CO₂-Low Interfacial Tension Viscoelastic Fluid Synergistic Flooding in Tight Reservoirs

Longlong Chen, Xinwei Liao, Shanfa Tang, Shuyun Feng,* Ruijia Tang, Shaojing Jiang, and Yuanwu Dong

ABSTRACT: Tight oil reservoirs have poor physical properties, insufficient formation energy, and low natural productivity. CO₂ flooding is an important technical mean that enhances the oil recovery of dense reservoirs and achieves effective CO₂ sequestration, but strong heterogeneity of the tight oil reservoir usually results in gas channeling and poor enhanced oil recovery effect. The existing methods to prevent gas channeling are mainly to use the small-molecule amine system and the polymer gel system to plug fracture and high permeability channels. The small-molecular amine system has low flash points and pollutes the environment and the polymer gel has poor injectivity and great damage to the formation, which limit their large-scale application. Therefore, a new viewpoint of CO₂-low interfacial tension viscoelastic fluid synergistic flooding for enhanced oil recovery in a tight oil reservoir was made. The performance of low interfacial tension viscoelastic fluid (GOBT) was studied. The injectivity and oil displacement effect of CO₂-GOBT synergistic flooding were evaluated, and the mechanism of CO₂-GOBT synergistic flooding was discussed. The experimental results showed that 0.4% GOBT is a low interfacial tension viscoelastic fluid, which has strong adaptability to the salinity water of tight oil reservoirs (6788−80,000 mg/L), good viscosity stability at different pHs, excellent capacity to emulsify crude oil, and the ability to improve reservoir water wettability. CO₂ alternating 0.4% GOBT flooding has good injection ability in cores (Kf = 0.249 mD), and injecting 0.4% GOBT can effectively increase the injection pressure of subsequent CO₂ flooding. CO₂ alternating 0.4% GOBT flooding can effectively improve water flooding recovery in tight sandstone reservoirs, which is better than CO₂ flooding and 0.4% GOBT flooding in both homogeneous and heterogeneous conditions. The mechanisms of CO₂ alternating 0.4% GOBT flooding to enhance the oil recovery include that GOBT and CO₂ foam block high permeability layers, shunt and sweep low permeability layers, and GOBT emulsify and wash oil. CO₂ partially dissolving in GOBT synergistically enhances the core water wettability, which improves GOBT injectability, emulsification, and stripping ability to residual oil.

1. INTRODUCTION

Tight oil reservoir is characterized by low porosity, low permeability, conspicuous interface effect between fluid and rock, and poor reservoir fluid mobility.1−4 and injecting gas,5−7 active water,8−10 and low salinity water11 are effective methods to improve its oil recovery. The gas injection can replenish reservoir energy, reduce oil viscosity, expand crude oil, and improve oil mobility;12 this is the main choice for the development of tight reservoirs. CO₂ flooding is the most ideal way, which can realize underground storage to effectively reduce carbon emissions and has good economic and social benefits.13−14 However, the existence of fractures and large pore channels easily leads to gas channeling during CO₂ injection, which limits the swept volume of CO₂ flooding and enhanced oil recovery (EOR) effect.15−19 Hence, scholars have explored water alternating gas, foam, and gel technologies to regulate and control cracks, delay gas channeling, and improve the aspirating profile.20−23 The strong heterogeneity or high permeability grade difference in the tight oil reservoir more easily leads to ineffective water−gas alternating injection, and the remaining oil in the low permeability layer cannot be started.24 CO₂ foam flooding has a better EOR effect than water alternating gas flooding, and microbubble is more stable, but CO₂ foam can only meet the plugging and shunting requirements of heterogeneous cores with low permeability, micron-size cracks (40−83 μm), and...
permeability grade difference below 30.23–26 Natural polymers (starch, cellulose) and synthetic polymer gels have good plugging performance in tight fractured reservoirs (≥0.1 mD), but there are some deficiencies in the fracture width adaptability (0.08–0.65 mm), higher viscosity of the initial injection fluid, and long gel reaction time (6–20 h) in the reservoir.27–30 Surfactants can be adsorbed on solid—liquid, liquid—liquid, and gas—liquid interfaces to change the wettability of the reservoir rock surface, reduce the interfacial tension between oil and water, emulsify crude oil, and form foam to improve the oil recovery.31–33 In particular, viscoelastic surfactant or viscoelastic fluid flooding has a function similar to the combination flooding of the surfactant and the polymer, and good injectivity due to the small molecular weight of the surfactant can improve the water injection sweep volume and displacement efficiency and enhance the oil recovery by 10–20% and is an attractive new technology for EOR.34–37 However, the existing viscoelastic fluid displacement system is complex and has the possibility of chromatographic separation. It is more important that there is no literature report on viscoelastic fluid synergetic flooding in tight reservoirs according to the deficiency of existing CO2 flooding technology and the excellent performance of low interfacial tension viscoelastic fluid flooding. The synergistic displacement oil of CO2 and low interfacial tension viscoelastic fluid can be carried out by injecting CO2 and low interfacial tension viscoelastic fluid into the reservoir alternately at a smaller slug size, so as to realize the synergistic effect of CO2 and viscoelastic fluid flooding with low interfacial tension to improve tight oil recovery.

