OIL RECOVERY BY WATER IMBIBITION IN ASMARI FRACTURED ROCK

H. Karimaie [1] - O.Torsæter [1] - M.R.Esfahani [2]
1-Norwegian University of Science and Technology (NTNU) -Trondheim-Norway
2-Research Institute of Petroleum of Iran (RIPI)

This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Toronto, Canada, 21-25 August 2005

ABSTRACT
In this paper the results from experiments of water injection in fractured carbonate rock are reported. The experimental setup consists of a column of 3 Asmari limestone outcrop cores which are taken from the southern part of Iran. The column of cores was placed in the center of a plexiglass cylinder while the annulus between the core wall and the cylinder wall serves as the fracture. Water injection tests were performed by injecting water from the bottom and producing from the top. The system experienced an advancing oil/water level in the fracture. The composite core was also under complete immersion for around 5-7 days after finishing the experiment which causes to change the boundary conditions from partially to fully covered. Immersion type experiment was also performed separately. The effect of rate and initial water saturation on oil recovery by imbibition mechanism was investigated experimentally. Water injection tests have been performed at three different rates and three different initial water saturations. It was found that breakthrough recovery is higher when injection rate is low while the final oil recovery is more or less independent of the rate. It is also clear that oil recovery increased with increase in initial water saturation. The results show that oil recovery by water injection is low in Asmari limestone. Therefore, low tension system has been used in order to increase the recovery and its effect on oil recovery is investigated experimentally. The experimental results presented indicate that oil recovery is increased due to increase in gravity effect. In addition, the results indicate that permeability and length of the matrix block are important parameters in the process.

INTRODUCTION
Oil recovery by water injection in water-wet rock is mainly controlled by spontaneous imbibition. However, several large and significant fields exist that consist of fractured carbonates with mixed wetting properties. Asmari limestone is such an example which is an important hydrocarbon producing formation in the southern part of Iran. The main reservoirs in southwest Iran occur in the extensively fractured carbonate rocks of the Tertiary Asmari Formation. The Asmari limestone is a hard, compact rock, fine to coarse-grained and slightly marly anhydritic or sandy [1]. The presence of fractures at Asmari reservoirs is evidenced by mud losses, high productivities not correlatable to matrix permeabilities, pressure build up characteristics, flowmeter surveys, and core analysis [1].

Initial water saturation has been observed to be in the range of 25 % or less (good rock) to between 25-50 % (poor rock) [(2)]. Therefore the efficiency of water imbibition in different initial water saturation and different rates is an important question in Asmari limestone fields. Answer to such a question may be found by experimental investigation of the effect of initial water saturation and rate on water injection.

Some studies about the effect of initial water saturation on oil recovery have been published by different authors but their results are not consistent. Zhou et al. [(3)] studied the relationship of wettability, initial water saturation, and oil recovery by countercurrent spontaneous imbibition and waterflooding in oil-water-rock (Berea sandstone) systems. They found that imbibition rate and final oil recovery increased with increase in initial water saturation. Viksund et al. [(4)] performed spontaneous imbibition tests on strongly water-wet chalk and Berea sandstone in oil-water-rock systems. They found that the final oil recovery by spontaneous imbibition in Berea sandstone showed little variation with change in initial water saturation from 0 to about 30%. For the chalk samples tested by Viksund et al, the imbibition rate first increased with increase in initial water saturation and then decreased slightly as initial water saturation increased above 34%. Tong et al., [(5)] studied the effect of initial water saturation on Berea sandstone and found that imbibition rate was very sensitive to initial water saturation. After scaling, the oil recovery increased with increase in initial water saturation while before scaling the oil recovery did not vary systematically with initial water saturation.

Tang and Firoozabadi [(6)] studied the effect of initial water saturation on water injection in water-wet and mixed-wet fractured porous media. They found that the effect of initial water saturation on oil recovery depends on wettability. For a strongly water wet condition, oil recovery by water injection can decrease mildly with an increase in initial water saturation. However, for weakly water-wet conditions, the oil recovery by water injection can increase significantly with an increase in initial water saturation. According to their results the rate and final oil recovery may vary depending on the rate of injection, initial water saturation and matrix wettability.

