Simulation study of sanding region prediction in unconsolidated reservoir with frac-pack

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Abstract. Frac-packing has been widely used in the development of unconsolidated sandstone reservoirs because it can meet the needs of stimulation and sand control. In this work, the induced stress generated by the artificial fracture was taken into consideration to simulate the geo-structure of a frac-packing well. The fluid-structure coupling model was utilized to solve the reservoir stress distribution, and the critical equivalent plastic strain was introduced to determine whether the element was damaged. Using the proposed model, the comparison between gravel packing and frac-packing on the critical sanding velocity and sanding region distribution were carried out. Sensitivity analysis of parameters that may affect the sanding of frac-packing well, such as Young's modulus, fracture width and length were conducted as well. The simulation results showed that frac-packing is an effective sand control technique which can reduce the reservoir sanding significantly.

1. Introduction

Due to weak diagenesis and low compressive strength, the unconsolidated reservoir is easy sanding. Sanding is the cause of many problems in the oil industry and it affects the completion adversely. These problems include, but are not limited to, plugging the perforations or production liner, wellbore instability, failure of sand control completions [1]. At present, sand control methods are developing rapidly, including gravel packing, chemical sand control, etc. However, conventional gravel packing sand control will lead to high skin effect, which cannot reach the expected production increase target. Frac-packing is a new well completion method that combines tip screen-out fracturing and gravel packing fracturing sand control technology. It can reduce sanding and increase production at the same time. Therefore, it is of particular research value to predict the plastic sanding area of frac-packing wells in an unconsolidated sandstone reservoir.

In general, numerical methods in the mechanical modeling are categorized under continuum and discontinuum approaches. In the continuum approach, matters are treated as continuous in deriving the governing differential equations [2-12]. Discrete element method (DEM) is a useful tool to simulate sanding especially to understand the mechanism of sanding. However, it cannot be used for large-scale problems because of large computational time required.

In this work, the induced stress generated by the artificial fracture was taken into consideration to simulate the geo-structure of a frac-packing well. The fluid-structure coupling model was used to solve the reservoir stress distribution, and the critical equivalent plastic strain was introduced to determine
whether the element was damaged. The effects of gravel packing and frac-packing on the critical sanding velocity and the sanding region distribution were compared by using the established model. The sensitivity analysis of Young's modulus, fracture width and fracture length affecting sanding of frac-packing wells was carried out. The simulation results showed that frac-packing is an effective sand control technology, which can significantly reduce the sanding rate of the reservoir. It has a certain reference value for oil well production and sand control.

2. Model description

2.1. Induced stress model of artificial fracture

The in-situ stress field will be disturbed by the artificial fractures produced by hydraulic fracturing. That will produce induced stress, which affects the distribution of sanding area in the reservoir. The induced stress field can be obtained according to the plane strain problem, and the simplified stress model of artificial fracture can be acquired.

By using the method of complex variable function, the fracture induced stress field is obtained as follows:

\[
\sigma_n = -p \left( \frac{a^2}{r_1} \right)^2 \sin \theta \sin \frac{1}{2}(\theta_1 + \theta_2) + p \left[ \frac{r}{(r_c)^2} \cos \left( \theta - \frac{1}{2} \theta_1 - \frac{1}{2} \theta_2 \right) \right]_{-1}^{+1} \\
\sigma_y = -p \left( \frac{a^2}{r_2} \right)^2 \sin \theta \cos \frac{1}{2}(\theta_1 + \theta_2) + p \left[ \frac{r}{(r_c)^2} \cos \left( \theta - \frac{1}{2} \theta_1 - \frac{1}{2} \theta_2 \right) \right]_{-1}^{+1} \\
\tau_y = -p \left( \frac{a^2}{r_c} \right)^2 \sin \theta \sin \frac{1}{2}(\theta_1 + \theta_2) \\
\text{in the equation, P is the pressure on the fracture surface, MPa.}
\]

From the geometric model of artificial fracture in the reservoir, the relationship of geometric parameters in the above formula can be deduced:

\[
\begin{align*}
\rho &= \sqrt{x^2 + y^2} \\
r_1 &= \sqrt{x^2 + (y + c)^2} \\
r_2 &= \sqrt{x^2 + (y - c)^2} \\
\theta_1 &= \arctan\left( \frac{x}{y} \right) \\
\theta_2 &= \arctan\left( \frac{x}{(y - c)} \right) \\
\theta_3 &= \arctan\left( \frac{x}{(y + c)} \right)
\end{align*}
\]

In the equation above, c = H/2; H is the fracture height, m. Formula (1)-(3) is the induced stress field of artificial fracture. According to the principle of stress superposition, the superposition with in-situ stress field can reflect the real stress distribution around the fracture after hydraulic fracturing.

