CAPILLARY DESATURATION CURVES FOR EVALUATING SURFACTANT PERFORMANCE BY CORE FLOODING EXPERIMENTS

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ABSTRACT

Capillary desaturation curves are normally generated in laboratory scale by means of core flooding experiments to evaluate the surfactant formulations for chemical injection in EOR projects. Low tension surfactant solution is the only liquid that could increase the dimensionless capillary number in order of magnitude of 10^3.

Two types of core samples have been used in core flooding experiments to develop capillary desaturation curves, i.e., generic and standard Classhach core samples. In Addition, VS surfactant and additional alcohols are also used in these experiments.

The higher the capillary number could generate a lower the residual oil saturation. Moreover, each rock may have a particular capillary desaturation curve depending on the rock properties. Therefore before implementing chemical injection in a pilot scale, capillary desaturation curve should be developed in laboratory to evaluate the surfactant injection performance.

*Key words**:** Capillary Number, Residual oil saturation, Surfactant injection*

I. INTRODUCTION

The residual oil saturation (ROS) in waterflood swept zones is a target for enhanced oil recovery processes. Chemical injection is the best option for low to medium reservoirs temperature and depth. Surfactant is surface active agent which is generally used in chemical flooding in terms of enhanced waterflood, SP (surfactant-polymer) flood, and ASP (alkaline-surfactant-polymer) flood. To determine the surfactant performance, CDC (Capillary desaturation curve) which depicts the relationship between ROS and capillary number (Nc) can be used. Nc is the ratio of viscous forces to capillary forces.

This dimensionless ratio of Nc has been given many expressions in the literature, where the most applied definitions are:

$Nc,_1 = ka\ \Delta P / L\sigma$

$Nc,_2 = V\mu/\sigma$

- ka = absolute permeability, (cm^2)
- ΔP = pressure drop across the core (pa)
- L = core length (cm)
- σ = interfacial tension (mN/m)
- V = apparent velocity (m/s)
- μ = viscosity of displacing fluid (Pa.s)

Capillary number is altered both by increase of viscous forces and by reducing capillary forces (lowering the interfacial tension, IFT), but the order of magnitude of the decreasing capillary force is much more pronounced compared to the increase of viscous force since the reduction of IFT could approach 10^{-3} mN/m.

The forces responsible for retaining oil in a porous medium are a complex function of viscous and capillary forces, and are influences of several parameters such as permeability, pore size distribution, wettability, saturations, fluid distribution and saturation history.[1] Critical capillary number, which is capillary number where the residual saturation after waterflood starts to decrease, is fairly constant even though transport properties, water flood ROS, and relative permeability are different. The average value of the critical capillary number defined as $(ka\ \Delta P/L\sigma)_{cr}$ was $(3.8\pm1.1)\times10^{-5}$. Moreover, with regard to wetting behavior, the critical capillary number is about one order of magnitude higher for oil-wet conditions than that under water-wet conditions.[2] In addition to that, the different rock properties may change the slope of the CDC.

CDC is normally developed to determine the relationship between capillary number and residual oil saturation during coreflood experiments. This paper discusses more detail the CDC development and the relationship between Nc and ROS to determine surfactant concentration that will be used as guidance for chemical injection.

II. EXPERIMENTAL

Core flooding experiments are the main works to construct CDC of the surfactant performance. However, some other preliminary works should be done before core flooding. Those works include reservoir fluid preparation, rock property determination, and surfactant screening.

A. *Reservoir Fluid Preparation*

Samples of formation water and oil were taken from Well-1 which were produced from the interest zone. The water content approximately 15.552 mg/L equivalent NaCl with high divalent ions such as Ca^{++} and Mg^{++}. Ca^{++} content is 297 mg/L and Mg^{++} 41 mg/L. The high divalent ions content should be considered in the surfactant selection.