The most important forces describing the flow of liquid during the oil production process are viscous, gravity and capillary forces. In fractured reservoirs, capillary imbibition is regarded as a main mechanism for oil recovery during waterflooding. This is partly related to the fact that many of the fractured reservoirs found today are water-wet. Clearly for water-wet rock the capillary pressure are always positive with no negative part. Thus the oil displacement is mainly controlled by capillary forces and is independent upon the matrix block height. For a mixed wetting rock there might be a substantial negative part of the capillary pressure curve. Therefore water injection may lead to a significant amount of oil recovery from the matrix block because the capillary pressure curve is predominantly negative. In this situation the gravity-capillary equilibrium point of the water–oil capillary pressure curve no longer corresponds to the end point of the relative permeability curves. The gravity forces have to extend the capillary forces for oil to be recovered beyond the capillary cross-over saturation. Thus the ultimate recovery will be influenced by the effective matrix height [(7)]. Therefore capillary and gravity are the most important forces during spontaneous imbibiton which is a function of interfacial tension, wettability, density differences and pore size distribution. Also the height of the matrix blocks in Iranian reservoirs is quite long which implies that gravity may be an effective force in oil recovery. The block dimensions in Haft Kel field are varied from 6 to 13 ft in height with radii of 6-8 ft for example [(2)]. Several authors have addressed the importance of gravity force during spontaneous imbibiton in ultra low interfacial tension [(8, 9, 10, 11, 12)]. Schechter et al [(10)] introduced the inverse Bond number, N_B^{-1} for showing the relative importance of gravity to capillary forces as expressed in the following form:

$$N_B^{-1} = C\frac{\sigma\sqrt{\phi / k}}{\Delta\rho g H} \qquad (1)$$

Where C=0.4 for the capillary tube model, and H is the height of the medium. They showed that for a system with well-defined wetting properties, capillary forces are dominant for N_B^{-1}>5 and gravity forces for N_B^{-1}<<1. In the intermediate range, 0.2<N_B^{-1}<5, both capillary and gravity forces can be active in the displacement. If capillary forces dominate the spontaneous process, i.e. N_B^{-1}>5, the oil is produced in a countercurrent flow mode from all surfaces. The oil will be produced mainly from the upper part of the porous medium when N_B^{-1} is in the intermediate range, 0.2<N_B^{-1} < 5. Both capillary and gravity forces are assumed to be active in the displacement process. In this case, the gravity contribution is high and will cause considerable segregation of the flow, which keeps relative permeabilities high, and capillary forces are still strong enough to boost the driving force for flow [(10)]. In other words, as N_B^{-1} is reduced by decreasing IFT or increasing the density difference, gravity forces become more important. In the limit of very low values of N_B^{-1}, the flow is completely segregated by gravity. In this case, the relative permeability of both phases is higher because flow is segregated and cocurrent and also resistance to flow are lower. As far as we know, there are a limited study related to imbibition at low N_B^{-1}, especially for systems in which N_B^{-1} is lowered by reducing the IFT. In this paper, we report experimental data of such an investigation. As IFT is reduced there is a transition from counter-current capillary dominated flow to cocurrent gravity-driven flow in imbibition [(10)]. Generally spontaneous imbibition is attributed with capillarity in the water-wet systems. However, for oil-wet systems and/or the systems which are preferentially mixed-wet, capillarity is the mechanism that retains the oil in the matrix and imbibition does not occur. In oil-wet systems, oil is remained into the matrix due to surface wettability and capillarity. In such cases reduction of IFT and alteration of the wettability will reduce the tendency for capillarity to retain the oil. If wettability is altered to preferentially water-wet and/or capillarity is diminished through ultra low IFTs, gravity will still tend to force oil to flow upward and out of the matrix into the fracture system [(10)]. In addition of a decrease in IFT, some other parameters like permeability, porosity, density difference between the phases and core height will have influence on the contribution of the gravity and capillary forces. One of the methods for activating the gravity forces is using the surfactant solutions. Injection of surfactant can recover additional oil by lowering the water-oil

interfacial tension (IFT) or altering the rock wettability which in turn will accelerate the gravity segregation and improve the oil recovery.
In the present work we started with a slightly water-wet Asmari limestone outcrop of low permeability. Experiments aimed at investigating the effect of rate, initial water saturation and gravity on oil recovery on this type of rock. For this purpose, we have performed laboratory measurements on Asmari limestone outcrop with a porosity of approximately 15% and permeability less than 1 md. Thin section studies, capillary pressure, relative permeability and Amott wettability indices have been measured separately on the short plugs which were prepared from each tall block for better understanding of the system behavior.
After doing some careful experiments and certifying the low oil recovery in the normal condition, an attempt is made to investigate the relative influence of capillary and gravity forces on the fluid flow by varying the height of the core and IFT between the phases. In this study dilute surfactant imbibition tests on Asmari limestone and Bentheimer sandstone cores were performed to produce additional oil.
Some additional experiments were performed to evaluate and verify the importance of gravity effects at low IFT on the long Bentheimer sample.

GEOLOGICAL SAMPLE INFORMATION

Three carbonate outcrop samples were selected from the tall blocks of the Asmari Formation in southern of Iran. Optical thin section analyses were performed to characterise the mineralogy and porosity types (see Fig.1). The samples are limestone (grainstone – packstone) with abundant coralline algae and 15-20 % porosity. The left picture is showing moldic and vuggy porosity (blue). Sparitic calcite cement is shown by white color. The right picture is showing a dark coating around some of the larger fossil grains, possibly organic/recording early oil-staining, and later in part replaced by pyrite. It might be a good evidence for explain the weak water wettability of the samples.

