



In-Situ Stress Evolution and Refracturing Simulations of Horizontal Wells in Tight Conglomerate Reservoir

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Abstract. After volume fracturing, horizontal wells in Mahu tight conglomerate reservoir have the problems of rapid production decline and low predicted recovery. Therefore, it is urgent to carry out the research of refracturing and other EOR methods. The effect of refracturing is affected by the change of in-situ stress field caused by primary hydraulic fractures and production. Taking well block Ma18 as an example, the author carried out the research on refracturing simulation of horizontal wells by adopting the integrated process of coupling fracturing, production, and four-dimensional in-situ stress simulation. And the following research results were obtained. First, Hydraulic fracturing is not easy to form a complex fracture network under the conditions of undeveloped natural fractures, high stress difference, and, high gravel content. Second, the close of unpropped fracture and the conductivity decrease of the propped fracture will accelerate the decline rate and reduce the ultimate recovery. Third, the decrease value of the min horizontal principal stress is about 0.58 times of the decrease value of reservoir pressure. And the closer to the horizontal well, the greater the reduction of the min horizontal principal stress. Fourth, rapid water injection before refracturing results in sharp changes in the magnitude and direction of in-situ stress. In order to reduce the heterogeneity of stress field, it is recommended to soak the well for 40 days. Fifth, refracturing after water injection can significantly increase the fracture length of refracturing and well production. According to the remaining oil distribution, refracturing the old fractures is the best refracturing method in well block Ma18. The research results will strongly guide the implementation and promotion of refracturing in horizontal wells of tight conglomerate reservoir.

Keywords: Tight conglomerate reservoir · Geology-engineering integration · 4D in-situ stress · Supplementing energy by water injection · Refracturing

1 Introduction

With the increasing demand for oil production and the rapid depletion of conventional oil and gas, the exploration and development of unconventional oil and gas resources

such as tight oil has attracted more and more attention of the oil industry [1, 2]. The Mahu oilfield in Junggar Basin is a super-large tight conglomerate oilfield with reserves of 10×10^8 t discovered in recent years [3, 4]. With horizontal drilling and multi-stage hydraulic fracturing, oil production from the Mahu oilfield exceeded 2 million tons in 2020. However, due to the complex geological characteristics of the reservoir and the the continuous decrease of hydraulic fracture conductivity, the production of horizontal wells in Mahu oilfield decreases rapidly and the predicted recovery rate is low [5, 6]. As an important means to improve production and recovery, the technology of refracturing is widely used in the development of unconventional oil and gas resources [7, 8]. During the refracturing, due to the change of the in-situ stress field, the hydraulic fracture will not expand along the fracture path of the initial fracturing [9]. The change of in-situ stress field is mainly caused by the existence of initial hydraulic fracture induced stress field and the change of reservoir pressure caused by production. The comprehensive effect of the two factors determines the direction of fracture propagation in refracturing [10]. Zuo X. B. [11] studied the fracturing design and fracture forming mechanism during refracturing, and considered that the stress field induced by the initial fractures is one of the main mechanisms of the new fracture turning in refracturing. Mao C. [12] found through simulation that permeability anisotropy had a great influence on the stress change induced by production. Weng and Siebrits [13] explained the effect of production-induced stress field around the initial hydraulic fracture on refracturing fracture propagation.

In conclusion, a large number of studies have described the influence of initial hydraulic fracture induced stress field and production-induced stress field on refracturing. But there is no study on the influence of stress field change caused by water injection before refracturing. Based on this, this paper takes the horizontal well in well block Ma18 of Mahu oilfield as the target, and adopts the means of coupling fracturing, production, and four-dimensional in-situ stress simulation to analyze the variation law of in-situ stress field during production and water injection. On this basis, the best refracturing scheme is discussed.

2 Reservoir Characteristics and Development Status

Well block Ma18 is in the west slope of Mahu sag. The Triassic Baikouquan Formation in this area is a southeast dipping monocline structure, which is cut into several fault blocks by two groups of faults in plane. It is a lithologic - structural reservoir controlled by faults [14]. The Baikouquan formation reservoir in Ma18 has an oil-bearing area of 82.04 km^2 and a geological oil reserve of 5947×10^4 t. And the oil-bearing horizons are T_1b_1 and T_1b_2 . The average gravel content of T_1b_1 is 51.5%, the average porosity is 10.38%, the average gas permeability is 5.48 mD, the liquid permeability is 0.39 mD, and the average oil saturation is 52.7%. The average gravel content of T_1b_2 is 51.5%, the average porosity is 9.56%, the average gas permeability is 2.27 mD, the liquid permeability is 0.16 mD, and the average oil saturation is 44.7%. T_1b_1 reservoir is superior to T_1b_2 reservoir in both physical property and oil content, and is the main development layer at present.

