Petroleum and Coal

Article **Open Access**

OPTIMIZATION OF RECOVERY FACTOR IN CONCURRENT DEVELOPMENT OF THIN OIL RIM RESERVOIR USING SURFACTANT-WATER-ALTERNATING-GAS INJECTION

S. O. Salufu[1,2], S. O. Isehunwa[1], R. U. Onolemhemhen[3]

[1] *Department of Petroleum Engineering, University of Ibadan, Ibadan, Oyo State, Nigeria*
[2] *Department of Geophysics, Ambrose Alli University, Ekpoma, Edo State, Nigeria*
[3] *Department of Chemical Engineering, University of Lagos, Lagos State, Nigeria*

Received June 17, 2019; Accepted September 19, 2019

Abstract

Eclipse 100 simulator was used to model three cases for concurrent development of a thin oil rim reservoir; the base case (no injection), WAG, and Surfactant-Water-Alternating-Gas (SWAG) injection, to ascertain the performance of SWAG injection in recovery factor optimization with special attention on the effects of injection well position, fluid sequence, and fluid ratio on the SWAG performance. Sensitivity analysis was carried out and Logistic Regression was used to delineate model with the best combination for optimizing recovery factor in concurrent production of thin oil rim reservoirs. The result shows that SWAG injection at OWC, SWAG ratio 1:4:2, and fluid sequence of surfactant/gas/water, gave the best recovery factor of 7.7% compare to the base case and WAG that gave 5.8% and 6.48% respectively. While gas recovery factor was 23.9% compare to base case that was 23%. However, SWAG injection at GOC with SWAG ratio 1:4:2 gave oil recovery factor of 7.25% and gas recovery factor of 25.36% compare to WAG and base cases that were 6.16% and 25.18% respectively. Result of LRA for SWAG was 0.064 while LRA value for WAG injection at same fluid sequence and injection position was 0.054. This result shows that the type of injection fluid, fluid ratio, injection well position, and fluid sequence, have great influence on recovery factor optimization..

***Keywords**: SWAG; Injection well position; Injection fluid sequence; Concurrent development; Thin oil rim reservoir.*

1. Introduction

There are technical challenges synonymous with concurrent development of oil rim reservoirs. Majority of the world's oil rim reservoirs are associated with large gas cap [1]. Early development of such large gas cap can negatively impact oil recovery due to loss of drive energy and re-saturation losses [2-4]. Large gas cap tends to favour high GOR [5]. The occurrence of high GOR in oil rim reservoirs promotes density reduction in the mixture such that crude becomes lighter. The lighter the oil the more sensitive to shrinkage response thus, the volume of oil reduces. As the gas cap overlying the thin oil is produced alongside the oil concurrently, it causes serious pressure disequilibrium to the pressure being exerted on the oil column [6] by the underlying water thus, resulting to upward movement of water in the direction of least resistance. This impacts negatively on the well productivity and enhances the rate of depletion. However, Sedigheh and Mahdi [7] observed in their work that well productivity can be improved by WAG process. WAG process gives incremental oil production [8]. WAG injection leads to improve recovery through contact of the un-swept zones of the reservoir, particularly the attic and cellular oil through the exploitation of gas segregation to the top and accumulation of water at the bottom [9]. Billiter and Dandona [10] introduced a way of developing both gas and oil concurrently in oil rim reservoirs by injecting water at the gas-oil contact while simultaneously produced the gas cap and oil column. Majority of the enhanced oil recovery techniques (EOR) such has WAG, gas injection, and water injection, are associated with complex technical challenges hence, residual oil remains un-producible. It is very important to design another effective technique to ensure that the untapped residual oil in concurrent thin oil rim reservoir development due to these technical challenges in concurrent development of thin oil rim is put on stream at better recovery factor.

Water Alternating Gas (WAG) injection technique has been observed by Mehdi and Babak [9] to have multiple advantages of improving reservoir pressure, de-saturation of residual oil saturation [10], improving mobility by decreasing inter facial tension IFT [11], wettability alteration [12], and increasing both microscopic and macroscopic sweep efficiency [3]. Olabode *et al.* [13] did four types of concurrent oil and gas development of oil rim reservoir scenarios by injecting WAG at up dip and down dip; and by injecting foam at up dip and down dip. They observed from their study that WAG gave good incremental oil recovery at down dip compare to the base case while foam gave a better recovery when injected at down dip. However, they only attributed the cause of the recoveries to only the type of fluid injected without looking at other technical aspect such as fluid ratio, fluid injection sequence, and they did not exploit other possible injection position in the reservoir to compare the best position that will give best recovery factor. The disadvantage of using foam is when the stability of foam is low, it cannot move or flow through a long distance of formation over the period of operation thus, causing foams to be less efficient to recover more oil [14]. Patrizio *et al.* [15] observed in their work that polymeric surfactant improves the performances of EOR in some cases due to its ability to provide simultaneous increase in water viscosity and decrease interfacial tension. However, the pitfall of this method is that it cannot be injected in reservoirs with low permeability.

