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WATER CONING IN FRACTURED RESERVOIRS: A SIMULATION STUDY

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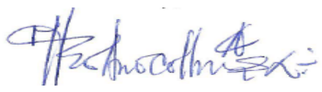
DECLARATION

I hereby declare that this Thesis entitled '**Water Coning in Fractured Reservoirs: A Simulation Study**' has been written by me and that it is the record of my own research work. It has not been presented in any pervious application for a higher degree. All sources of information are specifically acknowledged using references.



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DEDICATION

This Thesis work is dedicated to my beloved mother; late Mrs. Grace Ndarake Okon, for her painstaking contributions to my early education.

ABSTRACT

Water coning is a complex phenomenon that depends on a large number of variables which include among others: production rate, perforation interval, mobility ratio, capillary pressure, etc. Its production can greatly affect the productivity of a well and the reservoir at large. In fractured reservoirs, the phenomenon is more complex owing to the high permeability of the fractures in the porous media. With this complexity in mind, water coning behaviour in fractured reservoir was studied by simulating a reservoir supported by a strong aquifer using ECLIPSE-100 Black-Oil Simulator. The water cut (WCT), oil production rate (OPR) and water saturation (BWSAT) at the producing interval (Block 1, 1, 7) were used to evaluate the coning phenomenon in a fractured reservoir. In the course of the study, sensitivity analyses on the modelled reservoir's anisotropy ratio (k_v/k_h), production rate (q), storativity capacity (ω), fracture width (b) and fracture permeability (k_f) were conducted to evaluate their effect on coning behaviour in fractured reservoir. The results obtained depict that while the anisotropy ratio is very significant in water cut and water saturation at the perforating interval it has no adverse effect on oil production rate. It was however, observed that the water cut and oil production rate decreased as the production rate (q) increased. Furthermore, the water cut, oil production rate and water saturation (BWSAT) from the fractured reservoir is sensitive to the storativity capacity (ω) depending on the fracture porosity (φ_f). Conversely, the fracture's width (b) and permeability (k_f) have no significant effect on the coning behaviour of the modelled fracture reservoir. However, anisotropy ratio (k_v/k_h), production rate as well as storativity capacity (ω) are significant parameters in evaluating coning phenomenon in fractured reservoirs.

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NOMENCLATURE

B_o: Oil formation volume factor, *rb/stb*

h: Initial oil formation thickness, *ft*

h_{op}: Oil column height above perforations, *ft*

h_p: Perforation length, *ft*

k_h: Horizontal permeability, *md*

k_v: Vertical permeability, *md*

k_f: Fracture permeability, *md*

k_m: Matrix permeability, *md*

k_{ro}: Oil relative permeability, *md*

μ_o: Oil viscosity, *cp*

μ_w: Water viscosity, *cp*

r_{De}: Dimensionless drainage radius, *ft*

r_e: Drainage radius, *ft*

r_w: Wellbore radius, *ft*

M: Water oil mobility ratio

ρ_o: Oil density, *lb/cuft*

ρ_w: Water density, *lb/cuft*

$\Delta\rho$: Density difference, *lb/cuft*

t_D: Dimensionless breakthrough time

t_{BT}: Breakthrough time, *day*

φ_m**:** Matrix porosity

φ_f: Fracture porosity

ψ_w: Water dimensionless function

ε: Fraction of oil column height above perforations

δ_w: Fraction of perforated intervals.

P_{wf}: Flowing bottom hole pressure, *psi*

P_{ws}: Static well pressure, *psi*

q_D: Dimensionless production rate

Q_{oc}: Critical oil production rate, *std/d*

1.0 INTRODUCTION

The production of water from oil producing wells is a common occurrence in oilfields (Namani *et al.*, 2007). This is attributed to one or more of such phenomenon; normal rise of oil-water contact (WOC), water coning as well as water fingering. Oil production from a well that partly penetrates oil zone overlying water may cause the oil/water interface to deform into a bell shape. This deformation is usually called water coning and occurs when the vertical component of the viscous force exceeds the net gravity force (Høyland *et al.*, 1989). In other words, simultaneous production of oil and water from the oil well because of unbalancing between viscous and gravitational forces is known as water coning phenomenon. Therefore, it is worth mentioning that two forces control the mechanism of water coning in oil and/or gas reservoirs: dynamic viscous force and gravity force. Water coning phenomenon constitutes one of the most complex problems pertaining to oil production (Saad *et al.*, 1995). Coning phenomenon is more challenging in fractured reservoirs owing to their intrinsic difference of them and the heterogeneity and high permeable medium of the fractures compared to matrixes (Foroozesh *et al.*, 2008). On the other hand, water coning in naturally fractured reservoirs often result in excessive water production which can kill a well or severely curtain its economics life due to water handling (Beattie and Roberts, 1996).

In the study of water coning phenomenon both in homogeneous (conventional) and fractured reservoirs, three parameters are determined: critical rate, breakthrough time and water cut performance after breakthrough. It is of essence to understand the term *critical rate.* At a certain production rate, the water cone is stable with it apex at a distance below the bottom of the well, but an infinitesimal rate increase will cause instability and water breakthrough. This limiting rate is called the critical rate for water coning (Høyland *et al.*, 1989). Therefore, critical rate is defined as the maximum allowable oil flow rate that can be imposed on the well to avoid a cone breakthrough (Salavatov and Ghareeb, 2009). In fractured reservoirs, critical rate are influenced by extra factors such as fracture storativity (ω), fracture transmissivity (λ), fracture pattern and their interaction to matrixes; especially around the wellbore (Namani *et al.*, 2007). Bahrami *et al*. (2004) mention that in naturally fractured reservoirs because of heterogeneity and non-uniform fracture distribution, development of cone is asymmetrical and estimation of critical rate and breakthrough time requires modelling with an understanding of fracture pattern around the producing well. These facts attest to the challenges and complexity of coning study in fractured reservoirs.

In conventional reservoirs the extent of cone growth and/or its stabilization depend on factors such as; mobility ratio, oil zone thickness, the extent of the well penetration and vertical permeability; of which the most important parameter is the total production rate (Namani *et al*., 2007). In addition Saleh and Khalaf (2009) mention that water coning depends on the properties of the porous media, oil-water viscosity ratio, distance from the oil-water interface to the well, production rate, densities of the fluids and capillary effects. Conversely, in fractured reservoirs this problem is more complicated because of the dual porosity system in the fractured reservoir which results in formation of two cones (i.e. coning in the fracture and matrix). Depending on the rates, a fast moving cone may be developing in the fracture whilst a slow moving cone is observed in the matrix. The relative position of the two cones is rate sensitive and is a function of reservoir properties (Al-Aflagh and Ershaghi, 1993). It is worth mentioning here that the key parameter in determining water coning tendency is the vertical to horizontal permeability ratio, k_v/k_h. The presence of natural fractures however often results in high values of k_v/k_h providing conditions conducive to water coning (Beattie and Roberts, 1996). Therefore high vertical permeabilities in fractures are bound to accelerate the coning process resulting in lowering of the critical rates and more rapid breakthrough times. In addition, the preferential path for fluid flow through the fractures and the uneven fracture conductivities commonly observed in naturally fractured reservoirs is expected to affect wells regardless of their structural position (Al-Aflagh and Ershaghi, 1993).

In order to study the coning phenomenon in fractured reservoir, solving the two phase governing partial differential equations of oil and water flow in heterogeneous porous media for radial system is utmost important. Besides, understanding the effect of various rock and fluid properties such as absolute permeability, oil thickness, completion interval location, production rate, fluid viscosity and density is very crucial

(Foroozesh *et al.*, 2008). Therefore, coning phenomenon in fractured reservoir will be studied using ECLIPSE-100 simulator. The simulation study will evaluate the effect of this phenomenon on the water cut, oil production rate and water saturation at the producing interval of the modelled fractured reservoir. Furthermore, a sensitivity study of the reservoir parameters on the coning phenomenon will be examined in this study.

1.1 STATEMENT OF THE PROBLEM

Coning is a near wellbore problem that requires careful study and understanding of the phenomenon. In heterogeneous reservoirs the phenomenon is more complex compared to homogeneous reservoirs as a result of the permeability difference between the matrixes and the fractures in the fractured (heterogeneous) reservoirs. As a result of this, the phenomenon result in adverse water production in the producing well, thus resulting to excessive water handling related problems which may lead to early abandonment of the well.

1.2 PURPOSE OF THE STUDY

A fractured reservoir is model with ECLIPSE-100 Simulator. The main purpose of this simulation study is to;

- Evaluate the water coning effect on the water-cut in fractured reservoirs.
- Evaluate the coning effect on the oil production rate in fractured reservoirs.
- Evaluate the sensitivity of the reservoir parameters on the coning study.

2.0 LITERATURE REVIEW

A survey of literature indicates that many studies have been reported on water coning in homogeneous (conventional) oil reservoirs; ranging from experimental studies to analytical and numerical simulation. The focus of study has tended to be on the development of correlations for critical rate, time to breakthrough and WOR (water-oil ratio) following breakthrough (Beattie and Roberts, 1996). In contrast to homogeneous oil reservoir, relatively few studies have been reported on aspect of water coning in fractured oil reservoir. In other words, some research efforts and solutions have been developed to reduce the level of severity of water coning in fractured reservoirs. An overview of the research findings are presented below:

Høyland *et al*. (1989) presented critical rate for water coning from correlation and analytical solution. Their analytical solution is an extension of Muskat and Wyckoff theory developed in 1935. Numerical simulation was employed to check the validity of the analytical solution obtained. After several simulation runs, Høyland *et al*. stated that the critical rate of water coning is independent of water permeability, the shape of the water/oil relative permeability curve between endpoints, water viscosity and wellbore radius. Thus, the critical rate is a linear (direct) function of oil formation volume factor (B_o) and a nonlinear function of well penetration, radial extent, total oil thickness and permeability ratio.

Al-Afaleg and Ershaghi (1993) assess the coning phenomena in naturally fractured reservoir from simulation approach. They established that the empirical correlation for homogeneous single porosity reservoirs are inapplicable to naturally fractured reservoirs, as the results are optimistic in estimating the breakthrough time and critical rates. However, Al-Afaleg and Ershaghi state that if the naturally fractured reservoir is represented by a homogeneously fractured system then the correlation developed can be used to approximate the estimation of breakthrough time provided bulk fractured properties are pre-estimated from well tests and other data. They further mention that no correlation or even simulation study can help to predict the estimation of critical rates and breakthrough time if the fracture pattern is not accurately delineated. Al-Afaleg and Erashaghi establish that two cones are observe in naturally fractured reservoirs; a fast moving cone in the fracture network followed by a slower moving cone in the matrix.

Golf-Racht and Sonier (1994) examine water coning in fractured reservoir. Their simulation work demonstrates that the critical rates in a conventional reservoir and a fractured reservoir are controlled by the same criteria and therefore the flows in both cases are governed by the same forces. They further demonstrate that under certain conditions the limitations of oil rate in the Muskat *critical rate* is not justified. They mention that to assess the capacity of a well to produce with moderate or with high coning water-cut, the best approach is to estimate it before the production testing through reverse coning. Therefore, Golf-Racht and Sonier established that the existence of high vertical permeabilities arising from a high vertical fracture density is a key parameter in influencing water coning behaviour in naturally fractured reservoirs.

Saad *et al.* in 1995 evaluates water coning in fractured basement reservoir from experimental study. Their results indicates that the capillary pressure effect may be generally neglected if the distance between the oil-water contact (WOC) and the fluid entry is sufficiently large compared to the capillary rise. They also put forth that the difference in viscosity between the oil and water phases is the main factor affecting the breakthrough time. Furthermore, they established that the critical radius (R_c) is independent of the position of the initial oil-water contact for a given production rate.

Beattie and Roberts (1996) study water coning in naturally fractured gas reservoirs. Their simulation work established that high vertical permeability due to the presence of natural fractures enable water to cone significant distances above the initial gas-water contact. They establish that imbibition of water from fractures to the matrix has a significant influence on water coning behaviour. Thus, reservoir properties which restrict the degree of invasion of the matrix block favour rise of the water level in the fractures toward the well. They further mention that the operating conditions and reservoir properties conducive to water coning behaviour in single porosity formations influence the water coning behaviour in naturally fractured reservoirs in a similar manner.

Bahrami *et al.* in 2004 evaluate coning phenomena in naturally fractured reservoirs. From their numerical simulation study they presented (develop) a method suitable for hand calculations to predict breakthrough time and water cut at each time for a specific oil production rate. They stated that as water breaks into the well through fractures, a considerable amount of producible oil remains in matrix in cone-invaded zone and decreases oil recovery. They further mention that increase in matrix porosity or fracture porosity results delay in breakthrough time and increase water cut. Thus, breakthrough time is more sensitive to fracture porosity and water cut is more sensitive to matrix porosity. Also breakthrough time is more sensitive to horizontal fracture permeability and vertical fracture permeability and water cut is more sensitive to horizontal fracture permeability and horizontal matrix permeability. Finally, they established that the matrix block size does not have any specific effect on breakthrough time and water cut in coning phenomenon in fractured reservoirs.

Namani *et al.* (2007) investigate water coning phenomenon in Iranian carbonate fractured reservoir. Their investigation reveals that oil layer thickness, well penetration, fracture permeability; especially horizontal fracture permeability, production rate, mobility ratio, storativity and conductivity have considerable effect on water coning in fractured reservoirs. They further states that fracture spacing, skin factor and aquifer power have no effect on the water coning in fractured reservoirs. Also the fracture pattern especially around the well is very important in water coning study in fractured reservoirs. Thus, the role of horizontal permeability is more than vertical permeability because the increase of horizontal permeability can distribute water cone in horizontal plane and delays the water breakthrough time.

Perez-Martinez *et al*. (2012) presented a simulation study of water coning in naturally fractured carbonate heavy oil reservoir. They found that water coning occurs in fractured porous media with permeabilities up to 10 Darcys and that water coning occurs in both good and poorly cemented wells. They also obtain correlations to determine the maximum height of water coning considering good and poor cement. Thus, with the correlations obtained the minimum safe distance between the oil-water contact and the producing interval for a specified free of water oil production rate (critical rate) can be easily determined. Based on the analysis of their results, they stated that the matrix-fracture partition ratio has little influence in determining the maximum height of water coning.

