Application of flue-gas foam in thermal-chemical flooding for medium-depth heavy oil reservoirs

Qingjun Du1,2 | Hao Liu1,2 | Guanghuan Wu3 | Jian Hou1,2 | Kang Zhou1,2 | Yongge Liu1,2

1Key Laboratory of Unconventional Oil & Gas Development (China University of Petroleum (East China)), Ministry of Education, Qingdao, China
2School of Petroleum Engineering, China University of Petroleum (East China), Qingdao, China
3Research Institute of Exploration and Development, Shengli Oilfield SINOPEC, Dongying, China

Correspondence
Jian Hou, Key Laboratory of Unconventional Oil & Gas Development (China University of Petroleum (East China)), Ministry of Education, Qingdao 266580, China.
Email: houjian@upc.edu.cn

Funding information
National Key Research and Development Program of China, Grant/Award Number: 2018YFA0702404; National Natural Science Foundation of China, Grant/Award Number: 51574269; National Science Foundation for Distinguished Young Scholars of China, Grant/Award Number: 51625403; Important National Science and Technology Specific Projects of China, Grant/Award Number: 2016ZX05011-003; Fundamental Research Funds for the Central Universities, Grant/Award Number: 15CX08004A, 18CX02169A and 18CX02094A; China Postdoctoral Science Foundation, Grant/Award Number: 2017M and 622319; Natural Science Foundation of Shandong Province, Grant/Award Number: ZR2018BEE004

Abstract
Heat loss in wellbore during steam injection is considerable due to the deep burial of medium-depth heavy oil reservoirs, leading to a low steam quality in the bottom of well. As for hot water flooding, the mobility ratio between oil and water is small, which decreases oil recovery. Flue-gas foam assisted thermal-chemical flooding is a new method for heavy oil reservoir. Compared to hot water flooding, flue-gas foam assisted thermal-chemical flooding can decrease oil viscosity, achieving higher sweep efficiency. However, the combined mechanisms of all the injected components have not been studied systematically. In this work, the role of CO2, viscosity reducer and hot water for oil viscosity reduction and distribution characteristics of residual oil were studied using the numerical simulation methods. Results show that although the percentage of viscosity reduction contribution of viscosity reducer can be as high as 60%, only wider range of this effect can help recover more remaining oil effectively. In the presence of flue-gas foam, CO2 and viscosity reducer can decrease oil viscosity in the upper and bottom layers of the reservoir, respectively. Two parameters of the area proportion of removed-oil (ARRO) and the average removed-oil saturation (SDRO) are defined. It is believed that both ARRO and SDRO are quite small for the hot water flooding, which is assisted by viscosity reducer. The flue-gas foam can obviously expand the area of removed-oil, but the average removed-oil saturation is slightly lower. The combination of flue-gas foam and viscosity reducer is a promising displacement method.

KEYWORDS
flue-gas foam assisted thermal-chemical flooding, heavy oil, medium-depth reservoir, numerical simulation, removed-oil
1 | INTRODUCTION

Heavy oil reservoirs, belonging to unconventional reservoirs which possess some unique characteristics, are usually exploited by hot fluid or chemicals to reduce oil viscosity. Thermal fluid injection methods generally include steam flooding and hot water flooding. Oil recovery from steam flooding can be above 40%, making it one of the best thermal recovery methods. However, steam flooding may not be effective because the steam chamber cannot well expand, resulting from the high burial depth, high formation pressure of the reservoir, and low-steam quality. 

Accordingly, hot water flooding is an alternative to steam flooding for this kind of reservoir, which is not quite suitable for steam flooding. Hot water flooding is scarcely used in practice considering that hot water flooding may lead to low sweep efficiency.

At present, the injection of thermal-chemical fluid, including hot water and viscosity reducer, is generally used to reduce the viscosity of crude oil and increase the sweep efficiency of heat flow by injecting gas foam. It had been proved by the core flooding test and field application that foam assisted steam flooding can recover more oil than the conventional steam flooding. 

Talbi et al. realized that immiscible CO2 can help increase oil recovery by dissolving in crude oil when the formation pressure is above 6 MPa. Meanwhile, Emadi et al. believed that injecting CO2 into heavy oil could result in low sweep efficiency as well as low displacement efficiency comparing with that injecting CO2 into light oil. By conducting a series of visualization experiments, Li et al. proposed that CO2 foam cannot only increase sweep efficiency, but also increase the displacement efficiency. Du et al. observed that the gas channeling in heavy oil reservoirs when conducted with CO2 huff and puff, in order to solve this problem, provided a new organic fiber composite gel to plug the channeling. Li et al. showed that the CO2 and viscosity reducer assisted steam huff and puff technology for horizontal wells achieves the rolling replacement of viscosity reduction of viscosity reducer, CO2, and steam, which reduces the steam injection pressure and expands the steam sweep area. Fan et al. added viscosity reducer named HD-2 into heavy oil at 553 K and found that viscosity reduction rate for oil can be as high as 95%. By conducting PVT tests, Li et al. acquired the effect of CO2 to swelling factor and viscosity of oil when heavy oil was saturated with CO2. Wang et al. reported a successful application nitrogen and viscosity reducer assisted steam huff and puff technology (HNDS) in Chunfeng oilfield. Although the effects of gas foam and viscosity reducer for recovering heavy oil has been verified, the combined mechanisms of all the injected components and heat have not been studied systematically.

