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Flue Gas-Assisted Steam Flooding in Heavy Oil Reservoirs: Experimental Study and Numerical Simulation

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ABSTRACT

To address the issue of steam override and low oil-steam ratios in the middle to late stages of steam flooding development in heavy oil reservoirs, experiments and numerical simulation studies on flue gas-assisted steam flooding were conducted following steam flooding. This study investigates a heavy oil reservoir block in the Xinjiang Oilfield as its research subject and conducts one-dimensional core displacement experiments to comparatively analyze the impact of various injection media on oil displacement efficiency. The experimental results demonstrate that flue gas-assisted steam flooding can enhanced oil recovery by up to 5.84% in comparison to steam flooding. A mechanism model for flue gas-assisted steam flooding in heavy oil reservoirs with a five-spot well pattern was established based on a core numerical model calibrated to experimental data and supplemented by geological reservoir characteristics data. This model is used to systematically study the mechanism and effect of the above methods in heavy oil reservoir development. The results indicated that flue gas-assisted steam flooding is an effective technique to enhance the oil recovery. Injected flue gas not only increases the contact time between steam and crude oil but also mitigates steam override and expand steam sweep range. Oil recovery improvement is significant when the steam to flue gas molar fraction ratio is 8:2, and oil recovery is 63.36%. The results of the injection mode study show that slug injection facilitates superior steam penetration into the lower reservoir compared to continuous injection. At this moment, the periodic pressure difference formed in the reservoir can improve the efficiency of the oil displacement. The study findings could be valuable in designing flue gas-assisted steam flooding for heavy oil reservoirs.

Keywords: steam flooding, flue gas, heavy oil, displacement test, numerical simulation, enhanced oil recovery

NONMENCLATURE

Abbreviations	
SF	Steam Flooding
FGF	Flue Gas Flooding
FGASF	Flue Gas-Assisted Steam Flooding
SI	Slug Injection
CI	Continuous Injection

1. INTRODUCTION

With the rapid development of the global economy and the continuous increase in energy demand, most oil field developments have entered the mid-to-late stages, facing challenges in maintaining and increasing production[1]. Heavy oil, being an unconventional hydrocarbon resource, harbors significant development potential, with global reserves estimated at approximately 100 billion tons, including heavy oil, extra-heavy oil, and natural bitumen[2]. Through the transformation of development methods, the efficient development of heavy oil reservoirs will significantly alleviate the supply-demand imbalance of petroleum resources[3,4].

The development of heavy oil reservoirs is hindered by high crude oil viscosity and poor fluidity, with steam injection currently being the predominant method used[5,6]. Nevertheless, as the majority of heavy oil reservoirs enter the mid-to-late stages of development, serious issues arise with steam channeling and steam override phenomena, leading to decreased efficiency in steam heat utilization[7]. Moreover, the relatively high energy consumption and carbon emissions during heavy oil thermal recovery processes pose challenges to achieving the objectives of "peak carbon" and "carbon neutrality"[8]. In ultra-heavy oil reservoirs with shallow reservoir depths and high crude oil viscosity, the low reservoir temperature and significant heat loss during the steam injection process lead to condensation occurring easily as the steam front advances, thereby affecting the coverage range of steam injection[9]. Exploring replacement technologies for heavy oil

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reservoir development after steam flooding (SF) is crucial to enhance the coverage range of thermal waves and the efficiency of thermal utilization during the steam injection process[10].

Flue gas-assisted steam flooding (FGASF) can effectively enhance the development efficiency of steam flooding, reduce on-site steam consumption, and facilitate the utilization of flue gas produced by oilfields, thereby decreasing CO_2 emissions[11]. Injected flue gas can extend the reach of steam, reduce heat loss, and enhance heat transfer in deep reservoirs, among other functions[12,13]. In the current context of heavy oil reservoir development and the "dual carbon goals" initiative, FGASF emerges as a practical approach to enhance the oil recovery of heavy oil reservoirs. However, the influence of steam and flue gas injection composition and methods on the mechanisms and development effects of FGASF remains unclear and requires further elucidation. This study focuses on a heavy oil reservoir in a Xinjiang Oilfield. Initially, this study compares the oil recovery of flue gas flooding (FGF), SF, and FGASF using one-dimensional core physical simulation experiments. The core experiments are utilized to establish a numerical model of the core, followed by the fitting of experimental data. A mechanistic model of FGASF for heavy oil reservoirs is established based on the five-spot well pattern by integrating reservoir characteristic parameters. The influence of injection gas composition and injection mode on development effects is systematically investigated to further elucidate the mechanisms and development effects of FGASF for enhancing oil recovery. This study aims to provide technical support and theoretical guidance for the efficient development of heavy oil reservoirs.

