WETTING AND WATERFLOOD OIL RECOVERY OF A MODERATELY VISCOUS CRUDE OIL

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ABSTRACT

A laboratory waterflood study of a moderately viscous crude oil is reported. Schuricht crude oil, with room temperature viscosity of 46 cp, is shown to alter wetting and waterflood oil recovery. The extent of wetting alteration is a function of both the duration and temperature at which a Berea core containing connate water is aged in the oil, as has been shown for less viscous crudes. Core tests include rate and extent of imbibition, waterflood recovery as a function of wetting and flood rate, and history matching with a coreflood simulator to estimate capillary pressure and relative permeabilities. Micromodel visualization tests provide further evidence for the alteration of wetting by Schuricht crude oil.

INTRODUCTION

The need to duplicate reservoir wetting conditions in laboratory displacement studies is now widely accepted. The first of two main approaches is to obtain so-called fresh cores from the field by procedures designed to minimize possible changes in wettability. The second is to clean the core of reservoir fluids, reestablish the original brine saturation, and age the core with crude oil. Studies of wettability alteration by exposure to crude oil show reproducible trends, but extensive results are limited to a few specific cases. In this study, trends observed previously for lighter crude oils (5 to 20 cp, Jadhunandan and Morrow, 1991) are confirmed for a more viscous oil from the Schuricht field in Wyoming.

Systematic studies of aging time show that about 2-4 weeks of aging is often sufficient to reach a stabilized wetting condition, presumably because some form of adsorption equilibrium is achieved. Aging temperature is also an important variable. Cuiec (1992) recommends that the core be aged at reservoir temperature. If the reservoir temperature is more than 80°C, an aging temperature of 80°C is often chosen, mainly for convenience in laboratory procedure. Agreement between results for fresh and restored core samples provide the best available evidence that reservoir wettability conditions have been reproduced in the laboratory.

Jadhunandan and Morrow (1991) explored the factors that control wettability and oil recovery by waterflooding in crude oil/brine/rock systems. Using samples of Berea sandstone, a range of wetting states was obtained by changing the aging procedure. Variables in this procedure are the type of crude oil, brine composition, aging temperature, initial water saturation, and aging time. Examples of how the

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wettability index changes with initial water saturation for two crude oils are presented in Fig. 1. A correlation of the effects of wettability on waterflood recovery and performance was presented. It was found that optimum recovery was obtained at very weakly water-wet but close to neutral wettability conditions. Zhou *et al.* (1993) also studied effects of various parameters on wettability change as measured by short-term imbibition rates. For an Alaskan crude oil/brine/rock (COBR) system, they showed that the rate of imbibition of water decreased with increase in aging time and aging temperature.

In the present study, alteration of wetting by exposure to crude oil and the relationship between wetting and recovery by waterflooding is investigated for a crude oil of 46 cp viscosity (at ambient conditions) from the Schuricht field. Studies on many different crude oils are needed to determine whether and to what extent trends are general. Schuricht was chosen because

1) an adequate quantity of oil was available from a single untreated (hence uncontaminated) well;

2) the oil was of moderately high viscosity and could, therefore, be used to study the combined effect of unfavorable mobility ratio and wettability; and

3) the Schuricht field is being considered as a target for application of a microbial recovery process (Thomas *et al.*, 1991). The present study provides baseline data for waterflood recoveries for this oil.

The effects of aging time and temperature on the wettability state induced by Schuricht crude oil are reported. The relationships between wettability and oil recovery by waterflooding for this moderately viscous crude are observed directly in micromodels and indirectly in cores. Relative permeabilities and capillary pressures were calculated from the history match to core flood production data. Core flood simulations also provide a measure of wettability from production data that is closely analogous to the Amott index.

EXPERIMENTAL METHODS

FLUIDS

Schuricht crude oil from Wyoming was used as the oil phase. The viscosity of this oil as received was 46 cp at 25°C, 26 cp at 40°C, and 20 cp at 53°C. The oil was used without filtration for all the tests reported here. Additional details, including elemental analysis for carbon, hydrogen, nitrogen and sulfur constituents of Schuricht crude oil and of the asphaltene fraction precipitated with pentane, as well as the moisture content of this oil as a function of temperature, are presented elsewhere (Buckley, 1993).

Two different brines were prepared. For the first series of tests (core sample Group S), a 2% $CaCl_2$ brine was used. A brine composed of 2.5% NaCl and 0.5% $CaCl_2$ was used for core sample Group V. These brine compositions will be abbreviated as Ca brine and Na-Ca brine, respectively. Liquid densities at 25°C are as follows: Ca brine, 1.033 g/cm^3; Na-Ca brine, 1.020 g/cm^3; and Schuricht crude oil, 0.898 g/cm^3.