In fact, CO2 foam or N2 foam requires a large amount of gas, while the gas injection cost is also quite high. In the process of China's economic development, a large amount of flue gas (nitrogen and carbon dioxide volume ratio is 4:1) is generated by steel enterprises or power plants. The industrial flue gas is applied to oil field production, which not only improves oil recovery, but also realizes the recycling of polluting gases. Many scholars have investigated the mechanism and application of flue gas for oil recovery. Wang & Li used a 60-cm-long core experiment to study the mechanism of flue gas in the process of heavy oil development by multi-thermal fluids. Flue gas can expand the swept scope, increasing the heat transfer resistance and hindering the move of steam to the cold body. Pang et al. analyzed the mechanism of flue gas in steam flooding using one-dimensional and three-dimensional displacement experiments. Among them, CO2 dissolution in oil can reduce viscosity and improve oil displacement efficiency, which is beneficial to displace the remaining oil at the top. Wu et al. and Dong et al. studied the mechanism of enhancing oil recovery using flue gas assisted steam flooding. Han et al. uses full diameter core to study the feasibility of supplementing formation energy by flue gas drive after water flooding. Li et al. and Huang et al. studied the effect of flue gas and n-hexane interaction on heavy oil properties after steam flooding. However, in the process of flue gas flooding, channeling is easily occurring by decreasing the sweep coefficient. Compounding flue gas and foaming agent solution can inhibit gas channeling by producing flue-gas foam and reducing the viscosity of crude oil. At present, limited studies were reported in this field.

The position and degree of removed-oil by flue-gas foam and hot water are quite different. Investigation on the removed-oil distribution in flue-gas foam assisted thermal-chemical flooding is helpful to understand the contribution of different components for enhanced oil recovery, which may lay a foundation for the optimization of flue-gas foam assisted thermal-chemical viscosity-reduction. The degree and location of removed-oil can be characterized by the difference of removed-oil distribution at a certain time after hot water flooding and at the same time with different development methods. As a post-pilot analysis, Hou et al. defined the conception of “response remaining oil saturation” in surfactant-polymer flooding. Liu et al. used this concept and investigated the position and shape of response remaining oil in the reservoir for displacing agent/foam assisted steam flooding by applying numerical simulation method. This paper mainly studies the distribution characteristics and formation mechanism of residual oil in flue-gas foam assisted thermal-chemical flooding.

In this paper, based on the characterization of these chemical agents such as flue-gas foam and viscosity reducer, a physical property characterization model is established, and a reservoir numerical simulation model is established by using the heavy oil reservoir conditions in the Shengli oilfield of China. Based on the distribution characteristics of
removed-oil in flue-gas foam assisted thermal-chemical flooding, the oil displacement mechanism and synergistic effect of various components in flue-gas foam and viscosity reducer were studied. The conception of “removed-oil” is used to determine the distribution of oil displaced by flue-gas foam assisted thermal-chemical flooding compared to the conventional hot water flooding.

2 NUMERICAL MODELS

2.1 Mechanism characterization models

2.1.1 Chemical reaction foam model

Flue-gas foam reduces the mobility of gas phase by increasing the gas viscosity.\(^3\)\(^9\) Gas phase contains four components, that is, \(N_2\), \(CO_2\), \(N_2\) foam, and \(CO_2\) foam. The apparent viscosity of gas phase is calculated from the viscosity and molar concentration of each component as shown in Equation (1).

\[
\mu_g = \frac{\sum_{i=1}^{4} y_i \mu_i M_i^{1/2}}{\sum_{i=1}^{4} y_i M_i^{1/2}}
\]

where \(i\) is component number, representing \(N_2\), \(CO_2\), \(N_2\) foam, and \(CO_2\) foam; \(\mu_g\) is apparent viscosity of gas phase, \(mPa\cdot s\); \(\mu_i\) is viscosity of component \(i\), \(mPa\cdot s\); \(y_i\) is component molar concentration of component \(i\) in gas phase, \(f\); \(M_i\) is molecular weight of component \(i\), g/mol.

The generation and destruction of foam is a dynamic reaction process. The CMG STARS version of the chemical reaction foam model implemented here is as shown in Equation (2). The generation rate and destruction rate are related to reaction rate constant, component molar concentration, and capillary force. The reaction rate constant depends on the gas type and foam agent properties.

\[
4.3 \times 10^{-5} F_F + 1.0 N_2 \Rightarrow 1.0 F_{N_2}
\]
\[
4.3 \times 10^{-5} F_F + 1.0 CO_2 \Rightarrow 1.0 F_{CO_2}
\]

where \(F_F\) is foam agent and \(F_{N_2}\) and \(F_{CO_2}\) are \(N_2\) foam and \(CO_2\) foam, respectively.

2.1.2 Oil viscosity reduction model

Oil viscosity can be reduced by viscosity reducer, heating, and \(CO_2\) dissolution. Water-soluble viscosity reducer can reduce crude oil viscosity while increasing oil mobility through miscibility. In the flooding process, viscosity reducer mixes with heavy oil, decreasing the oil viscosity; the viscosity reduction rate is more than 90%. In reservoir numerical simulation, two oil components are defined; that is, one is the original heavy oil component, and the other is the low-viscosity oil component after viscosity reduction. The process of viscosity reduction is characterized by oil viscosity reduction model, as shown in Equation (3). It is shown that consuming \(8.5 \times 10^{-4}\) mole viscosity reducer, 1.0 mole original heavy oil could be changed to 1.0 mole low viscosity oil.

\[
1.0 \text{Oil}_H + 8.5 \times 10^{-4} A_R \rightarrow 1.0 \text{Oil}_L + 8.5 \times 10^{-4} \text{Water}
\]

where \(\text{Oil}_H\) is the original heavy oil component; \(\text{Oil}_L\) is low-viscosity oil component; and \(A_R\) is viscosity reducer.

Viscosity of oil/viscosity reducer mixtures is defined as the mixing viscosity of two components. The Arrhenius viscosity mixing model is used to calculate oil phase viscosity, as shown in Equation (4).

\[
\ln \mu_x = x_1 \ln \mu_{oH} + x_2 \ln \mu_{oL}
\]

where \(\mu_x\) is a mixing oil viscosity, \(mPa\cdot s\); \(\mu_{oH}\) and \(\mu_{oL}\) are viscosity of original heavy oil and low-viscosity oil, respectively, \(mPa\cdot s\); \(x_1\) and \(x_2\) are molar concentration in the oil phase of original heavy oil and low-viscosity oil, respectively, \(f\).

