Field Application and Experimental Investigation of Interfacial Characteristics of Surfactant and CO₂ Alternative Injection

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ABSTRACT: CO₂ injection and water alternating gas (WAG) injection are crucial to improve the oil recovery method and have optimized development in numerous oil fields. Many issues, such as gas channeling, water clogging, and a shortage of gas injection capacity, are addressed in the studies. Considering these conflicts, we suggest in this work a unique method of surfactant alternating gas (SAG) injection. Additionally, axisymmetric drop shape analysis and other approaches are utilized to explore the interface properties of a variety of systems, including CO₂/carbonated water/water/surfactant/oil systems. SAG injection combines the advantages of surfactant and WAG injection. Although CO₂ molecules have an effect on surfactant aggregation at the oil−water interface in the SAG system, carbonated water has little effect on surfactant performance in lowering oil−water interface tension.

Pilot studies reveal that a SAG ratio of 3:2 at 74 °C and 0.5 wt% concentration significantly improves oil recovery.

1. INTRODUCTION

CO₂ flooding is the most promising enhanced oil recovery (EOR) technology, and it has been employed effectively in numerous reservoir types. The fundamental problem with CO₂ flooding at the moment is that it is restricted by the CO₂ source and has inadequate mobility control, resulting in early CO₂ overriding and fingering, CO₂ breakthrough, corrosion in producing wells, CO₂ separation and recycle injection, and so on. Composed with CO₂ flooding, water alternating gas (WAG) injection controls the fluid mobility ratio and stabilizes fluid lead front. WAG has been constantly developed and applied since 1957, when it was initially used in the North Pembina field in Canada. The method combines the benefits of water and gas injections by sequentially injecting water and gas plugs, and WAG may enlarge macro sweep efficiencies in gas injection processes and enhance the micro displacement efficiency. The WAG performance is highly affected by the injection strategies (e.g., injection well pattern, WAG ratio, number of WAG cycles, volume of each cycle, and injection rate and pressure). Due to the gravity segregation between gas and crude oil, a majority of top oil is displaced by gas injected and that of the bottom oil by water injected. The WAG may dramatically lower CO₂ flow rate following gas flooding, reducing flow resistance of the oil phase, raise seepage resistance of the water phase, and make crude oil easier to drive out. However, when the reservoir is heterogeneous, the early gas breakthrough will happen in the high permeability zone or fracture zone of the swept area by WAG injection, resulting in low sweep efficiency and limited EOR improvement. LandSim (Tracy Energy Technology) is a reservoir simulation software for CO₂ EOR and sequestration and gas channeling phenomenon prediction. Variations in reservoir permeability, on the other hand, have a significant impact on WAG performance. Khan and Mandal investigate the benefits and drawbacks of WAG displacement caused by permeability.

Received: June 9, 2022
Accepted: August 22, 2022
Published: September 13, 2022
heterogeneities such as permeability anisotropy, high permeability streaks, matrix permeability, dolomite, and thin dense stylolite layers. Water clogging, inadequate mobility control in heavy oil reservoirs, low gas injection capacity, and other issues are common with the WAG system. As a result, the majority of oil fields employing WAG technology are unable to attain the projected recovery factor.