MICROMODEL VISUALIZATIONS

Waterfloods of Schuricht crude oil with the Na-Ca brine were observed in an etched glass micromodel made by techniques described previously (McKellar and Wardlaw, 1982). The physical characteristics of this model and the techniques, including cleaning, have recently been described elsewhere (Buckley, 1993).

The model, completely saturated with Na-Ca brine, was allowed to equilibrate at room conditions, before oil flooding. Several waterfloods, intended to distinguish viscous from wetting effects and to study the effect of high temperature aging in crude oil, were performed. These included waterflood of a viscous mineral oil (46 cp) and two Schuricht tests of the effects of aging time and temperature on waterflood displacement mechanisms at the pore scale.

CORE PREPARATION

Two sets of 3.79 cm diameter cores were cut from two blocks (identified as S and V cores) of Berea sandstone. Core lengths ranged from 6.46 to 7.29 cm. Core samples were dried at room temperature, followed by drying at 100°C for four days, and then evacuated prior to weighing. Gas permeabilities were measured and plugs were then saturated with deaerated brine and aged for several days to permit equilibration between ionic constituents of the brine and surface minerals.

After saturation, core samples were inserted into Hassler-type core holders at a confining pressure of 300 psi. About 20 pore volumes (PV) of brine were flowed through the samples to replace the aged brine. Porosity was then evaluated from dry and saturated weights, taking into account the brine density. The core was replaced in the holder, and permeability to brine was measured at constant pressure drop. Properties of individual cores are given in Table 1. Permeability to nitrogen ranged from 548 to 735 md, and porosity averaged about 21%.

Cores were flooded with about 10 PV of Schuricht crude oil at approximately 40 psi to establish initial saturations of water (S_{wi}) and oil (S_{oi}). Cores were then covered with crude oil in a beaker and aged for a specified time, t_a, and temperature, T_A. For cores aged at room temperature, the beakers were covered with parafilm. For high temperature aging, the beakers were covered with aluminum foil. Aging temperature and aging time were varied as listed in Table 2. After the aging period, cores were cooled to room temperature and reflooded with fresh crude oil. All subsequent displacement tests were run at room conditions. Permeability to oil at initial water saturation was measured. In one series of tests, initial saturations were reestablished in the course of testing the reproducibility of oil recovery by waterflooding.

DETERMINATION OF AMOTT INDEX TO WATER, I_w

Cores from group S at S_{wi} were placed in glass beakers full of brine. After expulsion of oil by brine appeared to have ceased (usually no additional oil production for 2 to 3 days), the change in saturation from spontaneous imbibition, ΔS_{ws}, was determined from the core weight. Oil recovery by forced displacement, ΔS_{ws}, was determined by waterflooding at 40 psi pressure gradient. The Amott wettability index to water, I_w is given by (Amott, 1959)

$$I_w = \frac{\Delta S_{ws}}{\Delta S_{ws} + \Delta S_{sf}} \quad .$$

A novel approach to determining I_w through simulation of waterflood recovery curves and pressure history was also tested.

SPONTANEOUS IMBIBITION RATES

Rates of spontaneous imbibition were measured for cores in Group V. Each core was suspended from a Mettler SP 180 balance by a monofilament nylon line and immersed in brine (about 800 ml) contained in a 1000 ml beaker. Expelled Schuricht crude oil often clung to the outside surface of the core. Prior to recording the core weight, this oil was removed with the aid of a PTFE stirring rod. Changes in saturation with time could then be determined gravimetrically. A period of about one week was allowed for spontaneous imbibition.

WATERFLOODING EXPERIMENTS

The waterflooding apparatus is shown schematically in Fig. 2. The cores were held in Hassler type core holders (3.5 in. long) at a confining pressure of 300 psi and ambient temperature. Before beginning a waterflood, the core was flushed with fresh Schuricht oil to displace the oil contained in the core during the aging process. An ISCO constant rate metering pump (Model 314) was used, with decane displacing the brine from a reservoir. Rates of injection could be varied from 2 to 200 ml/hr.

HISTORY MATCHING

Waterflood oil production and ΔP across the core were matched using a one-dimensional model based on the generalization of Darcy's law for multiphase flow. The k_r and P_c curves resulting from this history matching process are reported.