2.1 CRITICAL PRODUCTION RATE

The term which is widely used in the literature to describe the critical limits for the occurrence of water coning is the critical production rate, Q_c (Saad *et al.*, 1995). A number of methods have been developed to determine the critical production rate (Q_c) in homogeneous reservoirs. Such method include Muskat and Wyckoff's(1935) method, Chaney *et al*. (1956) method, Craft and Hawkins (1959) method, Meyer and Gardner's (1963) method, Chierici-Ciucci's (1964) method, Schols (1972) method, Chaperon's (1986) method, Høyland *et al*. (1989) method, Guo and Lee (1993) method, etc. In this regard, some of these equations as well as correlations are stated below:

Chaney *et al*. (1956) method:

$$Q_{oc} = 0.5288 \times 10^{-4} \left[\frac{k_o(\rho_w - \rho_o)}{\mu_o B_o}\right] Q_{curve} \qquad ..(1)$$

Where:

$$Q_{curve} = 0.1313(h^2 - h_p^2) + 34.0(\frac{52-h}{44})^2 - 250\left(\frac{h_p}{h} - 0.30\right)\left(\frac{h-10}{90}\right)^2 - 40.0$$

Craft and Hawkins (1959) method:

$$Q_{oc} = 0.0783 \times 10^{-4} \left[\frac{h(P_{ws} - P_{wf})}{ln\left({}^{r_e}/_{r_w}\right)}\right]\left(\frac{k_o}{\mu_o B_o}\right) PR. \qquad .(2)$$

Where:

$$PR = b'\left[1 + 7\sqrt{\frac{r_w}{2b'h}} \cos b' 90°\right]$$

Meyer and Gardner (1963) method:

$$Q_{oc} = 0.246 \times 10^{-4} \left[\frac{\rho_w - \rho_o}{\ln\left({}^{r_e}/_{r_w}\right)}\right]\left(\frac{k_o}{\mu_o B_o}\right)(h^2 - h_p^2). \qquad .(3)$$

Chierici – Ciucci's (1964) method:

$$Q_{oc} = 0.492 \times 10^{-4} \frac{h^2(\rho_w - \rho_o)}{\mu_o B_o}(k_{ro} k_h)\Psi_w(r_{De}, \varepsilon, \delta_w). \quad . \quad . \quad . \quad .(4)$$

Where:

$$r_{De} = \frac{r_e}{h}\sqrt{\frac{k_h}{k_v}}, \quad \varepsilon = \frac{h_p}{h}, \quad \Psi_w = \text{Water dimensionless function obtain from chart}$$

and $\delta_w = \frac{D_b}{h}$

Schools (1972) method:

$$Q_{oc} = 0.0783 \times 10^{-4}\left[\frac{(\rho_w - \rho_o)k_o(h^2 - h_p^2)}{\mu_o B_o}\right]\left[0.432 + \frac{\pi}{ln(^{r_e}/_{r_w})}\right](^{h}/_{r_e})^{0.14}. \quad .(5)$$

Chaperon's (1986) method:

$$Q_{oc} = 0.0783 \times 10^{-4} \frac{k_h(h - h_p)^2}{\mu_o B_o}[\Delta\rho]q_c^*. \quad . \quad . \quad . \quad . \quad . \quad .(6)$$

Where:

$$q_c^* = 0.7311 + (^{1.943}/_{a''}) \text{ and } a'' = (^{r_e}/_{h})\sqrt{^{k_v}/_{k_h}}$$

Høyland *et al.* (1989) method:

$$Q_{oc} = 0.246 \times 10^{-4}\left[\frac{h^2(\rho_w - \rho_o)k_h}{\mu_o B_o}\right]q_{cD}. \quad . \quad . \quad . \quad . \quad . \quad .(7)$$

Where:

$$r_D = \frac{r_e}{h}\sqrt{\frac{k_v}{k_h}} \text{ and } q_{cD} = \text{Dimensionless critical rate obtain from chart}$$

Guo and Lee (1993) method:

$$Q_{oc} = \frac{\Delta\rho k_v}{\mu_o}\left[r_e - \sqrt{r_e^2 - r_e(h_o - h_{op})}\right]^2\left[\frac{k_v}{\sqrt{k_h^2 + k_v^2}} + \frac{h_{op}\left[\frac{1}{r_w} - \frac{1}{r_e}\right]}{ln(^{r_e}/_{r_w})}\right]. \quad . \quad . \quad . \quad (8)$$

Conversely, in fractured reservoir Birk's (1963) method is the only method available method in the literature for determining critical oil production rate (Saad *et al.*, 1995; Namani *et al.*, 2007). However, some correlations have been proposed for determining the critical production rate in heterogeneous reservoir. Saleh and Khalaf (2009) proposed correlation (Eq. 9) for determining critical rate in fractured reservoir. This equation took into account the heterogeneity degree (H*D) of the reservoir as well as the capillary pressure (P_c) between water and oil in the reservoir.

Saleh and Khalaf (2009) equation:

$$Q_{oc} = 1.75 \times 10^{-3} \left(\frac{\rho_w - \rho_o}{ln\left({r_e}/{r_w} \right)} \right)^{1.075} \left(\frac{k_o}{\mu_o B_o} \right) (h^{2.15} - D^{1.995})(H * D) + 87.8 ln P_c. \quad (9)$$

2.2 BREAKTHROUGH TIME

The second parameter of concern to the reservoir engineer in predicting water or gas coning is the breakthrough time, that is; the time needed for the water or gas to enter the perforation after the beginning of oil production. Several correlations have been developed to calculate the critical oil production rate to avoid water or gas breakthrough. However, fewer of such correlations are available in literature for predicting water or gas breakthrough time. Sobocinski and Cornelius (1965) developed a correlation for predicting the breakthrough time based on laboratory experimental data and computer program results. The correlation involves dimensionless groups of reservoir and fluid properties i.e., dimensionless cone height (Z) and dimensionless breakthrough time $(t_D)_{BT}$. Bournazel and Jeanson (1971) developed a method for calculating breakthrough time based on their experimental data. Their model assumed a homogeneous reservoir and radial flow of oil and water at the outer limit. However, Bournazel correlation involves the same dimensionless group as the Sobocinski correlation. These equations are presented below:

Sobocinski and Cornelius (1965) Method:

$$t_{BT} = \frac{\mu_o \varphi h (t_D)_{BT_{Sobocinski}}}{1.37 \times 10^{-3} (\rho_w - \rho_o) k_h F_k (1 + M^{\alpha})}. \quad (10)$$

Where;

$$(t_D)_{BT_{Sobocinski}} = \frac{Z}{4} \left(\frac{16 + 7Z - 3Z^2}{7 - 2Z} \right). \quad (11)$$

$$Z = \frac{3.07\times10^{-3}(\rho_w-\rho_o)k_h h(h-D)}{\mu_o q B_o} \qquad (12)$$

$$F_k = \frac{k_v}{k_h} \qquad (13)$$

Bournazel and Jeanson (1971) Method:

$$t_{BT} = \frac{\mu_o \varphi h (t_D)_{BT_{Bournazel}}}{1.37\times10^{-3}(\rho_w-\rho_o)k_h F_k(1+M^{\alpha})} \qquad (14)$$

Where;

$$(t_D)_{BT_{Bournazel}} = \frac{Z}{3-0.7Z} \qquad (15)$$

Z and F_k are the same as Eq. (11) and Eq. (12) above respectively. Also in the both equations α is given as;

$\alpha = 0.5$ for $M < 1$ and 0.6 for $1 < M < 10$

Apart from Sobocinski (1965) and Bournazel (1971) methods, Rhecam *et al.* (2000) developed a correlation to estimate the breakthrough time as a function of the various reservoir and fluid properties. The results of their regression analysis are express as;

Rhecam, Osisanya and Touami (2000) Method:

$$t_{BT} = 2996\left(\frac{1}{r_{e_D}}\right)^{1.11}\left(\frac{1}{q_D}\right)^{0.68}(1+M)^{0.64}\left(1-\frac{h_p}{h_o}\right)^{0.65}\left(1-\frac{h_{bp}}{h_o}\right)^{1.4}\left(1-\frac{h_{ap}}{h_o}\right)^{0.99} \qquad (16)$$

Where;

$$r_{eD} = \frac{r_e}{h_o}\sqrt{\frac{k_v}{k_h}},\quad q_D = \frac{651.4\mu_o B_o q_o}{h_o^2(\rho_w-\rho_o)kh} \text{ and } M = \frac{\mu_o k_{rw}}{\mu_w k_{ro}}$$

However, Behrami *et al.* (2004) propose a correlation to predict the breakthrough time for a specific oil production rate in homogeneous fractured reservoirs. The results of the sensitivity analysis were used to provide data for developing the correlation for breakthrough time as a function of various reservoir parameters. Thus, the correlation is given as;

Bahrami, Shadizadeh and Goodarzniya (2004) Method:

$$t_{BT} = 1.054 \times 10^{-3} (\varphi^*_{tbt})^{0.989} 0.9591^{k^*} (k^*_{tbt})^{2.6655} (Q^*)^{1.6647}. \qquad . \qquad (17)$$

Where;

$$\varphi^*_{tbt} = (\varphi_m + 0.091)^{1.954} \left(1 + 87.06\varphi_f\right)$$

$$k^*_{tbt} = k_{mh}^{0.01181} \left(5.9654 - exp(-10.213 k_{mv})\right) k_{fh}^{0.3955} k_{fv}^{-0.0476}$$

$$Q^* = 1.3875 \left(\frac{(h_o^2 - h_p^2)(\rho_w - \rho_o)}{Q_o \mu_o B_o}\right)^{0.68} \left(1 + \frac{\mu_o k_{rw@S_{or}}}{\mu_w k_{ro@S_{wi}}}\right)^{0.64}$$

3.0 RESERVOIR MODEL/DESCRIPTION

ECLIPSE-100 Simulator is used in this work to study water coning in fractured reservoir. The simulator is an adaptable dual porosity dual permeability simulator that account for the matrixes and fractures porosity and permeability respectively. A radial model is employ in this study. The fractured model comprises of 15 layers (i.e. 8-matrixes and 7-fractures) in the z-direction and 10 grids in the r-direction, the model is depicted in Figure 1. A production well with a radius of 0.20ft is placed at the center with the producing intervals between layer 7 and 8. Table 1 through 3 shows the base case reservoir rock and fluid properties (description) used in the simulation studies. The reservoir fluid description data in the model is extracted from Chappelear ECLIPSE data file (i.e. CHAP.DATA). These reservoir fluid data is depicted in figure 2 and 3. Worth noted in this simulation study is that the fracture compressibility is assumed to be equal to the oil compressibility (i.e. $C_f = C_o$).

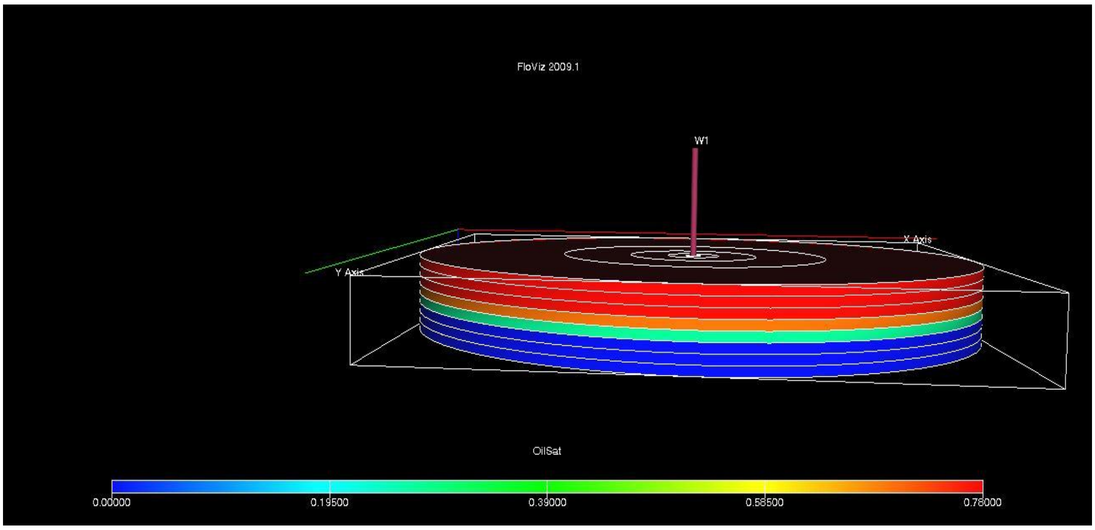

Fig. 1: RESERVOIR MODEL

Table 1: Reservoir Fluid Properties

Water Density (ρ_w), lb/cuft	63.02
Water Viscosity (μ_w), cp	0.96
Oil Density (ρ_o), lb/cuft	45.00
Oil Viscosity (μ_o), cp	1.233
Formation Volume Factor (B_o), RB/STB	1.0915

Table 2: Reservoir Model Properties (Base-case)

Reservoir Thickness (h), ft	100
Drainage Radius (r_e), ft	2098
Perforation Interval, ft	20
Well Radius (r_w), ft	0.20
Fractured Porosity (φ_f)	0.001
Fractured Permeability (k_f), md	300
Fractured Width, ft	0.001
Fracture Compressibility (C_f), psi^{-1}	4.0×10^{-6}
Matrix Porosity (φ_m)	0.18
Matrix Permeability (k_m), md	1.25
Matrix Block size, ft	5.0
Matrix Compressibility (C_f), psi^{-1}	3.0×10^{-6}
Initial Water Saturation (S_{wi})	0.22
Production Rate (q), BPD	3000

Table 3: Relative Permeability Data

- Matrix

Sw	Krw	Kro	Pc (psia)
0.22	0.00	1.000	7.00
0.30	0.07	0.400	4.00
0.40	0.15	0.125	3.00
0.50	0.24	0.065	2.50
0.60	0.33	0.005	2.00
0.80	0.65	0.001	1.00
0.90	0.83	0.000	0.50
1.00	1.00	0.000	0.00

- Fracture

Sw	Krw	Kro	Pc
0.00	0.00	1.00	0.00
1.00	1.00	0.00	0.00

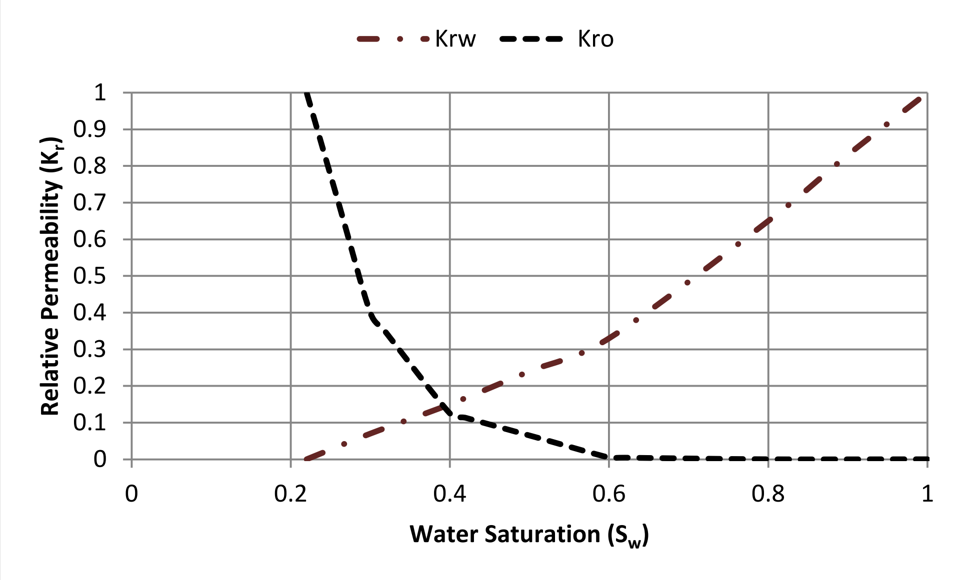

Fig. 2: Relative Permeability Curve

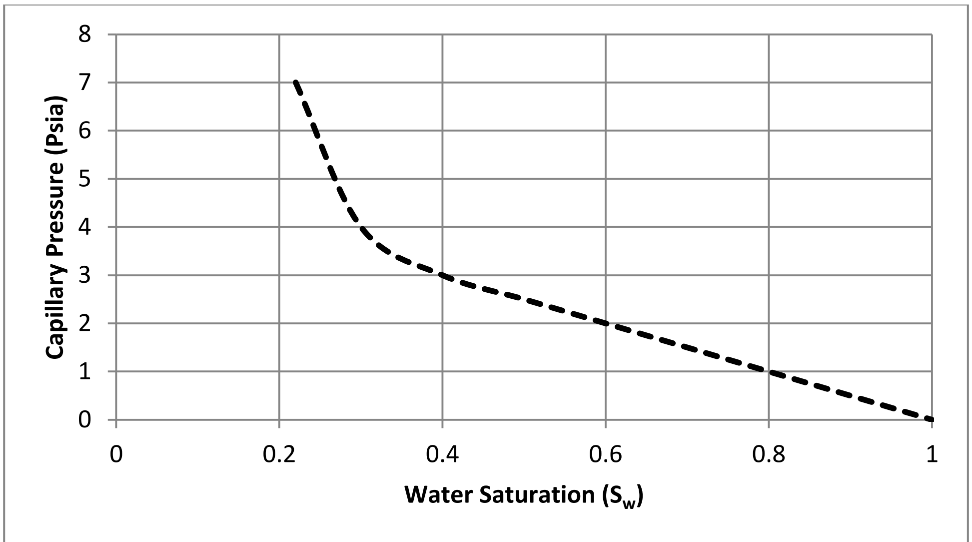

Fig. 3: Capillary Pressure Curve

3.1 SIMULATION WORK

As earlier alluded to, the simulation study was performed with ECLIPSE-100 Simulator. The reservoir properties (Table 1), fluid properties (Table 2) and relative permeability data (Table 3) were used to write the ECLIPSE input data file that result in the Base-case model study/results. To evaluate the water coning effect in the fractured model, three (3) parameters were selected for evaluation, that is; water cut (WCT), oil production rate (OPR) and water saturation (BWSAT) at the producing interval (1, 1, 7). However, it is worth mentioning here that since coning is a near wellbore effect the water saturation at the producing interval will present the effect of this phenomenon in the wellbore. In this regard, the results of the Base-case model are depicted in Figure 4 through 6.