ROCK AND FLUID DATA

Three Asmari limestone outcrop samples have been selected for the experiments. Total length of the samples is around 116 cm and the core diameter is 2.5 inch. Normal decane with density 0.73 gr/cc and viscosity 0.92 cp was used as the oil phase and deareated solution of 3 w % KCl is used as brine for both injection water and connate water.

WETTABILITY MEASUREMENT

Amott wettability test was performed on the samples to get an idea about the wettability. After reaching to S_{wi} the samples were put into the Amott cell for 2 months and the amount of produced oil was recorded against time. After that, the samples were placed into the centrifuge for measuring the fluid extraction under forced displacement. The end point oil recovery by spontaneous imbibition and water displacement was used to calculate the Amott index to water. Results are shown in Table 1. It is clear that the samples are showing slightly water wet behavior. No spontaneous uptake of oil was observed at residual oil saturation.

CORE ANALYSIS

Some plugs have been prepared for core analysis. Table 1 represents the physical properties of the samples. The core plugs which had a diameter of 3.7 cm and length of 4-5 cm were cleaned by use of methanol and toluene. All cleaned samples were placed in an oven at a temperature of 120 ^{o}C for 48 h. A helium porosimeter and an air permeameter were used for porosity and absolute permeability measurements.

CAPILLARY PRESSURE AND RELATIVE PERMEABILITY

Drainage and imbibition capillary pressure were obtained by the centrifuge method. The cores were saturated with brine and rotated in the centrifuge while they were surrounded by the nonwetting phase (n-decane) at increasing speeds. The cores were then removed and submerged in brine for at least 20 days. The amount of oil which is produced spontaneously was recorded. The positive part of the imbibition capillary pressure curve was modeled (Hegre 1992) (13). In order to obtain the negative part of the capillary pressure the cores were rotated in the centrifuge while surrounded by water at increasing speed. Capillary pressure and saturation were determined and corrected by Hassler-Brunner (14) method in each step. Also imbibition relative permeability was measured by unsteady state method under constant differential pressure (15 bar). Initially the cores were 100 % saturated with brine and absolute permeability was measured. The cores were then oil flooded to reach to connate water saturation. After establishing the connate water, oil was then displaced by brine until no more oil production was observed. Relative permeability was then calculated using Jones-Roszelle (15) graphical techniques. S_w is equal to 0.55 at K_{rw}=K_{ro} which confirms the Amott test results regarding the wettability state of the sample which is slightly water wet. The capillary pressure and relative permeability curves are shown in Fig. 2.

WATER INJECTION TESTS

Apparatus and experimental procedure

Due to the high length of the samples, soxhlet cleaning was not suitable for removing the adsorbed material on the pore surface of the samples. This was clear from repeatability tests where the results were different from the first one. Therefore cleaning has been done using flushing. The samples were placed in a core holder and 50 bar confining pressure were applied on the system. Hot toluene and methanol was injected under 0.8 bar/cm pressure gradient. Direction of flushing was reversed several times in order to assure the cleaning. Flooding was continued until no change of the color was observed. Samples was placed into the oven under 120 ^{0}C for two days for drying. After complete drying, the sample was placed into the core holder and both ends of the system were connected to the vacuum pump for at least 5 hr. Then oil was introduced into the core holder for saturation. Some experiments have been done with the presence of initial water saturation. Initial water have been established by evacuation method (in one test) or by displacement. The procedure for evacuating is as follows:

At first each sample was fully saturated with brine and a period of 1-2 days was allowed for complete saturation. Then they were placed in the plexiglass core holder and thereafter in an oven at 66 ^{0} C while both ends of the core holder was connected to the vacuum pump under 50 mbar evacuation. A liquid trap was also used in order to gather the liquid. Desired saturation was established by measuring the amount of liquid which came out from the sample and it was checked by measuring the weight of the core. After establishing the initial water saturation, the samples were evacuated for 5 hours and then saturated with oil.

