

Numerical Simulation Study on Optimization of Injection-Production Coupling Parameters in Complex Fault Block Reservoirs

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Abstract: Taking complex fault-block reservoir in Biyang Depression as the research object, the influence of different factors on the coupling development mode of injection-production was studied. The numerical simulation method was used to evaluate the influence of intervention timing, injection intensity, periodic injection volume and production strength on the coupling implementation effect of the fault-block reservoir, and the coupling development parameters were optimized. The main knowledge obtained is that the timing and intensity of intervention are the main controlling factors of injection-production coupling in fault block reservoirs. The earlier the intervention time, that is, the lower the water cut, the better the injection and production coupling development effect. There is an optimal injection intensity, and the coupling injection and production effect is the best when the injection and production ratio is kept at 1:1. When the pressure is restored to 100%-120%, the coupling injection and production development effect is the best, and the periodic water injection volume is 2400-3200m³. The higher the strength of liquid production, the faster the oil recovery rate.

Keywords: Complex fault-block reservoir; Injection and production coupling; Main control factor; Numerical simulation.

1. Introduction

Due to its complexity and particularity in reservoir development and residual oil distribution, fault block reservoirs are highly difficult to develop in the field [1-2]. In addition, due to the serious heterogeneity of the reservoir, with the continuous development of the reservoir, injected water preferentially enters the high permeability interval, while the crude oil in the low permeability interval cannot be effectively used, the water cut of the reservoir increases rapidly, and the formation energy cannot be effectively supplemented [3]. Therefore, it is easy to form residual oil enrichment in areas with poor porosity and permeability development and general reservoir physical properties.

Most of the reservoirs in China have entered the high water cut stage, and how to dig the remaining potential oil has become a problem that is facing and needs to be solved urgently. Although the use of chemical flooding, microbial flooding, thermal recovery and gas injection can achieve enhanced oil recovery in a relatively short period of time, these methods are complicated to operate during the development process and have high development costs. [4-6] Therefore, in the actual reservoir development, the adjustment water drive development mode is often explored in depth, and the main adjustment modes include: injection-production well pattern encryption, water plugging and profile control, horizontal well development, injection-production coupling development, etc. Among them, the development of injection-production coupling breaks the original single isopercolation channel inside the reservoir through unstable water injection Wells, and changes the isopercolation field and pressure field between injection-production Wells, thereby expanding the spread range of injected water[7]. Through the bidirectional adjustment between oil and water Wells, the alternating cooperative development of injection-production Wells is realized. At the

same time, in the reservoir, the pressure disturbance changes the natural flow field of the fluid, avoids the formation of natural flow line between oil and water Wells, and makes the remaining oil in the unswept area of the reservoir to be effectively used, and increases the swept volume of water drive and thus improves the oil recovery[8-10].

Previous scholars used numerical simulation methods to study the injection-production coupling development of complex fault block reservoirs. Based on this, this paper takes the complex fault-block reservoir in Biyang Depression, East China as the research object to carry out the influence of different factors on the coupled injection-production development mode, and uses the numerical simulation method to analyze the main control factors for enhanced oil recovery of the fault-block reservoir, in order to provide reasonable and effective development strategies for the coupled injection-production mode under different reservoir conditions.

2. Numerical Simulation of Injection-production Coupling

Taking the typical unit well group with dynamic injection-production coupling as the research target, the author established reservoir geological model and numerical model according to reservoir geology and production data, and carried out fine historical fitting according to the production performance of the target well group. On the basis of this simulation, the stratified streamline flow field simulation of typical target well groups is carried out.

2.1. Build the model

According to the injection and production coupling development mode, the reservoir geological model is established by taking the typical unit well group Gu30 as an example, and the reservoir numerical model is established by using the Petrol-Re software to carry out detailed numerical

simulation research. The grid size of the main layer in the study area is $15m \times 15m \times 1.5m$, and the total number of grids is $100 \times 70 \times 70 = 490,000$. The parameters refer to the actual reservoir conditions. The formation crude oil density is 0.875 g/cm^3 , the formation crude oil viscosity is $88 \text{ mPa}\cdot\text{s}$, the

saturation pressure is 4.15 MPa , the gas-oil ratio is $12.3 \text{ m}^3/\text{t}$, and the volume coefficient is $1.055 \text{ m}^3/\text{m}^3$. The reservoir porosity, permeability and oil saturation models are shown in Figure 1.