SWAG is the cyclic injection of surfactant, water, and gas alternatively into the reservoir. Because of surfactant ability to act as active surface agent in reducing interfacial tension between residual oil saturation in the pore spaces of reservoir and other reservoir's fluid; and gas and other fluids in the reservoir. Thus, has better efficiency in better recovery of oil and gas than WAG. Hirasaki *et al.* [16] recovered 95% of water flood remaining oil by injecting low surfactant concentration. Surfactant recovery mechanism is based on the reduction of interfacial tension of two different phases. It does not have problem of travelling through the formation when it is a long distance as in foam [16]. Similarly, surfactant does not have injection problem in reservoirs with low permeability as polymeric surfactant [16]. Residual oil saturation will be de-saturated to half in the pore spaces of a reservoir if the capillary number is increased from a typical number of 10^{-7} for water flooding by 1000 times [17]. Practically, the capillary number cannot be increased by 1000 times [17]. However, addition of surfactant of low concentrate will increase the capillary number by more than 1000 times [17]. Thus reduces IFT and subsequently enhances oil droplet momentum to flow more easily through pore throats as a result of reduced capillary trapping better than WAG and foam. The oil droplets move forward, merged with the oil down the stream to form oil bank [17]. Hence this present work intends injecting SWAG at four different injecting well positions (GOC, OWC, up dip, and down dip position) within the reservoir and compare the result with the result of case when only WAG is injected, and the result when neither SWAG nor WAG is injected (base case). In each case, different fluid ratio and fluid injection sequence scenarios were carried out to identify the best case with the best fluid ratio and best fluid injection sequence that gives the best improved recovery factors for oil and gas in concurrent development of thin oil rim reservoirs.

2. Materials and methods

Static simulation was done using Petrel. Thereafter the static model was exported into Eclipse for dynamic modeling. Three different models were made for concurrent development of oil and gas in a thin oil rim reservoir; the base case without SWAG and WAG injection, case of WAG injection, and case of SWAG injection. In each of the two other models apart from the base case model, four different scenarios (Fig. 1.) of injection well positions; GOC (Fig. 2), OWC (Fig. 3), up dip, and down dip positions; six fluid ratios scenarios (1:1, 4:2, 3:2, 2:3, 2:3, and 4:4), and two fluid injection sequences (gas/water and water/gas) were modeled and sensitivity analysis was carried out and statistical analysis tool, Logistic Regression Analysis (LRA) was used to test the contributing strength of fluid ratio scenario, fluid injection well position scenarios, and injection fluid sequence in each model to the improvement of oil and gas recovery factors using statistical software, NCSS 12. This was done to delineate model with the best combination of fluid ratio, fluid injection sequence, and injection well position that optimizes concurrent production of oil and gas in thin oil rim reservoirs with the best recovery factors.

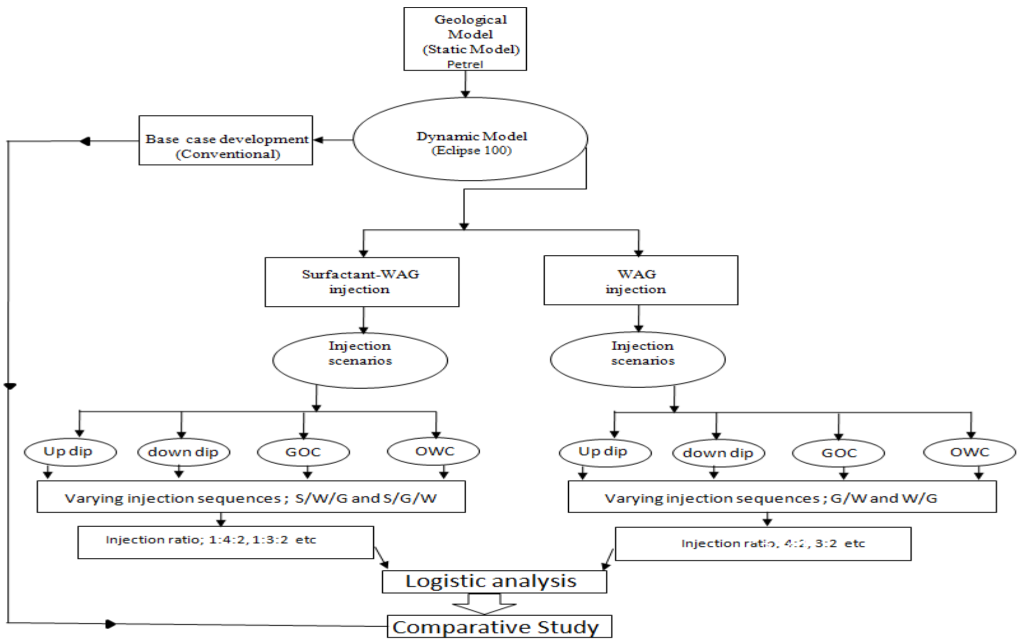

Fig. 1. Methodology workflow for concurrent development

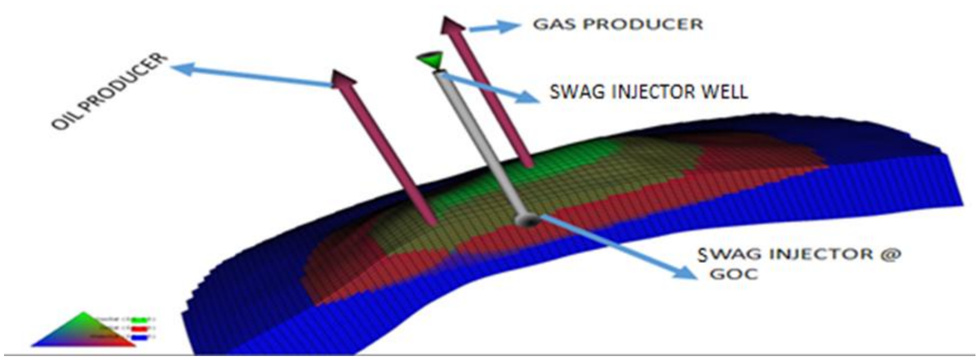

Fig. 2. 3D model view of concurrent development with injection well position at OGC for Obed field, Niger Delta, Nigeria

