# A Study of Flow Behaviour of Solution Gas Drive Reservoirs by Using Secondary Methods for Cumulative Production

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## ABSTRACT

Solution gas drive reservoirs are characterized by rapid and continuous decline of reservoir pressure. This rapid and continuous decline of reservoir pressure causes a direct decline of reservoir performance at the early stages of the life of the reservoir. The principal energy source, gas liberation from crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced is inadequate to produce such reservoirs to their full capacities. Ultimate oil recovery from the natural flow of a solution-gas drive reservoir makes it one of the least efficient primary recovery mechanisms. This leaves a substantial amount of remaining oil residing in the reservoir which must be produced.

The practical application of various production parameters and relations to predict the good performance analysis of a solution gas drive reservoir is the primary objective of this study. These parameters include: IPR (inflow performance relation), OPR (outflow performance relation) and PI (productivity index). Predicting the amount of Reserves present in solution gas reservoirs by adapting different techniques. Material Balance for Predicting Primary Recovery of Hydrocarbons from the well. Case study to predict the Inflow Performance relationship of well how pressure is maintained in well. Theoretical data was used to predict the performance behavior of a solution gas drive reservoir from start of production till its abandonment. IPRs and OPRs were developed during the forecasting, over the life of the reservoir.

In this work, historical shut-in pressure data acquired was used as the average reservoir pressure to compute the pressure drop due to a particular production rate at any time. The productivity index was then computed. Field data were used to test the model and good results were obtained.

**Keywords**: gas drive, pressure, GOR, Volume, material balance

## 1. INTRODUCTION

well performance analysis of a solution gas drive reservoir which involvesinflow performance, outflow performance and productivity index determination during the life ofthe reservoir. However, due to the low recovery of solution gas drive reservoir, artificial lift technologies such as gas lift may be employed for continuous production of the reservoir. Another challenge is to know when to change tubing for optimum production. In this study, I used IPR-OPR to determine the time of tubing change or gas-lift installation and predicting the initial reserves of solution gas reservoirs by using Material Balance Equation (MBE)and application of MBE by using Muskat MBE method.

### 1.1 STUDY APPROACH

Inflow performance relation (IPR) in conjunction with the outflow performance relation (OPR) for the whole life of the well is designed in accordance with the material balance equation prediction. This design is done with regards to the available gas lift and maximum production constraints. Production forecast is made based on Fetkovich's model (for present IPR) to know the time when tubing strings will be replaced for optimum production. Also, IPRs of a naturally fractured reservoir is also developed for vertical. Finally.

### 1.2 OBJECTIVES

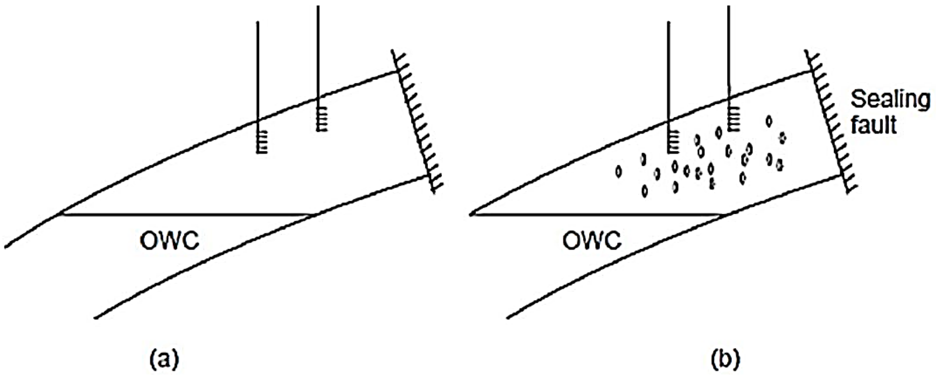
The objectives of this work are to:

- Forecast the production plan of the oil well.
- Predicting the initial reserves of solution gas reserves by material balance equation
- Application of Muskat method to identify the recovery factor and cumulative production of well by gathering data from the different wells
- Application of Gas lift to enhance the well.

## 2. Material Balance for Solution Gas Drive Reservoirs

Havlena and Odeh (1963) examined several cases of varying reservoir types with equation 3.4 and showed that the relationship can be arranged into a form of a straight line. Solution gas drivereservoirs are assumed to be volumetric due to the absence of water influx and gas caps. In determining the material balance for this type of drive mechanism, two phases can be distinguished, as shown in Figure 3.2 (a) when the reservoir oil is undersaturated and (b) when the pressure is fallen below the bubble point and a free gas phase exists in the reservoir (Dake, 1978).[1]

Figure 3.3 Solution gas drive reservoir; (a) above bubble point pressure; liquid oil, (b)below bubble point; oil plus




liberated solution gas

**2.1 Above Bubble Point Pressure (Under Saturated Oil)**:

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 (3.5) becomes:

$$N_p B_o = N B_{oi} \left( \frac{(B_o - B_{oi})}{B_{oi}} + \frac{(c_w S_{wc} + c_f)}{1 - S_{wc}} \Delta p \right) \qquad (2.1)$$

with

$\Delta p = p_i - p$

where pi = initial reservoir pressure, psi

p = current reservoir pressure, psi

Hawkins (1955) introduced the oil compressibility $c_o$ into the MBE to further simplify theequation. Oil compressibility is therefore defined as:

$$c_o = \frac{(B_o - B_{oi})}{B_{oi} \Delta p} \qquad (2.2)$$

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

$$N_pB_o = NB_{oi}\left(c_o \frac{(c_w S_{wc} + c_f)}{1 - S_{wc}}\right)\Delta p \tag{2.3}$$

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

So+Swc=1 (3.8)

and substituting eqn. (3.6) into eqn. (3.7) gives the reduced form of the material balance as:

$$N_pB_o = NB_{oi}\left(\frac{(c_o S_o + c_w S_{wc} + c_f)}{1 - S_{wc}}\right)\Delta p \tag{2.4}$$

or

$$N_pB_o = NB_{oi} c_o \Delta p \tag{2.5}$$

Where

$$c_o = \frac{1}{1 - S_{wc}}(c_o S_o + c_w S_{wc} + c_f) \tag{2.6}$$

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

The calculation of future reservoir production, therefore, does not require a trial-and-errorprocedure, but can be obtained directly from the above expression (Tarek, 2001).

