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Critical Review and Improved Simulation Studies on Comparative Evaluation of Waterflooding and Gas Injection in Niger Delta Thin-Bed Reservoir

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INFORMATION

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ABSTRACT

This study improved the conclusions provided by Obibuike et al. (2022) by critically examining the Pressure-Volume-Temperature (PVT) properties, well placement, establishing hydrocarbon pore volume injected (HDPVI) as the basis of comparison (instead of time), and conducting the flood simulations at more reasonable pressures. Furthermore, a sensitivity study of dip was performed on the given reservoir which concluded that EOR benefits from gas versus water injection are highly sensitive to this variable, such that a generalized conclusion of water versus gas cannot be made. It also identifies additional variables that may also affect the relative results for areas of further study.

1. Introduction

The primary method for recovering crude oil from the subsurface reservoir relies on the natural energy and high pressure within the reservoir to push the oil to the surface. However, this energy is not sustainable and over time, this continuous recovery process causes a decline in pressure and energy within the oil-bearing formation (Adeniyi et al., 2008).

Once the primary energy of a reservoir reaches a point where it cannot sustain the production of reservoir fluids any longer, secondary recovery processes are employed. When reservoir pressure depletion begins and primary recovery production significantly declines, secondary oil recovery methods are employed to improve oil production. The two fundamental methods used for secondary oil recovery are gas injection and water injection. Gas is injected into the primary or secondary gas caps, while water is injected into the production zone or water bearing zone (Radwan et al., 2021). EOR operations aim to maximize crude oil recovery and a variety of approaches may be used depending on the reservoir's characteristics and stage of production at the time (Nmegbu et al., 2017; Udy et al., 2017).

Gas injection is a widely employed technique in declining oil fields to enhance recovery, offering the potential to recover a substantial portion, if not all, of the oil originally present in the reservoir. The injection of gases such as CO_2, hydrocarbon gases, or steam has been shown to achieve near 100% efficiency in displacing oil from regions that have been effectively swept by the injected gas. This method holds significant promise for maximizing oil recovery and holds importance in the context of reservoir management strategies (Jamshidnezhad, 2009; Lake, 1989).

However, the effectiveness of sweep efficiency is frequently hindered by challenges arising from reservoir heterogeneity, the high mobility of gas, and the density disparities among gas, oil, and water phases. These factors contribute to suboptimal sweep efficiency during gas injection processes (Faisal et al., 2009).

In the same vein, the low density of gas in reservoirs with relatively homogeneous characteristics can cause gravity override, resulting in a significant limitation to gas sweep efficiency and subsequent oil recovery (Jamshidnezhad, 2009).

Water injection is the most widely use EOR method due to its ease of injection, low cost of implementation, and high displacement efficiency in comparison to other methods (Johns et al., 2000). It has been recognized as an effective technique in the realm of secondary oil recovery, primarily due to its ability to enhance the field recovery factor by facilitating improved macroscopic displacement and pressure maintenance (Aghaeifar et al., 2018).

The goal of this paper is to attempt to reproduce the results achieved in Obibuike et al. (2022), describe the problems that were found, and derive new results after fixing these problems. The primary activities that made up this study were:

- verify the assumptions made in Obibuike et al. (2022),
- build a PVT table as is needed for simulation,
- compare the results reported in Obibuike et al. (2022) to the ones obtained in this study,
- research and suggest ways the results could be improved.

The model from Obibuike et al. (2022) was reproduced and it was observed that the model was in fact a 2-D model, as fluid could only flow in two directions (x and z directions) and the given PVT data didn't produce the expected OOIP from the paper. In addition, time was used as an independent parameter when the field oil recovery (FOR) obtained during waterflooding was compared to FOR from gas injection, which ended up being misleading because the floods were conducted at different speeds. Furthermore, differences in well placement and reservoir pressures between the waterflooding and gas injection cases did not seem to make the comparisons fair.

Before the simulation work started, problems were identified in Obibuike et al. (2022) including:

- The model is a 2-D model and not 3-D, as stated by the authors, as the fluids can only flow in two directions (x and z).
- The injections rates, for both gas and waterflooding, presented in the abstract by the authors were different from the ones used in the method section of the paper.
- The explanations given on some graphical results didn't match the graph itself.
- Time was used as an independent parameter when comparing the field oil recovery (FOR) for both waterflooding and gas injections, which ended up being misleading because the flood rates were not the same.
- The PVT data presented in the paper didn't match the formation volume factor at bubble point pressure, based on standard oil PVT correlations.
- The well configuration in the gas injection case led to significant oil volumes being left behind simply due to poor well placement.The average reservoir pressure during gas injection in Obibuike et al. (2022) was significantly lower than the initial reservoir pressure and the waterflood case.

2. Methods

2.1. PVT Table

The PVT data used in the paper for the simulation study are shown in Table 1. It can be noted that oil and gas properties like formation volume factors and viscosity were not provided as a function of pressure.