In order to establish the connate water by displacement method the following method was used:

After 100% saturating the core with brine, it was flooded with oil in order to reach to connate water. Establishing the connate water was a time consuming step, where water was displaced by oil at a pressure gradient around 0.8 bar/cm. The direction of oil injection was reversed several times after breakthrough to make the saturation profile more uniform. After establishing the connate water, experiment was started by putting the composite core into a long plexiglass cylinder. The annular space between the column of cores and plexiglass tube was initially filled with oil. Figure 3 shows the setup that is used for water injection experiments. The matrix blocks were placed in a visual core holder which is made of 7 cm thick plexi glass. This type of core holder allows measuring the fracture-water level data which in turn provides the rate of water imbibition in the matrix block at each time. There are two caps in the top and bottom of the core holder for injecting and producing the fluid. Due to variation of diameter for the samples fracture aperture which is the small gap between the rock surface and the body of the core holder is between 2-2.5 mm. The system consists of a composite core of 3 cylindrical blocks that measure 6.6 cm in diameter (in average). The total length of the composite block is 116 cm. The total porosity for the system including the fracture and matrix is 33.7 % and matrix porosity is around 14-15 %. Total fracture pore volume including dead volumes is 650 cc and total pore volume (matrix+ fracture) is 1300 cc. Screws were used in order to centralize the long core and some spacers are placed at the bottom for complete coverage of the core and simulating the fracture system. Each test started by injection of the brine solution at the lower end of the tube using a constant rate pump. The outlet was open to atmosphere, providing a constant pressure production. As the experiment was running, the fracture water level (FWL) rose to the top of the tube. During the constant rate flow experiments, collected amount of wetting (brine) and non-wetting phases and FWL in the annular space were recorded as a function of time. Slower rates allow the water to contact the matrix for a longer time. Brine injection was continued until no oil production was recorded. The injection was stopped to ensure equilibrium saturation of the core and started again after 2 days to measure the remaining oil produced. Therefore each test lasts approximately 1 week. After each run the cores were placed in the core holder and flushed with methanol and toluene for cleaning and thereafter placed into the oven and prepared for the next run.

In naturally fractured reservoirs, when water is injected, it has a preference to flow in fracture system due to its high permeability. Therefore the water oil contact (WOC) tends to have faster advancement in the fracture system than in the matrix block. The effect will be more pronounced if the matrix is tight so that the rate of water advancement in the fracture will be high. In result, the matrix becomes totally immersed in water and

countercurrent flow will be the dominant process. In the immersion experiment, the composite core was placed in the plexiglass tube with spacers at the bottom and some screws around it for ensuring complete coverage and centralized composite core. The core holder was connected to a graduated cylinder through a pipe with large throat diameter which permitted the flow of produced oil blobs from the top of the core holder to the graduated cylinder (see figure 3). Oil recovery was measured by monitoring the oil-water interface in the graduated cylinder. In immersion test, some oil blobs formed on the rock surfaces and grew up gradually. After a period of time they were large enough and detached from the surface and moved towards the top of the graduated cylinder.
In the low tension experiments, we used a system consisting of n-decane, brine (3.7% NaCl), Sodium dodecyl Sulphate and Iso amyl alcohol and had an interfacial tension of 0.057 mN/m. The viscosity of the aqueous phase of this fluid system was measured by a Bohlin VOR rheometer to 1.93 cp at $20\,°C$. The system readily separated into two phases after mixing of the components and a light scattering experiment (sending red laser light through the phase) clearly showed that nearly all micelles were located in the aqueous phase. An analysis of the aqueous phase of the system used showed that the water phase had an oil content of 0.56% wt. Imbibition experiments were performed with oil saturated core with and without connate water which was placed in the apparatus (see Fig.3 b) while it was surrounded by the water phase. Some additional tests were performed on Asmari limestone and Bentheimer sandstone samples which have different lengths and permeability. The core properties and test conditions are given in Table 2. The results by Cuiec et al. [(16)] show that reducing the IFT can decrease the imbibition rate. They presented some results related to low permeable chalk samples with permeabilities between 1 to 3 md. In this work, an attempt has been done to cover a wide range of permeabilities by using the limestone and Bentheimer sandstone samples. The cores were allowed to remain completely immersed in the wetting phase until oil production was complete. The produced oil was collected in the graduated tube.

RESULTS AND DISCUSSION

The effect of initial water saturation on oil recovery for the weakly water-wet Asmari composite system is presented in Fig. 4. Both immersion and rising water level type of experiment have been carried out. The established initial water saturation is varied from 0 to 25% while water injection rate is constant for all three experiments (1 cm^3/min). Water injection was stopped for 2 days after each water breakthrough. Each test takes approximately 7 days for rising water level type and approximately 1 month for immersion type of test. The result shows that oil production rate increases with increase in initial water saturation. It is interesting to note that induction time is decreasing with increase in initial water saturation in immersion type experiment. Also the required time to reach the residual oil saturation is decreasing with increase in S_{wi} and the times are 950,773 and 630 hr for S_{wi} equal to 0, 14 and 25 % respectively. The final oil recovery is also increasing with increase in S_{wi}. The result is consistent with that reported by Firoozabadi [(6)] on weakly water-wet chalk.
Figure 5 shows the results for weakly water wet Asmari stack of blocks at different rates. The flow rates of 0.5, 1 and 5 cm^3/min were selected for the tests. In the low rate

