COREFLOOD STUDY OF LOW SALINITY EFFECT IN LOW PERMEABILITY SANDSTONE RESERVOIRS

Wu Jiazhong; Xie Quan; Liu Li; Liu Qingjie;Qin Jishun; Ma Desheng;Wu Kangyun;

Yan Shouguo

State Key Laboratory of Enhanced Oil Recovery・Research Institute of Petroleum Exploration and Development of CNPC,
Beijing, China

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Abstract

Ionic adjustment waterflooding has been a promising technique to recover oil in sandstone reservoirs. However, the optimum conditions to improve oil recovery by ionic adjustment waterflooding are still not clear because of the lack of understanding of O/W/S interaction mechanisms. In this study, several coreflood experiments were conducted to refine the mechanisms involved in improving oil recovery in low permeability sandstone reservoirs which is seldom investigated in recent years. The cores used in the displacement experiment were extracted from Reservoir Chang 81 of Xifeng oilfield with low permeability, narrow radius of pore throat and large specific surface area, leading to relatively low water flooding efficiency from the X-ray, SEM and coreflood experiment. In this paper, the coreflood tests were conducted with low salinity water as secondary (starting at Swi) and tertiary (starting at Sorw) mode experiments. The experimental results showed that the ultimate oil recovery by the Low salinity waterflooding is 37.8%~45.6%, compared to 23.3-30.0% using conventional waterflooding with synthetic formation water salinity of 57114mg/L. Ionic adjustment waterflooding could enhance oil recovery by 13.3%~14.5% under the residual oil saturation condition which was established by synthetic brine water. At the initial water saturation condition, the ionic adjustment waterflooding could recover additional 15.6% of oil in place compared with the conventional formation water flooding at the same injection core PV and flow rate. Moreover, no sign of formation damage was observed from the differential pressure during the low salinity water displacement, since the differential pressure was lower than that in the conventional cases displaced by brine water (high salinity) at the same displacement velocity. Additional, no solid particles were produced during ionic adjustment waterflooding.

INTRODUCTION

Waterflooding technology has been the most successful approach to improve oil recovery. A key point to reach this success of waterflooding is that the differential pressure can be formed by the water injection which is necessary to displace oil out of formation. And also, waterflooding involves much lower cost investment and convenient operation compared to polymer and surfactant flooding. However, it was found that water chemistry and salinity level have a significant influence on oil recovery during the past decade from the experiment in the laboratory and field trials. In recent years, extensive research has shown that salinity change and ionic composition of the injected water can be favorable to affect oil/brine/rock interactions, enhancing microscopic displacement efficiency[1, 2], frontal water saturation and adjusting mobility ratio[3], eventually improving waterflooding oil recovery. However, it's difficult to establish the effective pressure gradient from the injection well to production well regarding low permeability reservoirs. The water injection pressure can be lowered through low salinity water flooding with remaining oil saturation reduction, as can be seen from Fig.2 and Fig.3. Additional, as the matter of fact, the reserves of oil in low permeability reservoirs in China can not be ignored. Consequently, the research on the feasibility of the low salinity effect to develop low permeability reservoirs is extraordinary meaningful and urgent to guarantee oil supply in China. The major objective of this paper is to concentrate on the possibility of the low salinity effect in Xi Feng oil field of Chang Qing Oil Company with the permeability less than 1 mD, as can be seen from Table 1. The recovery factor versus injected PV was obtained through coreflood tests which were conducted with low salinity water at initial-water saturation (Swi) and remaining oil saturation after waterflood (Sorw). And also, the variation of differential pressure from the downstream and upstream was analyzed as the low salinity water was injected into the upstream of the core. Ultimately, the magnitude of pH of the effluent fluid was investigated from the coreflood test.

