Initiation and propagation of cracks in problems of petrothermal energy

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Abstract. One of the challenges in using petrothermal energy is creating a fractured reservoir. The depth of formations suitable for exploitation is higher than that of formations for which hydraulic fracturing operations are usually carried out in hydrocarbons production. Therefore, the study of hydraulic fracturing features at great depths can be useful for petrothermal energy. The paper compares the pressures required for the initiation and propagation of a hydraulic fracture for a reservoir located at a depth of 5 kilometers and characterized by a strong contrast in compressive stresses. Fully 3D model is used to simulate fracture propagation and obtain propagation pressure. The initiation pressure is calculated based on the elastic equilibrium equations the solution. It is shown that the initiation pressure may greatly underestimate the pressure required for fracture propagation.

Introduction

Petrothermal energy is one of the most promising types of renewable energy sources [1]. However, despite the large reserves of thermal energy in dry rocks, its renewability and the wide distribution of places suitable for use, the development of petrothermal energy is limited by a number of technical problems, solutions to which still require improvement. One of such problems is the creation of reservoir with sufficient permeability, which would provide low energy losses when filtering the heating liquid from the injection well to the production well. The complexity of the problem is caused by the large depth (more than 3 km) of the reservoirs suitable for petrothermal energy production.

Although the modern mining industry has experience in drilling wells of great depth (for example Russian Kola Superdeep Borehole and Z-40 at the Chaivo field or Maersk Oil BD-04A in Qatar), the technology of drilling to such depths cannot be considered widespread and cheap. The technology of hydraulic fracturing, which is used to create fracture is even less developed for large depths. Thus, 90% of wells in the USA for hydraulic fracturing (the most easily obtained statistics) are drilled at depths of less than 3.5 km [2].

The limited use of hydraulic fracturing for deep-lying formations is caused not only by drilling cost that increases with depth, but also by necessity of high pressure for hydraulic fracture initiation and propagation. The pressure required to initiate a fracture from a perforated well can be estimated relatively simply using the analysis of rock stress state, may be with porosity, plasticity [3] or size effect [4] taking into account.

To obtain the pressure that is needed for fracture propagation, it is necessary to solve a more complex problem and to take into account the fluid and pumping properties [5]. One more problem is that the requirements for the fluid used for fracture initiation and propagation contradict each other. Indeed, the high enough initiation pressure can be achieved by increasing the fluid pressure on the surface and by increasing the hydrostatic pressure by using heavier fluids (muds, mixtures). At the same time, the heavier fluids usually have a higher viscosity that increases the propagation pressure. Therefore, the formulation of requirements for a fluid suitable for both initiation and propagation of a hydraulic fracture at great depth is a non-trivial task.

Here the early stage of hydraulic fracture propagation is simulated using fully 3D model [6-9] for the parameters of Lower Amin gas field (Oman). The formation lies at a great depth (up to 5 km) and characterized by high compressive stresses (100-180 MPa) with big contrast. The pressure predicted by the 3D fracture propagation model has been compared with initiation pressure calculated for the same parameters [10, 11].

1 Problem statement

The simulation is carried out for the reservoir parameters of Depth Khulud field in West Lower Amin formation located at the depth 5000 m [10, 11].

The reservoir parameters are as follows: Young modulus $E = 46$ GPa, Poisson coefficient 0.137, tensile strength 5 MPa. Stress state is set by minimal horizontal
stress \( \sigma_b = 102 \text{ MPa} \), maximal horizontal stress \( \sigma_H = 172 \text{ MPa} \) and overburden stress \( \sigma_v = 124 \text{ MPa} \). Fracture toughness is not known from the field data and is taken equal to typical for rocks value \( K_{ic} = 3 \text{ MPa m}^{1/2} \).

The wellbore with diameter of 15 mm is loaded with pressure sufficient to create initial fracture. Modeling of rock breaking in the well vicinity and initial fracture construction procedure are described in [12]. The pressures required for fracture initiation (initiation pressures) are calculated in [10, 11]. Here it is assumed that the transverse fracture has already been formed and has a radius 2 times larger than the wellbore radius. To simplify the computational grid perforation is not taken into account and the fracture propagates from initial fracture. Two wellbore orientations are considered (see fig 1): vertical (\( \theta = 0^\circ \)) and horizontal (\( \theta = 90^\circ, 0 < \varphi < 45^\circ \)).

