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A Comparative Study on the Performance of Different Secondary Recovery Techniques for Effective Production from Oil Rim Reservoirs

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Abstract

Early water and gas breakthrough is a challenge for developing thin oil rim reservoirs. Secondary recovery methods such as water, gas, simultaneous water and gas (SWAG) and gravity-assisted simultaneous water and gas injection (GASWAG) methods are proven methods for developing thin oil rim reservoirs. Knowledge about a preferred technique is important to minimize cost and enhance performance. In this study, various water and gas injection scenarios applied to thin oil rim reservoirs were evaluated using reservoir simulation studies such that horizontal and vertical wells were used for production and injection respectively. The performance indicators considered include cumulative oil produced, oil production rate, and the onset of water and gas coning. Simulation results showed that injecting gas at the gas-oil contact (case 1) and at the water-oil contact (case 2) were the least favorable in improving oil recovery and in delaying gas coning and gas-cap surface production. SWAG and GASWAG resulted to an increase in production rate by 18.5% and 37.9% respectively in comparison to gas injection. Water injection at water-oil contact (case 3), SWAG and GASWAG augmented reservoir pressure with GASWAG sustaining the force balance within the reservoir much more than other methods during the simulation period. GASWAG technique also resulted to a 28% increase in cumulative oil produced in comparison to SWAG. This is because the GASWAG technique improved sweep efficiency with the downward movement of water and the upward movement of injected gas. Results from this study shows that GASWAG is a preferred method for developing thin oil rim reservoirs and should be adopted. It is however recommended to carry out an optimization study which determines the optimal input parameters for a GASWAG process that maximizes cumulative oil produced and delays water and gas breakthrough.

Keywords: Water Injection, Gas Injection, Simultaneous Water and Gas Injection, Gravity-Assisted Simultaneous Water and Gas Injection, Well Placement, Oil Recovery.

1. Introduction

Oil rim reservoirs are unconventional reservoirs occupied by a strong aquifer and a substantial gas cap that provides complex conditions for producing reserve oil. Concerning the economic prosperity of drilling this type of reservoir, petroleum engineers try to find new enhanced oil recovery techniques to produce more oil, which is sparingly profitable owing to the tremendous experience of drilling and production operations. Several proposed methods can improve oil recovery efficiency from thin oil column reservoirs with strong aquifers and large gas caps. These techniques involve horizontal production wells, edge water injection into the oil zones and gas injection at the oil-water contact (WOC). The difficulties encountered in oil rim simulation studies are largely connected to gas cap-driven reservoirs. Based on the reservoir drive, the categories of oil rims will display an estimate of oil recovery from various secondary injection strategies. Models for accurate classifications and estimating oil recovery under various production and injection schemes have been created with the aid of the design of experiments on reservoir geometry, reservoir, fluid, and operational parameters from the literature [1].

Oil production using natural reservoir energy (primary oil recovery techniques) only recovers about 30% to 50% of the original oil in place (OIIP); the remaining oil is left in the reservoir at residual saturation. As the reservoir is put to production, reservoir energy begins to deplete to a level that continual production from the reservoir becomes uneconomical. The reduction in reservoir pressure continues with production until a stage where the reservoir pressure reaches the bubble point pressure, at this critical pressure, two-phase fluids begin to appear in the reservoir. The gas initially dissolved in the oil comes out of the solution and flows preferentially towards producing wells since it is less viscous than oil. Consequently, the oil production rate and oil recovery factors are lowered. Water and gas injection is usually employed to maintain reservoir pressure above the bubble point for improved oil production [2].

Various secondary oil recovery methods have been deployed and applied to mature and depleted oil reservoirs. These methods help to improve oil recovery compared to primary reservoir depletion. Water injection is used to recover reservoir oil based on its varying density; thus, oil is recovered through immiscible displacement [3]. The water injection method is limited to recovering hydrocarbons at much higher permeable reservoirs. When this method is used, there is a high possibility of water breakthrough, which may cause production problems and technical issues at the wellhead and the expected large production of water [4].