Table 1. PVT parameters (Obibuike et al., 2022)

Parameters	Values
Initial reservoir pressure	4500 psia
Bubble point pressure	3471 psia
Formation volume factor	1.25 rb/stb
Reservoir temperature	178°F
Formation compressibility	4.07E-6 psi^{-1}
Water compressibility	3.07E-6 psi^{-1}
API gravity	39 API
Oil density	51.8 lb/ft^3
Gas density	0.06054 lb/ft^3
Water density	62.4 lb/ft^3
Viscosity	4 cp

Table 2. Fluid property constants

Property	Value
Oil Density at STP	51.8 lb/ft^3
Water Density at STP	62.4 lb/ft^3
Gas Density at STP	76.3 lb/ft^3
C_o	17.38 ft^3/MM ft^3/psi
C_w	3.02 ft^3/MM ft^3/psi
μ_w at reservoir temperature	0.38
DVO/DP	$4.86x10^{-5}$

In order to conduct a new simulation, the simulation software used in this study, ACRO's Comprehensive Reservoir Simulator, requires black-oil properties in the form of a table, along with other constants discussed below. These variables include; slope of change in oil viscosity against change in pressure when the oil is undersaturated (DVO/DP), oil compressibility at bubble point pressure (C_O), oil formation volume factor (B_O), gas formation volume factor (B_g), solution gas-oil ratio (R_S), oil viscosity, gas viscosity, etc.

Table 2 shows gas, oil and water properties derived from Obibuike et al. (2022), entered as constants, that were used in this study. PVT properties as a function of pressure were then created using standard PVT correlations and are shown in Table 3. This PVT table is a representation of the black-oil fluid properties, up to and through the bubble point, with an infinite supply of free gas. This is done so that the simulation software will know how to handle excess gas if needed and the row of 3471 psi pressure signifies the actual reservoir bubble point.

Table 3: Oil PVT properties as a function of pressure

Pressure (psi)	B_o (rb/stb)	B_g (rb/mcf)	R_s (mcf/stb)	μ_o (cp)	μ_g (cp)
14.7	1.068	217.700	0.0014	1.572	0.01240
200	1.082	15.588	0.0314	1.338	0.01255
400	1.101	7.574	0.0715	1.134	0.01280
750	1.139	3.843	0.1508	0.896	0.01344
1200	1.192	2.263	0.2635	0.714	0.01461
2000	1.297	1.269	0.4831	0.535	0.01774
3000	1.439	0.858	0.7817	0.418	0.02275
3471	1.509	0.767	0.9295	0.381	0.02513
4000	1.59	0.697	1.0999	0.348	0.02767
5000	1.748	0.616	1.4335	0.302	0.03202
6000	1.913	0.567	1.7799	0.268	0.03581
7000	2.083	0.534	2.1372	0.242	0.03916
8000	2.257	0.510	2.5043	0.222	0.04218

Upon deriving the figures in Table 3, it was discovered that Bo did not match what was reported in Obibuike et al. (2022). Accordingly, the Bo as reported in Obibuike et al. (2022) was discarded and the Bo trend as shown in Table 3 was used instead. The reservoir data used in Obibuike et al. (2022) are shown in Table 4.

Table 4. Reservoir data (Obibuike et al., 2022)

Parameter	Values
Porosity	0.20
Permeability	1350 mD
Wellbore ID	5.921 in
Interstitial water saturation	0.2
Reservoir pay thickness	60 ft
Reservoir depth	8000 ft
Reservoir acreage	500 acres

2.2. Volumetric Parameters

Despite what was reported in Table 5, some parameters that were presented in Obibuike et al. (2022) conflicted with this table, for instance, 700 acres was presented as total reservoir acreage instead of 500 acres in Table 5. And also, some parameters were absent and had to be inferred from images (like the depth of the oil/water contact).

Table 5. Oil Recovery and Recovery Factors (Obibuike et al., 2022)

	Waterflooding	Gas Injection
Recovery (STB)	7782820	3276980
RF	38%	16%

Accordingly, this study back solves to a STOOIP number, based on reported oil recovered and recovery factors from the respective water and gas cases (which were consistent). This step would make it possible to evaluate flood performance as a function of hydrocarbon pore volumes in a comparable way.

$$STOOIP = \frac{Recovery(STB)}{RFx10^6}(MMSTB) \quad (1)$$

Using the *Equation 1*, the STOOIP value for both waterflooding and gas injection is 20.48 MMSTB. The model parameters used to determine STOOIP in Obibuike et al. (2022) and the model parameters use in this study to match the STOOIP value of 20.48MMSTB are presented in Table 6, with the differences highlighted in red. The oil formation volume factor, Bo, from Obibuike et al. (2022) was modified in this study for two reasons, which will be discussed in more details later. These reasons were that the Bo from Obibuike et al. (2022) didn't match correlations and, dynamic simulation results showed reservoir pressure changes that would be impossible with the fluid description from Obibuike et al. (2022). Accordingly, it was believed Bo as determined from PVT correlations was probably more accurate.

