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Technical approaches to improve Producing Oil from a Depletion Drive reservoir

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Abstract - a type of reservoir drive mechanisms which is distinguished by incessant and rapid decrease of reservoir pressure is called depletion drive reservoir. The performance of reservoir will be declined directly by this rapid and continuous decline of reservoir pressure at initial phases of the reservoir s' lifetime. Releasing gas from the crude oil is indicated as the main source of energy and the solution gas will start to expand, when the reservoir pressure is reduced and it is insufficient to produce economic amount of crude oil from the reservoirs. Producing crude oil naturally from depleted gas drive reservoir will result in leaving a substantial amount of the crude oil as residual oil saturation, thus it is mentioned as the lease efficient mechanisms of primary recovery.

Crude oil recovery from depletion drive reservoir can be utilized and improved at later period of the reservoir's life by using artificial lift, for example, applying lifting with continuous gas or with velocity string or positive displacement pump. In this study a synthetic data based on material balance is examined to prognosticate primary oil recovery for depletion – gas drive reservoir. the examination will show the factors that based on can be decided and suggested to apply either velocity strings technology, continues gas lifting or positive displacement pumping are to be utilized based on time at various phases of the reservoir's life.

Index Terms - Depletion Drive, Oil Recovery, Oil Well Performance, Inflow Performance, Outflow Performance, Tubing String Design.

INTRODUCTION

The mechanisms of driving fluid from the oil trap and through the porous media in the reservoir is called natural drive mechanisms which gives natural energy to the fluid such as expansion in order to flow through that media toward the wells [1]. Having acknowledgment about different mechanisms of natural fluid driving in the reservoir is considered as an important factor for reservoir engineer to understand about the reservoir behavior and to estimate the future reservoir's performance because natural energy is the main source of controlling fluid flow behavior in the reservoir [2].

The main source of natural drive mechanisms is due to expansions and several kinds of expansions can be occurred inside and/or outside of the reservoirs because of removing fluid in the pore spaces when the fluid start to flow in the porous media. The types of expansions are of hydrocarbons expansion, connate water expansion and rock expansion that gives energy to the fluid in order to flow inside the reservoir to through it. Furthermore, gas cap's expansion outside the producing zone might also provide a considerable amount of energy for the reservoir [3]. The basic natural drive mechanisms are mentioned as dissolved or depletion gas drive, water drive, gas cup drive, gravity drainage drive and combination drive that can provide natural energy to recover crude oil [1]-[3].

According to [3], one of the vital types of reservoir drive mechanisms is called solution gas drive or Dissolved gas drive. It is also mentioned as depletion gas drive or internal gas drive. Producing oil from the reservoir is the main cause of reducing reservoir pressure, after that, the dissolved gas will be expanded and then liberated from the crude oil. The liberated gas is considered as the source of energy to drive crude oil from the microscopic pore spaces of reservoir, when its pressure released to under bubble point pressure. The reservoirs which are derived by solution gas is recognized by rapid and continues pressure decline and this is because of that there are no external trap of fluid or caps of gas to provide the replacements for the produced fluids. Moreover, water is not produced with crude oil from the reservoirs which are characterized by depletion gas drive mechanisms, but rapid increase of gas-oil ratio (GOR) and low oil recovery are the main features to recognize these types of reservoirs. Additionally, only 5% to near 30% of ultimate oil recovery is recorded from depletion drive reservoir and this is mean that the amount of oil residual or remaining oil in reservoir is high. As a result, secondary recovery or artificial lifting will be required as the best candidate to increase oil recovery from the reservoirs and from the wellbore to surface [3].

LITERATURE REVIEW

A. *Depletion Drive Reservoir*

Reservoir recovery mechanisms are classified into various classes. One of the main recovery mechanisms is depletion drives or also called solution gas drive which is recognized by having gas liberation as its leading energy source. The gas liberation occurs when the gas that is dissolved in the oil (at reservoir conditions), expands during production due to pressure reduction [4].

All of these occur because the reservoir pressure is greater than the saturation pressure (bubble- point pressure) but during production the pressure falls below the saturation pressure, which leads to gas expansion that in turn displace the residual liquid phase. This process takes place through few stages. In the first stage, gas expands without flowing (does not leave the solution) because gas flow requires reaching the critical gas saturation point. At the second stage, the gas phase reaches this point which typically ranges between 2 to 10%. At this point, gas starts flowing at a rate that is equivalent to its saturation. Figure 1 illustrates the ideal behavior of a field under dissolved gas drive depletion [5].

It is mentioned by [4]-[5] that, the gas liberation and production increase as the pressure loss increase i.e. further pressure decline leads to additional gas release. This happens repeatedly until the reservoir depletion takes place. At surface conditions, depletion drive reservoirs are characterized by:

- Highly growing GOR.
- Diminishing oil rates.
- Pressure decline is less intense than that occurs during liquid expansion.
- No or slight water production.

As illustrated in Fig. 1, GOR curve has a bizarre form. When reservoir pressure (Pr) is lower than bubble point pressure (Pb), GOR remains constant and it will be equal to initial gas solubility (Rs). After that, it diminishes slightly until critical gas solution is achieved. After this point, it rises promptly and ultimately at the time when the reservoir draws close the depletion pressure and the field life descends to the termination. In this sort of reservoirs, the final recovery factor value is to some extents low and ranges between approximately 5 to 30% of the OOIP. Gas-oil relative permeability is a substantial parameter in depletion gad drive reservoirs. In fact, the increase in GOR curve is associated with increasing Kg (gas permeability) with reference to oil, when the oil saturation raised, accordingly. The lesser the critical gas saturation, the faster the gas mobility, hence, speeding up the depletion and deteriorating the final recovery [4]-[6].

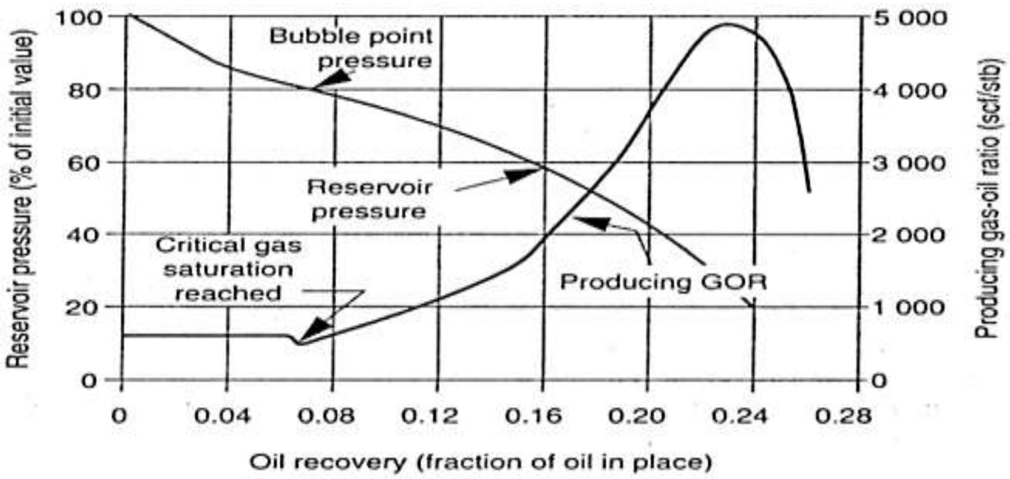


Fig. 1: Shows the behavior of production of a dissolved gas reservoir [6]

