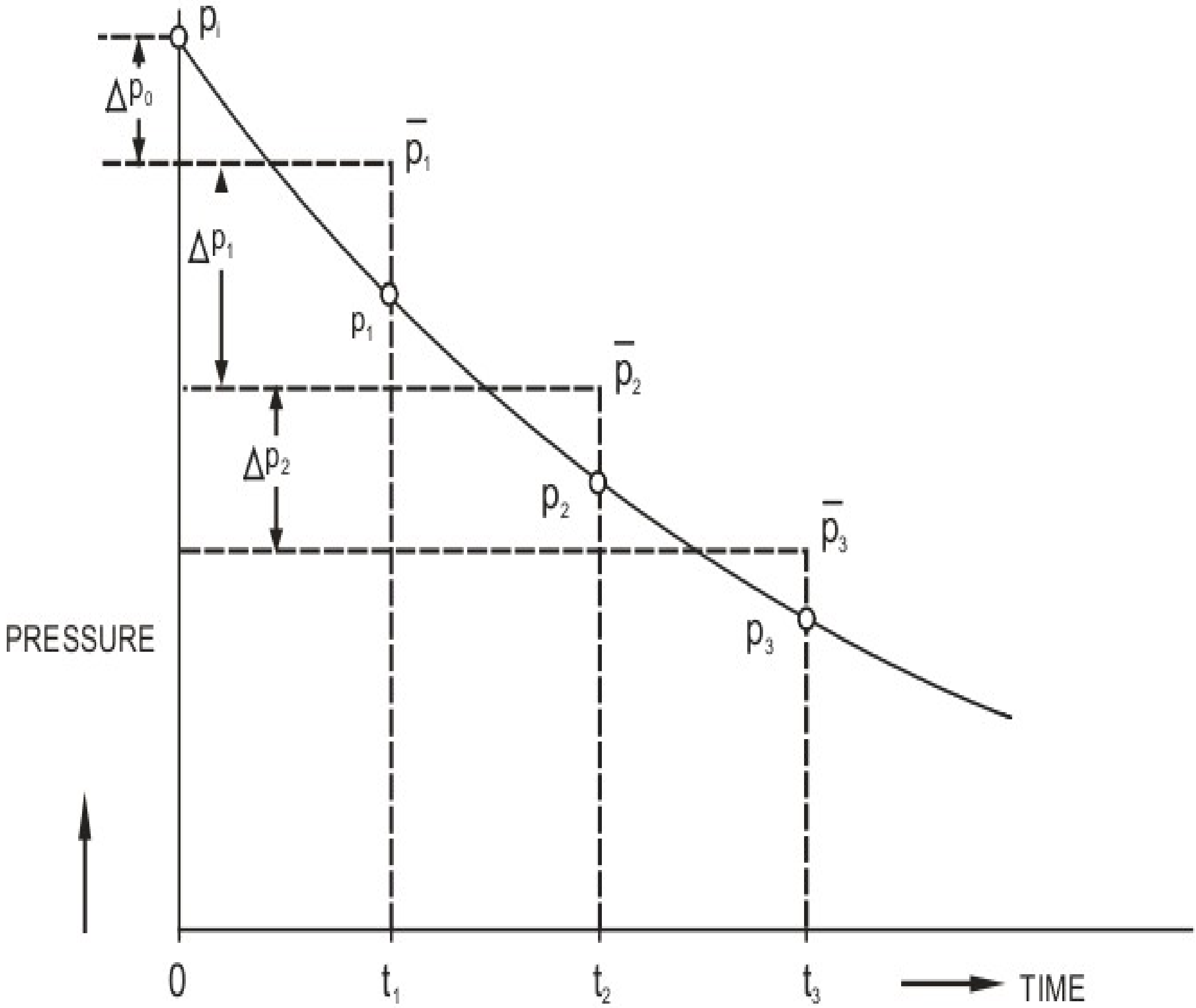
3.2 AQUIFER FITTING USING THE UNSTEADY STATE THEORY OF HURST AND VAN EVERDINGEN

The cumulative water influx into a reservoir, due to an instantaneous pressure drop applied at the outer boundary is expressed as:

$$W_e = U \Delta P W_D(t_D) \qquad 3.18$$

For the pressure drop between each step, Δp, the corresponding water influx can be calculated using equ. (3.15). Superposition of the separate influxes, with respect to time, will give the cumulative water influx.

The method of approximating the continuous pressure decline, by a series of pressure steps, is that suggested by van Everdingen, Timmerman and McMahon which is illustrated in Fig 3.1



(Dake ,1998)

Fig 3.1 : Matching a continuous pressure decline at the reservoir-aquifer boundary by a series of discrete pressure steps

Suppose that the observed reservoir pressures, which are assumed to be equal to the pressures at the original hydrocarbon-water contact, are pi, p1, p2, p3 .... etc., at times 0, t1, t2, t3 .... etc. Then the average pressure levels during the time intervals should be drawn in such a way that

$$\bar{P}_1 = \frac{P_i + P_1}{2} \tag{3.19}$$

$$\bar{P}_2=\frac{P_1+P_2}{2} \qquad 3.20$$

-
-
-

$$\bar{P}_j=\frac{P_{j-1}+P_2}{2} \qquad 3.21$$

The pressure drops occurring at times 0, t1, t2 . . . etc. are then

$$\Delta P_o=P_i-\bar{P}_2=\mathrm{P}_i-\frac{P_i+P_1}{2}=\frac{P_i-P_1}{2} \qquad 3.22$$

$$\Delta P_1=P_1-\bar{P}_2=\frac{P_i+P_1}{2}-\frac{P_1+P_2}{2}=\frac{P_i-P_2}{2} \qquad 3.23$$

$$\Delta P_2=P_2-\bar{P}_3=\frac{P_1+P_2}{2}-\frac{P_2+P_3}{2}=\frac{P_1-P_3}{2} \qquad 3.24$$

-
-
-

$$\Delta P_j=P_j-\bar{P}_{j+i}=\frac{P_{j-1}+P_j}{2}-\frac{P_j+P_{j+1}}{2}=\frac{P_{j-1}-P_{j+1}}{2} \qquad 3.25$$

Therefore, to calculate the cumulative water influx We at some arbitrary time T, which corresponds to the end of the nth time step, requires the superposition of solutions of type, equ. (3.15), to give

$$T_D - t_{D2} + \ldots \Delta P_j W_D (T_D - t_{Dj}) + \ldots \Delta P_{n-1} W_D$$
$$T_D - t_{D1} + \Delta P_2 W_D$$
$$\Delta P_o W_D (T_D) + \Delta P_1 W_D$$
$$W_e (T) = U \qquad 3.26$$

where Δpj is the pressure drop at time tj, given by equ. (4.17), and W D (TD - tDj) is the dimensionless cumulative water influx, obtained from figs. 9.3 - 9.7, for the dimensionless time TD - tDj during which the effect of the pressure drop is felt. Summing the terms in the latter equation gives

$$W_e (T) = U \sum \Delta P_j W_D (T_D - T_{Dj}) \qquad 3.27$$

Since annual time steps have been selected, the dimensionless time coefficient can most conveniently be expressed, with t in years and all other parameters in field units, as

$$t_D = \frac{2.309\, kt}{\Phi \mu c_t r_e^2} \qquad 3.28$$

$$r_D = \frac{r_a}{r_e} \qquad 3.29$$

$$c_t = c_w + c_f \qquad 3.30$$

$$f = \frac{encroachmentangle}{360^o} \qquad 3.31$$

$$U = 1.119\, f \Phi h c_t r_e^2 \qquad 3.32$$

3.3 Application of Tracy Method in Predicting Oil Recovery

Table 3.1 : Production Data

RESERVOIR PROPERTIES AND PRODUCTION DATA	
RESERVOIR PROPERTIES	
Initial pressure, psia	2740.00
Initial temperature, F	200.00
Bubble point pressure, psia	2730.00
OOIP, MMSTB	312.00
Rsi, scf/STB	650.00
Boi, RB/STB	1.40
Swi, %	0.05
Average porosity, %	0.25
Average permeability, md	200.00
Reservoir radius, ft	9200.00
Average thickness, ft	100.00
Water compressibility, psi^-1	4*10^(-6)
Rock compressibility, psi^-1	3*10^(-6)

