International Journal of Current Science Research and Review
ISSN: 2581-8341
Volume 07 Issue 02 February 2024
DOI: 10.47191/ijcsrr/V7-i2-39, Impact Factor: 7.943
IJCSRR @ 2024
www.ijcsrr.org

Effect of Aquifer Strength and Gas-cap Size on Oil Recovery Efficiency in Thin-Oil Rim

Obinaba, Helen Nneka[1], Mbachu, Ijeoma Irene[2], Ogali, Oscar Okoronkwo Ikechukwu[3], Onyekonwu, Mike Obi[4]
[1,2,3,4] Petroleum and Gas Engineering University of Port Harcourt, Rivers, Nigeria.

ABSTRACT: Recovering oil from thin oil rim reservoirs depends on some factors such as the gas-cap size, thickness of initial oil column, aquifer strength, permeability anisotropy (k_V/k_H), and rock and fluid properties. The arbitrary selection of these factors by researchers during investigation limits the systematic assessment of the influence of these factors on hydrocarbon recovery from thin oil rim reservoirs. This work investigated the effect of aquifer strength, gas cap size, and permeability anisotropy on hydrocarbon recovery, using design of experiment (DOE) as a tool in the systematic selection of some of the factors that influence hydrocarbon recovery. A static model of the base case oil rim was built in Petrel. Using Eclipse simulator, two other reservoir models having different gas cap sizes from the base case were built. Forty-eight simulation cases were generated using the result from the design of experiment (DOE). The aquifer model used is a Fetkovich analytical aquifer model, and the aquifer volume factors used for this investigation are 0.7, 1.0, 1.5 and 2.5, while the gas cap sizes (m-factor) used are 0.5, 1.0 and 2.0. The permeability anisotropy used are 0.01, 0.05, 0.10 and 0.40. Each simulation case was made to run for a period of twenty years (20years) and the results for the Field Oil Efficiency (FOE), Field Water Production Total (FWPT) and Field Gas Production Total (FGPT) were obtained and analyzed. It was found from this study that, the oil percentage recovery will increase as the gas cap size is decreased, while the percentage gas and water recoveries will increase as the size of the gas cap is increased for a thin oil rim reservoir. Again, for a thin oil rim reservoir with gas cap size of $0.50 \leq m \leq 2.00$, percentage recovery of gas, oil and water will increase with aquifer volume. Also, based on the result obtained, a thin oil rim reservoir with small to moderate gas cap size ($0.5 \leq m \leq 1.0$) will yield higher oil recoveries irrespective of the k_V/k_H ratio.

KEYWORDS: Aquifer Strength, Cumulative Production, Gas Cap Size, Permeability Anisotropy, Simulation.

1. INTRODUCTION

Thin oil rim reservoirs are reservoirs which have pay zone less than 100ft (30.48 m) and the oil columns are rested upon by free gas, and water lie beneath the oil column [1]. Because of their limited thickness, the hydrocarbon column in the thin oil rim reservoirs are located mostly in the capillary transition zone, irrespective of the property and type of rock. Also, the aquifer that is lying underneath the oil column and the gas cap that is resting above, together with high water saturation that exits in the capillary transition zone, form flow dynamics that are complex in the thin oil rim reservoirs [2]. Maximizing hydrocarbon recovery from thin oil rim reservoirs present grave challenges to methods of completion, production policy and reserves estimation ([3], [4], [5]). These challenges can be technical and commercial and can make field development to be less attractive [2]. Among the technical challenges noted by [2] are, water and gas coning, water and gas breakthrough, spread resources, complicated production and drive mechanism, having understanding of the capillary and transition zones, smearing of oil into gas cap when production is taking place, low recovery factor, well type, well design, well drilling, well completion, unavailability of data from the capillary transition zone and, predictive models which are reliable.

Recovering oil from thin oil rim reservoirs generally, depends on many factors which include the strength of the aquifer, the size of the gas-cap, the thickness of initial oil column, also, the rock and fluid properties [5]. [6] observed that depending on the subject reservoir, several static and dynamic properties drive the performance of an oil-rim reservoir. [7], noted as well that comprehensive understanding of reservoir architecture and fluid distribution is very important. Therefore, it becomes basis to efficiently evaluate the earlier failures, identifies solution and guides technology utilization in thin oil rim development. Thin oil rim reservoir can either be regarded as pancake or doughnut configuration. This depends on the formation of the gas cap and oil column as shown in Fig.1. [6], in their work observed that for pan-cake configuration, a plan view of the reservoir would reveal the oil zone enclosing the gas zone in concentric manner, while for doughnut configuration, the plan view reveals the gas cap "resting" on the oil column completely covering the gas- oil contact. According to [8], when subjected to similar conditions, the doughnut configuration often presents greater challenges to hydrocarbon recovery from an oil rim than the pancake configuration because of the effects of gravity. Again, although the mechanism of undesirable gas and water production in the oil wells are not necessarily the same, the performance and reserves of the oil well are not encouraging in both oil rim configurations.

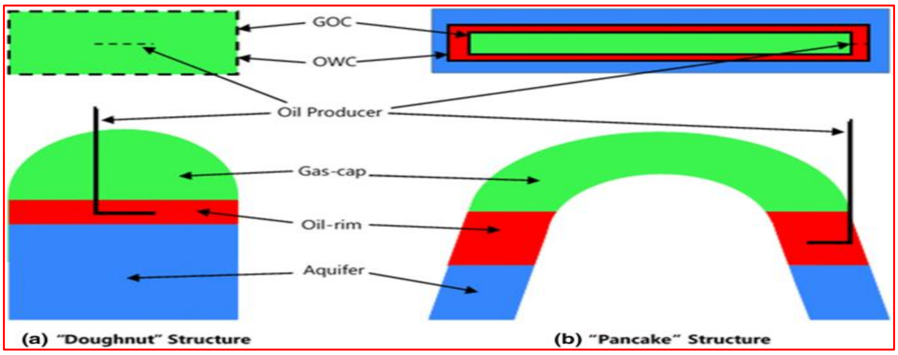


Fig 1. Configurations of oil-rim reservoirs in plan and cross-section [8]

Several rock, fluid and reservoir properties or factors have been identified which influence hydrocarbon recovery from thin oil rim reservoirs. These factors include rock properties such as porosity, permeability, permeability anisotropy, and wettability; fluid properties such as viscosity and formation volume factor; relative permeability and capillary pressure; and other reservoir related properties like gas cap size and strength of the underlying aquifer ([9], [10], [11]). Understanding the influence of these factors on thin oil rim reservoir is crucial to maximizing hydrocarbon recovery from these reservoirs ([9], [12], [13]). Several investigations, howbeit limited, have been carried out to assess the influences of these factors on hydrocarbon recovery from thin oil rim reservoirs.

