Solid State Science and Technology, Vol. 26, No 1 (2018) 271-277
ISSN 0128-7389 | *http://journal.masshp.net*

INTERFACIAL TENSION MEASUREMENT OF LIGHT OIL FROM FANG OILFIELD BY USING ALKALINE-POLYMER FLOODING

Pakorn Asavaritikrai and Kreangkrai Maneeintr

Carbon Capture, Storage and Utilization Research Laboratory,
Department of Mining and Petroleum Engineering,
Faculty of Engineering, Chulalongkorn University, THAILAND.

Corresponding author: pakorn435@hotmail.com

ABSTRACT

Enhanced oil recovery especially alkaline-polymer flooding is an essential technique to improve oil recovery. It involves injection of alkaline to reduce interfacial tension (IFT) between displacing and displaced phases and polymer to improve mobility ratio to produce more oil. In Fang oilfield, Thailand, light oil production can be increased by using chemicals to reduce IFT of oil and water. In this study, sodium hydroxide (NaOH) and hydrolyzed polyacrylamide (HPAM) are used as alkali and polymer, respectively to lower the IFT with various conditions. Therefore, the objective of this work is to measure the IFT and evaluate the effects of parameters such as concentration, pressure, temperature, and salinity on IFT reduction for oil from Thailand. The results present that concentration of chemical plays a key role for IFT reduction accounting for 99.49%. IFT reduces with the increase of temperature up to 49.30%. Pressure has less effect on IFT reduction. However, salinity can increase IFT for 94.74% at low alkali concentration while HPAM could be more benefit in other aspects such as the mobility control process. The results of this work can apply to increase more oil production for Fang oilfield with the optimum conditions.

Keywords: Enhanced oil recovery; interfacial tension; alkaline-polymer flooding; light oil

INTRODUCTION

In oil production, waterflooding is the most widely used method to increase oil recovery due to its low costs and simple operations [1]. However, a large amount of oil droplets (around 70% of the original oil in place (OOIP) [2]) are trapped by capillary forces. Using some chemicals such as alkaline, surfactant and polymer injected into the reservoir can bring those residual oil to the surface. Due to the high viscosity of the polymer solution, polymer flooding helps increase oil productivity by decreasing the mobility ratio of water to oil and increases the sweep efficiency. Also, with the long chain structure of polymer molecules, they are capable of dragging the residual oil out of the retention area and create steady oil channels to increase oil recovery [3]. Another interesting mechanism is that the adsorbed polymer molecules resist the flow of aqueous phase, thereby decreasing the water relative permeability [3]. Polymer that has been used widely is hydrolyzed polyacrylamide (HPAM) because of its price and large-scale production [4].

Another technique that has been used to enhance oil production is the alkaline-polymer (AP) flooding. It involves injection of alkaline that can react with the petroleum acid to form in situ surfactant. This surfactant can reduce the interfacial tension (IFT) between displacing and displaced phases and reduce the residual oil saturation, leading to the higher value of both sweep efficiency and displacement efficiency to produce more oil [5]. Several operating mechanisms on alkaline flooding were proposed. Johnson [6] summarized them into the following categories: (1) emulsification and entrainment, (2) emulsification and entrapment, (3) wettability reversal (oil-wet to water-wet), (4) wettability reversal (water-wet to oil-wet), and (5) emulsification and coalescence. The occurrence of each mechanism depends on various parameters of the system such as pH, acid number, salinity, pore structure, etc. At least the in-situ surfactant generation and emulsification appear on most of the mechanisms.

Polymers are believed to have little impact on the IFT [7]. However, when the polymer is added to the alkaline solution, they would work together to achieve the better performance. In Fang oilfield, Thailand, light oil production can be increased by using chemicals to reduce IFT of oil and water. In this study, sodium hydroxide (NaOH) and hydrolyzed polyacrylamide (HPAM) are used as alkali and polymer, respectively to lower the IFT with various conditions. Therefore, the objective of this work is to measure the IFT and evaluate the effects of parameters such as concentration, pressure, temperature, and salinity on IFT reduction for oil from Thailand.

EXPERIMENTAL

Chemicals

Oil sample is obtained from Fang oilfield, Thailand. The viscosity of oil is 145 cP with the acid number of 0.89 mg KOH/g. Simulated brine is prepared from distilled water with the mixture of sodium chloride and sodium bicarbonate purchased from Ajax at salinity of 500, 750 and 1,000 ppm. Sodium hydroxide is purchased from Ajax. Hydrolyzed polyacrylamide (HPAM) is obtained from Sigma-Aldrich.