PRODUCTION DATA

	P	Np	Rp	Rs	Bg	Bo
Year	(psia)	(MMSTB)	(scf/STB)	(scf/STB)	(RB/Mscf)	(RB/STB)
0	2740	0	0.0	650	0.00093	1.404
1	2500	7.88	760.0	592	0.00098	1.374
2	2290	18.42	845.0	545	0.00107	1.349
3	2109	29.15	920.5	507	0.00117	1.329
4	1949	40.69	975.1	471	0.00128	1.316
5	1818	50.14	1025.0	442	0.00139	1.303
6	1702	58.42	1065.0	418	0.00150	1.294
7	1608	65.39	1095.0	398	0.00160	1.287
8	1635	70.74	1120.0	383	0.00170	1.280
9	1480	74.54	1145.0	371	0.00176	1.276

(Dake , 1994)

Table 3.2 : Tracy Method in Predicting Oil Recovery Result

P	Rs	Bg	Bo	Φo	Φg	Φw	GOR Estimate	GOR avg	Δ Np	We
(psia)	(scf/STB)	(RB/Mscf)	(RB/STB)					scf/stb	MMSTB	(Mmrb)
2740	650	0.00093	1.404							0
2500	592	0.00098	1.374	29.57675112	0.0365	37.25782414	660	655	3.203281931	3.775
2290	545	0.00107	1.349	13.35396687	0.0187	17.43679163	720.264053009	687.6320265	17.34327667	12.848
2109	507	0.00117	1.329	7.971075723	0.0127	10.83306251	693.615180243	690.6236034	13.79569755	24.024
1949	471	0.00128	1.316	5.053287982	0.0091	7.0861678	1392.60016858	1041.611886	12.29890482	35.775
1818	442	0.00139	1.303	3.660535828	0.0074	5.3157559	3519.50807434	2280.55998	6.040499005	47.276
1720	418	0.00150	1.294	2.802521008	0.0063	4.201680672	7656.17579244	4968.367886	2.702779649	58.035
1608	398	0.00160	1.287	2.271837876	0.0056	3.494060098	14001.9565853	9485.162236	1.222965876	67.778
1535	383	0.00170	1.28	1.906335253	0.0052	3.031221582	23489.1424328	16487.15233	0.551504472	76.259
1480	371	0.00176	1.276	1.716174526	0.0048	2.754517409	37424.6970671	26955.9247	0.265431351	83.398

Table 3.3 : Tracy Method in Predicting Oil Recovery Result continues

Np1	Np/N	Sorw	So	Sg	Krg/Kro	Uo/Ug	Inst. GOR	Gp1	Tolerance	Δ Gp
MMSTB								MM scf		
0	0				0.00000	28.70588235	0	0		
3.203281931	0.012099359	0.857	0.926	0.024	0.00260	32.46987952	710.264053	2098.149665	171.3517139	2098.149665
20.5465586	0.041179487	0.840	0.857	0.093	0.00299	36.72839506	683.6151802	14023.94215	536.0278989	11925.79248
34.34225615	0.077	0.830	0.777	0.173	0.01851	41.64556962	1382.600169	23551.5765	572.2534937	9527.634352
46.64116097	0.114663462	0.820	0.665	0.285	0.06269	47.14285714	3509.508074	36362.26194	565.5076531	12810.68545
52.68165997	0.151525641	0.800	0.588	0.362	0.14374	53.46666667	7646.175792	50137.98224	563.307676	13775.72029
55.38443962	0.186009615	0.790	0.463	0.487	0.25900	60.75342466	13991.95659	63566.38585	555.8445378	13428.40361
56.6074055	0.217237179	0.770	0.458273847	0.492	0.41493	69.15492958	23479.14243	75166.41559	548.8204053	11600.02974
57.15890997	0.244419872	0.760	0.3542	0.596	0.62555	78.62318841	37414.69707	84259.15383	543.1579266	9092.738244
57.42434132	0.267301282	0.750	0.274204819	0.676	0.90894	89.47761194	59335.10017	91414.10135	541.7212428	7154.947519

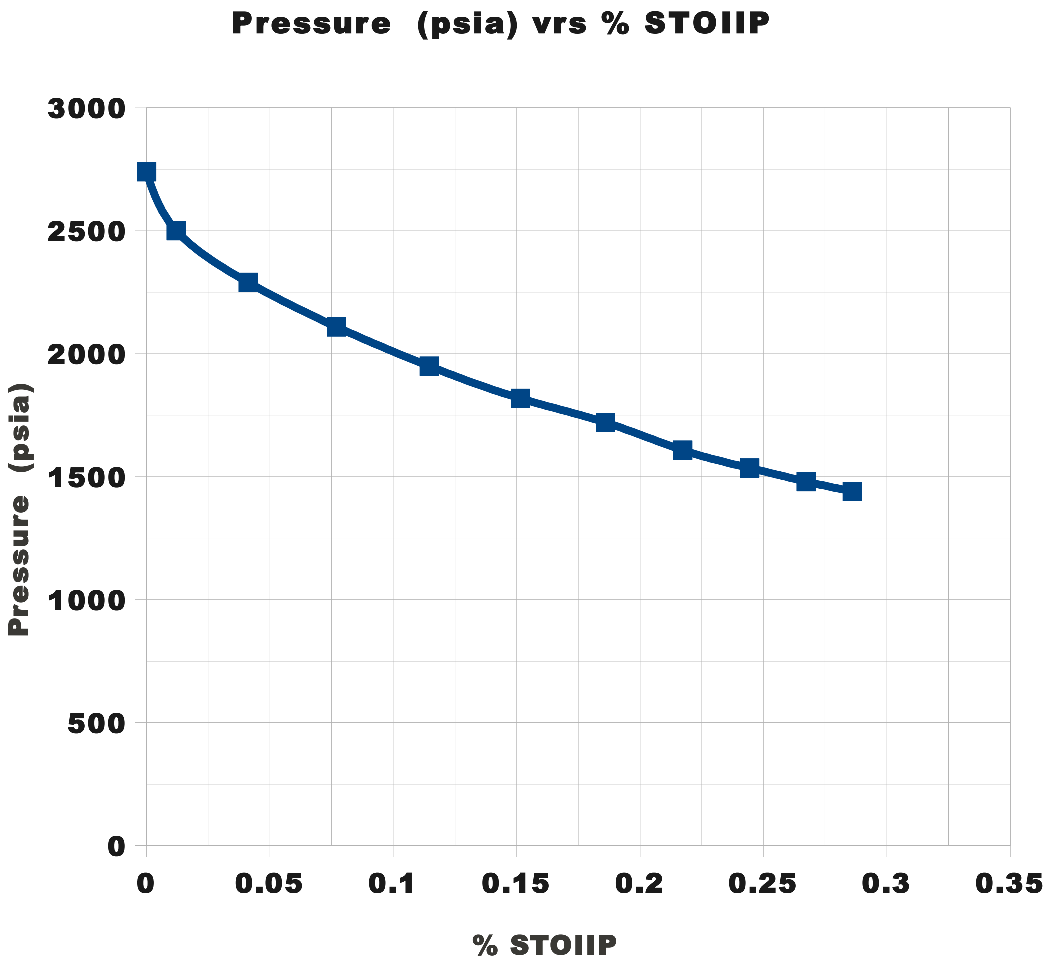


Figure 3.2: Pressure decline as a function of the oil recovery

It is observed from figure 3.2 that a recovery of about 29% STOIIP only could be obtained at a depletion pressure of 100 psi (abandonment).

