Simulation of Solution Gas Drive Reservoir

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Abstract —— **Solution gas drive reservoirs are characterized by a rapid and continuous decline of reservoir pressure. This type of reservoirs are suffering from the early decline of reservoir performance at the primary stage of its life. The classical methods of predicting solution gas drive reservoirs are based on setting assumptions considering the whole reservoir to be a homogeneous tank of uniform rock and fluid properties. They ignore the pressure changes across the reservoir and all fluid properties and pressure are averaged over the entire reservoir. Such simplified assumptions restrict the general solution to special cases. Because of these limitations of material balance methods, Reservoir simulation is used to approximate the general solution for fluid flow equations by using a finite difference approach to calculate reservoir pressure and fluid saturation in a reservoir at different spaces and times depending on fluid and rock properties. The effect of production rate on recovery, the effect of geometry, location, and well spacing, and which are the most effective parameters on recovery can be investigated under different conditions by using the reservoir simulation technique.**

The effect of parameters such as production rate and well drainage area on predicting the variation of pressure and saturation in the reservoir is considered. It is concluded that solution gas drives reservoir production under large pressure and saturation gradients are sensitive to production rate with respect to time of production. The well bottom hole pressure from the simulator is compared to the well bottom hole pressure calculated from the analytical solution of the good test equation of two-phase flow and gives a reasonable match for the first time of production. While oil saturation at the well from the simulator is compared to the oil saturation at the well from the analytical solution and didn't give a good match.

I. INTRODUCTION

Solution gas drive is one of the most common drive mechanisms in oil reservoirs. In this type of reservoir, the recovery of oil occurs by the expansion of fluids in the reservoir and its associated pore space. There are two stages of drive forces associated with this kind of reservoir. When the initial pressure is above bubble point pressure, the drive of oil occurs due to the effective compressibility of the system (oil, connate water, pore space). In the second stage of drive when the reservoir pressure reaches the bubble point pressure, the driving force comes from the expansion of gas released from the solution as pressure declines. The liberated gas bubbles expand and increase in size until the critical gas saturation is reached then gas can flow with oil and causes a reduction of oil due to pressure decline and reduce oil permeability. Liberated gas can migrate vertically depending on vertical permeability and can form secondary gas gap. The principal drive mechanism is the expansion of the oil and its originally dissolved gas as well as the associated pore space. The increase in fluid volumes during the process is equivalent to the production. As pressure is reduced rapidly and continuously in this type of reservoir remarked by [1], the oil expands due to compressibility and eventually gas comes out of the solution from the oil as the bubble point pressure of the fluid is reached. The expanding gas provides the force to drive the oil hence the term solution gas drive. It is sometimes called dissolved gas drive [2].

When the gas saturation reaches the critical value, the free gas begins to flow. At fairly low gas saturations, the gas mobility, k_g/u_g, becomes large and the oil mobility, k_o/u_o, is small, resulting in high gas-oil ratios and in low oil recoveries, usually in the range of 5 to 25% [3].

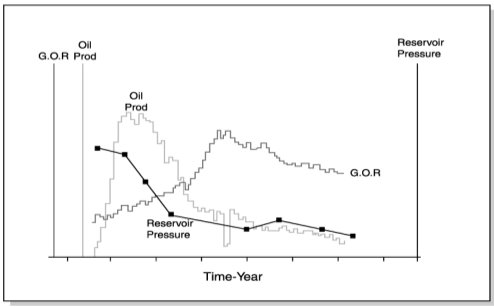

Figure 1. Ideal Production behavior of a solution gas-drive reservoir

Predicting the performance of solution gas drive was first studied by Traner, Musket, and Tracy. Their method is based on employing and combining three equations (material balance equation, instantaneous GOR, saturation equation). These methods relate the pressure decline to the oil recovery and gas-oil ratio. Several methods including Muskat's method, Schilthius' method, Tracy's method and Tarner's method have appeared in literature for predicting the recovery performance of this type of reservoir based on rock and fluid properties

The Muskat's method gains a slight advantage over the others as seen in its wide application due to its simplicity. In furtherance to this, the analysis of the reservoir deliverability to estimate the production rate at any given flowing bottom-hole pressure is a key to forecasting reservoir performance[4]. In the Musket method, the rate of change of variables that affect the production of gas and oil assumed can be evaluated for a small drop in pressure. The incremental gas and oil production can be calculated for the small pressure drop [3]. The Muskat method is based on the assumption of uniform oil saturation in the whole reservoir and the solution will break down when there is appreciable gas segregation in the formation. In the Muskat method, the values of the many variables that effect the production of gas and oil and the values of the rates of changes of these variables with pressure are evaluated at any stage of depletion pressure.