Experimental Studies

Materials

Xi Feng oil field consists of the area of Bai Ma, Dong Zhi, Ban Qiao, Gu Chengchuan and Shi She with the proved geological reserves at 2.3967×10^8t, the use of oil-bearing area of 196.03km^2, the use of geological reserves of 1.2815×10^8t which is major provider of the production in Long Dong area. The permeability and porosity from logging interpretation are 1.12×10^{-3} μm^2 and 10.7%, respectively. Moreover, the content of clay minerals in the formation ranges from 11.4%—34.3%, and the relative capacity of the individual mineral and clay micro-distribution measured by SEM were shown from Table 2 and Fig.1. From the literature published by Wu Jiazhong [4] , it can be investigated that the formation is rich in throats with the diameter at micro and sub-micrometer. The median radius of the throats is about 0.05-0.29 μm with the average magnitude of 0.18 μm. The reservoir rock is oil wet at the reservoir temperature at 65℃. Oil sample used in the coreflood experiment was degassed crude oil from the well head in Xi Feng Oilfield. The density of oil sample is 0.81g/cm^3 at temperature of 65 degree Celsius. The viscosity of the experimental oil was tested using a capillary viscometer at the temperature of 65 degree Celsius. The oil sample viscosity is 9.0cp, and the composition of the oil used in the experiment can be seen from Table 3. Synthetic formation water was used in the coreflooding test. The composition of the synthetic brine and formation brine are given in Table 4. The total salinity of the brine water is 58430mg/L with the concentration of Ca^{2+} and Mg^{2+} at 2460mg/L and 317mg/L, respectively.

Experimental Preparation

All of the coreflood measurements were conducted under 65℃ and the core plugs used in the experiment were extracted from a well with the number of 137, Table 1. A Quizix-SP-5400 pump with the accurate control at the constant low flow rate was set up in the flooding system. The experimental procedures adopted in this paper are as follows.1) Core plugs of approximately 2.5 cm in diameter and 5.0 cm in length were cut from the whole core, which was drilled from the Xi 137 well with brine. 2) The core plugs were evacuated for 10 hours, and then were saturated with formation water for another 10 hours at room temperature. The porosity of the core could be calculated from the bulk volume of the rock and the weight difference between dry weight and the weight of core saturated with formation brine. 3) Afterwards, the initial water saturation (i.e. irreducible water saturation), Swi was established by injecting 2.0-2.5 PV of mineral oil with the viscosity at 15.5mPa.s in room temperature in each direction. It was injected at a rate of 0.01 mL/min with a net confining pressure not exceeding 3 MPa under room temperature to prevent the water inside of the core from evaporation within high temperature. The weight of the cores before mineral oil displacement was measured to calculate the Swi. 4)Then, the volume of the mineral oil was displaced by the crude oil used in the experiment under 65℃ and the core was put inside of the core holder which was in the oven to restore wettability. 5) Ultimately, the core plugs were flooded with formation brine with flow rate at 0.025ml/min at the room temperature to obtain Sorw. The volume of oil displaced by the formation brine and the weight of the core before brine displacement were measured to calculate Sorw.

Results and Discussion

One can see from Figure 2 and 3 that the recovery factor was improved by13.3% for core 19# and 14.5% for core 23# at the residual oil saturation through ionic adjustment waterflooding after synthetic formation brine flooding with the recovery 29.4% and 23.3%, respectively. From the coreflood experiment conducted under initial water saturation Fig.4, it indicated that the ultimate recovery of core 40# which was only displaced by synthetic formation brine with salinity of 57114g/cm^3 was 30.0%. However, a 45.6% recovery factor for core 23# was achieved through ionic adjustment waterflooding. Coreflood experiments illustrated that ionic adjustment waterflooding is a promising technology to improve oil recovery for low permeability sandstone. Differential pressure alternation was investigated in this paper as well from the corelood test, since it is acknowledged that it's extraordinary difficult to maintain the effective production pressure differential in low permeability reservoir for the strong heterogeneity and high magnitude of capillary force in low permeability reservoirs. Nevertheless, no formation damage was observed due to injecting ionic adjustment waterflooding. An interesting observation is that the differential pressure was a little bit lower after ionic adjustment waterflooding than that at the residual oil saturation, as given in Fig.2 and Fig.3. It is expected as due to the extra produced oil, the water permeability is higher. Eventually, the magnitude of pH of effluent fluid was measured, as shown in Fig.5. It was observed that the magnitude of pH of effluent fluid displaced by ionic adjustment waterflooding is higher than that displaced by synthetic formation brine within increase of 1-3pH from the residual oil saturation and initial water saturation. This phenomenon was formulated by Sandengen [5] .