3.2 SENSITIVITY STUDY

Further simulation studies were carried out to evaluate the effect(s) of the reservoir properties on the coning phenomenon in fractured reservoirs. The properties evaluated are as follows;

- Anisotropy ratio (k_v/k_h).
- Production rate (q).
- Storativity capacity (ω).
- Fracture width (b).
- Fracture Permeability (k_f).

Anisotropy Ratio (k_v/k_h):

Anisotropy ratio simply implies the ratio of the vertical permeability (k_v) to the horizontal permeability (k_h) in the reservoir. To evaluate this effect in coning behavior in fractured reservoir, five scenarios were selected. The scenarios ratios are presented in Table 4. The results obtained from these simulation runs are depicted in Figure 4 through 6.

Table 4: Anisotropy Ratio (k_v/k_h)

RUN NAME	Anisotropy Ratio
Base-case	0.10
CON1	0.20
CON2	0.25
CON3	0.50
CON4	1.00

Production Rate (q):

The production rate (q) was also employ in this simulation study to evaluate the effect of water coning in fractured reservoir. Therefore, five (5) different scenarios were simulated. Table 5 shows the production rates used in the different scenarios; as the results obtained are presented in figure 7 through 9.

Table 5: Production Rate (q)

RUN NAME	Production Rate (q), BPD
Base-case	3000
CON5	500
CON6	1000
CON7	1500
CON8	2000
CON9	2500

Storativity Capacity (ω):

Another parameter considered in this simulation study is the reservoir storativity capacity (ω). To evaluate this parameter's effect on coning study in fractured reservoir, the fracture porosity (φ_f) was varied. Four (4) scenarios were evaluated in this work; Table 6 shows the fracture's porosity (φ_f) and storativity capacity (ω) of different scenarios. Equation 18 expressed the storativity capacity (ω) in this simulation study. The results obtained are presented in Figure 10 through 12.

$$\omega = \frac{\varphi_f c_f}{(\varphi_f c_f + \varphi_m c_m)} . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \qquad (18)$$

Table 6: Storativity Capacity (ω)

RUN NAME	Fracture Porosity (φ_f)	Storativity Capacity (ω)
Base-case	0.001	0.007
CON10	0.002	0.013
CON11	0.003	0.018
CON12	0.004	0.023
CON13	0.005	0.027

Fracture Width (b):

The fracture width (b) was varies in the study to examine it effect in the coning phenomenon in fractured reservoir. In this regard, four (4) scenarios were examined; the different scenarios are indicated in Table 7. Figure 13 through 15 depict the results obtained from the simulation runs.

Table 7: Fracture Width (b)

RUN NAME	Fracture Width (ft)
Base-case	0.001
CON14	0.005
CON15	0.010
CON16	0.015
CON17	0.020

Fracture Permeability (k_f):

Finally in this sensitivity evaluation of coning phenomenon in fractured reservoir, the fracture permeability was evaluated with different scenarios of fracture permeability (k_f). Table 8 present the different scenarios fracture permeability (k_f) and the results obtained from the simulation runs are presented in Figure 16 through 18.

Table 8: Fracture Permeability (k_f)

RUN NAME	Fracture Permeability(k_f), md
Base-case	300
CON18	600
CON19	900
CON20	1200
CON21	1500

4.0 RESULTS AND DISCUSSION

4.1 BASE-CASE MODEL RESULT

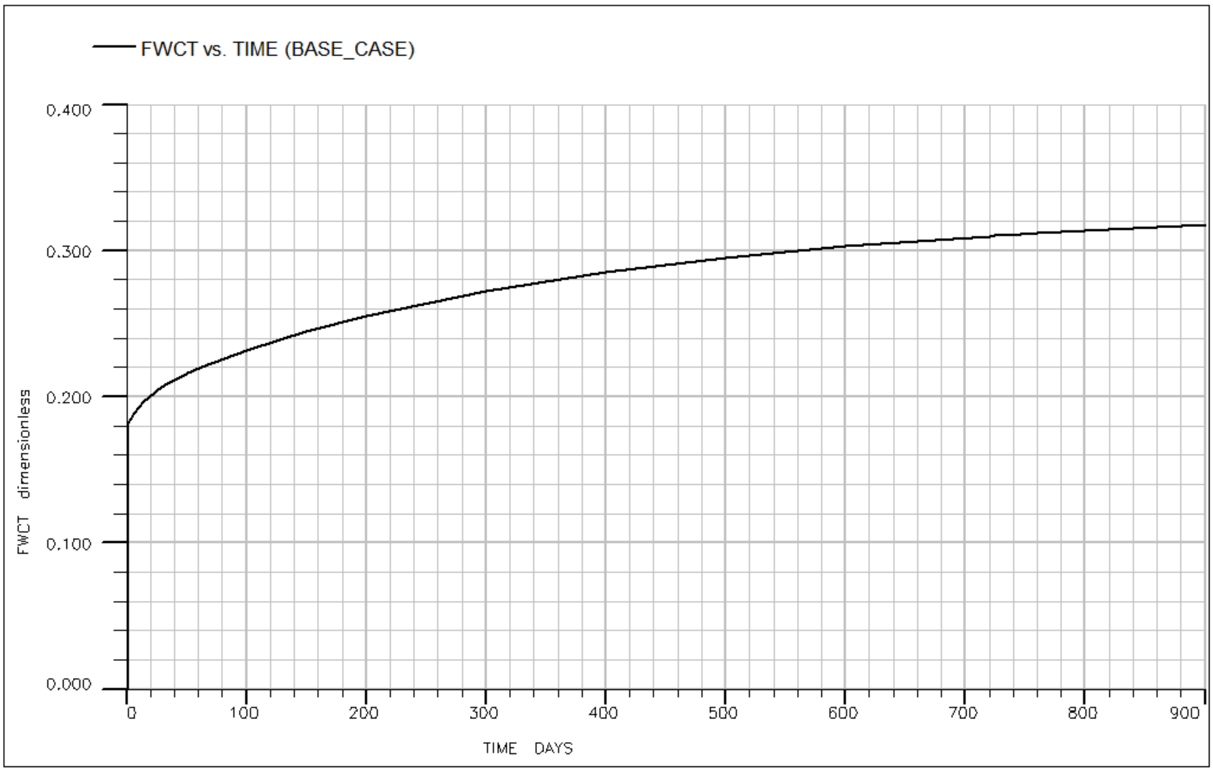

Fig. 4: Water Cut vs Time (Base-case)

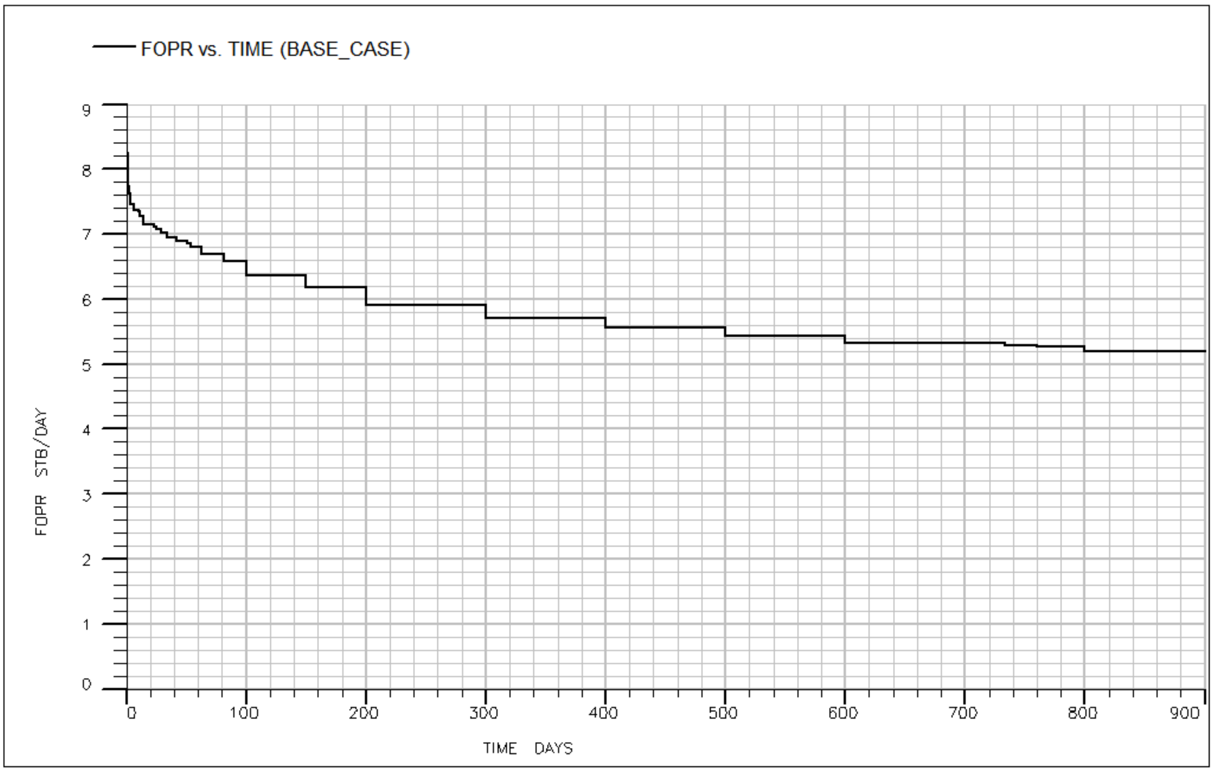

Fig. 5: Oil Production Rate vs Time (Base-case)

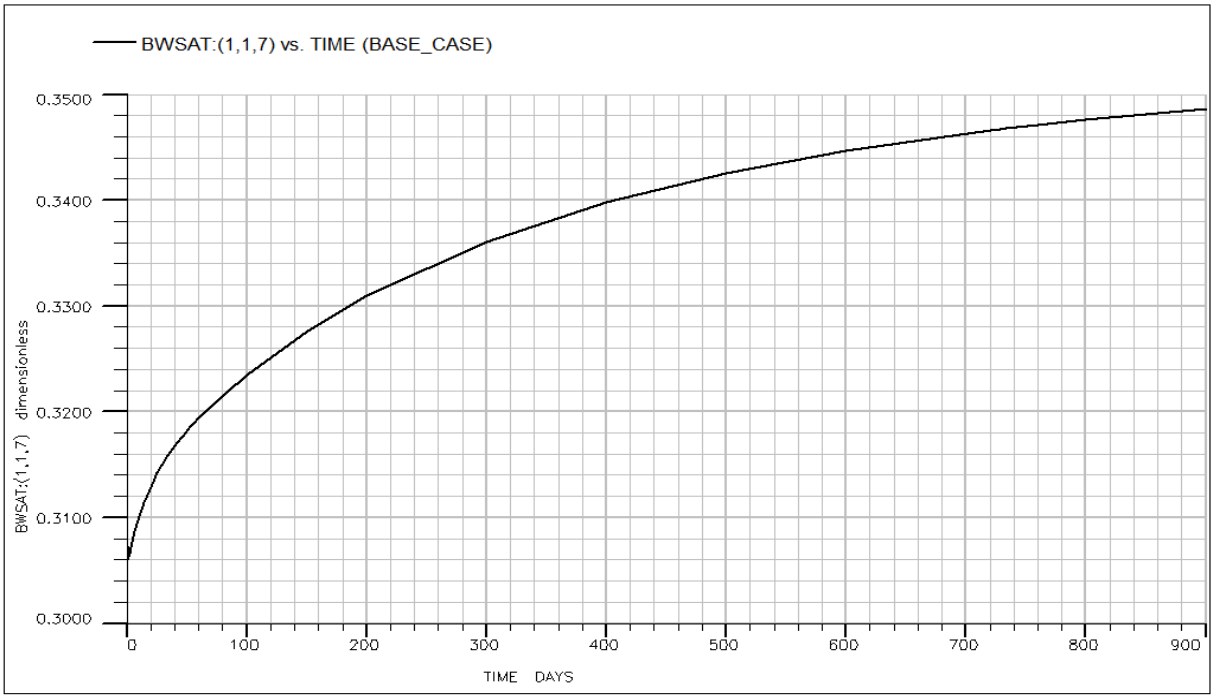

Fig. 6: Water Saturation (Block 1, 1, 7) vs Time (Base-case)

Figure 4 through 6 depict the results obtained from the Base-case model simulation run. As already mentioned in this work, three parameters are taken into account to evaluate the water coning phenomenon in fractured reservoir. These parameters are: Water Cut (WCT), Oil Production Rate (OPR) and Water Saturation (BWSAT) at the producing (perforation) interval (Block 1, 1, 7). Figure 4 indicate the water cut from the fractured model in the simulation study. The figure (Fig. 4) shows that the water cut of the fractured model increase as the production time increases. Thus, this is a direct indication that water is produce more than the oil in the model matrix, as the water in the aquifer cone into the producing interval. However, the causes of this high water cut in fractured reservoir is difficult to establish with a single reservoir parameter as the fluid flow in fractured reservoir is more complex compared to conventional reservoir. In this regard, the water cut is quite challenging to predict coning phenomenon in fractured reservoir as the storativity, transmissivity, imbibition mechanism and matrix-fracture interaction are significant.

