Research on Water Cone Behavior in a Heavy Oil Reservoir with Bottom Water Considering the Starting Pressure Gradient
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ABSTRACT: Aiming at the unclear reorganization of the water cone shape and its flooding scope for a horizontal well in a heavy oil reservoir with bottom water, a new method was proposed in this paper to establish a numerical model with the starting pressure gradient (SPG) by commercial software to study water cone behavior. The results show that there exists SPG in heavy oil reservoirs ranging from $10^{-4}$ to $10^{-3}$ magnitude with mobility under 30 $\mu m^2/mPa\cdot s$. With a mobility of 33 $\mu m^2/mPa\cdot s$, the water cone and flooding scope from the model with SPG is 120 m shorter than that without SPG. Upon increasing the mobility from 11 to 90 $\mu m^2/mPa\cdot s$, the flooding scope of the model with SPG changes from 125 to 315 m, showing a power exponential form. The new method proposed in this paper was significant for the water cone behavior study and has broad applications in heavy oil reservoir development in the future.

1. INTRODUCTION

The development of heavy oil reservoirs with bottom water is one of the big challenges in the oil and gas exploitation field worldwide.1,2 Developing reservoirs in these types often shows early water appearance, short water-free period, high water cut ratio, and even violent water cut ratio after water breakthrough, which reduces oil recovery and increases oilfield production risk.3,4

Currently, the application of a horizontal well has been widely known as an effective technology to enhance oil recovery for heavy oil reservoirs with bottom water, especially for those with thin layers.5–7 Compared with a vertical well, a horizontal well has the advantages of a larger contact area with the reservoir and smaller production pressure drop, which results in larger water cone, higher sweeping efficiency, lower drawdown, higher improved oil recovery, and better economics.4

The core technology for developing this type of reservoirs using horizontal wells exists in the description of the water cone. The evolution of water cone and its sweeping scope has a deep influence on the developing and adjusting project design. In the past decades, many researchers have conducted experimental, analytical, and numerical studies on water cone behavior of horizontal wells.8–10 However, the results of different research methods varied largely, especially for the heavy oil reservoir. For example, the sweeping scope from the laboratory experiments is much lower than that from numerical simulations. Based on vast literature research, we found that, in the porous medium, the heavy oil reservoir is similar to the low permeability reservoir, which is a non-Darcy flow with a starting pressure gradient (SPG).11 So, to heavy oil reservoirs, seepage can occur only if the production pressure gradient is greater than the SPG.12−14 However, the existing commercial numerical simulation software, such as Eclipse CMG and Petrel Re, are all based on the Darcy seepage model and cannot directly characterize the non-Darcy flow in heavy oil reservoirs. The theoretical formula cannot yet take complex geological and production conditions into consideration besides SPG. The existing laboratory experiment results were also unreal although considering SPG because they were largely limited by the model size. All the problems mentioned above seriously influence the exact description of water cone behavior and sweeping scope in heavy oil reservoirs with bottom water, which have an impact on further development and adjustment of this type of reservoirs (Tables 1 and 2).15−17

In this paper, we propose a new equivalent simulation method to achieve the equivalent characterization of the SPG in the commercial numerical simulation software of heavy oil reservoirs. Then, we construct a numerical model based on the new method to observe the evolution of water cone behavior and sweeping scope in heavy oil reservoirs with bottom water. Meanwhile, we also expanded the physical model size to remove the influence of the model size on the experimental
results. Finally, we comprehensively compared the results from the new method with that from a laboratory experiment with a full-size physical model and logging interpretation to verify its correctness. The new method proposed in this paper was significant in the water cone behavior study and has broad applications in heavy oil reservoir development in the future (Figures 1-3).

2. RESULTS AND DISCUSSION

2.1. Starting Pressure Gradient under Different Mobilities. The core samples listed in Table 3 were used to measure the SPG under different mobility conditions. The results are shown in Table 3 and Figure 4.

From Table 3, the SPG ranges from 0.00030 to 0.00141 MPa/m, while the mobility ranges from 0.637 to 33.557 $10^{-3}$ μm$^2$/mPa·s. Based on the results, a fitting curve was obtained to describe the relationship between SPG and mobility, as shown in Figure 4. The formula is as follows

$$G_p = 0.001 \left( \frac{k}{u} \right)^{-0.352}$$

In the formula, $G_p$ is the starting pressure gradient, MPa/m; $K$ is the permeability, $10^{-3}$ μm$^2$; and $u$ is the crude oil viscosity, mPa·s.

