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Simulation of Radial Three-Phase Coning System

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ABSTRACT

This study reviews the performance of a three-phase coning model when simulated at different oil production rates, varying perforation intervals and permeability anisotropies. Data from the second comparative solution project which is a three-phase radial model with fifteen layers was used to run the sensitivities for production rates, perforation intervals and permeability anisotropies of the system. ECLIPSE 100 was used to simulate the different scenarios with the knowledge of the radial extent and fluid contacts of the system. The results obtained indicate that larger production rates increase the pressure gradient and consequently, improve the recovery efficiency of a reservoir. Longer perforation intervals produce more water while shorter perforation intervals produce less water; conversely, longer perforation intervals produce less gas and shorter perforation produce more gas. This indicates that smaller perforation intervals are likely to increase the water breakthrough time which is desirable. The result of simulating different anisotropic values - 0.01, 0.1 and 1.0, showed that smaller values of anisotropy enhance the performance of the reservoir. Therefore, when the value of horizontal permeability is much larger than the vertical permeability, the anisotropic ratio will be smaller and better recovery efficiency will be achieved and coning is minimized; hence, shorter perforation intervals are recommended.

Keywords: *Three-phase, Reservoir Simulation, Coning, Production Rate, Perforation Interval, Anisotropy*

1. INTRODUCTION

Reservoir Simulation is required by Petroleum Engineers to obtain an accurate performance prediction for a hydrocarbon reservoir under different operating conditions. Coning is a phenomenon where oil-water contact or gas-oil contact is experiencing profile change due to preferential flow between the different phases surrounding the wellbore. In vertical or slightly deviated wells, the profile somehow looks like a cone where water or gas which has higher mobility than oil will preferentially produce through perforations due to pressure drawdown around the wellbore. Pressure gradient is created as a result of production from the well and it tends to lower the gas-oil contact and raise the water-oil contact in the region near the wellbore. The aim of this study is to examine well performance with respect to the flow rate, the perforation interval and the anisotropic ratio of a three-phase coning system in a radial cross section having only one central producing well.

ECLIPSE 100 [9] is being used to simulate the different scenarios of this study. A three-phase coning study is a challenge that provides a good test of the stability and convergence behavior of a simulator, such as the ECLIPSE 100. It is important to note that the reservoir has initially an oil pressure of 3,600 psia at gas/oil contact and the well is completed in Blocks 1, 7 and 1, 8. The Reservoir description is given in Tables 1, Reservoir data in Table 2 and PVT properties in Table 3.

Table 1: Reservoir Description

Layer	Thickness (ft)	Kx (md)	Kz (md)	Porosity
1	20	35	3.5	0.087
2	15	47.5	4.75	0.097
3	26	148	14.8	0.111
4	15	202	20.2	0.160
5	16	90	9	0.13
6	14	418	41.8	0.17
7	8	775	77.5	0.17
8	8	60	6	0.08
9	18	682	68.2	0.14
10	12	472	47.2	0.13
11	19	125	12.5	0.12
12	18	300	30	0.105
13	20	137	13.7	0.120

14	50	191	19.1	0.116
15	100	350	35	0.157

Table 2: Basic Reservoir Data

Geometry	
Radial extent, ft	2050
Wellbore radius, ft	0.25
Radial position of first block centre, ft	0.84
Number of radial blocks	0.25, 2.00, 4.32, 9.33, 20.17
Number of vertical layers	15
Dip angle, degrees	0
Depth to top of formation, ft	9,000
Radial Block boundaries, ft	0.25, 2.00, 4.32, 9.33, 20.17, 43.56, 4.11,203.32 439.24, 948.92 and 2050.00
Reservoir and Fluid Data	
Pore Compressibility, Psi^{-1}	$4*10^{-6}$
Water compressibility,	$3*10^{-6}$
Oil Compressibility for undersaturated Oil,	$1*10^{-6}$
Oil Viscosity compressibility for undersaturated oil,	0
Stock tank oil density , Ibm/ft3	45.0
Stock tank water density, Ibm/ft3	63.02
Standard condition gas density, Ibm/ft3	0.07
Initial conditions	
Depth of gas/oil contact (GOC), ft	9035
Oil pressure at gas/oil contact, psi	3600
Capillary pressure at GOC, psi	0
Depth of water/oil contact, WOC, ft	9209
Capillary pressure at WOC, psi	0
Well Data	
Completion blocks	(1,7) (1,8)
Permeability thickness	6200 480
Skin	0, 0
Minimum BHP	3,000
Pump depth, ft	9110

Evans (1970) used a two-dimensional, three-phase, numerical reservoir simulator developed by Esso Production Research Company to model a reservoir. This Simulator computes pressure and saturation distributions in reservoirs where gas, oil and water flow simultaneously using implicit iteration techniques to solve flow equations at various time steps. He concluded that water flooding will result in movement of oil into the gas cap without significant movement of oil to producing wells or improved recoveries over expected primary depletion.