Another secondary recovery technique also applied to oil recovery is gas injection. The gas injection technique

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improves oil production due to gravity effects. The injected gas moves to the top, creating a secondary gas cap that compresses the oil column toward producing wells. Gas injection methods are commonly suitable for reservoirs with mid-low permeability and porosity, mid-low depth, mid-high temperature, and ordinary oil viscosity [5]. This technique is limited to an under-saturated reservoir because the dissolution of injected gas in the oil reduces the density and viscosity of the oil, thus, increasing its flow towards the productive intervals [6].

Water and gas injection plays a great role in increasing oil recovery. However, the sweep efficiency of gas is low due to reservoir heterogeneity and low gas viscosity and density. As a result, gravity override will occur, which lowers gas sweep and oil recovery [7]. Water is injected simultaneously with gas to control gas mobility (Jamshidnezhad, 2008.), leveraged on the force balance system by the injection of water and reinjection of produced gas around the thin oil column [8]. The three dominant forces responsible for the production and oil recovery in oil rim reservoirs are aquifer expansion, gas cap expansion, and viscous withdrawal. Scenarios where horizontal wells have been applied for the production of reserve oil in thin column reservoirs, gave optimum results when compared to vertical wells regarding the economic benefits and potential contact with the reservoir [9].

Production of thin oil layers is always considered a debate in petroleum industries because of high expenditures and little gain. Oil rim reservoirs are unconventional reservoirs with a substantial aquifer and a big gas cap that provides complex conditions for producing reserve oil [10]. According to the structure of the gas cap layer on the oil layers, the schematics of oil rim reservoirs are categorized as the pancake and doughnut structures (see Fig 1 below).

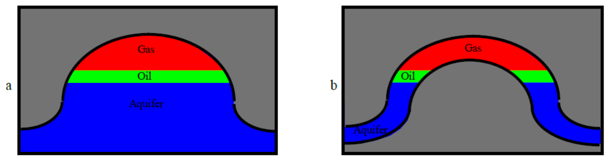

Fig. 1. Pancake and Doughnut structure of oil-rim Reservoirs

It is challenging to produce a reservoir with a thin oil rim and large gas cap. Gas or water breakthroughs are commonly seen and are responsible for disappointing oil recovery. The development becomes more challenging when a more significant oil recovery is expected and resources are needed to control depletion and maintain reservoir pressure [11]. It was further emphasized that commercial production from unconventional reservoirs requires multistage hydraulic fracturing and lengthy horizontal wells between 3,000 and 10,000 feet in length [12]. Tensile intrusion with increased permeability is brought on by the broken zones' proximity. Mechanical movements such as stress from fractures, motions toward slipping fractures, and various hydraulic fracture geometry are to blame for this. In these kinds of wellbore, there are complex transient flow characteristics. Diffusion could be a big help in getting the most out of an unconventional reservoir.

Some authors showed in their research work that the advantages of water injection outweighed those of gas injection for a weak aquifer in terms of incremental recovery [13]. This is because of the the large gas cap which provides the majority of the pressure support, making gas injection unnecessary, particularly if there is an effective gas-oil ratio (GOR) constraint in place. Aquifer strength, permeability anisotropy, GOR policy, and oil rim thickness during water and gas injection were all factors that were taken into consideration in their reservoir simulation study on oil rim development. Their modeling analysis demonstrates that the simultaneous injection of gas and water can increase oil rim recoveries by 15% of the original amount of oil.

2. Theoretical Concept

Secondary recovery methods applied to increase production from depleted reservoirs include water injection, gas injection, and the combination of the two (SWAG and GASWAG). The water alternating gas process (WAG) is a cyclic procedure of injecting water followed by gas to improve the microscopic and macroscopic sweep efficiency by maintaining initial high pressure, hinder gas breakthrough and abating oil viscosity [14].

Simultaneous water and gas injection (SWAG) is another injection scheme that involves the synchronized injection of water and gas along with an injection well. SWAG is a process that has emerged for conformance control. However, it has been studied less thoroughly [15]. It is known as SWAG injection when water and gas are mixed at the surface and injected simultaneously into the reservoir. In a scenario where the gas and water are injected separately using a dual injection well completion, it is referred to as selective simultaneous water alternating gas (SSWAG) [16]. The density difference between water and gas provides a sweep mechanism in which water sweeps the hydrocarbon downwards, and gas sweeps it upward. Generally, selecting the best secondary recovery method always proves challenging because the optimum scenario that accounts for the increase in oil production within a cycle time with the minimum miscibility pressure, high mobility ratio and early breakthrough in the reservoir must be considered [14].

