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Simulation of Co_2 Water Alternating Gas (Wag) in 2d Vertical Cross-Section

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Abstract

Using a 2D vertical model of 500x1x50blocks of thickness 0.1m, porosity of 0.3 and, a Hydrocarbon Pore volume (HCPV) of 7.5m^3, the effect of CO_2 WAG is studied in this work, looking at the effect of heterogeneity and miscible on the recovery, water cut, and other parameters. To begin with, two 1D slim tube mode of 500x1x1blocks of thickness 0.1m and 5000x1x1blocks, the thickness of 0.01m was used in determining the Minimum Miscible Pressure MMP that was used in the simulation model. The slim tube models were run using different reservoir pressure for an optimum recovery value, a pressure of 150bar was obtained to be the minimum pressure at which CO_2 is miscible with hydrocarbon. Using 150bar as the MMP, a 2D homogeneous model with reservoir pressure of 200bars was run using different recovery techniques which include WAG, Waterflooding, and CO_2 flooding. The results show a recovery of 99% using CO_2 with an early gas breakthrough, as for the WAG case, a recovery of 96.2% was achieved with no water and a little gas breakthrough at the end of the simulation and that makes it a suitable candidate as no or little cost of water or gas treatment will be required. The water flooding case has the worst recovery with an early water breakthrough but suitable at lower pressure. For miscibility sensitivity, similar models were re-run using the same recovery techniques at a lower pressure, the outcome shows a lower recovery after several days of production. Some sensitivity cases were also carried out by introducing shales, stochastic shales, into the models, using both miscible and immiscible pressures.

Keyword: *WAG; Recovery; water breakthrough; and CO_2 miscible pressure*

1.0 INTRODUCTION

One of the most efficient methods of improving recovery is the use of Water Alternating Gas (WAG) to recover oil from an oil reservoir. WAG is an enhanced recovery technique where water and gas are injected into a reservoir either alternatively or simultaneously to improve the recovery. The purpose of gas injection is to improve the efficiency of the microscopic displacement whereas water flooding maximizes the sweep efficiency. In general, using the WAG technique, oil recovery efficiency is improved. Christensen et al. (2001) state that WAG is one of the most effective enhanced oil recovery mechanisms in a carbonate reservoir.

The most common gases that are injected into an oil reservoir are CO_2 or N_2, for this work, CO_2 will be used. The idea behind using CO_2 is to improve the recovery as well as to maximize the CO_2 storage to reduce its effect on the atmosphere.

Many field and laboratory work has been conducted on CO_2 gas used for oil recovery and the results were encouraging. There are various mechanisms by which the gas is used to displace oil this includes

1. Solution gas drive
2. Immiscible CO_2 drive

3. Hydrocarbon- CO_2 miscible drive
4. Hydrocarbon vaporization
5. Direct miscible CO_2 drive etc

Other mechanisms also exist but mostly practice in the industries only. (L.W. Holm 1974)

In the North Sea and the Gulf of Mexico, miscible gas flooding is usually used as the method of improving oil recovery, this is because the technique reduces the oil saturation to a value lower than the residual oil saturation (Kang et al., 2016). A major problem with using CO_2 to displace oil is the contrast in the mobility of the gas injected and the oil to be displaced as such it leads to viscous fingering and an early breakthrough of the solvent these leads to lower oil recovery and an increase in the cost of gas treatment (Blunt et al, 1993 and Zainab I. A et al 2017). The availability of the gas to be used for the oil recovery is another challenge as the gas may be limited or not available for injection (Hoffman, 2014).

Although the CO_2 technique of oil recovery might be expensive especially when the gas has broken through but based on a presentation by Charles A Kossack (2013) on EOR Processes, it has shown that apart from chemical EOR, CO_2 is cheaper when compared with other gases and thermal method of oil recovery. The experiment carried out by (Vincent A. et al, 1993) shows that using WAG tapering ie increasing water injection and reducing CO_2 injection to a certain ration improves the recovery.

When using CO_2 flooding as a recovery mechanism, the process in which the hydrocarbon flow to the surface is either by swelling the oil, reducing the oil viscosity, vaporizing the intermediate and heavy hydrocarbons, internal solution gas drive, multi-contact miscibility among others.

In reality, CO_2 in its purest form with no contaminants doesn't exist. Contaminants such as methane (CH_4) and H_2S are commonly found in CO_2, these contaminants affect the miscibility pressure. The presence of CH_4 increases the miscibility pressure while H_2S decreases it. Other problems associated with use CO_2 include; viscous instability, produced gas separation, solubility in water which leads to corrosion, its health hazard, and the effect of gas fingering which leads to an early gas breakthrough.

1.1 EFFECT OF CO_2 ON RESERVOIR FLUID

For water flooding alone, there is no reaction between the water and the hydrocarbon but with the case of CO_2, the gas reacts in one way or the other reacts with the hydrocarbon which effects the oil quality and recovery. Some of the characteristics of CO_2 in the oil, when used as recovery agents, includes

1. Reduction of oil viscosity
2. Increase in oil density
3. Promotion and swelling of the oil
4. High solubility in water etc

Due to the above effect of CO_2 in the oil when used as a recovery agent, an efficient way of using the gas for recovery is by injecting the gas at a pressure in which miscible displacement is attended. A displacement of almost 100% is achieved on C_5 to C_{30} when the injected CO_2 used for the recovery is within the miscible pressure (Holm, 1974). Immiscible displacement occurs when CO_2 is injected into an oil reservoir at a lower pressure which results in immiscibility, in such a situation the above mention effects on the properties of the oil occurs. Unlike other gas injection recovery mechanisms, CO_2 doesn't depend on the presence of lighter hydrocarbons in the reservoir for oil displacement, instead, it is more suitable for depleted reservoirs with no gas.

