Experimental Study and Thoughts on Safety and Environmental Protection of Steam Flooding of Horizontal Wells in a Heavy Oil Reservoir

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ABSTRACT: Based on similarity criteria, a scaled physical model was fabricated, containing four horizontal wells and representing one-fourth of an inverted nine-spot steam-flooding pattern. A series of steam-flooding physical simulation experiments were carried out after different types of integral cyclic steam stimulations. Temperature distributions in the model reservoir, overburden, and substratum were measured at intervals. Production performance could be exactly recorded. The spatial temperature distribution of the whole model could be obtained. The phenomena of steam channeling, steam override, and secondary heterogeneity were observed obviously. The results that show steam flooding would cause steam overlap and characteristics of steam channeling during steam flooding after different types of integral cyclic steam stimulation were very distinct. The reservoir would have different temperature fields and different flow resistance because of different integral cyclic steam stimulations. The formation fluid would bypass the place with large flow resistance (low-temperature zone), forming secondary heterogeneity and affecting the displacement effect and thus the development effect. The recovery percent of a heavy oil reservoir developed by steam flooding was low, and it would bring some potential safety risks and problems with environmental protection. The experimental results provide theoretical support for further study of the mechanism of steam flooding.

1. INTRODUCTION

At present, the demand for oil resources is increasing all over the world, while the development of conventional oil resources is gradually entering the middle and late stages.1,2 Heavy oil resources have attracted more and more attention because of their huge reserves all over the world.3–5 Heavy oil reservoir development could be roughly divided into heavy oil thermal recovery technology and heavy oil cold recovery technology.6–9 At present, heavy oil thermal recovery technology is the most widely used. It can be divided into cyclic steam stimulation, steam flooding, SAGD, in situ combustion, and so on from the perspective of injection and production technology.10,11 Cyclic steam stimulation and steam flooding, as the most important development technologies used to develop heavy oil in the world, contribute a large part to heavy oil production.12,13 At present, the development of heavy oil by horizontal wells has occupied the leading position in China’s heavy oil development, and its production is 80% that of heavy oil.14,15 Although cyclic steam stimulation is still the most economical and efficient heavy oil recovery technology presently, the recovery factor is generally less than 25%. Therefore, horizontal well steam flooding technology is still the most valuable technology for heavy oil reservoir development.16–18

Steam overlap would occur in the steam injection development reservoir because of low steam density, resulting in poor vertical sweep efficiency and oil washing efficiency.19,20 Due to the great difference in flow performance between steam and heavy oil, steam channeling often occurred during steam flooding, resulting in the poor horizontal sweep effect of steam injection development and low oil washing efficiency, which affected the recovery of heavy oil. In recent years, many scholars and researchers have conducted in-depth research on steam flooding. Steam flooding is a process of continuously injecting high dryness steam to heat the reservoir, reduce the viscosity of underground crude oil, improve the flow capacity of heavy oil, and displace crude oil into the production well.21,22 Similar to cyclic steam stimulation, the recovery mechanism of steam flooding included not only heating viscosity reduction,23 steam distillation, and solvent extraction23,24 but also miscible
displacement, stripping of oil and gas on crude oil, etc. The screening conditions such as oil saturation, permeability, effective thickness, and crude oil viscosity for steam flooding development of heavy oil reservoirs have been successfully formulated. The sensitivity evaluation of influencing factors of horizontal well steam flooding in heavy oil reservoirs was carried out. The influencing factors included horizontal well length, horizontal permeability, vertical permeability, crude oil viscosity, etc., and the influence degree was different in different situations. The optimization design of steam injection and the well layout mode of horizontal wells have also been widely studied. The results showed that the effect of developing a heavy oil reservoir with horizontal wells as production wells was better than that with vertical wells, and preheating must be carried out before steam injection. Only after the whole reservoir was heated evenly, steam flooding could achieve a better development effect. The research on the reasonable well pattern of steam flooding in horizontal wells was carried out through numerical simulation and reservoir engineering methods. The results show that the development effect of the injection-production well pattern arranged in rows was the best by comparing and analyzing the steam flooding with nine different horizontal well patterns. The uneven suction along the horizontal section had also attracted scholars’ attention during horizontal well steam flooding.