Equipment

An interfacial tension apparatus, Model 700, Vinci Technologies, is used for this study. The maximum working pressure and temperature are 69 MPa (or 10,000 psi) and 180°C (or 350°F), respectively. The pressure inside the IFT cell is measured by a pressure gauge with 0.5 percent of span accuracy. Oil is fed to the system through a sample cylinder. The rising oil can be formed. The generated drop is detected with an accurate and calibrated video lens system and analyzed with Drop Analysis System software (DAS).

Experimental Procedures

To prepare the alkaline-polymer solution, 1,000 ppm of HPAM and 0.05 wt% of sodium hydroxide will be dissolved in the simulated brine at 750 ppm. The solution and the crude oil will be heated to 80°C. At the certain temperature, the density of the solution is measured by using the density meter. The alkaline-polymer solution would be injected to the IFT equipment together with the crude oil at 1,000 psig to measure the IFT. The results are obtained from the integrated software provided by the Vinci Company. Operating conditions are varied, i.e., the polymer concentration of 500, 1,000, and 2,000 ppm, the alkali concentration of 0.025, 0.05, 0.1 wt%, the temperature from 70 to 90°C, and the pressure of 500, 1,000, and 1,500 psi. NaCl and $NaHCO3$ would be added to the solution to make the salinity of 500, 750, and 1,000 ppm.

RESULTS AND DISCUSSION

Effects of Alkali Concentration

Figure 1 shows the effects of alkali concentration ranging from 0 to0.1 wt% and temperature from 70°C to 90°C on IFT reduction. It presents that alkali concentration can drastically reduce the IFT for 99.49%. It could be explained by the higher rate of in situ surfactant generation when the alkali concentration is higher which results in lowering the IFT. Moreover, IFT becomes less than 1 mN/m when the alkali concentration is more than 0.05 wt%. Beyond this concentration, IFT is almost stable because there are sufficient amount of in situ surfactant at the oil/water interface.

Effects of Temperature

Also, from Figure 1, temperature has the impact on the IFT because at the higher temperature, more in situ surfactant can be formed at the oil/water interface. According to Wei [8], increasing the temperature could increase the solubility of water in oil, which reduces the free energy between two immiscible fluids and thus decrease the IFT. From the results, IFT reduces with the increase of temperature up to 49.30%.

Effects of Polymer Concentration

Furthermore, the concentration of polymer (0 to 2,000 ppm) does not engage in the IFT reduction as shown in Figure 2. Increasing HPAM concentration tends to increase the IFT. The reason is that HPAM can react with NaOH and the polymer is hydrolyzed. So the alkali is consumed and its concentration decreases. The amount of in-situ surfactant then decreases and results in the higher IFT. The results corresponds to the study from Levitt et al. [9] that the extensive hydrolysis of HPAM will occur under alkaline conditions and significantly enhance the polymer's viscosity. So HPAM could be more benefit in other aspects such as the mobility control process. However, the increasing trend could not be observed at the alkali concentration of 0.1 wt% because the amount of alkali was high enough that it could generate the excess amount of in situ surfactant at the oil/water interface.