CONCLUSIONS

In this paper, the coreflood tests were conducted with ionic adjustment waterflooding at initial water saturation (Swi) and remaining oil saturation after waterflood (Sorw). Several observations have been made during this study:

- The ultimate oil recovery by the ionic adjustment waterflooding reached to 37.8%~45.6%, compared with the conventional waterflooding with synthetic formation water with salinity 57114mg/L at 23.3%~30.0% in low permeability sandstone from Xifeng oil field.
- The magnitude of pH of effluent fluid displaced by ionic adjustment waterflooding is higher than that displaced by synthetic formation brine within increase of 1-3pH.
- Differential pressure was decreased at residual oil saturation invaded by ionic adjustment waterflooding compared to formation brine.

ACKNOWLEDGEMENT

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Table 1 the core parameters of experiment

Sample	Ka	Swi	Kw	Ko(Swi)	EOR (HSW)	EOR (IAW)
	mD	(%)	mD	mD	(%)	(%)
2	2.09	30.4	0.493	0.296	29.4	42.7
3	0.70	29.4	0.172	0.084	23.3	37.8
4	1.49	33.2	0.596	0.290	30.0	
5	1.67	38.1	0.734	0.232		45.6

Table 2 the mineral composition of the core plugs extracted form Xi 137

Sample	The relative content of minerals（%）				Mineral types and content（%）				Total clay minerals(%）
	I/S	I	K	C	quartz	potassium	plagioclase	calcite	
1	30	14	27	29	44.8	7.1	21.5	0.1	26.5
2	32	12	28	28	43.2	11.9	20.9	0.4	23.6
3	33	11	30	26	41.7	13.8	16.7	0.7	27.1
4	36	15	24	25	37.6	13.9	19.2	0.9	28.4
5	37	15	24	24	35.2	13.6	21.8	1.1	28.3
6	36	16	24	24	45.2	11	24.8	7.6	11.4
7	38	13	22	27	41.1	9.8	23.8	0.2	25.1
Average	34.1	14	24.7	27.2	41.3	11.5	20.7	1.5	25.3

Table 3: Ingredients of the oil sample from Changqing Oilfield

Ingredients	Saturated hydrocarbon	Aromatic hydrocarbon	Non-hydrocarbon	Asphaltic bitumen
wt%	65.05	23.3	6.68	4.97

Table 4 the composition of the formation brine and synthetic brine

Sources	ingredients（mg/l)							Total salinity(mg/l)
	$K^{+}+Na^{+}$	Ca^{2+}	Mg^{2+}	HCO_3^{-}	Cl^{-}	SO_4^{2-}	Ba^{2+}	
Formation brine	19249	2460	317	308	35220	0	876	58430
Synthetic brine	19249	2460	317	308	34781	0	0	57115
0.1(IAW)	1900	200	30	30	3199	210	0	5569
0.05(IAW)	950	100	15	1599	15	105	0	2784

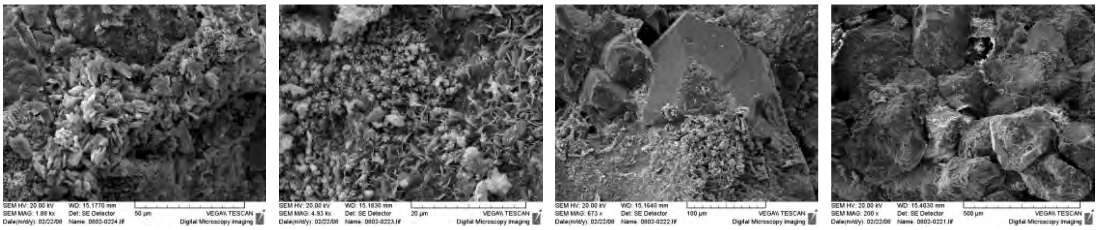
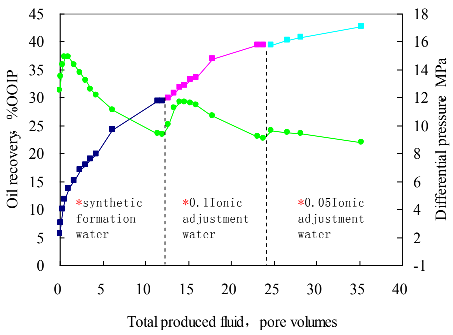