RESULTS AND DISCUSSION

EFFECT OF AGING TIME ON WETTABILITY

The wettability index for water was determined for four S series cores, with Ca brine, aged in crude oil at 53°C for times ranging from 3 to 30 days (Fig 3). After 12 days, I_w was reduced to a minimum value of about 0.4; longer aging had little further effect, so a standard aging time of 15 days was adopted for subsequent tests. This aging time is consistent with times usually needed to achieve stable wetting conditions in other crude oil/brine/rock systems (Cuiec, 1992).

EFFECT OF AGING TEMPERATURE ON WETTABILITY

The effect of aging temperature on I_w was evaluated using the Na-Ca brine and 15 days aging. As observed previously for Moutray and ST-86 crude oils, I_w generally decreased with an increase in aging temperature (Fig. 4). This change in wetting, as measured by I_w, is reflected in the results of imbibition, waterflood, and micromodel visualization tests as described below and in the rate of spontaneous imbibition of Na-Ca brine. Imbibition rate tests were performed at room conditions after 15 days aging in oil at temperatures of 26, 40, 53, and 80°C. The results of these experiments are summarized in Fig. 5.

Both the rate of spontaneous imbibition and the amount of oil recovered by this process tended to decrease as aging temperature increased. Oil recovery ranged from a high ot 32% for the core aged at ambient conditions to a low value of 27% for the core aged at 80°C. The trend of decrease in early-time imbibition rate with increase in aging temperature has been reported previously for two other crude oil systems (Zhou *et al.*, 1993). The Schuricht crude oil imbibition rate is less temperature-sensitive than the previously studied systems in the range of 26° to 53°C, but it showed a large decrease when the aging temperature was raised to 80°C.

Values of I_w were less sensitive to aging temperature than reported previously for two other oils. However, distinct change in wetting properties was demonstrated by strong suppression of imbibition rate for the core aged at 80 °C. These results illustrate the difficulty of attempting to characterize complex wetting conditions by a simple method such as the Amott test.

Effect of Brine Composition and Initial Water Saturation

Previous studies with Moutray crude oil have shown that the wettability index decreased with a decrease in the initial water saturation and that Ca brine tended to give a greater reduction in wettability than Na brine (Jadhunandan and Morrow, 1991). These variables were not considered in detail in the present study, but the lower values of I_w observed for the S series cores, which also had lower initial water saturations and used a Ca brine, are consistent with those earlier observations.

Waterflooding—Effect of Aging Temperature

To examine the effect of aging temperature on waterflood recoveries, floods were run at a standard injection rate of 7.5 ml/hr. For aging temperatures of 26, 40, 53, and 80°C, oil recovery was minor after 3 PV injection and was nearly complete for all these runs after injection of about 7 PV of brine. Recoveries increased significantly with aging temperature, as shown in Fig. 6. As judged from previous experience, S_{wi} values (Table 1) varied somewhat more than expected ($\pm 2.2\%$ of the mean value). Microscopic displacement efficiency and residual oil saturation are shown as a function of aging temperature in Fig. 7. Overall, the trends of lower residual oil saturation and better recovery for less water-wet conditions, previously demonstrated for Moutray crude oil (Jadhunandan and Morrow, 1991), are confirmed for Schuricht crude oil.

Visualization of Waterfloods

A waterflood of a mixture of paraffin oils, with viscosity matching the Schuricht crude oil, was observed. The displacement was virtually indistinguishable from displacements of much less viscous Soltrol 130 (2 cp). Trapping of oil occurs in virtually all large pores due to snap-off in downstream throats. Snap-off events are rapid and throats fill quickly, demonstrating that viscosity alone has little, if any, visible effect on the outcome of a waterflood at very strongly water-wet conditions.

With Schuricht, wetting depended on the time and temperature of exposure of the model to oil. One Schuricht crude oil waterflood was performed shortly after the oil flood was completed and the saturation distribution throughout the model was recorded on videotape. Aging in crude oil was thus limited to a matter of an hour or two at room temperature. At the end of the oil flood, the model remained preferentially water-wet, as demonstrated by spontaneous imbibition of water near the outlet when the pump was turned off. The subsequent waterflood was the most water-wet of any crude oil waterflood in this model to date. Oil was trapped in multipore ganglia by very slow snap-off events. Flood water swelled the existing connate water wedges in the corners formed where the two glass plates are fused together. Dual occupancy and dual flow of both water and oil in a single pore or throat are readily visible in this displacement.

The observed microscopic displacement pattern can be explained by preferentially water-wet conditions with a low but finite advancing contact angle, θ_a. This assumption is consistent with the fairly water-wet Amott index of 0.61 measured in Berea core aged at room temperature for a much longer period of time (15 days). The viscosity of the oil impacts the flowing fractions of water and oil as indicated by the simplified form of the fractional flow equation,

$$f_w = \frac{1}{1 + \frac{k_o}{k_w}\frac{\mu_w}{\mu_o}} ,$$

where f_w is the fractional flow of water, k_o and k_w are the permeabilities, and μ_o and μ_w are the viscosities for oil and water respectively. Thus, increasing the ratio of oil to water viscosities decreases the denominator and increases f_w.