Table 6. Volumetric Reservoir Data Comparison

Parameters	(Obibuike et al., 2022)	This Study
Reservoir area (acres)	500	692
Thickness (ft)	60	60
Effective porosity	0.2	0.2
Connate water saturation	0.2	0.2
Initial oil formation volume factor (rb/stb)	1.25	1.51
No. of grids (x, y, and z)	50, 1 and 15	50, 1, and 15
Cell sizes in ft (x, y, and z)	242 x 1800 x 300	279 x 2163 x 4
Top of Reservoir (ft)	8000	8000
Oil-Water Contact (ft)	Not reported	8036
Calculated STOOIP (MMBO)	Not reported	20.48

2.3. Dynamic Parameters

2.3.1. Relative Permeability

Relative permeability curves are important to any simulation study as they help in calculating fractional flow and quantify the irreducible saturations (end points). Relative permeability was not specified in Obibuike et al. (2022). In this study therefore, residual endpoints were estimated and the curves were simple straight lines. Table 7 shows the relative permeability of oil in presence of water while Table 8 shows the liquid saturation alongside the relative permeability of oil in presence of gas.

Table 7. Relative permeability of oil in the presence of water

Sw	Krw	Krow
0.2	0	1
0.8	1	0
1.0	1	0

Table 8. Liquid saturation and the relative permeability of oil in the presence of gas

SL	Krog	Krg
0.3	0	1
0.92	1	0
1.0	1	0

2.3.2. Reservoir Pressure

The reservoir pressures from Obibuike et al. (2022) during gas injection were significantly lower than the initial reservoir pressure and the bubble point pressure, unlike the water case (Fig. 1). Moreover, it was not even possible to drop the pressure to what was shown in Fig. 1 unless the bubble point pressure was changed to a very low number (750 psi), further suggesting the PVT description in Obibuike et al. (2022) was wrong. A better methodology would thus be to do water and gas injection at comparable pressures above the bubble point pressure.

3. Results and Discussion

The results are separated into 3 different cases for simplicity.

- When the model from Obibuike et al. (2022) was reproduced with the same reservoir pressure parameters, production/injection rates and well placement,
- When the problems found from Obibuike et al. (2022) were corrected in terms of pressures and well placement,
- Case 2 was modified by examining dip as a sensitivity variable (Li et al., 2023).

3.1. Case 1

Fig. 2 shows the gridblock for waterflooding at initialization. Likewise, Fig. 3 shows the gridblock for gas injection at initialization stage (left image) and the flood shape after 10,000 days (right image). It can be seen that the injection well placement in Fig. 3 didn't allow for proper sweeping of the oil and this resulted to large amount of oil being left behind at the end of the simulation. Note how at the end of the simulation, the reservoir appears to have undergone significant solution gas depletion. This occurs because the gas injection was too low to replace reservoir withdrawal and pressures dropped to values significantly below the bubble point.

Pressure matches for the case 1 runs are shown in Fig. 4. Note how once the bubble point is reached for the gas injection case, solution gas appears to reduce the speed of the pressure depletion. This suggests the oil description for the gas injection case in Obibuike et al. (2022) had a very low bubble point. Interestingly, a much better pressure match is achieved when the bubble point pressure is set to 750 psi. So this finding also indicates likely problems with the PVT description in Obibuike et al. (2022). In order to understand why the average reservoir pressure was so low, the total HDPVI during water and gas injection were determined as shown in Fig. 5. From this figure it was apparent that the gas injection case injected significantly less reservoir volume than the water injection case (water injection appears to be 18 times faster than the gas injection scenario). This finding makes sense when Bg is considered as follows.

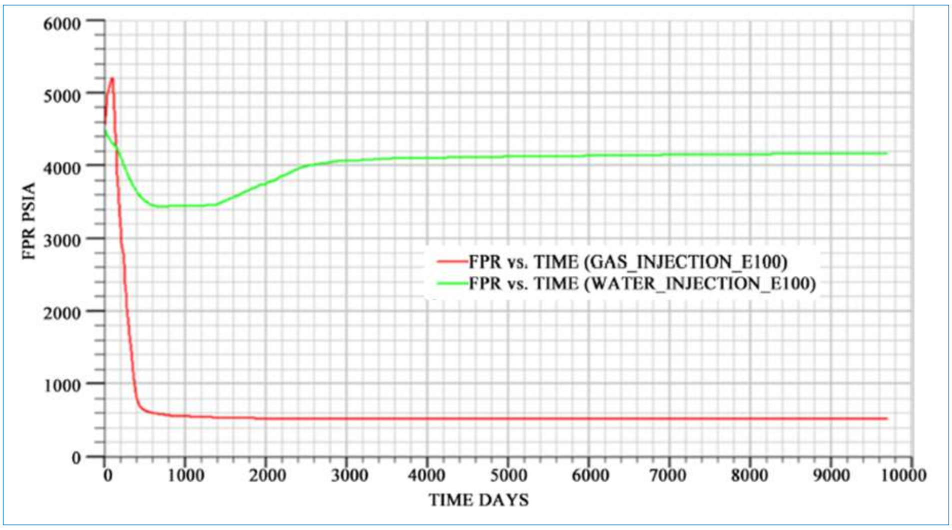

Fig. 1. Average Reservoir Pressure for Waterflooding and Gas Injection (Obibuike et al., 2022)