B. Inflow Performance Relationship

Primarily, reservoir fluids at reservoir conditions (at or above bubble-point pressure) exist as a single phase. However, at the very beginning of production, reservoir fluids instantly enter the multiphase conditions due to pressure reduction to a point that is beneath the bubble point. As a result, formation volume factor has a value greater than unity [7]. The IPR curves can be set up, when the different values of the bottom hole flowing pressure are recorded and available for each of the gross flow rate in order to be plotted parallel to each other. As mentioned before, as the production begins the pressure is lowered to beneath bubble point, then gas is released from the solution, which in turn increases the oil viscosity. This result is considered as a reduction of well potential. Hence, oil output is decreased, because the force which can drive the reservoir s' fluid to flow is exerted on both liquid and gas phase movement. The concept of the constant productivity index (PI) is not useful and standing anymore. Given that IPR cannot be easily calculated under multiphase flow conditions, in this work Vogel's method will be used for estimating the IPR [8].

C. Outflow Performance Relationship

Oil production can occur via both tubing and casing. It starts from the bottom hole up to the surface (vertical flow). The better option is one that provides better performance which in most cases is oil production through tubing. The outflow performance can be introduced as the behavior of the well in forcing the reservoir fluid to move upwards to the surface. This performance can be represented by plotting flow rate versus flow pressure (bottom-hole pressure), see fig. 2 [9].

The tubing performance or vertical lift performance depends on several factors including fluid surface pressure, tubing size, GOR, PVT properties, well depth, water-cut. Plus, tubing performance is influenced by pressure loss. This pressure loss is a result of chokes, valves and connections that cause restrictions in tubing, which consequently influence the tubing performance. Moreover, an important parameters in tubing performance curve is bottom hole pressure of a flowing gas bottom hole pressure. However, it cannot be practically measured by pressure gauge at the bottom hole. Instead, a list of various techniques has been suggested, from which Gilbert method which consist pressure gradient charts has been used in this work to find bottom hole flowing pressure (P_{wf}) using gradient curves to analyze outflow performance [10]-[11].

$$P_{wf} = f(P_{wh}, Qwell, Twf, Twh, depth, ID, \gamma g, Ppc, Tpc) \qquad (1)$$

Typically, the oil flow rate and corresponding flowing bottom-hole pressure can be identified by combining inflow performance curve (IPR) and outflow performance curve (OPR) represents what the well can deliver to the surface when the IPR relates to what the reservoir can deliver to the bottom hole. Outflow performance curve (OPR) at an indicated pressure of reservoir and particular tubing size and wellhead pressure as the parameters of tubing string. Then, the oil well flowing performance can be analyzed as the combination of the reservoir performance (inflow) and the tubing string performance (outflow). The systems of analysis approach, often called NODAL Analysis, has been applied to "analyze the performance of systems composed of interacting components." [15].

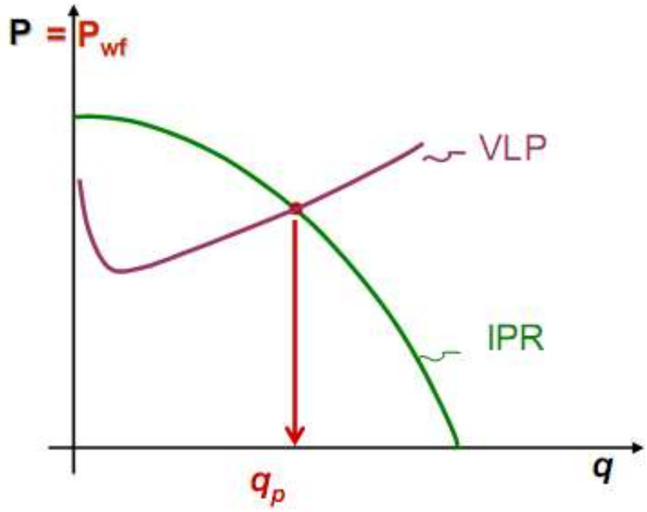


Fig. 2: The IPR and VLP Curves [10]

D. *Artificial Lift*

Oil production requires energy to carry the fluids from reservoir to the surface. When the reservoir fluids flow naturally in the well, the well is known as flowing wells. Most of the wells are flowing wells at the first stages of their lifetime. This is due to the naturally power within the reservoir that is sufficient to drive the produced fluids up to the surface. In dissolved gas drive reservoir, the source of energy is depletion of reservoir pressure and formation gas [12]. However, after sometime of production this energy is not enough to meet the requirements of natural flow or it can be described as actual production rate. When this happens, artificial lift becomes a necessity to increase the production rate to the satisfactory level [12]. Artificial lift, as the name indicates is artificial (contrast to natural drive) for raising the oil from the well bottom to the surface. Artificial lifting process is carried out by utilizing two units. The first one is pumping unit which is mainly a pump that is used to overcome the bottom hole pressure i.e. adding lifting pressure in order to increase the production rate to the desirable level. The second one is velocity string [13]. The reason behind using this is improving the lift efficiency [14]. The artificial lift process is applied to:

- Increase Pr, therefore recovering more crude oil.
- Stimulating depleted wells that lost their natural flow. Thus, it can expand the well life.
- Boosting the production rate and the economic benefit of younger wells.

Artificial lift selection is a substantial point for boosting the well profitability. Selection of artificial wells requires economic analysis of the well and studying reservoir deliverability. These points must be included in the selection planning to avoid poor selection that negatively affects both production and operating cost. Artificial lifts are categorized into several methods, but the two main methods are pump lift and gas lift [12]-[13]-[14].

E. *Oil Recovery Models in Depletion Gas Drive Reservoirs*

There are numerous techniques to predict functioning of depletion gas reservoir associating pressure drop to oil recovery and gas-oil ratio, the wide spread methods are the approach of Tracy, the approach of Muskat and the approach of Tarnery. In general, the next presumptions are established: reservoir monotony (consistency) at the entire time in terms of porosity, fluid saturation and relative permeability; negligible gravity segregation forces; consistent pressure across the reservoir. In oil zones as well as gas zones (meaning across the reservoir, the volume factors of oil and gas, the oil and gas viscosities plus the solution gas ought to be similar); a gas liberation mechanism that is similar to that used for fluid properties determination, and no infraction of water and trivial production of water; equilibrium at any time amidst the oil and the gas phases [15]-[16].
In this project, primary oil recovery for dissolve gas drive has been predicting by employing Muskat's method and the primary source of data which is used in this project is applying material balance to display synthetic reservoir performance. The saturated future IPRs of the reservoir was predicted through the Vogel method. Moreover, the method of positive displacement pumping and gas lift with velocity string as artificial lift are suggested for later stages of the reservoir production [15]-[16]. A Theoretical Perspective to calculate primary oil recovery for solution gas drive reservoir by applying The Muskat's model is also done for liberated gas reservoir by [13].

