PERFORMANCE OF NEAR-MISCIBLE GAS AND SWAG INJECTION IN A MIXED-WET CORE

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ABSTRACT
Oil recovery from mature waterflood can be enhanced by combined injection of water and gas in an alternating (WAG) or simultaneous (SWAG) scheme. However, less experience has been gained on the performance of WAG and SWAG in mixed-wet systems with low gas-oil IFT. We present results of a series of high-pressure displacement tests in a mixed-wet sandstone core.

We demonstrate that In near-miscible continuous gas injection, unlike immiscible gas injection, the oil recovery continues at a significant rate after the main gas breakthrough and nearly total oil recovery can be achieved. The results of near-miscible SWAG injection experiments that we have performed with different SWAG (gas/water volumetric) ratios are also presented and discussed. Comparison of oil recovery by water injection, continuous gas injection and SWAG injection shows that oil recovery due to SWAG is the highest, in this mixed-wet core.

INTRODUCTION
Sometimes gas and water are both available for injection into the reservoir as a means of improving recovery. In such cases it would be possible to inject a combination of gas and water either alternately (WAG) or simultaneously (SWAG). It is known that using the WAG or SWAG injection some extra oil can be produced. Unfortunately, the underlying physics of the three-phase flow is not well understood to allow reliable predictions to be made for economic evaluation. This recovery method will involve drainage and imbibition processes taking place sequentially. Their three-phase relative permeability and capillary pressure functions are, therefore, extremely complex. It is practically impossible to develop such functions for realistic reservoir situations, using routine core displacement methods.

Some authors such as Guzman *et al* (1994) have shown that there is significant uncertainty associated with the selection of the three-phase relative permeability model for field scale simulations of gas and WAG injections. Guzman's results have shown that, in a reservoir scale modelling, this uncertainty is translated into doubtful simulation results in terms of distribution of the fluids, total oil recovery and fluid production rates.
Generally, three-phase relative permeabilities are calculated from empirical correlations, which are based on the corresponding two-phase relative permeability data. Furthermore,

when these correlations are applied, most simulators implicitly assume that the reservoir is a water wet system and the oil is the intermediate-wetting phase with the gas being non-wetting phase. Therefore the oil relative permeability is a function of two saturations, Kro (Sg, Sw). This further implies that water and gas three phase relative permeabilities depend only on their own saturations, i.e. the three phase quantities, Krw = Krw(Sw) and Krg = Krg(Sg). Many experiments indicate, however, that reservoirs are not strongly water-wet but can attain a wide variety of wettability states in which certain clusters of pores are water-wet and others are oil-wet. For these states the saturation-dependencies for the corresponding three-phase relative permeabilities are not systematically known. The problem becomes more complicated for three-phase system with a very low gas-oil IFT (near miscible systems). Near-miscible gasflood refers to injection of gases that do not develop complete miscibility with the oil, but come close. Compared to miscible gas injection, a near-miscible gas injection appears more attractive from both economic and operational standpoints. In reservoirs where pressure is lower than MMP a near-miscible operation may be more feasible than a miscible one.

2D simulation studies (Burger et al, 1994, Thomas et. al, 1994) have demonstrated that injectant with less enrichment than that required for first-contact miscible with the oil often yields optimum oil recoveries owing to better sweep efficiencies in heterogeneous reservoir models. Field-scale simulations show that near-miscible solvents are attractive because of improved sweep over miscible solvents (Pande 1992). Burger *et al.* (1994) showed that economically optimum enrichment in high-viscosity-ratio secondary gasfloods could be operated at pressures below the MMP. Thomas *et al.* (1994) reported that gas-oil IFT can be reduced adequately under near-miscible conditions and that zero IFT is unnecessary for effective displacement processes in realistic porous media. Shyeh-Yung (1991) demonstrated that tertiary gasflood recoveries below MMP do not decrease as severely as predicted by slim-tube tests for CO_2.

Core flood experiments of near-miscible gas injection have been reported before (Soroush and Saidi 1999) but as far as we are aware no three-phase core experiments involving both near-miscible gas and mixed-wet core is available in literature. We have performed a set of high-pressure, near miscible, core flood experiments on a 1000 mD mixed-wet sandstone core to obtain an improved understanding of the WAG and SWAG processes and to develop tools that can be used for accurate prediction of additional oil recovery.