### 2.2 Below Bubble Point Pressure (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 Saturated reservoir is one that originally exists at its bubble point pressure. Once the pressure falls below the bubble point solutiongas is liberated from the oil leading, in many cases, to a chaotic and largely uncontrollable situation in the reservoir, which is the characteristic of what is referred to as the solution gas drive process. Assuming that the water and rock expansion term $E_{f,w}$ = 0 or negligible in comparison with the expansion of solution gas, the general MBE may be expressed by:

$$N = \frac{N_pB_o + (G_p - N_pR_s)B_g}{(B_o - B_{oi}) + (R_{si} - R_s)B_g} \tag{2.7}$$

The above MBE contains two unknowns, which are:

Cumulative oil production $N_p$

Cumulative gas production $G_p$

In predicting the primary recovery performance of a solution gas drive reservoir in terms of these unknowns, the following reservoir and PVT data must be available (Tarek, 2001):

- Original Oil in Place N
- Hydrocarbon PVT data

- Initial fluid saturations
- Relative permeability data

## 3. MATERIAL BALANCE FOR PREDICTING PRIMARY RECOVERY

### 3.1 Muskat Material Balance in Predicting Primary Recovery

Muskat Material Balance in Predicting Primary Recovery From Dake, 1994, consider an initially saturated gas reservoir from which Np (stb) of oil have been produced. Then the oil remaining in the reservoir at that stage of depletion is:

$$N_r = N - N_p = \frac{VS_o}{B_o} \quad (\text{stb}) \tag{3.1}$$

where V is the pore volume (rb). The change in this volume with pressure is:

$$\frac{dN_r}{dp} = V\frac{1}{B_o}\frac{dS_o}{dp} - V\frac{S_o}{B_{o^2}}\frac{dB_o}{dp} \tag{3.2}$$

The total volume of dissolved and free gas in the reservoir is:

$$G_r = V\frac{S_o R_s}{B_o} + (1 - S_o - S_{wc})\frac{V}{B_g} \quad (\text{stb}) \tag{3.3}$$

And its change in volume with pressure is:

$$\frac{dG_r}{dp} = V\left(\frac{S_o}{B_o}\frac{dR_s}{dp} + \frac{R_s}{B_o}\frac{dS_o}{dp} - \frac{R_s S_o}{B_{o^2}}\frac{dB_o}{dp} - \frac{1}{B_g}\frac{dS_o}{dp} - \frac{1 - S_o - S_{wc}}{B_{g^2}}\frac{dB_g}{dp}\right) \tag{3.4}$$

The instantaneous GOR while producing at this stage of depletion can be obtained by dividing equation

$$R = \frac{\frac{S_o}{B_o}\frac{dR_s}{dp} + \frac{R_s}{B_o}\frac{dS_o}{dp} - \frac{R_s S_o}{B_{o^2}}\frac{dB_o}{dp} - \frac{1}{B_g}\frac{dS_o}{dp} - \frac{1 - S_o - S_{wc}}{B_{g^2}}\frac{dB_g}{dp}}{\frac{1}{B_o}\frac{dS_o}{dp} - \frac{S_o}{B_{o^2}}\frac{dB_o}{dp}} \tag{3.5}$$

An alternative expression for the producing GOR can be obtained by applying Darcy's law for gas/oil flow in the reservoir as:

$$GOR = R_s + \frac{k_{rg}}{B_g}\frac{B_o}{k_{ro}}\frac{\mu_o}{\mu_g} \quad (\text{scf/stb}) \tag{3.6}$$

in which krg and kro are the relative permeabilities to oil and gas. Equation can be equated and solved to give the oil saturation derivative with respect to pressure as:

$$\frac{dS_o}{dp} = \frac{\frac{S_o B_g}{B_o}\frac{dR_s}{dp} + \frac{S_o}{B_o}\frac{k_{rg}}{k_{ro}}\frac{\mu_o}{\mu_g}\frac{dB_o}{dp} + (1 - S_o - S_{wc}) B_g \frac{d(1/B_g)}{dp}}{1 + \frac{k_{rg}}{k_{ro}}\frac{\mu_o}{\mu_g}} \tag{3.7}$$

with

$$\Delta S_o = S_o* - S_o$$

$$\Delta p = p* - p$$

where

So * , p* = oil saturation and average reservoir pressure at the beginning of the pressure step

So, p = oil saturation and average reservoir pressure at the end of the time step

Rs = gas solubility, scf/stb

Bg = gas formation volume factor, bbl/scf

Craft et al, 1991, suggested the calculations can be greatly facilitated by computing and preparing in advance in graphical form the following pressure dependent groups

$$X(p)=\frac{B_g}{B_o}\frac{dR_s}{dp} \tag{3.8}$$

$$Y(p)=\frac{1}{B_o}\frac{\mu_o}{\mu_g}\frac{dB_o}{dp} \tag{3.9}$$

$$Z(p)=B_g\frac{d(1/B_g)}{dp} \tag{3.10}$$

Introducing the above pressure dependent terms into equation 4.19 gives:

$$\frac{\Delta S_o}{\Delta p}=\frac{S_o X(p)+S_o\frac{k_{rg}}{k_{ro}}Y(p)+(1-S_o-S_{wc})Z(p)}{1+\frac{k_{rg}}{k_{ro}}\frac{\mu_o}{\mu_g}} \tag{3.11}$$

### 3.2 Procedure:

Craft et al, 1991 proposed the following procedure for solving Muskat's equation fro a given pressure drop Δp, that is, (p* - p). The procedure is as follows:

Step 1: Prepare a plot of krg/kro versus gas saturation.

Step 2: Plot Rs, Bo and (1/Bg) versus pressure and determine the slope of each plot at selected pressures, that is, dBo/dp. dRs/dp and d(1/Bg)/dp.

Step 3: Calculate the pressure dependent terms X(p), Y(p) and Z(p) that correspond to the selected pressures in step 2.

Step 4: Plot the pressure dependent terms as a function of pressure.

Step 5: Graphically determine the values of X(p), Y(p) and Z(p) that corresponds to the pressure p.

Step 6: Solve equation (3.11) for (ΔSo/Δp) by using the oil saturation So * at the beginning of the pressure drop interval p *.

Step 7: Determine the oil saturation So at the average reservoir pressure p, from

$$S_o=S_o-(p-p)\left(\frac{\Delta S_o}{\Delta p}\right) \tag{3.12}$$

Step 8: Using the So from step 7 and the pressure p, recalculate (ΔSo/Δp) from equation

Step 9: Calculate the average value for (ΔSo/Δp) from the two values obtained in step 6 and 8, or

$$\left(\frac{\Delta S_o}{\Delta p}\right)_{\text{avg}}=\frac{1}{2}\left[\left(\frac{\Delta S_o}{\Delta p}\right)_{\text{step 6}}+\left(\frac{\Delta S_o}{\Delta p}\right)_{\text{step 8}}\right] \tag{3.13}$$

Step 10: Using (ΔSo/Δp)avg, solve for the oil saturation So from:

$$S_o=S_o-(p-p)\left(\frac{\Delta S_o}{\Delta p}\right)_{\text{avg}} \tag{3.14}$$

This value of So becomes So * for the next pressure drop interval.
Calculate gas saturation Sg by:

$$S_g = 1 - S_{wi} - S_o \tag{3.15}$$

Step 12: Using the saturation equation, that is,

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

Step 13: Calculate the cumulative gas production Gp as:

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

Step 14: Repeat steps 5 through 13 for all pressure drops of interest.

This procedure is used in predicting the primary oil recovery using synthetic data from a solution gas drive reservoir for this project.[2]

### 3.4 Application of Muskat's Method in Predicting Oil Recovery

Consider a volumetric depletion drive reservoir that exists at its bubble point pressure of 2500 psi with relevant reservoir data provided. Also, detailed fluid property data are listed for the various pressure depletion steps as follows:

Given

Initial Reservoir Pressure (pi = pb) = 2500 psi

Initial Reservoir Temperature = 180 F

Initial Oil in Place (N) = 56000000 STB

Initial Water Saturation (Swi) = 0.2

Initial Oil Saturation (Soi) = 0.8

Table 3.1 gives the fluid property data for the reservoir. Power regression has been used to fit a curve to the gas relative permeability and the equation and correlation of the fit is provided. Similarly, exponential regression has been used to fit a line for the oil relative permeability and the equation and correlation of the fit is also provided. These equations are used to determine the relative permeability at specific gas saturations.