The reservoir Poisson's ratio is 0.121–0.339, Young's modulus is 16.328–59.339 GPA, and brittleness index is 17.3–62.4 in Ma18. The maximum horizontal principal

stress is close to the east-west direction. The horizontal principal stresses difference is as high as 10–15 MPa. Previous studies have shown [15–17] that for reservoirs without developed natural fractures, hydraulic fractures in conglomerate fracturing under high stress difference are mainly around gravel. The fracture morphology is simple and it is difficult to form complex fracture network.

Well block Ma18 is in the period of high-speed production. During 2015–2020, the number of wells increased from 80 to 254, and the verified annual oil production increased from 4.13×10^4 t to 63.5×10^4 t. The pressure coefficient of the working area is 1.43–1.7, indicating that the overall formation capacity is sufficient. However, due to the strong stress sensitivity and inadequate primary fracturing, horizontal well production declines rapidly (see Table 1) and the predicted recovery is low (12%–15.7%). Previous tests have shown that injection pressure of water flooding is high. Fracture water channeling characteristics are obvious, and water flooding effect is poor. Therefore, it is urgent to carry out researches on enhanced oil recovery in Ma18. In order to provide guidance for horizontal well refracturing in Mahu tight conglomerate reservoir, this paper mainly analyzes the evolution of in-situ stress field and the best plan of horizontal well refracturing.

Table 1. Comparison of production decline rate in Baikouquan formation of well block Ma18.

Well block		Decline rate of self-spraying period	
		Rapid decline period	Slow decline period
Ma18	Southeast region	29.0	18.6
	The central region	35.6	24.4
	Northwest region	66.6	34.8

3 Four-Dimensional In-Situ Stress Simulation

3.1 Initial Fracturing and Production Simulation

Fracturing Simulation

The geological parameters and main fracturing process parameters of T₁b₁ in Ma18 well block are shown in Table 2. A 3D model with a size of 1200 m × 700 m × 40 m was established according to the “geology - engineering integrated simulation process” [18]. Studies [19] have shown that the reasonable well spacing of depleted horizontal wells in well block Ma18 is 300–350 m. Therefore, the author carried out fracturing simulation for two horizontal wells with a horizontal section length of 1000 m and a well spacing of 300 m. In view of the limitations of the boundary element method (BEM) used in the unconventional fracture model (UFM), the effects of gravel on hydraulic fracture propagation were simulated by using several groups of microscale natural fracture methods. As shown in Fig. 1, the fracturing simulation results show that the hydraulic fracture length

of the two horizontal Wells is 138–226 m and the propped fracture length is 131–208 m. The hydraulic fracture height is 33 m, and the propped height is 16–24 m. The distribution range of hydraulic fracture length and fracture height is basically consistent with the microseismic monitoring results. The difference between hydraulic fracture length and propped fracture length is small, but the hydraulic fracture height is obviously larger than the propped fracture height. There are no frac hits in the well spacing of 300 m, and the fracture pattern is mainly asymmetric simple fractures macroscopically.

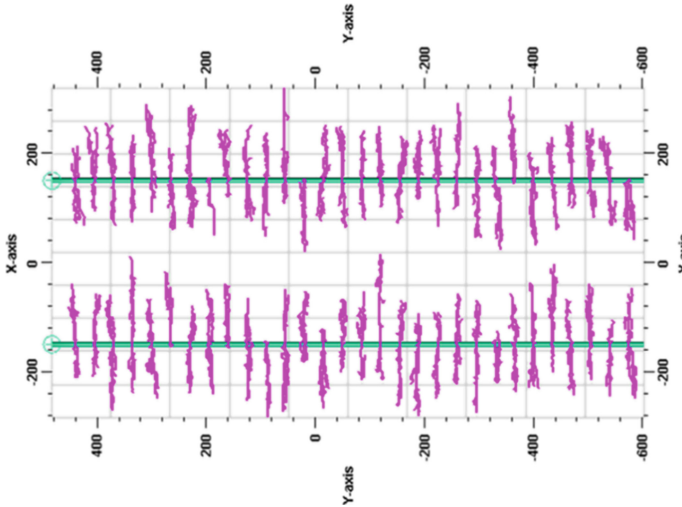


Fig. 1. 2D fracture network distribution for initial fracturing.

Table 2. Geological parameters and engineering parameters of T₁b₁ in well block Ma18.

