Influence of Temperature and Interfacial Tension on Spontaneous Imbibition Process.

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Abstract

Spontaneous imbibition is a mechanism that can significantly contribute to the production rate and final oil recovery in fractured and stratified reservoirs.

This mechanism is affected by rock and fluid properties and it has been reported by several authors to be strongly dependent on interfacial tension (IFT) and contact angle. Both magnitudes are influenced by system temperature.

In this work a laboratory study is performed on the influence of IFT and temperature on production rate and oil recovery for a given rock-fluid system. All sequences were performed on rock and fluid samples from Argentine basins. Rock samples were of medium permeability (56.1 to 83.1 mD) and porosity ranging from 18.7 % to 22.9 %. The fluids used were formation water and medium viscosity oil (45 cp at standard conditions). The samples were carried to irreducible water saturation before performing the imbibition tests resembling the assumed reservoir condition.

Initial tests were designed including representative water, oil and rock samples at several temperature levels. Another sequence of tests were performed with the addition of variable amounts of water dispersed surfactant. A noticeable influence of experimental conditions was found on the final results. As part of the tests, the same final temperature was reached through single and several steps observing the differences in overall performance.

Introduction

Spontaneous imbibition process is recognized as an important factor in oil recovery mechanism from naturally fractured reservoirs having a strong waterwet matrix subjected to waterflooding or waterdrive. Imbibition is the process that allows water to flow from the fractures into the oil saturated matrix blocks by capillary forces, displacing the oil from the blocks into the fractures.

In the same way, it could be possible for the water to flow from a high to a lower permeability layer in a stratified reservoir provided there is sufficient vertical permeability.

This process efficiency is strongly dependent on the fluids and rock properties.

The use of surfactant solutions in waterflooding is designed to recover residual oil by reducing the capillary forces between oil and the displacing fluid. The low IFT of the surfactant solution-oil pair leads to a reduction of the capillary pressure. This fact suggests that the imbibition driving force would be reduced, which would cause a decrease in the oil recovery rate.

Spontaneous imbibition process has been studied by many authors at different flow conditions and fluid - rock properties[1-7].

It has been shown that a reduction of the IFT may actually increase or decrease the imbibition rate depending on the relative contribution of capillary and gravity forces. This ratio could be quantified by the inverse of the Bond number defined as:

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

where C is a constant with a value of 0.4 for a capillary tube model.

When N_B^{-1} is large, capillary forces are dominant and if N_B^{-1} approaches to zero, gravity forces dominate the flow. Shabir et al.[8] did research work on intermediate permeability samples for which only radial flow was allowed by sealing the top and bottom sides of the samples with epoxy. For low IFT experiments (0.05 dyne/cm) a decrease in oil recovery rates was observed, compared with those of intermediate and high IFT. However, the ultimate recovery was significantly higher for the low IFT imbibition tests. A change was also observed in the flow behavior in both samples for intermediate and low IFT values experiments. In the case of high IFT (23.4 dyne/cm) oil was produced from the complete radial face of the sample. Whereas when the IFT was reduced, more than 70% of the oil was produced from the top side of the radial face, the rest flowing from the lower portion. This shows that oil imbibition displacement occurred because of two different regimes, the capillary and gravity forces.

In other work, Keijzer et al.[9], showed that a reduction of the IFT, has no effect on final oil recovery, but it modifies the imbibition rate. The experiments suggest that the imbibition driving force is not necessarily proportional to the IFT between fluids.

Donmez A.[10] performed different studies on the effect of temperature in the imbibition process. It was concluded that the viscosity reduction with increasing temperature is the main factor affecting the imbibition recovery rate. The increase in the final oil recovery with increasing temperature is attributed to variables such as the reduction of IFT with temperature (causing a decrease in Sor), the thermal volumetric expansion of the oil and an increase in water wettability with temperature found for Berea sandstone[11]. The relative importance of each of these factors is not clear. However, all of them can contribute to an increase in the final oil recovery.