Figure 5 shows the oil production rate from the fractured model. The result (Fig. 5) indicate a rapid decrease in the oil production rate in the first 200 days after which there was a steady decline in the oil production rate. However, this rapid decline in oil production is attributed to the presence of coning phenomenon in the matrix of the fractured model reservoir. Therefore, as the water cone through the fracture (fast moving) and matrix (slow moving) in the modeled reservoir, this result in decrease in the oil production rate. Conversely, as the coning move into the matrix block the declination of oil production rate become steady. Thus, it worth mentioning that in fractured reservoirs two coning phenomenon are experience; fast moving coning at the fracture and slow moving in the matrix block.

Figure 6 present the water saturation (BWSAT) at the producing (perforation) interval (Block 1, 1, 7). The result (Fig. 6) indicates a rapid water saturation of the producing interval matrix block. This increased water saturation is as a result of coning phenomenon in the matrix block, whereby the coning water saturate the producing matrix block and increases the water saturation (S_w) rapidly from its connate water (S_{wi}) as the oil is produce. However, the rapid increase in the water saturation at the producing interval (Fig. 6) account for the increased in the water cut (Fig. 4) from the fractured model in the simulation study. Therefore, it is imperative to state here that the coning phenomenon in fractured reservoir increases the water saturation at the perforation interval hereby resulting in increased water cut.

4.2 SENSITIVITY STUDY MODEL RESULTS

As aforementioned five reservoir's parameters were considered for the sensitivity study, that is; anisotropy ratio (k_v/k_h), production rate (q), storativity capacity (ω), fracture width (b) and fracture permeability (k_f). The results obtained from these simulation runs are depicted as follows:

4.2.1 EFFECT OF ANISOTROPY RATIO

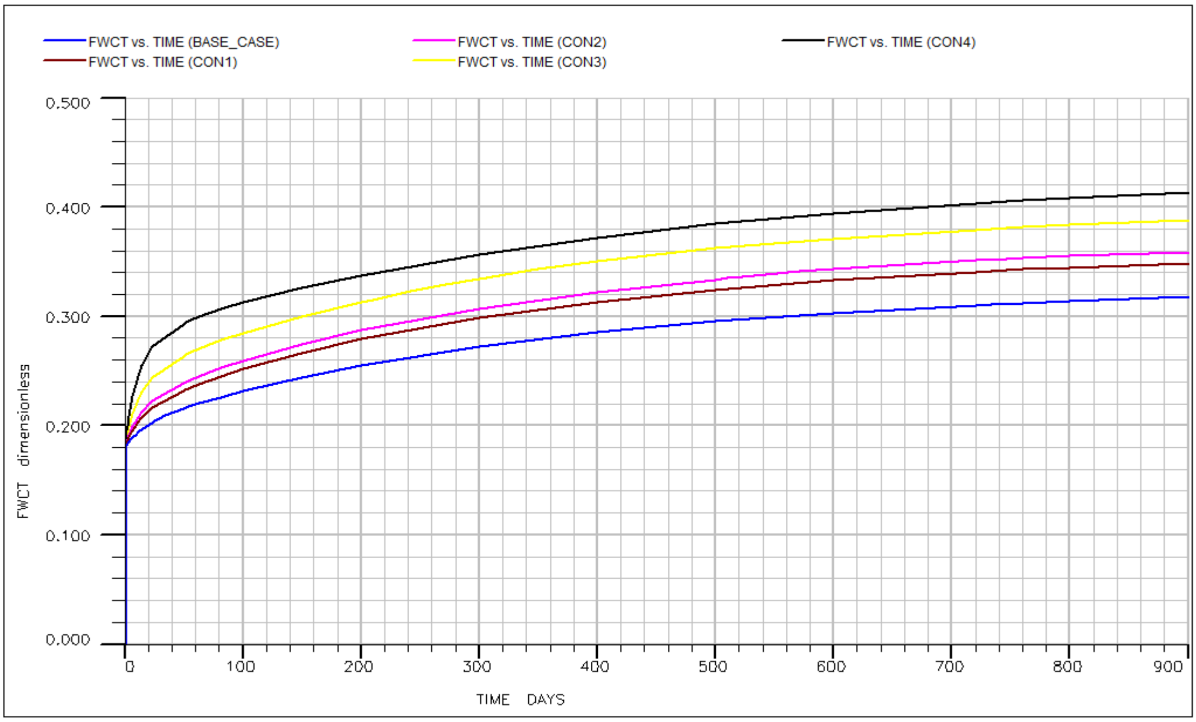

Fig. 7: Water Cut vs Time (Anisotropy Ratio)

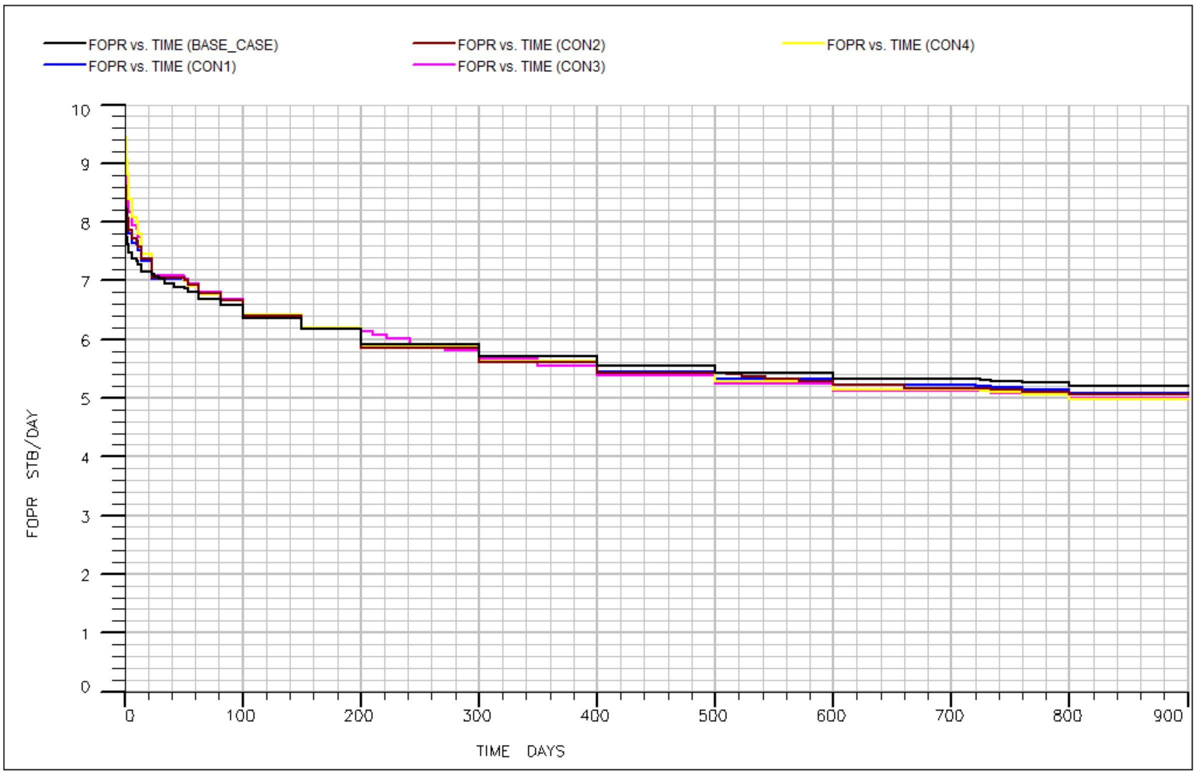

Fig. 8: Oil Production Rate vs Time (Anisotropy Ratio)

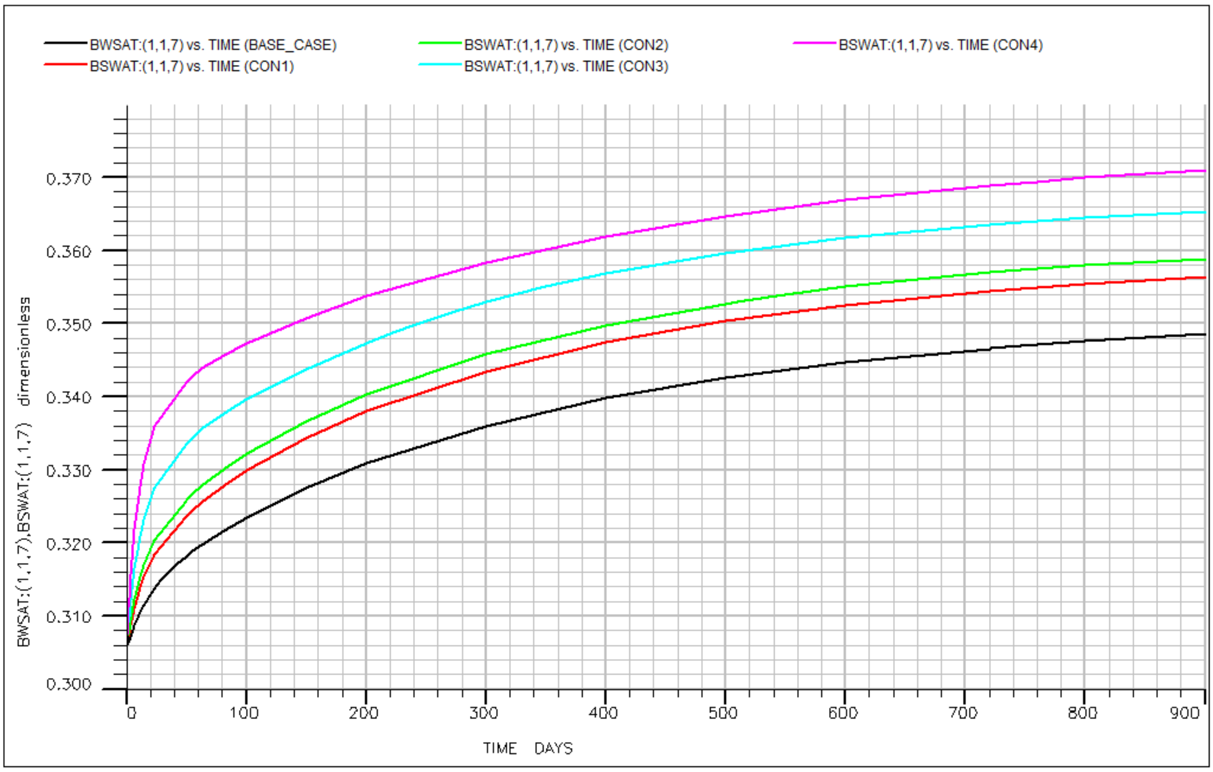

Fig. 9: Water Saturation (Block 1, 1, 7) vs Time (Anisotropy Ratio)

Figure 7 through 9 presents the effect of anisotropy ratio compared to the Base-case fractured model reservoir in this simulation study of water coning in fractured reservoir. Figure 7 depict the effect of anisotropy ratio of different scenarios on the fractured model water cut. The result (Fig. 7) indicates that the water cut obtained increase as the anisotropy ratio increases. That is to say that increase in the vertical permeability (k_v) will enhance coning phenomenon in the fracture reservoir, since water coning phenomenon is an upward movement of water as a result of pressure drawdown in the wellbore. Therefore with reference to Table 4, variation of the anisotropy ratio in the vertical permeability (k_v) establish upward movement of water in the fractured model reservoir and result in high water cut from the simulation study of water coning in fractured reservoir.

Figure 8 shows the oil production rate from the effect of anisotropy ratio on the fractured model different scenarios compared with the Base-case. The result (Fig. 8) depicts that there is no significant variation in the oil production rate obtained from all cases (scenarios) compared with the Base-case fractured model. This result shows that increase in anisotropy ratio (i.e. increase in vertical permeabilty) have no effect on oil production from fractured reservoir. This is as a result of the horizontal movement of oil into the wellbore; that is, distribution of fluid in horizontal plane. Therefore, in coning study in fractured reservoir increase in the vertical permeability has no role in the oil production rate as the oil transmissibility is in the horizontal direction.

Figure 9 is the result of the different scenarios of anisotropy ratio effect compared with the Base-case fractured model. The result (Fig. 9) depicts that the water saturation at the producing interval increase as the anisotropy ratio increases. As already stated that increase in anisotropy ratio result in upward movement of water. Therefore, this upward movement of water cone into the producting interval matrix block and increase its water saturation. In other words, the increased water saturation at the producing (perforation) interval as a result of increased anisotropy ratio explain the high water cut obtained from the same scenarios in the simulation study.

4.2.2 EFFECT OF PRODUCTION RATE

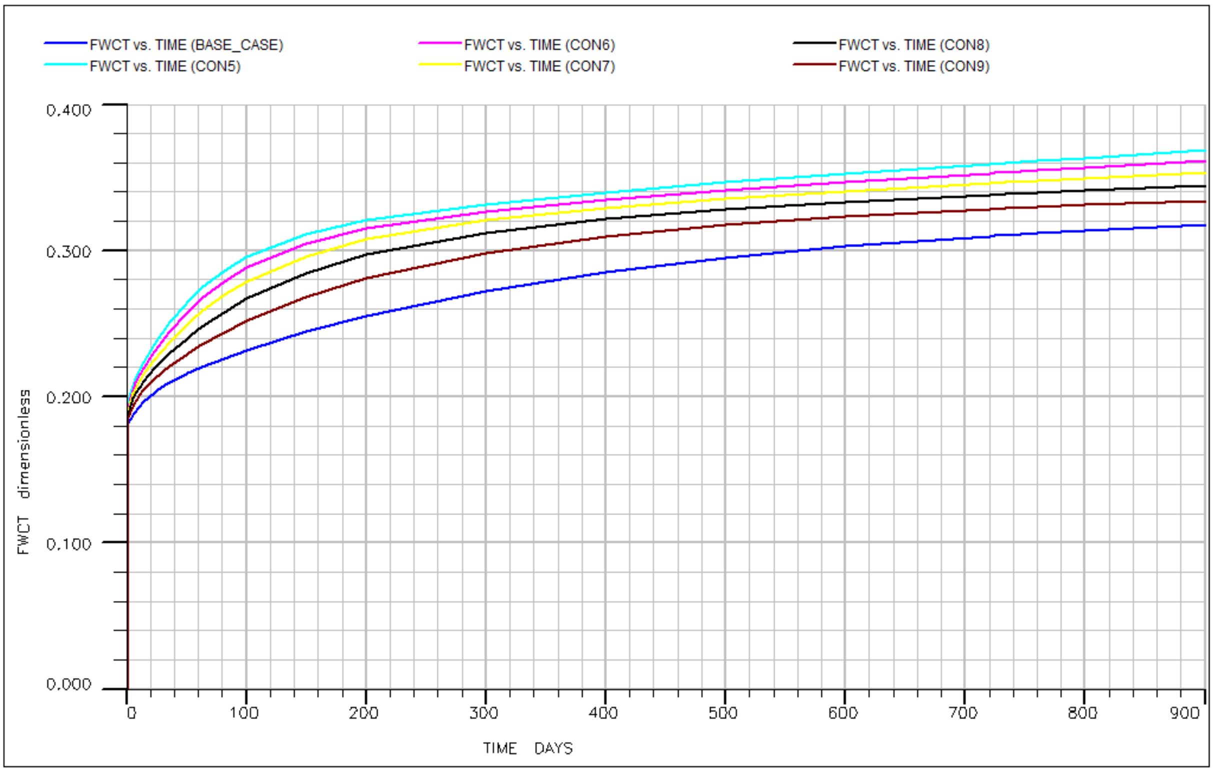

Fig. 10: Water Cut vs Time (Production Rate)