Table 3: PVT Properties

	Saturated Oil				Water			Gas		
Pressure	Bo	Density	Viscosity	Solution,GOR	Bw	Density	Viscosity	Bg	Density	Viscosity
400	1.012	49.497	1.17	165	1.01303	62.212	0.96	5.90	2.119	0.0130
800	1.0255	48.100	1.14	335	1.01182	62.286	0.96	2.95	4.238	0.0135
1200	1.038	49.372	1.11	500	1.01061	62.360	0.96	1.96	6.397	0.0140
1600	1.051	50.726	1.08	665	1.0094	62.436	0.96	1.47	8.506	0.0145
2000	1.063	52.072	1.06	828	1.0082	62.510	0.96	1.18	10.596	0.0150
2400	1.075	53.318	1.03	985	1.007	62.585	0.96	0.98	12.758	0.0155
2800	1.087	54.399	1.00	1130	1.0058	62.659	0.96	0.84	14.885	0.016
3200	1.0985	55.424	0.98	1270	1.0046	62.734	0.96	0.74	16.236	0.0165
3600	1.110	56.203	0.95	1390	1.00341	62.808	0.96	0.65	19.236	0.0170
4000	1.12	56.930	0.94	1500	1.00222	62.883	0.96	0.59	21.192	0.0175
4200	1.13	57.534	0.92	1600	1.00103	62.958	0.96	0.54	23.154	0.0180
4600	1.14	57.864	0.91	1676	0.99985	63.032	0.96	0.49	25.517	0.0185
5200	1.148	58.267	0.90	1750	0.99666	63.107	0.96	0.45	27.785	0.0190
5600	1.155	58.564	0.89	1810	1.01182	63.181	0.96	0.42	29.769	0.0195

Water-coning is often a serious operational problem in oil formations with underlying water. (Alikhan and Ali, 1985). It was noted that in field operations, when water-coning is being considered a number of strategies, ranging from production limitation to production at maximum rate, possibly with interval control can be adopted. The state-of-the-art of water-coning was reviewed from the point of view of field operations, experimental modeling and numerical simulation. it was observed that water-coning control measures are of limited efficacy at best, under practical conditions. Production at very high rates - with concomitant high water production rates – was seen to be problematic in the Middle East reservoirs, with very highly saline connate water. Experimental modeling of water-coning was fairly successful on a single well basis but was not practicable on a field-wide basis, hence, the numerical difficulties involved and some of the solutions proposed. Generally, a useful view of all aspects of water-coning which should be of value to large segment of petroleum engineers and researchers was shown.

In the Second Comparative Solution Project, eleven companies were involved. The problem being considered was a three-phase coning system that could be described by a radial cross-section with one central producing well. The oil and water densities were nearly equal, so the oil/water capillary transition zone extends high up into the oil column. (Weinstein, *et al.*, 1986). Several reservoir simulators including a Vectorized Implicit Program (VIP) which are usually fully implicit, three-phase, black-oil simulators, were used by these companies to analyze this kind of model. These programs perform fully implicit, simultaneous calculations of pressure, saturation and wellbore. The program efficiently solve both single-well and field-scale production problems and is fully implicit in saturation and bubble points and use a modified Newton-Raphson iteration to solve simultaneously for three unknowns per grid block. (Weinstein, *et al.,* 1986). The different simulators used by these companies to address the problem were described. Though it was difficult to draw any general conclusions from the data, they were able to point out a few ideas that occurred while solving the problem. Some of the participants noted that the problem involves rate variations that would not likely occur in practice and the solution GOR is unusually high for oil with high density. (Ngheim *et al.*,1991 Christie and Blunt, 2001) Chen and Zhang, 2009)

1.1 Optimization of Oil/ Water Coning System

Guo and Lee, (1993) presented the mechanism of water coning process whereby; analytical solution was used to determine the optimum wellbore-penetration interval of a well that partially penetrates an oil reservoir from its top. This optimum completion interval was expected to be less than one-third of the total thickness of the oil zone depending on oil-zone thickness, wellbore radius and drainage area of the well. Two-phase super-critical performance of horizontal wells can be modeled by an extension of the gravity-drainage model for critical rate. Three-phase critical rate was modeled by coupling two two-phase models. The well location appears to have limited direct influence on the oil rate, whereas the gas and water rates were significantly affected by the well location. (Tiefenthal, 1994) The possibility of using horizontal well to reduce water coning and improve oil recovery was evaluated by Wu, *et al.*, 1995. The simulation results and field histories used showed that horizontal wells completed in the gas cap could significantly reduce water coning and improve the ultimate oil recovery in thin oil rim reservoirs.

1.2 Prediction of Critical Oil Rates

A generalized empirical correlation was developed by (Recham and Osisanya, 2000) to predict the critical oil rate and water breakthrough time in vertical and horizontal wells. Numerical simulation was used to analyze the relevant fluid and reservoir parameters that affect water coning in 3-D radial vertical well model and 3-D Cartesian horizontal well model. The method of determining the average oil column height below perforations at breakthrough (h_{wb}), was developed from the stepwise procedure. A number of simulation runs were made to investigate the coning performance at different reservoir and fluid properties for both models and appropriate plots were made. Water-oil ratio (WOR) was plotted against average oil column height below perforations (h_{bp}), on a semi-log scale, from which (h_{wb}) was determined. Once the (h_{wb}) data was obtained for all the simulation runs, regression analysis was then used to define the relationship between (h_{wb}) and various reservoir and fluid properties.

High water production problem is usually expected during the development of oilfield reservoirs. However, poor field results and low efficiency of operational efforts to mitigate the water production problem has been experienced in oil and gas production mainly due to lack of precise diagnosis to identify the problem. (Sheremetov, *et al.*, 2007)

2. METHODS

Eclipse 100 software is being used for this study to investigate the well performance for the following scenarios:

1. Running the simulator with different oil production rates (500, 1000, 2000STB/day) for a period of 3 years and examining the resultant water cuts, cumulative oil production and GORs.

2. Running the simulator with a constant oil rate of 1000stb/d, and three different well completion locations. The following blocks were perforated (1,7) and (1,8), (1,5) and (1,6) and (1,9) and (1,10) medium, short and long intervals respectively. Water cuts, cumulative oil production and GORs will also be examined.