With a less viscous oil, small but finite water advancing contact angles have been shown to inhibit snap-off in the throats of this model (Buckley, 1993). Snap-off of water collars in throats has never been observed for crude oils ranging in viscosity from 5 to 20 cp with short aging times. The greater viscosity of Schuricht crude oil may permit an increased flowing fraction of water, and thus overcome the effect of the contact angle. Water wedges can swell to the point where snap-off can occur in some, although not all, throats. The result is very poor displacement efficiency and extensive trapping of large ganglia.

In a second test, the model was flooded with Schuricht crude oil as above. The micromodel inlet and outlet were then sealed and the model was stored for 18 days in an oven at 80°C. The distribution of fluids before and after the aging period and the subsequent waterflood, were recorded on videotape. Before aging, oil filled the bulk of the porous space in the model. Water was visible in some wedges and bridging some throats. Interfaces were concave with respect to the water phase, indicating preferential wetting by water during the oil flood, a pattern of fluid distribution common to all the crude oils studied in this model. After aging, droplets of water were common in the centers of many pores where there had been no water droplets before. Apparently, during the aging period, some water was displaced by oil from the glass surfaces. The volume of water thus rearranged is small, but its significance with respect to wetting and waterflood displacement mechanisms is not. The waterflood of the aged model appeared to be intermediate to slightly oil-wet. Without continuity of water in corner wedges, water displaces the terminal menisci instead of swelling water wedges, with the result that there is very little trapping. The slow formation and snap-off of water collars is not observed and the displacement is much more efficient.

Both the change in wetting to less water-wet and the improved displacement efficiency are in accordance with the results of wettability assessments and waterflood oil recovery results in cores.

WATERFLOOD INJECTION RATE

Little is known about the combined effect of wettability and mobility ratio on oil recovery at different flow rates. Previous results showed that systems with wettability indices in the range $I_w = 0$ to 0.5 showed a slight tendency for recovery to decrease with an increase in rate (Jadhunandan and Morrow, 1991) suggesting that capillary end effects are not a problem and that oil recovery depends on a subtle balance between weak imbibition and viscous forces. For a light oil with wettability in the range $I_w = 0.5$ to 0.8, recovery increased with flow rate. Retention of oil by end effects is even less likely for this wettability range than for less water wet systems. The degree to which these results are valid for providing general guidance needs to be tested further.

In the present study, three tests were run at displacement rates of 7.5, 20, and 30 ml/hr using cores that had all first been aged in Schuricht crude oil for 15 days at 53° C. An Amott index to water of 0.5 was measured for a similarly treated core (V-2). Increasing the waterflood rate decreases oil recovery as shown in Fig. 8. It should be noted that the initial water saturations—another experimental variable that can influence wetting alteration by exposure to crude oil—ranged from 25.2 to 30%, which may contribute to some of the differences in these three experiments. Nevertheless, there does appear to be a trend toward higher residual oil saturation and lower recovery efficiency as flow rate increases, as reported previously for Moutray crude oil at comparable wetting conditions.

WATERFLOOD SIMULATIONS

The histories of oil recovery and water injection pressure have been matched to give estimates of the relationships between fluid saturations and both capillary pressures and relative permeabilities to water and to oil for five sets of data (cores V-1, V-6, V-7, V-10, and V-12). Examples of the resulting P_c and k_r curves are presented in Figs. 9 and 10. Two of the matches are shown here (Figs. 11 and 12). Details of additional history matches are included in a report by Villard, et al. (1993). Neither uniqueness of solution nor detailed sensitivity analysis have been investigated.

All of the core flood simulations resulted in capillary pressure vs. water saturation relationships that are positive at the low saturations and slightly negative at high water saturations. Much of the change in saturation for both cases shown here occurs at a capillary pressure near zero.

The saturation at which capillary pressure crosses from positive to negative values, together with the initial and residual water saturations, can be interpreted as an Amott index for imbibition of water for the simulated waterflood. Table 3 lists values of I_w obtained from the simulations and compares them with the measured I_w values for similarly treated cores. The correspondence for the few points available is reasonable, although further verification is needed to test a wider range of wettability states before the usefulness of this method of obtaining an Amott index for water can be judged with any reliability. Most of the uncertainty is associated with the low values of P_c that can obscure the point at which the S_w curve crosses the pressure axis. Similar uncertainty exists in traditional Amott measurements where the time allowed for spontaneous imbibition may be limited for practical reasons and inadequate for completion of the imbibition process.