In this paper, the CO2 and low interfacial tension viscoelastic fluid synergetic oil displacement effect and mechanism were studied by rheological properties, interfacial activity, wettability tests, and core flooding experiments. The injectivity and cooperative displacing oil effect of CO2 and the low interfacial tension viscoelastic fluid (GOBT) in tight reservoir cores were systematically studied, which enriched the EOR technology and theory of heterogeneous tight reservoirs.

2. RESULTS AND DISCUSSION

2.1. Performance of GOBT. 2.1.1. Basic Performance and Influencing Factors of GOBT. 2.1.1.1. Basic Performance. The basic properties of GOBT with different concentrations are shown in Table 1. As shown in Table 1, the viscosity of GOBT gradually increased with an increase in GOBT concentration, but the interfacial tension and \( \tan \delta \) values decreased, which indicates that the interfacial activity and elasticity enhanced. When the GOBT concentration was 0.4%, its viscosity reached 3.42 mPa·s at a reservoir temperature of 47.2 °C which is the approximate crude oil viscosity of the oil reservoir (3.4 mPa·s), \( \tan \delta = 0.5992 \times 1 \), and the oil–water interfacial tension of 0.4% GOBT was \( 2.31 \times 10^{-2} \text{ mN/m} \) which is in the low interfacial tension range. Thus, 0.4% GOBT is indeed a low interfacial tension viscoelastic fluid, and the mobility ratio with the formation crude oil is close to 1. That means 0.4% GOBT had good mobility adjustment ability when injected into heterogeneous tight oil reservoirs and had the potential for preventing CO2 gas channeling.

2.1.1.2. Influencing Factors. The effect of salinity on the basic performance of 0.4% GOBT is shown in Figures 1, 2 and Table 2. As can be seen from Figure 1, the viscosity of 0.4% GOBT decreased slightly with the increase of salinity, and the reduction rate was less than 6.1%. This illustrated that the change of salinity had little effect on the viscosity of 0.4% GOBT. As shown in Figure 2, when the salinity is increased from 6788 to 80,000 mg/L, the interfacial tension between 0.4% GOBT and crude oil has little change (2.16–2.54 \( \times 10^{-2} \text{ mN/m} \)) and always remains in the low interfacial tension range (\( 10^{-2} \text{ mN/m} \)). According to the data in Table 2, the \( \tan \delta \) value of 0.4%
GOBT fluctuated with the increase of salinity but was always less than 1.

In other words, GOBT always belongs to a viscoelastic fluid that is mainly elastic in the range of experimental salinity. In summary, the salinity had a slight effect on the viscosity, interfacial activity, and viscoelasticity of 0.4% GOBT, indicating that GOBT has good salinity (6788–80,000 mg/L) adaptability.

The effect of CO2 dissolving in 0.4% GOBT on its pH value and viscosity was investigated. The experimental results are shown in Table 3. It can be seen from Table 3 that under the pressure of 0.1MPa, as the time of CO2 dissolving in the GOBT increases, the pH value of GOBT gradually decreased from 8.5 and stabilized at 5.4, but the viscosity only shows a downward trend. This phenomenon indicated that CO2 dissolves in GOBT and reduces the pH value, resulting in a slight decrease in viscosity. The in-depth analysis found that the viscosity of 0.4% GOBT was mildly affected by pH, and the viscosity reduction rate was only 6.7%.

2.1.2. Other Performance of GOBT. 2.1.2.1. Effect of GOBT on the Wettability of the Reservoir Core. The test results of the water and oil contact angles of the reservoir core are shown in Figure 3. The water phase wetting angle on the core surface decreased from 45° to 8.4°, meaning the core became more hydrophilic. Inversely, the oil phase wetting angle on the core surface increased from 17.9° to 24.2°, that is, the core soaked by 0.4% GOBT becomes relatively less lipophilic. In a word, the core became more hydrophilic after soaking with 0.4% GOBT. In other words, when injecting 0.4% GOBT into the tight reservoir, the surface of pore media changed to more hydrophilic and the adhesion force of pore surface to oil is reduced, which will be beneficial to the injection of viscoelastic fluid and the start-up and stripping of residual oil in pores, as well as the improvement of the recovery degree.

2.1.2.2. Emulsifying Performance of GOBT. The dehydration rate is listed in Table 4. With the increase of the emulsion standing time, the dehydration rate of the emulsion gradually increased under different oil–water ratios (from 3:7 to 1:1 and 7:3), but the growth rate of the dehydration rate was obviously different. For example, with the increase of the oil–water ratio, the water separation rate increased from 0 to 6.67% and finally reached 42.8% after the emulsion stood for 5 min, which illustrated that GOBT has an emulsifying effect on crude oil, but the emulsion stability is obviously affected by the oil–water ratio. A high oil–water ratio is not conducive to the emulsification of oil–water by GOBT and emulsion stability, such as 7:3. This phenomenon was attributed to the presence of the unique micellar structure of GOBT and surface hydrophilic groups. The GOBT is similar to a hydrophilic emulsifier and tends to form oil-in-water emulsions. On the contrary, a high oil–water ratio (>50%) is easier to form water-in-oil emulsions, so emulsion formation is more difficult and unstable.