1.2 MINIMUM MISCIBLE PRESSURE (MMP)

To avoid the problems associated with immiscible displacement, the Minimum Miscible Pressure (MMP) must be determined so that the minimum pressure in which the gas (CO_2) is injected for the recovery is known (Holm, 1974). MMP is a criterion to use in selecting a reservoir for CO_2 injection. This is because the reservoir must be able to withstand the minimum pressure that the gas will be injected at to avoid fracturing. Once a reservoir is not capable of withstanding such pressure then it is not suitable for CO_2 injection this is because maximum recovery is not achievable.

To determine the minimum pressure required for a certain reservoir, a slim tube test is usually carried out where CO_2 is injected at different pressures. A graph of the oil recovery factor against individual pressures is plotted. It will be observed that the recovery factor increases with pressure increase until a certain pressure is reached where the recovery doesn't change any more. The pressure at which the recovery factor remains virtually the same is the minimum miscible pressure. Generally, miscible displacements were defined to have a total recovery after 1.2 PV of CO_2 have being injected which is similar to the results obtained from series of tests carried out (Yellig and Metcalfe, 1980).

1.3 SUITABLE RESERVOIR FOR CO_2 EOR

Below is a summary of the oil and reservoir properties that makes it a suitable candidate for CO_2 EOR (Charles A. 2013)

Oil properties

- API Gravity: >25, ideal 36
- Viscosity : <10cp, ideal <1.5cp
- Composition: high % C_5 to C_{12}

Reservoir properties

- Depth: >2500ft
- Pressure: >1500psi (P_{res} >MMP; $P_{inj} < P_{frac}$)
- Temperature: low to allow miscibility
- Gas Cap: small or none
- Heterogeneity: low
- Oil saturation: >20%, ideal >55%
- Permeability: >1mD
- Formation: Sandstone or Carbonate reservoirs

1.4 HYSTERESIS AND RELATIVE PERMEABILITY MODELS

Hysteresis is a phenomenon that occurs when using WAG for oil recovery from a reservoir, it affects the imbibition and drainage gas relative permeability curves. Whenever the effect of hysteresis is omitted in a model, trapped gas may not be simulated and so also the prediction of residual gas saturation which is a key factor in CO_2 sequestration studies is not possible. To achieve accurate results from a given model, a valid hysteresis must be run alongside a WAG simulation, (Yousef Ghomian et al 2008 and Simeon 2014).

Spiteri and Jaunes (2006) have shown that hysteresis controls recovery behavior during immiscible WAG and as such hysteresis must be accounted for when using WAG in carbonate or a sandstone reservoir. The overall benefit of gas trapping is only captured using hysteresis models, this is because it reduces the mobility of the non-wetting phase as such improves the oil recovery.

According to Jerauld et al. (1997) and Christensen et al, (2000), the equation for calculating the amount of trapped gas developed by Land (1971) does not correctly fit laboratory data.

Therefore, they came up with a modified version of the Land's equation. The proposed equations by Land are given below

$$S_g = S_{gf} + S_{gr} \quad (1)$$

$$\frac{1}{S_{gr}} - \frac{1}{S_{gi}} = C \quad (2)$$

Where C is the Lands Constant, S_{gi} and S_{gf} stand for initial gas saturation and the mobile gas saturation respectively whereas S_{gr} and S_g stand for residual gas saturation and gas saturation.

2.0 METHODOLOGY

2.1 1D SLIM-TUBE MODEL

A 1D slim-tube compositional model made up 500 x 1 x 1 grid block with a dimension of 50 x 0.1 x0.1 m was used in determining the Minimum Miscible Pressure MMP which serves as an input parameter for the 2D model. In this model CO_2 alone was injected into the model at different reservoir pressures to determine the optimum MMP. To determine the MMP, a reservoir rate of 0.12 m^3/day of CO_2 which is equivalent to 2.4HCPV /day was used as the CO_2 injection rate, and thereafter a graph of oil recovery against various injection pressure was plotted and the optimum MMP is obtained. The result is discussed in the result section of this report. The fluid property data used in the 1D slim-tube model is the same as the 2D models discussed in the next section. **Table 1** below provides the additional properties of the slim tube model.

Table1: Additional properties of slim tube model

	PROPERTIES	
1	Model type	Compositional model
2	Composition	CO_2 and Oil
3	Total number of cells	500
4	Porosity	0.1
5	Permeability	3000mD
6	Equation of state	Peng Robinson
7	Reservoir temp	53^0C

2.2 2D HOMOGENEOUS BASE CASE

The model here is a 2D vertical cross-section which is made up of 500 x 1 x 50 grid blocks making a total of 25,000 cells of dimensions 50 x 0.1 x 5 m. WAG injection was simulated with several alternating cycles in which water and gas are injected until a minimum oil production rate of 0.08 m^3/day is attend or the model has run a 500-time step of 0.2 days before the simulation stops. A WAG ratio of 1:1 is used with a cycle length of 0.25 days (6 hours). The model is made up of 2 wells (1 injector, 1producer) which are located in the first and the last grid cells in the x-direction respectively. The wells are completed across the entire length of the model (that is the whole 5m in the z-direction) except for some sensitivity cases. The homogeneous base case model is made of average horizontal permeability of 100mD with an average porosity of 0.3. An Eclipse 300 software was used for this work using a compositional model simulator.

Using the reservoir injection rate as a fixed variable to control the well bottom hole pressure so that the pressure change does not go beyond a Δp of 20 bars, a 0.3 m^3/days of both water

and gas (CO_2) are injected which is equivalent to 0.04 HCPV/day of water and CO_2 when using a WAG model. For some sensitivity cases where only gas or water are injected, a reservoir rate of 0.5 m^3/days (equivalent to 0.067 HCPV/day) of gas is injected whereas for the water it remains the same as the WAG case that is 0.3 m^3/days (0.04 HCPV/day).
For any compositional model calculation, a certain equation of state must be used. Here the Peng- Robinson equation of state calculations is used along with the introduction of a term that slightly modifies the Peng-Robinson model. A typical Peng-Robinson equation is given below
Peng-Robinson (1979)

$$P = \frac{RT}{V-b} - \frac{a(T)}{V(V-b)+b(V-b)} \quad (3)$$

$$a(T) = 0.45724\frac{R^2T_c^2}{P_c}(1+k(1-T_r^{0.5})^2) \quad (4)$$

$$T_r = \frac{T}{T_c} \quad (5)$$

$$k = 0.37464 + 1.5422w - 0.26922w^2 \quad (6)$$

$$b = \frac{0.0780RT_c}{P_c} \quad (7)$$

The injector and the producer were set at a rate such that the maximum bottom hole pressure of the injector and the minimum bottom hole pressure of the producers' difference is between 10-20bars. For the miscible case the initial reservoir pressure is set at 200bars whereas, for the immiscible cases, the reservoir pressure is set at 110bars. The density of water is set at 1000 kg/m^3, whereas the densities of gas and oil were calculated using the equation of state during the simulation. A summary of other properties of the reservoir are listed in **Table 2** below:

Table 2: Addition properties of the 2D cross-sectional model

SUMMARY OF OTHER 2D RESERVOIR INPUT DATA	
Dip angle	0
Kv/kh	0.4
Initial oil sat	1
Initial water sat	0
Res temp	53 ^{0}C
Res depth	3000 m

2.2.1 SENSITIVITY ANALYSIS

After building and running the homogeneous base-case with WAG, some homogeneous and other sensitivities were carried out to find a way to compare the outcomes of the results. The various sensitivity cases that were run are hereby listed below:

1. Altering the model from WAG to water injector only
2. Injecting CO_2 alone without water
3. Stating with water injection for a certain period before switching to WAG
4. WAG EOR with immiscible pressure

The above-mentioned cases were run individually and the results are discussed in the results and discussion section.

2.3 HETEROGENEOUS CASES

To see the effect of heterogeneity on the oil recovery efficiency, sweep efficiency, water breakthrough, etc, different heterogeneous models ranging from layered, random, and those with shale were run. The 2D heterogeneous models have the same properties as the homogeneous models except for the variations in the permeabilities. **Table 3** and **Figure 1** below shows the permeability distribution of the heterogeneous models.

Table 3: Summary of Permeability Distribution for Heterogeneous Models

Permeability	Layered Case	HLHLH	Coarsening upwards	Fining upwards	Units
Layer 1	30	150	100	20	mD
Layer 2	20	30	80	30	mD
Layer 3	50	150	50	50	mD
Layer 4	10	30	30	80	mD
Layer 5	120	150	20	100	mD

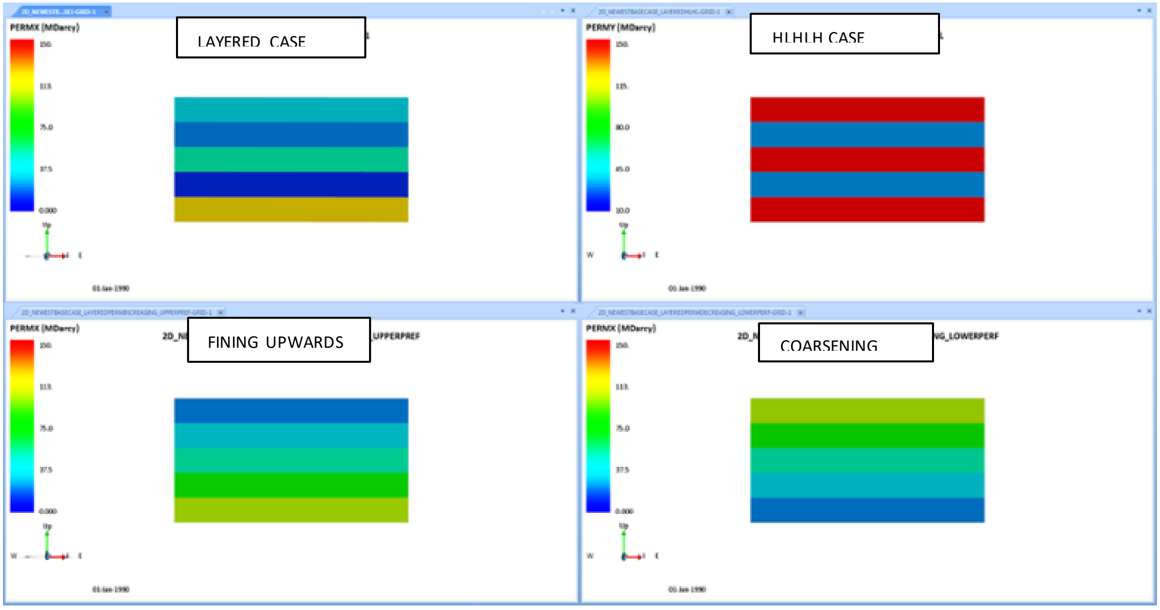

Figure 1: Permeability distribution of the heterogeneous models

Lastly, the random model is composed of randomly distributed permeabilities across the entire grid blocks ranging between 100 to 0.01mD. Some shaly models made up of non-transmissible shales distributed across the model were also built, the shaly model can be categories into 3 different classes.

a. Randomly distributed shales across the model with matrix permeability of 100mD and shale of 0.0 transmissibility. This shale distribution is also subdivided into 2

  i. 25% of the reservoir contains shale

  ii. 30% of the reservoir contains shale

b. Stochastic shales which are about 20% of the reservoir with 0 transmissibility and a matrix of 100mD as well. The shales are distributed random long the x-direction and are about 5m long which is about 50 grid blocks long.

c. The last heterogeneous model is a combination of the layered model and the stochastic shale model. Here the stochastic shales are added to the layered model to give a more heterogeneous model.

Figure 2 shows the distribution of shale across the grid blocks.

