

AES/PE/12-15 **TITLE: EXPERIMENTAL INVESTIGATION OF
NON OPTIMUM CONDITIONS OF ALKALINE
SURFACTANT POLYMER FLOODING**

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FLOODING**

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TA Report number : **AES/PE/12-15**

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ABSTRACT

Alkaline Surfactant Polymer (ASP) flooding is a chemical EOR technique that takes advantage of both interfacial tension reduction and mobility control. Core flooding tests show almost 100% recovery when the experiment is carried out under optimal conditions, i.e., a middle phase micro-emulsion characterized by extremely low interfacial tension is formed when a phase behavior test is done. In the field, reservoir heterogeneity causes mixing, which takes the system away from its optimal condition. Another major drawback of the ASP floods is the high cost of the associated chemicals. In some cases the logistics can also be a major challenge.

Therefore this thesis considers the application of ASP at non optimal conditions. We study this application by performing series of core flood experiments. For a given surfactant concentration we determined the optimal condition by varying the alkali concentration, which turns out to be 1.75 w/w% of Sodium Carbonate (Na_2CO_3). Subsequently we performed vertical flow experiments using alkaline weight percentages from 1.0 % to 2.25 % with increments of 0.25% around the optimum. Initially we used a 38.3 cm core, which gave an unexpected low recovery of 68% to residual oil, after injection of two pore volume (PV). Injection of over-optimum solutions resulted in even worse recoveries, while injection of under-optimum solutions led to higher recoveries at chemical break-through for 1.5 w/w% and 1.25 w/w% before it dropped again for 1.0 w/w%.

To understand this behavior we repeated the experiment with shorter cores (30 cm and 17 cm) at optimum conditions, which gave a recovery of more than 90% (95% of the oil initially in place (OIIP)), which value is often encountered in literature.

We propose that instabilities may be the cause of the low recoveries after a stability analysis shows that the system apparent viscosity is higher than the viscosity of the displacing ASP solution.

1 INTRODUCTION

The need for Enhanced Oil Recovery (EOR) production have increased over the years because of the decline in the discovery of new oil producing fields and the ever increasing demand for hydrocarbons. There are also concerns that most of the newly discovered hydrocarbon fields do not contain oil that can easily be produced by natural reservoir pressure depletion drive, hence there is a need to look for more efficient ways of extracting extra oil from existing (brown) and newly discovered (green) fields (BP statistical review of world energy (June 2012)).

There are three main classes of EOR currently being applied in the oil and gas industry viz: thermal, gas, and chemical methods.

Thermal methods involve the application of heat to reduce the viscosity of oil by introducing hot water, steam or air into the reservoir. The reduction in viscosity is needed to ensure a more favorable mobility ratio which helps the oil to be easily swept out of the reservoir. Thermal methods are usually applied to reservoirs containing heavy oil and tar.

Gas methods involve injecting gases like carbon dioxide (CO_2), nitrogen or hydrocarbon gases into the reservoir to bring about one of the following displacement processes: reduction of viscosity, swelling and expansion of the oil, vaporization of oil, a miscibility effect and interfacial tension reduction.

Chemical method involves the use of chemicals such as polymer, surfactant, alkaline and low salinity fluid to influence the oil displacement in the reservoir. The mechanism of oil production using chemical method could occur through one or more of the following processes: interfacial tension reduction, wettability alteration and mobility control.

This thesis focus on the application of Alkaline Surfactant Polymer (ASP) flooding, which is one of the chemical methods for the extraction of more oil from the reservoir after the application of water flooding. Several field applications of ASP have been carried out among which are: Daqing oil field in China where an incremental oil recovery of 20% after ASP has been reported by Xiaoming Yang et al (2003). A 26.8% incremental oil recovery of OOIP was also reported in the Cambridge Minnelusa field in Wyoming, USA (Jay Vargo et al (1999)). The Tanner oil field in Wyoming, USA also had an incremental recovery of 10% as reported by Pitts et al. (1999) and Qiao Qi et al (2000) reported an incremental OOIP of 24% in the Karamay oil field in China.

1.1 THEORY OF ALKALINE SURFACTANT POLYMER FLOODING

Alkaline Surfactant Polymer enhanced oil recovery method involves the combination of the properties of alkali, surfactant and polymer in altering the interaction between rock and fluid, lowering the interfacial tension between the fluids in contact and providing a more favorable mobility control which results in the recovery of more oil than obtained from a conventional drive.

The mechanism of oil production by ASP depends on increasing the capillary number N_c , which is a dimensionless number that is indicative of the amount of trapped oil in a reservoir after a core flooding operation. It is the ratio of the viscous force and the local capillary force i.e.,

$$N_c = \frac{u \cdot \mu}{\sigma},$$

where u = darcy velocity

μ = viscosity of fluid

σ =interfacial tension between two fluid phases

The higher the capillary number, the lower the residual oil saturation in the reservoir after a flooding operation. In order to increase the capillary number, one has to increase the viscosity of the displacing fluid and reduce the interfacial tension between the displacing and the displaced fluid. The components of the ASP process have the properties of being able to increase both the viscosity of displacing fluid and reducing interfacial tension at the same time resulting in an increase of both macroscopic and microscopic sweep efficiency. The contribution of the various components of the ASP process is explained below.

Alkali undergoes hydrolysis to form a hydroxyl ion and a cation when it comes in contact with an aqueous solution. The released cation reacts with the natural acids present in the oil to generate in-situ soap through a saponification process. The generated in-situ soap contributes to the reduction of interfacial tension between the oil and aqueous solution. Alkali also forms negative ion on the surface of the rock solid, preventing the adsorption of injected surfactants on the rock. The adsorption of surfactant on the rock surface is a major concern in the ASP process as it results in loss of valuable expensive chemicals to the rock and preventing the surfactant from moving into the oil-water interface.

Surfactants are surface active agents having at least one hydrophilic and at least one hydrophobic group in the same molecule. As a result of this property, they can bond the

interface between oil and aqueous phase, and significantly lower the interfacial tensions between both phases and alter the wetting properties of the rock. Surfactants are energetically favorable to be located at the interface rather than in the bulk phase of the fluid. The positioning of surfactant molecules at the oil-aqueous phase interface enables bonding of both phases which result in the reduction of interfacial tension between both phases. The reduction of interfacial tension leads to a reduction of capillary forces in the pore and helps to increase the microscopic sweep of the oil from the reservoir (Larry W. Lake (1989)).

Polymer is added to provide mobility control by increasing the viscosity of the displacing fluid so that its mobility decreases, improving the macroscopic sweep of oil by creating a more stable displacement front, which also counteracts fingering of the aqueous phase through the oil in the reservoir. This is achieved by maintaining a favorable mobility ratio M and gravity number (G) between the oil and aqueous phase (see D. N. Dietz (1952) and L. P. Dake (1978)). The mobility ratio is defined as the ratio of the mobility of the displacing fluid to the mobility of the displaced fluid and is mathematically expressed as

$$M = \frac{\lambda_w}{\lambda_o},$$

$$M = \frac{k_{rwe}\mu_o}{\mu_w k_{roe}},$$

while the gravity number is given by

$$G = \frac{\Delta\rho_{wo}g\sin\theta}{\left(\frac{u}{\lambda_{we}}\right)}.$$

Usually in a displacement process, we try to achieve a stable oil-aqueous phase interface by meeting certain conditions as explained below:

To have an unconditional stability, the mobility ratio, M must be less than or equal to one, meaning that the aqueous phase will be less mobile than the oil phase.

Conditional stability occurs if M is greater than or equal to one, in which case we have to compare it to the gravity number. If $M < 1+G$, then the system will be stable otherwise, there will be instability in the system.

1.2 OUTLINE/ OBJECTIVE

The Alkaline surfactant Polymer flooding has some challenges with its application as an EOR method viz.

To achieve very low residual oil saturations with ASP flooding, two conditions should be simultaneously satisfied in porous media: 1) the injected chemicals must achieve the optimum conditions, and 2) the attained optimum condition must be maintained through the process. However, as natural porous media exhibits medium to high degrees of heterogeneity, the mixing between the in-situ brine and the injected solution might move the phase behavior towards non-optimum conditions. Because the reservoir properties e.g. the permeability varies spatially, the phase behavior could also be different in different parts of the reservoir due to mixing caused by heterogeneity.

Moreover, a major drawback of ASP floods is the high cost of the associated chemicals and also problems associated with logistics. Therefore, we can argue that the highest oil recovery obtained by an optimum solution might not be the optimum recovery from an economic perspective e.g. if the cost of chemicals and their transportation is considered.

Furthermore, the micro-emulsion formed between the oil and aqueous phase, is usually more viscous than the oil phase and thus making the process to require higher injection pressure into the reservoir and/or more efficient mobility control, to produce the oil. The production of micro-emulsion is not also useful and will have to be separated from the produced oil. This separation will introduce extra cost to the whole process.

For a better optimization of the ASP process, it is best to reduce the quantity of the chemicals used for the preparation of the ASP. As stated by Nelson et al (1984) in the design of an ASP process, there are certain parameters that can be controlled. These include type and amount of alkali and surfactant, and the salinity. In this thesis, we choose to vary the amount of the injected alkali. Our objective is to investigate the oil recoveries obtained by injecting non-optimum solutions.

2 PHASE BEHAVIOR TEST OF MICROEMULSIONS

A phase behavior test is very important in the surfactant-based EOR process because it can be used as an indicator of the formation of ultra-low interfacial tension between the oleic phase and the aqueous phase. The phase behavior of a micro-emulsion system is usually a function of types, concentration of surfactants, co-surfactants, oil, brine, alcohol and temperature.

In order to identify the optimum condition of the selected surfactant and the crude oil system, a phase behavior experiment was carried out using synthetic brine of a fixed surfactant concentration (0.3 w/w %) with varying salinities. The tubes were filled with oil and water to a ratio of one (10 ml each). The aqueous phase of the tubes contained different amounts of alkali. The phase behavior test was performed at a temperature of 54 °C. The existence of a minimum interfacial tension between the oil and the aqueous phase is indicated by the formation of a third micro-emulsion phase, which separates both the oil and aqueous phase. We did not measure the interfacial tension.

The experimental result of the phase behavior of micro-emulsions can be divided into three classes with varying salinity, namely viz: lower-phase micro-emulsion, upper phase micro-emulsion and middle phase micro-emulsion. Figure 2.1 illustrates the relationship between salinity and different micro-emulsion phase behavior.

At low salinities, two phases which are lower phase micro-emulsion and pure excess oil are formed. The oil is normally on top of the micro emulsion because it has a lower density as shown in result (i) to (vi) of the phase behavior test, shown in Figure 2.1. It is called a Winsor type I, or type II (-). In the nomenclature and the classification we follow Larry W. Lake (1989)

When the salinity is very high, a two phase solution is also formed with an upper phase micro-emulsion being in contact with excess brine. The density of the micro-emulsion is lower than the density of brine hence the reason for being the upper phase. The result (x) of the phase behavior test shown in Figure 2.1 falls under this category. The upper phase micro-emulsion is also named type II (+) or Winsor type II.

At some optimum salinity somewhere between low and high salinity, a three phase solution is formed, where the middle phase is a micro-emulsion containing all the surfactant in the system in contact with excess oil and brine as shown in test result (vii) to (ix) in Figure 2.1. The oil with the lowest density is on top while pure excess brine with the largest density is at the bottom of the micro-emulsion. The middle phase micro-emulsion is also named type III,

or Winsor type III. Due to the presence of all the surfactant of the mixture in the type III micro-emulsion, its presence with oil will create a low interfacial tension which will enable easy displacement of the oil. Nelson (1980) proposed three regions in the type III system which is the lower, middle and upper region. The type III middle region is the point where we have about the same volume of excess oil and excess brine in contact with the middle phase micro emulsion. The lower type III micro-emulsion phase region is a transition between end of type II(-) and beginning of type III middle phase micro-emulsion while the upper type III micro-emulsion is a transition between end of type III middle phase micro-emulsion and beginning of type II(+) micro-emulsion,

An extra phase behavior test was carried out at the optimum condition of 1.75w/w% Na_2CO_3 but with polymer added to the aqueous phase to observe the effect of polymer on the phase behavior. The result of the test shows that polymers have a small effect on phase behavior as a type III micro-emulsion was formed with the bulk of the polymer staying in the lower of the two phases. This is shown in result (xi) (Figure2.1) of the phase behavior test result. Note also that the presence of polymer decreases the volume of the micro-emulsion phase.

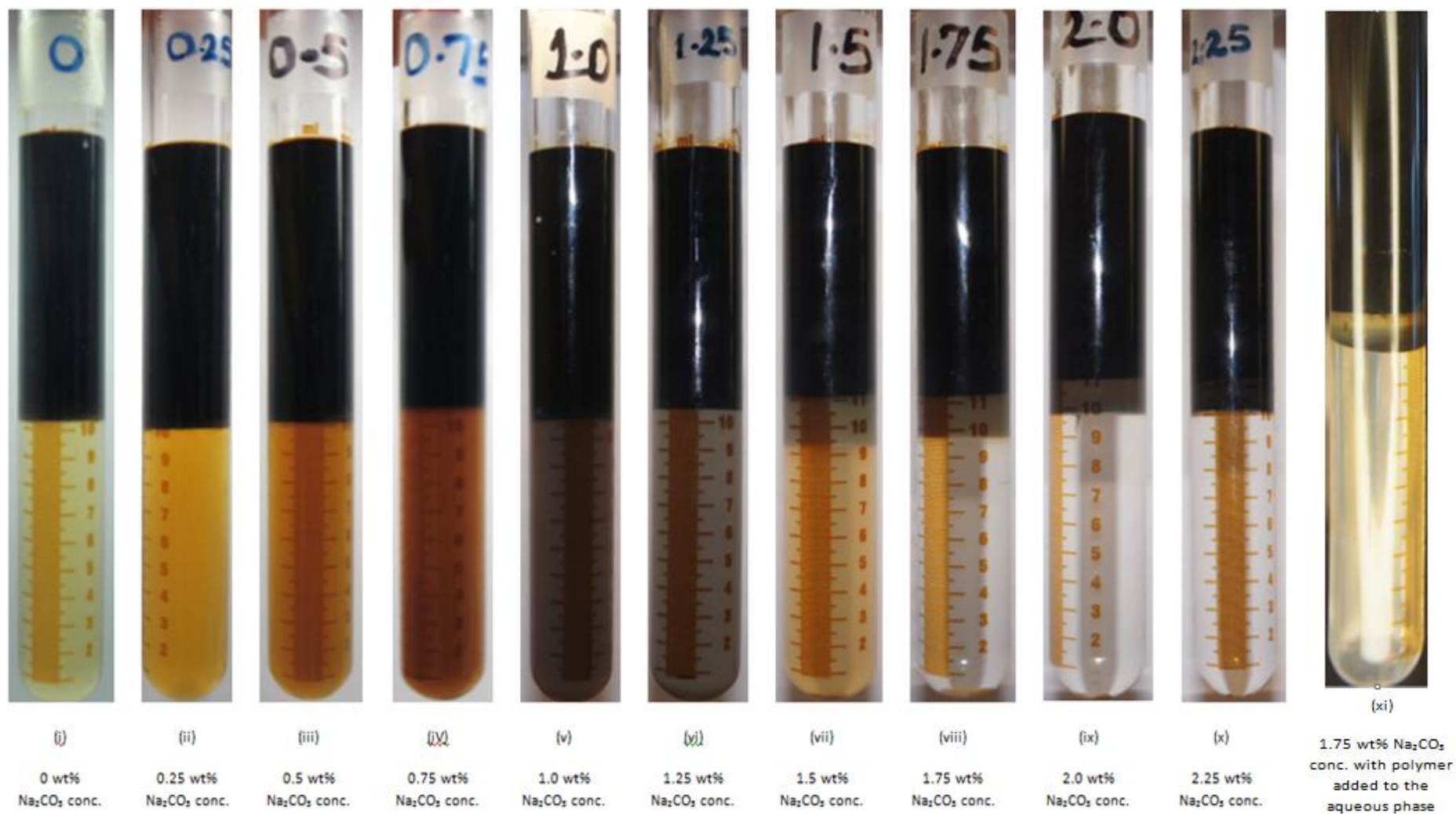


Figure 2-1 Phase behavior test at various Na_2CO_3 concentration

3 ALKALINE SURFACTANT POLYMER FLOODING EXPERIMENTS

Based on the result of the phase behavior test, the optimum condition of the crude oil with surfactant solution was found to exist at 1.75 w/w % of Na_2CO_3 concentration. So in order to evaluate the efficiency of the non optimum condition of the ASP flooding, six different ASP solutions at optimum, below optimum and above optimum Na_2CO_3 concentration were prepared and used for core flooding experiment to produce trapped oil in the core after a water flooding operation, so that a comparison can be made between the performance of the optimum solution and that of the non optimum solution. Table 3.1 shows a summary of the properties of the fluids used in the experiments.

Table 3.1 FLUID PROPERTIES

Fluid Properties	
Water Density	1010 kg/m ³
Oil Density	850 kg/m ³
Water viscosity	0.55 cp @ 54 °C
Oil viscosity	9 cp @ 54 °C
Polymer viscosity	30cp @ 54 °C
Surfactant Concentration	0.30 w/w %
Polymer Concentration	0.27w/w %

3.1 EXPERIMENTAL SETUP

A core flooding set up is made with a core barrel containing a 38.3 cm length and 3.7 cm diameter core, placed vertically inside an oven at a temperature of 54 °C. Both ends of the core are connected to a transducer to measure the pressure difference between the inlet and outlet of the core with time. Two pumps are used in the experiment for the following functions: one to inject water and ASP solution into the core and the other one to inject oil into the core. A back pressure of 5 bar is provided to stabilize the system with nitrogen gas, while CO_2 gas is connected to the set up for displacement of air from the core, before it is saturated with brine. The schematic of the setup is shown in Figure 3.1.