There is much literature related to the mechanism, influencing factors, and problems facing cyclic steam stimulation and steam flooding with horizontal wells. Most oil wells would turn to steam flooding after several rounds of cyclic steam stimulation. Scholars’ research focused on the factors affecting the effect of steam flooding and how to improve the methods of steam flooding and the means of alternative development after steam flooding in horizontal wells. However, almost all theories and reported experiments did not refer to the impact of different types of integral cyclic steam stimulation on the following steam flooding, the degree of the impact, and the mechanism of the impact.

This article attempts to provide some qualitative information on production dynamic characteristics and the impact of different cyclic steam stimulations on the following steam flooding. A series of physical simulation experiments were carried out with steam flooding after different types of integral cyclic steam stimulations. Temperature distributions, production performance, steam channeling, and steam override could be exactly obtained. The experimental results showed that different integral cyclic steam stimulations would cause secondary heterogeneity and affect the subsequent steam flooding. Finally, this paper analyzed the kind of integral cyclic steam stimulation before steam flooding and what kind of alternative development technology was conducive to reservoir development from the perspective of safety and environmental protection.

2. EXPERIMENTS

2.1. Experimental Apparatus and Materials. The schematic of steam flooding experiments after cyclic steam stimulation were shown in Figure 1, and the equipment mainly consisted of four parts, an injection system, simulated reservoir system, data acquisition system, and production system. The injection system was divided into two parts, including an oil injection device and steam injection device. Each injection system included a constant speed injection pump, in which the injection flow error of the pump was less than 0.01 mL/min and the pressure accuracy error was less than 0.5%. In the experiment, the steam generator was used to generate high-temperature and high-quality steam; the maximum working temperature was 350 °C and the maximum working pressure was 35 MPa. The maximum steam injection rate was 60 mL/min, and the maximum gas flow rate was 500 mL/min. The simulated reservoir system mainly consisted of a model body and thermotank. The size of the quartz glass was 30 cm × 30 cm × 20 cm, and the temperature resistance of the model was 300 °C with a pressure resistance of 5 MPa (Figure 2). The model was filled with quartz sand, oil, and water to simulate the oil reservoir. A fixed weight of 30–40 mesh crushed quartz sand was packed into the model. The simulated oil reservoir had an average porosity of 36% and a water permeability range of 8 darcy. The data acquisition and recording system consisted of a temperature sensor, pressure sensor, data collector, and computer with intelligent numerical software. Forty-nine high-precision constantan alloy thermocouples were utilized to measure the temperature of an oil reservoir, and three probes...
were utilized to measure system pressure. The production system consisted of a back-pressure valve and measuring cylinder.

The experimental materials included quartz sand, which could resist a temperature of 300 °C and maximum pressure of 10 MPa, crude oil, and distilled water. The oil used in the experiments was the degassed crude oil with a viscosity of 57 825 mPa·s and density of 0.986 g/cm³ at 28 °C. The simulated oil reservoir consisted of an oil layer, upper caprock, and lower bottom layer. Clay was used to simulate the upper cap layer and lower bottom layer. The upper cap layer and bottom layer were 7 cm thick, respectively. Quartz sand was used to simulate the oil layer, and the oil layer was 6 cm thick.

2.2. Experimental Schemes. The purpose of reservoir physical simulation was to simulate the actual reservoir injection-production performance under laboratory conditions to reveal the dynamics and influence the law of steam flooding after different integral cyclic steam stimulations. The similarity criterion35 was an effective method used to calculate laboratory simulation parameters. The field parameters could be transformed to experimental parameters (as shown in Table 1) by using the similarity criterion, which was beneficial for conducting laboratory experiments. Each experimental parameter could be calculated according to the field parameters and the specific similarity criterion number. The relevant calculation of steam simulation was used as an example. However, before the use of the similarity criterion, a scaling ratio \( r(L) \) had to be obtained first, which was usually expressed by

\[
r(L) = x_m/x_p = h_m/h_p
\]

where \( x \) is the well space, \( m \); \( h \) is net pay, \( m \); \( m \) represents the experimental model; and \( p \) represents the oil field.

