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Research on the Zonal Coupling Mechanism of Flue Gas-Assisted Cyclic Steam Stimulation

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ABSTRACT

In the later stage of cycle steam stimulation(CSS), the production capacity decreases and the water cut increases. As an alternative development method to cycle steam stimulation, the flue gas-assisted cycle steam stimulation(FGACSS) has been widely applied in heavy oil development. However, existing research has not been able to reveal the mechanisms of different components in different zones, making it difficult to provide effective guidance. In this paper, based on the analysis of production dynamics from typical wells in the Moltuk field, a mechanistic model of FGACSS is constructed. The different zones of action for different components are delineated, and microscopic displacement experiments are conducted to study the flow states of oil, gas, and water in different zones at the microscopic level. The research results show that, based on the distribution of different components and reservoir parameters, the wellbore to far-well region can be divided into three zones: the high-temperature zone (0-25m), recombination zone (25-100m), and increased pressure zone (100-200m). In the high-temperature zone, the main mechanism is the viscosity reduction through condensation of steam. The flow state is water-oil, with different flow characteristics in large and small pores. In the recombination zone, viscosity reduction is achieved through heat conduction and CO_2 dissolution. The presence of CO_2 and N_2 in the gas phase increases the pressure, and the flow state at the microscopic level is water-oil-gas-oil. The hot water and non-condensable gas displace different types of residual oil. In the increased pressure zone, only N_2 is present, and the pressure continuously decreases. The flow state is gas-oil. Based on the dynamic analysis of typical wells, this paper proposes a multi-composition zoning coupling mechanism, providing reference for further research on FGACSS mechanisms and adjustments to production measures.

Keywords: heavy oil, flue-gas assisted cyclic steam stimulation, zonal coupling mechanism, production analysis, microscopic experiment

NONMENCLATURE

Abbreviations	
CSS	Cycle Steam Stimulation
FGACSS	Flue Gas-Assisted Cycle Steam Stimulation
SAGD	Steam-Assisted Gravity Drainage
Symbols	
d	Day
t	ton

1. INTRODUCTION

Heavy oil has attracted widespread attention globally due to its abundant reserves and wide distribution worldwide. However, its high viscosity and density pose significant challenges to its development. Thermal recovery methods such as steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) are commonly used to reduce the viscosity of heavy oil to enhance its flowability. Steam-assisted production methods account for 60% to 80% of the total production of heavy oil[1,2]. Currently, most oil fields reach a decline stage of CSS, resulting in decreased oil production, increased water content, and overall reduced production efficiency, necessitating new replacement methods. Flue gas-assisted cyclic steam stimulation is one of the main replacement methods, where flue gas mainly consists of

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CO_2 and N_2. Injecting flue gas along with steam into the heavy oil reservoir can improve steam utilization and development effectiveness.