Fig.1 SEM analysis of formation in Xi 137 well



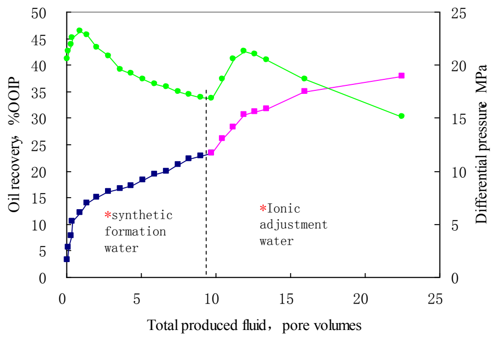


Fig.2 Oil recovery and DP vs. PV of core 2# Fig.3 Oil recovery and DP vs. PV of core 3#

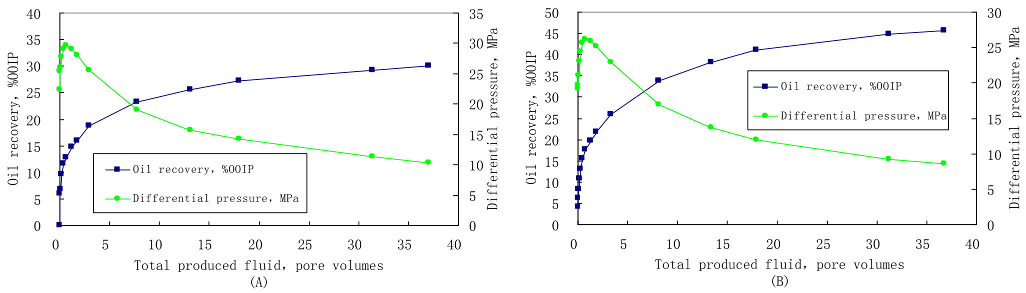


Fig.4 Oil recovery and DP vs. PV of cores

(A. high salinity waterflooding of core 4#; B. Ionic adjustment waterflooding of core 5#)

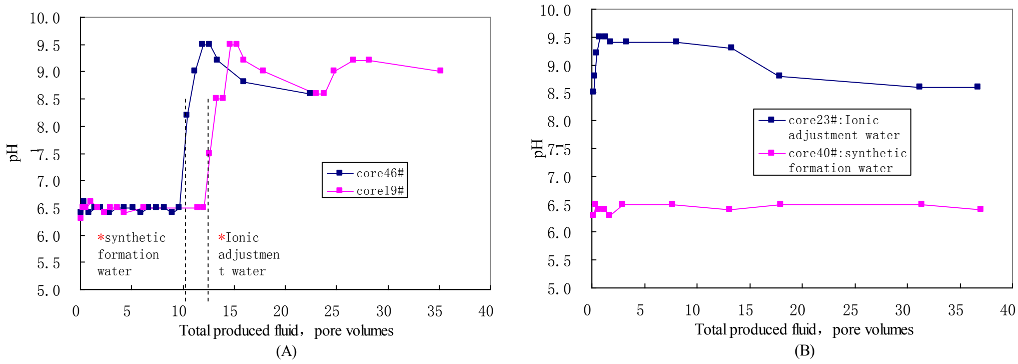


Fig.5 pH variation of effluent fluids

(A. ionic adjustment waterflooding applied in residual oil saturation;

B. ionic adjustment waterflooding applied in initial water saturation)