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The Effect of WAG Ratio and Oil Density on Oil Recovery by Immiscible Water Alternating Gas Flooding

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Abstract

An Enhanced Oil Recovery (EOR) method named Immiscible Water-Alternating-Gas (IWAG) is one of the well-established methods for improving oil recovery in reservoirs. IWAG injection combines both improved displacement efficiency of the gas flooding with an improved macroscopic sweep by water injection. The objective of this study is to investigate the effect of Water-Alternating-Gas (WAG) ratio and oil density on residual oil recovery during IWAG flooding process using dimensions of a real reservoir. A series of six injections were conducted at WAG ratio of 1:1, 1:2, 1:3 and oil densities of 0.72 g/cc, 0.81 g/cc, 0.88 g/cc with flow rate of 1 cc/min for every injection. In this study, a secondary recovery method, which is water-flooding, had been conducted first and continued with immiscible gas-flooding before the start of IWAG to determine the overall recovery factor that can be increased with the utilization of IWAG as an EOR tertiary method. Water flooding had resulted in good oil recovery, which was about 36%–50% Oil Initially In Place (OIIP). Meanwhile immiscible gas-flooding had resulted in only 1%–3% OIIP. The results showed that a WAG ratio of 1:1 was the optimal ratio since the tertiary oil recovery using IWAG was 8% and total 45% of OIIP whereas oil density of 0.72 g/cc was the optimal density which gave 9% of oil recovery using IWAG and total 64% of OIIP. The experimental outcome additionally demonstrated that the IWAG method becomes more efficient in equal water and gas slug ratio which is favourable for low oil density. This is because water and gas help in both microscopic and macroscopic sweep efficiency whereas the mobility of low oil density is higher and flows with low resistance.

1. Introduction

The process of Water Alternating Gas Injection (WAG) injection comprising of injection of water and gas slugs simultaneously or in the form of cyclic alternation with the goal of improving sweep efficiency of water flooding and gas injection projects is to decrease viscous fingering and gas overriding phenomena. In comparison with water

flooding, the use of gas injection improves displacement efficiency under desirable conditions.

However, this process usually has weaker sweep efficiency and is an expensive operation due to the need for large volumes of injection fluid under the condition of continuous injection. Injection of gas after water flooding in the form of WAG would be more efficient than continuous injection of water or gas to improve recovery percent. WAG is a combination of an improved microscopic displacement efficiency during gas injection operation and an improved sweep efficiency during water flooding operation.

Major effective factors during the process of WAG processes are; reservoir heterogeneity, reservoir rock wettability, properties of reservoir rock and reservoir fluids, different injection techniques, parameters of WAG including the number of cycles, WAG ratio and slug size.

The process of WAG can be classified in different forms by the methods of fluid injection. The most common categorization is the difference between miscible and immiscible injection.

This study aims to investigate the effect of WAG ratio and oil density by IWAG. IWAG is the process of WAG injection where the gas injected is not miscible with residual oil in the pore channels. IWAG's advantage include; better pressure support, reduced water handling cost and high production rates; [2].

WAG ratio and oil density are two of the most important parameters which influence performance of oil recovery. Thus, the study about these two parameters should be conducted.

2. Materials and Methods

Figure 1 shows the flowchart of one cycle experiment.

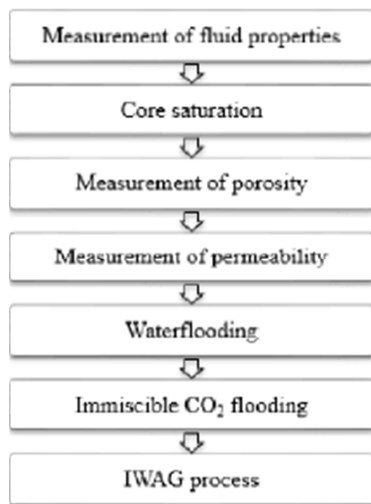


Figure 1. Experimental Procedure.

2.1. Fluid Properties Determination

Fluid properties determination involved the determination of oil and brine properties. Properties of oil that have been measured are; oil density (ρ_{oil}) and oil viscosity (μ_{oil}) whereas

for brine the properties are; brine density (ρ_{brine}), brine viscosity (μ_{brine}) and oil-water (brine) IFT.

2.1.1. Crude Oil

Due to the fact that crude oil from the oil field was not readily available for several reasons, paraffin oil which exhibits similar properties with crude oil was used in the experiment of water-gas slug size ratio. For the experiment of oil density parameters, the fluids used in this experiment are paraffin, kerosene and lubricant oil as the oleic phase, CO₂ as the gas phase and NaCl with 20,000ppm concentration as the brine. Table 1. shows the density, viscosity and IFT of different types of oil used in this experiment.

Table 1. Properties of Different Types of Oil.

Type of Oil	Density, g/cc	Viscosity, cp	IFT, mNm
Kerosene	0.72	13	25
Paraffin	0.81	23	3
Lubricant	0.88	160	47

2.1.2. Brine Solutions

Generally most of the fields use sea water as the reservoir brine and injection water due to its availability that can be obtained in very large quantities within a short period of time. Therefore, since the main component of sea water is sodium chloride, NaCl. 20,000ppm, 2wt% NaCl was prepared as synthetic brine water.