[14] investigated the effect of gas cap and aquifer size on oil recovery from a reservoir with a thin oil rim using a single well numerical reservoir model. Their work involved varying the sizes of gas cap and aquifer, and well location to find out the effect these parameters will have on oil recovery. They proposed that for reservoirs with large gas cap, placing the horizontal well below the water-oil contact may be more favorable. Then for reservoir with small gas cap and large aquifer, placing the horizontal well above the gas oil contact will be more advantageous. However, the sizes of the aquifer and gas cap were arbitrary selected without the use of design of experiment. Using numerical simulation, [15] carried out a study to investigate the effect of various parameters on recovery factor for the development of thin oil rim reservoir. Eight different parameters (gas cap size, aquifer strength, horizontal permeability, oil production rate, well spacing, ratio of horizontal permeability to vertical permeability, oil viscosity and oil rim thickness) affecting recovery factors were investigated, given the most important factor to be horizontal permeability. This resulted to a simple correlation for each parameter which relates each parameter to recovery factor. The short fall of this work is the arbitrary selection of the sizes of these parameters without the use of experimental design, thereby limiting the systematic assessment of the influence of these factors on hydrocarbon recovery of thin oil rim reservoirs.

[16] investigated the use of horizontal well with different completion scenarios to maximize oil recovery from thin oil rim reservoir. Using Levenberg-Marquardt algorithm, a recovery factor correlation was developed as a simple tool to evaluate the performance of thin oil rims. The result from this work showed that oil recovery from a thin oil rim reservoir with a large associated gas cap increases as the horizontal permeability increases and decreases as the oil rate and horizontal well length increases. For quick decision making, [6] proposed a screening guideline for oil-rim reservoir using three development scenarios of sequential oil-then –gas (OTG), concurrent oil- and –gas (COG), and gas-only development (GOD). Using a two-level factorial design, they created 17 experiments from a set of static and dynamic properties to study the effect of these properties on recovery factor for a thin oil rim. Comparing the performance of the three development scenarios with regards to the properties selected, they affirmed that OTG and COG were preferred as the best development options when these properties are favorable to oil flow. But where the recovery of oil is of utmost concern, OTG was preferred. Again, when the properties are less favorable to oil flow, GOD was preferred.

International Journal of Current Science Research and Review
ISSN: 2581-8341
Volume 07 Issue 02 February 2024
DOI: 10.47191/ijcsrr/V7-i2-39, Impact Factor: 7.943
IJCSRR @ 2024
www.ijcsrr.org

[17] proposed a measure by which gas injection into the reservoir (at the oil-water contact) was utilized to increase oil recovery factor and abate water production using vertical wells. Volume of produced water and recovery factor were compared for five different cases for a period of 40years and the result was a high GOR for the gas injection at the oil-water contact, which was the proposed case, but a recovery factor of 44% against other cases. Although it was believed that horizontal wells give better recovery than other methods, but this work by [17] proved otherwise in that the proposed method gave better recovery with vertical wells, but for the disadvantage of high GOR. This high GOR was not regarded as a problem per se as [17], proffer solution to it in that they suggested a viable solution of gas recycling which is achieved by injecting the gas produced back into the gas cap.

[13] compared simultaneous oil and gas production with successive production in combination with production rate and well geometry using a box-model. They did this to improve the overall field development plan and to ascertain the extent of recovery. An oil rim in the Niger Delta region was used to investigate the influences that well configuration and production rates ranging between 500 to 2000stb/day would have on oil recovery using concurrent and sequential production strategies. The results from the three cases they analyzed showed that concurrent production was a required development option for field oil and gas reserves. Again, considering the three cases, a 1000stb/day production rate was contemplated appropriate in the developing oil and gas production. Then for the case of well configuration, it was discovered that horizontal completion did better compared to the vertical completion when oil recovery is considered. At the end of the analysis, they concluded that the concurrent oil and gas production was the best strategy to be taken into consideration in developing oil rim, that sequential production was not certainly a bad option (although not a safer option) for the actual field of study. This sequential strategy, they stated, may be appropriate where the only active source of reservoir energy is gas cap expansion, or where the gas cap expansion has prevailing effect on the other sources of reservoir energy.

[18], investigated the productivity of oil rims using different water and gas injection pattern. He considered six different pattern scenarios of water and gas injection at three different rates (1000, 1500 and 2000stb/day). Improved oil recovery estimates of 5.43% was recorded for inverted direct line water injection, 4.51% was recorded for inverted staggered water injection, 5.41%, was recorded for inverted 4 spot injection, 4.93% was recorded for 5 spot water injection, 5.89% was recorded for inverted 7 spot water injection, and 5.82% was recorded for inverted 9 spot water injection. After the analysis, their results showed that the pattern water injection at 1000stb/day is more appropriate for optimal oil recovery for oil rim under concurrent production.

Several authors carried out work on the effect of different parameters on recovery factor. These include assessing the effect of several parameters on recovery factor (RF) for the development of thin oil rim reservoir using a 2D black oil simulation model as case study [15]; and assessing influences of varying aquifer strength and production rates on hydrocarbon recovery using a gas condensate reservoir model as case study [20]; and assessing influences of vertical to horizontal permeability ratios (k_V/k_H) and aquifer volume factor using a heavy crude oil carbonate reservoir as case study [21]. However, values used for parameters in these studies were selected in a somewhat arbitrary fashion, thereby limiting the systematic assessment of the influence of these factors on hydrocarbon recovery of thin oil rim reservoirs. Again, Previous studies ([15], [20], and [21]) used either a box-shaped model or reservoir with constant elevation, therefore, incorporating gravity effects was not done. The effects of the aforementioned factors on an "actual" reservoir are therefore lacking to the best of our knowledge. Consequently, the inferences from their studies are weak and of limited applicability in evaluating other thin oil rim reservoirs. Therefore, this work aims at evaluating the effect of gas cap size and aquifer strength and permeability anisotropy on hydrocarbon recovery from thin oil rim reservoir using a case study field.