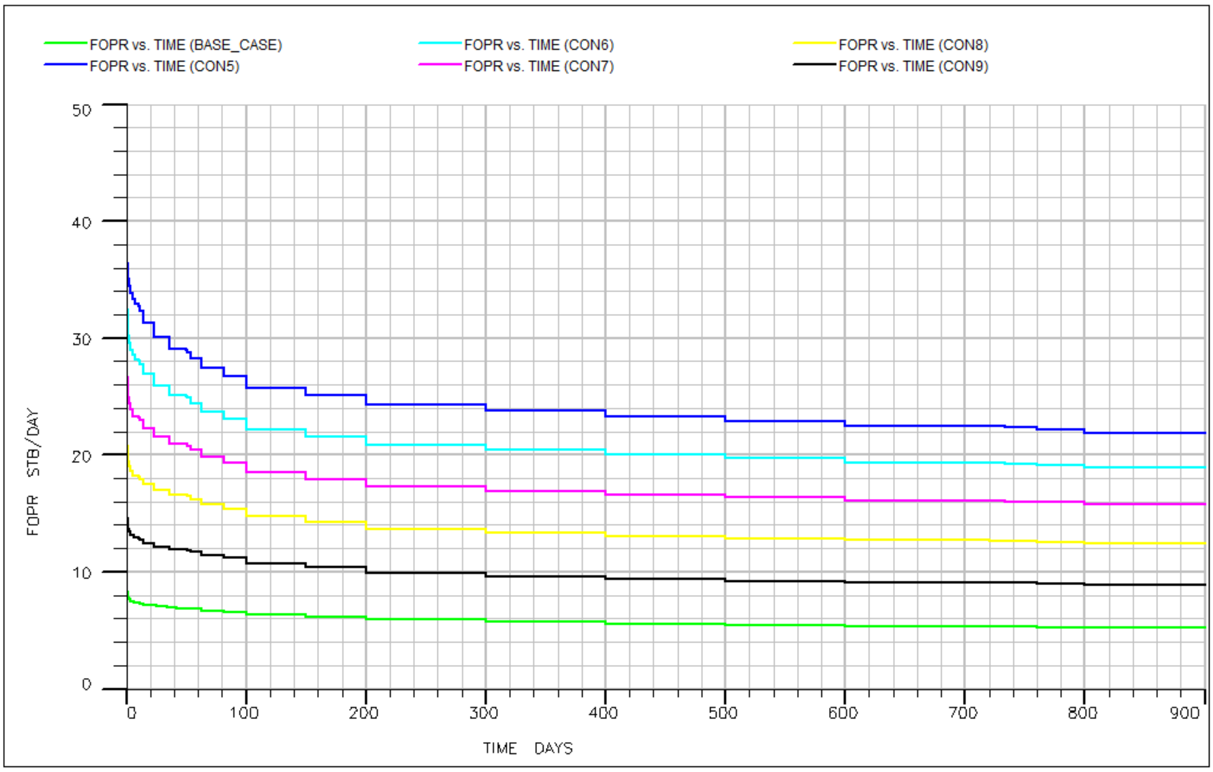

Fig. 11: Oil Production Rate vs Time (Production Rate)

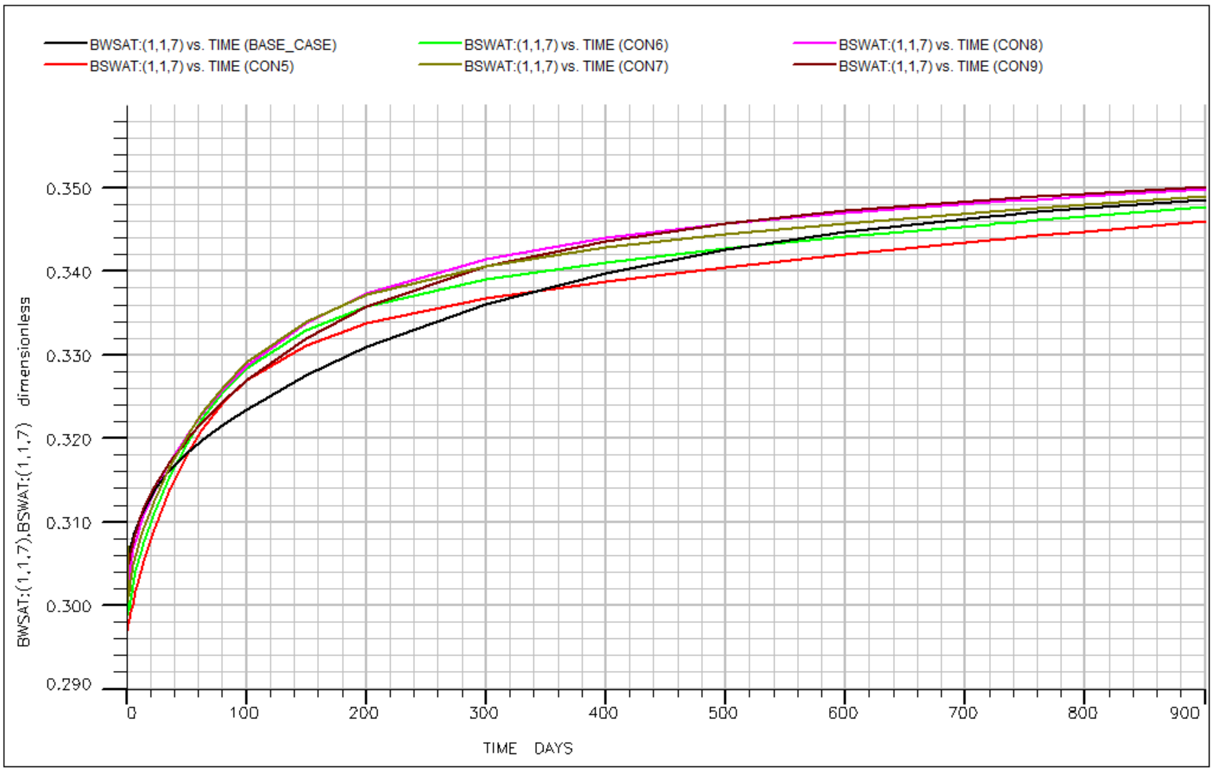

Fig. 12: Water Saturation (Blocl 1, 1, 7) vs Time (Production Rate)

Figure 10 through 12 present the different scenarios effect of production rate (q) on the fractured model compared with the Base-case. Figure 10 depict the production rate effect of different scenarios and Base-case water cut. The results (Fig. 10) indicate that the water cut obtained with least production rate; 500 BPD (barrel per day) is higher compared to other scenarios and the Base-case production rate from the fractured model. Hence, water cut decrease as the production rate increase. This is owing to the fact that at the production rate of 500 BPD (low production rate) coning phenomenon is controlled by the fast moving coning in the fracture. However, with increased production rate the water cut is controlled by the slow moving coning phenomenon in the matrix. This account for the low water cut obtained as the production rate increases in the sensitivity study as well as the Base-case fracture model.

Figure 11 shows the oil production rate obtained from sensitivity study of different scenarios of production rate on the fractured model. The result obtained (Fig. 11) indicates a significant difference among the different scenarios and the Base-case model. From the figure (Fig. 11) it is observed that the least production rate (500 BPD) produces the highest oil production rate compared to other scenarios' production rate and the Base-case model. This is attributed to the different role of coning at the fracture and the matrix. Thus, at the least (low) production rate the coning phenomenon in the matrix is slower allowing much oil to be produce from the matrix into the fracture for production. As such, this account for the high oil production rate at low production rate. Apparently, the coning phenomenon in the matrix increase as the production rate increases thereby hinders the movement (production) of oil from the matrix. In this regard, increase in production rate will result in decrease in the oil production rate from the study on coning phenomenon in fractured reservoir.

Figure 12 present the water saturation at the producing interval from the different sensitivity study scenarios compared with the Base-case model. The figure (Fig. 12) indicate variations in the water saturation at the producing interval obtained from all cases (i.e. sensitivity scenarios and Base-case). Two distinct results are observed:

- The rate of water saturation at the producing interval.
- The ultimate water saturation at the producing interval.

Thus, the rate of water saturation at the producing interval is a direct response to the production rate. In other words, the rate of water saturation at the producing interval increase as the production rate increases. It is worth to state here that the rate of water saturation at the producing interval is much controlled by the fast moving coning in the fracture. Conversely, the variations in the ultimate water saturation at the producing interval is about the same for all cases except for the lowest production rate (500 BPD). Therefore, the ultimate water saturation at the producing interval is controlled by the slow moving coning phenomenon in the matrix of the fractured reservoir.

4.2.3 EFFECT OF STORATIVITY CAPACITY (ω)

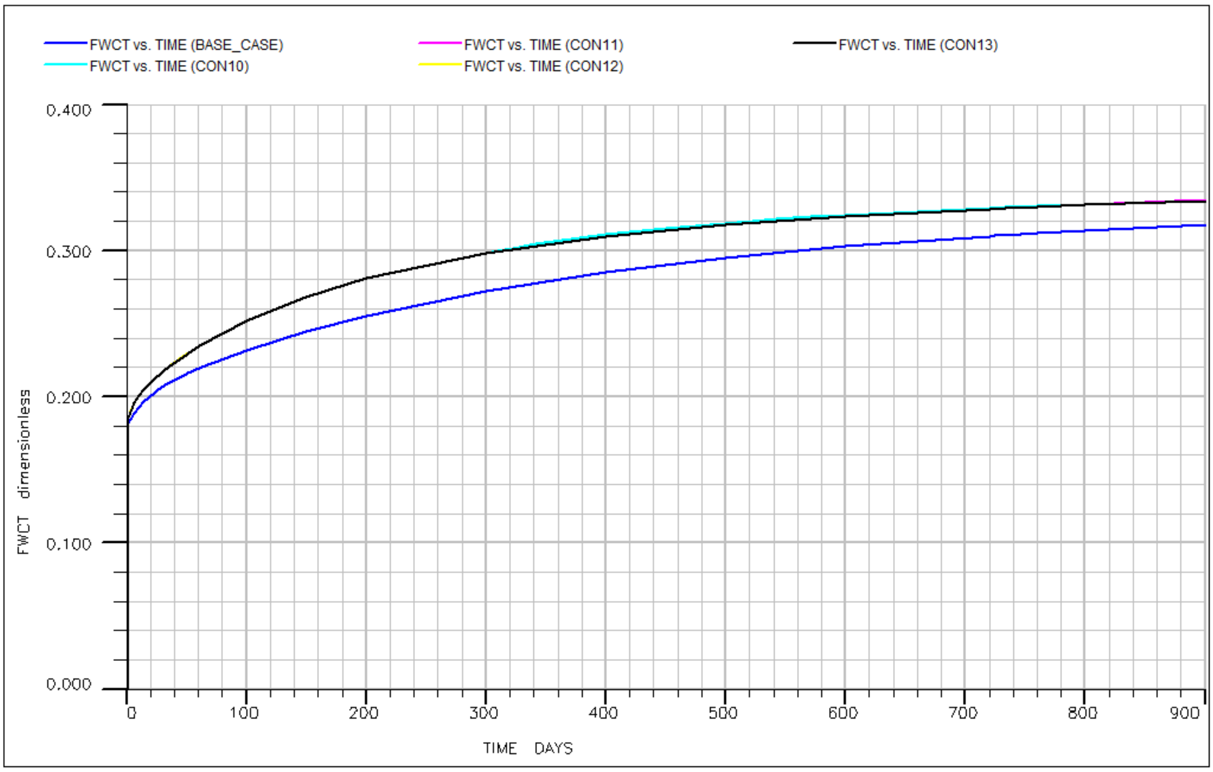

Fig. 13: Water Cut vs Time (Storativity Capacity)

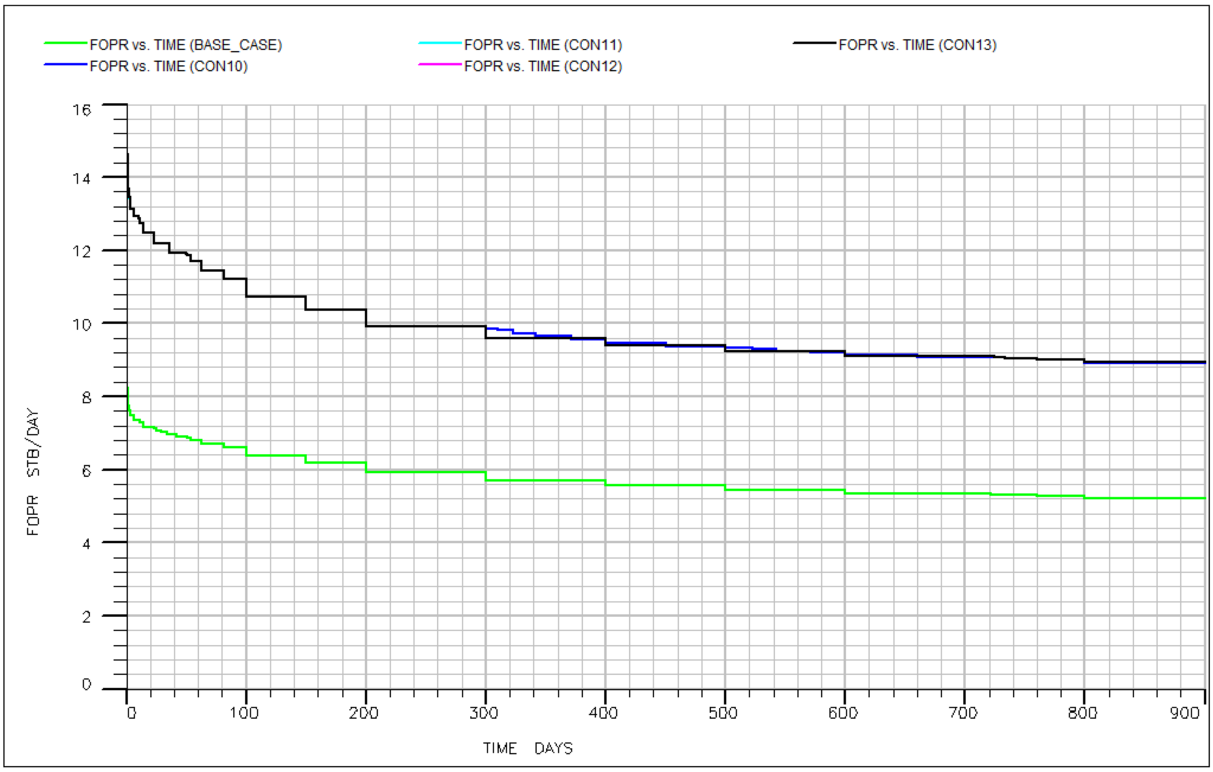

Fig. 14: Oil Production Rate vs Time (Storativity Capacity)