2.2. CO2-GOBT Alternating Injectivity Experiment. The permeability of the tight oil reservoir core selected for the injection experiment was 0.249 mD, and the experimental results are shown in Figure 4. First, CO2 was injected steadily at a low injection pressure, and then 0.4% GOBT viscoelastic fluid was injected until the injection pressure gradually increased to 3.01 MPa and stays stable; finally, CO2 was injected again, and the final injection pressure stabilized at 2.58 MPa, indicating that CO2 alternating 0.4% GOBT flooding has good injectability and the stable pressure can be reached at different injection stages. In addition, it is known from the change of CO2 injection pressure before and after the injection of 0.4% GOBT that the GOBT not only has good injection performance in tight reservoirs but also can effectively plug the pore throat and improve the sweep ability of subsequent CO2 flooding.

2.3. Effect of CO2-GOBT Synergistic Flooding. 2.3.1. Homogeneous Core Flooding. The CO2 flooding, 0.3PV 0.4% GOBT flooding and subsequent water flooding, and CO2 alternating 0.4% GOBT flooding (0.3PV alternating four cycles)

Table 2. Effect of Salinity on the Viscoelasticity of 0.4% GOBT at 47.2 °C

| Salinity/mg·L⁻¹ | tan δ | Elasticity or Viscosity |
|-----------------|-------|------------------------|
| 6788            | 0.5992| elasticity             |
| 10,000          | 0.5348| elasticity             |
| 20,000          | 0.7127| elasticity             |
| 40,000          | 0.6904| elasticity             |
| 60,000          | 0.4976| elasticity             |
| 80,000          | 0.8831| elasticity             |

Table 3. Effect of CO2 Dissolution Time in 0.4% GOBT on Its pH and Viscosity

| Time/s | pH | Viscosity/mPa·s⁻¹ |
|--------|----|------------------|
| 0      | 8.5| 3.42             |
| 30     | 6.2| 3.36             |
| 60     | 5.7| 3.23             |
| 90     | 5.4| 3.21             |
| 120    | 5.4| 3.19             |

Table 4. Emulsification of GOBT to Crude Oil (47.2 °C)

| Dehydration Rate/% | Oil: 0.4% GOBT = 3:7 | Oil: 0.4% GOBT = 1:1 | Oil: 0.4% GOBT = 7:3 |
|--------------------|-----------------------|-----------------------|-----------------------|
| Time/min           |                       |                       |                       |
| 0                  | 0                     | 0                     | 0                     |
| 5                  | 0                     | 6.67                  | 42.8                  |
| 10                 | 13.3                  | 66.7                  | 76.2                  |
| 20                 | 22.2                  | 80.9                  | 88.1                  |
| 60                 | 22.2                  | 80.9                  | 88.1                  |
were conducted at 47.2 °C after water flooding reached 90% water cut. The EOR results of three different displacement methods are shown in Figure 5 and Table 5. The results indicated that continuous CO₂ flooding can only increase the recovery by 2.21%. Injecting 0.3PV 0.4% GOBT and continuing water flooding improved the oil recovery by 3.77%, which was 1.56% higher than that of CO₂ flooding, indicating that 0.4% GOBT does have a certain oil washing ability. Although CO₂ alternating 0.4% GOBT flooding was only implemented in four cycles, the recovery of CO₂ alternating 0.4% GOBT flooding (0.3PV alternating) increased by 4.41%, which was 2.2 and 0.64% higher than those of CO₂ flooding and 0.4% GOBT flooding, respectively, and this implied that CO₂ alternating 0.4% GOBT flooding exhibited a good synergistic effect.

2.3.2. Heterogeneous Core Flooding. The high and low permeability dual-pipe flooding experiments were implemented using a tight reservoir core with a permeability range of 4.3. The oil displacement effect of CO₂ flooding, 0.3PV 0.4% GOBT flooding and subsequent water flooding, and CO₂ alternating 0.4% GOBT flooding (0.3PV alternating) was studied after water flooding to 90%. The relationship between the recovery rate and the injected volume is shown in Figure 6 and the experimental results are shown in Table 6.

As can be seen from the data in Figure 6 and Table 6, the effect of continuous CO₂ flooding was poorer. The recovery efficiency of the low permeability layer only increased by 0.56%, and even that of the high permeability layer only increased by 1.16%. While injecting 0.3PV 0.4% GOBT and continuing water flooding significantly improved the oil recovery, the low permeability layer and high permeability layer recovery increased, respectively, by 20.99 and 13.88%, which indicated that GOBT can indeed seal the high permeability layer and can effectively increase the swept volume so that the subsequent waterflood can be obviously diverted to the low permeability layer, which greatly improves the recovery ratio of the low permeability layer. Meanwhile, there is still an obvious plugging and oil washing effect in the high permeability layer, which further increased the recovery efficiency by nearly 14%. CO₂ alternating GOBT flooding (0.3PV alternating five cycles) enhanced the oil recovery more effectively compared with CO₂ flooding and GOBT flooding, the CO₂ sweep volume and
shunting effect obviously increased, the recovery efficiency of the low permeability layer increased by 31.41%, and the high permeability layer was blocked more effectively. The seepage oil washing ability of the high permeability layer decreased in the subsequent CO₂ flooding, and the recovery rate was only 7.93%.

