Hydro-mechanical coupling numerical simulation method of multi-scale pores and fractures in tight reservoir

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Abstract. In the fracturing, injection and production of unconventional tight reservoirs, the change of fluid pressure will cause significant changes in effective stress, which will greatly affect the dynamic characteristics of the reservoir. On the basis of the adaptive seepage numerical simulation method for different scale medium of tight oil in the early stage, through the study of the deformation mechanism and deformation law of natural/artificial fractures and matrix pores during the whole life cycle including hydraulic fracturing, production and fluid injection to supplement energy, the dynamic variation models of multi medium geometry, physical properties, conductivity and well index are established, and the multi medium fluid solid coupling dynamic simulation technology is formed. The integrated dynamic simulation of multi-media complex seepage and hydro-mechanical coupling is realized.

1. Introduction

Tight reservoirs have pores and natural fractures of different sizes from micron to nano. The artificial fractures formed by hydraulic fracturing make the fluid flow more complex. Throughout the development lifecycle, tight reservoirs usually go through the stages of fracturing, development and fluid injection to supplement energy [1-2]. In different development stages, with the change of fluid pressure, Parameters such as size, porosity and permeability of reservoir matrix, natural fractures and artificial fractures will also change dynamically, and ultimately affect the performance of oil wells. Therefore, the effect of multi-scale hydro-mechanical coupling must be considered in the simulation of the whole life cycle development process of tight reservoir [3-4].

At present, there are many researches on numerical simulation considering hydro-mechanical coupling of different types of reservoirs [5-8]. Barenblatt et al (1960) established the dual medium model [9], and Warren et al (1963) simplified and generalized it. Based on the equivalent continuum model and the nested discrete fracture model [10], Yan et al (2019) proposed an effective mathematical model to simulate the coupling problem of fluid mechanics in porous media with fractures and caves [11]. Zhang et al (2019) put forward a new fluid structure coupling calculation scheme for fracture cavity medium, and carried out numerical simulation research with FLAC3D software [12]. But these researches are mainly aimed at conventional or fractured reservoir, which can not adapt to the complex geological conditions of multi-scale pore fracture medium development in tight reservoir, nor can it simulate the development methods of fracturing, exploitation and fluid injection. In this paper, based on the self-developed numerical simulation model of tight reservoir
development [13], a multi-scale mathematical model of hydro-mechanical coupling is established and added to carry out the numerical simulation research of hydro-mechanical coupling in tight reservoir development mode of fracturing, production and fluid injection.

2. Hydro-mechanical interaction mechanism of multi-scale pores and fractures
In the whole development process of tight reservoir, with the change of formation fluid pressure in different development stages, the attribute parameters such as size, porosity and permeability of matrix pores and natural / artificial fractures will change dynamically [14-16]. The change of attribute parameters of these seepage media will lead to the change of fluid conductivity between media and well index of oil wells, and affect the fluid seepage ability between seepage media and between reservoir and wellbore.

The change of pore geometry and physical parameters with fluid pressure in tight reservoir is relatively simple, but the dynamic change of fracture is complex.

Fracturing and fluid injection are the process of fluid pressure increasing. Fractures will experience rock fracture, natural fracture opening and fracture extension. When the fluid pressure in the fracture is greater than the normal stress on the fracture surface, the natural fracture opens. After fracture and opening, the fracture size will continue to extend along the edge of the fracture. The change of pore geometry is shown in Figure 1(a), and the changing rules of fracture are shown in Figure 1(b) and Figure 1(c).

3. Hydro-mechanical coupling model of multi-scale pores and fractures

3.1. Dynamic change model of multi-scale pores and fractures
According to the dynamic variation of property parameters with pressure of matrix pores, natural fractures and artificial fractures in the process of fracturing and injection, the dynamic change models of porosity and permeability in different stages are established by using piecewise function. These

Figure 1. Variation of pore and fracture medium property parameters during fracturing and injection.

Figure 2. Variation of pore and fracture medium property parameters during production.