This application of the Muskat's method in predicting oil recovery illustrates the proposed procedure by Craft et al, 1991 for solving Muskat's equation fro a given pressure drop Δp, that is, (p* - p)

Table 3.1: Fluid property data

| Pressure (Psia) | Bo(bbl/STB) | Rso(SCF/STB) | 1/Bg(SCF/bbl) |
|---|---|---|---|
| 2500 | 1.498 | 721 | 955 |
| 2100 | 1.429 | 617 | 781 |
| 1700 | 1.361 | 513 | 612 |
| 1300 | 1.292 | 409 | 453 |
| 900 | 1224 | 305 | 303 |
| 500 | 1156 | 201 | 163 |
| 100 | 1.081 | 97 | 31 |

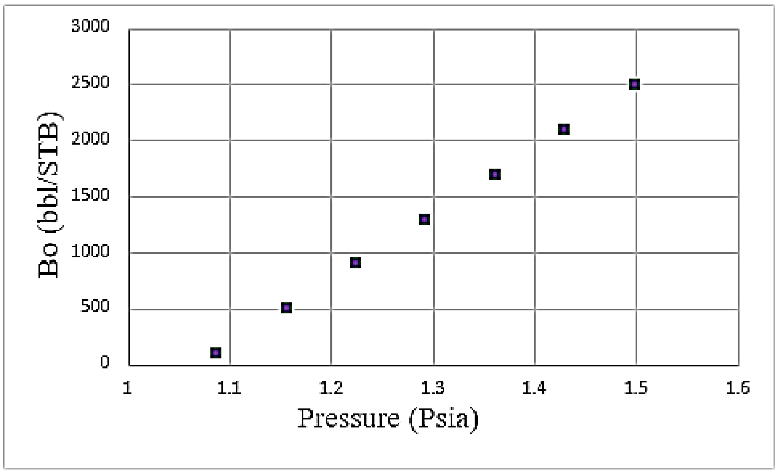



Figure 3.1: Plot of Bo versus pressure

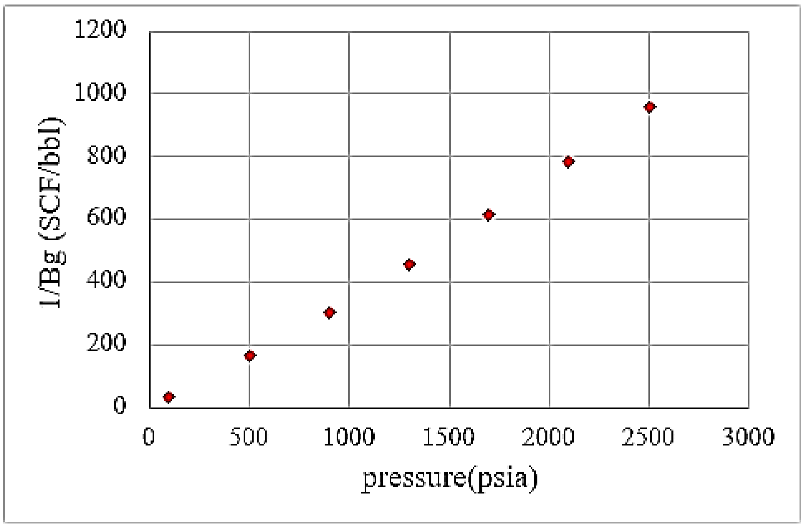



Figure 3.2: Plot of 1/Bg versus pressure

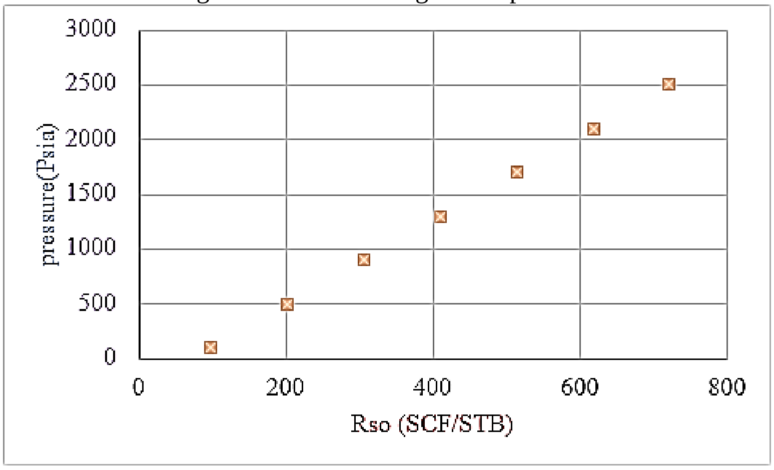



Figure 3.3: Plot of Rso versus pressure

**Slopes:**

dBo/ dp =0. 000171 dRso /dp =0 . 26 d (1/B g) / dp =0 .385

Table 4.2: Muskat's primary recovery prediction result

| **Np** | **GOR** | **Gp** | **Np/N** | **Recovery** |
|---|---|---|---|---|
| (STB) | (scf/STB) | (scf) | - | (% STOIIP) |
| 1.19E+005 | 540 | 721 | 0.0296 | 0 |
| 2.19E+006 | 739.7453027 | 1.65E+009 | 0.0391 | 3.915 |
| 4.73E+006 | 2974.617372 | 5.48E+009 | 0.0846 | 8.455 |
| 5.78E+006 | 9624.532692 | 1.14E+010 | 0.1032 | 10.318 |
| 6.32E+006 | 18547.31895 | 1.88E+010 | 0.1128 | 11.285 |
| 6.71E+006 | 24818.28543 | 2.74E+010 | 0.1198 | 11.979 |
| 7.19E+006 | 11264.60316 | 3.66E+010 | 0.1284 | 12.843 |

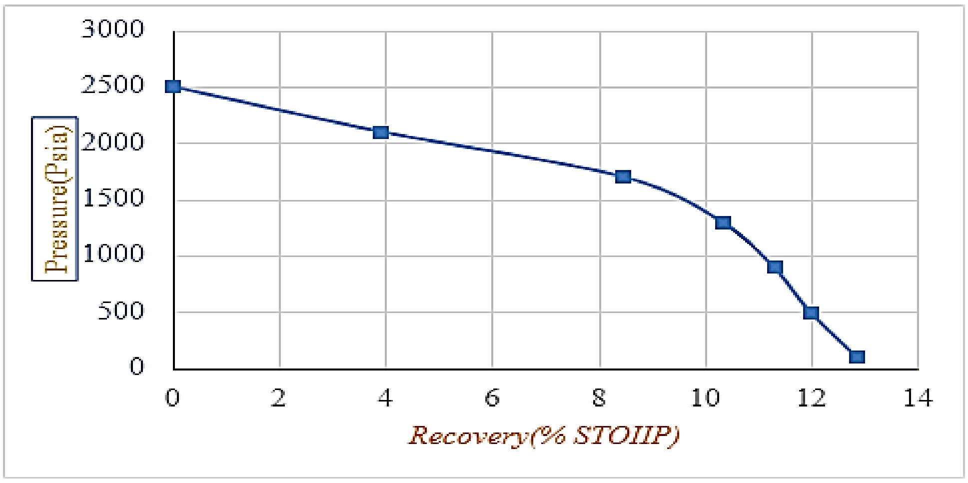



Figure 3.4 Pressure decline as a function of the oil recovery

It is observed from that a recovery of about 13% STOIIP only could be obtained at a depletion pressure of 100 psi (abandonment). This depicts a typical final recovery factor in this kind of reservoirs (solution – gas drive), ranging approximately from 7 to 35% of the STOIIP (Cosentino, 2001).

