The Study on Shale Wellbore Stability with Coupled Mechanical–Chemical Processes in Wushi Oilfield

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Abstract. Wellbore instability (WI) is a challenge in the drilling process, which often causes complex accidents. Measures should be taken to prevent WI in low-strength formation. It is crucial in wellbore engineering to ensure wellbore stability. In fact, WI was solved with large sources of lost time and trouble cost. However, at present, the mechanism of the instability of the shale borehole wall is unclear. To study the shale WI in Wushi Oilfield, the rock mechanics parameters of rocks were tested according to the actual situation of the oilfield. Experimental results were helpful to determine parameters for numerical simulation. A mechanical–chemical coupling model of shale wellbore was established. The numerical simulation results indicated that there was stress concentration around the wellbore wall. The effects of rock elastic modulus, cohesive force, deviation angle, azimuth, drilling fluid density, and hydration time on the stability of the shale borehole were analyzed. The numerical simulation results could provide a reference for on-site drilling optimization.

1. Introduction

Wellbore instability (WI) is a technical problem in the development of oil and gas resources. Several complex accidents are caused by WI such as wellbore collapse, expansion, or reduction. To handle these issues, a lot of time and money is required. The Wushi Oilfield mainly comprised fault-block lithologic reservoirs with complicated geological characteristics. In the oilfield, the wellbore block delayed the drilling process. In addition, WI led to a prolonged construction period and frequent accidents. Therefore, it is necessary to study the WI in Wushi Oilfield.

Numerous researchers have studied WI. In terms of rock mechanics, stress distribution around a borehole was first studied by Westergard (1940). The linear elastic stress state solution for inclined formation, nonstrait wellbore, and uneven in situ stress in three directions was proposed by Fairhur (1964). The stress solution of wellbore under the 3D stress state was calculated by Hubbert and Willis (1972). Considering the interaction of external normal stress (external or confining pressure) and internal stress (internal or pore pressure), the concept of the effective stress principle was first proposed based on the assumption of loose soil by Terzaghi (1959). Considering the drilling fluid flow and temperature changes, a novel calculation model of stress around wells was established by Ong (1994). The mechanical characteristics and borehole stability of hard and brittle shale in Sichuan were studied by Liu et al. (2019).

Regarding the effect of chemistry on wellbore stability (WS), the shale hydration swelling pressure experiment was conducted, and the hydration stress was expressed as a function of water activity in
the shale (Chenevert, 1969). The basic reasons for the influence of shale hydration on WS were analyzed theoretically. After long-term accumulation, a full set of geological data, field data, and core or cutting experiments for WI were presented by Darly (1969). In terms of research on the coupling of mechanics and chemistry, a mechanical–chemical coupling model for WS was developed by Yew and Chenevert (1990). Mody and Hale (1993) established a model considering the influence of chemical potential on stress based on the molecular free energy theory of thermodynamics. Wong and Heidug (1994) introduced chemical action into Bolt’s porous media theory and calculated the stress–strain distribution around wells. Jin and Chen (2004) proposed a method for determining the critical collapse time of water-sensitive shale formation. Recently, Pouett et al. (2012) analyzed the numerical simulation of thermal–hydraulic–mechanics–chemistry coupling via finite element software. Meng et al. (2019) analyzed the WS formation with fractures. Moreover, Rafieepour et al. (2020) designed mud density using a cost-effective chemo–thermo–poroelastic WS model.

At present, the shale WI mechanism is still unclear and cannot meet the needs of engineering problems. In this study, a model considering mechanical and chemical effects was established, and the factors affecting the instability of the shale borehole wall were analyzed. The stability of the borehole wall during drilling is crucial to drilling security.

2. Experimental test

Rock mechanical parameters are the basic data for solving WI problems. It is helpful for engineers to understand the actual formation with experimental tests. The rock used in our experiment was obtained from the Liushagang Formation in Wushi Oilfield. The elastic modulus, Poisson's ratio, internal friction angle, cohesion, and other mechanical parameters were evaluated, which are crucial to analyze the mechanical characteristics of WI in Wushi Oilfield.

To reduce the impact of the differences between rock samples on the test results as well as the workload, a monolithic method was employed for mechanical testing. The monolithic method entails measuring the strength of the rock when the volume strain increment was zero (the expansion point) with the same sample under different confining pressure conditions. This method could shorten the test period and improve test efficiency. Since data points were obtained from the same core, the discreteness of experimental data could be effectively reduced, which was convenient for experimental analysis.