Generally, viscosity of the crude oil decreases with the increasing temperature.\(^4\)\(^0\) The effect of temperature on oil viscosity is investigated by drawing the viscous-temperature curve.\(^4\)\(^1\) In this study, the oil viscosity-temperature curves are drawn for both the original heavy oil and the low-viscosity oil. With the knowledge of the viscosity of the original heavy oil and low-viscosity oil, the mixing oil viscosity at a specific temperature is determined by the Arrhenius viscosity mixing model.\(^4\)\(^2\)

2.2 Numerical simulation models

2.2.1 Reservoir modeling parameters

A pilot test of hot water flooding after conventional water flooding was implemented in the Shengli oilfield, which has typical characteristics of medium-depth heavy-oil reservoirs in China. The reservoir is buried in the depth of 1276 m under the ground with an average net pay thickness of 13.5 m, an average porosity of 0.32, an average permeability of 1530 \(\times 10^{-3}\) \(\mu m^2\), the initial oil saturation of 0.65, the initial reservoir pressure of 12.2 MPa, the reservoir temperature of 338.15 K, and the oil viscosity under the reservoir conditions of 285.0 mPa.s. This reservoir contains three layers (ie, \(Ng5^3\), \(Ng5^4\), \(Ng5^5\)) with a positive rhythm distribution. Twenty-one production wells and 4 injection wells in total are created in this model. At present, this reservoir has been developed by water flooding in the beginning. The recovery percent and water cut of water flooding stage are 19.17% and 95.00%, respectively.

It is difficult to conduct our work using a full field model because it contains lots of uncertain influencing factors which can make misunderstand the displacement mechanism of multi-fluid thermal recovery. Based on the
characteristics of this reservoir, a pair of injection-production wells are selected in the simulation region, as shown in Figure 1. This model is divided into $27 \times 27 \times 6$ grids. Dimensions for the grid blocks in the X, Y directions are both set to 5.4 m. The average net pay thickness of each layer is set as 2.25 m according to net pay thickness of the real field. An injection well (INJECTOR) and a production well (PRODUCER) are located in the model with all of the layers perforated.

### 2.2.2 Component model and parameters

CMG-SRARS was used to perform the reservoir numerical simulation by establishing a three-dimension 9-component model (including water, foaming agent, viscosity reducer, original heavy oil, low-viscosity oil, CO$_2$, N$_2$, CO$_2$ foam, and N$_2$ foam). The simulation mechanisms include the following: Hot water reduces the viscosity of crude oil by heating up; viscosity reducer reduces the interfacial tension and viscosity with emulsification; gas foam increases the viscosity of gas phase by expanding the sweep efficiency of viscosity reducer; N$_2$ possesses high compressibility, low-thermal conductivity, which can increase the formation pressure while reducing the heat loss; and CO$_2$ can dissolve into crude oil, reducing the viscosity and improving the mobility of the crude oil.

The chemical reaction parameters are shown in Table 1. The equilibrium constant of CO$_2$ is obtained from the laboratory experiments, as shown in Figure 2. Figure 3 presents the viscosity-temperature curves for original heavy oil and low-viscosity oil. Viscosity reduction rate of the viscosity reducer is about 90% at 338.15 K.

### 2.2.3 Simulation details

The scheme of hot water flooding is first simulated as a basic scheme; specifically, the hot water injecting rate is 200 m$^3$/d, the temperature of hot water is 433.15 K, and the production-injection ratio is 1.1, which is stopped when water cut reaches 96%. In this work, 4 different flooding schemes after hot water flooding are designed as shown in Table 2.

#### Table 1 The chemical reaction parameters

| Foam         | Parameters                  | Value  |
|--------------|-----------------------------|--------|
| N$_2$ Foam   | Generation rate (m$^3$/mol.s) | $1.72 \times 10^5$ |
|              | Decay rate (m$^3$/mol.s)     | $2.08 \times 10^6$ |
|              | Residual resistance coefficient | 2.5     |
|              | Apparent viscosity (mPa.s)   | 75     |
| CO$_2$ Foam  | Generation rate (m$^3$/mol.s) | $1.72 \times 10^5$ |
|              | Decay rate (m$^3$/mol.s)     | $2.82 \times 10^6$ |
|              | Residual resistance coefficient | 2.1     |
|              | Apparent viscosity (mPa.s)   | 45     |

In this paper, HW refers to hot water flooding; RH refers to viscosity reducer flooding and subsequent hot water flooding; CRH refers to CO$_2$/viscosity reduce compound flooding and subsequent hot water flooding; FH refers to flue-gas foam flooding and subsequent hot water flooding; and FRH refers to flue-gas foam/viscosity reducer compound flooding and subsequent hot water flooding.

Table 3 presents the simulation results of the five above flooding schemes. Compared with hot water flooding, these
floodling schemes all improved the final oil recovery. In addition, the combination of multiple additives can improve the recovery more effectively. The enhanced oil recovery from viscosity reducer flooding is 3.1% more compared to the hot water flooding, while FRH is 11.9% more than that of the hot water flooding.

3 RESULTS AND DISCUSSIONS

3.1 Characteristics of oil viscosity reduction

One of the most important oil recovery mechanisms is oil viscosity reduction, which cannot only increase the sweep efficiency, but also increase the displacement efficiency. In the flue-gas foam assisted thermal-chemical flooding, many components play an important role in reducing the viscosity of oil. In order to analyze the viscosity reduction effect of each component, the location and degree of oil viscosity reduction in the horizontal and vertical directions of reservoirs were calculated.