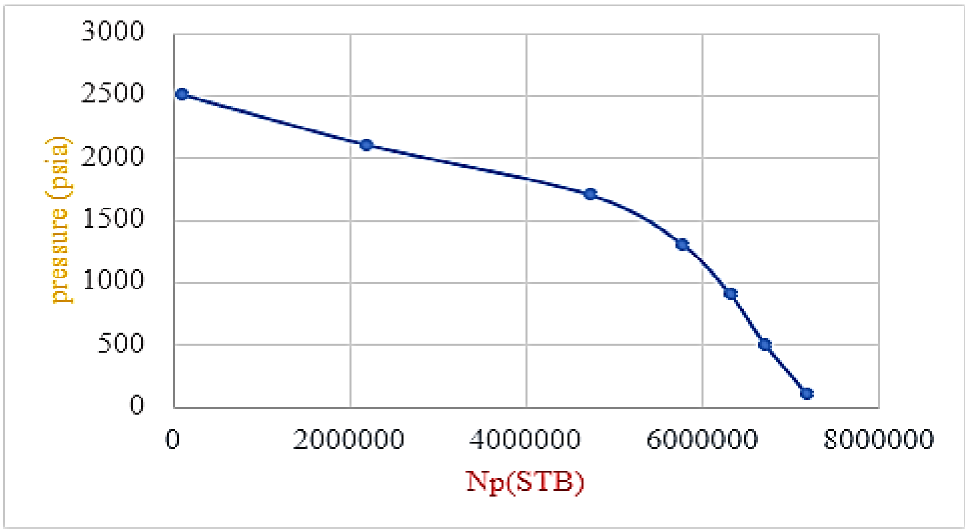



Figure 3.5: Pressure decline as a function of cumulative oil produced

Figure 4.6 exhibits similar behavior as figure 4.5 with a cumulative oil production of about 7.2 MM STB at abandonment pressure.

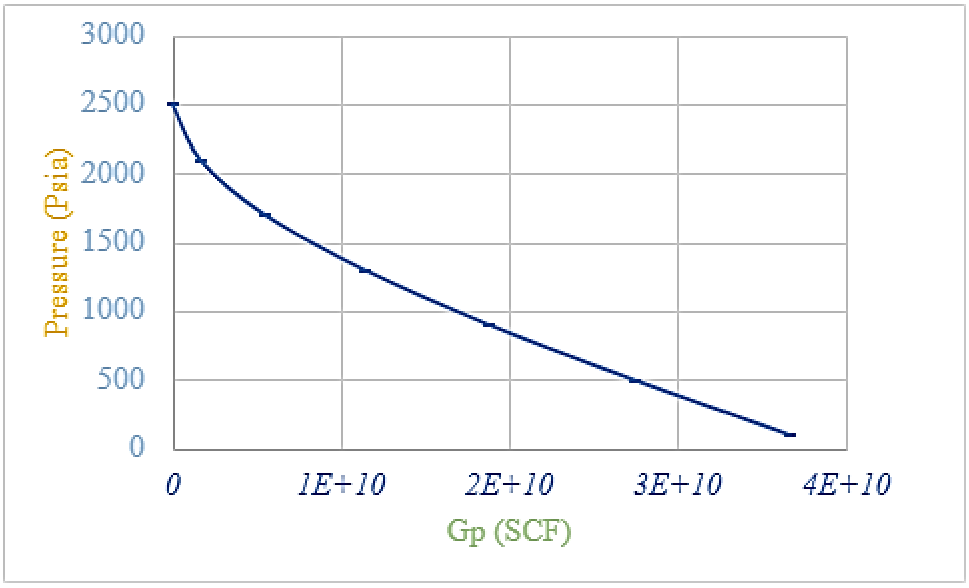



Figure 3.6: Pressure decline as a function of cumulative gas produced

Gas begins to flow when the critical gas saturation is reached. Figure 4.7 shows an inverse relationship which buttresses the fact that, 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, 2001).

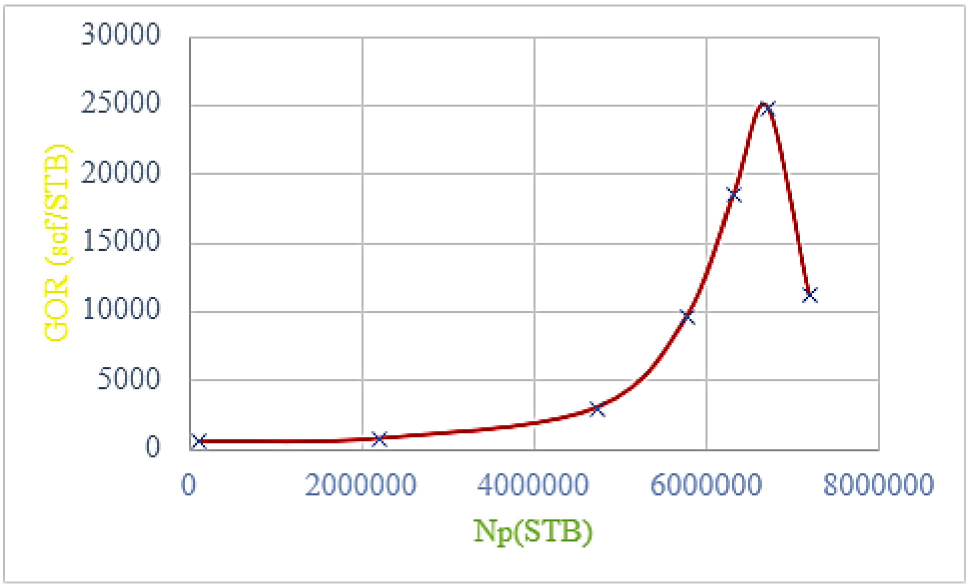



Figure 3.7: GOR development as a function of cumulative oil produced

Figure 4.8 exhibits with a GOR of about 12,000 scf/stb corresponding to a cumulative oil production of about 7.2 MM STB.

## 4.Generation of IPR Curves:

IPR curves are developed by using different techniques such as Vogel's Method (Sinle point method), Fetkovich Method (Double point method) and New IPR model. The IPR curves are developed between the flowing bottom hole pressure ($p_{wf}$),psia vs Flow Rate (Qo) STB/D [3]

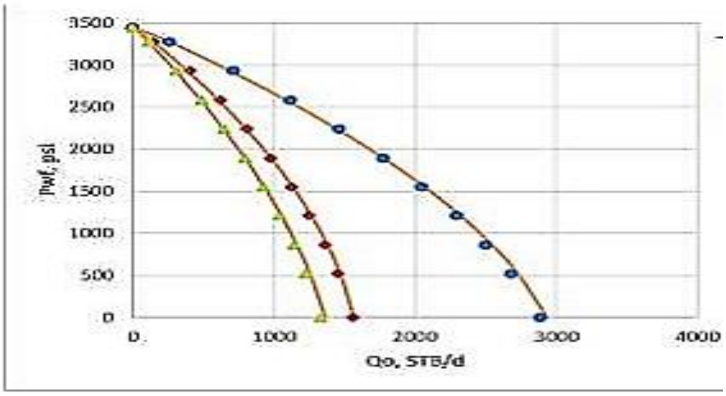



Figure 4.1: Generation of IPR Curves

## 5. Behavior Of Reservoir Fluid Properties In Solution Gas Reservoir

The behavior of fluid properties at various reservoir pressures is also illustrated in Figure below. With reservoir pressure above the bubble point pressure, the oil dynamic viscosity is barely constant but rapidly increases below the bubble point pressure. This is due to the liberation of free gas from the solution gas drive reservoir. This free gas produced causes a decrease in the solution GOR whiles increasing the produced GOR.[4]