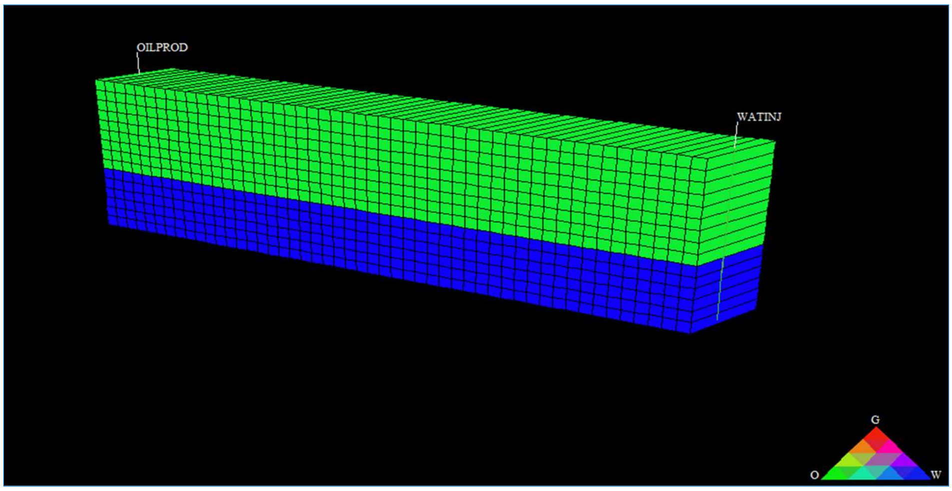

Fig. 2. Gridblock for waterflooding at initialization using the model parameters from Obibuike et al. (2022)

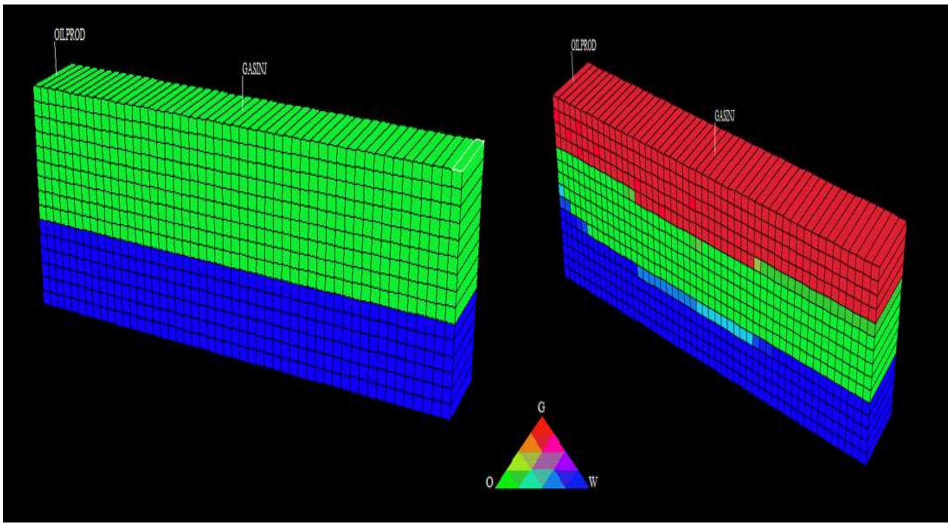

Fig. 1. Gridblock for gas injection from Obibuike et al. (2022) at initialization and after 10000 days

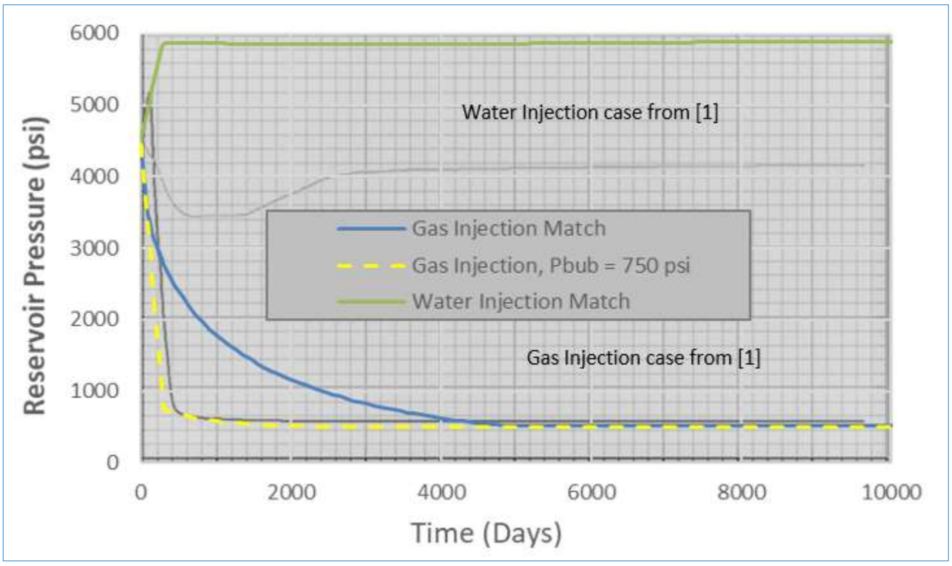

Fig. 4. Average reservoir pressure match graph showing pressure from Obibuike et al. (2022) in grayscale along with pressures found in this study