3.1.1 Horizontal distribution of oil viscosity

The layers 1, 3, and 5 are selected to analyze the horizontal distribution of oil viscosity in different schemes, as shown in Figure 4. It can be seen that, for hot water flooding and viscosity reducer flooding, the distribution of oil viscosity in each layer is similar, liking a circular around the injection well. The area of lower viscosity oil in bottom horizon is slightly less than that in upper layer, which is mainly due to the fast seepage rate of hot water in bottom layer. For CRH flooding, the viscosity reduction area of oil in the upper layer is larger, but the area of oil viscosity below 80 mPa·s is smaller, while in the bottom layer, it is larger. This is mainly due to the effect of buoyant and channeling of CO₂, so that the viscosity reduction of oil in the upper layer is caused by the dissolution of CO₂, and in the bottom layer, it is by viscosity reducer. For FH and FRH, the area of oil viscosity that lower than 80 mPa·s in the bottom layer is larger than that in the upper layer. This is mainly due to the existence of foam, which makes CO₂ and viscosity reducer play a role together, and the viscosity reduction efficiency is higher.

| No. | Scheme                              | Flue gas and chemical agent slugs                                                                                       |
|-----|-------------------------------------|-------------------------------------------------------------------------------------------------------------------------|
| 1   | Hot water flooding (HW)             | /                                                                                                                       |
| 2   | Viscosity reducer + Hot water flooding (RH) | Viscosity reducer slug 0.3 PV (concentration of 0.06%)                                                                |
| 3   | CO₂/viscosity reducer + Hot water flooding (CRH) | Five slugs of WAG (0.03 PV CO₂ and 0.03 PV hot water in each slug), followed by the viscosity reducer slug of 0.3 PV (concentration of 0.06%) |
| 4   | Flue-gas foam + Hot water flooding (FH) | 0.4 PV flue-gas foam (volume ratio of N₂ and CO₂ is 4:1, foaming agent concentration of 0.5%)                             |
| 5   | Flue-gas foam/viscosity reducer + Hot water flooding (FRH) | 0.4 PV flue-gas foam (volume ratio of N₂ and CO₂ is 4:1, foaming agent concentration of 0.5%), followed by the viscosity reducer slug of 0.3 PV and viscosity reducer concentration of 0.06% |

Abbreviations: C, CO₂ flooding; F, flue-gas foam flooding; H, hot water flooding; R, viscosity reducer flooding.

TABLE 3 Simulation results of different schemes

| Schemes | HW | RH | CRH | FH | FRH |
|---------|----|----|-----|----|-----|
| Oil recovery, % | 32.7 | 35.8 | 41.5 | 41.2 | 44.6 |
| Enhanced oil recovery, % | – | 3.1 | 8.8 | 8.5 | 11.9 |
Compared with hot water flooding, RH mainly reduces the oil viscosity and expands the sweep efficiency in the bottom layers. The area of viscosity reduction is near the injection well. As for CRH flooding, both CO₂ and viscosity reducer can reduce the oil viscosity, in which CO₂ can dissolve in the oil of upper layers to reduce the oil viscosity, while the viscosity reducer mainly reduces oil viscosity in the bottom layers. The synergistic effect of CO₂ and viscosity reducer enlarges the area of viscosity reduction. As for FH flooding, foam inhibits the override of CO₂ to the upper layers and inhibit the channeling of viscosity reducer at the bottom layers. As a result, viscosity reducer and CO₂ gas can achieve an equilibrium drive between layers. As for FRH flooding, the area of low viscosity oil is large in the bottom layers and has spread to the production well, while it presents a ring-like shape near the injection well in the upper layers.

3.1.2 | Vertical distribution of oil viscosity

Figure 5 shows the increment of oil viscosity reduction in each layer of the reservoir for different schemes. Viscosity reducer can reduce oil viscosity in the lower layers than that in the upper layers of RH. In Figure 5, it can be seen that after injecting CO₂ and viscosity reducer syntactically for CRH, oil viscosity of each layer is reduced significantly. Removed-oil displaced by CRH in the upper layers is mainly gained by the mechanism of gas driving and profile controlling. It is found that the effect of viscosity reduction of FH in the central layers is better than that in other layers, which is as a result of heat-preservation function of N₂. Meanwhile, CO₂ in foam (FH and FRH) can help reduce oil viscosity, which thus increases the removed-oil correspondingly. By injecting foam and viscosity reducer syntactically (FRH), oil viscosity of lower layers is reduced significantly, leading to a higher removed-oil saturation in this area.

3.1.3 | Viscosity reduction contribution degree of different components

It is believed that the oil displacement is closely related to oil viscosity reduction. However, the contributions of viscosity reducer, heating, and CO₂ dissolution to oil viscosity reduction are different. According to the numerical simulation results, molar concentration of the original heavy oil, low-viscosity oil, and CO₂ in oil phase of each grid is obtained, and the viscosity of oil saturated by CO₂ or by low-viscosity oil can be calculated using the Arrhenius viscosity mixing model, as shown in Equations (5 and 6). So, the contributions from viscosity reducer, heating, or CO₂ can be calculated by

![Figure 4](image1)

The horizontal distribution of oil viscosity for different schemes

![Figure 5](image2)

Viscosity reduction curves of different schemes
Equations (7-9). Summarizing the contribution degrees of all grids from each layer, the viscosity reduction contribution degrees of viscosity reducer, heating, and CO₂ to each layer can thereby be calculated.

\[
\ln \mu_{oc} = y_1 \ln \mu_{oH} + y_2 \ln \mu_{co2} \quad (5)
\]

\[
\ln \mu_{oR} = y_1 \ln \mu_{oH} + y_3 \ln \mu_{ol} \quad (6)
\]

\[
C_{co2} = \frac{\mu_{oH} - \mu_{oc}}{\mu_{oH} - \mu_{o}} \times 100\% \quad (7)
\]

\[
C_R = \frac{\mu_{oH} - \mu_{oR}}{\mu_{oH} - \mu_{o}} \times 100\% \quad (8)
\]

\[
C_H = 100 - C_{CO2} - C_R \quad (9)
\]

where \(\mu_{oc}\) is the viscosity of oil saturated by CO₂; \(\mu_{oR}\) is the viscosity of oil saturated by low-viscosity oil; \(\mu_{co2}\) is the viscosity of CO₂ in oil phase; \(\mu_{ol}\) is the viscosity of low-viscosity oil generated by viscosity reducer; \(\mu_{o}\) is the viscosity of oil processed by viscosity reducer, heating, and CO₂; \(\mu_{oH}\) is the viscosity of original heavy oil at reservoir temperature; \(y_1\) is the mole fraction of original heavy oil in oil phase; \(y_2\) is the mole fraction of CO₂ in oil phase; \(y_3\) is the mole fraction of low-viscosity oil in oil phase; \(C_{co2}\) is the viscosity reduction contribution of CO₂; \(C_R\) is the viscosity reduction contribution of viscosity reducer; \(C_H\) is the viscosity reduction contribution of heating.