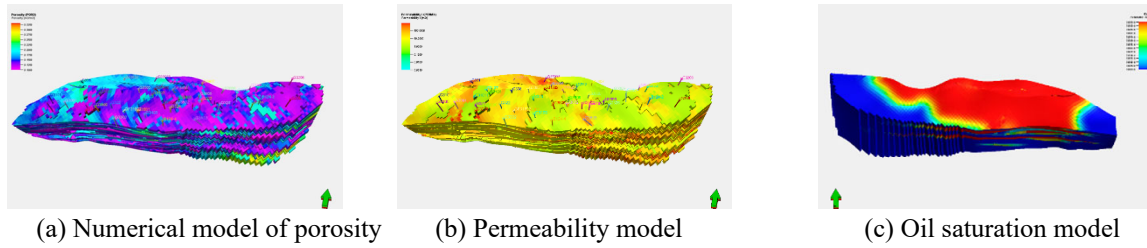


Figure 1. Numerical model of reservoir in study area

2.2. Development history fitting

On the basis of the establishment of the reservoir numerical model, the fine historical fitting is carried out according to the production dynamic data of each well in the Gu30 well group. The fitting results of some important production index parameters are shown in Figure 2 and 3. From the historical fitting results, it can be found that the single well simulation

of Gu30 well group is in good agreement with the actual production index parameter curve, and the fitting coincidence rate of typical single well is greater than 90%. Some parameter curves have some deviations, but the overall historical fitting condition is good, and the numerical model can truly reflect the development history and current situation of the reservoir.