2. METHODOLOGY

2.1 Reservoir Model Description

Reservoir X, which is a base case model is an anticlinal structure situated in an offshore region of the Niger Delta with the depth of 10421ft. The oil rim height is an average of 45ft, and the reservoir has a large gas cap overlying a large aquifer (Fig. 2). The average initial temperature and pressure of this reservoir are 200°F and 4540psia respectively, and the simulation model is a single porosity system. The rock and fluid properties for the base case for this study is presented in Table 1. The PVT and SCAL (Special Core Analysis) data are also given in Table 2.

.

International Journal of Current Science Research and Review
ISSN: 2581-8341
Volume 07 Issue 02 February 2024
DOI: 10.47191/ijcsrr/V7-i2-39, Impact Factor: 7.943
IJCSRR @ 2024
www.ijcsrr.org

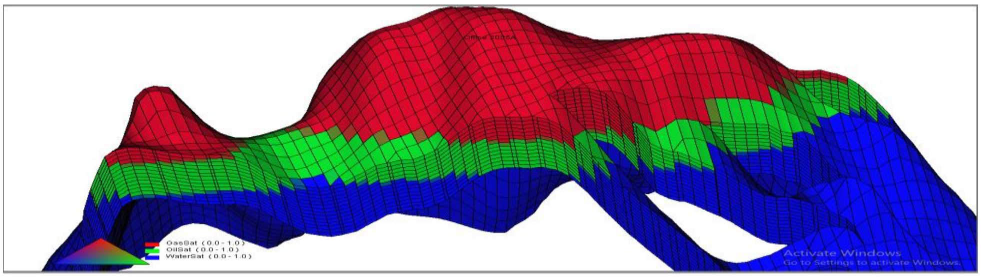


Fig. 2. A Side View of Thin Oil Rim Reservoir X

Table 1. Rock and Fluid Properties from Reservoir X (Base Case)

	Property	**Value**
Average Reservoir Properties	Depth	10421ft
	Porosity, #	0.23
	Permeability, k	1292mD
	Reservoir Thickness	45ft
	Net to Gross	0.81
	Initial Reservoir Pressure, P_i	4540psia
	Initial Water Saturation, S_{wi}	0.15
	Formation Water Compressibility, C_w	2.986×10^{-1} psi^{-6}
	Rock Compressibility, C_f	1.1767×10^{-1}psi^{-6}
	m-factor (ratio of gas cap to oil volume)	2
Initial Fluid Properties	Viscosity, μ_{oi}	0.42110cp
	Formation Volume Factor, B_{oi}	1.512rb/stb
	Saturation Pressure, P_b	4540psia
	Instantaneous GOR	963.5scf/stb
Average Aquifer Properties	Porosity, $\#_a$	0.24
	Permeability, k_a	1292mD
	Thickness	70ft
	Inner Radius, r_e	5604ft
	Angle of influence	360°
Contact	GOC	10421ft
	WOC	10466ft

Table 2. PVT and SCAL Data

Reservoir	**P_i(psia)**	**R_{si}(scf/stb)**	**B_{oi}(rb/stb)**	**Reservoir Temperature(^{0}F)**	**^{0}API Gravity of Oil**	**Specific Gravity of Oil**
X	4540	963.5	1.512	200	33.086	0.85

2.2 Distribution of Fluid in the Reservoir

At the natural state, the reservoir has a large gas cap (m- factor= 2), an aquifer volume factor of 1.0 and k_V/k_H value of 0.10 in relation to the volume of oil in place. The Water-Oil Contact is 10466ft, while the Gas-Oil Contact is 10421ft. shows the fluid saturation diagram for the base case reservoir model, the second reservoir Y was created by adjusting the contacts of the base case reservoir. This Reservoir X has a gas cap size of m=1.0. This third reservoir has a gas cap size of m=0.5.

International Journal of Current Science Research and Review
ISSN: 2581-8341
Volume 07 Issue 02 February 2024
DOI: 10.47191/ijcsrr/V7-i2-39, Impact Factor: 7.943
IJCSRR @ 2024
www.ijcsrr.org

2.3 Relative Permeability Models

SCAL (Special Core Analysis) is used to analyze the petrophysical properties of the reservoirs such as relative permeability by the administration of Corey correlation. The relative permeability curves are schematically plotted in Fig. 3.

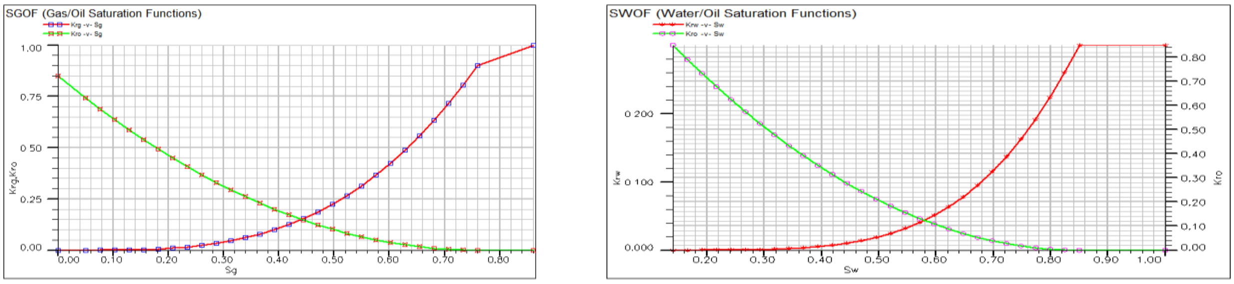


Fig 3. Gas/oil and Water/oil relative permeability curves (Base Case)

2.4 Fluid Model

The pressure-volume-temperature (PVT) relationships of the fluids were generated from standard correlations. As an example, the resulting fluid properties as functions of pressure are presented in Fig. 4 for the base case.