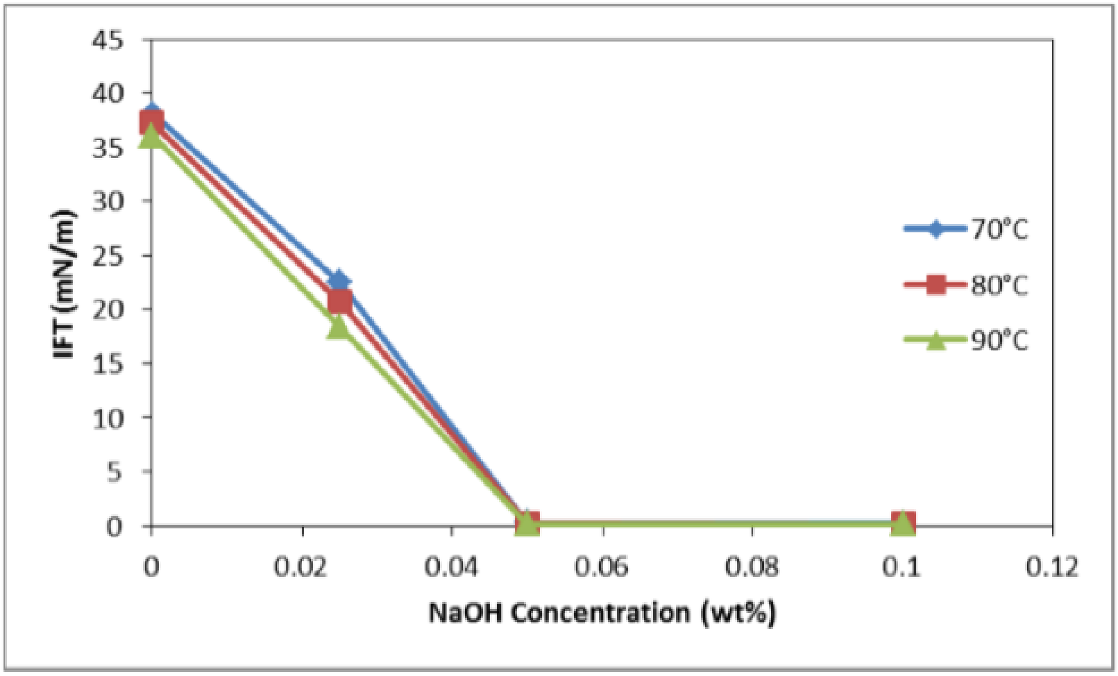

Figure 1: Effect of NaOH concentration on the IFT at various temperatures (Polymer concentration = 1,000 ppm, pressure = 1,000 psi, salinity = 750 ppm)

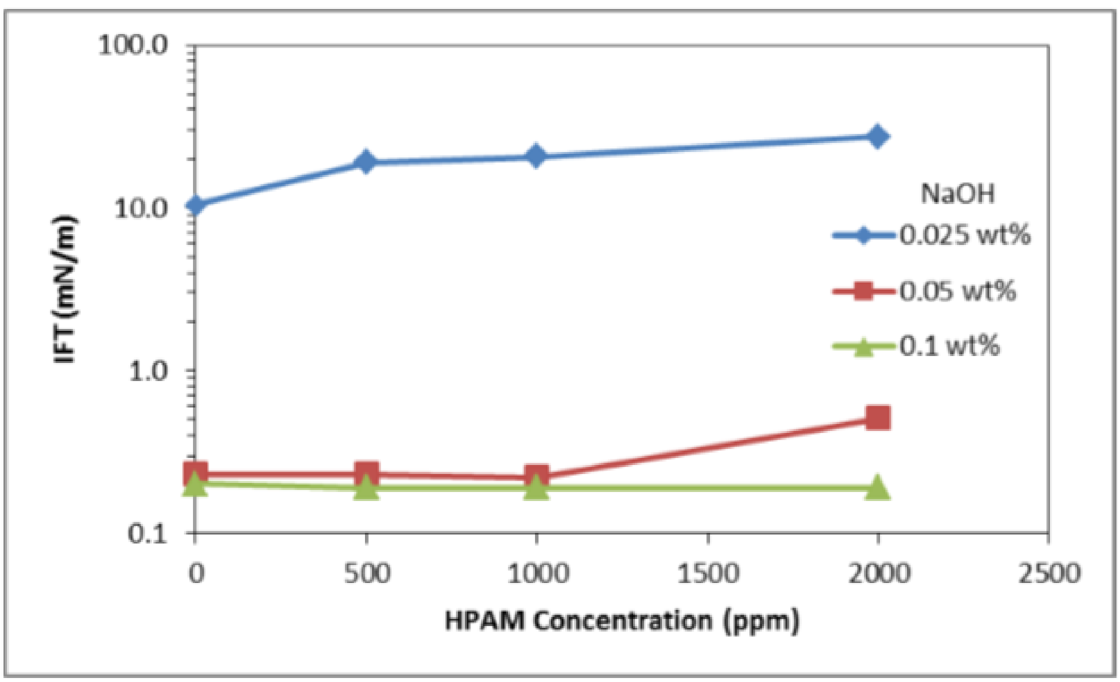

Figure 2: Effect of HPAM concentration on the IFT at various NaOH concentrations (Temperature = 80°C, pressure = 1,000 psi, salinity = 750 ppm)

Effects of Pressure

Pressure (500 to 1,500 psi) has small effect on the IFT. It can be observed from Figure 3 that the IFT does not change much when pressure changes. The reason is that the oil/water system which is liquid phase has high intermolecular force compared with the gas phase system so the IFT is not affected by the change of pressure. Hassan et al. [10] concluded that the IFT would slightly change with pressure at constant temperature in the range of 1 to 204 atm.