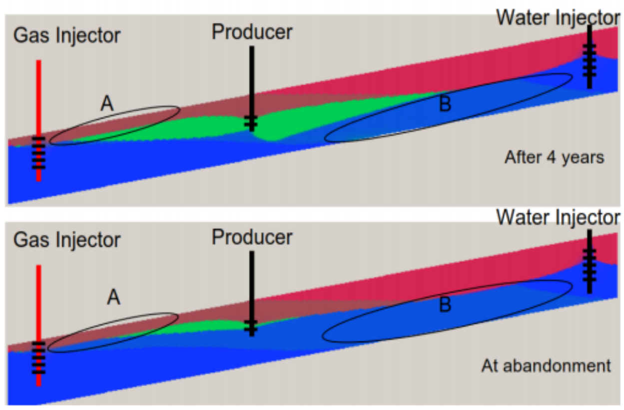

Fig. 2. Fluid movement for gravity-assisted simultaneous water and gas injection (GASWAG) *[17]*

The performance of SWAG injection can be affected by several factors, including the fluid properties, rock-fluid interaction, injection pattern, cycling time, injection/production pressure and rate, three-phase relative permeability effects and flow dispersion, and finally, the initialization time for WAG [18] [19] as figure 2 ilustrates. The efficiency of the WAG/SWAG injection techniques depends on the characteristics of the reservoir, and the advantage of this technique includes; a reduction in gas mobility (Mobility control), improved overall recovery (sweep efficiency and residual oil recovery) and improved financial performance (net cash flow) [16].

The oil recovery factor obtained when gas and water injection rates are doubled or reduced may differ from the one obtained before changing the injection rates. Likewise, SWAG performance with down-dip gas injection and up-dip water injection may not be similar [20].

This Gravity Assisted Simultaneous Water and Gas injection scheme (GASWAG) improves the sweep efficiency of the lower section in the inner part of the oil rim with the downward movement of water while increasing the sweep efficiency of the upper unit on the outer part of the oil rim with an upward trend of injected gas. This method is distinguished from regular SWAG because the water is injected up dip while gas is injected down dip. This injection scheme improves oil recovery because sweep efficiency is maximized by water and gas movement under gravity [17]. Discovered in a reservoir setting where displacement occurred along a gentle dipping structure, the gas would displace the oil in the upper part of the reservoir, and water will implicitly displace oil in the lower part of the reservoir. Combined with the sparse well spacing in a gentle dipping oil rim, the GASWAG injection scheme resulted in optimum sweep efficiency.

The objective of this paper is to evaluate and estimate the total oil recovered and its efficiency with the aid of these secondary oil recovery techniques; Gas injection, Water injection, simultaneous water, and gas injection (SWAG) as well as the gravity-assisted simultaneous water and gas injection (GASWAG) and to investigate the secondary oil recovery approach with the best pressure support/maintenance for an oil rim reservoir.

3. Materials and Method

3.1. Materials

The materials used for this study is Eclipse 100 and a black oil reservoir simulator. The reservoir model used is heterogeneous with an oil column thickness of 60ft, and 80ft thickness for the aquifer and gas cap respectively. The geometric and reservoir petrophysical properties of the reservoir model are shown in Table 1 and are based on available field data for accurate description and delineation of the reservoir. Using the data shown in Table 1, a reservoir simulation model was developed as shown in Figure 3.