3. Anisotropy ratio of 0.01, 0.1 and 1.0 is run at a constant oil production rate of 1000stb/d and cumulative oil production, water cuts and GORs are examined.

2.1 Basic Fluid Flow Equations in Oil Reservoirs

The ideal steady-state flow equation for radial system is obtained when there is no change anywhere with time in the reservoir and is based on the following assumptions:

a. Thickness is uniform and permeability is constant
b. The fluid is incompressible
c. Flow across any circumference is a constant.

The steady-state equation can be expressed as (Chaudry, 2004):

$$q_o = \frac{0.00708kh\left(P_e - P_{wf}\right)}{\mu_o \beta_o \ln\left({r_e}/{r_w} \right)} \qquad (1)$$

If the permeability is improved or damaged, there will be a skin factor resulting in a pressure drop (ΔP_{skin}) subtracted from the pressure drop term. The equation will thus be expressed as:

$$q_o = \frac{0.00708kh\left(P_e - P_{wf} - \Delta P_{skin}\right)}{\mu_o \beta_o \ln\left({r_e}/{r_w} \right)} \qquad (2)$$

Where ΔP_{skin} is the pressure drop due to skin.

2.2 Multiphase Buildup Test Analysis

Basic buildup equations can be modified to model multiphase flow. For an infinite acting reservoir, the equation is expressed as:

$$P_{ws} = P_i - \frac{162.6q_t}{\lambda_t h}\log\left(\frac{\Delta t}{t_p + \Delta t}\right) \qquad (3)$$

The flow rate is obtained by making q_t the subject of the equation.

Where

$$q_t = q_o B_o + \left(q_g - \frac{q_o R_s}{1000}\right)B_g + q_w B_w \qquad (4)$$

And

$$\lambda_t = \frac{k_o}{\mu_o} + \frac{k_g}{\mu_g} + \frac{k_w}{\mu_w} \qquad (5)$$

Many authors (Abass and Bass, 1988, Bournazel and Jeanson 1971, Chaperon, 1986, Guo and Lee, 1992, Hoyland *et al.*, 1986, Muskat and Wyckoff, 1935, Schols, 1972, Yang and Wattenbarger, 1991) have addressed the challenge of coning by the term critical oil rate (maximum production rate without producing water or gas), water-oil ratio (WOR), gas-oil ratio (GOR) and water and gas breakthrough times. Determination of appropriate oil rate for maximum economic oil recovery is a complicated and controversial issue in oil field development. For supercritical oil rate, a parameter sensitivity analysis is done using a base case and then running other simulations by varying the base case data. The parameters are grouped together by regression analysis and results were obtained for vertical and horizontal wells (Recham, 2001):

For vertical wells:

$$Q_{sc,v} = 3.5026*10^{-6}\left(r_{eD}\right)^{0.91}\left(\mu_o\right)^{-0.22}\left(\frac{\rho_w - \rho_o}{\rho_o - \rho_g}\right)^{0.017}\left(h_o\right)^{2.717}\left(\frac{k_v}{k_h}\right)^{-0.563}\left(k_h\right)^{0.534}\left(1-\frac{h_p}{h_o}\right)^{-2.128}\left(1-\frac{h_{ap}}{h_o}\right)^{-0.376}\left(1-\frac{h_{bp}}{h_o}\right)^{-0.463} \qquad (6)$$

Where

$$r_{eD} = \frac{r_e}{h_o}\sqrt{k_v/k_h} \qquad (6a)$$

For horizontal well:

$$Q_{sc,h} = 2.8248*10^{-11}\left(X_D\right)^{2.332}\left(\mu_o\right)^{-0.182}\left(\frac{\rho_w-\rho_o}{\rho_o-\rho_g}\right)^{0.158}\left(h_o\right)^{4.753}\left(\frac{k_v}{k_h}\right)^{-1.234}\left(k_h\right)^{0.2396}$$

$$\left(L\right)^{0.211}\left(1-\frac{h_{ap}}{h_o}\right)^{-0.036}\left(1-\frac{h_{bp}}{h_o}\right)^{-0.211} \qquad (7)$$

$$X_D = \frac{X_a}{h_o}\sqrt{k_v/k_h} \qquad (7a)$$

3. RESULTS AND DISCUSSION

3.1 Scenario 1: Different Oil Production Rates

Running the simulator under different oil production rates of 500, 1000 and 2000STB/day for a period of 3 years will generate the plot of cumulative oil Production, water cut and GOR as seen in Figures 1, 2 and 3 respectively. Figure 1 shows effect of cumulative oil production in an oil reservoir where the oil zone has an aquifer and water coning could affect the flow rate of a producing well. Increase in the liquid production rate creates higher pressure gradients in the reservoir which leads to increased vertical force and shorter water breakthrough time as cumulative oil production increases. In the Figure, the field oil production total steadily increases from the origin up to the time year 2 and has a gentle slope to the end of the simulation. At year 2, the cumulative oil production for 500, 1000 and 2000stb/d flow rates are 350 Mstb, 560 Mstb and 575Mstb which slightly increased to 380 Mstb, 580 Mstb and 600 Mstb respectively at the end of the simulation.

