Research Article
Experimental Investigation and Numerical Simulation of Dynamic Characteristics for Multithermal Fluid-Assisted SAGD in Extraheavy Oil Reservoir

Zhenhua Xu,1 Xiaokun Zhang,1 Zhenyi Cao,2 Pengcheng Liu,1 Zhe Yuan,3 Lanxiang Shi,4 and Botao Kang5

1School of Energy Resources, China University of Geosciences, Beijing 100083, China
2Department of Oilfield Exploration & Development, PetroChina Coalbed Methane Company Limited, Linfen 041000, China
3Great Wall Drilling Engineering Kunshan Company, PetroChina, Suzhou 215337, China
4Research Institute of Petroleum Exploration and Development, PetroChina, Beijing 100083, China
5CNOOC Research Institute Co. Ltd., CNOOC, Beijing 100028, China

Correspondence should be addressed to Pengcheng Liu; liupengcheng8883@sohu.com

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Loss of the vast majority of heat and steam is an unavoidable problem encountered during conventional steam-assisted gravity drainage (SAGD) in extraheavy oil reservoirs. The noncondensate gas coinjection technique of reducing energy consumption and enhancing oil recovery can effectively solve this problem. Aiming at extraheavy oil with a high initial viscosity, the influence of noncondensate gases in multithermal fluids on the physical parameters of extraheavy oil was experimentally studied; the production characteristics and mechanism of multithermal fluid-assisted SAGD were studied through numerical simulation. A comparative investigation of the conventional SAGD and multithermal fluid-assisted SAGD injection schemes was conducted. The characteristics and mechanism of the steam chamber during the production processes were analyzed. The results show that a steam-gas-oil system forms in the steam chamber in the case of multithermal fluids. The steam chamber can be partitioned into four zones, and the flow of the oil mainly occurs in the steam condensation zone and the oil drainage zone. The injected multithermal fluids increase the horizontal expansion of the steam chamber, while the dissolved carbon dioxide reduces the residual oil saturation. Moreover, the nitrogen injection significantly reduces the heat loss and increases the heat utilization for multithermal fluid-assisted SAGD in developing extraheavy oil reservoirs.

1. Introduction

Extraheavy oil reservoirs with a high initial viscosity under reservoir conditions are usually effectively exploited using thermal methods [1]. Steam-assisted gravity drainage (SAGD) is commonly used to develop extraheavy oil reservoirs [2, 3]. Nevertheless, the low utilization rate and high-energy loss of the SAGD process are major problems, which result in its limited application [4]. The production efficiency of the SAGD is low, and the cost of the production process is high [5].

Improving the production efficiency to achieve a more economical method has become the focus of many studies. Chemical solvents have been introduced as injected additives to enhance oil recovery [6–9]. The expansive solvent-SAGD (ES-SAGD) process makes full use of the mass transfer effect of the light hydrocarbon components [10, 11]. The mixed hydrocarbon gas injection of steam has been shown to significantly enhance oil recovery in oilfield projects and laboratory experiments, and it significantly reduces the amount of steam injection [12, 13]. Nevertheless, heavy oil has different components and physical properties, and the selection of suitable solvents is crucial to the successful development of the ES-SAGD technique [14–19]. Moreover, extraheavy oil has a high asphaltene content, and when the intermixture of extraheavy oil and some solvents occurs, asphaltene...
precipitation and hardening have been observed [20–22]. Asphaltenes precipitate can block the reservoir's pores and cause unrecoverable damage to the reservoir [23].

For extraheavy oil reservoirs, steam flooding is characterized by a high cost, low recovery factor, and poor economic benefits [24]. Many scholars have presented multicomponent steam-gas displacement techniques, the gas components of which mainly include CO2, N2, air, or flue gas. Therefore, the steam-assisted and gas push (SAGP) process was presented as a new heavy oil reservoir development technique [25, 26]. The effect of noncondensate gas (e.g., CO2 and N2) mixed steam injection on the liquid phase condensation is limited in the SAGP production process [27–30]. N2 has good thermal insulation properties and large compressibility; it is clean, nonpoisonous, readily available, and inexpensive [31, 32]. The solubility of CO2 in heavy oil is 50–100 m3/m3 at 6.0 MPa, and the volume expansion of crude oil is 10–20%, which reduces the oil viscosity by more than 80% [33, 34]. Moreover, CO2 is highly soluble in the asphaltene components, which can further enhance oil recovery [35]. However, the sweep efficiency is relatively low when only CO2 is injected [36].