2.1.3. Gas Injected

Carbondioxide (CO₂) gas was chosen as the flooding agent because of its ability to vaporize hydrocarbon from paraffin oil, reducing oil viscosities thus improving the sweep efficiency. Bhatia et al (2011) [9]; reported that better saturation profiles of CO₂ WAG injections is shown in the core as against the use of hydrocarbon gases. Besides, CO₂ is normally the usual gas that is used in the field.

2.1.4. Viscosity and Density Measurement

Viscosity and density of fluids were the two main parameters that must be measured. Viscosity indicates their resistance to flow, defined as the ratio of shear stress to shear rate while density defined as its mass per unit volume. The measurements of these two properties are very important to determine the effectiveness of the WAG performance.

(i). Viscosity Measurement

Viscosity was calibrated using a Brookfield viscometer with a circulated water bath.

(ii). Density Measurement

Fluid density was determined by using the equation below

$$\rho = \frac{M_2 - M_1}{V} \quad (1)$$

Where ρ = Fluid density, g/cc; M_1 = Weight of pycnometer, g; M_2 = Weight of the pycnometer with measuring fluid, g and V = Volume of the measuring fluid, cc.

2.1.5. Interfacial Tension Measurement

There are many IFT measurement methods, such as capillary rise, Wilhelmy plate, Du Nuoy Ring Method, Spinning drop, pendant drop, maximum bubble pressure method, etc. In this study, the Du Nouy Ring method was used to measure the interfacial tension.

2.2. Porous Medium

All of the laboratory experiments were conducted at room pressure, 14.7 psia and a temperature of 28°C. The experimental setup involved using a PVC model (Figures 2 & 3) with 120 cm long and 2.5 cm in diameter as the porous

medium for the total of six tests carried out. The sand was first cleaned by water and dried under the sun. The sand was sieved to the sizes of 150 – 350 μm and was dried again in the oven at 70°C overnight. Figure 3 shows the prototype of the sand pack model.

The sand pack model was used to represent the reservoir model because it is relatively homogeneous and has a high absolute permeability. The same sand packing method was used to prepare the model for each experiment to become a reference in-order to eliminate the effects of heterogeneity. Moreover, the value of porosity and permeability of the model were considered as constant since the same packing was applied.

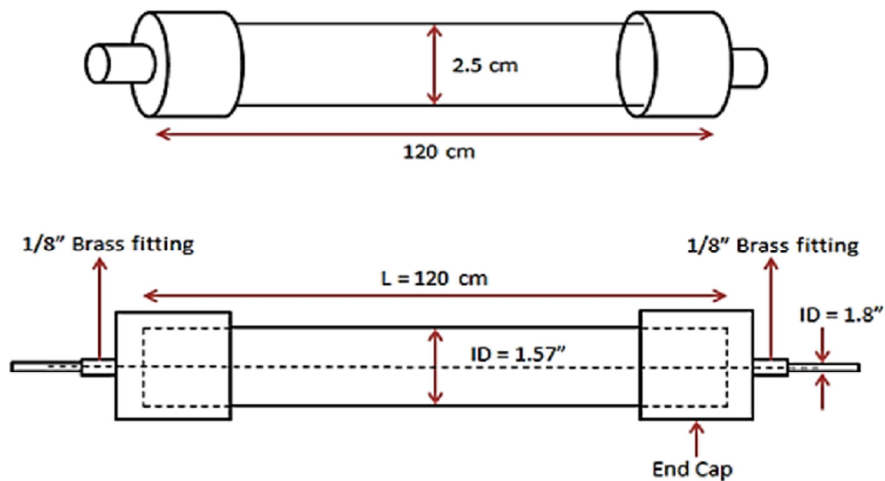


Figure 2. Design of Sand Pack Model.

2.2.1. Porous Medium Characterization



Figure 3. Prototype of the Sand Pack Model.

Table 2. Basic Properties of the PVC Sand Pack Model.

Parameter	Value	Unit
Length	120	cm
Thickness	2.5	cm
Porosity	34	%
Permeability	7.3	D
Area	4.9	cm ²
Bulk Volume	589	cm ³

Characterization of the porous medium was done to determine the main parameters in the porous media such as porosity and permeability. Table 2 shows the basic properties of the PVC sand pack model.

Table 3. Comparison between Reservoir and Sand Pack Model.

Parameter	Reservoir Model	Sand Pack Model
Length (L)	1729 ft	120 cm
Thickness (h)	35 ft	2.5 cm

2.2.2. Porosity and Permeability Measurement

Porosity is the ratio of pore volume to bulk volume of a porous media. Absolute permeability is the ability to flow or transmit fluid through a porous media conducted when single fluid or phase is present in the porous media.

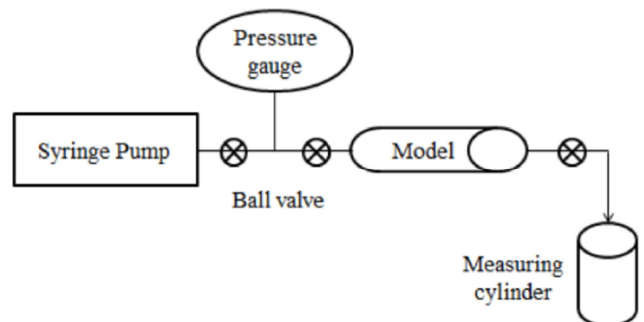


Figure 4. Schematic diagram for porosity and permeability measurement.

