Low gas-liquid ratio foam flooding for conventional heavy oil

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Abstract: The recovery of heavy oil by water flooding is 10% lower than that of conventional crude oil, so enhanced oil recovery (EOR) is of great significance for heavy oil. In this paper, foam flooding with a gas-liquid ratio (GLR) of 0.2:1 for the Zhuangxi heavy oil (325 mPa·s at 55 °C) was performed on cores, sand packs and plate model. In sand pack tests, polymer enhanced foam flooding increased oil recovery by 39.8%, which was 11.4% higher than that for alkali/surfactant/polymer (ASP) flooding under the same conditions. Polymer enhanced foam flooding in plate models shows that the low GLR foam flooding increased oil recovery by about 30%, even when the extended water flooding was finished at 90% water cut. Moreover, it was discovered by microscopy that foam was more stable in heavy oil than in light oil. These results confirm that low GLR foam flooding is a promising technology for displacing conventional heavy oil.

Key word: Low gas-liquid ratio, foam flooding, enhanced oil recovery, conventional heavy oil

1 Introduction

Water drive heavy oil reservoirs are characterized by loosely consolidated sand with well-developed flow channels. Moreover, much oil is bypassed because of the high mobility ratio between the displacing fluids and oil (Abrams, 1975; Albartamani et al, 1999; Miller, 2006; Wassmuth et al, 2007; Mai et al, 2009; Aladasani and Bai, 2010). Generally speaking, the recoveries of water flooding for these reservoirs are at least lower 10% than those for conventional oil reservoirs (Bryan et al, 2008). So it is more important to improve sweep efficiency than microscopic displacement efficiency for the enhanced oil recovery (EOR) techniques suitable for heavy oil reservoirs.

Foam flooding as an EOR technique has been used for about 50 years. Because foam has higher apparent viscosity than the conventional displacing fluids, it is often used as a mobility control agent in conventional reservoirs (Llave et al, 1990; Li et al, 2008; Farajzadeh et al, 2009; Srivastava et al, 2009). With the development of high temperature resistant foaming agents, foam is becoming the main profile control agent in thermal recovery. Previous research has proved that foam can reduce the relative permeability of the injected chemical slug, increase the sweep efficiency and displacement efficiency of the displacing system, and thus increase oil recovery (Kang et al, 2010; Wang et al, 2001).

However, conventional foam flooding has two disadvantages. The high cost of gas injection is the first obstacle. The gas-liquid ratio (GLR) of the conventional foam flooding is generally required to be 1:1 (Yuan et al, 2004; Lin and Yang, 2006; Zhou et al, 2006; Li et al, 2009; Ren et al, 2009; Tang, 2009; Zhang et al, 2009). Assuming that the reservoir pressure is 10 MPa, the GLR under surface conditions should be nearly as large as 100:1. The production cost of nitrogen is at least 1.5 Yuan(RMB)/m³ (under standard conditions), and then 150 Yuan will be allocated for 1 m³ liquid displacing agent (about 50 Yuan). It can be seen that the cost of gas injection is a considerable part of the total cost of foam flooding. The second problem is the high injection pressure. Water-alternating-gas (WAG) injection is often used in field tests of foam flooding, nonetheless high injection pressure still remains. For example, in the pilot test of combined foam flooding in the Sabei North Block 2, Daqing Oilfield, the gas injection pressure was almost 10 MPa higher than that of water flooding (Chao, 2006), and the same phenomenon emerged in nitrogen enhanced foam flooding in well 28-8 drilled in the Gudao Middle Block 2, Shengli Oilfield (Zhang et al, 2005).

In view of the above-mentioned disadvantages of the conventional foam flood, whether the low GLR foam flooding in terms of simultaneous injection of water and gas can be carried out deserves further discussion. In the laboratory studies in China, the lowest GLR was 0.4:1 (Yuan et al, 2004) and low GLR foam flooding was overlooked as most attention had been paid on the evaluation of sealing characteristics and

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oil displacement performance of high GLR foam. However, the results of foam flooding field test in the Daqing Oilfield showed that though the real GLR was only 0.34:1 (designed GLR is 1:1), the oil recovery due to foam flood was still 25% higher than that due to water injection (Chao, 2006). This result confirms the feasibility of low GLR foam flooding in oilfields.