In the last decade, flue gas, which is rich in CO2 and N2, has gradually been introduced as an additive injected into the formation, and this process has reduced the environmental pollution caused by such gases [37]. Then, the high-temperature and high-pressure multithermal fluids are generated by injecting fuel and air into the combustion chamber through the high-pressure combustion mechanism [38]. Its main components are N2, CO2, and steam. Compared to traditional steam, multithermal fluids are a mixture of multiple gases with higher latent heat and superheated steam [39, 40]. In recent years, some scholars have measured the PVT physical properties of flue gas dissolved in heavy oil under different temperatures and pressures using laboratory experiments. The role of multithermal fluids in the development of extraheavy oil reservoirs was studied using models of different dimensions of SAGD physical experiments [41, 42].

Similar to the SAGD and SAGP, the main function of injecting multithermal fluids is to enhance the oil's fluidity [41]. However, there are some differences. First, in the SAGP technique, the injected gas is usually a single gas (methane, N2, or CO2) [43], while multithermal fluids are a mixture of superheated steam and a variety of noncondensable gases (e.g., N2, CO2, CH4, CO, and other gases) [41]. Furthermore, due to the different steam generation methods used in these two production schemes, the heat-carrying capacity of the steam is higher during the multithermal fluid process. The steam component in the former is generally saturated steam, while the component in the latter is superheated steam [44].

Although gas-assisted SAGD and the mechanisms of flow in reservoir development through horizontal well have been extensively researched [45–50], its application to the production mechanisms of multithermal fluid-assisted SAGD has seldom been studied, especially for the development of extraheavy reservoirs.

In this study, the influence of the injection of noncondensate gases into extraheavy oil was studied experimentally, and the production characteristics and mechanism of multithermal fluid-assisted SAGD were studied through the numerical simulation of two different injection schemes. In this study, the effects of multithermal fluids on the extension of the steam chamber were examined and evaluated. The dynamic changes in the steam chamber, temperature, oil viscosity, oil saturation, fluidity of oil phase, and other parameters were compared under different production schemes. The simulation performances and results were analyzed and revealed that thermal coinjection fluids are an effective process for enhancing oil recovery in extraheavy oil reservoirs.

2. Experiments

2.1. Experimental Apparatus. Figure 1 shows the experimental equipment used for the PVT experiment for the noncondensates of extraheavy oil. The influences of the noncondensate gases (mainly CO2 and N2) used in the multithermal fluid-assisted SAGD on the physical parameters of the extraheavy oil were investigated, and the necessary data for the subsequent simulations were obtained.

The main experimental devices include a high-pressure rheometer, a piston-type high-pressure mixer, a sampler, and a gas acquisition unit. The piston-type high-pressure mixer is composed of a controller and a mixer cylinder. The controller controls the rotation of the mixer cylinder and detects the temperature and pressure inside the cylinder. The configuration of the mixer cylinder is similar to that of the piston container. One end of the piston is loaded with the oil sample, and the other end is connected with the ISCO pump to adjust the pressure inside the mixer cylinder. The gas flowmeter monitors and controls the volume of the methane, CO2, and N2 injected into the mixer cylinder.

2.2. Experimental Materials

2.2.1. Extraheavy Oil. The oil sample used for the PVT experiments was acquired from the Xinjiang Fengcheng oil reservoir, which is a heavy oil reservoir. The oil sample had a density of 0.994 g/cm3 at 20°C.