The main objective of this work is to study the influence of IFT and temperature on the spontaneous imbibition process to be applied in oil fields of the San Jorge Basin, (Santa Cruz, Argentina). This fields are composed by a sequence of layers having a high permeability contrast. Sometimes crossflow is observed between them. During the waterflooding, the injected water tends to flow through the high permeability channels, resulting in an early water breakthrough. The imbibition takes place in the proximity of these high permeability flooded layers.

At the previously mentioned works, different synthetic fluids have been used. The results seem to show a great dependence on the rock and fluid properties used hence neither general conclusions, nor equation were found to describe the spontaneous imbibition process.

Trying to obtain representative results, natural reservoir fluids and porous media were used in this work. It is well known that the main variables affecting the imbibition process, such as viscosity, IFT, contact angle and others, are temperature dependent. For this reason the experiments were performed at different temperatures in order to study its influence.

Experimental description

Rock properties: Six samples were selected according to their permeability and porosity properties, as shown in table 1. They were water saturated and then carried to irreducible water saturation (Swi) with oil. All the sample surfaces were exposed to imbibition.

Fluid properties and preparation: Natural formation water was used having 15000 ppm NaCl. It was filtered out by 0.2 μm micropore film.

The oil belonged to the same formation. It was heated during 14 hours at 90 °C to eliminate the dissolved gas in order to prevent gas liberation during the experiment.

The oil viscosity behavior with temperature is shown in Fig. 1. The measurement was made with a Brookfield viscometer. Oil density was 0.8780 g/cc at 20 °C measured by picnometer.

Low IFT solutions were prepared by adding different amounts of a surfactant to the formation water. The concentrations used were 0.2% and 0.3% by volume. The solutions properties are shown in Table 2 and Fig. 2. The IFT was measured using a Krüss spinning drop tensiometer.

Experiments were performed in Ammot cups as shown in Fig. 3. The water circulation system was designed to obtain a constant surfactant concentration at the surface exposed to imbibition. In this way, a constant boundary condition was maintained, generating a steady concentration gradient with no pressure differences. This modification was necessary due to the observation of big oil droplets that became fixed to the rock samples in the low IFT experiments. These drops had a low contact angle because of the low IFT, and they increased in size as more oil was produced. This caused a reduction in the imbibition-exposed surface resulting in a poor imbibition rate. The circulation of the imbibition fluid allowed the small oil droplets to be removed from the sample surface. No presssure gradients were imposed in the sample. A peristaltic pump was used for this purpose as shown in the figure.

The experiments were performed at constant temperature in a thermostatized camera. Due to the big size of the camera an air circulation system was needed to guarantee a homogeneous temperature distribution. The temperature variation inside the camera was kept within ± 3 °C.

Both sets of experiments (without and with surfactants) were carried out over the same rock samples. After the first set of experiments, performed using natural formation water, the samples were carried again to irreducible water saturation using the same oil.

The second set of the experiments was performed using two different concentrations of surfactants.

In order to study the temperature effect, the following steps were done:

1-Two rock samples were initially exposed to water imbibition at 20°C. Once the oil production stopped, the temperature was raised up to 60°C. When no more oil was produced, it was raised again to 80ºC, finishing the experiment when negligible oil production was observed at this final temperature.

2-Two other rock samples were subjected to imbibition with natural water, at an initial temperature of 60ºC.When no oil production was observed, the temperature was raised up to 80ºC. As in the former case, the experiment was stopped when a non observable amount of oil was produced from these samples.

3- The last two rock samples were subjected to natural water imbibition with initial and final temperature of 80ºC, finishing the experiments when no more oil was produced from the samples.

The six samples were carried to irreducible water saturation after these sets of experiments, to be used in the experiments carried out using surfactant solutions as imbibition fluid.

Study the IFT effect: Similar procedure was followed using 0.3% and 0.2% by volume surfactant solution concentration:

1- Two rock samples were subjected to imbibition with the surfactant solutions and initial temperature of 60ºC. In these experiments the imbibition solution circulation method was adopted as mentioned before. When no more oil was produced from those samples, the temperature was raised up to 80ºC. This experiment finished when no more observable oil was produced at this final temperature.