In conclusion, for heterogeneous tight reservoirs, CO₂ and 0.4% GOBT alternate flooding really have a good synergistic oil flooding effect, which can better seal the high permeability layer and improve the sweep ability of CO₂ in the low permeability layer and significantly enhance the oil recovery.

### 2.4. Mechanism of CO₂-GOBT Synergistic Oil Displacement

#### 2.4.1. Plugging the High Permeability Layer and Starting-Up the Low Permeability Layer by Shunting

As can be seen from Figure 7, under the same permeability grade difference (4.3), CO₂ mainly flowed through the high permeability layer in CO₂ flooding, with a shunt rate of 99.55%. By injecting 0.3PV 0.4% GOBT and subsequent waterflooding, the high permeability layer was effectively sealed, and the shunt index of the high permeability layer decreased to 94.15%. While the CO₂ alternating 0.4% GOBT flooding had a better plugging effect, the shunt rate of the high permeability layer decreased to 86.93%.

The results showed that the plugging of CO₂ alternating 0.4% GOBT flooding is more effective than 0.3PV 0.4% GOBT alternating water flooding. This phenomenon was ascribed to the formation of CO₂ foam during the CO₂ alternating GOBT flooding process, which strengthened the plugging effect of the high permeability layer. Table 7 describes that there was obvious foam in the produced liquid of the alternate flooding containing CO₂ under the same permeability grade difference and the same alternate flooding slug size and period. Besides, alternating flooding containing CO₂ had a better plugging effect for high permeability layers and could start the low permeability layer more efficiently to enhance the oil recovery. For example, the recovery of CO₂ alternating 0.4% GOBT flooding in the high permeability layer was significantly lower than that of the 0.4% GOBT alternating water flooding, but the total recovery of CO₂ alternating 0.4% GOBT flooding was nearly 1% higher than that of the 0.4% GOBT alternating water flooding.

#### 2.4.2. Low Interfacial Tension and Emulsifying and Washing Oil Effect

According to the data in Table 1, the GOBT belongs to low interfacial tension (10^{-2} mN/m) viscoelastic fluid and is mainly elastic (tan δ < 1) at a concentration of 0.2–0.4% and has the ability to emulsify and start the residual oil (IFT < 2.7 × 10^{-2} mN/m). The data in Table 4 indicate that 0.4% GOBT could emulsify different proportions of oil and water (3:7–7:3), the stability of emulsion was closely related to the oil content, that is, the emulsion with low oil content had good stability, and the dehydration rate in 1 h was only 22.2%. Meanwhile, the oil displacement experiment also proved that there was an obvious oil washing effect in both single-pipe homogeneous core flooding and dual-pipe parallel heterogeneous core flooding. As shown in Table 5, 0.3PV 0.4% GOBT flooding and subsequent water flooding were conducted after single-pipe homogeneous core water flooding until water cut reached 98%, and the recovery ratio only increased by 3.77%. According to Table 6, 0.3PV 0.4% GOBT flooding could effectively block the high permeability layer and increase the recovery rate of the low permeability layer by 20.99% after parallel dual-pipe heterogeneous core water flooding; meanwhile, the recovery rate of the high permeability layer increased by 13.88% based on 56.48% of water flooding recovery due to the GOBT entering into the high permeability layer.

#### 2.4.3. Wettability Change and Improved GOBT Injectibility and the Ability to Emulsify and Peel off Residual Oil

The cores of tight reservoirs were treated by CO₂ aqueous solution, GOBT, and CO₂-GOBT. The contact angles of the core water phase and oil phase are measured and presented in Figure 8. As shown in Figure 8, the CO₂ aqueous solution reduces the hydrophilicity of the core, the core was more inclined to be oil-wet, and the oil-phase contact angle was only 12.1°. The GOBT and CO₂-GOBT enhanced the hydrophilicity of the core, the effect of CO₂/GOBT was more obvious, and the water-phase contact angle was only 7.4°, which was conducive to injection of GOBT and CO₂-GOBT and could significantly reduce the injection pressure of displacement fluid. In addition, GOBT is beneficial to emulsification and stripping of remaining oil and to improve the recovery of residual oil in the high permeability layer.

### 3. CONCLUSIONS

(1) 0.4% GOBT is a low interfacial tension viscoelastic fluid, which was highly adaptable to salinity water in tight oil reservoirs, exhibited good viscosity stability at different pHs, and also possessed the ability to emulsify crude oil and improve the water wettability of the reservoir.

(2) The CO₂ alternating 0.4% GOBT flooding has good injectability, the stable pressure can be reached at different injection stages, and the injection pressure of subsequent CO₂ flooding increased significantly after injecting 0.4% GOBT, which reflected good injectivity and plugged the pore throat effect of GOBT.

(3) The single-tube core flooding experiment showed that CO₂ flooding, 0.3PV 0.4% GOBT flooding and subsequent water flooding, and CO₂ alternating 0.4% GOBT flooding increased recovery by 2.21, 3.77, and 4.41%, respectively, after water flooding reached 90% water cut, which indicated that 0.4% GOBT does have a certain oil washing ability and CO₂-0.4% GOBT alternate flooding also exhibited a good synergistic effect.