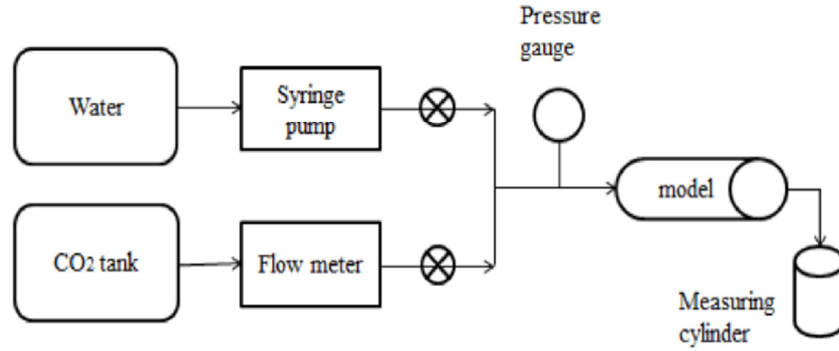


Figure 5. Schematic diagram for IWAG apparatus.



(a) Vacuuming of the sand pack model

(b) Porosity determination process

(c) Permeability determination process

Figure 6. Porosity and Permeability determination.

Porosity was determined from equation 4 and permeability from equation 5.

$$PV = \frac{W_2 - W_1}{\rho_w} \quad (2)$$

$$V_{bulk} = \frac{\pi d^2 L}{4} \quad (3)$$

$$\phi = \frac{PV}{V_{bulk}} \quad (4)$$

$$k = \frac{Q\mu L}{A\Delta P} \quad (5)$$

Where PV = Pore Volume, cc; W_1 = Weight of dry sand pack model, g; W_2 = Weight of 100% saturated sand pack model, g; ρ_w = Density of brine (2 wt% of brine solution), g/cc; V_{bulk} = Bulk volume of sand pack model, cc; d = diameter of the model, cm; L = Length of the model, cm; ϕ =

Porosity (fraction); k = Absolute permeability, Darcy, Q = Flow rate, cc/s; μ = Fluid viscosity, cp; l = length of the core, cm; A = Area of flow, cm^2 and ΔP = Pressure drop, atm.

2.3. Irreducible Water Saturation Measurement

Irreducible water saturation (S_{wirr}) is defined as the lowest water saturation that can be achieved on a core plug by displacing the water by oil or gas. In all the laboratory experiments, water is displaced by oil. This state was achieved by flowing oil through the water-saturated sample. Irreducible water saturation was determined from equation 6.

$$S_{wirr} = \frac{V_t - V_w}{V_t} \quad (6)$$

2.4. Residual Oil Saturation Measurement

After water was displaced by oil, oil was displaced by water injection. In this study, the wetting phase is the water and the non-wetting phase is the oil.

2.5. Flow Rate

Flow rate is an important parameter to be determined before conducting core flooding. The injection rate for any EOR implementation in the field is usually 1 to 2 ft/day. In this laboratory study, a flow rate of 1cc/min was used in order to reduce the gravity segregation of injected fluid in the sand pack model.

3. IWAG Experimental Apparatus

Figure 5 shows the schematic diagram of the IWAG experimental apparatus. The apparatus in Figure 7; consists of a syringe pump, ball valves, flow meter and a measuring

cylinder as a collector.

The syringe pump can be used to set any desired injection rate. The fluid were stored in a syringe and it needs to be set on the pump before starting the injection process. NaCl concentration and CO₂ were pumped alternately into the model. To measure the volume of CO₂ injected, a flow meter was used. CO₂ was pumped to the test model by manipulating ball valves. The displacing fluids were pumped into one end of the model through the injection port and the produced fluids were collected by the measuring cylinder. The displaced fluids were displaced out through the other end of the model, collected and measured in a cylinder. The fluids produced were water and a mixture of CO₂ and oil.

