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The Effect of Temperature and Rock Permeability on Oil-Water Relative Permeability Curves of Waxy Crude Oil

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ABSTRACT
Wax deposition has always been a problem for the production of waxy crude oil. When the reservoir temperature is below the wax appearance temperature (WAT), wax would precipitate in the oil phase as wax crystals, which could increase the oil viscosity and decrease the permeability of the rock. In this study, a series of core flooding experiments under 5 different temperatures and using two groups of core samples with permeability liein300 md and 1000 md respectively were carried out to investigate the effect of temperature and rock permeability on waxy crude oil-water relative permeability curves under reservoir condition. The results revealed that temperature has a significant influence on relative permeability, especially when the temperature is below the WAT (70℃ in this study). The initial water decreased by 40% and the residual oil saturation increased to about 2.5 times when temperature decreased from 85℃ to 50℃ for experiments of both two groups in this study. Oil recovery decreased as the temperature dropped. There was not much difference between the oil recovery of cores with permeability of 1000 md and that with permeability of 300 md until the temperature dropped to 70℃, and the difference increased to 8% when temperature decreased to 50℃, which implies that reservoir with lower permeability is easier to be damaged by wax deposition only when the temperature drops to below WAT. According to this work, it is suggested that reservoir temperature should be better maintained higher than theWAT when extracting waxy crude oil of this reservoir, or at least above 60℃.
Key words -Waxy crude oil, temperature, permeability, relative permeability curve, oil recovery factor

I. INTRODUCTION

Crude oils with high paraffin content and pour point are classified as a waxy crudes. The separation of wax as solid phase from crude oils occurs due mainly to the cooling of oil (1). Wax deposition in reservoir would damage the formation severely by blocking the pore throats, thus decreasing the rock permeability. Also, it could increase the oil viscosity, making it hard for the oil to flow and leading to a higher residual oil saturation. So it's important to find a way to develop waxy crude oil reservoir without causing too much wax deposition.

In this study, we plan to investigate the influence of temperature and permeability on the relative permeability curves and oil recovery of waxy crude oil. To do such, water are injected through the natural core samples saturated with a waxy crude oil under different temperatures and reservoir pressure. Then by obtaining the production results and use of relative permeability methods, we calculated and extracted the relative permeability curves of all the cases.

Relative permeability is perhaps the most important parameter in describing underground flow behavior of immiscible fluids. It basically represent multiphase flow of fluids as controlled by the interaction of viscous and capillary forces within a porous medium. Altering temperature can cause changes in the relative levels of these two forces. This, in turn, may affect the flow characteristics of the different fluids within the porous medium.

There are two basic approaches for determination of relative permeability curves from laboratory core flow tests. In the steady-state method, the fluids are injected simultaneously into core plugs. In the unsteady-state method, a fluid is injected to displace another fluid present in the core. Steady-state test data processing is relative simple, but experiments are tedious and time consuming. In contrast, unsteady-state laboratory tests can be performed rapidly, but data evaluation is a much difficult task. In this study, the unsteady-state method is used, as well as the JBN analytical methods due to its simple and quick calculation steps.

II. EXPERIMENTAL DETAILS AND PROCEDURE

Undegassed waxy crude oil samples from one of the east Africa oil reservoirs were used in this work. Physical properties of the oil under reservoir conditions and the properties of formation water used are shown in table 1 and table 2 respectively.

Table 1. Oil Properties

Parameter		Value at reservoir condition
		(22.7 Mpa& 87 ℃)
API	-	31.5
Viscosity	cp	18.2
Density	g/cc	0.82
WAT	℃	70
Pour Point	℃	45

Table 2. Properties of Formation Water

Formation Water									
Cation (mg/l)			Anion (mg/l)				Salinity (mg/l)	Water Type	PH
K^{++} Na^{+}	Mg^{2+}	Ca^{2+}	Cl^{-}	SO_4^{2-}	HCO_3^{-}	$CO3^{2-}$			
2903	1	5	2293	151	1811	0	7164	$NaHCO_3$	9.4

2.1 Core sample properties

Natural cores taken from field were used in this study, one of them is shown in Fig. 1. There were two groups of core samples, one are natural cores with permeability lie in 1000 mD and the other 300 mD.The properties of the core samples are given in Table 3.

In order to get the results under 5 different temperatures ineach permeability level, 10 sets of flooding experiments were planned, but there are only 6 natural cores, so some of the cores were used twice. The sequence of using the cores are shown in Table 4.