Take RH as an example, Figure 6A shows the viscosity reduction contributions of viscosity reducer and heating to each layer at the end of RH flooding. Furthermore, selecting layer 3 as the typical layer, the change of viscosity reduction contribution along the connecting lines between the injection well and production well is shown as Figure 6B. The viscosity reduction contribution of heating from the upper layer to the bottom layer is decreased. The contribution of heating in the bottom layer is 16%, and that of the top layer is about 50%. The viscosity reducer acts mainly near the injection well with the contribution reaching about 92%. When the distance from injection well exceeds 80 m, the contribution of heating increases gradually to 98% near the production well.

The viscosity reduction contribution from viscosity reducer, heating, and CO₂ for CRH, FH, and FRH are shown in Figures 7-9. It is found that oil viscosity reduction by heating is an important mechanism in all schemes. Compare Figure 7 with Figure 9, although the contribution of viscosity reducer can be more than 60%, the effect mainly concentrates near the injection well and bottom layers. However, the removed-oil is very few in this region due to the less residual oil saturation after hot water flooding. Flue-gas foam expands the sweep area of viscosity reducer. As a result, how to further expand the area of viscosity reducer should be the main purpose in the following study. CO₂ is not considered to be suitable for displacing heavy oil, which can be proved by Figure 8. Therefore, by using foam to control the profile of CO₂, the area of viscosity reduction contribution of CO₂ can be effectively expanded the distance between injection well and...
production well, which means that more remaining oil can be recovered by the injected CO$_2$.

3.2 | Spread area of gas and chemical agents

3.2.1 | Migration and distribution characteristic of foam

Figure 10 presents the distribution of mole concentration of foam during FH flooding. Figure 10A shows that the horizontal distribution of mole concentration in gas phase at the three stages, that is, the end of flue-gas-foam slug injection, 0.3 PV’s, and 0.6 PV’s water injection in the successive hot water flooding after flue gas injection. In order to characterize the variation of mole concentration of foam between the injection well and production well, foam mole concentration is drawn with the distance from injection well at the time nodes, as shown in Figure 10B. The ring-like distribution of foam is observed at the end of foam injecting scenarios, indicating that the velocity of foam migration is uniform in the horizontal distribution. Meanwhile, because the foam has the characteristics of “stability in water and instability in oil” and the oil saturation in the upper layers are higher than that in the bottom layers, the spread area of foam is larger in the bottom layers. After injecting foam, hot water is injected. Under the influence of gravity, the mole concentration of foam in the bottom layers begins to decrease, resulting in the accumulation of foam in the upper layers. The plugging effect of foam reduces the gas channeling in the upper layers, and the area of removed-oil by FH in the upper and middle layers is obviously enlarged.

3.2.2 | Migration and distribution characteristic of flue gas

The practice has proved that much more flue gas migrates in the top of reservoir if only the flue-gas flooding was applied, leading to only small amount of oil displaced in the bottom of reservoir. Flue gas is conducive to balance the displacement profile. Figure 11 shows the distribution of flue-gas saturation in layers 1, 3, and 5 at the three stages, that is, the end of flue-gas foam slug injection, 0.3 PV’s, and 0.6 PV’s water injection in the successive hot water flooding after flue gas injection. Flue gas is circularly distributed near the injection well horizontally. In vertical, the distribution of flue gas is similar in different layers, indicating that flue gas in foam flooding is more uniform than that in single flue-gas flooding. In the stage of hot water flooding after flue-gas foam injected, flue gas tends to distribute in the upper layers due to the overriding effect. The gas saturation in the bottom layers decreases. Due to the profile control effect of foam, gas distribution in the upper layers expands, suggesting that foam effectively reduces the gas channeling and thus increases the sweeping efficiency.

3.2.3 | Migration and distribution characteristic of viscosity reducer

Figures 12 and 13 show the distribution of viscosity reducer (concentration of viscosity reducer in water phase) in the layers 1, 3, and 5 from RH and CRH at the end of viscosity-reducer slug injection, 0.1 PV’s, and 0.2 PV’s hot water injection in the successive hot water flooding. The viscosity reducer mainly migrates along the bottom layers when the viscosity reducer is used alone. With the subsequent hot water injection, the
viscosity reducer in the upper layers disappeared rapidly due to the high oil saturation and the fast-chemical reaction and consumption of the viscosity reducer. As a result, the sweeping area of viscosity reducer is quite small in the CRH flooding.

As for the CRH flooding, viscosity reducer is injected with CO$_2$, the area of viscosity reducer is larger than that of RH and CO$_2$ distribution in the upper layers. In the hot water flooding stage, the distribution area of viscosity reducers in each layer is expanded, and the phenomenon of tongue-in appears. This is mainly due to the CO$_2$ channeling along the mainstream between the injection well and the production well, resulting in the decrease of flow resistance along the mainstream. However, compared with the RH, the distribution range of viscosity reducers in the upper and lower reservoirs of CRH is expanded to a certain extent, and the CO$_2$ distribution in the upper reservoirs is wider; as a result, CRH can achieve a much larger sweeping efficiency than the RH.