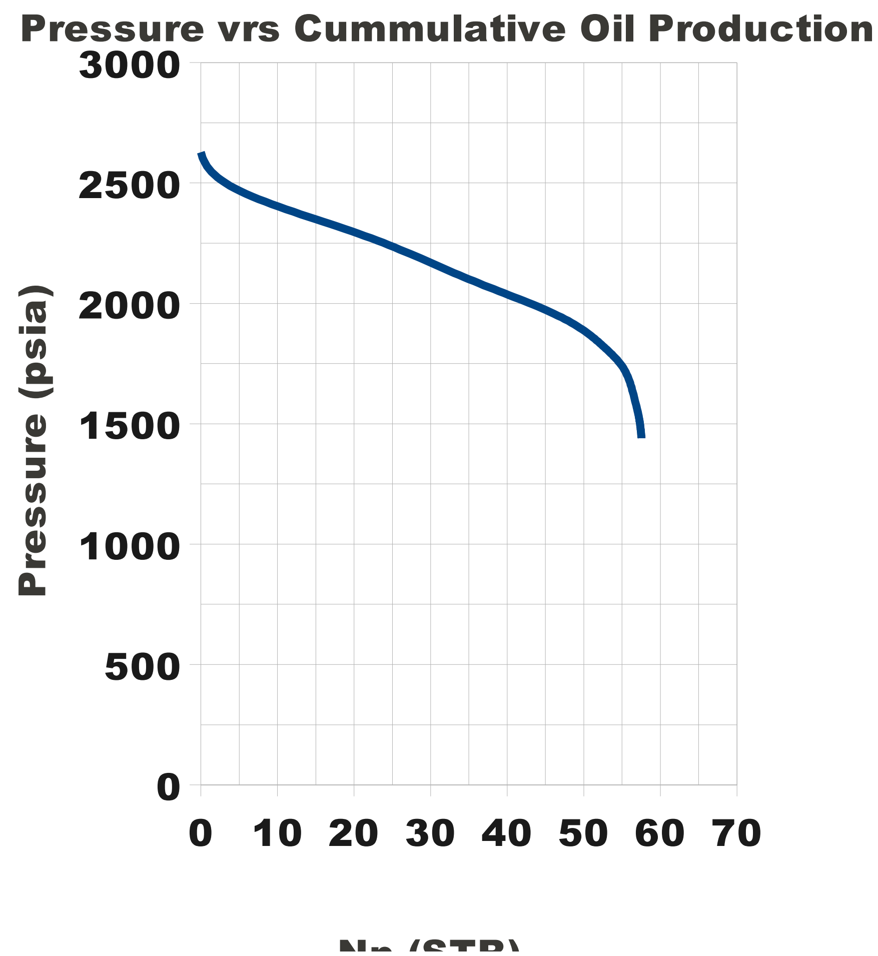


Figure 3.3: Pressure decline as a function cumulative oil production

Figure 3.3 exhibits similar behaviour as figure 3.6 with a cumulative oil production of about 57 MM STB at abandonment pressure.

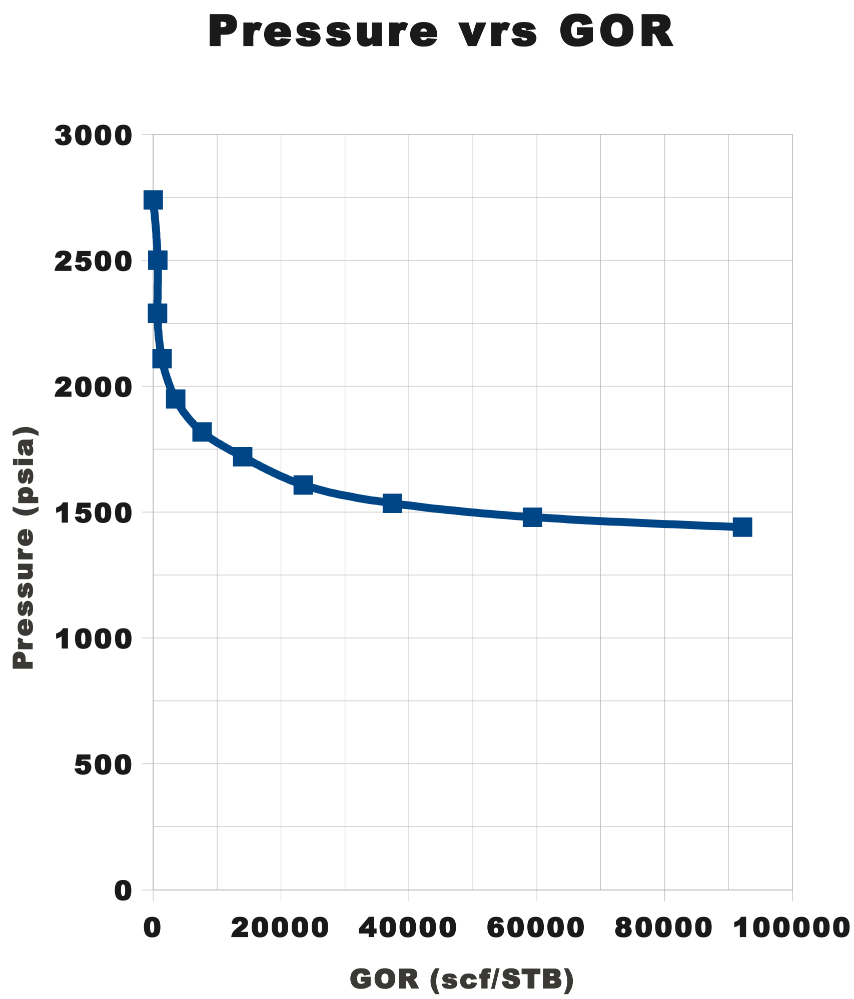


Figure 3.4: Pressure decline as a function of GOR

Chapter 4
Design of Artificial Lift and Tubing Strings

4.1 DESIGN PARAMETER

The following data is available for the oil well:

Average reservoir pressure = 2740 psi
Water Cut = 0%
Initial Gas – Liquid ratio (GLRi) = 721 scf/stb
J* = 1.5
API = 25
Specific gravity to gas = 0.7
Average Temperature = 170 °F
Reservoir depth = 7500 ft
Wellhead pressure = 150 psi
Inclination angle with Horizontal = 90o (vertical well)
Nominal tubing sizes of 1/2”, 1”, 1 1/2”, 2 3/8”, or 3 1⁄2” is employed in the design ofthe gas lift.

4.2 Under-saturated Inflow Performance Relationship (IPR)

The linear IPR is valid for single phase flow of fluids in the reservoir. It is not valid for compressible flow. An under-saturated reservoir is a reservoir that has an average reservoir pressure higher than the bubble point. Since the reservoir originally exists at its bubble point pressure, fluid flowing in the reservoir goes to multiphase conditions immediately at the start of production when the pressure is lower than the bubble point. As the pressure inside the reservoir goes below the bubble point value, gas comes out of solution reducing the oil saturation and relative permeability, and increasing oil viscosity. Also the formation volume factor is always greater than one due to the gas in solution (Prado, 2008). The oil productivity is reduced since now the driving force for fluid movement is spent moving the liquid and the gas phases (Prado, 2008). The constant productivity index (PI) concept is no longer valid. Since IPR under multiphase flow conditions can not be easily calculated, Fetkovich’s empirical correlation is employed to estimate the IPR.

4.3 Fetkovich' Correlation

Fetkovich's correlation is usually the one that is more conservative always under predicting flow capacity in comparison to the other IPR equations (Prado, 2008). Fetkovich is also a simpler equation which in some cases can simplify some of the calculations. Even being the most conservative of the IPRs, because it is not a model and just a correlation, it can over predict flow capacities for some reservoirs that are severely affected by the presence of free gas in the porous media. Fetkovich's correlation is given by equation 4.1 as:

$$\frac{q}{q_{max}} = 1 + b\left(\frac{P_{wf}}{\bar{P}}\right) - (1+b)\left(\frac{P_{wf}}{\bar{P}}\right) \qquad 4.1$$

where b=0

At the bubble point pressure (that is Pb = Pavg), the corresponding bubble point flowrate is given by equation 4.2 as:

$$q_b = J\left(P - P_b\right) \qquad 4.2$$

$$q_b = 1.5\left(2740 - 2740\right)$$

$$q_b = 0$$

The absolute open flow (AOF) or the maximum flowrate qmax is given by equation 4.3 as:

$$q_{max} = q_b + \frac{JP_b}{2+b} \qquad 4.3$$

$$q_{max} = 0 + \frac{1.5 * 2740}{2+0} = 2055\, bpd$$

Figure 4.1 shows the present IPR curve for the reservoir at its initial conditions using Fetkovich