experiment the fracture water level started to rise very slowly compare to the other tests. At early times, the water is in contact with the lower boundaries of the block and oil is in contact to the other boundaries which resulted in cocurrent imbibition. The advance of fracture water level was more or less constant, which is an indication of low imbibition of the water in the matrix. FWL velocity was decreasing gradually (not significantly) after a period of time. One explanation is that when time passes there will be more exchange area between matrix and water in the fracture and this causes more imbibition of water into the matrix. As injection rate increases the fracture water level velocity increases and this in turn gives shorter time for oil production from the blocks before they were submerged in water. Therefore oil recovery at breakthrough time decreased when injection rate is increased. Also as rate increases more small blobs of oil could be observed before water-oil contact on the rock surface. They will be detached from the rock surface after a period of time. The number of blobs increases when rate increases which causes more recovery after water breakthrough. It is interesting to note that even at low injection rate, imbibition is not very strong before water breakthrough (recovery is less than 7% for all tests). After breakthrough, the blocks are totally submerged and about 4-6 % of oil is recovered in a certain time (about one week). The reason is that immersion creates a larger surface area between the matrix and water in the fracture which resulted to more recovery. The final oil recovery is approximately 10 % for all three injection rates. Little difference between recovery behavior vs. PV injected in different rates was observed. However, we can not make a strong statement about this effect because the effect is small and within the range of uncertainty. After conducting many carefully tests, it was clear that oil recovery is quite low and capillary imbibition can not be a strong driving force. Therefore using the surfactant for reducing the IFT and increasing the effect of gravity and/or altering the wettability was recommended. Karimaie et.al [(12)] increased the inverse of Bond Number by using synthetic oil (Tetralin) with the density equal to 0.973 gr/cm^3 that was very close to the brine density. They changed N_B^{-1} from 2.6 to 31.8 in order to change the flow mode by doing experiments on 116 cm fired Bentheimer core. In continuation of that work and also in order to compare with limestone sample, we did some immersion experiments on Bentheimer sandstone and Asmari limestone in low tension system. The experiments were performed to evaluate and verify the importance of gravity effects at low IFT.

Figs 6-10 are recovery curves for each of the cores investigated. Each plot shows observed behavior for the high and low values of IFT. Fig. 6-7 demonstrate that as IFT was reduced, the rate of imbibition slowed down in the 10 md Asmari limestone core. At high IFT brine rapidly imbibed into the core due to countercurrent capillary imbibition while gravity driven cocurrent flow is governed at low IFT which helps prevent snap-off and entrapment and allows high total recoveries [(10)]. The imbibition profiles for short limestone plugs with low permeability for test 3-7 are shown in Fig. 8. Inverse bond number for experiments are also shown in table 2, which are in the range of capillary-gravity dominated flow. For intermediate values of N_B^{-1}, both capillary and gravity are active forces which are the main reason for high recovery of the samples. In this case, the gravity contribution is high and will cause considerable segregation of the flow, which keeps relative permeabilities high, and capillary forces are still strong enough to boost the driving force for flow [10]. A similar trend was observed for the 1300 md Bentheimer core which is shown in Fig.9. In the high IFT case N_B^{-1} is equal to 31.8 and process is capillary countercurrent. The final recovery is around 44% as reported in the previous study [12]. In the low IFT case, N_B^{-1} is reduced to 0.0026 which means that process is cocurrent and highly dominated by gravity. Therefore relative permeabilities of fluids are higher [17] and imbibition rate is mainly controlled by density difference which causes higher recovery (80%). Also it is an evidenced that length and permeability are important factors for the process. The effect of initial water saturation in ultra low IFT for Bentheimer sample is shown in Fig. 10. It is clear that the rate of recovery is higher when sample contains of initial water saturation, but the final recovery is the same.

CONCLUSION

Our interpretation from these experiments leads to the conclusion that the recovery from water injection in Asmari limestone reservoir is quite low. The results from the experiments also reveal that:

1-In the low injection rate the block has more time for imbibition before water breakthrough. Therefore breakthrough recovery is higher when injection rate is low.

2-Increasing injection rate had little effect on final recovery behavior in this type of rock.

3-When injection rate increases, water breakthrough occurs earlier and the portion of oil to be recovered by immersion increases.

4-The rate of oil recovery and final oil recovery increases with increase in initial water saturation while the behavior of induction time is opposite and it is decreased with increase in initial water saturation.

5-Reduction of the IFT may play a significant role and increase the final recovery due to increase of the gravity effect which in turn changes the process from capillary countercurrent flow to gravity driven cocurrent flow.

6- The presence of connate water can reduce the rate of imbibition in low tension system. However, the final recovery is not influenced by the connate water.

ACKNOWLEDGEMENT

This work was financially supported by National Iranian Oil Company and Statoil. Their support is appreciated.