2.2.2. Noncondensable Gas. The gases included industrial N2, industrial CO2, and methane. All the gases were 99.0% pure.

2.3. Experimental Procedures

(1) The oil sample was dehydrated, and the viscosity-temperature curve of the sample was measured. The mixer cylinder was heated to the experimental test temperature, the oil sample was poured into the mixer cylinder, and the injected volume was recorded. The corresponding methane volume was calculated based on the initial dissolved gas-oil ratio and the volume of the oil sample, and the mixer cylinder was injected. The mixer cylinder was set to flip mode to stir and evenly mix the sample until the oil-gas system reached equilibrium (i.e., the pressure did not drop within 2.0 hours).

(2) The volume of CO2 and N2 to be injected was calculated based on the component proportions of CO2
and N\textsubscript{2} (15% : 85%) and the remaining volume of the gas phase in the mixer cylinder. The volume of CO\textsubscript{2} and N\textsubscript{2} was injected through the gas flowmeter control, the mixer cylinder pressure was adjusted to the experimental pressure using the ISCO pump, and the stirring and mixing continued until equilibrium was reached (i.e., the pressure did not drop within 2.0 hours)

(3) The outlet end of the sampler was connected to the high-temperature and high-pressure rheometer, and the viscosity of the oil sample was measured under different temperatures and pressures. By discharging the water in the piston to adjust the pressure of the mixer cylinder, the expansion volume of the mixer cylinder was measured and the expansion volume of the heavy oil sample was calculated

(4) The mass of the empty sampler was measured. The valve was opened and the backpressure at the end of the sampler was set slightly below the target pressure (within 0.2 MPa) to ensure that the pressure inside the sampler was stable and to avoid degassing. The valve was closed once the flow of the oil out of the sampler at the outlet was continuous, and the oil sample was deemed to fully fill the sampler

(5) The sampler filled with oil was weighed in order to calculate the density of the oil sample. The gas acquisition unit was connected to separate the dissolved gas. The volume of the dissolved gas was measured using the drainage method, and the solubility was calculated

2.4. Experimental Results. The PVT characteristics of the mixture of extraheavy oil and multithermal fluids were measured at different pressures and temperatures. Figure 2 shows the PVT experiment results including the extraheavy oil density, viscosity, dissolved gas-oil ratio, and volumetric oil expansion.

As can be seen from Figures 2(a) and 2(c), at the same pressure, the density and viscosity of the oil gradually decreased with increasing temperature, and the range of the decrease gradually increased. At the same temperature, the density and viscosity of the oil also decreased with increasing pressure. The dissolution of the injected noncondensable gas (mainly CO\textsubscript{2} and C\textsubscript{1}) in the sample resulted in a decrease in the viscosity of the oil. At a given temperature, as the pressure increased, more CO\textsubscript{2} dissolved and the viscosity of the oil sample decreased, but the decreased viscosity changes the rate at unit temperature.

As can be seen from Figure 2(b), at a given pressure, the solubility of the noncondensate gas in the oil gradually decreases with increasing temperature, and the decrease gradually became larger. At a given temperature, the dissolved gas-oil ratio increased with increasing pressure. The temperature and pressure affect the intermolecular clearance and the movement of the gas molecules, thus affecting their solubility. The movement of the gas molecules increases as the temperature increases, causing less noncondensate gas to dissolve in the oil. At a given temperature, the gas molecule gap gradually decreases with increasing pressure, causing more noncondensate gas to dissolve in the oil.

In this experiment, the volumetric expansion of the oil sample at 66 °C was measured. As is shown in Figure 2(d), the sample in the mixer cylinder began to expand as water was discharged and the pressure decreased. The total volume increased to 889 mL as the pressure dropped from 15.93 MPa to 2.18 MPa. The amplitude of the volume expansion changed significantly at the intersection of two tangents of the volume-pressure curve, which is approximately equal to the saturation pressure of the oil sample. Therefore, according to the curve, the bubble point pressure of the oil sample was 4.16 MPa at 66 °C.