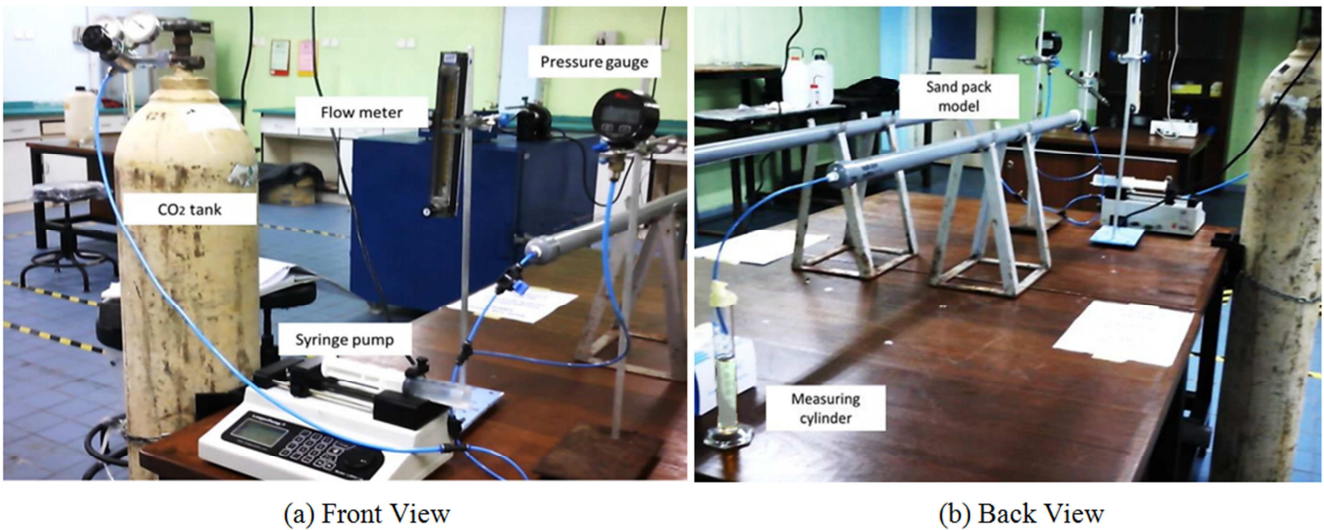


Figure 7. Experimental Apparatus.

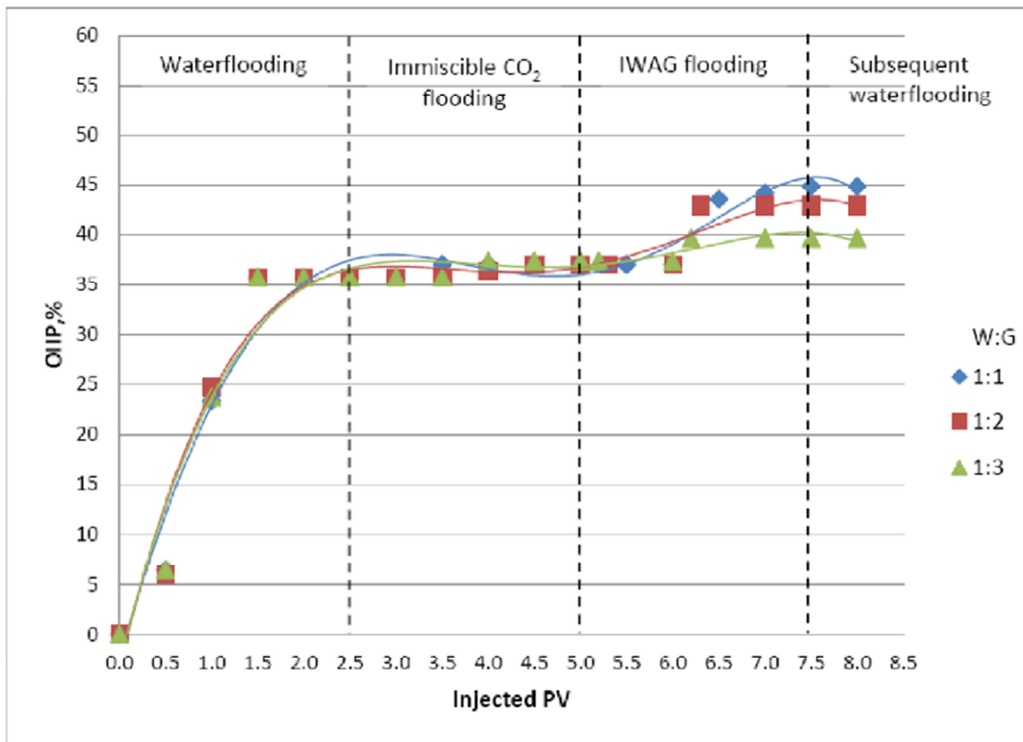


Figure 8. Comparison of OIIP, % versus Pore Volume Injected at Different WAG ratios.

4. Results and Discussions

A total of six experiments were conducted with three models of different WAG slug size ratios and three models of different oil densities.

4.1. The Effect of WAG Ratio

In order to determine the effect of different WAG slug size ratio's with increasing CO₂ slug ratios on OIIP of oil recovery. Each cycle of injection started with water and ended with CO₂ slug with a flow rate of 1 cc/min after 2.5 PV injected. Subsequent 0.5 PV water flooding was carried out to make sure there were no more oil displaced and the recovery remains constant.

4.1.1. Comparison at Different WAG Ratios

Table 4. Total Oil Recovery at Different WAG Slug Size Ratios.

WAG slug size ratio	OIIP (%)			Total OIIP (%)
	Water flooding	Immiscible CO ₂ flooding	IWAG	
1:1	36	1	8	45
1:2	36	1	6	43
1:3	36	2	2	40

Figure 8 shows the relationship between three different WAG slug size ratios and percentage or recovery for water flooding, immiscible CO₂ flooding and IWAG flooding recorded at every 0.5PV and a total of 2.5 PV for each type of flooding. In a water-wet system, during the early stages of a water flood, the brine exists as a film around the sand grains and the oil fills the remaining pore space. During the middle of the flood, the oil saturation has been decreased and exists partly as continuous droplets in other channels. At the end of the flood, when the oil has been reduced to residual oil saturation, S_{or} ; the oil exists primarily as a discontinuous phase of droplets or globules that have been isolated and trapped by the displacing brine.

