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Research article

Simulation of complex fracture networks influenced by natural fractures in shale gas reservoir

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Abstract

When hydraulic fractures intersect with natural fractures, the geometry and complexity of a fracture network are determined by the initiation and propagation pattern which is affected by a number of factors. Based on the fracture mechanics, the criterion for initiation and propagation of a fracture was introduced to analyze the tendency of a propagating angle and factors affecting propagating pressure. On this basis, a mathematic model with a complex fracture network was established to investigate how the fracture network form changes with different parameters, including rock mechanics, in-situ stress distribution, fracture properties, and frac treatment parameters. The solving process of this model was accelerated by classifying the calculation nodes on the extending direction of the fracture by equal pressure gradients, and solving the geometrical parameters prior to the iteration fitting flow distribution. With the initiation and propagation criterion as the bases for the propagation of branch fractures, this method decreased the iteration times through eliminating the fitting of the fracture length in conventional 3D fracture simulation. The simulation results indicated that the formation with abundant natural fractures and smaller in-situ stress difference is sufficient conditions for fracture network development. If the pressure in the hydraulic fractures can be kept at a high level by temporary sealing or diversion, the branch fractures will propagate further with minor curvature radius, thus enlarging the reservoir stimulation area. The simulated shape of fracture network can be well matched with the field microseismic mapping in data point range and distribution density, validating the accuracy of this model.

Keywords: Shale gas; Hydraulic fracturing; Initiation and propagation criterion; Propagating angle; Propagating pressure; Fracture network; Complex fracture model

The conventional hydraulic fracturing simulation usually assumes that there are no natural fractures in the homogeneous formation, and on two sides of the borehole produce bi-wing, symmetric and planar fractures perpendicular to the minimum principal stress [1]. However, both the direct fracturing test in well [2] and indirect micro-seismic monitoring [3] show asymmetric and irregular fracture networks will form in shale gas reservoirs with natural fractures.

The initiation and propagation of natural fractures are the basis for the formation of fracture network. By experimental and theoretical analysis, many researchers have studied the physical phenomenon after the intersection of artificial and natural fractures and established the criterion for fracture propagation [4,5]; Warpinski [6] investigated the shear slip failure triggered by shearing stress on the fracture surface by the line friction theory, and analyzed the tensile failure triggered by normal stress on the fracture surface with Mohr–Coulomb Criterion. Beugelsdijk et al. [7] analyzed the effect of horizontal stress difference, displacement and viscosity on branch fracture propagation by experiment. The

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research shows that the complexity of fracture network intersected with natural fractures is not only related to the crustal stress but also mechanics, natural fracture and fracturing parameters as well as physical property of working fluid [8—10].

After the artificial fracture intersects the natural fracture, the initiation and propagation mechanism of branch fractures greatly impact the geometry and complexity of the fracture network. Based on the theory of fracture mechanics, the author introduced the criterion of initiation and propagation of fractures; on this basis, considering the influence of additional stress field, the complex fracture network model was constructed for complex fracture network created during shale gas reservoir fracturing, in the solution process the calculation nodes are divided by equal pressure gradient on the propagation direction of the fracture, and the fracture network is figured out with the node pressure as key variable; moreover, the initiation and propagation criterion is taken as the basis to identify the propagation of branch fractures to avoid the complicated fitting of the fracture length in the conventional 3D fracture simulation. Compared with the line network model [11], this model fully considers the effect of random fractures on the whole fracture network structure, and the shape of fracture network on two sides of borehole is asymmetric and the branch fractures inside are not evenly spaced, which fits the micro-seismic monitoring results better. Compared with the unconventional fracture model [12], the established initiation and propagation criterion takes into account the crack tip circumferential stress under the joint action of shear and normal stress, which can rationally explains the phenomenon of crack diversion during the propagation and calculates the angle change during the extension of branch fractures; and the calculation can be effectively accelerated by improving the numerical solution.