The crude oil sample used was first analyzed for its physical and chemical characteristics, such as composition, specific gravity, viscosity, and density. These properties will be used to design the injected fluid. Viscosity of the oil is 0.63 cp at reservoir temperature (150°F), and gravity of 43.8°API.

B. *Rock Property*

A native core sample was taken from the interest zone. Two core plugs were drilled for core flood experiments. In addition to that, two core plugs of

Table 1
Petrophysical Properties

Core Data	Length (cm)	Diameter (cm)	Porosity (%)	PV (cc)	Ka (mD)	Kw (mD)
Native Core#1	7.33	3.67	20.19	15.66	45.00	2.46
Native Core#2	8.72	3.73	19.78	18.85	404.00	67.80
Classhach#1	7.55	3.76	18.20	15.24	450.00	68.80
Classhach#2	7.54	3.76	18.10	15.15	897.70	117.70

Table 2
Fluid Injection Design

Order	Native Core#1	Native Core#2	Classhach#1	Classhach#2
1	Water Flood	Water Flood	Water Flood	Water Flood
2	0.01 % VS	0.07 % VS	0.01 % VS	0.01 % VS
3	0.03% VS	0.05 % VS	0.03% VS	0.13 % VS Plus 0.10 % IAA
4	0.05 % VS	0.10 % VS	0.05 % VS	0.2 % VS Plus 0.10 % IAA
5	0.10 % VS	0.13 % VS Plus 0.10 % IAA	0.10 % VS	0.3 % VS Plus 0.10 % IAA
6	0.13 % VS Plus 0.10 % IBA	0.2 % VS Plus 0.10 % IAA	0.13 % VS Plus 0.10 % IAA	0.13 % VS Plus 0.20 % IBA
7	0.13 % VS Plus 0.10 % IAA		0.2 % VS Plus 0.10 % IAA	
8			0.3 % VS Plus 0.10 % IAA	

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Classhach standard core were prepared as well. These core samples were analyzed for their composition and rock mineral type by X-ray diffraction (XRD), and both types of core are classified as sandstone. The petrophysical properties are summarized in Table 1.

C. *Surfactant*

Surfactant used in this research is a commercial product and bought from market, namely VS. VS is an amphoteric surfactant which has a high surface active agent and soluble in water. Three types of alcohol also were used as in the fluid injection design i.e.: Iso Propyl Alcohol (IPA), Iso Butyl Alcohol (IBA), and Iso Amyl Alcohol (IAA). Alcohol is normally added into surfactant solution to reduce inter-

Table 3
Recovery Factor

Core Flood	RF of WF (%)	ROS (%)	RF of Chem. Flood (%)	RF Total (%)
Native Core#1	45.26	54.74	0.66	45.92
Native Core#2	69.26	30.74	8.92	78.18
Classhach#1	72.56	27.44	11.21	83.77
Classhach#2	70.98	29.02	15.18	86.16