Objective of Study

Analysing the performance of solution gas drive reservoir by using black-oil model of reservoir simulator Eclipse-100

Studying the pressure and saturation changes with time and space inside the reservoir system and near wellbore

Problem Statement

Classical material balance methods are applied after making simplifying assumptions which restrict the general solution to special cases

Because of these limitation of material balance methods, Reservoir simulation is used to approximate the general solution for fluid flow equations by using finite difference approach to calculate reservoir pressure and fluid saturation in a reservoir at different space and time depending on fluid and rock properties

Scope of Work

Constructing radial cylindrical reservoir model with one vertical well in the Centre. Input fluid and rock properties and general reservoir data into simulator , initialize the model, and test the simulation results. Interpretations and recommendations

A. *Modified Methods for Predicting the Performance of Solution Gas Drive.*

All the mentioned methods use the static material balance principle with the combination of dynamic principle of current producing gas-oil ratio equation to predict the performance at average reservoir pressure when gas saturation exceeds the critical value using rock and fluid properties [3]. These methods assume uniform pressure and saturation throughout the reservoir. To improve the reliability of prediction, some investigators tried to modify these methods to take into account the effect of pressure and saturation gradients throuout the reservoir.

El-khatib presents a new modified method to relate the pressure at the well to the average reservoir pressure by an equation derived from the analytical solution of the diffusivity equation .He also relate the oil saturation at the well to the average oil saturation in the reservoir. The producing gas-oil ratio was evaluated from the pressure and saturation at well. In this method the effect of such parameters as production rate, well spacing, and well damage on reservoir performance were considered. It was concluded that solution gas-drive reservoirs producing under large pressure and saturation gradients are sensitive to production rate. Other investigators extended the application of Muskat model to any point in the reservoir when the pressure and saturation gradient were small. In all of the methods mentioned previously, the effect of gravity and capillary pressure The heterogeneity of reservoir properties and the complexity of fluid flow phenomena in porous media was the reason behind the development of numerical reservoir simulation as a new tool in predicting the performance of reservoir beside the classical material balance calculations The objective of this research was to investigate into the effects of flow rate and drainage area on flow capacity, how cumulative production relates to the decline pressure and time and how average reservoir pressure declines with time

oil recovery, and produced oil. These methods include Muskat's method, Schilthius' method, Tracy's method and Tarner's Method. Due to the complexity of this type of reservoirs a number of simplified conventions are made to make their solution reasonably simple[3]. Among them includes the fact that the reservoir is uniform at all times regarding porosity, flu id saturations and relative permeabilities. It is also assumed that uniform pressure exit throughout in both gas and oil

zones which implies that gas and oil volume factors, gas and oil viscosities as well as solution gas will remain the same throughout the reservoir. It is further assumed that

B. Analytical Solution of Diffusivity Equation for Two Phase Flow

El-Khatib presents equation derived from the analytical solution of diffusivity equation. This equation relates the pressure at the well to the reservoir pressure as follows

$$P_{wf} = P_{av} - \frac{70.6xQ_t}{kh\lambda_{tot}} \ln\left(\frac{2.2458xA}{C_A r_w^2} e^{2S} \right)$$

This equation will be used to estimate the following well pressure at a given average reservoir pressure. This equation also will used in examining the validation of reservoir model by comparing bottom hole pressure calculated by the simulator to that one calculated by the equation. For two phase flow (oil and gas) the value of λ_{tot} depends on the saturation at the well where:-

$$\lambda_{tot} = \frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g}$$

$$Q_t = q_o B_o + (q_g - q_o R_s) B_g$$

II. MATERIALS AND METHODS

The study begins with identifying the key elements of predicting the performance of solution gas drive reservoir and the classical material balance methods used in predicting the performance of such kind of reservoirs .The classical tank model which assumes uniform distribution of properties within the reservoir is replaced by the new numerical reservoir simulation technique that divides the reservoir into many small blocks to take into consideration the variation and heterogeneity in the reservoir properties.

A. Single well simulation

Single well simulation study used in reservoir engineering for studying for water and gas coning problems and well testing. it can be used to predict the well productivity and future performance. In single well model radial-cylindrical coordinates systems are used to model movement of water or free gas towards producing well. Radial cylindrical system are un equally in space the block away from the well is large while the block close to the well is small. Hence, there is some difficulty stems from the increasing in fluid velocity in the near-wellbore vicinity. For this reason, it is necessary to take smaller time steps to generate numerically stable results. [6] mentioned some rules relating to construction of a cylindrical grid system in which The pressure points are spaced logarithmically away from the well bore i.e $r_{i+1}=\alpha lg\ r_i$ where i=1,2,3 …nr-1 and $\alpha lg= (re/rw)^{1/nr}$ for block –centered grid . The block boundaries for interblock flow calculations are determined by the formula

$$r_{i+1/2} = \frac{r_{i+1} - r_i}{log_e(r_{i+1}/r_i)}$$

B. Data Required for Simulation study

An inadequate reservoir description data may leads to the error in the results of simulation. It is necessary to check the quality and quantity of required data for simulation study. Depending on available data and the knowledge of the nature of physical processes taking place in the reservoir the reservoir simulation model can be classified in several ways according to the features of models. [5] classified the reservoir models depending on the following features and their treatments.