Shifts in both simulated relative permeability curves are observed. Changing wetting by increasing the temperature at which cores are exposed to crude oil shifts the crossover point (the point at which k_{ro} and k_{rw} are equal). As I_w decreases, the crossover point moves toward higher brine saturations. At the same time, the relative permeability to water increases slightly, although k_{rw} is very low in all cases. The commonly illustrated shift of the crossover point from right to left as wetting goes from water-wet to oil-wet, found in published discussions of wettability and relative permeability (Craig, 1971), is not supported by these results.

CONCLUSIONS

- Schuricht crude oil alters wetting of Berea sandstone cores, as measured by imbibition methods. As with previously studied crude oils, the extent of wetting alteration can be varied by changing the aging time and temperature.
- Oil recovery efficiency was less for this viscous crude oil than for previously studied, less viscous oils. Nevertheless, oil recovery was greater than has previously been reported for strongly water-wet conditions and much less viscous mineral oils.
- Decreasing water wetness, as indicated by a lower Amott index to water in the range from 0.6 to 0.5, gave improved oil recovery.
- Improved recovery was also demonstrated by visualizations of waterfloods which showed that Schuricht crude oil initially gives preferentially water-wet conditions, and changes to more nearly intermediate wetting after aging at high temperature. Trapping of multipore ganglia in the water-wet displacement gives poorer recovery efficiency than is observed for the intermediately wetted model after high temperature aging at initial oil saturation.
- For the system studied, increased waterflood rate reduced oil recovery efficiency slightly.
- Waterflood oil production and pressure drop curves could be adequately simulated with a one-dimensional core flood simulator, with both capillary pressure and relative permeabilities to oil and to water as results of the simulation.
- Simulated capillary pressure curves gave reasonable estimates of the Amott index to water.

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Table 1. Properties of Core Samples

NO.	CORE NO.	LENGTH (cm)	DIAMETER (cm)	PERMEABILITY (md)		PORE VOLUME cm^3	POROSITY (%)	*Swi* (%)
				k_{n2}	k_b			
1	S-14	6.73	3.79	620	231	16.56	21.8	15.0
2	S-15	6.77	3.79	612	281	16.01	21.0	22.0
3	S-17	6.56	3.79	615	223	15.95	21.6	23.0
4	S-30	6.47	3.79	662	248	15.56	22.0	23.5
5	V-1	7.16	3.80	548	323	17.12	21.8	25.2
6	V-2	7.18	3.79	594	329	17.31	21.3	27.8
7	V-5	6.98	3.80	592	221	16.97	21.4	30.0
8	V-6	7.17	3.80	622	317	17.11	21.1	29.6
9	V-7	7.20	3.79	606	265	17.13	21.1	30.0
10	V-10	7.08	3.79	631	229	17.43	21.8	28.3
11	V-11	7.12	3.79	597	223	17.25	21.4	27.5
12	V-12	6.85	3.79	579	326	16.54	21.4	27.4
13	V-17	7.28	3.81	735	374	18.02	21.7	28.4
14	V-19	7.23	3.81	663	318	17.85	21.7	29.4
15	V-20	7.29	3.80	684	321	17.67	21.4	27.5

Table 2. Summary of Experiments

Core	Aging Time	Aging Temp. (°C)	Brine Composition NaCl (%)	Brine Composition $CaCl_2$ (%)	Type of Experiment: Amott I_w	Type of Experiment: Imbibition Rate Oil Recovery (%OOIP)	Type of Experiment: Waterflood Rate (ml/hr)	Type of Experiment: Waterflood $E_D = 1 - \frac{S_{or}}{S_{oi}}$
S-15	3 days	53°	0	2	.63			
S-17	12 days				.425		2.0	0.48
S-14	18 days				.40			
S-30	30 days				.40			
V-11	15 days	26°	2.5	0.5	.61	32.1		
V-12							7.5	0.46
V-5	15 days	40°	2.5	0.5	.58	31.4		
V-6							7.5	0.48
V-1	15 days	53°	2.5	0.5			7.5	0.57
V-2					.50	29.7		
V-10							20.0	0.56
V-7							30.0	0.53
V-19	15 days	80°	2.5	0.5	.52	27.6		
V-20							7.5	0.6