1. Conditions for fracture initiation and propagation

1.1. Stress intensity factor produced by shear stress

The type II stress intensity factor created by shear stress on the surface of oval natural fracture under the crustal stress is:

$$K_{\mathrm{II}} = \frac{4\sqrt{\tau b \kappa^2}}{\Theta}\left(\frac{1}{C}\sin\omega\sin\theta\frac{\kappa'}{B}\right) \tag{1}$$

$$\Theta = \left(\sin^2\theta + \frac{b^2}{a^2}\cos^2\theta\right)^{1/4},\ B = (k^2 - \upsilon)E(k) + \upsilon k'^2 K(k),\ C = (k^2 + \upsilon k')E(k) - \upsilon k'^2 K(k),\ k = 1 - \frac{b^2}{a^2},$$

$$k' = \frac{b}{a}$$

where $K(k)$ and $E(k)$ are the complete integral of the first and second kind of ellipse, respectively; τ is shear stress, MPa; υ is Poisson's ratio; ω is the intersection angle between the shear stress direction and elliptic long axis; θ is the intersection angle between any point at the elliptic margin and long axis; a and b is the length of fracture half long and short axis, respectively, m.

1.2. Stress intensity factor produced by normal stress

During the propagation of hydraulic fracture, the continuously extending fracture length and the intra-fracture pressure re-distribution will lead to the dynamic variation of crack tip stress intensity factor triggered by normal stress. The nodes are divided by the equal pressure gradient along the fracture extending direction at the initial cracking position, and then the superimposition principle is employed to calculate the value of crack tip stress intensity factor under different node pressures. And the division of pressure nodes is shown in Fig. 1

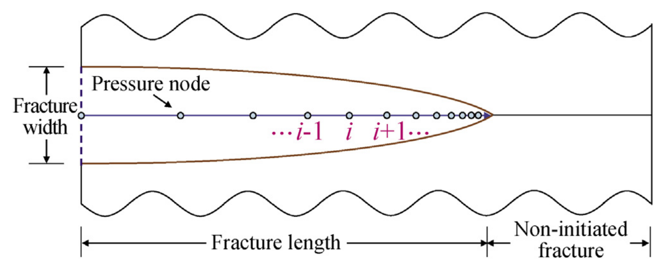

Figure 1. Division of fracture pressure nodes.

The stress intensity factor generated by different node pressure [13]:
where $l(i)$ is the space from the pressure node No. i to the initial position; l is artificial fracture length; $P_{\mathrm{net}}(i)$ is the net pressure at the node No. i.

On this basis, the type I stress intensity factor under the normal stress can be expressed as:

$$K_{\mathrm{I}(i)} = \frac{p_{\mathrm{net}(i)}}{\sqrt{\pi l}}F \tag{2}$$

$$F = \sqrt{\frac{1-\eta}{2}}\left[\frac{2}{1-\eta} + 0.978\,8 + 1.11(1-\eta) - 0.319\,4(1-\eta)^2 - 0.101\,7(1-\eta)^3\right],\ \eta = \frac{l_{(i)}}{l}$$

$$K_{\mathrm{I}} = \sum_{i=1}^{n} K_{\mathrm{I}(i)}\left[p_{\mathrm{net}(i)},\ l_{(i)},\ l\right] \tag{3}$$

where n is the number of total pressure nodes divided.

1.3. Additional pressure field

When extending at the same time, multiple branch fractures will be influenced by the normal and shear stress of the neighboring fractures, forming additional pressure field. The analytical formula proposed by Crouch et al. after modification by Olson [14], is expressed as:

$$\sigma_{\mathrm{n}}^{i}=\sum_{j-1}^{N} G^{ij} C_{\mathrm{ns}}^{ij} D_{\mathrm{s}}^{j}+\sum_{j-1}^{N} G^{ij} C_{\mathrm{nn}}^{ij} D_{\mathrm{n}}^{j} \tag{4}$$

where C_{ns}^{ij} and C_{nm}^{ij} is plane strain elastic coefficient respectively; D_{s}^{j} and D_{n}^{j} is the discontinuous displacement on each micro-segment caused by shear and normal stress, respectively (fracture width calculated on the basis of fluid solid coupling); G^{ij} is a 3D coefficient of correction proposed by Olson, which introduces the effects of fracture height and space on the additional stress field.