The data used in the study was taken from an offshore field in shallow marine environment water depth about 50 m .The reservoir structure is anticline and the lithology of reservoir is sandstone .Oil column about 130 ft thickness. The top of the reservoir lies on a 4815 ft TVs .There is no free gas cap and gas-oil contact depth is set at the top of formation and water-oil contact about 4948 ft .The formation pressure is normal pressure .The reservoir is saturated reservoir the initial pressure 2139 psia and the bubble point pressure from constant composition expansion test is 2116 psi and solution gas oil ratio from deferential vaporization test at 2116 psia and 155 °F is 334 scf/stb .The initial reservoir temperature is 155 °F as measured during well test. Oil density about 23.7 °API . TABLE.1 Rock and fluid properties

Rock and fluid properties	
Porosity %	0.36
Thickness ,ft	130
Permeability , md Kr= K_θ=KZ	300
Reservoir Temperature, °F	155
Rock compressibility,1/psi	2.787 e-006 at 1874 psi
Water compressibility ,1/psi	2.9955 e-006
Water FVF, RB/STB	1.013825
Water viscosity ,cp	0.4129
Depth to top of formation, ft	4815
Initial condition	
Initial pressure ,psi	2139
Reservoir depth, ft	4815
Bubble Point Pressure	2116

This study focus on analyzing the reservoir pressure and saturation variations within reservoir and near well bore vicinity. Since the best reservoir model is the simplest model which still represents realistically all important aspects of the physical process of interest [5] , a simple representation of reservoir with uniform distribution of properties will be used in defining the reservoir model .

with one rock type. Net to cross value (NTG) A single-well Radial Cylindrical reservoir model has been developed for simulating reservoir performance when reservoir pressure drops below the initial bubble point pressure .The radial model is a representation of one well with drainage volume covering an area of external radius about 500 ft with no flow boundary . This model assumes homogeneous reservoir with uniform porosity 0.36 and permeability 300 md within one horizontal layer with net sand thickness 130 ft, and ratio of vertical to horizontal permeability (kv/kh) is 1 .An r/z model as shown in Figures (2) and(3) has cell radii ri+1/ri=constant .As stated in literature [5] when radial flow equation solved numerically , smaller and smaller grid increments are necessary as (r $\longrightarrow$ rw) in order to maintain uniform accuracy (the ratio of largest to smallest Δr is typically of the order of 100.) The logarithmic grid cell spacing defined by the formula:-

$\frac{r_{i+1}}{r_i} = (\frac{r_e}{r_w})^{\left(\frac{1}{(N-1)}\right)}$ Where i=1, 2, 3,…….., N and N = number of grid cells. This radial model has a well radius rw=0.583 ft (7″ well bore) and the external boundary

radius re=500 ft. Two cases of number of grid cells″ has been tested with the model; case-1 (N=50), case -2 (N=100).The details of gridding are presented in Table (2). The only fluid in the reservoir is oil with connate water and dissolved gas .No initially or secondary gas cap and no active water influx. Lithology of reservoir is sandstone with one rock type. Net to cross value (NTG) assumed equal to 1. For purpose of studying the near well bore changes in pressure and saturation, the effect of changing grid size and production rates will be examined at different cases to study pressure and saturation profile change in the reservoir in the r direction. Table- 1 gives a detail description of the developed reservoir model