The size of the production tubing or diameter can play a significant role in acquiring the adequate level of liquid production. The tubing size must be in such a way to overcome the production and economical failures. Each size has different effectiveness in liquid carrying capacity. For instance, larger tubing low liquid transport capacity, because of less gas velocity and less friction pressure. While, smaller size tubing possesses a more acceptable liquid transporting due to higher gas velocity and higher friction loss. Additionally, too large tubing results in liquid loading in the well, and in such a case the well dies [17].

METHOD AND MATERIAL

The type of the reservoir that presents at its initial pressure of 2500 psi is a volumetric depletion drive reservoir with providing a relevant data of the reservoir in Table 1. In addition, a prepared plot of relative permeability to gas and oil versus gas saturation is shown in fig 3. the synthetic data based on material balance is examined to prognosticate primary oil recovery for depletion – gas drive reservoir by using Muskat‘s method. The performance of the reservoir has been evaluated by applying the methods of Gilbert to predict OPR and Vogel to predict IPR in this case of study and they are discussed in the next pages.

Table 1: shows the reservoir data

Reservoir Parameters	Value
Initial reservoir pressure	2500 psi
Percent of produced Water	0%
Gas Liquid Ratio (GLR)	721 scf/stb
Productivity Index	0.75
API Gravity	30°
Gas Specific gravity	0.7
Average reservoir temperature	170° F
Wellhead pressure	140 psi
thickness of the pay zone	7400 ft
First oil saturation	0.78
First water saturation	0.22
Initial oil in place (N)	MSTB

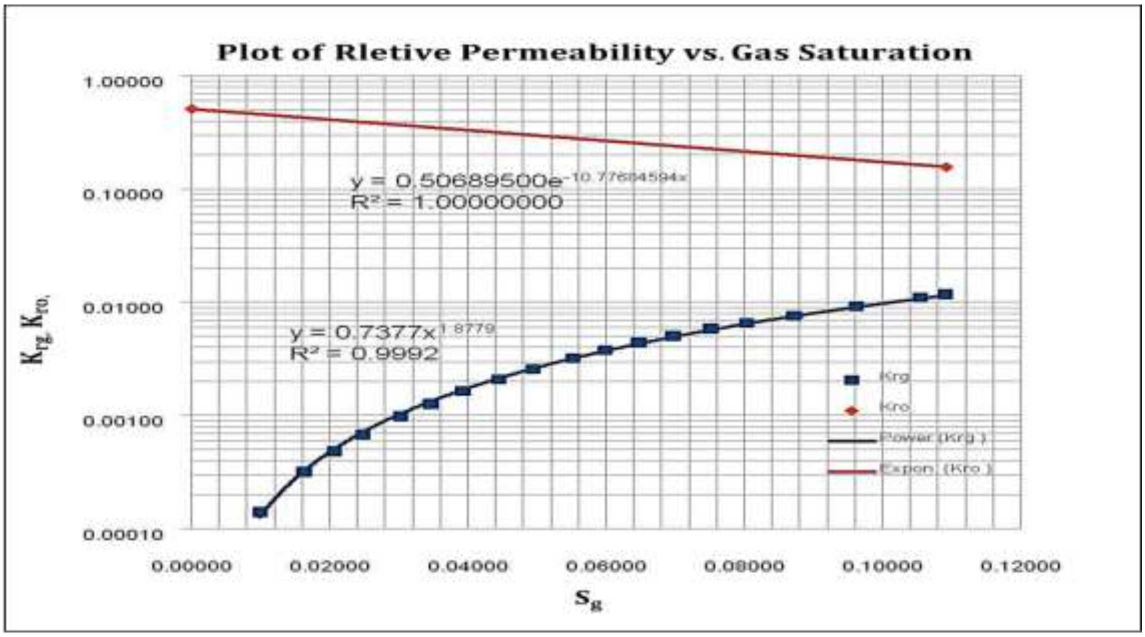


Fig. 3: A organized plot of relative permeability to gas and oil vs. gas saturation

A. *Muskat‘s Method Application to Predict Oil Recovery of the Reservoir*

A material balance is demonstrated by Muskat in the form of limited pressure changes in small increments. The adjustments of variables that have a great impact on oil production are assumed at each depletion or dropping pressure phases. It is assumed that the value of variables hold for a minor decline in pressure and that gradual recovery can be determined or the slight drop in pressure [15]. Referring to [16], when, the gas-oil relative permeability at any liquid saturation and PVT data are known, a difference technique of the material balance equation can be used to calculate the oil recovery by depletion of pressure as in (2):

$$\frac{dSo}{dp}=\frac{\frac{S_O B_g}{B_O}\frac{dR_S}{dp}+\frac{S_O}{B_O}\frac{K_{rg}\mu_O}{K_{ro}\mu_g}\frac{dB_O}{dp}+\left(1-S_O-S_W\right)B_g\frac{d\left(\frac{1}{B_g}\right)}{dp}}{1+\frac{K_{rg}\mu_O}{K_{ro}\mu_g}} \qquad (2)$$

The saturation of the reservoir at that time is linked to the change in producing oil and the rapid gas – oil ratio out of variation in saturation at all pressure values, [16]. Using (ΔSo/Δp) that is mainly the average, the oil saturation S_o can be solved as in (3):

$$S_O = S_O * -\left(P * -P\right)\left(\frac{\Delta S_O}{\Delta P}\right)_{avg} \qquad (3)$$

Cumulative oil production is computed as in (4):

$$Np = N\left[1-\left(\frac{B_{Oi}}{B_O}\right)\left(\frac{S_O}{1-S_{Wi}}\right)\right] \qquad (4)$$

And then the following (5) is used to calculate cumulative gas production:

$$G_P = G_p \oplus \Delta GP \qquad (5)$$

Where:

$$\Delta G_P = \left(GOR\right)_{avg}\Delta N_P \qquad (6)$$

In the next pages, applying the approach of Muskat for estimation of primary recovery in depletion gas drive reservoir is developed in fig. 5, 6, 7, 10, 11, 12 and 13.