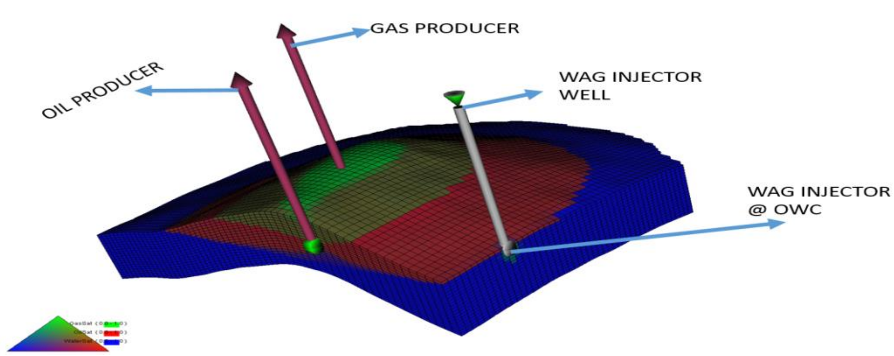

Fig. 3. 3D model view of concurrent development with injection well position at OWC for Obed field, Niger Delta

Field data from Obed field, Niger Delta Basin was used as a case study for the simulations. Base case (without injection) was used to develop oil and gas in thin oil rim reservoir concurrently, different scenarios under SWAG and WAG injection were modeled using miscible gas injection process with gas/water and water/gas injection sequence using non-hydrocarbon gas ($C0_2$) as the injection gas because it has been shown by Scrivastava and Mahli [8] that $C0_2$ gives better result in miscible injection. Under SWAG injection, low surfactant concentration of 0.8% (Table 1.) was used because it has been shown by Hirasaki *et al.* [16] that low surfactant concentration recovers 95% of remaining oil in water flooding. The surfactant was dissolved in water solution and injected at 200 stb/day while water and gas were injected cyclically at 4000 stb/day and 2000 mscf/day respectively after the surfactant injection. Under WAG injection, water and gas were injected at rate of 4000 stb/day and mscf/day respectively similar to SWAG injection. In each scenario, the oil and gas well were produced concurrently for 15 years to identify their production profiles and recoveries at the end of prediction time. Injection of SWAG and WAG started 1year 3 months after production started under natural depletion immediately the GOR became high and there was water cut.

Table 1. Surfactant and reservoir properties for Obed thin oil rim reservoir

S/N	Parameters	Values	Units
1	surfactant concentration	0.8	%
2	Formation water salinity	70000	ppm
3	surfactant injection rate	200	stb/day
4	Volume of surfactant injected	1.0956	MMstb
5	Oil viscosity	0.26307	cp
6	permeability	1056.9	md
7	Reservoir Temperature	171	deg/f
8	oil saturation	0.115	
9	Aquifer strength	Moderate	
10	Depth to oil column	6025	ft
11	API	32	
12	Dip Angle	1.33	Degree
13	Gas Wetness (OGR)	0.699	stb/Mscf
14	Oil Column Height	39	ft
15	Gas Cap Size (M-Factor)	1.43	
16	Oil rate (Qo)	2000	stb/day
17	Krw(Rel. Perm to Water)	0.18	
18	GOR control (*Rsi)	4	
19	BHP (Bottom hole Pressure)	3000	Psia

2.1. Dynamic model development

2.1.1. Case definition

The static models for Obed reservoir were built in Petrel® and exported to Eclipse® for the dynamic simulation. Simulation start date was defined for the cases depending on the well's production start date. Grid dimensions (in x, y and z directions) were specified (Table 2). Cartesian grid and corner point grid geometry options were chosen for more accurate reservoir modeling. Reservoir fluid phases (water, oil, gas, dissolved gas and vaporized oil) were defined. A fully implicit solution method was used for all the runs to guarantee convergence of the solution type.

Table 2. Simulation grid dimensions

Reservoir	Grid dimensions (i/j/k)	Number of cctive cells	Number of inactive cells
Obed	91*74*20	134 680	8 138

2.1.2. Model Initialization

Model was initialized under hydrostatic equilibrations, the contact used were carried forward from the static modeling. Table 3 and Table 4 present the equilibration data specifications and the initialized volume respectively. Carter-Tracy analytical aquifer was attached as bottom drive to sustain the energy of the reservoir. The aquifer parameters are as presented in Table 4.

Table 3. Equilibration data

Reservoir	Pi(psia)	(Datum depth) (ft.)	GOC (ft.)	OWC (ft.)
Obed	3518	6 025	6 025	6 064

Table 4. Aquifer parameters initialized volume

Aquifer perm (md)	88.13
Aquifer angle	180°
Compressibility	3.20^{-06}
Aquifer thickness (ft)	45
STOOIP (MMSTB)	44.29
GIIP (BSCF)	18.1

2.1.3. Development Strategies

Concurrent oil and gas production was carried out on Obed field's reservoir. One oil and gas well each has been drilled in Obed reservoir to produce concurrently. The set economic and operational limits/constraints were

- Oil production off-take rate 2000STB/D
- Minimum oil production rate of 100 STB/D
- Maximum water cut of 95%
- Minimum THP of 150 psia
- Minimum BHP of 1000 psia
- Start of Production, Jan 2017
- End of prediction, Jan 2032
- Prediction duration is 15 years
- Gas production off-take rate 5 MSCF/D
- Minimum gas production rate 1 MSCF/D

3. Results and discussion

The result of the base case when SWAG nor WAG injection was not taken place showed that the oil production total decline rapidly after concurrent production for one year and three months (Fig. 4), the water cut set-in at about one year plus, and the GOR rose up (Fig. 5). As the water cut commenced and the GOR rose up, the reservoir pressure dropped drastically and the oil production rate was severely affected negatively (Fig. 3) subsequently the oil recovery factor, 5.8%, was negatively affected as result of the technical problems that came up due to the concurrent development and the nature of the reservoir in question (thin oil rim reservoir). However, the recovery factor for gas was 23.69%. This was because of gas cap expansion that was being favoured by concurrent development of gas and oil resulting to high gas production while oil production will be very low.

