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Screening of Development Options for Oil-Rim Reservoir: Simulation Approach

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Abstract

A prevailing issue with managing oil rim reservoirs is maximizing oil recovery by managing the gas off-take from the reservoirs, screening of development options for oil-rim reservoirs are expensive and technically vigorous given available alternatives. The impact of a number of subsurface factors with their inherent uncertainties was investigated using simulation approach for a generic oil rim to predict the performance of alpha reservoir under different depletion scenarios (oil production only, sequential oil production then gas, concurrent oil and gas production and gas production only).

Results showed that the concurrent oil and gas development option for the reservoir performed best for a gas off-take rate of 2% FGIIP. The sequential oil then gas development option with a recovery factor of 14.3% performed best in terms of oil recovery and gas production at rate of 110,000 MSCF/D amongst the other options considered. The water production results showed that the concurrent development option produced 80% water cut which was within the allowable economic limits as against the other development options.

This study is useful for preliminary assessment and screening of thin oil-rim columns for a composite technical, economic, commercial, operational feasibility study before conducting expensive detailed study for the project to commence.

Keywords*: Development scenario; Recovery factor; Screening; Simulation method; Thin oil-rim.*

1. Introduction

Oil rim reservoirs refer to reservoirs with thin (large volume) oil zones crammed between gas-cap and bottom water [1]. In most cases, this oil is often extremely difficult to produce economically by conventional methods and are generally characterized by development and production challenges such as double coning and early water coning tendency [2-5], water production is one of the recurrent problems during oil production from petroleum reservoirs and is even a greater occurrence in oil rim reservoirs. Rahim *et al.* [6] defined oil rim reservoirs as thin oil column reservoirs usually underlain by water and/or overlain by gas, having thickness ranging from less than 30ft up to 90ft. Usually this column may be in a pancake or rim shape mainly in the capillary transition zone due to its limited thickness regardless of the rock type and property [7]. The average high saturation of water in the capillary transition zone together with the underlain aquifer and overlain gas cap create complex flow dynamics in such reservoirs [6]. Thus, oil production from oil rim reservoirs has continually be a challenge due to their thinly spread oil resources and intricate production mechanisms.

Lawal [8] described the configuration of the oil rim as either doughnut or pancake; a plan view of the oil rim reservoir of pancake configuration would reveal the oil zone enclosing the gas zone as concentric circles, the fluid contacts could be identified within the concentric circles of the plan view (Figure 1). But for the doughnut configuration, the gas cap sits roughly on the oil column, the gas-oil contact is not quite visible from the plan view. The reserves and performance of oil wells in both configurations remain at risk.

Oil companies are faced with technical and commercial challenges in the process of developing oil rims and producing from the capillary transition zone, which make such field development technically and economically less attractive. Some of the technical challenges include:

the concern for water and/or gas coning and breakthrough, spread out resources, complicated production and drive mechanism, understanding of the capillary transition and invasion zones, oil smearing into the gas cap during production, low recovery factor (typically less than 18%), well type/design/drilling/completion, lack of data from the capillary transition zone (i.e. oil zone) and reliable predictive models [6].

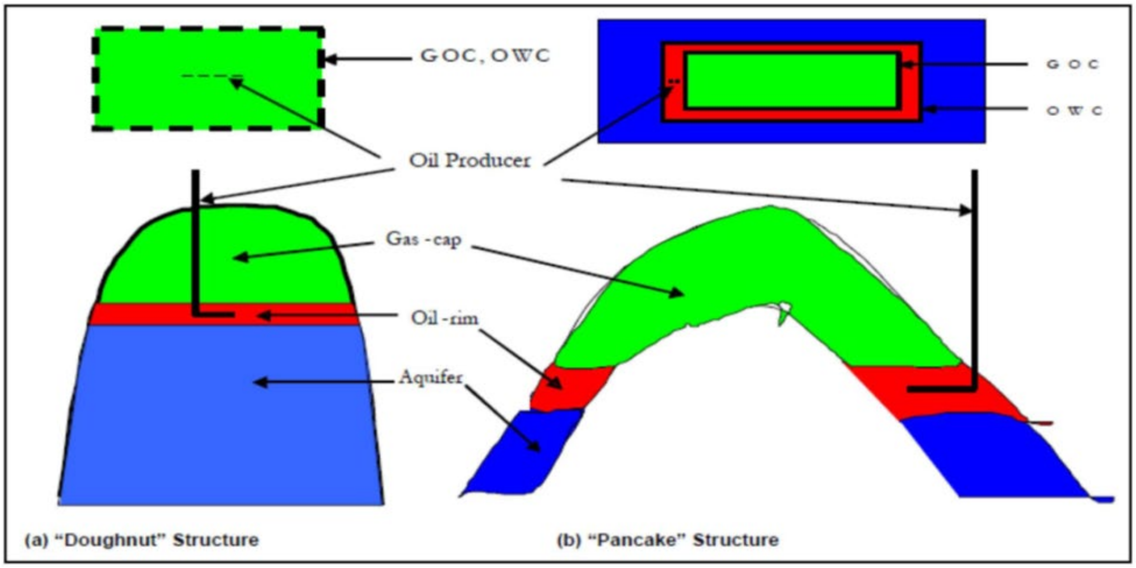

Figure 1. Plan and cross-sectional view of oil rim reservoir configuration [2]

The work of most authors [9-11] showed that most if not all of the reservoirs in the Niger Delta have thickness of less than 80ft and therefore susceptible to coning problems as a result the movement of oil-water and gas-oil contacts could be very sensitive to conventional production operation and cause detrimental early water and gas breakthrough. However, the application of technological advancement in well completion design together with proactive reservoir simulation approaches, performance monitoring as well as appropriate depletion strategies can make the oil rim development profitable. Extensive studies [12-14] revealed that water and/or gas coning is or are major technical issue in developing these oil rim reservoirs which has negative impact on the ultimate recovery and the economics of the project.