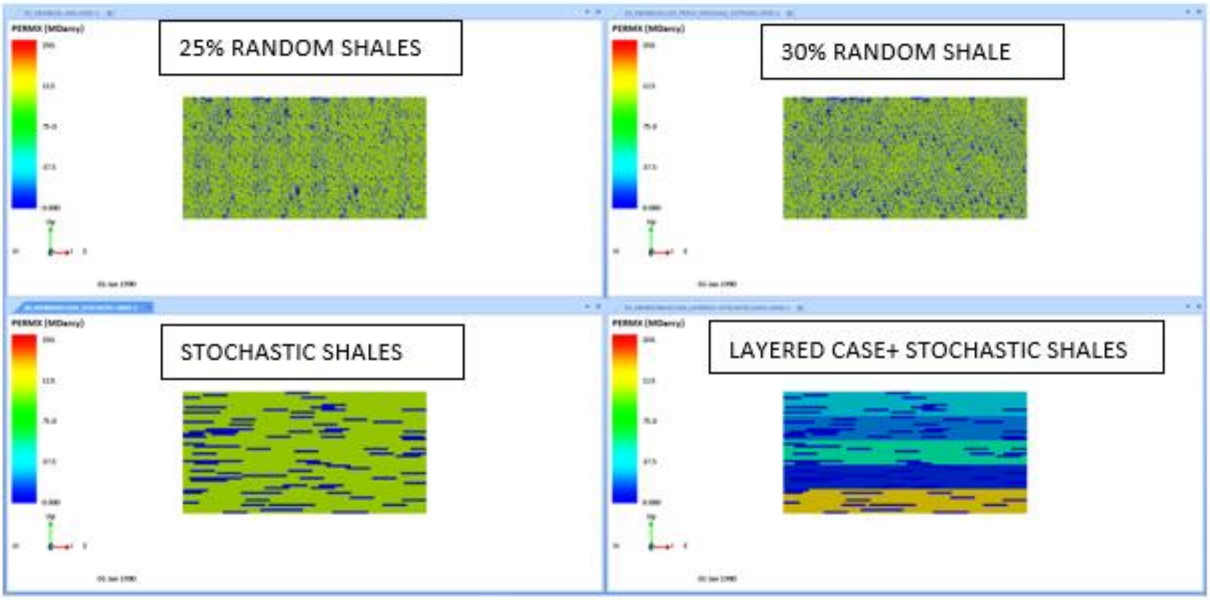

Figure 2: Permeability distribution of the shale heterogeneous models

2.4 EFFECT OF MISCIBLE PRESSURE

In the sensitivity analysis, the models were run with pressures lower than the obtain MMP to determine the effect of miscibility. The pressure is lower in some of the homogeneous and heterogeneous models already discussed above, the impacts were studied and discussed in the next section.

3.0 RESULTS AND DISCUSSION

3.1 1D SLIM TUBE NUMERICAL SIMULATION MODEL

To determine the minimum miscible pressure, the 1D slim tube model described in the methodology was used. Varying the model pressure and running several cases, the figure below was obtained

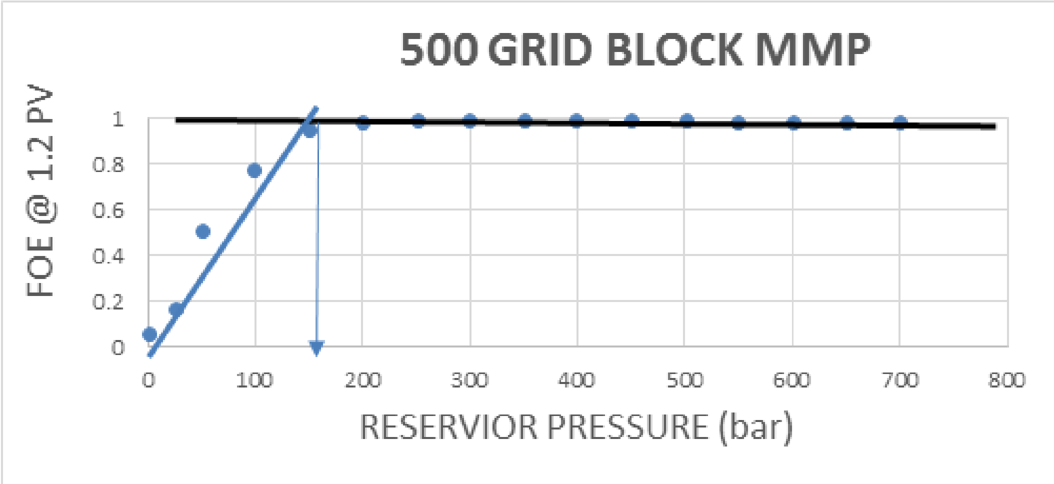

Figure 3: A plot of FOE against different reversion pressure to determine MMP for 500 grid blocks slim tube model

Injecting $C0_2$ at $0.12m^3$/day which equals 1.2PV/day gives rise to the result above. A plot of Field Oil Enhancement FOE against Pressure (bar) as shown in **Figure 3** above. It can be observed that the FOE value stabilizes at a pressure between 100 to 200 bars. The above result is for the 1D model with 500 grid blocks of dimensions 0.1x0.1x0.1m with a porosity of 0.1 and a permeability of 3000mD.
To be sure of the MMP, another model was run but now with a total of 5000 grid blocks of dimensions 0.01x0.1x0.1m with similar porosity and permeability as the first model. **Figure 4** below shows the outcome of the simulation.