Scholars both domestically and internationally have conducted research on the different mechanisms of FGACSS through experiments and simulations. Yang et al. studied the production enhancement mechanism of non-condensable gases in FGACSS through experiments and numerical simulations. They found that CO_2 in FGACSS can effectively reduce the viscosity of heavy oil and the residual oil saturation, while N_2 assists in expanding the steam sweep range and reducing steam losses[3]. Zhang et al. used CMG simulation on a discrete wellbore model and suggested that non-condensable gases can compound with steam to reduce viscosity, expand the steam sweep coefficient, and improve the thermal efficiency of FGACSS[4]. Ge et al. studied the oil displacement mechanism of FGACSS using a one-dimensional sand-packed tube model. They divided the displacement process of FGACSS into four mechanisms: initiation, displacement, breakthrough, and erosion, and proposed that thermal viscosity reduction is the most significant mechanism[5]. Wang et al. conducted condensation experiments with water vapor and found that flue gas hinders the condensation heat transfer coefficient between steam and reservoir rocks, thereby expanding the heating range of the steam chamber[6]. Wang et al. conducted condensation experiments and one-dimensional core displacement experiments, and found that while flue gas increases heat transfer resistance, it also forms gas channels, providing a flow path for steam, and promotes the sequestration of CO_2[7]. Huang et al. compared the changes in the four components of heavy oil before and after displacement by FGACSS through experiments on rock cores. They found that steam can crack heavy components such as asphaltenes and resins, reducing the viscosity of heavy oil[8]. Isabel Sandoval M et al. conducted three-dimensional experiments on multi-component thermal fluid huff-n-puff, statistically analyzing the production of FGACSS under different huff-n-puff cycles. They found that the early-stage effect of FGACSS is better than the later-stage effect[9]. Liu et al. conducted high-temperature and high-pressure PVT experiments as well as one-dimensional, two-dimensional, and three-dimensional experiments, and found that the solubility of CO_2 in water vapor exhibits a non-linear relationship with temperature. They proposed the synergistic effect of water vapor, CO_2, and N_2, and suggested that the higher capillary number of FGACSS is the fundamental reason for their high displacement efficiency[10]. Liu et al. conducted physical simulation experiments and found that the dissolution and viscosity reduction effect of CO_2 in heavy oil is significantly better than that of N_2. Based on a practical field model, they proposed that the heating radius and recovery rate of multi-component thermal fluid huff-n-puff are better than those of steam huff-n-puff, and suggested the synergistic effect among steam, CO_2, and N_2[11]. Zhang et al. established a numerical model and compared it with steam huff-n-puff to study the production enhancement mechanism of FGACSS. They concluded that FGACSS can expand the steam chamber sweep range, improve reservoir energy, and reduce the coupling and competition between different media in FGACSS[12].

This paper is based on the production data from two wells, HMB-16 and HMB-17, in the Moltuk Oilfield. It analyzes the variations in oil production and water cut during the FGACSS process. Additionally, a numerical model of the FGACSS field is established to delineate the different compositional zones and reveal the coupling mechanisms in different regions within the reservoir. Finally, microscopic experiments are conducted to study the microflow characteristics in different zones, providing a theoretical foundation for the subsequent development of FGACSS.

2. PRODUCTION CHARACTERISTICS OF FGACSS

2.1 Field Proflie

The Murtuk Oilfield is located on the eastern slope of the Pre-Caspian Basin in Kazakhstan, characterized by the development of four east-trending normal faults. The reservoir is a shallow reservoir from 150m to 300m. It is a major onshore shallow sandstone heavy oil reservoir. The geological reserves can reach 1.9×108 tons. By 2023, 185 Wells will be in production. Since 2014, the Murtuk Oilfield has been developed using thermal and cold production methods. Among them, the main thermal method is cyclic steam stimulation (CSS) for production. However, after 3~5 cycles of CSS, it faced issues such as low production rates and increasing water cut. Since 2018, Flue Gas-Assisted Cyclic Steam Stimulation (FGACSS) has been conducted in the Murtuk block.