2.2. The fluid-structure coupling model

During the oil and gas production in an unconsolidated sandstone reservoir, the loading of fluid seepage leads to the porous media framework's deformation. When the deformation exceeds the limit of sanding's critical value, the rock skeleton will be destroyed, and part of the skeleton sand will be peeled off into movable sand. The movable sand will migrate with the reservoir fluid, and blockage inside the porous media, therefore, affect the geo-structure of the reservoir rock and the internal seepage flow. Thus, the fluid-structure coupling effect generated by the seepage flow, skeleton deformation and formation of the movable sand should be taken into full consideration during the simulation work.

The fluid-structure coupling model used in the calculation is as follows:

\[
\sigma_{j,i} - (a \partial t_p) + f_i = 0
\]
In the equation, \( \sigma_{ij} \) is stress tensor, MPa; \( \delta_y \) is Kronecker function; \( \alpha \) is Biot coefficient, dimensionless; \( p \) is pore pressure, MPa; \( f \) is body load, MPa.

The constitutive equation of elastoplastic material in incremental form is as follows:

\[
\begin{align*}
\{d\sigma_y\} &= \{D\}\{d\varepsilon_y\} \\
\{d\varepsilon_y\}_e &= \{d\varepsilon_y\} - \{d\varepsilon_y\}_p - \{d\varepsilon_y\}_w
\end{align*}
\]

(7) (8)

In the equation above, \( \{d\sigma_y\} \) is the effective stress tensor, MPa; \( \{D\} \) is the elastic matrix; \( \varepsilon_y \) is the elastic strain tensor; \( \varepsilon_y \) is the total strain; \( \varepsilon_y^p \) is the plastic strain increment; \( \varepsilon_y^w \) is the strain caused by the change of water content in the medium.

The seepage equation considering fluid-structure Coupling is as follows:

\[
\nabla \cdot \left( \frac{\rho K}{\mu} \nabla p \right) + \phi C_\eta \frac{\partial \phi}{\partial t} + \rho \frac{\partial \phi}{\partial t} = 0
\]

(9)

In the equation, \( K \) is the absolute permeability of porous media, mD; \( \mu \) is the liquid viscosity, Pa·s; \( \phi \) is the porosity of porous media; \( C_\eta \) is the compressibility of fluid, MPa\(^{-1}\).

Assuming that only pore deformation occurs in the solid skeleton, the relationship between porosity and deformation is as follows:

\[
\frac{\partial \phi}{\partial t} = \frac{1}{1 + \varepsilon} \frac{\partial \varepsilon_v}{\partial t}
\]

(10)

In the equation, \( \varepsilon_v \) is the volumetric strain, \( \varepsilon_v = \varepsilon_x + \varepsilon_y + \varepsilon_z \); \( \phi_i \) is the initial porosity.

Equation (6)-(10) is the fluid-solid coupling model of the reservoir. The finite element method is used to solve the model.

2.3. The critical sanding criterion

Given the problem of sanding in oil wells, there are many criteria for judging sanding in reservoir damage. In this study, the equivalent plastic strain criterion is used to determine whether the gravel packing sand control well is damaged or not. The equivalent plastic strain of reservoir is expressed as follows:

\[
\varepsilon_{ep} = \sqrt{\frac{2}{3} (\varepsilon_{p1}^2 + \varepsilon_{p2}^2 + \varepsilon_{p3}^2)}
\]

(11)

In the equation above, \( \varepsilon_{p1}, \varepsilon_{p2}, \varepsilon_{p3} \) are the plastic strains in the three principal stress directions, dimensionless.

A large number of sanding experiments show that when the equivalent plastic strain of reservoir exceeds 0.3% to 0.8%, the rock structure will be destroyed and the skeleton sand will begin to peel off from the rock mass. In this study, 0.3% is taken as the critical plastic strain value of oil well sanding. The area where the plastic strain exceeds 0.3% is the plastic sanding area.