The additional stress field needs to be calculated at every time step during the numerical calculation, then be acted on the crustal stress field, which is used for the pressure formula of initiation and propagation and the iterated calculation of fracture geometry at different nodes.

2. Criterion of fracture initiation and propagation

When the fracturing fluid enters a natural fracture, if the intra-fracture pressure exceeds the normal stress and tensile strength on the fracture surface, the natural fracture will be opened and form a branch fracture with a certain width. The calculation formula for the normal stress on the fracture surface is:

$$\sigma=\sigma_1 \cos^2 \alpha+\sigma_2 \cos^2 \beta+\sigma_3 \cos^2 \gamma+T_0 \tag{5}$$

where T_0 is the tensile strength, MPa; σ is normal pressure on the fracture surface, MPa; $\sigma 2$ is vertical stress, MPa; $\sigma 1$ and $\sigma 3$ is horizontal stress, MPa; α, β, γ is the intersection angle between the fracture surface normal and principal stress direction, respectively.

The net pressure at different nodes is:

$$p_{\mathrm{net}(i)}=p_{\mathrm{f}(i)}-\sigma \tag{6}$$

After substituting net pressure at each node into formula (3), the fracture initiation calculation formula is:

$$\sum_{i=1}^{m} K_{\mathrm{I}(i)}\left[p_{\mathrm{net}(i)},\ l_{(i)},\ l\right] \geq K_{\mathrm{Ic}} \tag{7}$$

where m is the node number corresponding to the fracture initiation, $m \leq n$.

Based on the maximum circumferential stress theory [15] proposed by Erdogan, the type I–II compound fracture propagation angle equation can be deduced:

$$\theta_0=\arccos\left(\frac{3K_{\mathrm{II}}^2+K_{\mathrm{I}}\sqrt{K_{\mathrm{I}}^2+8K_{\mathrm{II}}^2}}{K_{\mathrm{I}}^2+9K_{\mathrm{II}}^2}\right) \tag{8}$$

And type I–II compound fracture propagation equation:

$$\cos \frac{\theta_0}{2}\left[K_{\mathrm{I}} \sin \theta_0+K_{\mathrm{II}}(3 \cos \theta_0-1)\right]=K_{\mathrm{I\,c}} \tag{9}$$

3. Complex fracture network model

The assumed conditions for the model include: ① all the natural fractures are vertical; ② the formation is assumed as a homogeneous, isotropic and continuous elastic body in the area without natural fractures; ③ the reservoir is thick, so there is no formation penetration; and ④ the extending velocity of the fracture in the vertical direction is less than that in the lateral direction.

The complex fracture network comprises the following equations:

1) Initiation and propagation equation: see formula (7) and (9)
2) Fracture width equation

Assuming the pay zone is thick enough, and the intra-fracture net pressure $p_{\mathrm{net}}=p_{\mathrm{f}}(x,t)-\sigma'$, $\sigma'=\sigma+\sigma_n^i$, the width equation at any position z on the cross section of fracture:

$$w_j(x,z,t)=\frac{4(1-\upsilon^2)}{E} p_{\mathrm{net}} \sqrt{\left[\frac{h_j(x,t)}{2}\right]^2-z^2} \tag{10}$$

3) Pressure drop equation

Based on the inter-plane pressure drop equation by Nolte, the channel shape factor $\phi_j(\mathrm{n})$ was introduced to get the intra-fracture pressure drop equation:

$$\frac{\partial p_j(x,t)}{\partial x}=-2^{n+1}\left[\frac{(2n+1)q_j(x,t)}{n\phi_j(n)h_j(x,t)}\right]^n \frac{K}{[w_j(x,0,t)]^{2n+1}} \tag{11}$$

$$\phi_j(n)=\int_{-0.5}^{0.5}\left[\frac{w_j(x,z,t)}{w_j(x,0,t)}\right]^m \mathrm{d}\left[\frac{z_j}{h_j(x,t)}\right]$$

$$m=\frac{2n+1}{n}$$

4) Height equation

$$K_{\mathrm{e}}=\frac{1}{\sqrt{\pi h_j(x,t)/2}} \int_{-h_j(x,t)/2}^{h_j(x,t)/2} p_{\mathrm{net}}(z) \frac{\sqrt{[h_j(x,t)/2]+z}}{\sqrt{[h_j(x,t)/2]-z}} \mathrm{d}z \tag{12}$$

5) Continuity equation

$$-\frac{\partial q_j(x,t)}{\partial x}=\frac{2h_j(x,t)C_{\mathrm{t}}(x,t)}{\sqrt{t-\tau(x)}}+\frac{\partial A_j(x,t)}{\partial t} \tag{13}$$

The initial and boundary conditions for the model is similar to that for 3D model, but after intersecting with fracture, the flow rate at the intersection needs to be redistributed evenly.