Category of parameters	Properties	Vaules		
		T ₁ b ₁ ¹	T ₁ b ₁ ²	T ₁ b ₁ ³
Geological parameter	Porosity	0.105	0.118	0.076
	Permeability, mD	1.04	1.35	0.66
	Young’s modulus, GPa	17.69	17.14	15.18
	Poisson’s ratio	0.25	0.25	0.26
	Max horizontal stress, MPa	69.8	69.5	69.4
	Min horizontal stress, MPa	58	57.7	58.6
	Overburden stress, MPa	78.9	79.2	79.9
	Max stress angle, degree	90	90	90
Engineering parameters	Stage spacing, m	70		
	Number of clusters per stage	2		
	Volume of fracturing fluid, m ³	1050		
	Proppant dosage, t	116.2		
	Treating rate, m ³ /min	6–8		

Production Simulation

Based on the above fracturing simulation results, the unstructured grid hydraulic fracture characterization technology was adopted to establish the numerical simulation model of the well group as shown in Fig. 2. The total mesh number of the model is 256,000. As shown in Fig. 3, stress sensitivity curves of matrix and hydraulic fracture were established based on experimental data and historical experience. As shown in Fig. 4, both wells adopted a production system with fixed production in the early stage and fixed pressure in the later stage. The predicted stable production period is 21 months, and the accumulative oil of well_A and Well_B are $4.48 \times 10^4 \text{ m}^3$ and $4.41 \times 10^4 \text{ m}^3$ respectively after 10 years of simulation. The oil reserves in the model are $77.76 \times 10^4 \text{ m}^3$, and the predicted recovery factor after primary fracturing is 11.43%.

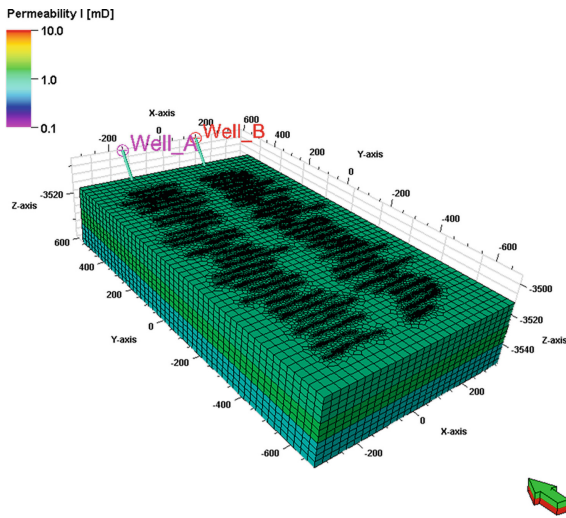


Fig. 2. Schematic diagram of unstructured grid numerical simulation model for well group.

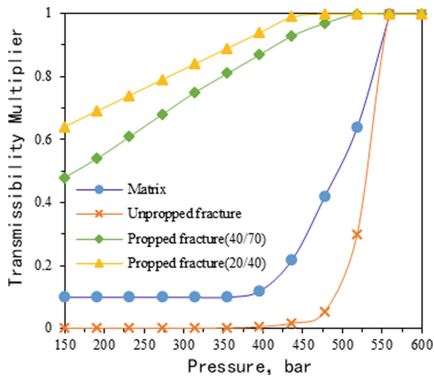


Fig. 3. Stress sensitive curves of matrix and hydraulic fractures

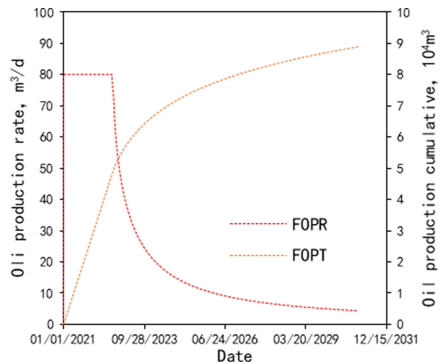


Fig. 4. Production prediction curves of well group after initial fracturing

As shown in Fig. 5, the initial permeability multiplier of unpropped fracture, ceramsite 40/70, and ceramsite 40/20 propped fracture is 1. As shown in Fig. 6, it can be seen from the variation of hydraulic fracture conductivity during the production process that the unpropped fracture is basically closed after about 6 months of production. The conductivity of propped fracture continues to decrease with the decrease of pore pressure. After 24 months of production, the conductivity of propped fracture also decreased significantly, and the daily oil production per well decreased from 40 m³/d at the initial stage to 19.8 m³/d. This indicates that stress sensitivity will accelerate the rate of production decline and reduce the ultimate recovery factor. However, with the increase of pore pressure after water injection, the hydraulic fracture conductivity of primary fracturing gradually increases. The propped fracture can be restored to close to the initial conductivity. However, the recovery degree of conductivity of unpropped fracture is low.