TABLE.2 Details of grid dimensions

Radial model case-1	
Gridding model	50 x 1 x 1
Well radius(r_w), ft	0.583
Outer boundary radius (r_e), ft	500
Vertical thickness (Δz), ft	130
Angle in Theta direction, degree	360
Radial coordinates, (Δr), ft 0.09 0.10 0.11 0.13 0.15 0.17 0.20 0.23 0.26 0.30 0.34 0.39 0.45 0.52 0.59 0.68 0.78 0.90 1.03 1.18 1.36 1.56 1.79 2.05 2.36 2.70 3.10 3.56 4.09 4.69 5.39 6.18 7.09 8.14 9.35 10.73 12.31 14.13 16.22 18.62 21.37 24.53 28.16 32.32 37.09 42.58 48.87 56.09 64.38/	
Radial model case-2	Same values of (r_w , r_e, Δz and ө)as in case-1
Gridding model	100 x 1 x 1
Radial coordinates (Δr).ft 0.04 0.04 0.05 0.05 0.05 0.06 0.06 0.07 0.07 0.08 0.08 0.09 0.09 0.10 0.11 0.11 0.12 0.13 0.14 0.15 0.16 0.17 0.18 0.20 0.21 0.23 0.24 0.26 0.28 0.30 0.32 0.34 0.37 0.39 0.42 0.45 0.48 0.51 0.55 0.59 0.63 0.68 0.720.77 0.83 0.89 0.95 1.02 1.09 1.171.25 1.34 1.43 1.53 1.64 1.75 1.88 2.01 2.15 2.30 2.47 2.64 2.83 3.03 3.24 3.47 3.72 3.98 4.26 4.56 4.88 5.23 5.60 5.99 6.41 6.87 7.35 7.87 8.43 9.02 9.66 10.34 11.07 11.85 12.69 13.58 14.54 15.57 16.67 17.84 19.10 20.45 21.90 23.44 25.10 26.87 28.77 30.80 32.97	

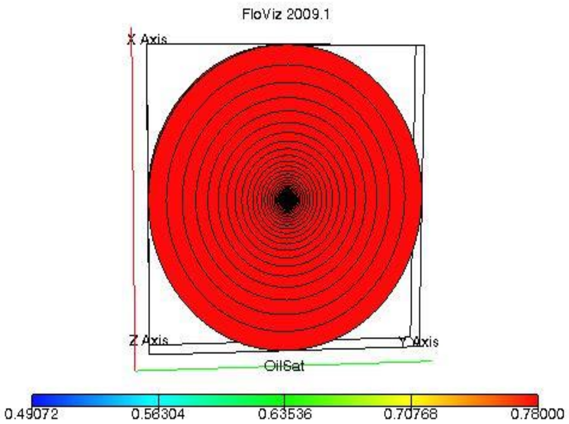

Figure 2. Radial grid model cas-1 (number of grid cells is 50)

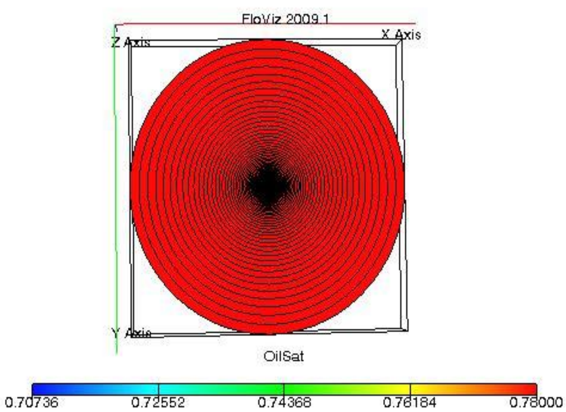

Figure 3. Radial grid model case-2 (number of grid cells is 100)

III. RESULTS OF SIMULATION

A. Matching Initial Fluids in Place

To make sure the reservoir model which has been input to the simulator is validated for initial time, it is useful to check the amount of initial fluids in place calculated by the simulator. The amount of initial fluids in place oil and dissolved gas calculated by the simulator should be in agreement with volumetric calculations. STOIP is calculated in volumetric calculation equal to 4.40 x10^6 STB and dissolved initial gas equal to 1472.76 x10^6Mscf. The simulator gives approximately the same amount of fluids in place

SUMMARY OF RUN radial

DATE	YEARS YEARS	DAY	MONTH	YEAR	FOIP STB	FGIP MSCF *10**3	FOE	FGOR MSCF/STB
01-JAN-2010	0	1	1	2010	4419766	1469.696	0	0

The yellow highlighted figures represents field oil in place (FOIP) and field gas in place (FGIP) as calculated by the simulator

B. Interpretation of the Results of Simulation

The simulator has been run by using the same input file data with changing some parameters at each time to study the effect of changing these parameters on the distribution of pressure and phases saturation within the reservoir when the reservoir is produced for a period of time between 1000 to 3000 days. The following cases have been tested:-

Case-1

The well is produced with 1000 STB/D with and Setting well bottom

hole pressure to 1000 psi

Case-2

The well is produced with 5000 STB/D with and

Setting well bottom hole pressure on 1000 psi

Two cases of number of grid cells in the model

Grid model consist of 50 grid cells (as defined in radial model Table 2-case-1)

Grid model consist of 100 grid cells (as defined in radial model Table 2-case-2)