REFERENCES:

1. Aguillera. R. “Naturally fractured reservoirs” Petroleum Pub. Co., Tulsa, 1980, 614 pp.
2. Saidi, A.M. “Reservoir engineering of Fractured Reservoirs” .Total 1986. Page 800.
3. Zhou, X., Morrow, N.R., and Ma, S.: “ Interrelationship of Wettability, initial water saturation, Aging Time, and Oil Recovery by Spontaneous Imbibition and Waterflooding,” SPEJ (June 2000),5 (2),199.
4. Viksund, B.G., Morrow, N.R., Ma, S., Wang, W and Graue, A.:” Initail Water Satruration and Oil Recovery from Chalk and Sandstone by Spontaneous Imbibiton,” Proceedings of 1998 International Symposium of the Society of Core Analysis, The Hague, Netherlands, Sept.14-16.

5. Tong, Z., Xie, X., and Morrow, N.R.:" Scaling of Viscosity Ratio for Oil recovery by Imbibition from Mixed-Wet Rocks," Paper SCA 2001, Edinburgh, UK, September 17-19, 2001.
6. Guo-Qing Tang and Firoozababdi, A., " Effect of Pressure Gradient and Initial Water saturation on Water Injection in water-Wet and Mixed-wet Fractured Porous Media" SPE no. 74711.
7. Aziz, K. and Settari, A.: "Petroleum Reservoir Simulation", Applied Science Publishers LTD (1979).
8. Austad, T. and Milter, J," Spontaneous imbibition of water into low permeable chalk at different wettabilities using surfactants". Paper SPE 37236 presented at the International Symposium on Oilfield Chemistry held in Houston; TX; USA; Febuary 18-21.
9. Gesztesi, G., Bodola, M., Tåråk, J., Toth; J., and Mathing, B., 1997. "Laboratory and field studies on gravitational effect in low-tension waterflooding". Paper presented at the 9th European Symposium on Improved Oil recovery held in Hague, Netherlands, October 20-22.
10. D.S.Schechter, Denqen Zhou, and F.M.Orr Jr. "Capillary imbibition and gravity segregation in low IFT systems". Paper SPE 22594 presented at the 66 th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Dallas, TX, October 6-9. 1991.
11. Hirasaki, G, and Zhang, D.Z., "Surface Chemistry of Oil Recovery from Fractured, Oil-Wet, carbonate Formations". SPE Journal. June 2004.
12. Karimaie, H, O. Torsæter, M.R.Esfahani, M.dadashpour and S.M. Hashemi., "Experimental Investigation of Oil Recovery During water Imbibition". Presented at the 7th wettability symposium held in Houston, Texas, USA, 15 May of 2004.
13. Hegre, T.M.:" Evaluation of Tertiary flooding in Fractured Chalk Using Numerical Simulation Models". RUTH (1992-1995) page 125-128.
14. Hassler G.L. and Brunner E.:"Measurement of Capillary pressure in Small Core Samples", AIME, 1945 Vol. 160,114-123.
15. Jones, S.C. and Roszelle, W.O. "Graphical techniques for determining relative permeability from displacement experiments" JPT, P 807-817, May 1978
16. Cuiec, L.E., Bourbiaux, B. and Kalaydjian F., "Imbibition in Low-Permeability Porous Media: Understanding and Improvement of Oil recovery", SPE/DOE 20259, presented at 7th Annual Symposium on EOR, Tulsa, April, 1990.
17. Bourbiaux, B.J. and Kaladjian,F.J."Experimental Study of Cocurrent and Countercurrent Flows in Natural Porous Media", SPE paper # 18283, Oct.1988.

Table 1. Rock properties and Amott indices for the samples used in the study.

Sample No.	Permeability (md)	Porosity (%)	Displacement of oil by water		
			Spontaneous produced volume V_{sp} (cm^3)	Forced produced volume V_f (cm^3)	Amott wettability index
1	0.5	14.0	2.6	2.5	0.51
2	0.8	14.6	1.1	1.5	0.42
3	0.9	15.8	1.5	1.0	0.60

Table 2. Data for imbibition experiments with use of surfactant.

Test	Type of rock	K (md)	S_{wi}	Core height (cm)	Inverse Bond number, N_B^{-1}
1	Asmari Lim.	10	---	13.0	0.26
2	Asmari Lim.	10	---	5.0	0.51
3	Asmari Lim.	0.5	0.2	4.5	3.63
4	Asmari Lim.	0.5	---	5.36	3.27
5	Asmari Lim.	0.5	---	4.91	3.051
6	Asmari Lim.	0.5	---	4.96	3.56
7	Asmari Lim.	0.5	---	8.1	1.89
8	Bentheimer	1300	0.18	116	0.043
9	Bentheimer	1300	---	116	0.043
10	Bentheimer	1300	---	7.0	0.043