Table 1. Reservoir properties used to develop reservoir model

S/N	Reservoir Properties	value	unit
1	Reservoir depth	8000	ft
2	Oil density	52.89	Ib/ft^3
3	Water density	63.20	Ib/ft^3
4	Gas density	0.09613	Ib/ft^3
5	Oil viscosity	3.0	cp
6	Oil FVF	1.20	Rb/stb
7	Gas viscosity	0.027	cp
8	Oil column thickness	60	ft
9	Wellbore radius	0.5	ft
10	Water saturation	15	%
11	Initial reservoir pressure	4500	psia
12	Reservoir temperature	172	^{0}F
13	API	33.8	^{0}API
14	Water compressibility	0.000003347	1/psi
15	Water FVF	1.02	Rb/stb
16	Aquifer thickness	80	ft
17	Gas cap thickness	80	ft
18	Reservoir width	2200	ft

A no-flow boundary condition was considered at the sides of the reservoir model for all cases. The model consists of a gas cap and an aquifer at the top and bottom of the reservoir respectively. The datum depth of the reservoir is 8000 ft with an initial reservoir pressure for the model was 4500 psi. The depths of the gas – oil and oil – water contacts are 8080 ft and 8140 ft respectively, resulting in an oil zone thickness of 60 ft characteristic of oil rim reservoirs. A water and gas injection rate of 2000 stb/day and 2000mscf/day was used when injecting either or a combination of water and gas to depict each injection scenario. A bottomhole flowing pressure of 2000 psi was used for the horizontal well in each case.

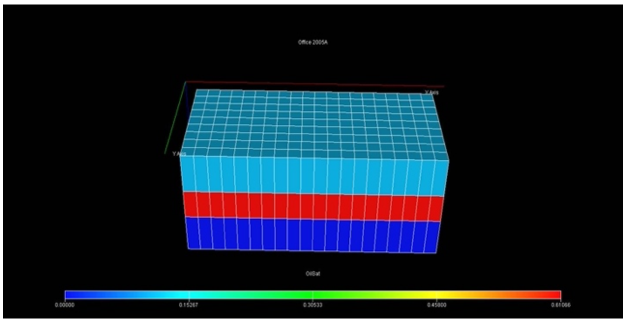

Fig. 3. Block model of reservoir M showing grid blocks

The horizontal wells were used for saucing while vertical wells were used for sinking to penetrate the target reservoir. The reservoir was depleted naturally and by application of gas injection, water injection, simultaneous water and gas injection (SWAG), and gravity-assisted simultaneous water and gas injection (GASWAG). These secondary oil recovery methods were modeled with ECLIPSE numerical reservoir simulator, and the scenarios with optimum required results were selected.

3.2. Method

A block model representation of an oil rim reservoir (reservoir M) was developed. The reservoir properties were gotten from the natural reservoir properties of a known oil rim reservoir, while those unavailable were moderated in consistency with real-life scenarios. The data set of 'HORZWELL' from the ECLIPSE data file was used and redesigned for modeling because it perfectly suits the conditions of an oil rim reservoir. The reservoir condition was made heterogeneous by including a permeability data of 'SPE9' in the ECLIPSE data file. The block model consisted of 20 grid blocks on the x-axis (horizontal 'DXV20*100' ft thick), 9 grid blocks on the y-axis ('DYV 110 110 110 110 110 110 110 110 110' ft), and three grid blocks on the z-axis ('DZ 180*80 180*60 180*80' ft) each specifying the thickness of the aquifer, gas cap, and oil column. The duration (time step) of the simulation was 1000 days.

3.2.1. Secondary Recovery Methods

This simulation study is limited to pressure maintenance methods only. A horizontal well with connections and open completions was used as the producer and was drilled into the target (oil column). Injector wells with open completions were placed at the water-oil contact (WOC) and Gas-Oil contact (GOC), considering the different injection scenarios. The flood pattern for cases 1-4 is a direct line drive (Fig 4) with one injector well (vertical) placed directly opposite the horizontal producer well with connections. The field oil production total, pressure maintenance, and water and gas production of all cases were investigated to select the most preferred based on study objective.