(4) The parallel two-tube core heterogeneous oil displacement experiment indicated that CO₂ alternating 0.4% GOBT flooding can more effectively plug the high permeability layer than 0.4% GOBT flooding, and enhancing the recovery (31.41%) of the low permeability layer was better than that of CO₂ flooding (0.56%) and

**Table 5. Oil Displacement Effect of Different Displacement Modes on Homogeneous Cores**

| number | Kᵢ/μmD | φ/% | Sₑ/% | water flooding recovery/% | total recovery/% | enhanced oil recovery/% | displacement modes |
|--------|--------|-----|------|---------------------------|----------------|------------------------|-------------------|
| 1      | 0.30   | 9.6 | 32.2 | 58.76                     | 60.97          | 2.21                   | CO₂ flooding      |
| 2      | 0.26   | 11.6| 35.9 | 58.83                     | 62.60          | 3.77                   | 0.3PV 0.4% GOBT flooding and subsequent water flooding |
| 3      | 0.27   | 10.8| 33.4 | 59.20                     | 63.61          | 4.41                   | CO₂ alternating 0.4% GOBT flooding (0.3PV alternating) |

https://doi.org/10.1021/acsomega.1c06803
ACS Omega 2022, 7, 6271–6279
0.4% GOBT + water flooding (20.99%) and really had a
good synergistic oil flooding effect.

(5) The mechanism of CO₂ alternating 0.4% GOBT flooding
to enhance the oil recovery includes that GOBT and CO₂
foam block high permeability layers, shunt and sweep low-
permeability layers, and GOBT emulsify and wash oil.
CO₂ partially dissolving in GOBT synergistically
enhances the reservoir core hydrophilicity, which
improves GOBT injectability, emulsification, and strip-
ning ability to residual oil.

4. MATERIALS AND METHODS

4.1. Materials. NaCl, KCl, CaCl₂, Na₂SO₄, MgCl₂,
NaHCO₃, and Na₂CO₃ were purchased from Aladdin
Biochemical Technology Co., Ltd, Shanghai, China. Low
interfacial tension viscoelastic fluid (GOBT) was provided by
the School of Petroleum Engineering, Yangtze University. The
oil used for the test is a live oil prepared from dehydrated
reservoir crude oil with a viscosity of 3.4 mPa·s (47.2 °C). The
experimental cores are reservoir cores ($K_g = 0.141−0.81$ mD).

4.2. Methods. 4.2.1. Fluid Preparation. 4.2.1.1. Injection
Water Preparation. Injection water was prepared by weighing
0.6152 g of NaCl, 9.5664 g of Na₂SO₄, 0.4521 g of NaHCO₃,
1.7493 g of CaCl₂, 1.1533 g of MgCl₂·6H₂O, and 0.0397 g of
KCl and putting them into pure water successively and stirring
until completely dissolved. Simulated injection water with a
salinity of 6788 mg/L was held in a 2 L volumetric
flask for use, and the ionic composition of injected water is shown in Table 8.

4.2.1.2. Formation Water Preparation. Formation water was
prepared by weighing 34.9698 g of NaCl, 1.9345 g of Na₂SO₄,
0.2732 g of NaHCO₃, 102.3120 g of CaCl₂, 1.1910 g of MgCl₂·
6H₂O, and 19.3195 g of KCl and putting them into pure water
successively and stirring until completely dissolved. Simulated
formation water with a salinity of 80,000 mg/L was held in a 2 L
volumetric flask for use, and the ionic composition of formation
water is shown in Table 9.

4.2.1.3. GOBT Preparation. The required amount of GOBT
was added to the injection water (6788 mg/L), stirring
continuously for 2 h until completely dissolved. GOBT with a
concentration of 0.1, 0.2, 0.3, and 0.4% were prepared and left
for 2 h for use.

4.2.1.4. 0.4% GOBT with Different Salinity Preparation.
0.4% GOBT was prepared by diluting the prepared formation
water (80,000 mg/L) with pure water to the required salinity.

4.2.2. Rheological Properties Test. 4.2.2.1. Viscosity Meas-
urements. The viscosity measurements were conducted by a
DV-2T Brookfield viscometer. The viscosities of the
fluid at a
shear rate of 7 s⁻¹ were recorded at 47.2 °C. The viscosity test
error was about 0.005 mPa·s.

4.2.2.2. Viscoelasticity Measurements. The stress scanning for GOBT was conducted by a MCR301 interfacial rheometer at
47.2 °C. The change of modulus with the angular frequency was
investigated. The storage modulus $G'$ and the loss modulus $G''$
were determined, and the loss factor $\tan \delta$ was calculated by the
eq 1. In this equation, $G'$ and $G''$ are, respectively, the storage
modulus and loss modulus. $\delta$ is the phase angle, which
represents the phase difference between shear stress and shear
strain, and when $\tan \delta < 1$, the fluid is mainly elastic; when $\tan \delta$
> 1, the fluid is mainly viscous.

$$\tan \delta = \frac{G''}{G'}$$
4.2.3. **Interfacial Tension Tests.** The interfacial tension between GOBT with different salinities and dehydrated crude oil was measured by a TX500C spin drop interfacial tensiometer at a speed of 5000 rpm and 47.2 °C.