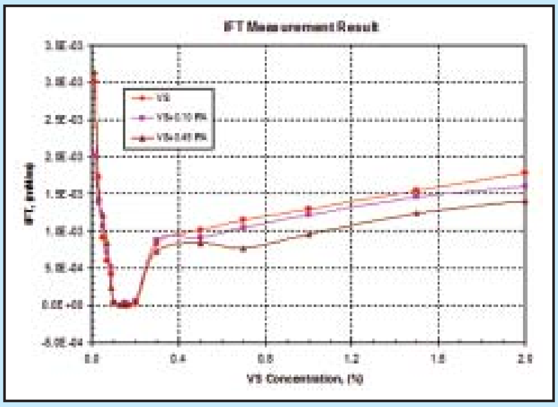

Figure 1
IFT of VS and VS plus IPA

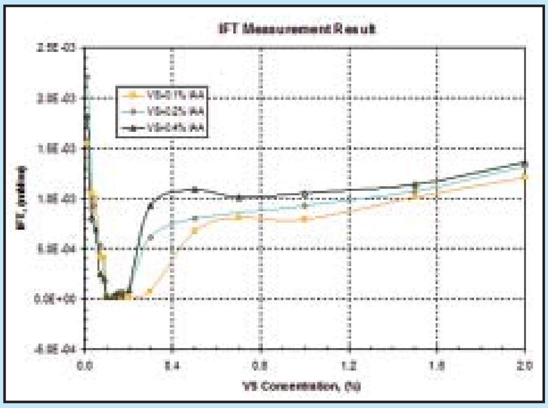

Figure 3
IFT of VS and VS plus IPA

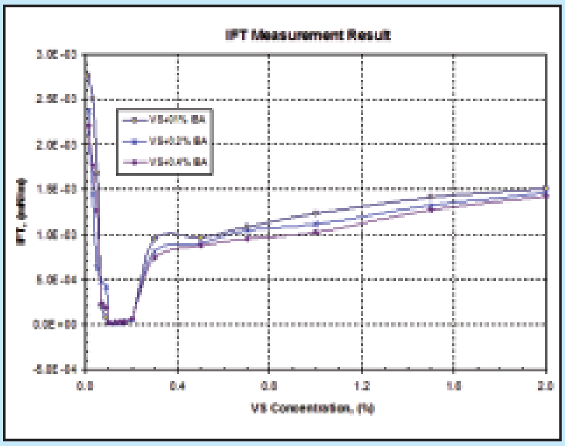

Figure 2
IFT of VS plus IBA

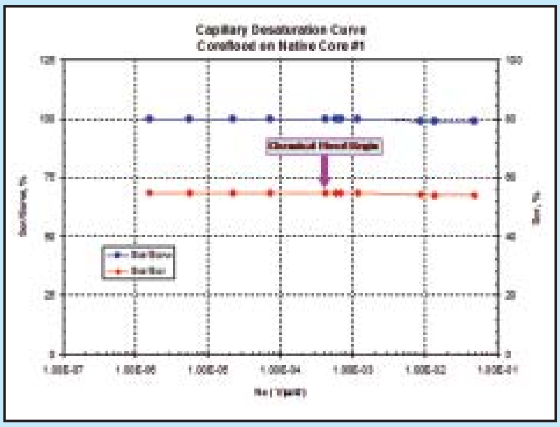

Figure 4
CDC of Native Core#1

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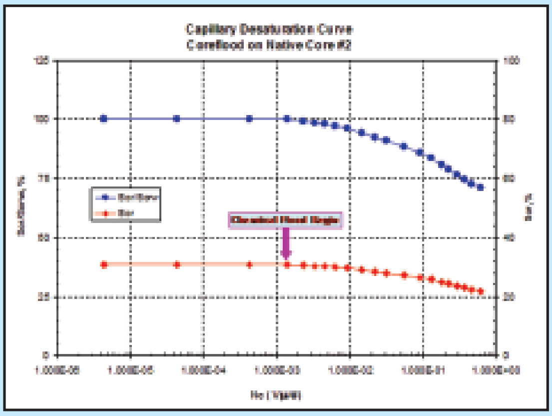

Figure 5
CDC of Native Core#2

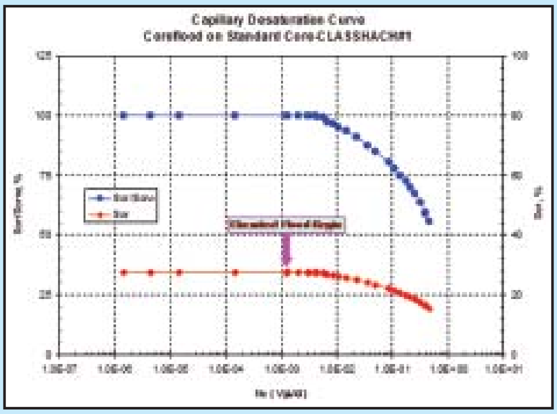

Figure 6
CDC of Classhach Core#1

facial tension. The surfactant solution is very clear and no precipitation indicated compatibility with the formation water. IFT measurements with the oil generate ultra low interfacial tension. Figures 1 to 3 show the IFT measurement of the surfactant as well as with additional alcohols.