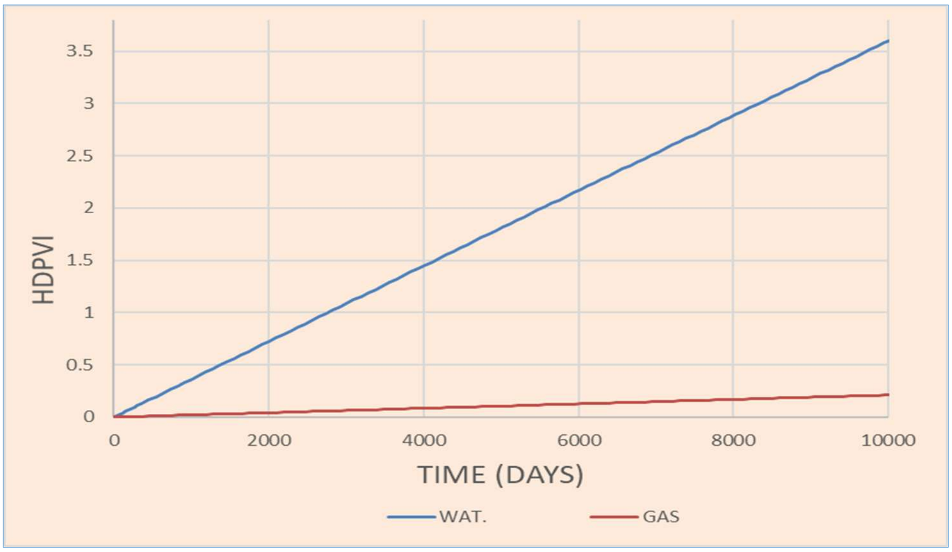

Fig. 5. Total HDPVI during water and gas injection against time

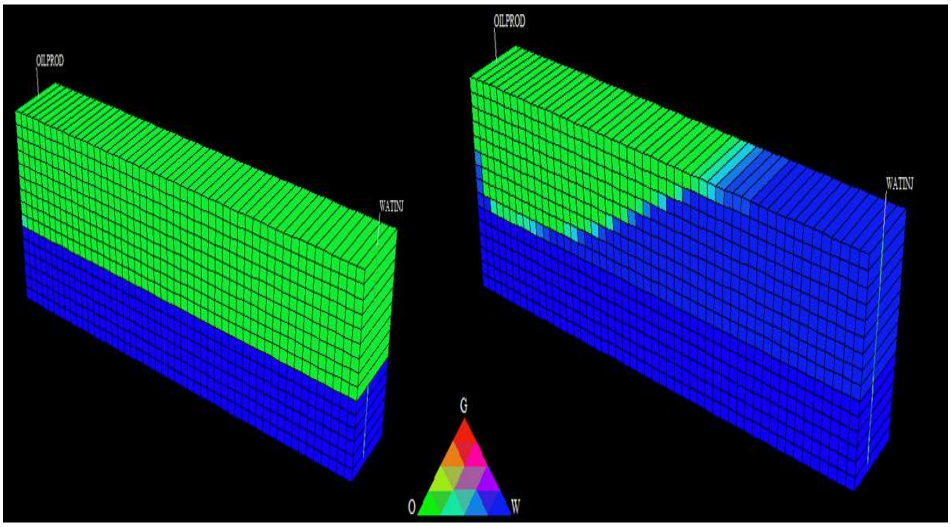

Fig. 2. The initialization stage and flood front in the modified water injection case

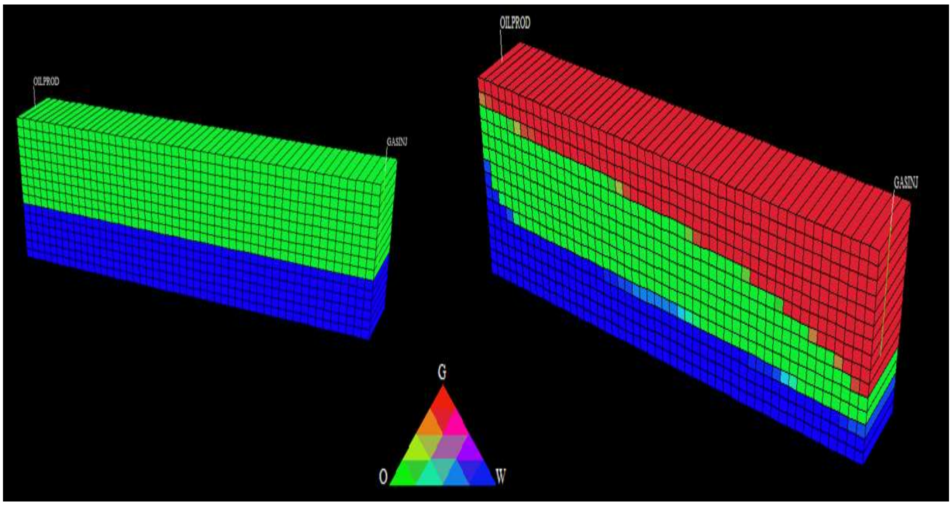

Fig. 7. The initialization stage and flood front in the modified gas injection case