4.2.4. **Wettability Measurements.** Reservoir cores were washed and dried and cut into thin sections with the same diameter and thickness. The core thin sections were placed in CO2 water solution, GOBT, and CO2-GOBT for 6 h, and then the core thin sections were taken out and dried naturally. The contact angle (θ) on the surface of the core thin section was measured by an OCA 50 automatic contact angle measuring instrument, and the wettability was characterized by changes in the contact angle (θ).

4.2.5. **Emulsifying Property Tests.** The GOBT and dehydrated crude oil were mixed according to a certain oil−water ratio and then vibrated up and down 100 times to make the two phases mix evenly. Then, the emulsion was left standing at 47.2 °C, and the volume of precipitated water was observed and recorded. The dehydration rate of the emulsion was calculated by the ratio of the precipitated water volume to the initial GOBT volume to indicate the emulsifying capacity of GOBT on crude oil.

4.2.6. **CO2-Low Interfacial Tension Viscoelastic Fluid (GOBT) Alternating Injectivity Experiment.** The alternating injectivity experiment of CO2-GOBT was conducted to investigate the alternating injectivity of CO2-GOBT under 0.249 mD and 47.2 °C.

4.2.7. **Oil Displacement Performance. 4.2.7.1. Homogeneous Model Oil Displacement Experiments.** The CO2 flooding, GOBT flooding, and CO2-GOBT synergistic flooding were conducted on the core by constant pressure displacement at 47.2 °C to compare the oil displacement efficiency.

4.2.7.2. **Heterogeneous Model Oil Displacement Experiments.** The CO2 flooding, GOBT flooding, and CO2-GOBT synergistic flooding were conducted by constant pressure displacement, simulating the formation heterogeneity at 47.2 °C to compare the oil displacement efficiency. The three groups...
of dual-tube cores are 0.81 mD/0.189 mD, 1.01 mD/0.25 mD, and 0.745 mD/0.172 mD, with a grade difference of 4.3.

**AUTHOR INFORMATION**

**Corresponding Author**
Shuyun Feng — School of Petroleum Engineering, Yangtze University, Wuhan, Hubei 430100, China; ✉ orcid.org/0000-0002-8496-4274; Email: 201971220@yangtzeu.edu.cn

**Authors**
Longlong Chen — State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum, Beijing 102249, China; Yanchang Petroleum Group CO., Ltd., Xian, Shanxi 710075, China
Xinwei Liao — State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum, Beijing 102249, China
Shanfa Tang — School of Petroleum Engineering, Yangtze University, Wuhan, Hubei 430100, China
Ruija Tang — Yanchang Petroleum Group CO., Ltd., Xian, Shanxi 710075, China
Shaojing Jiang — Yanchang Petroleum Group CO., Ltd., Xian, Shanxi 710075, China
Yuanwu Dong — School of Petroleum Engineering, Yangtze University, Wuhan, Hubei 430100, China

Complete contact information is available at: https://pubs.acs.org/10.1021/acsomega.1c06803

**Notes**
The authors declare no competing financial interest.

**ACKNOWLEDGMENTS**
We gratefully acknowledge the financial support by the National Natural Science Foundation of China (51774049), the National Natural Science Foundation of China (51474035), and Key R & D Program of Shaanxi Province (S2021-YF-YBGY-128S).