EXPERIMENTAL STUDIES

Here we first present a description of the core and the fluids that were used in the experimental work. We then present results of the experiments.

Core Preparation

Prior to performing coreflood experiments a preparation procedure has been followed to determine properties of the core and also check the degree of its homogeneity. Once the core is loaded and the helium porosity and nitrogen permeability of the core are measured, it is saturated with a 1% brine solution. A 1% sodium chloride/calcium chloride brine solution is used to desensitise any clay minerals and prevent them from swelling and restricting flow. Table 1 shows the properties of the core.

Tracer Analysis and Porosity Profiling

Tracer analysis of the core was conducted to ensure that there were no major heterogeneities, such as fractures or permeability layers, in the core, which if not detected might influence the results of multiphase flow experiments. Our x-ray facility was also used to investigate the internal variation in porosity along the core sample following the tracer analysis. The difference between the x-ray counts when the core was fully saturated with methane and brine was used to plot porosity versus length for the Clashach core. This plot is shown in Figure 1, which shows an average porosity of around 17% and the porosity profile along the length of the core.

Test Fluids

For the experiments reported here a three-component three-phase fluid system was used at 37.8 °C (100 °F). The aqueous phase was 1% sodium chloride/calcium chloride brine solution. The hydrocarbon components were *n*-butane (n-C_4) and methane (C_1). To avoid mass transfer during the experiments, the fluids (C_1, n-C_4 and brine) were pre-equilibrated at the pressure and temperature of the experiments. Table 2 shows the physical properties of the hydrocarbon vapour (gas) and that of hydrocarbon liquid (oil), at the prevailing conditions of the experiments. The values reported for viscosity and density are estimated values. The IFT values have been measured in our laboratories by pendant drop method and represent equilibrium values within the equilibrium 3-phase system.

Development of Mixed-Wettability

Significant efforts have been directed at development of controlled and stable mixed-wet conditions. In general, core wettability can be altered by either suitable chemicals or by ageing it in a suitable crude oil. In our laboratories we have extensive experience in applying both methods. Although using chemicals is less time consuming and involves a relatively simpler procedure but the stability of the modified wettability (in contact with water) is generally poor and open to question. Ageing in crude oils involves a more difficult procedure and requires careful planning and is much more time consuming. However, once a modified wettability condition has been achieved, it could be very stable and long lasting. We have identified a suitable crude oil and procedure to achieve mixed wettability. Before attempting to alter the wettability of the main rock, we tested our procedure on small core plugs and thin slides taken from the same rock. The resultant modified wettability was analysed and evaluated by both Environmental Scanning Electron Microscope (ESEM) and by wettability index determination (Amott and USBM).

Mixed-wet Core

The core was first thoroughly cleaned by a succession of solvent injection and dried. Then the initial water saturation was established. This is a relatively long (3 to 4 weeks) process. Having established S_{wi}, the core was placed in a constant temperature oven and the crude oil was injected through it. The injection of the crude oil continued at a slow rate for a week to supply fresh crude. The core chamber was then shut in and the core was allowed to age in the crude oil for a period of two weeks at 40 °C. After this ageing period, the core went through another long period of cleaning to make sure that the ageing crude had been displaced from the core and would not contaminate the test fluids. The crude oil was first flushed out of the core by injecting a mineral oil followed briefly with a mild solvent (decalin). Decalin itself was displaced by normal decane (nC_{10}), which was in turn displaced with high-pressure methane (C1) injection. At this stage the core was used to perform a number of flow measurement tests. To evaluate and quantify the modified wettability of the core, it was removed from the core holder and a two-inch piece was cut from it. This core plug was used to determine the core wettability by performing a USBM test.

USBM Wettability Index Test

USBM index was determined by measuring the capillary pressure curves, using the centrifuge technique. Figure 2 shows the results of the test of the mixed-wet core as measured for us by a service company. As it can be seen the core plug had a USBM index of - 0.02, which shows that the core wettability was mixed-wet with an average neutral wettability.