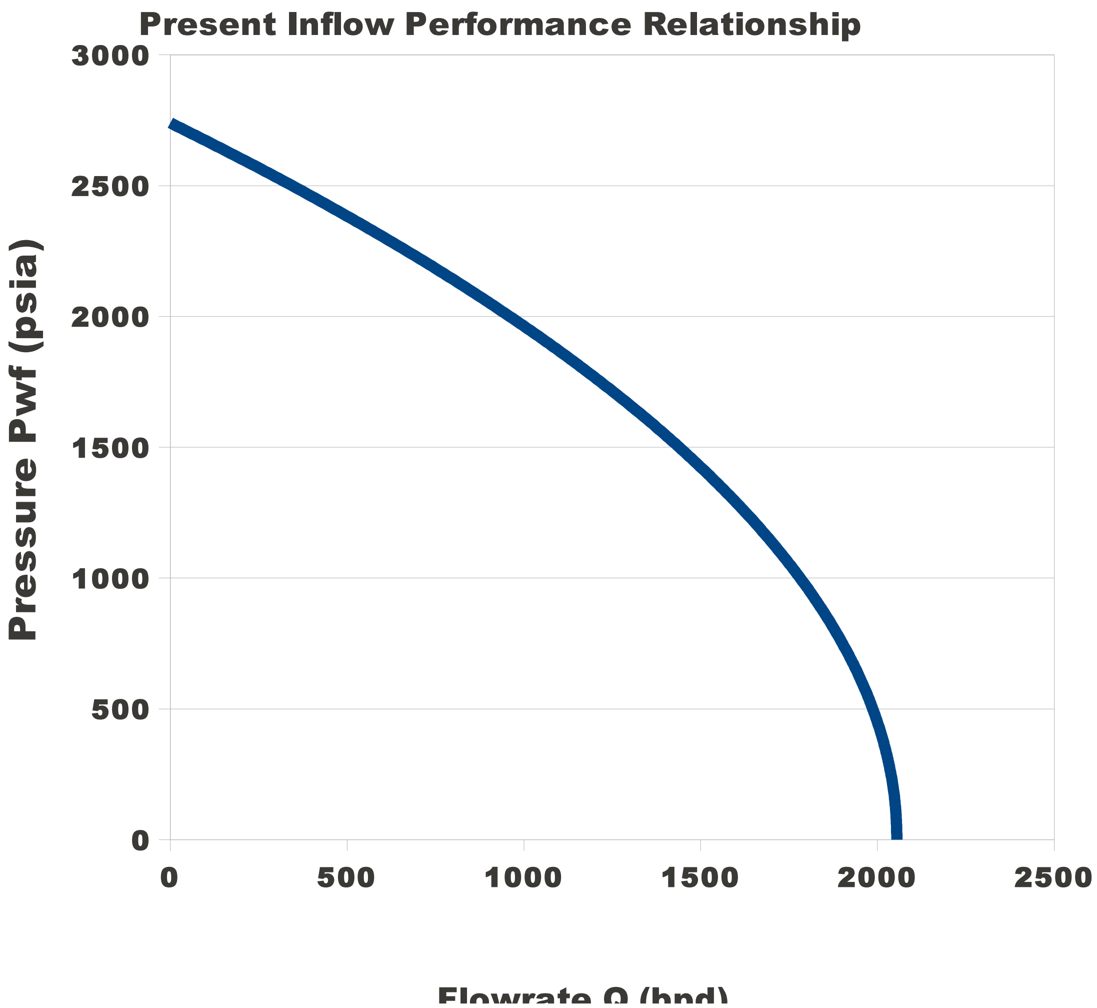


Figure 4.1: Present IPR of reservoir at initial conditions

4.4 Saturated Future IPR

The prediction of the future IPR is very important to forecast future well production. There are many approximate methods to simulate the effects of depletion on productivity index for saturated conditions (Prado, 2008). Usually, those methods provide an equation relating changes in the productivity index J* as a function of reservoir average pressure. The methods for future reservoir prediction express changes in J* as a function of changes in average reservoir pressure. One of such methods is the Eickmeier method which is used in this case study.

4.4.1 Eickmeir Method

The Eickmeir method is given by equation 4.4 as:

$$\frac{J^{\bar{p}_2}}{J^{p_1}} = \left(\frac{\bar{P}_2}{\bar{P}_1}\right)^2 \qquad 4.4$$

The effect of changes in average reservoir pressure over the absolute open flow is also determined using equation 4.5 as:

$$\frac{Q_{max}^{p_2}}{Q_{max}^{\bar{p}_1}} = \left(\frac{\bar{P}_2}{\bar{P}_1}\right)^3 \qquad 4.5$$

Figure 4.4 shows saturated future IPR curves at selected depletion pressures

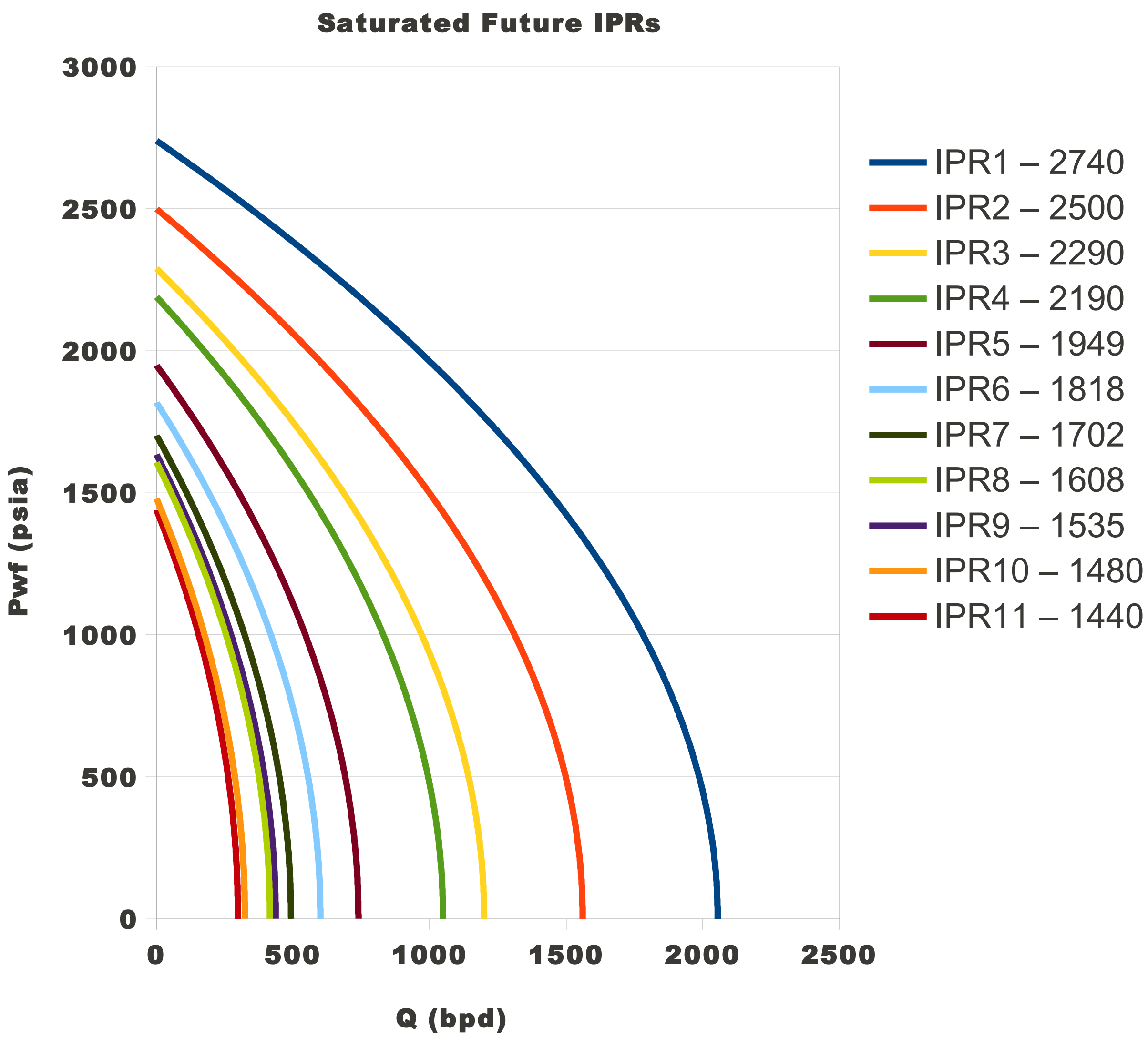


Figure 4.2: Saturated future IPRs using Eickmeier method

4.5 Tubing String Design and Selection

The size (diameter) of the production tubing can play an important role in the effectiveness with which the well can produce liquid (Lea et al., 2008). There is an optimum tubing size for any well system (Beggs, 2003). Smaller tubing sizes have higher frictional losses and higher gas velocities which provide better transport for the produced liquids. Larger tubing sizes, on the other hand, tend to have lower frictional pressure drops due to lower gas velocities and in turn lower the liquid carrying capacity (Lea et al., 2008). Tubing too large will cause a well to load up with liquids and die (Begss, 2003). In designing tubing string, it then becomes important to balance these effects over the life of the field (Lea et al., 2008). Figure 4.5 is a plot of the outflow performance (OPR) of the various tubing sizes superimposed on the IPR curves. It is clearly observed that the smaller size tubings (0.5", 1" and 1.5") have excessive frictional losses with low production rates thereby restricting production

