Impacts of hydraulic fracture patterns on production performance of tight oil reservoirs

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Summary

Owing to the technology of multistage hydraulic fracturing in horizontal wells, the exploration of tight oil reservoirs has been developed very fast in the Jilin oil field, China. Thus it is important to identify hydraulic fracture pattern mechanisms. In this paper, we first examine five irregular hydraulic fracture patterns for a single perforation stage, and further discuss their effects on well production. This paper also presents a numerical simulation methodology to analyze the production performance with the consideration of the closure of hydraulic fractures. This study provides new insights on hydraulic fracturing and can be a reference for future hydraulic fracturing design in unconventional tight reservoirs.

Introduction

Since reservoir properties in tight formations are extremely low, oil and gas cannot flow to a wellbore naturally at economic rates without a stimulation treatment. In recent years, the successful application of multi-stage hydraulic fracturing and horizontal well treatments, which play a crucial role in economic tight oil production, can induce a large contact area between hydraulic fractures and reservoirs. But the cost of a hydraulic fracturing treatment remains very high, despite the recent success in tight oil development. Therefore, optimization of hydraulic fracturing treatment design is significantly desirable. There have been many attempts in the past to optimize fracturing treatment design for tight oil reservoirs. There are great uncertainties in fracture pattern characterization, which remains a challenge in tight oil reservoirs. In this work, we proposed five different hydraulic fracture patterns within one perforation stage to simulate and compare the well performance of different patterns. In a hydraulic fracturing process, the permeability of a fracture system changes with time as fractures gradually close. This study analyzes the importance of the closure of fractures in reservoir engineering in the Jilin field.

Theory and/or Method

In this study, CMG STARS is used to perform the tight oil reservoir simulation, where 20 (I-direction) × 58 (J-direction) × 56 (K-direction) grid blocks are used with a grid size of 50 m in length (I-direction), 50 m in width (J-direction) and 1 m in thickness (K-direction). The grid top ranges from 2,000 m to 2,056 m. Properties of the tight oil reservoir are all obtained from the Jilin field data, as shown in Table 1.

Table 1. Properties of a simulation model of the reservoir

Reservoir temperature (℃)	80
Reservoir compressibility (KPa^{-1})	1e^{-7}
Permeability (md)	0.08645
Reference depth (m)	2,020
Reference pressure (MPa^{-1})	27
Water-oil contact (m)	3,000
Bottom hole pressure (MPa)	20

We presented five complex hydraulic fracture patterns with varying fracture half-length within one perforation stage, as illustrated in Fig.1. The total fracture length remains the same for each fracture pattern (2,500 m). The details for each individual fracture half-length in each case are described in Table 2.

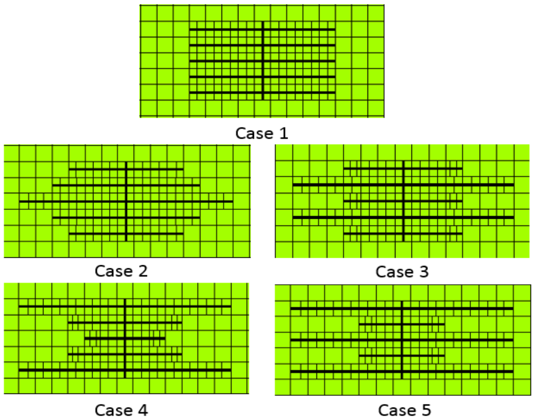


Table 2. Fracture half lengths of five different fracture patterns

Fracture Half-length (m)	1st	2nd	3rd	4th	5th
Case 1	500	500	500	500	500
Case 2	380	500	740	500	380
Case 3	340	740	340	740	340
Case 4	740	400	220	400	740
Case 5	740	140	740	140	740

Figure 1. Five different hydraulic fracture patterns

Hydraulic fractures are the main flow chanels for oil transport in tight oil reservers, and, therefore, the fracture permeability is a cricial parameter for oil production. Fig. 2 shows the full view of the hydraulic fracture simulation model. In a hydraulic fracturing process, a decrease in well bottom hole flowing pressure induces the fracture closure, which in turn influences the permeability (Fig. 3). In this study, considering the fracture closure, several values of fracture permeability's production performance are compared, so we can find the condition under which the fracture closure may be ignored for the reservoir simulation.