Fluid Flow Tests (Mixed-wet Core)

In the following coreflood tests the core orientation was horizontal and on constant rotation to minimise gravity effect.

Gas Injection (Unsteady-state, Immiscible Fluids)

Having altered the core wettability to mixed wet, an unsteady-state gas injection test was carried out at 1200 psia (corresponding to a gas-oil IFT of 2.7 mNm^{-1}). This test was done to allow us to compare the results of a similar immiscible gas-oil displacement test that had been carried out previously using the water-wet core.

Having saturated the mixed-wet core with oil (in presence of 8% water) and pressurised it to 1200 psia, gas was injected through the core at 200 cm^3/hr. This rate of gas injection was selected based on a series of gas injection tests, which showed that for gas injection rates of 200 cm3/hr, and lower, oil recovery was not a function of the rate of gas injection. Figure 3 shows the oil recovery during this unsteady-state gas injection. The injection of gas was continued until almost 9 PV of gas had been injected. Figure 3 also shows a comparison of oil recovery between the gas injection test carried out in the mixed-wet core and a similar test carried out in the water-wet core. It appears that there is a very small difference between the amounts of oil recovered in the two tests with the mixed-wet core recovering a little less oil. This little difference is well within the accuracy of the test, however, it could also mean that in the mixed-wet core, as a result of the presence of oil-wet pores, oil retention has been slightly higher than the water-wet core and hence, resulting in a slight reduction in oil recovery.

Gas Injection (Unsteady-state, Near-miscible)

This unsteady-state test was carried out using near-miscible gas/oil at 1840 psia (corresponding to a gas-oil IFT of 0.04 mNm^{-1}). The test results also allowed us to compare the performance of gas flood at high IFT with results at a very low IFT. As a similar test had previously been carried out in the water-wet core at the same gas-oil IFT value, it was also possible to investigate the effect of wettability on the gas injection process.

Having saturated the mixed-wet core with oil (in presence of connate water) and pressurised it to 1840 psia, near-miscible gas was injected through the core at 200 cm^3/hr. Figure 4 shows the oil recovery during this unsteady-state gas injection. The injection of gas was continued until almost 7.5 PV of gas had been injected. Figure 4 also compares the recovery of oil during near-miscible gas injection with immiscible gas injection both carried out in the mixed-wet core. Clearly the displacement of oil by near-miscible gas has been much more effective than the displacement with immiscible (high-IFT) gas. This is a result of both lower gas-oil IFT and lower oil viscosity in the near-miscible gas injection case. Figure 5 demonstrates the effect of core wettability (mixed-wet vs. water-wet) on oil recovery during near-miscible gas injection. The plot shows that low-IFT gas injection in the mixed-wet core has ultimately recovered around 5% additional oil compared to water-wet experiments.

Oil Injection (Unsteady-state, Near-miscible)

In the WAG process different types of displacement can take place within the reservoir. One is the displacement of gas by a bank of oil that has been formed as a result of alternating injection of water and gas. To check this effect an unsteady-state oil injection test was carried out in the mixed-wet core. Initially, the core (containing 8% connate water) was saturated with gas at 1840 psia (corresponding to a gas-oil IFT of 0.04 mNm^{-1}). Then oil was injected through the core at a rate of 200 cm^3/hr. Figures 6 and 7 show the gas and oil recovery during this unsteady-state oil injection. Figure 8 shows that, as expected, prior to oil breakthrough only gas was recovered from the core. However, when the oil front reached the production end of the core (breakthrough) at 0.6 PV of oil injection, almost instantly the gas production ceases and thereafter the core effluent is almost entirely oil. This is again demonstrated in Figure13 which shows that prior to the oil breakthrough no oil production takes place and immediately after the oil breakthrough the oil production plot follow the trend of a diagonal line with slop of 1. Figure 8 also compares the oil recovery in near miscible gas injection with that of gas recovery in near-miscible oil injection in the mixed-wet core. As it can be seen, for the same gas-oil-rock system, when gas displaces oil, the amount of oil recovery is by far higher than gas recovery when oil displaces gas. This Figure also shows that when oil displaces gas, the breakthrough is delayed compare to when gas displaces oil and, as a result, the recovery of the gas during oil flood, at breakthrough, is higher than the recovery of the oil during gas injection. This is a direct consequence of viscosity contrast between gas and oil and also due to the fact that oil recovery continues, at significant rates, after gas breakthrough (through highly conductive oil layers being present) but gas recovery after oil breakthrough cannot take place due to absence of gas layers.