**REFERENCES**
(1) Yang, T. Y.; Zhang, Y.; Yang, Z.; Ting, C. Mechanism of enhanced oil recovery by CO2 flooding in tight sandstone reservoirs. Sci. Technol. Eng. 2019, 19, 113–118.
(2) Zeng, J.; Cheng, S.; Kong, X.; Guo, K.; Wang, H. Non-Darcy flow in oil accumulation (oil displacing water) and relative permeability and oil saturation characteristics of low-permeability sandstones. Petrol. Sci. 2010, 7, 20–30.
(3) Saboorian-Jooybari, H.; Pourafshary, P. Significance of non-Darcy flow effect in fractured tight reservoirs. J. Nat. Gas Sci. Eng. 2015, 24, 132–143.
(4) Abedini, A.; Torabi, F. On the CO2 storage potential of cyclic CO2 injection process for enhanced oil recovery. Fuel 2014, 124, 14–27.
(5) Zheng, T. Y.; Liu, X.; Yang, Z.; Luo, Y.; Zhang, Y.; He, Y.; Xiong, S. Research progress on application of natural gas to enhance oil recovery in tight reservoirs. Appl. Chem. Ind. 2020, 49, 190–195.
(6) Tovar, F. D.; Eide, O.; Graue, A.; Schechter, D. S. Experimental investigation of enhanced recovery in unconventional liquid reservoirs using CO2: a look ahead to the future of unconventional EOR. SPE Unconventional Resources Conference; OnePetro, 2014.
(7) Zhang, B.; Dang, W.; Wang, S.; He, X. CO2-EOR in chang 8 tight sandstone reservoir of Honghe oilfield in Ordos Basin. Oil Gas Geol. 2016, 37, 272–275.
(8) Qin, Z.; Zhou, J.; Xie, J. Experiment on enhanced oil recovery by surfactant-injection oil displacement system in tight sandstone reservoirs. Fault Oil Gas Field 2020, 27, 628–632.
(9) Yu, H.; Yang, Z.; Liu, J.; Chen, Z.; Cheng, S.; Lei, Q. EOR method by the carbonated water injection (CWI) for tight oil reservoirs. Pet. Geol. Oilfield Dev. Daqing 2019, 38, 166–174.
(10) Kathel, P.; Mohanty, K. K. EOR in tight oil reservoirs through wettability alteration. SPE Annual Technical Conference and Exhibition; OnePetro, 2013.
(11) Wei, B.; Liu, J.; Zhang, X.; Pu, W. Advances of enhanced oil recovery method and theory in tight reservoirs. J. Southwest Pet. Univ., Sci. Technol. Ed. 2021, 43, 91–102.
(12) Kang, Y.; Tain, J.; Luo, P.; You, L.; Liu, X. Technical bottlenecks and development strategies of enhancing recovery for tight oil reservoirs. Acta Petrol. Sin. 2020, 41, 467–477.
(13) Yu, W.; Lashgari, H. R.; Wu, K.; Sepehrnoori, K. CO2 injection for enhanced oil recovery in Bakken tight oil reservoirs. Fuel 2015, 159, 354–363.
(14) Jaber, A. K.; Awang, M. B. Field-scale investigation of different miscible CO2-injection modes to improve oil recovery in a clastic highly heterogeneous reservoir. J. Pet. Explor. Prod. Technol. 2017, 7, 125–146.
(15) Hu, S. Y.; Tao, S.; Yan, W.; Men, G.; Tang, Z.; Xue, J.; Jia, X.; Chen, X.; Jiang, T.; Huang, D. Advances on continental tight oil accumulation and key technologies for exploration and development in China. Nat. Gas Geosci. 2019, 30, 7–17.
(16) Abedini, A.; Torabi, F. Oil Recovery Performance of Immiscible and Miscible CO2 Huff-and-Puff Processes. Energy Fuel 2014, 28, 774–784.
(17) Zhong, J.; Abedini, A.; Xu, L.; Xu, Y.; Qi, Z.; Mostofi, F.; Sinton, D. Nanomodel visualization of fluid injections in tight formations. Nanoscale 2018, 10, 21994–22002.
(18) Abedini, A.; Torabi, F.; Mosavat, N. Performance of immiscible and miscible CO2 injection process in a tight carbonate reservoir (experimental and simulation approach). Int. J. Oil Gas Coal Technol. 2015, 9, 265–279. Jianming, F.; Zhang, Q.; Huo, M.; Tian, J.; Li, W. Laboratory study on optimization of CO2 injection development ways of ultra-low permeability reservoirs. J. Xin Shiyou Univ. Nat. Sci. Ed. 2015, 30, 39–42.
(19) Guo, M.; Huang, C.; Dong, X.; Zhou, Y.; Tang, R. CO2 EOR mechanism of tight sandstone reservoir in Yanchang oilfield. Chem. Eng. Oil Gas 2018, 47, 75–79.
(20) Dong, J.; Wu, S.; Xing, G.; Fan, T.; Wang, B. Factors affecting water alternating hydrocarbon gas miscible flooding in a low permeability reservoir. International Petroleum Technology Conference; OnePetro, 2019.
(21) Zhang, M.; Zhao, F.; Lv, G.; Hou, J.; Song, L.; Feng, H.; Zhang, D. Experimental study on the adaptation limit of WAG to improve CO2 flooding effect. Oilfield Chem. 2020, 37, 279–286.
(22) Liu, S.; Peng, B.; Liu, Q.; Li, X.; Xue, M. Study on impact of particle of CO2 foam system for flooding on its performance. Petrol. Reserv. Eval. Dev. 2020, 10, 33–38.

---

**Table 8. Ionic Composition of Injected Water (mg L⁻¹)**

| ion       | Na⁺, K⁺ | Ca²⁺ | Mg²⁺ | Cl⁻ | SO₄²⁻ | HCO₃⁻ | salinity/mg L⁻¹ |
|-----------|---------|------|------|-----|-------|-------|-----------------|
| 1695      | 349.74  | 75.01| 1033.48 | 3470.9 | 164.1 | 6788          |

**Table 9. Ionic Composition of Formation Water (mg L⁻¹)**

| ion       | Na⁺, K⁺ | Ca²⁺ | Mg²⁺ | Cl⁻ | SO₄²⁻ | HCO₃⁻ | salinity/mg L⁻¹ |
|-----------|---------|------|------|-----|-------|-------|-----------------|
| 10183     | 19148   | 71   | 49233 | 654 | 99    | 80,000 |
Songyan, L. J.; Wang, L.; Han, R.; Li, L.; Li, A.; Li, Z. Experimental study on supercritical CO2 foam flooding in fractured tight reservoirs. *Pet. Geol. Recovery Effic.* 2020, 27, 29–35.

Jinseng, Z.; Tan, J.; Gu, Z.; Liu, X. Experimental study on the CO2 foam injecting way of profile control and flooding in heterogeneous reservoirs. *Eng. Sci.* 2012, 14, 87–93.