### 3.3 Distribution characteristics of removed-oil

The conception of “removed-oil” is used to determine the distribution of oil displaced by flue-gas foam assisted thermal-chemical flooding compared to the conventional hot water flooding.
flooding. The removed-oil saturation is not only affected by the difference between remaining oil saturation after flue-gas foam assisted thermal-chemical flooding and after hot water flooding, but also considers the influences on oil saturation by heat and oil swelling by CO₂ dissolving. Equations (10-13) are used to calculate the removed-oil saturation of each grid in the numerical simulation model. \( S_{orHW}, S_{orCFDW}, \rho_{orHW}, \rho_{or}, \rho_{oCFDW}, \rho_{CO₂} \) and \( X \) can be got from the numerical simulation results.

\[
S_{Ro}(i,j,k) = S_{orHW}(i,j,k) - S_{orCFDW}(i,j,k) \quad (10)
\]

\[
S_{orHW}(i,j,k) = S_{orHW}(i,j,k) \cdot \frac{\rho_{oHW}(i,j,k)}{\rho_{o}(i,j,k)} \quad (11)
\]

\[
S_{orFRH}(i,j,k) = S_{orFRH}(i,j,k) \cdot \frac{\rho_{oFRH}(i,j,k)}{\rho_{o}(i,j,k)} \quad (12)
\]

\[
\rho_{oFRH}(i,j,k) = \frac{1}{\left( \frac{X_{i,j,k}}{\rho_{CO₂}(i,j,k)} + \frac{1 - X_{i,j,k}}{\rho_{oHW}(i,j,k)} \right)} \quad (13)
\]

where \( i, j, \) and \( k \) are the serial numbers of numerical simulation grid; \( S_{Ro} \) is the removed-oil saturation in flue-gas foam assisted thermal-chemical flooding; \( S_{orHW} \) is the effective remaining oil saturation after hot water flooding; \( S_{orFRH} \) is the effective remaining oil saturation after flue-gas foam assisted thermal-chemical flooding; \( S_{orHW} \) is the remaining oil saturation after hot water flooding; \( S_{orFRH} \) is the remaining oil saturation after hot water flooding.

**FIGURE 12** Migration and distribution characteristic of the viscosity reducer in RH. (A) Concentration of viscosity reducer. (B) Concentration of viscosity reducer with distance from injection well

**FIGURE 13** Migration and distribution characteristic of the viscosity reducer in CRH. (A) Concentration of viscosity reducer. (B) Concentration of viscosity reducer with distance from injection well
oil saturation after flue-gas foam assisted thermal-chemical flooding; \( \rho_{\text{oHW}} \) is the oil density after hot water flooding; \( \rho_{\text{oFRH}} \) is the oil density after gas foam assisted thermal-chemical flooding; \( \rho_{\text{CO}} \) is the \( \text{CO}_2 \) density; \( \rho_{\text{o}} \) is oil density at the origin state of reservoir; and \( X \) is the \( \text{CO}_2 \) mass fraction of in oil phase.

In order to quantitatively characterize the distribution characteristics of “removed-oil,” two parameters, that is, ARRO and SDRO, are thus defined. ARRO is defined as the proportion of grid area with the removed-oil saturation higher than 0 to the total area of all grids in the simulation. SDRO is defined as the averaged removed-oil saturation in the grid with the removed-oil saturation higher than 0.

Figure 14 shows the results of ARRO and SDRO in different flooding schemes. It can be concluded that both ARRO and SDRO of RH are the lowest among all the schemes. FH, which mainly applies flues-gas foam, can achieve the highest ARRO. Using \( \text{CO}_2 \) and viscosity reducer, CRH helps to gain the highest SDRO. To sum up, flue gas, especially \( \text{CO}_2 \), can help acquire a higher area ratio of removed-oil, while viscosity reducer can help achieve the higher saturation degree of removed-oil.

3.3.1 | The horizontal distribution of removed-oil

Figure 15 shows the horizontal distribution of removed-oil saturation in layers 1, 3, and 5, respectively. Overall, the removed-oil in the upper layers is mainly produced from \( \text{CO}_2 \) dissolution, while the removed-oil in the bottom layers is resulted from the viscosity reducer. As for RH flooding, the distribution area of removed-oil is small, which is mainly distributed in the annular area between the injection well and the production well. The ARRO and SDRO in each layer are similar. As for CRH flooding, due to the gas overlap, oil in the upper layers is dissolved by \( \text{CO}_2 \) to reduce viscosity, resulting in more removed-oil. The removed-oil in the bottom layers is similar to that of RH. As for FH flooding, flue-gas foam increases the sweep area of \( \text{CO}_2 \). The distribution area of removed-oil in the upper layers is large, which is mainly located on sides of the mainstream line. However, due to the absence of viscosity reducer, the removed-oil distribution in the bottom layers is relatively small. As for FRH flooding, under the combined effects of \( \text{CO}_2 \), viscosity reducer and foam, the distribution area and saturation of removed-oil are larger, which thus results in a high oil recovery.

3.3.2 | Vertical distribution of removed-oil

In order to investigate the vertical distribution characteristics of removed-oil, the ARRO and SDRO in each layer...
are calculated after being displaced by flue-gas foam assisted thermal-chemical flooding, as shown in Figure 16. As for RH flooding, the averaged removed-oil saturation in each layer is similar, while the area ratio of removed-oil in the bottom layers is higher than that in the upper layers. Overall, the area ratio of removed-oil of the whole model is significantly smaller than that of other schemes. The removed-oil distribution for CRH presents not only a higher area and saturation at the upper layers but also a higher saturation in the bottom layers. As for FH flooding, the area and saturation of removed-oil are both higher with the help of flue gas. Compared with FH, the area and saturation of removed-oil displaced by FRH at the upper layers is slightly lower, while it is much higher at the bottom layers, indicating that the removed-oil in each layer can be effectively recovered.