2. EXPERIMENTS

2.1 Experimental materials

The oil used in the experiment is crude oil from a heavy oil reservoir in the Xinjiang Oilfield, China. The heavy oil sample has a viscosity of 693 mPa • s and a density of 0.931 g/cm^3 at 55℃. The viscosity versus temperature curve of the oil used is shown in Fig. 1. The experiment employed a gas mixture of N_2 and CO_2, with a molar fraction ratio of N_2 to CO_2 of 6:1. The steam is generated by a steam generator at a temperature of 240℃. The water used in the experiment is prepared indoors to have properties similar to the formation water in the target block based on analysis. It is then used for experimental saturation. Each core has a diameter of 2.5 cm and a length of 30 cm.

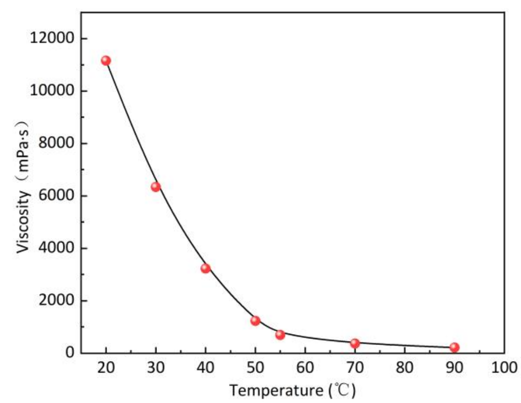


Fig. 1 Oil viscosity versus temperature in the simulation model

2.2 Experimental apparatus

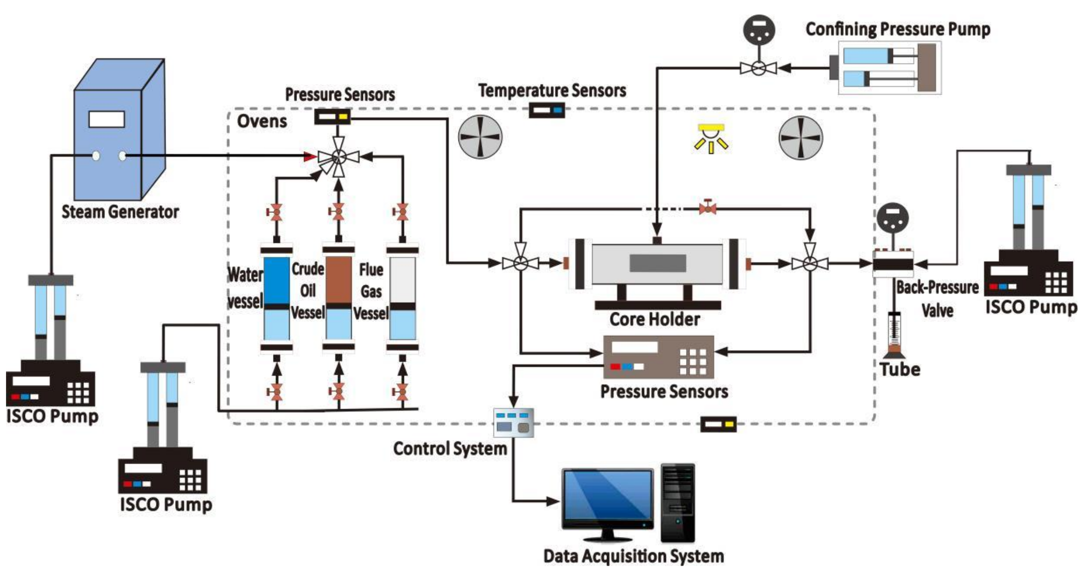


Fig. 2 Experimental apparatus for FGASF physical simulation

The apparatus for the FGASF physical simulation experiment is shown in Fig. 2. The primary instruments and equipment include a constant temperature box, core holder, ISCO high-precision piston pump, intermediate container, steam generator, confining pressure pump, pressure sensor, back pressure valve, oil-water metering device, and a data acquisition and control system.