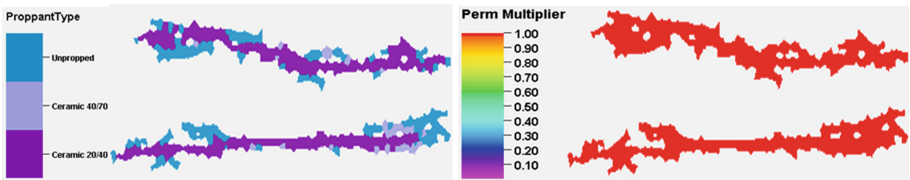


Fig. 5. Different types of hydraulic fractures (left) and permeability multiplier of initial fractures (right) of stage 9 of well_B.

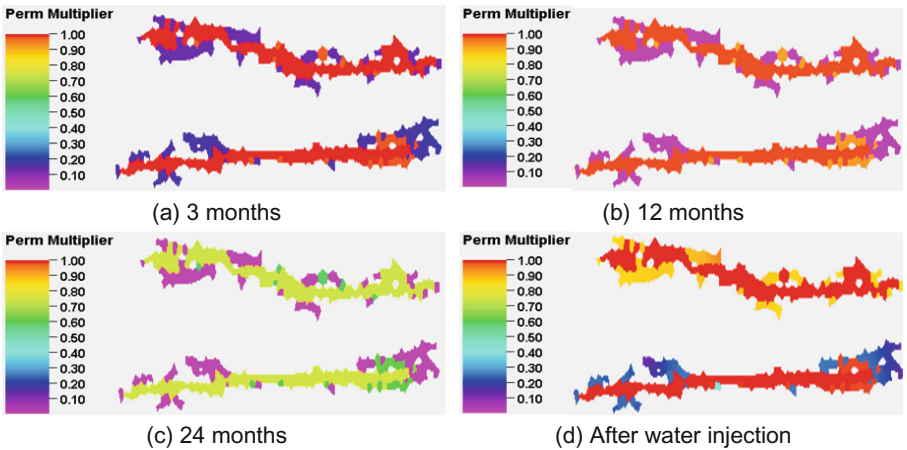


Fig. 6. Variations of permeability multiplier of different types of hydraulic fractures during production.

3.2 Simulation of In-Situ Stress Field Evolution

Based on the aforementioned production simulation results, the four-dimensional in-situ stress modeling technology was adopted to obtain the in-situ stress field at different times in the production process. As shown in Fig. 7, the minimum horizontal principal stress

decreases as the reservoir pressure decreases. The horizontal well trajectory of the model is along the Y direction, and the X coordinate of well_A is -150 m, and the X coordinate of well_B is 150 m. As shown in Fig. 8 and Fig. 9, it is predicted that after 2 years of production, the overburden stress will remain basically unchanged and the maximum horizontal principal stress will decrease by about 17 MPa. Along the X direction of the model, the reservoir pressure and the minimum horizontal principal stress show a “W” shape, indicating that the closer to the horizontal well, the greater the reservoir pressure and the minimum horizontal principal stress decrease. As shown in Fig. 10, the minimum horizontal principal stress drop is approximately 0.58 times the reservoir pressure drop.