WAG injection (Near-miscible, starting with water injection)

This test was carried out to evaluate the process of WAG injection by near-miscible gas injection in the mixed-wet core. The core containing connate water was saturated with oil at 1840 psia. Then two cycles of water injection, followed by gas injection, were carried out. The injection rates in all the cycles were constant at 200 cm^3/h.

1st water injection

Brine (1% sodium chloride/calcium chloride) was injected through the core until oil production stopped. As the initial water was not mobile, before the water breakthrough only oil was produced. When water broke through at the production end of the core, oil production stopped almost immediately and no more oil was produced.

1st gas injection

After the above-mentioned water injection period, gas was injected through the core at the same rate as the preceding water injection. The injection of this near-miscible gas was continued until almost 1.5 PV of gas had been injected. We observed that initially (before gas breakthrough) there was no oil or gas production and the only phase that was being produced was water. This is due to high water saturation within the core, which was brought about by the previous water injection period. What is interesting is the fact that oil recovery does not begin until gas breakthrough takes place. This confirms our micromodel observations of near-miscible gas injection in which oil flow would take place alongside the flowing gas. The micromodel experiments of near-miscible gas injection also showed that if enough gas was injected, almost all of the oil that had been contacted by the injected gas was recovered.

2nd water injection

The second cycle of WAG test began with the 2nd water injection in which almost 1 PV of brine was injected through the core. During this cycle of water injection, initially only gas and, to a much lower extent, oil was produced until water breakthrough took place. The oil recovery started slowly with gas production and increased steadily until the water broke through, when the oil recovery stopped. This is again consistent with the results of our micromodel experiments that showed fragmentation of the continuous gas paths during water injection, which resulted in cessation of oil flow.

2nd gas injection

The second gas injection was carried out and continued for around 1.5 PV. These tests showed very similar trends to what was observed during the 1st period of gas injection, however, less oil was produced in this cycle than the first cycle of gas injection.

Figure 9 shows oil recovery during fluid injection subsequent to the initial waterflood, as a fraction of residual oil saturation to waterflood. It can be seen that the first gas injection period recovered 50% of the oil, which was trapped after the initial waterflood. The second cycle of water and gas injection recovered around 24% and 22% of the residual oil, respectively. The remaining oil-in-place after the second cycle of WAG was only about 4% of the residual oil after initial waterflood.

SWAG injection with gas/water ratio of 1 (Near-miscible, mixed-wet)

Preparation

Having performed the aforementioned WAG test, preparation was made to perform a SWAG (Simultaneous Water and Gas) injection test using near-miscible fluids and the same mixed-wet core that was used in the previous tests. As explained above, at the end of the preceding WAG test almost all of the oil originally contained in the core had been recovered and the core was essentially saturated with water and gas. To prepare for the SWAG test, first it was necessary to establish an initial-oil-saturation. To do this, the core was initially subjected to an oil flood. During this oil injection period, the injected oil displaced most of the gas. To ensure that no gas had been left behind, the core pressure was raised to 2100 psia. This pressure is above the saturation pressure (1840 psia) of the oil and gas and any trapped gas would have been dissolved in the oil at this pressure. The resultant liquid phase (oil) was then displaced by oil equilibrated with gas at 1840 psia. Having injected several pore volumes of the equilibrium oil, the core pressure was slowly dropped back to the test pressure, 1840 psia. This procedure ensured that no gas was present in the core while establishing an initial oil and water saturation of 61.5 and 38.5 %PV, respectively.