2 Model description

Fully 3D model of the initial stage of hydraulic fracture propagation is developed under the following assumptions. Rock is assumed homogeneous, isotropic, elastic, and brittle. The first assumption is not satisfied in general case, but looks logical when the fracture is supposed to be smaller than the size of the inhomogeneity. Leak off is not taken into account due to the time of the process under consideration is too small and amount of fluid leaked from the fracture is negligible.

The model basis is given in [6], and then the method elastic equilibrium equations and propagation criterion are improved in [7] and [9], respectively. In [8] fluid model is generalized for non-Newtonian fluid and in the same paper it is also shown that the Newtonian fluid model can be used for complex fluids at the early propagation stage. Therefore, the fluid is further considered Newtonian without limitation of generality.

3 Computational results

3.1 Fluid and pump parameters influence

In the first paragraphs, a vertical wellbore is considered (\( \theta = 0^\circ \)). Fig. 2 and 3 show the dependences of the wellbore pressure \( p(t) \) and the fracture radius \( R(t) \) on the time. For fluid viscosity is fixed \( \mu = 1 \text{ Pa s} \) and pumping rate \( Q \) varies from 0.3 to 3 m\(^3\)/s. Average pumping rate value \( Q = 0.1 \text{ m}^3/\text{s} \) (about 40 bbl/min) is typical for hydraulic fracture procedure, and viscosity value is near to artificial viscosity of hydraulic fracture fluid. Pressure on fig 2 and further is taken in the wellbore near the fracture entrance. Surface pressure can be estimated by subtracting the hydrostatic pressure that is approximately equal to \( \Delta p_{\text{static}} = \rho g H \) equal to 50 MPa for water with \( \rho = 1000 \text{ kg/m}^3 \) and up to 140 MPa for drilling mud with \( \rho = 2700 \text{ kg/m}^3 \) for example.

Fig. 2. Wellbore pressure versus time for fixed viscosity and various inflow rate: 1 – \( Q = 0.03 \text{ m}^3/\text{s} \); 2 – \( Q = 0.1 \text{ m}^3/\text{s} \); 3 – \( Q = 0.3 \text{ m}^3/\text{s} \).

Fig. 3. Fracture radius versus time for fixed viscosity and various inflow rate: 1 – \( Q = 0.03 \text{ m}^3/\text{s} \); 2 – \( Q = 0.1 \text{ m}^3/\text{s} \); 3 – \( Q = 0.3 \text{ m}^3/\text{s} \).

Fig. 4 shows the wellbore pressure versus fracture radius calculated for pumping rate \( Q = 0.1 \text{ m}^3/\text{s} \) and various fluid viscosity. It should be noted that variations in viscosity and pumping rate affect the pressure-radius dependency in the same way [13], so combination of fig. 2 and fig. 3 gives the same pattern for pumping rate variation as fig. 4 gives for viscosity variation.

Fig. 2 and 4 show an obvious way to reduce the propagation pressure. It can be made by degreasing fluid viscosity or pumping rate. But this method causes reducing of fracture propagation speed (see Fig. 3) so the fracturing fluid may leaks from the fracture into formation. Another way to reduce the propagation pressure is to increase the initial fracture. For example, increasing the radius from 0.3 m to 0.5 m leads to a decreasing in pressure by 20 MPa to 40 MPa depending on the pumping rate. Unlike the fracture initiation process, the perforation size becomes important. As it has been shown in [10], the perforation size does not affect the initiation pressure, but the bigger perforation induces the bigger initial fracture and so can lead to propagation pressure decreasing.
orthogonally to the fracture plane. 290 MPa for fluid viscosity. For example propagation pressure varies from 253 to 2 explosion. Pressure obtained under the assumption that the perforation is optimally oriented and account the perforation and wellbore influence on stress state in its vicinity, so it overestimates the initiation pressure. In [11, 10] the fracture initiation pressure was obtained for various well orientations and perforations. There numerical calculation of rock stress-strain state and the fracture criterion, taking into account the size effect were used. Pressure obtained under the assumption that the perforation is optimally oriented and the perforation surface. Thus, the initiation pressure do depend on compressive stress. Thus for fracture of radius $R < 0.65 m$ the net pressure in case of 2 time lower compressive stress is also 34 MPa lower than net pressure in case of original stress value.