From Figure 4, we can see that the starting pressure gradient increases with decreasing mobility. With the mobility smaller than $5 \times 10^{-3}$ μm$^2$/mPa·s, the SPG decreases quickly from $10^{-3}$ to $10^{-4}$ magnitude. When the mobility is larger than $5 \times 10^{-3}$ μm$^2$/mPa·s, the SPG decreases slowly and is maintained at $10^{-4}$ magnitude. The relationship between them is a power exponent form, and the relative coefficient is up to 0.9604.

Table 1. Core Sample Parameter Analysis

| number | viscosity (mPa·s) | Swcr (%) | permeability ($10^{-3}$ μm$^2$) |
|--------|------------------|----------|----------------------------------|
| K30    | 266.2            | 17.24    | 336.03                           |
| K64    | 266.2            | 15.86    | 1385.42                          |
| K61    | 266.2            | 15.2     | 1565.24                          |
| K31    | 513.1            | 23.12    | 331.83                           |
| K54    | 513.1            | 18.21    | 1384.3                           |
| K12    | 154.3            | 26.48    | 337.43                           |
| K21    | 154.3            | 27.34    | 625.36                           |
| K19    | 154.3            | 24.4     | 3679.01                          |
| K51    | 70.6             | 23.25    | 550.46                           |
| K67    | 70.6             | 16.71    | 867.99                           |
| K75    | 70.6             | 22.15    | 2085.95                          |
| K28    | 266.2            | 20.27    | 350.01                           |
| K72    | 266.2            | 22.13    | 1446.4                           |
| K36    | 513.1            | 20.48    | 326.74                           |
| K65    | 513.1            | 21.26    | 1334.98                          |
| K61    | 154.3            | 23.05    | 1671.38                          |
| K78    | 154.3            | 27.44    | 3331.34                          |
| K45    | 70.6             | 20.59    | 2369.12                          |

Table 2. Main Parameters of the Conceptual Model

| parameter | value          |
|-----------|----------------|
| datum top depth (ft) | 5150           |
| oil–water interface depth (ft) | 5190           |
| oil–water interface pressure (psi) | 2248.4         |
| crude oil viscosity (mPa·s) | 50–200         |
| formation water viscosity (mPa·s) | 0.4            |
| permeability ($10^{-3}$ μm$^2$) | 4500           |
| porosity (%) | 27.0           |
| original oil saturation (%) | 4.2             |
| formation oil volume factor | 1.038          |
Table 3. Starting Pressure Gradient Measurement

| number | viscosity (mPa·s) | permeability (10^{-13} μm²) | mobility (10^{-3} μm²/mPa·s) | SPG (MPa/m) |
|--------|-----------------|-----------------------------|-------------------------------|-------------|
| K30    | 266.2           | 336.03                      | 1.262                         | 0.00095     |
| K64    | 266.2           | 1385.42                     | 5.204                         | 0.0005      |
| K61    | 266.2           | 1565.24                     | 5.879                         | 0.00049     |
| K31    | 513.1           | 331.83                      | 0.647                         | 0.00141     |
| K54    | 513.1           | 1384.3                      | 2.698                         | 0.00061     |
| K12    | 154.3           | 337.43                      | 2.187                         | 0.00082     |
| K21    | 154.3           | 625.36                      | 4.053                         | 0.00065     |
| K19    | 154.3           | 3679.01                     | 23.843                        | 0.00036     |
| K51    | 70.6            | 550.46                      | 7.797                         | 0.00048     |
| K67    | 70.6            | 867.99                      | 12.294                        | 0.00042     |
| K75    | 70.6            | 2085.95                     | 29.546                        | 0.00031     |
| K28    | 266.2           | 350.01                      | 1.315                         | 0.00079     |
| K72    | 266.2           | 1446.4                      | 5.433                         | 0.00055     |
| K36    | 513.1           | 326.74                      | 0.637                         | 0.00125     |
| K65    | 513.1           | 1334.98                     | 2.602                         | 0.00065     |
| K61    | 154.3           | 1671.38                     | 10.832                        | 0.00042     |
| K78    | 154.3           | 3331.34                     | 21.59                         | 0.00036     |
| K45    | 70.6            | 2369.12                     | 33.557                        | 0.00030     |

Figure 4. Relationship between mobility and starting pressure gradient.

2.2. Water Cone Behavior with and without Considering the Starting Pressure Gradient. The conceptual model with the main parameters listed in Table 2 was established to explore the influence of mobility on water cone behavior and production curves accordingly. The crude oil viscosity was fixed at 135 mPa·s. The results are shown in Figures 5–7.