SWAG injection

Having established an initial oil saturation of 61.5 and water saturation of 38.5 %PV at 1840 psia, water and gas were simultaneously injected through the core. Both water and gas were injected at an equal rate of 100 cm^3/h (total fluid injection rate of 200 cm^3/h and a SWAG ratio of 1). The SWAG injection was continued until almost 1.5 PV had been injected. Figures 10 and 11 show the plot of gas and oil recovery versus SWAG injection. It can be seen from the gas recovery plot that initially no gas was recovered, as there was originally no gas in the core. The oil recovery plot shows that as water and gas are (simultaneously) injected through the core, only oil is being recovered from the core up until around 0.3PV of SWAG injection. At around 0.3PV, gas breakthrough happens and thereafter gas and oil are both being recovered. This point is shown from the gas recovery plot and also from a bend on the oil recovery curve. At around SWAG injection of 0.75PV, water breakthrough also took place and after that point all the three phases of water and oil and gas were produced. This point is shown by a second and sharper bend on the oil recovery curve.

Figure 12 shows the oil recovery versus SWAG injection volumes. However, in this plot the oil recovery is expressed in terms of initial oil in place. As it can be seen, after almost 1.5 PV of SWAG injections, 90% of the initial oil saturation had been recovered.

Figure 13 has been prepared to compare the performance of SWAG injection against water or gas only injection. This plot shows oil recovery at the breakthrough for water injection, gas injection and also the previous SWAG injection test all carried out using the near-miscible gas-oil system and the mixed-wet core. As it can be seen, the SWAG injection test produced the highest oil recovery followed by waterflood and gas injection. However, it should be emphasise that the initial oil and water saturations have not been the same in these tests.

Figure 12, also reveals that since gas breakthrough had happened much earlier than the water breakthrough, it had retarded the oil recovery too early. Therefore, to maximise oil recovery the SWAG injection has to be performed at a lower gas-to-water ratio to delay the gas breakthrough and to bring it closer to the water breakthrough. To obtain the optimum value of SWAG ratio, it is important to carry out more tests with different values of gas/water ratio. This is planned for the near future.

<u>WAG injection (Near-miscible, starting with gas injection)</u>

First the initial conditions were established in the core with an oil saturation of 60 %PV and a water saturation of 40 %PV. Unlike the previous WAG injection test, this test began by initial gas injection as opposed to initial water injection. The injection rates in all the tests were constant at 200 cm^3/h, unless otherwise stated.

1st gas injection

Having saturated the mixed-wet core with 60% oil and 40% water at 1840 psia the 1st gas injection was carried out. After injecting around 1 PV of near-miscible gas, gas injection stopped and water injection commenced. We observed that despite recovering around 43 %PV of oil almost no water had been recovered during this gas injection. This is attributed to both a very low value of gas-oil IFT and a high viscosity contrast between water (nearly 1.0 mPa.s) and oil (ca 0.04 mPa.s).

1st water injection

Having performed a gas injection period, water was injected and it was continued until around 0.6 PV of water had been injected. It was observed that initially (before water breakthrough) there was a slow oil recovery but a significant gas production. When water was about to break through at the production end of the core a sharp rise in oil production took place. This indicates that a bank of oil had been formed by the invasion of some of the oil-filled pores and had been moving ahead of the waterfront. The presence of these oil banks has also been observed in our micromodel experiments (Sohrabi et al, 2000, Sohrabi et al, 2004). Shortly after the water breakthrough the production of both oil and gas stops and only water is produced thereafter.

2nd gas injection

The second cycle of WAG injection began with the 2nd gas injection period (after water injection) in which almost 1.2 PV of near-miscible gas was injected through the core. During this second cycle of gas injection, initially only water was being produced up until the gas breakthrough took place. The oil recovery began after the gas breakthrough, which confirms the previous micromodel observation that the flow of oil is associated with the flow of gas.

2nd water injection

The second water injection period was the final stage of this WAG test. The injection was continued for about 1 PV. As soon as water injection commenced, gas and oil recovery started to show. The simultaneous production of oil and gas continued until the water breakthrough. At this point the recovery of both gas and oil ceased. Initially, the pore volume of the core was saturated with 60% oil and 40% water. The 1st gas injection period reduced the oil saturation to around 20%. Subsequent water and gas injection periods reduced the oil saturation further and at the after the 2nd water injection period only less than 3% of the core pore volume was occupied by oil.

