Analysis of Diagnostic Fracture Injection Tests for Shale Gas Wells

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Abstract. Formation pressure estimation of shale gas wells is one of the key factors affecting production prediction of gas wells, and diagnostic fracture injection test analysis is an important means to accurately obtain formation pressure parameters. In this paper, through the establishment of shale gas well diagnostic fracture injection test model, taking ChangNing shale gas field as an example, the actual test data of pre-production gas wells are fitted. Then analysis the change law of pressure transient curves and the model fitting results with conventional analysis method comparing with the results - G function diagnosis curve method to explain, optimizing fracture closure point selection mode, this paper proposes a new method to determine fracture closure point: when G derivative curve begins to deviate from the initial linear trend, correct selection of closed point, to obtain accurate formation pressure coefficient, formation pore pressure of reservoir parameters such as reservoir. At the same time, the improved method is used to evaluate the reservoir parameters of the actual gas wells in ChangNing, providing theoretical guidance for the subsequent fracturing construction and production.

Keywords: shale gas; well test; diagnostic fracture injection test; well test interpretation; fracture closure.

1. Introduction
Since routine well test operations tend to require a long shut-in time to accurately obtain formation pressure, in order to reduce the shut-in time, we can choose to conduct diagnostic fracture injection tests before the formal fracturing operation. The diagnostic fracture injection tests (DFIT) [1-3] aim at producing diagnostic fracture around the wellbore by injecting a small amount of fluid, obtain pressure decline data after shut-in, and use interpretation and analysis methods estimate reservoir permeability, original formation pressure and other parameters. The fitting of actual test data shows that the traditional diagnostic fracture interpretation and analysis method—G-function diagnostic curve method has a certain error when judging the fracture closure point [4-5].

In order to accurately find the fracture closure point on the G function curve, in this paper, the accurate closure time of the fracture will be will explored from of fracture shape and rock properties,
etc., the theoretical model of diagnostic fracture injection test for shale gas reservoirs based on fracture network is established, the pressure history is analyzed before and after the fracture closes, the selection method of fracture closure point is improved, the more accurate curve analysis method is established, and basic theoretical support is provided for rapid breakthrough of exploration and development in shale gas.

2. Establishment of Fracture Network Seepage Model in Shale Gas

2.1. Assumption

This simulation is to establish the corresponding shale gas horizontal well model based on the actual diagnostic fracture injection test operation data of Changning shale gas field, the wellbore storage coefficient C is 0.0184 m³/MPa, the initial reservoir pressure is 33.7 MPa, the horizontal wellhead is connected to the outside world, the boundary pressure is 1.01 Mpa, the shear modulus G is a fixed value 15000 Mpa, and the Poisson's ratio υ is a fixed value 0.25.

2.2. Establishment of fracture network seepage model in shale gas

(1) Fracturing fluid flow and fracture opening

According to actual operating conditions, the fracturing fluid is directly simulated as a single-phase liquid water flow of constant composition here. In the fracture, the unsteady-state mass conservation equation that meets Darcy's law is solved (formula 1):

\[
\frac{\partial(E_0)}{\partial t} = -\nabla \cdot (q_{flux} e) - q_{leakoff} + s
\]

\[
q_{flux} = -\rho k \mu \nabla p
\]

In the formula: \(E\) is the total opening of the fracture, which represents the fluid volume of unit fracture surface area, m; \(\rho\) represents the density of fracturing fluid, kg/m³; \(q_{flux}\) represents the mass flux when fracturing fluid flowing through the fracture, kg/(m²•h); \(e\) is the hydraulic opening of the fracture, m; \(q_{leakoff}\) represents the mass flow where the fracturing fluid leaks into the surrounding substrate in unit fracture surface area; \(s\) represents the source term of a well.

The expression (2) of fracture permeability is:

\[
k = \frac{e^2}{12}
\]

The flow conductivity of fracture \(T\) is the product of permeability and hydraulic opening; here the cubic law expression (3) of Witherspoon et al. [6] is used:

\[
T = k e = \frac{e^3}{12}
\]

So far, the nonlinear relationship among pressure, stress, deformation and total fracture opening and hydraulic opening has been established. At this time, "closed" fracture is defined as fracture where the fluid pressure is less than the normal stress and the walls contact. The surface roughness of the fracture makes the closed fracture still maintain the hydraulic opening and total opening. The expression for calculating the unit opening of closed fracture (4):

\[
E = \frac{E_0}{1+9\sigma'_n/\sigma_{n, \text{ref}}}
\]

In the formula: \(E_0\) represents the total fracture opening when the effective stress is equal to 0, m; \(\sigma_{n, \text{ref}}\) represents the effective normal stress required when the total opening is reduced by 90%, MPa; \(\sigma'_n\) is the effective normal stress, which is equal to the difference between the normal stress \(\sigma_n\) and the fluid pressure.