2-Two other samples were subjected to imbibition with the surfactant solutions but, this time, at initial and final temperature of 80ºC. The imbibition fluid circulation was also used for these experiments. As in the previous cases, the experience was stopped when no more oil production was measurable.

Results and experimental data analysis

Water imbibition: The results obtained with water imbibition of the rock samples at different temperatures are shown in Fig. 4.

A strong imbibition rate and final oil recovery dependence with temperature was observed.

The samples initially subjected to 20°C reached a final oil recovery of 30% of OOIP. A sharp increase in oil recovery was observed when temperature was raised to 60°C, reaching a similar value to those samples with 60°C as initial temperature. The observed final oil recovery values were 47% and 44% of OOIP respectively.

With the increase of temperature to 80°C the final oil recovery presented a slight increase to 49% of OOIP in the samples with initial temperature of 20ºC and 60ºC respectively.

The graphic shows a significant difference in final oil recovery in the samples that started imbibition at 80°C reaching 60% of OOIP. This implies that the final oil recovery is strongly dependent on temperature history.

The imbibition rate was significantly lower for the samples starting at 20°C with respect to the ones initially at higher temperature. No difference in the imbibition rate was observed between the samples that started at 60°C and 80°C.

These results highlight the importance of performing laboratory imbibition experiments at reservoir temperature in order to get representative data.

Low IFT imbibition: Fig. 5 shows the results obtained in the second sets of experiments. No significant difference in imbibition rate and final oil recovery was observed between the low IFT set of experiments and those performed with water.

The final oil recovery in the experiments conducted at 60°C was 43.7% of OOIP for the 0.2% surfactant solution and 48% of OOIP for the 0.3% solution. As in the case of water imbibition the increase in temperature to 80°C caused a small increase in the final oil recovery, reaching values of 44.5% of OOIP for the 0.2% surfactant solution and 50% of OOIP for the 0.3% solution.

However, in the experiments that started at 80°C the final oil recovery was 55.6% of OOIP and 59.7% of OOIP for 0.2% and 0.3% surfactant solutions respectively.

These results show again the influence of the temperature history on the final oil recovery.

It is worth mentioning that in the experiments a higher imbibition rate and higher oil recovery were observed for the lowest IFT solutions experiments.

No significant difference in the imbibition rate was observed between the experiments carried out with water and those with surfactant solution.

Discussion

The mathematical models published in the literature can not reproduce the data obtained. These scaling equations (Ec. 2) predict a decrease in the imbibition rate as the IFT of the fluid decreases. This effect was not measured in our experiments but higher imbibition velocities were observed for the 0.3% surfactant solution than for the 0.2% surfactant solution.

$$t_d = t\sqrt{k/\phi}\left(\frac{\sigma}{\mu L^2}\right) \qquad (2)$$

Mattax and Kyte stated that the validity of this equation is found only when capillary forces are dominant. In this case it was observed that the oil droplets were produced homogeneously from all the faces of the samples, indicating that gravity forces are not significant according to the results presented by Al Lawati et al[8].

No differences were observed in the imbibition behavior by reducing more than 1000 times the capillary to viscous forces ratio, expressed by the N_B^{-1}. This result appears to be in contrast with results previously presented in the literature, where an increase in final oil recovery is reached when N_B^{-1} is decreased below a critical value.

A homogeneous production was always observed from the whole sample surface for either high or low IFT solutions. These results, which are not coincident with those from other authors, are a clear evidence of the strong dependence of the experimental behavior on the fluid properties and their interaction with the rock.

Conclusions

As a result of this study, the following conclusions are presented:

1- The existent scaling equations do not reproduce the experimental results in all cases. There is an absence of an adequate general physical-mathematical model to describe the imbibition mechanism.

This model should take into account interface fluid-fluid and fluids-rock physic properties as well as adsorption and chemical interactions. It is clear that the classical fluid mechanics currently in use, can not easily describe this process.

2- None of the existing scaling mathematical models present dependence of the recovery rates and final oil recovery with temperature.

This effect should be considered in scaling up experimental results to reservoirs in which the temperature could be modified in thermal recovery process.