There is an amount of residual oil that is left in the reservoir after a water flooding program due to characteristics of heavy oil reservoirs. Whether the residual oil can affect the stability of foam or not is the key factor to successfully implement foam flooding in heavy oil reservoirs. Previous works proved that oil had a strong destabilizing effect on foam. Some research (Suffridge et al, 1989; Schramm and Novosada, 1990; Schramm et al, 1993; Vikingstad et al, 2006) found that alkanes with lower molecular weight offered a more adverse environment to foam. Wu et al (2008) evaluated the interactions between foam and Daqing crude oil, and discovered that the light oil containing less asphaltene and resin was more destructive to foam than heavy oil.

In this paper, the foam stability in the presence of different oils and the effect of low GLR foam flooding on the Zhuangxi heavy oil are investigated. This provides some guidance for the implementation of low GLR foam flooding in waterflooded heavy oil reservoirs.

2 Experimental

2.1 Materials

DS, a sulfonate surfactant synthesized in the laboratory, was used as a foamer. Partially hydrolyzed polyacrylamide (HPAM) with a molecular weight of $1,400 \times 10^4$ was obtained from the Beijing Hengju Chemical Group Company. Na_2CO_3 (analytical purity) was commercially available.

The oil was collected from well 106-15-18 drilled in the Zhuangxi heavy oil reservoir, Shengli Oilfield and its properties are listed in Table 1. The initial reservoir temperature is 55 °C. The salinity and composition of formation water collected from well 106-15-18 are shown in Table 2. Synthetic formation water was prepared with the reagent-grade chemicals based on the analysis of formation water. All solutions used were prepared with the synthetic formation water.

Table 1 Basic properties of the Zhuangxi heavy oil

Density (55 °C) g/cm ³	Viscosity (55 °C) mPa·s	Acid number mg KOH/g oil	Resin %	Asphaltene %
0.9302	325	0.80	19.7	0.835

Table 2 Analysis of the formation brine

Ion content, mg/L							Total salinity mg/L	pH value
$\text{K}^+ + \text{Na}^+$	Ca^{2+}	Mg^{2+}	SO_4^{2-}	CO_3^{2-}	HCO_3^-	Cl^-		
1751.0	103.0	11.1	47.4	23.7	602.2	2501.0	5039	8.35

Two foaming systems were used in the experiments. The

first consisted of 0.2wt% DS and 0.5wt% Na_2CO_3 ; the other was composed of 0.2wt% DS, 0.5wt% Na_2CO_3 , and 0.1wt% HPAM. The foam generated by the first foaming system is called ordinary foam and the foam generated by the second foaming system is named polymer enhanced foam.

The basic parameters of cores and sand packs used in displacement tests are given in Table 3. Ten core samples, each 15 cm long and 2.5 cm in diameter, were obtained from the Geological Scientific Research Institute of Shengli Oilfield. Three sand packs were prepared in linear sand pack cells (30 cm long and 2.5 cm in diameter) using 80-100 mesh quartz sand. In the process of packing the cells, the quartz sand was added in several increments. Deionized water was used to moisten the sand and the cells were gently vibrated to ensure a homogenous packing density. In this process, the water surface was kept above the sand surface to avoid the entrapment of air. All the cores and sand packs are water wet.

The plate model is a homogeneous sand-packed model 30cm×30cm×6cm. Fig. 1 is a schematic of the plate model. The injection well 3 and the production well 2 were located at diagonally opposite corners of the model. Wells 1, 5, and 4 were only used in the process of saturating the model with water or oil. The quartz sand used in this test was a mixture of quartz sand 100 mesh and 80-100 mesh with a weight ratio of 3:1. The plate model were prepared as follows: The plate model was filled with the mixed sand and fixed, then the water was injected from well 3 and produced from wells 1, 2, and 4 in turn, until the production rate of the three production wells was equal to the injection rate. The basic parameters of the plate model are listed in Table 3.