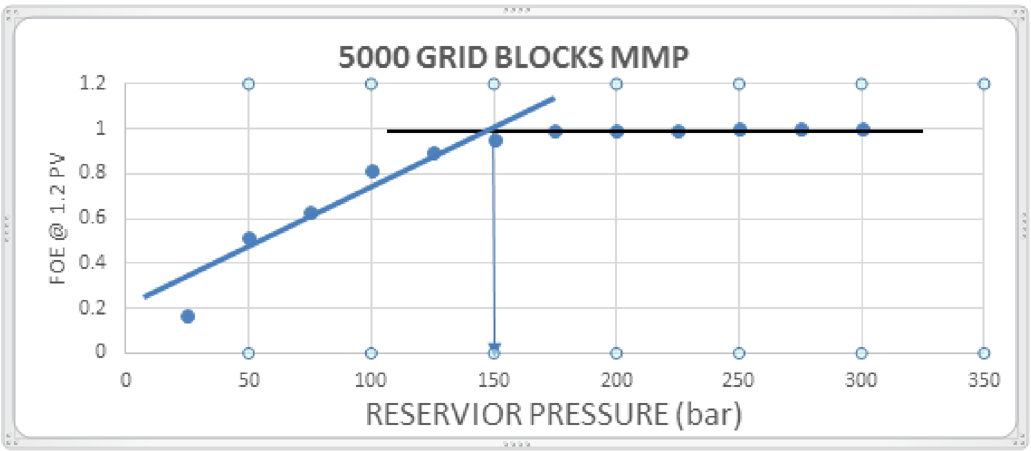

Figure 4: A plot of FOE against different reversion pressure to determine MMP for 5000 grid blocks slim tube model

From **Figure 4** it can observe that the FOE begins to stabilize at a pressure that corresponds to around 150 bar. Based on the above observations, 150 bar was selected to be used as the MMP in subsequent simulations. Throughout this research work, all immiscible model simulations will be run with pressures of less than 150 bars, while for the miscible models, the simulations will run using pressures above 150 bars.
The molar compositions of the components in the oil phase in the model are presented in **Figure 5**, showing the cases of both miscible and immiscible pressures where the red line (XMF 1) indicated the molar composition of CO_2 in all the 500 cells using an injection pressure of 200 bar. The molar composition decreases from left to right as the gas moves

along the cell. The other lines show the initial composition of the hydrocarbons (C_1 to C_{30}), here it could be observed that the compositions increase from left to right in the reservoir cells.

Figure 5 also shows how miscibility at different pressures in the reservoir is represented. It can be observed from left to right of the figure that for a system with an injection pressure above the MMP, the gas molar composition is approximately 1 near the injector and reduces gradually from left to right till it diminishes toward 0 near the producer.

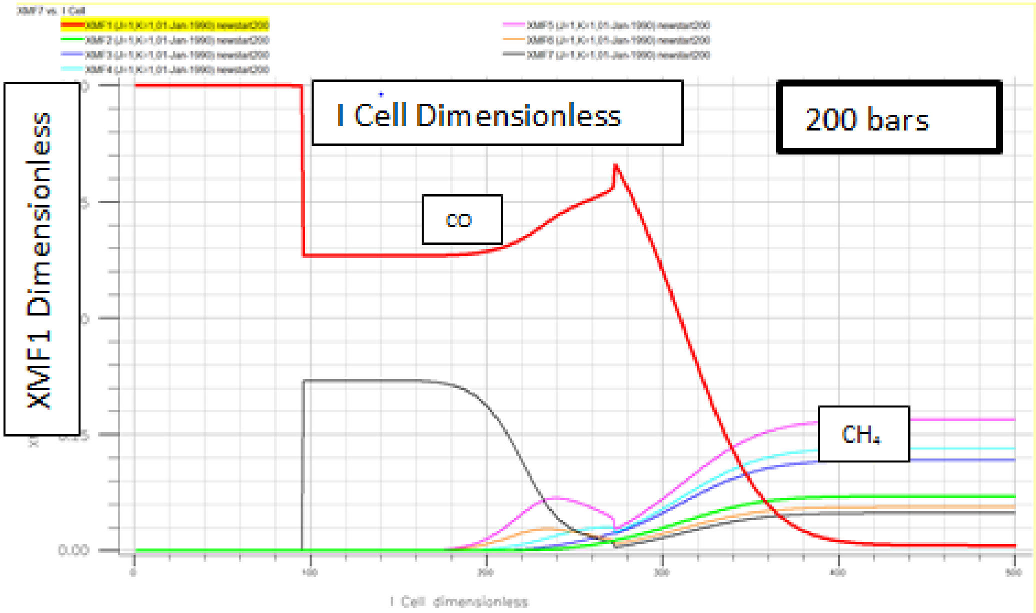

Figure 5: The molar composition of all the 7 component against cell number for a reservoir with 200 bars (above MMP)

3.2 2D NUMERICAL SIMULATION MODELS

3.2.1 HOMOGENEOUS MODELS

Using the homogeneous models, several sensitivities were run to show the differences in the recovery efficiencies. The sensitivities ran include, injecting both water and gas (CO_2) as WAG (Base case), injecting gas only, water flooding followed by WAG, and injecting only water. All the mentioned sensitivities were run using pressures above the miscible pressure, except for a single WAG model which was run using a pressure below the MMP. **Figure 6** is a bar chart of oil recovery efficiency (FOE), production days, and water cut.