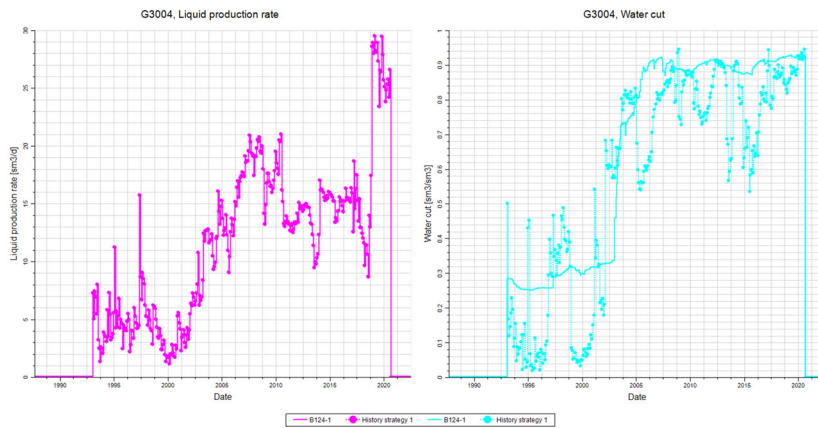


Figure 2. Historical fitting of daily fluid and water cut in Gu3004 well

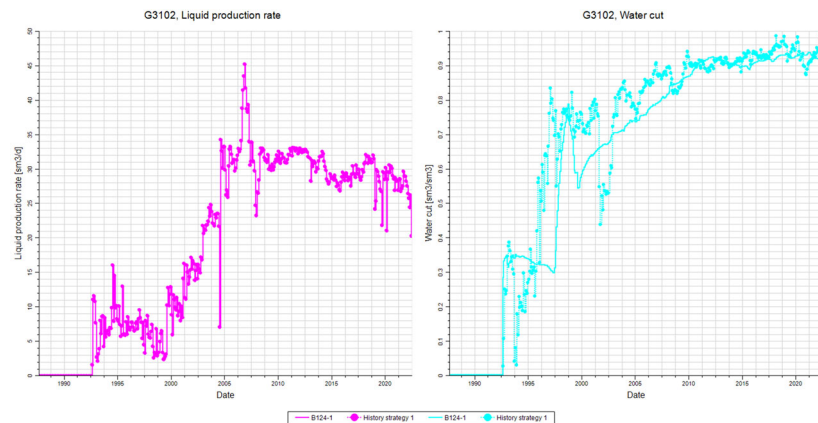


Figure 3. Historical fitting of daily fluid and water cut in Gu3102 well

2.3. Streamline field simulation

The author used tNavigator software to conduct numerical simulation of stratified flow lines on the reservoir model after historical fitting, and compared and analyzed the morphology of stratified flow lines with the main flow sources of some oil Wells in the reservoir. On the whole, H31 small laminar flow

lines had the widest distribution range (FIG. 4). Through the analysis and comparison, it is obvious that the flow rate of G3805, G3407 and G3803 in the H31 small formation is mainly from the G3505 injection well. The traffic of G3802 is mainly from GF3406; The flow rate of G3504 and G3104 is mainly from the two injection Wells G3505 and GF3406.

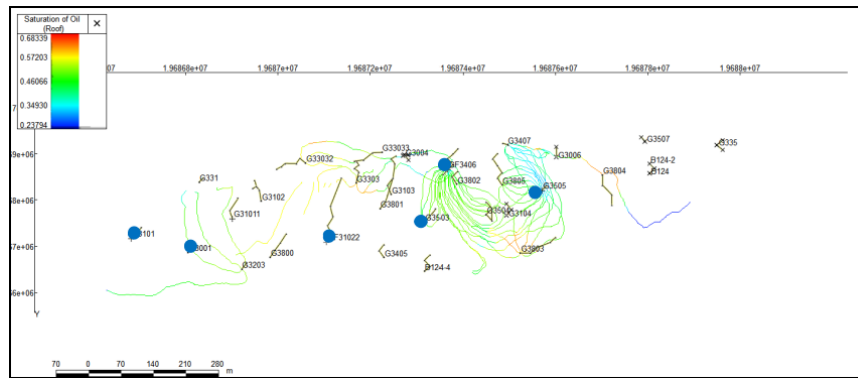


Figure 4. Streamlines field distribution of H31 small-layer layered

3. Study on Main Controlling Factors of Injection and Production Coupling

Taking Gu30 well group with dynamic injection-production coupling as an example, numerical simulation method is used to study the development policy limits of typical injection-production coupling model, and the influence evaluation and optimization study are carried out by selecting the intervention time, periodic injection amount, water injection speed, liquid production speed and other main control factors of injection-production coupling. The main control factors of injection and production coupling and the technical policy limits of parameter optimization are formed.

3.1. Intervention timing

Five schemes with water cut of 40%, 60%, 80%, 90% and 98%

98% were selected respectively. The injection rate of 85m³/d and the periodic injection rate of 3000 m³ were adopted for injection. After injection, the well was shut down for 10 days, and the oil well produced at a rate of 20 m³/d for 457 days. The simulation results of different intervention timing schemes are shown in the table below. The numerical simulation results show that the earlier the intervention time, the better the injection and production coupling effect.

Table 1. Cumulative oil increase at different intervention times

Intervention timing	Cumulative oil increase
40%	4908.66
60%	4352.28
80%	3522.26
90%	2363.23
	989.49