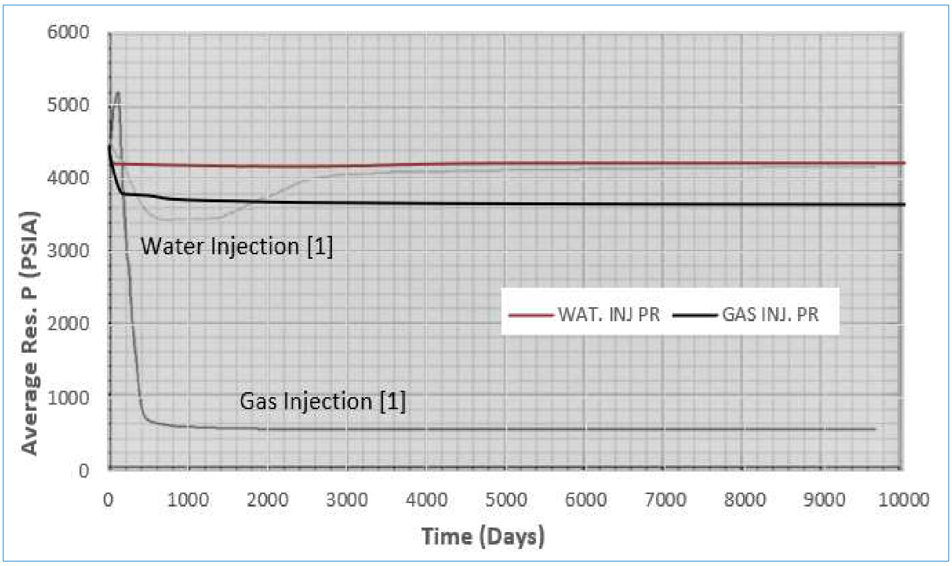

Fig. 8. Average reservoir pressures for water injection and gas injection with well controls that keep the reservoir pressure fairly constant (colored) versus reservoir pressures from Obibuike et al. (2022) in grayscale

Table 9. Recovery factors from Obibuike et al. (2022) versus recovery factors from this study

	Cum. RF from Obibuike et al. (2022)	Cum. RF from this study at 1.5 HDPVI
Water Injection	38%	73%
Gas Injection	16%	38%

At initial conditions, Bg at 4500 psi is about 0.65 RB/MSF and well controls at the gas injector specify to inject at a maximum of 6000 psi BHP or maximum of 1000 MCF/D. This means the gas injector is restricted to injecting at $1000 \, x \, 0.65 = 650$ reservoir bbl/day, which is significantly below the production rate and thus it is not possible to maintain reservoir pressure. In summary, the flood speed for the gas injection case was not comparable to the water injection case and evaluating them both at a fixed time was misleading.

3.2. Case 2

Case 1 was modified by using the reservoir pressure controls in Table 9 and the gas injection well was placed at a location away from the producer, with the intent of improving oil production. Fig. 6 shows the initialization stage and the progressive flood front of the modified water injection model. Fig. 7 shows the same thing for the gas injection case. Note that even though the injected gas still suffered sweep inefficiency, recovery was improved because of the well placement and higher reservoir pressures.

The average reservoir pressures for both water and gas injection from this case were compared to those obtained from Obibuike et al. (2022). It can be seen in Fig. 8 that the drawdown for both water (orange trendline) and gas (black trendline) injections were maintained above the bubble point and was kept fairly constant while the drawdown from Obibuike et al. (2022) during water injection (faded pink trendline) was also above the bubble point but that of the gas injection (faded green trendline) was well below the bubble point as was demonstrated in case 1. And also, because the flood rates between the water and gas injection cases may still be slightly different, case 2 field oil recoveries are compared using Hydrocarbon Pore Volumes of Injection (HDPVI), as opposed to time, which eliminates one of the problems found in Obibuike et al. (2022). Table 9 shows the recovery factors from Obibuike et al. (2022) in comparison with the recovery factors from this study, where reservoir pressures were maintained, well locations improved, and the comparison was done at 1.5 HDPVI.

3.2. Case 3

In case 3, reservoir dip was examined by creating 3 sensitivities: 1, 3, and 5 degrees of dip as measured in the Y direction. The models with dip were created so the average reservoir depth was the same as before and the oil-water contact was adjusted so the STOOIP was also the same. Finally, production well locations were moved away from the water contact in order to maximize oil recovery. Fig. 9 shows the 1-degree dip case for water injection at initialization and after 1.5 HDPVIs injection.

