Chemical-assisted steam flooding (CASF) is a promising method for heavy oils. However, few researches have investigated the CASF performance on offshore heavy oil reservoirs recovery after water flooding. In this study, a numerical simulation model was developed to simulate CASF processes for offshore heavy oil reservoirs after water flooding. Then, a comparison of CASF and various thermal methods was made to assess the feasibility of CASF in an offshore heavy reservoir of Bohai Bay, China. Finally, sensitivity analysis was performed to evaluate the effects of the gas-liquid ratio, foaming agent concentration, surfactant concentration, the size of nitrogen foam slug, the size of surfactant slug, and the number of chemical injection round on CASF performance by the developed model. The results showed that the developed numerical method can precisely simulate the CASF processes. CASF is a potential and effective method for offshore heavy oil reservoirs after water flooding. The most suitable gas-liquid ratio was around 2:1 under the simulation conditions. Considering the economic benefit, it is significant to optimize the CASF parameters, such as foaming agent concentration, the size of nitrogen foam slug, and the number of chemical injection round.

1. Introduction

Recently, with the gradual depletion of onshore oil resources, the exploitation of offshore oil resources has attracted much attention [1]. Offshore heavy oil as an important part of offshore resources has played an increasingly important role in industry [2, 3]. Heavy oil resources are abundant in the Bohai Bay of China, which has approximately 4 billion tons of heavy oil resources [4]. Water flooding is an important method of recovering heavy oil worldwide and launched on offshore oilfields in Bohai Bay to economically recover offshore heavy oils [5]. However, the recovery factors were less than 15% [6]. This implies that more than 85% of the oil remains in the reservoirs after the process becomes uneconomic to continue operation. Therefore, the incentive is strong for the development of appropriate follow-up techniques for water flooding that will maximize the recovery potential and profitability from these offshore heavy oil reservoirs in Bohai Bay, China.

Thermal methods are widely used to develop heavy oil reservoirs, such as hot water flooding, cyclic steam stimulation, and steam flooding [7, 8]. Hot water flooding is an immiscible displacement process of crude oil by hot water [9]. Hot water in reservoir can increase reservoir temperature, implement reservoir energy, and displace crude oil to wellbore. However, hot water cannot carry enough heat into reservoir because of its low enthalpy. Compared with hot water, steam has higher enthalpy [10]. Therefore, cyclic steam stimulation and steam flooding are potential methods for the development of heavy oil reservoirs after water flooding. However, for cyclic steam stimulation, with the increase of CSS cycles, oil production and oil-steam ratio gradually decrease in the later stage, resulting in a low economic benefit [11]. For steam flooding, the channeling forms during water
flooding significantly restrict the increase of oil production of steam flooding. In addition, the formation heterogeneity and mobility difference between steam and heavy oil often result in viscous fingering and steam gravity override [12]. Chemical-assisted steam flooding (CASF) techniques have been proposed to improve the oil recovery of steam flooding by injection of nitrogen foams and surfactants [13, 14]. For example, Yuan et al. [15] performed a series of sand pack experiments to examine the effects of gas-liquid ratio, permeability, and oil saturation on the stability and blocking mechanisms of foam during nitrogen foam-assisted steam flooding. The experimental results indicated that nitrogen foam was selective to block larger pores and throats in porous media with high permeability. The most suitable gas-liquid ratio of the injected foam was around 1:1 [15]. Bruns and Babadagli conducted displacement tests by using a visual Hele-Shaw model and found that injecting surfactant as a steam additive reduced the interfacial tension (IFT) between steam and heavy oil [16]. Wang et al. [17] investigated the effects of foam on the performance of steam flooding. The results show that the ultimate oil recovery of the chemical assisted steam flooding is 76.9%, 39.7% higher than that of pure steam flooding [17].

The investigations mentioned above suggest that CASF is a promising method for heavy oils. However, few researches have investigated the CASF performance on offshore heavy oil reservoirs recovery after water flooding. The numerical simulation method for CASF is deficient. In addition, the effects of operational parameters on the performance of CASF are still unclear. In this study, a numerical simulation model was developed to simulate CASF processes for offshore heavy oil reservoirs after water flooding. Then, a comparison of CASF and various thermal methods, such as hot water flooding, steam flooding, and cyclic steam stimulation, was made to assess the feasibility of CASF in offshore heavy oil reservoirs after water flooding. Finally, sensitivity analysis was performed to evaluate the effects of gas-liquid ratio, foaming agent concentration, surfactant concentration, the size of nitrogen foam slug, the size of surfactant slug, and the number of chemical injection round on CASF performance by the developed model. The results of this study will lay the foundation for design of CASF in offshore heavy oil reservoirs after water flooding.