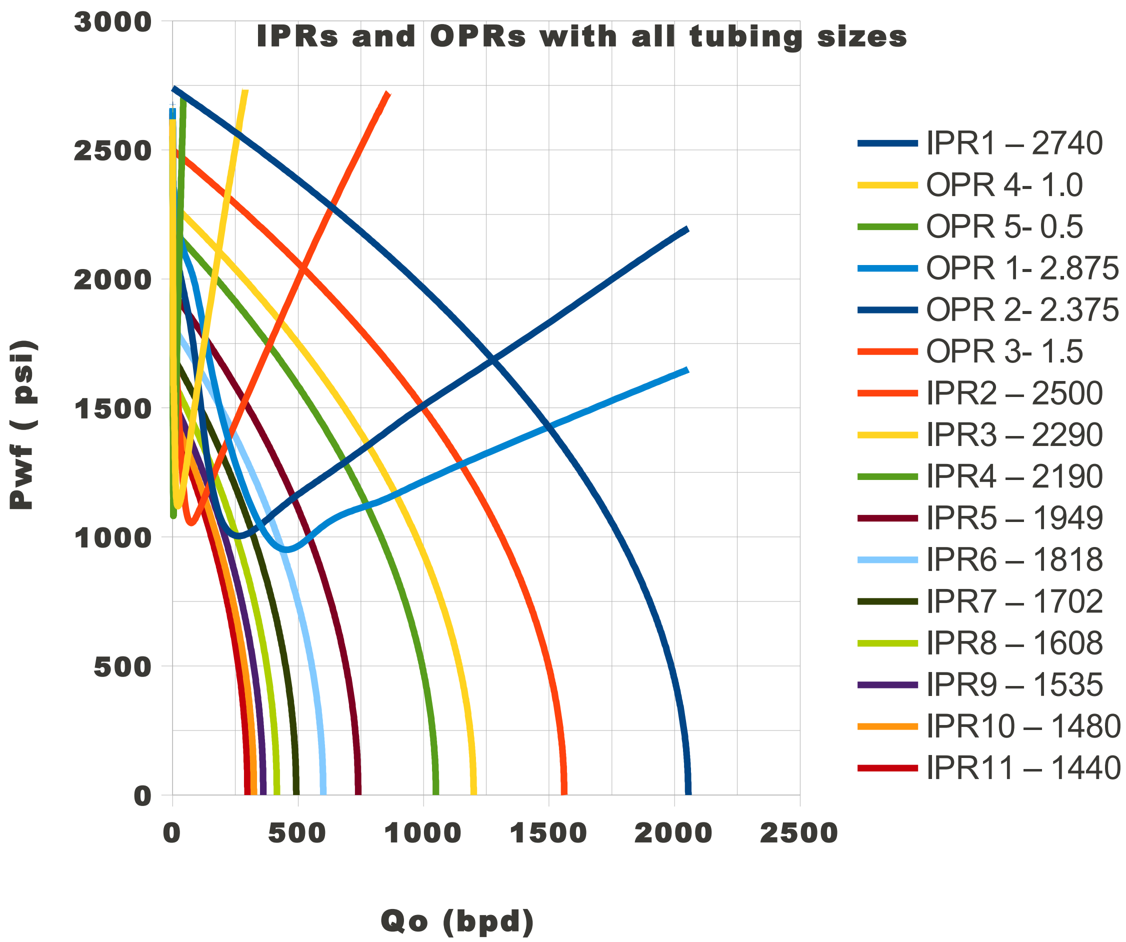


Figure 4.3: Plot of IPRs and OPRs for the various tubing sizes

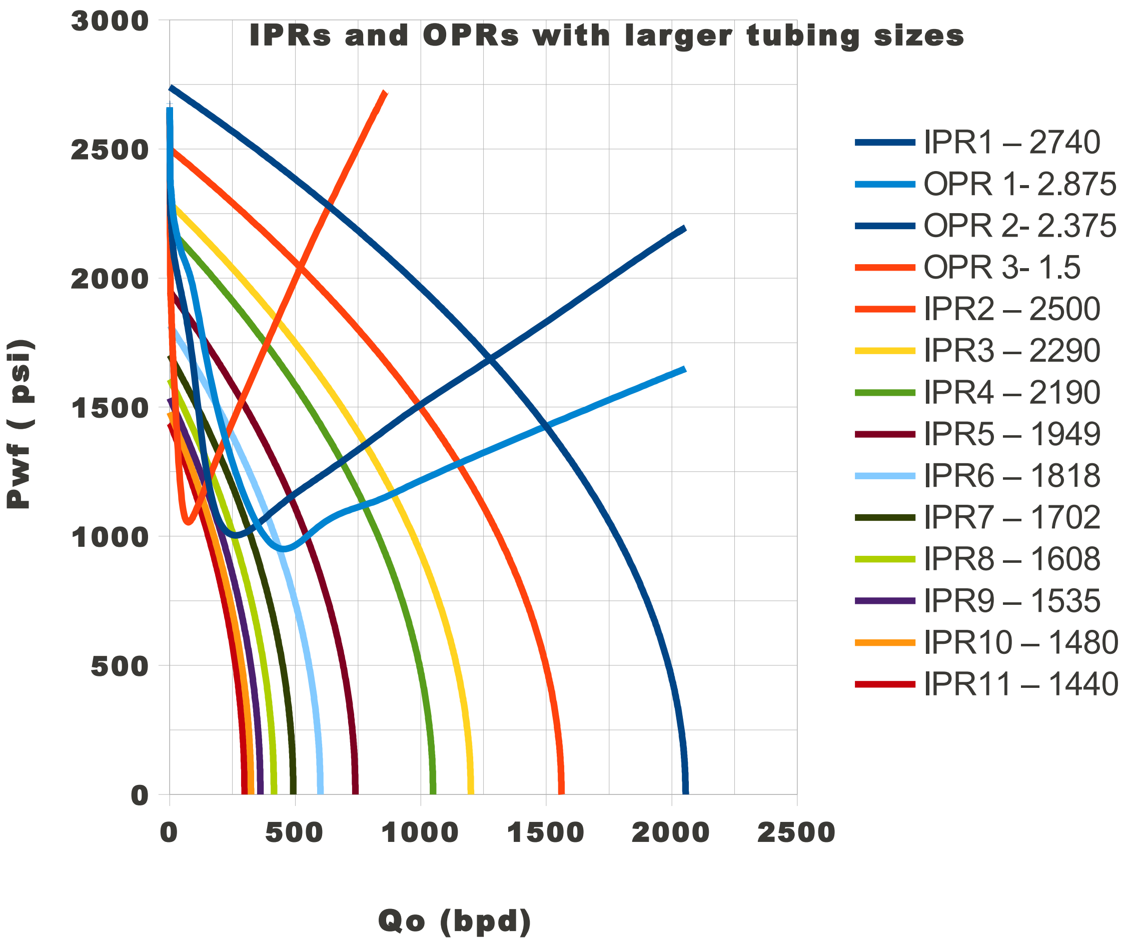


Figure 4.4: Plot of IPRs and OPRs for the various tubing sizes

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

Tubing sizes (inches)	Production Capacity (bpd)
1.5	600
2.38	1275
2.88	1500

For the three different tubing sizes the effect of gravity is the same irrespective of the tubing size selected. However, this is not the case for the frictional loss effect (dominant at higher flowrate areas). The 2.38” tubing produces the reservoir from an average pressure of 2740 psi at a GOR of 760 scf/stb up to a pressure of about 1300 psi as shown below