**Experimental Length of the Horizontal Section.** The practical length of the horizontal section was 200 m, so the model well length should be 20 cm. Because one-fourth of an inverted nine-spot steam flooding pattern was simulated in the model, the well length in the model only needed half of the actual well length. That was to say, the length of the horizontal section was 10 cm.

**Experimental Well Spacing.** The practical well spacing was 100 m, so the model well length should be 10 cm.

**Experimental Average Effective Thickness.** The horizontal well space and net pay were 100 and 6 m in the oil field, respectively. The well space was 10 cm in the experimental model, so \( r(L) = 10 \text{ cm}/100 \text{ m} = 0.001 \). Accordingly, the model net pay was 6 cm.

![Figure 2. Schematic diagram of a simulated well location.](https://doi.org/10.1021/acsomega.2c00127)

Table 1. Comparison of Field Parameters and Experimental Parameters

| category | parameters | field | experiment |
|----------|-----------|-------|------------|
| Formation parameter | length of horizontal section (m/cm) | 200 | 10 |
| | well spacing (m/cm) | 100 | 10 |
| | average effective thickness (m/cm) | 6 | 6 |
| | porosity (%) | 34.8 | 36 |
| | absolute permeability (μm²) | 4.927 | 8.1 |
| | viscosity of degassed oil at 28 °C (mPa·s) | 56400 | 57825 |
| | steam temperature (°C) | 300 | 250 |
| | steam pressure (MPa) | 8.579 | 13 |
| | reservoir temperature (°C) | 28 | 28 |
| | steam quality percentage | 80 | 80 |
| | reservoir pressure (MPa) | 4.5 | 4.5 |
| | injection time (a/min) | 20 | 2 |
| | cumulative steam injection rate (t/mL) | 23.8 × 10⁴ | 220 |
| | steam flooding time (a/min) | 1 | 38 |
| | injection rate (t/a/mL/min) | 144 | 60 |

The physical model could be made when the length of the horizontal section, well spacing, and average effective thickness were determined. The permeability of the experimental model was determined by the amount of the quartz sand filled in the model, the uniformity of filling, and the degree of compaction. If all experimental parameters were calculated in strict accordance with the similarity criterion, the physical experiment could not be carried out normally. The similarity criterion should be relaxed appropriately and reasonably. The principle of similar cumulative gas injection was adopted during steam simulation in this experiment. The experiment was designed based on the principle of similar cumulative gas injection during steam simulation, and the calculation results were shown in Table 1.

According to the similarity criteria35 of steam flooding, the relevant parameters of the steam flooding stage were also calculated, and the results were shown in Table 1. Because this experiment simulated one-fourth of an inverted nine-spot steam-flooding pattern, the steam injection speed was 1/2 of the calculated value, which was 30 mL/min.

In order to effectively reveal the development performance and effect of steam flooding after different integral cyclic steam simulations, seven different types of integral cyclic steam stimulations were designed, as shown in Table 2. As shown in Table 3, the parameters of steam huff and puff for each well were consistent in each group experiment. The first group of experiments shows that steam huff and puff was carried out in 4 wells at the same time. The second group of experiments shows that steam huff and puff is carried out in the order of 1# well, 2# well, 3# well, and 4# well. The sequence of steam stimulation in other groups was shown in Table 2.

In each group of experiments, steam-flooding experiments were carried out after steam simulation. The 1# wells were steam injection wells, and the others were production wells. The production would be stopped when steam channeling occurs in
any production well during steam flooding. The experiment would be stopped until steam channeling occurred in three production wells.

2.3. Experimental Procedures.

(1) Filling of reservoir model. First, the three-dimensional model kettle was clearly filled by kerosene, detergent, and water. Then it was dried in a constant-temperature oven to ensure that the quartz sand and clay filled in the kettle were not polluted. When the model was completely dry, the model was successively filled with 7 cm of thick clay, 6 cm of thick quartz sand, and 7 cm of clay to simulate the bottom layer, oil layer, and caprock.

(2) Sealing test. The sealing performance of the model was tested using high-pressure nitrogen gas. The system pressure was maintained at 6 MPa for 1 h to determine whether leakage points existed. The pressure drop was within 0.2 MPa; otherwise, the whole simulated reservoir would be rechecked and reassembled.

(3) Connecting process. According to Figure 1, each device and auxiliary equipment were installed, and then the simulated model was placed in the thermostat during the whole experiment process.