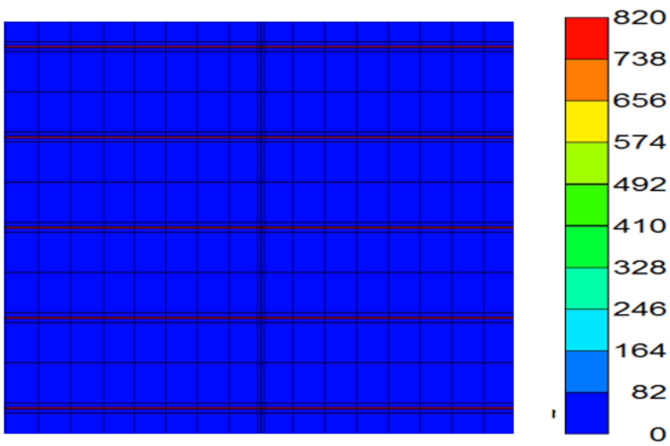


Figure 2. The full view of hydraulic fracture model permeability (in md) with time

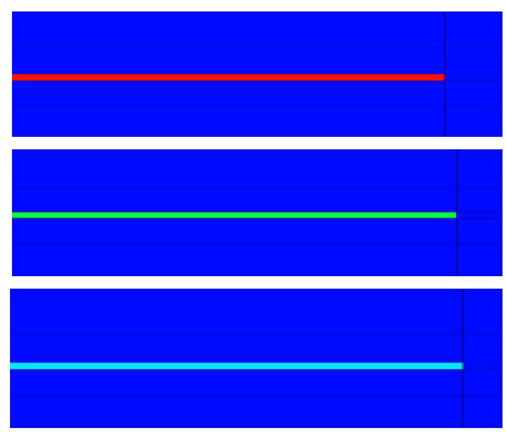
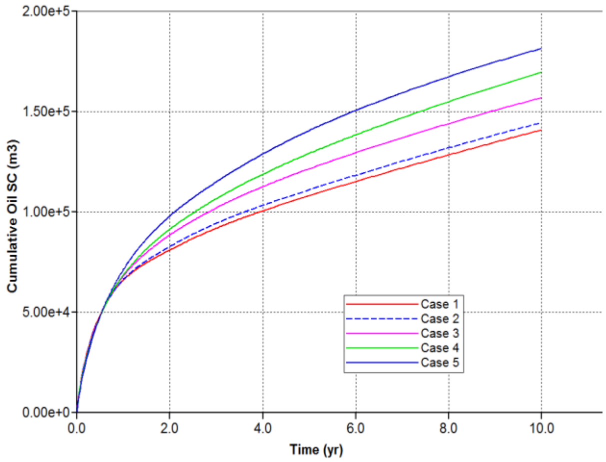


Figure 3. The change of single hydraulic fracture

Examples

Fig. 4 is the comparison of cumulative oil production for five irregular fracture patterns. For the five different fracture patterns' production curves at early production time (less than 2 years), the well performance of each case exhibits the same trend, which is because the same total fracture length leads to the same contact area between the fractures and the reservoir before fracture interference occurs. However, after 2 years of production, the well performance in each case is very different. Among the five cases, Cases 1 and 5 show the lowest and the highest oil production results, respectively.



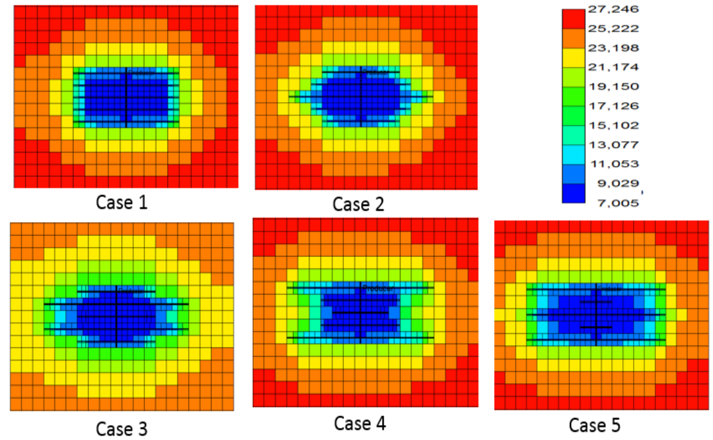


Figure 4. Comparisons of cumulative oil production with five cases

Figure 5. Pressure distribution of five cases at 10 years of oil production

It can be explained by the pressure distribution in the five cases at 10 years of oil production as shown in Fig. 5. Case 5 owns the largest drainage area and Case 1 owns the smallest drainage area, which indicates that longer outer fractures lead to a larger drainage area and higher oil production from low permeability tight oil reservoirs.