2.3 Experimental programme and procedure

The experimental temperature is set to 55℃ to simulate reservoir conditions, with the initial pressure of the core holder at 4 MPa. During displacement, the experimental back pressure is maintained at 2 MPa, and the injection rate is 0.5 ml/min. After achieving a oil recovery of 20% through steam flooding, separate experiments are conducted for SF, FGF, and FGASF to compare the oil displacement effects of the three injection media. Table 1 presents the experimental design, core parameters, and programme.

Table1 Scheme design table for different test modes

Number	*1*	*2*	*3*
Permeability(mD)	596	610	602
Porosity	0.2608	0.2621	0.2642
Oil saturation	0.7682	0.7562	0.7633
Displacing medium	SF	FGF	FGASF

3. RESULTS AND DISCUSSION

The results of one-dimensional core flooding tests indicate that the recovery factor after steam flooding conversion to FGF is 37.23%, which is significantly lower than those of SF and FGASF, at 62.71% and 68.55%, respectively. It is observed that the viscosity and mobility of crude oil are key factors affecting the oil displacement efficiency in heavy oil reservoirs. FGASF exhibits higher oil displacement efficiency than SF.

Fig. 3 shows the injection pressure difference curves for the three experimental schemes. The pressure differential during FGF rapidly decreases and eventually stabilizes at 0.03 MPa. This phenomenon occurs because the FGF process does not carry sufficient heat, leading to decreased crude oil fluidity and subsequent gas channeling. During the initial injection stage (Phase II in Fig. 3), the pressure difference in SF is marginally greater than in FGASF. This discrepancy arises from the higher heat content carried by SF, which causes thermal expansion due to elevated pore temperatures. As displacement progresses, as shown in Phase III of Fig. 3, the pressure differential during FGASF is significantly greater than during SF. This indicates that the injected flue gas exerts a significant pressurization effect during the FGASF process. Additionally, the injected flue gas forms dispersed bubbles with steam and crude oil, generating the Jamin effect as they pass through the pore throats of the core, thereby increasing the displacement pressure differential. This effect extends the thermal action range, thus enhancing the recovery factor.

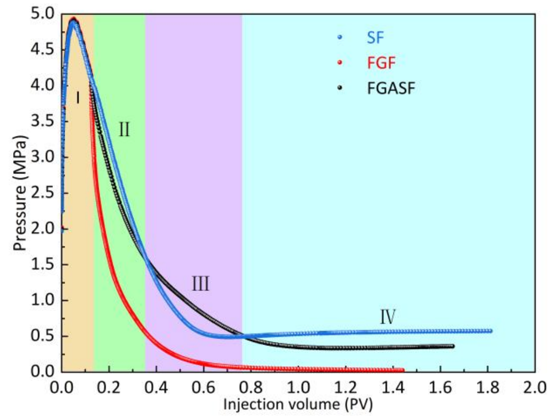


Fig. 3 Relationship between pressure and injection volume

4. NUMERICAL SIMULATION

Analyze the influence of different gas compositions and various injection methods on the effectiveness of FGASF at an oil reservoir scale. Use experimental parameters from one-dimensional core experiments of FGASF to establish a numerical model. Fit the experimental data to obtain representative relative permeability curves and characteristic parameters of the core in the study area, and establish a mechanistic model for FGASF in heavy oil reservoirs using a five-spot well pattern.

4.1 Model description

4.1.1 Numerical modelling of core tests

Using the core tests, we establish a one-dimensional mechanistic model of the core with the cross-sectional area equivalence method. The model employs a three-dimensional Cartesian grid consisting of 1700 grids (5×68×5). The dimensions are 30 cm in length, 2.216 cm in width, and 2.216 cm in height. The reservoir characteristic parameters are presented in Table 2. The relative permeability curves are adjusted based on the results of core flooding tests, and the oil recovery fitting is shown in Fig. 4.