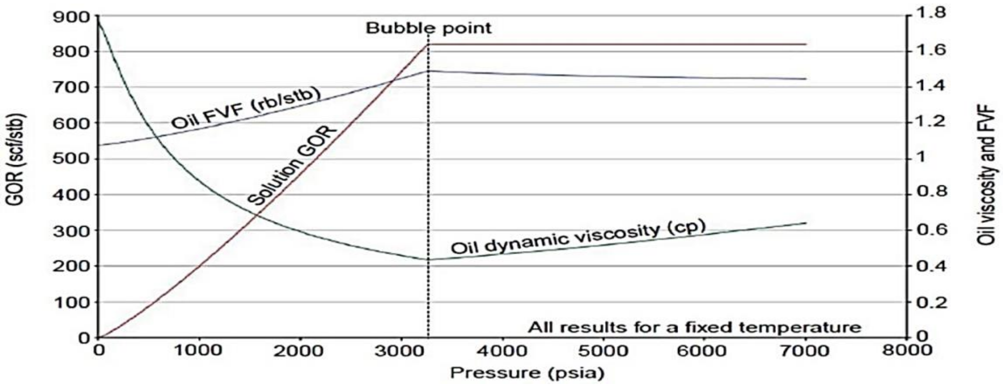



Figure 5.1: Behavior of Reservoir Fluid Properties in solution gas reservoir

## 6 Case study:

Frederic Gallice and Michael L. Wiggins presented multi rate-test data for a well producing from the Hunton Lime in the Carry City Field, Oklahoma. The test was conducted in approximately 2 weeks during the well, which was producing at random rates, rather than in an increasing or decreasing rate sequence. The average reservoir pressure was 1600 psia, with an estimated bubble-point pressure of 2530 psia and an assumed skin value of zero. The multi-rate test of this well is summarized in Table5.1

Table 6.1: multi-rate test of the well

| Test Data | | |
|---|---|---|
| **SI.no** | **pwf, psia** | **Qo, STB/D** |
| 1 | 1600 | 0 |
| 2 | 1558 | 235 |
| 3 | 1497 | 565 |
| 4 | 1476 | 610 |
| 5 | 1470 | 720 |
| 6 | 1342 | 1045 |
| 7 | 1267 | 1260 |
| 8 | 1194 | 1470 |
| 9 | 1066 | 1625 |
| 10 | 996 | 1765 |
| 11 | 867 | 1895 |
| 12 | 787 | 1965 |
| 13 | 534 | 2260 |

| | | |
|---|---|---|
| 14 | 351 | 2353 |
| 15 | 183 | 2435 |
| 16 | 166 | 2450 |
| 17 | 0 | 2450 |

Table presents the predictions of the well's performance for the test information at a flowing bottomhole pressure of 1194 psia, which representing a 25 % of the pressure drawdown. As can be observed, the maximum well deliverability varies from 2550 to 4265 STB/D. The largest flow rate was calculated with Wiggins's IPR, while the smallest rate was obtained using Fetkovich model. shows the resultant IPR curves for the different methods of calculations such as Vogel, Fetkovich, Wiggins, and Sukarno in comparison with the actual field data and the new developed IPR model. It is clear from this figure that the method of the new developed IPR model is succeed to estimate the actual well performance. In addition, it can be clearly concluded from this figure that the methods of the new developed IPR model and Fetkovich's model are nearly estimate the maximum oil flow rate for this well more accurately than the other models, and as indicated, the other methods overestimate the actual performance.

Table 6.2 Prediction of the performance of Case No.1 at 25 % of the pressure draw down

| **Field Data** | | **The new IPR method** | **Vogel method** | **Fetkovich method** | **Wiggins method** |
|---|---|---|---|---|---|
| $P_{wf,}$ psia | $Q_{o,}$ STB/D | $Q_o$ ,STB/D | $Q_{o,}$ STB/D | $Q_{o,}$ STB/D | $Q_o$ ,STB/D |
| 1600 | 0 | 0 | 0 | 0 | 0 |
| 1558 | 235 | 297 | 169 | 213 | 164 |
| 1497 | 565 | 614 | 408 | 444 | 398 |
| 1476 | 610 | 703 | 489 | 516 | 477 |
| 1470 | 720 | 728 | 511 | 536 | 499 |
| 1342 | 1045 | 1140 | 977 | 920 | 965 |
| 1267 | 1260 | 1321 | 1233 | 1115 | 1225 |
| 1194 | 1470 | 1470 | 1470 | 1288 | 1470 |
| 1066 | 1625 | 1688 | 1856 | 1559 | 1879 |
| 996 | 1765 | 1790 | 2051 | 1690 | 2091 |
| 867 | 1895 | 1954 | 2382 | 1905 | 2462 |
| 787 | 1965 | 2044 | 2569 | 2021 | 2679 |
| 534 | 2260 | 2284 | 3062 | 2309 | 3297 |
| 351 | 2353 | 2428 | 3329 | 2447 | 3680 |
| 183 | 2435 | 2544 | 3507 | 2522 | 3985 |
| 166 | 2450 | 2555 | 3521 | 2527 | 4013 |
| 0 | | 2657 | 3627 | 2550 | 4265 |

The average absolute errors percent between the actual flow-rate data and the calculated rate for the five IPR methods that used in this study are shown in Fig.9 for the comparison. It is clear from this figure that the new developed IPR model has the lowest average absolute error percent that is 6.47 %, while the average absolute error percent for Fetkovich's method is 8.56 %. The other singlepoint methods have average absolute errors percent ranging from 20.1 to 32.3 % for Sukarno and Wiggins, respectively.

In summary, the new model provided the best estimates of well performance for this case's entire range of interest. The multipoint method of Fetkovich tends to do a better job of predicting well performance than the other three single-point methods. Overall, the single-point methods of Vogel, Wiggins, and Sukarno provided similar great average differences in this case. As indicated in this work, the more important relationship to evaluate well performance is the relationship between the oil mobility function and the average reservoir pressure, and this was clearly demonstrated from the value of the average absolute error percent that resulted from using the new developed IPR model.[5]