Effect of Salinity

Figure 4 shows the effect of salinity ranging from 500 to 1,000 ppm on the change of IFT. The IFT is increased with the higher salinity for low alkali concentrations. Salinity can increase IFT up to 94.74% at 70°C and 0.05 wt% of NaOH. According to Sheng [7], salt ions prevented negative charges on polymer's backbone from repelling one another. Since the charge is neutralized, the polymer structures are compressed. These compressed and neutralized polymers can interfere with the link between the nonpolar (hydrophobic) part of the in situ surfactant and oil so that the IFT is increased instead of decreased. However, at the highest alkali concentration, 0.1 wt%, the IFT is decreased with the increasing salinity. One mechanism that can explain this phenomenon is that when the amount of alkali is high, salt ions could impact on alkali rather than polymer. High salt charges could push more in situ surfactant to the oil/water interface, leading to the lower IFT.

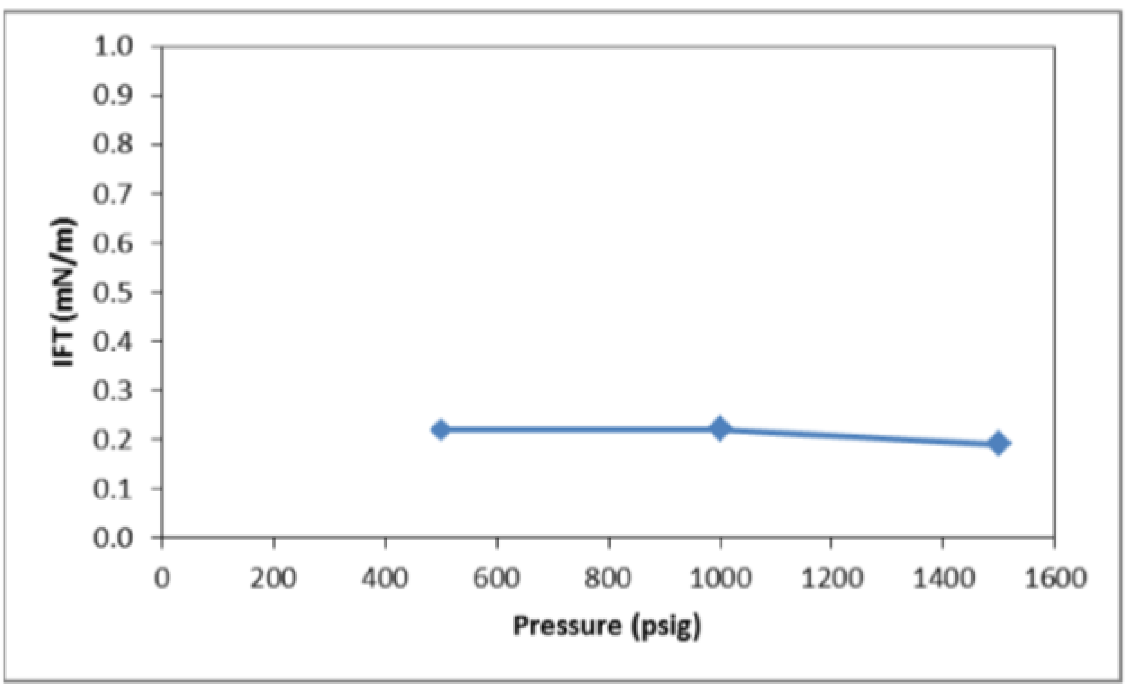

Figure 3: Effect of pressure on the IFT (NaOH concentration = 0.05 wt%, HPAM concentration = 1,000 ppm, temperature = 80°C, salinity = 750 ppm)