During water flooding process, at first 1.5PV, oil recovery for all three WAG ratios are relatively increasing with constant rate because the water injected acts as a piston-like displacement by evenly sweeping the front oil. At this time, maximum oil recovery was recorded. After 1.5PV, the graph is constant and there is no increase in oil recovery. This is due to the occurrence of gravity segregation where the injected water tends to flow at the bottom part of the model only. This occurs because the water has a higher density than oil. It is important to note that plain gas injection is considered as a part of WAG process with a WAG slug size ratio of 0:1, hence the design issues pertinent to WAG are applicable to plain gas as well.

Thus, immiscible CO₂ flooding was carried out after water flooding and both of them act as secondary recovery processes. During immiscible CO₂ flooding, the graph shows a slight increase in oil recovery, which is only about 1% at 3.5PV for all three WAG ratios. This is due to the possibility of viscosity fingering phenomena and the problem of early

breakthrough of gas. This occurs because the gas has a relatively high mobility compared to oil thus an early breakthrough of gas takes place. Tertiary recovery using WAG flooding was carried out after immiscible CO₂ flooding. From the graph, the WAG slug size ratio 1:1 gives the highest increment of oil recovery which is 8% as compared to other ratios.

4.1.2. Discussion on Studied WAG Ratios

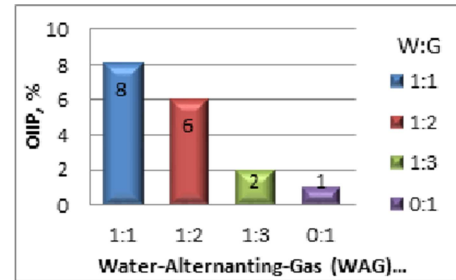


Figure 9. Incremental OIIP, % at Different WAG Ratios.

Figure 9 shows the increment of OIIP during WAG flooding where the optimum WAG ratio is seen to be 1:1 with equal water and gas slugs to be injected or maximum recovery. With a WAG ratio lower than 1 (i.e. WAG ratio 0:1, 1:2 and 1:3) the volume of gas injected is higher than the injected water and thus shows a decrease in OIIP. This is mainly due to the improvement of sweep efficiency by the water and displacement efficiency by the gas slug that are equally the same size. Study from Gorell (1988), [3]; showed that equal WAG ratios are more efficient and are insensitive to assume levels of trapping. From Al-Shuraiqi et al (2003) [4], the optimum oil recovery was obtained at a WAG ratio 1:1. WAG ratios of 0:1, 1:2 and 1:3 with increasing CO₂ slug size gives lower oil recovery. This may cause a gas tongue to develop at the top of the reservoir leading to an early gas breakthrough since gas possesses a very high mobility within the porous media. Issues that could arise as a cause of a very low WAG ratio (where too much gas is injected) are viscous fingering due to high proportion of gas in relation to water, the mobility ratio of the displacing phase may be higher than 1 and poor macroscopic sweep efficiency which may result in a decreased overall recovery.

The importance for an optimum WAG ratio is to avoid having too much water which may lead to a poor macroscopic displacement because water reduces the displacement efficiency when compared to gas and a water tongue may develop at the bottom of the reservoir. On the other hand, injecting too much gas will result in a gas tongue forming at the top of the reservoir. This is known as gas override and this may lead to a poor horizontal and possibly vertical sweep efficiency; Larsen et al. 2000 [2].

Injecting too much gas possesses a very high mobility and this may negatively impact the success of the WAG process. Blackwell (1960), [6]; suggested that the volume of injected gas should be sufficient to deliver gas to the WAG front at the rate overall to the reservoir recovery. The reason for this

is because the injected gas is lost due to gas trapping to be replaced within the reservoir to maintain the displacement efficiency of the WAG process. Al-Shuraiqi (2003), [4]; also proposes that recovery from WAG is a function of rate as well as WAG ratio. In essence, an optimum WAG ratio

should be adequate to attain a good mobility within the reservoir while maintaining a large throughput rate and at the same time giving a low segregation effect; Jerauld, 2000 [21]; Larsen et al, 1995 [6].