The experimental device was a comprehensive rock stress test system produced by the American GCTS company. The experimental core obtained from Wushi Oilfield was processed into a standard core column of 25-mm diameter and 50-mm height. Experiments on rock mechanical parameters under different confining pressures were performed on the core, and the stress–strain curve was obtained.

The experimental scheme of rock mechanical parameters is shown in Table 1. According to the relationship between rock stress and strain, rock mechanical parameters, such as elastic modulus, Poisson's ratio, and compressive strength, could be calculated. The Mohr circle was employed to solve two key parameters: the rock’s internal friction angle and cohesion. The stress–strain curve and Mohr–Coulomb failure envelope are shown in Figure 1. The experimental specimens after the deformation are shown in Figure 2. The calculation results of rock mechanics parameters are shown in Table 2. The shale in Wushi Oilfield has low cohesive force and compressive strength. Therefore, the shale wellbore tends to be unstable.
Table 1. Experimental scheme of rock mechanics parameters.

| Sample number | Top depth (m) | Bottom depth (m) | Confining pressure 1 (MPa) | Confining pressure 2 (MPa) | Confining pressure 3 (MPa) | Confining pressure 4 (MPa) | Confining pressure 5 (MPa) |
|---------------|---------------|------------------|----------------------------|---------------------------|---------------------------|---------------------------|---------------------------|
| #1            | 2,416.31      | 2,418.32         | 0                          | 5                         | 15                        | 30                        | \                         |
| #2            | 2,418.32      | 2,420.27         | 0                          | 5                         | 15                        | 30                        | \                         |
| #3            | 2,420.27      | 2,422.14         | 0                          | 5                         | 15                        | 25                        | 35                        |
| #4            | 2,777.50      | 2,779.37         | 0                          | 5                         | 10                        | 20                        | 40                        |
| #5            | 2,779.37      | 2,781.20         | 0                          | 5                         | 10                        | 20                        | 40                        |
| #6            | 2,779.37      | 2,781.20         | 0                          | 5                         | 10                        | 20                        | 40                        |

Figure 1. The stress–strain curve and Mohr–Coulomb failure envelope diagram of rock sample #1

Figure 2. Comparison chart of rock sample #1 before and after experiment

Table 2. Results of rock mechanics parameters

| Sample number | Elasticity modulus (GPa) | Poisson's ratio | Compressive strength (MPa) | Cohesion (MPa) | Internal friction angle (°) |
|---------------|--------------------------|-----------------|----------------------------|----------------|---------------------------|
| #1            | 9.13                     | 0.27            | 37.2                       | 11.9           | 23.43                     |
| #2            | 5.61                     | 0.37            | 27.9                       | 10.7           | 29.54                     |
| #3            | 7.96                     | 0.29            | 25                         | 5.6            | 30.34                     |
| #4            | 3.66                     | 0.26            | 10                         | 4.1            | 36.87                     |
| #5            | 7.89                     | 0.26            | 10                         | 8.9            | 29.89                     |
| #6            | 3.65                     | 0.28            | 6                          | 7.2            | 22.61                     |
3. Mechanical–chemical model

When a drilling fluid is filtered into a formation, the rock mechanical parameters and stress state of the surrounding rocks will change because the clay minerals in the shale would undergo hydration. In most cases, fluid seepage is divided into two. One is that the fluid permeates under the action of a pressure difference, and the other is that the fluid can relatively permeate through a semipermeable membrane under the action of a chemical potential difference. For the instability of shale, it is necessary to analyze the mechanical–chemical interactions.

The solute concentration profile can be calculated as follows (Lomba et al., 2000):

$$\frac{\partial C_s}{\partial t} = D \left( \frac{\partial^2 C_s}{\partial x^2} + \frac{\partial^2 C_s}{\partial y^2} \right)$$

(1)

where $D$ is the solute diffusion coefficient (m/s$^2$), and $C_s$ is the solution concentration.