Figure 14 shows oil recovery during water and gas injection subsequent to the initial gas flood, as fraction of the residual oil saturation after the initial gas flood. It can be seen that the first water injection period recovered 31% of the oil, which was trapped after the initial gas injection. The second cycle of gas and water injection recovered around 33% and 22% of the residual oil, respectively. Direct comparison between oil recoveries at different stages of this WAG injection that had begun by gas injection with the WAG test that started with water injection could be misleading. This is due to the fact that different volumes of fluids have been injected in the two tests and this makes stage-by-stage comparison inappropriate. It is especially true for gas injection periods in which significant additional oil recovery can be achieved by continuation of the injecting near-miscible gas.

CONCLUSIONS

Using crude oil ageing procedure, the core wettability was successfully altered from water-wet to mixed-wet, as indicated by the measured USBM index of -0.02. The mixed-wet core was used to perform a series of two-phase and three-phase WAG and SWAG experiments. These experimental results will be used to predict 3-phase relative permeability curves using the available 3-phase models to evaluate their applicability for mixed-wet and near-miscible systems.

The conclusions drawn from this work are based on our core-scale experiments and may not be applicable to reservoirs. The main conclusions are as follows:

- The difference in oil recovery due to gas injection in the water-wet core and the neutral-wet core at gas-oil IFT of 2.7 mNm^{-1} was minimal.
- As expected, oil recovery due to near-miscible gas (0.04 mNm^{-1}) injection in the mixed-wet core was much higher than that of the immiscible gas (2.7 mNm^{-1}) injection in the same core.
- Ultimate oil recovery by near-miscible gas injection in the mixed-wet core was significantly higher than gas recovery due to oil injection in the same core and at

the same low gas-oil IFT. However, at breakthrough, gas recovery due to oil injection was higher than oil recovery due to gas injection.

- As had been observed previously in our micromodel experiments, in near miscible gas injection oil recovery continues, at a significant rate, after the gas breakthrough and can lead to nearly total oil recovery.
- Oil recovery by near-miscible SWAG injection is a very efficient recovery method. In the SWAG test that has been reported here, for gas-water ration of 1, oil recovery at breakthrough was higher than water injection alone and near-miscible gas injection alone. SWAG oil recovery is expected to be even higher if the injection is carried out at the optimum SWAG (gas-water) ratio.

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Table 1: Core Properties.

Core	Length / cm	Diameter / cm	Porosity / frac.	k/ mD
Clashach	67.0	4.98	0.17	1000

Table 2: Properties of C1/n-C4 mixture at 37.8 C.

P /psia	ρg /kgm^{-3}	ρ_L /kgm^{-3}	μ_g /mPa.s	μ_L /mPa.s	IFT /mN m^{-1}
1200	86.68	466.06	0.0141	0.0793	2.7
1840	211.4	317.4	0.0249	0.0405	0.04

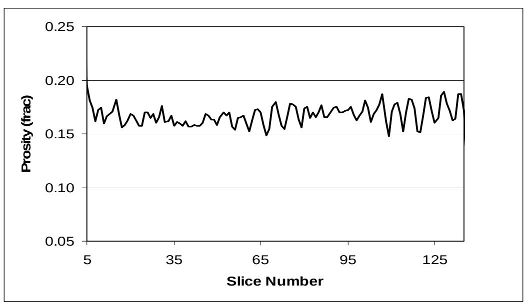

Figure 1 - Porosity profile for the Clashach core.

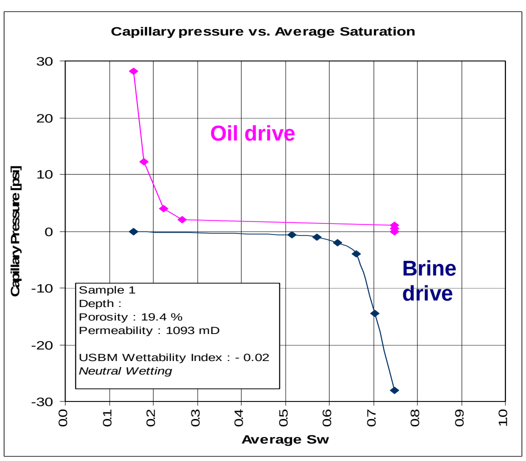

Figure 2– Capillary pressure versus water saturation obtained during USBM wettability test carried out on the mixed-wet core by centrifuge.