3.2 EXPERIMENTAL PROCEEDURE

The following procedure outlined below was followed in each of the core flooding experiments.

1. First the core was flushed with CO₂ for several pore volumes to displace the air in the core. Since CO₂ is highly soluble in water, it can be removed during core saturation with brine.
2. The setup was vacuumed for about 1 hour to remove most of the air and CO₂ in the core.
3. 20PV of 3 w/w % NaCl water was injected into the core at a rate of 1 ml/min until the saturation of water in the core was 1 i.e. $S_w=1$.
4. Next oil was injected into the core at a rate of 1 ml/min until there was no measurable water production at the producer.
5. The core was then flooded with brine until there was no measurable oil production. The breakthrough time of water was also recorded.
6. ASP flooding EOR was then applied to produce the remaining oil in the core at a rate of 0.05ml/min corresponding to real velocity of 1 ft/d. The breakthrough time of ASP was also recorded

3.3 EXPERIMENTAL SETUP FOR SUB OPTIMUM CONDITION OF ALKALINE SURFACTANT POLYMER FLOODING

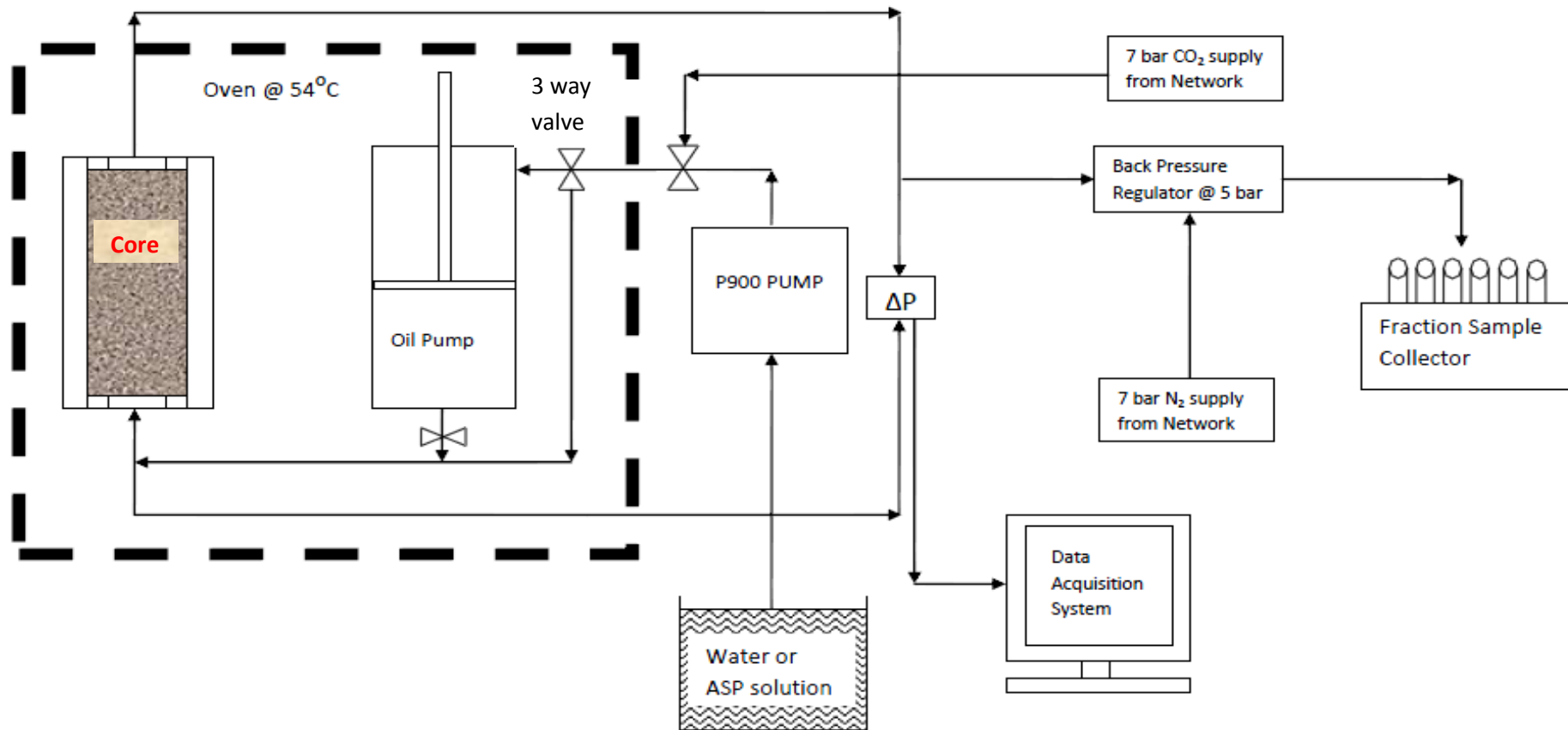


Figure 3-1 Schematic of the experimental setup used for the ASP core flooding experiments

3.4 DESCRIPTION AND DISCUSSION OF EXPERIMENTAL RESULT

3.4.1 Experiment 1- 1.75 w/w % Na_2CO_3 on 38.3 cm length core

The first experiment was performed to evaluate the efficiency of the formulation at optimum conditions, i.e. an ASP solution with 1.75 wt% Na_2CO_3 . The results of the different stages of the experiment are shown in Figure 3.2 through Figure 3.6. In the first stage of the experiment (Figure 3.2), oil is injected into the core to displace brine (3 w/w % NaCl) used for core saturation. Because the viscosity ratio between the oil and the brine is 16, a favorable mobility ratio exist between both fluids, resulting in an initial constant water cut production that drops to near zero at 0.85 PV injected which is the time of oil breakthrough. The tubes in the fraction collector have an average volume of 20 ml. However, at breakthrough the collecting tubes were switched. In the same way the cumulative oil in the core increased linearly until oil breakthrough. We continue to inject oil until there is no more measurable water production, the point at which the water present in the core is very close to the connate water saturation.

In the next step (Fig. 3.3) we displace oil by brine (3 w/w % NaCl). The core is initially filled with oil and connate water saturation of 11.5%. We observe a typical Buckley-Leverett profile. First before the shock breaks through, pure oil is produced up to 0.3 PV of injected water. Subsequently water breakthrough occurs and the water cut increases and injection is continued until no more oil is produced.

Figure 3.4 presents the oil recovery factor and the oil saturation in the core after water injection. Before breakthrough the oil in the core drops linearly until water breakthrough. Subsequently the oil in the core gradually decreases. It can be anticipated that it drops to residual oil saturation after many pore volume of brine injected. The oil recovery factor increases linearly until water breakthrough occurs. Then it gradually increases until there is no more oil production due to capillary effect.

The remaining oil trapped in the core after water flooding was then produced by injecting 1.75 w/w % Na_2CO_3 of ASP solution. Figure 3.5 shows the result of the produced oil cut and oil recovery factor (with respect to the residual oil saturation after water flooding) of the ASP injection. It can be observed that the oil cut increases steadily reaching a peak value of 0.56 at 0.65 PV ASP injected. The chemical break through occurs at 0.85 PV of ASP injected with a recovery factor of 0.52 to residual oil saturation and a total recovery factor of 0.74. The oil cut decreases after chemical breakthrough. The ASP recovery factor with respect to residual oil saturation after 2 PV injection is 0.68 while the total recovery factor from water injection (WI) and ASP injection is 0.84. A cross section through the core which has been cut into 12

pieces as shown by Figure 3.6 clearly shows a loss of stability of the displacement front which results in bypassing of the oil and consequently the trapping of more oil.

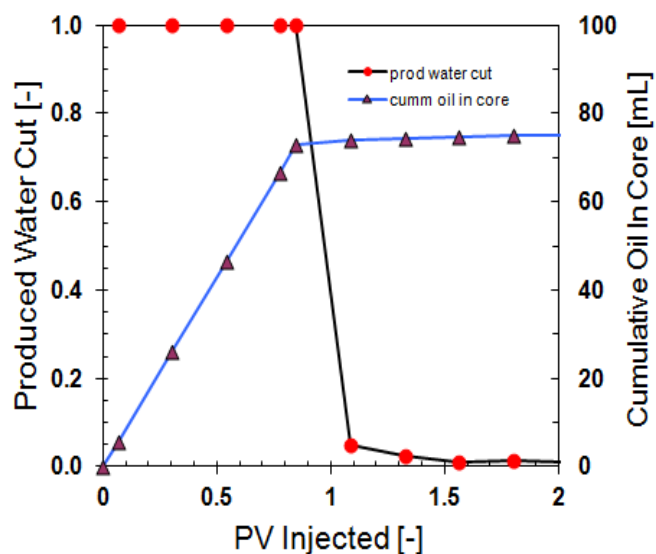


Figure 3-2 Produced water cut and cumulative oil in core during oil injection for experiment 1

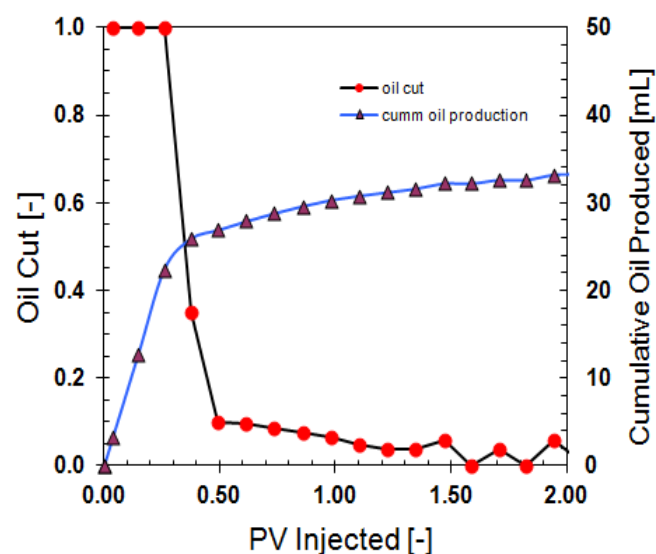


Figure 3-3 Produced oil cut and cumulative oil production during water injection for experiment 1

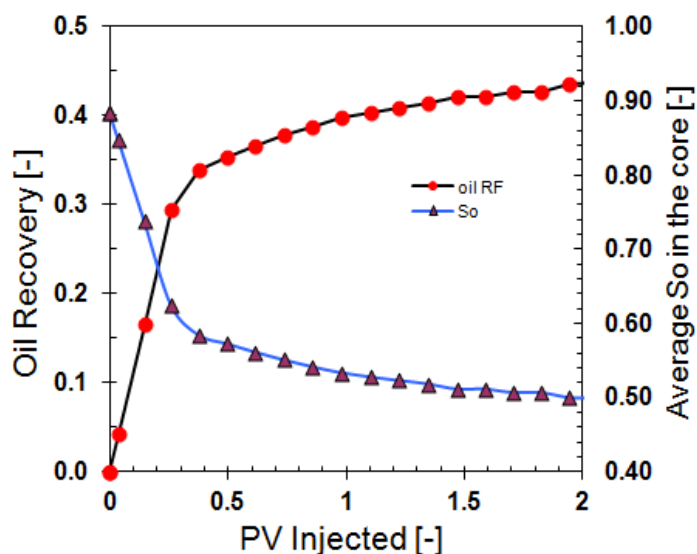


Figure 3-4 Oil recovery factor and average oil saturation in core after water injection for experiment 1

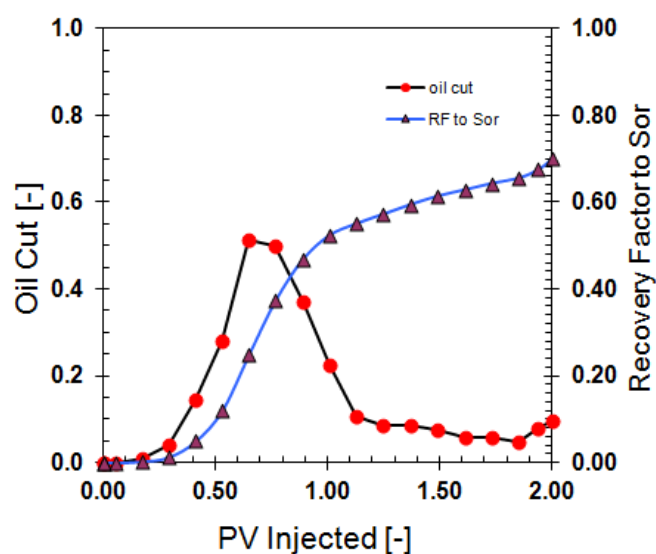


Figure 3-5 Produced oil cut and recovery factor to residual oil saturation after injecting ASP of 1.75 w/w % Na_2CO_3

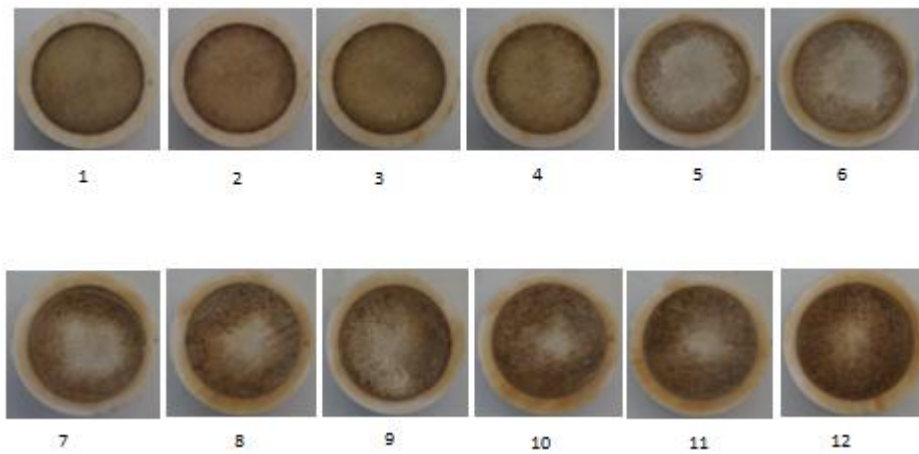


Figure 3-6 Cross section of core for experiment 1

The same experimental procedure was repeated for the core length of 38.3 cm, using brine of 3 w/w % NaCl each time for core saturation and water flooding, while various Na_2CO_3 w/w % concentration of ASP at non optimum conditions were injected in decreasing order: i.e., 2.5 w/w %, 2.0 w/w %, 1.5 w/w %, 1.25 w/w % and 1.0 w/w % for the various experiments.

The result of the oil injection (step3) and water flooding (step 4) for these experiments are very much similar to what was obtained in the first experiment (1.75 w/w % Na_2CO_3) and they have been displayed in section A.1 to A.5 of the Appendix A (Experiment 2 to 6). The result of the produced oil cut and oil recovery factor to residual oil saturation due to ASP injection at different Na_2CO_3 concentrations is shown in Figure 3.7 to Figure 3.11.

Figure 3.7 shows the result of the oil cut and oil recovery factor to S_{or} for Experiment 2, where the ASP solution with over optimum concentration of 2.25 w/w % was injected after water flooding. It can be seen that the oil cut does not show a plateau with injected PV. Indeed the oil cut increases sharply reaching a peak 0.51 at 0.71 PV when chemical breakthrough occurs with no plateau production and drops from that point to very low values. The recovery factor with respect to residual oil saturation at chemical breakthrough is 0.38 while the total recovery factor is 0.65. After injection of 2 PV ASP, the recovery factor to residual oil saturation is 0.58 while the total recovery factor from water flooding and ASP is 0.76. A cross section through the core (Figure A.4 in section A.1 of Appendix A) shows a very poor displacement with much of the oil trapped in the core, which is an indication of loss of stability of the front during displacement.

The result of Experiment 3 where ASP at an over optimum concentration of 2 w/w % Na_2CO_3 concentration was injected is shown in Figure 3.8. We observe that the produced oil cut is not

so favorable and chemical breakthrough occurs after injection of 0.85 PV of ASP with recovery factor to residual oil saturation being 0.42, while the total recovery factor is 0.65. The oil recovery after injection of 2 PV of ASP with respect to residual oil is 0.57 and the total oil recovery is 0.74. A cross section through the core (Figure A.8 in section A.2 of Appendix A) shows significant amount of oil trapped in the core which is an indication ASP fingering through the core as a result of the loss of stability of the displacement front.

Experiment 4 was carried out at an under optimum concentration of ASP using 1.5 w/w % Na_2CO_3 . Figure 3.9 shows the result of the experiment and as we can see, the produce oil cut is reasonably good, increasing steadily to a peak value of 0.6 oil cut after 0.63PV and the oil cut is maintained at 0.6 until an injection of 0.86 PV ASP. The oil cut starts to drop at chemical breakthrough after injection of 0.94 PV of ASP. At this point, the recovery factor to residual oil saturation is 0.6 while the total recovery factor is 0.75. After injection of 2 PV, the oil recovery factor with respect to residual oil saturation is 0.66 and the total oil recovery factor from water injection and ASP is 0.8. A cross section through the core shows a reasonable stable displacement of oil through the core after ASP flooding (Figure A.12 in section A.3 of Appendix A)

Experiment 5 was carried out using an under-optimum concentration of 1.25 w/w % Na_2CO_3 . The result of the ASP injection for this experiment (Figure 3.10) shows a good oil production profile with the oil cut increasing steadily to a peak value of 0.8 at 0.93 PV ASP injection which is also the point of chemical breakthrough. At chemical breakthrough, the recovery factor to residual oil saturation is 0.7 while the overall recovery factor is 0.83. After injection of 2 PV of ASP, the oil recovery factor to residual oil (to water flooding) is 0.8 while the overall recovery factor from both water injection and ASP is 0.88. A cross section through the core (Figure A.16 in section A.4 of Appendix A) shows a very good displacement of oil through the core with very little oil being trapped.