Figure 2 is the water cut plot for the simulation; the water cut was stable for about 2 months at 0.12, 0.13 and 0.14 for the 500, 1000 and 2000stb/d rates respectively before a rapid increase to a maximum of 0.33, 0.43 and 0.44 at year 2. In Figure 3, the Field gas-oil ratio started at 1.4 Mscf/stb for all the production rates. At the beginning when only solution gas was produced, the GOR was relatively stable, then, as the production of free gas started, the GOR increased rapidly. A rapid change for 2000stb/d production rate started at about 2 months,

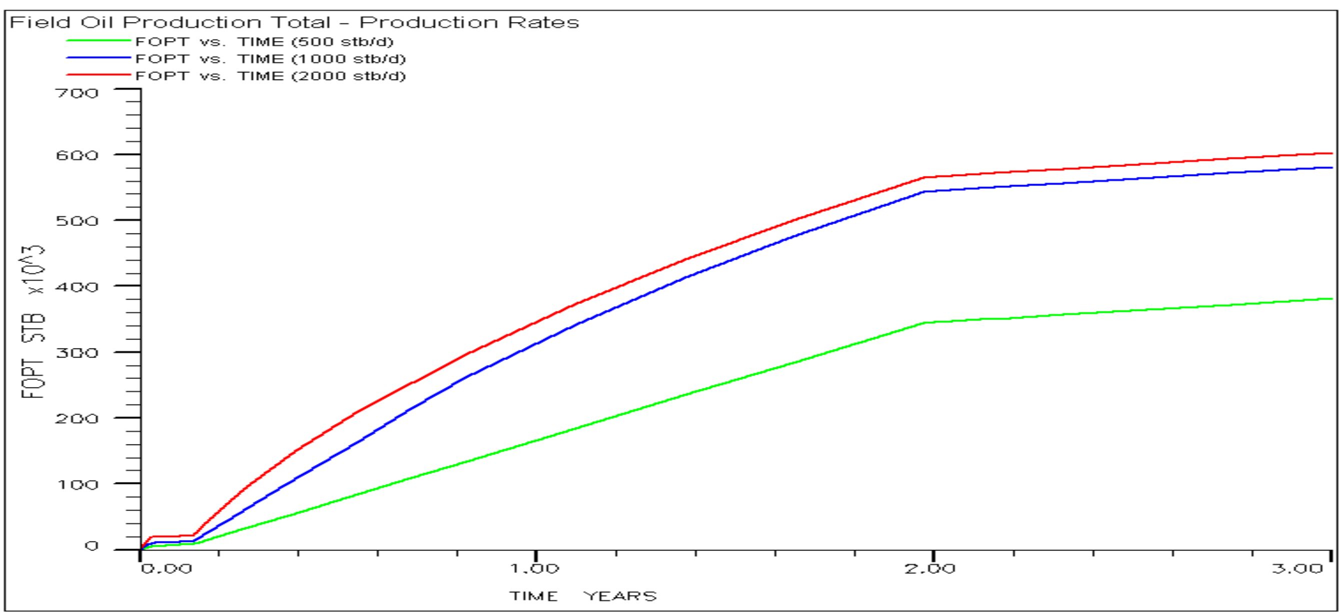

Figure 1: Cumulative oil production for different oil production rates

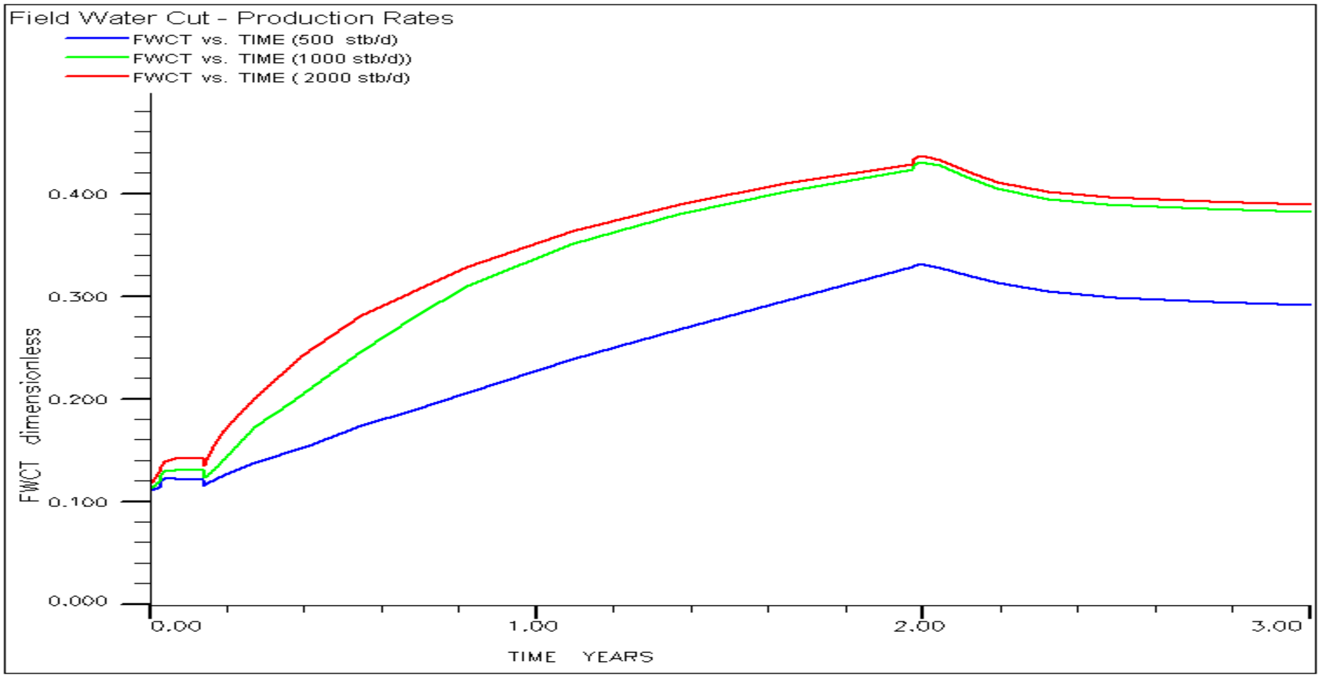

Figure 2 : Field Water cut for different oil production rates

for 1000stb/d about 3 months and for 500stb/d it started about 6 months. The maximum GOR reached was 2.18Mscf/stb, 2.95Mscf/stb and 2.95Mscf/stb for 500, 1000 and 2000stb/d respectively, before a sharp drop to 1.35 Mscf/stb at year 2 and maintained this value to the end of the simulation.