In the process of production, with the decrease of pore pressure, the width of fracture will gradually narrow until closure occurs, and proppants in the artificial fracture will break and fail. The change of pore geometry is shown in Figure 2(a), and the changing rules of fracture are shown in Figure 2(b) and Figure 2(c). Closure pressure is the fluid pressure required to keep natural / artificial fractures from closing exactly.
models can be used to describe the non-linear variation of physical parameters in the stages of matrix pore deformation, natural fracture opening, artificial fracture rupture and extension. The calculation models are shown in Table 1.

**Table 1. Parameters change model of pores and fractures during fracturing and fluid injection.**

| Reservoir matrix | Natural fracture | Artificial fracture |
|------------------|------------------|---------------------|
| \( M_m = M_{mi} \) | \( P = P_i \) | \( M_f = M_{fi}e^{b_f^1(P-P_i)} \) | \( M_F = M_{mi}e^{b_m(P-P_i)} \) |
| \( M_m = M_{mi}e^{b_m(P-P_i)} \) | \( P_i < P \leq P_{mc} \) | \( M_f = M_{fo} \) | \( P = P_{fo} \) |
| \( M_m = M_{mc} \) | \( P = P_{mc} \) | \( M_f = M_{fo}e^{b_f^1(P-P_{fo})} \) | \( M_F = M_{po}e^{b_F^1(P-P_{fo})} \) |
| \( M_m = M_{mc}e^{b_m1(P-P_{mc})} \) | \( P_{mc} < P \) | \( P < P_{fo} \) | \( P_f < P \) |

Where \( M \) is physical parameter, porosity or permeability that changes with pressure; \( P_i \) is the original pore pressure; \( P_{mc} \) is the pore / artificial fracture initiation pressure; \( P_{fo} \) is the opening (closing) pressure of natural fractures, \( P_{fe} \) is the natural fracture extension pressure; \( P_{fe} \) is the extension pressure of artificial fracture; \( M_{mi} \) is the original porosity/permeability of the matrix; \( M_{fi} \) is the original porosity/permeability of natural fractures; \( b_m^1 \) is the elastic deformation porosity/permeability deformation coefficient of reservoir matrix; \( b_m^2 \) is the plastic deformation porosity/permeability deformation coefficient of reservoir matrix; \( b_f^1 \) is the elastic deformation porosity/permeability deformation coefficient of natural fractures; \( b_f^2 \) is the deformation coefficient of porosity/permeability when natural fractures expand and extend; \( b_f^2 \) is the porosity/permeability deformation coefficient when artificial fractures are closed. These parameters are constant for a specific reservoir.

According to the dynamic change mechanism of matrix porosity, natural fracture and artificial fracture in the process of production, the dynamic change models of porosity and permeability in different stages are established. These models can be used to describe the nonlinear variation of physical parameters in the stages of shrinkage of matrix pores and closure of natural and artificial fractures. The calculation models are shown in Table 2.

**Table 2. Parameters change model of pores and fractures during development.**

| Reservoir matrix | Natural fracture | Artificial fracture |
|------------------|------------------|---------------------|
| \( M_m = M_{mp} \) | \( P = P_p \) | \( M_f = M_{fp}e^{b_f^1(P-P_p)} \) | \( M_F = M_{fp}e^{b_F^1(P-P_p)} \) |
| \( M_m = M_{mp}e^{b_m1(P-P_p)} \) | \( P_{mc} < P \leq P_p \) | \( M_f = M_{fp} \) | \( P = P_{fo} \) |
| \( M_m = M_{mc1} \) | \( P = P_{mc} \) | \( M_f = M_{fp}e^{b_f^1(P-P_{fo})} \) | \( M_F = M_{fp}e^{b_F^1(P-P_{fo})} \) |
| \( M_m = M_{mc}e^{b_m1(P-P_{mc})} \) | \( P < P_{mc} \) | \( P < P_{fo} \) | \( P < P_{fo} \) |