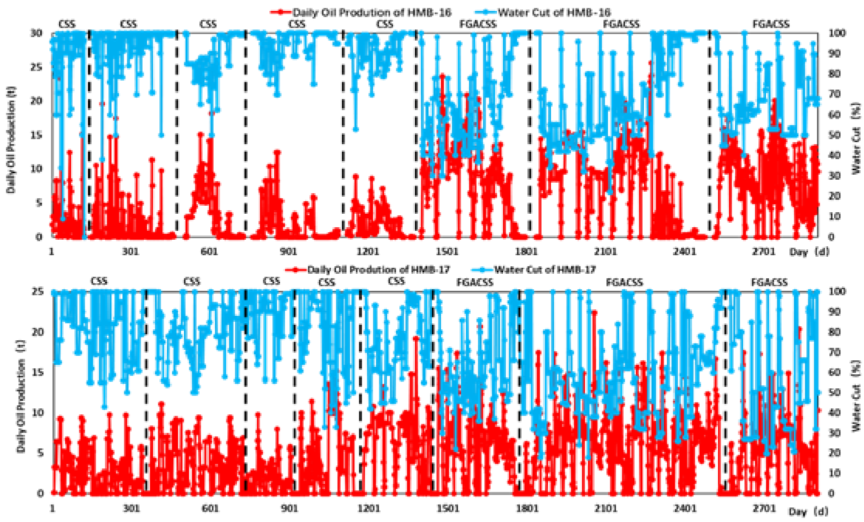


Fig. 1. HMB-16 and HMB-17 Production Dynamic

2.2 Oil production

In the first three cycles of CSS, the daily production is 5~10t/d, and the stable production period is basically throughout the whole throughput cycle, while in the last two cycles of CSS, the daily oil production is greatly reduced (0~5t/d), and the stable production period becomes shorter, and the stable production time is not more than half. In 5 years of CSS, the cumulative oil production is 2437t, the oil-steam ratio in the whole process is 0.11, and the production efficiency is relatively low. After FGACSS, due to non-condensate gas, the reduction of heat loss declines, and non-condensate gas can replenish sufficient formation pressure, and daily oil production can be significantly increased to 10-20 t/d, which can achieve almost full stability throughout the production phase. The cumulative oil production of FGACSS is 11,570 t, and the average oil-steam ratio is 2.1, which is 4.7 times and 19 times of the CSS stage, respectively, and the production efficiency is greatly improved.

In the ongoing process of the late FGACSS, due to the decrease of oil available in the late near-wellbore area, the steam injected in the eighth round was twice that of the first two steam injection cycles, and the oil-steam ratio was only 1/3 of that of the sixth cycle. Therefore, it can be shown that moderate steam and non-condensate gas supplementation is required in the later stage of FGACSS to maintain stable production.

2.3 Water cut

The gradual increase of water cut in the later stage of CSS is also one of the main problems faced. As shown in the Fig. 1, in the first three cycles of CSS, the water cut is relatively low at about 80%, while in the last two cycles, the water cut is basically 90%~100%. Among them, most of the produced water in CSS comes from the injected water steam. After the water steam is injected into the formation, the water steam is quickly condensed into hot water in the well entering area. Oil and water flow out of the well. In the late stage of CSS, the oil saturation in the near-well area decreased, and the water saturation increased, so the water cut increased significantly. After FGACSS conversion, the water cut of each cycle was maintained between 40% and 60%, and basically did not change with the change of the cycle. On the one hand, the non-condensate gas replenishes the heavy oil far away from the well and maintains the lower water saturation. On the other hand, the flow capacity of gases is much higher than that of liquids, limiting the output of water.

3. ZONAL COUPLINGMENCHANISMS OF FGACSS

3.1 Model establishment

Based on the dynamic analysis of wells HMB-16 and HMB-17 using the Mohr-Coulomb HMB-16 and HMB-17 wells, it was observed that in the late stage of cyclic steam stimulation (CSS), the oil production rate decreases and the water cut increases, resulting in a shorter stable production period. However, after converting from CSS to flue gas-assisted cyclic steam stimulation (FAGCSS), there is a significant increase in daily oil production and bottomhole flowing pressure, while the water cut decreases substantially. Therefore, in this study, a mechanism model for the conversion from steam CSS to FGACSS was established based on the reservoir properties and production data obtained from the Mohr-Coulomb analysis. The model was developed using the STARS thermal recovery module of CMG, as shown in Fig. 2.