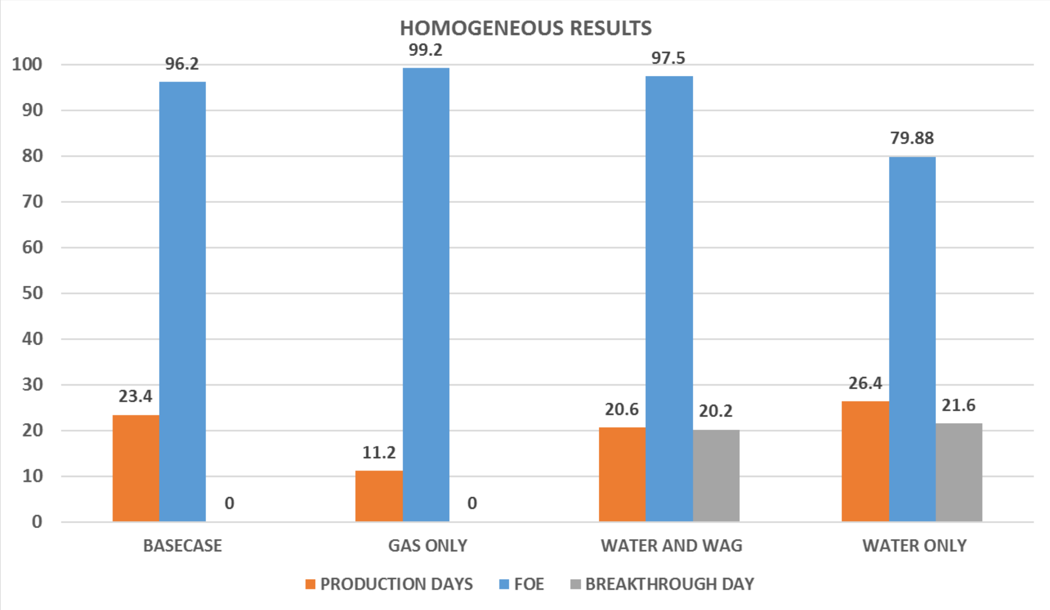

Figure 6: Results of Homogeneous base case

The chart summarises the recoveries of all the different cases ran, from above it can be seen that injecting gas alone gives the best recovery within a short period, this is because the gas injection rate was high when injecting gas alone compared to when carrying out WAG. To achieve a relatively constant bottom hole pressure throughout the whole production time, the gas pressure has to be high as such a better recovery. On the other hand, looking at the other results, it could be observed that flooding with water initially before introducing WAG gives a better recovery followed by the case in which WAG was used from unset and finally using water alone.

3.2.1.1 EFFECT OF MISCIBILITY ON THE 2D HOMOGENEOUS MODEL

Having obtained the above results, another sensitivity was run to look at the effect of miscibility that is comparing the oil recoveries (FOE) and production days for the models run with pressures above and below the MMP. The same four (4) homogenous models as above were used here only pressures were varied.

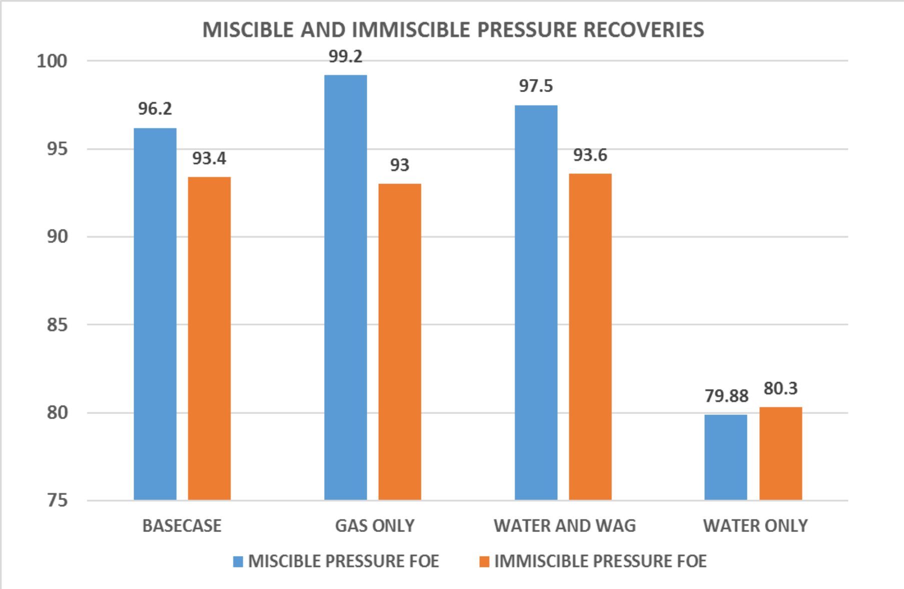

Figure7: Recoveries for Miscible and immiscible pressure Models

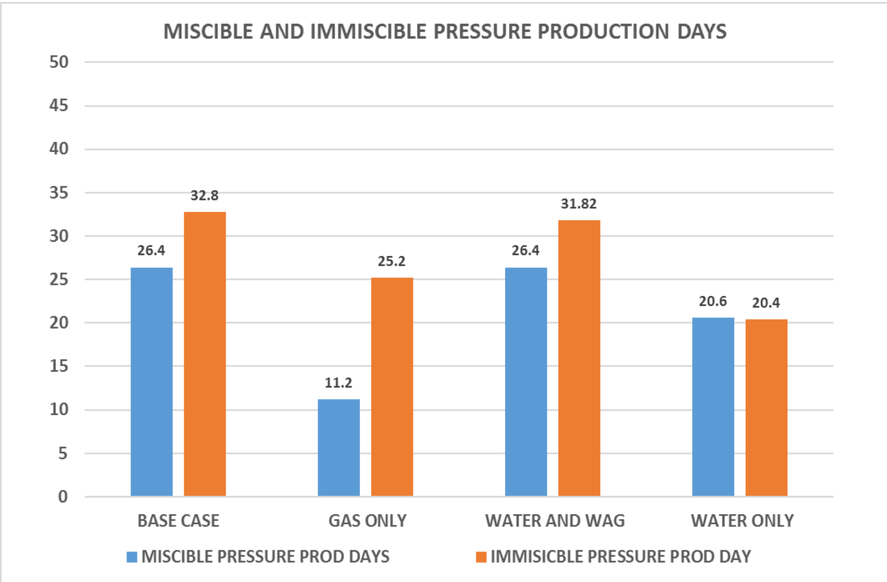

Figure 8: Number of Production Days for Miscible and Immiscible Pressure Models

From **Figure 7** above, it is clear for all the scenarios that the recovery efficiencies are better in the miscible cases than the immiscible ones. The number of days taken to achieve such recoveries is higher in the immiscible models than the miscible models as shown in **Figure 8**. Even though the FOE for the immiscible cases is not bad, the only issue is it takes a long time about 150 to 200% more days to achieve what was achieved with a miscible pressure or closer to that. For instance, looking at the case where only gas was injected, for the miscible case it took only 11.2days to achieve a recovery of 99.2% FOE whereas comparing to the immiscible case, it can be seen that it took more than 25 days to achieve 93% FOE and yet it is still lower than recovery obtain from the miscible pressure. Lastly, looking at the case where only water is injected, it could be observed that there are no significant differences between the two pressure cases, the lower pressure case gives a better recovery with a shorter duration. This is because at low pressure the effect of early water breakthrough is controlled.
From the analysis above one can deduce that whenever CO_2 is injected into a reservoir at a pressure above the MMP, much better oil recovery is achieved and the opposite is the case

for water flooding as the result above shows that water flooding is more effective when lower injection pressure is used.