Okwananke and Isehunwa [15] noted that horizontal wells have been generally accepted as a better way to improve recovery in the case of coning. The application of horizontal well technology in the development of oil rims has been on the increase in recent times due to their higher oil production capacity at reduced drawdown in comparison to conventional vertical wells. Horizontal wells are now accepted as conventional wells for oil rim reservoirs due to their higher length of contact with the thin oil rim when drilled through as against that of vertical wells [6]. The low reservoir contact area and the large pressure drop that is associated with flow into a vertical well makes such wells to be highly prone to coning, hence the productivity of vertical wells in thin oil reservoirs is often marginal if not uneconomic particularly when the mobility ratio is unfavorable and the permeabilities are low to moderate [6]. Generally, horizontal wells reduce coning issues and improve recovery in thin oil rims, in their work, [6,16] submitted that production increase of 2 to 5 times that of vertical wells have been observed and that horizontal wells are now accepted as the better way to improve recovery.

Coning refers to the upward movement of water and/or downward movement of gas in the reservoir, into the perforations of a producing well [17]. The term is referred to as coning because the shape of the interface resembles an upright (for water coning) or inverted cone (for gas coning) when the well produces the unwanted phase (water and/or gas). Coning occurs when viscous forces exceed gravity forces near the wellbore of a well under production which results in high gas-oil ratio (GOR) for gas coning or high water cut (BSW) for water coning [17]. Water and gas coning are common in oil rim reservoirs, with attendant consequences of drastic drop in reservoir pressure and overall recovery efficiency of the oil reservoirs. According to [16], some of the key factors controlling oil rim development are coning and cusping of the underlying water and the overlain gas, respectively, aquifer strength, permeability distribution, and reservoir geometry across the reservoir. Because of the challenges that follow it, oil and gas industry is not as fast in developing oil rim reservoirs when compared to conventional oil reservoirs, if not legally bounded by government, some will rather just produce the gas and ignore the oil rims [16,18].

Another crucial challenges facing the evaluation of oil rim reservoirs is the considerable manpower and computational costs often incurred in screening the possible development options at the initial stages [2-3,17]. Detailed and computationally rigorous and expensive reservoir simulation studies are conducted, even at the preliminary stages of opportunity maturation as decision makers are typically faced with making a choice among various development options [2-3]. Hence, the relative cost of deploying commercial simulators at early stages of project evaluation which may not be optimal is therefore additional challenges facing the evaluation of thin oil rim reservoirs. With third parties like government regulators and partners, independent verification of results of simulation can be highly demanding. The need for relatively simple methods and techniques of evaluating the technical limits of oil rim development and validating simulation forecast predictions is inevitable.

1.1. Development options of oil rims

Several authors [2,7,19-24] have recommended different development strategies for thin oil development, [2] in their study concluded that with respect to oil rim deposits, the petroleum industry is faced with the following development alternatives:

- Produce both oil and gas concurrently (Which fluid is jeopardized?)
- Produce gas first then oil later (How does this impact oil recovery?)
- Produce oil first then the gas cap (Gas deferment may put pressure on oil supplies)
- Produce gas only and abandon the oil (Is this tenable? Is it consistent with local regulations?)

In their works [2-4,7,19,25], observed that development and depletion of thin oil columns possibilities include: Sequential development, Alternative phased development (otherwise known as gas cap gas blow down), Concurrent oil and gas development and Gas only development.

1.1.1. Sequential (oil then gas) development

This is the conventional development strategy for oil rim development. Here, production wells are initially drilled and completed in the oil zone. Off-take is managed by balancing gas cap expansion and aquifer encroachment to minimize movement of the rim. Oil recovery and production performance will depend largely on the balance of water drive and gas cap drive. Hence conservation of the energy of the gas cap will majorly lead to higher recovery of oil. Off-take rates are controlled to manage coning and cusping to prevent excessive gas production. The second stage is to produce the gas after the oil rim has been produced to economic limit.

1.1.2. Alternative (gas then oil) phased development

This is also known as the gas cap blow down in which case oil production is initially ignored while the gas cap is depleted. In their study, [26] showed that provided a strong aquifer exists, oil recovery can be maximized from an oil rim reservoir with a small gas cap by blowing down the gas cap during the initial stages of the production phase; while [25] remarked that the essence of this strategy is to develop the gas cap first and then allow the oil rim to move to the crest of the reservoir that will be produced by the same crestal gas well rather than attempting to control off-take and manage coning and cusping effect. The production of gas from the gas cap leads to loss of energy from the system and causes risk of losing oil through saturation losses in the gas cap when there is a very strong aquifer.

1.1.3.Concurrent oil and gas development

This option involves the depletion of the oil zone and the cap simultaneously, here the gas cap is developed fully or partially while the oil is produced through either the same or different ducts. The basic principle behind this method is to accelerate gas production and at the same time targeting to not reduce significantly the oil recoverable volumes. Van *et al.* [27] gave two major approaches to concurrent oil and gas development as:

i) Limiting the movement of the oil rim by managing the drive mechanisms accordingly, achieved by increasing the pressure support to the least dominant drive by fluid injection to either the gas cap or the aquifer. Alternatively, reduction in the oil rim movement can be achieved by decreasing pressure support to the most dominant drive through production from either the gas cap or the aquifer.
ii) Allowing some controlled movement of the oil rim and applying recompletion technology to track the movement of the rim or alternative well design and/or smart completion design to optimize oil recovery.

1.1.4.Gas only development

This approach focuses only on the gas cap and makes no attempt on the oil rim development. This scenario is needed when the oil rim has been evaluated to be uneconomical to develop. The gas recovery will strongly depend on aquifer support, residual gas saturation and availability of surface compression [25].