D. *Fluid Injection Design*

Table 2 is detail of the fluid injection designs; the order of the injection fluids is summarized consecutively in column one based on descending order of IFT. The IFT value is the only criteria for selection of the injection fluids without considering the type of alcohol used.

E. *Flooding Procedure*

The water-saturated core was placed in the core holder. The core was first saturated with formation water to 100% S_w. The core was then flooded with the oil, until it reached the irreducible water saturation, S_{wi}. The core was then flooded with formation water as a secondary recovery. Water injection was terminated when oil production approached zero, so that the core reached its residual oil saturation (S_{or}). At the next stage successive surfactant injections as mentioned in Table 2 were done as an application of EOR. all parameters such as production, pressure, saturation, and time were read during flooding.

III. CDC CONSTRUCTION

A. *Native core#1*

Water flood on Native core#1 produced 45.24% recovery of oil, and oil left in core approximately was

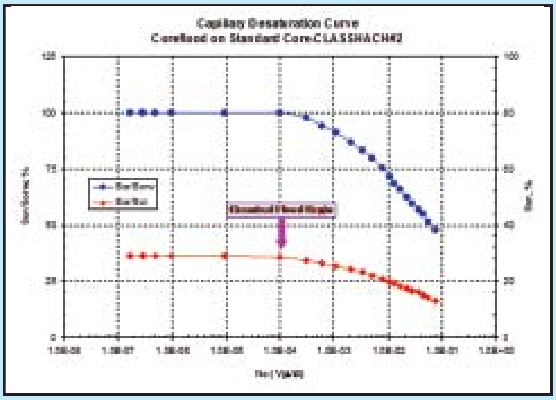

Figure 7
CDC of Classhach Core#2

around 45.26%. The consecutive surfactant floods only increased the additional oil recovery of 0.66%. The CDC is presented in Figure 4.

B. *Native Core#2*

Oil recovery factor of water flood was 69.26% while the successive surfactant floods made up the recovery to the level of 78.18% or 8.92% improvement. The CDC is presented in Figure 5.

C. *Classhach#1*

Initial water flood of this standard core Classhach#1 generated oil recovery of 72.56%, while the following surfactant floods improved additional oil recovery of 11.21%. The detail CDC is presented in Figure 6.

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D. Classhach#2

Water flood of standard core Classhach#2 could produce oil recovery of 70.98%, whereas the following surfactant floods improved additional oil recovery of 15.18%. The detail CDC is presented in Figure 7.

The complete core flood results are tabulated in Table 3, which is indicated that the lower permeability rock gives the lower water flood recovery factor. Similarly, the lower permeability rock also generates a smaller recovery factor when injected by surfactant flood.

Figures 4 to 7 summarize CDC of the surfactant floods. They also depict that CDC is not only influenced by the property of surfactant but also by rock properties such as permeability. The higher rock permeability gives higher recovery than the lower permeability. Based on the CDC, then, surfactant concentration for surfactant flood can be determined precisely with the consideration of the oil improvement recovery.

IV. CONCLUSIONS

1. Capillary desaturation curve is the appropriate tool to select surfactant concentration for chemical flood in EOR projects.
2. Surfactant solution could improve the dimensionless capillary number in order of magnitude of 10^3.
3. Higher the capillary numbers basically generate lower residual oil saturations, which 10^{-3} capillary number is the critical number in these experiments where reduction of residual oil saturation starts to occur.
4. Each typical rock may have a particular capillary desaturation curve depending on the rock properties especially rock permeability. Therefore before implemented chemical injection in a pilot scale, capillary desaturation curve should be developed in laboratory.

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