Where \( P_p \) is the pore pressure at the start of production; \( M_{mp} \) is the original porosity/permeability of the matrix at the beginning of production; \( M_{fi} \) is the original porosity/permeability of natural fracture at the beginning of production; \( b_m^1 \) is the porosity/permeability deformation coefficient of the matrix plastic deformation of reservoir during production; \( b_f^2 \) is the porosity/permeability deformation coefficient when natural fractures are closed; \( b_f^2 \) is the porosity/permeability deformation coefficient when artificial fractures are closed. These parameters are constant for a specific reservoir. These
deformation parameters can be obtained by rock mechanics experiment and seepage experiment, and the key critical pressure can also be verified by field small-scale fracturing test.

3.2. Dynamic change model of conductivity and well index

3.2.1. Model of conductivity variation between seepage media. In different development stages, the dynamic change of attribute parameters of pores and fractures will lead to the change of conductivity between these seepage media. The model considering the dynamic change of conductivity is:

\[ T_{mn} [K(p)] = \frac{\alpha_m [K(p)] \alpha_n [K(p)]}{\alpha_m [K(p)] + \alpha_n [K(p)]} \]  

Where, \( T_{mn} \) is the conductivity between adjacent grids; \( \alpha_m \) is the shape factor of grid m; \( \alpha_n \) is the shape factor of grid n; \( \alpha_m \) and \( \alpha_n \) are the functions of permeability \( K_m \) and permeability \( K_n \) of each grid respectively; \( m, n \) is the subscript, indicating the adjacent m grid and n grid, which can be matrix grid, natural fracture grid or artificial fracture grid. The two functions of \( \alpha_m [K(p)] \) and \( \alpha_n [K(p)] \) represent that the shape factor of grid m and adjacent grid n vary with the permeability of the grid.

3.2.2. Dynamic variation model of well index in tight reservoir. In the process of depletion production, the pressure near the wellbore drops sharply, and in the process of fracturing and injection, the pressure rises sharply, which leads to the dynamic changes of fracture and matrix parameters. In this case, the well index dynamic model should be used to calculate the change of well index.

\[ WI(p) = \frac{2\pi \sqrt{K_x(p)K_y(p)L}}{ln\left(\frac{r_e}{r_w}\right) + s} \]  

Where, \( WI \) is the well index; \( K_x \) is the permeability of seepage medium in X direction; \( K_y \) is the permeability of seepage medium in Y direction; \( L \) is the wellbore length involved in the calculation; \( r_e \) is the wellbore control radius; \( r_w \) is the wellbore radius; \( s \) is the wellbore skin.

4. Dynamic simulation of hydro-mechanical coupling in tight reservoir

4.1. Simulation of oil well life cycle of fracturing, soak and production process
The research adopts self-developed multi-media numerical simulators with different scales. Firstly, the reliability of the model is verified based on the parameters of xp8 well in Ordos Basin tight reservoir, and the bottom hole flowing pressure is fitted according to the daily oil production. The simulation parameters are shown in the Table 3, and the fitting results are shown in the Figure 3 and Figure 4.

| Parameters                              | Value | Parameters                              | Value |
|-----------------------------------------|-------|-----------------------------------------|-------|
| Horizontal well length, m               | 1300  | Original porosity of matrix, %          | 8     |
| Formation thickness, m                 | 14    | Original permeability of matrix, mD     | 0.3   |
| Reservoir length in x-direction, m      | 1800  | Original porosity of natural/artificial fractures, % | 2/10 |
| Reservoir length in y-direction, m      | 1000  | Original permeability of natural/artificial fractures, mD | 100/2000 |
| Density at reservoir condition, g/cm³  | 0.74  | Matrix plastic porosity/permeability deformation coefficient | 0.15/0.25 |
| Viscosity at reservoir condition, cp    | 1.2   | Elastic porosity/permeability deformation coefficient of natural fractures | 0.2/0.35 |
| Pore compressibility, MPa⁻¹             | 0.0035| Elastic porosity/permeability deformation coefficient of artificial fracture | 0.4/0.5 |
The integrated simulation of fracturing, soaking and production process is carried out by using the model. According to the construction parameters and fracturing time of each fracturing section, the multi-stage fracturing process of horizontal well is simulated; Then, the process of pressure diffusion in the process of soaking well after fracturing is simulated dynamically; Finally, according to the production system and dynamic data, the production process is simulated, and the dynamic simulation of pressure injection production integration is realized. The simulation results are shown in the Figure 5. It can be seen that in the fracturing process, the pressure is mainly concentrated in the artificial fracture, and the pressure gradually diffuses in the reservoir matrix when the well is soaked. After the flowback, the pressure near the well decreases, and the pressure further decreases during the production process.