The following results are obtained from the simulation. In order to infer the distribution of pressure and saturation, the graphical plots between the following parameters are displayed by eclipse office:-

Well Pressure, average field pressure, and external pressure versus time on normal and log scale for different production rates. Oil saturation at the well and average field oil saturation versus time. Gas saturation at the well and average field gas saturation versus time Block pressure versus distance from well bore(radius)

Block pressure versus distance from well bore on logarithmic scale Field GOR versus time for different production rates and different well bottom hole pressure limit. Field average pressure and field oil saturation versus time for different rates. Field average pressure field GOR, and field oil saturation versus recovery factor for different production rates. Field average pressure ,field GOR, and field production rate versus time for different production rates

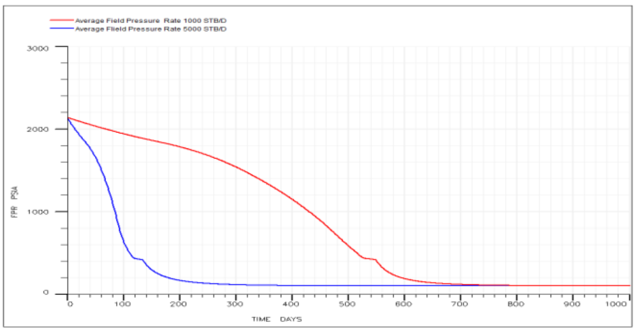

Figure 4. Average field pressure versus time . Production Rate 1000 /5000 STB/D

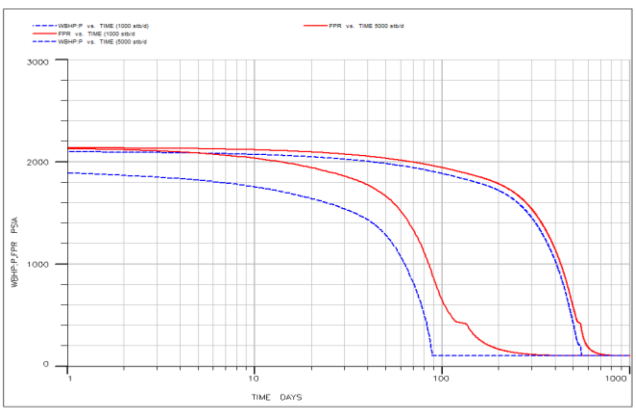

Figure 5. well pressure,average field pressure ,and externalpressure versus log tim . Production Rates 1000/5000 STB/D

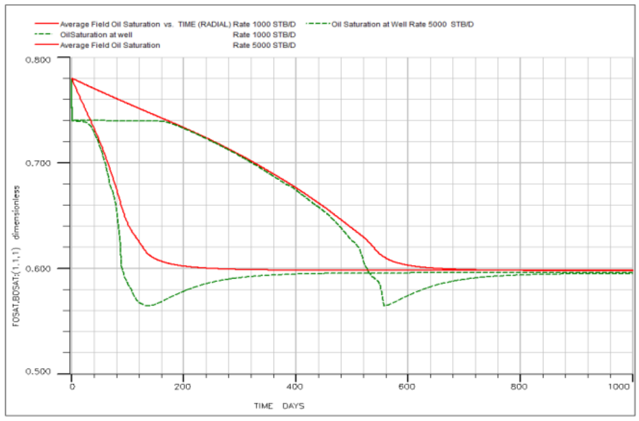

Figure 6. oil saturation at the well and average field oil saturation versus time . Production Rates 1000 /5000 STB/D with bottom hole pressure limit 100 psi

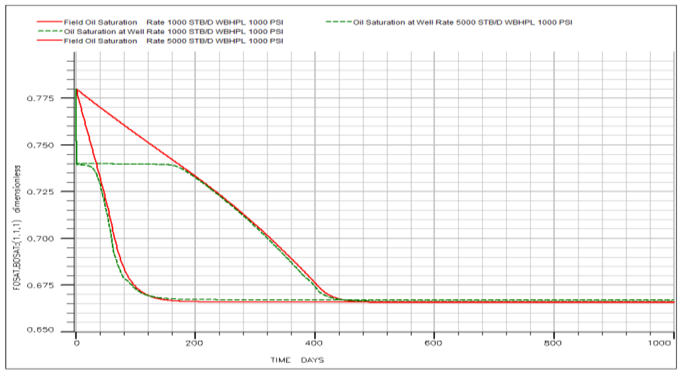

Figure 7. oil saturation at the well and average field oil saturation versus time . Production Rates 1000 /5000 STB/D with well bottom hole pressure 1000 psi