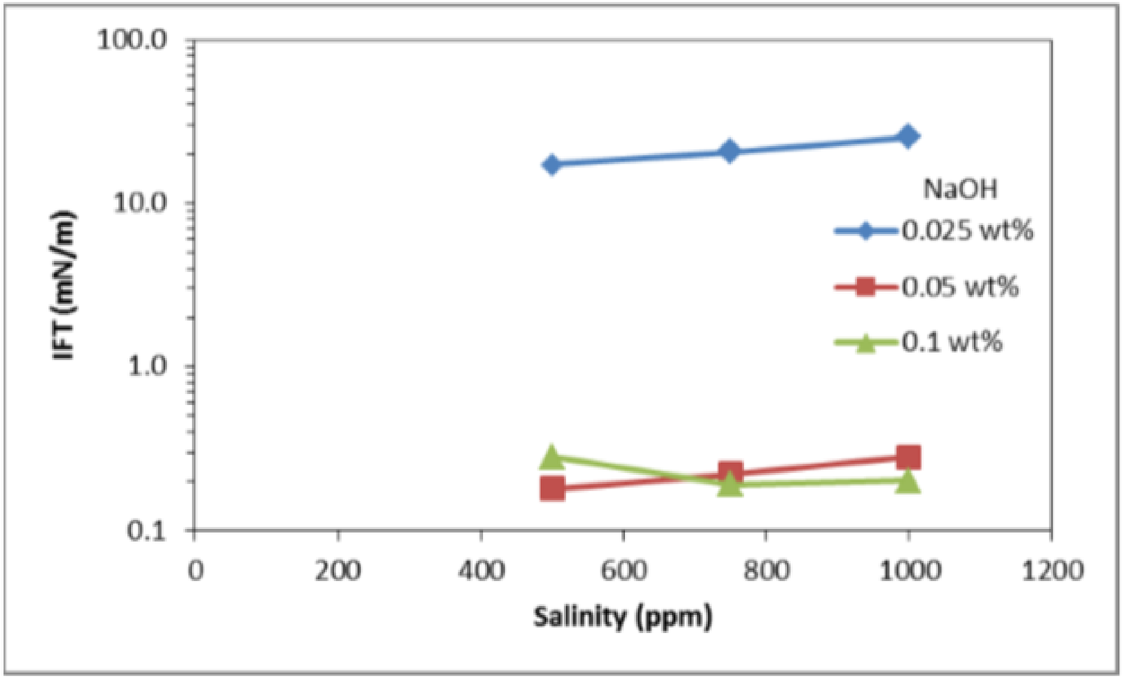

Figure 4: Effect of salinity on the IFT at various NaOH concentrations (HPAM concentration = 1,000 ppm, temperature = 80°C, pressure = 1,000 psi)

CONCLUSION

Effects of parameters such as concentration, pressure, temperature, and salinity on IFT of oil from Thailand and alkaline-polymer solution are investigated. The chemical concentration is the main factor for IFT reduction accounting for 99.49%. IFT reduces with the increase of temperature up to 49.30%. Polymer tends to increase IFT due to the alkaline consumption reaction. So polymer could be more benefit in other aspects such as the mobility control process. Pressure has less effect on IFT reduction. Salinity can increase IFT for 94.74% for low alkali concentrations, while decrease IFT for high alkali concentration. The results of this work can apply to increase more oil production with the optimum conditions.

ACKNOWLEDGMENT

The authors would like to gratefully acknowledge Chevron Thailand Exploration and Production Ltd., for financial support of this project.

REFERENCES

[1] M.H. Sedaghat, M.H. Ghazanfari, M. Masihi, D. Rashtchian *Journal of Petroleum Science and Engineering,* **108** 370-382 (2013)
[2] T. Doscher, F. Wise. *Journal of Petroleum Technology,* **28** 575-585 (1976)

[3] J. Wang, H. Liu. *Journal of Industrial and Engineering Chemistry*, **20** 656-667 (2014)
[4] J. J. Sheng (2013). Enhanced Oil Recovery: Field Case Studies. Gulf Professional Publishing.
[5] Z. Chen, X. Zhao, Z. Wang, M. Fu. *Colloids and Surfaces A: Physicochemical and Engineering Aspects*, **469** 150-157 (2015)
[6] C. Johnson Jr. *Journal of Petroleum Technology*, **28** 85-92 (1976)
[7] J. J. J. Sheng (2011). Modern Chemical Enhanced Oil Recovery: theory and practice. Gulf Professional Publishing.
[8] X. Wei (2005). Experimental Investigation of Dynamic Interfacial Interactions at Reservoir Conditions. Louisiana State University and Agricultural and Mechanical College.
[9] D. B. Levitt, G. A. Pope, S. Jouenne. *CSPE Reservoir Evaluation & Engineering*, **14** 281-286 (2011)
[10] M.E. Hassan, R.F. Nielsen, J.C. Calhoun. *Journal of Petroleum Technology*, 5 299- 306 (1953)