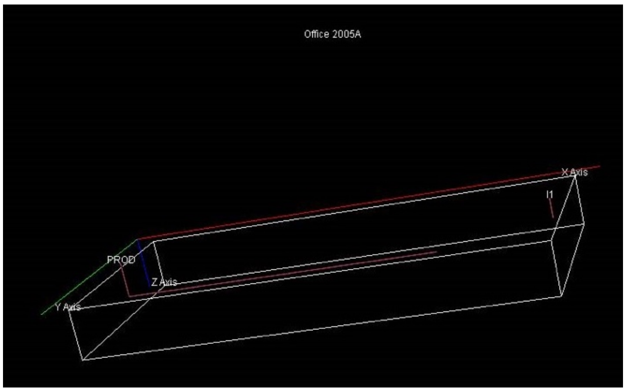

Fig. 4. Flood Pattern for Cases 1-4

3.2.1.1. Case 1- Gas injection at Gas-Oil Contact

This case is intended to highlight the effects of injecting gas at the gas-oil contact or gas zone in the oil rim reservoir. The simulation had a time step of 1000 days and the well pattern considered was a direct line drive (one injector and one producer). Injector and producer wells were positioned at the extreme ends of the reservoir to reduce the gas breakthrough time. High and low Injection rates were tested. Optimum rates were selected.

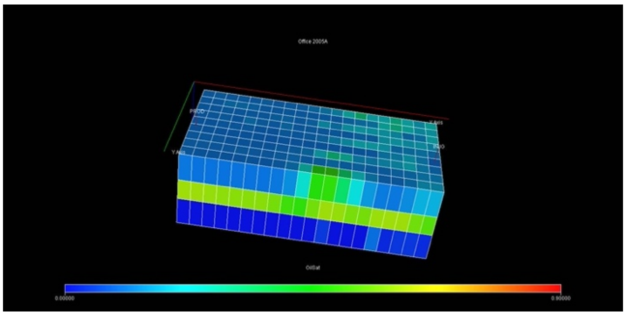

Fig. 5. Case 1- Gas injection at GOC

3.2.1.2. Case 2- Gas Injection at Water-Oil Contact

The effects of injecting gas at the water-oil contact to improve oil recovery are to be investigated. Wells were placed at extreme ends to prolong the time it takes for water or gas to breakthrough into the producer well. The injection rate was analyzed, and high and low rates were investigated to select the best recovery approach in this scenario.

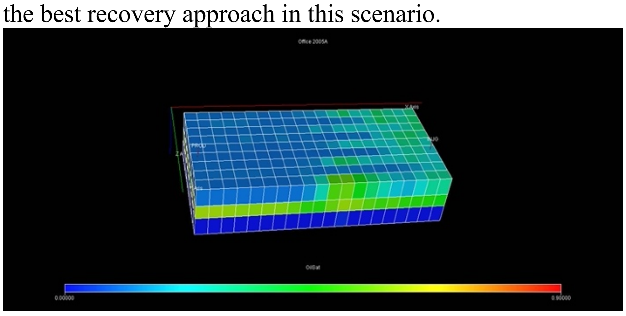

Fig. 6. Case 2- Gas injection at WOC

3.2.1.3. Case 3 - Water Injection at Water-Oil Contact

The effects of injecting water at the WOC or aquifer into an oil rim reservoir to improve recovery were investigated. The injector and producer wells were placed at both ends of the reservoir. Control of the injection rate was considered as the reservoir already has a strong aquifer. This was done to reduce water breakthrough time into producer wells.

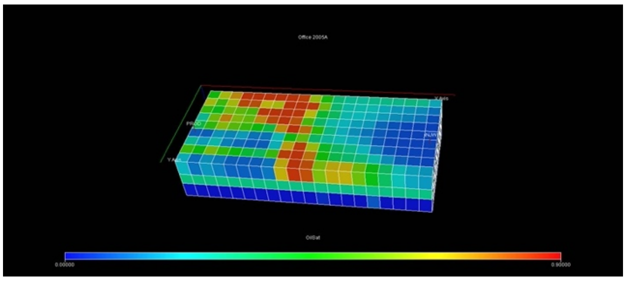

Fig. 7. Case 3- Water injection at WOC

3.2.1.4. Case 4 - Water injection at Gas-Oil contact

The effects of injecting water at the gas-oil contact to improve overall oil recovery from an oil rim reservoir were investigated. The aquifer and gas cap thickness remained constant as well as the injection rate throughout the simulation period of 1000 days.The injection rate was controlled to simulate the effects of 'water fencing' in an oil rim reservoir. The pattern of injection was a direct line drive (Fig. 8).