Where x_j is fracture length, m; w_j (x,z,t) is fracture width, m; h_j (x,t) is fracture height, m; $p_{\text{net}}(x,t)$ is intra-fracture pressure, MPa; $q_j(x,t)$ is flow rate, m^3/min; E is Young's modulus, GPa; n is flow index, dimensionless; K is consistency coefficient, Pa·S^n; C^t is filtration coefficient, m $\text{min}^{-0.5}$; Aj is cross sectional area of fracture, m^2; t is operation time, min; $\tau(x)$ is the time when the fluid reaches x at t, min; subscript j represents some branch fracture within the network.

The improved solution for the complex fracture model is:

1) Calculate the initial fracture length at different time steps with the fracture length of 2D KPN model: $L_{t_s} = 0.6((Eq^3)/(2(1-\upsilon^2)\mu h^4))^{1/5} t_s^{4/5}$, and classify the calculation node by constant pressure drop in the fracture propagation direction using bottom-hole or intersection pressure as initial condition $(p_{\text{net}} + \Delta p)_{(i)} = ((16\mu q E^3 \Delta L_{\text{ts}})/((1-\upsilon^2)\pi h^4))^{1/4}$, then substitute the node pressure into the initiation fracture equation to calculate fracture length that can actually open.
2) According to the pressure at the node for the fracture height equation, the fracture height at different node is calculated.
3) Substitute the fracture height and pressure at the node into the fracture width equation to figure out the fracture width at different nodes.
4) Substitute the calculated geometry and initial flow rate into the pressure drop equation to get the new pressure at the node, and compare the difference with the former equal pressure drop node and fit the initial node pressure to meet $|p'_{\text{net}(i)} - p_{\text{net}(i)}| \le \varepsilon$.
5) Further substitute fracture width and height for the continuity equation of 1D flow at different nodes to figure out the flow rate distribution at different nodes, and compare the flow rate with that at the assumed initial node. If inconsistent, change the formula of initial flow rate distribution, and repeat procedure 1 to 5 and finally realize the flow rate fitting $|q'_{(i)} - q_{(i)}| \le \eta$.
6) Before updating the time step, the conditions for fracture propagation need to be considered, to judge whether the fracture will continue to extend at the next moment with the crack tip azimuth, intra-fracture pressure and additional stress field at this moment, calculate the extending angle of dynamic variation. If the conditions are met, the next time step will be entered, and procedure steps 1 to 6 are repeated until the fracture ceases propagation.

The fracture network simulation work flow for natural gas fracturing is shown in Fig. 2.