1.2. Factors affecting recovery from oil rim reservoirs

Olamigoke and Isehunwa [28] assessed a combination of subsurface and operational parameters to identify the key parameters necessary for developing response surface correlations useful in estimating oil recovery under conventional or concurrent development. The following parameters were identified as the dominant factors in various descending order: oil rim thickness, horizontal permeability, oil viscosity, gas cap size (m-factor), dimensionless aquifer radius, perforation position, permeability anisotropy, gas cap off-take, oil rim off-take, reservoir dips. Various other authors [4,10,29] have identified similar dynamic and static properties that affect the performance of oil rim reservoirs. The factors identified play important roles in determining the fluid flow dynamics and recovery factor for an identified oil rim configuration. The impact of some other subsurface factors such as reservoir geometry, magnitude of dip, degree of heterogeneity, well type and location were shown to perform important role for a given oil rim resource.

Based on results of several performance data in the industry, horizontal wells have been noted to be better option for developing thin oil rim reservoirs when compared to conventional (vertical) wells. Some other factors to be considered when designing the depletion strategy include well placement against the fluid contacts, well length (e.g. horizontal well length for the oil column), well pattern and spacing, and off-take constraints.

1.3. Existing models for oil rim reservoirs

Most models originated from either performance data, analytical or simulation studies [4,7,23,28,30-31,33]; Irrgang [30] used limited data from conventional well completions in several thin oil reservoirs to develop correlation for estimating the ultimate recovery per well in case study reservoirs in Australia, while Kabir *et al.* [10] performed parametric studies to developed correlations used as quick evaluation and screening tool for the exploitation of thin oil columns from simulation results of optimum completions made. Vo *et al.* [31] in their look-back analysis of the performance of 50 horizontal oil wells of the Serang fields in Indonesia identified specific relations between reserves and reservoir-well parameters which could be useful for predicting future well performance, especially during early screening stages of field development. Their result established a not too linear dependency relationship between recovery efficiency and oil column thickness for both horizontal and vertical production wells. On the basis of production data from 20 oil-rim reservoirs with thickness below 100ft, Osoro *et al.* [32] arrived at a correlation for recovery factor with net oil column thickness for accumulations in the Niger Delta oil fields. The results from the Serang fields were shown to have consistently performed better than the results from the Niger Delta fields both for conventional and horizontal wells. Yeoh [33] developed a numerical simulation model of thin oil rim reservoir which was restricted to oil only development option, the work showed the dependence of oil recovery factor on horizontal permeability, permeability anisotropy, oil viscosity, gas-cap size, aquifer size, well spacing, oil rate and initial oil thickness.

Oil and gas development strategy and screening method for the thin oil columns are identified as a major operational challenge [1], Lawal *et al.* [2] put forward that none of the current screening models was premised on rigorous theoretical studies. Hence, the critical challenge for early decision making as a tool for screening is to select the most appropriate development option, although several studies have been carried out on oil rim reservoirs and their depletion strategies, concurrent production of the gas cap and the oil rim is still a recurring challenge [1,34-35]. Some earlier investigators did not consider discontinuous production of the gas cap.

The major challenge in the reservoir under study is to manage gas off-take rate to optimize hydrocarbon recovery of the oil rim reservoir. As a result, the primarily aim of this work is concentrated on formulating some guidelines to accelerate the process of handling key decision challenges during the early stages of field development planning and actual development of oil rim reservoirs in the Niger Delta. While the other specific objectives include:

- To evaluate the feasibility of concurrent production of gas cap with continuous oil production in oil rims.
- To demonstrate the applicability of the swing gas option for concurrent production of oil and gas cap from thin oil columns and compare production performance with the concurrent method.
- Screening and selecting the optimum development strategy for the oil rim reservoirs.

2. Materials and method

In this study, a 3D three-phase black oil finite difference simulator was used to simulate thin oil column reservoir using data from oil rim reservoir in the Niger Delta. The materials used in the study include: Eclipse simulator, well and reservoir data.

2.1. Numerical model description

The structure of the reservoir model is a 3D model with the reservoir rock and fluid properties populated across the grid. The 3D section of reservoir being modeled has dimensions 8000' x 8000' x 300', and it is divided into fifteen layers of equal thickness. The number of cells in the x and y directions are both 20 each. A matched PVT model of representative fluid was used while one horizontal production well and one vertical injection well were placed in the model accordingly to study the oil and gas recovery mechanisms. Additionally, a 2-level local grid refinement was set around the well which aptly captures the pressure distribution around the horizontal well and the drawdown. Properties such as permeability and porosity were used throughout the well. The model is a case where there was neither shale barrier nor faults. The model is meant to capture the geologic description of the reservoir and to focus on the basic physics of oil rim depletion strategies and also as a screening tool. The effect of impurities (i.e. N_2, CO_2, etc.) was neglected, hence assumed as zero. Relative permeability models of different types were used for the oil rim and gas cap columns of the reservoir to model the different displacement processes occurring in each column with higher precision. The relative permeability models were generated using Corey correlations. The capillary pressure was assumed to be negligible due to the high permeability of the generic reservoir. The reservoir rock and fluid properties used in the model is presented in Table 1.

Table 1. Oil rim reservoir rock and fluid properties

Reservoir/Well and fluid properties	Value
Oil density (lb/ft^3)	56.85
Water density (lb/ft^3)	65.55
Gas density (lb/ft^3)	0.04104
Gas-oil ratio (scf/stb)	1000
Water salinity (ppm)	20000
Permeability (mD)	1000
Oil column thickness (ft)	60

Reservoir/Well and fluid properties	Value
Well bore radius (ft)	0.33
Porosity (%)	27
Reservoir Pressure (psia)	4207
Bubble point pressure (psia)	4207
Reservoir temperature (ºF)	200
Rock compressibility (1/psi)	1.081398E-5
API (degree)	39
Gas gravity	0.6
Horizontal well length (ft)	2000
Reservoir depth (ft)	7560
Oil relative permeability	0.7
Gas relative permeability	0.85
Water relative permeability	0.5

2.2. Reservoir simulations

The reservoir model used in the simulation was built using data from Alpha oil rim reservoir (Figure 2) in the Niger Delta. Four development scenarios were considered: scenario 1 (oil production only), scenario 2 (oil production first then gas), scenario 3 (concurrent oil and gas production) and scenario 4 (gas production only). A maximum simulation time of 30 years was applied across all the model runs. The well was drilled and completed as a horizontal whereas a vertical well was used to drill the gas portion of the reservoir. Both the oil and gas wells were constrained to a bottom-hole pressure (BHP) of 1500 psi which is about 36% of the initial reservoir pressure. The relatively low abandonment pressure was applied to entertain the option of any artificial lift method like gas lift or ESP deployment in the later stages of the production lives of the wells. The wells have good productivity with a skin factor of 0 and hence non-Darcy effects were assumed to be negligible in the gas wells. In addition to the threshold liquid and gas rate constraints applied for either of the oil or gas wells, the water-cut was restricted to 80% for the wells.