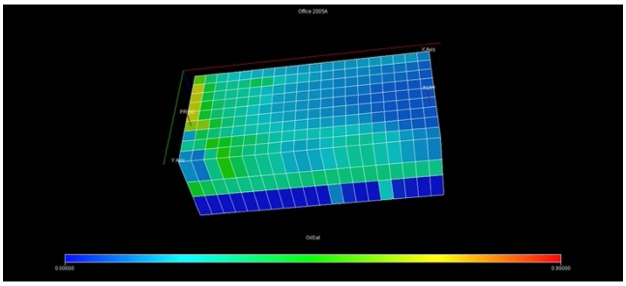

Fig. 8. Case 4- water injection at GOC

3.2.1.5. Case 5- Simultaneous Water and Gas Injection (SWAG)

This case involved injecting water and gas simultaneously into the reservoir using different injector wells. The effects of force balance between the gas-oil contact and the water-oil contact by injecting gas at the GOC and water at the WOC, respectively, were investigated. The well pattern was a 3-spot configuration (Fig 9). Injection rates were controlled to suppress the effects of early water and gas coning in the reservoir. The injection rates of both injector wells were considered, and the optimal scenario that created a balance in the system was selected.

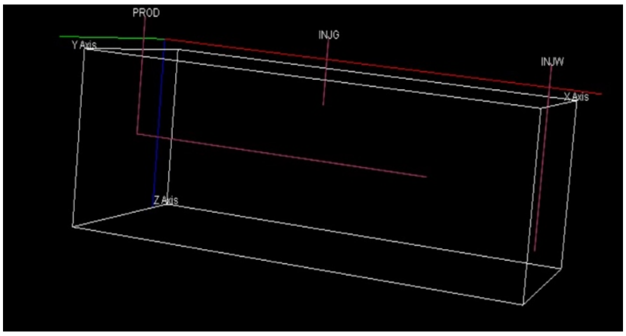

Fig. 9. Well placement skeletal

3.2.1.6. Case 6- Gravity Assisted Simultaneous Water and Gas injection (GASWAG)

This case is similar to the regular SWAG injection, except that water is injected at the gas-oil contact in contrast to SWAG, gas is injected at the water-oil contact. The force balance of WOC and GOC was investigated. The downward movement of water and upward movement of the injected gas were considered and also the recovery factor upon which this technique was built. The well pattern is a 3-spot pattern (single horizontal producers and two injectors). Injection rates for both injector wells were controlled to prevent early water and gas coning at the producer well.

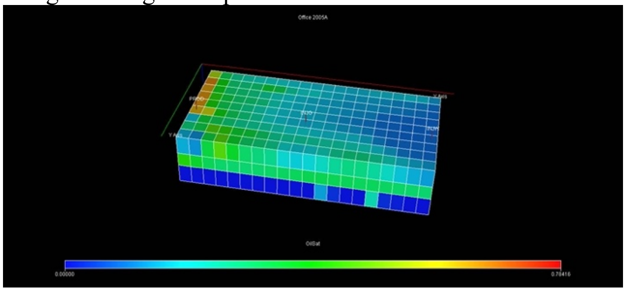

Fig. 10. The Gas injector well is placed between the producer well and the Water injector

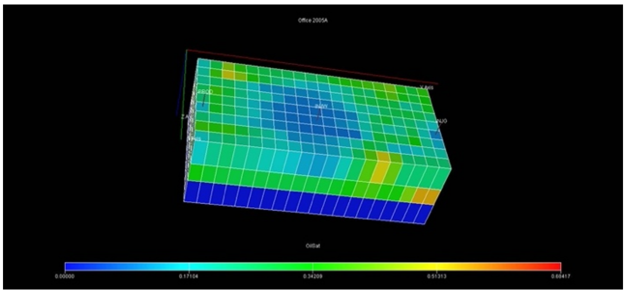

Fig. 11. Water injector well placed between a Gas injector well and producer well

4. Results and Discussions

4.1. Results

Figures 12, 13, 14, and 15 shows the total water, gas, and oil produced, oil recovery factor and variation of pressure under the various depletion methods considered during reservoir simulation study.