(4) Oil filling. The simulated reservoir was first evacuated of its air and saturated with water to determine the porosity. The water permeability of the simulated reservoirs was determined. This water was then displaced by crude oil at a constant injection rate until the inlet and outlet oil velocities of the model were identical. The model began water flooding again to reduce the oil saturation to a fixed value.

(5) Data acquisition. According to the experimental scheme (Tables 2 and 3), steam simulation and steam flooding were carried out successively; the pressure and temperature data during the experiment were collected automatically every 10 s, and the produced liquid was collected manually in real time.

(6) Data processing and result analysis. The collected temperature field data and injection production data were digitized, which can reflect the development performance of each stage of the reservoir in real time. Different rules during steam flooding could be obtained by observing and processing these numerical inversion pictures.

3. RESULTS AND DISCUSSION

3.1. Dynamic Characteristic Analysis. Figure 3 reflected the dynamic oil production characteristics, and water was cut during four oil wells and cyclic steam stimulation simultaneously. The duration of each steam simulation cycle was 20 min, including a steam injection time of 2 min, soaking time of 1 min, and production time of 17 min. The cyclic steam stimulation stage was divided into three rounds, and the steam injection rate increased with the cycle by 15%.

The periodic oil volume of each oil well was about 8–11 mL, and the total oil production of each oil well in the three cycles was 27–28 mL (Figure 3). The cumulative oil production of the four wells was 112.1 mL. The recovery factor in the steam huff and puff stage was 13.3%. The reservoir temperature reached the inflection point temperature after three rounds of cyclic steam stimulation, and the temperature in most areas of the reservoir reached more than 110 °C (Figure 4). The reservoir basically formed thermal connection and reached the conditions for steam flooding.

In order to study the development effect of steam flooding after different cyclic steam stimulations, steam flooding experiments after seven groups of different combined steam stimulation (Table 4) development methods were carried out. Figures 5–18 reflected the dynamic characteristics and

![Figure 3](https://doi.org/10.1021/acsomega.2c00127)

**Figure 3.** Variation of oil volume and water cut with steam simulation time (no. 1).
temperature field distribution. During steam flooding experiments, if there was steam channeling in any production well, it was shut down immediately, and steam injection continued until all wells had steam channeling.

Figure 5 presented the oil volume and water cut, and Figure 6 presented the temperature field distribution of the no. 1 experiment. During this experiment, steam channeling first occurred in the 2# well at 43 min, then in the 4# well at 51 min, and finally in the 3# well at 60 min. The whole experiment lasted 60 min, and the cumulative oil production was 227.3 mL, including 76.5 mL in the 2# well, 73.3 mL in the 3# well, and 77.5 mL in the 4# well. The recovery factor in the whole stage was 26.9%.

It could be seen from Figure 6 that due to the good average permeability of the reservoir and the uniform heating of the reservoir the advance of the steam front was gentle, and there was no obvious steam breakthrough until the steam front advanced to the production well. The steam front first advanced to the 2# well, and the steam was channeled from the toe end of the steam injection well (1# well) to the root end of the 2# production well. This channeling mode was also called “B−A”. The 2# well was closed immediately after steam channeling, and the steam front advanced to the 4# well and 3# well. It could be clearly seen from the temperature field diagram. As shown in Figure 6, the steam channeling between the 1# well and 4# well was in “B−B” mode, and the steam channeling mode between the 1# well and the 3# well was the “B−A” mode.

Figure 7 presented the oil volume and water cut, and Figure 8 presented the temperature field distribution of the no. 2 experiment. During this experiment, steam channeling first occurred in the 4# well at 30 min, then in the 3# well at 60 min, and finally in the 2# well at 86 min. The whole experiment lasted 86 min, and the cumulative oil production was 143.2 mL, including 38 mL in the 2# well, 47.7 mL in the 3# well, and 57.5 mL in the 4# well. The recovery factor in the whole stage was 17%.

As shown in Figure 8, the advance of the steam front was uneven, and the temperature distribution around each production well varied greatly, resulting in obvious steam inrush. The steam front first advanced to the 4# well, and the steam was channeled from the injection well (1# well) to the 4# production well. The 4# well was closed immediately after steam channeling, and the steam front advanced to the 3# well and finally to the 2# well. The steam channeling between the 1# well and 3# well was the “B−A” mode, and the steam channeling mode between the 1# well and 2# well was the “B−A” mode.