3.2.2 HETEROGENEOUS MODELS

In this section, heterogeneity has been introduced into the base case model to see what effects will heterogeneity has on the models. Some heterogeneous models were run ranging from layered to randomly distributed types, others are having low permeability in the upper layer and high permeability in the bottom layers and vice verse. **Figure 1** and **Table 3** shows the permeability distribution of each of the cases.

Figure 8 below shows the FOE, production days, and water production days for the heterogeneous model. It could be observed that the recoveries are almost the same except that some cases achieved such recoveries earlier compared to others. The chart also gives a summary of the recovery efficiency of the case along with their respective water breakthrough time.

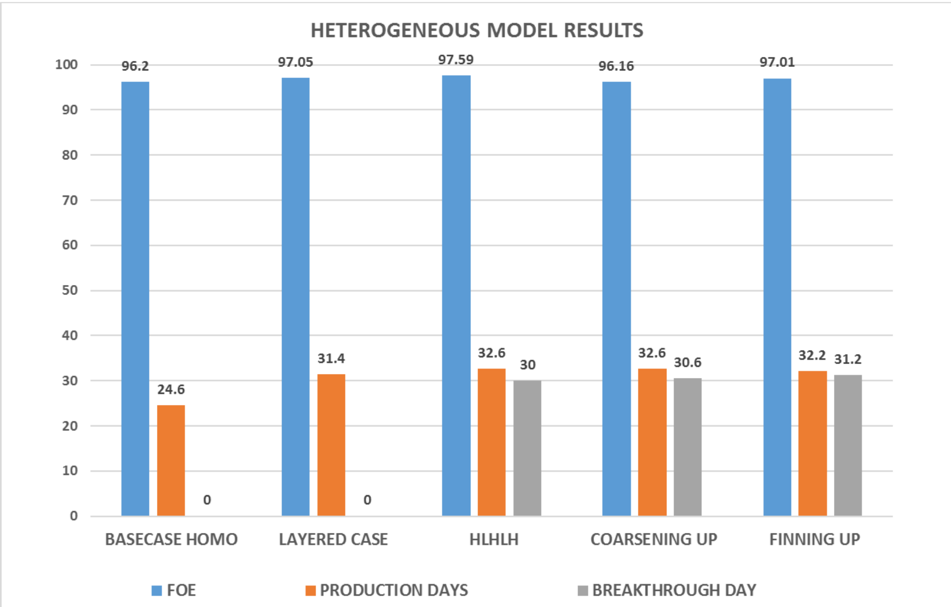

Figure 9: Results of Heterogenous Models

Due to the heterogeneous nature of the models, water breakthrough days can be observed to be different between the models. For instance, looking at the heterogenous case of finning up, it could be observed that water production begins almost concurrently with the oil production while in the layered case water was not produce throughout the 31.4 days of production.

3.2.2.1 EFFECT OF MISCIBILITY ON THE 2D HETEROGENEOUS MODEL

Figure 10 below summarises the effect of miscibility on heterogeneous models. Two models with different levels of heterogeneity were run at different pressures one above the MMP while the other below the MMP. The result shows that the recovery efficiency of the models declines as the pressure is lowered below the MMP. Another factor that was looked into is the water breakthrough time, the results show that the models with immiscible pressures have an early water breakthrough. For instance, in the layered case model with pressure above MMP, there was no water breakthrough observed whereas using a pressure below the MMP, early water breaks through was seen.

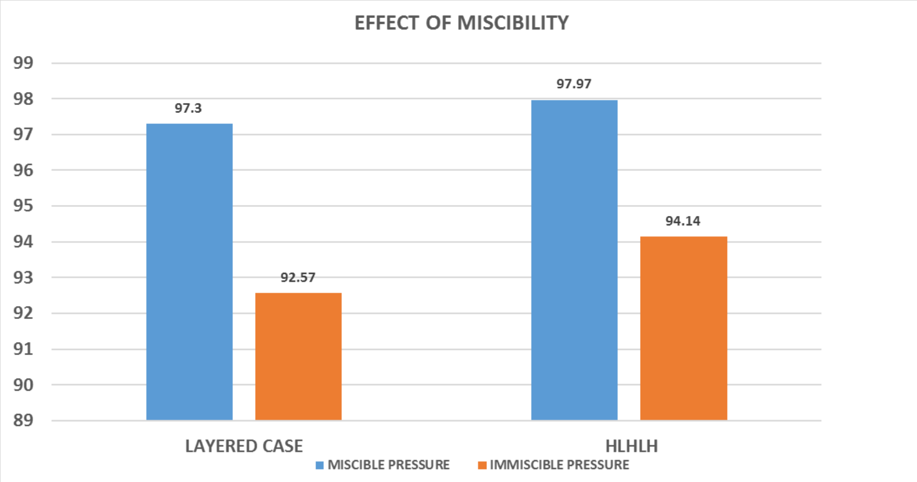

Figure 10: Effect of Miscibility on Heteregous Models

3.2.3 HETEROGENEOUS MODELS WITH SHALES

Table 4 and Figure 10 represents the outcome of the simulations ran for the heterogeneous models with shales randomly distributed across the entire model. The result shows an oil recovery ranging between 92 to 96.3% in all the cases with similar production days of around 26 days except for the case of layered+stochastic model which took 31.6 days to achieve a 96.3% recovery.

Table 4: Summary of Results for Shaly Heteroguos Models

	SCENARIOS	Days	MAX FOE (%)	FWCT (%)
1	25% Random Shales	27.4	0.924	0
2	30% Random Shales	26.6	0.932	0
3	Layered + Stochastic Shales	31.6	0.963	0
4	Stochastic Shales	27.4	0.945	0

For the case of water cut, all the four models ran with shales have not shown any sign of water breakthrough as it remains 0 for all the cases throughout the production period.