Fig. 1 A schematic of the plate model

2.2 Evaluation of foaming systems

2.2.1 Foaming ability and foam stability measurements

The Waring blender test was used to measure the properties of the two foaming systems. The procedure of this test was as follows: 100 mL of foaming solution was poured into a 1-liter Waring blender cup and stirred for exactly 1 minute at a speed of 2,000 rpm, then the resulting foam was immediately transferred into a 1,000 mL graduated cylinder. The initial foam volume in milliliters was recorded. The time required for the foam to drain out one half of its initial volume was recorded as the foam half-life.

2.2.2 Emulsification tests

Considering the characteristics of heavy oil, not only good foaming capacity but also excellent emulsification

Table 3 Basic parameters of cores/sand packs used in displacement tests

Run No.	Porous medium	Permeability to water $10^{-3} \mu\text{m}^2$	Porosity %	Initial oil saturation %	Chemical slug	GLR	Designed slug size PV
1	Core	450	21.20	86.2	Ordinary foam	0.1:1	1
2	Core	570	25.00	87.4	Ordinary foam	0.2:1	1
3	Core	558	24.87	86.7	Ordinary foam	0.3:1	1
4	Core	425	25.68	85.7	Ordinary foam	0.4:1	1
5	Core	425	24.87	87.6	Ordinary foam	0.5:1	1
6	Core	442	22.56	86.2	Ordinary foam	1:1	1
7	Core	558	25.82	85.3	Ordinary foam	2:1	1
8	Core	464	25.82	85.0	Ordinary foam	0.2:1	0.2
9	Core	442	23.92	87.1	Ordinary foam	0.2:1	0.4
10	Core	604	24.19	83.6	Ordinary foam	0.2:1	0.6
11	Sand pack	1273	39.17	81.4	Polymer enhanced foam	0.2:1	0.3
12	Sand pack	2058	39.11	89.2	Polymer enhanced foam	0.2:1	0.6
13	Sand pack	1998	39.11	86.8	ASP solution	—	0.3
14	Plate model	2780	43.11	84.6	Polymer enhanced foam	0.2:1	0.3

capacity is required for a foaming system. This performance was evaluated by the instability index (ISI). The procedure of this test is as follows: 5 mL foaming solution and 5 mL crude oil were poured into a graduated test tube (10 mL), then the tube was sealed with a glass stopper and oscillated up and down 50 times, then the tube was immediately put into a constant temperature water bath vertically and timing started. The volume in milliliters of aqueous phase separated from the test emulsion formed from the oil and foaming solution was recorded every 2 minute for 30 minutes, curves between aqueous phase and time were plotted, and the ISI was calculated as follows:

$$ISI = \int_0^t V(t) dt / t \quad (1)$$

where ISI is the instability index, mL; t is the separation time of the emulsion system, min; $V(t)$ is the functional

relationship between the volume of aqueous phase separated from the emulsion and the separation time of the emulsion.

2.2.3 Interfacial tension measurements

The oil-water interfacial tensions (IFTs) were determined with a Texas-500 spinning drop interfacial tensionmeter (USA). Equipped with an image capture device and image acquisition software, this instrument can automatically record the dynamic interfacial tension.

2.3 Physical simulation experiments

Schematics of displacement tests in cores and plate model are shown in Figs. 2 and 3, respectively.

A 201-FKASVBAA gas mass flow meter, produced by Parker Hannifin Company, America, was used to control the flow rate of gas accurately in the experiments. Its highest resistant pressure was 6 MPa and the flow-rate range was 0-50 mL/min under standard conditions.

Fig. 2 A schematic of displacement apparatus for the 1-D physical model

1-Nitrogen cylinder, 2-Booster pump, 3-High-pressure nitrogen cylinder, 4-Gas mass flow control system, 5-Constant flow pump, 6-Thermostatic chamber, 7-Oil cylinder, 8-Water cylinder, 9-Foam generator, 10-Vent valve, 11-Core/sand pack holder, 12-Back pressure valve, 13-Fluid measuring system, 14-Hand pump

Fig. 3 A schematic of displacement apparatus for the plate model

1-Nitrogen cylinder, 2-Booster pump, 3-High-pressure nitrogen cylinder, 4-Gas mass flow control system, 5-Constant flow pump, 6-Thermostatic chamber, 7-Oil cylinder, 8-Water cylinder, 9-Foam generator, 10-Vent valve, 11-Plate model, 12-Back pressure valve, 13-Fluid measuring system, 14-Pressure acquisition system, 15-Hand pump