3- The experimental results highlight the strong dependence of the imbibition process on the particular combination of rock and fluid used.

Thus, it is recommended to perform imbibition experiments in conditions as close to those in the reservoir as possible, in order to get representative data. It is also recommended to perform these experiments at different temperatures and IFTs to evaluate the influence on the spontaneous imbibition process for each particular case, until a general equation could be developed.

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Nomenclature

σ	*Interfacial tension, dyne/cm*
ϕ	*Porosity, fraction*
k	*Absolute permeability,md*
$\Delta\rho g$	*Density diference, gm/cm^3*
H	*Height of a porosus medium, cm*
t	*Imbibition time, sec*
t_d	*Dimensionless time.*

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sample	porosity	Poral vol.	K_g	S_{wi}	OOIP
	%	cc	md	%	cc
1	20,5	16,2	68,2	31	11,2
2	20,3	15,7	66,9	33	10,5
3	22,9	18,6	68,4	31	12,8
4	22,3	17,5	73,4	29	12,4
5	18,7	14,7	83,1	33	9,8
6	20,3	16,3	56,1	27	11,9

Table 1: Basic Petrophysical Properties of the Samples.

Surfactant Concentration			
0.2%		0.3%	
Temperature (°C)	IFT (dyn/cm)	Temperature (°C)	IFT (dyn/cm)
34.0	1.29 ± 0.03	36.5	0.62 ± 0.02
59.4	0.528 ± 0.09	60.0	0.12 ± 0.02
76.3	0.034 ± 0.002	80.0	0.026 ± 0.001

Note: Tipical values of IFT without surfactant are in the range from 26 to 30 dyn/cm at 20°C in this reservoir.

Table 2: Fluids Properties

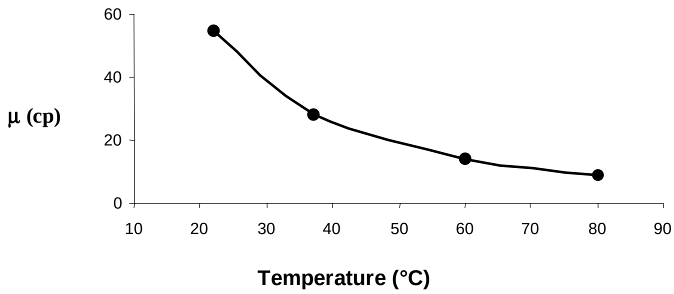

Fig. 1: Change of viscosity with temperature

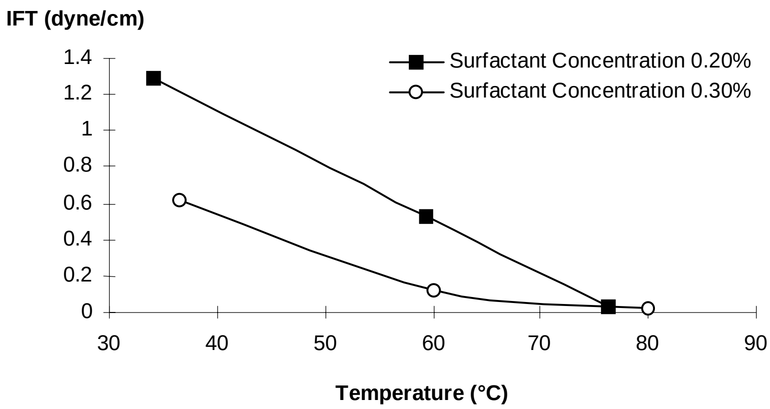

Fig.2: Change of IFT with Temperature.