In order to solve the above problems, many researchers add chemical agents to the WAG process to reduce interfacial tension (IFT) at the water–oil interface and improve the mobility ratio. It is a novel technology that involves injecting chemicals alternately with gas (CEWAG). CEWAG is important for minimizing IFT, controlling mobility, reducing water blocking impact, and reducing oil viscosity due to CO₂ dissolving and oil swelling. Several CEWAG approaches, such as surfactant alternating gas (SAG) injection, polymer alternating gas (PAG) injection, and alkali–surfactant–polymer (ASP) alternating gas (ASPAG) injection, are being studied in the lab as well as in field experiments, and provide the best results for increased oil recovery. Behzadi and Towler used a CMG simulator to investigate the sensitivity of ASPAG to development effects. For varied reservoir conditions, ASPAG can achieve substantially greater oil recovery than ASP or WAG flooding. Farad et al. studied and concluded that pH and slug size are important parameters that influence ASPAG efficiency in oil recovery. The pH effect was dependent on oil qualities such as acidity. Injection of a slug containing 0.1 wt% polymer, 0.1% surfactant, and alkali with a pH of 11 and a slug ratio of 1:1 resulted in the best recovery (15.4%). PAG overcomes the challenges of gas breakthrough and gravity segregation for the extraction of heavy oil, which are limitations of WAG processes. Li et al. investigated and concluded that PAG enhances oil recovery by up to 14.3%, which is 7.0% greater than the WAG injection in the TR78 sector of the North Burbank Unit. The modeling results also show that injection polymer may dramatically lower the gas-to-oil ratio (at the production well), delay gas breakthrough significantly, and enlarge gas and water sweep efficiency throughout the PAG process. Jamal et al. used global optimization algorithms to examine the optimal parameters of a PAG injection method, including polymer concentration. However, due to limited permeability or other adverse characteristics, some reservoir conditions are not favorable to the usage of polymers. In these reservoirs, the ASPAG and PAG approaches are unsuccessful. As a result, SAG technology becomes more extensively applicable. Because of the reduction in IFT and contact angle, as well as foam generation, surfactants are necessary in the SAG injection process. Foam can help with a variety of problems, such as better sweep, fewer gravity overrides, less viscous fingering, and gas entertainment from high pressure. Many studies have shown that SAG produces better experimental and application results. SAG has advantages over co-injection of surfactant and gas, due to the operational complexity of co-injection and pipeline corrosion. Salehi et al. investigated the effects of SAG sensitive parameters on EOR experimentally. The SAG ratio of 1:1 with 0.2 cm³/min at 70 °C and 144.74 × 10⁵ Pa has the highest oil removal efficiency. Similarly, relevant experiments have shown that SAG achieves better development results for heavy and semi-heavy oil reservoirs. Surfactant adsorption in reservoir rocks can have an impact on the anticipated development effect. Safarzadeh et al. studied the effect of calcium lignosulfonate on adsorption phenomenon in SAG.

Adsortion experiments showed that when N₂ is used instead of CH₄, the density of sodium dodecyl sulfate adsorption on silica is lowered. It can be lowered by using calcium lignosulfonate as sacrificial agents, and the quantity of adsorption reduction increases with concentration. Gandomkar et al. investigated the influence of CO₂ foam on the mobility ratio and EOR at various surfactant concentrations in SAG experiments. Foam generation in porous media is extremely sensitive to reservoir heterogeneities. Unfortunately, there have not been many research studies on the subject. In addition, there is a lack of comparison between the interface characteristics of various systems.

Given the current state of research, PAG and ASPAG technologies, for example, are influenced by formation water pH and salinity in terms of EOR due to the incorporation of polymers. SAG technology, on the other hand, is completely unregulated and has higher research and marketing possibilities.