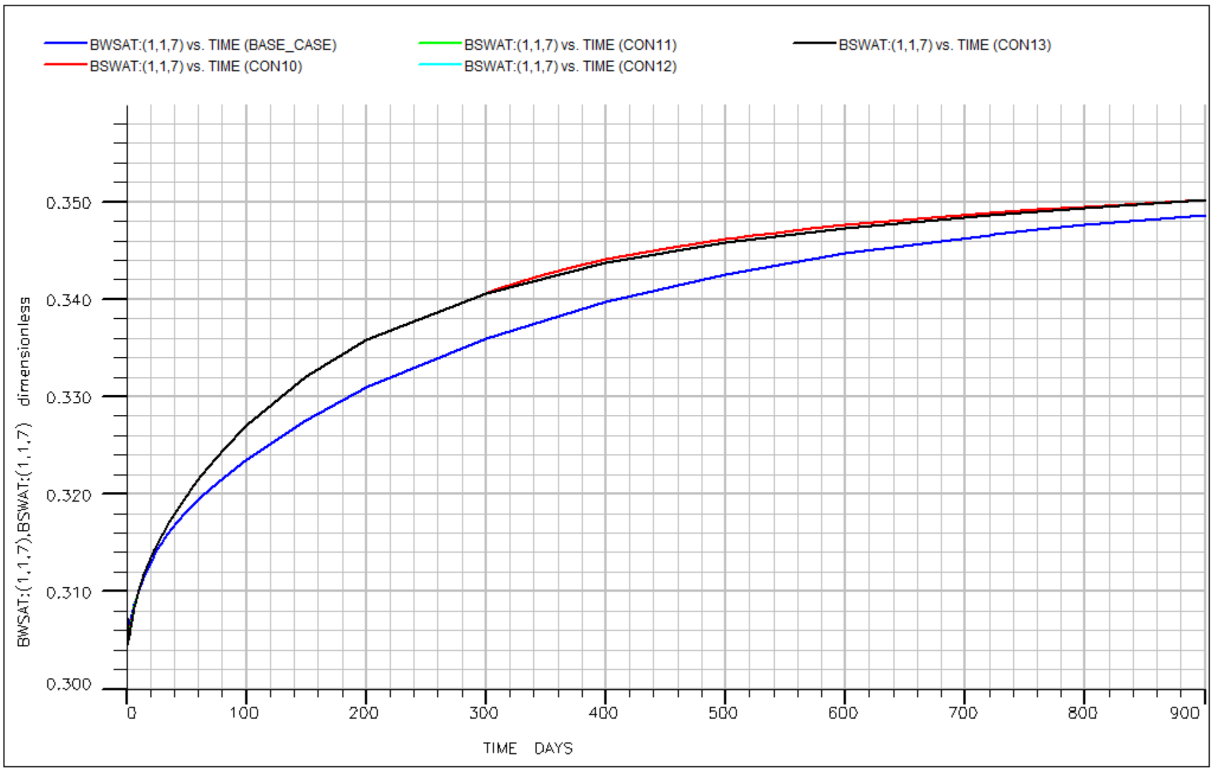

Fig. 15: Water Saturation (Block 1, 1, 7) vs Time (Storativity Capacity)

Firgure 13 through 15 present the result of the sensitivity study of storativity capacity (ω) in the fractured model by varying the fracture porosity (φ_f). The different scenarios of storativity capacity (ω) are compared with the Base-case model. Figure 13 depict the water cut obtained from different scenarios of storativity capacity (ω) compared with Base-case. The result (Fig. 13) shows that the there was no significant variation in water cut from the different scenarios of storativity capacity (ω). But there was a variation in water cut when comparing the Base-case and different storativity capacity (ω) scenarios results. Thus, the increased storativity capacity (ω) causes rapid movement of oil from the matrix into the fracture. As such the fast moving cone in the fracture and displacement of water by oil in the fracture will result in high water cut. Conversely, this phenomenon is not significant among the different storativity capacity (ω) scenarios as their difference (storativity capacity (ω) value) in this simulation study is not much. Thus, the fast movement of oil from the matrix into the fracture as well as fast coning in the fracture occur almost at the same interval.

Figure 14 shows the different scenarios of storativity capacity (ω) effect on the oil production rate from the fractured model. The figure (Fig. 14) indicates that oil production rate from the different scenarios are not effected by variation of the storativity capacity (ω). However, comparing the different scenarios of storativity capacity (ω) with the Base-case model, the result indicate an increase in the oil production rate form the different scenarios. With reference to Table 6, the increased oil production rate result from the different scenarios is attributed to the fact that there is a significant increase in the storativity capacity (ω) value of the different scenarios compared to the Base-case model value. Thus, there was a faster movement of oil from the matrix to the fracture that result in increased oil production rate. Conversely, the similarity in the different scenarios's oil production rate is owing to the fact that there is no significant difference in their storativity capacity (ω) value.

Figure 15 present the water saturation at the producing interval obtained from sensitivity study of storativity capacity (ω) and compared with the Base-case fractured model. The result (Fig. 15) shows that there was no significant variation among the different scenarios of storativity capacity (ω) water saturation at the producing interval. However, comparison of the Base-case and different scenarios' storativity capacity (ω) water saturation at producing interval depicts an increase in the water saturation. These difference between the Base-case and different scenarios' storativity capacity (ω) water saturation at the producing interval is as a result of the coning of water into the producing interval matrix, because of rapid movement of oil from the matrix into the fracture. Conversely, this phenomenon was not very significant among the different scenarios as their storativity capacity (ω) values were very close. In other words, the difference between the storativity capacity (ω) value of different scenarios was not much compared to the Base-case model.

4.2.4 EFFECT OF FRACTURE WIDTH (b)

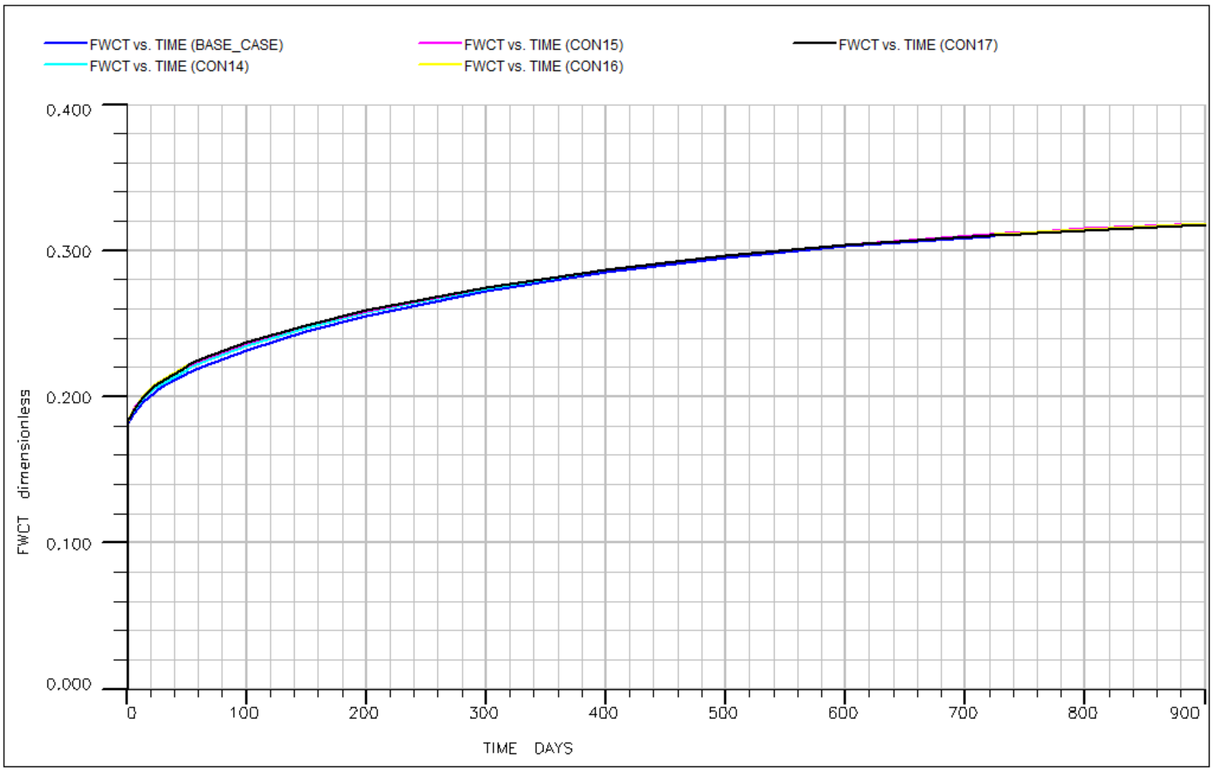

Fig. 16: Water Cut vs Time (Fracture Width)

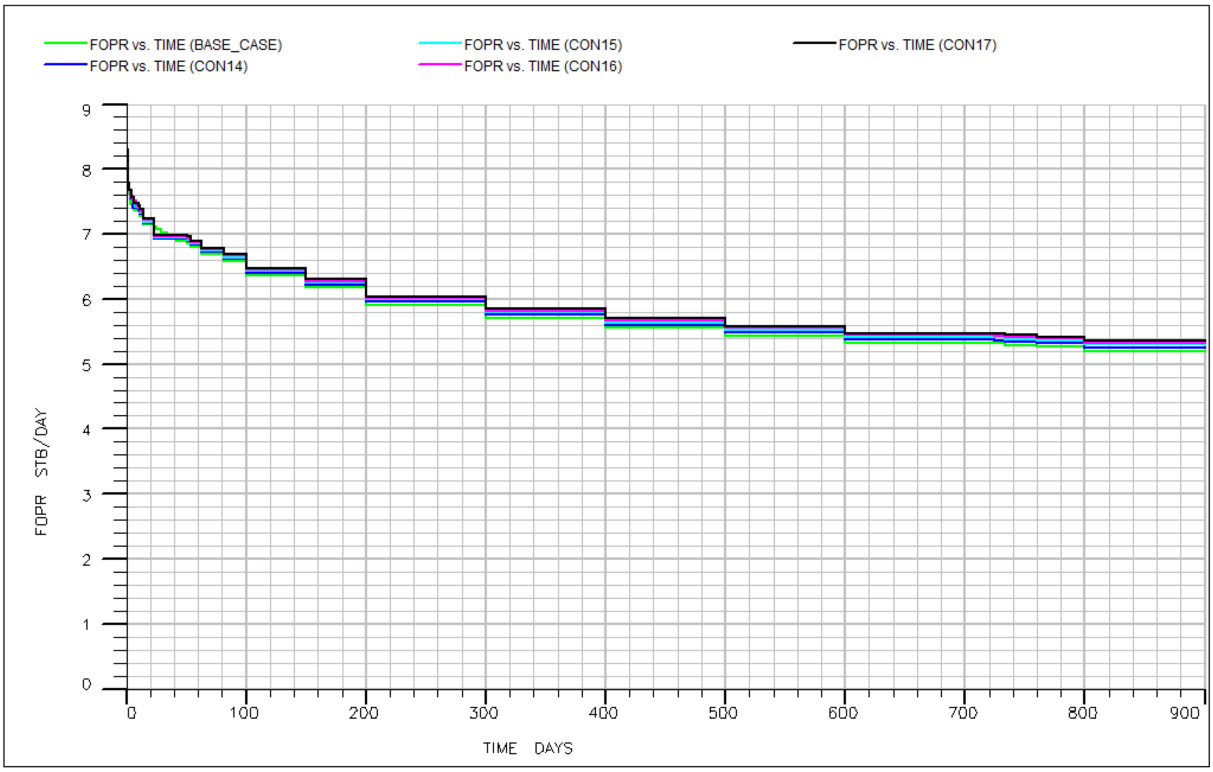

Fig. 17: Oil Production Rate vs Time (Fracture Width)

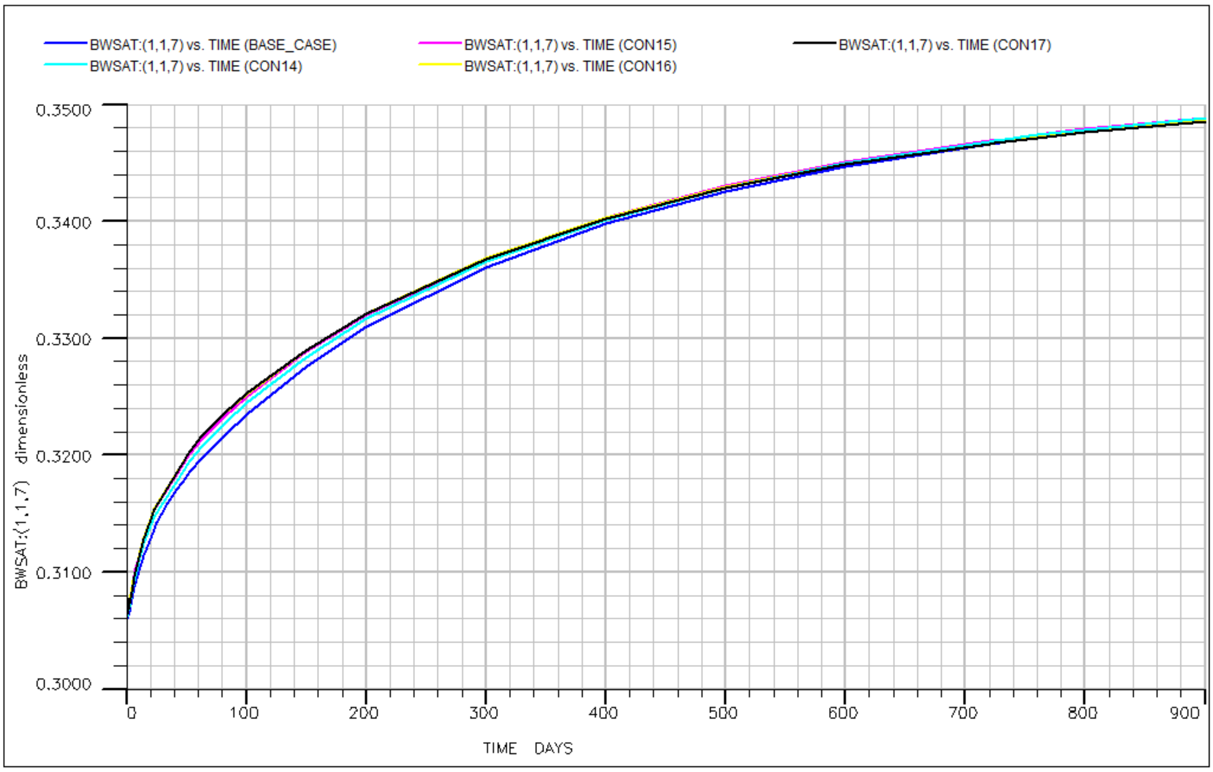

Fig. 18: Water Saturation (Block 1, 1, 7) vs Time (Fracture Width)

Figure 16 through 18 present the results obtained from variation of fracture width (b) in the fractured model in this coning phenomenon study in fractured reservoir. Figure 16 depict the water cut from the different scenarios compared with the Base-case model result. The result (Fig. 16) indicates that there was no significant variation in the water cut obtained from all scenarios and the Base-case model. The result is owing to the fact that the coning at the fracture is a fast moving one. Thus, it is independent of the fracture width; as the fracture is a passive channel (network) in the fracture reservoir.