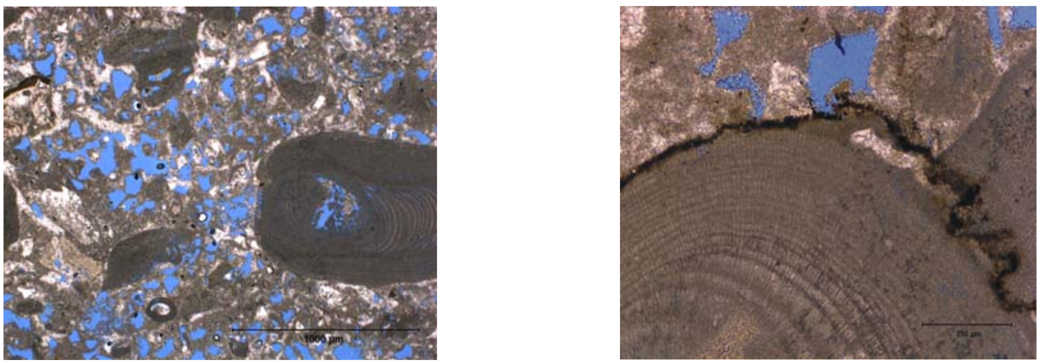


Fig 1. Optical micrograph of Asmari limestone showing moldic and vuggy porosity (blue-left one) and a dark coating around some of the larger fossil grains (right one).

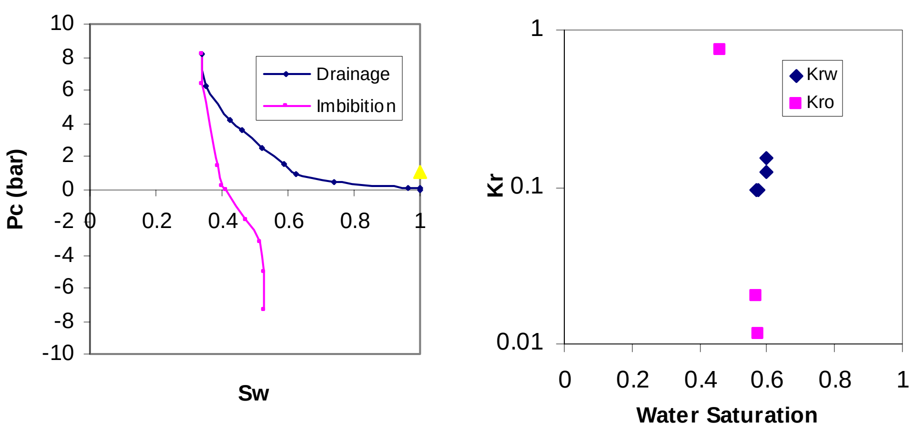


Fig .2- Typical capillary pressure and relative permeability curve for Asmari limestone

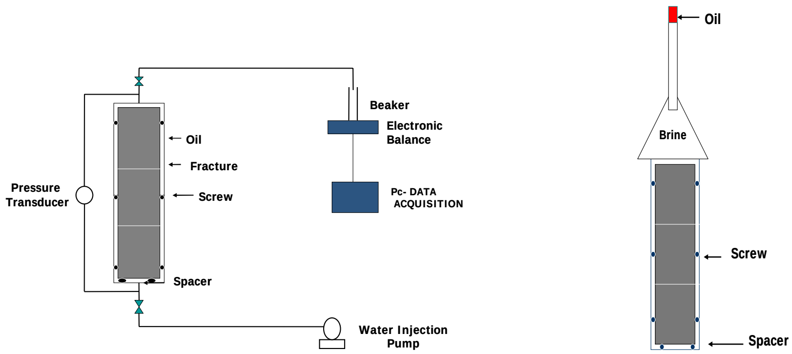


Fig 3- Schematic of apparatus a) rising water level type (left one) b) Immesion type (right one).

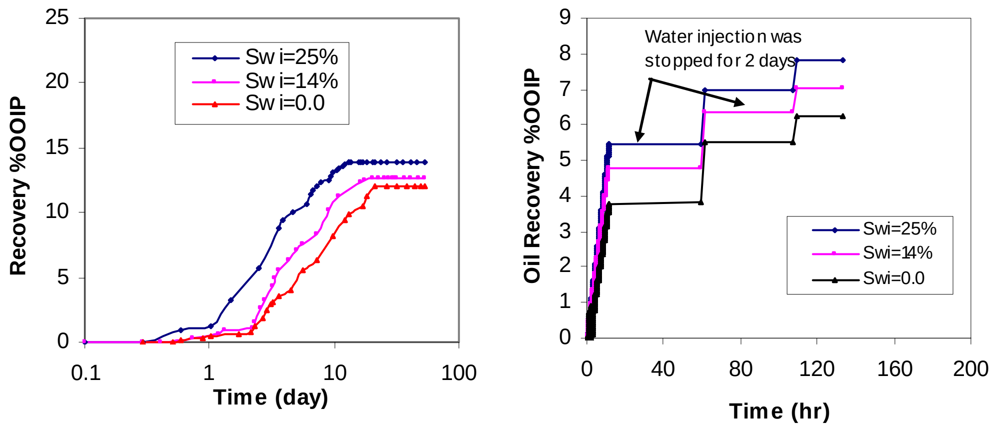
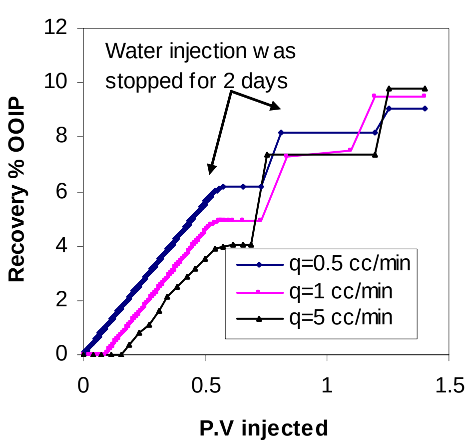