Figure 5 illustrates the evolution of the water cone with and without considering SPG. During the flooding process, the water cone both grew quickly for the water cut before 85% and then grew slowly after that. For example, the two models at every water cut stage, there always exists differences in the water cone size, shape, and flooding scope. For the existence of SPG, the water cone size, shape, and flooding scope are much smaller in model with SPG than those in model without SPG. Finally, at the water cut stage of 98%, the flooding scope with SPG is 450 m and that without SPG is 570 m.

Figures 6 and 7 show the changes in oil production rate and water cut during the evolution of the water cone. During the flooding process, both the oil production rate and water cut vary quickly first for the water cut before 85% and then become slow after that. This is according to the water cone behavior shown in Figure 5, which is the water cone grew quickly for the water cut before 85% and then grew slowly after that. Compared with those in the model without SPG, the oil production rate decreases much faster and the water cut increases much faster in the model with SPG. Moreover, from Figure 7, we can see that the oil production cumulative of the model without SPG is much more than that with SPG. The reason lies in that the existence of SPG limited the growing and flooding scope of the water cone, which leads to more water production and unstarting oil.

2.3. Water Cone Behavior from Numerical Model Simulations under Different Mobilities. The conceptual model with the main parameters listed in Table 2 was established to explore the influence of mobility on water cone behavior and production curves accordingly. The permeability was fixed at 4500 mD, and the crude oil viscosity ranges from 50 to 400 mPa·s. The results are shown in Figures 8–11 and Table 4.

Figure 8 illustrates the final shape and flooding scope of water cones under different mobility conditions. With the increase of crude oil viscosity and decrease of mobility accordingly, the water cone size and flooding scope decrease from 315 to 125 m. Besides, from Figure 9a,b, we can see that the oil production rate decreases much quickly and the water cut increases fastly. The reason lies in two aspects. First, with the increment of crude oil viscosity, the fingering phenomenon is significant, which results in a quick breakthrough in bottom water. Second, with the increment of crude oil viscosity, the mobility decreases accordingly, which leads to a higher SPG, as described in Figure 4 and Formula 7. The higher the SPG, the smaller the water cone and the flooding scope. Both of the reasons mentioned above contribute to the quicker increment of water cut and decrement of oil production rate. Finally, mobility has a significant influence on the cumulative oil production, as shown in Figure 10.

Based on the results shown in Table 4, a fitting curve was obtained to describe the relationship between the water cone flooding radius and mobility and between the water cone flooding radius and viscosity, as shown in Figure 11 a,b. The formula is as follows:

\[ Y = 92.567*\ln(X) - 98.302 \]  

In the formula, \( Y \) is the water cone flooding radius, \( m \), and \( X \) is the mobility, \( 10^{-3} \mu m^2/\text{mPa·s} \).

From Figure 11, we can see that the water cone flooding radius increases with increasing mobility and decreases with increasing viscosity from 315 to 125 m. The relationship between them is a power exponent form, and the relative coefficient is up to 0.9988.

2.4. Grid Size Sensitivity Analysis. In the conventional numerical models, the grid size has a deep influence on numerical results. In this part, a series of conceptual models were built to analyze the grid sensitivity for models with and without SPG. The grid size varies from 1 to 30 m, respectively, and the results are shown in Figure 12.

From Figure 12a,b, with the increment of grid size, the water cone radii of models with and without SPG both increase. Differently, the models considering SPG increases slowly, while that of models without considering SPG increases rapidly. The reason lies in that conventional models without considering
SPG belong to liner seepage, the oil saturation degree changes where the pressure changes, and the grid size is the main factor to influence the water cone radius. However, in the model with SPG in this paper, the SPG is related to the grid size; the bigger the grid, the higher the SPG; with considering SPG, the water cone radius changes slightly with the increment of grid size, from 220 to 232, which meets the field application requirements.

3. CONCLUSIONS

A new method was proposed in this paper to establish a numerical model with considering a starting pressure gradient (SPG) to study the water cone behavior. From what we studied above, the conclusions could be summarized as follows:

1. There exists SPG in a heavy oil reservoir, with values ranging from $10^{-4}$ to $10^{-3}$ magnitude with mobility under 30 $\mu$m$^2$/mPa·s.

Figure 5. Water cone behavior with and without considering SPG.

Figure 6. Production curves with and without considering the SPG Oil production rate (a) and water cut (b).

Figure 7. Oil production cumulative with and without considering SPG.
The SPG could be considered in commercial simulation software with the new method proposed in this paper. The SPG influences the water cone behavior significantly. With a mobility of 33 μm²/mPa·s, the water cone and flooding scope from a model with SPG is 120 m shorter than that without SPG.