In this paper, the target block is located in Jiangsu Basin of North China and is a complex fault-block reservoir, which is impacted by fault control and paleo-uplift. There are two strataums from top to bottom, which are Duo Section and the Dai Section. In particular, the Duo Segment is our target oil reservoir. The Duo Segment is a medium- to high-permeability reservoir, which has an oil-bearing area of 0.49 km² and an average effective thickness of 26.3 m. The Duo Segment is divided into nine layers. The Duo Segment has a high permeability, with an average porosity of 27.12% and a permeability of 1394 mD that has significant heterogeneity. The reservoir temperature is 74 °C. The formation water salinity and subsurface crude oil viscosity are 25 000 mg/L and 32.5 mPa·s, respectively. There are four development stages in this reservoir after 1992, which are depletion production, water injection, well pattern adjustment, and production layer adjustment. The injection–production ratio is lower than one and the vertical heterogeneity is high. The residual oil distribution is influenced by the frequent adjustment of the production layer in the latter stage. In the target reservoir, the effect of polymer flooding is limited due to high salinity. The injection–production well spacing is less than 80 m after multiple infilling and adjustment of the well pattern, which cause gas channeling during the CO₂ flooding process. In 2016, CO₂ flooding was implemented, and a gas breakthrough with a high gas production rate was observed in one month after the gas injection. Thus, fast gas breakthrough is the challenge of CO₂ flooding. The water cut was increased dramatically to 91.4% in 2016. The implementation of conventional hydrodynamic adjustment techniques has become less effective. A new EOR method is needed in the target reservoir. In this study, we investigated the interface change characteristics of several injection methods, including CO₂ flooding, WAG, and SAG, studied the displacement mechanism, and experimentally proved the optimal SAG injection combination, which serves as a useful reference for comparable reservoirs.

2. RESULTS AND DISCUSSION

2.1. Experiment. In this paper, axisymmetric drop shape analysis and other approaches are used to investigate the interfacial rules and IFT experiments of several systems, including CO₂/water/carbonated water/surfactant/crude oil. Long-core displacement experiments are performed to evaluate
the displacement effect and recovery of various systems. The gas we study during gas flooding is CO$_2$.

2.1.1. Material. The target block is in eastern China. The sampling is taken from the target block. CO$_2$ gas with ultra-high purity of 99.95% is used. A long-core sample is used (length: 0.75 m, diameter: 2.5 cm, permeability: 1400 mD, porosity: 27%). The viscosity of formation crude oil is 32.5 mPas, and formation water salinity is 25,000 mg/l. The experiments are carried out at the target block reservoir temperature (74 °C). CO$_2$ is in the supercritical state under experimental conditions.

2.1.2. Study on Interfacial Interaction Law of CO$_2$/Water/Carbonated Water/Crude Oil. The axysymmetric drop shape analysis technique is used in this paper to analyze the interfacial interaction for three systems of water/carbonated water/CO$_2$/oil at reservoir temperature and pressure and to determine the dynamic interfacial tension (DIFT) and equilibrium interfacial tension (EIFT) with pressure change at reservoir temperature, respectively.

The IFT apparatus is measured up to 200 °C and 70 MPa. The instrument includes visible pressure—volume—temperature (PVT) cell, an image processing system, a light source, a crude oil supply system, a CO$_2$ supply system, and bulk fluid tanks, as shown in Figure 1. A stainless-steel needle installed at the top of the PVT cell is used to measure the dynamic IFT between crude oil and the water/carbonated water/CO$_2$ system. Details of the experimental procedures include the following steps:

1) Water/carbonated water/CO$_2$ is injected into the bulk fluid tanks, which are then pressure-balanced and gently pumped into the PVT cell. Under the specified pressure, an oil sample is pumped into the inlet pump.

2) The PVT cell and the inlet pump are set at the specified temperature. Then, oil droplets are introduced with the stainless-steel needle.

3) The exterior profile of the oil droplets is acquired using a computer image processing system.

It should be noted that every oil droplet is kept for more than 15 min, and at least three oil droplets are taken at each pressure point. The picture magnification is adjusted by the needle diameter, and the density of crude oil is measured by high temperature and pressure densitometer, and the equilibrium IFT can be calculated according to the shape of the oil droplet.

2.1.2.1. Interfacial Characteristics between Crude Oil and CO$_2$. During the early stage of oil–CO$_2$ interaction in the autoclave, the volume and form of oil vary continuously; at this time, there is diffusion mass transfer between CO$_2$ and oil. Figure 2a shows how CO$_2$ removes light components from oil.