Figure 9 presented the oil volume and water cut, and Figure 10 presented the temperature field distribution of the no. 3 experiment. During this experiment, steam channeling first occurred in the 4# well at 31 min, then in the 2# well at 56 min, and finally in the 3# well at 80 min. The whole experiment lasted 80 min, and the cumulative oil production was 160 mL, including 45 mL in the 2# well, 61.7 mL in the 3# well, and 53.3

Table 4. Oil Recovery of Different Experiments

| no. | production time | oil production (mL) | oil recovery | steam-channeling sequence |
|-----|----------------|---------------------|--------------|----------------------------|
| 1   | 60             | 227.3               | 26.9%        | 2−4−3                      |
| 2   | 86             | 143.2               | 17%          | 4−3−2                      |
| 3   | 80             | 160                 | 18.9%        | 4−2−3                      |
| 4   | 78             | 179                 | 21.2%        | 4−3−2                      |
| 5   | 75             | 194                 | 23.1%        | 4−2−3                      |
| 6   | 69             | 210.5               | 25%          | 4−2−3                      |
| 7   | 89             | 125                 | 14.8%        | 2−4−3                      |
mL in the 4# well. The recovery factor in the whole stage was 18.9%.

As shown in Figure 10, the advance of the steam front was also uneven, and the temperature distribution around each production well varied greatly, resulting in obvious steam inrush. The steam front first advanced to the 4# well, and the steam was channeled from the toe end of the steam injection well (1# well) to the toe end of the 4# production well. This channeling mode was also called "B−B". The 4# well was closed immediately after steam channeling, and the steam front advanced to the 2# well and finally to the 3# well.

Figure 11 presented the oil volume and water cut, and Figure 12 presented the temperature field distribution of the no. 4 experiment. During this experiment, steam channeling first occurred in the 4# well at 45 min, then in the 3# well at 53 min, and finally in the 2# well at 78 min. The whole experiment lasted...
78 min, and the cumulative oil production was 177 mL, including 44.5 mL in the 2# well, 73.6 mL in the 3# well, and 58.9 mL in the 4# well. The recovery factor in the whole stage was 21.2%.

As shown in Figure 12, the advance of the steam front was also uneven, and the temperature distribution around each production well varied greatly, resulting in obvious steam inrush. The steam front first advanced to the 4# well, and the steam was channeled from the toe end of the steam injection well (1# well) to the toe end of the 4# production well. This channeling mode was also called “B−B”. The 4# well was closed immediately after steam channeling, and the steam front advanced to the 3# well and finally to the 2# well.

Figure 13 presented the oil volume and water cut, and Figure 14 presented the temperature field distribution of the no. 5 experiment. During this experiment, steam channeling first occurred in the 4# well at 43 min, then in the 2# well at 48 min, and finally in the 3# well at 75 min. The whole experiment lasted 75 min, and the cumulative oil production was 193.7 mL, including 68 mL in the 2# well, 39.7 mL in the 3# well, and 79 mL in the 4# well. The recovery factor in the whole stage was 23.1%.

As shown in Figure 14, the advance of steam front was also uneven, and the temperature distribution around each production well varied greatly, resulting in obvious steam inrush. The steam front first advanced to the 2# well, and the steam was channeled from the toe end of the steam injection well (1# well) to the root end of the 2# production well. This channeling mode was also called “B−A”. The 2# well was closed immediately after steam channeling, and the steam front advanced to the 4# well and finally to the 3# well.

Figure 15 presented the oil volume and water cut, and Figure 16 presented the temperature field distribution of the no. 6 experiment. During this experiment, steam channeling first occurred in the 4# well at 48 min, then in the 2# well at 53 min, and finally in the 3# well at 69 min. The whole experiment lasted 69 min, and the cumulative oil production was 210.5 mL, including 68 mL in the 2# well, 80.5 mL in the 3# well, and 62.5 mL in the 4# well. The recovery factor in the whole stage was 25%.