Zhang, P.; Diao, Y.; Shan, Y.; Pei, S.; Yang, H. Experimental investigation of amine-surfactant CO2 foam for smart mobility control during CO2 flooding. *J. Petrol. Sci. Eng.* 2020, 184, 106511.

Ahmed, S.; Elraies, K. A.; Forooozesh, J.; Bi Mohd Shafian, S. R.; Hashmet, M. R.; Hsia, I. C. C.; Almansour, A. Experimental Investigation of Immiscible Supercritical Carbon Dioxide Foam Rheology for Improved Oil Recovery. *J. Earth Sci.* 2017, 28, 835–841.

Li, D.; Zhang, L.; Liu, Y.-M.; Kang, W.-L.; Ren, S.-R. CO2 triggered gelation for mobility control and channeling blocking during CO2 flooding processes. *Petrol. Sci.* 2016, 13, 247–258.

Li, F.; Luo, Y.; Ding, K.; Liu, C.; Liu, W.; Ke, A.; Wang, D. The laboratory performance evaluation of CO2 gas flooding channeling sealing agent in block G89-1 of shengli oilfield. *Oilfield Chem.* 2014, 31, 51–55.

Jiang, S.; Wang, W.; Huang, C.; Yang, H.; Yu, H. Application of modified starch gel system to prevent CO2 breakthrough. *Spec. Oil Gas Reservoirs* 2016, 23, 136–140.

Zhao, Z. Synthesis and application of zwitterionic gemini surfactant flooding agent. *Fault Oil Gas Field* 2019, 26, 119–122.

Shi, Y.; Liu, W.; Guan, B.; Cong, S.; Kang, J. Study on high efficiency imbibition system and performance for ultra-low permeability reservoir. *Appl. Chem. Ind.* 2021, 50, 2386–2390.

Lopes, L. F.; Façanha, J. M. F.; Maqueira, L.; Ribeiro, F. R. T.; Perez-Gramatges, A. Coarsening reduction strategies to stabilize CO2 foam formed with a zwitterionic surfactant in porous media. *J. Petrol. Sci. Eng.* 2021, 207, 109141.

Ruizhi, H. T.; Tang, S.; Jin, L.; Mpelwa, M.; Feng, S.; Jiang, Z. Construct and performance evaluation of low interfacial tension anionic Gemini surfactant viscoelastic fluid. *Oilfield Chem.* 2020, 37, 93–101.

Mpelwa, M.; Tang, S.; Jin, L.; Hu, R.; Wang, C.; Hu, Y. The study on the properties of the newly extended Gemini surfactants and their application potentials in the petroleum industry. *J. Petrol. Sci. Eng.* 2020, 186, 106799.

Mpelwa, M.; Tang, S.; Jin, L.; Hu, R. New sulfonate Gemini surfactants: synthesis and evaluation for enhanced oil recovery applications. *J. Dispersion Sci. Technol.* 2020, 1, 2091.

Hu, B.; Tang, S.; Mpelwa, M.; Jin, L.; Jiang, Z.; Feng, S.; Zheng, Y. Study on the structure-activity relationship between the molecular structure of anionic Gemini surfactants and the rheological properties of their micelle solutions. *J. Dispersion Sci. Technol.* 2020, 1.

Li, X. P.; Yu, L.; Ji, Y. Q.; Wu, B.; Li, G. Z.; Zheng, L. Q. New type flooding systems in enhanced oil recovery. *Chin. Chem. Lett.* 2009, 20, 1251–1254.

Li, K.; Jing, X.; Qu, D.; Pu, W.; Wei, B. Pore-level investigations on the oil displacement mechanisms of a viscoelastic surfactant in porous media. *J. Petrol. Sci. Eng.* 2019, 173, 748–757.

Siggel, L.; Santa, M.; Hansch, M.; Nowak, M.; Ranft, M.; Weiss, H.; Hajnal, D.; Schreiner, E.; Otter, G.; Tinsley, J. A new class of viscoelastic surfactants for enhanced oil recovery. *SPE Improved Oil Recovery: OnePetro*, 2012.

Azad, M.; Sultan, A. Extending the applicability of chemical EOR in high salinity, high temperature & fractured carbonate reservoir through viscoelastic surfactants. *SPE Saudi Arabia Section Technical Symposium and Exhibition*, Al-Khobar, Saudi Arabia, 2014.

Zhu, Y.; Fan, J.; Liu, X.; Li, J. Studies on viscoelastic surfactants for its potential EOR application in the low permeability reservoirs. *SPE Improved Oil Recovery Conference*, Tulsa, Oklahoma, USA, 2016.

Li, K.-X.; Jing, X.-q.; He, S.; Ren, H.; Wei, B. Laboratory study displacement efficiency of viscoelastic surfactant solution in enhanced oil recovery. *Energy Fuel* 2016, 30, 4467–4474.

Janjua, A. N.; Sultan, A. S.; Kamal, M. S. Investigation of heavy oil recovery using sequential viscoelastic surfactant and chelating agent solutions as EOR fluid for HTHS conditions carbonate reservoirs. *SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition*, 2018.