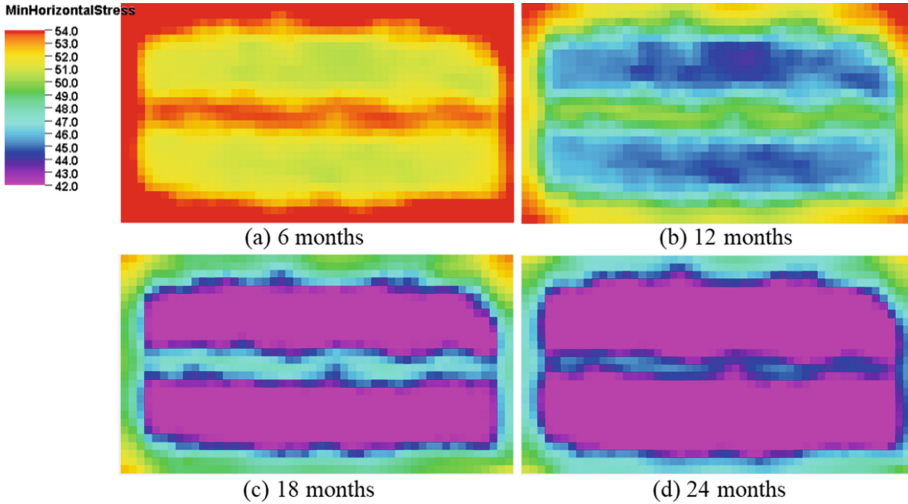


Fig. 7. Min horizontal principal stress variation during production

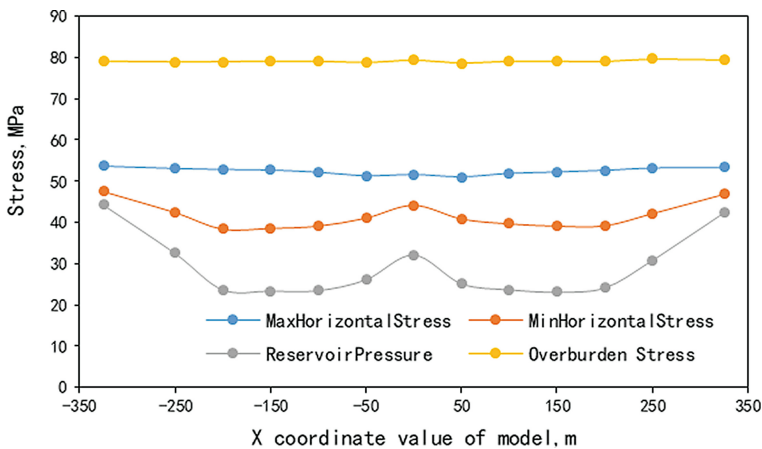


Fig. 8. Distribution of stress and reservoir pressure in X section direction after 2 years of production.

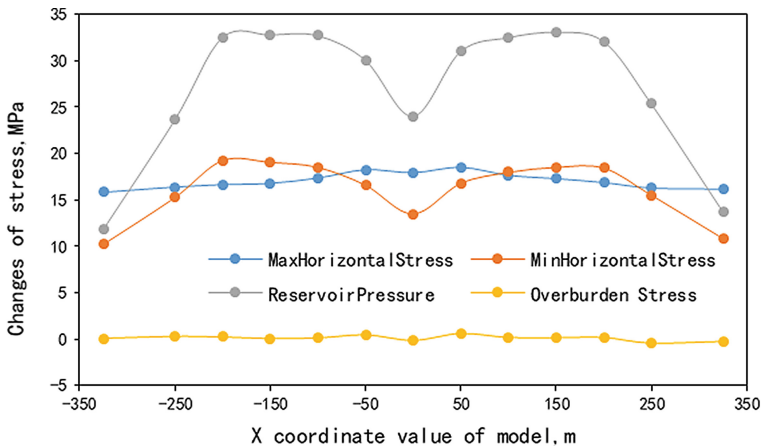


Fig. 9. The changes of stress and formation pressure in the direction of X section after 2 years of production.

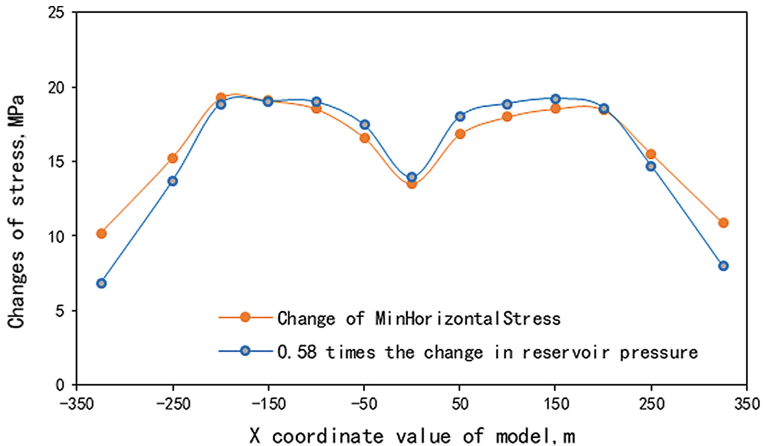


Fig. 10. The relationship between the changes of min horizontal principal stress and the changes of reservoir pressure.

In order to supplement formation energy, the author simulates the water injection to increase energy before refracturing. When the daily oil production decreases to half of the initial oil production, water injection is used to increase energy according to 80% of accumulative oil production. As shown in Fig. 11, the formation pressure rises to 77% of the original formation pressure. As shown in Fig. 12 and Fig. 13, rapid water injection results in sharp changes in stress magnitude and direction. With the increase of the soaking time, the stress field gradually recovered. But after the soaking time reached 40 days, the stress field changed little. In order to ensure the effectiveness of energy supplement and reduce the heterogeneity of stress field, it is suggested that the well be stewed for 40 days after water injection and then refractured.