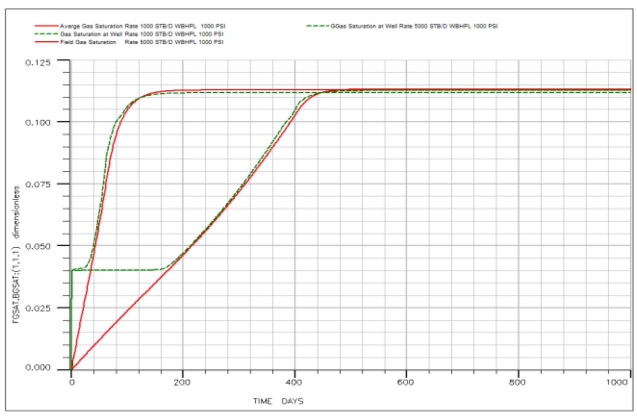

Figure 8. gas saturation at the well and average field gas saturation versus time . Production Rate 1000 /5000 STB/D with bottom hole pressure limit 1000 psi

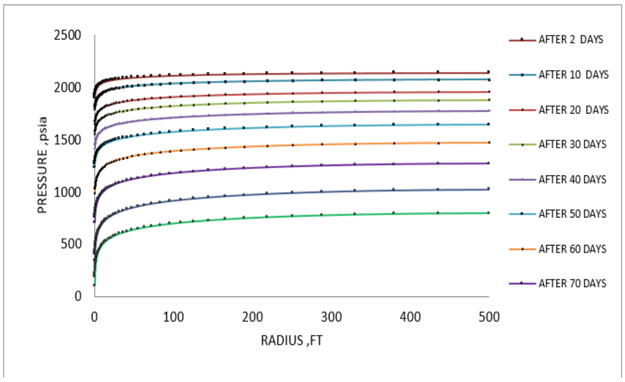

Figure 9. Block Pressure versus radius (for 50 cells-5000 STB/D –WBHPL(100 psi)

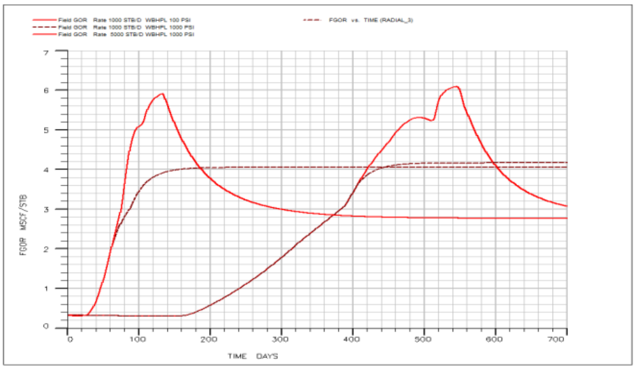

Figure 10. Gas oil ratio for different production rates 1000/5000 STB/D- WBHPL(100 psia)

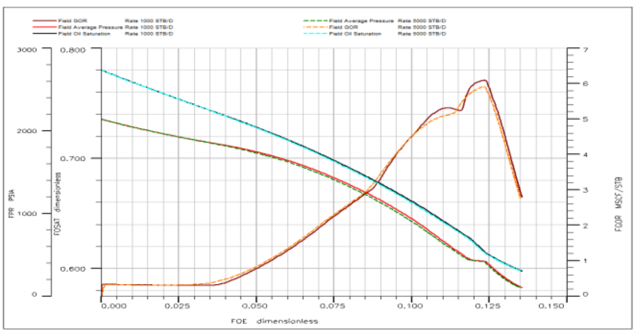

Figure 11. FPR,FOSAT ,and FGOR versus Recovery factor (FOE) . Prodution Rates 1000/5000 STB/D-WBHPL(100psia

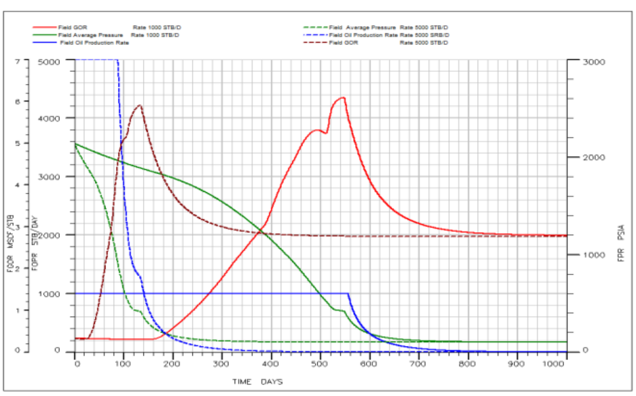

Figure 12. FGOR ,FPR&FOPR versus TIME - Prodction Rates 1000/5000 STB/D- WBHPL(100psia)