Table 3. Imbibition of Water

Aging Temperature (°C)	Standard Amott Tests					Recalculated Amott Indices		Slow Rate Waterfloods			
	Core ID	S_{oi} (%)	S_{or} Spontaneous Imbibition (%)	S_{or} 40 psi waterflood (%)	I_w	I_w*	I_w**	Core ID	S_{oi} (%)	S_{or} (%)	I_w Simulation
25	V-11	72.5	49.2	34.3	0.61	0.70	0.70	V-12	72.6	39.3	0.68
40	V-5	70.0	48.0	32.1	0.58	0.65	0.64	V-6	70.4	36.2	0.68
53	V-2	72.2	50.8	29.3	0.50	0.53	0.50	V-1	74.8	31.9	0.53
80	V-19	70.6	51.1	33.1	0.52	0.47	0.45	V-20	72.5	28.9	0.63

I_w* = recalculated with slow waterflood S_{or} instead of 40 psi S_{or}.

I_w** = recalculated with slow waterflood S_{or} and S_{oi} values.

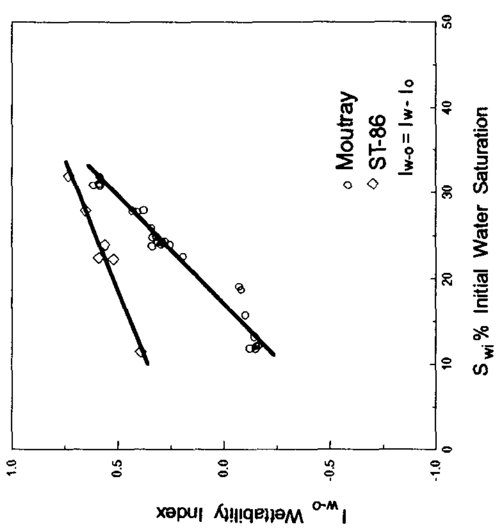

Fig. 1. Variation of Amott Index with initial water saturation (after Jadhunandan and Morrow, 1991).

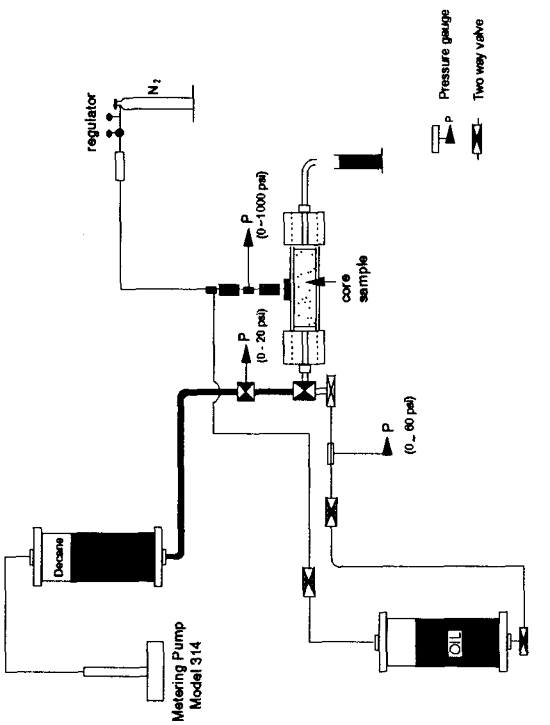

Fig. 2. Experimental apparatus for constant flow rate waterflooding.

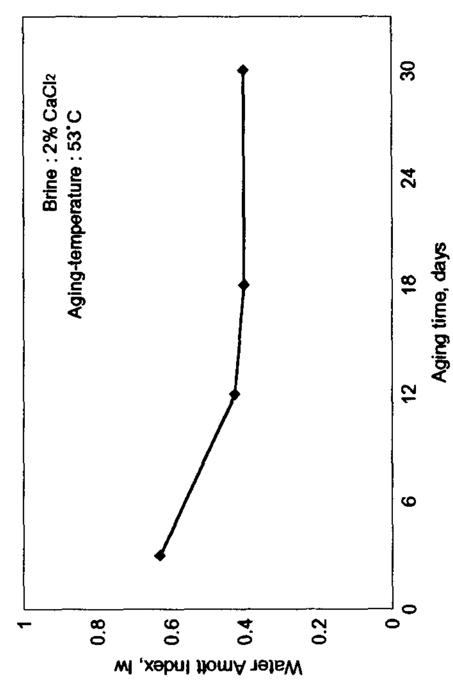

Fig 3 . Amott index to water--variation with rock-fluid aging time.