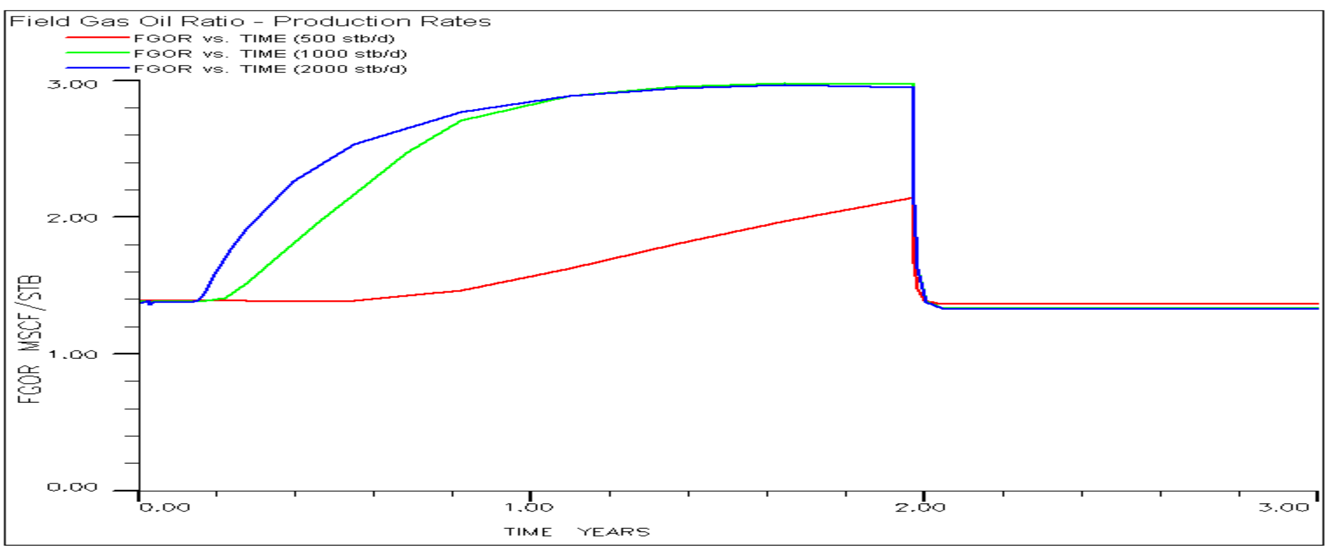

Figure 3: Field Gas Oil Ratios for different oil production rates

3.2 Scenario 2: Perforation Intervals

A constant oil production rate of 1000stb/d is being used to evaluate different well completion locations. Making three runs with perforations in blocks (1,5) (1,6), (1,7) (1,8) and (1,9) (1,10) produced the results represented in Figures 4 – 6. Figure 4 is the plot of cumulative oil production for the period. The block (1,5) (1,6) represents a short perforation interval, block (1,7) (1,8) represents the medium perforation interval while (1,9) (1,10) is the long perforation interval.

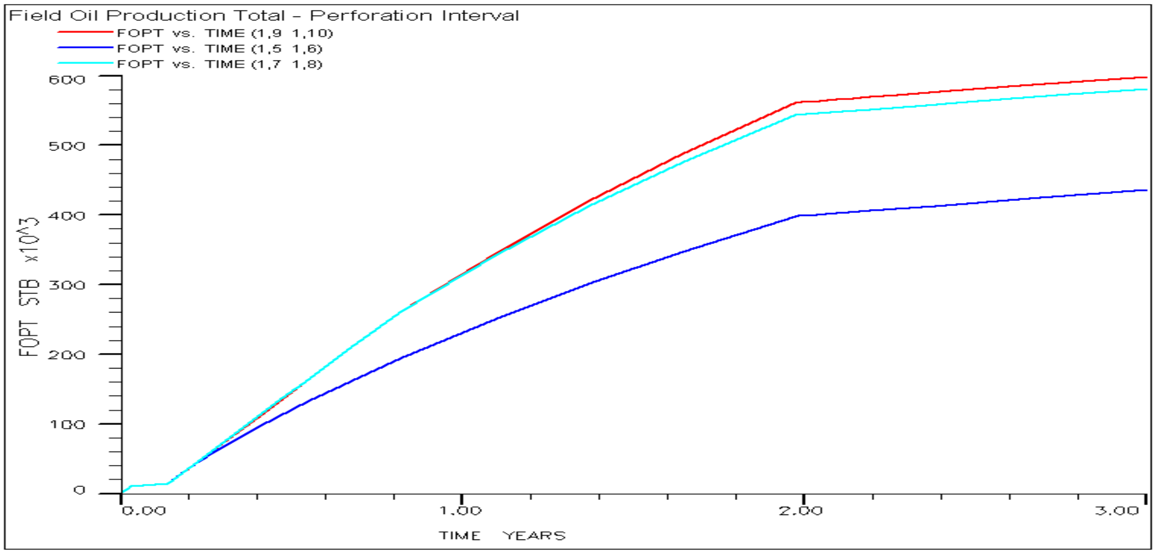

Figure 4: Cumulative oil production for different Perforation intervals

The cumulative production was directly proportional with time and increases rapidly up to 400Mstb, 540Mstb and 560Mstb at year 2 for short, medium and long perforation intervals respectively. From year 2 to the end of simulation, the increase in the cumulative production was not significant because production sharply dropped for the three runs. Water cut is illustrated in Figure 5 which shows a sharp difference for the three runs. The short perforation interval started from 0.08 and reached a maximum of 0.28 at year 2, the medium started from 0.13 and increased to 0.43 at time year 2 while the long perforation interval started from 0.38 and increased to 0.57 at year 2.