Figure 3.11 shows the result of experiment 6, where 1.0 w/w% Na_2CO_3 concentration of ASP at an under-optimum condition was injected after core flooding with brine. We observe that the oil cut increases steadily, reaching a peak value of 0.65 at an injection of 0.75 PV of ASP, dropping after chemical breakthrough at 0.77 PV to near zero. The recovery factor to residual oil saturation at chemical breakthrough is 0.58 and the overall recovery factor is 0.75. At 2 PV of ASP injection, the recovery factor to residual oil is 0.65 while the overall recovery factor due to water flooding and ASP injection is 0.79. From Figure A.20 (in section A.5 of Appendix A), which is a cross section through the core at the end of the experiment, we can

see some trapped oil in the core which is an indication of loss of front stability during oil displacement.

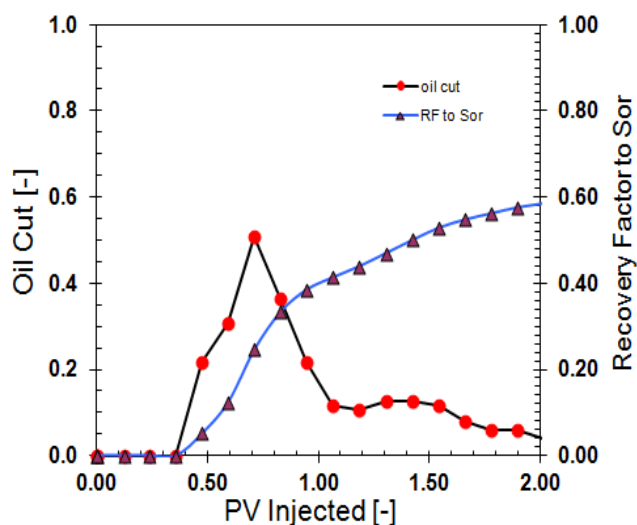


Figure 3-7 Produced oil cut and recovery factor while injecting 2.25 w/w % Na_2CO_3 ASP

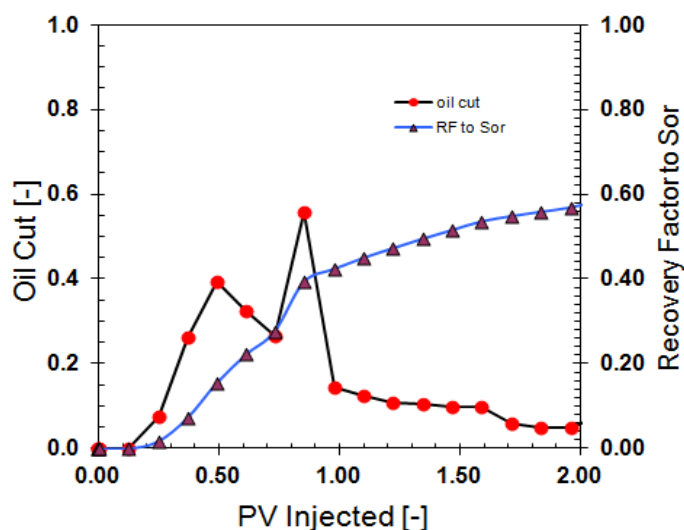


Figure 3-8 Produced oil cut and recovery factor while injecting 2.0 w/w % Na_2CO_3 ASP

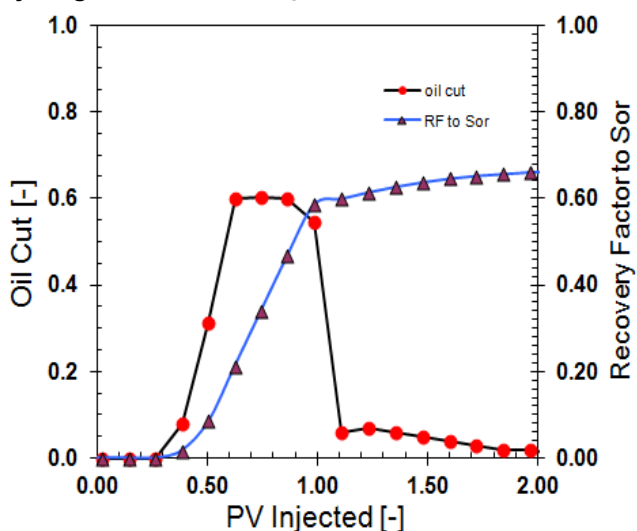


Figure 3-9 Produced oil cut and recovery factor while injecting 1.5 w/w % Na_2CO_3 ASP

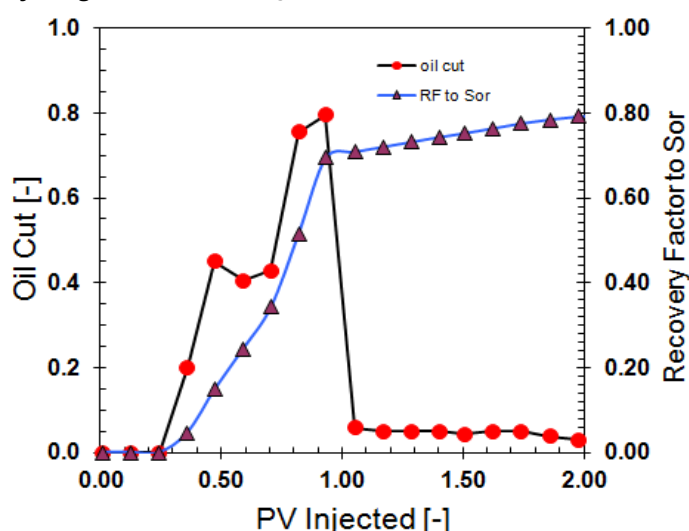


Figure 3-10 Produced oil cut and recovery factor while injecting 1.25 w/w % Na_2CO_3 ASP

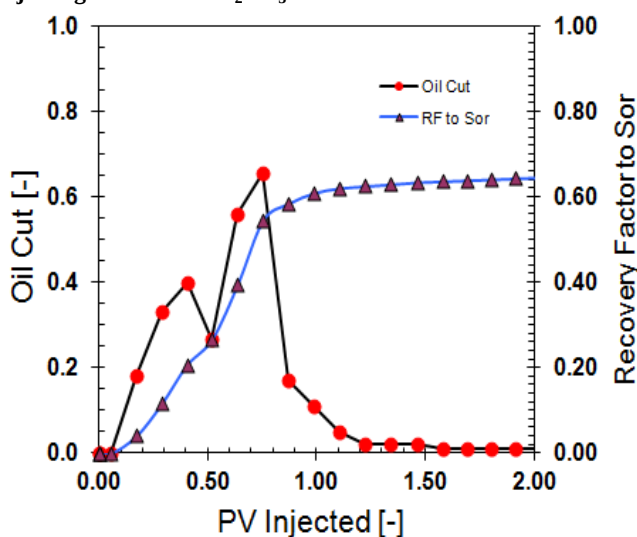


Figure 3-11 Produced oil cut and recovery factor while injecting 1.0 w/w % Na_2CO_3 ASP

3.4.2 Effect of Initial and Injected Salinity on ASP Displacement Efficiency

This section describes two additional experiments. As mentioned earlier the salinity of the initial and the injected brine was 3 w/w % NaCl, which is equivalent of 11975 ppm Na^+ ion. The Na^+ equivalent concentration of the optimum solution was about 11525 ppm. One hypothesis for the inefficient recovery of the optimum solution was the slightly higher salinity of the in-situ brine, causing the system to become over-optimum at the front end mixing zone. To examine the validity of this hypothesis, we performed experiments with initial and injected water salinity of 1.0 w/w % NaCl (Na^+ equivalent of 3931 ppm), which keeps the solution at under-optimum conditions in case there is mixing at the front. In one experiment we used concept of salinity gradient to improve the oil recovery. In the salinity gradient concept, the ASP solution of optimum salinity is followed by injection of an ASP solution with a lower salinity.

In Experiment 7, the core was first saturated with a 1.0 w/w % NaCl brine and then oil was injected into the core until there was no measurable water production. Water flooding of the core was done with 1.0 w/w % NaCl to produce the oil in the core. Finally, ASP solution with 1.75 w/w % Na_2CO_3 concentration was injected into the core to produce the remaining oil in the core.

Similar to Experiment 7, the core used in Experiment 8 was first saturated with 1.0 w/w % NaCl brine after which oil was injected until there was no more water production. The core was then water flooded using 1 w/w % brine. At the end of water injection, 0.5 PV of a slug with an optimum salinity ASP solution of 1.75 wt % Na_2CO_3 was injected followed by a 1.2 PV of an under optimum ASP solution of 1.0 wt % Na_2CO_3 and then demineralized water was injected behind to push the ASP through the core. The result of the oil injection and core flooding operation for both Experiment 7 and 8 are shown in the section A.6 and A.7 of the Appendix (Experiment 7 and 8).

As we can see from the result of the ASP injection for experiment 7 (Figure 3.12), the produced oil cut is poor with the chemical breakthrough occurring after injection of 0.82 PV of ASP at which point the recovery factor to residual oil saturation is 0.44 while the total recovery factor is 0.66. After injection of 2 PV, the recovery factor to residual oil saturation is 0.53, while the total recovery factor due to the combined effect of water flooding and ASP injection is 0.72. A cross section through the core (Figure A.24 in Appendix A) shows that much of the oil is trapped in the second half of the core at the end of the experiment.

Figure 3.13 shows the result of the produced oil cut and recovery factor for Experiment 8. The result shows an oil cut similar to Experiment 1, which rises steadily with a value of 0.22 at 0.38 PV ASP to a peak value of 0.70 after injection of 0.69 PV. The chemical breakthrough occurred after an injection of 0.87 PV of ASP into the core with a recovery factor of 0.63 to residual oil saturation and 0.79 to total oil production. At the point of injection of 2 PV (0.5 PV of 1.75 w/w % Na_2CO_3 + 1.2 PV 1.0 w/w % Na_2CO_3 + 0.3 PV of demineralized water), the recovery factor to residual oil saturation is 0.76 and the total recovery factor due to combined effect of water flooding and ASP injection is 0.86. A cross section through the core is shown in Figure A.28 (Appendix A). We can see that less oil is trapped in the core when compared to experiment 1.

3.4.3 Effect on Core Length on ASP Displacement Efficiency

In order to monitor the effect of the length of core on the recovery factor of ASP experiment at optimum condition, two more core flooding experiment (Experiment 9 and 10) were carried out with an ASP solution of 1.75 w/w % Na_2CO_3 on cores of length 30 cm and 17 cm respectively. We had anticipated getting close to a 100% recovery from Experiment 1 where we used a 38.3 cm length core to carry out a core flooding experiment with ASP concentration at optimum value of 1.75 w/w% Na_2CO_3 . However, the result of the experiment was below expectation (total recovery of 0.84). Therefore, we decided to examine the effect of the core length on the oil displacement efficiency by ASP at optimum condition. Like in previous experiments, the cores were first saturated with 3 w/w % NaCl brine, then oil was injected until there was no more water production, after which the oil was produced using 3 w/w% NaCl brine. ASP was finally injected to produce the remaining trapped oil (after water flooding) in the core. The result of the oil injection and water flooding is shown in section A.8 and A.9 of the Appendix A (Experiment 9 and 10)

Figure 3.14 shows the oil cut and recovery factor to residual oil saturation for the ASP injection on the 30 cm length core (Experiment 9). The produced oil cut increased steadily reaching a peak value of 0.65 after injection of 0.92 PV of ASP at chemical breakthrough after which the oil cut decreases to near zero at 2 PV ASP injection. The recovery factor at chemical breakthrough to residual oil saturation is 0.67, while the total recovery factor is 0.86. The final recovery factor after injection of 2 PV to residual oil saturation is 0.90 while the total recovery factor with respect to water flooding and ASP injection is 0.96. A cross section through the core in section A.8 of Appendix A (Figure A.32) shows an efficient sweep of almost all the oil in the core.

The result of the ASP injection on the 17 cm length core (Experiment 10) is displayed in Figure 3.15. We can see a steady increase in the oil cut from 0.33 at 0.38 PV to a peak value of 0.63 at an injection of 0.74 PV ASP. The chemical breakthrough occurred after injection of 0.92 PV of ASP, when the recovery factor to residual oil saturation is 0.71 while total recovery factor is 0.85. After injection of 2 PV of ASP, the recovery factor with respect to residual oil saturation is 0.90 while the total recover factor due to water and ASP injection is 0.95. Figure A.36 in section A.9 of Appendix A shows a cross section through the 17 cm core at the end of the experiment. We can once again see a clean sweeping of almost all the oil in the core at the optimum ASP concentration of 1.75 w/w % Na_2CO_3 .

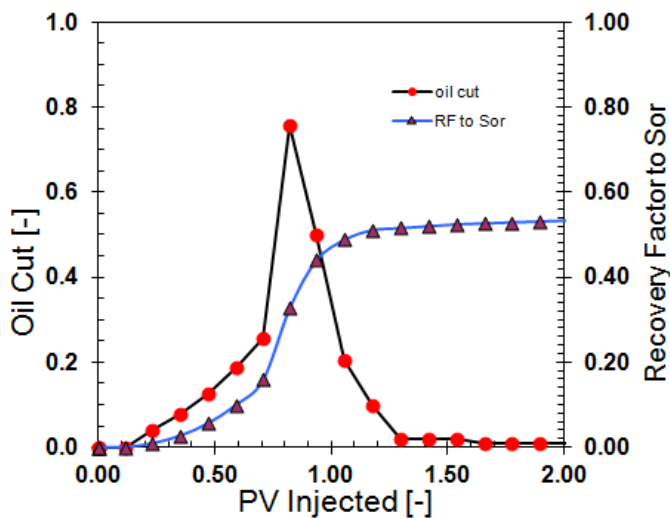


Figure 3-12 Produced oil cut and recovery factor during the injection of 1.75 w/w % Na_2CO_3 ASP with 1w/w % brine used for saturation and water flooding

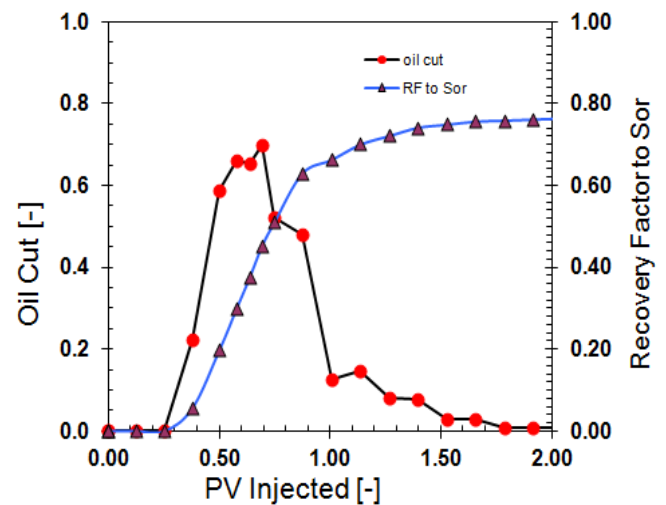


Figure 3-13 Produced oil cut and recovery factor during the injection of 0.5PV of 1.75 w/w % Na_2CO_3 chased by 1.2PV 1.0 w/w % Na_2CO_3 and demineralized water

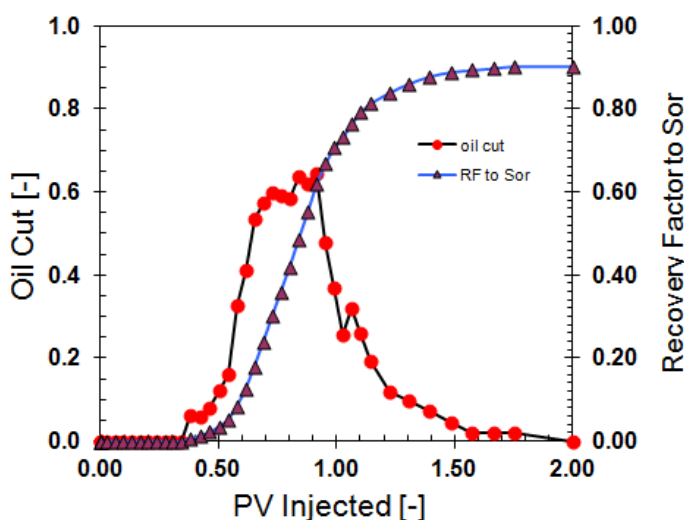


Figure 3-14 Produced oil cut and recovery factor during injection of 1.75 w/w % Na_2CO_3 ASP for 30cm length core

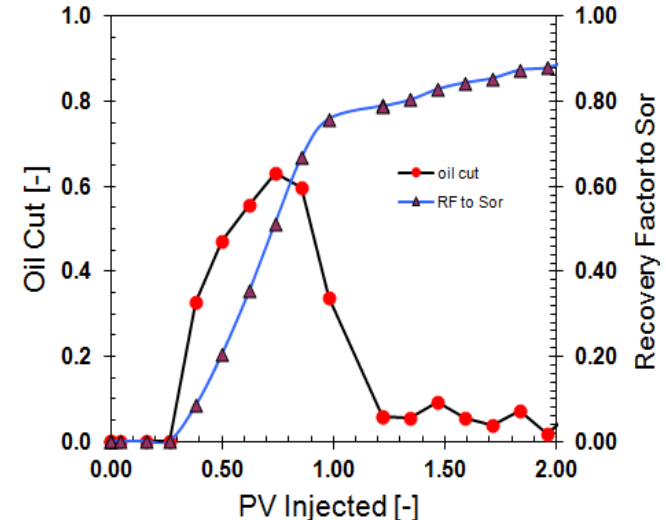


Figure 3-15 Produced oil cut and recovery factor during injection of 1.75 w/w % Na_2CO_3 ASP for 17cm length core

3.4.4 Stability Consideration, Pressure Drop and System Viscosity during ASP Injection.

The pressure drop through the core for ASP injection and the corresponding viscosity of fluid in the core for the ten experiments is shown in Figure 3.16 to 3.25. A chemical test was done on the produced aqueous phase in the lab to check for the concentration of surfactant in the phase. We expected that the experiments done with ASP solution at under optimum concentration will favor the formation of a type (II-) micro-emulsion in which case the surfactant in the system will be in the lower aqueous phase. The result of the chemical analysis carried out on the aqueous phase of the under optimum ASP solutions (1.0 w/w % and 1.25 w/w % Na_2CO_3) showed the absence of any trace of surfactant in the produced aqueous phase of 1.0 w/w% Na_2CO_3 while the aqueous phase of 1.25 w/w % Na_2CO_3 ASP concentration had very little trace of surfactant far below expectation.