C. Comparison of Pressure at Well (Pwf) Calculated by Simulator with the Analytical Solution

By assuming skin factor is zero and taking geometry factor CA for circular reservoir equal to 36.1,the following results are obtained from analytical solution**:-**

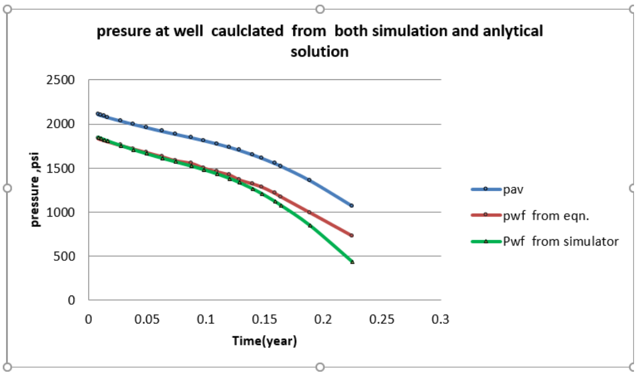

Figure 13. Comparison of P_{wf} from simulation and P_{wf} from analytical solution

D. Comparison of Oil Saturation at Well (Sow) Calculated by Simulator with the Analytical Solution.

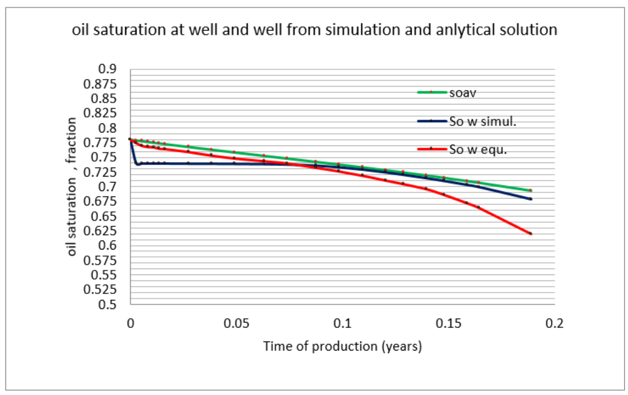

Figure (14) Comparison of So_w from simulation and So_w from analytical solution

IV. DISCUSSIONS OF THE RESULTS

From the obtained results, it is concluded that there are two factors, which are production rate and drainage area, can be identified to have great effect on both reservoir pressure and fluids saturation in the reservoir. When the well is produced at constant rate the pressure decline rate depends on parameters such as drainage area, hydraulic diffusivity(k/μφc), and well bottom hole pressure. For the first time of production, the pressure decline in the well bore and the blocks near the well bore is not affected by the presence of boundaries out in the reservoir and the system appears to be infinite and the flow is described as transient flow in which $\frac{\partial P_{wf}}{\partial t}$ is variable. When the production proceeds with time the outer boundary influences the pressure response. When keeping production rate constant, the rate of change of pressure with respect to time is constant and the flow is semi-steady state flow. As in figure (14) transient period is very short (2) days. Transient period depends on the magnitude of diffusivity constant k/(μφc) which in our case is large. When diffusivity constant is large the reservoir pressure reaches equilibrium faster and the period of transient flow will be short.

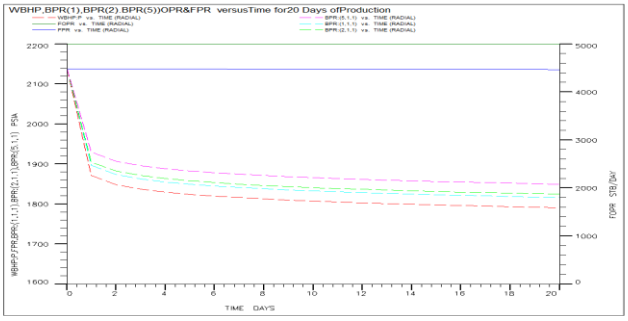

Figure 15. Reservoir pressure response for the first time of production

Solution gas drive reservoirs are very sensitive to production rate with respect to time of production When the well is produced with 5000 STB/ D, the pressure decline and increase in field GOR is much greater than when the well is produced at 1000 STB/D. This is shown in figures (4) and (10). In terms of recovery factor the difference in the reservoir pressure and gas oil ratio is very small with different production rates as shown in figure (11).

The second factor is well bottom hole pressure limit. When the well is produced with setting well bottom hole pressure limit on 100 psi , this case is identified by rapid pressure decline and high increase in GOR .Setting well bottom hole pressure limit on 1000 psi reduces the decline in reservoir pressure and reduces GOR . Less reservoir pressure decline and less increase in cumulative GOR will be achieved if the well bottom hole pressure is set at 1000 psi this is shown on figures (10). From this note, it is recommended for solution gas drive reservoir to produced at certain value of well bottom hole pressure to keep produced gas oil ratio within the designing limit and to keep reservoir pressure within the limit of being capable of pushing the produced oil to the well head and from well head to separation station.