Figure 17 present the oil production rate from the different scenarios compared with the Base-case model. The figure (Fig. 17) shows that the oil production rate obtained from all cases depicts no significant variation. This result is attributed to the fact that the coning phenomenon in the fracture has no or less impact on the matrix, as the oil is accumulated in the matrix. Thus, oil production rate in fracture reservoir is dependent on the matrix characteristic. Therefore varying the fracture width has no effect on the oil production rate in this coning phenomenon study in fracture reservoir.

Figure 18 shows the water saturation at the producing interval from the different scenarios compared with the Base-case model. The result (Fig. 18) depict no significant variation in the water saturation at the producing interval obtained from all cases (different scenarios and Base-case). Apparently the result is in line with the result obtained in the water cut (Fig. 16) from the variation of fracture width. Therefore, the water saturation at the producing interval in all cases is dependent on the coning phenomenon in the matrix. This account for the no variation in water cut (Fig. 16) and water saturation at the producing interval (Fig. 18) in the coning study in fracture reservoir. Hence, fracture width has no direct compact on the water cut, oil production rate and water saturation at the producing interval in water coning in fractured reservoir.

4.2.5 EFFECT OF FRACTURE PERMEABILITY (k_f)

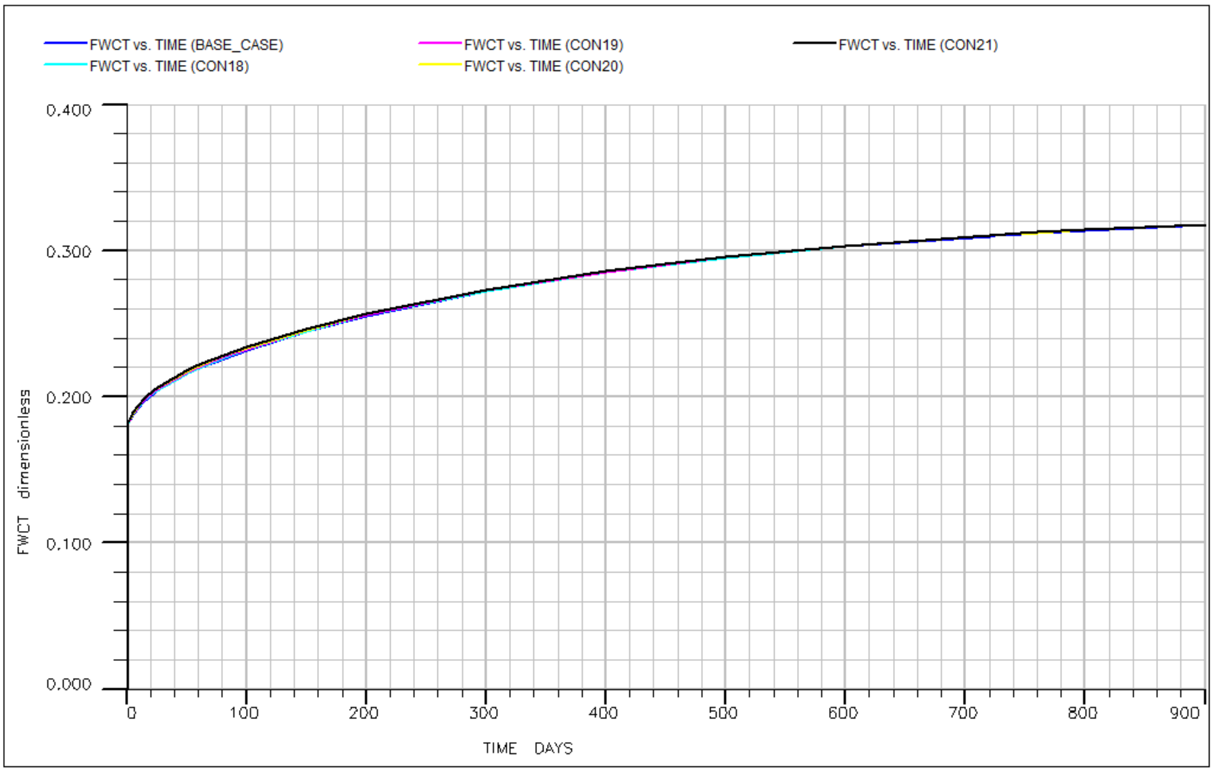

Fig. 19: Water Cut vs Time (Fracture Permeability)

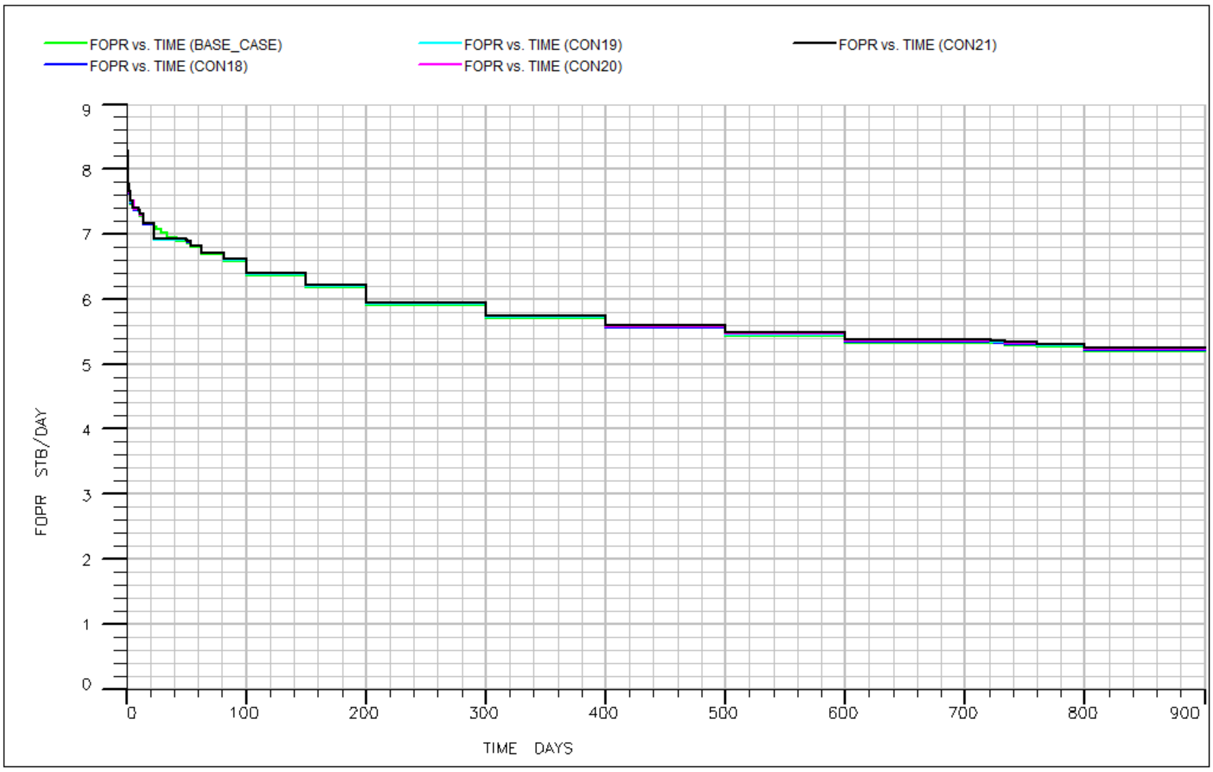

Fig. 20: Oil Production Rate vs Time (Fracture Permeability)

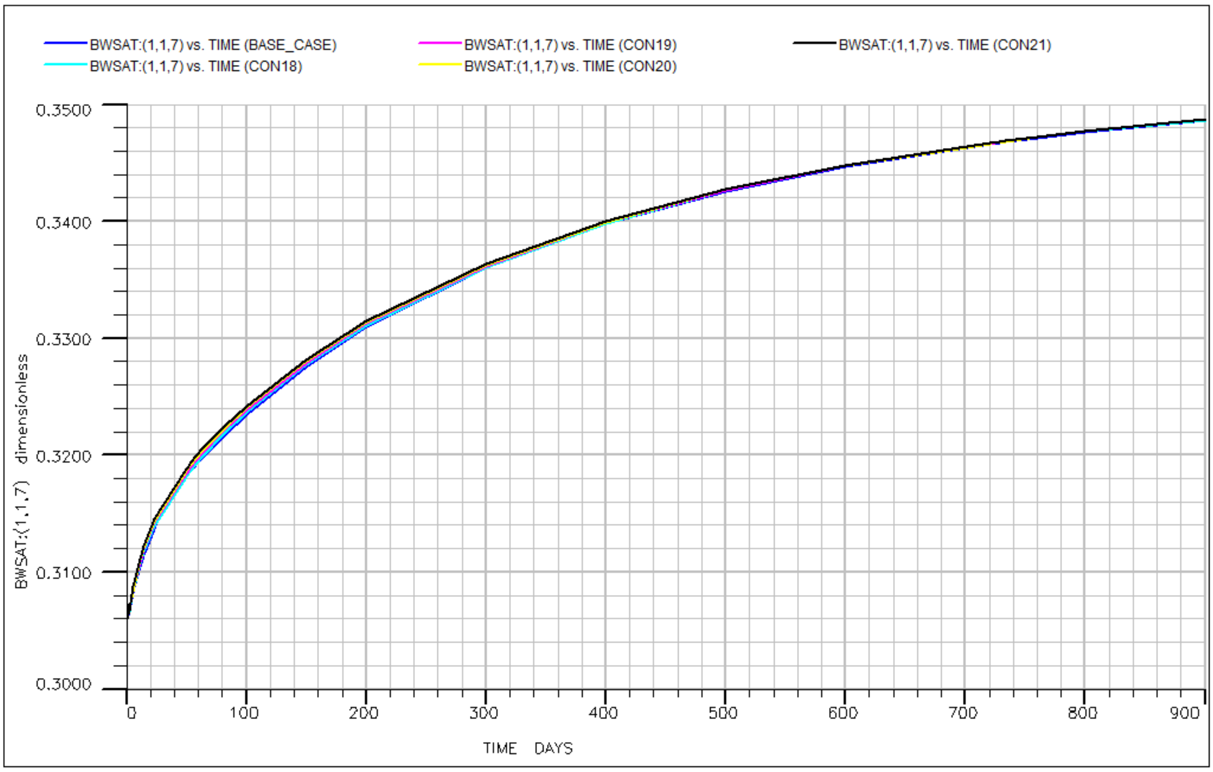

Fig. 21: Water Saturation (Block 1, 1, 7) vs Time (Fracture Permeability)

Fracture permeability is the most important uncontrollable parameter in water coning phenomenon, because in fracture reservoir water cone front in fractures moves faster than matrixes (Namani*et al*., 2007). Figure 19 through 21 present the sensitivity study of different scenarios of fracture permeability and the Base-case model results. Figure 19 depict the water cut from the different scenarios compared with the Base-case. The result (Fig. 19) indicates that the fracture permeability has no effect on the water cut obtained from the coning study in fractured reservoir. This result is attributed to the fact that the water cut is controlled by the coning movement in the matrix. Moreover in fractured reservoir fracture act as a passive channel (network) for fluid flow. Therefore owing to the high permeability of the fracture compared to the matrix, the water cut obtained does not depend on the fracture permeability (k_f).

Figure 20 account for the oil production rate from different scenarios of fracture permeability compared with Base-case model. The result (Fig. 20) depicts that the fracture permeability variation has no significant effect/result on the oil production rate obtained from the coning study in fractured reservoir. The attributing factor to this result is that oil is accumulated in the matrix block (low permeability) of the fractured reservoir. In that case, the coning phenomenon in the fracture with high permeability moves faster without any effect on the oil production rate from the matrix.

Figure 21 present the water saturation at the producing interval from different scenarios of fracture permeability (k_f) compared with Base-case model. Apparently the result (Fig. 21) indicates no significant variation from the different scenarios results and the Base-case model. This is owing to the fact that the coning phenomenon at the producing interval is controlled by the slow moving coning in the matrix. Therefore varying the fracture permeability did not increase the water saturation at the producing interval. As this also account for the results obtained in the water cut (Fig. 19).

5.0 CONCLUSION

Water coning behaviour is important reservoir phenomenon that occurs in reservoirs that are driven and/or supported by aquifers. In fractured reservoirs this phenomenon is very challenging owing to the dual permeability of the porous media resulting in two coning phenomena: fracture and matrix coning. In the course of this simulation study, sensitivity analysis was carried out to determine the sensitivity of certain parameters to coning behaviour in a fractured reservoir. These parameters include, among others anisotropy ratio (k_v/k_h), production rate (q), storativity capacity (ω), fracture width (b) and fracture permeability (k_f). Based on the results obtained from the fractured model, the following conclusions can be drawn from this simulation study:

1. Increase in the vertical permeability (i.e., increase in anisotropy ratio (k_v/k_h)) will result in increased water cut and water saturation at the producing interval without any significant effect on the oil production rate from the fractured reservoir.
2. The water cut and oil production rate obtain decreased as production rate increased due to the fact that at low rate, water cut is controlled by fast moving cone at the fracture whilst oil production rate is controlled by slow moving cone in the matrix.
3. The water cut oil production rate and water saturation at the producing interval increased as the storativity capacity (ω) increased. However, the sensitivity of these parameters depends to a large extent, on fracture porosity (φ_f) just as the storativity capacity (ω) depends on the fracture porosity (φ_f).
4. The fracture width (b) has no effect on the water cut, oil production rate and water saturation at the producing interval.
5. The water cut, oil production rate and water saturation at the producing interval is not dependable on the fracture permeability (k_f) in water coning phenomenon in fractured reservoirs.