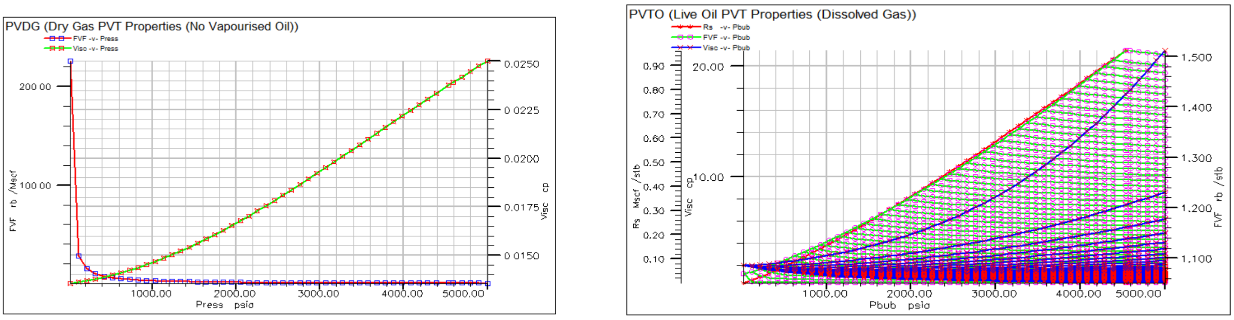


Fig 4. Dry gas and Live oil PVT Properties (Base Case)

2.5 Dynamic Modelling and Simulation

A static model of an oil rim was built in Petrel to represent the conceptual oil rim Reservoir X and was exported to Eclipse for dynamic modelling. Simulation model initialization was done to estimate the Fluid in Place with respect to map coordinates and dimensions; 97×38×14 and 51604 grid cells.

2.6 Reservoir Simulation

The parameters to be investigated are the size of the gas cap (m-factor), the strength of aquifer volume and permeability anisotropy. The anisotropic permeability (k_V/k_H) was brought into this investigation to see how it will affect the behavior of the model which was used for this investigation. For the gas cap size (m-factor), we used the values of 0.5, 1.0 and 2.0 (the actual reservoir model). The smaller sizes of m-factor which were used for this investigation instead of larger values was because the model could only accommodate these smaller sizes and not sizes above the gas cap size of 2.

The aquifer model used is a Fetkovich analytical aquifer model, and the aquifer volume factors used for this investigation are 0.7, 1.0, 1.5 and 2.5. The choice of these values was because of the limitation of the model. Aquifer was not eliminated completely less than 0.7 because, being a thin oil rim reservoir, if the aquifer is reduced below 0.7, the base of the oil rim will no longer be communicating with the entire aquifer which will stop this reservoir from being a thin oil rim. The aquifer factor of 2.5 was used because of the model and volume available, therefore it could not be extended/stretched more than this value.

The values of the k_V/k_H used are 0.01, 0.05, 0.10 and 0.40. The reason for the choice is because the k_V/k_H= 0.01 will mimic little or no communication between the layers of the model, whereas the k_V/k_H= 0.4 means that there is a lot of communication between the layers. With these three values of gas cap size, four values of aquifer volume size and four values of k_V/k_H, a total of

International Journal of Current Science Research and Review
ISSN: 2581-8341
Volume 07 Issue 02 February 2024
DOI: 10.47191/ijcsrr/V7-i2-39, Impact Factor: 7.943
IJCSRR @ 2024
www.ijcsrr.org

forty-eight (48) simulation cases were generated using Design-Of-Experiment (DOE). The base case for this study is the simulation having m-factor of 2.0, Aquifer volume factor of 1.0 and k_V/k_H of 0.10.

3. RESULTS AND DISCUSSION

3.1 Effect of k_V/k_H on Reservoir with m-factor = 2.0 and AqVol-factor = 1.0

Fig. 5 shows the effect of the variation of the ratio of vertical permeability to horizontal permeability (k_V/k_H) on the Field Gas Production Total (FGPT) and the Field Gas Efficiency (FGE). It can be observed that the four cases with different k_V/k_H ratio followed the same path of recovery for a period of 1.5 years before they deviated taking different paths of recovery. Before this deviation, the effect of the different vertical anisotropy was not felt because all the cases had fixed and similar production rate. After this period of 1.5 years, the effect of k_Vk_H on FGPT and FGE became apparent in the different cases as the rates of production changed. Cumulative gas produced (FGPT) was 126,606,590 Mscf for k_V/k_H=0.40 which is 73.18% of the in-place gas volume, while the low vertical permeability ratio (k_V/k_H) of 0.01 produced 121,490,630 Mscf of gas which is 69.82% of the in-place gas volume. These values show that the recovery efficiency of gas increases with vertical permeability. This is because, the high vertical permeability offered an easier flow path to the flow of gas than the low permeability values. With high permeability ratio, the gas travels easily into the oil leg, and because of this, the gas in the gas cap is not retained for much longer causing the well to reach its economic limit quickly (less than 3years).

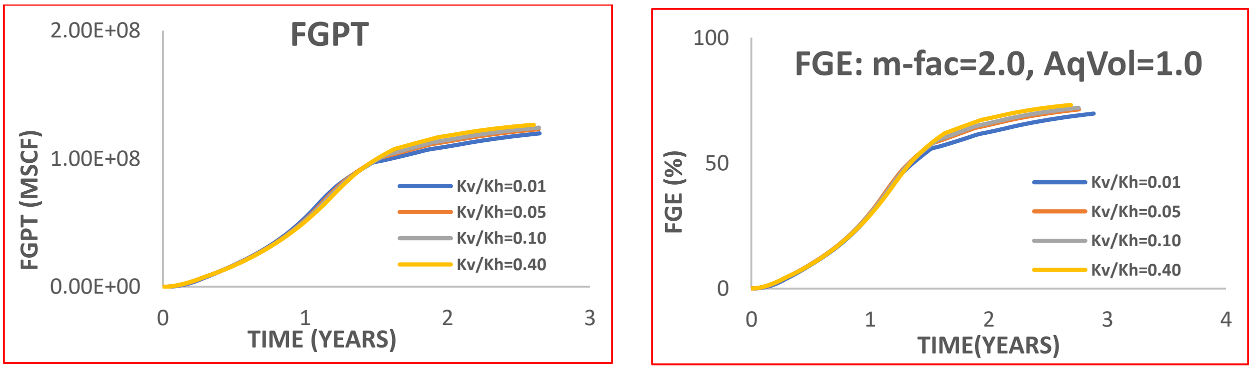


Fig 5. Effect of k_V/k_H on Field Gas Production Total (FGPT) and Field Gas Efficiency (FGE)

A similar trend as seen in the Field Gas Production Total (FGPT) and the Field Gas Recovery Efficiency is observed also for Field Oil Production Total (FOPT) and the Field Oil Efficiency as shown in Fig. 6. The sensitivity study on k_V/k_H showed that higher k_V/k_H (k_V/k_H = 0.40) yielded a higher cumulative produced oil of 3,066,981 STB and a recovery efficiency of 7.70% compared to other ratios, while the low k_V/k_H (k_V/k_H=0.01) yielded FOPT of 2,905,507 STB and an oil recovery efficiency of 7.26%. This result showed that as the vertical permeability is increased, the recovery efficiency of oil increased because higher k_V/k_H offers easier flow path to reservoir fluid recovery.