Table 1 shows the test results of dissolved gas components collected in the experiment. According to Table 1, C\textsubscript{1} was the main component in dissolved gas, followed by CO\textsubscript{2}, while the content of N\textsubscript{2} was less than 1% under different temperatures and pressures, and it was basically insoluble in heavy oil. Under the same pressure condition, the content of component C\textsubscript{1} increased with the increased temperature, while the content of CO\textsubscript{2} decreased, indicating that compared with C\textsubscript{1}, the high-temperature environment was not conducive to the dissolution of CO\textsubscript{2}. However, at the same temperature, with the increased pressure, the content of C\textsubscript{1} in the dissolved gas has a relatively large decrease, while the content of CO\textsubscript{2} is relatively increased. Under the conditions of 6.0 MPa and 46 °C, the contents of the two components were close to the same, indicating that C\textsubscript{1} was first dissolved in heavy oil under low-pressure environment, while the CO\textsubscript{2}...
component was more easily dissolved in heavy oil under high-pressure environment.

3. Numerical Simulation

3.1. Model Parameters. The CMG-STARS software was used to study the conventional SAGD and multithermal fluid-assisted SAGD processes. A homogeneous reservoir model with two horizontal wells was established. The X, Y, and Z directions of the model grid quantities were 20, 59, and 36, respectively. And the lengths of a grid in the X, Y, and Z directions were 25 m, 2 m, and 1 m, respectively. There was a 5 m vertical distance between the horizontal wells. The CMG Winprop was used to define the solubility of the CO₂ dissolved in the crude oil using the K value (i.e., the equilibrium constant) of gas-liquid in the original reservoir. The injected fluid was composed of superheated steam, N₂, and CO₂, and the equilibrium constant of the gas was calculated using an empirical formula [51]. Figure 3 shows the relative permeability curves of the simulation. Table 2 lists the key parameters used in the simulations.

CO₂ and methane were defined as the oil phase, and N₂ was set as the gas phase in the basic settings. The dissolution of the CO₂ in the oil was set based on the equilibrium constant. Ten years of oil production was simulated. For the conventional SAGD, the steam quality was 0.9, the steam injection temperature was 243°C, and the steam injection volume was 150 m³/day.
In order to prevent the vast loss of heat (i.e., steam flow to the production well to form steam channeling), the maximum steam flow rate of the production well was set as 2 m³/day. For the multithermal fluid-assisted SAGD, the steam quality of the injected steam was set to 1 and the injection pressure was set to 3.5 MPa (under this condition, the saturation temperature was 243 °C). The injection temperature was 250 °C, with a superheat degree of 7. The ratio of steam to gas was 1.5 : 1 (t/Sm³), and the ratio of N₂ to CO₂ was 1 : 1 (Sm³/Sm³).

### Table 1: Dissolved gas component test results.

| No. | Pressure (MPa) | Temperature (°C) | CO₂ (%) | C₁ (%) | N₂ (%) |
|-----|---------------|-----------------|---------|--------|--------|
| 1   | 2.00          | 46              | 13.11   | 86.55  | 0.28   |
| 2   | 2.00          | 66              | 7.57    | 92.15  | 0.14   |
| 3   | 2.00          | 100             | 3.78    | 95.77  | 0.02   |
| 4   | 2.00          | 200             | 1.44    | 97.79  | —      |
| 5   | 4.00          | 46              | 30.19   | 69.43  | 0.33   |
| 6   | 4.00          | 66              | 24.57   | 75.11  | 0.18   |
| 7   | 4.00          | 100             | 16.08   | 83.41  | 0.06   |
| 8   | 4.00          | 200             | 9.86    | 89.23  | 0.05   |
| 9   | 6.00          | 46              | 47.38   | 51.87  | 0.68   |
| 10  | 6.00          | 66              | 43.05   | 56.59  | 0.19   |
| 11  | 6.00          | 100             | 35.94   | 62.92  | 0.11   |
| 12  | 6.00          | 200             | 20.15   | 78.00  | 0.05   |