3.1. Effects of injection well position in SWAG and WAG injections during concurrent development of oil rim on oil and gas recovery factors

The result of SWAG and WAG injections (Table 6) for all the injection positions show better improved oil recovery factors than the base case. The result of oil recovery factor for SWAG injection at GOC, OWC, up dip, and down dip positions varies across the various SWAG ratios (Table 5). However, the recovery factor for SWAG injection at OWC showed the highest recoveries (Fig. 5) ranging from 7.20% to 7.7% (Table 5), but when the position of injection of SWAG was positioned at GOC, oil recovery factor dropped slightly to a range of 7.07% to 7.25% (Table 5). When the position of injection well was placed at down dip, the oil recovery factor improved rapidly within the range of 7.09% to 7.45% compare to the GOC positions. For the same injection fluid (SWAG), when it was injected at up dip, the values of oil recoveries factors dropped rapidly to a range of 6.95% to 7.13% (Table 5) across various SWAG ratios.

The changes in the recovery factors observed across different injection positions in the same reservoir with same constant reservoir fluid properties and reservoir conditions shows that the position of injection well placement in a thin oil rim reservoir, that is developed concurrently affects oil recovery factor. The highest oil recovery factor was obtained when the SWAG was positioned at OWC (Fig. 5).

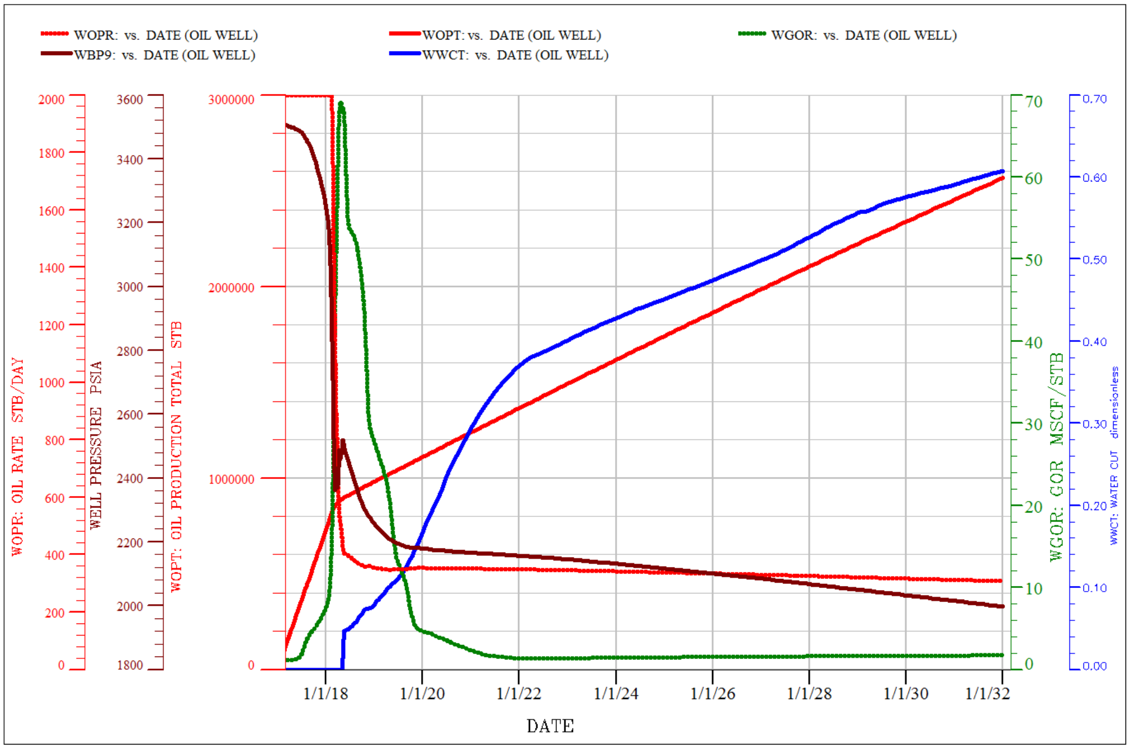

Fig. 4. Result of the base case for Obed field, Niger Delta, Nigeri

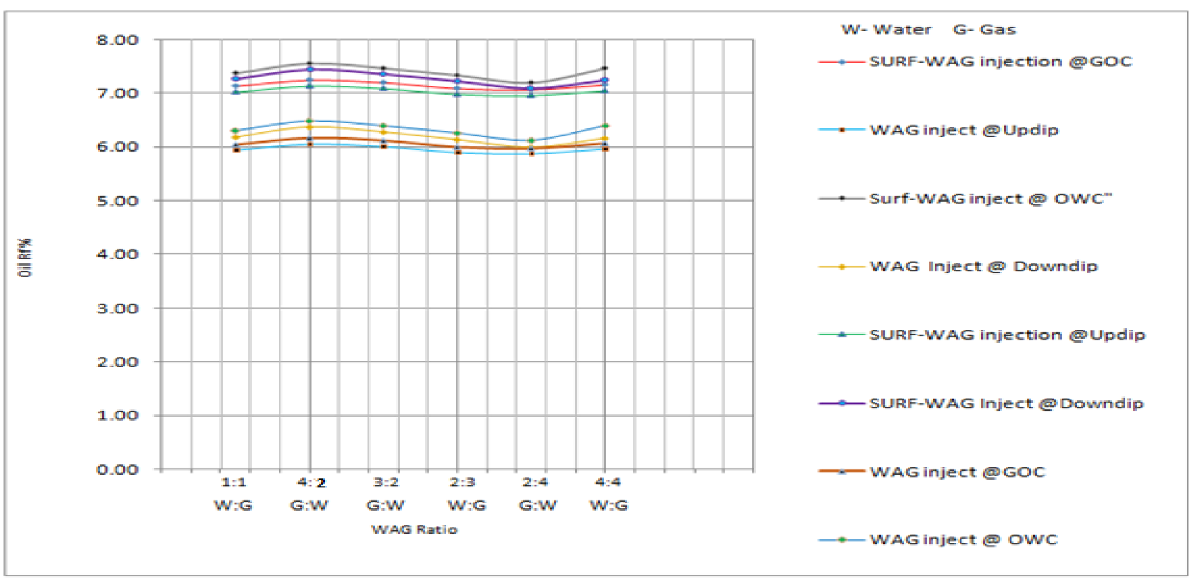

Fig. 5. Plot of oil recovery factor against fluids ratio and fluid injection sequence for various injection positions in concurrent development of Obed oil rim reservoir

Table 5. Summary of surfactant-WAG and WAG injections scenarios result for injection well positioned at OWC, GOC, up dip, and down dip in concurrent development of Obed thin oil rim

SURFACTANT-WAG INJECTION @ GOC					SURFACTANT-WAG INJECTION @ OWC				