3.2 Comparison of fracture initiation and propagation pressures

Initiation pressure can be calculated by simple formula [14] based of Kirsch problem solution

$$p'_{init} = 3\sigma_{min} - \sigma_{max} + \sigma_v = 3\sigma_h - \sigma_v + \sigma_c. \quad (1)$$

For given parameters the initiation pressure equals to $p'_{init} = 205 MPa$. But the formula (1) does not take into account the perforation and wellbore influence on stress state in its vicinity. Therefore, it overestimates the initiation pressure. In [11, 10] the fracture initiation pressure was obtained for various well orientations and perforations. There numerical calculation of rock stress-strain state and the fracture criterion, taking into account the size effect were used. Pressure obtained under the assumption that the perforation is optimally oriented and it was equal to $p'_{init} = 90 MPa$ for vertical fracture. It is more less that propagation pressure shown on fig 2, 4. For example propagation pressure varies from 253 to 290 MPa for fluid viscosity $\mu$ varied from 0.3 to 3 Pa.s and fracture radius $R = 0.65 m$ (that propagates 0.5 m from the wellbore).

The pressure required to initiate a fracture is independent of the fluid and injection parameters, while the propagation pressure depends on them, but within the fracture propagation model, this pressure cannot be less than the rock compressive stress acting orthogonally to the fracture plane ($\sigma_c = 124 MPa$). Initiation pressure may be lower than this value because wellbore disturbs the stress state in its vicinity and may increase stress contrast that decreases the initiation pressure at perforation surface. Thus, the initiation pressure sometimes has little to say about the pressure required to propagate a fracture and can only be as a rough lower bound.

3.3 Compressive stress influence

Classical hydraulic fracture models and modern simulators (Pyfrac [15], TerraFrac [16], GOHFER [17]) use net pressure $p_{net} = p - \sigma_v$ and do not take into account the compressive stress $\sigma_{min}$ orthogonal to the fracture surface. In the case of a developed fracture, which usually propagates in the viscous regime [13] (with or without leak off), this assumption is applicable, but for the initial stage it is not obvious. To check this assumption, calculations were performed for compressive stresses $\sigma_c$ orthogonal to the fracture plane equal to 50% (62 MPa) and 75% (93 MPa) of the original value (124 MPa). Pumping rate and fluid viscosity are taken equal to $Q = 0.1 m^3/s$ and $\mu = 1 Pa.s$ respectively (like line 2 on fig 2-4). Fig. 5 shows net wellbore pressures $p_{net} = p - \sigma_v$ as a function of fracture radius $R$ and fig. 6 shows the distribution the pressure in the fracture as function of radius coordinate $R_w < R$.

This observation can be explained by the presence of the empty space near the fracture front (fluid lag) caused by the fluid front that does not reach the fracture front. In terms of net pressure this small part of fracture is compressed by the value of $\sigma_v$ that is very high. Higher compressive stress causes more compression of the fracture and a larger pressure gradient near the fluid front is required to open the fracture. It can also be seen that the size of this section $\Delta R$ is small and its size decreases with increasing compressive stresses from $\Delta R = 0.9 mm$ for $\sigma_c = 124 MPa$ to $\Delta R = 2.5 mm$ for $\sigma_c = 62 MPa$ as it shown on fig 6. Note that the models written in terms of net pressure without fluid lag taken into account will give the same net pressure for all values of

![Fig. 4. Wellbore pressure versus fracture radius obtained for fixed inflow rate and various viscosity: 1 – $\mu = 0.33 Pa.s$; 2 – $\mu = 1 Pa.s$; 3 – $\mu = 3 Pa.s$.](image)

![Fig. 5. Wellbore pressure vs fracture radius for various orthogonal compressive stress $\sigma_c$: 1 – 124 MPa; 2 – 93 MPa; 3 – 62 MPa; 4 – 31 MPa.](image)

![Fig. 6. Pressure distribution along radial coordinate for various orthogonal compressive stress $\sigma_c$: 1 – 124 MPa; 2 – 93 MPa; 3 – 62 MPa; 4 – 31 MPa.](image)
compressive stress \( \sigma_n \). It is not important for developed fracture due to the fluid lag size is negligible in comparison with the fracture size but it may affect the pressure for the small fractures.