The pore pressure profile is coupled with the flux of both water and solute. The coupled equation for pore pressure can be expressed as follows (Yu et al., 2001):

$$\frac{\partial P}{\partial t} + \frac{K_x}{c_r} \left( \frac{\partial^2 P}{\partial x^2} + \frac{\partial^2 P}{\partial y^2} \right) - \frac{nRTK_x}{c_r} \left( \frac{\partial^2 C_s}{\partial x^2} + \frac{\partial^2 C_s}{\partial y^2} \right) = 0$$

(2)

where $K_x$ is the hydraulic diffusion coefficient, $K_2$ is the membrane efficiency coefficient, $T$ is the thermodynamic temperature, $R$ is the gas constant, and $c_r$ is the formation water compressibility coefficient.

Considering the difference in mechanical parameters perpendicular and parallel to the formation, the formation rock is a transversely isotropic material, and the constitutive equation is as follows (Abouseleiman et al., 2005):

$$\begin{bmatrix}
\sigma_{rr} \\
\sigma_{\theta \theta} \\
\sigma_{zz} \\
\tau_{r \theta} \\
\tau_{r z} \\
\tau_{\theta z}
\end{bmatrix} = \begin{bmatrix}
M_{11} & M_{12} & M_{13} & 0 & 0 & 0 \\
M_{12} & M_{11} & M_{13} & 0 & 0 & 0 \\
M_{13} & M_{13} & M_{33} & 0 & 0 & 0 \\
0 & 0 & 0 & G & 0 & 0 \\
0 & 0 & 0 & 0 & G' & 0 \\
0 & 0 & 0 & 0 & 0 & G''
\end{bmatrix} \begin{bmatrix}
\varepsilon_{rr} \\
\varepsilon_{\theta \theta} \\
\varepsilon_{zz} \\
\gamma_{r \theta} \\
\gamma_{r z} \\
\gamma_{\theta z}
\end{bmatrix} + \begin{bmatrix}
\alpha \\
\alpha' \\
p
\end{bmatrix}$$

(3)

\[ M_{11} = \frac{E \left( E' - E'' \right)}{(1 + \nu) \left( E' - E'' - 2E'' \right)} \]

\[ M_{12} = \frac{E \left( E' + E'' \right)}{(1 + \nu) \left( E' - E'' - 2E'' \right)} \]

\[ M_{13} = \frac{EE'}{\left( E' - E'' - 2E'' \right)} \]

\[ M_{33} = \frac{E'}{(E' - E'' - 2E'')} \]

(4)

where $K_s$ is the bulk modulus of the formation rock.

The stress balance equation is as follows:

$$\alpha = 1 - \frac{M_{11} + M_{13} + M_{33}}{3K_s} \quad \alpha' = 1 - \frac{2M_{13} + M_{33}}{3K_s}$$

(6)

Directional wells are mostly located in this oilfield according to field data. Therefore, the deviation angle and azimuth should be considered in the W1 model. Different coordinate systems were established. The model could be used to calculate the well diameter expansion rate under the conditions of different deviation angles and azimuth with the conversion of coordinate systems (Liu et al., 2015).

Collapse failure occurs when rock stress exceeds rock strength. The shale has a weak surface of bedding, which significantly influences rock fragmentation. Therefore, a rock failure criterion considering the weak surface was established. The yield criterion of the rock body is as follows:
\[ \sigma_{1}^{\text{max}} = \sigma_{3}^{\text{min}} + 2(C_r + \sigma_{3}^{\text{min}} u_r) \left[ \left( 1 + u_r^2 \right)^{1/2} + u_r \right] \]  

(7)

The yield criterion for the weak side is as follows (Liu et al., 2015):

\[ \left[ \left( r_{bp}^{r} \right)^2 + \left( r_{bp}^{b} \right)^2 \right]^{1/2} = C_{bp} + u_{bp} \sigma_{bp} \]  

(8)

where \( C_r \) and \( u_{r} \), respectively, represent the cohesive force and internal friction coefficient of the rock body; \( C_{bp} \) and \( u_{bp} \), respectively, represent the cohesive force and internal friction coefficient of the weak surface. Through the coordinate system conversion, the rock stress and yield state under the conditions of different bedding plane occurrences, deviation angles, and well azimuth angles could be calculated.

4. Analysis of WI factors

4.1. Influence of drilling fluid density on WI

The fluid column pressure generated by the drilling fluid in the wellbore supports the wellbore. The drilling fluid density plays a paramount role to ensure WS in engineering projects.