After the initial stage of contact, the interfacial interaction between oil and CO$_2$ at various pressures. There is no significant mass transfer between CO$_2$ and oil when the pressure is 16 MPa; however, when the pressure is raised to 26 MPa, the dissolution and extraction effect can be seen in slight light components, and changes in the volume and shape of the oil droplet are significant. This interaction gradually increases with increasing pressure, and the mutual diffusion and mass transfer becomes stronger when the pressure is raised to 41 MPa. This is because CO$_2$ can extract low molecular weight components at low pressure, and the higher molecular weight components that CO$_2$ can extract steadily increase as pressure increases. More light components in crude oil are extracted by CO$_2$ that is, more components in crude oil are mixed with CO$_2$, and the residual heavy components that cannot be mixed with CO$_2$ are reduced accordingly, whereas the components that are mixed with CO$_2$ can easily be replaced from the reservoir pore space, improving oil recovery.

2.1.2.2. Interfacial Characteristics between Crude Oil and Carbonated Water. Figure 4 shows that at 8 MPa, CO$_2$ diffuses from the water to oil phase over time. A thin layer of light hydrocarbons forms at the interface of oil and carbonated water (CW). When pressure increases to 14 MPa, the light hydrocarbon layer interface expands. In comparison to the CO$_2$/crude oil system, the water phase separates the CO$_2$ gas phase from the oil phase, CO$_2$ can only diffuse from the water to the oil phase, and the shape of the oil droplet in CW is more stable. When pressure increases to 30 MPa, the light component extraction phenomena become more visible, and we can clearly detect that CO$_2$ extracts from the light components at the top of the oil droplet, as well as the light hydrocarbon layers around the oil droplet become thicker. It demonstrates that when pressure increases, the speed of CO$_2$ traveling across the contact increases, and the extraction effect with oil droplets becomes more noticeable.

2.1.2.3. Interfacial Characteristics between Crude Oil and Formation Water. At different pressures, the forms of the oil
droplets do not alter, and their sizes stay largely same, and no distinct mass extraction phenomenon occurs (Figure 5).

2.1.2.4. Comparison of EIFT of Different Systems. EIFT values of different systems are examined in our work. As demonstrated in Figure 6, as system pressure increases, CO$_2$ solubility in the water phase increases, but the EIFT between oil and water drops (Figure 7). EIFT of the oil–CW system declines slowly and remains essentially constant after the system pressure reaches 17.09 MPa, whereas EIFT of the oil–water system stays essentially constant as pressure increases. The oil–CW EIFT is dropped by 13.94% after CO$_2$ injection. It has been demonstrated that injecting CO$_2$ decreases the oil–CW EIFT effectively.

The EIFT between crude oil and CO$_2$ reduces dramatically as pressure increases. At roughly 23 MPa, EIFT value is less than 2 mN/m, and partial miscibility can be achieved during the CO$_2$ flooding process.

2.1.3. Study on the Interaction Law between Surfactant and Crude Oil. Initial water–oil IFT is around 20–30 mN/m, and by selecting appropriate surfactants, water–oil IFT may be decreased to $10^{-3}$ or even $10^{-4}$ mN/m. The residual oil saturation is near to zero when the capillary number exceeds $10^{-2}$, according to the link between capillary number and the recovery factor. To generate such a high capillary number, IFT must exceed $10^{-3}$ mN/m. At present, ultra-low IFT is defined as oil–water IFT less than 0.01 mN/m. In recent decades, ultra-low IFT has been a critical component of chemical flooding research and a key indication for assessing surfactant flooding.

Water–oil DIFT tests for solutions containing surfactant at concentrations of 0.05, 0.1, 0.15, 0.2, 0.3, 0.4, 0.5, and 0.6 wt% are performed at 74 °C with distilled water base.