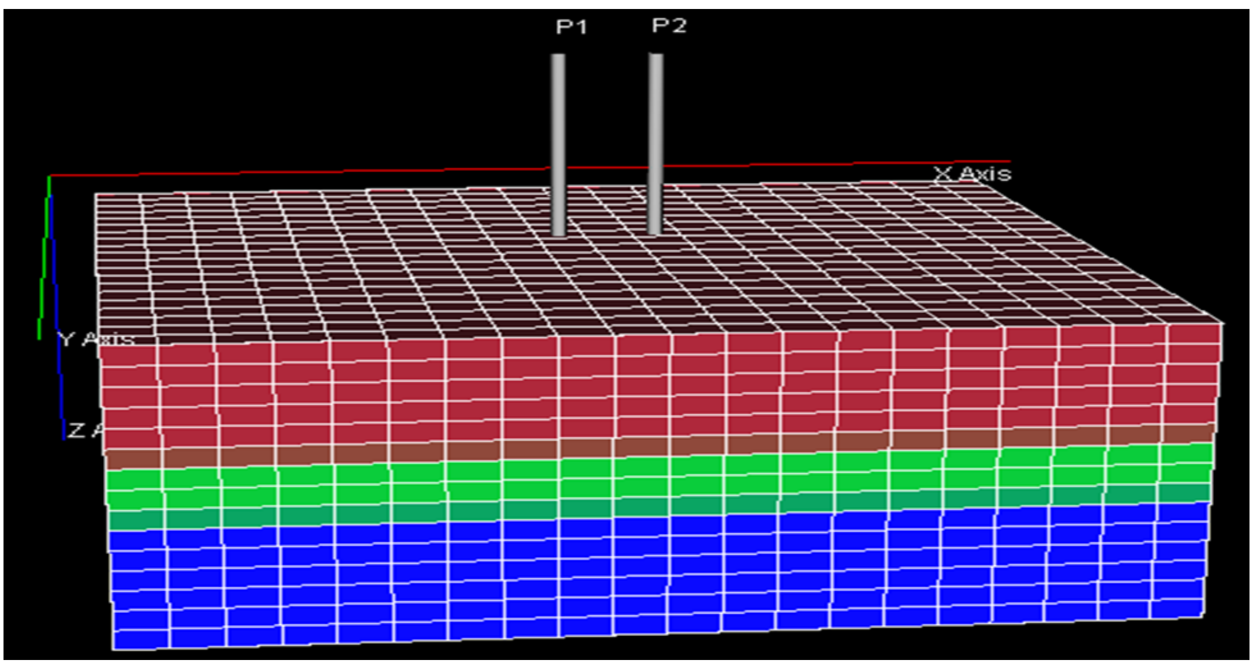

Figure 2. Concurrent oil and gas production

2.3. Fluid modeling

The reservoir fluid contains three phases namely gas, oil and water, the oil is live oil (i.e. oil with dissolved gas), these phases properties were generated using Eclipse PVT Correlation.

The bubble point pressure was set equal to the pressure at the gas-oil contact. API gravity and specific gas gravity are used as input variables. The PVT correlations were used to obtain the closest representative models of the provided PVT data. In this approach, key fluid properties such as solution gas-oil ratio (Rs), hydrocarbon fluid viscosities, and their resulting mobility values were varied between various runs that were undertaken.

2.4. Well description and placement

One horizontal oil production well was placed in the model and perforated at the oil column to replicate oil recovery only scenario. Then one vertical well was included in the model to mimic gas production when oil production has reached its economic limit. The well fluids were produced concurrently (oil produced from the horizontal well and gas from the vertical well). This is to replicate the concurrent oil and gas production case. Also gas production only was evaluated by placing only one vertical well for gas production. All these oil rim development scenarios were evaluated to select the best scenario that matches varying reservoir rock and fluid properties. This arrangement is aimed at obtaining an accurate relationship between recovery and the reservoir parameters. In order to take into account, the pressure drop along the horizontal section of the well, a homogeneous mixture wellbore flow model was applied. Following the similar step, a horizontal gas production well was placed in the gas-cap which was used for the gas-cap production for the Oil then gas, Concurrent, Swing gas and Gas only production scenarios. Using the model described, a thickness of 60ft and the initialization parameters given in Table 1, a sensitivity analysis was carried out to obtain the optimum horizontal well placement for oil production and optimum vertical well placement for the gas production.

2.5. Sequential (oil then gas) production case model

The oil production then gas case was modeled to replicate the production of oil first and then gas production later from oil rim reservoir. In this case one horizontal well was completed at the oil column for oil production and one vertical well for gas production was completed at the gas column for gas production. The model designed for this run mimics a situation where the reservoir is being depleted from the oil column with negligible or no production from the gas cap. Production of gas commences when the oil production has reached its economic limit. The following constraints were applied to model this case:

i. Initial Liquid production rate of 1800 STB/day
ii. Minimum Oil well BHP of 1500 psi
iii. Minimum oil economic limit of 200 STB/day
iv. Maximum allowable water cut of 80%
v. Gas production rate of 60500Mscf/day
vi. Minimum gas well BHP of 1500 psi
vii. Simulation time of 40 years