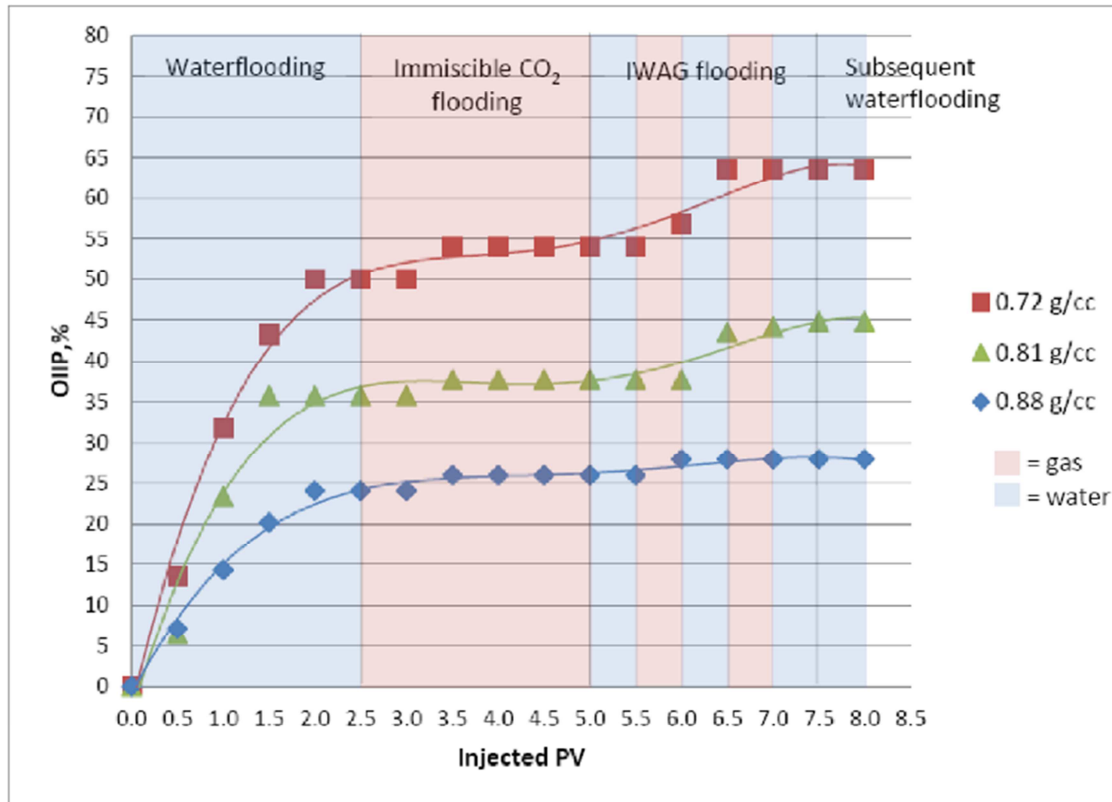


Figure 10. Incremental OIIP, % at Different Oil Densities.

4.2. Effect of Oil Density

An experimental study was carried out to determine the effect of different oil densities on OIIP of oil recovery. The water-CO₂ slug size ratio 1:1 remained constant throughout the experiment. Each cycle of injection started with water and ended with CO₂ slug with a flow rate of 1 cc/min after 2.5 PV injected. Subsequent 0.5PV water flooding was carried out to make sure there were no more oil displaced and the recovery remains constant.

4.2.1. Analysis on Oil Density

Table 5. Total Oil Recovery at Different Oil Densities.

Oil density (g/cc)	OIIP (%)			Total OIIP (%)
	Water flooding	Immiscible CO ₂ flooding	IWAG	
0.72	50	4	9	64
0.81	36	2	7	45
0.88	24	2	2	28

Figure 10 shows the relationship between three different oil densities and percentage recovery for water flooding, immiscible CO₂ flooding and IWAG flooding recorded at every 0.5 PV and total of 2.5 PV for each type of flooding. During water flooding process, the increment of oil recovery

for each oil density were different. This is due to different flow resistance of oil which depends on density.

From the graph, oil density of 0.72 g/cc shows the highest incremental oil recovery compared to others because of its lowest density and viscosity. At 2PV, oil recovery for all three IWAG ratios are relatively increasing with a constant rate because the water injected acts like a piston which evenly sweeps the front oil. At this time, maximum oil recovery was recorded. After 2PV, the graph is constant and there is no increase in oil recovery. This is due to the occurrence of gravity segregation where the injected water tends to flow at the bottom part of the model only. This occurs because the water has a higher density than oil.

During immiscible CO₂ flooding, the graph shows a slight increase in oil recovery which is only about 2% at 3.5 PV. This is due to the possibility of viscous fingering phenomena and the early breakthrough of gas. This occurs because the gas has a relatively high mobility compared to water and thus early breakthrough of gas takes place. Lower density also allows the injected gas to migrate to the top of the reservoir and sweeps the attic oil without sweeping the bottom of the reservoir. Tertiary recovery using IWAG flooding was carried out after immiscible CO₂ flooding. From the graph, an oil density of 0.72 g/cc gives the highest increment of oil

recovery which is 9% as compared to other ratios.

4.2.2. Discussion on Studied Oil Densities

Figure 11 shows that the percentage of oil recovery for tertiary recovery using WAG is inversely proportional to the oil density, higher oil density resulting in lower oil recovery. WAG process is different from the other methods because it is involving two important density parameters which are the density ratio of gas to oil and water to gas. Both of these parameters will affect the performance of the WAG process. During flooding process, gravity segregation of the fluids occurred when the gravity force due to the density difference between the fluids used is comparable with the viscous forces.

Blackwell *et al* (1960), [6]; reported that the higher ratio of viscosity and density of water to gas would yield a higher oil recovery, viscosity fingering phenomena and gravity segregation due to different oil densities can be reduced. In a simulation study conducted by Stone (1982), [7]; the alteration of viscosity and density ratio can influence the effect of gravity segregation as much as 400%. Rapoport (1953), [8]; reported that for each different viscosity, the density ratio will affect the

efficiency of water flooding and will produce different percentages of recoveries. Thus the properties of fluid to be used in the experiment should be given scrutiny.

By conducting this experiment with parameters of different oil densities, many factors of displacement efficiencies can be discussed. The microscopic displacement efficiency by gas is affected by IFT and capillary pressure. Meanwhile, the most important factor that affects the macroscopic displacement efficiency by water is the mobility of the displacing fluids compared with the mobility of the displaced fluids.