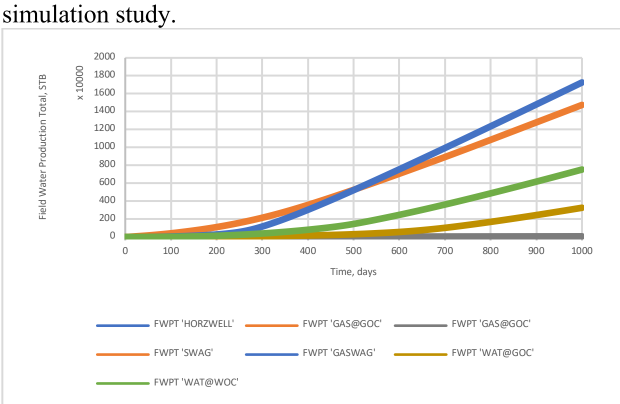

Fig. 12. Comparison of Cumulative Field Water Produced for all cases

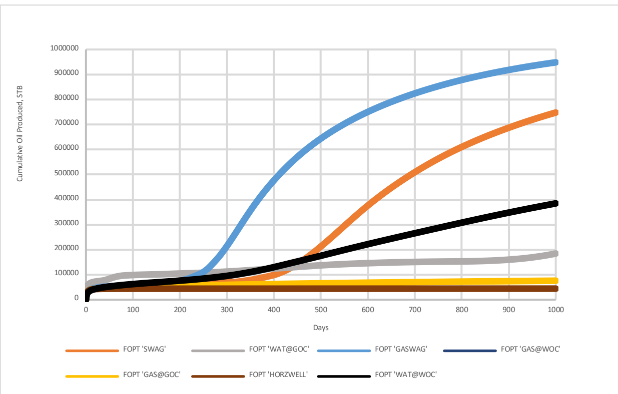

Fig. 13. Comparison of Cumulative Field oil Produced for all cases

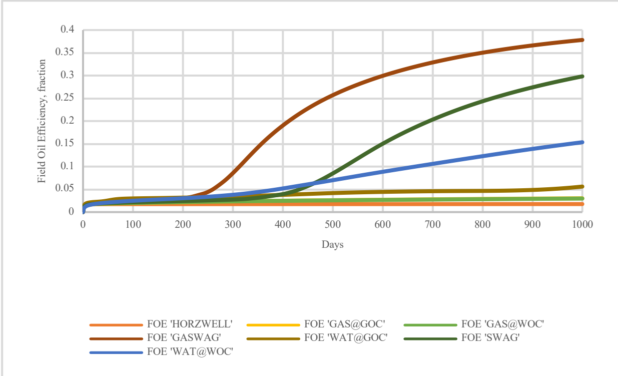

Fig. 14. Field oil recovery efficiency for all cases

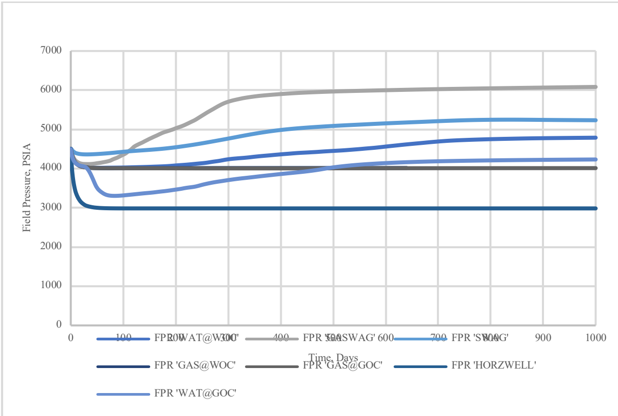

Fig. 15. Variation of field pressure with time for all cases

4.2. Discussion of Results

From figure 12, it can be observed that the total water produced was minimal for gas-based secondary recovery methods: gas injection at GOC and gas injection at WOC, respectively (< 500,000bbl in total). For combination methods, a considerable amount of water was produced when water and gas were injected simultaneously with gravity effects (GASWAG). As a result, the water injected at the GOC broke into the wellbore and was produced maximally at a longer time than in water injection methods. The varying injection rates is partly responsible for the different total water produced in Reservoir M. When gas is injected into the reservoir, gas cap blow down (production of the gas cap in an oil rim reservoir). When water was injected, the cumulative gas produced was relatively small compared to that obtained when gas was injected into the reservoir. The GASWAG technique showed a reduced gas production and can be attributed to the injected water which served as a barrier between the gas zone and the oil zone causing gas cap blow down to be significantly reduced.