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APPENDIX

BASE-CASE DATA FILE:

```
-- THE WELL RATE IS SUBJECT TO LARGE CHANGES, AND AT ABOUT 250 DAYS

-- CHANGES FROM FLOW RATE TO BHP CONTROL.

--
=========================================================================

RUNSPEC

TITLE

       WATER CONING IN FRACTURED RESERVOIRS: A SIMULATION STUDY

DIMENS

  10   1  15  /

RADIAL

NONNC

OIL

WATER

FIELD

EQLDIMS

1  100   10    1   20 /

TABDIMS

  1    1   19   15   15   15 /

REGDIMS

  15    1    0    0  /

WELLDIMS

  1    2    1    1 /

NUPCOL

  4 /

START

  1 'JAN' 2010  /

NSTACK

  24 /

DEBUG

2  0  0   0  0  0  1 /

--NOSIM

GRID
=============================================================

-------- IN THIS SECTION , THE GEOMETRY OF THE SIMULATION GRID AND THE

-------- ROCK PERMEABILITIES AND POROSITIES ARE DEFINED.

---------------------------------------------------------------------

COLUMNS

10  60 /

--3456789

      PSEUDO

      SAVE

       /

      COLUMNS

1  80 /

--  SPECIFY INNER RADIUS OF 1ST GRID BLOCK IN THE RADIAL DIRECTION

INRAD

 0.25 /

--   SPECIFY GRID BLOCK DIMENSIONS IN THE R DIRECTION

DRV

   0.10 0.25 0.65 1.15 10.85

   45.0 135.0 285.0 515.0 1105.0 /

-- SPECIFY CELL THICKNESSES ( DZ ), RADIAL PERMEABILITIES ( PERMR )

-- AND POROSITIES ( PORO ) FOR EACH LAYER OF THE GRID. ALSO CELL TOP

-- DEPTHS ( TOPS ) FOR LAYER 1. DTHETA IS SET TO 360 DEGREES FOR EVERY

-- GRID BLOCK IN THE RESERVOIR.
```

```
--   ARRAY   VALUE  ------ BOX ------

EQUALS

'DTHETA'  360   /  BOX DEFAULTS TO THE WHOLE GRID

   'DZ'    20    1 10  1  1  1  1  /  LAYER 1
   'PERMR'  1.25  /
   'PORO'   0.18  /
   'TOPS'   9000  /
   'DZ'   0.001  1 10  1  1  2  2  /
   'PERMR'  300   /
   'PORO'   0.001 /
   'DZ'    20    1 10  1  1  3  3  /  LAYER 2
   'PERMR'  1.25  /
   'PORO'   0.18  /
   'DZ'   0.001  1 10  1  1  4  4  /
   'PERMR'  300   /
   'PORO'   0.001 /
   'DZ'    20    1 10  1  1  5  5  /  LAYER 3
   'PERMR'  1.25  /
   'PORO'   0.18  /
   'DZ'   0.001  1 10  1  1  6  6  /
   'PERMR'  300   /
   'PORO'   0.001 /
   'DZ'    20    1 10  1  1  7  7  /  LAYER 4
   'PERMR'  1.25  /
   'PORO'   0.18  /
   'DZ'   0.001  1 10  1  1  8  8  /
   'PERMR'  300   /
   'PORO'   0.001 /
   'DZ'    20    1 10  1  1  9  9  /  LAYER 5
   'PERMR'  1.25  /
   'PORO'   0.18  /
   'DZ'   0.001  1 10  1  1  10  10  /
   'PERMR'  300   /
   'PORO'   0.001 /
   'DZ'    20    1 10  1  1  11  11  /  LAYER 6
   'PERMR'  1.25  /
   'PORO'   0.18  /
   'DZ'   0.001  1 10  1  1  12  12  /
   'PERMR'  300   /
   'PORO'   0.001 /
   'DZ'    20    1 10  1  1  13  13  /  LAYER 7
   'PERMR'  1.25  /
   'PORO'   0.18  /
   'DZ'   0.001  1 10  1  1  14  14  /
   'PERMR'  300   /
   'PORO'   0.001 /
   'DZ'    20    1 10  1  1  15  15  /  LAYER 8
   'PERMR'  1.25  /
   'PORO'   0.18  /
   /  EQUALS IS TERMINATED BY A NULL RECORD

--  COPY RADIAL PERMEABILITIES ( PERMR ) INTO VERTICAL PERMEABILITIES

--  ( PERMZ ) FOR THE WHOLE GRID, AND THEN MULTIPLY PERMZ BY 0.1.

-------- SOURCE    DESTINATION

COPY

     'PERMR'    'PERMZ'    /

/

-------- ARRAY    FACTOR

MULTIPLY

     'PERMZ'    0.1    /

/

-- OUTPUT OF CELL DIMENSIONS, PERMEABILITIES, POROSITY AND TOPS
```

```
-- DATA IS REQUESTED, AND OF THE CALCULATED PORE VOLUMES, CELL

-- CENTRE DEPTHS AND X AND Z DIRECTION TRANSMISSIBILITIES

RPTGRID

 1 1 1 1 0 1 0 0 0 1 0 1 1 1 1 0 1 /

PROPS
=========================================
======================

-------- THE PROPS SECTION DEFINES THE REL. PERMEABILITIES, CAPILLARY

-------- PRESSURES, AND THE PVT PROPERTIES OF THE RESERVOIR FLUIDS

-------------------------------------------------------------------
-

-- WATER RELATIVE PERMEABILITY AND CAPILLARY PRESSURE ARE TABULATED AS

-- A FUNCTION OF WATER SATURATION.

--

-- SWAT KRW PCOW

SWFN

0.22 0 7

 0.3 0.07 4

 0.4 0.15 3

 0.5 0.24 2.5

 0.6 0.33 2

 0.8 0.65 1

 0.9 0.83 0.5

 1 1 0 /

-- SIMILARLY FOR GAS

--

-- SGAS KRG PCOG

--SGFN 1 TABLES 19 NODES IN EACH FIELD 16:31 18 JAN 85

 -- .0000 .0000 .0000

 -- .0400 .0000 .2000

 -- .1000 .0220 .5000

 -- .2000 .1000 1.0000

 -- .3000 .2400 1.5000

 -- .4000 .3400 2.0000

 -- .5000 .4200 2.5000

 -- .6000 .5000 3.0000

 -- .7000 .8125 3.5000

 -- .7800 1.0000 3.9000

/

-- OIL RELATIVE PERMEABILITY IS TABULATED AGAINST OIL SATURATION

-- FOR OIL-WATER AND OIL-GAS-CONNATE WATER CASES

--

-- SOIL KROW

SOF2

 0.00 0.000

 0.20 0.000

 0.38 0.00432

 0.40 0.0048

 0.48 0.05288

 0.50 0.0649

 0.58 0.11298

 0.60 0.125

 0.68 0.345

 0.70 0.400

 0.74 0.700

 0.78 1.000 /

 /

-- PVT PROPERTIES OF WATER

-- REF. PRES. REF. FVF COMPRESSIBILITY REF VISCOSITY VISCOSIBILITY

PVTW
```

```
   3600   1.00341    3.0D-6     0.96       0  /

 PVDO

--PVT PROPERTIES OF DEAD OIL

--OIL (PRE)  BO    UO   control  output  from  section

 3200   1.0985   0.98

 3600   1.0915   0.95

  /

-- ROCK COMPRESSIBILITY

--

--   REF. PRES   COMPRESSIBILITY

ROCK

     3600       4.0D-6  /

-- SURFACE DENSITIES OF RESERVOIR FLUIDS

--

--     OIL  WATER  GAS

DENSITY

       45   63.02   0.0702  /

-- PVT PROPERTIES OF DRY GAS (NO VAPOURISED OIL)

-- WE WOULD USE PVTG TO SPECIFY THE PROPERTIES OF WET GAS

--

--  PGAS  BGAS  VISGAS

--PVDG

   -- 400   5.9   0.013

   -- 800   2.95  0.0135

   --1200   1.96  0.014

   --1600   1.47  0.0145

   --2000   1.18  0.015

   --2400   0.98  0.0155

   --2800   0.84  0.016

   --3200   0.74  0.0165

   --3600   0.65  0.017

   --4000   0.59  0.0175

   --4400   0.54  0.018

   --4800   0.49  0.0185

   --5200   0.45  0.019

   --5600   0.42  0.0195 /

-- PVT PROPERTIES OF LIVE OIL (WITH DISSOLVED GAS)

-- WE WOULD USE PVDO TO SPECIFY THE PROPERTIES OF DEAD OIL

--

-- FOR EACH VALUE OF RS THE SATURATION PRESSURE, FVF AND VISCOSITY

-- ARE SPECIFIED. FOR RS=1.81   THE FVF AND VISCOSITY OF

-- UNDERSATURATED OIL ARE DEFINED AS A FUNCTION OF PRESSURE. DATA

-- FOR UNDERSATURATED OIL MAY BE SUPPLIED FOR ANY RS, BUT MUST BE

-- SUPPLIED FOR THE HIGHEST RS (1.81).

--

--  RS     POIL   FVFO   VISO

--PVTO

  --0.165    400   1.012    1.17  /

  --0.335    800   1.0255   1.14  /

  --0.500   1200   1.038    1.11  /

  --0.665   1600   1.051    1.08  /

  --0.828   2000   1.063    1.06  /

  --0.985   2400   1.075    1.03  /

  --1.130   2800   1.087    1.00  /

  --1.270   3200   1.0985   0.98  /

  --1.390   3600   1.11     0.95  /

  --1.500   4000   1.12     0.94  /

  --1.600   4400   1.13     0.92  /
```

```
--1.676    4800   1.14    0.91  /
--1.750    5200   1.148   0.9   /
--1.810    5600   1.155   0.89
--       6000   1.1504   0.89
--       6400   1.1458   0.89
--       6800   1.1412   0.89
--       7200   1.1367   0.89  /
/
-- SWITCH ON OUTPUT OF ALL PROPS DATA
RPTPROPS
 8*1   /
REGIONS
=========================================
======================
-------- THE REGIONS SECTION DEFINES HOW THE RESERVOIR IS SPLIT INTO
-------- REGIONS BY SATURATION FUNCTION, PVT FUNCTION, FLUID IN PLACE
-------- REGION ETC.
-------------------------------------------------------------------
---
EQUALS
FIPNUM 1 1 10 1 1 1 1 /
FIPNUM 2 1 10 1 1 2 2 /
FIPNUM 3 1 10 1 1 3 3 /
FIPNUM 4 1 10 1 1 4 4 /
FIPNUM 5 1 10 1 1 5 5 /
FIPNUM 6 1 10 1 1 6 6 /
FIPNUM 7 1 10 1 1 7 7 /
FIPNUM 8 1 10 1 1 8 8 /
FIPNUM 9 1 10 1 1 9 9 /
FIPNUM 10 1 10 1 1 10 10 /
FIPNUM 11 1 10 1 1 11 11 /
FIPNUM 12 1 10 1 1 12 12 /
FIPNUM 13 1 10 1 1 13 13 /
FIPNUM 14 1 10 1 1 14 14 /
FIPNUM 15 1 10 1 1 15 15 /
/
 -- SWITCH ON OUTPUT OF FIPNUM
RPTREGS
 0 0 0 1 /
SOLUTION
=========================================
======================
-------- THE SOLUTION SECTION DEFINES THE INITIAL STATE OF THE SOLUTION
-------- VARIABLES (PHASE PRESSURES, SATURATIONS AND GAS-OIL RATIOS)
-------------------------------------------------------------------
---
-- DATA FOR INITIALISING FLUIDS TO POTENTIAL EQUILIBRIUM
--
-- DATUM DATUM OWC  OWC  GOC  GOC  RSVD RVVD  SOLN
--  DEPTH  PRESS DEPTH  PCOW  DEPTH  PCOG TABLE TABLE  METH
EQUIL
    9035  3600  9099   0    9020   0     0    0  /
-- SWITCH ON OUTPUT OF INITIAL SOLUTION
RPTSOL                          FIELD   16:05 12 DEC 88
  1  0  1  1  1  0  2  1  1  0  0  0  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  /
SUMMARY
=========================================
======================
-------- THIS SECTION SPECIFIES DATA TO BE WRITTEN TO THE SUMMARY FILES
-------- AND WHICH MAY LATER BE USED WITH THE ECLIPSE GRAPHICS PACKAGE
```

```
---------------------------------------------------------------------
---

-- FIELD Rates for Oil, Water, Liquid & 3 Phase Voidage

FOPR

FWPR

FLPR

FVPR

EXCEL

/

/

BWSAT

1 1 1

1 1 2

1 1 3

1 1 4

1 1 5

1 1 6

1 1 7

1 1 8

1 1 9

1 1 10

1 1 11

1 1 12

1 1 13

1 1 14

1 1 15

/

-- BOTTOM HOLE PRESSURE FOR WELL

WBHP

'W1'

/

-- FIELD Water Cut, GOR and Pressure

FWCT

FGOR

FPR

-- SWITCH ON REPORT OF WHAT IS TO GO ON THE SUMMARY FILES

RPTSMRY

1 /

SCHEDULE
=========================================
======================

-------- THE SCHEDULE SECTION DEFINES THE OPERATIONS TO BE SIMULATED

---------------------------------------------------------------------
---

-- CONTROLS ON OUTPUT AT EACH REPORT TIME

RPTSCHED                    FIELD   16:07 12 DEC
88

 1  0  1  1  0    0  2  2  2  0    0  2  0  0  0

 0  0  0  0  0    0  0  0  0  0    0  0  0  0  0

 0  0  0  0  0    0  0  0  1  0    0  0  0  0  0 /

-- FREE GAS IS NOT ALLOWED TO DISSOLVE IN UNDERSATURATED OIL

DRSDT

 0.0 /

-- WELL SPECIFICATION DATA

--

--    WELL   GROUP LOCATION  BHP   PI

--    NAME   NAMEI  J   DEPTH DEFN

WELSPECS                    FIELD   16:32 18 JAN
2010

'W1','G      ', 1,  1,9110.00,'OIL' /

/

-- COMPLETION SPECIFICATION DATA

--
```

```
--    WELL    -LOCATION- OPEN/ SAT CONN
--    NAME    I  J K1 K2 SHUT  TAB FACT
COMPDAT
'W1'  1  1  7  7 'OPEN' 0  27.228  /
'W1'  1  1  8  8 'OPEN' 0  2.1079  /
 /
-- PRODUCTION WELL CONTROLS - OIL RATE IS SET TO 1000 BPD
--
--    WELL    OPEN/  CNTL   OIL  WATER   GAS  LIQU  RES   BHP
--    NAME    SHUT   MODE  RATE RATE RATE RATE RATE
WCONPROD
   'W1'  'OPEN' 'ORAT' 1000   4*                3000  /
 /
-- SPECIFY UPPER LIMIT OF 1 DAY FOR NEXT TIME STEP
TUNING
1  /
/
 12 1 50 /
-- SPECIFY REPORT AT 10 DAYS
TSTEP
 10.00000
/
-- CUT OIL RATE TO 100 BPD
WELTARG
'W1', 'ORAT'  100.000000 /
/
-- SPECIFY UPPER LIMIT OF 1 DAY FOR NEXT TIME STEP
TUNING
1  /
/
 12 1 50 /
-- ADVANCE SIMULATION TO 50 DAYS
TSTEP
 40.00000
/
-- PUT OIL RATE BACK TO 1000 BPD
WELTARG
'W1', 'ORAT'  1000.00000 /
/
-- SPECIFY UPPER LIMIT OF 1 DAY FOR NEXT TIME STEP
TUNING
1  /
/
 12 1 50 /
-- AND ADVANCE TO 720 DAYS - WELL SWITCHES TO BHP CONTROL AT 250 DAYS
TSTEP
50.00000   100.0000   100.0000   100.0000   100.0000   100.0000  120.0000
/
-- CUT OIL RATE TO 100 BPD
WELTARG
'W1', 'ORAT'  100.000000 /
/
-- SPECIFY UPPER LIMIT OF 1 DAY FOR NEXT TIME STEP
TUNING
1  /
/
 12 1 50 /
```

```
-- ADVANCE TO 800 DAYS

TSTEP

 80.00000

/

-- RESET OUTPUT CONTROLS TO GET FULL OUTPUT
FOR LAST REPORT

RPTSCHED

  1  1  1  1  1  1  2  2  2  1  2  2  1  1  2  /

-- ADVANCE TO END OF SIMULATION (900 DAYS)

TSTEP

 100.0000

/

END
==========================================
=====================
```