B. Vogel's Method

In 1968, an empirical relationship was set up by Vogel for flow rate prediction of depletion drive reservoirs regarding the outflow pressure relied on the results from reservoir simulation. Furthermore, two types of reservoir are candidate to predict their IPR curves by using this method and they are shown in the following [19]:

- Saturated oil reservoirs pr ≤ pb

Saturated oil reservoir is defined by that its bubble-point pressure is recorded as initial reservoir pressure. [19] Summarized the process of utilizing Vogel technique in saturated oil reservoir, which can be used for constructing the IRP curve for a well which has a steady flow data point. Recording Qo value at Pwf can be accomplished, when the next two steps are applied:

Step 1: Q_o and P_{wf} (steady or stabilized flow rate) can be used to calculate Q_{omax} from (7):

$$(Q_o)_{max} = \frac{Q_o}{\left[1-0.2\left(\frac{P_{wf}}{P_r}\right)-0.8\left(\frac{P_{wf}}{P_r}\right)^2\right]} \qquad (7)$$

Step 2: In order to create IRP curve: assume various values of P_{wf} and apply them in (8) to calculate the corresponding Q_o:

$$Q_o = (Q_o)_{max}\left[1-0.2\left(\frac{P_{wf}}{P_r}\right)-0.8\left(\frac{P_{wf}}{P_r}\right)^2\right] \qquad (8)$$

- Under-saturated oil reservoirs pr > pb

Reference [9] noted that when the technique of Vogel can be applied for under-saturated reservoirs, there are the two potential consequences to the detailed stabilized flow test data which must be counted for are represented schematically in fig. 4.

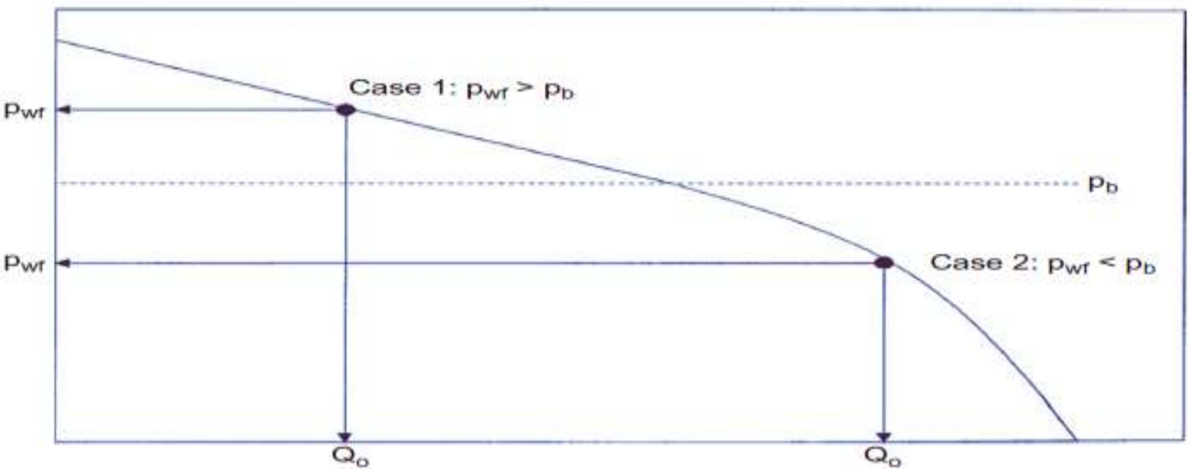


Fig. 4: Stabilized flow test data [19]

First case: the recorded steady bottom-hole flowing pressure is greatest than or equivalent to the bubble-point pressure, i.e. Pwf ≥ Pb
Second case: the recorded steady bubble-point pressure is higher than bottom-hole flowing pressure Pwf < Pb
Applying First Case for dissolved gas reservoir
When Pwf ≥ Pb. for this case begs described a procedure for IRP determination. The procedure is:
Calculating the productivity index J by using by means of (Qo and Pwf) i.e. stabilized test data point:

$$J = \frac{Q_o}{\bar{P}_r - P_{wf}} \quad (9)$$

Using J to calculate oil flow rate at Pb:

$$Q_{ob} = J(\bar{P}_r - P_b) \quad (10)$$

Generating IPR values by assuming various values of P_{wf} , but this time less than Pb (Pwf < Pb) to calculate Q_o (oil flow rate), through (11):

$$Q_o = Q_{ob} + \frac{J \times P_b}{1.8}\left[1 - 0.2\left(\frac{P_{wf}}{P_b}\right) - 0.8\left(\frac{P_{wf}}{P_b}\right)^2\right] \quad (11)$$

Note that the IPR is linear, when pwf ≥ pb, and is mentioned by (11):

$$Q_o = J(\bar{P}_r - P_{wf}) \quad (12)$$

Reference [20] stated that, the cumulative production increment needs a time increment to be produced and that time is computed as in (12):

$$\Delta t = \frac{\Delta N_p}{Q_{o(avg)}} \quad (13)$$

Based on that, the total time can be achieved by (14):

$$t = \sum \Delta t \quad (14)$$

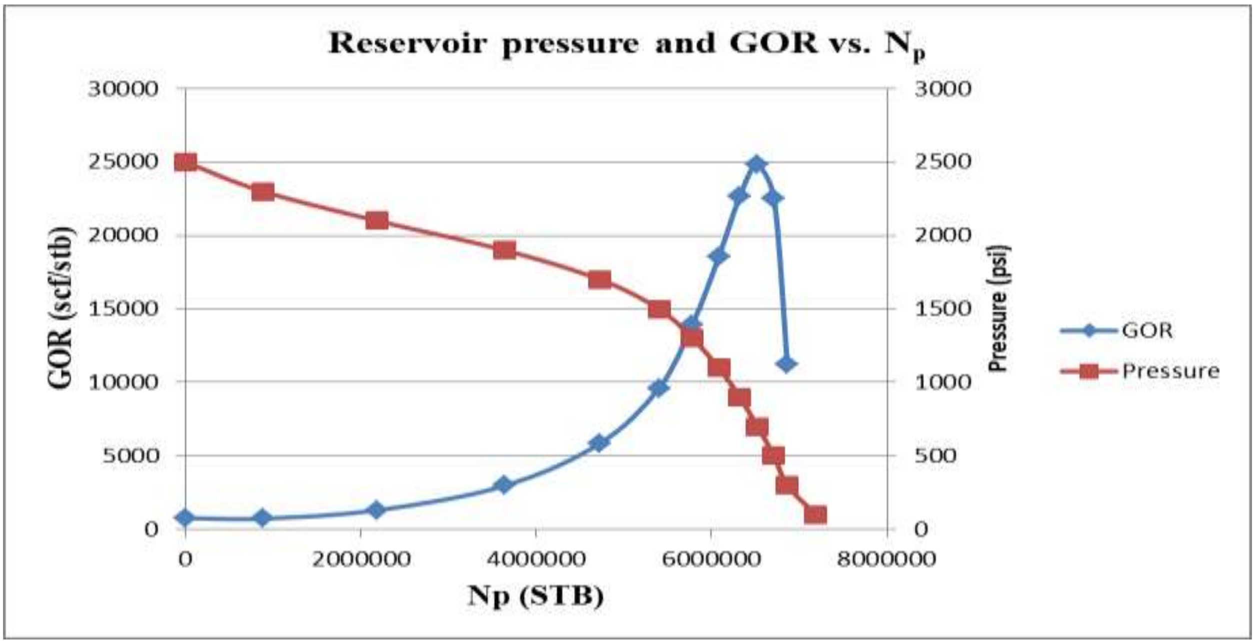
Hence, (15) can give the value of the cumulative production:

$$N_p = \sum \Delta N_p \quad (15)$$

RESULT AND DISCUSSION

A. Optimizing Hydrocarbon Recovery by Using Artificial lift

Fig. 5 demonstrates a plot between cumulative oil production (Np) and the amount of Gas Oil Ratio against average reservoir (Pr) pressure that are predicted by using Muskat's application. From the plot it can be seen that the continuous pressure decline causes quicker gas release, thus faster gas output as it. As a consequence, future pressure drop (in form of chain reaction) leads to quick



reservoir depletion [18]. It can be observed from fig. 5 that when a reservoir is naturally depleted, a cumulative oil production