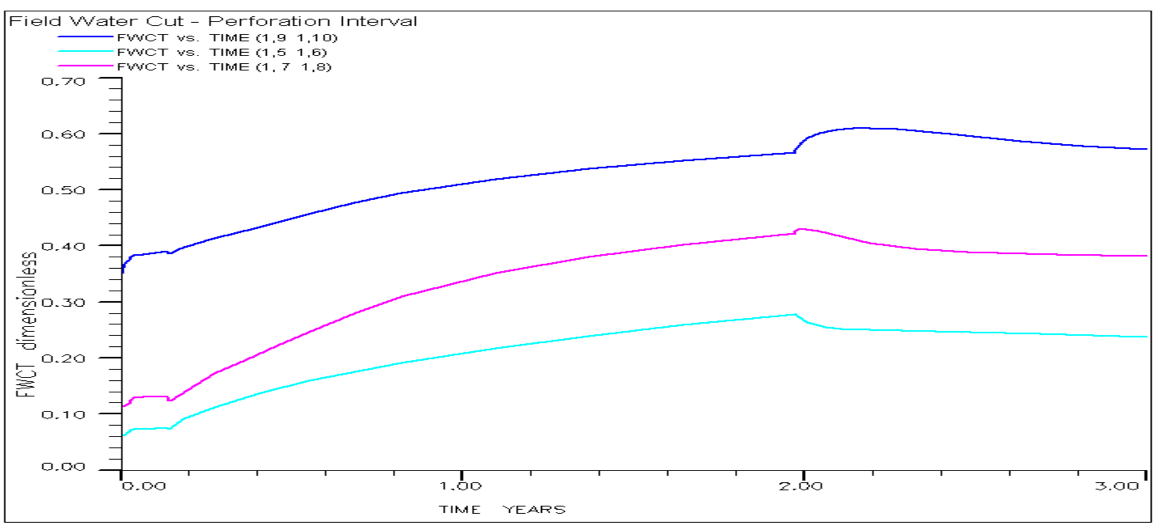

Figure 5: Field Water cuts for different Perforation intervals

Figure 6 is the GOR output for the three runs. All the runs started at 1.4Mscf/stb and after about 1 and half months, there was a rapid increase for the short perforation interval to a maximum of 3.5Mscf/stb at year 2 and a sharp drop to 1.4Mscf/stb until the end of simulation. For the medium perforation interval, there is a sharp increase from about 2 months up to 3.0Mscf/stb at year 2 and a sudden drop to 1.4 Mscf/stb till the end of the simulation. Lastly, the long perforation did not change until about the six month and the variation was relatively small to a maximum of 1.7 Mscf/stb at year 2 which also dropped to 1.4Mscf/stb to the end of the simulation.

The short perforation interval gives the highest GOR and lowest water-cut compared with the medium perforation interval which is the base case while, the long perforation interval gives the highest water cut and the lowest GOR.