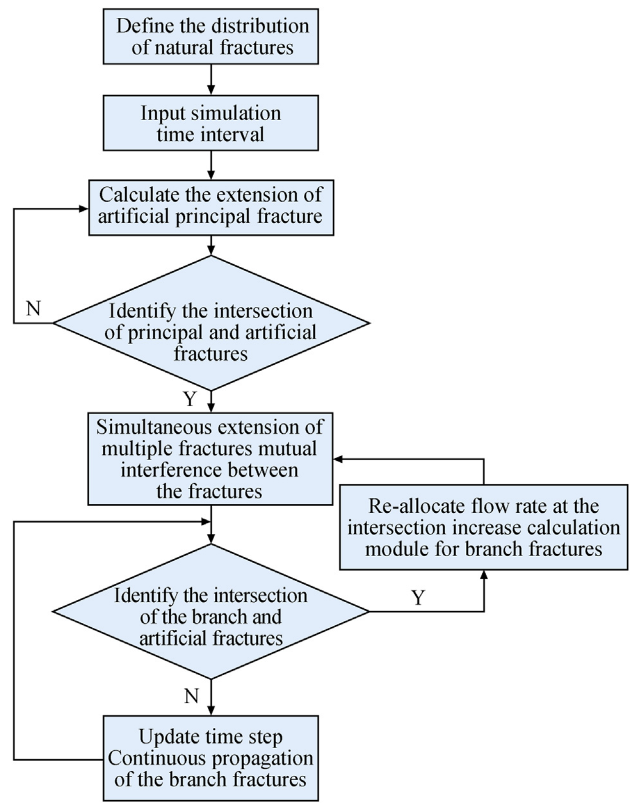

Figure 2. Simulation flow for complex fractures.

4. Analysis on the simulation results

4.1. Fracture extending angle

The extending angle formula can be used to analyze the effect of horizontal stress difference, intra-fracture net pressure and intersection angle on branch fracture extending track (Fig. 3).

When the horizontal stress difference keeps constant, the increase in intra-fracture net pressure, decrease in extending angle, and the increase in curvature radius of branch fracture extending track, can not only effectively broadens the fracture network width but also makes it easier to intersect with other fractures. But when the intra-fracture net pressure keeps constant and horizontal stress difference gradually increases, the bigger the extending angle varies, the smaller the curvature radius of branch fracture extending track will be, and the

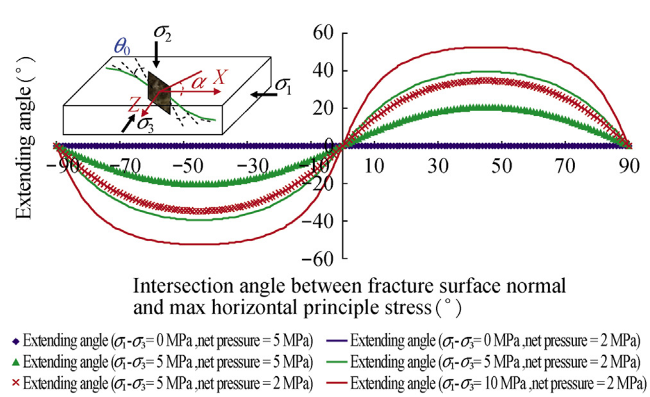

Figure 3. Variation of fracture extending angle.