4 | CONCLUSIONS

1. The mechanism of flue-gas foam assisted thermal-chemical flooding for the medium depth heavy oil reservoirs is viscosity-reduction by CO₂, viscosity reducer and hot water, and plugging channeling by flue-gas foam. Using viscosity reducer flooding, higher degree of viscosity-reduction occurs near the injection well, while it has a poor effect at the whole reservoir. FH flooding can achieve large removed-oil saturation by profile controlling of flue-gas foam. By co-injecting the foam and viscosity reducer in FRH flooding, more remaining oil are produced.

2. By analyzing the viscosity reduction contribution degree of each component and heating, it is believed that although viscosity reduction contribution of viscosity reducer can be as high as 60%, the removed-oil saturation is still low because viscosity reduction effect mainly concentrates near the injection. CO₂ is not suitable for displacing heavy oil due to its sever fingerling. However, by using CO₂ co-injected with foam, the viscosity reduction area can be effectively expanded, which indicates that more remaining oil can be recovered. As a result, finding a more effective way to control the CO₂ profile should be the main purpose in the following study.

3. Distribution of gases and chemicals has an important effect for enhancing oil recovery. When injecting viscosity reducer singly, the removed-oil area is the smallest, which is only 30% of the reservoir and mainly distributes near the injection well. When co-injecting flue gas with viscosity reducer, the compound effect of foam and viscosity reducer is better than both of CO₂ and viscosity reducer.

4. Distribution characteristics of removed-oil vary with different injection fluids. By investigating the horizontal and vertical distribution of removed-oil, the effects of CO₂, foam, and viscosity reducer are recognized. The injected CO₂ could cause gas breakthrough, resulting in a low area of removed-oil. Foam cannot only improve the injection profile, but also ease the gas fingering in the upper layers. The distributing area of viscosity reducer is limited when it is injected, while the co-injecting viscosity reducer with flue-gas foam can expand the area of viscosity reducer.

ACKNOWLEDGEMENTS

The authors greatly appreciate the financial support of the National Key Research and Development Program of China (Grant No. 2018YFA0702404), the National Natural Science Foundation of China (Grant No. 51574269), the National Science Foundation for Distinguished Young Scholars of China (Grant No. 51625403), the Important National Science and Technology Specific Projects of China (Grant No. 2016ZX05011-003), the Fundamental Research Funds for the Central Universities (Grant Nos. 15CX08004A, 18CX02169A, 18CX02094A), China Postdoctoral Science Foundation (Grant No. 2017M622319), and the Natural Science Foundation of Shandong Province (Grant No. ZR2018BEE004).

CONFLICT OF INTEREST

None declared.
REFERENCES

1. Liu Y, Jin Z, Li HA. Comparison of Peng-Robinson equation of state with capillary pressure model with engineering density-functional theory in describing the phase behavior of confined hydrocarbons. *SPE Journal*. 2018;23(05):1784-1797.

2. Shah A, Fishwick R, Wood J, Leete G, Rigg S, Greaves M. A review of novel techniques for heavy oil and bitumen extraction and upgrading. *Energy Environ. Sci.* 2010;3(6):700-714.

3. Huang X, Li A, Li X, Liu Y. Influence of typical core minerals on tight oil recovery during CO$_2$ flooding using the nuclear magnetic resonance technique. *Energy Fuels*. 2019;33(8):7154-7174.

4. Hamouda AA, Karoussi O, Chukwudeme EA. Relative permeability as a function of temperature, initial water saturation and flooding fluid compositions for modified oil-wet chalk. *J Petrol Sci Eng*. 2008;63(1-4):61-72.

5. Bagheripour Haghighi M, Ayatollahi S, Shabaninejad M. Comparing the performance and recovery mechanisms for steam flooding in heavy and light oil reservoirs. In *SPE Heavy Oil Conference Canada*, Society of Petroleum Engineers; 2012.

6. Cochran LE. Formation evaluation in the geothermal environment. The Geysers steam field, California. In *SPE Annual Technical Conference and Exhibition*, Society of Petroleum Engineers; 1979.

7. Ali SM. Heavy oil recovery-principles, practicality, potential, and problems. SPE Rocky Mountain Regional Meeting. Society of Petroleum Engineers; 1974.

8. Ali SM, Meldau RF. Current steamflood technology. *J Petrol Technol*. 1979;31(10):1-332.

9. Narayan KA, Walsh BW. An experimental investigation of hydrocarbon recovery from a porous medium by continuous steam injection. *Fuel*. 1988;67(2):215-220.

10. Zhang Y, Li X, Zhang X. Four fundamental principles for design and follow-up of steam flooding in heavy oil reservoirs. *Petrol Explor Develop*. 2008;35(6):715-719.

11. Kong S, Huang X, Li K, Song X. Adsorption/desorption isotherms of CH$_4$ and C$_2$H$_6$ on typical shale samples. *Fuel*. 2019;255:115632.

12. Diaz-Munoz J, Ali SM. Simulation of cyclic hot water stimulation of heavy oil wells. SPE 5668; 1975.

13. Kumar M, Hoang VT, Satik C, Rojas DH. High-mobility-ratio waterflood performance prediction: challenges and new insights. *SPE Reservoir Eval Eng*. 2008;11(01):186-196.

14. Alajmi AF, Gharbi R, Algharaib M. Investigating the performance of hot water injection in geostatistically generated permeable media. *J Petrol Sci Eng*. 2009;36(66):143-155.

15. Alajmi AF, Gharbi R, Algharaib M. The effect of heterogeneity and well configuration on the performance of hot water flood. *J Petrol Sci Eng*. 2014;122:524-533.

16. Martin WL. Results of a tertiary hot waterflood in a thin sand reservoir. *J Petrol Technol*. 1968;20(07):739-750.

17. Shi L, Liu P, Shen D, Liu P, Xi C, Zhang Y. Improving heavy oil recovery using a top-driving, CO$_2$-assisted hot-water flooding method in deep and pressure-depleted reservoirs. *J Petrol Sci Eng*. 2019;173:922-931.