(Np) $7x10^6$ STB can be gained, when the depletion pressure is 115 psi (that is to say abandonment pressure). This low value of oil recovery needs to be increased, with the purpose of enhancing oil production and optimizing investment income.
Higher recovery values can be obtained by utilizing artificial continues gas design. Moreover, for the reason that reservoir reached its bubble-point pressure at early stage of its life, critical gas saturation is supposedly attained at first stages and it can cause producing of massive volume of gas at first depletion stages. Then the produced gas is continually re-used in order to be injected to where it was produced (from reservoir) to lift gas in the well. For this reason, there is the needs for the design of continue gas lift. The design of the gas lift will be employed by nominal tubing sizes of 1.5", 2", 2 7/8" and 4".

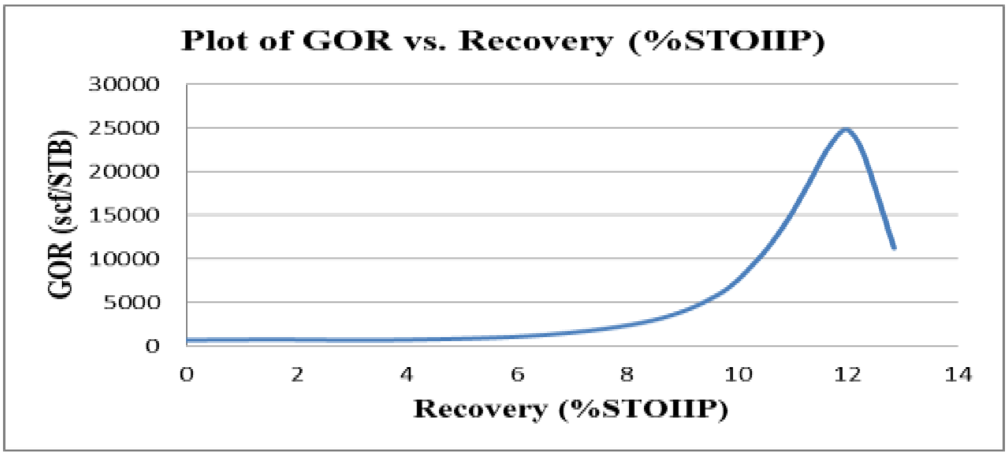
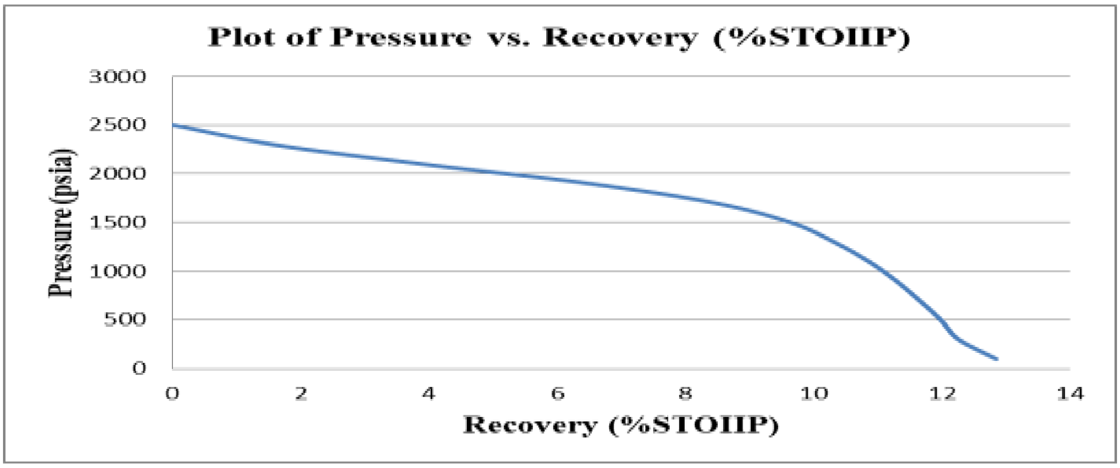


Fig. 5: Characteristics of the reservoir (depletion – gas drive reservoir)

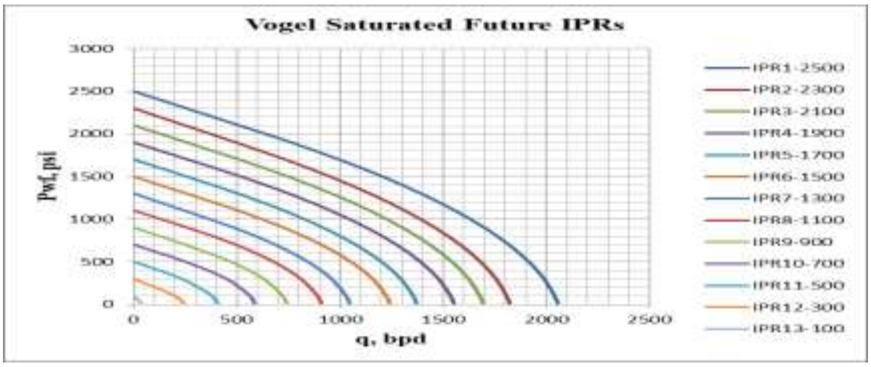
B. The Average Gas oil Ratio

From Muskat's method, the result of the relation between average gas oil ratios (GOR) against Oil Recovery before improving the performance of the reservoir is shown in fig. 6.
Fig. 6: GOR development as a function of oil recovery
The maximum value of GOR around 25000 scf/STB is recorded, when the oil recovery is about 12% STOIIP. In this case, the low oil recovery is responsible for the increasing gas oil ratio because of the consistent reduction in oil mobility in compare to cumulative gas mobility. As the result, gas bubbles will flow by larger numbers. It can be seen in fig.7 a recovery of about 13% STOIIP can be gained when the reservoir is depleted and it reached a pressure (115 psi) that is called abandonment pressure. At



this point GOR decreased from its peak point to 11500 (scf/STB) in fig. 6 [15].
Fig. 7: show recorded oil Recovery (% STOIIP) with reducing reservoir pressure
Vogel saturated future IPRs

Resource management requires determination of reservoir performance at any time in the future. IPR curves that are drawn by using Vogel method depict the flow of two phases in porous medium for each average reservoir pressure, see fig. 8. The curves of IPR are set up by scheming the recorded bottom hole pressure as a function of the gross flow rate. The observation showed that all the IPR curves are set up parallel to each other. Plus, according to the analysis, the maximum attainable flow rate is about 2055.86 bpd. In addition, with the reduction in reservoir pressure, the well potential also reduces
Fig. 8: Vogel saturated future IPRs
and this result can confirm the availability of depletion gas reservoir since the pressures are below bubble point pressure and the productivity for each reduced pressure is not constant. The value of average reservoir pressure is attained by the intercept IPR curves with y-axis.