When the fracture wall contacts and closes; the fracture opening decreases, but there is still residual opening, at this time, the resistance when the fracture further closes and deforms is increased and
because the flexibility to be greatly reduced. According to the study of Economides and Nolte (2000) [7], before the fracture is closed, the fracture width and net pressure present a linear relationship with the fracture flexibility. As shown in formula (5):

$$\bar{w} = c_ff P_{net}$$

(5)

In the formula: $c_f$ represents the fracture flexibility, m/MPa; $\bar{w}$ represents the average fracture width, m; $P_{net}$ represents the net pressure, MPa.

Thus it can be seen that when the fracture has not closed and expanded, the fracture flexibility is a certain value, at this time, the fracture flexibility is a function related to the shear modulus, Poisson's ratio and the fracture shape.

(2) Deformation boundary conditions

For an open unit, the stress boundary condition is the effective normal stress, which must be 0, and it is expressed by formula (6):

$$\sigma_n^r - P + \Delta\sigma_n = 0$$

(6)

In the formula: $\sigma_n^r$ represents the fracture normal stress caused by the remote load; $\Delta\sigma_n$ represents the normal stress change caused by the cumulative deformation induced stress field of all fracture units in the system.

(3) Generation and expansion of fracture

In this paper, the fracture expansion problem is handled through linear elastic fracture mechanics. In the fracture unit, the equation (7) proposed by Olson (2007) [8] can be used to calculate the stress intensity factor:

$$K_f = 0.806 \left( \frac{2G\sqrt{\alpha}}{4(1-\nu_p)\sqrt{a}} \right) E_{open}$$

(7)

$G$ is the shear modulus, $\nu_p$ is Poisson's ratio, and $a$ is defined as the half-length of the fracture unit. When the stress intensity factor is greater than the fracture strength $K_{IC}$, the fracture will be expanded from this unit, the expansion of the fracture is realized by activating the hydraulic fracture unit directly adjacent to the unit whose stress intensity factor is greater than the fracture strength.

3. Interpretation Methods of Diagnostic Fracture Injection Test Results in Shale Gas Wells

The established shale gas fracture network seepage model is used to simulate and match the DFIT data of a shale gas well in the Changning shale gas field, the relevant parameters are shown in Table 1, and the simulation results as shown in Fig. 1.

| Rock parameters of actual shale gas field S1 |
|---------------------------------------------|
| fracture strength $K_{IC}$ (MPa·m<sup>1/2</sup>) | 4 |
| Permeability $K$ (nD) | 60 |
| effective normal stress when the total opening is reduced by 90% $\sigma_{n,e_{ref}}$ (MPa) | 17 |
| minimum horizontal principal stress $\sigma_h$ (MPa) | 54.3 |

![Fig. 1 pressure change curve diagram of simulated and actual condition](image-url)
Fig. 2 diagnostic fracture injection test analysis diagram of G function curve

The dotted vertical line represents application of conventional methods-closure pressure selected by G function method in Fig. 2, at this time, the fracture is closed, and the minimum principal stress value is equal to the closure pressure, while the solid vertical line represents the actual correct minimum principal stress value. According to the simulation results, the actual minimum principal stress is 54.3 MPa, while the closure pressure estimated by the conventional method is 50.4 MPa. Obviously, there is a certain error between the analysis result of the conventional method and the actual situation.

Before the deviation occurs, G•dP/dG curve on the G function curve diagram is approximately regarded as a straight line starting from the origin. Therefore, when the fracture is in the open state, the slope of G•dP/dG curve is almost constant. It means that the derivative of pressure to G time is constant before the fracture is closed. Its derivative formula is:

$$\frac{dP}{dG} = \frac{dP}{dV_f} \cdot \frac{dV_f}{dG}$$

$V_f$ is the fracture volume which ignores the wellbore storage space; according to the definition of fracture flexibility, the term $\frac{dP}{dV_f}$ is directly proportional to the fracture stiffness and inversely proportional to the fracture flexibility; the term $\frac{dV_f}{dG}$ represents the change of fracture volume with G time, it is numerically equivalent to the change of leakage rate with G time.

When the fracture is in the open state, the fracture stiffness and leakage rate can be regarded as constant relative to G time [9]. Therefore, as long as the fracture is in the open state and the G•dP/dG curve is the straight line, the derivative term $\frac{dP}{dG}$ of the pressure to the G function is constant. Once the fracture is physically closed, since the additional fracture stiffness caused by the contact of the fracture wall will greatly increase the fracture stiffness, and the value of the $\frac{dP}{dG}$ term will increase significantly, it is reflected in the G•dP/dG curve, namely the curve rises sharply. Therefore, the following conclusion can be drawn: when the G•dP/dG curve starts to obviously deviate from the initial straight line trend, the closure point can be selected.