The effect of taking two different cases of number of grid cells 50 grid cells or 100 grid cells is almost gives identical results when the grid block size divides up in a logarithmic spacing. The result will be different if the grid spacing is not logarithmic. Figure (9) of block pressure versus distance (radius) indicate that 90 % pressure drop is in the vicinity of well bore. The pressure at a grid block that contains the well is different from the average pressure and different from the flowing bottom hole pressure. This is not considered in the classical material balance approach which assumes all the parts of the reservoir have the same pressure and fluid properties. It ignores the minor variation in the vicinity of the well bore.

Figures (6) and (7) show how the difference between oil saturation at the well and the average field oil saturation .I t is clear the variation in oil saturation in the vicinity of well bore and the field . From this observation we can conclude how MBE calculation which assumes average oil saturation for the entire field is not realistic especially at the early stage of production when the variation in oil saturation is large between the near well bore block and the far block from the well.

The Figure (8) show the variation in gas saturation at the well and the average gas saturation. Figure (9) shows the difference in pressure with radius at different production times. From this graph we can know the predicted pressure value at any point in the reservoir along r direction and at any time of production. We can know how much the reservoir pressure will changed at any part of reservoir after any time of production if the reservoir is produced with a constant rate. It shows the pressure decline trend with time

and how at the final stage of production the pressure will be the same for all parts of reservoir when the depletion pressure is close to the bottom hole pressure. From this observation we can predicate the time in which it is necessary to maintain the reservoir pressure to keep it within the range in which the reservoir is capable of production according to the requirement and design of production of the field.

From the results we obtained the recovery factor doesn't exceed 15 % for all cases. This indicates that the recovery factor of the solution gas drive reservoirs is relatively low compared to the other drive mechanism because there is no other source of drive and the recovery due to the solution gas. Performance of the reservoir and the maximum recovery factor depend on the
properties of relative permeability of the reservoir. When the vertical permeability is large, it is recommended to produce the reservoir with less production rate to help in migrating the gas to the top of formation and keeping the gas saturation at the vicinity of well bore at minimum level to avoid the early depletion of the reservoir. The comparison between the pressure at the well (P_{wf}) calculated by simulator and the pressure at well calculated from the analytical solution as shown in figur(13)indicate that there is a reasonable match at the first time of production .The comparison of oil saturation at well from the simulator and oil saturation at the well from the analytical solution as shown in figures (14) indicates there is no good match between the two solution. The best results from the simulation depends on the accuracy of input data and if there is real reservoir model and real production data, The simulator can be adjusted to achieve a good matching .The best The future performance of the reservoir depends on the matching between the predicated performance of the reservoir and the historical observed data if they are available.

V. CONCLUTION

- For solution gas drive reservoirs, the effect of parameters such as production rate and well drainage area on predicting the variation of pressure and saturation in reservoir is considered. It is concluded that solution gas drive reservoir producing under large pressure and saturation gradients are sensitive to production rate with respect to time of production .In terms of recovery factor, production rate has no effect on pressure and saturation distribution in reservoir.
- Low oil recovery of solution gas drive reservoir can be attributed to the increase gas relative permeability due to increase gas saturation as pressure declines below bubble point pressure. The early gas production from the reservoir reduces the drive energy of reservoir and the economic production limit of the field may be reached early.
- Due to difficulties in control depletion process below bubble point, it is recommended to overcome this by not letting the pressure fall to this point by maintaining the reservoir pressure at high level and accelerating the oil recovery towards the producing wells by water displacement

The details of simulation technique is very important:- model geometry , gridding ,grid spacing , and time step have significant effect on results of simulation

The accuracy of the result of simulation depend on the accuracy of input data.They have to be matched with observed historical performance of the reservoir.

Material balance supports reservoir simulation and provides insights into reservoir drive mechanism and hydrocarbon in place. It is very good in history matching that should be done for model validation.

Solution gas drive reservoirs producing under large pressure and saturation gradients are sensitive to production rate

The early gas production from the reservoir reduces the drive energy of reservoir and the economic production limit of the field may be reached early

It is recommended to use early artificial lift methods to prolong the life of the field

It is recommended to get fluid samples for PVT analysis in the early time of production of the field

Reservoir simulation incorporates material balance on a cell-by-cell basis. It is a powerful tool for understanding oil and gas reservoirs and predicting the reservoir performance under different conditions

Reservoir simulation provides basis for better reservoir

VI. REFERENCES

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