2. Reservoir and Production Characteristics

The Bohai Bay Basin is located in the eastern part of North China within it lies one of the largest offshore heavy oil deposits in China, roughly 4 billion tons of oil in place. L oilfield is a typical heavy oil reservoir located at the east of Bohai Bay. The heavy oil reservoir is at depths of 1100 to 1300 m, which is unconsolidated sandstones with a net thickness ratio of 0.25, and net pay varying from 29.6 to 75.5 m. The pressure gradient of L oilfield is 0.940 MPa/100 m, which belongs to the normal pressure system. The M formation is the main oil-bearing strata, with porosities of 9~42%, permeabilities of 5~11681 × 10⁻² μm², and oil saturations of 65~80%. Oil API and viscosity are variable in the range of 19.51~19.68° and 437.00~559.58 mPa·s, respectively. Saturated pressure of formation oil is between 3.160 and 3.410 MPa. Solution gas-oil ratio ranges from 7 to 11 m³/m³. Oil volume factor is between 1.035 and 1.036. In 2013, water flooding was launched on L oilfield. Horizontal wells with well space of 450~1100 m were adopted, and the well pattern is a five-spot well pattern. Because of its high oil viscosity and severe heterogeneity, early breakthrough of injected water was observed, and water cut in many wells increased to over 90%. The oil recovery factor during water flooding was less than 15%. Therefore, appropriate follow-up techniques are needed for increasing the heavy oil recovery from the L reservoir.

3. Building the Numerical Model

The flow of steam, nitrogen foam, and surfactant in porous media is considered to be a complex phenomenon. Therefore, the development of a detailed numerical method is necessary for clearly depicting CASF processes. In this study, a numerical model was developed to simulate CASF by using the CMG-STARS commercial software. A sector model was cut from a static reservoir model, and the grids of 26 × 17 × 35 (15470 grid cells) were adopted in the model to consider the reasonable runtime and simulation results (Figure 1).

To simulate the enhanced oil recovery mechanisms of nitrogen foams and surfactants, the components contained in CASF were lumped into 3 phases (water, oil, and gas) and 6 types (water, heavy oil, foaming agent, lamellae, surfactant, and N₂). The following chemical reaction equations were adapted for depicting the generation and rupture of nitrogen foams during CASF processes:

$$2.15 \times 10^{-5} \text{ mol foaming agent}$$
$$+ 1 \text{ mol H}_2\text{O} + 1 \text{ mol N}_2$$
$$= 1 \text{ mol lamellae} + 1 \text{ mol N}_2$$

$$1 \text{ mol lamellae} + 1 \text{ mol N}_2$$
$$= 2.15 \times 10^{-5} \text{ mol foaming agent}$$
$$+ 1 \text{ mol H}_2\text{O} + 1 \text{ mol N}_2$$

The generation of lamellae can block part of the pore network for gas flow, resulting in gas relative permeability reduction. In addition, the lamellae are foaming agent solution dispersed in gas phase, which increases the gas phase viscosity. The gas phase viscosity is calculated by the following equations.

$$\mu_{gi}(T_{abs}) = \text{avg}_{gi} \times T_{abs}^{bvg_i},$$

$$\mu_{g} = \frac{\sum_{i=1}^{numy} \text{visg}(i) \times y(i) \times \sqrt{\text{cmm}(i)}}{\sum_{i=1}^{numy} y(i) \times \sqrt{\text{cmm}(i)}},$$

where $\mu_{gi}$ is the component viscosity in mPa·s, $\mu_{g}$ is the gas phase viscosity in mPa·s, avg and bvg are the coefficients in power-law correlation for temperature dependence of gas phase viscosity of component $i$, $T_{abs}$ is the temperature in degrees K or R, numy is the total number of components in...
Surfactant can reduce the IFT between heavy oil and water, thus improving oil recovery of steam flooding. The IFT tests were performed to investigate the effects of surfactant on the IFT of heavy oil and water. As shown in Table 1, the usage of the surfactant to steam in CASF can achieve ultralow IFT.

Surfactant adsorption on the rock was simulated with a Langmuir-type model. Dynamic adsorption tests were performed to determine surfactant adsorption on a sandstone rock at various temperatures. As Table 2 shows, surfactant adsorption decreases with increasing temperatures because its solubility increases with increasing temperatures.

The rock and fluid properties used in the model are given in Table 3. The viscosity-temperature curves of the heavy oil, oil-water relative permeabilities, and gas-liquid relative permeabilities are shown in Figures 2 and 3.
In history matching of water flooding, for an injector, the constraints were the constant water injection rate, and the maximum bottom hole pressure was 17 MPa. For a producer, the constraints were constant liquid rate, and the minimum bottom hole pressure was 5 MPa. The production history matching of 4 horizontal wells was accomplished in the sector model. The maximum error of cumulative oil production and water cut is less than 10%, which has a good agreement. This indicates that the sector model after history matching of water flooding can be used to conduct the following feasibility evaluation and sensitivity analysis of CASF processes.