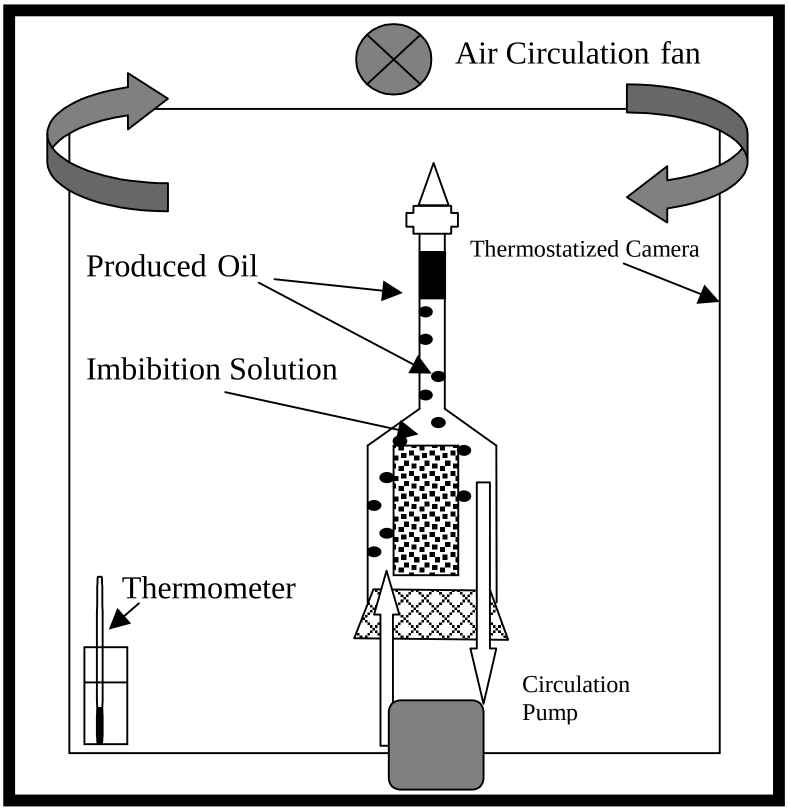

Fig 3: Ammot Cup used in the experience

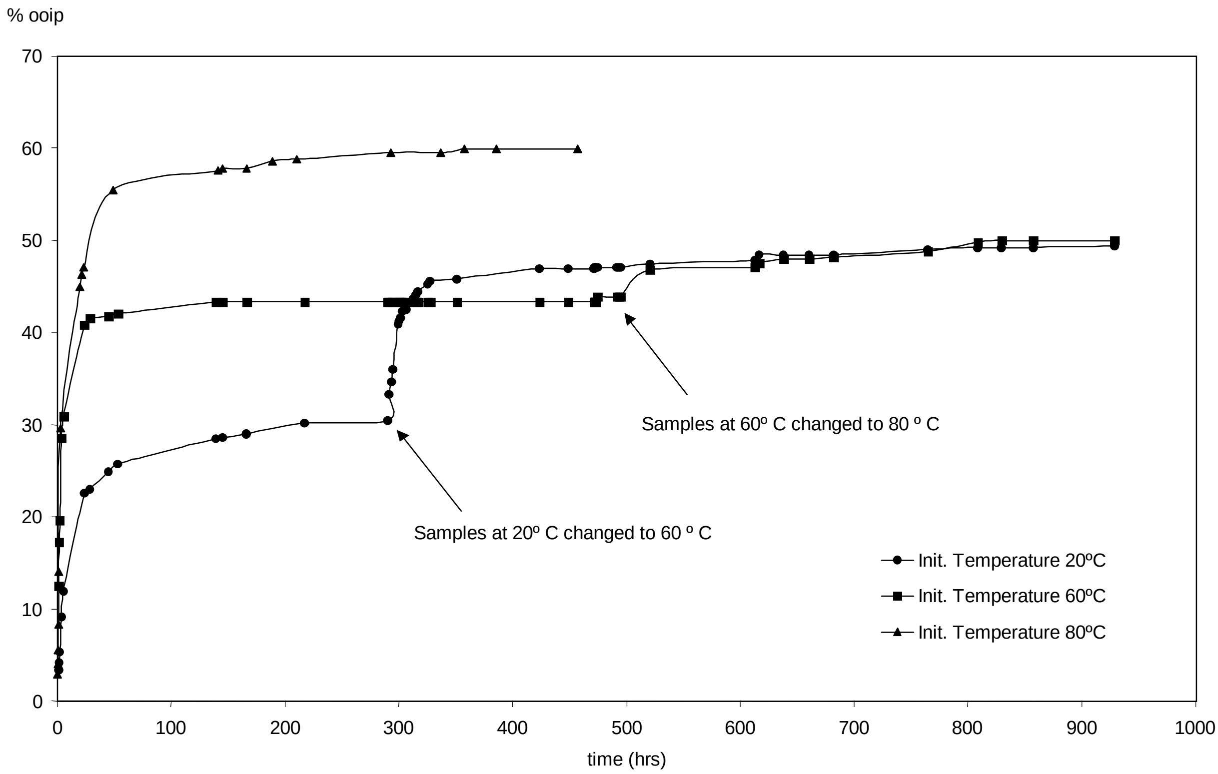