Here we can note one more difference between the fracture initiation and fracture propagation processes. Namely, in [10] it is shown that compressive stress acting in the plane orthogonal the wellbore affects the initiation pressure. At the same time, these compressive stresses act in the fracture plane and do not affect the propagation pressure. The dependence of pressure on the radius at the same compressive stresses, orthogonal to the fracture plane and reduced by a factor of 2, is less than 2% and can be caused by wellbore influence and numerical approximation error.

3.4 Horizontal wellbore orientation

Here in contrast with previous paragraphs, a horizontal wellbore is considered \((0 = 90°, 0 < \phi < 45°)\) on fig. 1). Compressive stresses acting in the fracture plane have little effect on the propagation pressure. Therefore, the qualitative effect of fluid and injection parameters on wellbore pressure will be the same for both vertical and horizontal wells. So figures similar to fig. 2 – fig. are not included here. But it should be noted that the difference between the initiation and propagation pressures will be smaller in this case. The initiation pressure obtained in the [11] is \( p_{\text{init}} = 125 \text{ MPa} \), and the propagation pressure at \( Q = 0.1 \text{ m}^3/\text{s} \) and \( \mu = 1 \text{ Pa·s} \) when the radius \( R = 0.65 \text{ m} \) is reached 198 MPa. This gives the difference \( p(R = 0.65) - p_{\text{init}} = 73 \text{ MPa} \) while for a vertical well, it was much larger, 177 MPa.

In the case of a horizontal well, there is one additional parameter – the wellbore orientation. For straight horizontal fracture it can be set by angle \( \phi \) between minimal rock in situ stress \( \sigma_n \) and the wellbore as it shown on fig. 7. Wellbore oriented in in the direction of minimum stresses \((\phi = 0)\) causes the fracture that propagates in the preferred fracture plane from the beginning, while wellbore deviation from this direction \((0 < \phi < 45°)\) leads to fracture curvature. It is easily can be seen on fig 7. Wellbore pressure vs fracture radius for various horizontal wellbore orientations are shown in fig 8 to demonstrate this effect. It is easy to see that wellbore misorientation increases propagation pressure, although as the fracture grows, the effect of wellbore orientation decreases. At the same time the fracture width in wellbore vicinity is slightly smaller than one at a distance from the wellbore (see fig 7).

And this pinching does not vanish with fracture growth.

![Fracture form and width distribution for non-optimal \((\phi = 30°)\) oriented wellbore.](image)

Fig. 7. Fracture form and width distribution for non-optimal \((\phi = 30°)\) oriented wellbore.

4 Conclusion

Full three-dimensional model is used to simulate fracture propagation in a reservoir located in the depth suitable for petrothermal energy purpose. The formation depth causes a complex stress state, characterized by large values of compressive stresses and their large difference in different directions. Under these conditions, it has been shown that the pressure required for fracture propagation can be much greater than the fracture initiation pressure. This is important, since the initiation pressure can be relatively easily estimated using analytical formulas or numerical solution of elastic equilibrium equations coupled with failure criteria. To calculate the propagation pressure, it is necessary to use a fracture propagation model that takes fluid flow into account.

The propagation model must also explicitly take into account compressive stresses orthogonal to the fracture plane. The difference between the net pressures in the wellbore obtained at actual and 2 times reduced compressive stresses can differ up to 20 MPa. Models operating only with net pressure are not able to consider this difference. Taking into account the fluid lag between fracture and fluid front is one of the ways to show this effect. Well deviation from the direction of the minimum horizontal stresses in case of high contrast can add another 20 MPa to the pressure, so the wellbore orientation is also important and should be considered.

This paper is prepared within the framework of the state assignment of IT SB RAS (121031800215-4).

References


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