### Table 2: Key parameters used in the numerical simulations.

| Parameter (unit) | Value |
|------------------|-------|
| Reservoir pressure (MPa) | 4.0   |
| Top depth (m)      | 440   |
| Porosity (f)       | 0.26  |
| Permeability X, Y (D) | 1.47  |
| Permeability Z (D) | 0.8   |
| Well length (m)    | 400   |
| Reservoir temperature (°C) | 21.3  |
| Oil saturation (f) | 0.70  |
| Oil viscosity at 50°C (mPa·s) | 74700 |
| The length of the reservoir (m) | 500   |
| The width of the reservoir (m) | 118   |
| The thickness of the reservoir (m) | 36    |

Figure 3: Relative permeability curves: (a) oil-water relative permeability curves; (b) liquid-gas relative permeability curves.

### 3.2. Simulation Results.

According to the results of the numerical simulation, Figures 4 and 5 show the front and side views, respectively, of the characteristics of the steam chambers of two schemes at the end of production. Figure 6 shows the distribution of the residual oil saturation.
As can be seen from Figures 4 and 5, the temperature of the upper region is lower in the side view of the multithermal fluid-assisted SAGD steam chamber, while the expansion region in the horizontal and downward directions is significantly larger in the front view. This is because the N₂ in the injected fluid forms a heat separation zone between the overlying formation and the reservoir, which reduces the heat loss from the steam chamber to the outside, resulting in the faster and more uniform lateral extension of the steam chamber in the multithermal fluid-assisted SAGD scheme. In addition, due to the partial pressure of N₂, the saturation temperature of the steam decreased as the saturation pressure of the steam decreased, and the temperature in the upper region decreased accordingly. In the later stage of the production process, there were significant differences between the two schemes. The steam chamber of the conventional SAGD scheme was V-shaped, while that of the multithermal fluid-assisted SAGD scheme was U-shaped.

As can be seen from Figure 6, at the end of the production process, the distributions of the residual oil saturations of the two schemes were also quite different. For the multithermal fluid-assisted SAGD scheme, the residual oil was mainly concentrated at the boundaries and bottom of the reservoir, and the area was also smaller than that of the conventional SAGD scheme.

Figure 7 shows the distributions of CO₂ and N₂ in the steam chamber of the multithermal fluid-assisted SAGD. As can be seen from Figure 7(b), the lower concentrations of CO₂ indicate that it was more easily dissolved in the extraheavy oil, which improved the oil fluidity and reduced the viscosity of the extraheavy oil. Therefore, the CO₂ was mainly focused in the middle and upper parts of the steam chamber. From Figure 7(b), because N₂ is difficult to dissolve in extraheavy oil, the results of the gas distribution simulation show higher concentrations of N₂ in the upper part of the oil reservoir, which served the purpose of heat insulation and pressure stabilization.

The results of the numerical simulations at the end of production are presented in Table 3. The oil recovery ratio curves of the two schemes are shown in Figure 8. In the first 3 years of production, the oil recovery of...
the two schemes was almost the same, but as the production time increased, the oil recovery of the multithermal fluid-assisted SAGD scheme was higher than that of the pure steam scheme.

As can be seen from Table 3, compared with the conventional SAGD, the multithermal fluid-assisted SAGD had a higher cumulative oil recovery and a lower cumulative steam-oil ratio (cSOR). Moreover, the volume of the steam chamber of the multithermal fluid-assisted SAGD was larger, and it had a better production performance.

### Table 3: Production results for the two development methods.

| Development method                  | Cumulative steam injection (m³) | Oil recovery (%) | cSOR  | Steam chamber volume (m³) |
|-------------------------------------|---------------------------------|-----------------|-------|--------------------------|
| Conventional SAGD                  | 522925.6                        | 38.40           | 6.41  | 26500.9                  |
| Multithermal fluid-assisted SAGD    | 439225.4                        | 41.99           | 4.70  | 38450.2                  |

4. **Results and Discussion**

4.1. *Steam Chamber Zone in the SAGD.* Figure 9 shows the right-half section of the steam chamber cross-section, from the left end (steam chamber’s center) to the right end (cold oil zone far from the chamber). From Figure 9, the steam chamber can be divided into four zones: a, b, c, and d. The red dotted lines on the cross-section illustrate the typical region of the study shown (the thickness in the Z direction is 1 m).
4.1.1. Pure Steam Zone. The formation temperature is basically unchanged, and the steam is saturated steam. As the steam flows, the rock pores are full of steam, and the oil saturation is the residual oil saturation.