4. Field Application

The method is applied in an actual operation Well M of Changning shale gas. The diagnostic fracture aim shale formation porosity is 3%, the effective thickness h of the formation is 3.0m, the gas viscosity $\mu$ is 0.0177cP, the well depth is 4300m, the vertical depth is 2592.65m; the maximum pump pressure is 49.8MPa, generally 45-49.8MPa; the maximum volume is 0.5m$^3$/min, generally 0.5m$^3$/min. The pump stopping pressure is 44MPa; the fluid volume injected into the formation is 3.16m$^3$. 
The pressure decline data after shut-in are used as derivative diagnostic curve diagram of G function and Bourdet double logarithmic derivative, so determine the closure time and pressure of the fracture, the relevant diagnostic curves are shown in Fig. 3 and Fig. 4:

![Fig. 3 G function diagnostic curve of Well M](image1)

**Fig. 3 G function diagnostic curve of Well M**

The diagnostic curve of G time function and Bourdet double logarithmic derivative both clearly show the closure point of the fracture. Corresponding to Fig. 3, the point where the G•dP/dG curve starts to obviously deviate from the initial straight line is selected, it shows obvious fracture closure characteristics, namely the closure time t_c is 9.8 minutes, and the closure pressure p_c is 51.928MPa. After the fracture is closed, the flow state of the formation fluid should be judged, as shown in Fig. 4, the radial flow occurs in formation fluid flow. Here the ACA analysis method is used to interpret the pressure history after the fracture is closed, so obtain the relevant formation parameters.

According to the ACA method, during the radial flow period, the radial flow time function F_R is defined as:

$$F_R(t, t_c) = \frac{1}{4}\ln(1 + \frac{1.6t_c}{t-t_c})$$

(8)

`t_c` is the time of fracture closure point from the beginning of fluid injection.

During the linear flow period, the linear flow time function F_L is defined:

$$F_L(t, t_c) = \frac{2}{\pi} sin^{-1}\left(\frac{t_c}{t}\right)$$

(9)

After calculating the radial flow time function F_R by formula (8), first, the diagnostic curve of dΔp/dln(F_L²) = F_L² is made to further determine the existence of radial flow, as shown in the Fig. 5. After calculating the radial flow time function F_R by formula (8), the radial flow special curve of pw-F_R...
is made, as shown in Fig. 6. The data section of radial flow is taken for linear regression, the original formation pressure $P_i$ is $34.619$MPa.

At this time, the slope $m_R$ of the straight line in the late stage of Fig. 6 is 196.8. Therefore, the formation permeability can be obtained by the formula (10):

$$K_h = 9000 \times \frac{Q_t}{m_R \theta_c}$$  \hspace{1cm} (10)

$Q_t$ is the total injection volume, $m^3$. The acquired parameters are substituted into formula (10):

$$K = 9000 \times \frac{3.16}{196.8 \times 9.8} \times \frac{0.0177}{3} = 0.0870$$ (mD)

The above results are organized, the formation parameters acquired of Well M after diagnostic fracture injection test are as follows: Table 2:

| sequence number | project                                   | analytical method   |
|-----------------|-------------------------------------------|---------------------|
|                 | G function                                | improved G function |
| 1               | closure time (min)                         | 33.3                | 9.8            | *              |
| 2               | closure pressure in bottom of well (MPa)   | 64.076              | 51.928         | *              |
| 3               | analyzed reservoir pore pressure (MPa)     | *                   | *              | 34.619         |
| 4               | reservoir pore pressure coefficient        | *                   | *              | 1.37           |
| 5               | reservoir permeability (mD)                | *                   | *              | 0.087          |

Thus it can be seen that the pressure coefficient of this shale gas well M is greater than 1.3, the original formation pressure is relatively high, the formation energy is enough, and the reservoir permeability is greater than 0.01md, which has high development significance and value, other
parameters obtained from the diagnostic fracture injection test will also provide relevant basis for subsequent production capacity estimation and production evaluation.

5. Conclusion
In this paper, the established shale gas seepage model based on fracture network is used to study the interpretation method of diagnostic fracture injection test in shale gas wells. The following conclusions are drawn during the whole research process:

(1) Considering the characteristics of shale gas reservoirs, the shale gas seepage model based on the fracture network is established in this paper, which better simulates the change law of pressure of diagnostic fracture injection test in shale gas well.

(2) The closure pressure between the simulated case and the actual gas field M is obtained by numerical simulation analysis, the results show that the traditional methods underestimate the closure pressure. A new method for judging the closure pressure is proposed based on the fracture closure pattern: namely when the G•dP/dG curve begins to deviate upwards sharply, the closure point can be selected correctly.

(3) The revised interpretation method is used to analyze the actual operating gas well M in the Changning shale gas reservoir, the original formation pressure, formation permeability and other parameters of the target well are accurately obtained, this proves that the original formation pressure of this block is relatively high, the formation energy is sufficient, and it has high development significance and value.

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