The highest oil recovery was obtained from case 6 (GASWAG) as shown in Figure 13. The effects of water fencing at the gas cap contributed to the recovery as it caused oil to be forced into the producing well rather than into the gas cap. GASWAG technique recovered 948707.25 STB of oil, which was 28% more than the oil recovered by the SWAG technique. Cases 1 & 2 as well as the natural depletion strategies resulted in the least amount of oil recovered from Reservoir M while Case 3 had substantial oil recovery but the recovery rate declined due to water breakthrough into the producing well.

The field's overall efficiency depicts the effectiveness of the secondary recovery process and how efficient the recovery of oil is over the stipulated simulation period. Figure 14 shows a comparison of field oil efficiency for all cases. Results show that the FOE for the recovery methods varied from a low value of 1.765 % for natural depletion to a high value of 37.8 % for GASWAG. It can be deduced from the plot that the cases involving singular gas injection led to the early loss of well and productivity. This can be attributed to high gas mobility since gas has a very low viscosity in comparison to that of oil causing gas to move faster than water and thus tends to cone the well rapidly when its saturation is increased.

Pressure maintenance was done to sustain the reservoir's energy which contributes to the sufficient drawdown to ease fluid flow into the wellbore and keep the fluid in a single phase (in the case of a solution gas reservoir). Figure 15 shows how the various cases considered maintained the reservoir pressure. Note that the initial reservoir pressure was 4500psia. From Figure 15, it can be observed that under the natural reservoir energy, the pressure declined rapidly from 4500 psia to below 1500 psia in 100 days. Cases 1 and 2 (Gas injection at WOC and at GOC respectively) showed an initial reservoir pressure increase of about 200 psia in the first 20 days, followed by a rapid pressure decline in just 100 days due to gas cap blow down. Cases 3 to 6 showed adequate pressure maintenance, with pressure rising from 4500 psia to a maximum of 5233.8672 psia. Case 6 had a little dip during the first 100days before stabilizing at a pressure of 5233.8672 psia at the end of the simulation. Results show that case 6 (GASWAG) resulted in the highest value of reservoir pressure at the end of simulation indicating its suitability to be applied in thin oil rim reservoirs.

Considering all the outputs highlighted in this study, it can be inferred that GASWAG (case 6) technique is most suitable for improving field oil production (Figure 13) and recovery efficiency (Figure 14) while maintaining reservoir pressure (Figure 14) throughout the simulation. The SWAG (case 5) and water injection at WOC (case 3) also recorded substantial recovery of oil. It can be deduced from the results of cases simulated that the cases involving singular gas injection (cases 1 &2) lost well productivity much earlier. This was attributed to high gas mobility which caused gas coning due to the rapid increase in reservoir saturation. Relatively, comparing the natural depletion to recovery involving secondary techniques, it was observed that the well production for natural drive was low.

5. Conclusion

The following conclusions were made from this study;

1. The simulation results showed that singular gas injection at gas-oil contact and water-oil contact (cases 1 and 2) were the least favorable for oil production in reservoir M, because these methods led to early gas coning and gas-cap surface production.
2. The GASWAG injection (case 6) yielded the highest oil recovery comparing relatively to the SWAG injection (case 5), and Cases 1-4 injection scenarios. This can be attributed to its water fencing strategy which prevents oil from smearing into the gas zones.
3. As seen from the FOE plot (Figure 15), FOE varied from a low value of 1.765 % for natural depletion to a high value of 37.8 % for GASWAG.
4. SWAG and GASWAG methods showed highest pressure maintenance in comparison with other secondary recovery techniques.

This work was carried out with rock and fluid properties of a known oil rim reservoir but was constrained to a block model study. Further work in this regard will focus on using key economic indicators such net present value, return on investment, and payout time in making decisions on a suitable secondary oil recovery method for thin oil rim reservoirs.

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