4.1.2. Steam Condensation Zone. The steam transfers heat when it touches the cold extraheavy oil before it condenses through diffusion of the steam. In this zone, the temperature at the edge of the steam chamber is basically unchanged or is slightly decreased. Due to the condensation and accumulation of the steam, the water saturation begins to increase significantly and reaches the maximum value at the boundary of the steam condensation zone. The extraheavy oil saturation also increases gradually.

4.1.3. Oil Drainage Zone. Due to the heat transfer between the injection fluid and the oil sand at the boundary of the steam chamber, the oil viscosity decreases and the flow capacity of the extraheavy oil significantly increases. The heated oil flows down into the production well at the bottom of the formation. As the distance to the oil drainage zone increases, the fluidity of the oil phase decreases. In the oil drainage zone, the condensate and movable oil flow downward under the action of gravity. For a reservoir of a certain thickness, the flux of oil mainly depends on the total heat transferred to the cold oil zone outside of the steam chamber. When the temperature of the chamber’s boundary is high, the additional heat can be transmitted to the cold oil zone, thus expanding the range of the oil drainage zone. In this zone, the water saturation continues to decrease.
4.1.4. Cold Oil Zone. This zone is the farthest from the injection well, and it is difficult to transfer the heat of the injected steam to this zone. Therefore, the temperature is relatively low and is basically the same as the original formation temperature. In this zone, the extraheavy oil cannot flow, and the oil saturation is the original formation of oil saturation.

4.2. Dynamic Characteristics of the Steam Chamber. In order to better analyze the role of the steam and injected gas in the multithermal fluid-assisted SAGD production process, in this study, the relationships between the different parameters (i.e., temperature, oil saturation, oil viscosity, and oil phase fluidity) and the distance to the center of the steam chamber were plotted. Figure 10 displays the changes in temperature with distance for the two schemes after 2 years of production.

As can be seen from Figure 10, for the two schemes, the temperatures in the pure steam zone and the steam condensation zone remained unchanged; the temperature of the conventional SAGD scheme was close to the steam injection temperature (228°C), while the temperature of the multithermal fluid-assisted SAGD scheme was slightly lower (221°C). This is because, in addition to steam, N₂ and CO₂ existed in the steam chamber. In this steam-gas-heavy oil system, a new equilibrium state was established based on the partial pressure of the noncondensable gas and its dissolution in oil. The newly formed saturation pressure-temperature relationship resulted in the temperature of the saturated steam in the multithermal fluid-assisted SAGD scheme being lower than that in the conventional SAGD scheme.

Figure 11 shows the relationships between the oil viscosity, oil phase fluidity, and the distance for the two different schemes. In the study region, the thickness of the pure steam zone of the multithermal fluid-assisted SAGD scheme (A: 0-7 m) is larger than that of the conventional SAGD scheme (A: 0-5 m). This indicates that after the multithermal fluids are injected, the expansion speed of the steam chamber accelerated. In the pure steam zone (A), the oil viscosity of the multithermal fluid-assisted SAGD scheme (5.68 mPa-s) was slightly lower than that of the conventional SAGD scheme (6.21 mPa-s). The thickness of the steam condensation zone of the multithermal fluid-assisted SAGD scheme (B: 7-11 m) was also greater than that of the conventional SAGD scheme (B: 5-7 m) at a given time. For the conventional SAGD scheme, in the oil drainage zone (C), the fluidity of the oil phase increased significantly, and it reached a maximum value of 36.8 mD/mPa-s. For the multithermal fluid-assisted SAGD scheme, the fluidity of the oil phase was higher, reaching a maximum of 39.7 mD/mPa-s, and the end of the oil drainage zone was farther away (C: ~21 m).