A similar scenario was observed in the experiments carried with an ASP solution of 1.75 w/w % of Na_2CO_3 . One would expect the produced sample to have a third phase containing all the micro-emulsion but no third phase was present in the produced aqueous/ oleic solution and an analysis of the aqueous phase shows no traces of surfactant. The experiments at an over optimum concentration of ASP was expected to form the type II (+) micro emulsion where all the surfactant in the system stays in the oleic phase and the result of the chemical analysis confirms our expectation as no trace of surfactant was found in the aqueous phase.

The absence of surfactant in the aqueous phase of the produced solution for the experiments with an under optimum concentration of ASP and also the absence of a third phase micro-emulsion for the experiment with optimum concentration of ASP can be due to either the adsorption of the surfactant on the rock surface or the reaction of the injected ASP (with 1.0 w/w% NaCl) front with a higher saline brine (3 w/w % NaCl) in the core after a water flooding operation.

The formation of a type II (+) micro-emulsion system has a negative effect on the displacement efficiency because the produced micro-emulsion with a higher viscosity stays in the oleic phase making the net viscosity of the oleic phase to be higher than the viscosity of the displacing ASP solution. This could create instability in the system. As long as the system remain in type II+, we will have a situation of ASP displacing an oleic phase containing highly viscous micro-emulsion, which will cause fingering through the system and result in the trapping of much oil.

A stability analysis was done on the system using the Dietz (1952) and Dake (1978) interface model. The model combines mobility ratio (M) between the displacing fluid and the displaced fluid together with gravity number (G) of the system to predict stability. The

criterion for stability is that mobility ratio must be less than one to have an unconditional stability. In a situation where the mobility ratio is more than one, then stability can only be achieved when the mobility ratio is less than $G+1$ else the system will be unstable.

The gravity number for each of the experiments was determined so that the maximum viscosity of the oleic phase (containing the micro-emulsion) required to maintain stability can be determined. The result of the calculated maximum oleic phase viscosity that will ensure stability of the system is shown in Table 3.2. The pressure drop recorded in the system due to the combined effect of the aqueous and oleic phase recorded during ASP injection for each of the experiments is shown in Figure 3.16 to 3.25. At the point of chemical breakthrough from the core, a large fluctuation in the pressure of the system is observed due to the production of a viscous micro-emulsion which flows alongside the oil and injected ASP, resulting in a multiphase flow system. The transducer reading is thus a reflection of the several phases flowing through the core. An average of these pressure drop readings is also displayed in Table 3.2. Based on the value of the transducer pressure reading, the average viscosity of the system was calculated to know how viscous the system is. The result of the calculated system viscosity is displayed in Table 3.2 alongside the maximum oleic phase viscosity required to maintain stability in the system. We can see clearly that the system viscosity calculated for each of the experiments is above the allowed oleic phase maximum viscosity required to maintain stability of the ASP/ oleic interface. The result of the stability analysis shows that for each of the experiments, we had the type II (+) micro-emulsion formed, which favors the upper phase containing all the surfactant in the system. Since the viscosity of the oleic phase is more than the viscosity of the displacing ASP solution (30 cp), we would expect fingering to occur through the oleic phase, which will result in the bypass of lot of trapped capillary bound oil. This is the observed reason for the poor performance of the ASP flooding experiments at optimum ASP concentration with 38.3cm length core.

However, the 30 cm and 17 cm length core was able to give us a total recovery factor of 0.96 and 0.95 respectively as shown in Table 3.3, even though they had instability during ASP injection. The hypothesis is that the ASP solution becomes unstable after it travels some distance in the core so that if the core length is not so long, the initiated fingers still survive the entire length of the core, leaving small amount of bypassed oil as compared to a longer core length like the 38.3 cm core, where the finger will have to travel more distance to produce all the trapped oil.

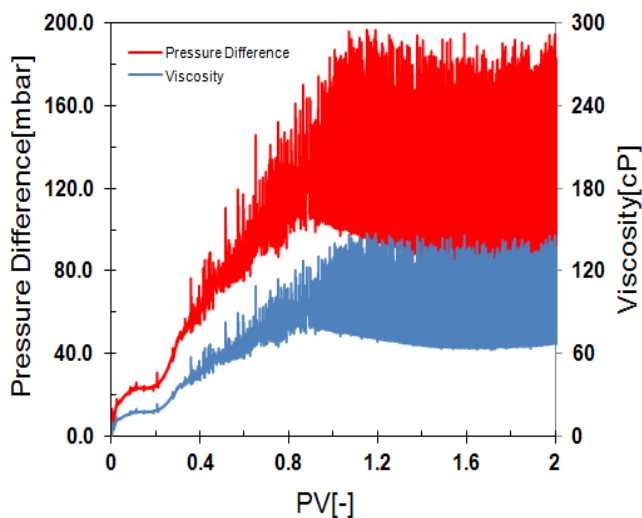


Figure 3-16 Transducer pressure difference during ASP injection for 2.25wt % Na_2CO_3 ASP experiment

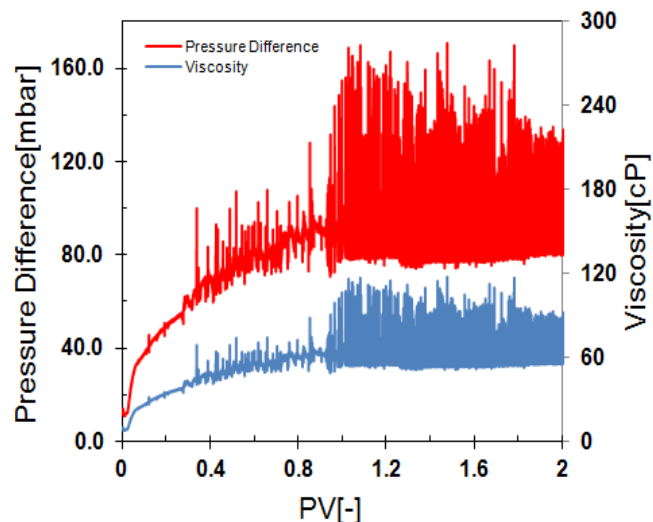


Figure 3-17 Transducer pressure difference during ASP Injection for 2.0wt % Na_2CO_3 ASP experiment

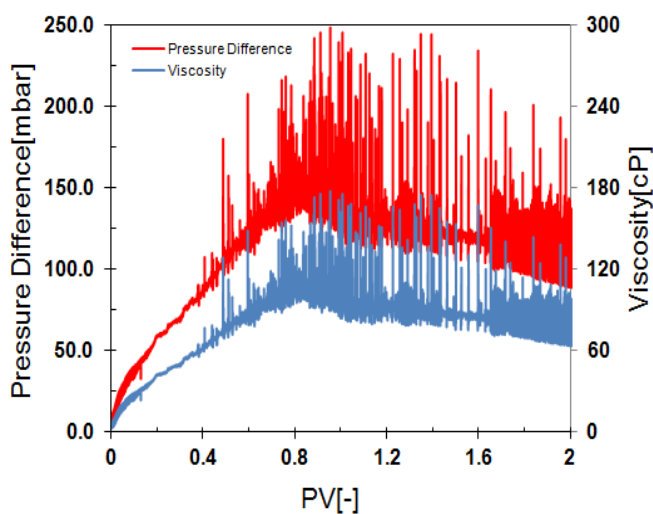


Figure 3-18 Transducer pressure difference during ASP injection for 1.75wt % Na_2CO_3 ASP experiment

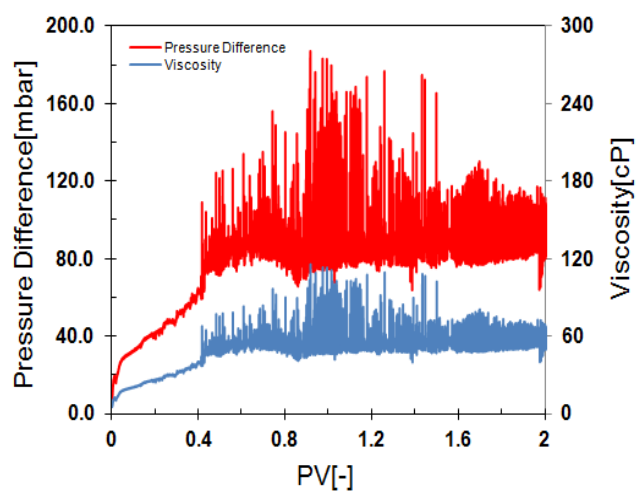


Figure 3-19 Transducer pressure difference during ASP Injection for 1.5wt % Na_2CO_3 ASP experiment

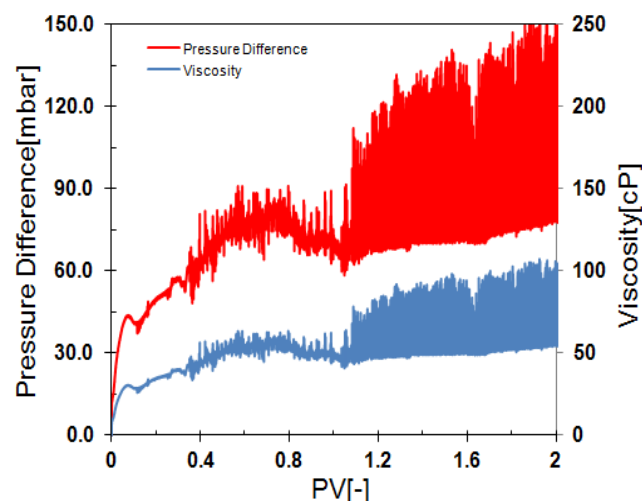


Figure 3-20 Transducer pressure difference during ASP injection for 1.25wt % Na_2CO_3 ASP experiment

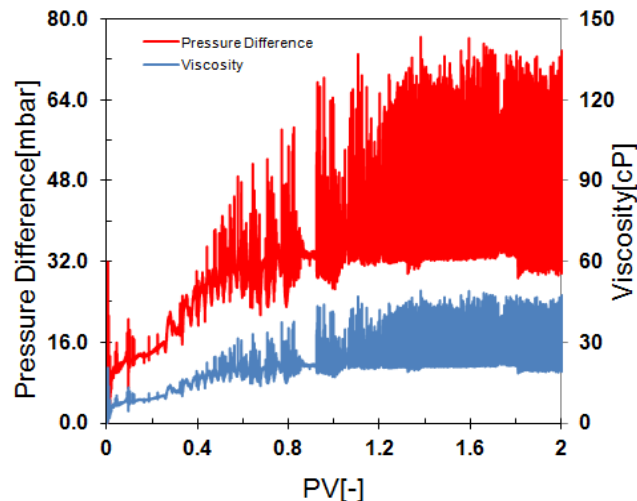


Figure 3-21 Transducer pressure difference during ASP injection for 1.0wt % Na_2CO_3 ASP experiment

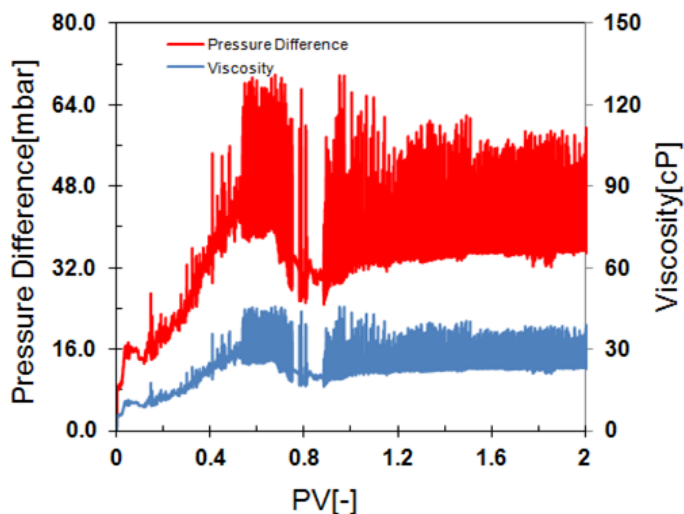


Figure 3-22 Transducer pressure difference during injection of 1.75 w/w% Na_2CO_3 ASP with 1w/w% brine used for core saturation and water flooding

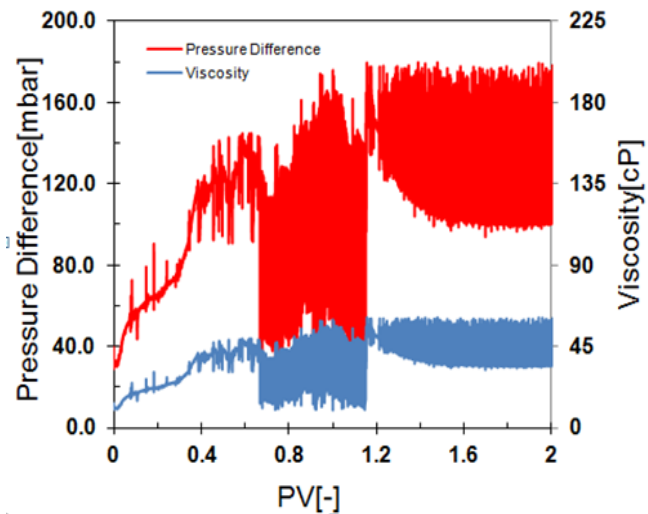


Figure 3-23 Transducer pressure difference during ASP injection of 0.5PV of 1.75 w/w % Na_2CO_3 chased by 1.2PV 1.0w/w% Na_2CO_3 and Demineralized water

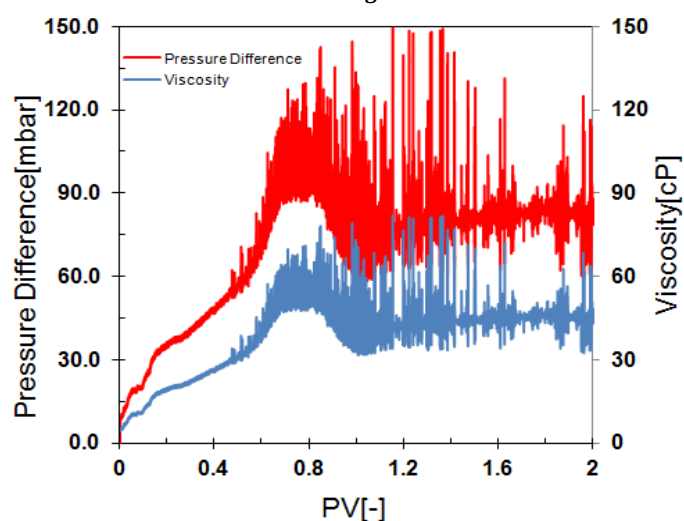


Figure 3-24 Transducer pressure difference during ASP injection for 1.75 w/w% Na_2CO_3 ASP with 30cm length core

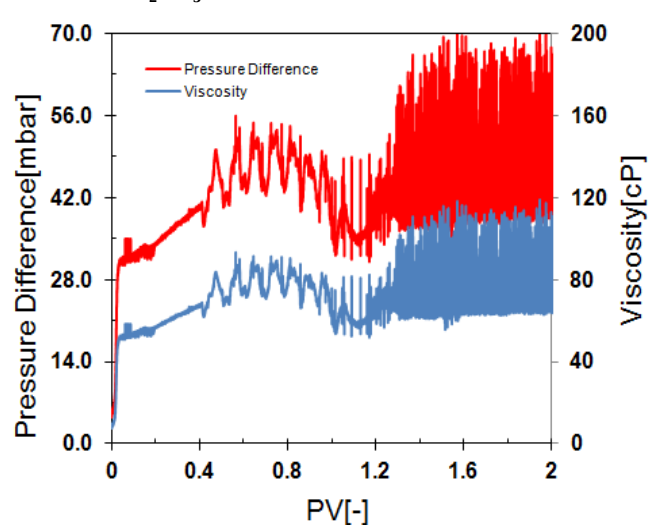


Figure 3-25 Transducer pressure difference during ASP injection for 1.75 w/w% Na_2CO_3 ASP with 17cm length core

Table 3.2 STABILITY CRITERIA

No	Na ₂ CO ₃ w/w %	Core Length (cm)	Brine Conc. Wt%	Core premeability (Darcy)	Gravity Number	G+1	Maximum oleic phase viscosity required for system to be stable (cP)	Recorded System Viscosity during ASP injection (cP)
1	1	38.3	3	1.95	0.0178	1.0178	30.5347	40.00
2	1.25	38.3	3	2.11	0.0193	1.0193	30.5785	70.00
3	1.5	38.3	3	1.92	0.0176	1.0176	30.5264	60.00
4	1.75	38.3	3	2.15	0.0197	1.0197	30.5895	75.00
5	2	38.3	3	2.07	0.0189	1.0189	30.5676	70.00
6	2.25	38.3	3	2.25	0.0206	1.0206	30.6169	85.00
7	1.75	38.3	1	1.97	0.0180	1.0180	30.5402	35.00
8	1.75 & 1.0	38.3	1	1.08	0.0099	1.0099	30.2961	45.00
9	1.75	30	3	1.42	0.0130	1.0130	30.3894	45.00
10	1.75	17	3	1.96	0.0179	1.0179	30.5374	80.00

3.4.5 Pressure Drop in Core During Oil and Water Injection.

The transducer pressure drop with PV increase during oil injection into the core for the various experiments is shown in section B.1 of Appendix B (Figure B.1 to Fig. B.8). The pressure drop is observed to increase with PV as the oil enters the core as determined by Darcy variables (fluid injection rate, cross sectional area of core, core permeability, fluid viscosity and length of core). Oil breakthrough in the core occurs after injection of 1.0 PV and pressure drop is experienced at that point. The reason for the pressure drop is due to a sudden decrease in the flow velocity of the oil front due an increase in its flow area on exiting the core. An increase in the pressure drop tapers after the oil break through gradually attaining a stable value as all the movable water is displaced from the core, such that the fluid flow through the core becomes single oil phase flow.