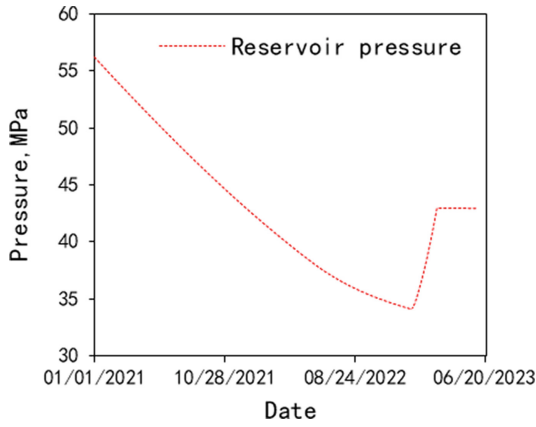


Fig. 11. Reservoir pressure curve during production and water injection

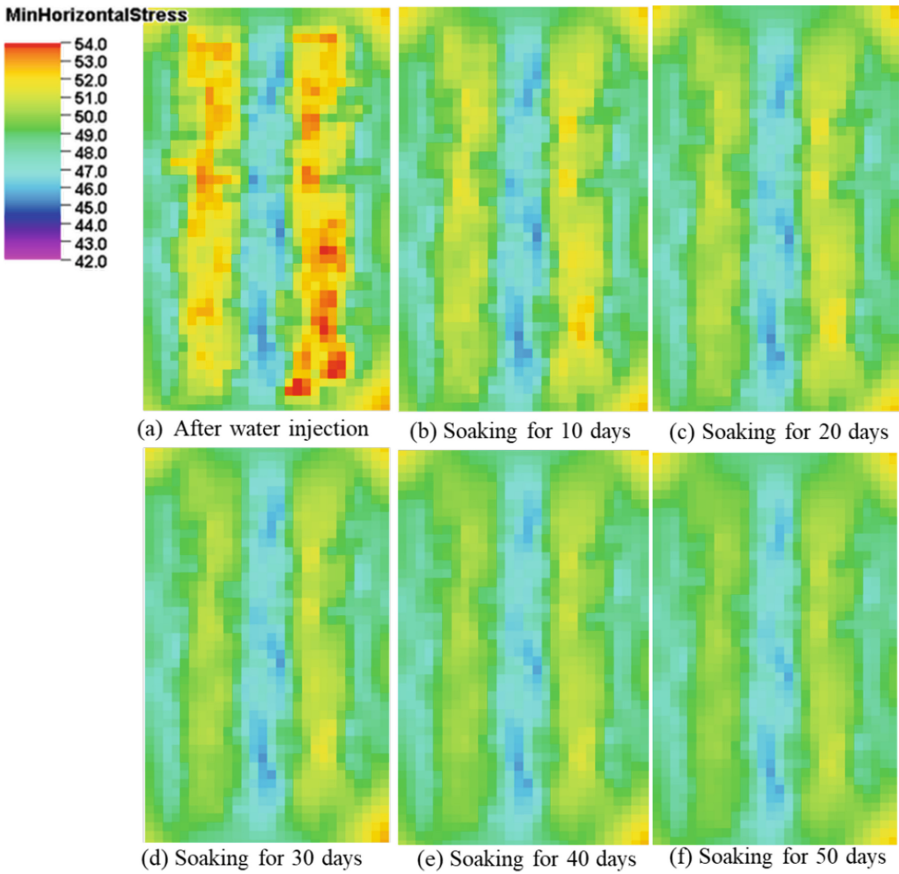


Fig. 12. Min horizontal principal stress changes after water injection and well soaking