C. *Tubing String Design and Selection*

The smaller size tubing is observed to possess extreme frictional loss, therefore it causes low production rate and restricted production. Preferred candidates of tubing size for well production are 1.5", 2", 2.875", 4". Nevertheless, by comparing the results of frictional loss and production rate, it is noticed that the lowest frictional loss is offered by 4" tubing size, which in turn cause liquid loading at first periods of the well lifetime (the well dies). The 2.875" tubing size, when compared to 4" and 2" tubing size, shows more acceptable frictional loss. Thus, 2.875" tubing size yields 1350 bpd for equilibrium production rate and 1350 psi for bottom hole flowing pressure as it is shown in fig. 9.

From table 2 the intersection point of these values: flow rate of the well, bottom hole flowing pressure and tubing performance of the well, provide operating points of different tubing size. In addition, 2 7/8" tubing was selected to produce the reservoir from the average reservoir pressure of 2500 psia at a Gas Oil Ratio of 721 scf/STB up to approximately 1350 psia with the capacity production of 1350 bpd as shown in fig. 8. Velocity string (1.5") would be required after this point and the result of using it is shown in table 3.

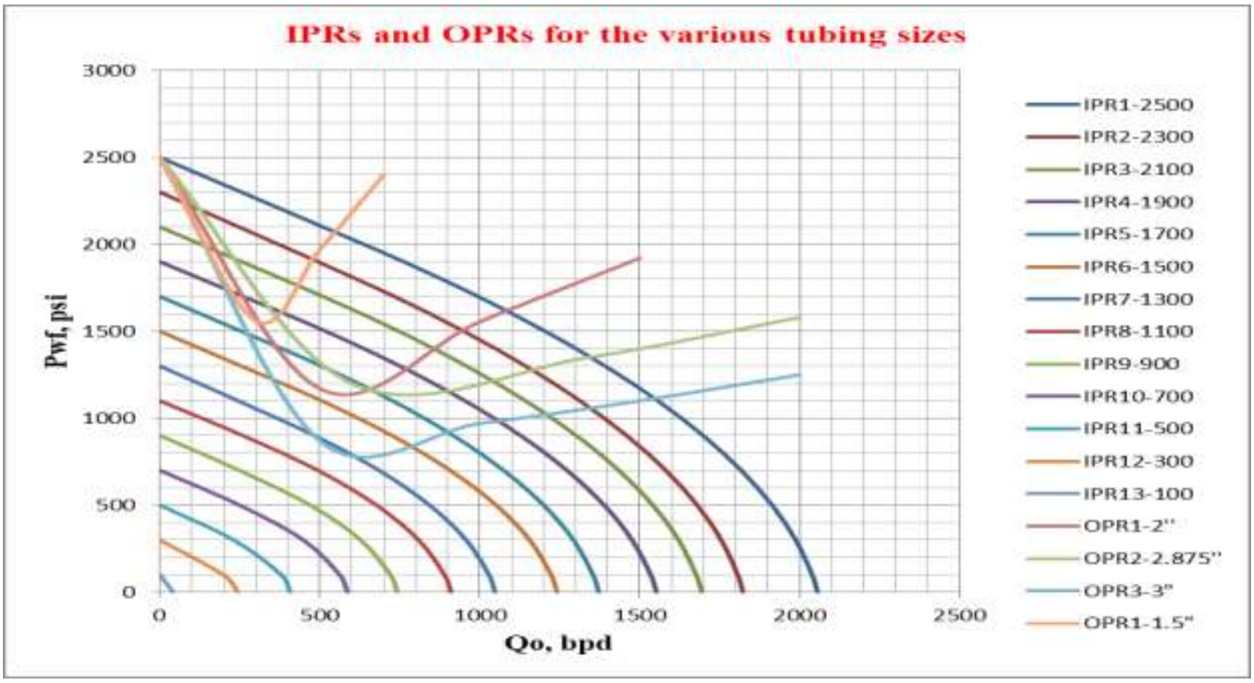


Fig. 9: Result of using various tubing size to Plot OPRs vs. IPR

Table 3: Various Tubing size with their Equivalent flow capacities

Tubing Size (inches)	**P_{wf} (psia)**	**Q_o (bpd)**	**$\Delta P = P_{wf} - P_{wh}$ (psi)**
1.5"	2080	550	2080-150=1930
2"	1610	1090	1610-150=1460
2.875"	1350	1350	1350-150=1200
4"	1100	1550	1100-150=950

D. *Recovery and Production s' Estimation based on Future time of Reservoir:*

The available average pressure of reservoirs' prediction based on time is a matter of great importance in the economics of reservoir value and development planning. The time of utilizing artificial lift and the time of installing the pumps and compressors becomes a necessity when production capacities are no longer sufficient. Two steps are required to accomplish this:
From fig. 10 and the corresponding average pressure P_{avg} are set as correspond to the incremental oil recovery ΔNp.
The average pressure is then applied on the fig. 11 to calculate the corresponding average equivalent production capacity Q_{oavg}. The equations (13. 14 and 15) can be used to calculate incremental time, total time and cumulative oil production, respectively.
Fig. 12 shows the result of reservoir performance. At almost 17505 days the field capacity flow reaches 50 bpd. After this point, production levels can be optimized by positive displacement pumping.
Fig. 13 represents the diffusion of the average reservoir pressure over time. Pressure depletion of the reservoir goes on to an area of around 900 psia. At abandonment, the produce of cumulative oil is about 6,300,000 stb. To select a production increment of 100,000 stb, determine the value of average pressure of reservoir Pavg that subsist within this producing period from fig. 10. Then from fig. 11 the value of Pavg is used to set the corresponding Qo(avg). The result of the production performance of the reservoir regarding time is provided in Table 3.