The procedure of displacement tests is as follows: 1) The core (or plate model) was saturated with synthesized formation water at room temperature to determine its permeability and pore volume; 2) The core was saturated with oil at 55 °C to measure its initial oil saturation; 3) Synthetic formation water was pumped into the core to displace oil until the water cut of produced fluids reached 98%; 4) A specified volume of chemical flooding system was injected into the core, and the synthetic formation water was subsequently pumped into the core until the water cut of produced fluids reached 98%. In foam flooding tests, this step was carried out as follows: firstly aqueous surfactant solution and nitrogen were added in a foam generator at a desired rate, and the vent valve was opened under certain back pressure until uniform foam was generated; secondly the vent valve was closed and the uniform foam was injected into the core to mobilize oil; and finally water was pumped to displace the oil until the water cut of produced fluids reached 98%. 5) The oil recovery and water cut during the displacement were calculated.

In displacement tests, the injection rate of liquid was 1.0 mL/min and the back pressure was fixed at 2 MPa unless otherwise specified.

In foam flooding tests, the liquid flow rate was kept constant and it is necessary to convert the gas flow rate under standard conditions into the value at the inlet pressure. The gas-liquid ratio (GLR) during the experiments is calculated as follows:

$$GLR = \frac{Q_g}{10PQ_l} \quad (2)$$

where Q_g is the gas flow rate under standard conditions, mL/min; Q_l is the liquid flow rate, mL/min; P is the inlet pressure, MPa.

2.4 Microscopic oil displacement experiments

Fig. 4 shows the experimental set-up used to visualize

the foam/oil interaction. This apparatus consisted of a glass etched micromodel with pore sizes of 50-800 μm , a microscope, a digital video camera, a pressure transducer, an injection pump etc.

Each experiment was conducted at 55 °C. A clean micro-model was first saturated with synthetic formation water, and then saturated with the heavy oil. The oil displacement started with the injection of foam and stopped when the foam was in full contact with oil. Meanwhile, video of interface between foam and oil was recorded and the effect of crude oil on foam stability was analyzed.

3 Results and discussion

3.1 Performance of foaming systems

The foaming performance and emulsification capacity of the two foaming systems used in the study are listed in Table 4.

Table 4 Performance of the foaming systems

Foaming system	Foaming performance		Emulsification capacity
	Foam volume mL	Half-life min	ISI mL
0.2wt% DS+0.5wt% Na_2CO_3	650	3.49	0
0.2wt% DS+0.5wt% Na_2CO_3 +0.1wt% HPAM	600	13	0

The foaming performance of the two foaming systems shows that a more stable foam can be achieved by using 0.1wt% HPAM. This is because the addition of HPAM increased the viscosity of the liquid films between bubbles. The drainage rate of the foam was decreased and the rate of the gas diffusion between bubbles was reduced (Shen et al, 2006).

Oil displacement system with a low instability index can

Fig. 4 A schematic of the micromodel apparatus

emulsify oil easily, so the oil remained in the swept area will be flooded out. The ISI of the emulsions generated from the foaming systems and Zhuangxi heavy oil were zero. This result indicates that both foaming systems exhibited good emulsification performance.

To examine the interaction of alkali and surfactant, the dynamic interfacial tensions of heavy oil and brine were measured for systems containing 0.2wt% DS, 0.2wt% DS+0.5wt% Na_2CO_3 , and 0.2wt% DS+0.5wt% Na_2CO_3 +0.1wt% HPAM. Fig. 5 shows the interfacial tensions between the Zhuangxi heavy oil and three aqueous solutions as a function of time. The results show that the dynamic interfacial tension was reduced by nearly one order of magnitude with the addition of 0.5wt% Na_2CO_3 . This indicates that alkali had a synergistic effect with surfactant on lowering interfacial tension. Although the addition of HPAM led to an increase in the interfacial tension of oil and brine, interfacial tension could be still reduced to the order of 10^{-3} mN/m.