As shown in Figure 16, the advance of the steam front was also uneven, and the temperature distribution around each production well varied greatly, resulting in obvious steam inrush. The steam front first advanced to the 4# well, and the steam was channeled from the toe end of the steam injection well.
to the root end of the 4# production well. This channeling mode was also called “B−A”. The 4# well was closed immediately after steam channeling, and the steam front advanced to the 2# well and finally to the 3# well.

Figure 17 presented the oil volume and water cut, and Figure 18 presented the temperature field distribution of the no. 7 experiment. During this experiment, steam channeling first occurred in the 2# well at 68 min, then in the 4# well at 73 min, and finally in the 3# well at 89 min. The whole experiment lasted 89 min, and the cumulative oil production was 125 mL, including 45 mL in the 2# well, 32 mL in the 3# well, and 45 mL in the 4# well. The recovery factor in the whole stage was 14.8%.

As shown in Figure 18, the advance of the steam front was also uneven, and the temperature distribution around each production well varied greatly, resulting in obvious steam breakthrough. The steam front first advanced to the 2# well, and the steam was channeled from the toe end of the steam injection well (1# well) to the root end of the 2# production well. This channeling mode was also called “B−A”. The 2# well was closed immediately after steam channeling, and the steam front advanced to the 4# well and finally to the 3# well.

Different cyclic steam stimulation led to uneven heating of the model reservoir. During steam flooding, the steam advanced along with high temperature and low seepage resistance, resulting in uneven steam sweep and uneven heating of the reservoir. This uneven heating of the reservoir caused uneven temperature field distribution, and uneven temperature field distribution would lead to uneven seepage resistance in each region of the reservoir. This uneven steam sweep caused by temperature was similar to that caused by reservoir heterogeneity. It showed that the reservoir with average permeability would cause a sweep effect similar to the heterogeneous reservoir due to different cyclic combined steam stimulation modes. Therefore, the nonuniform sweep effect caused by the development mode could be called secondary heterogeneity.

As shown in Table 4 that steam flooding was carried out after different combinations of steam stimulation. The production time, oil production, and steam-channeling sequence of each production well were different during the
steam-flooding stage. The development effect of heavy oil reservoirs caused by different combined steam stimulations was irreversible. In the first group of experiments, due to steam stimulation in four wells at the same time, the formation was heated simultaneously and evenly, and the overall temperature field was evenly distributed. There was no obvious sudden advancement of the steam front caused by different formation temperatures in the whole reservoir, and there was no uneven sweep caused by the secondary heterogeneity. Moreover, the temperature in most areas of the reservoir reached the inflection point temperature, so the steam front propulsion resistance was small and the most uniform, the steam displacement effect the best, the development effect the best, and the recovery factor the highest.

In the second group of experiments, there was obviously an unheated area with a low-temperature value between the 1# steam injection well and the 2# production well, which hindered the diffusion of steam to this area during steam flooding, so the steam first spread to the area and the area controlled by the 3# and 4# production wells.

In the third group of experiments, there was also an obvious cold area around the 1# steam injection well and 3# production well. The periphery of the steam injection well would be heated gradually with steam injection; however, it would also affect the development effect, and the 3# production well would be the last displaced well due to the existence of a cold zone.

In the fourth group of experiments, there was an obvious cold zone between the steam injection well and 2# production well, and the 3# and 4# wells were uniformly heated. In the process of steam drive, the steam would diffuse to the 3# and 4# steam injection wells and bypass the 2# production well.

In the fifth group of experiments, the temperature around wells 2# and 4# was relatively high, and the temperature around wells 1# and 3# was relatively cold; however, there was no obvious cold oil area. The steam advanced to wells 2# and 3# first and then to well 3#.

In the sixth group of experiments, the 2#, 3#, and 4# production wells had high ambient temperature and reached the inflection point temperature. During steam flooding, the steam injection wells gradually formed thermal connection with the three production wells with the increase of injected steam. The effect of steam flooding was similar to that of the first group of experiments.

In the group 7 experiment, the area around the three production wells was in the low-temperature area as a whole, which could not achieve the effect of thermal connectivity. Although there was no obvious secondary heterogeneity, the overall development effect was the worst.