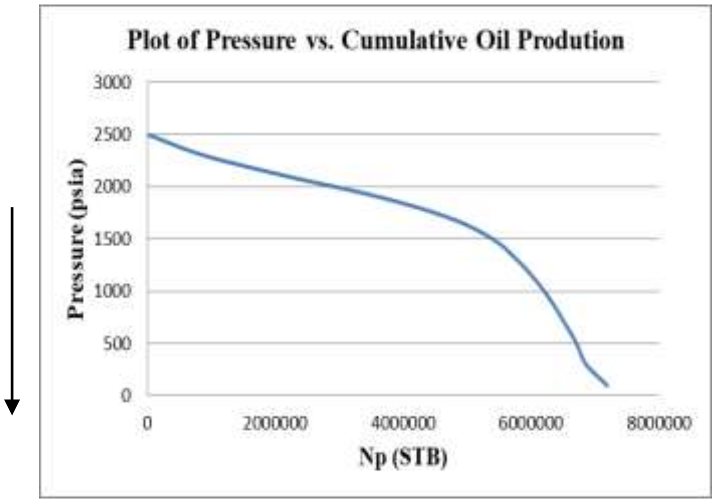


Fig 10: Cumulative oil production vs. average reservoir

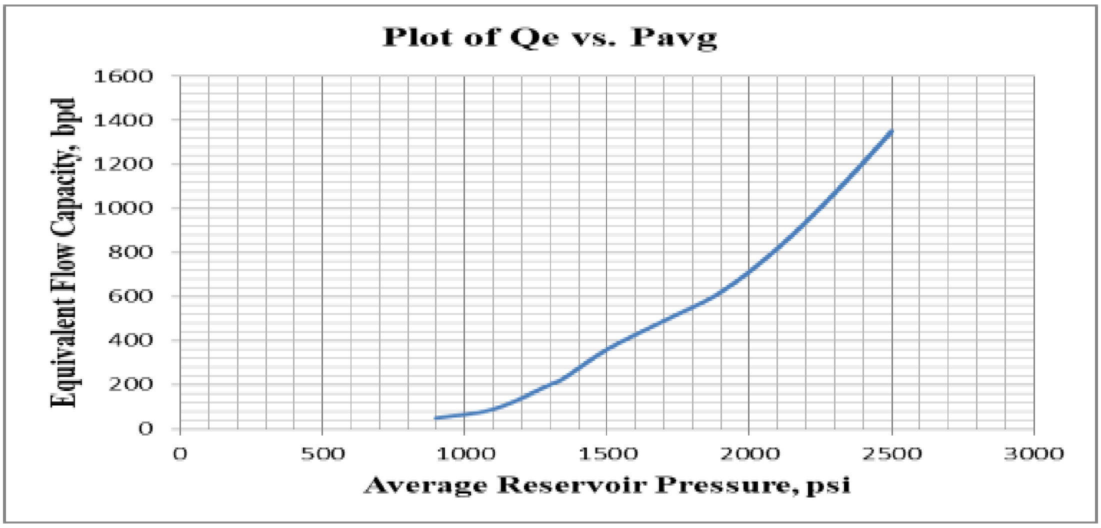


Fig. 11: Decline pressure vs. Equivalent flow capacity

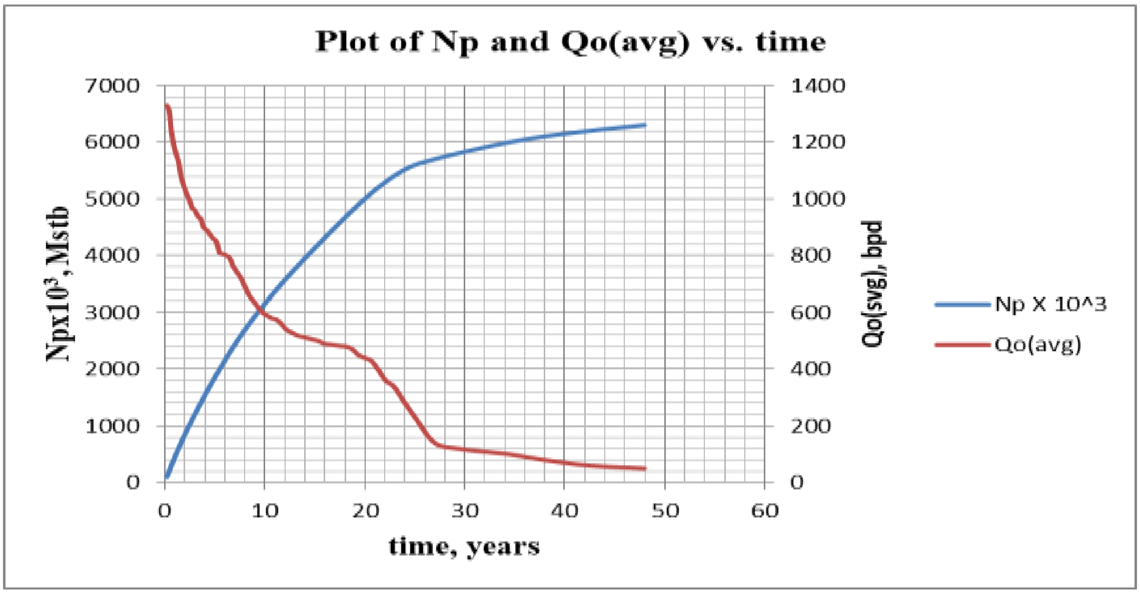


Fig. 12: shows production performance (NP and Qoavg) vs. time

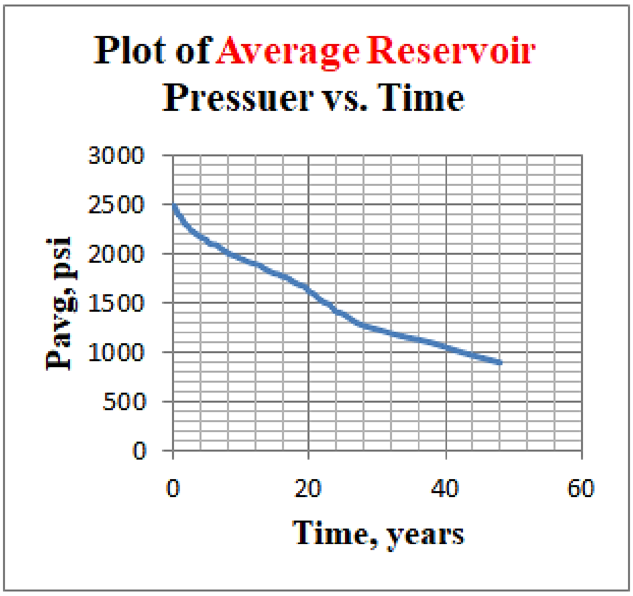


Fig. 13: Average reservoir pressure vs. tim

Table 4: the performance of reservoir production as a function of tim

$\Delta N_p \times 10^3$ STB	$N_p \times 10^3$ STB	P_{avg} PSIA	$Q_{o(avg)}$ BPD	Δt DAYS	t DAYS	Tubing String	t YEAR
100	100	2470	1320	74.09	74.09	2 7/8"	0.206
100	200	2450	1310	76.34	151.52	2 7/8"	0.415123
100	300	2410	1240	80.65	232.17	2 7/8"	0.636082
100	400	2400	1190	84.03	316.20	2 7/8"	0.866301
100	500	2380	1160	86.21	402.41	2 7/8"	1.102493
100	600	2350	1130	88.50	490.91	2 7/8"	1.344959
100	700	2320	1080	92.59	583.50	2 7/8"	1.59863
100	800	2300	1050	95.24	678.74	2 7/8"	1.859562
100	900	2290	1020	98.04	776.77	2 7/8"	2.128137
100	1000	2260	1000	100.00	876.77	2 7/8"	2.40211
100	1100	2240	970	103.09	979.87	2 7/8"	2.684575
100	1200	2230	960	104.17	1084.03	2 7/8"	2.969945
100	1300	2210	940	106.38	1190.42	2 7/8"	3.261425
100	1400	2200	930	107.53	1297.94	2 7/8"	3.556