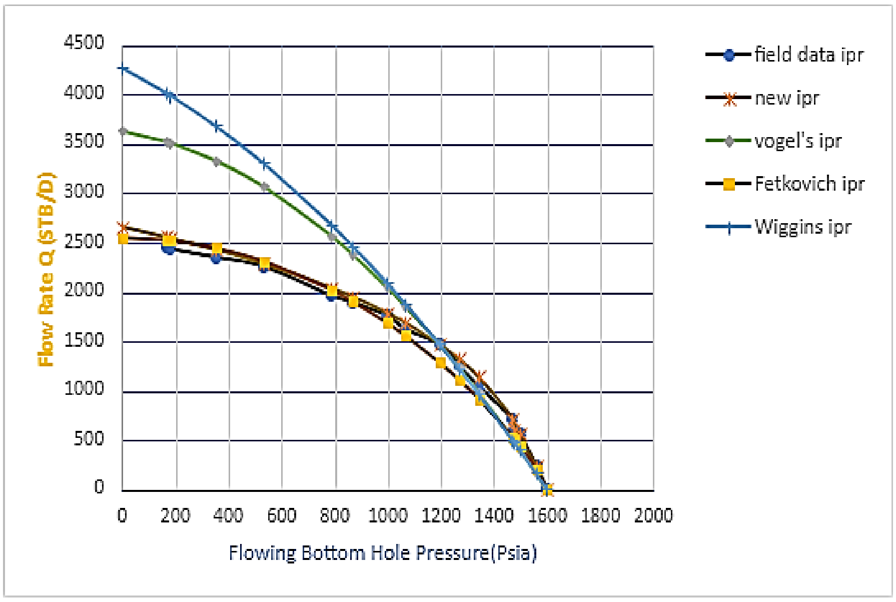



Figure 6.1 :Prediction of the performance of Case No.1 at 25 % of the pressure drawdown

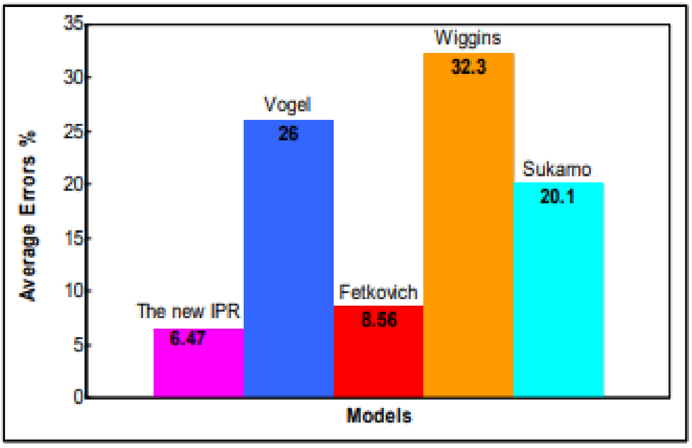



Figure 6.2: The average absolute errors percent at 25 % drawdown for Case No.1

## 7. Tubing Performance Relationship (TPR)

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 higer 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 (Beggs, 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. For this reason, only the three larger size tubings (2 3/8", 2 7/8" and 3 ½") are considered to be the better candidates to start producing the well. However, the 3 ½" tubing exhibits the lowest frictional loss which might cause the well to load up with liquids and die too early. The 2 7/8" tubing gives a much more reasonable frictional loss as compared to that of 3 ½" and 2 3/8" tubings with an equilibrium production rate of about 1350 bpd and an equivalent bottomhole flowing pressure of about 1350 psi [6]

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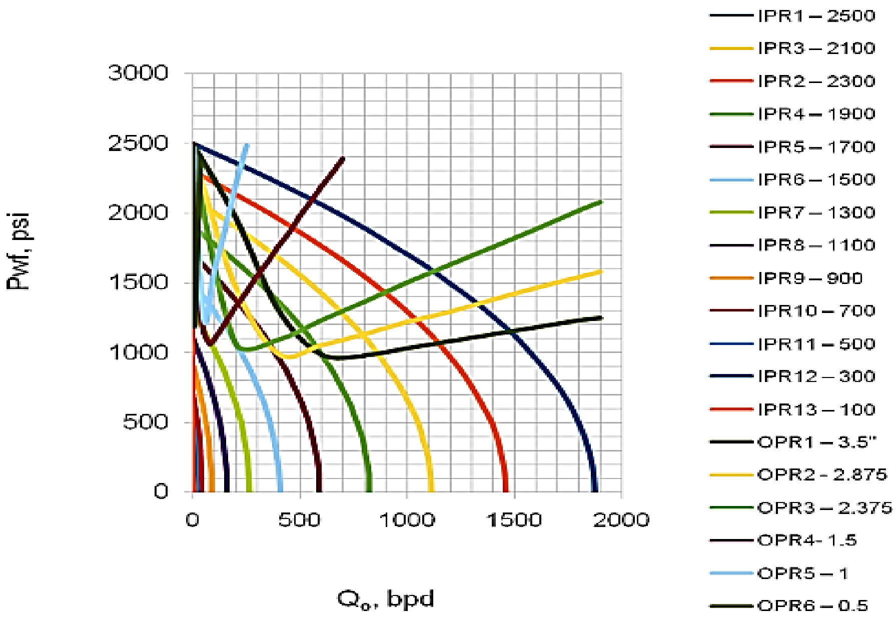


Figure 7.1: Plot of IPRs and OPRs for the various tubing sizes

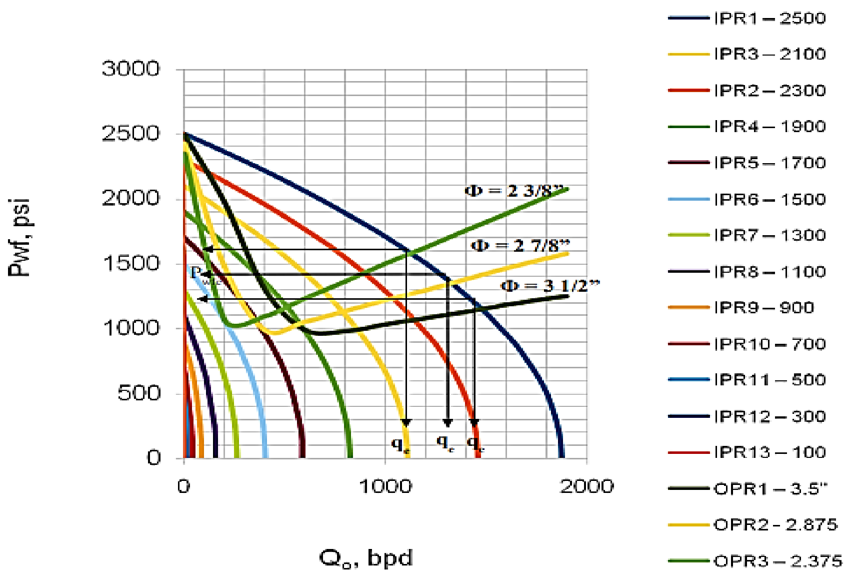


Figure 7.2: OPRs of larger tubing sizes and IPRs

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

**Equivalent flow capacities of larger tubing sizes:**

Table 7.1 Equivalent flow capacities of larger tubing sizes:

| Tubing sizes, inches | Producing Capacity, bpd |
|---|---|
| 2 3/8 | 1100 |
| 2 7/8 | 1350 |
| 3 1/2 | 1480 |

Since the effect of gravity (dominant at lower flowrate areas) is observed at almost a common bottomhole flowing pressure point, that is Pwf of about 1000 psi for the three different tubing sizes, its suggests that 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 7/8" tubing produces the reservoir from an average pressure of 2500 psi at a GOR of 721 scf/stb up to a pressure of about 1700 psi as shown in