Figures B.9 to B.16 in section B.2 of Appendix B, shows the pressure drop in the core during oil displacement by water flooding. It is observed that the pressure drops decreases sharply as water is injected into the core. The decrease in pressure drop is due to the replacement of oil of higher viscosity by water with a lower viscosity. Water has a lower viscosity and so will have less resistance to flow hence generating less pressure drop between the inlet and exit part of the core. The pressure drop decreases with increasing PV tapering off to near horizontal after water breakthrough. The reason why it takes some time for the pressure drop to be horizontal after 1 PV injection is due to the pressure of multiphase phase (oil and water) flow in the core, which influences the pressure drop as indicated by the transducer reading. As more PV is injected, more oil is displaced out of the core making the drop in pressure difference to reduce further until only water flows through the core. At that point, the pressure difference between the inlet and exit of the core is constant and appears as a horizontal line.

Table 3.3 SUMMARY OF EXPERIMENTAL RESULT

	Na ₂ CO ₃ conc (w/w %)	Core Length (cm)	Brine Conc. (w/wt %)	Core Permeability (darcy)	S _{or} to water	Oil inj PV @ OBT	Water inj PV @ OBT	PV @ Chem BT	RF to WF	RF to Chem BT	ASP RF to Sor @ Chem BT	Total RF @ 2PV	Total RF @ 2PV to Sor
1	1.75	38.3	3	2.15	0.47	0.85	0.3	0.85	0.46	0.74	0.52	0.84	0.68
2	2.25	38.3	3	2.25	0.49	0.77	0.3	0.71	0.43	0.65	0.38	0.76	0.58
3	2	38.3	3	2.07	0.58	0.77	0.3	0.85	0.39	0.65	0.42	0.74	0.57
4	1.5	38.3	3	1.92	0.56	0.87	0.31	0.94	0.41	0.75	0.6	0.8	0.66
5	1.25	38.3	3	2.11	0.5	0.78	0.3	0.93	0.43	0.83	0.7	0.88	0.8
6	1	38.3	3	1.95	0.51	0.72	0.29	0.77	0.4	0.75	0.58	0.79	0.65
7	1.75	38.3	1	1.97	0.51	0.8	0.29	0.82	0.4	0.66	0.44	0.72	0.53
8	1.75 & 1.0	38.3	1	1.08	0.46	0.8	0.3	0.87	0.42	0.79	0.63	0.86	0.76
9	1.75	30	3	1.42	0.37	0.79	0.27	0.92	0.56	0.86	0.67	0.96	0.9
10	1.75	17	3	1.96	0.46	0.79	0.26	0.92	0.49	0.85	0.71	0.95	0.9

4 CONCLUSION

We were able to successfully carry out core flooding experiments to enhance the understanding of the efficiency of oil displacement at non optimal salinity conditions of ASP solutions. A summary of the performance of the ten ASP core flooding experiments have been displayed in Table 3.3. The results in Table 3.3 show that with the 38.3 cm length core, the ASP solution at under-optimum concentration (e.g., 1.25 w/w % Na_2CO_3) gave the best oil recovery, while the over-optimum Na_2CO_3 concentration (e.g., 2.25 w/w %), gave the least oil recovery

The salinity of the ASP solution upstream of the oil bank could be greatly influenced by the salinity of the brine (used in the initial brine-flooding) if there is transfer of sodium ions from the NaCl in the initial brine to the injected ASP. In a situation where the salinity of the mixing at the ASP front goes above the optimum, a type II+ micro-emulsion will be formed. As a result the three-phase system is converted to a two-phase system. The oleic phase containing mainly oil and some water and surfactant is also called a micro-emulsion and has a high viscosity. Therefore, the formation of a type II (+) will result in a mechanism where the injected ASP displaces a highly viscous oleic phase. This will cause an instability of the displacement front resulting in the fingering of the ASP through the oleic phase, causing a bypass of lot of the trapped capillary oil in the core.

Creation of the right salinity gradient in the core could help to keep the micro-emulsion formed in the core to stay close to type III. The salinity of the injected ASP could change due interaction with the NaCl in brine used for the initial water flooding, which could increase or decrease the NaCl concentration, and could help to form a type III system. So in order to bring the NaCl concentration in the ASP back to optimum (type III micro-emulsion), a different salinity fluid (either pure polymer or ASP solution) is required to either dilute or increase the salinity of the ASP.

The length of core used for the experiment is very important for the performance of the ASP process in the laboratory. This was observed in the result of experiment 9 and 10 where an ASP solution at an optimum condition of 1.75 w/w % Na_2CO_3 was injected into a core of length of 30 cm and 17 cm respectively after water flooding. The result of both experiments shows an oil recovery factor to residual oil of 0.9 for both core lengths, while the total oil recovery was 0.96 and 0.95 respectively. However, when the results of Experiment 9 and 10 are compared with the result from Experiment 1 (where an oil recovery of only 0.84 was achieved for a core length of 38.3 (> 30) cm), we can see that core length plays an important

part in the recovery efficiency because even though the system formed an over optimum micro-emulsion as the ASP travels through the core length, the fingers formed in the shorter cores survives the entire length of the core since it has to travel less distance than for longer cores and the consequence is trapping of less capillary oil in the core.

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APPENDIX A

A.1 Experiment 2- 2.25 w/w % Na_2CO_3 on 38.3cm length core

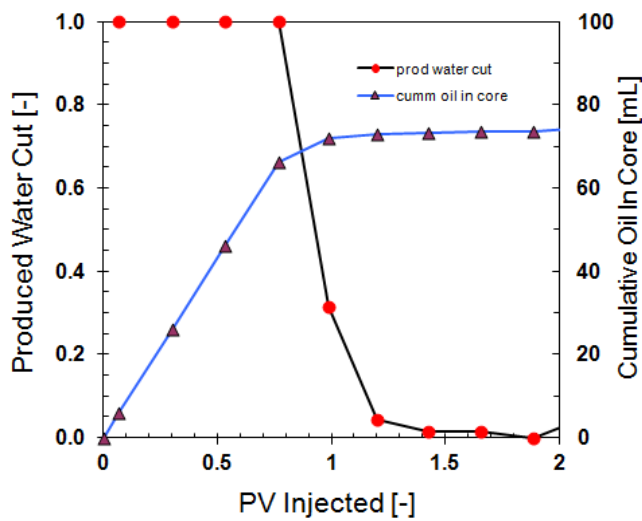


Figure A-1 Produced water cut and cumulative oil in core during oil injection

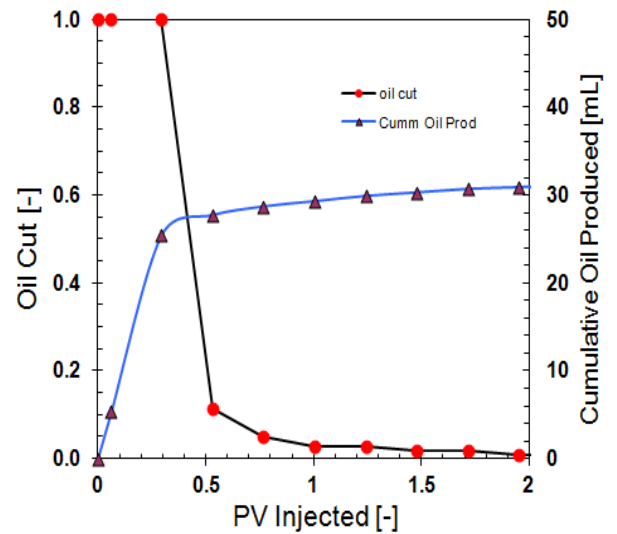


Figure A-2 Produced oil cut and cumulative oil production during water injection

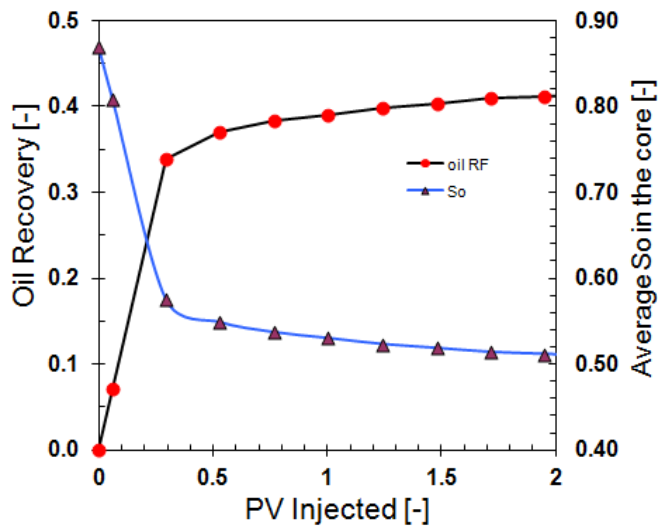


Figure A-3 Oil recovery factor and average oil saturation in core during water injection

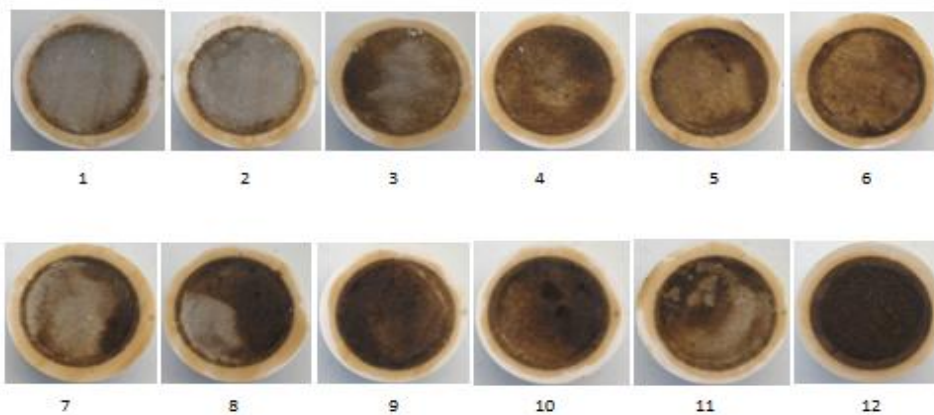


Figure A-4 Cross section of core at the end of experiment 2

A.2 Experiment 3- 2.0 w/w % Na_2CO_3 on 38.3cm length core

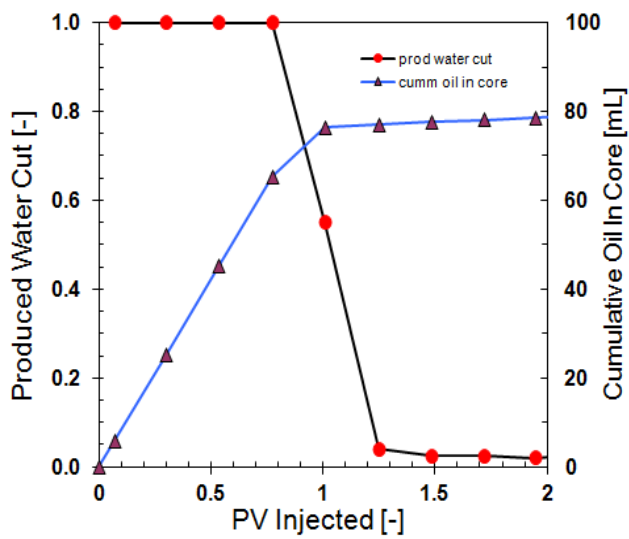


Figure A-5 Produced water cut and cumulative oil in core during oil injection

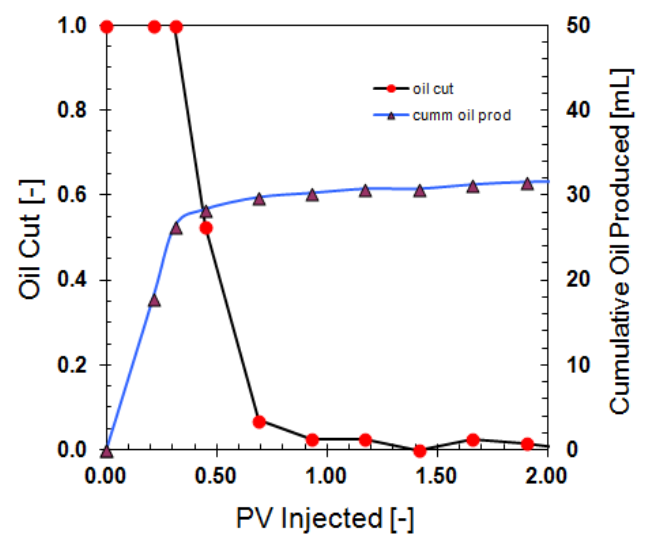


Figure A-6 Produced oil cut and cumulative oil production during water injection

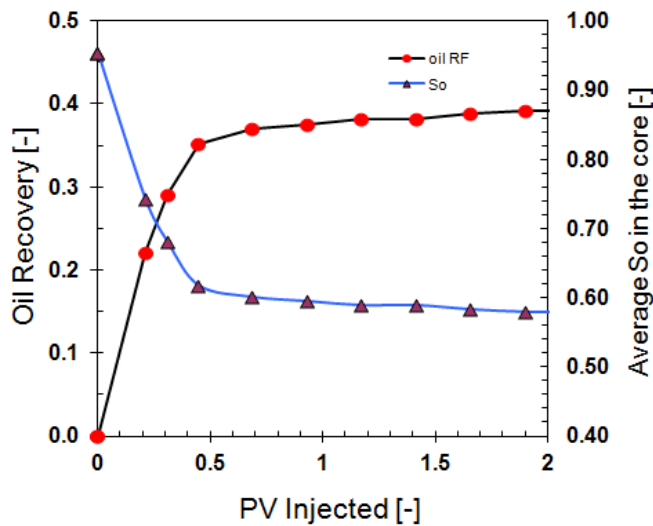


Figure A-7 Oil recovery factor and average oil saturation in core during water injection

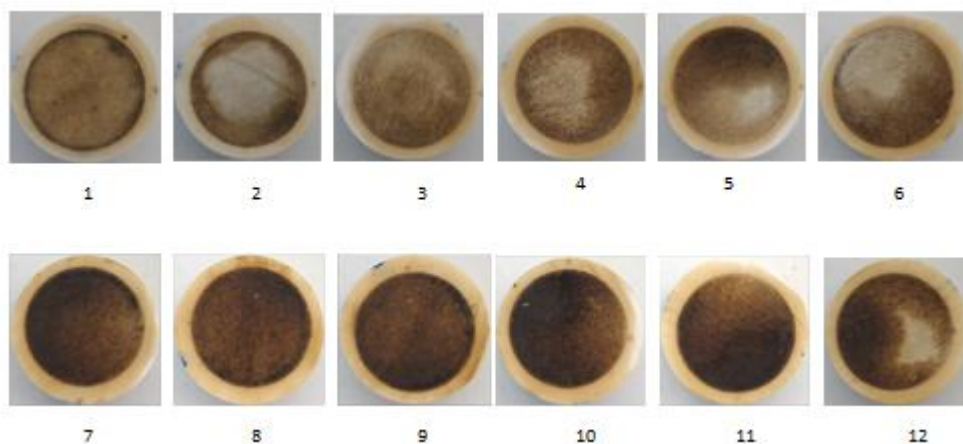


Figure A-8 Cross section of core at the end of experiment 3

A.3 Experiment 4- 1.5 w/w % Na_2CO_3 on 38.3cm length core

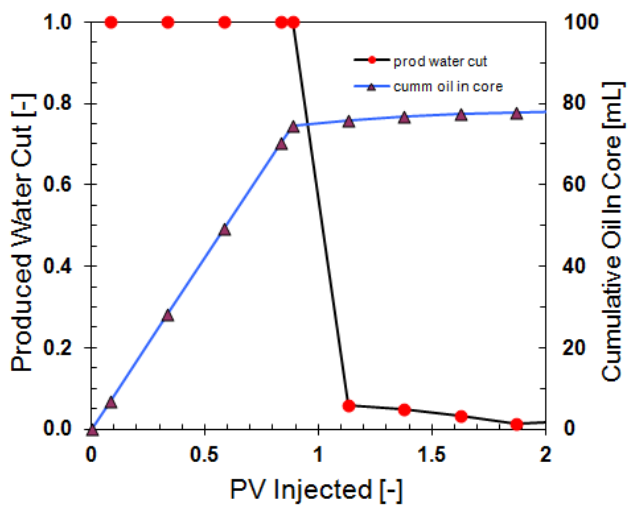


Figure A-9 Produced water cut and cumulative oil in core during oil injection

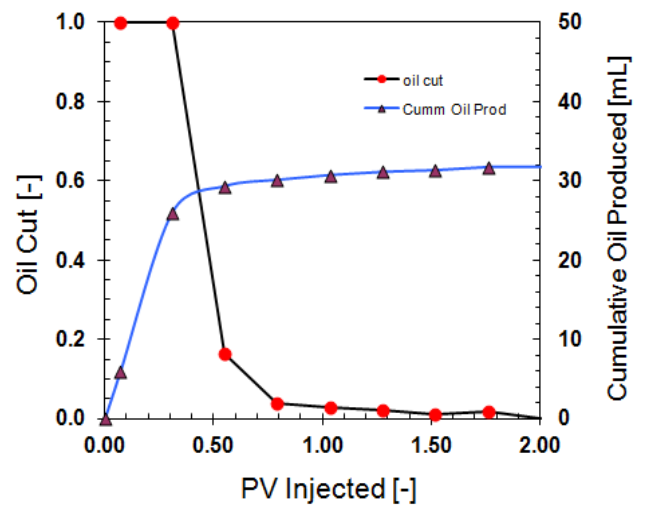


Figure A-10 Produced oil cut and cumulative oil production during water injection