18. Patzek TW. Field applications of steam foam for mobility improvement and profile control. *SPE Reservoir Eng*. 1996;11(02):79-86.

19. Dong X, Liu H, Chen Z, Wu K, Lu N, Zhang Q. Enhanced oil recovery techniques for heavy oil and oilsands reservoirs after steam injection. *Appl Energy*. 2019;239:1190-1211.

20. Talbi K, Kaiser T, Maini BB. Experimental investigation of co-based vapex for recovery of heavy oils and bitumen. *J Can Pet Technol*. 2008;47(4):54-61.

21. Emadi A, Sohrabi M, Jamialahmady M, Irland S, Robertson G. Mechanistic study of improved heavy oil recovery by CO$_2$-foam injection. In *SPE Enhanced Oil Recovery Conference*, Society of Petroleum Engineers; 2011.

22. Li S, Li Z, Li B. Experimental study and application on profile control using high-temperature foam. *J Petrol Sci Eng*. 2011;78(3-4):567-574.

23. Li Z, Lu T, Tao L, Li B, Zhang J, Li J. CO$_2$ and viscosity breaker assisted steam huff and puff technology for horizontal wells in a super-heavy oil reservoir. *Petrol Explor Develop*. 2011;38(5):600-605.

24. Du Q, Hou J, Zhao F, Zhou K, Liu W, Liu Y. A new organic fiber composite gel as a plugging agent for assisting CO$_2$ huff and puff in water channeling reservoirs. *J Petrol Sci Eng*. 2019;179:70-79.

25. Fan HF, Liu YJ, Zhong LG. The composition and viscosity changes of heavy oils after aquathermal cracking at the presence of reservoir minerals. *Oilfield Chem*. 2001;18(4):299-301.

26. Li H, Yang D, Tontiwachwuthikul P. Experimental and theoretical determination of equilibrium interfacial tension for the solvent (s)-CO$_2$–heavy oil systems. *Energy Fuels*. 2012;26(3):1776-1786.

27. Wang X, Jinzhu WJ, Qiao M. Horizontal well, nitrogen and viscosity reducer assisted steam huff and puff technology: Taking super heavy oil in shallow and thin beds, Chunfeng Oilfield, Junggar Basin, NW China, as an example. *Petrol Explor Develop*. 2013;40(1):104-110.

28. Fang T, Wang M, Gao Y, Zhang Y, Yan Y, Zhang J. Enhanced oil recovery with CO$_2$/N$_2$ slug in low permeability reservoir: Molecular dynamics simulation. *Chem Eng Sci*. 2019;197:204-211.

29. Liu Y, Ma X, Hou J. Comparing the effectiveness of SO$_2$ with CO$_2$ for replacing hydrocarbons from nanopores. *Energy Fuels*. 2013;27(8):7147-7154.

30. Wang Z, Li Z. Roles of flue gas in promoting steam flow and heat transfer in multi thermal fluid flooding. *Math Prob Eng*. 2019;2019:1-8.

31. Pang Z, Qi P, Zhang F, Ge T, Liu H. The experimental analysis of the role of flue gas injection for horizontal well steam flooding. *J Energy Res Technol*. 2018;140(10):102902.

32. Wu Z, Liu H, Wang X. 3D Experimental Investigation on Enhanced Oil Recovery by Flue Gas Coupled with Steam in Thick Oil Reservoirs. *Energy Fuels*. 2018;32(1):279-286.

33. Han H, Li S, Ma D, Ji Z, Yu H, Chen X. Investigation of flue gas displacement and storage after the water flooding in a full diameter conglomerate long-core. *Petrol Explor Develop*. 2019;179:70-79.

34. Li S, Li Z, Sun X. Effect of flue gas and n-hexane on heavy oil properties in steam flooding process. *Fuel*. 2017;187:84-93.

35. Huang X, Li T, Gao H, Zhao J, Wang C. Comparison of SO$_2$ with CO$_2$ for recovering shale resources using low-field nuclear magnetic resonance. *Fuel*. 2019;245:563-569.

36. Hou J, Du QJ, Shu QL, Zhang B, Gao D. Macroscopic response and follow-up of steam flooding in heavy oil reservoirs. In *SPE Heavy Oil Conference Canada*, Society of Petroleum Engineers; 2011.

37. Hou J, Pan G, Lu X, Wei C, Qiu M. The distribution characteristics of additional extracted oil displaced by surfactant–polymer
flooding and its genetic mechanisms. *J Petrol Sci Eng.* 2013;112:322-334.

38. Liu H, Hou J, Wu G, Wei T, Wang D, Wang C. Oil Recovery for heavy oil by displacing agent/foam assisted steam flooding: laboratory experiments, numerical simulations and field performances. In *SPE International Heavy Oil Conference and Exhibition*, Society of Petroleum Engineers; 2014.

39. Busahmin B, Maini B, Karri RR, Sabet M. Studies on the stability of the foamy oil in developing heavy oil reservoirs. *Defect Diffus Forum.* 2016;371:111-116.

40. Busahmin B, Maini BB. Measurements of surface tension for mineral and crude oil systems. *Defect Diffus Forum.* 2019;391:106-113.

41. Abusahmin BS, Karri RR, Maini BB. Influence of fluid and operating parameters on the recovery factors and gas oil ratio in high viscous reservoirs under foamy solution gas drive. *Fuel.* 2017;197:497-517.

42. Tavallali M, Maini B, Harding T, Busahmin B. Assessment of SAGD well configuration optimization in Lloydminster heavy oil reserve. In *SPE/EAGE European Unconventional Resources Conference & Exhibition-From Potential to Production*; 2012.

How to cite this article: Du Q, Liu H, Wu G, Hou J, Zhou K, Liu Y. Application of flue-gas foam in thermal-chemical flooding for medium-depth heavy oil reservoirs. *Energy Sci Eng.* 2019;7:2936–2949. [https://doi.org/10.1002/ese3.471](https://doi.org/10.1002/ese3.471)