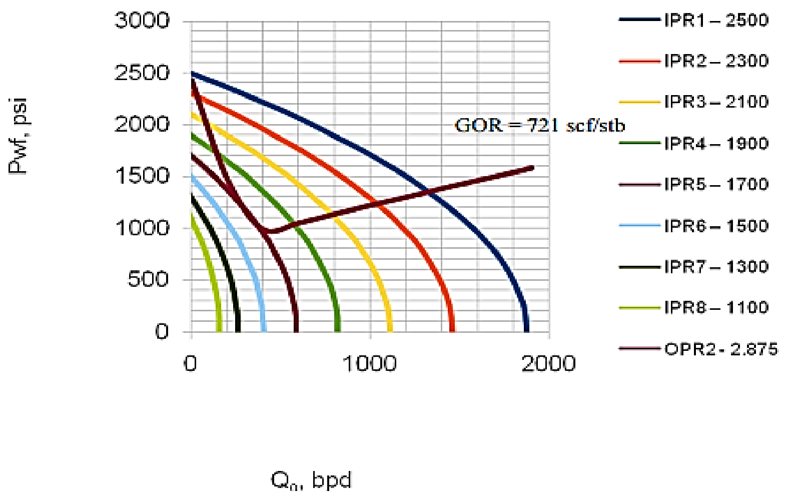


Figure 7.3: Performance of 2 7/8" tubing

## 7.1. Larger tubing's with Gas Lift:

The performances of the 2 7/8" and 2 3/8" tubings are investigated with increase in the GOR. Varying GORs of 1000, 1500, 2000 and 2500 scf/stb are analysed and plotted as shown in figures

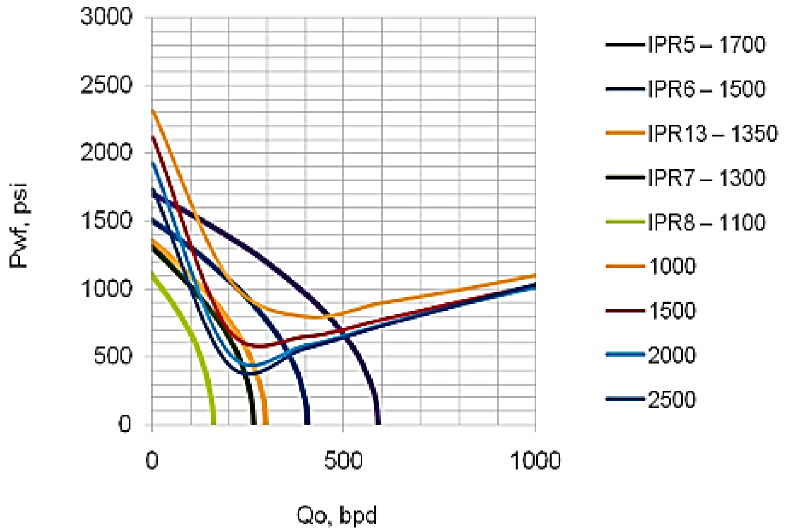


Figure 7.4: Performance of 2 7/8" tubing with varying GORs

From figure 6.1, it is observed that GLRs of 2000 and 2500 virtually give almost the same flow capacities of 500 bpd and equivalent bottomhole flowing pressure of 650 psi. This may be as a result of the gas saturation reaching its critical point. In addition, higher frictional loss is observed at higher flowrates for the two GORs. GLR of 1500 exhibits reasonable frictional loss with an equivalent flowrate of about 500 bpd (same with 2000 and 2500 GORs) and an equivalent bottomhole flowing pressure of 700 psi. GLR of 1000 shows frictional loss same as that of 1500 GOR but can only produce the reservoir to a pressure of 1500 psi (Δp = 200).

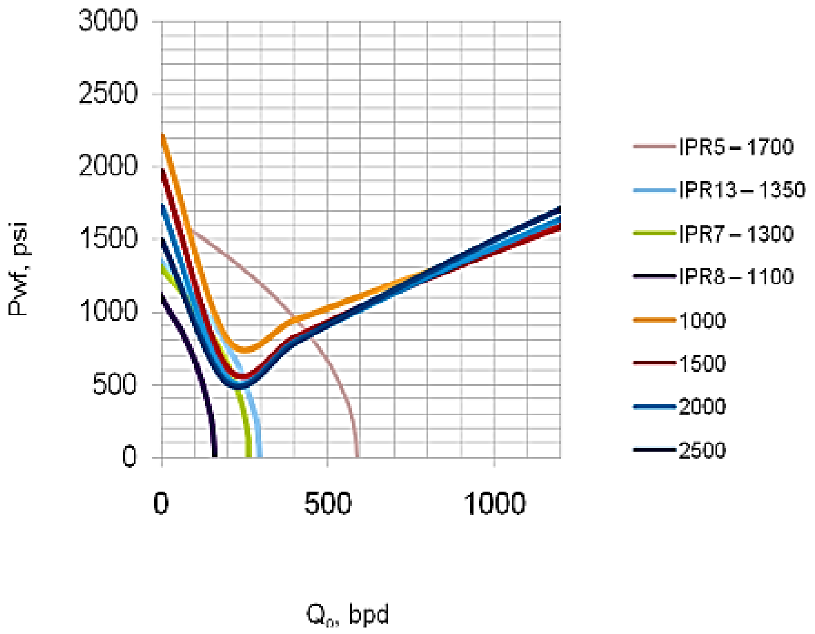


Figure 7.5: Performance of 2 3/8" tubing with varying GORs

From figure it is observed that GLRs of 2000 and 2500 give almost the same flow capacities of 450 bpd and equivalent bottomhole flowing pressure of 850 psi. In addition, higher frictional loss is observed at higher flowrates for the two GORs. GLR of 1500 exhibits reasonable frictional loss with an equivalent flowrate of about 450 bpd (same with 2000 and 2500 GORs) and an equivalent bottomhole flowing pressure of 900 psi. GLR of 1000 shows frictional loss lower than that of 1500 GOR but cannot produce the reservoir to a pressure of 1500 psi (Δp = 200 psi)

Table 71..1: Equivalent flow capacity and bottom-hole flowing pressures

| Tubing sizes, inches | Equilibrium Flow rates, bpd | Equilibrium Pwf, psi |
|---|---|---|
| 2 3/8 | 1100 | 1350 |
| 2 7/8 | 1350 | 1500 |
| 3 1/2 | 1480 | 1600 |

From the foregoing argument, a gas lift operation with a GOR of 1500 scf/stb on the 2 7/8" tubing proves to be the better choice. The 2 3/8" tubing does not perform any better than the 2 7/8" tubing and removing the already installed 2 7/8" for the 2 3/8" tubing causes time and money to be lost. Therefore, the reservoir is produced using the 2 7/8" tubing with a GOR of 1500 scf/stb from an average reservoir pressure of 1700 psi to 1300 psi.

Producing at lower pressures below 1350 psi with a 2 7/8" or 2 3/8" tubing may not be profitable even with gas lift as shown in figures 6.1 and 6.2. At this later stage in the life of the reservoir, velocity strings (smaller size tubings) are employed.