CUM OIL (MMSTB)	CUM GAS (BSCF)	WCT (%) @ EOP	RF @ EOP OIL (%)	GAS (%)	CUM OIL (MMSTB)	CUM GAS (BSCF)	WCT (%) @ EOP	RF @ EOP OIL (%)	GAS (%)
3.16	15.45	0.3	7.13	24.41	3.27	14.68	0.27	7.38	23.19
3.21	16.05	0.31	7.25	25.36	3.35	14.74	0.26	7.70	23.29
3.19	15.83	0.31	7.20	25.01	3.31	14.71	0.26	7.47	23.24
3.14	15.15	0.3	7.09	23.93	3.25	14.67	0.28	7.34	23.18
3.13	15.03	0.3	7.07	23.74	3.19	15.15	0.28	7.20	23.93
3.17	15.43	0.32	7.16	24.38	3.31	14.72	0.28	7.47	23.25
WAG INJECTION @ Updip					WAG INJECTION @ Downdip				
CUM OIL (MMSTB)	CUM GAS (BSCF)	WCT (%) @ EOP	RF @ EOP OIL (%)	GAS (%)	CUM OIL (MMSTB)	CUM GAS (BSCF)	WCT (%) @ EOP	RF @ EOP OIL (%)	GAS (%)
2.63	15.3	0.54	5.94	24.17	2.74	14.53	0.47	6.19	22.95
2.68	15.9	0.55	6.05	25.12	2.82	14.59	0.46	6.37	23.05
2.66	15.68	0.55	6.01	24.77	2.78	14.56	0.46	6.28	23.00
2.61	15.01	0.54	5.89	23.71	2.72	14.52	0.48	6.14	22.94
2.6	14.86	0.54	5.87	23.48	2.66	15	0.48	6.01	23.70
2.64	15.28	0.56	5.96	24.14	2.73	14.56	0.48	6.16	23.00
SURFACTANT-WAG INJECTION @ Updip					SURFACTANT-WAG INJECTION @ Down-dip				
CUM OIL (MMSTB)	CUM GAS (BSCF)	WCT (%) @ EOP	RF @ EOP OIL (%)	GAS (%)	CUM OIL (MMSTB)	CUM GAS (BSCF)	WCT (%) @ EOP	RF @ EOP OIL (%)	GAS (%)
3.11	15.41	0.3	7.02	24.34	3.22	14.64	0.47	7.27	23.13
3.16	16.01	0.31	7.13	25.29	3.3	14.7	0.46	7.45	23.22
3.14	15.79	0.31	7.09	24.94	3.26	14.67	0.46	7.36	23.18
3.09	15.12	0.3	6.98	23.89	3.2	14.63	0.48	7.23	23.11
3.08	14.97	0.3	6.95	23.65	3.14	15.11	0.48	7.09	23.87
3.12	15.39	0.32	7.04	24.31	3.21	14.67	0.48	7.25	23.18
			DEVELOPMENT CASES						
WAG INJECTION @ GOC					WAG INJECTION @ OWC				
CUM OIL (MMSTB)	CUM GAS (BSCF)	WCT (%) @ EOP	RF @ EOP OIL (%)	GAS (%)	CUM OIL (MMSTB)	CUM GAS (BSCF)	WCT (%) @ EOP	RF @ EOP OIL (%)	GAS (%)
2.68	15.34	0.54	6.05	24.23	2.79	14.57	0.47	6.30	23.02
2.73	15.94	0.55	6.16	25.18	2.87	14.63	0.46	6.48	23.11
2.71	15.72	0.55	6.12	24.83	2.83	14.6	0.46	6.39	23.06
2.66	15.04	0.54	6.01	23.76	2.77	14.56	0.48	6.25	23.00
2.65	14.92	0.54	5.98	23.57	2.71	15.04	0.48	6.12	23.76
2.69	15.32	0.56	6.07	24.20	2.83	14.61	0.48	6.39	23.08