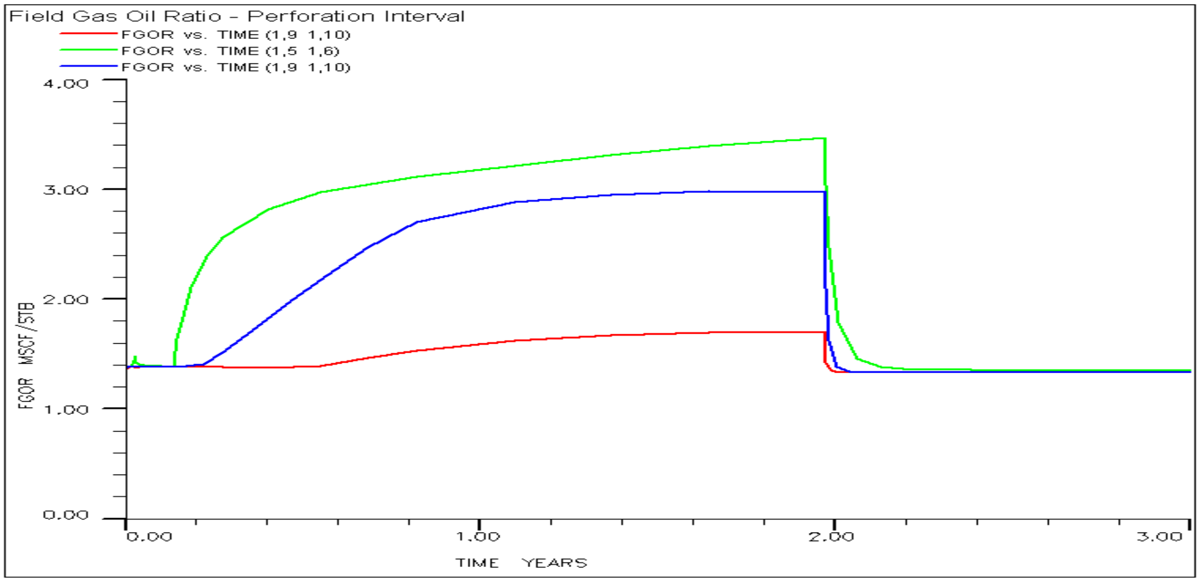

Figure 6: Field Gas oil Ratios for different Perforation intervals

3.3 Scenario 3: Anisotropic Ratio

The ratio of vertical and horizontal permeability is being examined. Figure 7 to 9 illustrate the result of running the values of anisotropy 0.01, 0.1 and 1.0 and the resultant Field Gas oil ratio, Field Water cut and Cumulative oil production. Figure 7 shows the Field Gas oil ratio sensitivity for anisotropy values. Field Gas oil ratio started from 1.4Mscf/stb for all the anisotropy values. For the anisotropy value of 1.0, FGOR suddenly increased to 3.5 mscf/stb after about two months and it continued to increase to a peak of 4.8 mscf/stb at 24 months. A sharp drop occurred at this 24 months back to 1.4 and remained at this value till the end of the simulation.

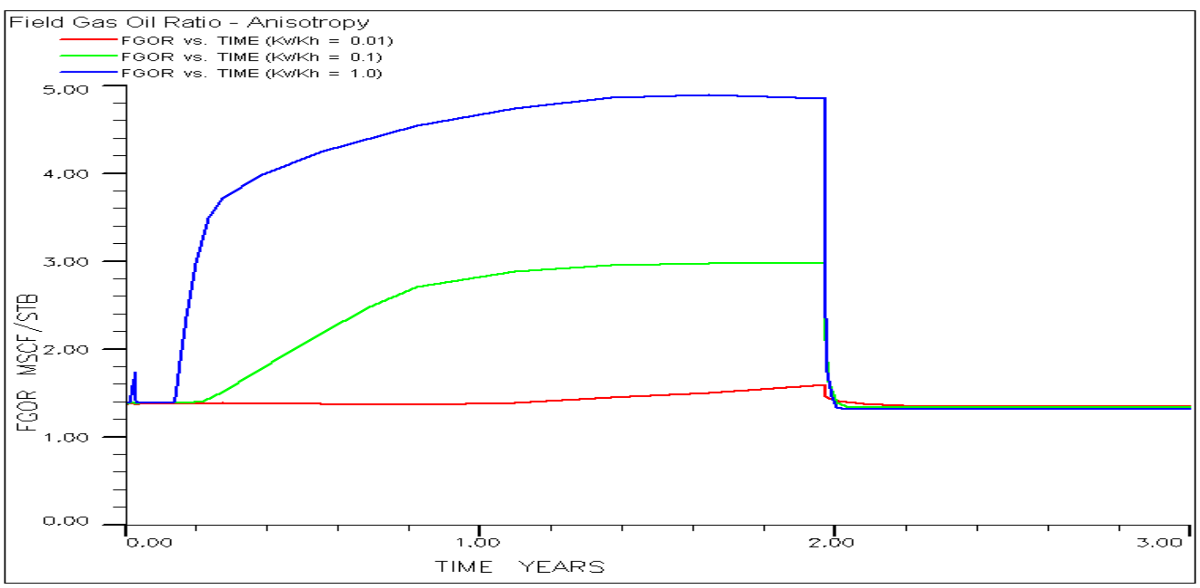

Figure 7: Field Gas oil Ratios for different Anisotropy values

For the value of 0.1 an increase started at 2 and half months and gradually increased to a peak of 3.0 at 24 months when a sharp drop brings the value back to 1.4 and remained on this value until the end of simulation. There was no significant increase for the anisotropy value of 0.01 throughout the period under consideration. In Figure 8, Field water cut for anisotropy value of 1.0 started from 0.2 and sharply increased to 0.5 at about 6 months and gradually increased to a peak of 0.64 at 24 months. For anisotropy of 0.1, the FWCT started from 0.13 and at about 2 months gradually increased to a peak of 0.42 at year 2.