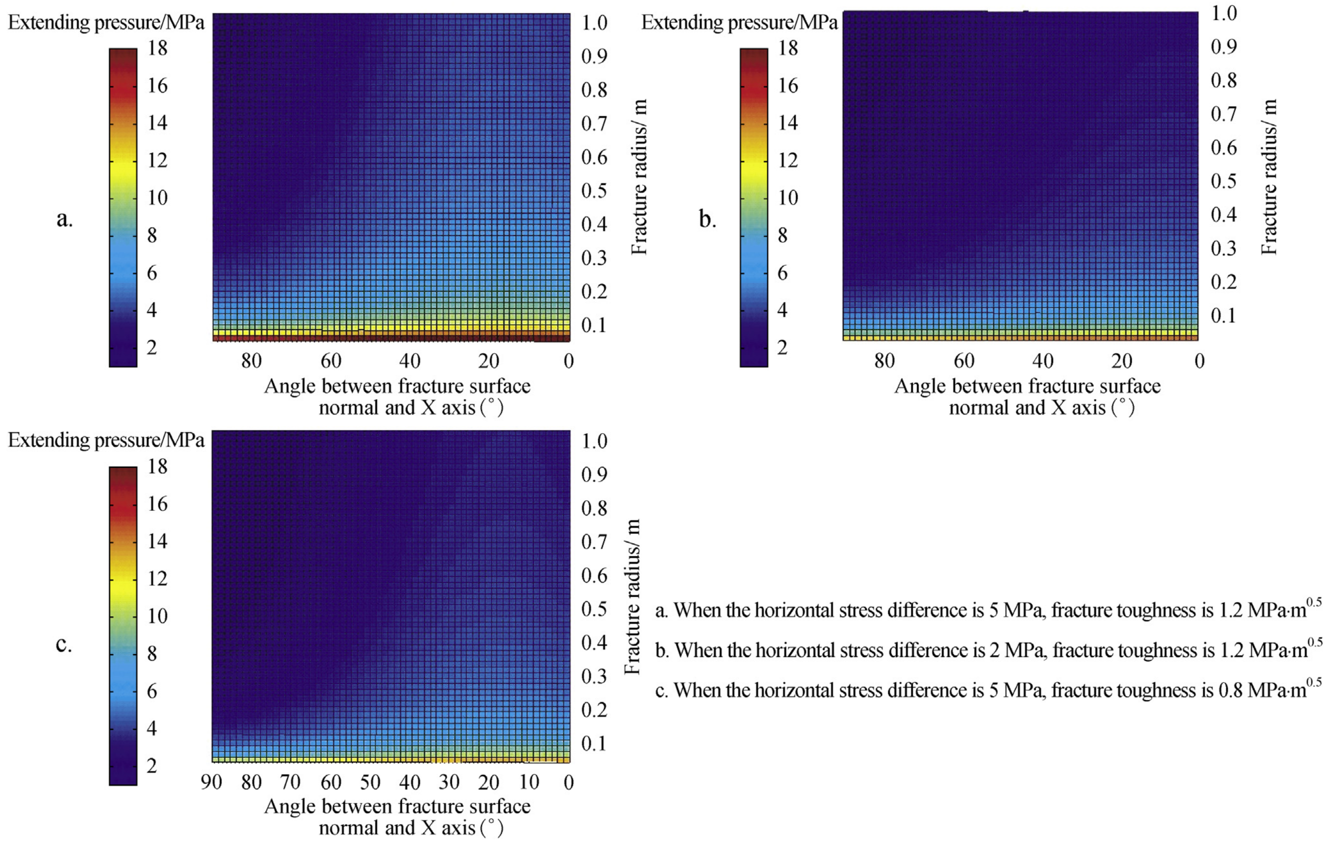

Figure 4. Variation of fracture extending pressure.