4.3. Effect to Mobility Ratio

Three fluids exist in this system such as water, CO₂ and oil. The effective permeability of these fluids is directly proportional to each flowing rates, whereas the density and viscosity inversely affect each of the flowing rates. Thus, flowing rates were determined by calculating effective permeability ratio and viscosity which is expressed as a Mobility Ratio, M.

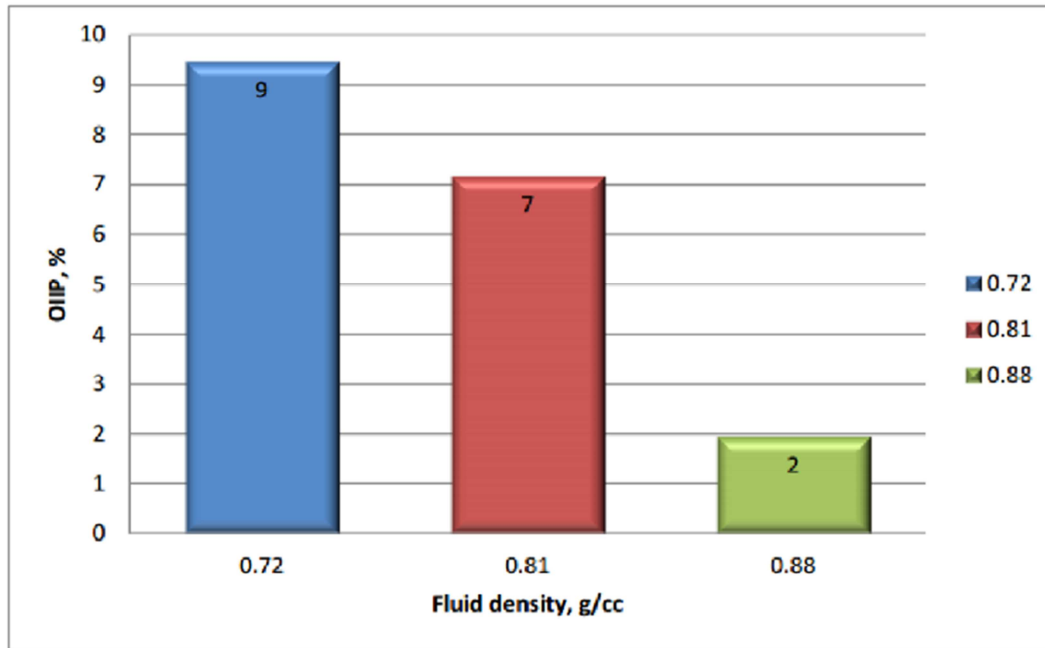


Figure 11. Incremental OIIP, % at Different Oil Densities.

$$M = \frac{\lambda_{displacingfluid}}{\lambda_{displacedfluid}} = \frac{\lambda_o + \lambda_w}{\lambda_g + \lambda_w} \quad (7)$$

Where; $\lambda_g = \frac{kr_g}{\mu g}$; $\lambda_o = \frac{kr_o}{\mu o}$; $\lambda_w = \frac{kr_w}{\mu w}$; λ = Transmissibility, k_r = relative permeability, μ = viscosity; g = gas, o=oil; w = water.

Table 6. Mobility Ratio for Water-Oil System and Water-CO₂.

Displacing Fluid	Displaced Fluid	Mobility Ratio, M
Water	Oil	16
CO ₂	Oil	2300

oil shows the lowest mobility ratio. For instance, high oil viscosity leads to an unfavorable mobility ratio between displacing and displaced fluid. A large fraction of the oil is not contacted by the injected fluid and the oil that is contacted is poorly displaced.

4.4. Effect to Capillary Number, N_c

Table 7. Capillary Number of Different Types of Oil.

Type of Oil	Oil Viscosity, cp	IFT (mN/m)	N _c
Kerosene	13	25	0.08
Paraffin	23	43	0.05
Lubricant	160	47	0.24

From this experiment, lubricant oil which represents heavy

Capillary number, N_c represents the relative effect of viscous forces versus surface tension acting across an interface between two immiscible liquids

$$N_c = \frac{v\mu}{\sigma} \tag{8}$$

Where, N_c = capillary number, v = Darcy velocity, σ = Interfacial Tension and μ = viscosity.

The magnitude of capillary forces is determined by IFT, wettability condition and pore geometry in which the trapped phase blobs exist. For a flowing liquid, if $N_c > 1$, then viscous forces dominate over interfacial forces. However if $N_c < 1$, then viscous forces are negligible compared with interfacial forces and the flow in porous media is dominated by capillary forces. Viscous force is set by permeability of the medium, applied pressure drop and viscosity of the displacing phase. From this study, all systems were dominated by interfacial force. In order to maximize efficiency, the capillary number should be minimized while maximizing mobility ratio. Therefore lowest IFT makes the injection process of WAG into the light oil system (kerosene) give the highest recovery. The significant decrease in oil recovery of lubricant oil as compared to other types of oil was due to the higher viscosity between the fluids and pressure gradient promoting a higher capillary number.