**Figure 3.** Daily production curve fitting by numerical simulation.

**Figure 4.** Bottom hole flowing pressure curve fitting by numerical simulation.

4.2. Effect of hydro-mechanical coupling on well development in depletion production

On the basis of the above model, the production of horizontal wells with and without hydro-mechanical coupling in depletion development mode is calculated respectively. The model introduced by Liu was used for the simulation without considering the hydro-mechanical coupling [13]. With the recovery of crude oil, the pore fluid pressure decreases gradually, which leads to the shrinkage of matrix pores, the deformation and closure of natural and artificial fractures, and the decrease of
reservoir physical properties, which leads to the decrease of reservoir conductivity and well index, and finally the decrease of oil well production. Through comparative analysis, it can be seen that without considering the fluid structure interaction, the daily production and cumulative production are larger than the actual situation, and the production is 17.8% higher than the actual situation, which indicates that the production is often overestimated when the fluid structure interaction is not considered. (Figure 6).

![Daily oil production curve](image1.png)  ![Cumulative oil production curve](image2.png)

**(Figure 6).** Effect of hydro-mechanical coupling on well development in depletion production.

4.3. **Effect of hydro-mechanical coupling on well development during fluid injection and production**

After depletion development, the simulation calculation of fluid injection to supplement formation energy in horizontal wells is continued. After a period of time (about 200 days) of the early stage of the depletion development, the formation energy is supplemented by water injection (30 days of injection cycle and 36t/d injection speed), and then the exploitation (180 days production time) is continued.

The simulation results show that the production decreases rapidly in the early stage of exploitation. By supplementing the formation energy, the production increases, the decline slows down, and the cumulative oil production increases. Through the comparative analysis of the influence of hydro-mechanical coupling on seepage process and development effect, the closer to the artificial fracture, the greater the influence of hydro-mechanical coupling on seepage. Due to the influence of hydro-mechanical coupling, the porosity and permeability can be doubled in the matrix pores near and far away from the artificial fractures, the results are shown in Figure 7 and Figure 8. When considering the fluid structure interaction, the daily production is reduced, and the cumulative oil production is reduced by 18.6% as shown in Figure 9 and Figure 10.

![Porosity variation](image3.png)  ![Permeability variation](image4.png)

**(Figure 7).** Porosity variation of grid porous media during injection and production.  
**(Figure 8).** Permeability variation of grid porous media during injection and production.
Figure 9. Daily production curve of injection and production process.

Figure 10. Cumulative production curve of injection and production process.

5. Conclusions

(1) According to the complex geological characteristics of tight reservoir, the dynamic change law of hydro-mechanical coupling of pores and fractures with different scales is studied, and the attribute parameters, conductivity and well index change models of pores and fractures under the condition of hydro-mechanical coupling are established innovatively.

(2) The integrated simulation of fracturing, soaking and production process of fractured horizontal wells in tight reservoirs can be realized by using multi-scale hydro-mechanical coupling method. The simulation results show that the simulation results of horizontal wells without considering hydro-mechanical coupling are larger than the actual production.

(3) The closer to the artificial fracture, the greater the influence of hydro-mechanical coupling. The difference of porosity and permeability of seepage media at different positions can be doubled.

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