Figure1. Natural core samples

Table 3. Rock Properties

Core #	Depth	Length	Radius	Density	Porosity	Absolute Permeability
	m	cm	cm	g/cm3	%	mD
5-076	2519.98	4.698	2.518	1.93	29.6	340.6
5-070	2519.48	4.756	2.514	1.9	29.5	331.1
5-001	2516.38	4.459	2.427	1.84	30.9	305.3
5-104	2521.38	4.977	2.452	1.84	30.7	966.2
5-079	2519.73	4.981	2.481	1.88	31.4	929.4
5-068	2519.42	5.225	2.454	1.86	29.8	923.3

Table 4. Sequence of Using the Cores

Test Temperature °C	1000 mD	300 mD	
85	5-068	5-001	first round
80	5-079	5-070	first round
70	5-104	5-076	first round
60	5-068	5-070	reused
50	5-079	5-076	reused

2.2 Apparatus

In order to have a reliable measurement, it's important to design the experiments properly. In this experimental work, unsteady-state method is used as well as the J.B.N. analytical method to calculate the relative permeability. Fig. 2 shows the relative permeability measurement apparatus (SYS-III two phase displacement system). This system was designed to conduct two phase relative permeability measurements under high temperature and pressure. It consists of an injection system, two-piston accumulators, a core holder, a back pressure regulator, an overburden pressure system, two constant temperature ovens, a separator, etc. The schematic of the apparatus are shown in Fig. 3.

Figure 2. Apparatus

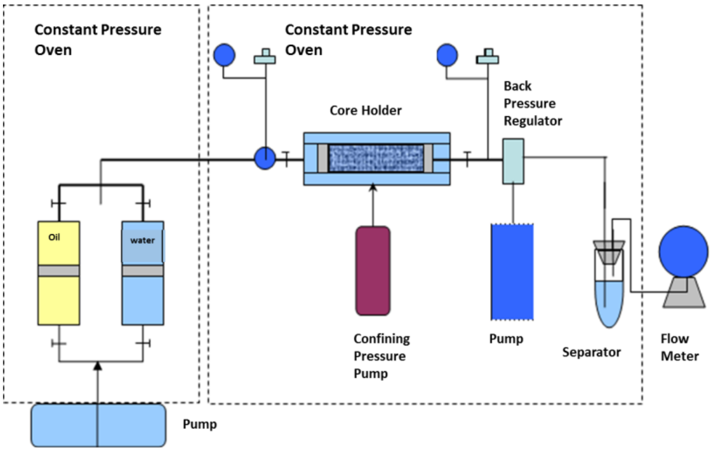

Figure3. Schematic of the apparatus

III. TEST PROCEDURE

The tests consisted 2 sets of injection test, first used the group of cores whose permeability lie in 1000 mD and second the other group whose permeability lie in 300 mD. Each of the tests include 2 successive cycles of injection (i.e. drainage and imbibition). At the start of each run the core was solvent cleaned, dried with hot nitrogen and evacuated. After core preparation, the core sample was saturated with the brine of salinity of 7164 mg/l. Then the core porosity was measured by comparing the weights of the dried and wetted core samples. Absolute permeability of the core was measured by flow of the brine through the core. Then the oven is set to experimental temperature. The experimental temperature were planned as 85℃ (the initial reservoir temperature), 80℃, 70℃, 60℃, and 50℃ respectively. After a while, absolute permeability of the core was measured again by flow of the brine through the core. After anhour, oil was injected into core at the rate of 0.1 cc/min up to 10 PV (pore volume) in order to reach to the irreducible water saturation. Then stop the pump and wait for 12 hours in order to let the core age. Afterwards, inject water into the core at a constant flow rate of 0.5 cc/min for 4 PV and then 1.0 cc/min for 30 PV and then, the amount of oil and water produced were measured and recorded. Using the pressure drop and produced volume recorded, relative permeability curves were extracted. Also invading-phase saturation was determined by mass balance calculations. Finally the relative permeability values were plotted versus saturation. Additionally, the confining pressure was set to 22 MPa and tests has been done at 16 MPa injection pressure.