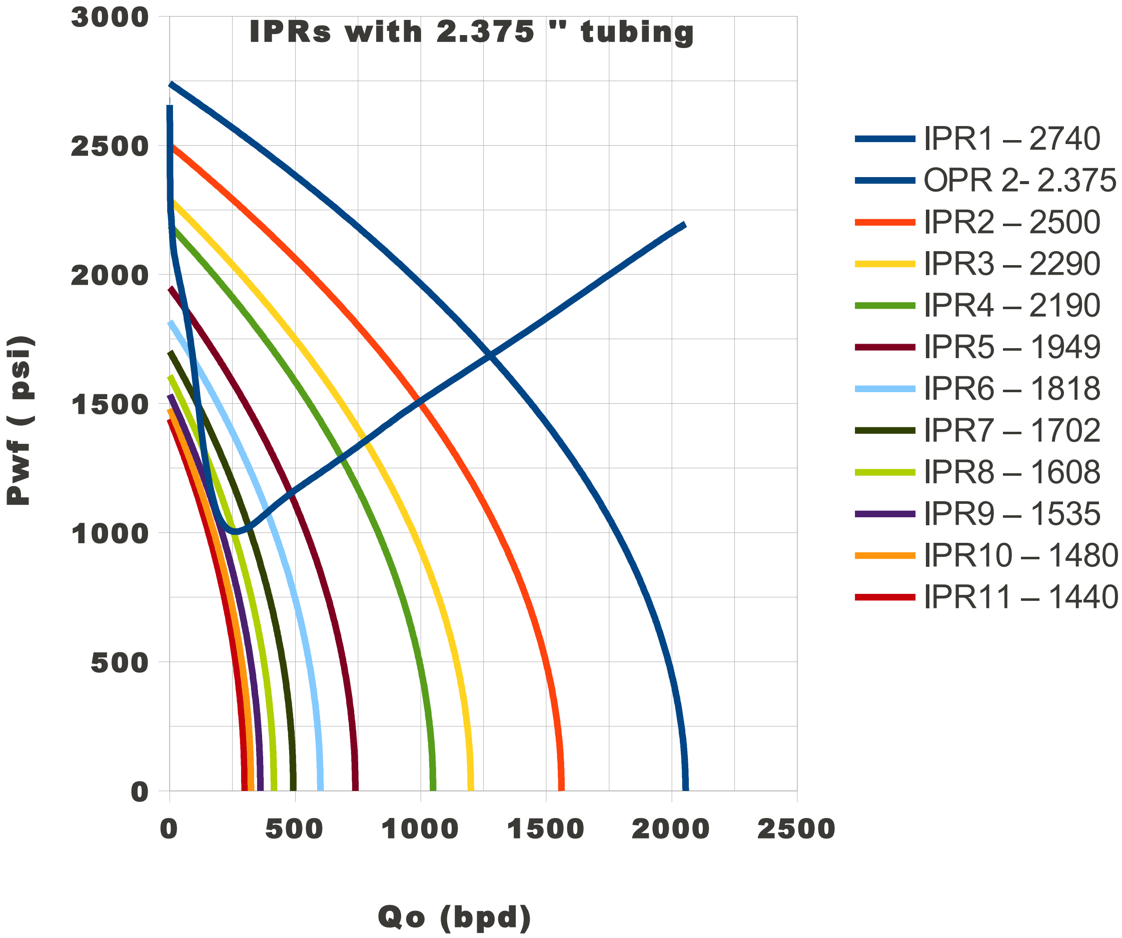


Figure 4.5 : Performance of 2.375” tubing

4.6 Larger Tubings with Gas Lift

The performances of the all the tubings (2.875", 2.375", 1.5" and 0.5,, are investigated with increase in the GOR to 1000 scf/stb

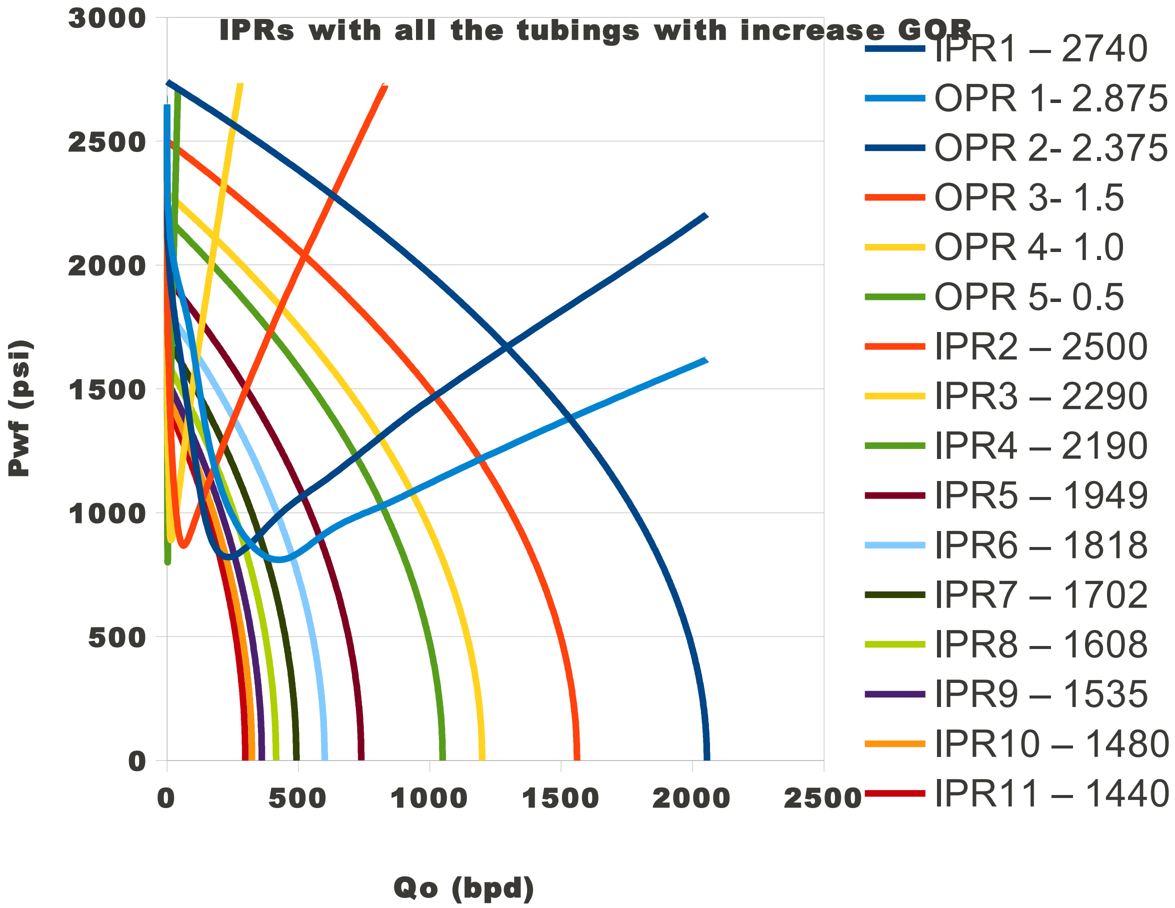


Figure 4.6: Performance of tubings (2.875'', 2.375'', 1.5'' and 0.5) with increase in GOR

From figure 4.6, it is observed that increasing the GLR to 1000 scf/stb virtually give almost the same flow capacity and equivalent bottomhole flowing pressure.

In Fig 4.7 it can be observed critically that using a 1.5" tubing (smaller size tubing compared to 2.375") the reservoir can be produced without the need for gas thus saving cost.

