Study on the policy boundary of rational development in high water cut period of medium and low permeability conglomerate reservoir

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Abstract. Using numerical simulation technology, the research and analysis of the rational development policy boundary of high and low water cut period in medium and low permeability conglomerate reservoirs are carried out. According to the research, (1) due to the strong homogeneity of the conglomerate reservoir, the injection water is unevenly propelled, and the remaining oil distribution between the oil and water wells is irregular; (2) the local layer pressure is maintained near the saturation pressure. The highest rate and the best development effect; (3) for medium and low permeability conglomerate reservoirs, the reasonable water injection intensity gradually increases with the increase of water content. For example, when the water content is 80%, the reasonable water injection intensity is 10m³/d/m; for a water content of 90%, a reasonable water injection strength of 6m³/d/m (3) for the different formation pressure and water content level of the reservoir, determine the ratio of injection and production, for example, the current formation pressure The oil layer with a water content of 8.0 MPa and a water content of 80% has a reasonable injection-production ratio of 1.05.

1. Introduction

For the domestic conglomerate oilfield as a whole, it has entered a high water-cut period and has difficulty in development. By optimizing the development and adjustment of water injection, the development effect and recovery factor of reservoir water flooding can be improved. To this end, this paper uses reservoir numerical simulation technology to carry out research on the rational development policy boundary of high and low water cut period in medium and low permeability conglomerate reservoirs. Firstly, the reasonable formation pressure of medium and low permeability conglomerate reservoirs in high water cut period is determined, and the reasonable water injection intensity under different water conditions is determined. The reasonable injection-production ratio is designed for different water and formation pressure levels of the reservoir, so that the reservoir is reasonable. The
pressure recovery rate or pressure drop rate reaches a reasonable formation pressure level, and the production is performed according to the injection-production balance when the reservoir returns to a reasonable formation pressure.

2. Numerical simulation establishment
In order to better simulate the strong heterogeneity of low-permeability conglomerate reservoirs, a numerical simulation model of permeability and distribution range (0-100) was established in this study. The saturation pressure is 8.5 MPa.

![Fig.1 Numerical simulation model permeability distribution](image1)

Development predictions were made using the established numerical simulation model and displaced to 98% water. By analyzing the remaining oil distribution field, it is known that due to the extremely strong heterogeneity of the conglomerate reservoir, the residual oil distribution between the oil and water wells is extremely uneven. Therefore, optimization of formation pressure and other parameters is essential for medium and low permeability conglomerate reservoirs.

![Fig.2 Remaining oil distribution at 98% water content](image2)

3. Reasonable formation pressure determination
Using non-equilibrium start, the water injection speed is 0.10 PV/a, the injection-production ratio is set to 1, the formation pressure is maintained at different levels (6.5, 7.5, 8.5, 9.5 and 10.5) MPa, developed to 98% water content, and the final water drive is evaluated. Recovery factor. It can be seen from the calculation that the development pressure of the formation pressure is maintained near the saturation pressure. When the average formation pressure is increased from 6.5 MPa to 8.5 MPa, the recovery factor is increased by 3.26%; the average formation pressure is increased from 8.5 MPa to 10.5 MPa,
and the recovery factor is reduced by 0.51%. The reason for the analysis is that when the pressure in the local layer is too low, the original degassing causes the original viscosity to increase, making it difficult to flow. On the other hand, after the gas is released, the oil reservoir changes from oil-water two-phase flow to oil-gas three-phase flow. The crude oil fluidity is further deteriorated; when the local layer pressure is too high, the viscosity of the oil phase oil increases due to the increase of pressure, and the fluidity deteriorates, which makes the overall development effect of the reservoir worse. Therefore, there is a reasonable interval for the formation pressure, which makes the overall development of the reservoir optimal.

![Fig.3 Recovery factor with formation pressure curve](image)

4. **Determination of reasonable water injection intensity**
In the study of the water injection intensity scheme, injection wells were dispensed according to different water injection strengths, and the injection-production ratio was controlled to be 1. According to the numerical simulation results, the overall recovery rate of low-permeability conglomerate reservoirs in different water-bearing stages gradually decreases with the increase of water injection intensity.

![Fig.4 Different conversion rate of recovery factor with formation pressure curve](image)

5. **Reasonable ratio of injection to production**
The oilfield injection-production ratio is an important parameter in the oilfield development process. The injection-production ratio is low and the formation pressure is not maintained.
Living, the output will be decremented; the injection-production ratio is large, the formation energy can be supplemented, but it may cause the water raft speed to increase and reduce the recovery rate. Therefore, it is necessary to properly control the injection-production ratio, maintain the formation energy, and prevent the block water flooding. For high-water-bearing conglomerate reservoirs, the formation pressure may be at different levels before comprehensive development and adjustment. A reasonable injection-production ratio under different formation pressure levels is designed for the practical problem, so that the formation pressure is restored to an optimal condition. Formation pressure level.

**Tab.1** of injection and production ratio schemes under different formation pressures and water cuts

| Current formation pressure (Mpa) | Different moisture content levels (%) | injection-production ratio |
|---------------------------------|--------------------------------------|---------------------------|
| 7.0                             |                                      | 80 | 1.00 | 1.05 | 1.10 | 1.15 | 1.20 |
|                                 |                                      | 85 | 1.00 | 1.05 | 1.10 | 1.15 | 1.20 |
|                                 |                                      | 90 | 1.00 | 1.05 | 1.10 | 1.15 | 1.20 |
| 8.0                             |                                      | 80 | 1.00 | 1.05 | 1.10 | 1.15 | 1.20 |
|                                 |                                      | 85 | 1.00 | 1.05 | 1.10 | 1.15 | 1.20 |
|                                 |                                      | 90 | 1.00 | 1.05 | 1.10 | 1.15 | 1.20 |
| 9.0                             |                                      | 80 | 0.80 | 0.85 | 0.90 | 0.95 | 1.00 |
|                                 |                                      | 85 | 0.80 | 0.85 | 0.90 | 0.95 | 1.00 |
|                                 |                                      | 90 | 0.80 | 0.85 | 0.90 | 0.95 | 1.00 |
| 10.0                            |                                      | 80 | 0.80 | 0.85 | 0.90 | 0.95 | 1.00 |
|                                 |                                      | 85 | 0.80 | 0.85 | 0.90 | 0.95 | 1.00 |
|                                 |                                      | 90 | 0.80 | 0.85 | 0.90 | 0.95 | 1.00 |

**Fig.5** Study on the optimal injection-production ratio of different formation pressures in the water-bearing stage

Using the results of this paper, by controlling the reasonable development limit, the formation pressure, water injection intensity and injection-production ratio are maintained within a reasonable range. According to the streamline results, the injection water distribution is more uniform, and the ripple situation is larger than before the adjustment. The yield uncontrolled scheme increased by 2.1%.

6. Conclusion
(1) The development pressure of the formation pressure is maintained near the saturation pressure;
(2) The reasonable flow pressure is 4.0-5.5 MPa when the water injection speed is 0.10 PV/a; the reasonable flow pressure is 3.5-5.0 MPa at a speed of 0.15 PV/a; the reasonable flow pressure is 3.5-4.0 MPa at a speed of 0.20 PV/a.

(3) The reasonable injection pressure is 10.5-12.0 MPa when the water injection speed is 0.10 PV/a; the reasonable injection pressure is 11.5-13.0 MPa for the speed of 0.15 PV/a; the reasonable injection pressure is 13.0-14.0 MPa for the speed of 0.20 PV/a.

(4) After adjusting the pressure system to a reasonable range, the recovery factor increased by 1.34%.

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