Figure 3. Borehole collapse diagram under different drilling fluid density conditions:

(a–f) \( \rho_m = 1.24, 1.28, 1.32, 1.36, 1.40, \) and 1.44 cm\(^3\), respectively.

For different drilling fluid densities, the mechanical–chemical coupling WS model was used to calculate the degree of borehole collapse under different drilling fluid densities. As shown in Figure 3, when the density of drilling fluid increased, the degree of borehole wall collapse first decreased and then increased. The caliper expansion rate was calculated, and the curve of the caliper expansion rate with the density of drilling fluid was obtained. From Figure 4, with an increase in the drilling fluid density, the well diameter expansion rate first decreased and then increased. The well diameter expansion rate was the smallest when the drilling fluid density was in the range of 1.35–1.39 g/cm\(^3\).
4.2. Influence of rock mechanics parameters on WI

Rock mechanics parameters significantly influence WI. The mechanical–chemical coupling WS model was used to calculate the degree of borehole collapse under different rock mechanics parameters. The curves of well diameter expansion rate with formation elastic modulus and cohesive force are plotted in Figures 5 and 6. The rate of borehole expansion increased with the decrease in cohesion and elastic modulus. The elastic modulus and cohesion of the formation were both high, indicating that it was well cemented. In this case, the wellbore was relatively stable.

4.3. Influence of borehole trajectory on WI

Numerous experimental and theoretical studies have found that the stability of the borehole wall is not only closely related to rock mechanics parameters but also depends on wellbore trajectory parameters. The mechanical–chemical coupling model could be used to analyze the WI under different deviation and azimuth angles. From Figure 7, the deviation angle significantly influences the caliper expansion rate. When the deviation angle was around 18°, the caliper expansion rate was low. According to oil field data, the dip angle of the Liushagang Formation in Wushi Oilfield was 18°. In other words, the wellbore was most stable when it was perpendicular to the weak surface. When the well deviation was greater than the formation dip, the well diameter expansion rate increased with the deviation angle.
The change curve of the caliper expansion rate with the azimuth is depicted in Figure 8. When the azimuth was the same as the horizontal minimum in situ stress direction, the caliper expansion rate was the smallest. The horizontal minimum in situ stress direction of the Liushagang Formation was about 45°. Therefore, it is advisable to drill in the northeast or southwest direction. It is significant to avoid the borehole azimuth being the same as the horizontal maximum principal stress direction. This can prevent the formation from collapsing and ensure WS during drilling.

4.4. Influence of hydration time on WI
In the process of drilling shale formation, drilling fluid filtrate will contact shale formation, and the shale suffers from hydration. This leads to corresponding changes in the pore pressure of the shale formation, the effective stress state of the surrounding rocks, and the strength parameters. This makes an initially stable well wall delayed collapse after being soaked in a drilling fluid. Figures 4–8 show the change in the well diameter expansion rate under the conditions of 1, 5, and 10 days of drilling fluid action time. These graphs show that, as the drilling fluid action time increased, the well diameter expansion rate increased, which was because the drilling fluid would leak out during the wellbore circulation as the drilling time increased. These factors reduce the strength of the rock and change the distribution of in situ stress, which increases the risk of WI.

5. Conclusions
To solve the problem of shale WI in Wushi Oilfield, a rock mechanics parameter experiment was performed, and a mechanical–chemical coupling model was established. The main results are summarized as follows.

- A monolithic method was employed for rock mechanics parameter testing. The borehole expansion rate increased with the decrease in cohesive force and elastic modulus. The shale in Wushi Oilfield had a low cohesive force and a low compressive strength of the formation rock. Therefore, the shale wellbore in Wushi Oilfield tended to be unstable.
- Wellbore trajectory significantly influences WS. The borehole expansion rate is the smallest when the borehole was perpendicular to the weak surface. The wellbore was most stable when the azimuth was the same as the direction of the horizontal minimum in situ stress. For the most stable condition, it is recommended to drill in the northeast or southwest direction with a deviation angle of around 18° in the Liushagang Formation.
- The drilling fluid density plays a paramount role in engineering to ensure WS. With the increase in drilling fluid density, the well diameter expansion rate first decreased and then increased. When the drilling fluid density was in the range of 1.35–1.39 g/cm³, the wellbore...
was relatively stable in the Liushagang Formation. The borehole became unstable as the hydration time increased. These results have reference significance for on-site drilling.

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