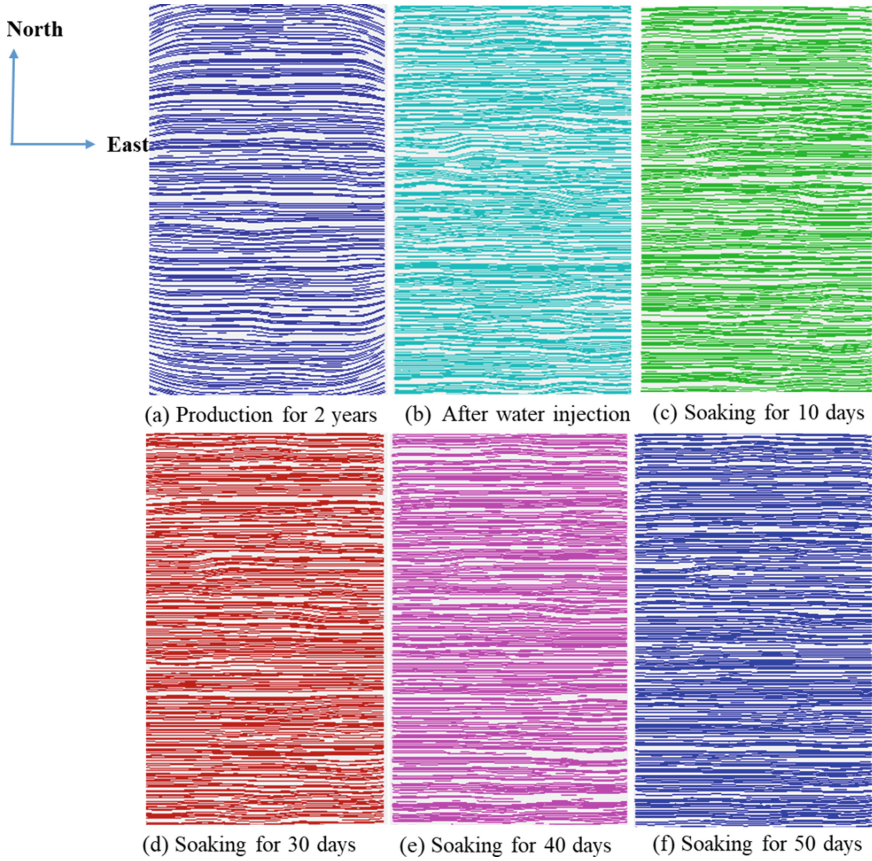


Fig. 13. Variation of stress direction during production and soaking

4 Refracturing Simulation and Stimulation Effect Evaluation

4.1 Distribution of Remaining Oil

As shown in Fig. 14, after the initial fracturing of horizontal wells, the remaining oil can be divided into three types: inter-well remaining oil (Type 1), inter-fracture remaining oil (Type 2), and, intra-fracture remaining oil (Type 3). When cluster spacing is 35 m, the remaining oil at the end of the initial fracturing prediction is mainly remaining oil between wells. This indicates that the cluster spacing of the working area is reasonable and there is no need to increase the perforation to reduce the cluster spacing. The asymmetric propagation and stress sensitivity of hydraulic fractures lead to the low degree of inter-well control and high inter-well remaining oil in some fracture stages. Therefore, increasing the scale of fracturing and making long fractures is the main method of refracturing in the working area.

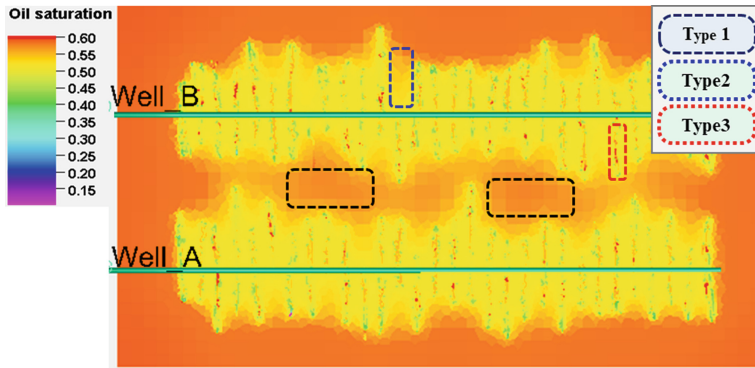
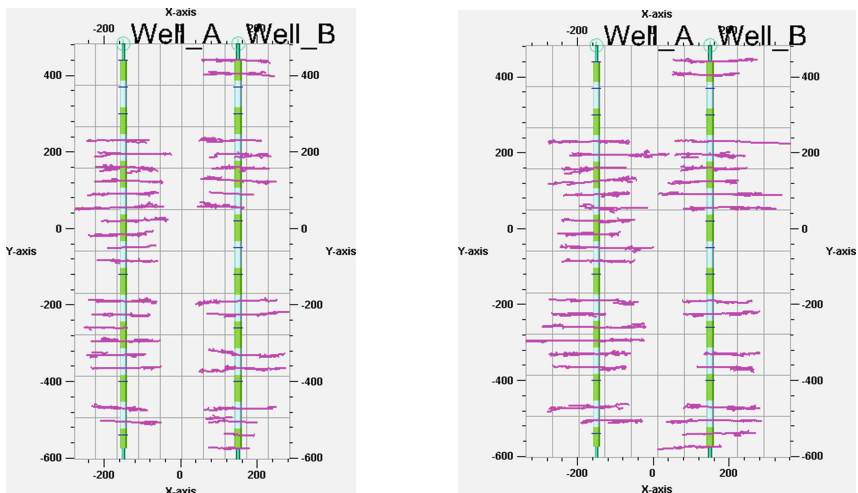


Fig. 14. Prediction of remaining oil distribution at the end of depletion development

4.2 Refracturing Simulation

The initial field was updated with the stress field and saturation field of 40 days after the water injection, and the discrete fracture network was generated by the combination of the primary hydraulic fracture and several groups of micro-scale natural fractures. Then refracturing simulation was carried out. To increase fracture length, the scale of a single stage was increased to 1.2 times of the initial fracturing scale. According to the remaining oil distribution between wells, a total of 17 refracturing stages (well_A 9 stages and well_B 8 stages) were optimized. As shown in Fig. 15 and Fig. 16, the average fracture lengths of initial fracturing, refracturing without water injection and refracturing after water injection are 166 m, 167 m, and 209 m, respectively. This means that supplementing formation energy is beneficial to fracture extension and increase refracturing volume.