Table 6. Summary of all the result of Logistic Regression Analysis in determining the contributing strength of different fluid injection sequences, fluid ratio, and injection fluid type, to R_f of oil and gas in concurrent development of Obed thin oil rim reservoir

		Contributing strength of different fluid injection sequences and fluid ratio to Rf in concurrent Dev. of thin oil rim reservoir					
Model	Development cases	W/G 1:1	G/W 4:2	W/G 2:3	G/W 2:4	W/G 4:4	G/W 3:2
1	Oil dev. when WAG is injected @ up dip	-0.042	0.001	-0.061	-0.069	-0.034	-0.015
2	Gas dev. when WAG is injected @ up dip	0.001	0.06	-0.031	-0.046	-0.002	0.038
3	Oil dev. when WAG is injected @ down dip	0.002	0.054	-0.018	-0.068	-0.011	0.027
4	Gas dev. when WAG is injected @ down dip	0.001	0.007	-0.001	0.05	0.003	0.003
5	Oil dev. when SWAG is injec @ up dip	-0.035	0.001	-0.049	-0.058	-0.029	-0.013
6	Gas dev. when SWAG is injec @ up dip	0.002	0.059	-0.063	-0.046	-0.002	0.038
7	Oil dev. when SWAG is injec @ down dip	-0.028	0.027	-0.041	-0.086	-0.034	0.002
8	Gas dev. when SWAG is injec @ down dip	-0.006	0.002	0.001	0.043	-0.003	-0.003
9	Oil dev. when SWAG is injec @ OWC	0.002	0.064	-0.012	-0.056	0.027	0.032
10	Gas dev. when SWAG is injec @ OWC	-0.003	0.003	-0.004	0.046	0.001	0.001
11	Oil dev. when SWAG is injec @ GOC	-0.22	0.016	-0.035	-0.41	-0.013	0.001
12	Gas dev. when SWAG is injec @ GOC	0.031	0.089	0.001	-0.013	0.029	0.068

Similarly, same observation was made in gas recovery factor. There were changes in the gas recoveries factors for SWAG injection with change in injection well position (Fig. 6). Injection of SWAG at GOC position gave the best gas recovery factors within the range of 23.74% to 25.36% (Table 5). When the injection well was positioned at up dip, the values of gas recovery factor dropped slightly (Table 5). When it was placed at down dip position, it dropped further while the least gas recovery factor was observed as the injection well was positioned at OWC (Table 5). Synonymously for WAG injection, same observation of oil recovery factors and gas changed with change in injection well position. The best oil recovery factor was observed when injection well was placed at OWC and the best gas recovery factor was observed when injection well was positioned at GOC. The least oil recovery factor was noticed when WAG was injected at GOC position while the least gas recovery factor was observed when injection well was placed at OWC (Fig. 6).

There was an increased in oil recovery factors and gas recovery factors compare to the base case for both SWAG and WAG injections at GOC, OWC, up dip, and down dip for various fluids ratio. Though, SWAG has the highest positive effect despite same fluid ratio and fluid injection sequences were applied. This shows that SWAG injection is more effective than WAG in developing oil and gas concurrently in thin oil rim reservoirs. Despite the properties of Obed thin oil rim reservoir do not allow it to be developed concurrently under Wynne's screening matrix which states that the oil column must range from 30 to100ft and m-factor (ratio of gas to oil volume) must range from 2 to 6, unlike Obed field that is 1.43. Similarly, the modified oil rim feasibility matrix by Olamigoke and Peacock [18] will fail to capture developing of Obed field concurrently and Olugbenga [1] modified matrix will not encourage concurrent development of Obed field thin oil rim reservoir that has horizontal permeability less than 1500md and falls out of m-factor range 7-10 for reservoir with dip less than 3°. However, this present method of strategies concurrent development of thin oil rim reservoir, injecting SWAG at OWC position enabled the reservoir to be optimally produced concurrently with improved oil recovery factor. While position of injection well at GOC improved the gas recovery factor optimally than any other position (Table 5)