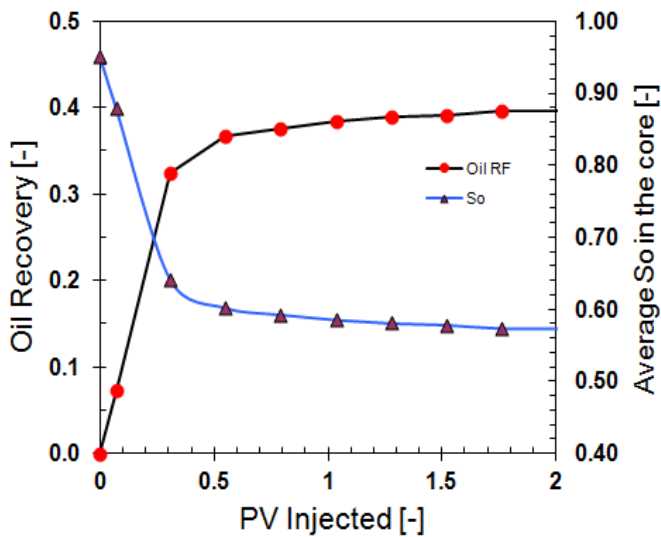


Figure A-11 Oil recovery factor and average oil saturation in core during water injection

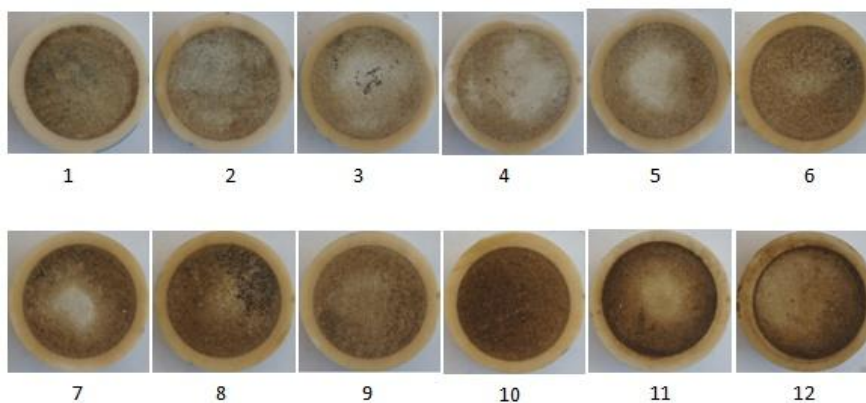


Figure A-12 Cross section of core at the end of experiment 4

A.4 Experiment 5- 1.25 w/w % Na_2CO_3 on 38.3cm length core

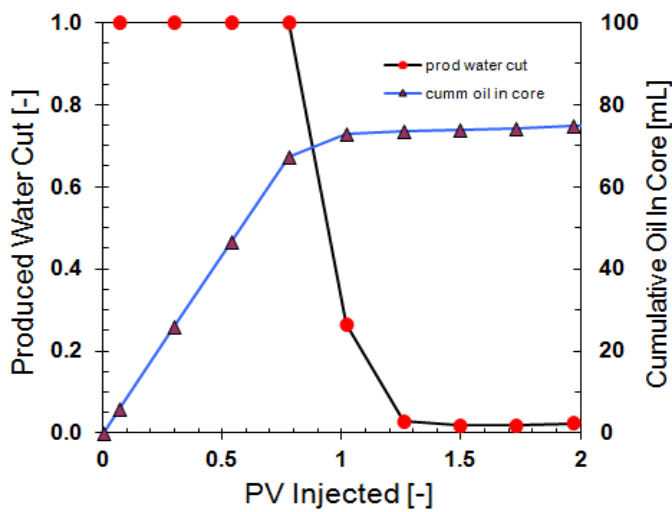


Figure A-13 Produced water cut and cumulative oil in core during oil injection

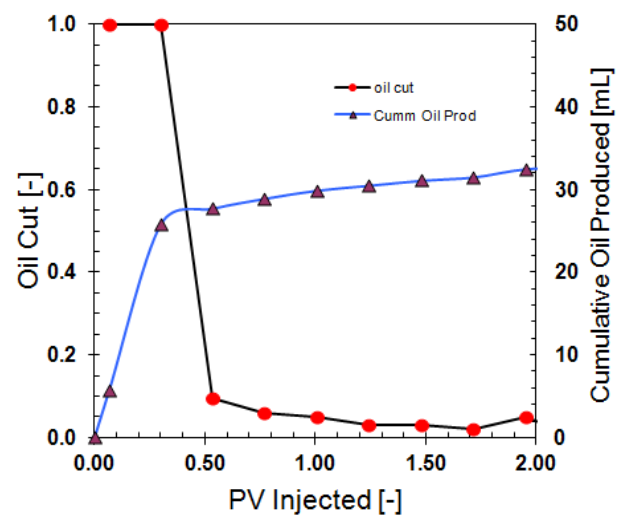


Figure A-14 Produced oil cut and cumulative oil production during water injection

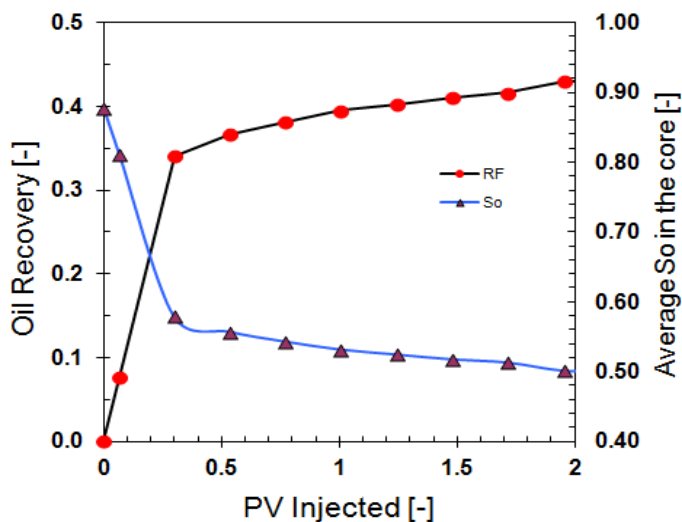


Figure A-15 Oil recovery factor and average oil saturation in core during water injection

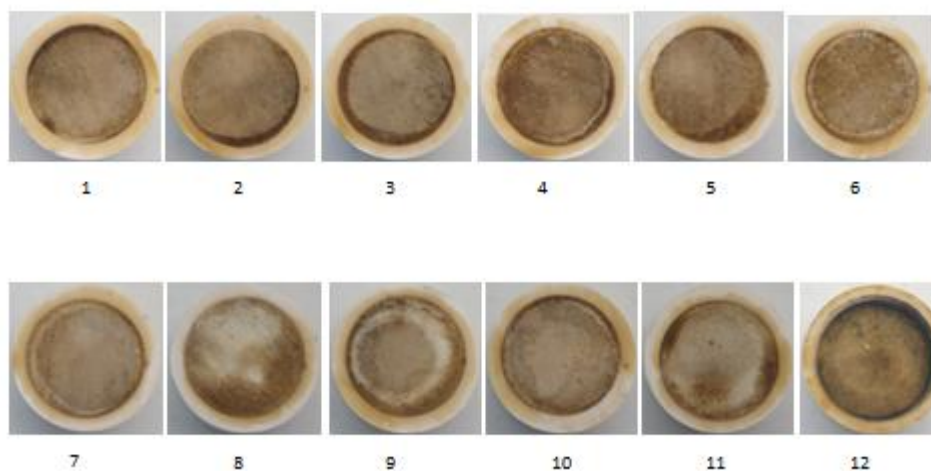


Figure A-16 Cross section of core at the end of experiment 5

A.5 Experiment 6- 1.0 w/w % Na_2CO_3 on 38.3cm length core

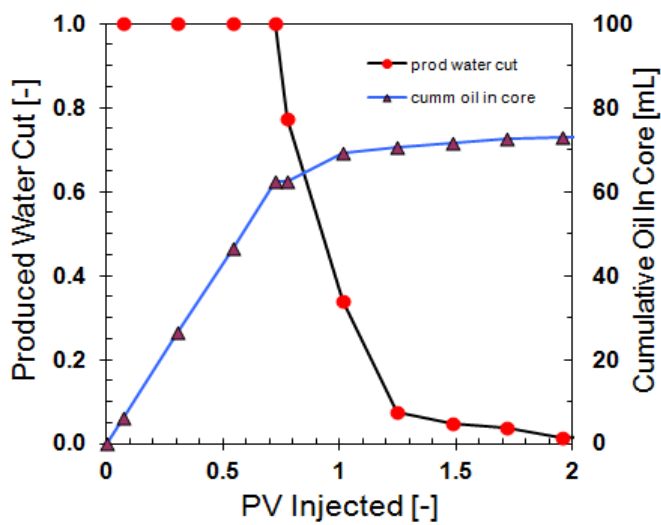


Figure A-17 Produced water cut and cumulative oil in core during oil injection

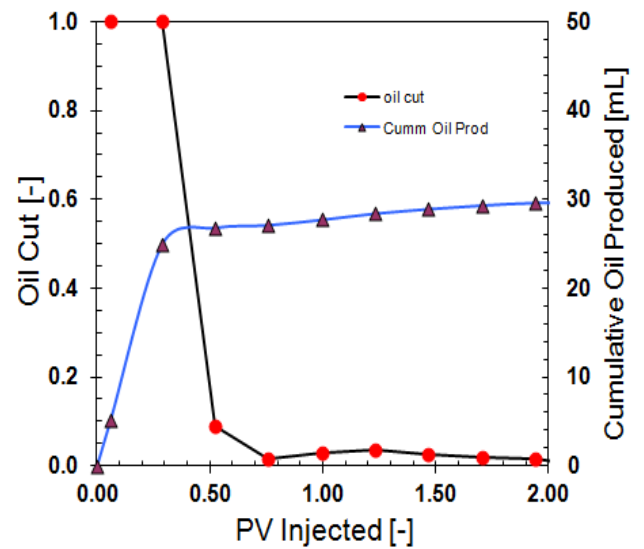


Figure A-18 Produced oil cut and cumulative oil production during water injection

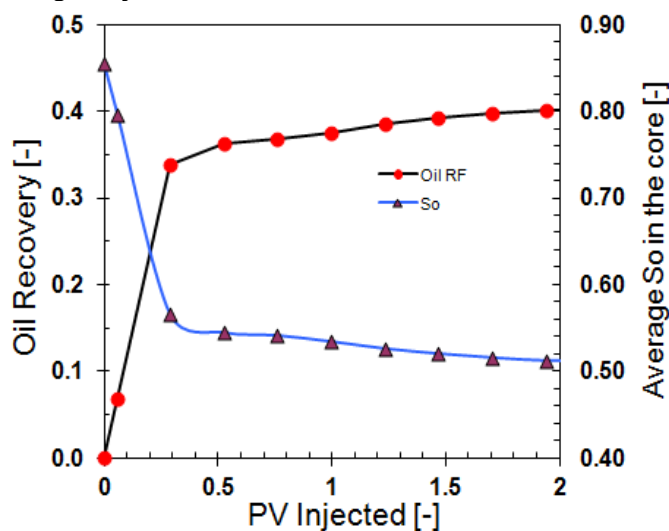


Figure A-19 Oil recovery factor and average oil saturation in core during water injection

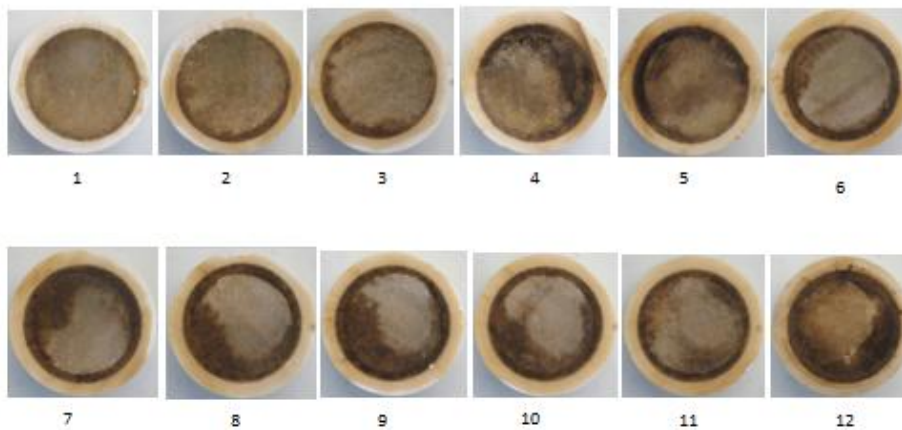


Figure A-20 Cross section of core at the end of experiment 6

A.6 Experiment 7- 1.75 w/w % Na_2CO_3 (1 wt% Brine) on 38.3cm length core

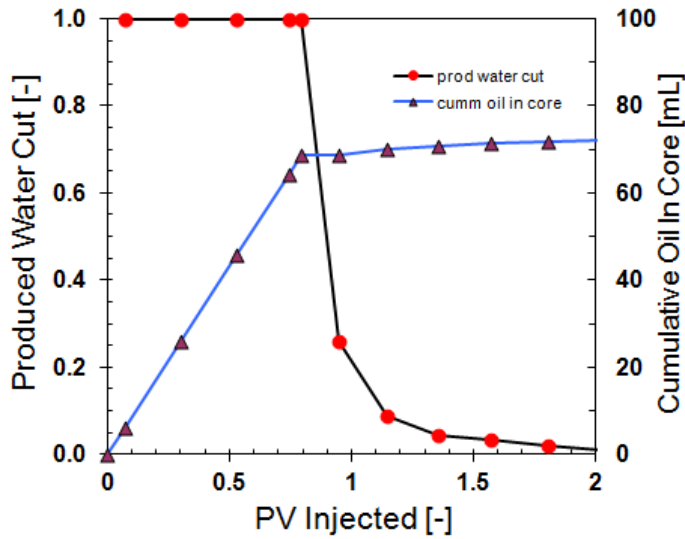


Figure A-21 Produced water cut and cumulative Oil in core during oil injection

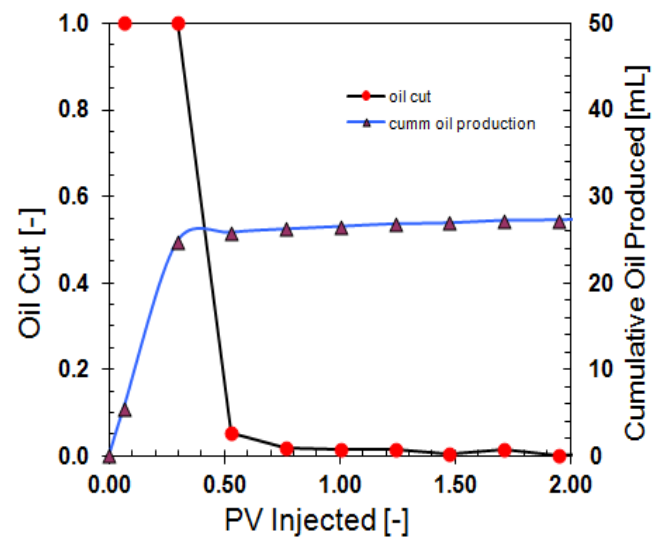


Figure A-22 Produced oil cut and cumulative oil production during water injection

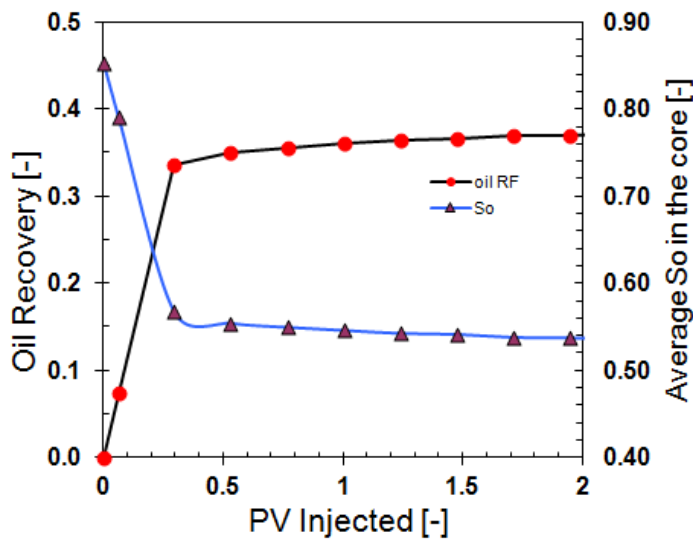


Figure A-23 Oil recovery factor and average oil saturation in core during water injection