Fig. 4: Water Imbibition at different temperatures

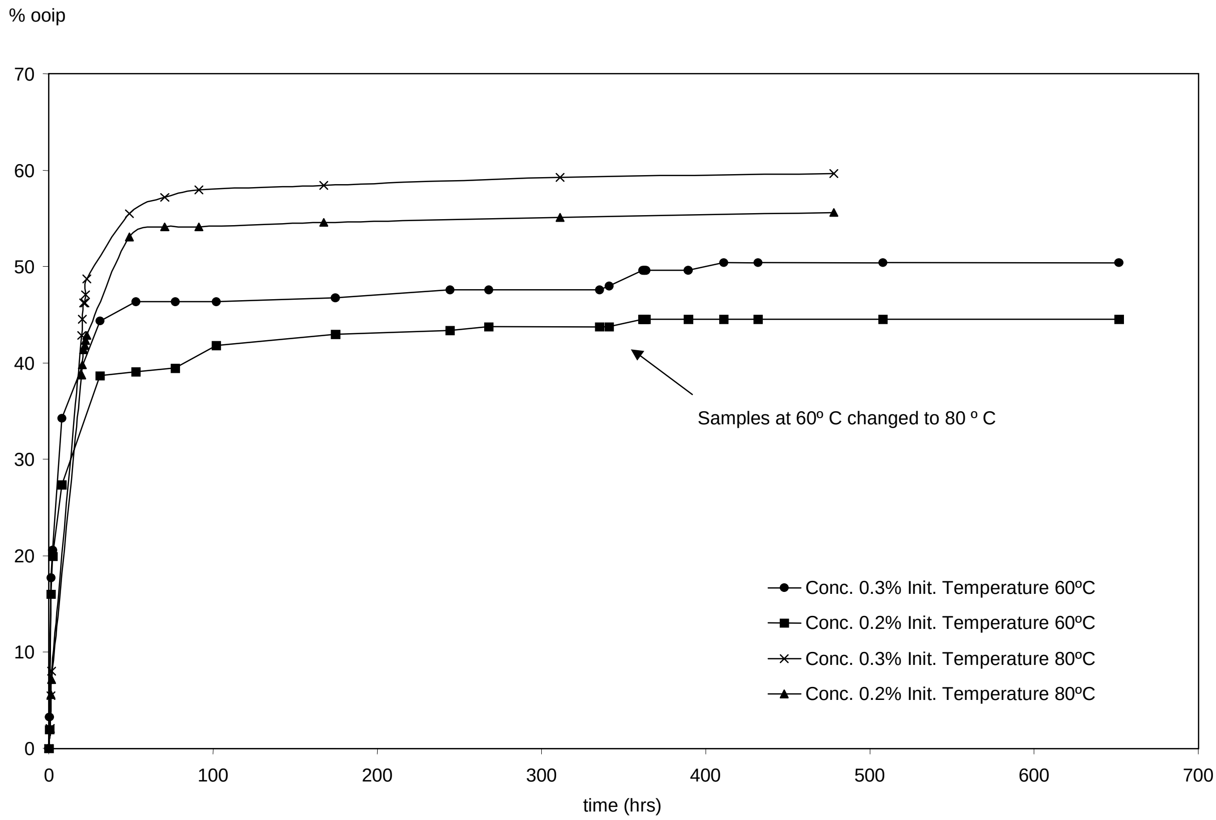

Fig. 5: Imbibition with Surfactant Solutions at different Temperatures