2.6. Concurrent oil and gas production case model

This case was modeled to replicate the production of oil and gas concurrently, here one horizontal well was completed at the oil column for oil production and one vertical well for gas production was completed at the gas column for gas production. The production of oil and gas commences at the same time. The gas well was perforated within the top 30% of the gas column in order to suppress potential coning of oil to the gas producer. The following constraints were applied to model this case:

i. Initial Liquid production rate of 1800 STB/day
ii. Minimum Oil well BHP of 1500 psi
iii. Minimum oil economic limit of 200 STB/day
iv. Maximum allowable water cut of 80%
v. Gas production rate varied from 2% to 10% of Free gas in place (FGIP)
vi. Minimum gas well BHP of 1500 psi
vii. Simulation time of 30 years

2.7. The swing gas production model

The underlining strategy here is that the gas cap is produced discontinuously in such a way that the gas well is produced in a cycle format while the oil is continuously produced. The well is produced for a fixed period and short-in for another period of time to be re-opened after a fixed time. The number of repetitive cycles of shut-in and production, off-take rates and production period were used as variables for simulation and hence for optimization. The following constraints were applied to model this case:

i. Initial Liquid production rate of 1800 STB/day
ii. Minimum Oil well BHP of 1500 psi
iii. Minimum oil economic limit of 200 STB/day
iv. Maximum allowable water cut of 80%
v. Minimum gas well BHP of 1500 psi
vi. Four (4) years of continuous production, 2years shut-in and 5 cycles.
vii. Simulation time of 30 years

2.8. Gas production only case model

This case was modeled to mimic the production gas only from oil rim reservoir. In this case one vertical well for gas production was completed at the gas column for gas production. The oil producer that was used in the sequential- oil then gas development was shut-in in order to ensure that gas is the only fluid produced in the scenario under study while keeping the gas well online for a simulation period of 30 years. The following constraints were applied to model this case:

i. Gas production rate of 60500Mscf/day
ii. Minimum gas well BHP of 1500 psi
iii. Maximum allowable water cut of 80%
iv. Minimum gas rate of 1000Mscf/day
v. Simulation time of 30 years

2.9. Aquifer model

A Carter Tracy aquifer was defined in the model and connected to the base of the grid block. The properties of the aquifer zone were derived from the grid blocks to which the aquifer model was attached. A finite linear aquifer model was attached to it at the base of the reservoir model.

3. Results and discussion

3.1. Effect of gas off-take rate on the recovery factor

The effect of percentage production of field gas initially in-place on oil recovery for concurrent oil and gas (COG) production (Figure 3) showed the field oil efficiency (FOE) also referred as Recovery Factor (RF) for gas off-take rates ranged between 2% to 10% inclusive mimicking sequential depletion for simulation for a period of 30 years. The result revealed a strong relationship between the gas off-take rates and the oil recovery. The oil recovery improves with a decrease in the gas off-take. This is because the gas in solution or free in the reservoir helps to drive the oil production at the surface. If gas monetization is not a problem, then we are better off reducing our gas production or by sustaining the gas in solution in the reservoir either as a solution gas or as free gas to drive higher oil production to the surface. Optimum off-take rate can be maintained by monitoring the gas-oil ratio (GOR). The plot showed the optimum gas off-take rate to be the 2% of the field gas initially in place (FGIIP) while least field oil recovery was observed for the gas off-take rate of 12% FGIIP. The results displayed a relationship of an indirect variation between the FOE and the gas off-take rates.

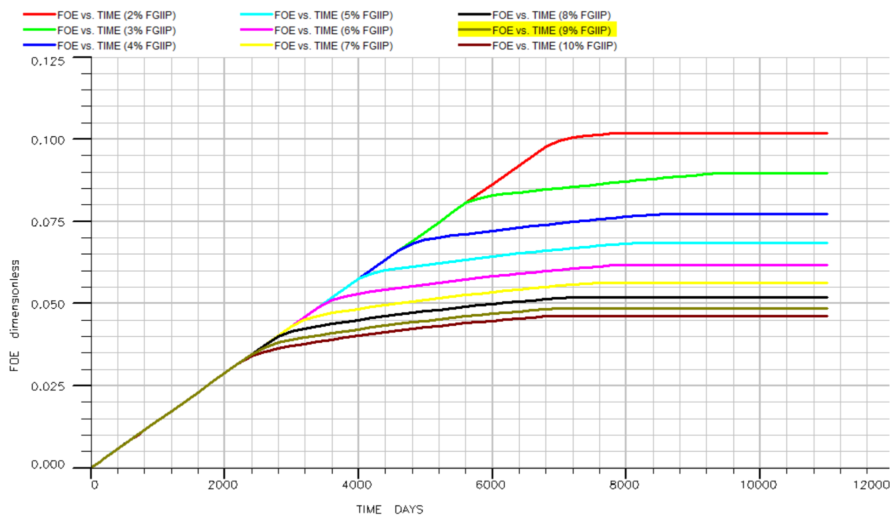

Figure 3. Effect of percentage production of field gas initially in-place on oil recovery for concurrent oil and gas (COG) production

3.2. Field gas production

The gas well came on stream at the rate of about 60,000 MSCF/D for the following development options: concurrent oil and gas development option, the swing gas development option and the gas only development option. For the sequential oil then gas development option the gas production was delayed till the end of the economic production level of the oil portion of the reservoir, the economic production life of the well dedicated for oil production took a period of 9 years before the gas well came on stream as captured in Figure 4. It maintained a steady increase till it attained a maximum rate of 110,000 MSCF/D.