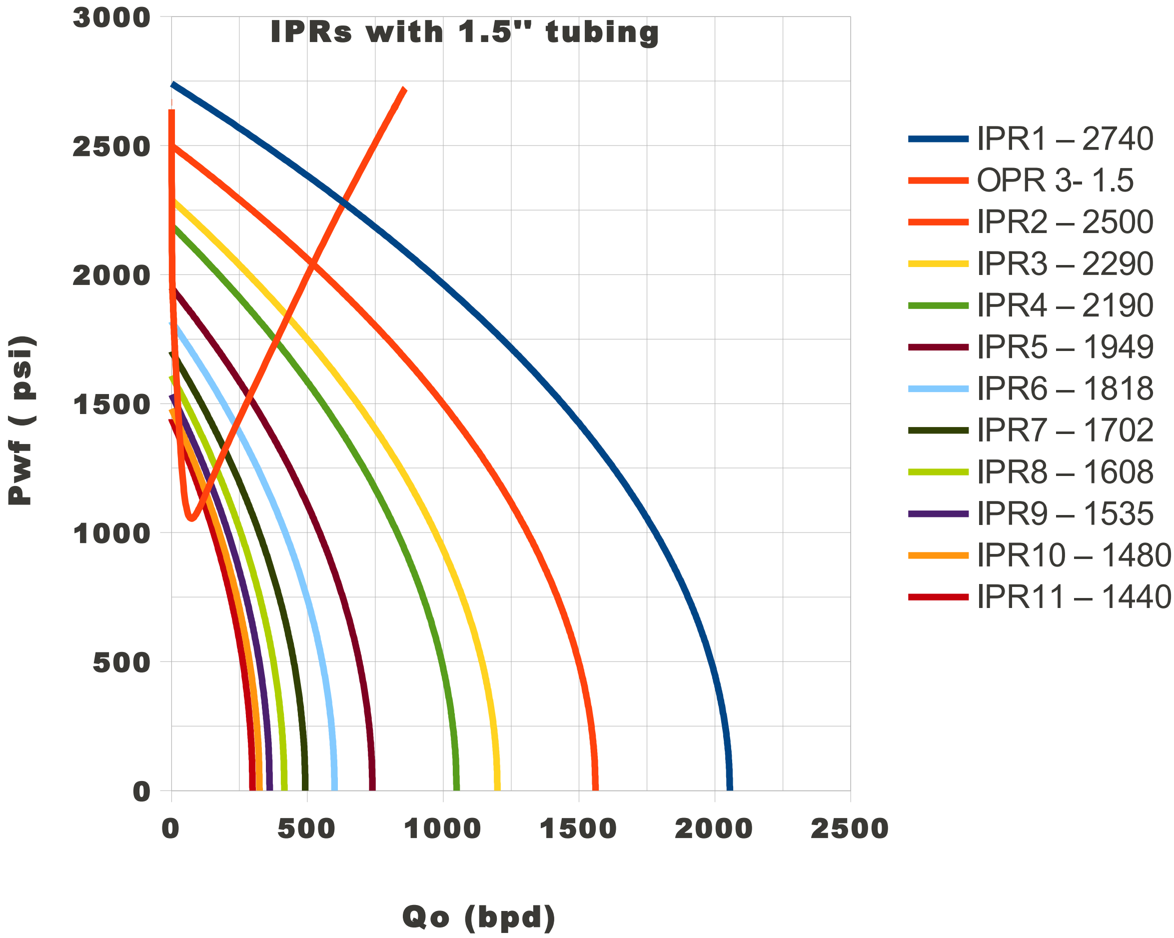


Figure 4.7: Performance of 1.5" tubing

4.7 Relating Performance to Time

Analysis to estimate at what value of average reservoir pressure the producing capacity or deliverability will have declined to is of utmost importance (Beggs, 2003). This type of information needs to be known as a function of time to facilitate development planning or to make economic evaluations (Beggs, 2003). The time to place the well on gas lift and time to install pump or compressors when certain producing capacities can no longer be met is very necessary (Beggs, 2003). The timing of the expenditure of money is required for any economic evaluation of a project or for comparison of projects that require investment (Beggs, 2003).

The table below gives the equivalent flow capacities of the various tubing sizes used and the respective average reservoir pressures.

Table 4.1: Average reservoir pressures and Equivalent Flow Capacity of tubings

Average Reservoir Pressure, Pavg (psi)	Equivalent Flow Capacity, Qo (bpd)
1290	2740
1000	2500
780	2290
690	2190
480	1949
390	1818
310	1720
250	1608
200	1535
120	1480
110	1440

Table 4.2: Incremental oil production at various reservoir pressures

Pavg	Δ Np (MMstb
2500	3.2
2290	17.34
2109	13.8
1949	12.3
1818	6.04
1720	2.7
1608	1.22
1535	0.55
1480	0.27
1440	0.12

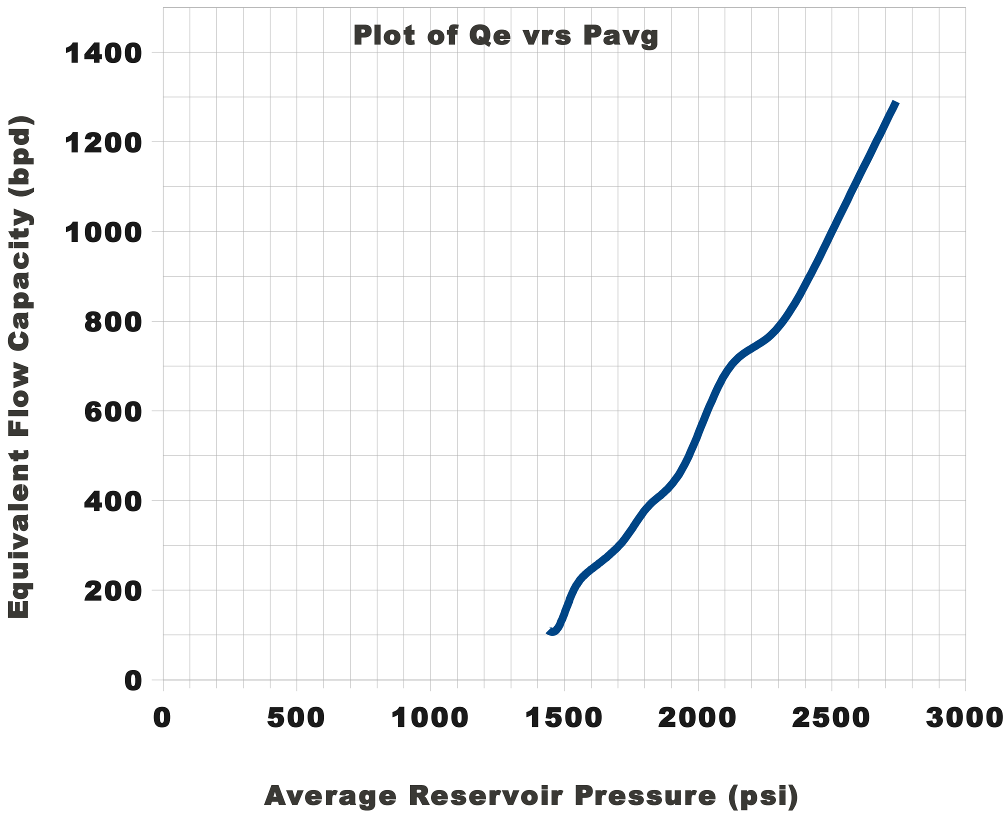


Figure 4.8: Oil producing capacity as a function of reservoir pressure

From table 4.2, selecting an increment of production of 1,000,000 stb, the average values of reservoir pressure Pavg that exist during this producing interval is determined from figure 4.13. Using the value of Pavg determined, its corresponding Qo(avg) is determined from figure 4.15. The time increment required to produce the cumulative production increment is calculated as:

$$\Delta t=\frac{\Delta N_p}{Q_o(avg)} \qquad 4.6$$

from which the total time is given by:

$$t=\sum \Delta t \qquad 4.7$$

and total cumulative production given by:

$$N_p=\sum \Delta N_p \qquad 4.8$$

The result of the above discussion is provided in table 4.4 and a plot of performance versus time is shown in figure 4.9 from which the time taken for the oil flowing capacity to reach 35 bpd (that is when pumping will start) is determined to be approximately 3900000 days. Figure 4.10 also shows the average pressure decline as a function of time.