Table2 Reservoir parameters used in the numerical simulations

Parameter	*Value*
Reservoir pressure (MPa)	4

Reservoir temperature (℃)	55
Porosity	0.26
Permeability I, J (mD)	600
Permeability K (mD)	60
Oil saturation	0.76
Formation compressibility(kPa^{-1})	9.85×10^{-5}
Thermal expansion coefficient ($℃^{-1}$)	3.75×10^{-5}
Rock volumetric heat capacity ($J\cdot m^{-3}\cdot ℃^{-1}$)	2.1×10^{6}
Rock thermal conductivity ($J\cdot m^{-1}\cdot d^{-1}\cdot ℃^{-1}$)	2.0×10^{5}
Water thermal conductivity ($J\cdot m^{-1}\cdot d^{-1}\cdot ℃^{-1}$)	5.5×10^{4}
Oil thermal conductivity ($J\cdot m^{-1}\cdot d^{-1}\cdot ℃^{-1}$)	1.2×10^{4}
Gas thermal conductivity ($J\cdot m^{-1}\cdot d^{-1}\cdot ℃^{-1}$)	4000
Volumetric heat capacity of over-/under-burden rock ($J\cdot m^{-3}\cdot ℃^{-1}$)	2.16×10^{6}
Thermal conductivity of over-/under-burden rock ($J\cdot m^{-1}\cdot d^{-1}\cdot ℃^{-1}$)	1.15×10^{5}
Temperature of injected steam(℃)	240
Steam quality (dimensionless)	0.7

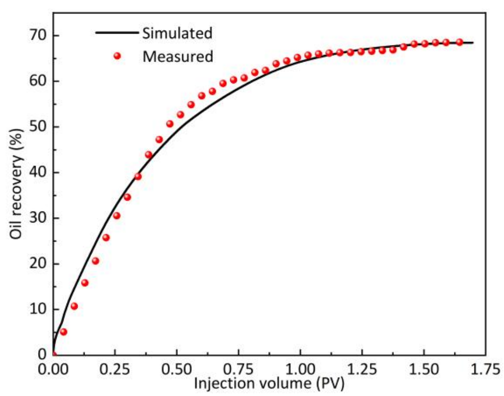


Fig. 4 Oil recovery fitting between results of numerical simulation and experiment

4.1.2 Numerical modelling of a five -spot well pattern

Based on the characteristic parameters of the study block, a five-spot well pattern FGASF mechanistic model was established using the STARS module of the CMG reservoir numerical simulation software. The model employs a three-dimensional Cartesian coordinate system with a total of 10,086 grids (41×41×6). The dimensions are a length of 205 m, a width of 205 m, and a height of 18 m. The constructed model is shown in Fig. 5. The characteristic parameters of the reservoir and the thermophysical parameters of the rock fluid used in the model are listed in Table 2. The relative permeability curves are obtained by fitting core experiments, and interpolation is conducted using endpoint values at different temperatures to accurately reflect the influence of temperature on fluid flow during actual thermal recovery processes.