The experimental results (Figures 8 and 9) reveal that as surfactant concentration increases, so does the EIFT between surfactant solution and crude oil. When surfactant concentration exceeds 0.2 wt%, EIFT between oil and water reduces to the order of $10^{-2}$ mN/m, attaining low IFT. When surfactant concentration exceeds 0.4 wt%, the performance of decreasing IFT improves dramatically, and ultra-low IFT may be achieved.
2.1.4. Study on the Interaction Law between Surfactant, \( \text{CO}_2 \), and Crude Oil. \( \text{CO}_2 \) is introduced in a certain ratio to the measuring chamber’s top, resulting in a \( \text{CO}_2 \) gas cap. The \( \text{CO}_2 \) gas cap creates a three-phase equilibrium between surfactant solution, crude oil, and \( \text{CO}_2 \). The pendant drop technique is used to examine various system interface interactions and EIFT, but is only effective at lower surfactant concentrations (0.01 to 0.03 wt%).

As pressure increases, EIFT between surfactant solution and crude oil drops. More surfactant molecules are organized at the oil−water interface as pressure increases, resulting in a drop in oil−water EIFT (Figure 10). When \( \text{CO}_2 \) is saturated in surfactant solution, the greater the pressure, the more \( \text{CO}_2 \) molecules congregate at the oil−water interface, changing surfactant molecule arrangement and increasing oil−water EIFT with pressure. However, there is no order of magnitude change in EIFT. The EIFT is only slightly affected by CW.

2.1.5. Oil Displacement Experiment. The core displacement experiment employs the HTHP long-core displacement technology. The experimental settings are identical to the target reservoir conditions (23 MPa and 74 °C). The lab core is 30 cm long, 2.54 cm in diameter, and has a permeability of roughly 1400 mD. The operating procedures for the long-core displacement experiment are as follows:

① After drying the core sample, the formation water in the core is saturated for 2 h, and the volume of saturated formation water is measured and utilized to compute the core pore volume.
② Inject 1.0 mL/min of formation oil into the core model, then measure the model outlet volume of water driven out and...
drive out a minimum of 2.0 PV. The volume of saturated oil is equal to the volume of water forced out. More than 12 h in a 74 °C oven.

③ Inject 2.0 PV of water at 1.0 mL/min and record the pressure and volume of oil recovered during water flooding. Fluids are injected into the cores at a constant rate of 1.0 mL/min. This system has five injection patterns (Table 1), each with different slug combinations. The displacement process records fluid pressure difference and fluid volume. Alternating injection involves injecting 1.0 mL/min of water or surfactant solution for 5 min, then CO₂ for 10 min (gas−liquid ratio is 2:1), then repeating the injection procedure until the experiment is complete.

Water flooding has the greatest injection pressure difference among the various displacement methods, followed by water−gas alternation, whereas gas injection has the smallest pressure difference. The oil displacement effect of water, CO₂, and surfactant injection alone is relatively poor after 1PV water injection, with an average increase in the recovery factor of 6−7%, whereas the oil displacement effect of alternating injection of CO₂ and surfactant is significantly improved, with an increase in the recovery factor of more than 10%. The best results are obtained by alternately injecting CO₂ and surfactant.

Injected CO₂ can swell the crude oil, lower its viscosity, generate miscibility, and lower the IFT between the oil and the CO₂−oil phase in near-miscible regions. Surfactant flooding is a chemical EOR technique in which a small amount of surfactant is mixed with the injected fluid to sweep the reservoir oil. The mobility of remaining oil, flooded by surfactant injection, is increased by reducing the IFT between the injected fluid and

![Figure 8. DIFT values of different surfactant concentrations and crude oil.](image1)

![Figure 9. EIFT values of surfactant concentrations and crude oil.](image2)
the remaining oil.\textsuperscript{21} WAG injection can overcome the problem of an undesirable mobility ratio and lower displacement efficiency of gas flooding.\textsuperscript{22} Water slug injection is used to prevent fast gas breakthrough. SAG injection has the advantages of surfactant flooding and CO\textsubscript{2} flooding, it can lower the IFTs of the systems, restrain gas breakthrough, and improve gas sweep volume.