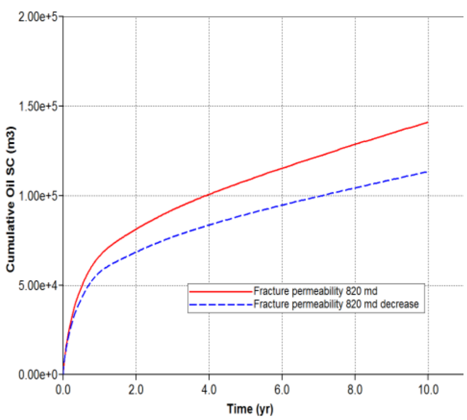


Figure 6. Production curves between fixed fracture permeability case (820 md) and decreased fracture permeability case

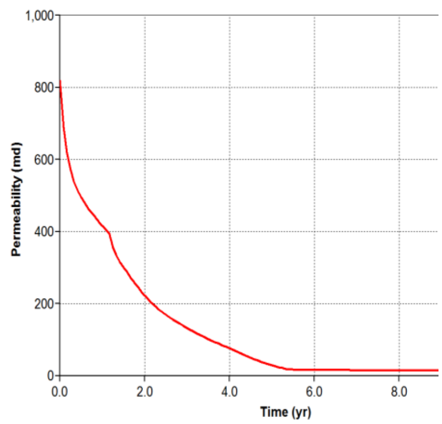


Figure 7. The decline curves of fracture permeability change with time (820 md)

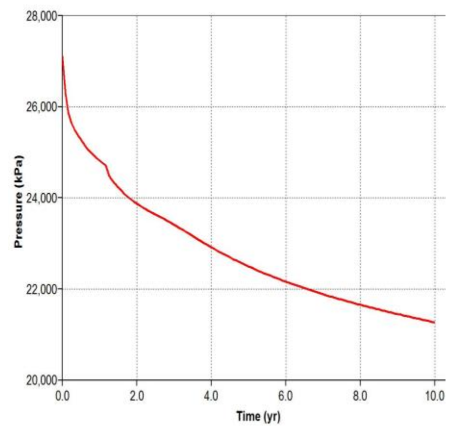


Figure 8. The decline curves of average pressure of entire field (820 md)

When the factrure permeability is 820 md (Fig. 6), we can see that at the early stage (less than 3 months) the production performances between two cases are similar. However, after one year of production, the well performances of different cases vary; this is because the fracture permeability varies. Especially, the cumulative production difference between two cases at 10 years equals 35.8%. The slope of the decreased fracture permeability case changes greatly than the other case with time.

Figs. 7 and 8 are the decline curves of the fracture permeability and average field pressure. At the early stage, the fracture permeability decreases at a significant rate as the average field pressure changes rapidly at the same time. When the pressure changes slowly, the fracture permeability also yields the same trend with pressure.

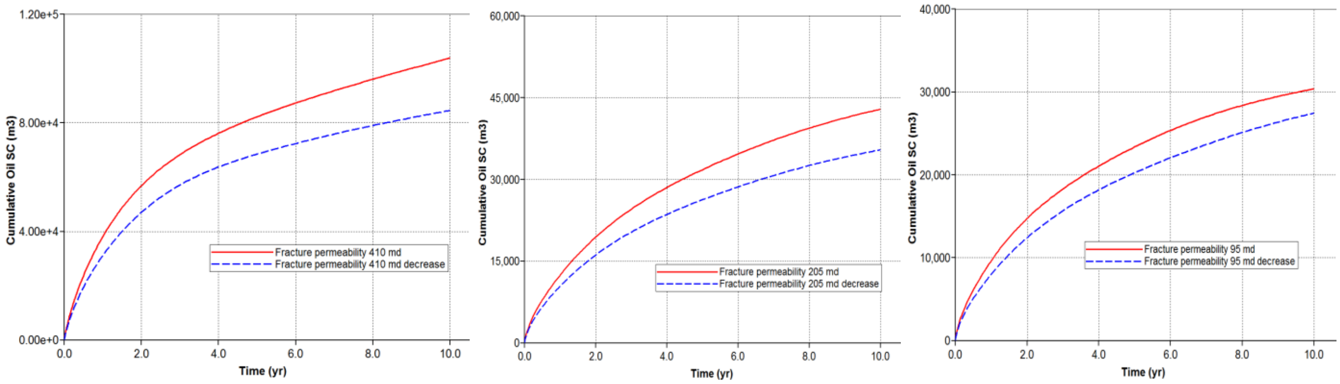


Figure 9. Comparisons of production curves between fixed fracture permeability and decreased fracture permeability cases for various permeability (410 md, 205 md, and 95 md)

At several different values of fracture permeability production performance is compared. When the fracture permeability is 410 md, the cumulative production difference between two cases at 10 years is 21.6%; when the fracture permeability is 205 md, the cumulative production difference between two cases at 10 years is 14.4%; when the fracture permeability is 95 md, the cumulative production difference between two cases at 10 years is 9.2%.

Conclusions

In this paper, we proposed five different irregular fracture patterns within one perforation stage in a tight oil reservoir and performed a series of simulation studies considering the fracture closure. The simulation results show that significant differences among these five fracture patterns exist regarding the oil production and the difference increases obviously with an expanding drainage area. Compared with the case with constant fracture permeability, the fracture permeability can be sensitive to pressure during the production life as shown by the case with changing fracture permeability.

Acknowledgements

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