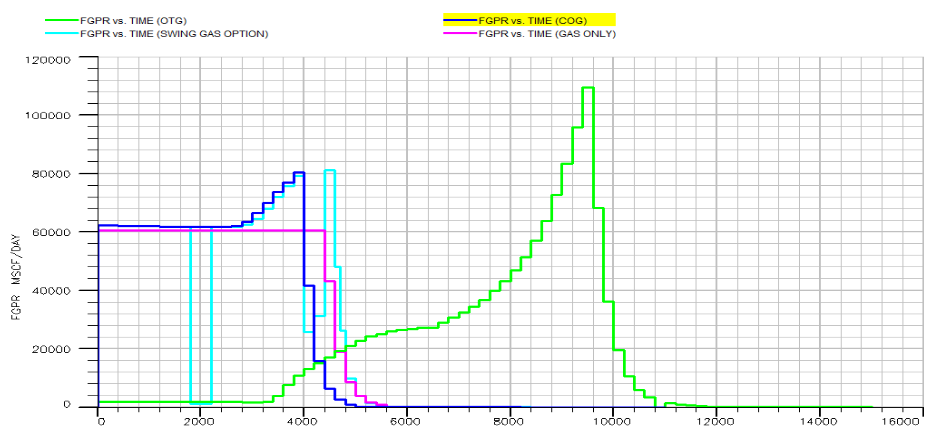

Figure 4. Gas production rate for the three cases: Oil Then Gas (OTG), Concurrent Oil and Gas (COG), Swing gas option

3.3. Oil recovery efficiency

The oil recovery efficiency (Figure 5) further showed field oil performance for three development scenarios including sequential oil then gas development, concurrent oil and gas development and the swing gas development options. A comparison of the three cases gave a recovery factor of ~14.3% for the sequential oil then gas development option, remotely followed by the swing gas development and then the concurrent oil and gas development options. There is an incremental recovery from the swing gas production when compared to the recovery from the concurrent oil and gas development option to a recovery factor of ~0.06%.

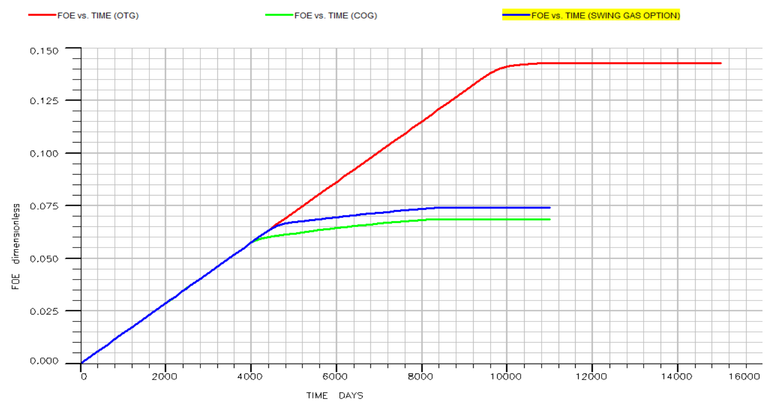

Figure 5. Oil recovery efficiency for the three cases: Oil Then Gas (OTG), Concurrent Oil and Gas (COG), Swing gas option

3.4. Effect of oil column thickness (H_o) on recovery

The Field oil efficiency (FOE) when tested with the oil column thickness ranging from 60ft to 20ft for the concurrent oil and gas development showed the 60ft thickness to be the best performing with 6.8% FOE while the 20ft thickness was the least performing with 2.8% FOE as shown in Figure 6. The effect of the oil column thickness was tested on the gas recovery (Figure 7). The gas recovery response was highest for the least oil column thickness of 20ft as considered in the simulation. The oil column thickness of 20ft attained the highest gas production at the shortest time when compared with the other values of oil column thickness.

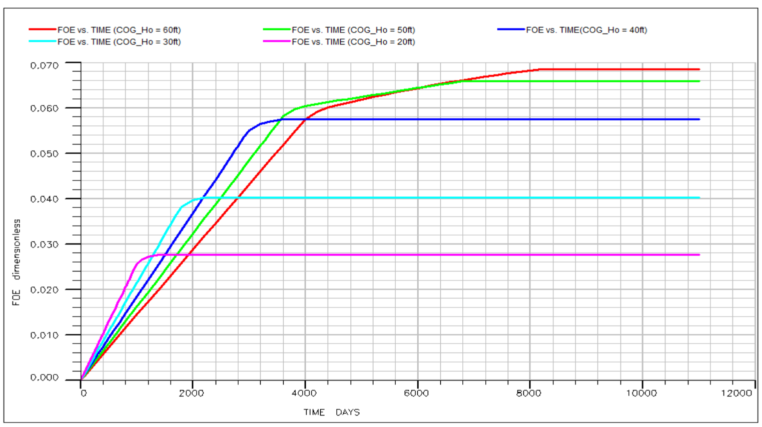

Figure 6. Oil recovery efficiency for the different values of oil column thickness for the Concurrent Oil and Gas (COG) option

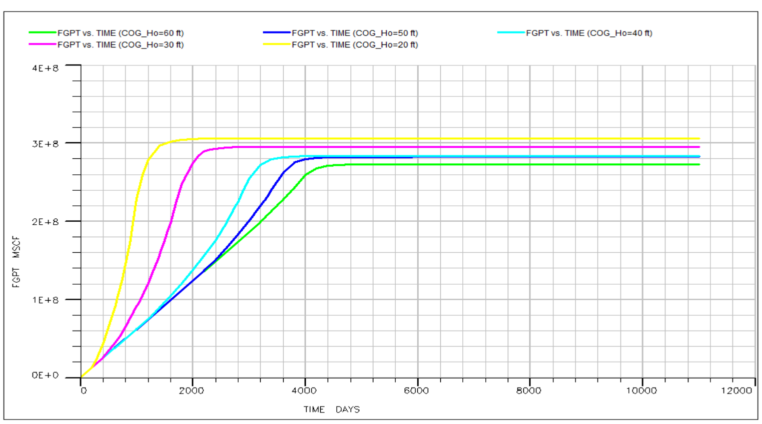

Figure 7. Response of oil column thickness to gas recovery

3.5. Sensitivity results on water production

One of the major challenges to production from oil rim reservoirs is controlling coning from the underlain aquifer or edge water source to the perforation area. Sensitivity checks were carried out on the effect of oil column thickness on the water production. For a base case of concurrent water and gas production, simulation runs were carried out for oil column thickness from 20 ft. to 60 ft. Simulation results showed optimum performance for the 60 ft. thickness with the least field water production total of close to 1.25 E+7 STB (Figure 8).