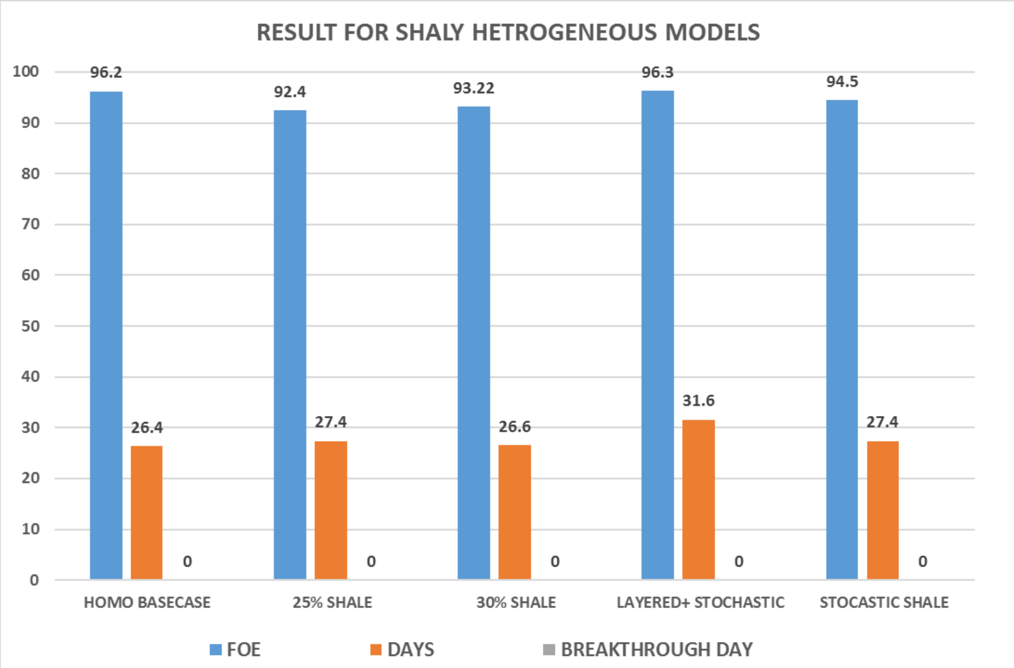

Figure 10: Shaly Heterogeneous Models

3.2.3.1 EFFECT OF MISCIBILITY ON THE SHALY 2D HETEROGENEOUS MODELS

As discussed with regards to other cases before, here the effect of miscibility is considered where the pressure used is below the miscible pressure. In **Figure 11** below, the oil recovery of both simulations run with pressure above and below MMP are compared.

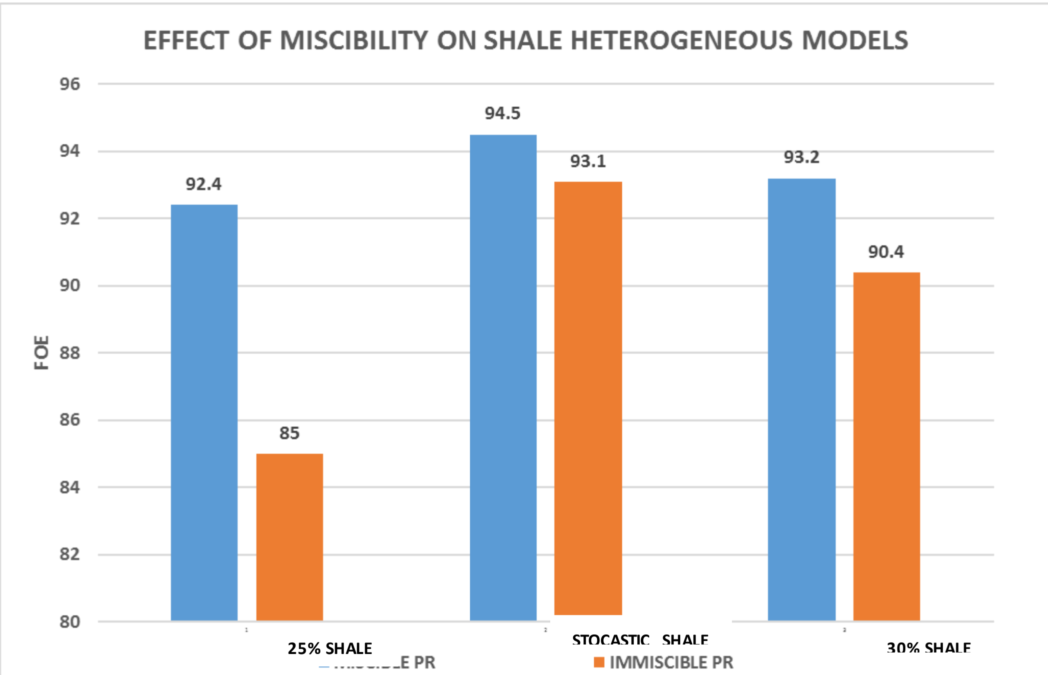

Figure 11: Effect of Miscibility on Shaly Heterogeneous Models

The results indicate that the recovery from 25% random shale is the most affected among all the all. A drop-in recovery from 92.4 to 85% was observed when a pressure below the MMP is used. Other cases ran for a longer period and still could not attend the recovery that was obtained for the miscible cases.

4.0 SUMMARY

After discussing the results obtained from the several simulations that were run with different parameters and properties, the following are the major summaries.

EOR with CO_2 WAG is an efficient mechanism to recover oil from a reservoir as seen from the results shown in the previous sections where all the recoveries are above 80%. The results from the homogeneous model suggested injecting CO_2 gas alone gives the best recovery within a short time followed by CO_2 WAG. Factors such as gas miscibility affect the overall oil recovery efficiency, production time, and water breakthrough.

Lastly, for the heterogeneous cases, it is clear that the layered case model is more suitable for CO_2 WAG compared to other models. The outcome shows a higher recovery factor within a shorter time with no water breakthrough throughout the production period.

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