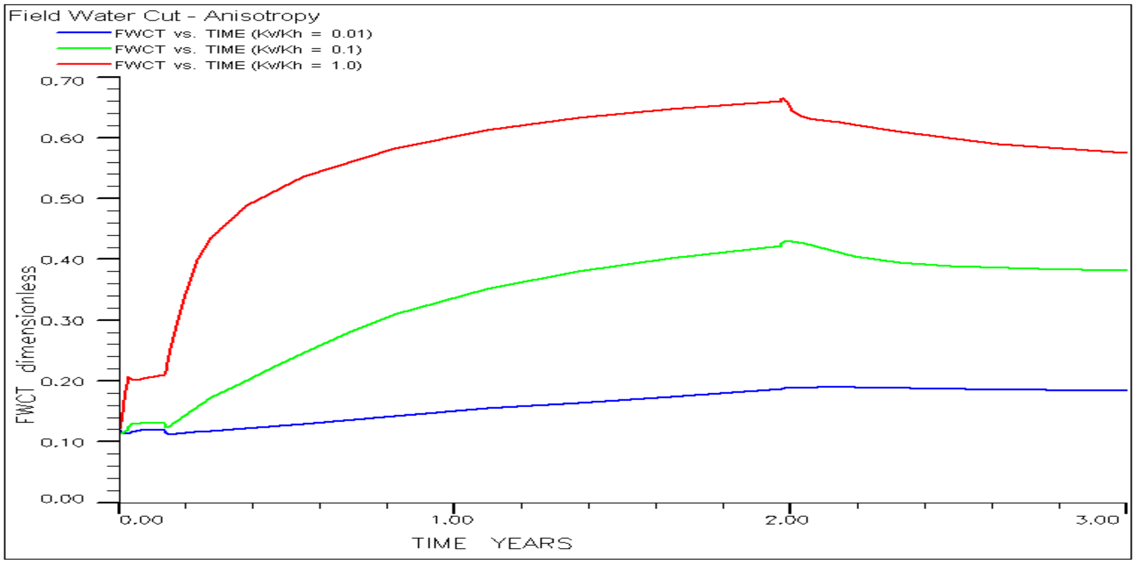

Figure 8: Field Water cuts for different Anisotropy values

The FWCT for anisotropy of 0.01 started at 0.12 but there was no significant increase throughout the period. In Figure 9, cumulative oil production was seen to start from origin for anisotropy value of 0.01 and steadily increased to 680Mstb at time year 2 while the value for anisotropy of 0.1 and 1.0 was 540Mstb and 340Mstb respectively at the same period of time.

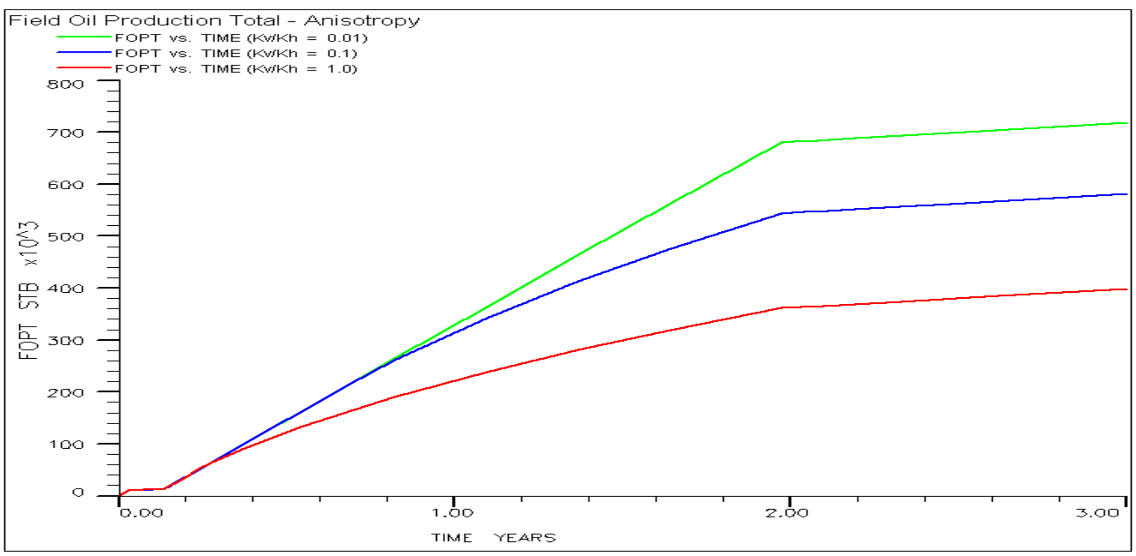

Figure 9: Cumulative oil production for different Anisotropy values

4. CONCLUSION

This study evaluates a three-phase coning model. A higher liquid production rate results in a higher cumulative oil production and recovery and the increased liquid production creates a high pressure gradient in the reservoir which leads to increased vertical force and shorter water breakthrough time.
A lower perforated interval results in a lower water-cut and high gas production whereas high perforated interval yields a high gas production and low water-cut.

When the difference between the horizontal permeability and vertical permeability is large, the oil recovery is expected to be high.

Smaller values of anisotropy increase the cumulative production and delays water coning.

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NOMENCLATURE

B_o	=	Oil formation volume factor, rb/stb
B_g	=	gas formation volume factor, rb/mscf
B_w	=	Water formation volume factor, rb/stb
h_o	=	Oil column thickness, ft
h_{ap}	=	Oil column thickness above perforation, ft
h_{bp}	=	Oil column thickness below perforation, ft
h_p	=	thickness perforated interval, ft
K_o	=	oil Permeability, mD
K_g	=	gas Permeability, mD
K_w	=	water Permeability, mD
L	=	Horizontal well length, ft
q_o	=	oil flow rate, stb/day
q_g	=	gas flow rate, stb/day
q_w	=	water flow rate, stb/day
q_t	=	total flow rate, stb/day
$Q_{sc,h}$	=	horizontal well super-critical rates, stb/day
$Q_{sc,v}$	=	vertical well super-critical rates, stb/day
P_e	=	External pressure, Psi
Pi	=	Initial Pressure, psi
P_{wf}	=	Flowing well pressure, Psi
P_{ws}	=	static well pressure, Psi
μ_o	=	Oil viscosity, cp
μ_g	=	gas viscosity, cp
μ_w	=	water viscosity, cp
r_e	=	drainage radius, ft
r_{eD}	=	Dimensionless drainage radius
r_w	=	wellbore radius, ft
q_t	=	total flow rate of oil, gas and water (bbl/day)
q_o	=	oil flow rate, stb/day
q_g	=	gas flow rate, mscf/day
q_w	=	water flow rate, stb/day
B_o	=	oil formation volume factor, rb/stb
B_g	=	gas formation volume factor, rb/mscf
B_w	=	water formation volume factor, rb/stb
R_s	=	solution gas oil ratio, scf/stb
ρ_o	=	oil density, gm/cc
ρ_g	=	gas density, gm/cc
ρ_w	=	water density, gm/cc
t_p	=	producing time, hr
Δt	=	shut-in time, hr
λ_t	=	total mobility ratio (mD/cp)
X_a	=	drainage width, ft
X_D	=	dimensionless drainage width