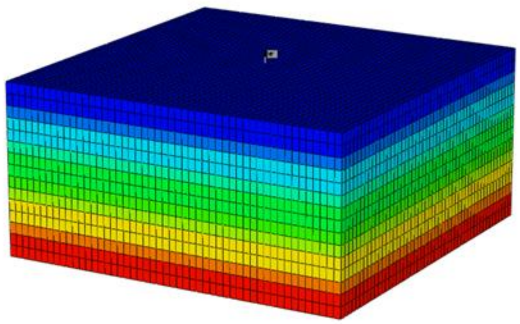


Fig. 2. HMB-16 and HMB-17 Production Dynamic

3.2 Three mechanism zones

After the injection of FGACSS into the reservoir, the interaction between steam, non-condensable gas, and heavy oil in the reservoir is a dynamic process. It is influenced by the properties of the injected medium and the effectiveness of the interaction varies. As shown in Fig. 3(a) and (b), based on the distribution of steam, CO_2, and N_2 in the reservoir, as well as the characteristics of temperature, viscosity, and pressure fields, and the distribution of substance content, the affected area of FAGCSS can be divided into three zones from the wellbore to the reservoir boundary: the high-temperature zone (0-25m), the recombination zone (25-100m), and the increased pressure zone (100-200m), corresponding to regions 1, 2, and 3 in Fig. 3 and Fig. 4, respectively.

After the injection of steam into the reservoir, it accumulates mainly in the 0-25m zone from the wellbore. Beyond 25m, the steam quality becomes negligible, resulting in the formation of the high-temperature zone. In this zone, the steam rapidly condenses, releasing a large amount of heat and significantly increasing the temperature. As a result, the viscosity of the heavy oil decreases dramatically, approaching zero. When non-condensable gas is present, it occupies the space between steam molecules, increasing the distance between them and hindering their aggregation and condensation. Additionally, both steam and non-condensable gas flow towards the condensation surface. The non-condensable gas forms a gas-rich layer between the condensation surface and the steam molecules in the air, impeding steam condensation. In terms of convective heat transfer, the non-condensable gas has strong diffusion characteristics. Under the influence of pressure differences, it interacts with the steam, resulting in higher steam velocities and enhanced convective heat transfer efficiency between the steam and the heavy oil.

In the recombination zone, which is located between 25-100m from the wellbore, the concentrations of CO_2 and N_2 increase. Both gases start to interact, resulting in a decrease in the viscosity of the heavy oil. At this stage, the steam quality is zero, and steam exists in the reservoir in the form of hot water. Heat transfer primarily occurs through conduction, and the temperature gradually decreases from 150°C to the initial reservoir temperature of 15°C. The concentration of CO_2 reaches its peak in this zone. However, the viscosity reduction achieved through CO_2 dissolution is limited. Consequently, the viscosity of the heavy oil continues to increase within this zone, rising from nearly 0 to 8000 mPa·s. By fitting the viscosity-temperature curve equation and using MATLAB calculation tools, it has been determined that the viscosity reduction rate achieved through CO_2 is only around 20% in the recombination zone. Therefore, in the entire reservoir, the condensation of steam is the primary mechanism for viscosity reduction.

In this zone, CO_2 and N_2 in the gas phase also contribute to increasing the reservoir pressure. The reservoir pressure is initially 3100 kPa, and it increases by 1100 kPa due to the presence of CO_2 and N_2. This increased pressure, once the well is opened, provides a significant driving force for the production of heavy oil.

In the zone between 100-200m from the wellbore, the reservoir temperature decreases to the initial reservoir temperature. Only N_2 is present in the injected fluid, and as the distance from the wellbore increases, the saturation of N_2 gradually decreases. Consequently, the pressure increment provided by N_2 decreases, reaching the original formation pressure at a distance of 200m.