### 7.2 Use of Velocity String (smaller tubings) with Gas Lift:

Figures 6.3, 6.4, and 6.5 show the performances of the velocity strings (tubing sizes of 1.5", 1" and 0.5") under gas lift operations. The investigation is done with GORs of 1000, 1500, 2000 and 2500 scf/stb. Figure 6.3 shows that the 1.5" tubing can produce the reservoir from a pressure of 1350 psi to 900 psi at a GOR of 1500. Comparing the frictional losses of 2000 and 2500 GORs to that of 1500, it is observed that 2000 and 2500 give higher frictional losses although the same equivalent flow capacities of about 140 bpd and equivalent bottomhole flowing pressure of 950 psi. The 1000 GOR has less frictional loss compared to the other GORs but it can only produce the well from 1350 psi up to a pressure of 1100 psi

where it has to be changed. Figure 6.4 shows all the GORs with high frictional losses with equivalent flow capacity of about 60 bpd. The frictional effect seems to impede the flow through this tubing. The frictional effect is even worse for the 0.5" tubing with an equivalent flow capacity of about 20 bpd. Based on the observations, the reservoir is produced with the 1.5" tubing from average reservoir pressure of 1350 psi to 900 psi at a GOR of 1500 scf/stb. At pressure below 900 psi, the frictional loss in the velocity strings may not permit optimal flow capacity and therefore pumping may be the option to consider.

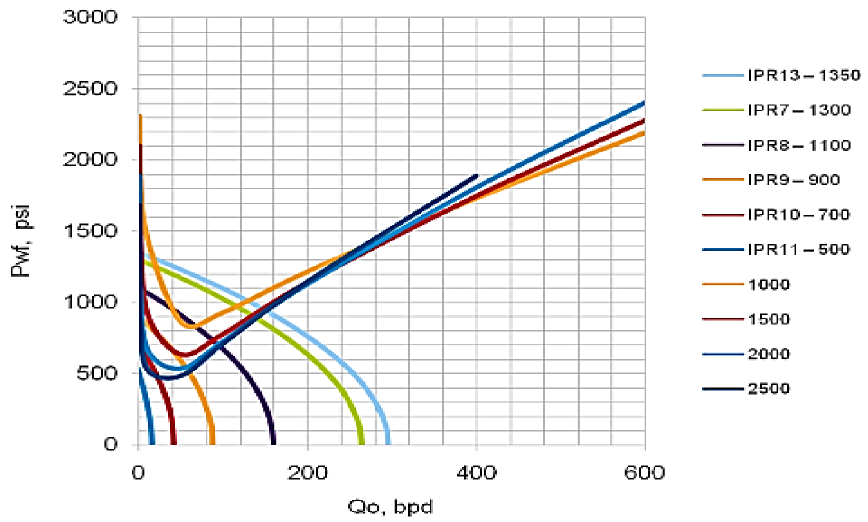


Figure 7.2.1: Performance of 1.5" tubing under varying GORs

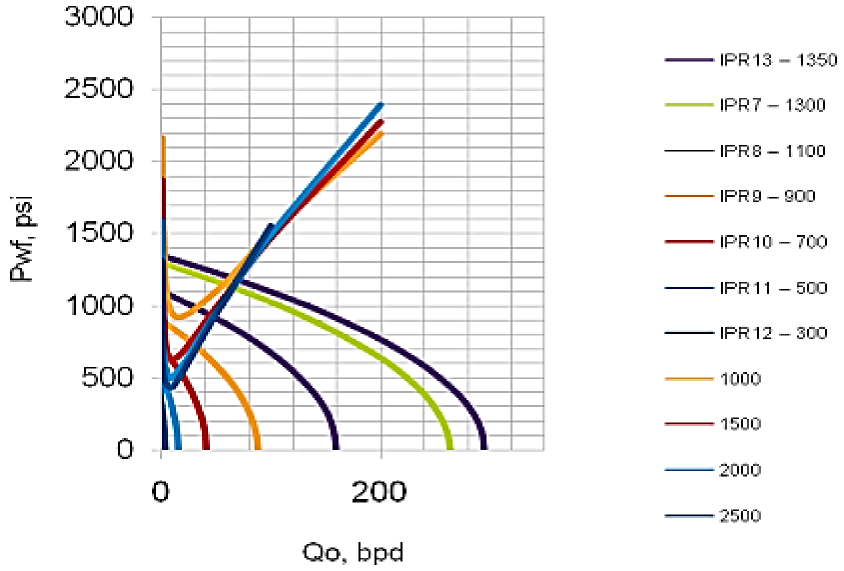


Figure 7.2.2: Performance of 1.0" tubing under varying GORs

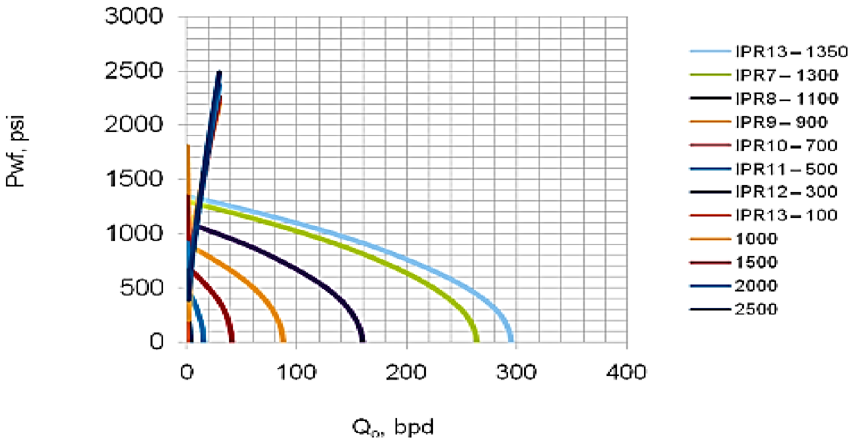


Figure 7.2.3: Performance of 0.5" tubing under varying GORs

## 8. Summary and Conclusion

### 8.1 Summary

The first objective of this project was to design natural flow and artificial lift tubing strings for the whole life of a well. The focus was placed on solution gas drive reservoirs which are characterised by a rapid and continuous decline of reservoir pressure.

The major disadvantage of this drive mechanism is its low ultimate recovery which suggests that large quantities of oil remain in the reservoir. The primary recovery from such drive was studied and predicted using Muskat's material balance method based on synthetic material balance data. The relationship between cumulative production and average reservoir pressure was determined. It turned out that by depleting the reservoir to 100 psi, a recovery of about of 13% STOIIP could be obtained at a GOR of about 12000 scf/stb. It was also observed that there is enough gas produced to lift the well. The major disadvantage of this type of drive mechanism makes it a good candidate for secondary recovery applications. Gas lifting was the secondary recovery technique applied in this project to increase the ultimate oil recovery. The energy of expansion of the injected gas propels (pushes) the oil to the surface. The gas also aerates the oil so that the effective density of the fluid is less and, thus, easier to get to the surface.

The size of the tubing string to employ in producing a gas lifted well was also an important aspect of this project. The flowing bottom-hole pressure required to lift the fluids up to the surface is influenced by size of the tubing string and for that matter the time when tubing strings should be replaced as a function of cumulative production was determined. This was achieved by relating performance to time in an attempt to meet the second objective which was to forecast the production of oil as well as the time when tubing strings should be replaced as a function of both cumulative production and time.

**8.2 Conclusion:**

The work in this project confirms the fact that solution–gas drive reservoirs are the best candidates for secondary recovery applications due to their low ultimate recovery (about 13% STOIIP).

For a particular quantity of injected gas for a specific tubing size, no significant oil recovery was obtained. There is always an optimal quantity of gas to be injected for a specific tubing size.

Velocity strings are associated with high frictional losses which impede oil flow at lower reservoir pressures. As a result, positive displacement pumping was the better option of producing the reservoir at such pressures.

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