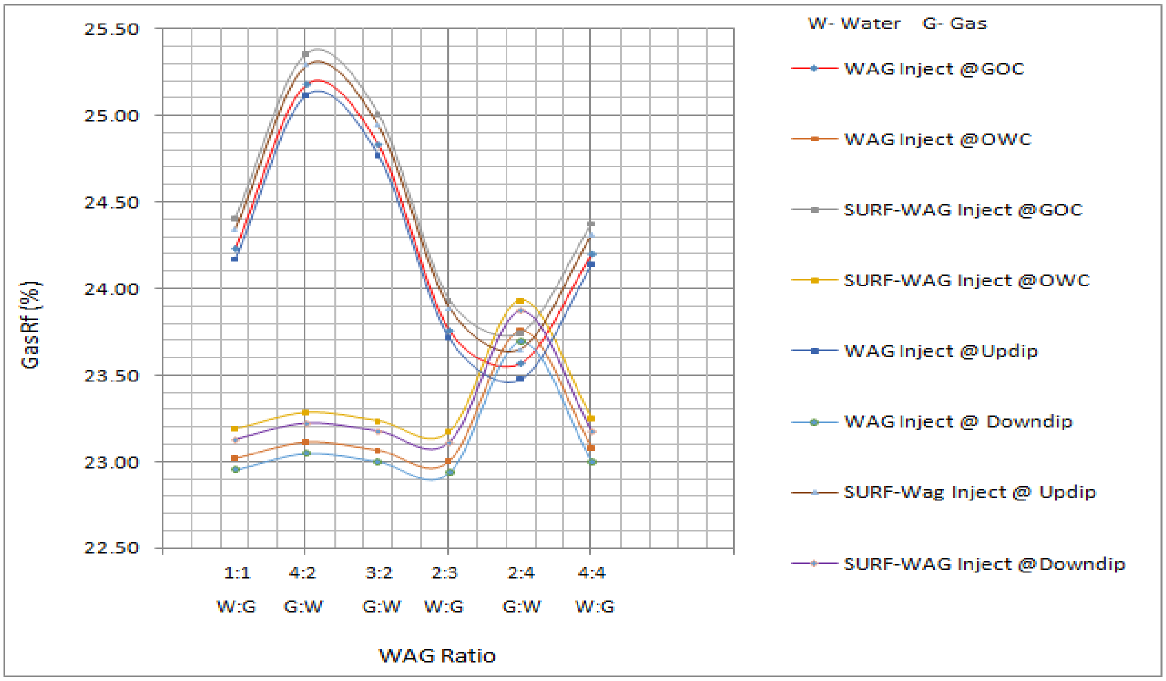

Fig. 6. Plot of gas recovery factor against fluids ratio and fluid injection sequence for various injection positions in concurrent development of Obed oil rim reservoir

3.2. Effects of SWAG ratio and injection fluid sequence on oil and gas recovery Factors in concurrent development of oil rim reservoirs

The effect of fluids ratio and injection fluid sequence under SWAG and WAG injection fluid at different well positions was analyzed using Logistic Regression Analysis (LRA) to determine the contributing strength of these scenarios in optimization of oil and gas recoveries in concurrent oil rim reservoir development. The result of LRA shows that for all the development cases, SWAG ratio 1:4:2 with surfactant being injected first followed by gas and water respectively, has the highest strength of contribution to improving both oil and gas recoveries factors. The LRA values for gas production when the SWAG ratio is 1:4:2, ranges from 0.001 to 0.086 with the highest value of 0.084 when SWAG was injected at GOC (Table 6). This observation shows that position of injection well placement, suitable for highest gas recovery factor optimization in concurrent development of a thin oil rime reservoir is GOC. That is why the LRA value for gas at GOC is 0.084 which is the highest value compare to other positions. The LRA values for oil when the SWAG ratio is 1:4:2 ranges from 0.001 to 0.064 with the highest value, 0.064 when SWAG was injected at OWC (Table 6). The occurrence of 0.064 at OWC has the highest value compare to other positions shows that OWC is the most suitable position for injection well placement during concurrent development of thin oil rim reservoir. SWAG injection with fluid ratio 1:4:2, and injection sequence of gas being injected first followed by water gives the best recovery factor optimization for both oil and gas compare to WAG and the base case. The result of LRA shows that fluids ratio of higher gas ratio than water when gas comes first as the injecting fluid showed the strongest contributing strength (Table 6)

Injection sequence, injection well placement position, and SWAG ratio have been observed in this study to have the highest significance effect in optimizing oil and gas recovery factors. In all the WAG scenarios, the scenario in which gas was injected first with higher ratio than water has been found to be effective for optimal recovery; SWAG ratio 1:4:2 (surfactant/gas/water) gives the highest recovery factor followed by 1:3:2 (surfactant/gas/water) while scenario where water was injected first and followed by gas with higher ratio, and SWAG scenario where gas was injected first with lower ratio to water have been observed to have the lowest oil and gas recovery factors (Fig. 7 and Fig. 8).