Fig. 10 shows the same thing for the gas injection case, where the injector was placed at the crest and the producer was placed near the oil-water contact. Note also that, even though initial average reservoir pressures were kept constant, injection BHPs for the water cases had to be increased from the original 4400 psi to 5100 psi to compensate for injecting deeper, where higher pressures existed due to the increased fluid gradient.

Fig. 11 shows the average reservoir pressures at 1° angle in comparison with the average reservoir pressures from Obibuike et al. (2022). It can be seen that the average reservoir pressures during water (WATINJ trendline) and gas (GASINJ trendline) injection were kept fairly constant above the bubble point.

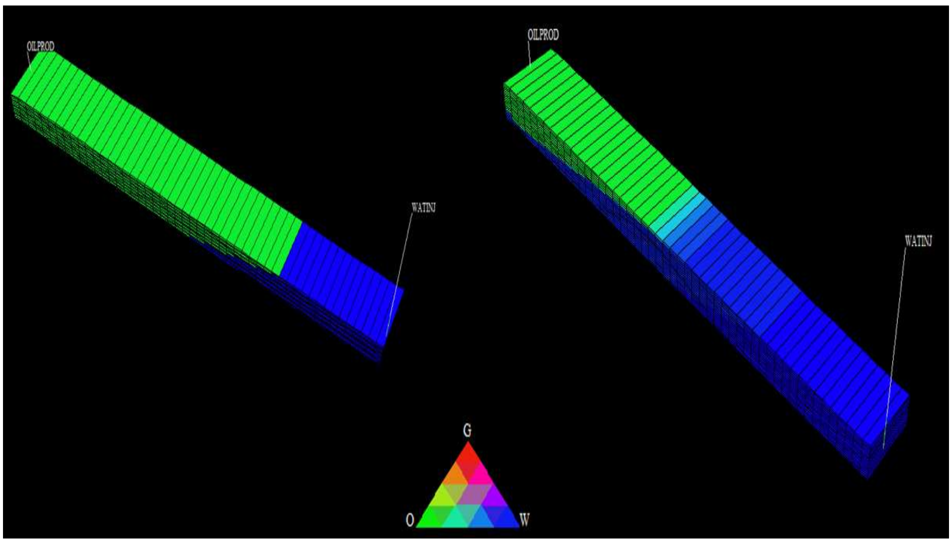

Fig. 9. Initialization stage and flood front after 1.5 HDPVIS at 1° dip angle during water injection

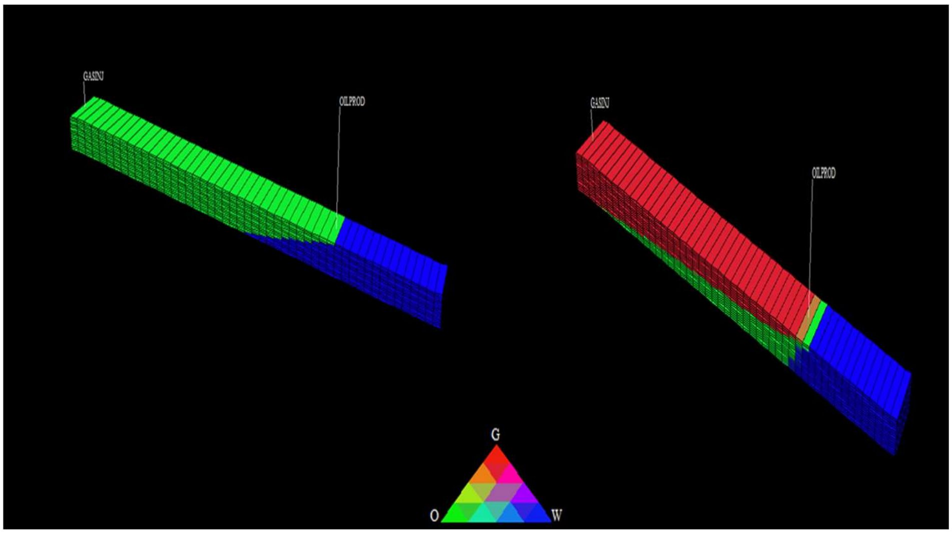

Fig. 10. Initialization stage and flood front after 1.5 HDPVIS At 1° dip angle during gas injection