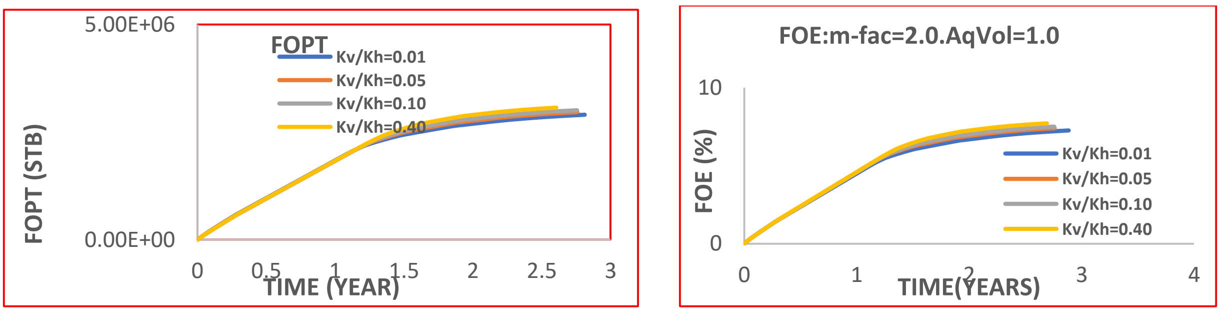


Fig. 6 Effect of k_V/k_H on Field Oil Production Total (FOPT) and Field Oil Efficiency (FOE)

Fig. 7 shows the results of the Field Water Production Total (FWPT) and the Field Water Efficiency (FWE) from the sensitivity analysis of Kv/k_H. From observation, increasing the k_V/k_H values from 0.01 to 0.40 increases the cumulative water

International Journal of Current Science Research and Review
ISSN: 2581-8341
Volume 07 Issue 02 February 2024
DOI: 10.47191/ijcsrr/V7-i2-39, Impact Factor: 7.943
IJCSRR @ 2024
www.ijcsrr.org

production. Higher k_V/k_H allows easier flow path for water to travel from the aquifer into the wellbore, it resulted in water influx into the reservoir leading to increase in the volume of water produced.

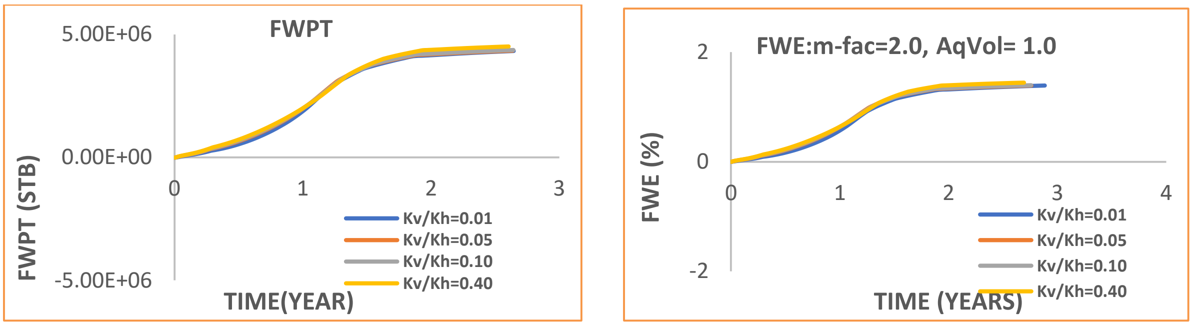


Fig. 7 Effect of k_V/k_H on Field Water Production Total (FWPT) and Field Water Efficiency (FWE)

3.2 Effect of m-factor on Reservoir with k_V/k_H =0.1 and Aq Vol-factor =1.0

The effects of the size of gas cap (m-factor) on fluid recovery are shown in Figs. 8 to 9. It is observed that as the reservoirs were placed on production, each reservoir behaved differently. The reservoir with the large gas cap size (m-factor=2.0) produced gas rapidly, with FGPT of 125,332,000 Mscf which is 72.03% of the in-place gas after a period of 2.7 years. This large percentage of gas production caused sharp pressure decline resulting in low oil recovery of 3,003,882 STB, a 7.15% of the in-place oil as can be seen in Figs. 8 and 9. This low percentage of oil produced is because of the sharp pressure decline due to high gas production from the gas cap and dissolved gas. This evolved gas flowed out of the oil zone and impeded oil recovery because the viscosity of the oil increased because of this gas leaving the oil. As a result of this also, the producing life of this reservoir ended after about two years and nine months. From observation, the reservoir with the large gas cap size (m-factor =2.0) had a short economic life span (2.7years) than the other two reservoirs which has m factors of 1.0 and 0.5 with economic life span of 8.6 and 10.1 years respectively. This is due to the size of its gas cap, large gas cap means more gas available to be produced limiting the production of oil because the available gas will move into the oil leg and be produced instead of the oil.

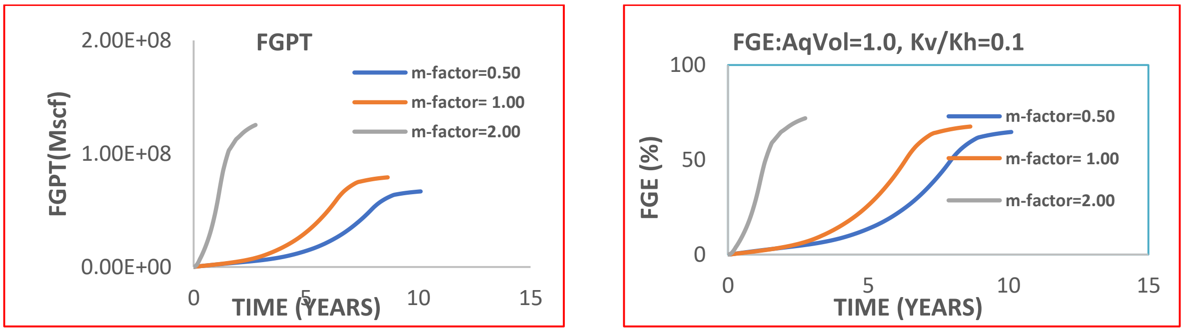


Fig. 8 Effect of m-factor on Field Gas Production Total (FGPT) and Field Gas Efficiency (FGE)