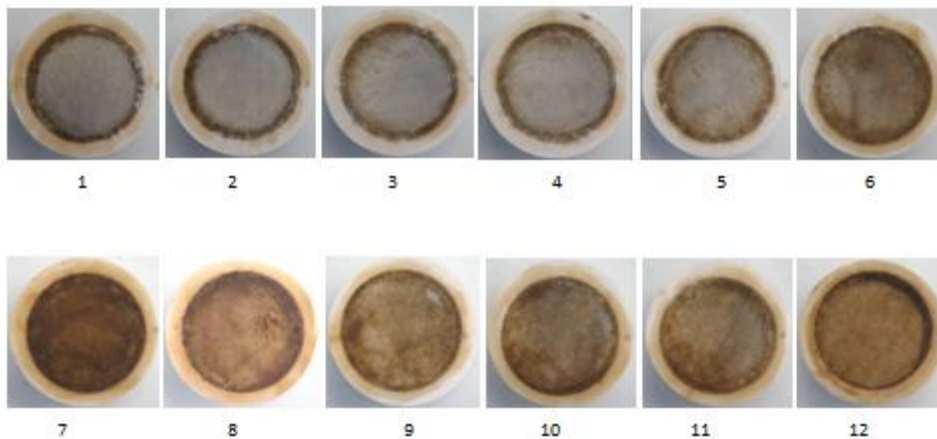


Figure A-24 Cross section of core at the end of experiment 7

A.7 Experiment 8- 0.5PV 1.75 w/w % Na_2CO_3 chased by 1.2PV 1.0 w/w % Na_2CO_3 and Demineralized water on 38.3cm length core

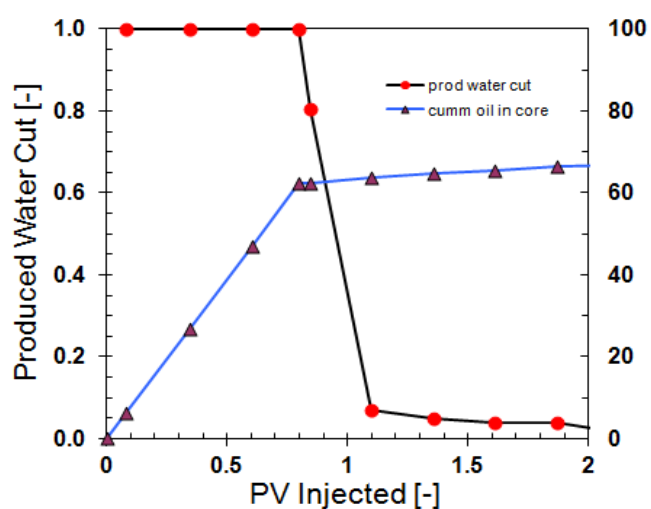


Figure A-25 Produced water cut and cumulative oil in core during oil injection

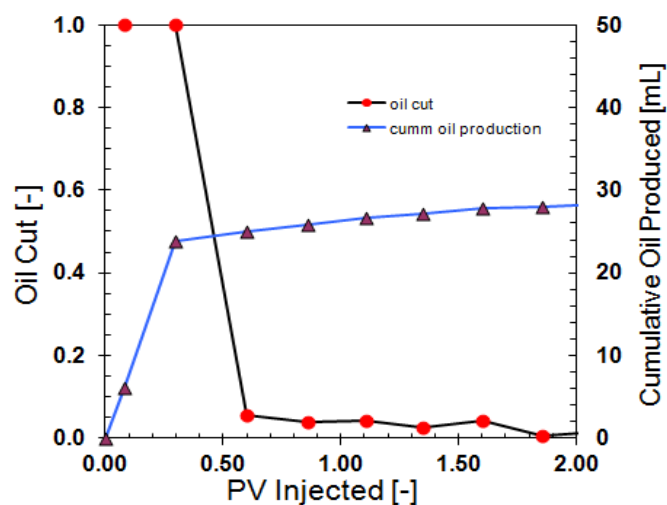


Figure A-26 Produced oil cut and cumulative oil production during water injection

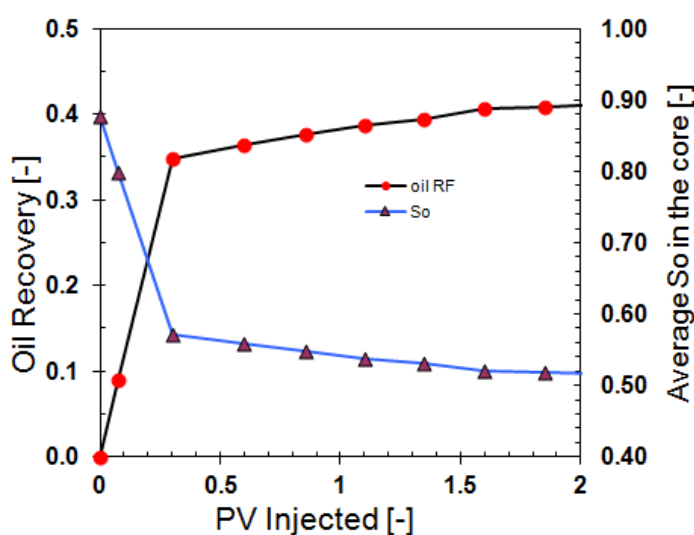


Figure A-27 Oil recovery factor and average oil saturation in core during water injection

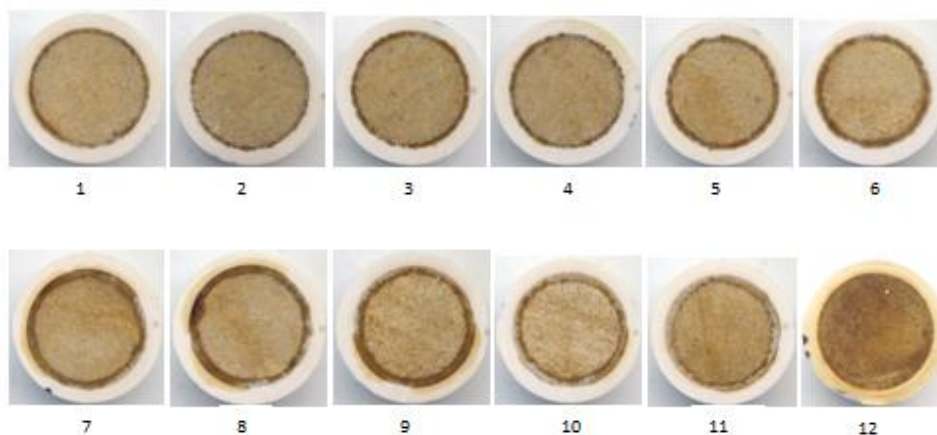


Figure A-28 Cross section of core at end of experiment 8

A.8 Experiment 9- 1.75 w/w % Na_2CO_3 using a 30cm core

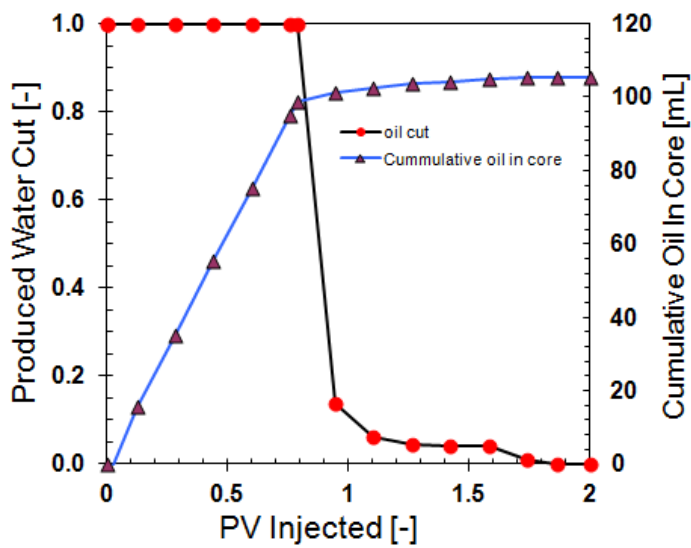


Figure A-29 Produced water cut and cumulative oil in core during oil injection

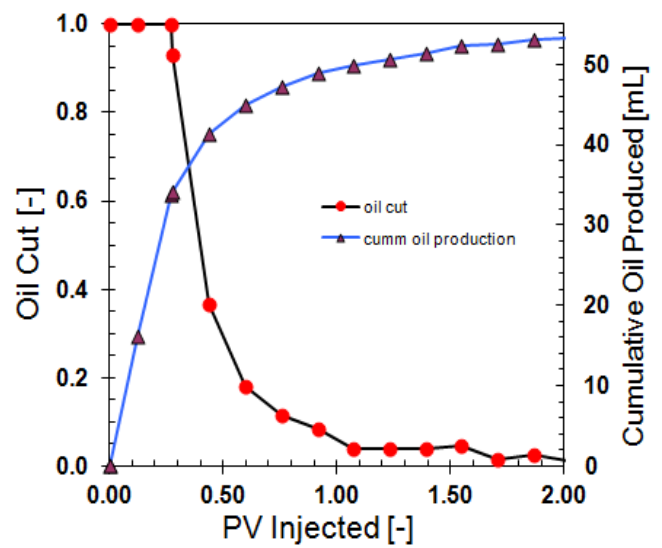


Figure A-30 Produced oil cut and cumulative oil production during water injection

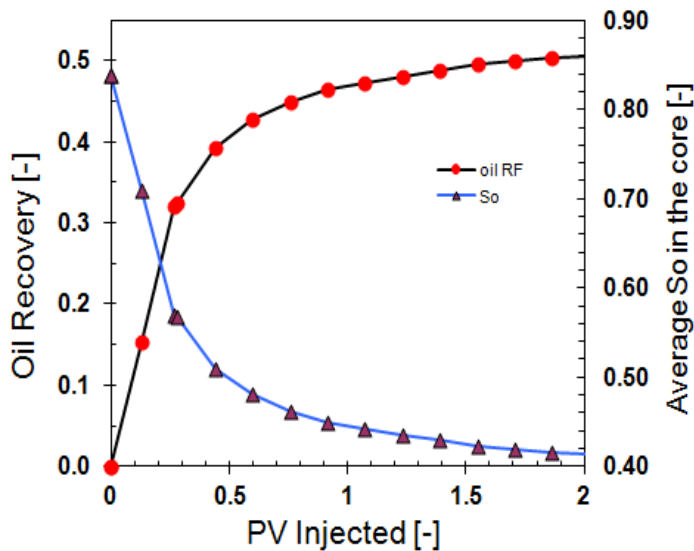


Figure A-31 Oil recovery factor and average oil saturation in core during water injection

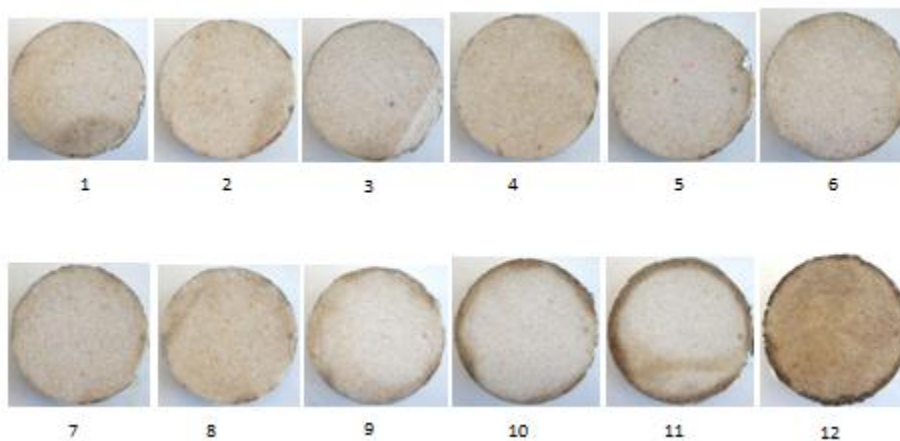


Figure A-32 Cross section of core at end of experiment 9

A.9 Experiment 10- 1.75 w/w % Na_2CO_3 using a 17cm core

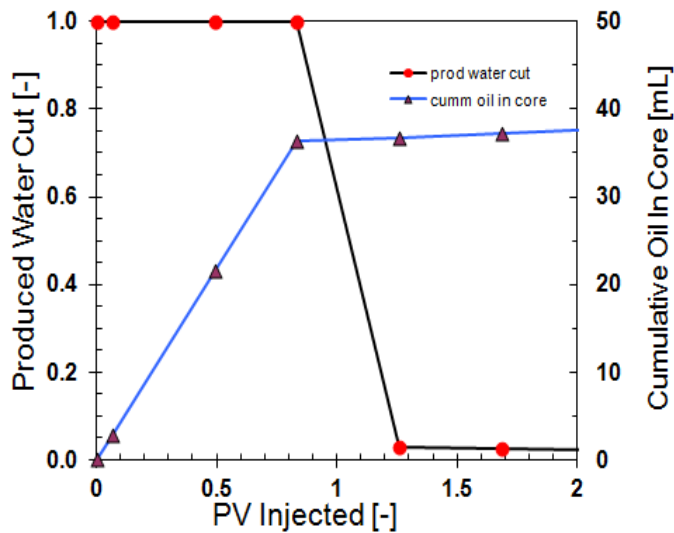


Figure A-33 Produced water cut and cumulative oil in core during oil injection

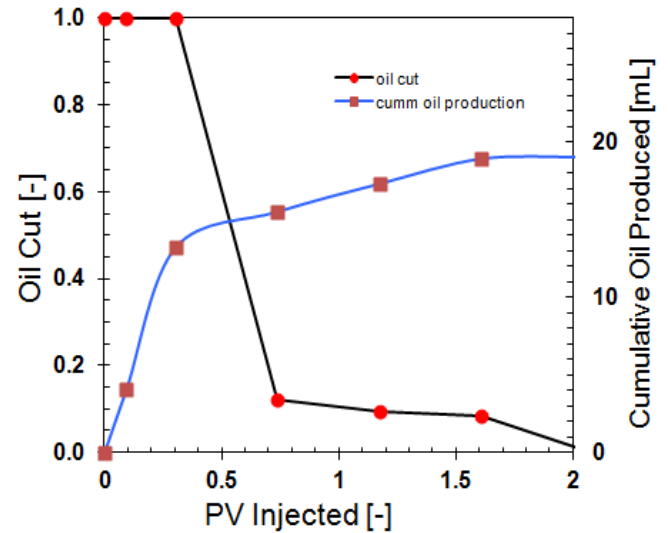


Figure A-34 Produced oil cut and cumulative oil production during water injection

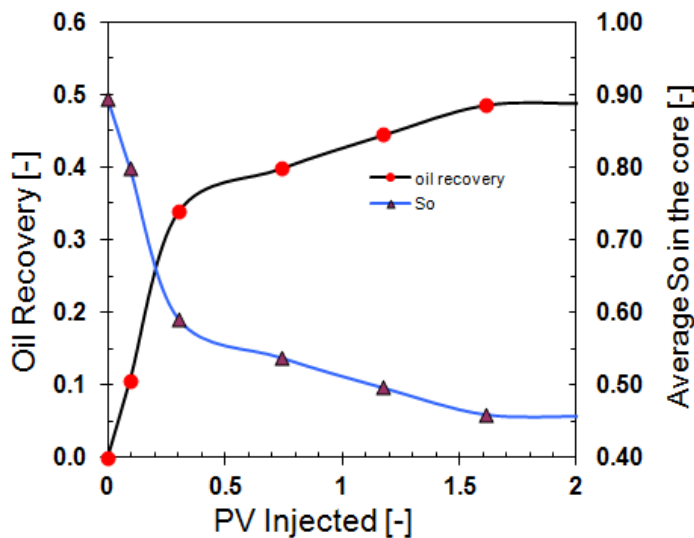


Figure A-35 Oil recovery factor and average oil saturation in core during water injection