Fig. 5 Dynamic interfacial tension between aqueous solutions and Zhuangxi heavy oil (at 55 °C)

3.2 Stability of foam in heavy oil

Taking 0.2wt% DS+0.5wt% Na_2CO_3 +0.1wt% HPAM as the foaming system, this paper presents a microscopic study of foam stability in different oils, as shown in Figs. 6 and 7. It is discovered that the foam stability and the way of bubbles coalescing in heavy oil are completely different from those in diesel oil.

Figs. 6 and 7 show that the foam is much more stable in heavy oil than in diesel oil. The time required for three sizable bubbles to coalesce to a large bubble in heavy oil was four times longer than that in diesel oil. That is because the asphaltene and resin molecules in heavy oil are much larger than the molecules in diesel oil. The diesel oil may easily penetrate into micellar aggregates that deplete surfactant molecules from the gas/liquid interface while the heavy oil is less likely to enter aggregates due to large asphaltene and resin molecules in it.

The way of bubbles coalescing in heavy oil is that small bubbles become smaller and big bubbles become bigger until the smaller ones disappear completely. However, bubbles in diesel mainly undergo rapid pairwise coalescence, the mechanism of which is difficult to distinguish.

3.3 Core and sand pack displacement tests

3.3.1 The effect of GLR

In order to evaluate the effect of gas-liquid ratio on the recovery efficiency of foam injected into the core, seven foam displacement tests (Runs 1 to 7 in Table 3) were performed on cores at different gas-liquid ratios (ranging from 0.1:1 to 2:1). Fig. 8 shows the core inlet pressure for Run 2. It can be seen that the pressure rose gradually after foam injection. This indicates that most of the foam went into and then effectively plugged the water channels formed during water flooding. The injection rates of the foaming solution and gas were kept constant in the whole process of foam injection. The ratio of gas to liquid was set to be 0.2:1 based on the inlet pressure at the end of water flooding. Therefore, the real gas-liquid ratio (calculated from Eq. (2)) in the porous media decreased

Fig. 6 Bubble coalescence in diesel oil

Fig. 7 Bubble coalescence in heavy oil

with the increase of the injection pressure and may be far less than 0.2. However, the oil production curve (Fig. 9) indicates that the oil recovery increased by 26.2% and the water cut decreased by 28% after foam flooding. This result confirms that although the real gas-liquid ratio was lower than 0.2:1, the effect of foam flooding on oil recovery is obvious.

Fig. 8 The change of real GLR and inlet pressure during foam injection (designed GLR was 0.2:1)

Fig. 9 Oil production curves of foam flooding with GLR of 0.2:1 (1.17 pore volumes (PV))

The oil production curves of seven core displacement tests (Fig. 10) shows that the oil recovery increased rapidly with the injection of foam after water flooding. The recovery increment becomes higher with the increase in the gas-liquid ratio.

The curves of tertiary oil recovery versus GLR for these seven flooding tests are plotted in Fig. 11. It shows that when the GLR was below 0.5:1, the oil recovery increased drastically with the increase in GLR. When the GLR was above 1:1, the increase in GLR only resulted in a small incremental recovery. This is because when the GLR increased from 0.1:1 to 0.5:1, more bubbles would be generated in the porous media leading to stronger blocking effect. However, when the GLR continued to increase, the gas breakthrough occurred, and the EOR effect of foam flooding became poor.

3.3.2 The effect of slug size

Maintaining the GLR at 0.2:1, the effect of foam slug size was evaluated. Taking 0.2wt% DS+0.5wt% Na_2CO_3 as the foaming system, the slug size was varied from 0.2 pore volume (PV) in Run 8, to 0.4 PV in Run 9, to 0.6 PV in Run 10, and to 1.0 PV in Run 2. Taking 0.2wt% DS+0.5wt% Na_2CO_3 +0.1wt% HPAM as the foaming system, the slug size was varied from 0.3 PV in Run 11, to 0.6 PV in Run 12 (see Table 3). The results of these core flood tests are listed in Table 5. Table 5 indicates that a large slug size led to a high oil recovery increment. The polymer enhanced foam had better displacement efficiency than the foam system without adding polymer. Polymer enhanced foam flooding achieved a high oil recovery increment even using a small foam slug.