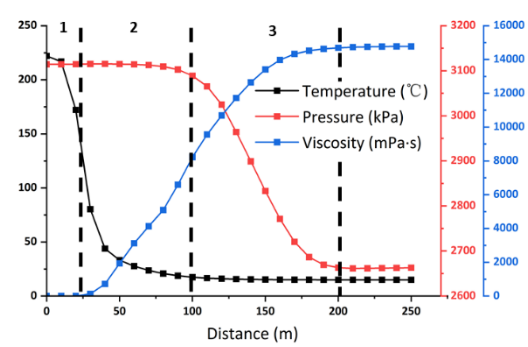


Fig. 3. Variation of reservoir parameters at different distances from well

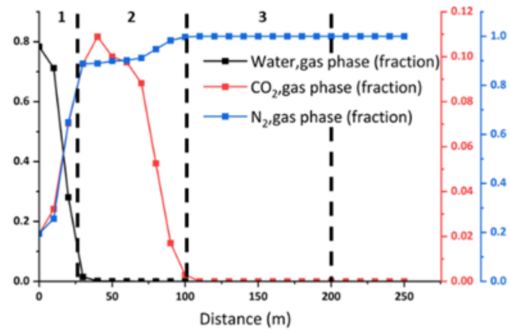


Fig. 4. Variation of fluid parameters at different distances from well

4. MICROSCOPIC EXPERIMENT OF DIFFERENT ZONE

4.1 Experimental apparatus and experimental procedure

Experimental oil is simulated heavy oil, and gas chromatography is used to measure the composition of four components in two different viscosity heavy oils: asphaltene 6.57%, resin 13.98%, aromatic hydrocarbon 30.54%, and saturated hydrocarbon 48.91%. The experiment uses distilled water and inorganic salts in a certain proportion to simulate formation water. The medium composed of Non-condensable gas (NCG) consists of CO_2 and N_2 with a purity of 99.9%. Distilled water is used to simulate hot water (steam is in gaseous state near the wellbore and condenses into liquid state in the formation away from the wellbore, so hot water is used to simulate steam in the formation, which has little effect on the experimental results). In order to distinguish between hot water and non-condensable gas, methyl red reagent is added to the hot water to dye it red. The dyeing agent only serves the purpose of coloring and does not react with oil, gas, or water. When hot water and non-condensable gas are co-injected, the ratio of hot water to non-condensable gas is 1:1. When injecting the multi-phase thermal fluid, the ratio of N2 to CO_2 in the non-condensable gas is 9:1. The experimental model is a microscopic visualization permeability model with an oil-wet matrix, with dimensions of 60mm × 60mm × 3.5mm. The effective pore area size is 45mm × 45mm, and the pore diameter is between 50-80 μm. The model is under a pressure of 2MPa and a temperature of 120℃. The microscopic visualization simulation system mainly includes constant pressure constant flow pump, ISCO pump, intermediate container, high-resolution microscopic camera. The main steps of FGACSS simulation visualization experiment are as follows:

(1) The micro-model is subjected to vacuum extraction for 45 minutes and then dried.

(2) Using a micro-displacement pump, the model is saturated with simulated formation water at a rate of 40μL/min, and after sufficient saturation, it is left to stand for 1 day.

(3) Using a micro-displacement pump, heavy oil is continuously injected into the saturated model with simulated formation water at a rate of 20μL/min until no more water flows out of the outlet. At this point, it is considered that the model is in a state of oil saturation with bound water, and it is aged for 3 days.

(4) The temperature is maintained at 20°C and the pressure is 1.5MPa. A high-definition camera is turned on for real-time image acquisition. Different media are injected into the micro-model at a rate of 40μL/min using a micro-pump, and the flow process and various phenomena in the experiment are recorded for analysis and research.

(5) The distribution of oil, gas, and water in the model is observed until the distribution no longer changes, indicating the end of displacement.