4.5. Effect to Displacement Efficiency, E_D

Displacement efficiency (E_D) accounts for the efficiency of recovering mobile hydrocarbon.

$$E_D = \frac{V_p S_{oi} - V_p S_{or}}{V_p S_{oi}} = \frac{S_{oi} - S_{or}}{S_{oi}} \tag{9}$$

Where E_D = Displacement efficiency, %; V_p = Pore Volume; S_{oi} = Initial water saturation, %; S_{or} = Residual oil saturation, %.

Table 8. Displacement Efficiency of Different Types of Oil.

Type of Oil	S_{oi} , %	S_{or} , %	E_D , %
Kerosene	50	45	10
Paraffin	64	60	6
Lubricant	77	75	3

From Table 8, kerosene oil shows the most efficient displacement (higher E_D) because it is the most mobile oil. During flooding, a large fraction of oil is contacted by the injected fluid and the oil that is contacted is displaced efficiently. Because of the lowest resistance and ease to flow out from the model. There is less trapped is generated by injected water and gas fingering phenomena occurs.

4.6. Effect to Viscous-to-Gravity Ratio, R_{vg}

Viscous to gravity ratio (R_{vg}) is defined as the ratio of vertical force to horizontal force for a fluid flow through a porous media.

$$R_{vg} = \left(\frac{v\mu_o}{k_o g \Delta\rho} \right) \left(\frac{L}{h} \right) \tag{10}$$

Where R_{vg} = Viscous gravity ratio, v = injection velocity, ft/s; μ_o = Oil viscosity, lb/ft.s; k_o = Oil permeability, Darcy; g = acceleration due to gravity, ft³/s; $\Delta\rho$ = density difference between fluids, lb/ft³; L = distance between wells, ft and h = reservoir thickness, ft.

Density difference between injected fluid and displacing fluid caused gravity forces to dominate over viscous forces. The importance of gravity segregation of fluids can be determined by R_{vg} , where vertical force may lead to viscous fingering while horizontal force results into gravity segregation or also known as gravity tonguing. During displacement of kerosene oil, gravity segregation may dominate over viscous forces since kerosene has the lowest oil viscosity. ($N_g > 1$)

$$N_g = \frac{k_v \Delta\rho g L^2}{k_h \Delta P_h H} \tag{11}$$

Where; N_g = Gravity Number; k_v = Vertical permeability, ft², k_h = Horizontal permeability, ft²; g = acceleration due to gravity ft³/s; $\Delta\rho$ = Density difference between fluids, lb/ft³; L = distance between wells, ft; H = reservoir thickness, ft and ΔP_h = pressure drop across horizontal direction, psia.

However, lubricant which is considered as heavy oil has the highest density and viscosity. During the flooding process, the difference between viscosity of injected fluid (water or gas) and displacement fluid (lubricant) is higher compared to other oil types and the viscous force becomes stronger ($N_g < 1$). This cause the lower viscous fluid (water or gas) to flow preferentially through the more highly permeable layers. This implies the creation of a horizontal fluid distribution that is not in gravity equilibrium.

5. Conclusions and Recommendations

5.1. Conclusions

The IWAG injection experiments that studied on the effect of WAG slug size ratio on OIIP of oil recovery have been successfully completed. Through this EOR study, the following conclusions can be made.

- 1) Secondary recovery which is a water flooding process had resulted in 36 – 50% of oil recovery while gas flooding resulted in 1 – 35 of oil recovery.
- 2) The further oil recovery of 1% – 8% was reported for IWAG flooding.
- 3) By injecting water and gas alternately, more oil can be produced rather than injecting water or gas alone.
- 4) The WAG slug size ratio of 1: 1 was the optimal since the tertiary oil recovery using IWAG was 8% and total 45% of OIIP.

- 5) The density of 0.72 g/cc was the optimal since the tertiary oil recovery using IWAG was 9% and total 64% of OIIP.
- 6) Oil recovery was more favorable at the same WAG ratio and using lowest oil density.
- 7) During IWAG flooding, CO₂ slug helps in microscopic sweep efficiency whereas water helps in macroscopic sweep efficiency.
- 8) The lower oil density will have higher mobility and flow with low resistance whereas higher oil density will have lower mobility and flows with a high resistance.

5.2. Recommendations

The recommendation from this study for future work to improve the results of this research have been proposed.

- 1) Experiment can be implemented at typical reservoir temperature and pressure in order to obtain a good indicator field scale injectivity during IWAG process.
- 2) Instead of PVC sand pack model, core flooding should be conducted using glass bead model to get better visual observation during IWAG process
- 3) Live reservoir fluids and formation rock samples should also be used but the costs and availability should be considered.
- 4) Wider range of WAG slug size ratio should be selected.
- 5) Precautions that are recommended to be taken and the errors suggested to be avoided are as follows;
 - a. All connections between the Teflon tubes to the model and syringe pump should be very firm and tidy in order to prevent leakage so that the volume of the fluids injected and the effluents collected will be equal to the measured volume.
 - b. Due to the longer and heavier sand pack model, the stand/core holder must be placed at both ends to avoid inclination of the model.
 - c. The oil should be mixed with dye to ease observation in order to see the trend of oil recoveries and to measure the volume of oil in the measuring cylinder precisely.
 - d. The sand pack model should be fully compacted to avoid large void in the model to ensure the porosity and permeability are precise. Little amount of water should be poured into the model during packing to make it more compact.

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