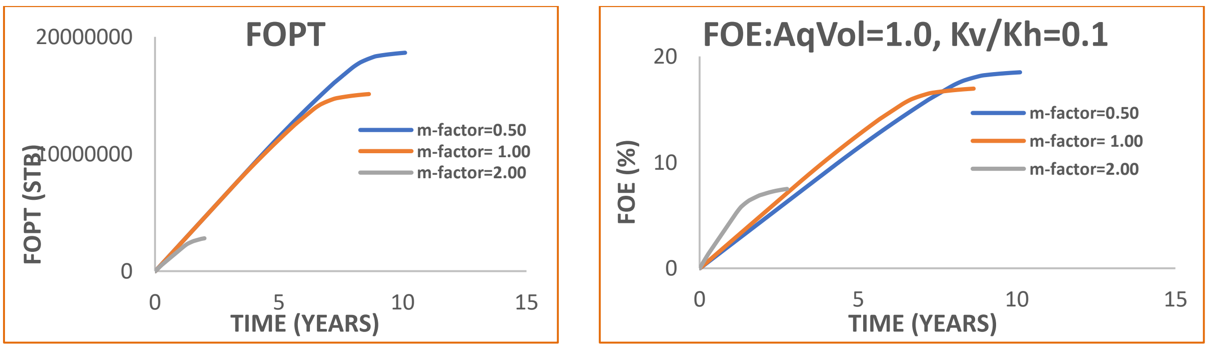
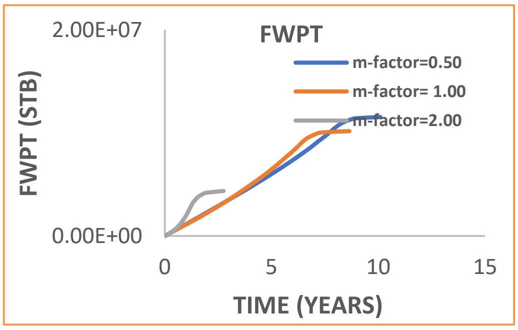


Fig. 9 Effect of m-factor on Field Oil Production Total (FOPT) and Field Oil Efficiency (FGE)

International Journal of Current Science Research and Review
ISSN: 2581-8341
Volume 07 Issue 02 February 2024
DOI: 10.47191/ijcsrr/V7-i2-39, Impact Factor: 7.943
IJCSRR @ 2024
www.ijcsrr.org

As production was initiated in the second reservoir with moderate gas cap size(m-factor) of m=1.0, the reservoir produced 79,062,824 Mscf of gas (67.67% of gas in-place), 15,123,506 STB of oil (16.97% of oil in-place) and 10,178,361 STB of water (3.25% of initial water) (Fig. 10). An increase is observed in the volume of oil and water produced with less volume of gas production compared to the first reservoir. This is because having a moderate gas cap, the rate of pressure decline was not as rapid as the pressure decline in the base case reservoir (m-factor = 2), therefore it took a longer time for this reservoir to be depleted leading to more of the oil being produced.



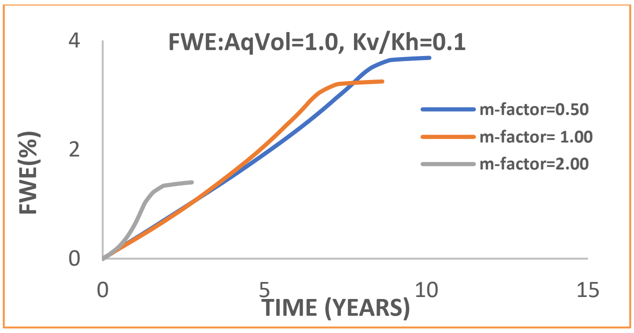
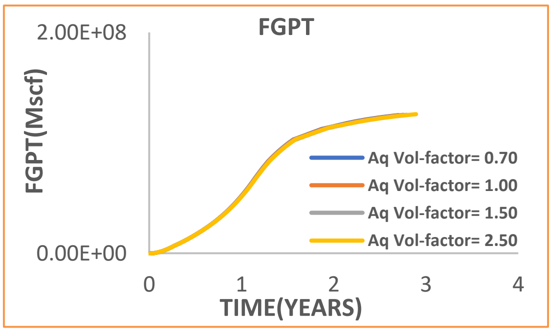


Fig. 10 Effect of m-factor on Field Water Production Total (FWPT) and Field Water Efficiency (FWE)

The reservoir which has a gas cap size (m-factor) of 0.5, an aquifer volume factor (Aq Vol-factor) of β=1.0 and vertical to horizontal permeability ratio of k_V/k_H = 0.1 produced 64.68% of the in-place gas volume (103,352,370Mscf), 18.50% of the oil in-place (100,758,340 STB) and 3.68% of the water in-place (313,449,860 STB). It is observed from this result that as the size of the gas cap was decreased from 2.0 to 1.0 and then 0.5, (from the first reservoir to the second and third reservoir), the percentage of the gas recovered decreased, while the percentage and volume of oil and water produced increased (Fig. 10). This result is because of the size of the gas cap. The presence of the small gas cap delayed the decline of reservoir pressure resulting in the effective permeability to oil to increase while the effective permeability to gas decreased. As a result of this, the percentage of oil produced increased, while the percentage of gas produced decreased.

3.3 Effect of Aquifer Volume (Strength) on Reservoir with k_V/k_H =0.1 and m-factor =2.0

Sensitivity analysis was carried out based on the different aquifer volumes, using aquifer volume factors(β) of 0.7, 1.0, 1.5 and 2.5. Fig. 11 shows that aquifer strength has negligible effect on the cumulative volume of gas produced and on the gas recovery efficiency because all the cases had fixed and same production rate. On the average, all the cases involved produced 72.6% of the initial gas in place (173,990,200 Mscf) which is a large amount of gas on the average of 125,384,995Mscf. When large gas cap exists in reservoir, as pressure declines, gas is evolved. This evolved gas flows to the oil zone, bypassing the oil and is produced in preference to the oil. This is because the viscosity of the oil has been increased as a result of the gas leaving the oil and this slows down the oil flow to the wellbore which is the case for this reservoir. This excessive gas production could dominate the flow in well, in consequence, the oil and water production will decrease. The producing life of this reservoir lasted for less than three years because of early gas breakthrough. Most of the gas that would have served for pressure maintenance was produced rapidly causing sharp pressure decline.