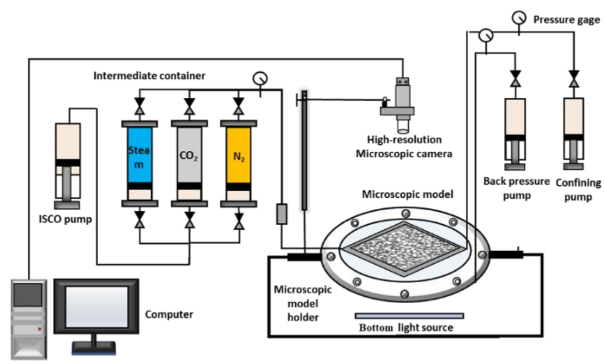


Fig. 5. FSACSS process mechanism zones

4.2 Microscopic mechanisms of different zones

During the FGACSS injection process, the mobility of non-condensable gas is superior to that of hot water, and the expansion capacity of N_2 is superior to that of CO_2. Therefore, N_2, CO_2, and hot water enter the pores in sequence. As shown in Fig. 6., from the upstream to the downstream of the flow, oil, gas, and water mainly exhibit three distribution patterns, representing the characteristics of oil, gas, and water in different zones. Near the main flow channel, where the pores are larger and the heavy oil has higher mobility, N_2 is sufficient to drive the flow of heavy oil at the displacement front. At the oil-water contact front, N_2 directly contacts the heavy oil, the flow state is gas-oil, corresponding to the increased pressure zone as shown in the yellow circle 1 in Fig. 6. Secondly, near the injection well, the three phases of oil, gas, and water mix and interact, the flow state is water-oil-gas-oil, just like the second yellow circle in Fig. 6, corresponding to the recombination zone. Finally, in the pores far from the main flow channel, non-condensable gas cannot displace the heavy oil in the throat, and only by heating with hot water can the mobility of heavy oil be improved, resulting in a distribution of hot water-oil, the flow state is water-oil, corresponding to the high-temperature zone as shown in the yellow circle 3 in Fig. 6. At the same time, the hot water in the pores is subjected to the replenishing and pressurizing effect of the non-condensable gas, which can extend to further pores. The three media, hot water, N_2, and CO_2, have coupled and synergistic effects, promoting the extraction of heavy oil.

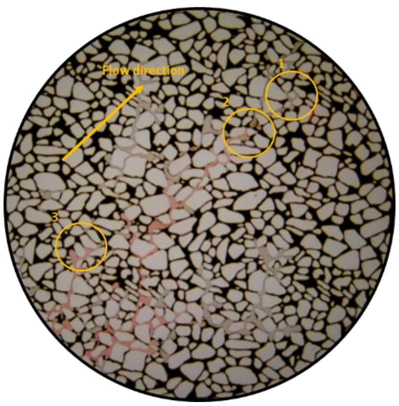
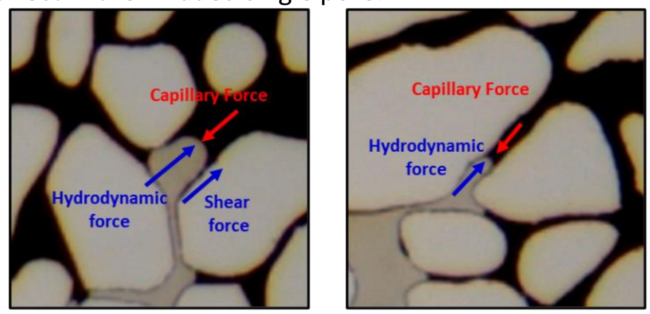


Fig. 6. Microscopic flow characteristics in different zones

In the high-temperature zone, hot water directly contacts the heavy oil, and the stress patterns in different-sized pores also affect the flow state in different pores. In the pores, the light hydrocarbon and aromatic hydrocarbon components of the heavy oil, with shorter molecular chains, are mainly concentrated in the middle of the throat, while the asphaltene molecules with longer chains are more prone to adsorption on the wall surface. In oil-wet pores, oil is the wetting phase and water is the non-wetting phase, and capillary forces act as resistance. The hydrodynamic force of hot water needs to overcome the capillary forces in order to displace the crude oil, as shown in Fig. 7. Due to the larger radius of the large pores, the capillary forces are smaller. After hot water invades the formation, it first displaces the heavy oil in the large pores. In the large pores, there are mainly two stages: in the first stage, hot water heats the heavy oil, reducing its viscosity. The hydrodynamic force of water overcomes the capillary forces and displaces the light components in the middle of the pores, while the heavy components adsorbed on the wall surface are not easily displaced. In the second stage, hot water flows along the already enlarged throat, continuously heating the heavy components on the wall surface, increasing molecular movement and stretching between long chains. The adsorption of asphaltene on the wall surface decreases significantly, and the shear force generated by hot water cleans the remaining oil on the wall. Therefore, hot water has a better displacement effect in the invaded single pore.