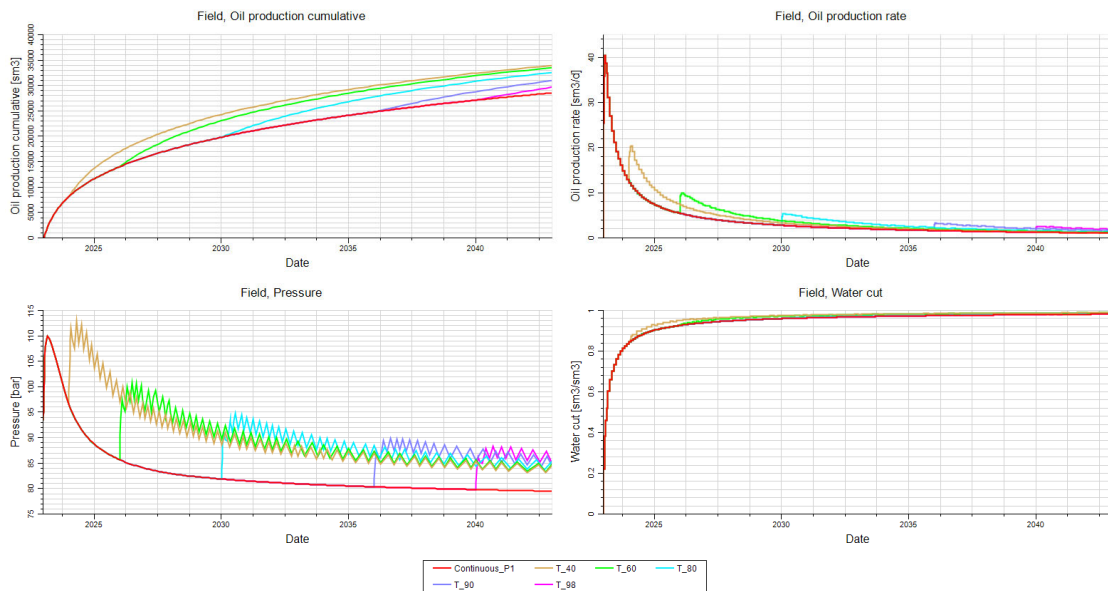


Figure 5. Main production parameter curves of the reservoir at different intervention times

3.2. Impact evaluation of injection intensity

The injection intensity is set to be 120%, 100%, 80%, 60% of the maximum injection intensity. When the injection intensity is 100%, the injection-production ratio can be maintained at about 1:1, and the liquid production can remain stable. When the injection intensity is small, the pressure continues to drop and the liquid production decreases,

resulting in the decrease of oil recovery. When the injection intensity increases, the liquid production can remain stable, but due to the excessive injection intensity, the dominant channel of injection water is channeling and the water cut rises. As a result, oil production declines. In other words, when the injection-production ratio is maintained at 1:1, the coupled injection-production effect is the best (Figure 6).

Table 2. Recovery degree under different injection intensity

Injection intensity	Recovery	
	Flooding	Injection-production coupling
Inj60	20.68	18.80
Inj80	22.76	21.49
Inj100	24.56	28.96
Inj120	20.98	23.59

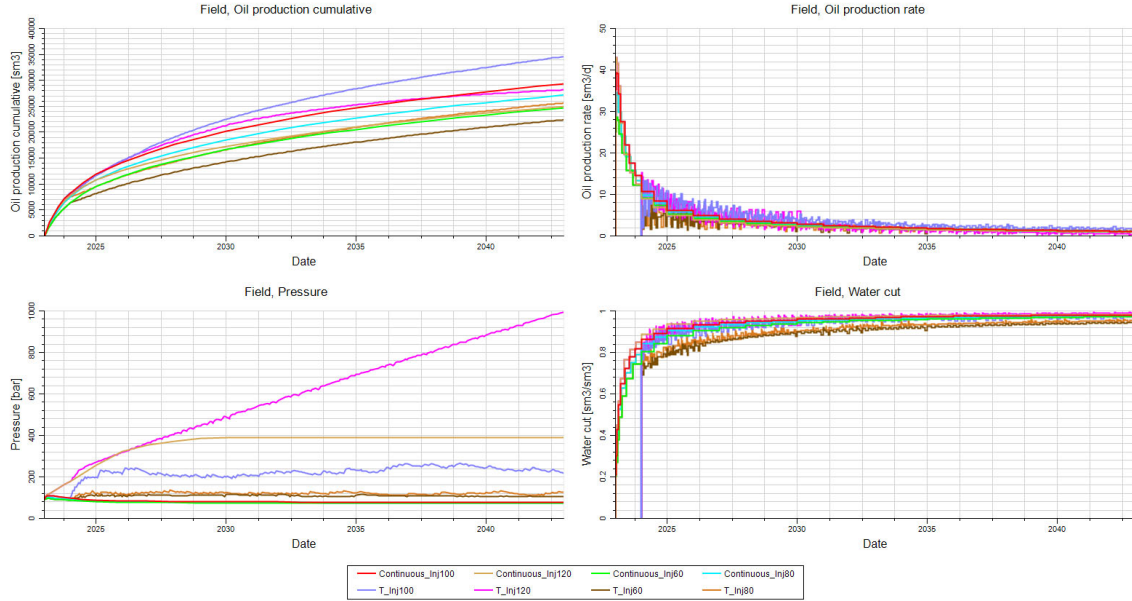


Figure 6. Main production parameter curves of reservoirs with different injection intensities