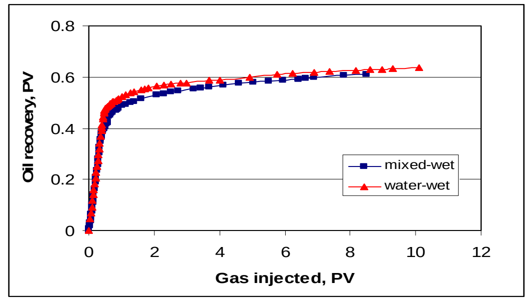

Figure 3 – Oil recovery during gas injection. Comparison of mixed-wet with water-wet core

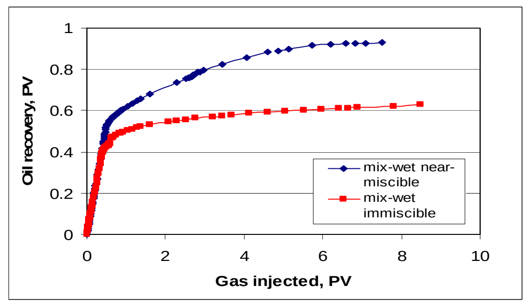

Figure 4 - Oil recovery during gas injection in the mixed-wet core, comparison of near-miscible gas vs. immiscible gas injection.

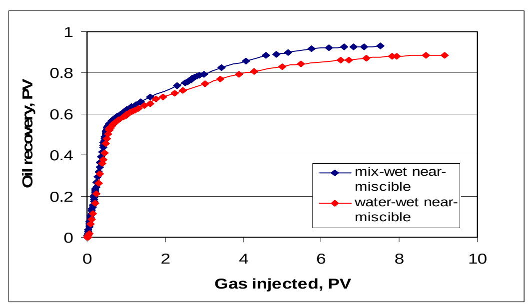

Figure 5 - Oil recovery during near-miscible gas injection test of water-wet & mixed-wet cores

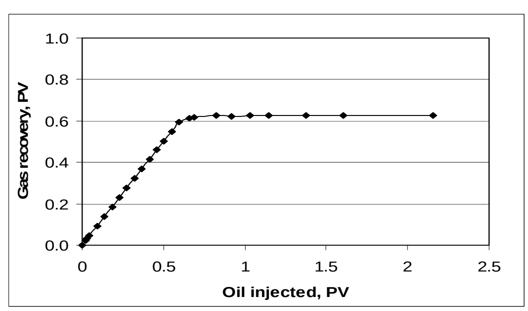

Figure 6 - Gas recovery during unsteady-state near-miscible oil injection in the mixed-wet core.

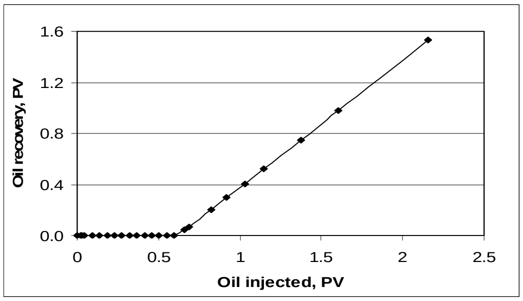

Figure 7 - Oil recovery during unsteady-state near-miscible oil injection in the mixed-wet core.

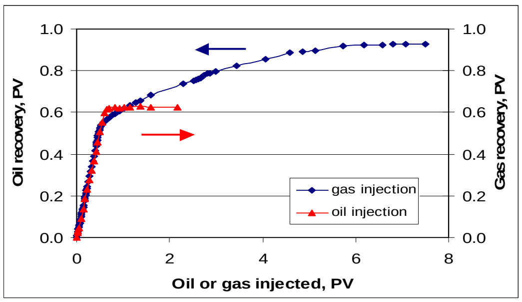

Figure 8 –Gas and oil recovery during low IFT displacement in the mixed-wet core.