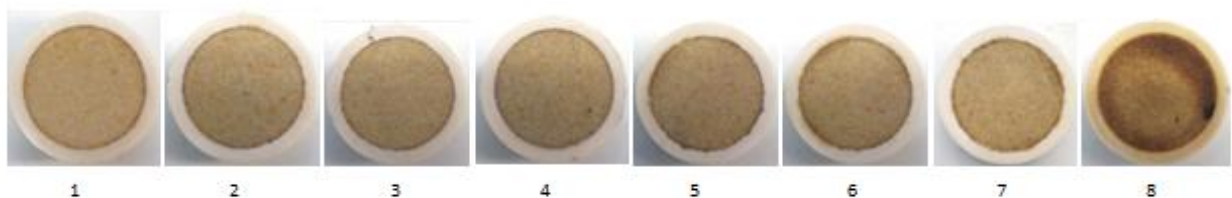


Figure A-36 Cross section of core at end of experiment 10

APPENDIX B

B.1 TRANSDUCER PRESSURE DIFFERENCE FOR OIL INJECTION

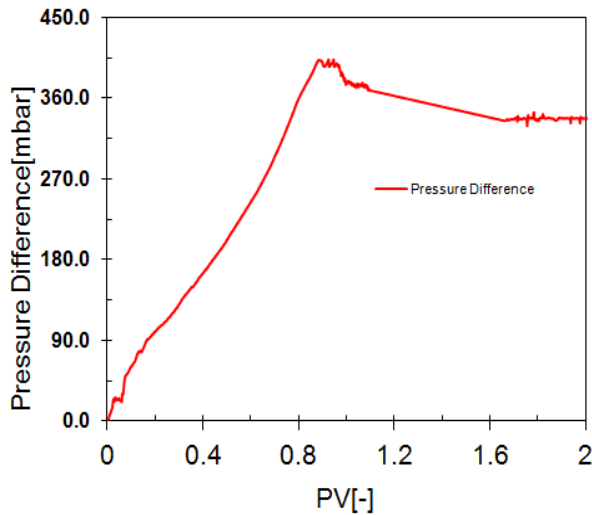


Figure B-1 Transducer pressure difference during oil injection for experiment 2

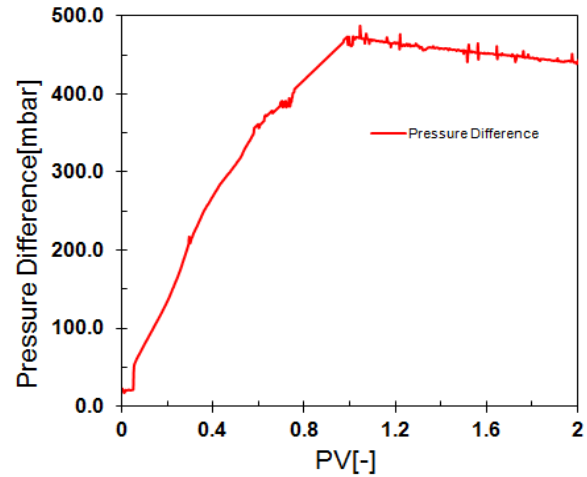


Figure B-2 Transducer pressure difference during oil injection for experiment 3

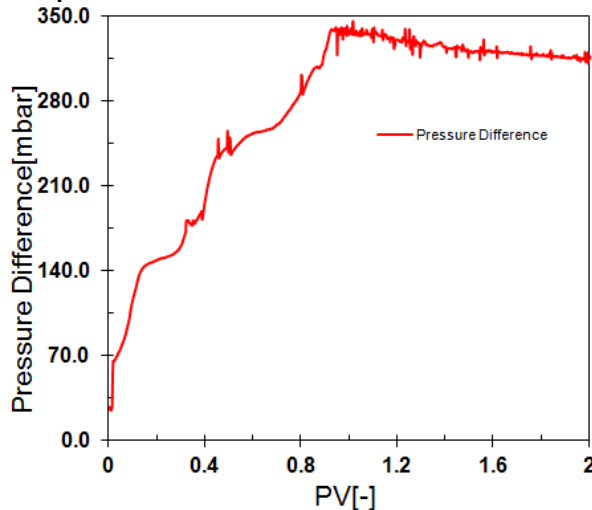


Figure B-3 Transducer pressure difference during oil injection for experiment 4

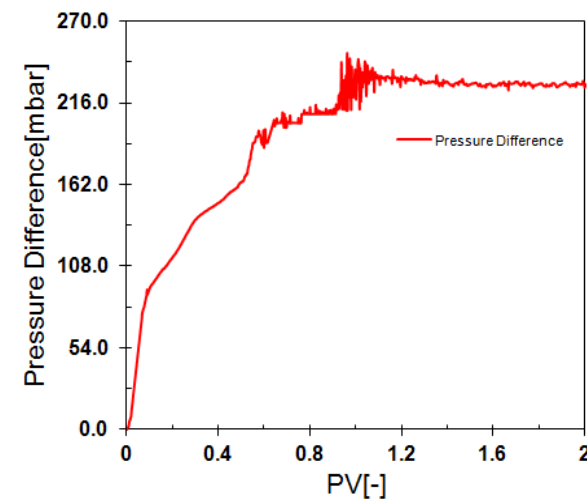


Figure B-4 Transducer pressure difference during oil injection for experiment 5

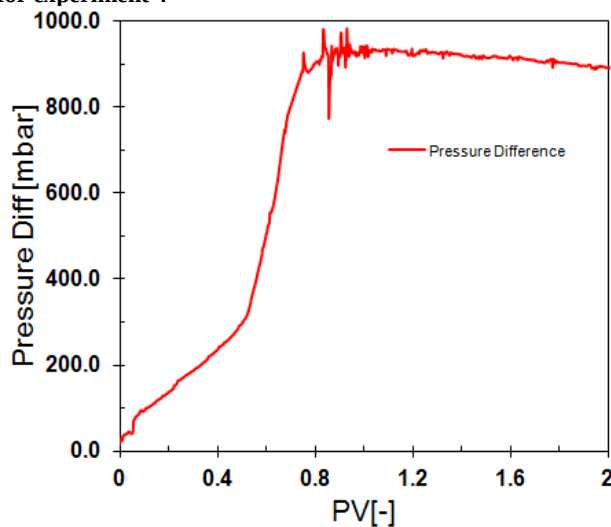


Figure B-5 Transducer pressure difference during oil injection for experiment 6

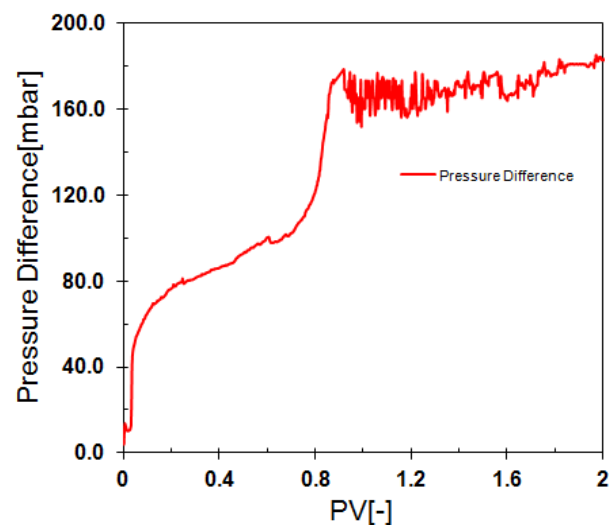


Figure B-6 Transducer pressure difference during oil injection for experiment 7

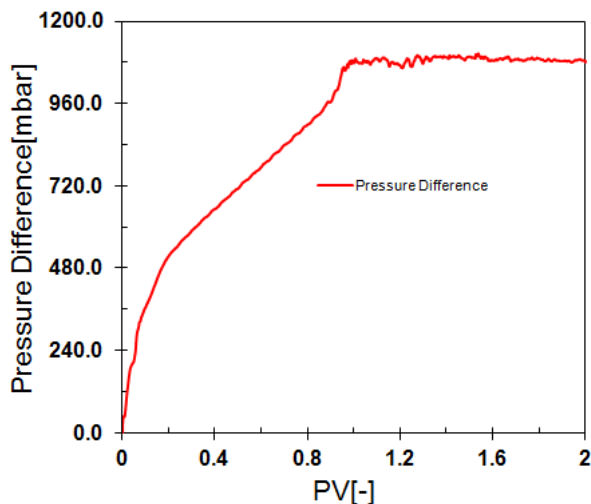


Figure B-7 Transducer pressure difference during oil injection for experiment 9 (30cm length core)

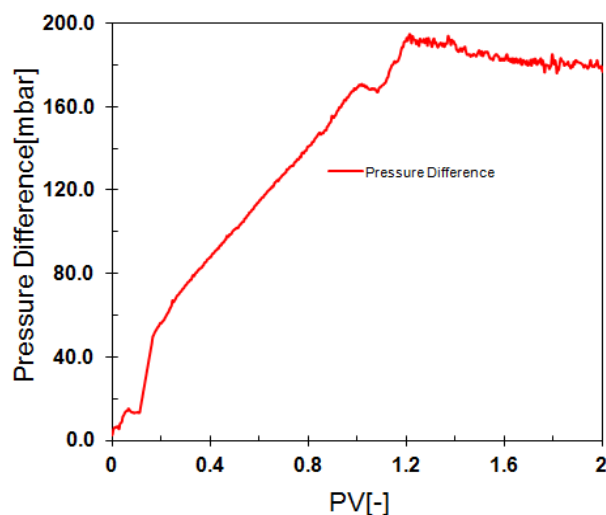


Figure B-8 Transducer pressure difference during oil injection for experiment 10 (17cm length core)

B.2 TRANSDUCER PRESSURE DIFFERENCE FOR WATER INJECTION

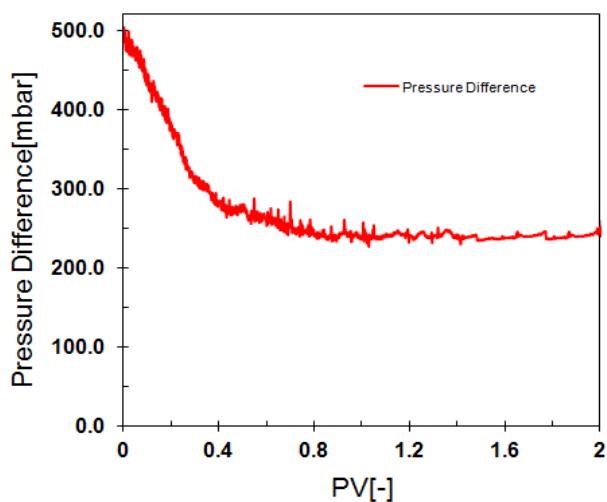


Figure B-9 Transducer pressure difference during water injection for experiment 1

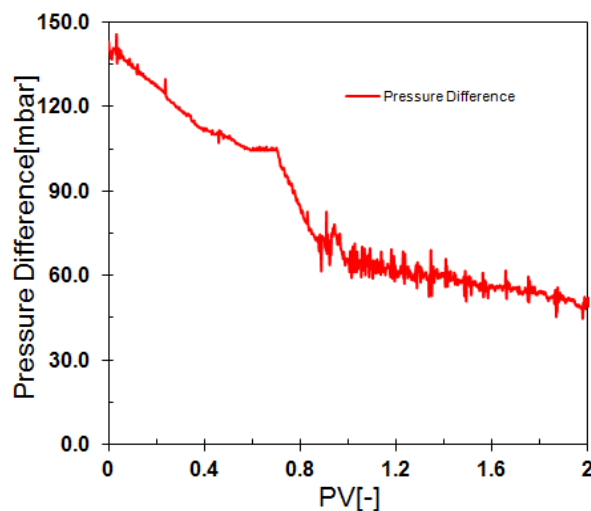


Figure B-10 Transducer pressure difference during water injection for experiment 2

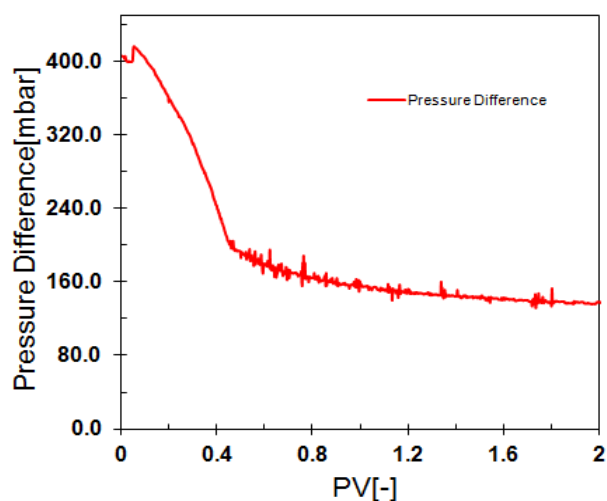


Figure B-11 Transducer pressure difference during water injection for experiment 4

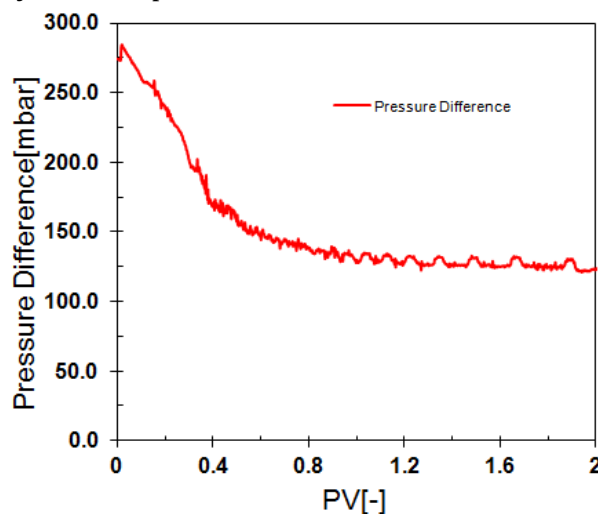


Figure B-12 Transducer pressure difference during water injection for experiment 5

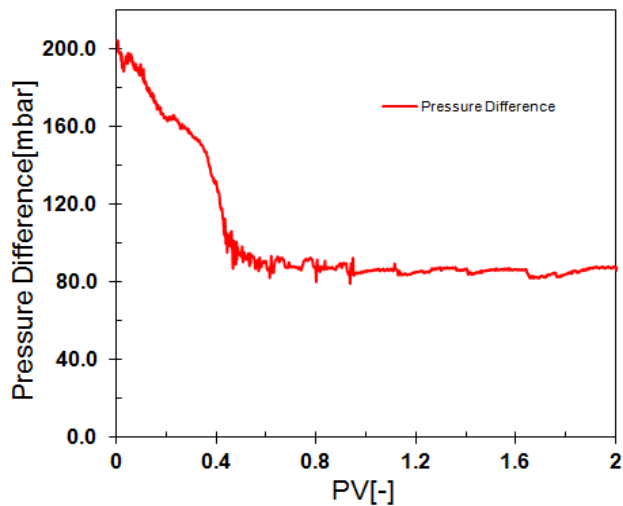


Figure B-13 Transducer pressure difference during water injection for experiment 6

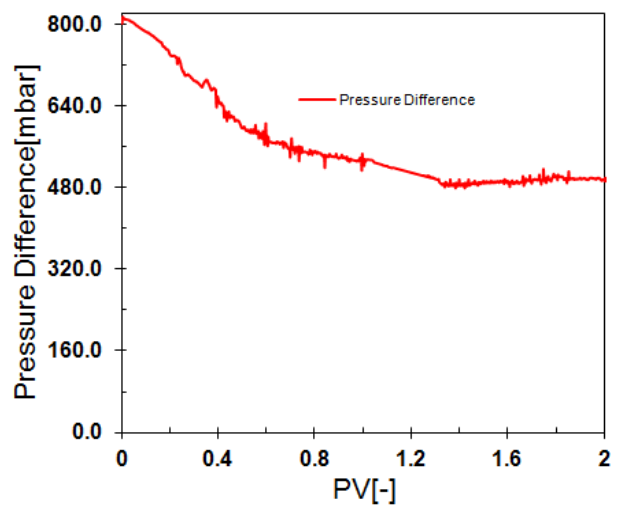


Figure B-14 Transducer pressure difference during water injection for experiment 8

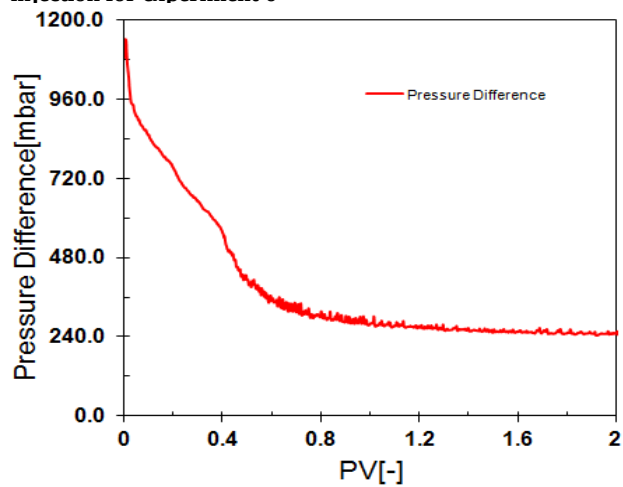


Figure B-15 Transducer pressure difference during water injection for experiment 9 (30cm length core)

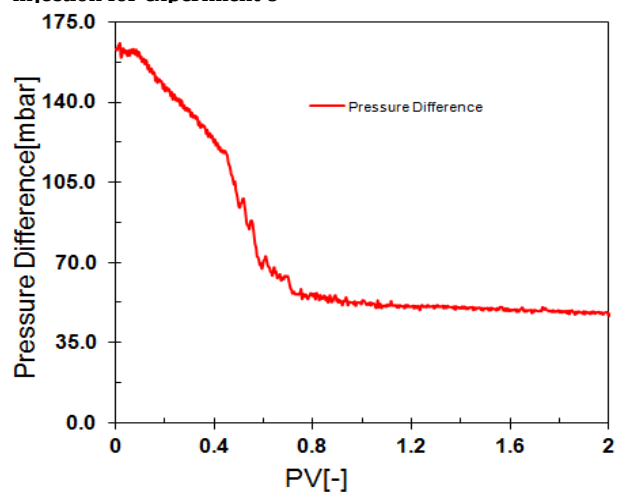


Figure B-16 Transducer pressure difference during water injection for experiment 10 (17cm length core)

Acknowledgements

First and foremost I would like to offer my sincerest gratitude to Dr. Rouhi Farajzadeh, for taking his time to put me through the basics I needed to start this thesis and also supporting me through advice and supervision throughout the entire period of working on this thesis. Special thanks also go to my second supervisor Professor Hans Bruining who also supported me throughout the duration of this project.

The technicians of Dietz lab: Dirk Delforterie, Henk van Asten, Mark Friebe, Ellen Meijvogel-de Koning have to be solemnly acknowledged for the time they took in helping me troubleshoot problems in the lab and also explaining how to use the lab facilities to me. My profound gratitude also goes to Paul Vermeulen of the Center for Electronic Development for the valuable time he spent troubleshooting problems related to the MP3 software for displaying transducer measurement.

Special thanks also goes to my lovely wife Stella Adesuwa Arhore for her patience and encouragement to me during my entire study period at the Delft University of Technology in the Netherlands.