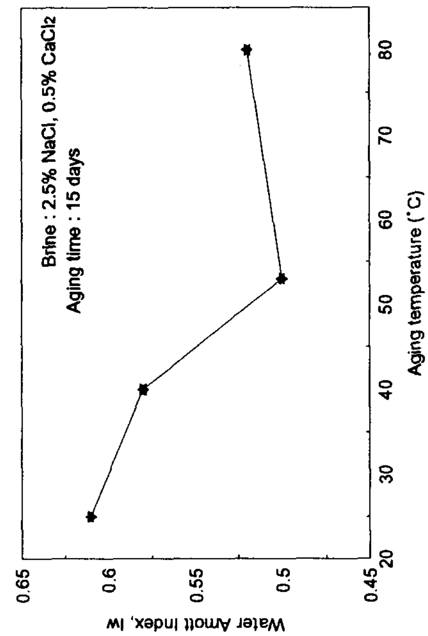

Fig. 4. Effect of aging temperature on Amott index to water.

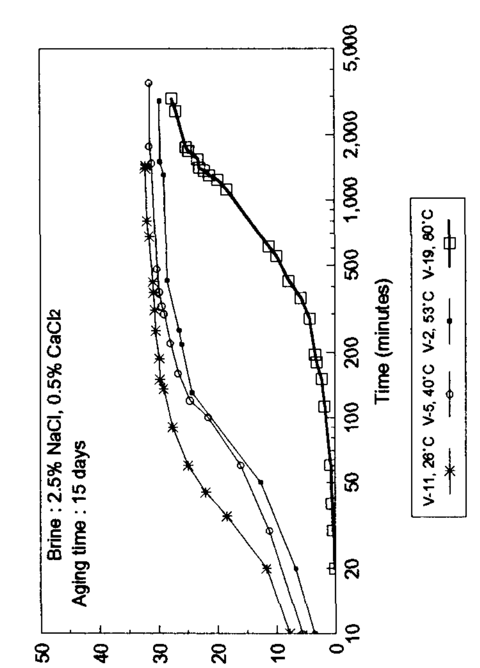

Fig. 5. Effect of aging temperature on rate of spontaneous imbibition of brine into Berea cores aged in Schuricht crude oil.

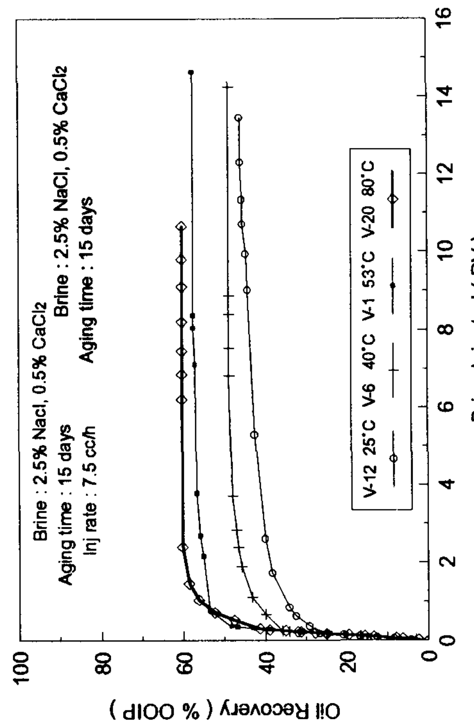

Fig. 6. Effect of aging temperature on waterflood oil recovery.

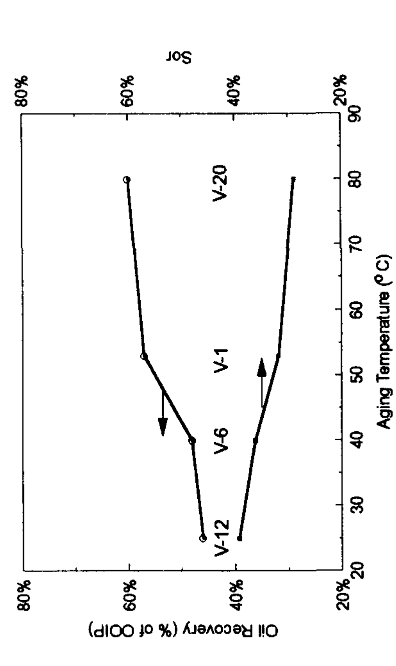

Fig. 7. Ultimate waterflood oil recovery and residual oil saturation for cores aged in crude oil at different temperatures.