IV. METHODOLOGY

JBN method calculates relative permeability based on the Equation 1 to Equation 4.

$$K_{ro} = f_o(S_w)\left[d\left(\frac{1}{\bar{V}(t)}\right)/d\left(\frac{1}{I\cdot\bar{V}(t)}\right)\right] \quad (1)$$

$$K_{rw} = K_{ro}\frac{\mu_w f_w(S_w)}{\mu_o f_o(S_w)} \quad (2)$$

$$S_{we} = S_{wi} + \bar{V}_o(t) - f_o(S_{we})\cdot\bar{V}(t) \quad (3)$$

$$I = \frac{Q(t)}{Q_o}\cdot\frac{\Delta p_o}{\Delta p(t)} \quad (4)$$

The oil recovery factor is calculated by Equation 5.

$$Oil\ Recovery\ Factor = \frac{(1-s_{wi})-(1-s_{we})}{(1-s_{wi})} \quad (5)$$

Where:

s_{wi} ----initial water saturation,

s_{we} ---- water saturation at the outlet.

$\bar{V}(t)$---- dimensionless cumulative fluid production volume

$\overline{V_o}(t)$ ----dimensionless cumulative oil production volume
$f_o(S_w)$ ---- oil cut, fraction
$f_w(S_w)$---- water cut, fraction
μ_w ---- water viscosity, cp
μ_o ---- oil viscosity, cp
K_{ro} ---- oil relative permeability
K_{rw} ---- water relative permeability
I ---- flow ability
Q_o ---- oil flow rate at the inlet, cm^3/s
$Q(t)$ ---- oil flow rate at the outlet, cm^3/s
Δp_o ---- initial pressure drop, MPa,
$\Delta p(t)$ ---- pressure drop at time t, MPa

V. RESULTS AND DISCUSSIONS

The unsteady-state displacement experiments were performed to investigate the effect of reservoir temperature and rock permeability on water-oil relative permeability and the ultimate oil recovery. Relative permeability curves extracted from the test results are shown in Fig. 4 and Fig. 5 respectively.

Based on the curves, it's obvious to see that temperature has a great influence on water-oil relative permeability curves. As the experimental temperature decreased from 85℃ to 50℃, the initial water saturation decreased from 0.463 to 0.256 for the first group with higher permeability, 0.447 to 0.271 for the second group with lower permeability. Besides, the residual oil saturation increasedfrom 0.236 to 0.569 for the first group with higher permeability, 0.243 to 0.615 for the second group with lower permeability. This is because the oil viscosity increased as the reservoir temperature decreased, leading to a higher flow resistant.

When the temperature dropped to 70℃, which is WAT of this waxy crude oil sample, wax will precipitate as wax crystals in the oil phase, and as the pressure dropped further, the crystals would accumulate and adsorbed onto the pore surface. As a result, some small throats will be blocked as well as some large pores, more oil will be trapped inside the cores. This could be proved by the increasing injection pressure as the temperature decreased. On reservoir scale, wax deposition would damage the formation significantly, the rock permeability would decrease and it's irreversible.

The most obvious change in initial water saturation and residual oil saturation happened when temperature dropped from 60℃ to 50℃, which indicates that the wax deposition might have reached its peak when temperature was between 60℃ and 50℃.

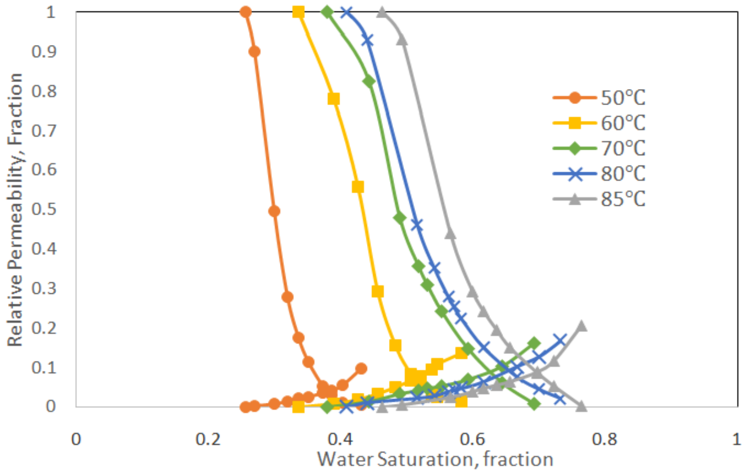

Figure 4. Water-oil relative permeability curve under different temperature (1000 mD group)