3.3. Evaluation of the impact of periodic injection volume

Set the periodic injection amount (pressure recovery level 80%, 100%, 120%, 150%, 200%), and set the maximum injection water amount for daily water injection. It can be seen from the curves of parameters corresponding to injection volume of different periods in the figure that the greater the

injection volume, the greater the recovery degree and accumulated oil production volume of the block, but the slower the corresponding oil production rate and the smaller the peak value. The simulation results show that when the pressure is restored to 100%~120%, the coupling injection and production development effect is the best, and the periodic water injection volume is 2400~3200m³.

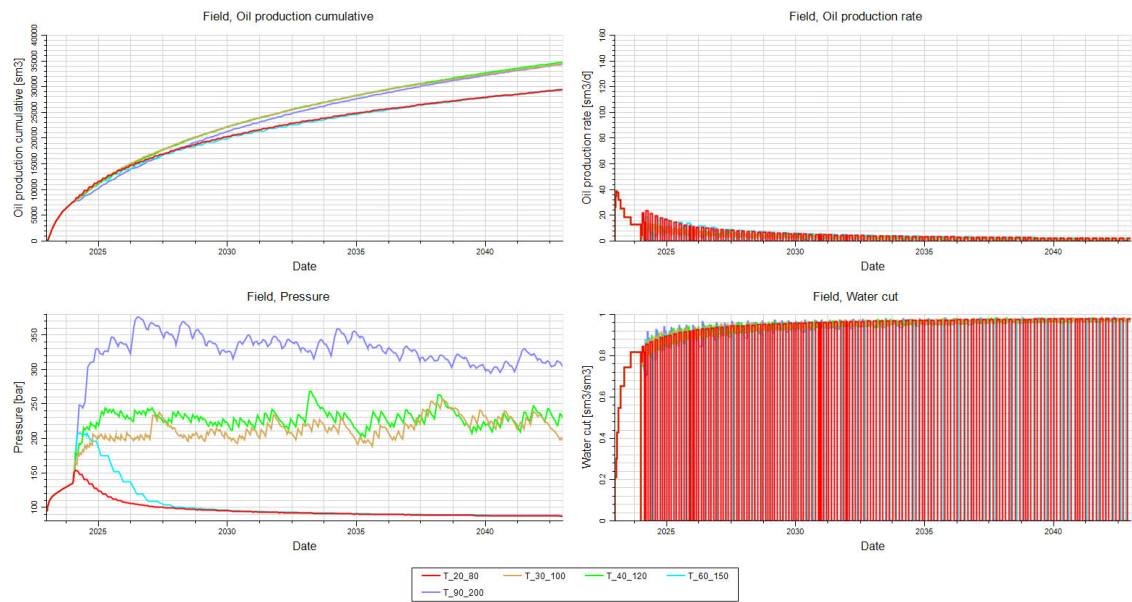


Figure 7. Main production parameter curves of the reservoir at different injection periods

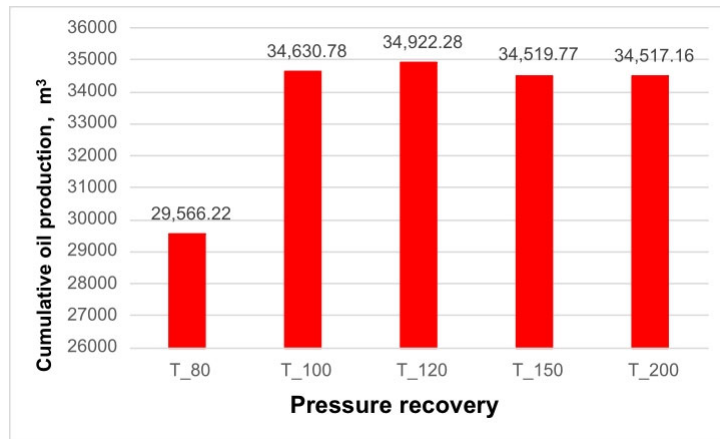


Figure 8. Cumulative oil production at different injection volumes for different cycles