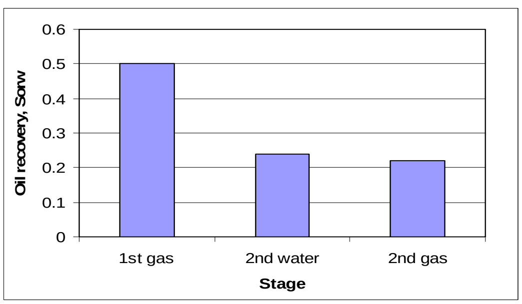

Figure 9 – Oil recovery (fraction of the waterflood residual oil) during different stages of near-miscible WAG test in the mixed-wet core (starting with water).

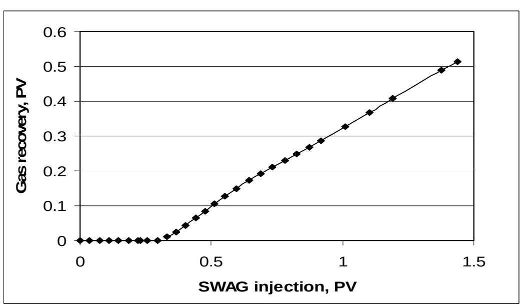

Figure 10 - Gas recovery (pore volume) during SWAG injection in the mixed-wet core with gas/water ratio of 1.

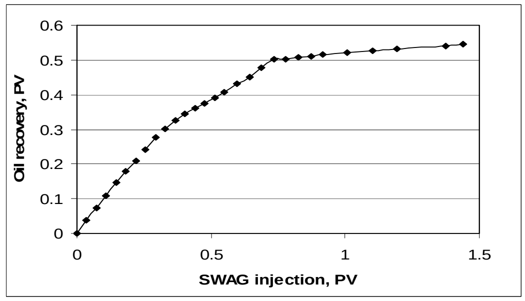

Figure 11 - Oil recovery (based on pore volume) during SWAG injection in the mixed-wet core.

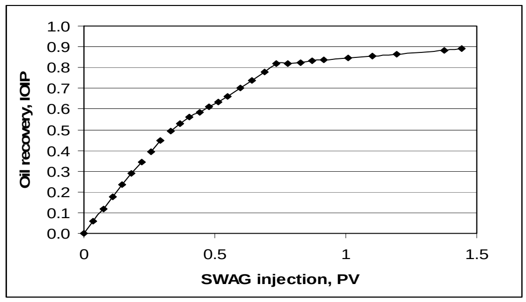

Figure 12 - Oil recovery during SWAG injection in the mixed-wet core with gas/water ratio of 1.

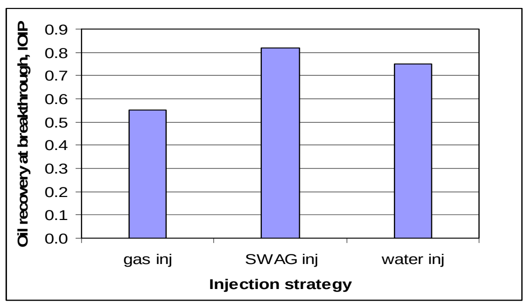

Figure 13 – Comparison of oil recovery (fraction of initial oil in place) during gas injection, SWAG and water injection in mixed-wet core.

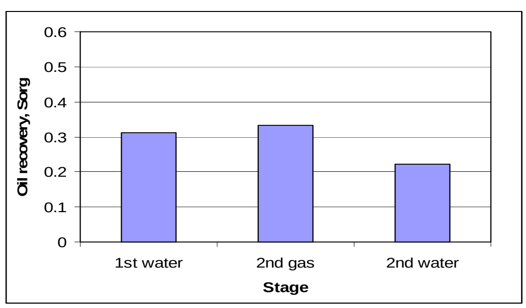

Figure 14 – Oil recovery (fraction of water flood residual oil) during different stages of the near-miscible WAG injection test in the mixed-wet core.