4. EXPERIMENTAL AND MODEL SECTION

4.1. Materials. Crude oil was obtained from the Panyu oilfield. Oil viscosity was measured using a Brookfield viscometer (DV-II+, Brookfield) at a reservoir temperature of 75 °C. The cone samples were collected from heavy oil reservoirs of the Panyu oilfield. The parameter analyses of cone samples are shown in Table 1.

4.2. Models. Based on the new method in this paper, a conceptual model considering a starting pressure gradient was established by Petrel Re. The number of grids is 500 × 500 × 15; the grid step lengths in the X, Y, and Z directions are all 4 ft. The water body size was infinite and controlled by Fetchovich. A horizontal well was arranged in the upper part of the reservoir. The main parameters of the conceptual model are shown in Table 2.

4.3. Starting Pressure Gradient Measurement. In this paper, the constant current method is used to determine the starting pressure gradient of the core sample. The experimental flow is shown in Figure 1.

The main experimental steps are as follows:

(4) The mobility has a significant influence on the evolution of water cone. By increasing the mobility from 11 to 90 μm²/mPa·s, the flooding scope of the model with SPG changes from 125 to 315 m, showing a power exponential form.

Table 4. Flooding Scope of Water Cone under Different Mobility Conditions

| permeability (×10⁻³ μm²) | viscosity (mPa·s) | M (×10⁻³ μm²/mPa·s) | R (m) |
|--------------------------|------------------|---------------------|------|
| 4500                     | 50               | 90                  | 315  |
| 4500                     | 70               | 64                  | 291  |
| 4500                     | 135              | 33                  | 225  |
| 4500                     | 200              | 22                  | 190  |
| 4500                     | 250              | 18                  | 170  |
| 4500                     | 400              | 11                  | 125  |

Figure 8. Water cone behavior with considering SPG under different mobilities (K = 4500 mD).

Figure 9. Production curves with considering SPG under different mobilities (K = 4500 mD): oil production rate (a) and water cut (b).

Figure 10. Oil production cumulative with considering SPG under different mobilities (K = 4500 mD).
(1) prepare the core samples according to SY/T 5336-2006;
(2) establish the critical water saturation by the oil flooding method according to SY/T 5345-2007;
(3) pump the oil to drive the core sample with the flow rate ranging from 0.001 to 0.5 mL/min and then record the corresponding pressure when the flow is stable; and
(4) replace the core and repeat the above steps to get 18 cores.

4.4. Equivalence Principle and Balance Zone Setup. Based on the current mature numerical simulation software Petrel Re, we reset the balance areas and the interarea threshold pressures through the new method in this paper to achieve the starting pressure gradient model. The formula is as follows

\[ \nu = 0 \quad (\Delta p \leq G) \]  
\[ \nu = \frac{k}{\mu} \left( \frac{\Delta p - G}{L} \right) \quad (\Delta p \geq G) \]

The seepage velocity formula for the starting pressure gradient model is as follows

\[ \nu = 0 \quad \left( \frac{\Delta p}{L} \leq c \right) \]
\[ \nu = \frac{k}{\mu} \left( \frac{\Delta p}{L} - c \right) \left( \frac{\Delta p}{L} \geq c \right) \]

In the formula, \( \nu \) is the seepage velocity, \( \mu \) is the permeability, \( 10^{-3} \mu m^2 \); \( \mu \) is the crude oil viscosity, mPa·s; \( c \) is the starting pressure gradient, MPa/m; \( G \) is the threshold pressure, MPa; \( L \) is the distance between the injection end and the production end, m; and \( \Delta p \) is the pressure drawdown between the injection end and the production end, MPa.

For the grid model, “fluids only flow between adjacent grids” is the most basic principle. On this basis, we designed the staggered looping method to set the balance areas, as shown in Figure 2. From Figure 2, adjacent to the balance area 1 is the balance area 2, and vice versa. With this new method, it is easy to achieve the equivalent characterization of the starting pressure gradient through setting the threshold pressure among balance areas.\(^{19}\)

In Petrel Re, we can set the balance areas, as shown in Figure 2, through the following formulas in the calculator section of Petrel-Re. The conceptual model was divided into three areas, as shown in Figure 3. There exists a starting pressure gradient between area 1 and area 2, both of which belong to the oil layer. There does not exist a starting pressure gradient inside area 3 since it belongs to the water layer. There also does not exist a starting pressure gradient between area 3 and area 1 and area 2.

\[ \text{region } 1 = \text{If } (\text{Int}((I + J + K)/2)) \]
\[ = ((I + J + K)/2, 2, 1) \]  
\[ \text{region } 2 = \text{If } (K > = 11, 3, \text{region}) \]
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Notes
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