3. Results and discussion

In this part, two groups of near-wellbore geometric models of high-pressure sand control and frac-packing sand control were established respectively. The effects of the two sand control methods on the gravel packing and frac-packing well are compared. The modelling parameters of the finite element model are shown in table 1.
**Table 1.** Fluid-solid coupling parameters of the model.

| Modeling parameters     | numerical value | unit   |
|-------------------------|-----------------|--------|
| Biot number             | 0.9             | /      |
| porosity                | 0.2             | /      |
| permeability            | $3 \times 10^{-14}$ | m$^3$  |
| Compressibility of fluid| $4 \times 10^{-10}$ | Pa$^{-1}$ |
| Fluid velocity          | 0.01            | m/s    |
| Reservoir fluid viscosity| 10             | mPa-s  |
| Young's modulus         | 10              | GPa    |
| Poisson's ratio         | 0.24            | /      |
| Borehole radius         | 0.15            | m      |
| Fracture width          | 0.3             | m      |
| Fracture length         | 15              | m      |

Setting the critical sanding plastic strain as 0.3%, the plastic sanding area under two sand control technologies can be obtained, as shown in Figure 1. The sanding region of the case with frac-packing was located near the artificial fracture, and the total sanding region was significantly smaller than the case with the gravel packing. That may because of the reduction of stress consideration effect brought by the artificial fracture.

![Figure 1](image_url)

(a) high pressure gravel packing  
(b) frac-packing.

**Figure 1.** Regional distribution of plastic sanding

Figure 2 shows the variation of critical sanding velocity with young's modulus under the two sand control technologies. The critical sanding velocity of high-pressure gravel pack sand control well improves linearly with the increase of Young's modulus. Its increase rate is lower than that of frac-packing sand control well. Compared with high-pressure gravel packing well, the critical sanding velocity of the frac-packing well is higher. With the increase of Young's modulus, the effect of artificial fracture on reservoir deformation is more significant, and the critical sanding velocity increases rapidly. It can be seen from the above figure that frac-packing technology can effectively improve the critical sanding velocity and improve the sanding condition of oil wells.
Figure 2. Comparison of critical sanding velocity between high pressure gravel packing and frac-packing.

In Figure 3, the variation of plastic sanding area with bottom hole Darcy velocity is compared between the two sand control technologies. It can be seen from the figure that after reaching the critical sanding velocity, the plastic sanding area of the two groups of models increases linearly with the bottom hole velocity. When the bottom hole velocity is higher than 0.008 m/s, the plastic damage will occur in the frac-packing model. With the increase of bottom hole fluid velocity, the growth rate of reservoir damage area is slower than that of high-pressure gravel packing under the same parameter setting.

Figure 3. Comparison of plastic sanding area between high pressure gravel packing and frac-packing.

4. Analysis of influencing factors on plastic sanding area
The main factors affecting the plastic sanding area of frac-packing wells are reservoir lithology and physical properties, oil well production system and fracture geometry. Under the condition that other modelling parameters are constant, the influence of Young's modulus, fracture width and fracture length on the plastic sanding area of the reservoir is studied.

Figure 4. Area map of plastic sanding area affected by young's modulus.
Figure 4 shows the variation of plastic sanding area with Young's modulus at different bottom hole velocities. With the gradual decrease of Young's modulus, the plastic sanding area increases obviously, and the critical sanding velocity decreases. The slope of the curve increases obviously, which means that the velocity sensitivity of the plastic sanding area is significantly improved.

![Figure 4](image)

Figure 5. Area map of plastic sanding area affected by fracture width and fracture length.

It can be seen from Figure 5 that with the gradual decrease of fracture width and fracture length, the plastic sanding area increases obviously, and the critical sanding velocity decreases.

5. Conclusion
In this paper, a simulation approach based on induced stress model of artificial fracture and fluid-structure coupling model was proposed to determine the sanding region of the frac-packing well. The finite element model was established and solved by the multiphysics coupling software COMSOL. According to the simulation results, the following conclusions can be drawn:

1. The critical sanding velocity of high-pressure gravel pack sand control well and frac-packing well increases linearly with the increase of reservoir Young's modulus. The critical sanding velocity of fractured packed well is higher.

2. After reaching the critical sanding velocity, the plastic sanding area of high-pressure gravel packing and frac-packing increases linearly with the bottom hole velocity. The growth rate of damage area is slower than that of high-pressure gravel packing under the same parameters.

3. With the gradual decrease of Young's modulus, the plastic sanding area increases obviously, and the critical sanding velocity decreases.

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