(a) Refracturing without water injection

(b) Refracturing with water injection

Fig. 15. Fracture network distribution of refracturing in wells A and B

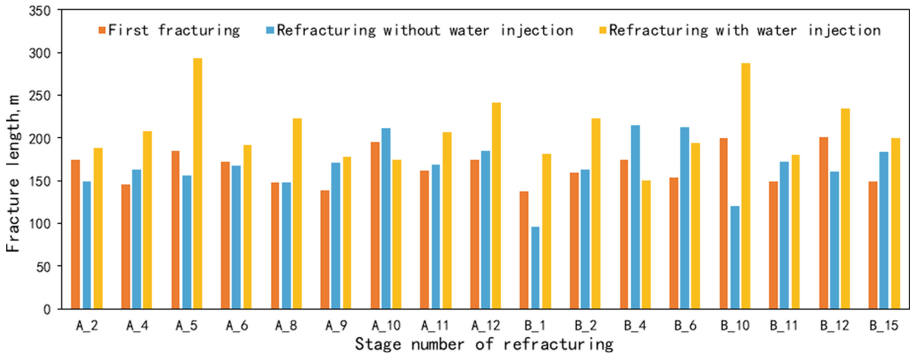


Fig. 16. Comparison of fracture length between refracturing and initial fracturing

4.3 Production Forecast and Scheme Optimization

In order to evaluate the increase of production by water injection and refracturing, the production indexes of three schemes of no refracturing after water injection, refracturing for some stages after water injection, and refracturing for all stages after water injection were simulated. As shown in Fig. 17, both water injection and refracturing can significantly increase well production and recovery. The greatest improvement was achieved when all stages were refractured. However, based on the remaining oil distribution, the optimal refracturing plan has a higher single-stage production increase (see Table 3). Therefore, in a low oil price environment, for the tight conglomerate reservoir refracturing, the optimal refracturing plan with water injection has the highest economic benefit. In other words, refracturing stages should be determined based on the remaining oil distribution.

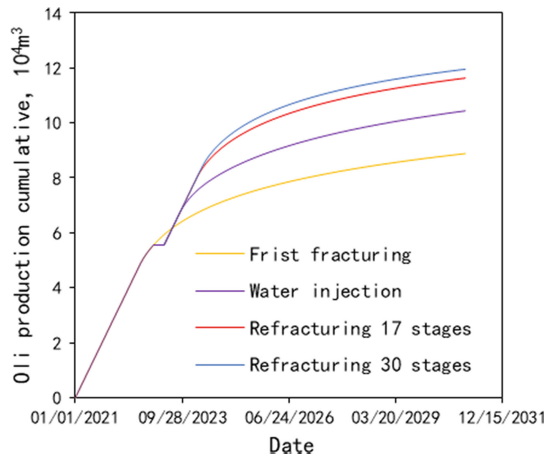


Fig. 17. Cumulative oil production prediction curves of four schemes

Table 3. Comparison table of prediction results of four schemes

Schemes	Total stable production time, month	Cumulative oil production, 10^4m^3	Single stage oil increment of refracturing, 10^4m^3	Recovery ratio, %	Recovery improvement, %
First fracturing	21	8.89	/	11.43	
Water injection	25.5	10.44	/	13.43	2
Refracturing 17 stages	30.5	11.63	0.16	14.96	3.53
Refracturing all stages	32	11.95	0.102	15.37	3.94

5 Conclusion

- (1) Hydraulic fractures are mainly asymmetric simple fractures under the conditions of undeveloped natural fractures, high stress difference, and, high gravel content in tight oil.
- (2) As the production time increasing, the unpropped fracture gradually closes and the propped fracture conductivity continues to decrease. These factors will accelerate the decline in well production and reduce the ultimate recovery.
- (3) During the production process, the overburden stress changes very little and the reduction of the minimum horizontal principal stress is about 0.58 times of the reduction of reservoir pressure. The closer to the horizontal well, the greater the decrease of the minimum horizontal principal stress.
- (4) Water injection before refracturing helps to restore formation pressure and horizontal principal stress. In order to reduce the heterogeneity of the stress field, it is suggested to soak the well for 40 days after water injection.
- (5) Refracturing after water injection can increase the fracture length and oil production. Under the current engineering parameters of well block Ma18, the remaining oil type is mainly inter-well remaining oil. The best refracturing method for the Ma18 horizontal well is to refracture the old fractures based on the remaining oil distribution.

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