For the multithermal fluid-assisted SAGD scheme, due to the steam condensation, the mole fraction of the injected mixture increased and the mole fraction of the steam in the gas phase decreased. Therefore, the condensation temperature of the steam decreased as the partial pressure decreased. Moreover, as the CO₂ dissolved into the oil, in the steam condensation zone (B), the steam condensed under certain CO₂ concentration and temperature conditions, and the rate of increase of the oil viscosity was slower, while the rate of increase of the oil phase fluidity was greater, and the oil viscosity was further decreased by the dissolved injected gases. As the distance gradually increased, the oil fluidity began to decrease. In the cold oil zone (D), the oil viscosity gradually increased to the original formation viscosity and the fluidity of the oil phase decreased to 0 (i.e., basically no flow).
In comparison, the oil viscosity at the boundary between the oil drainage zone (C) and the cold oil zone (D) was lower for the multithermal fluid-assisted SAGD scheme (136.8 mPa·s), than for the conventional SAGD scheme (213.1 mPa·s). In addition, the oil production rate of the multithermal fluid-assisted SAGD scheme was also larger, which is demonstrated by the difference in the areas above the oil phase fluidity curves in Figure 11. The area of the multithermal fluid-assisted SAGD scheme is larger than that of the conventional SAGD scheme.

Figure 12 shows the relationships between the oil saturation, water saturation, and the distance for the two different schemes. As can be seen from Figure 12(a), for the conventional SAGD scheme, in the pure steam zone (A: 0-5 m), the residual oil saturation was 0.22 and the water saturation was 0.42. However, in the steam condensation zone (B: 5-7 m), due to the steam condensation, the water saturation increased significantly to a maximum of 0.74 at the boundary of the steam condensation zone (B: ~7 m), and the oil saturation also began to increase. In the cold oil zone (D), the oil saturation and water saturation were the same as the original reservoir conditions.

As can be seen from Figure 12(b), for the multithermal fluid-assisted SAGD scheme, the area of the low oil saturation region increased, and the residual oil saturation was 0.20, which was slightly lower than that of the conventional SAGD scheme. The reason for this is the extraction and purification of the extraheavy oil by CO₂, which reduced the oil viscosity at the boundary between the oil drainage zone (C) and the cold oil zone (D).
saturation. Due to the release of the latent heat carried by the steam, the water saturation gradually increased, reaching a maximum of 0.69 at the edge of the steam condensation zone (B: ~11 m). At the boundary, the temperature of the steam-gas-heavy oil system began to decrease and the oil saturation was close to the original oil saturation.

In the oil drainage zone of the multithermal fluid-assisted SAGD scheme (C: 11-21 m), the steam and noncondensable gas contacted the extraheavy oil at the boundary, and the CO$_2$ was dissolved in the oil due to the oil-gas equilibrium. The solubility of the CO$_2$ in the oil was determined by the temperature and partial pressure of the CO$_2$ in the gas phase near the boundary of the zone, and a noncondensable gas enrichment region was formed. As a result of the change in the water saturation and oil phase fluidity, the thickness of the oil drainage zone in the multithermal fluid-assisted SAGD scheme (C: 11-21 m) became narrower, but the fluidity of the oil phase increased.

The distributions of the injected gas in the gas and oil phase also differed in the two production schemes. Figure 13 shows the mole fractions of N$_2$ and CO$_2$ in the gas and oil phases in the multithermal fluid-assisted SAGD.

By comparing the mole fractions of N$_2$ and CO$_2$, it can be seen that the content of N$_2$ was greater than that of CO$_2$ because the solubility of CO$_2$ in oil was far greater than that of N$_2$. At the boundary of the steam condensation zone (B), the mole fractions of CO$_2$ and N$_2$ in the gas phase were 0.38 and 0.52, respectively. Accordingly, the mole fraction of CO$_2$ in the oil phase was determined by the equilibrium state of the gas and oil, and it gradually increased to a maximum of 0.0027. Then, due to the change in the phase characteristics of the reservoir, the CO$_2$ component transitions from the oil phase to the gas phase.