2.2. Results. Based on the production data and numerical simulation results, the recovery factor reaches to the maximum with the CO\textsubscript{2} alternating surfactant solution injection method when the gas–liquid ratio is 2:3. The gas injection rate is 10 t/d and the surfactant solution injection rate is 100 m\textsuperscript{3}/d with 0.5 wt% concentration. After the field implement, the increment oil production is 8950 t and the EOR is 4.5%.

The CO\textsubscript{2} alternating surfactant solution injection combines the benefit of CO\textsubscript{2} and surfactant flooding. The oil–water IFT is reduced by the surfactant, which causes the increment of displacement efficiency. The sweep efficiency is also increased due to prevention of CO\textsubscript{2} channeling. In the high water cut reservoir, the CO\textsubscript{2} alternating surfactant solution injection is a potential EOR method and is worthy to popularize.

3. CONCLUSIONS

This project’s research led to the following findings:

(1) Strong interdiffusion exists at the early stage of contact between supercritical CO\textsubscript{2} and crude oil, and mass transfer is enhanced as system pressure increases. After a period of mutual contact, CO\textsubscript{2} and crude oil can finally establish a stable state.

(2) Surfactant can lower oil–water IFT to ultra-low levels (0.01 mN/m). For surfactant concentrations greater than 0.4 wt%, IFT can be as low as 10\textsuperscript{-3} mN/m. For surfactant concentrations between 0.2 and 0.4 wt%, IFT can be as low as 10\textsuperscript{-2} mN/m.

(3) IFT between oil and water in the target reservoir is approximately 14 mN/m. When CO\textsubscript{2} is added at different pressures, IFT between CW and crude oil is slightly higher than that of unsaturated CO\textsubscript{2}. The effect of CO\textsubscript{2} on the IFT between oil and CW can be considered minor compared to that of surfactant, which reduces the IFT by several orders of magnitude.

(4) Long-core displacement studies reveal that alternating injection of surfactant solution and CO\textsubscript{2} may greatly enhance displacement efficiency and improve the oil recovery factor by 14%. Superior development outcomes are obtained following pilot test implementation.

### Table 1. Statistics of the EOR Effect of Different Oil Displacement Systems

| case no. | displacement mode | injection system | injection pore volume | recovery % | EOR % |
|---------|------------------|------------------|-----------------------|------------|-------|
| 1       | water flooding   | 2.0 PV water flooding | 2.0                  | 63.2       | 6.0   |
| 2       | CO\textsubscript{2} flooding | 2.0 PV CO\textsubscript{2} flooding | 2.0                  | 62.6       | 7.3   |
| 3       | surfactant flooding | 2.17 PV 0.6 wt% surfactant flooding | 2.17                 | 64.8       | 7.5   |
| 4       | water alternating CO\textsubscript{2} injection | 0.08 PV water alternating 0.04 PV CO\textsubscript{2} (one cycle) | 2.0                  | 70.4       | 10.3  |
| 5       | surfactant alternating CO\textsubscript{2} injection | 0.08 PV surfactant alternating 0.04 PV CO\textsubscript{2} (one cycle) | 2.0                  | 73.9       | 13.8  |

**Figure 10.** Comparison of IFT of different systems.

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| 4       | water alternating CO\textsubscript{2} injection | 0.08 PV water alternating 0.04 PV CO\textsubscript{2} (one cycle) | 2.0                  | 70.4       | 10.3  |
| 5       | surfactant alternating CO\textsubscript{2} injection | 0.08 PV surfactant alternating 0.04 PV CO\textsubscript{2} (one cycle) | 2.0                  | 73.9       | 13.8  |
This research was supported by SINOPEC scientific and Exhibition.

The authors declare no competing financial interest.

ACKNOWLEDGMENTS

We thank East China Oil & Gas Company for project support. This research was supported by SINOPEC scientific and technological project (P17056-6).

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