Table 4.3 : Results of performance as a function of time

N (Mmstb)	P(avg)	Qo(avg)	Δt (days)	t (days)
1	2550	1050	952	952
2	2520	1020	1961	2913
3	2500	1000	3000	5913
4	2490	980	4082	9994
5	2480	970	5155	15149
6	2440	940	6383	21532
7	2430	930	7527	29059
8	2420	910	8791	37850
9	2410	900	10000	47850
10	2400	890	11236	59086
11	2390	880	12500	71586
12	2380	870	13793	85379
13	2370	876	14840	100219
14	2360	860	16279	116498
15	2350	850	17647	134145
16	2340	840	19048	153193
17	2330	830	20482	173675
18	2315	820	21951	195626
19	2310	810	23457	219083
20	2300	800	25000	244083
21	2290	790	26582	270665
22	2280	785	28025	298691
23	2270	780	29487	328178
24	2250	776	30928	359106
25	2240	770	32468	391573
26	2225	764	34031	425605
27	2210	758	35620	461225
28	2200	750	37333	498558
29	2190	745	38926	537484
30	2180	740	40541	578025
31	2160	735	42177	620202
32	2150	725	44138	664340
33	2130	717	46025	710365
34	2110	710	47887	758252
35	2100	700	50000	808252
36	2090	690	52174	860426
37	2080	680	54412	914838
38	2070	670	56716	971554
39	2050	620	62903	1034457
40	2040	600	66667	1101124
41	2020	585	70085	1171210
42	2010	575	73043	1244253
43	2000	550	78182	1322435
44	1990	525	83810	1406244
45	1980	500	90000	1496244
46	1970	475	96842	1593086
47	1960	470	100000	1693086
48	1910	460	104348	1797434
49	1900	450	108889	1906323
50	1890	430	116279	2022602
51	1880	420	121429	2144031
52	1850	410	126829	2270860
53	1800	400	132500	2403360
54	1790	375	144000	2547360
55	1720	320	171875	2719235
56	1650	250	224000	2943235
57	1550	200	285000	3228235

Fig 4.9 : Performance versus time

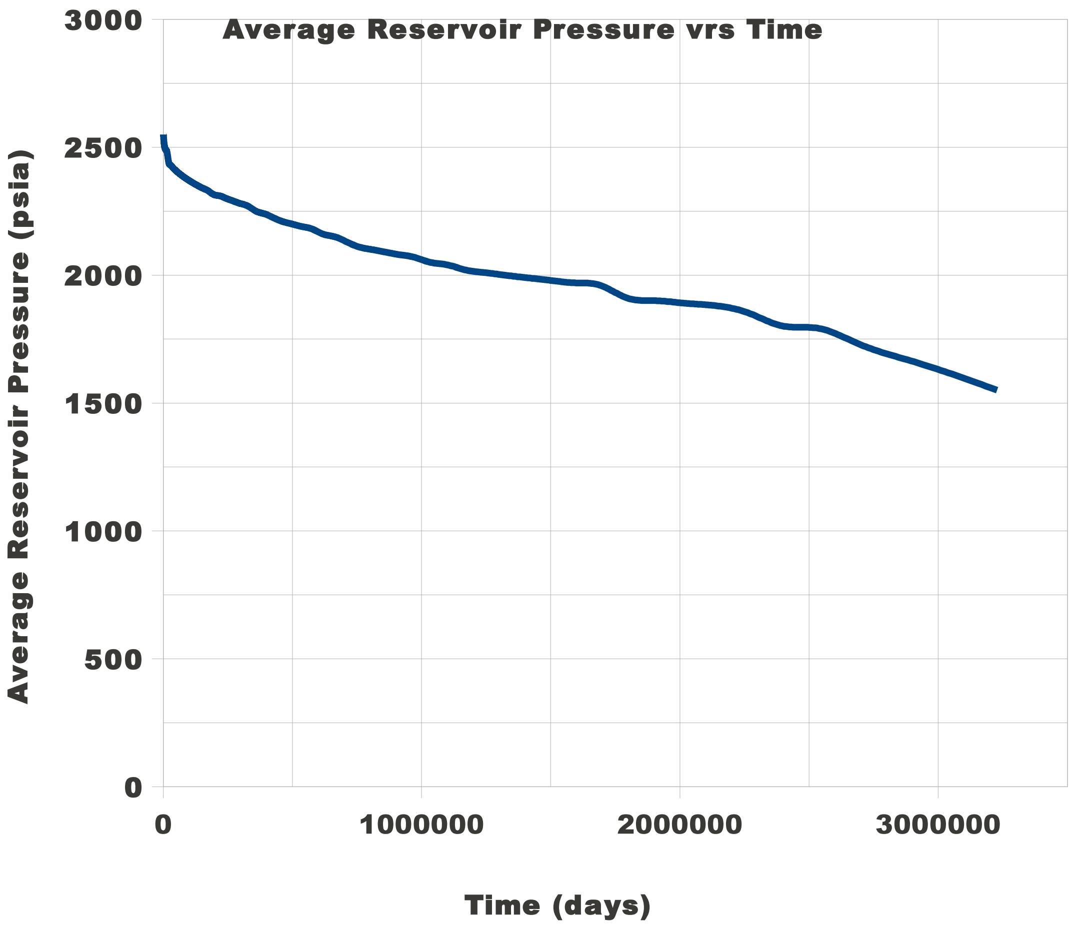


Fig 4.10:Average Reservoir Pressure versus time

A summary of the reservoir production performance with respect to time is given in table 4.4

Table 4.4 : Summary of the reservoir production performance as a function of time

	Start time of operation (days)	End time of operation (days)	Total time of operation (days)
2.375" @ GOR 760	0	3100000	3100000
1.5" @ GOR 760	3100000	3350000	250000000

CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

- Reservoir pressure was maintained much longer in comparison to other drive mechanism when there is an active water drive preferably edge water drive reservoirs which maintains a steady-flow condition for a long time before water breakthrough into the well.
- In selecting the optimum tubing size both the hydrostatic loss and friction loss due to the tubing string must be carefully analysed. Optimum tubing string for the production of this reservoir is the 2.375” tubing which produces the reservoir from an average pressure of 2740 psi at a GOR of 760 scf/stb up to a pressure of about 1300 psi

5.2 Recommendations

The following areas have been identified for improvement in the development of the work

- One of the assumptions in this work is the use of synthetic reservoir performance data based on material balance a possible extension is by incorporating more practical condition by including more wells and the performance with time better analysed
- Further oil production economic analysis should be inclusive in the work so that the optimum production pattern of the reservoir will be determined

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APPENDIX A

Nomenclature

P_i	Initial Reservoir Pressure
P	Reservoir pressure
Δp	Change in reservoir pressure = $p_i - p$
P_b	Bubble point pressure
N	Initial (original) oil in place
N_p	Cumulative oil produced
G_p	Cumulative gas produced
W_p	Cumulative water produced
R_p	Cumulative gas – oil ratio
GOR	Instantaneous gas – oil ratio
R_{si}	Initial gas solubility
R_s	Gas Solubility
B_{oi}	Initial oil formation volume factor
B_o	Oil formation volume factor
B_{gi}	Initial gas formation volume factor
B_g	Gas formation volume factor
B_w	Water formation volume factor
ϕ_o, ϕ_g, ϕ_w	PVT related properties which are functions of pressure
Den	Denominator
W_e	Cumulative water influx
W_i	Initial volume of water in the aquifer
m	Ratio of initial gas – cap – gas reservoir volume to initial reservoir oil volume
c_w	Water compressibility
c_f	Formation (rock) compressibility
c_o	Oil compressibility
S_{wc}	Connate water saturation
S_o	Oil saturation
S_o^*	Oil saturation at the beginning of pressure step
S_{oi}	Initial oil saturation

ΔS_o	Change in oil saturation
S_{wi}	Initial water saturation
S_w	Water saturation
$(S_L)_2$	Liquid saturation at the second pressure step
S_g	Gas saturation
P^*	Average reservoir pressure at the beginning of pressure step
P_1	Average reservoir pressure at the first pressure step
P_2	Average reservoir pressure at the second pressure step
G_{p1}	Cumulative gas produced at first pressure step
G_{p2}	Cumulative gas produced at second pressure step
N_{p1}	Cumulative oil produced at first pressure step
N_{p2}	Cumulative oil produced at second pressure step
R_{p2}	Cumulative gas – oil ratio at second pressure step
R_1	Instantaneous gas – oil ratio computed at pressure p_1
R_2	Instantaneous gas – oil ratio computed at pressure p_2
ΔG_p	Change in cumulative gas produced
ΔN_p	Change in cumulative oil produced
N_r	Oil remaining in the reservoir
G_r	Gas remaining in the reservoir
$(GOR)_{avg}$	Average instantaneous gas – oil ratio
GLR_i	Initial gas – liquid ratio
V	Pore volume
$X(p)$, $Y(p)$, $Z(p)$	Pressure dependent terms
k_{rg}	Gas relative permeability
k_{ro}	Oil relative permeability
μ_o	Oil viscosity
μ_g	Gas viscosity
P_{avg}	Average reservoir pressure
$Q_{o(avg)}$	Average oil flowrate
Q_e	Equivalent oil flowrate
q_e	Equivalent oil flowrate
q_{max}	Maximum oil flowrate
P_{wf}	Bottomhole flowing pressure
q_b	Bubble point flowrate

q	Flowrate
Q_o	Oil flowrate
J^*	Starting productivity index
Δt	Change in time
t	Time
F	Underground withdrawal
E_o	Expansion of oil
E_g	Expansion of the gas – cap gas