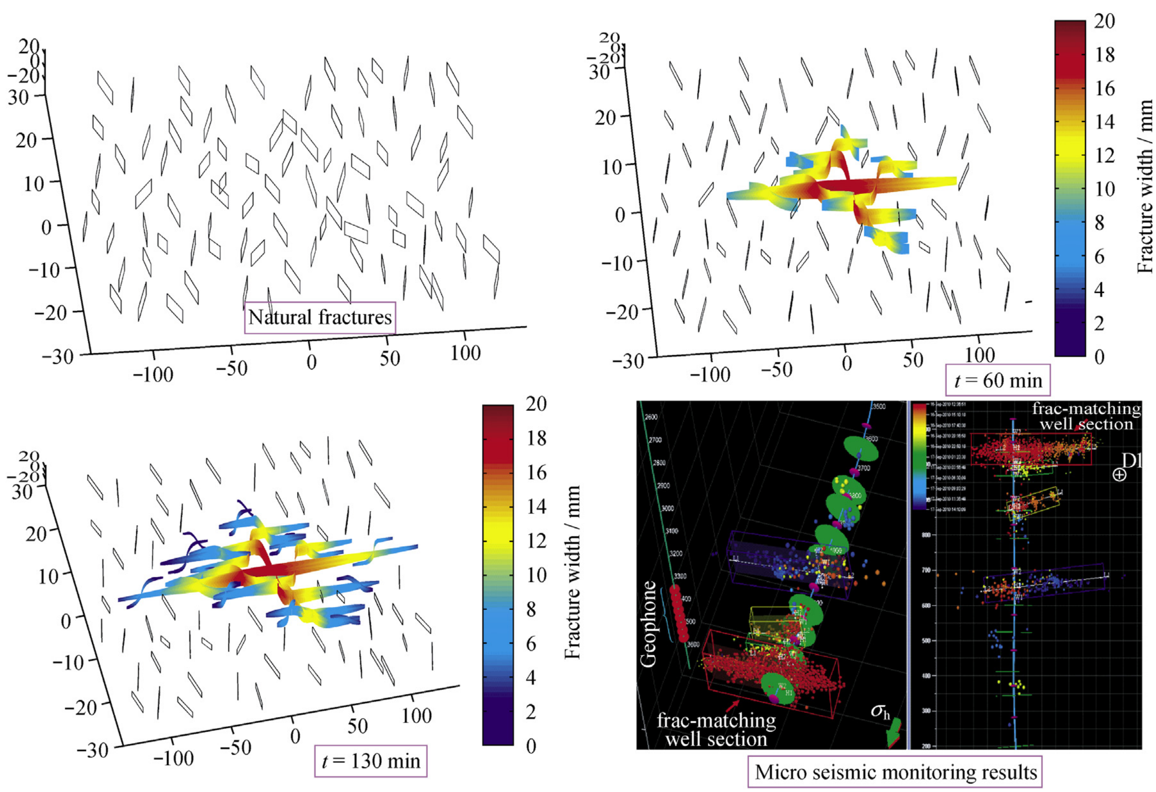

Figure 5. Simulation on fracture propagation variation affected by natural fractures.

fracture surface will become quickly perpendicular to the minimum principle stress direction in a small range, resulting in quick pressure drop within the fracture, making initiation and propagation of fracture more difficult. In order to improve fracturing effect, it is recommded to select blocks or zones with developed natural fractures or small horizontal stress difference suitable for volume fracturing, and the intra-fracture net pressure can be increased by optimizing operation parameters and materials.

4.2. Fracture extending pressure

According to the fracture propagation criterion, the effect of horizontal stress difference, fracture radius, intersection angle and rock fracture toughness on the pressure needed for fracture propagation were analyzed quantitatively (Fig. 4).

The simulation results show: the key factors affecting the natural fracture propagation include its length and azimuth, while the variation in fracture toughness has little impact on fracture propagation pressure. Therefore, for the fracturing of shale gas long horizontal well section, perforation should be done in zones with dense natural fractures; the well deployment doesn't need to follow the minimum principle stress direction completely, and the trend of natural fractures on the whole fracture network should be considered fully.

4.3. Complex fracture network

Based on “large injection, large displacement, low viscosity and low filtration” features of shale gas fracturing, and the geologic and operation parameters of a marine shale gas well, the forming process of complex fracture network and geometry of each branch fracture were simulated, and the detailed parameters are: maximum horizontal principle stress 37.5 MPa, minimum horizontal principle stress 34.5 MPa, Young's modulus 23.37 GPa, Poisson ratio 0.25, rock tensile strength 3 MPa, fracturing fluid viscosity 30 mPa s (construction/simulation key controllable variable), fracturing fluid density 1.02 g/cm^3, filter coefficient 0.0009 m min$^{-0.5}$ (operation/simulation key controllable variables), fracture toughness 1.21 MPa m$^{0.5}$, average operation displacement 8.5 m^3(operation/simulation key controllable variables), bottom hole pressure 55 MPa (operation/simulation key controllable variables), and time step 2 min. The natural fractures random in position, and manually set, are in an intersection angle of $\pm 0° - 40°$ with the direction of minimum horizontal principle stress and dip angle of 90°.

Compared the whole fracture network with the micro-seismic interpretation result, their geometric sizes are in good agreement, and the variation in data point density can be explained by the different form of fracture complexity (Fig. 5). The comparison has verified the calculation result of the model, and can be preliminarily used in fracturing design optimization.

5. Conclusions

1) By introducing the initiation and propagation criterion, establishing complex fracture network model and improving the numerical calculation, the simulation of fracturing networks of shale gas reservoir with large amounts of natural fractures has been realized, and the micro-seismic testing results were employed to verify the accuracy of the model.
2) The model can calculate the geometry of asymmetric and irregular complex fracture network in shale gas volume fracturing, and the results can be used for optimization of shale gas fracturing design.
3) When selecting shale gas “sweet points”, attention should be given to the identification and description of physical property parameters, such as natural fracture length, azimuth, dip angle and density, which are not only key input parameters to ensure the reliability of the simulation result, but also the material basis impacting the geometry and complexity of fracture network.
4) The utmost difficulty in complex fracture network simulation is considering both the analysis of fracture network shape and calculation of the branch fracture size, and we are seeking new ways in theoretical model and numerical solution.

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