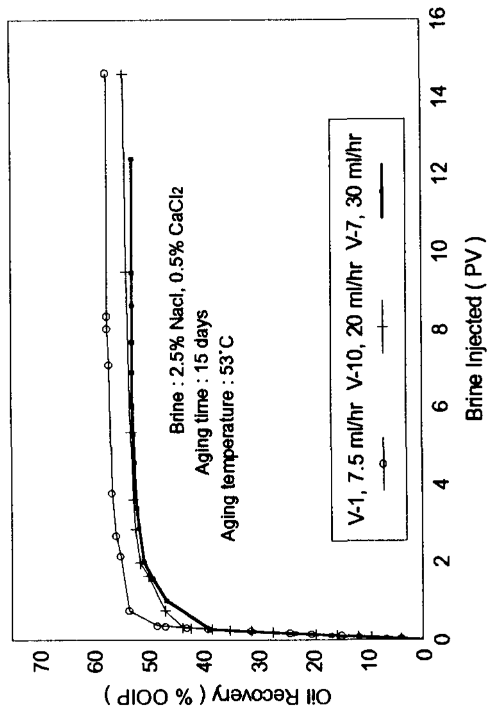

Fig. 8. Effect of flow rate on waterflood recovery.

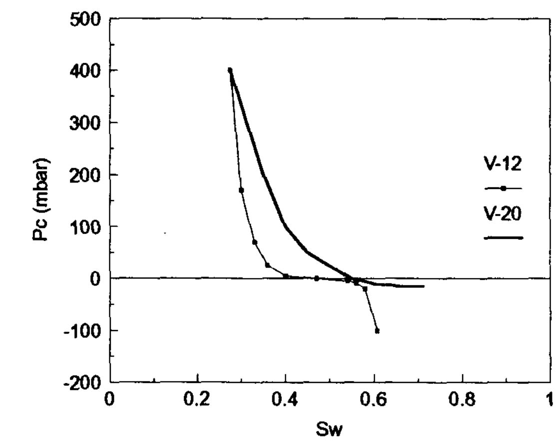

Fig. 9. Capillary pressure curves used to obtain history match in simulations.

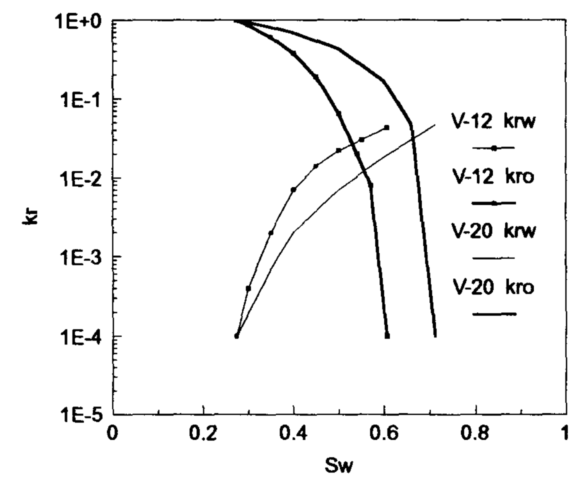

Fig. 10. Relative permeability curves used to obtain history match in simulations.

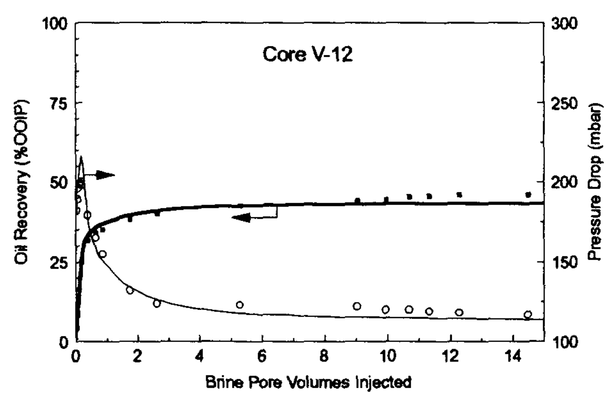

Fig. 11. History match to oil recovery and pressure drop data for Core V-12, aged at 25°C.

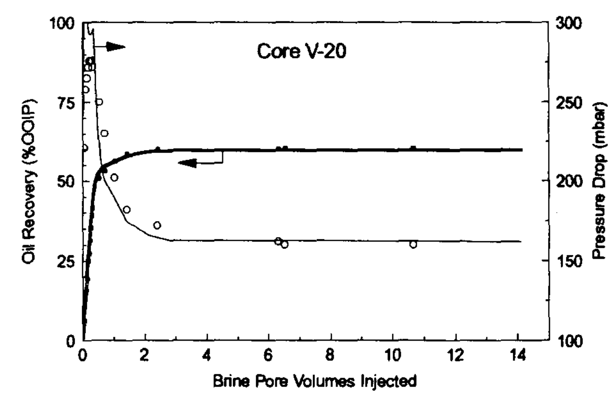

Fig. 12. History match to oil recovery and pressure drop data for Core V-20, aged at 80°C.