An alkali/surfactant/polymer (ASP) flood (0.2wt% DS+0.1wt% HPAM+0.5wt% Na_2CO_3) test was conducted and its result was compared with the results from polymer enhanced foam flood test. Figs. 12 and 13 show that the polymer enhanced foam improved oil recovery by about 39.8% while the ASP flood improved oil recovery by about 28.4%. The oil recovery increment of foam flooding

Fig. 10 Cumulative oil recovery curves of foam flooding with different GLRs (1 PV)

Fig. 11 Effect of gas-liquid ratio on oil recovery increment of foam flooding (1 PV)

Table 5 The effect of foam injection volume on oil displacement efficiency

Chemical slug	Real GLR	Slug size PV	Oil recovery in water flooding operation, %	Oil recovery increment after water flooding, %
Ordinary foam	0.2:1-0.16:1	0.2	44.43	13.9
	0.2:1-0.15:1	0.4	44.44	15.0
	0.21:1-0.12:1	0.6	44.30	18.1
	0.22:1-0.13:1	1	40.89	26.2
Polymer enhanced foam	0.23:1-0.17:1	0.3	42.98	39.8
	0.22:1-0.16:1	0.6	41.76	40.0

Fig. 12 Oil production curves of polymer enhanced foam flooding with GLR of 0.2:1 (0.32 PV) **Fig. 14** Oil production curves of polymer enhanced foam flooding with GLR of 0.2:1 (0.3 PV) **Fig. 13** Oil production curves of ASP flooding (0.31 PV)

was 11.4% higher than the latter. Compared with the ASP flood, the polymer enhanced foam has a better plugging capacity due to its higher apparent viscosity and higher foam stability. Moreover, our previous study of the microscopic oil displacement mechanism of foam flood and ASP flood for heavy oil (Pei et al, 2010) shows that polymer enhanced foam flooding achieves a higher sweep efficiency due to the Jamin effect, and the deformation of foam in the porous medium

causes a extrusion and entrainment effect on the residual oil, which enhance the displacement efficiency of the foam flooding further. This demonstrates a great potential of low GLR foam flooding for the Zhuangxi heavy oil.

3.4 Foam flooding in plate models

A sand pack can be regarded as a one-dimensional model. To verify the capability of low GLR foam to improve sweep efficiency, a physical simulation was further carried out in plate models with polymer enhanced foam (theoretical GLR was 0.2:1, foam slug was 0.3 PV).

Fig. 14 is the oil production curve when water and gas were injected simultaneously. It indicates that after water flooding, the low GLR foam would significantly reduce the water cut of produced fluids and improve oil recovery by about 30%.

Figs. 15-17 show the oil distribution in different sections of the sand pack at the end of subsequent water injection. These figures indicate that oil saturation at the bottom of the model was markedly lower than that in the upper section due to the gravitational differentiation. Both sides of the main diagonal line where the injection and production wells were located had low oil saturation, but there were much remaining oil on both sides of the other diagonal line. The test was

Fig. 15 Oil distribution on the bottom of the sand pack

Fig. 16 Oil distribution on the section about 1 cm from the bottom of the sand pack

Fig. 17 Oil distribution on the section about 2 cm from the bottom of the sand pack

finished when the water cut was 90%, and the oil recovery increment was about 30%. It can be seen from these figures, continuing water injection would improve oil recovery further.

4 Conclusions

1) For the Zhuangxi heavy oil (325 mPa·s at 55 °C), foam displacement tests show that the incremental oil recovery became higher with the increase in gas-liquid ratio (GLR). When the GLR was above 0.5:1, its increase only resulted in a small incremental oil recovery.

2) Sand pack tests indicate that polymer enhanced foam flooding with a GLR of 0.2:1 improved the oil recovery by 39.8%, which is 11% higher than that of ASP flooding under the same conditions.

3) Polymer enhanced foam flooding with a GLR of 0.2:1 in the plate model shows that there is gravitational differentiation in the model during flooding. Although the extended water flooding ended when the water cut was 90%, the low GLR foam flooding improved oil recovery by about 30%.

4) Microscopic visualization experiments show that foam in the heavy oil is much stable than in light oil, and the way bubbles coalesce in the heavy oil is different from that in diesel oil.

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