4. Feasibility Evaluation of CASF for Offshore Heavy Oil Recovery

In this study, a comparison of CASF and various thermal methods, such as hot water flooding (HWF), cyclic steam stimulation (CSS), steam flooding (SF), and chemical-assisted hot water flooding (CAHWF), was made to assess the feasibility of CASF in L reservoir after water flooding. The operational parameters of various thermal methods are shown in Table 4.

Figure 4 shows the simulation results of CASF and various thermal methods using the developed model. According to the incremental oil production (the volume of the difference of cumulative oil production between thermal method and water flooding), the performance of thermal methods for the offshore heavy oil reservoir after water flooding can be ranked as follows: CASF > SF > CAHWF > HWF > CSS. The CASF exhibits the highest incremental oil production and relatively high oil-steam ratio. The main reason is attributed to the enhanced oil recovery mechanisms of nitrogen foam and surfactant. Nitrogen foam has greater apparent viscosity and can effectively block the high-permeable channeling path under the action of the Jamin effect, thereby improving the sweep efficiency of steam flooding. In addition, the foaming agent itself, as a surfactant, can emulsify heavy oil to form emulsions with lower viscosity and better mobility. Surfactant can alter the wettability of reservoir rocks from oil wet to water wet and reduce drag forces between oil and steam phases by emulsification and IFT.
reduction. Therefore, CASF is a potential and effective method for offshore heavy oil reservoirs after water flooding.

5. Sensitivity Analysis

Sensitivity analysis was conducted to evaluate the effects of gas-liquid ratio, foaming agent concentration, surfactant concentration, size of nitrogen foam slug, size of surfactant slug, and the number of chemical injection round, on the CASF performance. For sensitivity analysis, the parameters of the base model of CASF are shown in Table 4.

5.1. Effect of the Gas-Liquid Ratio. The gas-liquid ratio of nitrogen foam is the volume ratio of nitrogen to foaming agent solution in CASF processes. The gas-liquid ratio is a key parameter that quantifies the amount of nitrogen injected. It affects the production efficiency and economic efficiency of CASF processes. The gas-liquid ratio is varied between 1:2 and 3:1, and the simulation results are presented in Figure 5. As shown in Figure 5, the production performance of CASF is strongly affected by the gas-liquid ratio. As expected, the incremental oil production, oil-steam ratio, CUF (the volume of the incremental oil production to per unit ton of the injected chemical), and heat efficiency (the volume of the incremental oil production to per unit kJ of the injected heat) increased with increasing gas-liquid ratio in low gas-liquid ratio stage. It reached the peak when the gas-liquid ratio was 2:1. This indicated that a relatively high gas-liquid ratio is benefit for the formation of stable nitrogen foams in the reservoir, which improves the CASF performance.

However, the phenomenon was changed while the gas-liquid ratio injected was more than 2:1. The incremental oil production, oil-steam ratio, CUF, and heat efficiency decreased with the increasing gas-liquid ratio. This is because, with the increase of gas-liquid ratio, more volume of nitrogen injected into the reservoir. The stability of nitrogen foam was greatly reduced due to the decay of interfacial viscoelastic modulus under high-temperature condition. In addition, a higher gas-liquid ratio increased the gas channel. Therefore, the production performance could not be improved as expected. The most suitable gas-liquid ratio of CASF was around 2:1.

5.2. Effect of the Foaming Agent Concentration. The foaming agent is a surfactant that can adsorb at the gas-liquid interface and stabilize the nitrogen foam. In the study, the effects of foaming agent concentrations of 0.1 wt.%, 0.3 wt.%,
0.5 wt.%, 1.0 wt.%, and 1.5 wt.% were investigated. Figure 6 reveals that the incremental oil production, oil-steam ratio, and heat efficiency have an increasing trend with the increase of foaming agent concentrations.

However, it is noted that the incremental oil production, oil-steam ratio, and heat efficiency increase rapidly with the increase of foaming agent concentrations at early stage. This is because more foaming agents injected into the reservoir were absorbed on the surface of heavy oil and steam at the beginning of flooding, which increases the nitrogen foam stability and the blocking ability. Then, the incremental oil production, oil-steam ratio, and heat efficiency slowly increase with the increase of foaming agent concentrations because the adsorption of foaming agents on the surface is saturated.