4.3. Production Mechanism of the Multithermal Fluid-Assisted SAGD. Table 4 lists the parameters of the steam chamber boundary, the thicknesses of the steam condensation zone, and the oil drainage zone in the upper part, the middle part, and the bottom part for the two different schemes after 2 years of production.

As can be seen from Table 4, for the conventional SAGD, from the top to the bottom, the thickness of the steam condensation zone is basically unchanged, and the thickness of the oil drainage zone and the oil phase fluidity gradually increase. For...
the multithermal fluid-assisted SAGD scheme, the changes in the parameters are basically consistent with those of the conventional SAGD scheme. The temperature of the chamber boundary increases slightly at the bottom, which may be due to the proximity to the steam injection well. The thickness of the oil drainage zone in the upper and middle parts of the conventional SAGD steam chamber is larger than that of the multithermal fluid-assisted SAGD steam chamber, but the fluidity of the oil phase is generally smaller.

In the multithermal fluid-assisted SAGD production process, in addition to the traditional mechanisms of heat transfer and viscosity reduction, the dissolution of the injected gas also increases the area of the low viscosity zone, which significantly improves the oil phase fluidity in the oil drainage zone, resulting in enhanced oil recovery. As the thicknesses of the pure steam zone and the steam condensation zone increase, the volume of the steam chamber increases significantly. The injected CO₂ has the effect of extracting and purifying the light components of the extraheavy oil, and it reduces the remaining oil saturation in the steam chamber. The equilibrium state of the steam-gas-heavy oil system near the boundary of the steam condensation zone determines the amount of injected gas dissolution. Most of the oil flow occurs in the oil drainage zone. From the top to the bottom of the reservoir, the fluidity of the oil phase gradually increases. In the cold oil zone, the oil phase fluidity is close to 0.

5. Conclusions

(1) The dissolution of mixed gases can improve the expansion capacity and further reduce the viscosity of extraheavy oil, which is beneficial to the flow of extraheavy oil. The dissolved gas-oil ratio increases with increasing pressure and decreases with increasing temperature. The density and viscosity of extraheavy oil decrease with increasing temperature and pressure. Volume of super heavy oil slowly increases initially and then sharply increases with decreasing pressure.

(2) Compared with the conventional SAGD in developing extraheavy oil reservoirs, for the multithermal fluid-assisted SAGD, the volume of the steam chamber is larger; the cumulative oil recovery is higher, and the cSOR is lower. In the production process, based on the changes in the oil saturation, water saturation, and oil phase fluidity, four zones can be delineated from the center of the steam chamber to the boundary: the pure steam zone, the steam condensation zone, the oil drainage zone, and the cold oil zone. The oil flow mainly occurs in the steam condensation zone and the oil drainage zone.

(3) In the steam chamber of the multithermal fluid-assisted SAGD, a steam-gas-oil system is formed. The relationship between the partial pressure of the noncondensable gas and the saturation pressure-temperature resulting from its dissolution in the oil results in a lower temperature in the steam chamber.

Due to the extraction and purification of CO₂, the residual oil saturation decreases. The thermal insulation of N₂ reduces the heat loss from the steam chamber to the outside. A noncondensable gas enrichment region is formed in the oil drainage zone, and the fluidity of the oil phase increases. As the oil saturation decreases and the oil phase fluidity increases, the cumulative oil production finally increases.

(4) The mole fraction of N₂ is larger than that of CO₂ in the gas phase. At the boundary of the steam condensation zone, the mole fractions of N₂ and CO₂ in the gas phase reach their maximum values, and the gas-oil equilibrium state determines the mole fraction of CO₂ in the oil phase. As it gradually diffuses farther away from the center of the steam chamber, the CO₂ component transitions from the oil phase into the gas phase.

Data Availability

The data that support the findings of this study are available from the corresponding author upon reasonable request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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