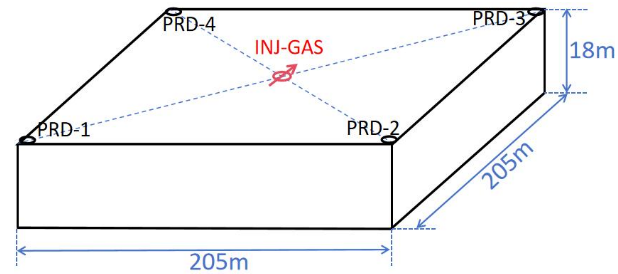


Fig. 5 3D reservoir model with five-spot well pattern

4.2 Simulation results

4.2.1 Effect of gas mole compositions

Using the established well group model, after simulating SF to a recovery factor of 20%, FGF, FGASF, and SF are conducted. The molar fraction ratios of steam to flue gas in the FGASF process are 5:5, 6:4, 7:3, 8:2, and 9:1, and the total volume of gas injected in all schemes remains consistent. Fig. 6 illustrates the simulation results of oil recovery for different gas injection compositions. It is observed that when the molar fraction ratio of steam to flue gas is at least 7:3, the recovery factor of FGASF surpasses that of SF. Specifically, when the molar fraction ratio of steam to flue gas is 8:2, FGASF achieves the optimal effect. When the molar fraction ratios of steam to flue gas are 5:5 and 6:4, the relatively lower steam content leads to limited heat-carrying capacity and poorer crude oil fluidity, resulting in a development effect inferior to that of steam flooding. Therefore, it is evident that a higher reservoir temperature is a prerequisite for fully utilizing the effect of FGASF.

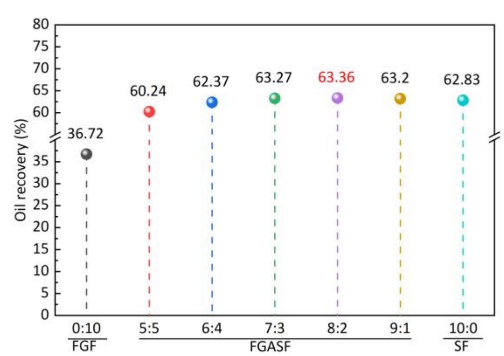


Fig. 6 Comparison of oil recovery in different gas compositions

Fig. 7 illustrates the planar distribution of the molar concentration of N_2 in the flue gas during FGASF. It is observed that during the oil and gas migration process, the flue gas forms a gas distribution zone at the front edge of the steam chamber. At this point, the flue gas first contacts the crude oil, resulting in expansion, viscosity reduction, and pressure increase, thereby enhancing the oil displacement effect.

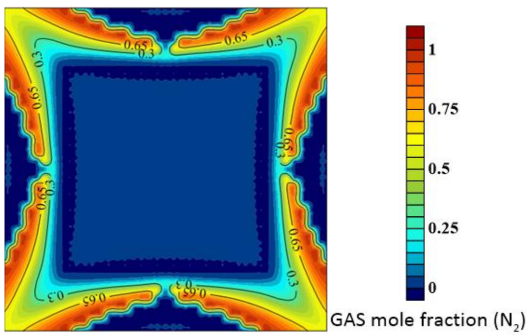
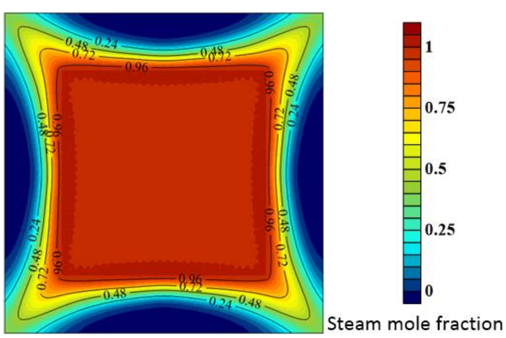
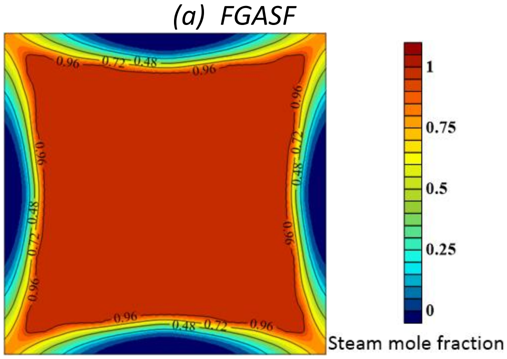


Fig. 7 Planar distribution of N_2 in FGASF process

Figs. 8(a) and 8(b) illustrate the planar distribution of the steam chamber for FGASF and SF on the 3000th day of model operation. It is observed that during the FGASF process, the flue gas at the leading edge of the steam chamber preferentially enters the easy breakthrough channels. This forms a barrier between the steam chamber and the easy breakthrough channels, reducing the relative permeability of steam in these channels, extending the contact time of steam with crude oil in the reservoir, and increasing the steam action period.