It could be seen from the above seven groups of experiments that the reservoir temperature field had the greatest impact on the effect of steam flooding. The first group of experiments with the best preheating effect of the reservoir had the best development effect during the steam flooding stage and the worst preheating effect of the reservoir of the seventh group of experiments. The reservoir with an obvious cold oil area would also affect the reservoir development effect, such as the experiments in groups 2, 3, and 4, because the heterogeneity of the secondary reservoir would affect the reservoir development effect.

3.2. Steam Overlap Characteristic Analysis. Figure 19 shows the temperature field of the top caprock reservoir and bottom layer of the reservoir at different times. There was an obvious overlap phenomenon in the process of steam flooding. It can be seen from the figure that the reservoir temperature (more than 190 °C) was the highest; the temperature of the top layer was more than 120 °C; and the temperature (more than 190 °C) of the bottom layer was the lowest. It can also be judged that the temperature and sweep coefficients of the upper, middle, and lower areas of the reservoir were inconsistent during the steam flooding, which also explains why the crude oil could not be fully exploited after the whole reservoir was completely swept. The faster the steam injection speed was and the longer the steam injection time was, the more obvious this overlap phenomenon would be.

3.3. Sustainable Development Analysis. From the experimental temperature field diagram and dynamic data, the
volume of produced fluid was greater than the volume of injected steam. Continuous steam flooding development of the heavy oil reservoir led to a reservoir deficit. It would bring potential safety hazards to the subsequent development of the reservoir.

In the seven groups of experiments, the volume of injected steam exceeded the formation of the pore volume during steam flooding, but there was still a large amount of crude oil in the formation. It required replacement technology to continue to develop heavy oil reservoirs.

As shown in Table 4, the production time during steam flooding in the seven groups of experiments was more than 60 min in the model reservoir, which was equivalent to about 2 years of actual reservoir production. Long-term steam flooding and thermal corrosion of pipelines and formations would bring certain potential safety and environmental protection hazards to formations and pipelines because the steam injected into the formation on the oilfield site was of high temperature, high pressure, and high pH value. When the steam was injected into the heavy oil reservoir, the strongly alkaline steam would react chemically with the minerals. Meanwhile, the mechanical carrying effect of steam and thermal fluid also easily blocked the reservoir and affected the displacement effect or led to large pores being blocked after the particles were carried out, resulting in local formation collapse and affecting the production. The production of steam needed to emit a large amount of carbon dioxide. Under the background of carbon neutralization, how to reduce carbon emissions would be a problem worthy of study.

Carbon-dioxide-assisted steam flooding was considered as a safe and environmentally friendly development technology, which could not only supplement formation pressure and prevent formation collapse but also neutralize the corrosion damage caused by a strong alkaline environment caused by hot steam. In addition, carbon dioxide could greatly improve crude oil recovery due to dissolved gas drive, miscible displacement, expanding crude oil, reducing crude oil viscosity, and increasing rock permeability with carbonated water. Similarly, the injection of carbon dioxide could neutralize the quality of carbon dioxide to be discharged to produce steam. In short, the carbon-dioxide-assisted steam drive was considered to be an efficient alternative development technology, which could also solve or alleviate the safety and environmental protection problems caused by steam drive.

4. CONCLUSIONS

In view of the findings in this study, the following conclusions could be drawn.

Steam overlap would occur in a heavy oil reservoir developed by steam injection. Steam overlap would cause the upper temperature of the reservoir to be higher than the bottom temperature; the upper oil washing efficiency and sweep coefficient were better; and the development effect of the upper part of the reservoir was better than that of the lower part, which is also the reason for the poor recovery effect of pure steam flooding.

The reservoir had different temperature fields after different combinations of steam stimulation in the reservoir with average permeability. Different temperature fields would lead to different flow resistance in the reservoir during steam flooding. The lower the temperature in the reservoir was, the greater the flow assistance of the fluid in the reservoir was. The fluid will bypass the place with large flow resistance (low-temperature zone), forming secondary heterogeneity and affecting the displacement effect and thus the development effect.

The recovery factor of the heavy oil reservoir developed by steam flooding was limited, and it would bring some hidden dangers of safety and environmental protection to the reservoir. Carbon-dioxide-assisted steam flooding could be considered as an effective, environmentally friendly, and safe way to increase the recovery factor.

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