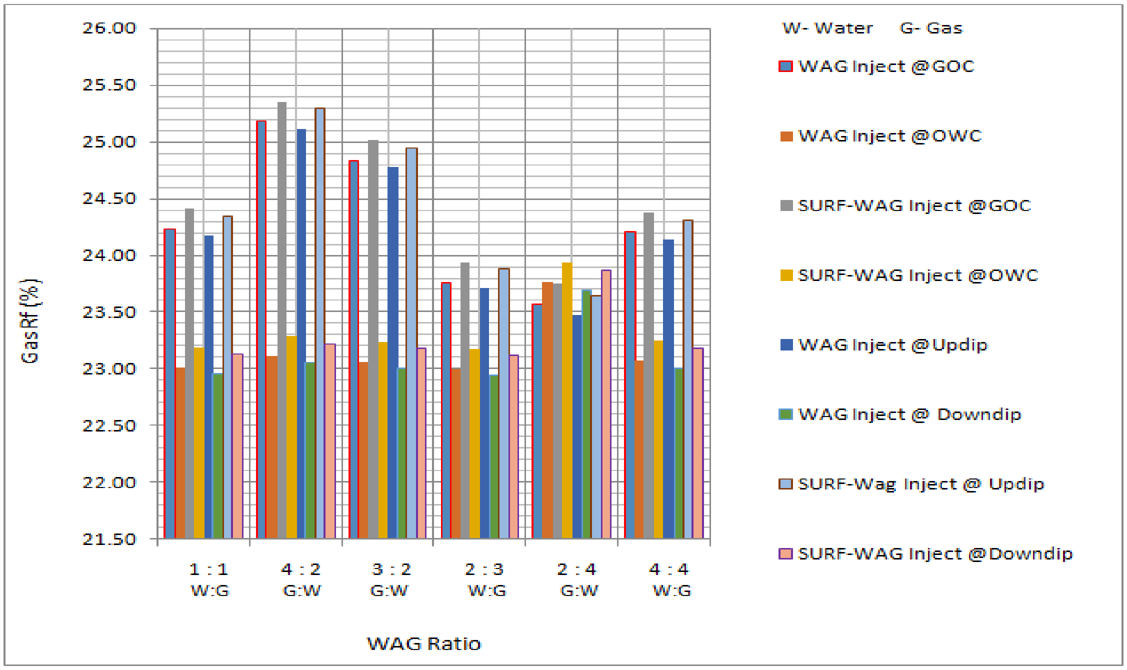

Fig. 7. Plot of gas recovery factor against fluid ratio and fluid injection sequence for Obed oil rim reservoir

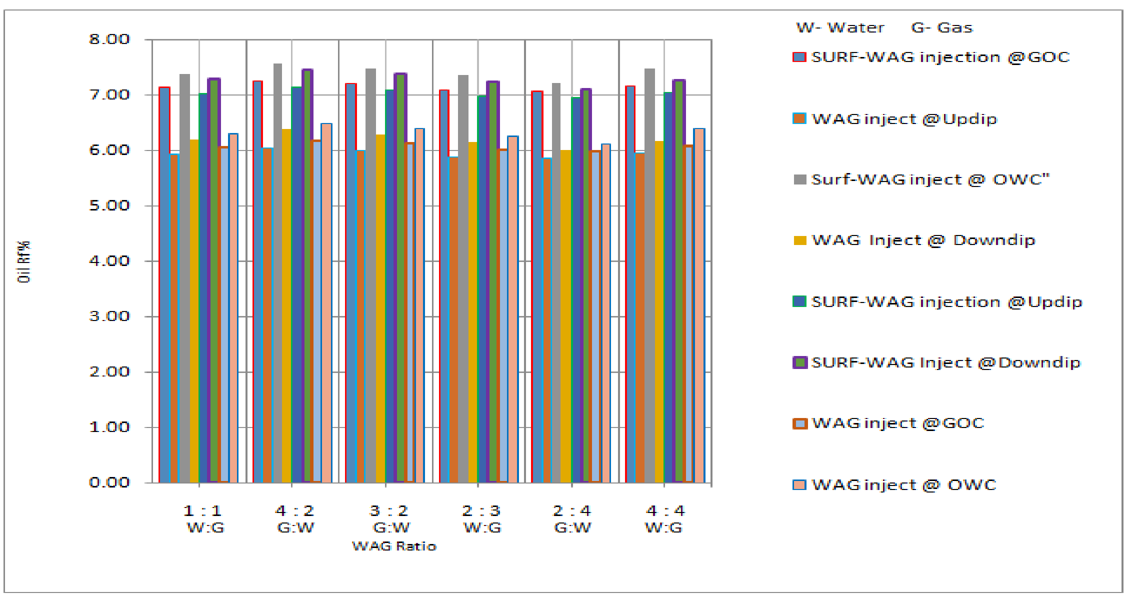

Fig 8. Plot of oil recovery factor against WAG ratio and fluid injection sequence for Obed oil rim reservoir

This phenomenon observed is as a result of the ability of gas to undergo compositional exchange that causes oil swelling and reduction in oil viscosity which leads to sweep efficiency of reservoir; and reduction in residual oil saturation thus causes microscopic sweep efficiency. If large volume of gas is injected first it sweeps the oil together and when water is injected after gas injection, water stabilizes the oil front because of its ability to stabilize the front and its ability to control the mobility of the oil already swept from the microscopic pores spaces in the reservoir towards the producing well. Hence, the recovery factor in this kind of SWAG scenario (high gas: low water) is found to have the best improved recovery factor and additional increase. However, the observation of lowest recovery factor in scenario of water being injected first followed by gas or low gas ratio followed by high water ratio is as a result of phenomenon of water-blocking that is common to water, thus isolating the residual oil from coming in contact with gas that would have reduced the residual oil saturation because of higher volume than gas. Better improved recovery factor for oil and gas observed when surfactant-WAG injection fluid was used than WAG injection fluid shows that the ability of Surfactant-WAG injection to lower the IFT is more than that of WAG, that is why more oil and gas were recovered more than when WAG was used and their recovery factors were more than that of WAG injection (Fig. 7 and Fig. 8)

4. Conclusion and recommendations

A study on the effect of injection well position, fluid ratio, and fluid injection sequence under two different injection fluids; SWAG and WAG injections, in concurrent development of thin oil rim reservoir has been carried out. The study shows that the position at which an injection well is placed in a reservoir, the fluid ratio, injection fluid sequence, and the kind of injection fluid being injected have significant effects on the optimization of gas and oil recovery factors in concurrent development of thin oil rim reservoirs. The best performance for oil recovery in scenarios studied, occurred when surfactant is injected in addition to gas and water injections alternatively at OWC for oil and at GOC for gas. However, injection well position at OWC give the best effect on reducing or mitigating against some of the technical challenges (high GOR and early water cut) that are associated with concurrent development of oil rim reservoirs. These performances in each scenario were only possible when the fluid injection sequence is surfactant follow by gas and water respectively.

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To whom correspondence should be addressed: Dr. S. O. Salufu, Department of Petroleum Engineering, University of Ibadan, Ibadan, Oyo State, Nigeria