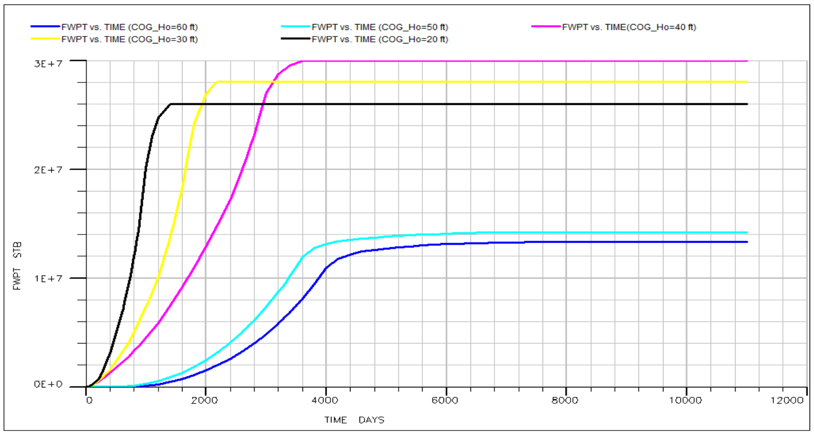

Figure 8. Effect of oil column thickness on cumulative water production for concurrent oil and gas (COG) production

The water production was further demonstrated from the water cut results as shown in Figure 9. Having originally restricted the water cut to a maximum value of 80%, the production till the permissible water cut could be determined. The concurrent and the swing gas development options were able to produce economically below the 80% water cut threshold till about 11 years while the sequential development option produced economically till 25 years.

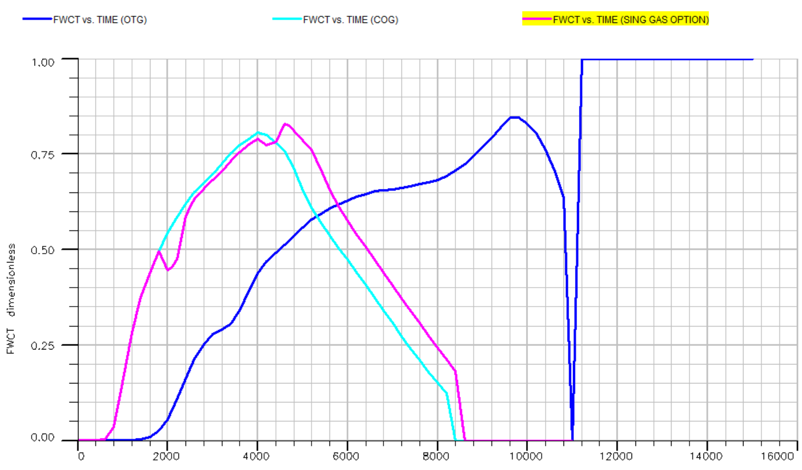

Figure 9. Water cut for the sequential, concurrent and the swing gas development options

3.6. Effect of gas cap size on recovery

The results of the simulation runs on the gas cap size (m) showed that an appreciable optimization can be achieved with respect to the choice of development option. Sensitivity checks carried out tried to evaluate the effect the gas cap sizes on the overall oil recovery for the sequential, concurrent and swing gas development options. For all the m-sizes (Figures 10 and 11) considered ranging from 6 to 2, the sequential development option performed best while the swing gas option was the least performed. In addition, the sequential development for the m-size of 2 (Figure 10) showed the highest recovery with a recovery factor of 14.3% with an appreciable incremental recovery factor of 6% from the swing gas development option.

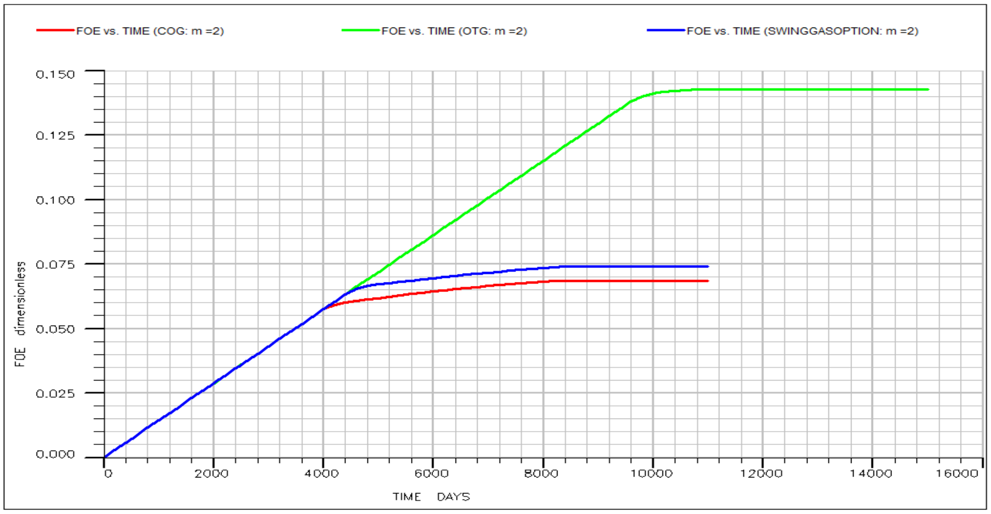

Figure 10. Effect of the gas cap size (m=2) on oil recovery for the sequential, concurrent and swing gas production cases