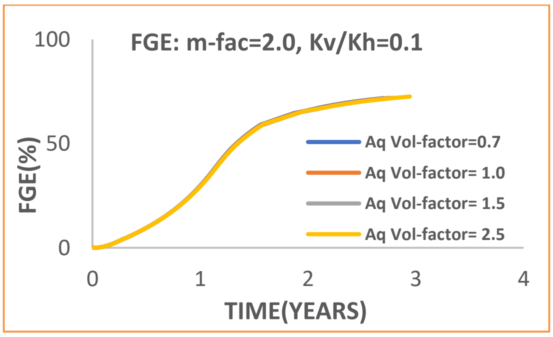


Fig. 11 Effect of AqVol-factor on Field Gas Production Total (FGPT) and Field Gas Efficiency (FGE)

International Journal of Current Science Research and Review
ISSN: 2581-8341
Volume 07 Issue 02 February 2024
DOI: 10.47191/ijcsrr/V7-i2-39, Impact Factor: 7.943
IJCSRR @ 2024
www.ijcsrr.org

Fig. 12 shows the effect of aquifer size on cumulative oil production and the oil recovery efficiency for the reservoir. From observation, increasing the strength of the aquifer from 0.7, 1.0, 1.5 to 2.5, caused a corresponding increase in the Field Oil Production Totals (FOPT) and the oil recovery efficiency, although, this effect of the aquifer volume was not seen at the beginning of the producing life of the reservoirs because all the simulated cases had fixed and similar production rate during early production time. The case with the higher aquifer volume (highest aquifer factor of 2.5) yielded higher FOE (7.74%) and FOPT (3,095,359Mscf) values (7.74% of the in-place oil), and the production lasted a longer time, a period of 2.9 years when compared to other cases considered. This is because the high aquifer volume (Aq-factor =2.5) offered greater path to flow of the reservoir fluid, hence the high oil production.

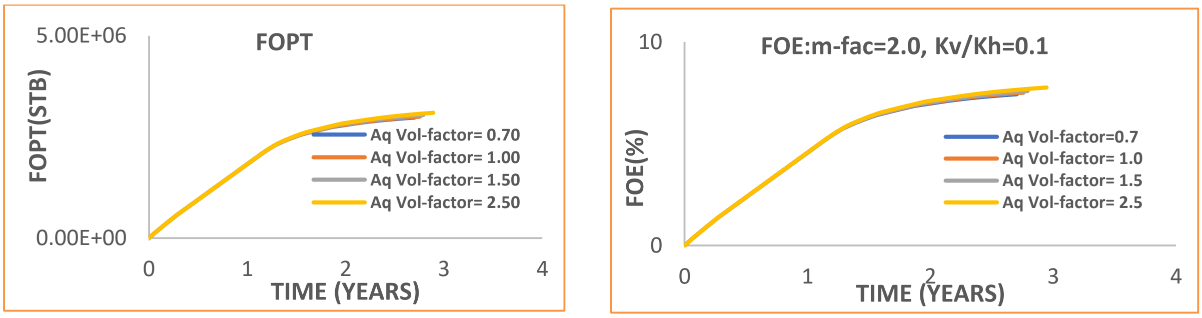


Fig. 12 Effect of AqVol-factor on Field Oil Production Total (FOPT) and Field Oil Efficiency (FOE)

Fig. 13 shows the effect of the size of aquifer volume on the Field Water Production Total (FWPT) and the percentage of water produced. The percentage volume of water produced increased with increasing size of the aquifer. The reservoir case with large aquifer factor produced more water (4,713,201 STB) than other cases as can be seen in Fig. 13. This is because the volume of water in this reservoir case is large, encouraging large amount of water to be produced. Excessive water production should be expected if we have large size of aquifer, hence the production of the large volume of water by the large aquifer size which is 1.50% of the in-place water (313,450,380 STB on the average).

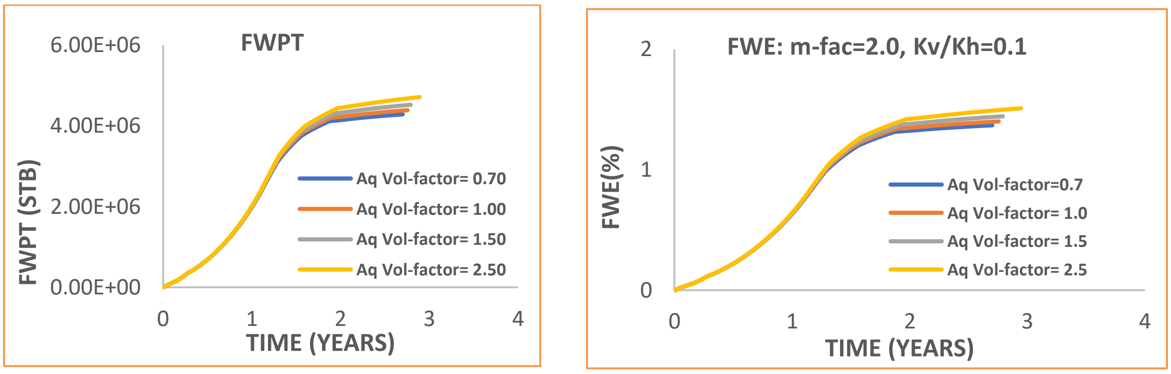


Fig. 13 Effect of AqVol-factor on Field Water Production Total (FWPT) and Field Water Efficiency (FWE)

4. CONCLUSION

Based on the design of experimental (DOE) results obtained from the thin oil reservoir study, the following conclusions are reached.

- The cumulative percentage recovery of gas, oil and water increase with increase in k_V/k_H ratio for a thin oil rim reservoir with a large gas cap (m=2.0).
- The percentage cumulative gas, oil and water increase as the aquifer volume is increased for a thin oil rim reservoir with a large gas cap of 2.0.
- A thin oil rim reservoir with large gas cap, the percentage gas, oil, and water recoveries will increase as the aquifer volume is increased irrespective of the k_V/k_H ratio.