(a) FGASF



(b) SF

Fig. 8 Planar distribution of steam in FGASF and SF process

4.2.2 Effect of injection mode

To elucidate the impact of slug injection (SI) and continuous injection (CI) on FGASF, the established mechanistic model was employed to simulate both injection methods: PI and CI. The slug injection cycle involved switching injections every month. During the simulation, the total amounts of injected flue gas and steam, as well as other model parameters, were kept constant. The grid (33, 21, 6), located in the lower part of the model and distant from the injection well, was selected as the observation point. Its specific position within the model is illustrated in Fig. 9.

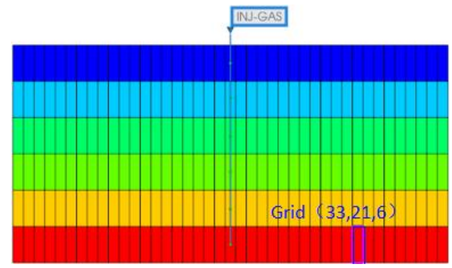
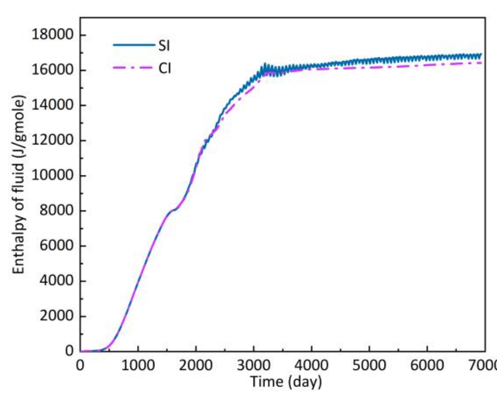
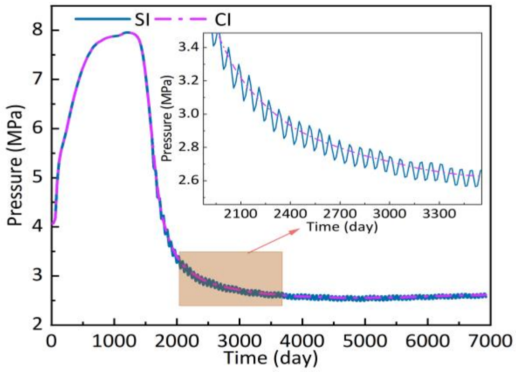


Fig. 9 Schematic representation of the position of the grid (33,21,6) in the model

Fig. 10 shows the curves of fluid enthalpy and pressure over time in the observation grid for different injection methods. Fig. 10(a) shows that the lower part of the reservoir grid achieves a higher fluid enthalpy value with SI compared to CI. This may be because, during CI, the mixture of flue gas and steam does not facilitate effective flue gas aggregation. In contrast, SI more easily forms effective aggregation at the top of the reservoir, effectively preventing heat loss. Additionally, it facilitates the downward spread of steam to the lower part of the reservoir, increasing the fluid enthalpy of the lower oil layer and thus improving oil recovery. Fig. 10(b) depicts the curve of grid pressure variation over time. SI can create periodic pressure differences, effectively supplementing the driving force of crude oil and facilitating its extraction.



(a) Enthalpy of fluid varies with time



(b) Pressure varies with time

Fig. 10 Fluid enthalpy and pressure in grid (33, 21, 6) for different injection mode in FGASF process

5. CONCLUSIONS

Compared to SF, FGASF can effectively reduce steam consumption and achieve a higher recovery rate. The results of the core experiments show a recovery of 68.55% for the FGASF, 62.71% for the SF and 37.23% for the FGF. The injected flue gas increases the interaction time between steam and crude oil. The optimal effect on oil recovery is achieved when the molar fraction ratio of injected steam to flue gas is 8:2. This ratio not only ensures the sufficient fluidity of crude oil but also maximizes the synergistic effect of flue gas and steam in enhancing oil recovery. The SI mode achieves a higher oil recovery than CI. This method can form a more stable flue gas accumulation at the top of the reservoir, increase the steam sweep area, and enhance oil displacement efficiency through the resulting periodic pressure differences. FGASF is an economical and reliable method to improve the oil recovery of heavy oil reservoirs.

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