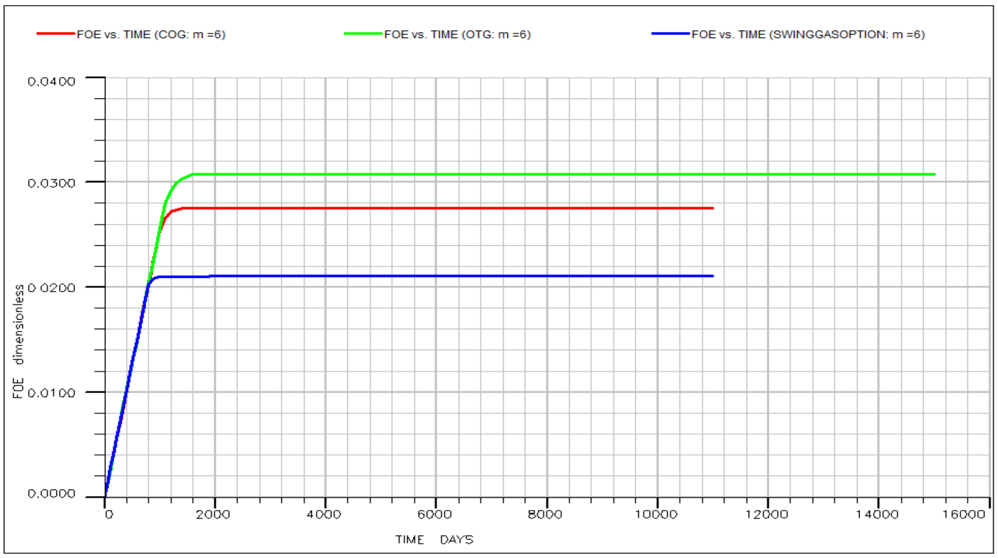

Figure 11. Effect of the gas cap size (m=6) on oil recovery for the sequential, concurrent and swing gas production cases

3.7. Effect of permeability anisotropy on the oil recovery

The ratio of vertical permeability to horizontal permeability (K_v/K_h) for values of 0.01, 0.1 and 1 was considered in the simulation. The effect of permeability anisotropy as tested showed slight response in terms of incremental recovery for the three K_v/K_h cases considered as shown in Figure 12. K_v/K_h value of 0.01 showed the highest oil recovery when compared to the other K_v/K_h values considered. Additionally in terms of the effect of K_v/K_h values on the water production, the K_v/K_h value of 0.01 was shown to be the optimum case having the lowest produced water value (Figure 13).

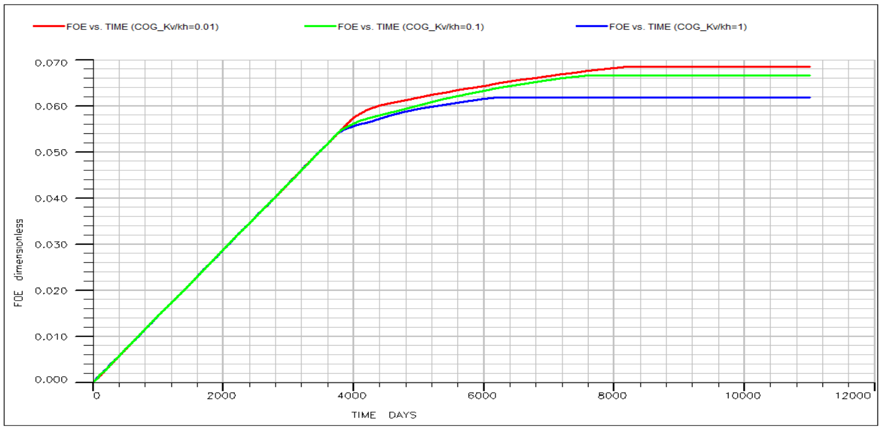

Figure 12. Effect of permeability anisotropy on oil recovery for concurrent oil and gas development option

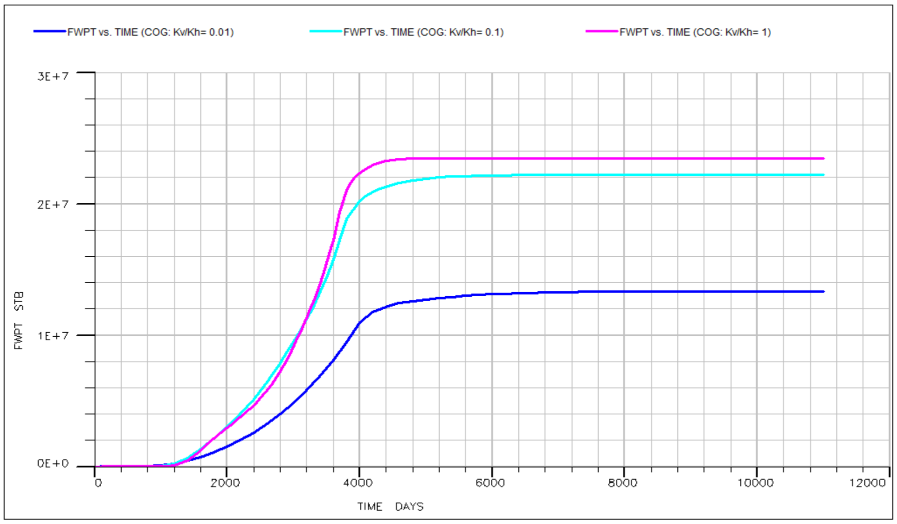

Figure 13. Effect of permeability anisotropy on water production concurrent oil and gas development option

4. Conclusion

The reservoir simulation with the use of idealized box models was used to develop depletion strategies for the Alpha thin oil rim reservoir that was under study. The key findings are thus:

- Sequential oil then gas development, concurrent oil and gas development and the swing gas production could support economic production provided gas off-take rates are maintained low from 2% to 6% of FGIIP per annum.
- The horizontal well that was used for oil production showed appreciable incremental production when the perforation is effected at the top half of the oil column. This helped to control coning and ensured optimized production was obtained from the oil column. Horizontal well length of 2000ft. was confirmed as the optimum horizontal well length when juxtaposed with the economic considerations and was found to be very sensitive to the permeability of the formation.
- The idealized simulation box model when history-matched with specific reservoir data-set was found to be effective in determining oil rim recovery sensitivity to the reservoir parameters and the depletion scenarios.
- The Response Surface Models (RSMs) generated for sequential oil then gas and concurrent oil and gas development can serve as first pass screening tool for such purpose. Results showed a higher recovery performance for sequential oil then gas development option to the concurrent oil and gas option.

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