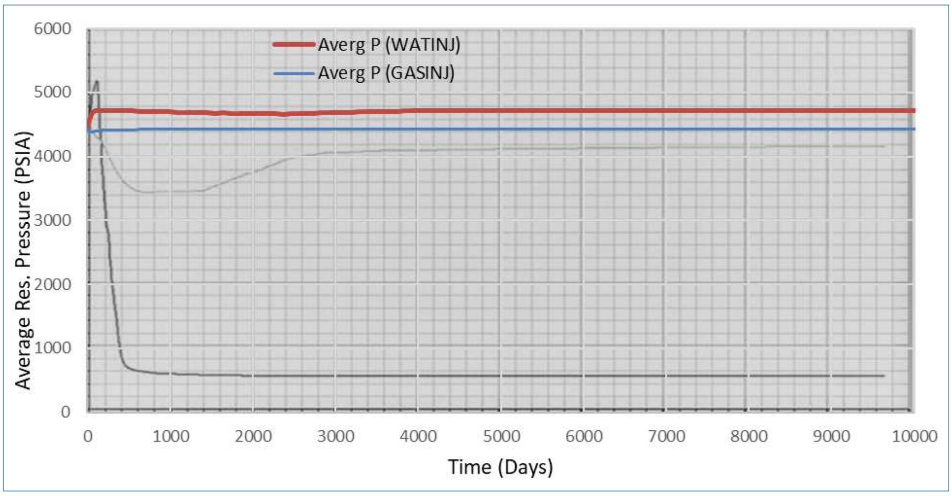

Fig. 11. Average reservoir pressures for water injection and gas injection at 1° (colored) versus reservoir pressures from Obibuike et al. (2022) in grayscale

Table 7 shows the results for the field oil recovery factors for 1-, 3- and 5-degree dip angles at 1.5 HDPVIs. It can be observed that as the angles of dip increase, the field oil recovery during gas injection increases and eventually surpasses the water injection recovery, which essentially remains constant, regardless of dip as first observed by Xiao et al. (2022). Furthermore, the recovery factors for both water and gas injections from this case are greater than those from the previous cases and significantly greater than those reported in Obibuike et al. (2022).

Table 11. Field oil recovery factors for 1o, 3o and 5o dips at 1.5 HDPVIs

Dip angle	Water injection RF (%)	Gas injection RF (%)
1°	75	51
3°	75	78
5°	75	86

4. Conclusion

In this study, PVT properties as a function of pressure were created using standard PVT correlations. Volumetrics were determined from oil recovered and recovery factors from Obibuike et al. (2022), and the simulation model geometry was adjusted to match the resulting STOOIP. Relative permeability in this study was estimated, while capillary pressure was ignored. And reservoir pressures were more carefully monitored to produce results that were comparable and made sense. Three scenarios were conducted using ACRO's Comprehensive Reservoir Simulator (ACRES) software with a black-oil fluid description.

1. The simulation work done in Obibuike et al. (2022) was exactly reproduced. HDPVIs for both water and gas injections were examined and revealed the gas injection case from Obibuike et al. (2022) injected significantly less reservoir volume than the water injection case, to the point that the gas injection case was doing little to nothing to improve recovery. Furthermore, it was also found that the gas injection pressure trend could not be matched unless a different bubble point was used, suggesting the PVT description in Obibuike et al. (2022) was problematic.

2. New pressure controls and well placement from this study

were used to reproduce the simulation work done in Obibuike et al. (2022) with a goal to improve recovery. In both water and gas injections, average reservoir pressure was maintained above the bubble point. As flood rates during water and gas injection were not the same, cumulative recovery were compared at 1.5 HDPVIs and waterflooding had 73% recovery factor while gas injection produced 38% recovery factor.

3. The effect of dip on the reservoir was examined here using sensitivities of 1, 3 and 5 degrees, while the average reservoir pressure was maintained above the bubble point, like before. From this it was found that field oil recovery during gas injection increased, eventually surpassing the water injection recovery, which remained fairly constant regardless of dip angle. Also, the recovery factors for both water and gas injections from this scenario were greater than those from the previous scenarios and by a large extent, greater than those reported in Obibuike et al. (2022).

In summary, this study shows that simulation model recovery can be significantly improved with proper pressure management and well placement. Moreover, gas injection can be an effective strategy when gravity can be used to minimize problems with viscosity and fluid density differences that occur in a flat, thin reservoir, making it difficult to form a general conclusion of gas versus water injection.

5. Recommendations for Future Work

The work done in this study only begins to examine the factors that affect real world reservoirs. Factors that could further affect recovery include.

1. Adding a 3rd dimension,
2. Adding heterogeneity (porosity, permeability, and rock types),
3. Using a real structural top,
4. Incorporating real data for vertical permeability and/or any flow barriers that might exist,
5. Using more realistic relative permeability and capillary pressure relationships and
6. Incorporating compositional effects that are missing in a black-oil description.

List of Abbreviations

EOR: Enhanced oil recovery
FOR: Field oil recovery efficiency
HDPVI: Hydrocarbon pore volume injected
ID: Internal diameter
Krg: Relative permeability of gas in the presence of oil
Krog: Relative permeability of oil in the presence of gas
Krow: Relative permeability of oil in the presence of water
Krw: Relative permeability of water in the presence of oil
mD: Milli-darcy
OOIP: Original oil in place
PVT: Pressure-volume-temperature
RF: Recovery factor
SL: Liquid saturation
STOOIP: Stock tank oil originally in place
Sw: Water saturation

Competing interests
The authors declare that they have no competing interests.

Authors' contributions
Idahor T. carried out the simulation and wrote the manuscript, Taylor P. supervised the processes and provided professional guidance while Mekunye F. performed additional validation.

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