In addition, as shown in Figure 6(b), the CUF decreased with the increasing foaming agent concentrations. This indicates that it is not economical to use foaming agents with higher concentrations due to the high cost. Therefore, there is an optimal foaming agent concentration for CASF processes to economically and efficiently recover offshore heavy oils after water flooding.

5.3. Effect of the Surfactant Concentration. Figure 7 illustrates the effect of surfactant concentrations varying from 0.05 wt.%
to 0.5 wt.% on the CASF performance. As presented in Figure 7, the incremental oil production, oil-steam ratio, and heat efficiency have an increasing trend with the increase of surfactant concentrations.

This is due to the fact that surfactant can reduce residual oil saturation and improve the oil displacement efficiency by the IFT decline and favourable wettability alteration. The performance of surfactant is directly influenced by the surfactant concentrations, and it increases on increasing surfactant concentrations (till the critical micellar concentration is reached), following which no significant increase in foaming was observed. In addition, Figure 7(b) indicates that the CUF decreases with the increasing surfactant concentrations. Therefore, it is important to optimize the surfactant concentration during CASF processes in order to get high oil recovery and better benefits.

5.4. Effect of the Size of Nitrogen Foam Slug. Figure 8 shows the effect of the size of nitrogen foam slug (15 d, 30 d, 45 d, 60 d, and 90 d) on the CASF performance. It can be seen from Figure 8 that the incremental oil production, oil-steam ratio, and heat efficiency increase, but the CUF decreases with the increase of the size of nitrogen foam slug. This is due to the fact that more nitrogen foams can effectively plug high permeability zones and improve the steam injection profile. In addition, as more N₂ overlapped in the reservoir top, the heat loss was moderated, and the injected thermal quantity was utilized more effectively. Due to the increase of the size of nitrogen
foam slug, the amount of foaming agents increases, which effectively reduced the IFT and alter the rock wettability.

However, it is noted that the CUF decreases greatly with the increase of the size of nitrogen foam slug. Therefore, it is not necessary to inject a large nitrogen foam slug, which is not economically feasible at the field scale, to recover significantly more oil than water flooding.

5.5. Effect of the Size of Surfactant Slug. Figure 9 shows how the CASF performance varies with different surfactant slug sizes (10 d, 20 d, 30 d, 40 d, and 50 d). The observations of the incremental oil production, oil-steam ratio, and heat efficiency are provided in Figure 9. The incremental oil production and oil-steam ratio obtained increase from 10 d to 50 d (Figure 9). This also leads to an increase in heat efficiency from $7.12 \times 10^{-6}$ to $7.60 \times 10^{-6}$ m$^3$/kJ. The presented results indicate that increasing surfactant slug size is found to greatly improve the CASF performance. This may be attributed to a higher amount of surfactant available for emulsification and IFT reduction. The results can also be compared in terms of CUF. Figure 9(b) shows that CUF greatly decreases with the increase of the surfactant slug size, which means the decreasing economic efficiency due to the increasing expense of the surfactant. Therefore, the size of surfactant slug must be carefully optimized to establish the best economic results of CASF processes.
5.6. Effect of the Number of Chemical Injection Round. Finally, the effect of the number of chemical injection round was investigated in the study. It can be seen from Figure 10 that the incremental oil production, oil-steam ratio, and heat efficiency have an increasing trend with the increase of the number of chemical injection round. These results showed that the production performance of CASF enhanced with the increase of the number of chemical injection round due to the synergistic actions of surfactant and nitrogen foam. However, the CUF decreased with the increasing round. So considering the economic benefit, it is significant to optimize the number of chemical injection round during the CASF processes.

6. Conclusions

(1) The performance of thermal methods for the offshore heavy oil reservoir after water flooding can be ranked as follows: CASF > SF > CAHWF > HWF > CSS. CASF is a potential and effective method for offshore heavy oil reservoirs after water flooding.

(2) The developed numerical method can precisely simulate the CASF processes in offshore heavy oil reservoirs after water flooding.

(3) The production performance of CASF is strongly affected by the gas-liquid ratio. The most suitable gas-liquid ratio of CASF was around 2 : 1 under the simulation conditions.

(4) The CASF performance was enhanced, but the CUF decreased with the increase of foaming agent and surfactant concentrations. Therefore, it is important to optimize the foaming agent and surfactant concentrations during the CASF to get higher oil recovery and better benefits.

(5) The CASF performance enhanced with the increase of the number of chemical injection round due to the synergistic actions of surfactant and nitrogen foam. However, considering the economic benefit, it is significant to optimize the number of chemical injection round during the CASF processes.

Data Availability

The raw/processed data required to reproduce these findings cannot be shared at this time as the data also forms part of an ongoing study.

Conflicts of Interest

The authors declare that there is no conflict of interest regarding the publication of this paper.

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