Fig 4 - Effect of S_{wi} on oil recovery on stack of Asmari blocks a) Immersion type experiment (left one) b) rising water level type experiment (right one).



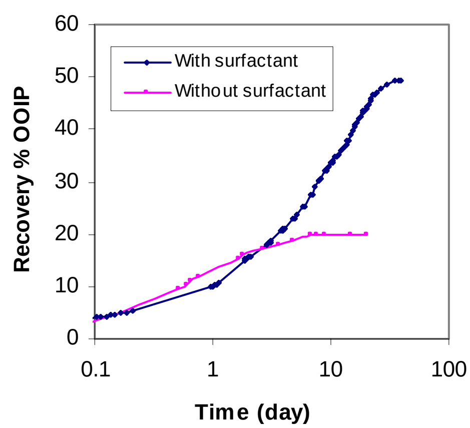
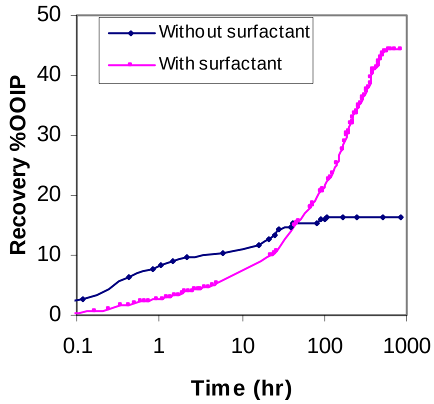


Fig 5 - Effect of rate on water injection

Fig 6 - Imbibition of brine into Asmari limestone-Test 1



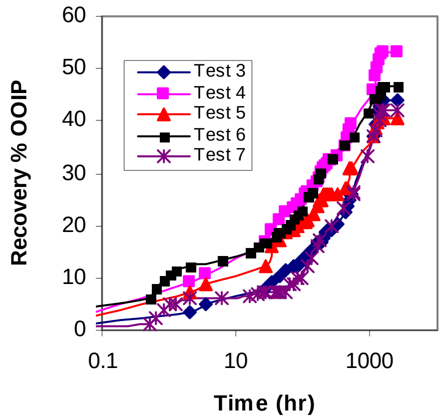
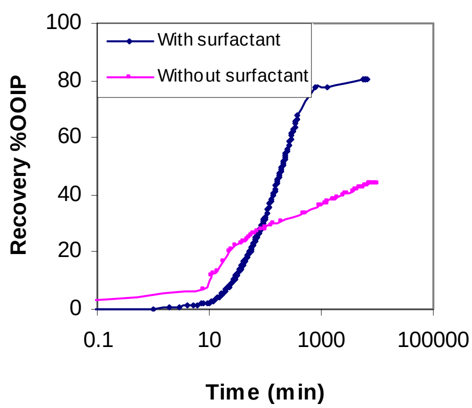


Fig 7 - Imbibition curve for Asmari-Test 2

Fig 8 - Imbibition curve for Asmari-Test 3-7



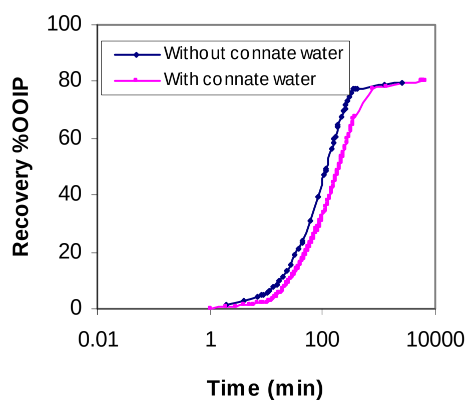


Fig 9 - Imbibition of brine into Bentheimer.Test 9

Fig 10 - Imbibition of brine into Bentheimer.Test 10