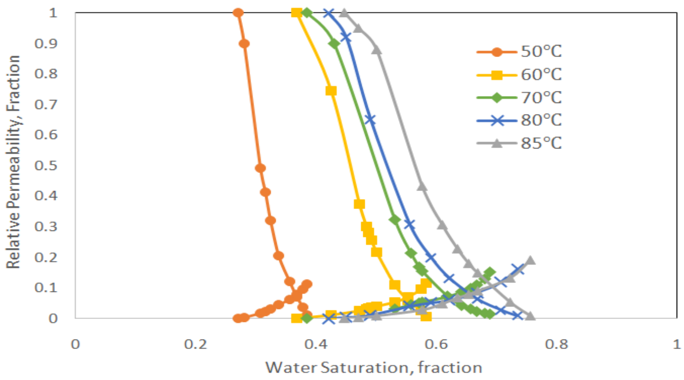

Figure 5. Water-oil relative permeability curve under different temperature (300 mD group)

The comparison of oil recovery factors of the 10 sets of unsteady-state displacement experiments are shown in Fig. 6, and the data is given in table 5.

The oil recovery factors of the first group with higher permeability are slightly higher than that of the second group with lower permeability when the temperature is above WAT (i.e. 85°C and 80°C), but when the temperature decreased below WAT, the difference between the oil recovery factors of the two groups start to increase from 1% at 70°C to 8% at 50°C. This illustrates that the reservoir with lower permeability (300 mD) would be more vulnerable to wax deposition compared to that with higher permeability (1000 mD) only when the temperature is below WAT by 10°C or 20°C.

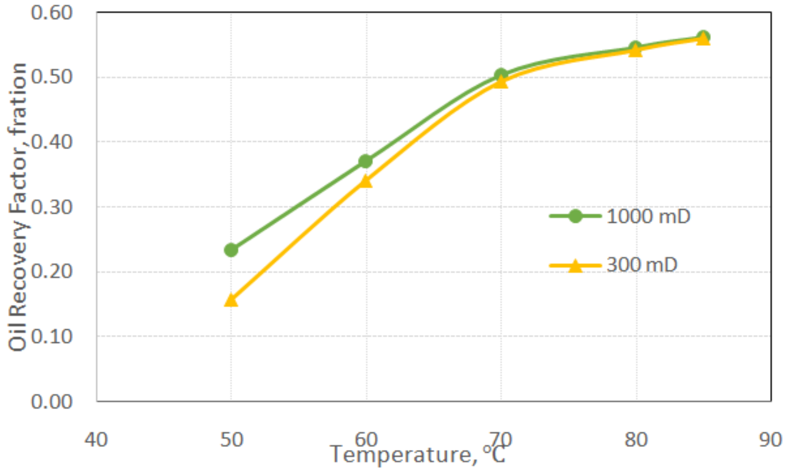

Figure 6. Oil recovery factors of 2 groups of displacement experiments

Table 5. Data of oil recovery factors

T/°C	1000 mD	300 mD	Difference
85	0.561	0.560	0.001
80	0.546	0.542	0.004
70	0.504	0.493	0.011
60	0.371	0.340	0.031
50	0.234	0.157	0.077

VI. CONCLUSIONS

10 experimental unsteady state displacement tests of water and waxy crude oil systems were performed on 6 natural sandstone core samples and relative permeability curves of both water and oil phases were determined for all the processes. Based on the results obtained in this work, the following conclusions can be drawn:

(1) Temperature has a great influence on water-oil relative permeability curves. As the experimental temperature decreased from 85°C to 50°C, the initial water saturation decreased about 40% and the residual oil saturation increased to 2.5 times inexperiments of both two groups. There are basically two reasons, one is that the oil viscosity increased due to wax deposition, the other is wax adsorption on the substrate changing the wettability of the rock.

(2) When temperature dropped from 60°C to 50°C, the change in initial water saturation and residual oil saturation was significant, which indicates that the wax deposition might have reached its peak when temperature was between 60°Cand 50°C for this oil sample. So it's suggested that when developing this oil reservoir, the temperature should at least be maintained above 60°C.

(3) Reservoir with lower permeability (300 mD in this case) would be more vulnerable to wax deposition compared to that with higher permeability (1000 mD in this case) only when the temperature is below WAT by 10°C or 20°C. When temperature is above WAT, there is not much difference.

So it's suggested that the reservoir should be developed above the WAT (70°C), or at least above 60°C.

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