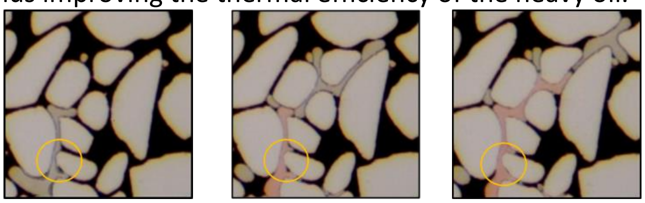
(a) (b)

Fig. 7. Stress condition in different pores in high-temperature region

In the recombination zone, there are three different substances: hot water, CO_2, and N_2, each playing a different role and their mechanisms are coupled together to promote heavy oil production. The viscosity of heavy oil is most sensitive to temperature changes, and hot water primarily heats the heavy oil, thus dominating the heating effect on the heavy oil. CO_2 can dissolve in the heavy oil and reduce its viscosity.

As shown in Fig. 8, the flow state of the oil-gas-water three phases varies during different injection processes in the recombination zone. In the single-phase hot water injection, the affected volume is large, but the overall displacement efficiency is low, mainly leaving behind clusters and columnar residual oil. During non-condensable gas (N_2 and CO_2) displacement, due to the good expansion characteristics and sufficient energy of the non-condensable gas, it is easier to displace oil with lower resistance in the main flow channels. However, the affected area is relatively small, and within this area, most of the pores can be invaded, resulting in fewer cluster and columnar residual oil. However, the displacement efficiency in individual pores is low, and film-like residual oil is easily formed. During simultaneous injection of hot water and non-condensable gas, the non-condensable gas enters the pores before the hot water, displacing the lighter and more mobile heavy oil in the central part of the pores, while the heavier components such as asphaltenes adsorb on the wall to form film-like residual oil. After the hot water enters the pores, it heats up the film-like residual oil near the wall, improving its mobility.

Subsequent hydraulic shear forces help to clean the residual oil remaining on the wall, thus improving the displacement efficiency. The yellow circle in Figure 10 represents the thick oil on the wall that was not displaced during the non-condensable gas injection but was displaced after the hot water injection. Due to the low thermal conductivity of the non-condensable gas, it hinders the heating of the lighter and more mobile heavy oil in the central part by the hot water, storing heat to heat the heavier and less mobile heavy oil on the wall, thus improving the thermal efficiency of the heavy oil.



(a) (b) (c)

Fig. 8. Flow condition in recombination zone

5. CONCLUSIONS

FGACSS has shown significant effects in the Murdock oilfield. After switching to FGACSS, daily oil production increases, the stable production period lengthens, the water cut decreases, just as HMB-16 and HMB-17. After multiple cycles, the daily production decreases, while the water cut remain relatively stable. FGACSS is more effective in reducing water cut than in increasing oil production.

From the well to the reservoir boundary, based on the effects of different compositions, it can be divided into different zones: high-temperature zone, recombination zone, increased pressure zone. In high-temperature zone, the primary mechanism is the release of latent heat through the condensation of steam. In this zone, the pressure is high and the viscosity of the heavy oil is low. In recombination zone, both hot water and CO_2 contribute to viscosity reduction through heat conduction and CO_2 dissolution in the heavy oil. The presence of CO_2 and N_2 in the gas phase also increases the pressure in the reservoir. In increased pressure zone, only N_2 is present. In this area, the temperature of the heavy oil is the same as the original formation temperature. As the distance from the wellbore increases, the pressure in the reservoir gradually decreases until it reaches the original formation pressure.

In different zones, there are different microflow states. In the high-temperature zone, the flow state is water-oil, where water displaces the intermediate heavy oil in the large pores and then displaces the wall heavy oil. In the recombination zone, the flow state is water-oil-gas-oil, where non-condensable gas displaces the middle heavy oil in the precursor pores, and subsequent hot water heats the wall heavy oil. Non-condensable gas and hot water displace different types of residual oil, improving the efficiency of single-pore displacement. In the increased pressure zone, the flow state is gas-oil.

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DECLARATION OF INTEREST STATEMENT

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. All authors read and approved the final manuscript.

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