- The percentage gas and water recoveries will increase as the size of the gas cap is increased, while the oil percentage recovery will increase as the gas cap size is decreased.
- A thin oil rim reservoir with small to moderate gas cap size ($0.5 \leq m \leq 1.0$) will yield higher oil recoveries irrespective of the k_V/k_H ratio. Also, lower k_V/k_H ratio will yield higher oil recoveries in thin oil rim reservoirs with small-to-moderate gas cap.
- A thin oil rim reservoir with gas cap size of $0.50 \leq m \leq 2.00$, percentage recovery of gas, oil and water will increase with aquifer volume.

REFERENCES

1. Davarpanah, A. and Mirshekari, B. (2018). A Simulation Study to Control the Oil Production Rate of Oil-rim Reservoir under Different Injectivity Scenarios. Department of Petroleum Engineering, Science and Research Branch, Islamic Azad University, Tehran, Iran.
2. Masoudi, R; Karkooti, Hand Othman, M.B. (2013). How to Get the Most Out of Your Oil Rim Reservoirs? IPTC 16740. *Proceedings of the International Petroleum Technology Conference*, Beijing, 26–28 March.
3. Silva, J.M. and Dawe, R. A. (2010). The Challenge of Producing Thin Oil Rims in Trinidad, *The West Indian Journal of Engineering*, 32, 36-41.
4. Kabir, C.S; Agamini, M and Holguin, R.A. (2004). Production Strategy for Thin Oil Columns in Saturated Reservoirs. *SPE Annual Technical Conference*, Abuja.
5. Uwaga A.O and Lawal K.A (2006) Concurrent Gas-cap and Oil-rim Production: The Swing Gas Option. SPE 105985. *Proceedings of the SPE Nigeria Annual International Conference and Exhibition,* Abuja, 31 Jul.–2 Aug.
6. John, I.J; Matemilola, S and Lawal K. (2019) Simple Guidelines for Screening Development Options for Oil-rim Reservoirs. SPE 198718. *Proceedings of SPE Nigeria Annual International Conference and Exhibition*, Lagos, 5–7 Aug.
7. Agus, I. L; Syofvas, S; Ilya R; Romie, L. V and Tariq, A.S (2019). A Strategic Approach to Address Challenge of Complex-Thin Oil Rim Development. SPE-197385-MS. *Proceeding of Abu Dhabi International Petroleum Exhibition & Conference held in Abu Dhabi, UAE,*
8. Lawal, K.A.; Yadua A.U.; Ovuru M.I.; Okoh, O.M.; Eyitayo S.I; Matemilola, S. and Olamigoke, O. (2019) Rapid Screening of Oil-rim Reservoirs for Development and Management. *Journal of Petroleum Exploration and Production Technology* (2020) 10:1155–1168 https://doi.org/10.1007/s13202-019-00810-6'.
9. Olamigoke, O. and Peacock, A., (2009). First-Pass Screening of Reservoirs with Large Gas Caps for Oil Rim Development. SPE 128603. *Proceedings of the Nigeria Annual International Conference and Exhibition*, Abuja.
10. Ibukun, S. (2011) "Evaluation of Oil Rim Reservoirs Development – A Case Study". Ibadan: Master of Science Thesis of the University of Ibadan, Department of Petroleum Engineering.
11. Kolbikov S (2012) Peculiarities of Thin Oil Rim Development. SPE 160678. *Proceedings of the SPE Russian Oil and Gas Exploration and Production Technical Conference and Exhibition*, 16 Moscow, Russia.
12. Obah, B.; Livinus, A. and Ezugwu, C.M. (2012). Simplified Models for Forecasting Oil Production: Niger Delta Oil Rim Reservoirs Case. *Petroleum Technology Development Journal*, 2 (2), 1–12.
13. Olabode, O; Egeonu, G; Ojo, T; Oguntade, T and Bamigboye, O. (2018). Predicting the Effect of Well Trajectory and Production Rates on Concurrent Oil and Gas Recovery from Thin Oil Rims. IOP Conference Series: Materials Science and Engineering 413(2018)012051. Doi:10.1088/1757-899X/413/1/012051
14. Iyare, U and Marcelle-De Silva, J. (2012). Effect of Gas Cap and Aquifer Strength on the Optimal Well Location for Thin Oil Rim Reservoirs. SPETT 2012 Energy Conference and Exhibition. Port of Spain, Trinidad.
15. Yeoh, X. O (2014). Thin Oil Rim Reservoir Development. Master of Science Thesis of the Department of Earth Science and Engineering Centre for Petroleum Studies, Imperial College London.
16. Augustine, A., Junin, R., Jeffrey, G. and Onyenkonwu, M. (2017) 'Exploitation of thin oil rims with large associated gas cap', Int. J. Petroleum Engineering, 3: (1)14–48.

17. Ogolo, N.A., Molokwu, V.C. and Onyekonwu, M.O. (2017). Proposed Technique for Improved Oil Recovery from Thin Oil Rim Reservoirs with Strong Aquifers and Large Gas Caps. SPE-189126MS. *Proceedings of the Nigeria Annual International Conference and Exhibition.*
18. Olabode, O. (2020). Effect of Water and Gas Injection Schemes on Synthetic Oil Rim Models. *Journal of Petroleum and Exploration Production Technology*. https ://doi. org/10.1007/s1320 2-020-00850 -3.
19. Olabode, O.; Sunday, I.; Oyinkepreye, O. and Daniel, A. (2020). Optimizing Productivity in Oil Rims: Simulation Studies on Horizontal Well Placement under Simultaneous Oil and Gas Production. *Journal of Petroleum Exploration and Production Technology* (2020) 11:385–397 https://doi.org/10.1007/s13202-020-01018-9
20. Fawzy, F. (2017). Investigation of the Optimum Production Strategies for the Economic Recovery of Gas Condensate Reservoirs with Different Aquifer Strength. SPE-189285-STU. *Proceedings of SPE International Student Paper Contest: Annual Technical Conference and Exhibition*. San Antonio Texas. USA.
21. Vatani, Z. and Ezzatyyar, P. (2019). Investigation Sensitivity Analysis and Comparison of the Oil Recovery Coefficient in Different Enhanced Oil Recovery Scenarios. Petroleum and Coal (2019); 61(5)924-931. ISSN 1337-7027 an Open Access Journal.