100	1500	2180	900	111.11	1409.06	2 7/8"	3.860438
100	1600	2170	890	112.36	1521.41	2 7/8"	4.168247
100	1700	2160	875	114.29	1635.70	2 7/8"	4.48137
100	1800	2150	860	116.28	1751.98	2 7/8"	4.799945
100	1900	2120	850	117.65	1869.63	2 7/8"	5.122274
100	2000	2105	810	123.46	1993.08	2 7/8"	5.460493
100	2100	2102	805	124.22	2117.31	2 7/8"	5.800849
100	2200	2100	800	125.00	2242.31	2 7/8"	6.143315
100	2300	2090	790	126.58	2368.89	2 7/8"	6.49011
100	2400	2070	760	131.58	2500.47	2 7/8"	6.850603
100	2500	2050	740	135.14	2635.60	2 7/8"	7.220822
100	2600	2035	720	138.89	2774.49	2 7/8"	7.601342
100	2700	2015	690	144.93	2919.42	2 7/8"	7.998411
100	2800	2000	660	151.52	3070.94	2 7/8"	8.413534
100	2900	1990	640	156.25	3227.19	2 7/8"	8.841616
100	3000	1980	620	161.29	3388.48	2 7/8"	9.206
100	3100	1960	600	166.67	3555.14	2 7/8"	9.415123
100	3200	1950	590	169.49	3724.63	2 7/8"	9.636082
100	3300	1935	580	172.41	3897.05	2 7/8"	10.866301
100	3400	1920	575	173.91	4070.96	2 7/8"	10.283507
100	3500	1910	560	178.57	4249.53	2 7/8"	10.74011
100	3600	1900	540	185.19	4434.72	2 7/8"	11.20447
100	3700	1890	530	188.68	4623.40	2 7/8"	11.67685
100	3800	1860	520	192.31	4815.70	2 7/8"	11.15332
100	3900	1840	515	194.17	5009.88	2 7/8"	12.64255
100	4000	1820	510	196.08	5205.96	2 7/8"	12.14992
100	4100	1805	505	198.02	5403.98	2 7/8"	12.66685
100	4200	1800	500	200.00	5603.98	2 7/8"	13.1937
100	4300	1780	490	204.08	5808.06	2 7/8"	13.7257
100	4400	1770	488	204.92	6012.98	2 7/8"	14.2629
100	4500	1750	485	206.19	6219.16	2 7/8"	14.80542
100	4600	1720	482	207.47	6426.63	2 7/8"	15.35337
100	4700	1700	480	208.33	6634.96	2 7/8"	15.91249
100	4800	1685	470	212.77	6847.73	2 7/8"	16.47392
100	4900	1670	450	222.22	7069.95	2 7/8"	17.03879
100	5000	1620	440	227.27	7297.23	2 7/8"	17.60721
100	5100	1600	430	232.56	7529.78	2 7/8"	18.17797
100	5200	1550	400	250.00	7779.78	2 7/8"	18.7609
100	5300	1510	360	277.78	8057.56	2 7/8"	19.36973
100	5400	1490	340	294.12	8351.68	2 7/8"	19.99241
100	5500	1420	290	344.83	8696.51	2 7/8"	20.62953
100	5600	1390	230	434.78	9131.29	1.5"	21.31447
100	5700	1300	140	714.29	9845.57	1.5"	22.07551
100	5800	1250	120	833.33	10678.91	1.5"	22.88132
100	5900	1200	110	909.09	11588.00	1.5"	23.82605
100	6000	1150	100	1000.00	12588.00	1.5"	25.01723
100	6100	1100	80	1250.00	13838.00	1.5"	26.97416
100	6200	1000	60	1666.67	15504.67	1.5"	29.25729
100	6300	900	50	2000.00	17504.67	1.5"	31.74795

CONCLUSION

Using technical method to design and outline artificial lift tubing strings and primary flow for the whole an oil well's stages is the first aim of this work. The concentration was focused on depletion gas drive reservoirs which are distinguished by that its pressure declines a rapidly and continuously. Minor eventual oil recovery is the main con of depletion drive mechanism and it proposes that the larger percent of oil in the reservoir will be left as residual oil saturation. The natural recovery from this drive was measured and projected by using the technique of Muskat for material balance on the basis of synthetic material balance data. The relationship amidst average reservoir pressure and cumulative production was resolved. It appeared that by depleting the reservoir to 115 psi, a recovery of about of 13% STOIIP could be acquired at around 115,000 scf/stb of GOR. Moreover, it was noticed that there is adequate amount of gas produced to lift the well. Based on the result of this project, depletion – gas drive reservoirs has been considered as the top option for secondary recovery usage because of their slight eventual recovery which is about 13% STOIIP. The eventual oil recovery can be boosted in this project by using Gas lift, additionally; the expansion energy of the injected gas raises the oil to the surface. The gas also aerates the oil (decreases the oil's weight) in a manner that the influential fluid density is slighter and, hence, it reaches the surface more readily.

Outflow performance of a well is observed to be hugely proportional to the size of the tubing. As mentioned in the previous sections, each of smaller and larger tubing size affects the production rate in a distinct manner. Smaller tubing has higher frictional loss but lower production rate. Larger tubing size has a lower frictional loss, but causes loading of liquid. For example, The 2 7/8" tubing results in an extra adequate frictional loss in comparison to that of 4" and 2" tubing with an equilibrium production rate of around 1350 bpd and an equivalent bottom-hole flowing pressure of around 1350 psi. Moreover, the tubing string sizes affect the flowing pressure that is required for lifting the fluids. Therefore, the replacement time of tubing string based on cumulative production was resolved. This was attained by associating performance to time in an effort to encounter the second aim which was to prognosticate the oil production, plus replacement time of tubing string as a function of both time and cumulative production. Velocity string is characterized by high friction losses which at low reservoir pressure hinder the oil flow. Consequently, positive displacement pumping was more acceptable choice in reservoir production after reaching the depleted pressures.

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