3.4. Impact evaluation of liquid recovery strength

The fluid production intensity of the injection-production coupling measures is set as 100%, 80% and 60% of the maximum fluid production intensity respectively, and the periodic injection/production ratio is 1. The numerical and analog results show that the greater the fluid production

intensity, the stronger the fluid production capacity of the oil well, the higher the fluid production level in the well area, and the faster the oil production speed. The faster the water content rises, the faster the relative decline is. The highest cumulative oil production. Therefore, in actual operation, the strength of liquid production can be set according to the requirements of production capacity and stable production.

Table 3. Cumulative oil increase of the model under different fluid recovery intensity

Liquid recovery strength	Cumulative oil increase
L rate100	5742.17
L rate80	4439.93
L rate60	3606.96

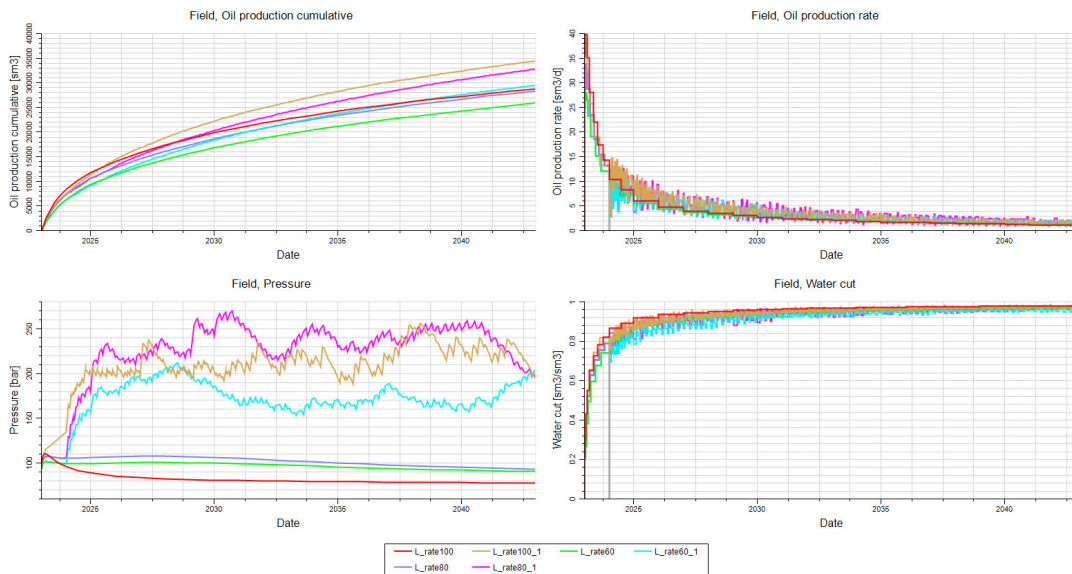


Figure 9. Main production parameter curves of the reservoir with different production strength

4. Conclusion

(1) The numerical simulation results show that the fitting coincidence rate of the typical single well of the Gu30 well group is greater than 90%; The distribution range of H31 small laminar flow lines is the widest.

(2) Intervention timing and intensity are important controlling factors of injection-production coupling in fault block reservoirs. The earlier the intervention time, that is, the lower the water cut, the better the injection and production coupling development effect. There is an optimal injection intensity, and the coupling injection and production effect is

the best when the injection and production ratio is kept at 1:1. When the pressure is restored to 100%-120%, the coupling injection and production development effect is the best, and the periodic water injection volume is 2400-3200m³. The higher the strength of liquid production, the faster the oil recovery rate.

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